Fitch
Ratings Update

June 7, 2005

Confidential

Recent Achievements

- Improved balance sheet
  - Reduced total debt ratio from 63.5% in 2003 to 57.9% in 2004 on a credit adjusted basis

- Successfully reduced trading risks
  - Total trading volume down by 71% in 2004 vs. 2002
  - Transitional trading book rolling off
    - $35 mm net fair value, and $32 mm will roll off by year-end 2005
  - Average VaR down by 64%
    - From $10.2 mm in 2002 to $4 mm in 2004

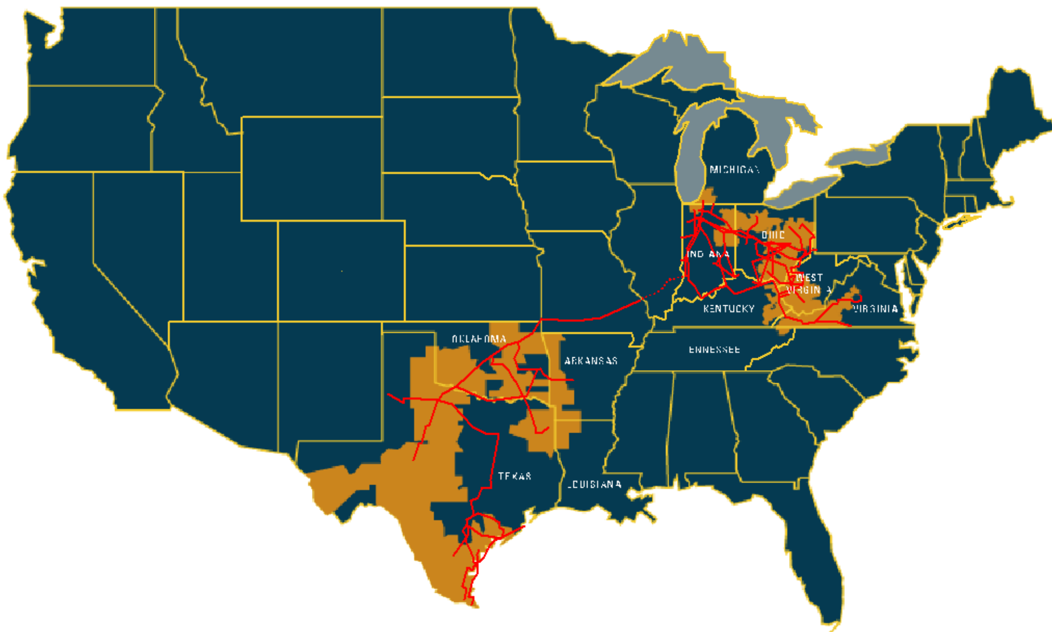
- Asset sale execution near completion
  - Closed $2.8 billion in asset sales through May 2005

- Maintained strong liquidity profile of $3.5 billion
  - Well above minimum thresholds for liquidity

- Operating Company Reorganization
  - Distribution and Customer Service operations reorganized into seven regional utility divisions in June 2004

AEP RISK PROFILE HAS IMPROVED DRAMATICALLY

Strength & Scale in Assets & Operations



Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Page 3 of 9556

New Regional Organization

- Michael Morris, CEO
  - Carl English, President AEP Utilities
    - Holly Koeppel, EVP AEP Utilities East
      - Kevin Walker, President Ohio
      - Dana Waldo, President Appalachian Power
      - Marsha Ryan, President Indiana-Michigan Power
      - Tim Mosher, President Kentucky Power
    - Tom Hagan, EVP AEP Utilities West
      - Charles Patton, President Texas
      - Nick Akins, President SWEPCO
      - Stuart Solomon, President Public Service of Oklahoma

SENIOR MANAGEMENT CLOSER TO CUSTOMERS AND REGULATORS

Kentucky Power

- Kentucky Power's business profile rating of '5' does not reflect current operating environment
  - Environmental surcharge legislation in place which allows recovery of retail portion of environmental expenditures
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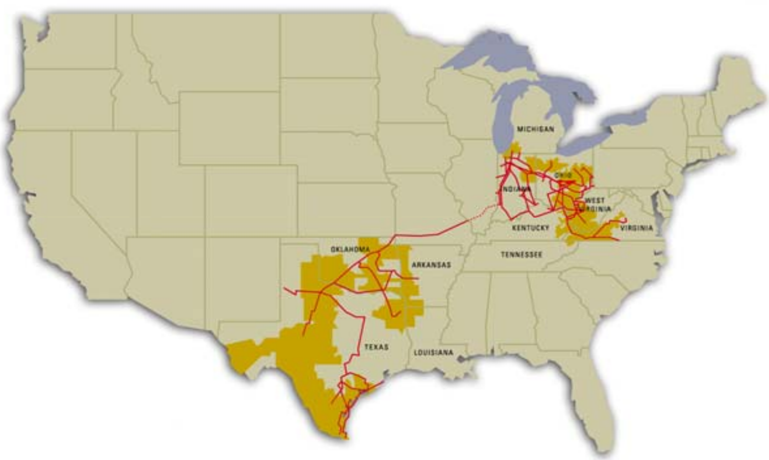
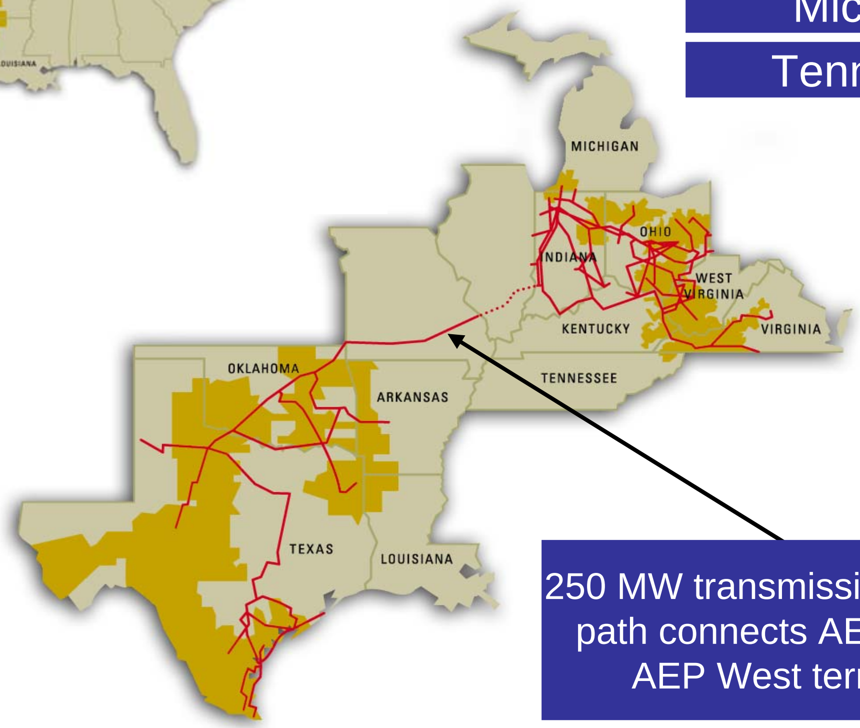
Where We Operate

- Ohio
- Indiana
- West Virginia
- Virginia
- Kentucky
- Michigan
- Tennessee





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250 MW transmission contract path connects AEP East & AEP West territories

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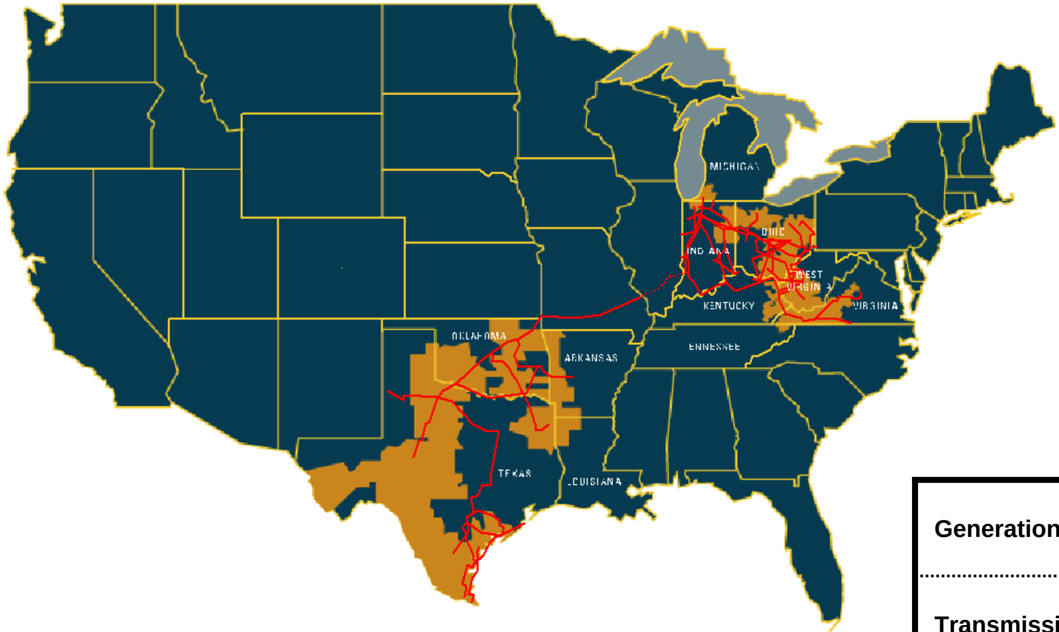

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OCTOBER 16, 2007

FITCH RATINGS

2007 RATINGS UPDATE

AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
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- Continue to plan for the I-765™ transmission line and ETT Joint Venture
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Continuing to execute on our strategies

Kentucky Power Regulatory Environment

Key Strategic Initiatives
- Plan for potential 2008 rate case.

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Jurisdictional Filing Requirements	
Time limitations between cases	None
Timing of rates in effect subject to refund	None, rates suspended for 6 months
Approximate time to order from filing date	6 months
Alternative forms of rate making	Environmental surcharge

AFUDC vs. Return on CWIP
Revenue requirement is calculated on capitalization versus rate base which includes CWIP; however, there is an AFUDC offset which partially negates the cash return effect of CWIP.

FITCH RATINGS

2008 RATINGS UPDATE

1 Riverside Plaza
Columbus, Ohio
August 4, 2008

AEP AMERICAN ELECTRIC POWER

AEP Financial Overview

- Holly Koeppel – EVP & Chief Financial Officer

AEP Financial Accomplishments

Since we last gathered . . .

- AEP has issued $1.8B in long-term debt to date resulting in approximately $815M after maturities, redemptions, and amortized principal.

- AEP Increased Liquidity by successfully executing a new $1B bank facility comprised of a 364-day LOC facility ($350M) and a 3-year LOC facility ($650M)

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- Successfully managing the auction rate security challenge…

    - At the end of the 2nd quarter, AEP has shed approximately $1.2B of its $1.5B Auction Rate Security portfolio from the end of 2007.

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2008 Financial Plan Highlights

2008 Plan

- ❑ Reduced capital expenditures by approximately $1 billion over the same forecast period (2008-2012) since the 2007 October Update
- ❑ Be poised to respond to an Ohio order late in the year to achieve earnings target
- ❑ Delay the IGCC until late next decade due to judicial challenge, regulatory uncertainty, alternative technology options including nuclear, and the potential for a reduction in demand
- ❑ Continue our environmental program and new generation projects planned for SWEPCO (Stall and Turk plants) and APCo (completion of Dresden plant)
- ❑ Refine our capital allocation at the operating companies to achieve optimal credit metrics and ROE targets
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- ❑ Still evaluating the impact of a Federal Appeals Court ruling to vacate and remand the entire Clean Air Interstate Rule (CAIR)

We are committed to achieving the long-term growth associated with this 2008 Plan and will aggressively pursue further value enhancement opportunities.

Kentucky Power Company Highlights

Regulatory Update

- Kentucky Power's next base rate case could be as early as 2010 with a test year ending 03/31/09
- KPCo currently has a fuel clause, a system sales tracker, a DSM rider and an environmental surcharge rider.

Big Sandy Construction Update

- Scrubber construction to commence in 2011

gridSMART

- Deployed "drive by" AMR for 140,000 residential meters in 2006. Plan to replace all meters with AMI technology in 2012.
- Existing Programs:
  - Existing Demand Side Management/Energy Efficiency (DSM/EE) programs cost $750,000 per year and receive favorable recovery.
  - Programs are focused on low income weatherization and heat pump programs for mobile homes.
  - Since 1996, the KPCo programs have achieved an estimated 4,329 kW summer demand reduction, 19,863 kW winter demand reduction and a 411,212 MWh reduction.

Kentucky Power (KPCo)

President: Timothy Mosher

Status of Regulation: Regulated/Bundled Rates

Overview: Organized in Kentucky in 1919, KPCo encompasses a service territory of 4,813 square miles and at December 31, 2007, KPCo had 471 employees. Among the principal industries served are petroleum refining, coal mining, primary metals, chemicals, and electronic/gas/sanitary services. KPCo is a member of PJM.

Load Growth:

	5 Year CAGR
Residential	0.1%
Commercial	1.3%
Industrial	1.0%
TOTAL	**0.8%**

Generating Capacity:	**1,060MW**
Through 2022, 15% of Rockport	**390MW**
Generating Capacity by Fuel Mix:	
•Coal:	**100%**
Transmission:	**1,235 Miles**
Distribution:	**9,848 Miles**
Customers:	**175,000**

Kentucky Power Financial Summary

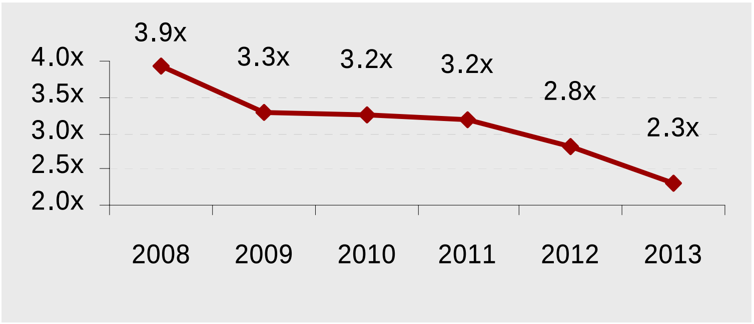
- ❑ Total Operating Revenues increase by $164M through the planning horizon

- ❑ Total Equity increases from $418M at the end of 2008 to $722M by the end of 2013

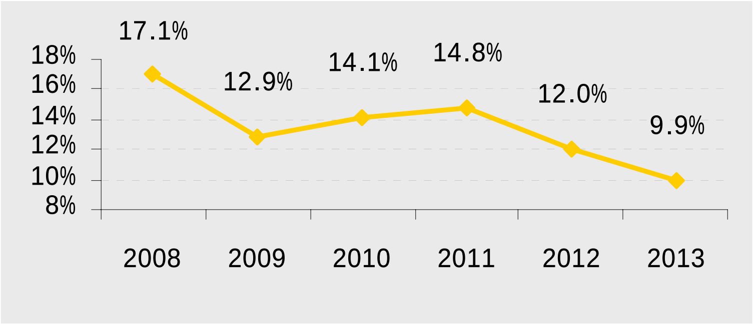
- ❑ Approximate Long-Term Debt issuance of $400M thru the financial planning horizon; Debt retirements total approximately $30M

- ❑ Emission allowance purchases reducing cash flow; however, they are fully recoverable per Kentucky's environmental tracker. This will be revised as CAIR rule rejection impact is known.

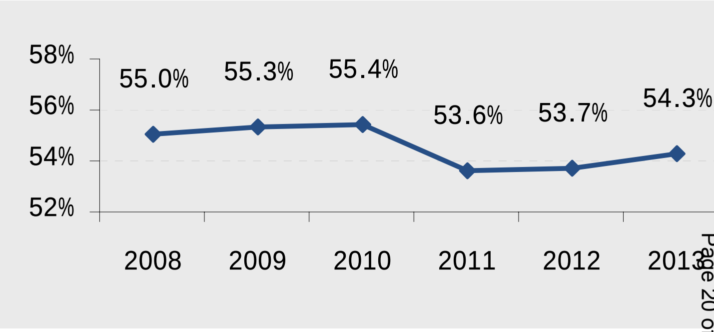
FFO to Interest Coverage



FFO to Total Debt



Total Debt to Total Capitalization



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Regulatory Environment - KPCo

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- KPCo currently has a fuel clause, a system sales tracker, a DSM rider and an environmental surcharge rider. In our settlement agreement in the 2006 base rate case, the intervenors and especially the Attorney General, made it clear they would not support any new riders.

Overall Regulatory Commission Environment

- The Commission does monitor SAIFI and CAIDI and requires an annual filing in April.
- Kentucky has a fair relationship with the State Commission regarding reliability due mainly to an open Management Audit that began in 2002. Of 23 specific issues, 5 still require annual filings.

Regulatory Issues

- This Commission has 3 commissioners, 2 of whom are brand new.
- The Commission closely scrutinizes informal visits as an outcome of the AG's allegation of ex-parte communications.

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Authorized ROE	❑ 10.5%, 2006

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AMERICAN ELECTRIC POWER

Fitch Ratings

Spring 2009 Ratings Update

May 13, 2009

AEP AMERICAN ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

AEP - Risk Reduction

Reasons for raising equity

- Gross proceeds of $1.69 billion to rebalance capitalization
- Liquidity position now stands at $3.5 billion which is more than sufficient for 2009/2010 maturities
- Commitment to BBB credit profile, prudent balance sheet, and liquidity management

Reduced regulatory risk

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Fuel clauses are now active in all jurisdictions
- Constructive local relationships deliver successful regulatory outcomes

Stable financial position

- Balanced approach to cost containment and capital allocation
- Capital expenditures have been reduced to $1.8 billion in 2010 and 2011
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth
- Reducing 2010 maturities through a tender on AEP, Inc. and expect to pre-fund Ohio Power
- Conservative dividend payout (57% vs. 68% Peer Group)

AEP is committed to a strong credit profile

- Commitment to a strong credit profile
  - Large infusion of equity to strengthen balance sheet
  - Equity contributions to subsidiary companies to stabilize credit
  - Debt levels well below 60%; stable/improving FFO/Debt metric
  - Prudent spending (CAPEX and O&M) during current economic slowdown
- Reduced risk
  - Ohio ESP decision – clarity around rate increases, fuel recovery, carbon regulation
  - Fuel clause active in all AEP jurisdictions
- Conservative liquidity management
  - Reduced reliance on short-term debt
  - Active strategy around credit line renewal
  - Pre-fund maturities; maintain cash position
- Committed to BBB rating at AEP, Inc.
  - Proactive, decisive, quick actions to support credit profile have been demonstrated

AEP AMERICAN ELECTRIC POWER

AEP

AMERICAN
ELECTRIC
POWER

AEP AMERICAN ELECTRIC POWER

Moody's Investor Service Ratings Update

June 6, 2005

Confidential

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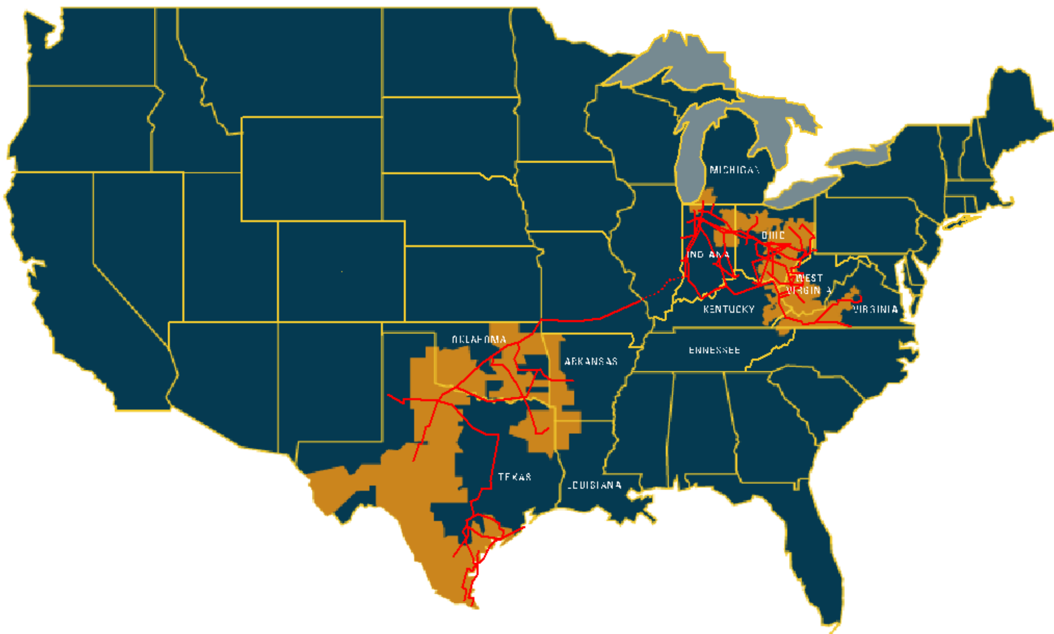

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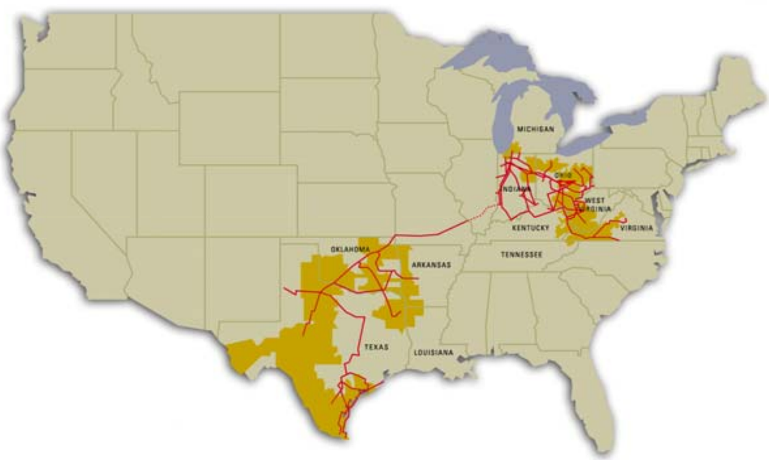

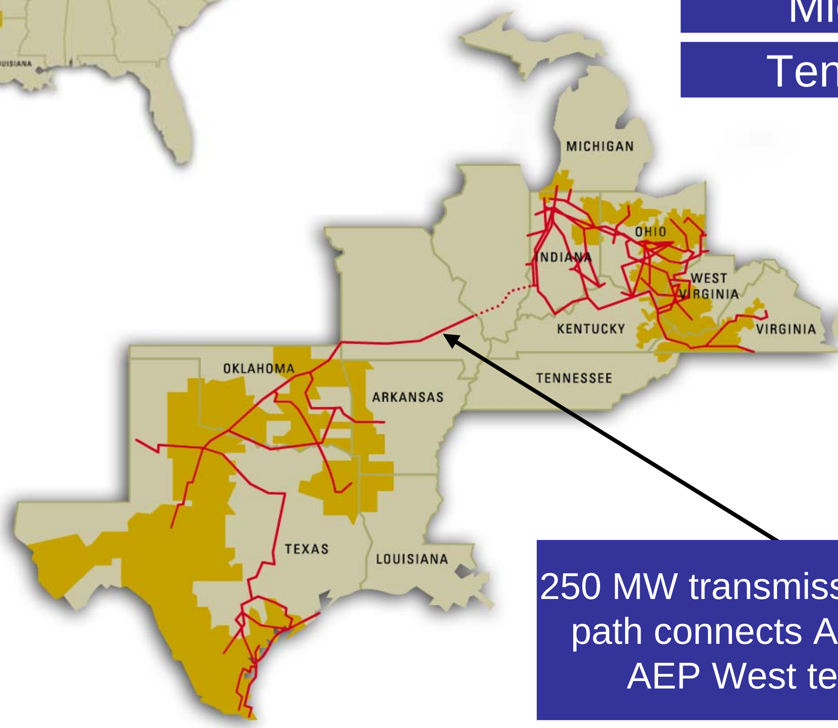

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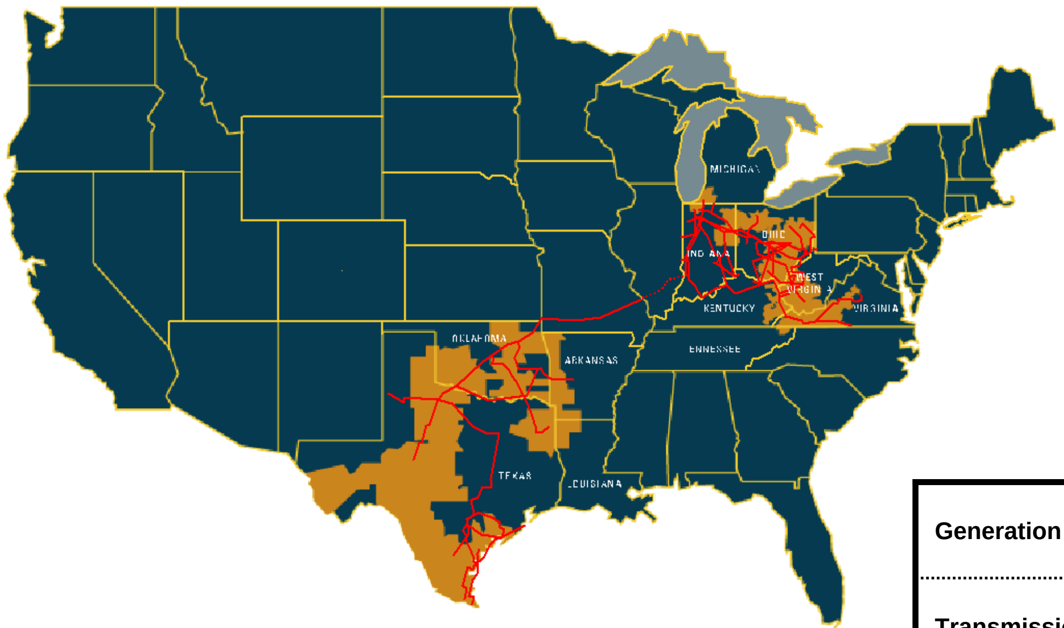

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SEPTEMBER 7, 2007

MOODY'S INVESTORS SERVICE

2007 RATINGS UPDATE

AMERICAN ELECTRIC POWER

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MOODY'S INVESTORS SERVICE

2008 RATINGS UPDATE

1 Riverside Plaza
Columbus, Ohio
July 30, 2008

Agenda

AEP Presentation to Moody's Investors Service

July 30, 2008

Introduction - Leadership, Management & Strategy (Mike Morris, Chairman & CEO)	8:00am - 8:30am
AEP Financial Update - (Holly Koeppel, EVP & Chief Financial Officer)	8:30am - 8:45am
Ohio Update - (Craig Baker, SVP Regulatory Services)	8:45am - 9:15am
Business Unit Review - (Venita McCellon-Allen, EVP AEP Utilities West / Craig Baker)	9:15am - 9:45am
Break	9:45am - 10:00am
Transmission - (Susan Tomasky, President AEP Transmission / Lisa Barton, VP Transmission)	10:00am - 10:30am
Generation & Sustainability - (Nick Akins, EVP Generation) Commodity Risk Management - (Chuck Zebula, SVP Fuel, Emissions & Logistics)	10:30am - 11:00am
Operating Company Financial Summaries - (Renee Hawkins, Mgr. Dir. Corporate Finance)	11:00am - 11:15am
Conclusion - (Holly Koeppel, EVP & Chief Financial Officer)	11:15am - 11:25am

Introduction

Leadership, Management & Strategy

- Mike Morris – Chairman & CEO

Leadership, Management & Strategy

Integrate Corporate Sustainability, Business Strategy & Daily Decision Making

- Put people first.
  - Health & safety of our employees and contractors.
  - Welfare of the communities in which we operate.
- Emphasize the importance of safety & environmental sustainability.
- AEP as a leader in corporate sustainability.
- Help customers understand the true value of electricity.
- Offer ways to encourage energy efficiency.
- Give customers greater control over use & cost.
- Obtain adequate & timely recover of AEP's costs while earning a reasonable return for shareholders.

Sustainability requires a strong and committed leadership team willing to be aggressive and take prudent risks to maintain AEP's role as an industry leader, meet the needs of our customers, deliver value to our shareholders and meet our sustainability vision.

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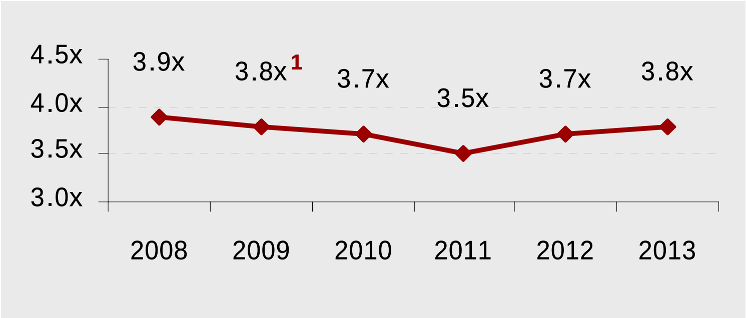
We are committed to achieving the long-term growth associated with this 2008 Plan and will aggressively pursue further value enhancement opportunities.

AEP Forecast Assumptions & Credit Ratios

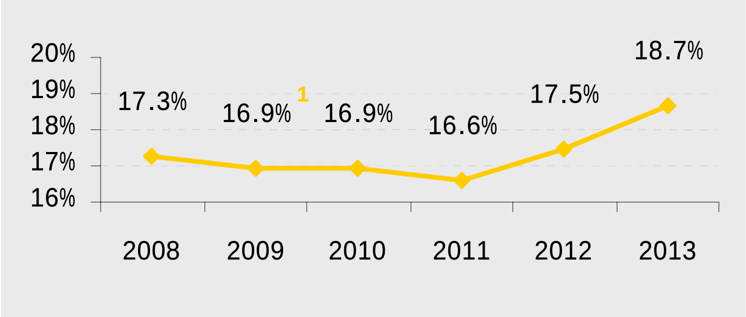
Financing Assumptions

- ❑ Maintain $100M cash balance
- ❑ 40% minimum common equity
- ❑ Target 50% minimum common equity at Ohio companies
- ❑ $315M of Hybrid Capital issued in 2008 at AEP Inc. (Basket C/Intermediate 50% Equity treatment)
- ❑ $150M in new equity each year from Dividend Reinvestment Plan
- ❑ Quarterly dividend raised $0.02 in 4th Quarter of each year ($0.08 annually)
- ❑ Average Short-Term debt rate from 2008 to 2013 is 4.42%
- ❑ Average Long-Term debt from 2008 thru 2013 is 7.00%

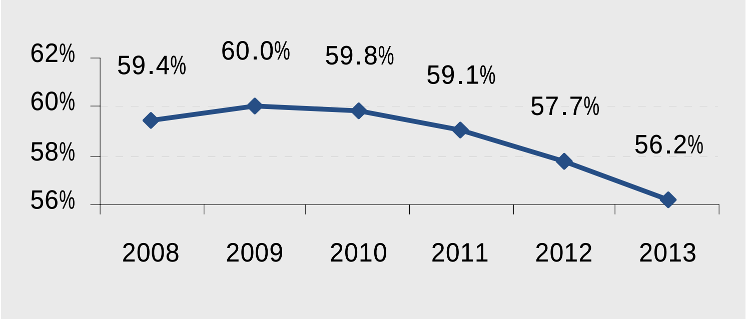
FFO to Interest Coverage



FFO to Total Debt



Total Debt to Total Capitalization



Note 1: Adjusted for one-time payment for BofA settlement

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Kentucky Power Company Highlights

❑ Regulatory Update

- Kentucky Power's next base rate case could be as early as 2010 with a test year ending 03/31/09
- KPCo currently has a fuel clause, a system sales tracker, a DSM rider and an environmental surcharge rider.

❑ Big Sandy Construction Update

- Scrubber construction to commence in 2011

❑ gridSMART

- Deployed "drive by" AMR for 140,000 residential meters in 2006. Plan to replace all meters with AMI technology in 2012.
- Existing Programs:
  - Existing Demand Side Management/Energy Efficiency (DSM/EE) programs cost $750,000 per year and receive favorable recovery.
  - Programs are focused on low income weatherization and heat pump programs for mobile homes.
  - Since 1996, the KPCo programs have achieved an estimated 4,329 kW summer demand reduction, 19,863 kW winter demand reduction and a 411,212 MWh reduction.

Kentucky Power (KPCo)

President: Timothy Mosher

Status of Regulation: Regulated/Bundled Rates

Overview: Organized in Kentucky in 1919, KPCo encompasses a service territory of 4,813 square miles and at December 31, 2007, KPCo had 471 employees. Among the principal industries served are petroleum refining, coal mining, primary metals, chemicals, and electronic/gas/sanitary services. KPCo is a member of PJM.

Load Growth:

	5 Year CAGR
Residential	0.1%
Commercial	1.3%
Industrial	1.0%
TOTAL	**0.8%**

Generating Capacity:	**1,060MW**
Through 2022, 15% of Rockport	**390MW**

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission:	**1,235 Miles**
Distribution:	**9,848 Miles**
Customers:	**175,000**

Kentucky Power Financial Summary

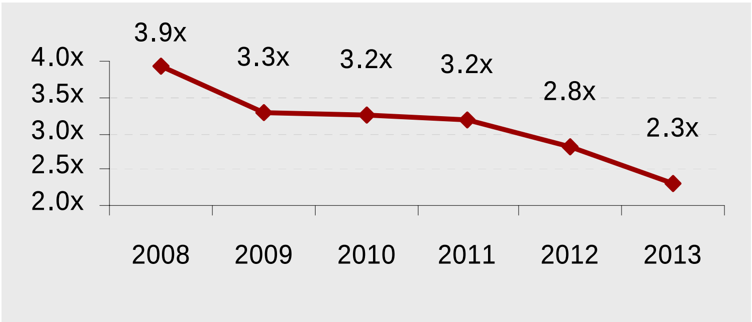
❑ Total Operating Revenues increase by $164M through the planning horizon

❑ Total Equity increases from $418M at the end of 2008 to $722M by the end of 2013

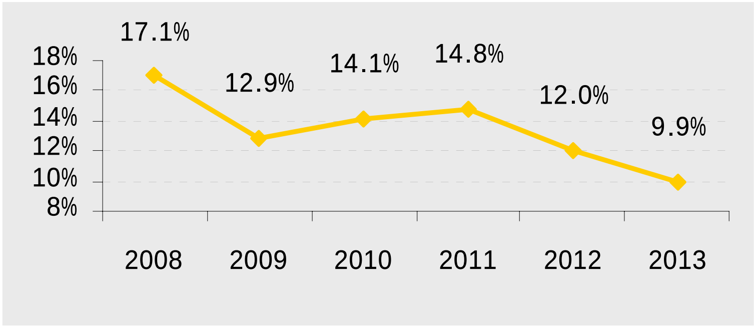
❑ Approximate Long-Term Debt issuance of $400M thru the financial planning horizon; Debt retirements total approximately $30M

❑ Emission allowance purchases reducing cash flow; however, they are fully recoverable per Kentucky's environmental tracker. This will be revised as CAIR rule rejection impact is known.

FFO to Interest Coverage



FFO to Total Debt



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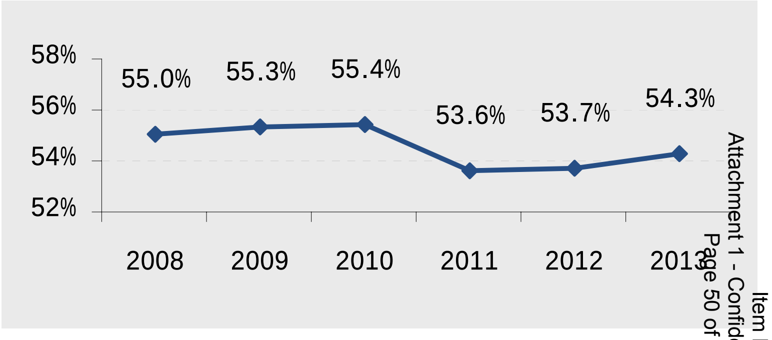

Regulatory Environment - KPCo

Key Strategic Initiatives
- Plan for potential 2010 rate case.

Rate Case Activity
- Last formal rate case was approved March 31, 2006 providing for $41 million in new revenue.
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- An environmental surcharge rate filing was approved January 24, 2007 allowing for recovery of KPCo's portion of the environmental spend at companies surplus in AEP's east generation pool.
- Our next base rate could be as early as 2010 with a test year ending 03/31/09.
- KPCo currently has a fuel clause, a system sales tracker, a DSM rider and an environmental surcharge rider. In our settlement agreement in the 2006 base rate case, the intervenors and especially the Attorney General, made it clear they would not support any new riders.

Overall Regulatory Commission Environment
- The Commission does monitor SAIFI and CAIDI and requires an annual filing in April.
- Kentucky has a fair relationship with the State Commission regarding reliability due mainly to an open Management Audit that began in 2002. Of 23 specific issues, 5 still require annual filings.

Regulatory Issues
- This Commission has 3 commissioners, 2 of whom are brand new.
- The Commission closely scrutinizes informal visits as an outcome of the AG's allegation of ex-parte communications.

Financial Snapshot - Return on Equity	
Authorized ROE	❑ 10.5%, 2006

Regulatory Toolbox
Environmental Surcharge: allowed recovery of environmental costs at Big Sandy and share of environmental costs incurred from AEP Power Pool capacity settlements.
System Sales Tracker: Monthly
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Off-System Sales Sharing: Yes, above and below base levels. Sharing above annual profits of approx. $25 million. Between that amount and $30 million, ratepayers receive 70%; above $30 million, 60%.

Jurisdictional Filing Requirements	
Time limitations between cases	❑ None
Timing of rates in effect subject to refund	❑ None, rates suspended for 6 months
Approximate time to order from filing date	❑ 6 months
Alternative forms of rate making	❑ Environmental surcharge

AFUDC vs. Return on CWIP
Revenue requirement is calculated on capitalization versus rate base which includes CWIP; however, there is an AFUDC offset which partially negates the cash return effect of CWIP.

THIS PAGE HAS BEEN REDACTED IN ITS ENTIRETY.

AMERICAN ELECTRIC POWER

Moody's Investors Service

Spring 2009 Ratings Update

April 23, 2009

AEP AMERICAN ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

AEP - Risk Reduction

Reasons for raising equity

- Gross proceeds of $1.69 billion to rebalance capitalization
- Liquidity position now stands at $3.5 billion which is more than sufficient for 2009/2010 maturities
- Commitment to Baa2 credit profile, prudent balance sheet, and liquidity management

Reduced regulatory risk

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Fuel clauses are now active in all jurisdictions
- Constructive local relationships deliver successful regulatory outcomes

Stable financial position

- Balanced approach to cost containment and capital allocation
- Capital expenditures have been reduced to $1.8 billion in 2010 and 2011
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth
- Reducing 2010 maturities through a tender on AEP, Inc. and expect to pre-fund Ohio Power
- Conservative dividend payout (57% vs. 68% Peer Group)

AEP is committed to a strong credit profile

- Commitment to a strong credit profile
  - Large infusion of equity to strengthen balance sheet
  - Equity contributions to subsidiary companies to stabilize credit
  - Debt levels well below 60%; stable/improving FFO/Debt metric
  - Prudent spending (CAPEX and O&M) during current economic slowdown
- Reduced risk
  - Ohio ESP decision – clarity around rate increases, fuel recovery, carbon regulation
  - Fuel clause active in all AEP jurisdictions
- Conservative liquidity management
  - Reduced reliance on short-term debt
  - Active strategy around credit line renewal
  - Pre-fund maturities; maintain cash position
- Committed to Baa2 rating at AEP, Inc.
  - Structural relationship of subsidiaries – Ohio Power (Baa1), SWEPCO (Baa1)
  - Proactive, decisive, quick actions to support credit profile have been demonstrated

AEP

AMERICAN
ELECTRIC
POWER

AEP AMERICAN ELECTRIC POWER

AEP AMERICAN® ELECTRIC POWER

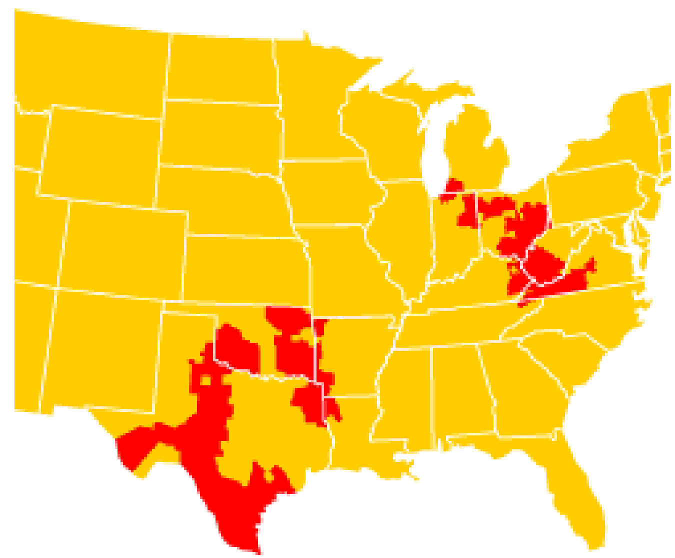
Moody's Investors Service Handout

May 4, 2011

American Electric Power

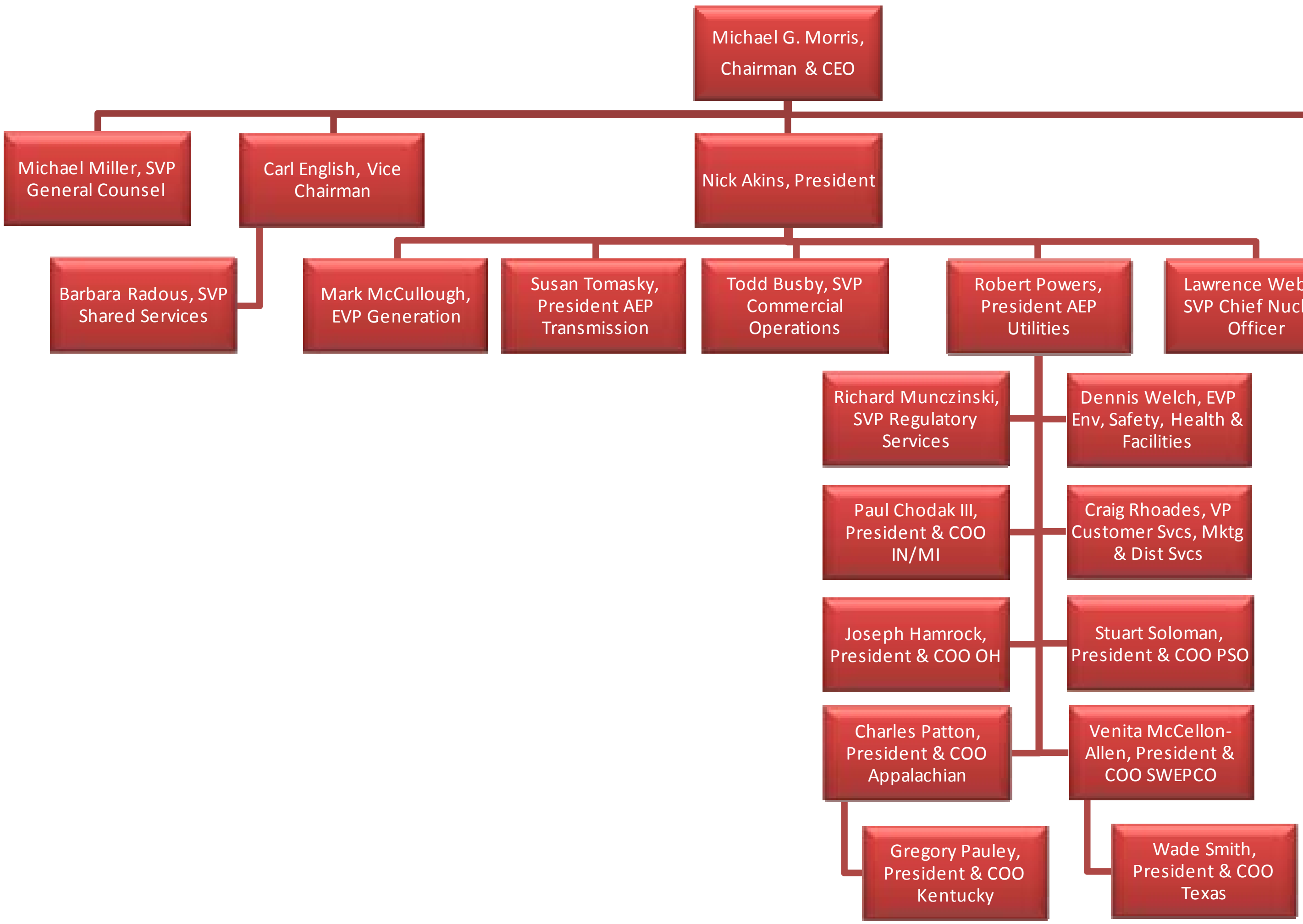
- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



AEP Fast Facts
5.3 million customers 39 GW of generation capacity 39,000 miles of transmission lines
$17B Market Capitalization BBB/Baa2/BBB credit rating

Management Organization Chart



Nick Akins Biography

Nicholas K. Akins

Nick Akins is President of American Electric Power, responsible for AEP's utilities, transmission, generation, commercial operations and OVEC/IKEC organizations.

From 2006 to 2010, Akins was executive vice president - Generation, responsible for all generation activities of AEP's approximately 40,000 MW of generation resources. This includes the engineering, construction, and operations of fossil and hydro generation, nuclear generation, fuels procurement, emission, and logistics, and other resource initiatives such as new generation, environmental retrofits, and carbon capture and storage. Akins was also responsible for the commercial operations, marketing and trading functions for the company.

Previously, he was president and chief operating officer for Southwestern Electric Power Company, serving approximately 439,000 customers in Louisiana, Arkansas and northeast Texas. Named to this position in 2004, he had authority for distribution operations and a wide range of customer and regulatory relationships.

Prior to this, Akins was vice president - energy marketing services, responsible for directing the activities of Market Development, including the transmission marketing and services functions, Energy Delivery External Affairs including community affairs, economic development, advocacy for regulatory and legislative positions within Energy Delivery. Additional responsibilities included the development and implementation of strategies for energy delivery related to AEP's entry into regional transmission organizations.

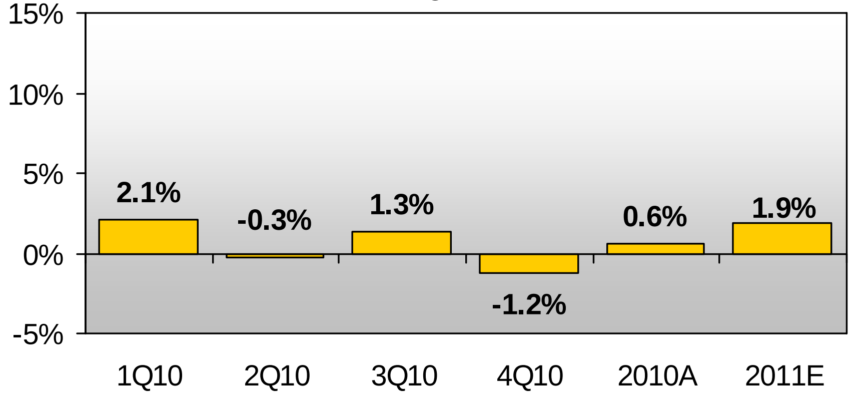
Akins was also vice president - industry restructuring for AEP responsible for enterprise-wide program management for restructuring initiatives in preparation for customer choice in AEP's various jurisdictions.
Previous to Central and South West Corp.'s (CSW) merger with AEP, he served in various director and manager roles within CSW and its operating companies involving mergers and acquisitions, industry restructuring, fuels, system dispatch operations and system planning.

He received a bachelor's degree in 1982 in electrical engineering from Louisiana Tech University in Ruston and a master's degree in electrical engineering in 1986 from Louisiana Tech. He has completed executive management programs at Louisiana State University, the University of Idaho and the Reactor Technology Course for Utility Executives at the Massachusetts Institute of Technology.

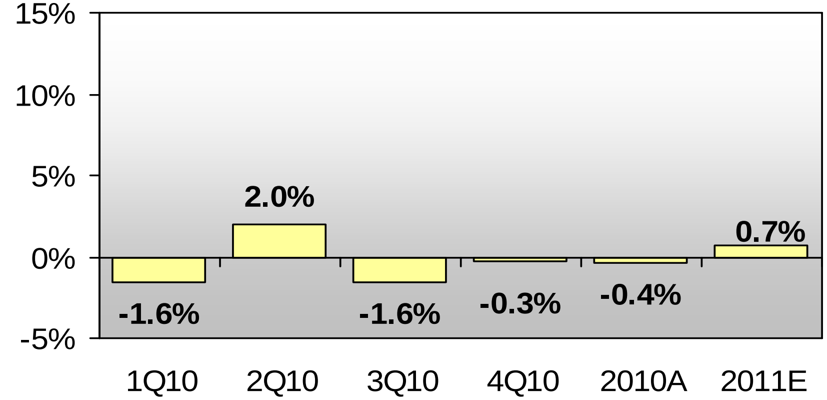
Akins is a registered professional engineer in Texas. He currently serves as the chairman of the Coal Utilization Research Council (CURC), and on the boards of the Electric Power Research Institute (EPRI), the Mid-Ohio Food Bank and the Greater Columbus Arts Council. He also serves on several subsidiary boards of AEP.

Normalized Load Trends

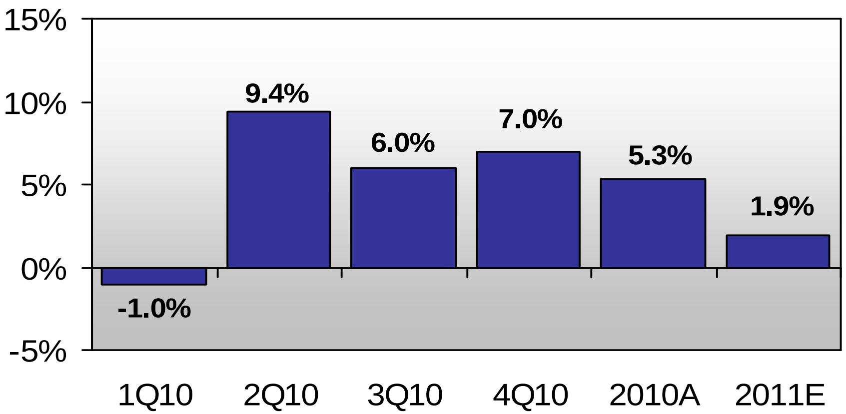
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



AEP Commercial Normalized GWh Sales
%Change vs. Prior Year

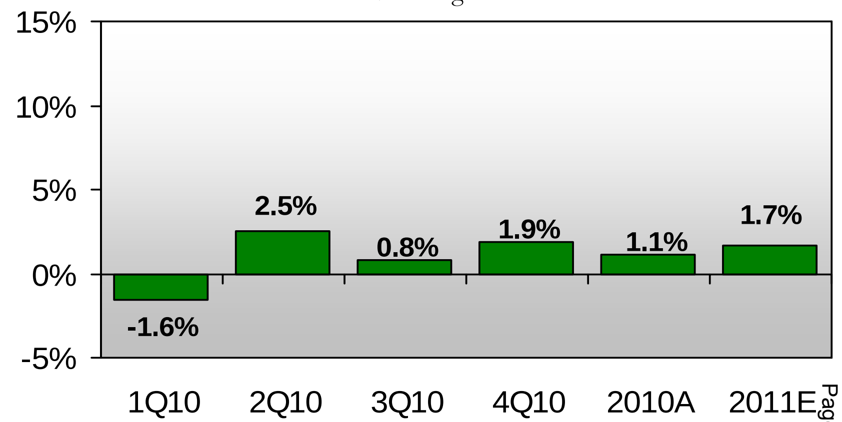


AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



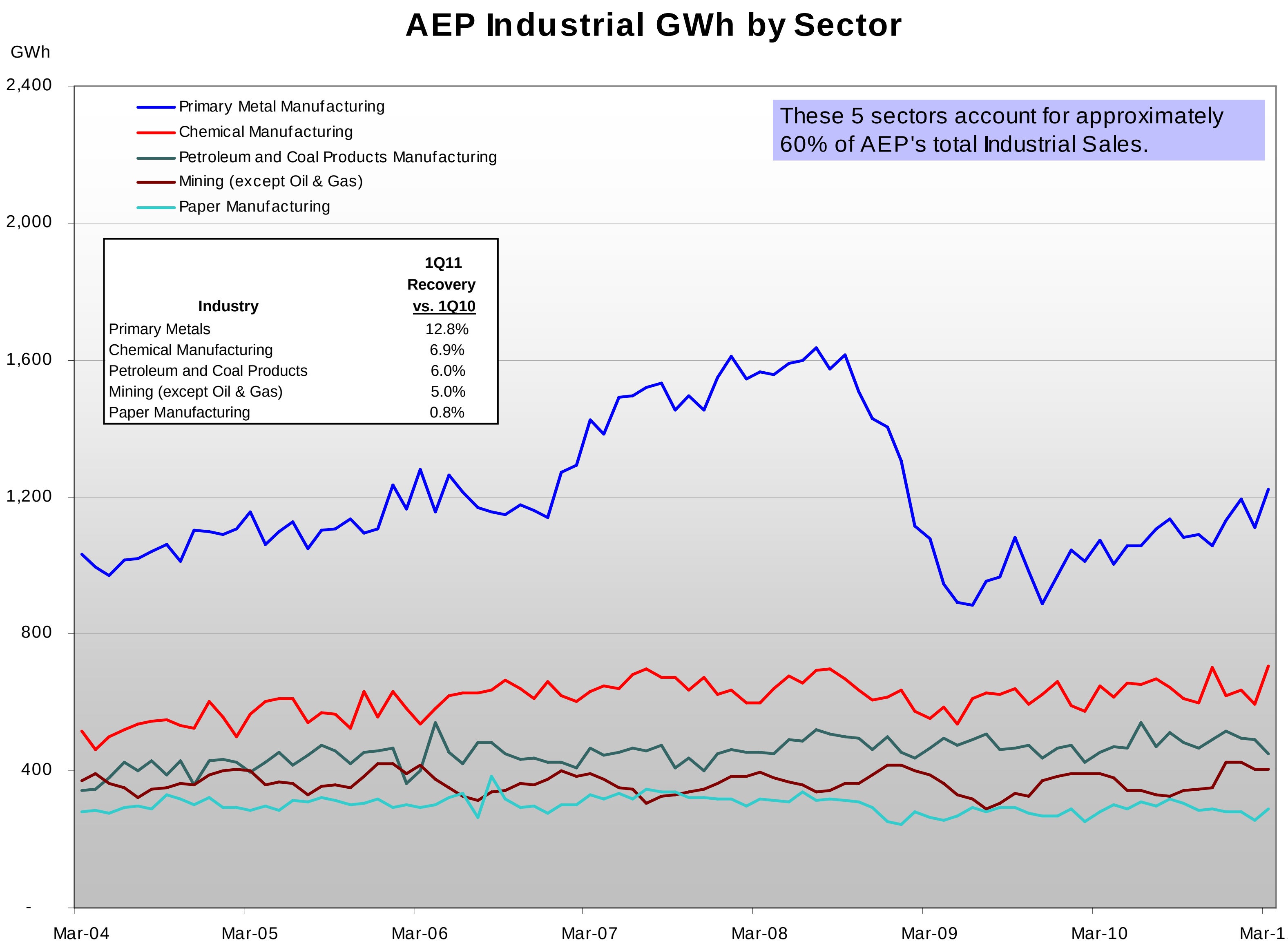
Note: Chart represents connected load

AEP Total Normalized GWh Sales*
%Change vs. Prior Year



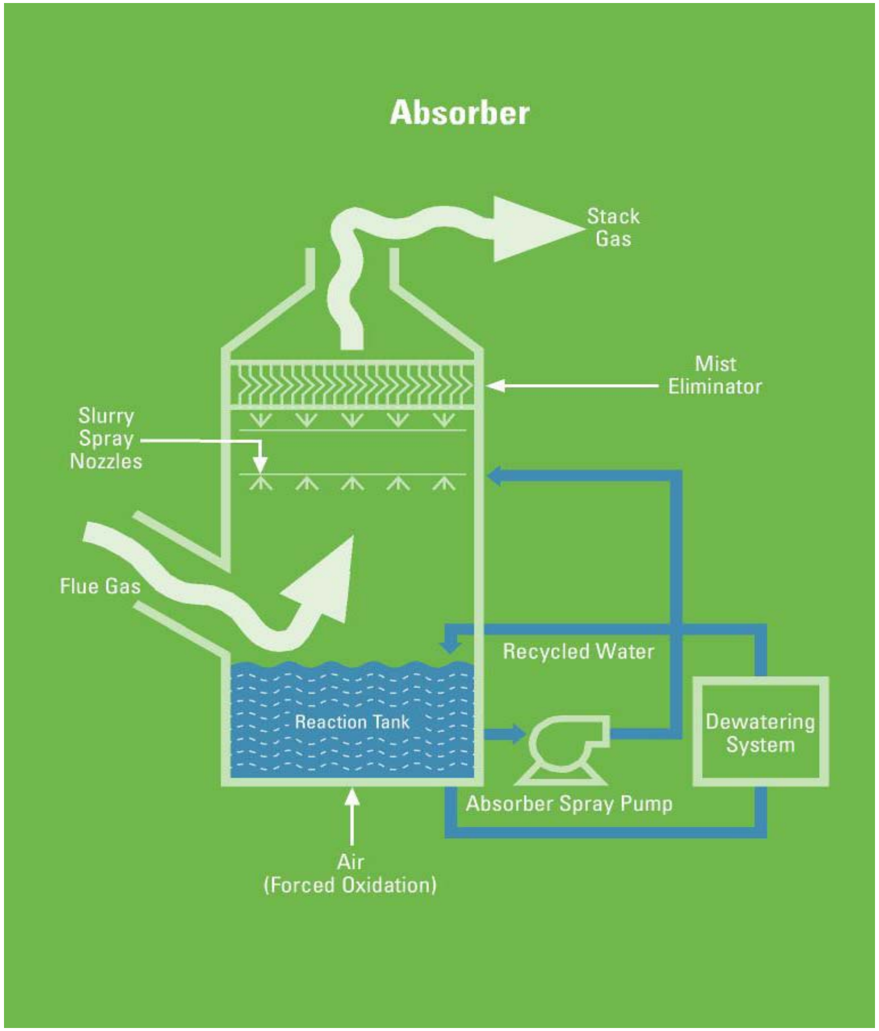
*includes firm wholesale load

Industrial Sales Volumes



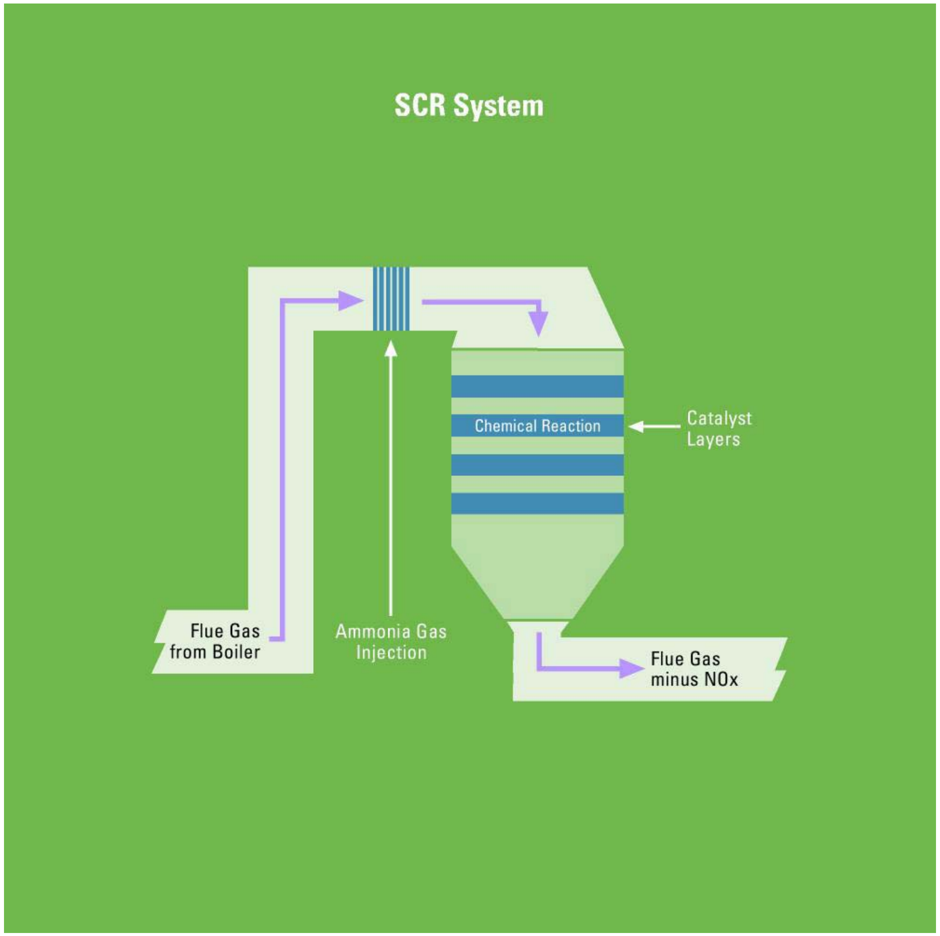
Industry	1Q11 Recovery vs. 1Q10
Primary Metals	12.8%
Chemical Manufacturing	6.9%
Petroleum and Coal Products	6.0%
Mining (except Oil & Gas)	5.0%
Paper Manufacturing	0.8%

How an FGD Works



- Limestone is fed from the silo and crushed in the ball mill
- Crushed limestone is mixed with water to form a slurry
- Exhaust gas is routed through absorber vessels where it is sprayed with the slurry
- SO_2 reacts with the slurry and forms calcium sulfate or gypsum
- The calcium sulfate falls to the lower part of the vessel
- Blowers inject air to force oxidation of the product
- Hydroclones wring out much of the water to produce gypsum: the water is re-circulated

How an SCR Works



- Urea, a harmless compound often used as fertilizer, is mixed with water
- Steam is used to drive the ammonia gas from the urea mixture
- The ammonia gas is piped into the flue gas ahead of the SCR
- The ammonia reacts with the flue gas as it passes over the catalyst, forming nitrogen gas and water vapor
- The harmless nitrogen and water vapor are released into the atmosphere

Standard and Poor's Ratings Update

June 6, 2005

Confidential

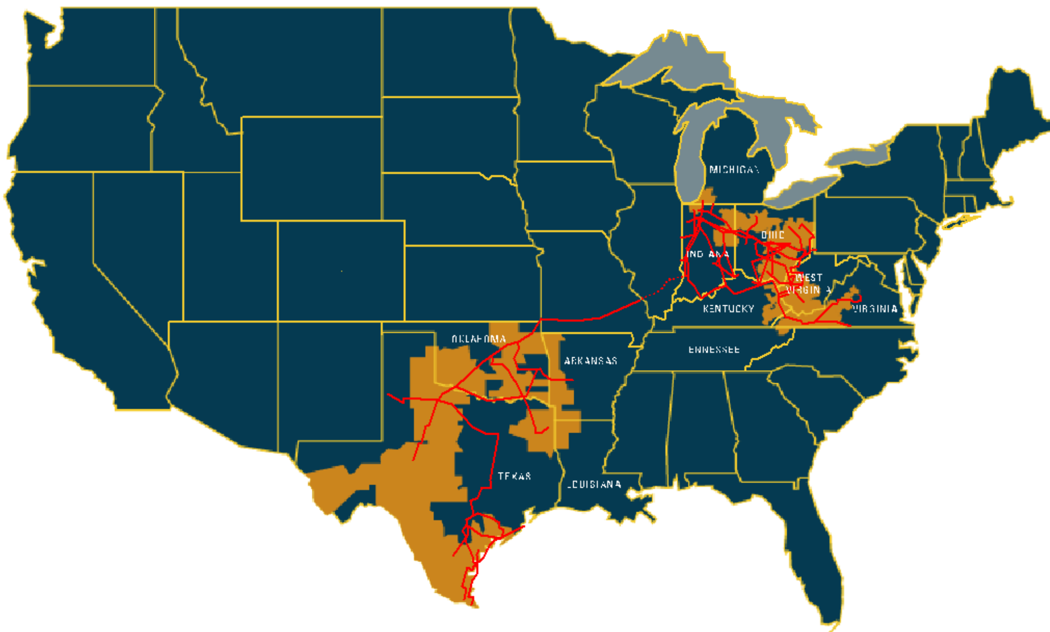
Recent Achievements

- Improved balance sheet
  - Reduced total debt ratio from 63.5% in 2003 to 57.9% in 2004 on a credit adjusted basis
- Successfully reduced trading risks
  - Total trading volume down by 71% in 2004 vs. 2002
  - Transitional trading book rolling off
    - $35 mm net fair value, and $32 mm will roll off by year-end 2005
  - Average VaR down by 64%
    - From $10.2 mm in 2002 to $4 mm in 2004
- Asset sale execution near completion
  - Closed $2.8 billion in asset sales through May 2005
- Maintained strong liquidity profile of $3.5 billion
  - Well above minimum thresholds for liquidity
- Operating Company Reorganization
  - Distribution and Customer Service operations reorganized into seven regional utility divisions in June 2004

AEP RISK PROFILE HAS IMPROVED DRAMATICALLY

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 66 of 9556

Strength & Scale in Assets & Operations



Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

New Regional Organization

- Michael Morris, CEO
  - Carl English, President AEP Utilities
    - Holly Koeppel, EVP AEP Utilities East
      - Kevin Walker, President Ohio
      - Dana Waldo, President Appalachian Power
      - Marsha Ryan, President Indiana-Michigan Power
      - Tim Mosher, President Kentucky Power
    - Tom Hagan, EVP AEP Utilities West
      - Charles Patton, President Texas
      - Nick Akins, President SWEPCO
      - Stuart Solomon, President Public Service of Oklahoma

SENIOR MANAGEMENT CLOSER TO CUSTOMERS AND REGULATORS

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Kentucky Power

- Kentucky Power's business profile rating of '5' does not reflect current operating environment
  - Environmental surcharge legislation in place which allows recovery of retail portion of environmental expenditures
  - Current application with KPSC to recover pool-related environmental costs
  - Rockport Unit Power Supply Agreement extended through end of 2022
  - KPSC is supportive of the Company

Standard & Poor's 2006 Ratings Update

August 2006

Confidential

Recent Achievements

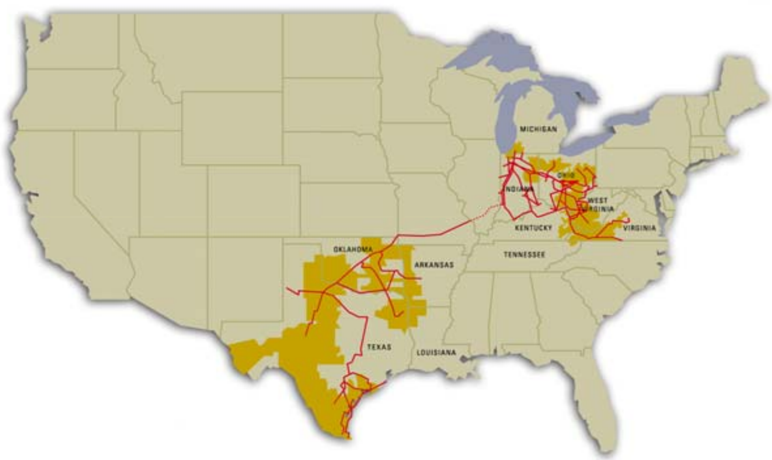
- Reached settlement on Texas securitization amount. Planning to issue securitization bonds in September 2006 of $1.7 billion.
- Purchased Waterford (821 MW) and Ceredo (505 MW) natural gas plants for attractive prices
- Currently secured $415 million of $500 million in rate recovery assumed in 2006 earnings guidance
- Completed & dedicated Wyoming-Jacksons Ferry 765-kV line
- Received approval from PUCO to proceed with first phase of IGCC construction and recover costs
- Fully funded pension plan

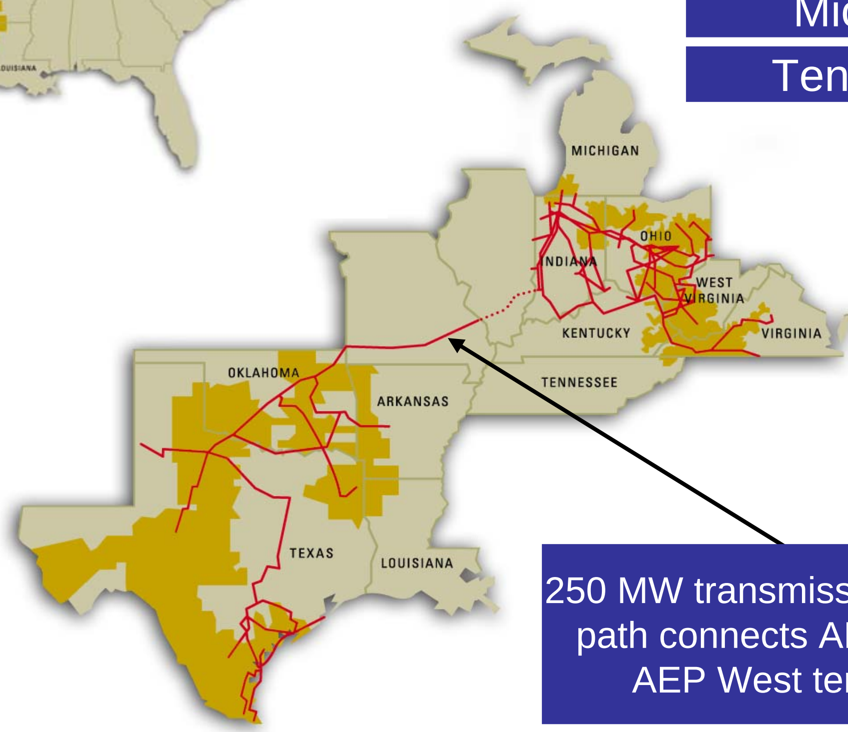
Recent Achievements

- Completed international non-core asset divestiture program
- Increased liquidity resources via upsizing revolving credit facilities to $3.0 billion and improving terms
- Closed 8 bond transactions totaling $2,270 million of senior unsecured notes over the past year. All deals were oversubscribed and most priced favorably to similarly rated peers at issuance.
- AEP's Business Profile risk has decreased dramatically over the last several years as a result of our focus on our core utility business

Where We Operate

Ohio
Indiana
West Virginia
Virginia
Kentucky
Michigan
Tennessee

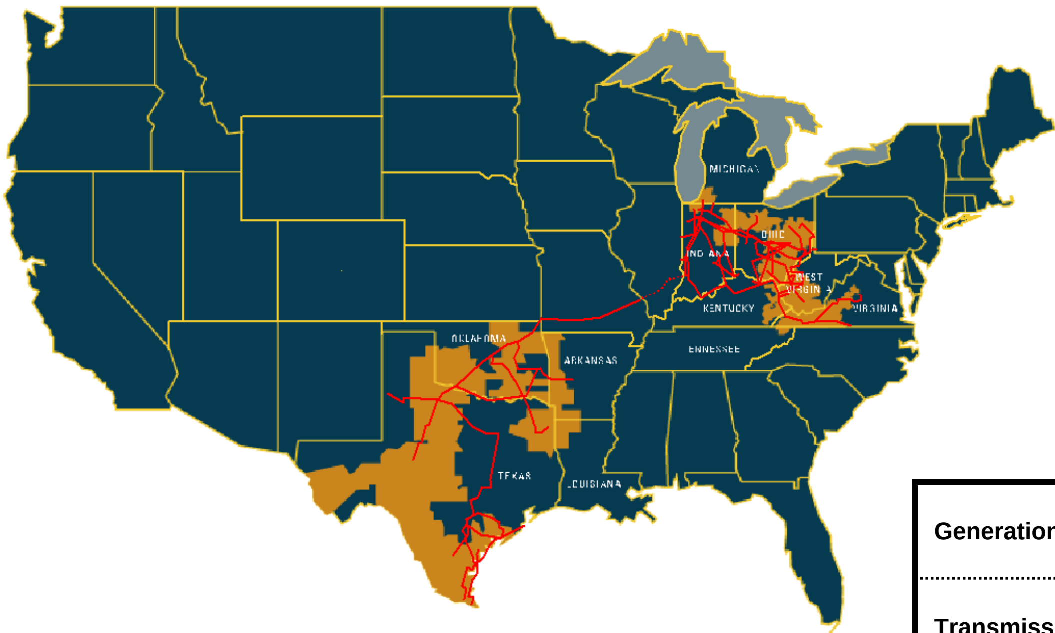




Oklahoma
Texas
Louisiana
Arkansas

250 MW transmission contract path connects AEP East & AEP West territories

Strength & Scale in Assets & Operations



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SEPTEMBER 7, 2007

STANDARD &POOR'S

2007 RATINGS UPDATE

AMERICAN ELECTRIC POWER

Recent Achievements

- Completed $1.7 Billion AEP Texas Central Company securitization in October 2006
- Completed sale of Dow Plaquemine for $64 million and announced sale of Sweeny plant for $80 million
- Continue to execute regulatory plans
  - Achieved to date $294M of the $338M Rate Recovery in 2007 guidance
- Continue to plan for the I-765™ transmission line and ETT Joint Venture
- Completed the plant acquisitions of Darby (480 MW) in April 2007, Lawrenceburg (1,140 MW) in May 2007, and announced acquisition of Dresden (580 MW) in August 2007
- Settled Lawton litigation for payments of $35 million with an 8.25% carrying charge to be collected from customers
- Transition to market prices in Ohio now being pursued

Continuing to execute on our strategies

Kentucky Power Regulatory Environment

Key Strategic Initiatives
- Plan for potential 2008 rate case.

Rate Case Activity
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AEP AMERICAN ELECTRIC POWER

STANDARD & POOR'S

2008 RATINGS UPDATE

1 Riverside Plaza
Columbus, Ohio
July 31, 2008

AEP AMERICAN ELECTRIC POWER

Introduction

Leadership, Management & Strategy

- Mike Morris – Chairman & CEO

Leadership, Management & Strategy

Integrate Corporate Sustainability, Business Strategy & Daily Decision Making

- Put people first.
  - Health & safety of our employees and contractors.
  - Welfare of the communities in which we operate.
- Emphasize the importance of safety & environmental sustainability.
- AEP as a leader in corporate sustainability.
- Help customers understand the true value of electricity.
- Offer ways to encourage energy efficiency.
- Give customers greater control over use & cost.
- Obtain adequate & timely recover of AEP's costs while earning a reasonable return for shareholders.

Sustainability requires a strong and committed leadership team willing to be aggressive and take prudent risks to maintain AEP's role as an industry leader, meet the needs of our customers, deliver value to our shareholders and meet our sustainability vision.

AEP Financial Overview

- Holly Koeppel – EVP and Chief Financial Officer

AEP Financial Accomplishments

Since we last gathered . . .

- AEP has issued $1.8B in long-term debt to date resulting in approximately $815M after maturities, redemptions, and amortized principal.

- AEP Increased Liquidity by successfully executing a new $1B bank facility comprised of a 364-day LOC facility ($350M) and a 3-year LOC facility ($650M)

- EPA New Source Review (NSR), settlement included a civil fine of $15M, environmental mitigation of $24M, and AEP will provide $36M for environmental projects coordinated with the federal government

- Successfully managing the auction rate security challenge…

  - At the end of the 2nd quarter, AEP has shed approximately $1.2B of its $1.5B Auction Rate Security portfolio from the end of 2007.

2008 Financial Plan Highlights

2008 Plan

- Reduced capital expenditures by approximately $1 billion over the same forecast period (2008-2012) since the 2007 October Update
- Be poised to respond to an Ohio order late in the year to achieve earnings target
- Delay the IGCC until late next decade due to judicial challenge, regulatory uncertainty, alternative technology options including nuclear, and the potential for a reduction in demand
- Continue our environmental program and new generation projects planned for SWEPCO (Stall and Turk plants) and APCo (completion of Dresden plant)
- Refine our capital allocation at the operating companies to achieve optimal credit metrics and ROE targets
- Sustain generation plant availability to continue to participate in wholesale power markets
- Still evaluating the impact of a Federal Appeals Court ruling to vacate and remand the entire Clean Air Interstate Rule (CAIR)

We are committed to achieving the long-term growth associated with this 2008 Plan and will aggressively pursue further value enhancement opportunities.

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Kentucky Power Financial Summary

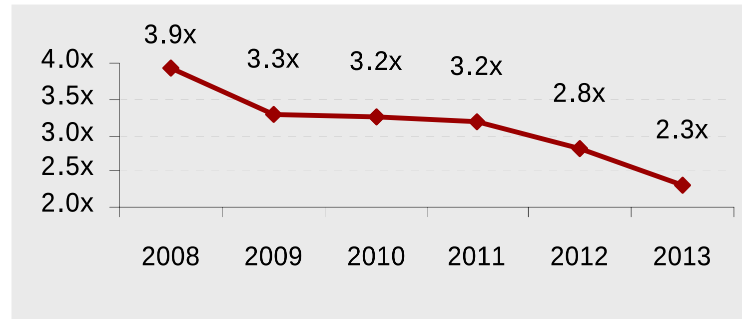
- Total Operating Revenues increase by $164M through the planning horizon

- Total Equity increases from $418M at the end of 2008 to $722M by the end of 2013

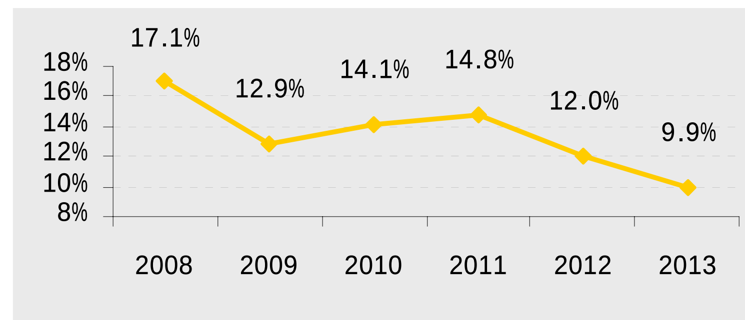
- Approximate Long-Term Debt issuance of $400M thru the financial planning horizon; Debt retirements total approximately $30M

- Emission allowance purchases reducing cash flow; however, they are fully recoverable per Kentucky's environmental tracker. This will be revised as CAIR rule rejection impact is known.

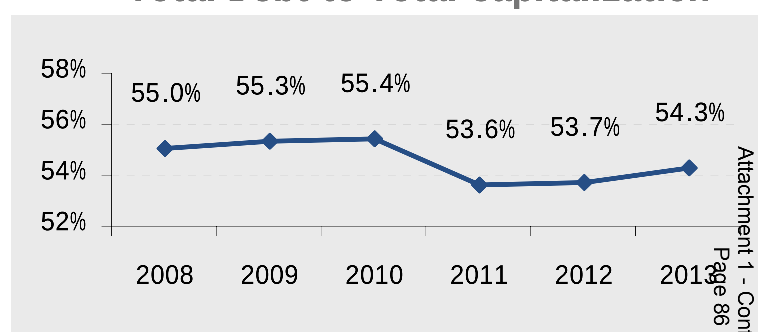
FFO to Interest Coverage



FFO to Total Debt



Total Debt to Total Capitalization



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Regulatory Environment - KPCo

Key Strategic Initiatives

- Plan for potential 2010 rate case.

Rate Case Activity

- Last formal rate case was approved March 31, 2006 providing for $41 million in new revenue.
- Rate cases are normally driven by a deterioration of earnings caused mainly by large construction projects and significant increases in O&M expenses.
- An environmental surcharge rate filing was approved January 24, 2007 allowing for recovery of KPCo’s portion of the environmental spend at companies surplus in AEP’s east generation pool.
- Our next base rate could be as early as 2010 with a test year ending 03/31/09.
- KPCo currently has a fuel clause, a system sales tracker, a DSM rider and an environmental surcharge rider. In our settlement agreement in the 2006 base rate case, the intervenors and especially the Attorney General, made it clear they would not support any new riders.

Overall Regulatory Commission Environment

- The Commission does monitor SAIFI and CAIDI and requires an annual filing in April.
- Kentucky has a fair relationship with the State Commission regarding reliability due mainly to an open Management Audit that began in 2002. Of 23 specific issues, 5 still require annual filings.

Regulatory Issues

- This Commission has 3 commissioners, 2 of whom are brand new.
- The Commission closely scrutinizes informal visits as an outcome of the AG’s allegation of ex-parte communications.

Financial Snapshot - Return on Equity	
Authorized ROE	❑ 10.5%, 2006

Regulatory Toolbox
Environmental Surcharge: allowed recovery of environmental costs at Big Sandy and share of environmental costs incurred from AEP Power Pool capacity settlements.
System Sales Tracker: Monthly
DSM Adjustment Clause: Monthly
Fuel Adjustment Clause: Monthly
Off-System Sales Sharing: Yes, above and below base levels. Sharing above annual profits of approx. $25 million. Between that amount and $30 million, ratepayers receive 70%; above $30 million, 60%.

Jurisdictional Filing Requirements	
Time limitations between cases	❑ None
Timing of rates in effect subject to refund	❑ None, rates suspended for 6 months
Approximate time to order from filing date	❑ 6 months
Alternative forms of rate making	❑ Environmental surcharge

AFUDC vs. Return on CWIP
Revenue requirement is calculated on capitalization versus rate base which includes CWIP; however, there is an AFUDC offset which partially negates the cash return effect of CWIP.

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AMERICAN ELECTRIC POWER

Standard and Poor’s

Spring 2009 Ratings Update

April 23, 2009

AEP AMERICAN ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

AEP - Risk Reduction

Reasons for raising equity

- Gross proceeds of $1.69 billion to rebalance capitalization
- Liquidity position now stands at $3.5 billion which is more than sufficient for 2009/2010 maturities
- Commitment to BBB credit profile, prudent balance sheet, and liquidity management

Reduced regulatory risk

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Fuel clauses are now active in all jurisdictions
- Constructive local relationships deliver successful regulatory outcomes

Stable financial position

- Balanced approach to cost containment and capital allocation
- Capital expenditures have been reduced to $1.8 billion in 2010 and 2011
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth
- Reducing 2010 maturities through a tender on AEP, Inc. and expect to pre-fund Ohio Power
- Conservative dividend payout (57% vs. 68% Peer Group)

AEP AMERICAN ELECTRIC POWER

AEP is committed to a strong credit profile

- Commitment to a strong credit profile
  - Large infusion of equity to strengthen balance sheet
  - Equity contributions to subsidiary companies to stabilize credit
  - Debt levels well below 60%; stable/improving FFO/Debt metric
  - Prudent spending (CAPEX and O&M) during current economic slowdown
- Reduced risk
  - Ohio ESP decision – clarity around rate increases, fuel recovery, carbon regulation
  - Fuel clause active in all AEP jurisdictions
- Conservative liquidity management
  - Reduced reliance on short-term debt
  - Active strategy around credit line renewal
  - Pre-fund maturities; maintain cash position
- Committed to BBB rating at AEP, Inc.
  - Proactive, decisive, quick actions to support credit profile have been demonstrated

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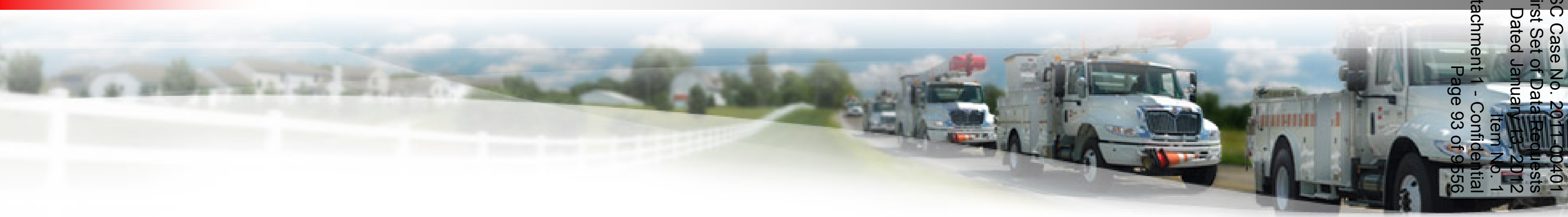
Standard & Poor's Meeting

November 16, 2010
New York, NY



Update on 2010 Priorities

2010 +

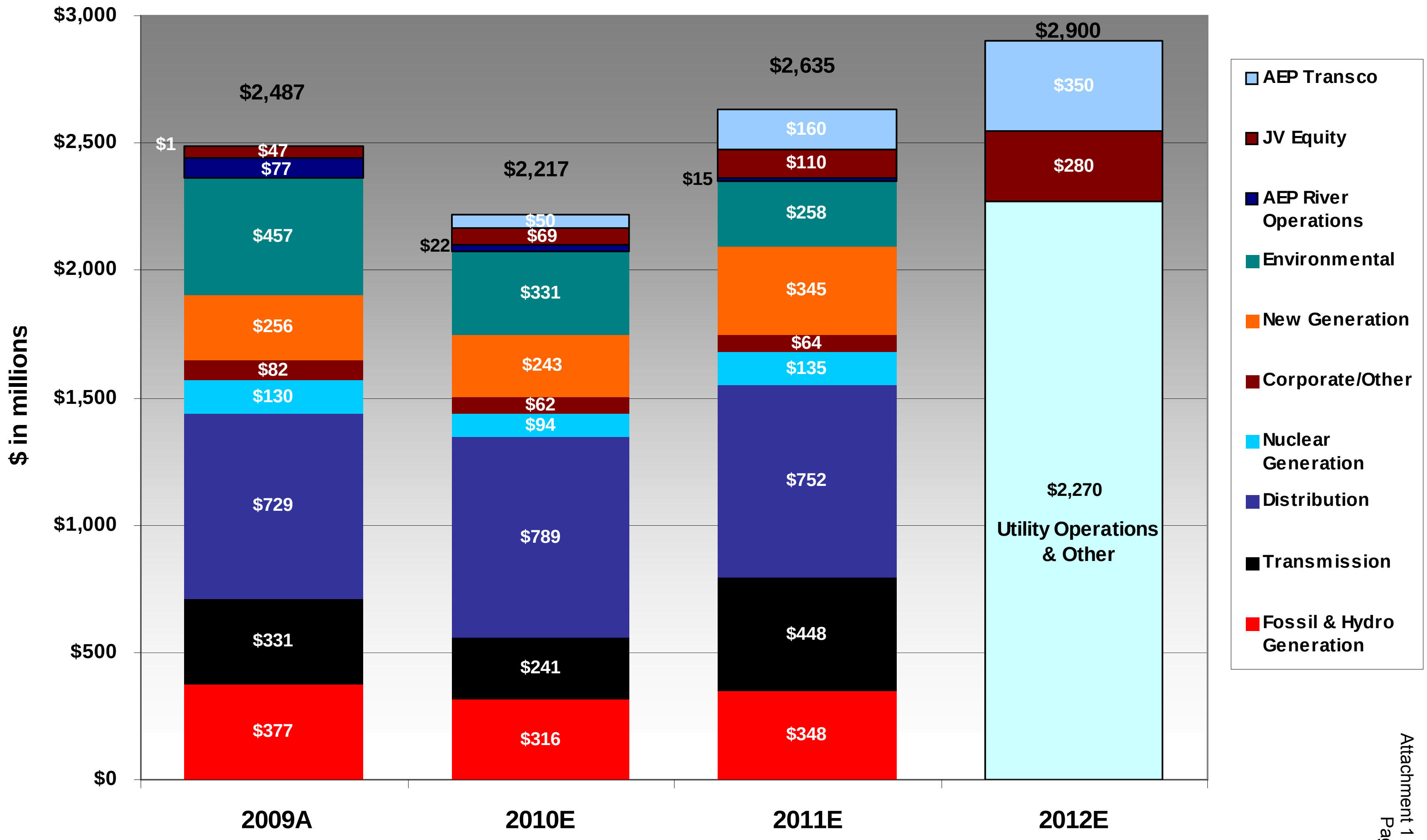
- Navigate through ongoing economic conditions
- Maintain capital spending and balance sheet discipline
- Continue delivering successful regulatory outcomes

✓ Capital spending plan on target for $2.2B in 2010
✓ Stable credit outlook
✓ Labor and non-labor O&M cuts of $150M
✓ Reasonable rate case outcomes in VA, KY, MI, TX
✓ Exceeded rate relief goal of $320M for 2010
✓ Filed SEET in Ohio
✓ Implemented enhanced operating company model
✓ Narrowing 2010 guidance to $2.95 to $3.05/share

- Participate in policy making at both the state and federal levels, particularly related to environmental/climate and transmission issues
- Invest in the next generation of energy infrastructure: high voltage transmission, CCS, gridSMART®

✓ Active in legislative efforts for cap & trade bills
✓ Vocal in transmission policy efforts
✓ ETT and Transco efforts moving forward
✓ Success with Mountaineer CCS project
✓ 4 gridSMART® pilots underway

Capital Expenditures



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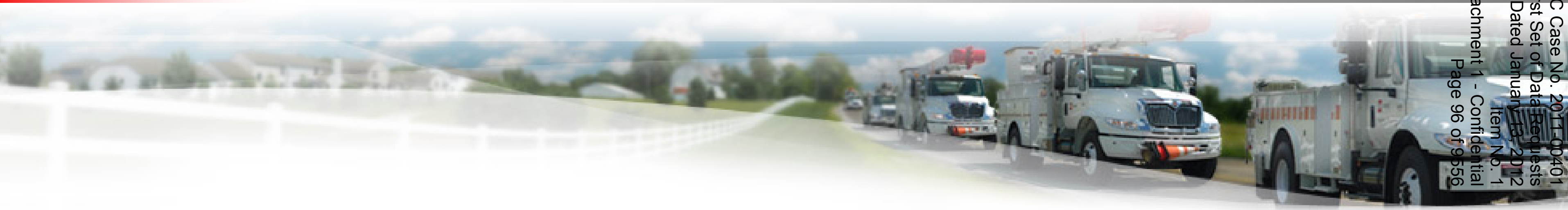
Standard & Poor's Meeting Handout

September 29, 2011



Management Participants

Nick Akins, AEP President

Brian Tierney, EVP & CFO

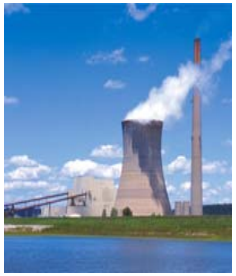
Joe Hamrock, President & COO, AEP Ohio

Rich Munczinski, SVP Regulatory Services

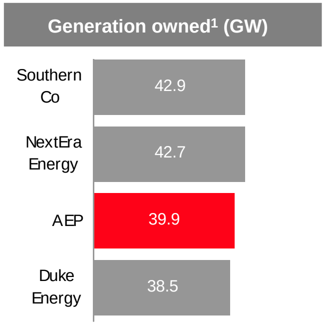
Chuck Zebula, Treasurer & SVP Investor Relations

Renee Hawkins, Asst. Treasurer & MD Corporate Finance

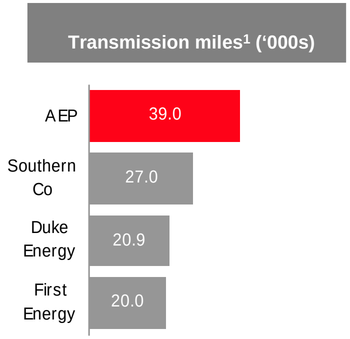
American Electric Power



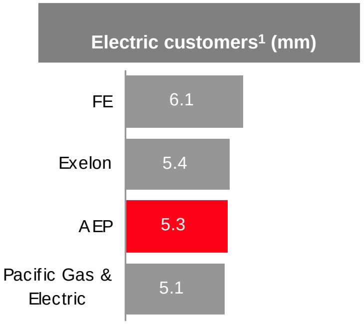
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

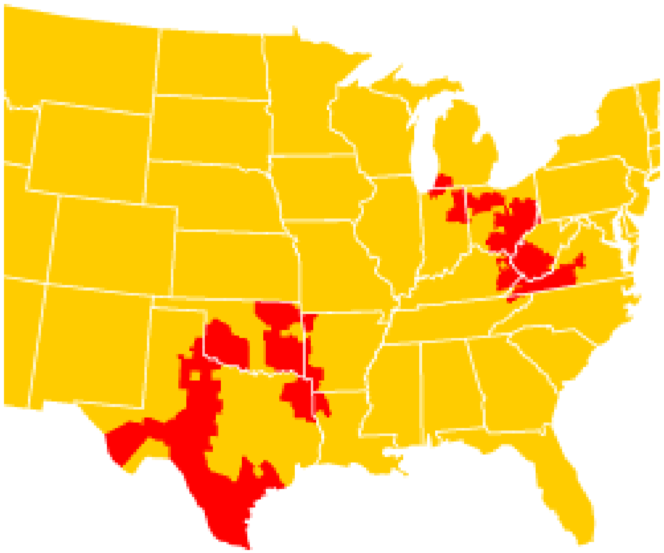


One of the largest U.S. electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.9B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

Strictly Confidential

KPSC Case No. 2011-00401
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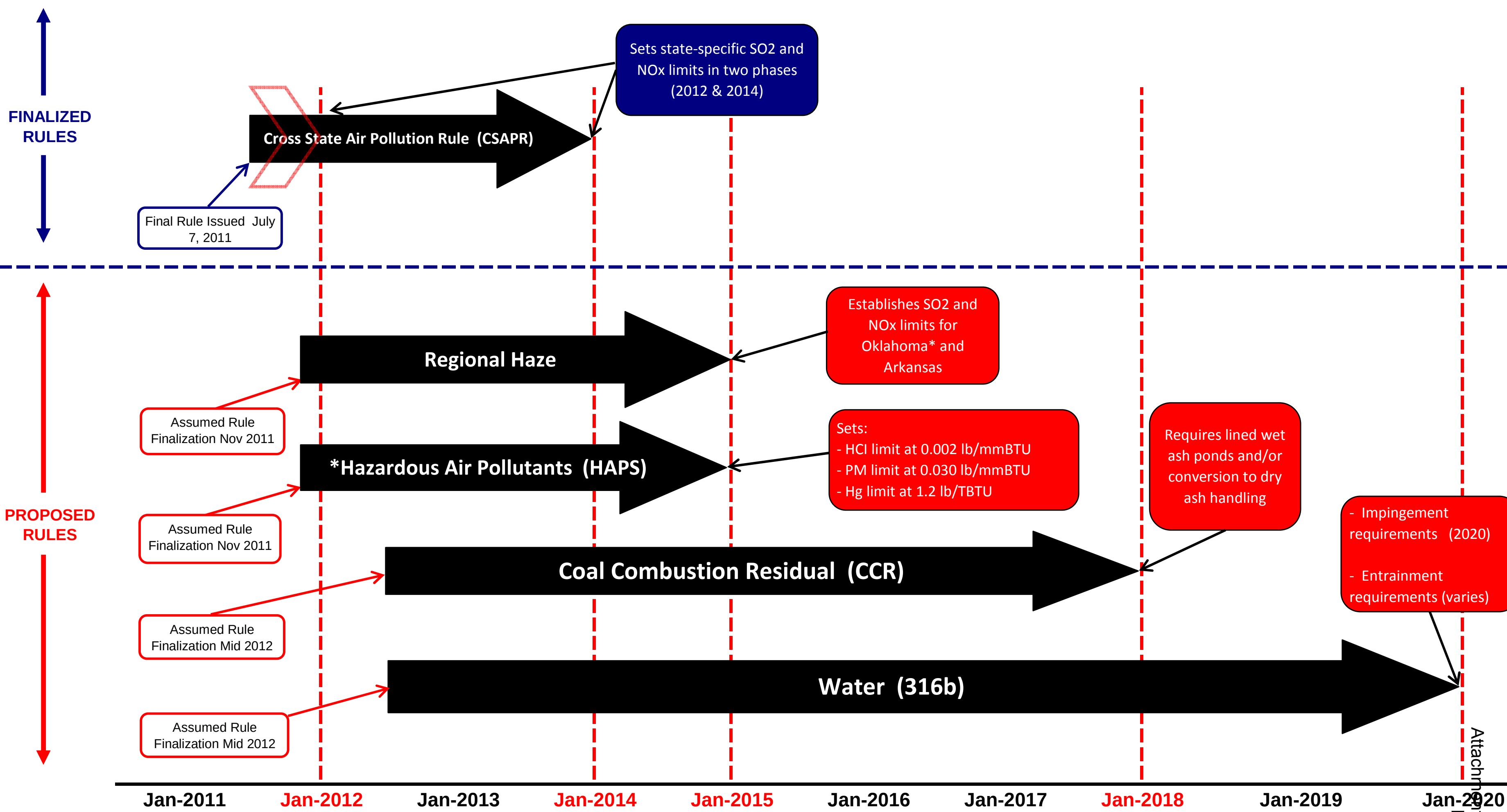
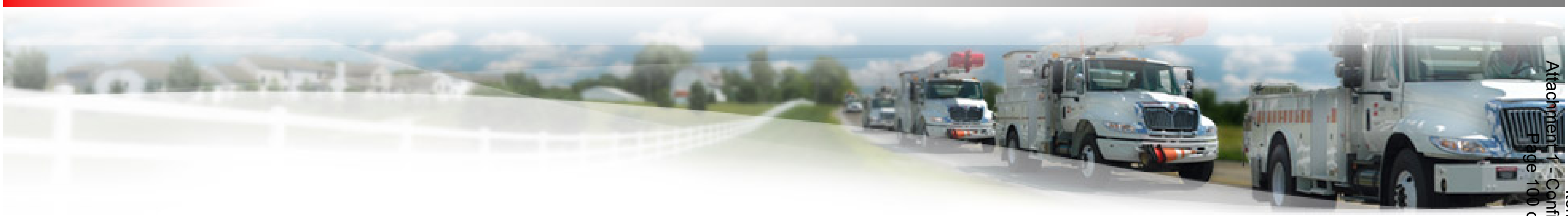
EPA Regulatory Deadlines



*** Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.**

AEP AMERICAN® ELECTRIC POWER

Barclays Office Visit
February 3, 2011



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Nick Akins - President

Brian X. Tierney - EVP and CFO

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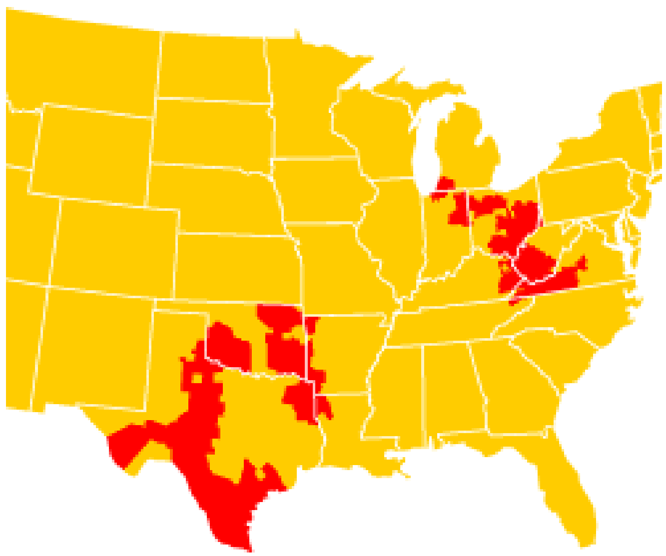
  - Return of Capital to Shareholders
  - Pension Funding
- **Strong Balance Sheet**
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- **Growth Opportunities**
  - Capital for utility platform
  - Transmission projects
- **Dividend yield of 5%**

Serving electric customers in 11 states



AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$17.7B Market Capitalization
BBB/Baa2/BBB credit rating

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Capital for Growth
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012
- Return of Capital to Shareholders
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings
- Capital to Reduce Risk
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Managing Operations and Investment

Challenges:

Required refinement of the operating company model and improved line-of-sight management due to decreased load growth, regulatory lag, reduced rate headroom, and environmental challenges

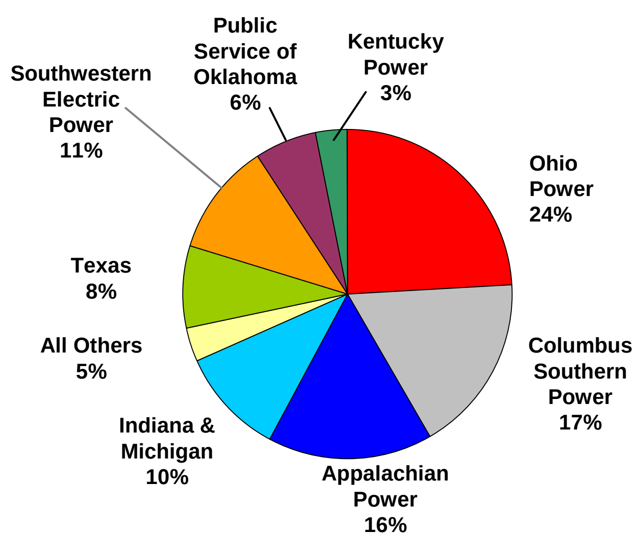
Actions:

- Empower operating company employees to drive results
- Efficiently allocate capital
- Demonstrate O&M and capital expenditure discipline
- Identify asset renewal strategy for investing in traditional distribution and transmission assets that enhance reliability and customer satisfaction
- Enable long-term planning discussions with regulators and legislators

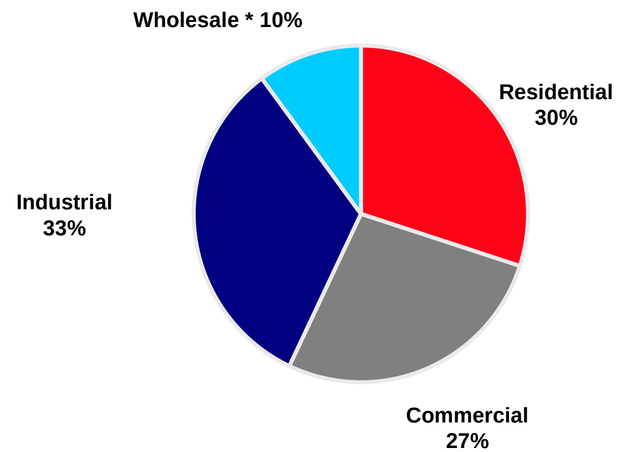
Expected Outcomes:
Optimize spending for more efficient return on investment
Improve dialogue with customers and regulators
Minimize lag in rate recovery

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



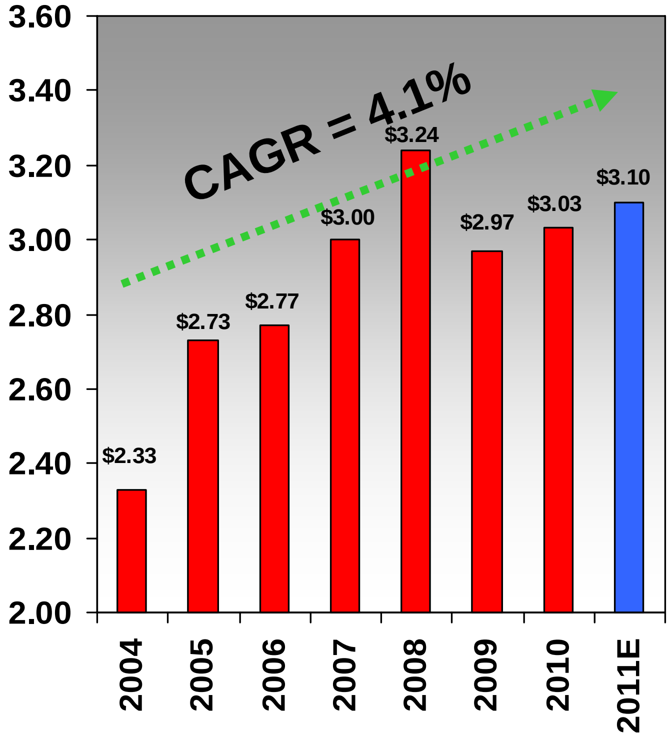
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

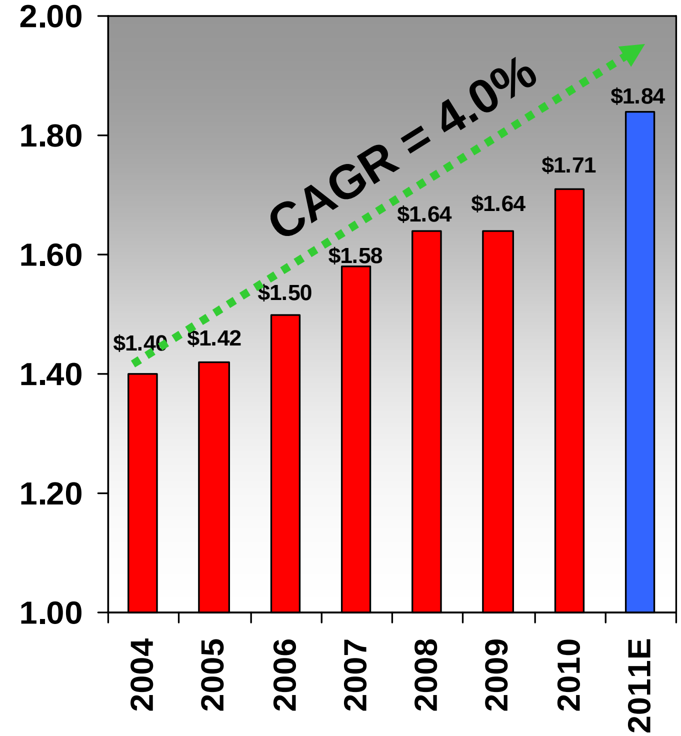
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



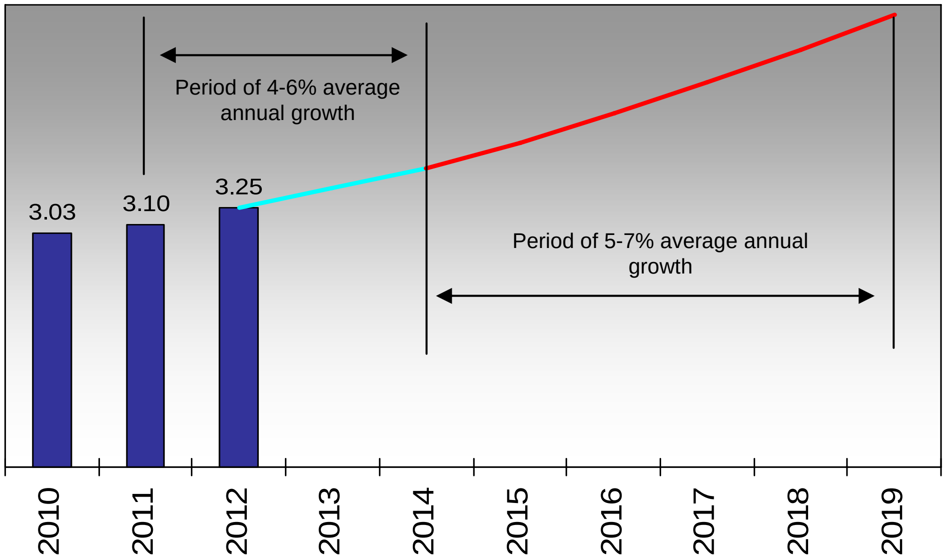
= subject to Board of Directors approval

- Dividend increased 12% in 2010
- 403rd consecutive quarterly dividend declared in January 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Ohio ESP Filing – Core Policy Issues

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

KPSC Case No. 2011-00401
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Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Approved Rate Bases & ROEs

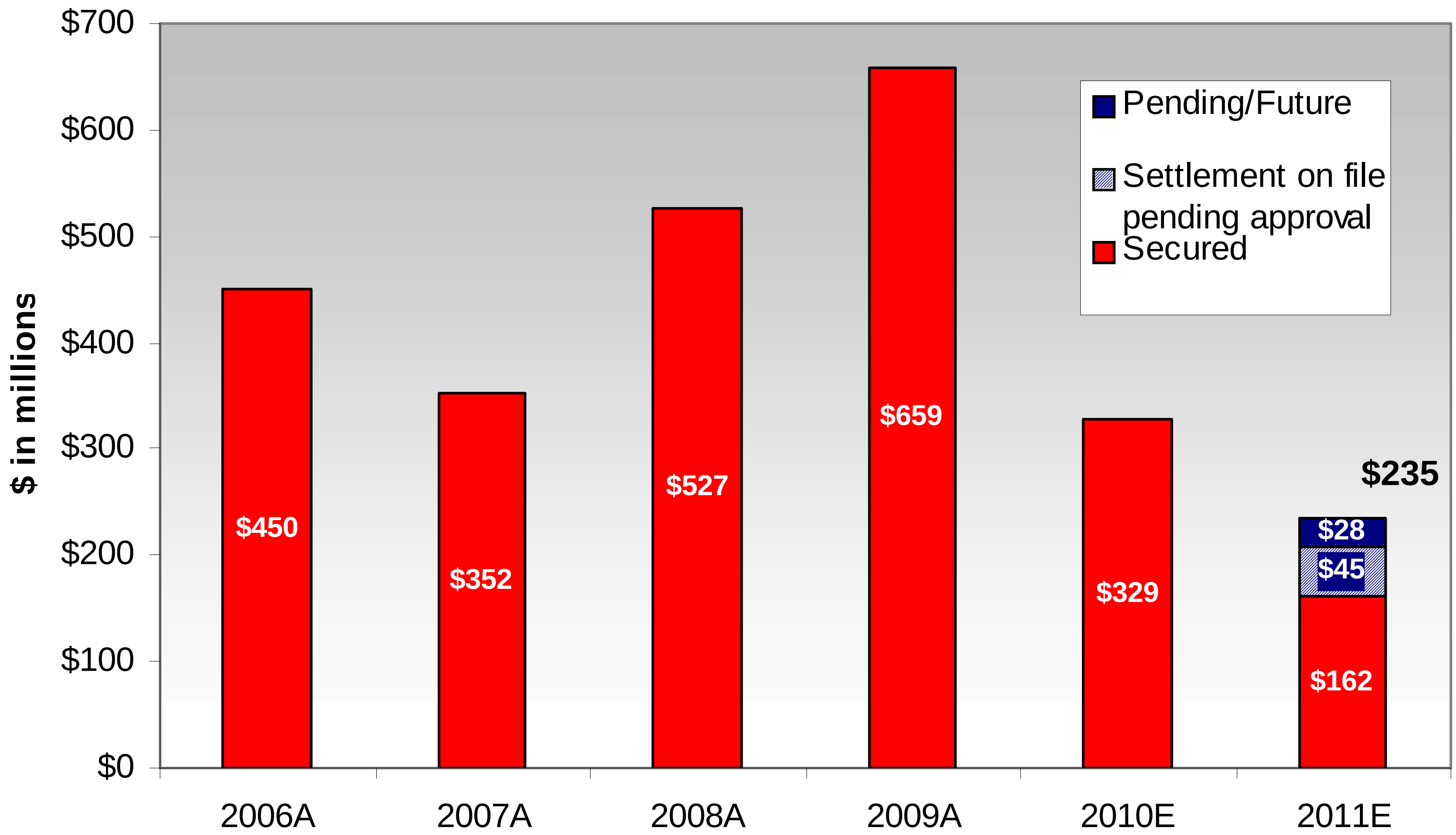
Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

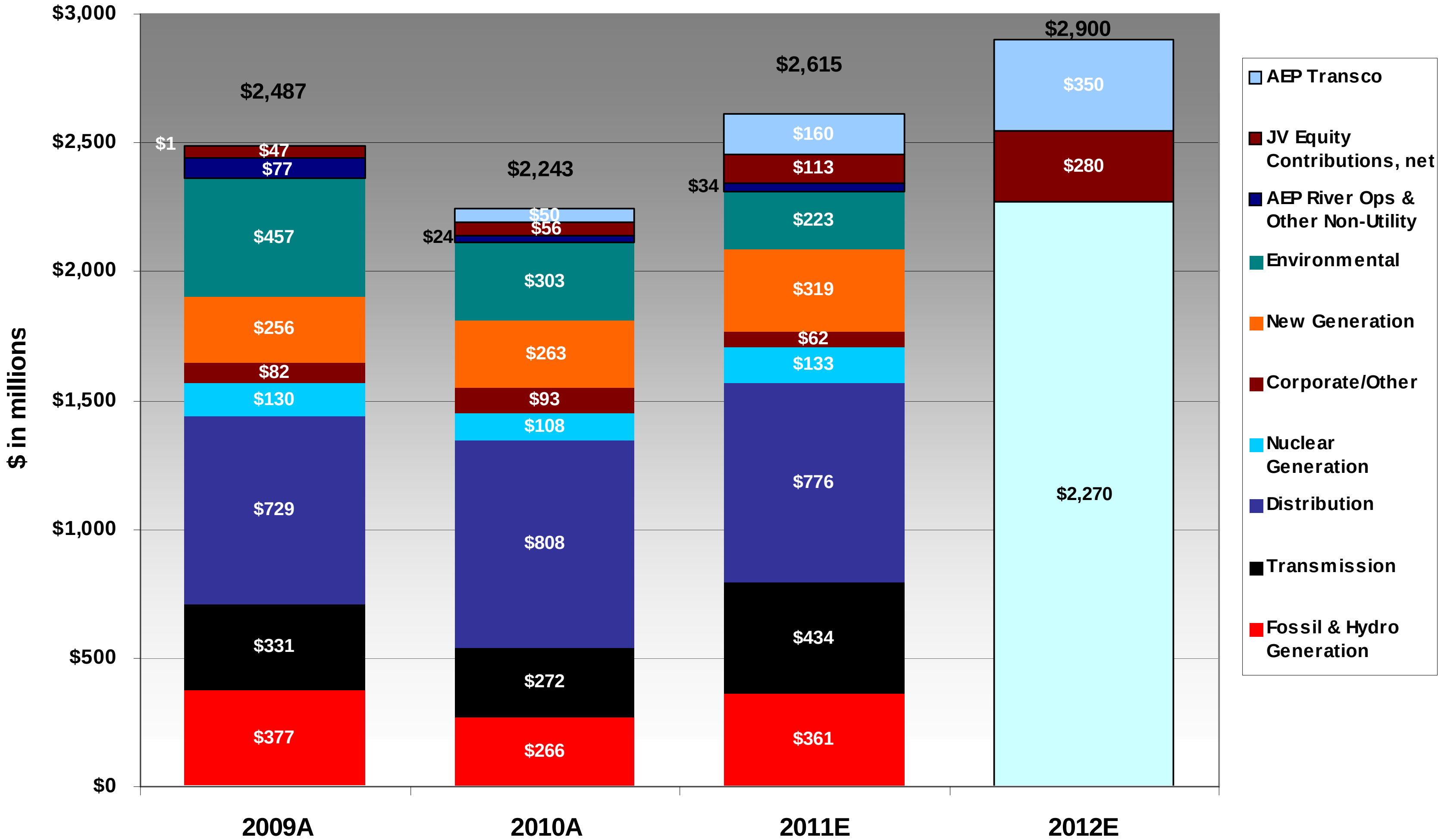
Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Active or pending rate cases include West Virginia and others yet to be filed

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Cash Flow Guidance

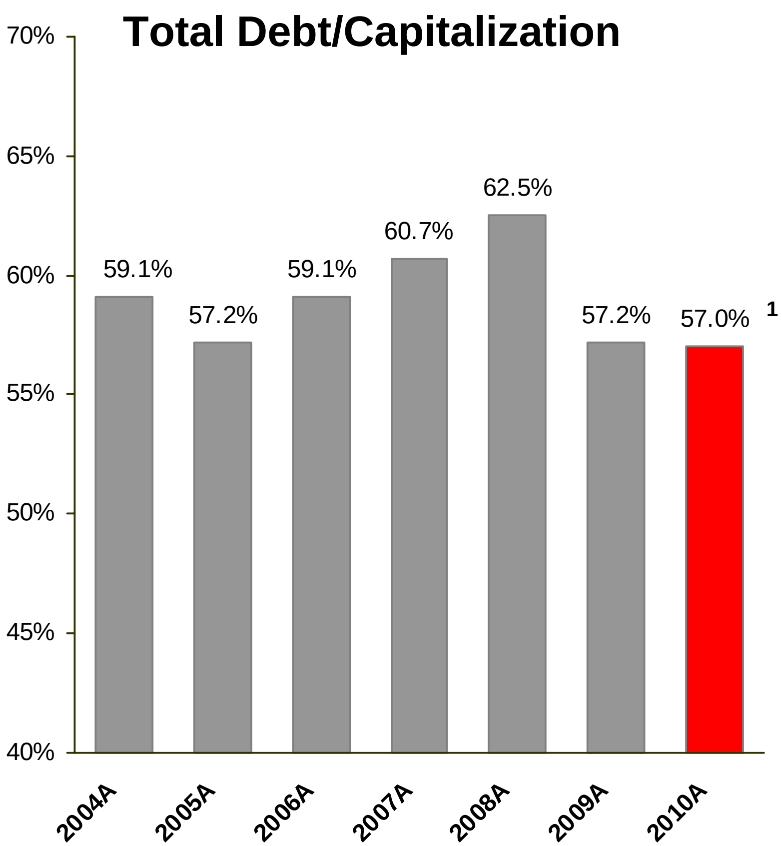
AEP®

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to September 30, 2010 10Q *Enron Bankruptcy* pages 56-57 for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



Current Liquidity Summary

Liquidity Summary (unadited)	**Actual 12/31/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Detailed Ongoing Earnings Guidance

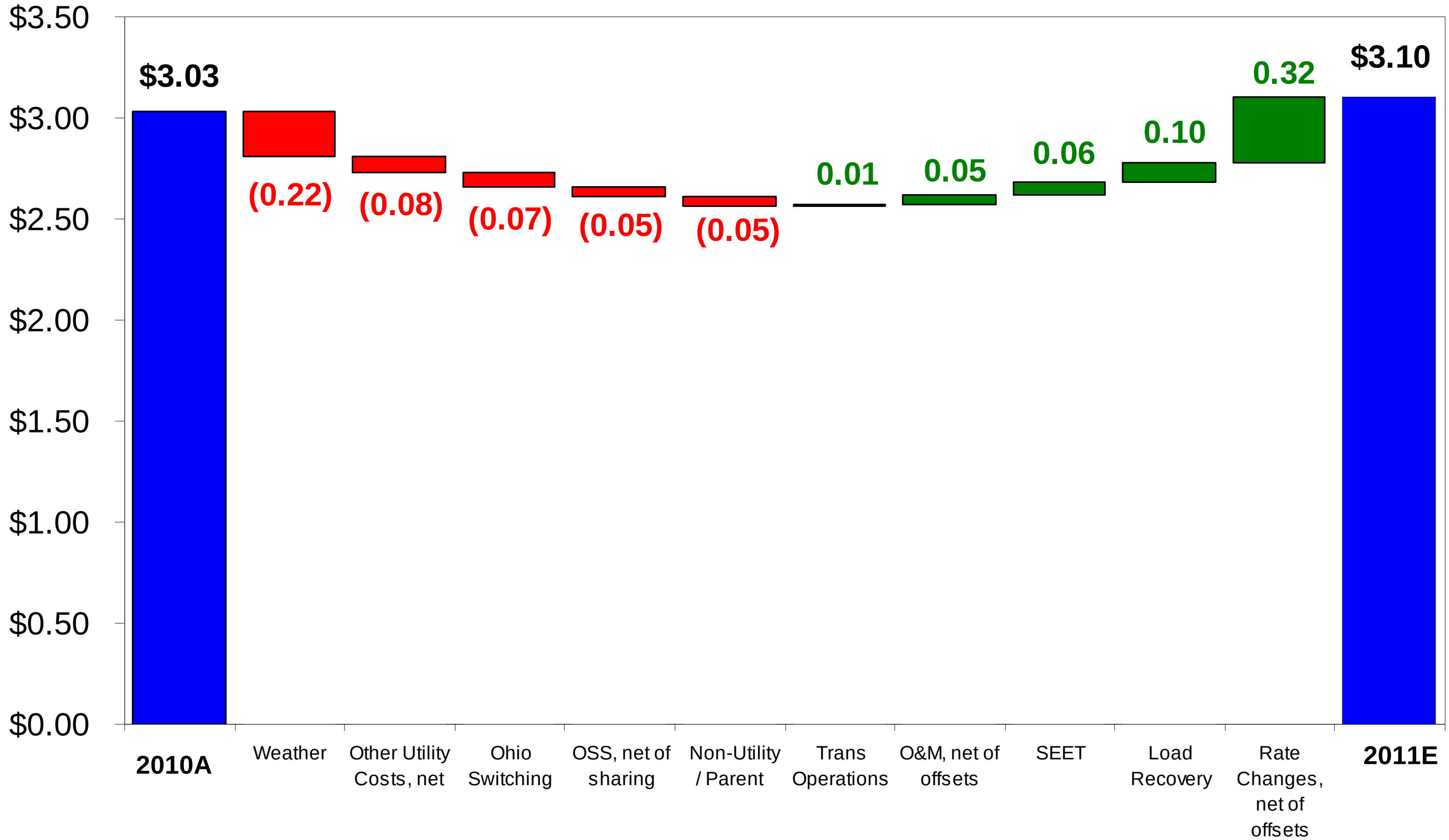
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

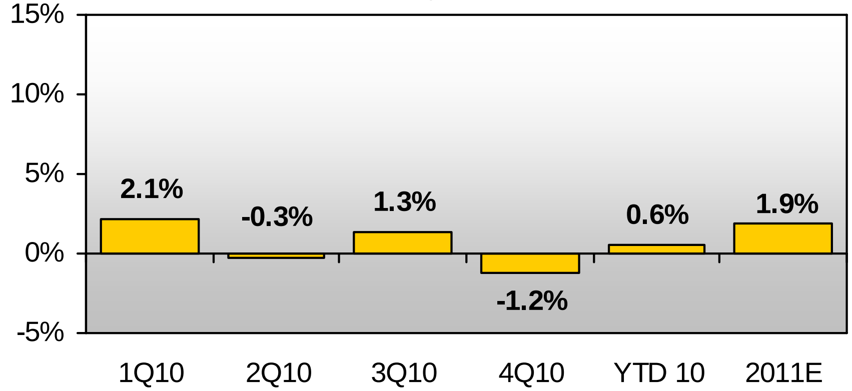


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

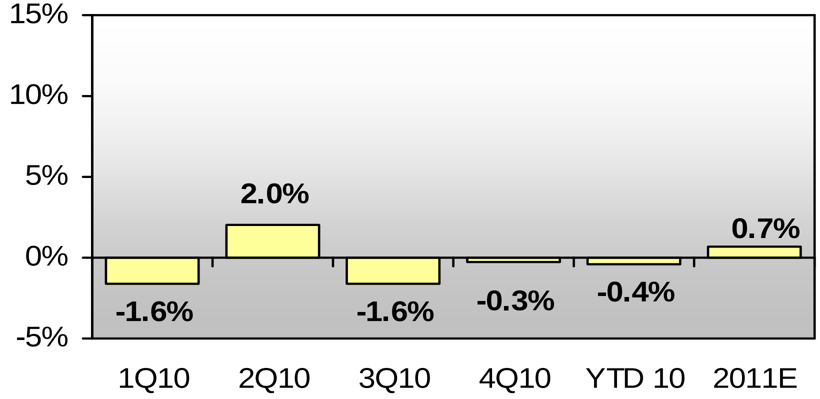
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

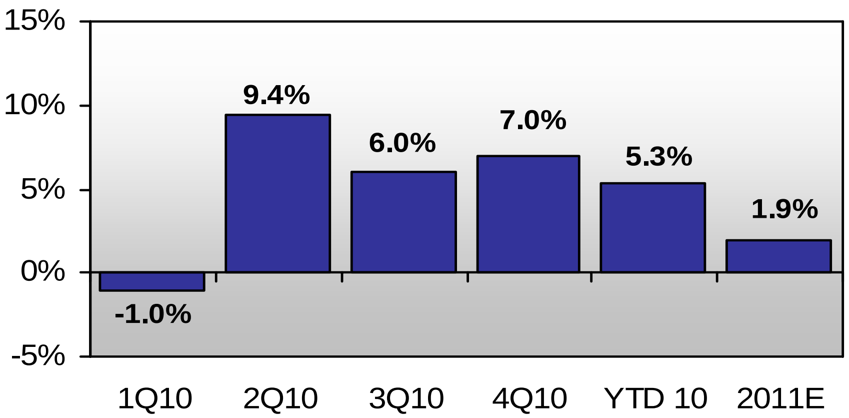
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



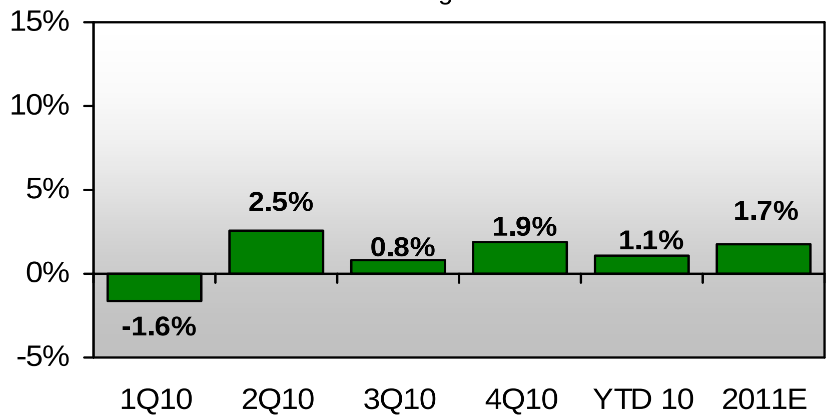
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

2011 Guidance and Business Initiatives

2011 Guidance: $3.00 - $3.20 per share

2011 Earnings Drivers

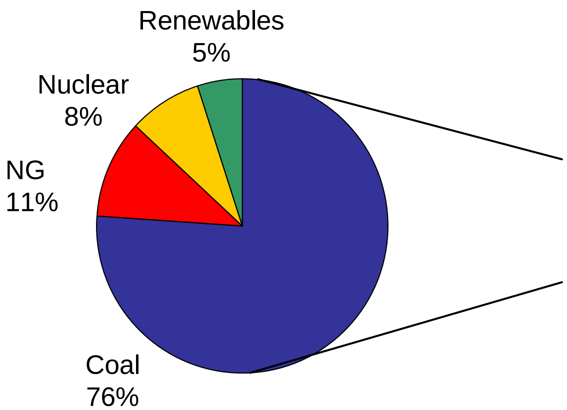
- Recovering Economy
- Rate changes (69% secured)
- Continued O&M discipline - $34M decrease net of offsets
- Customer switching – Ohio
- 2010 SEET at Columbus Southern Power

Business Initiatives

- Operating Transcos in OH, OK and MI; filings pending in other states
- AEP Eastern System Interconnection Agreement
- Bonus Depreciation
- Capital Allocation

AEP Generation Capacity

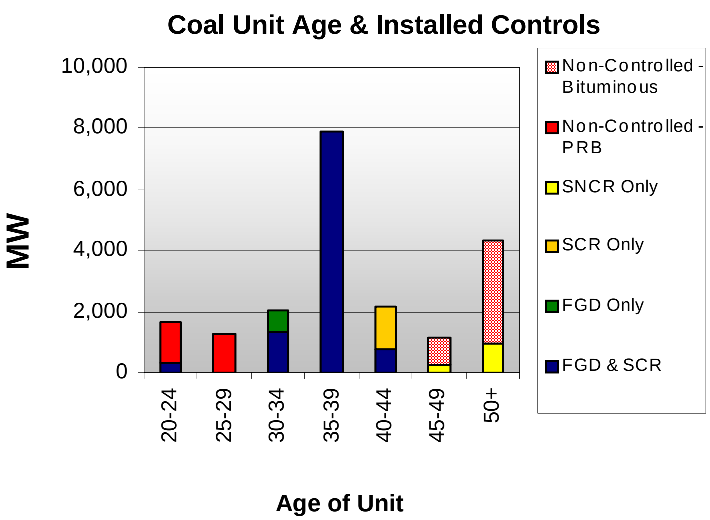
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



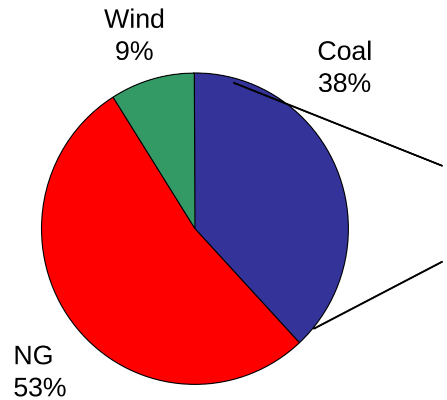
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



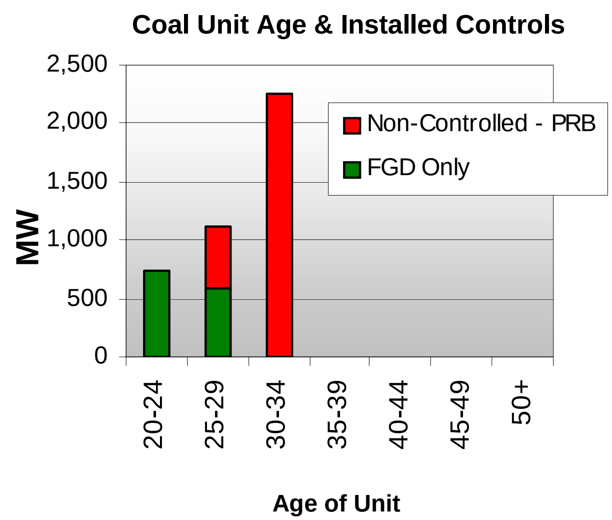
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

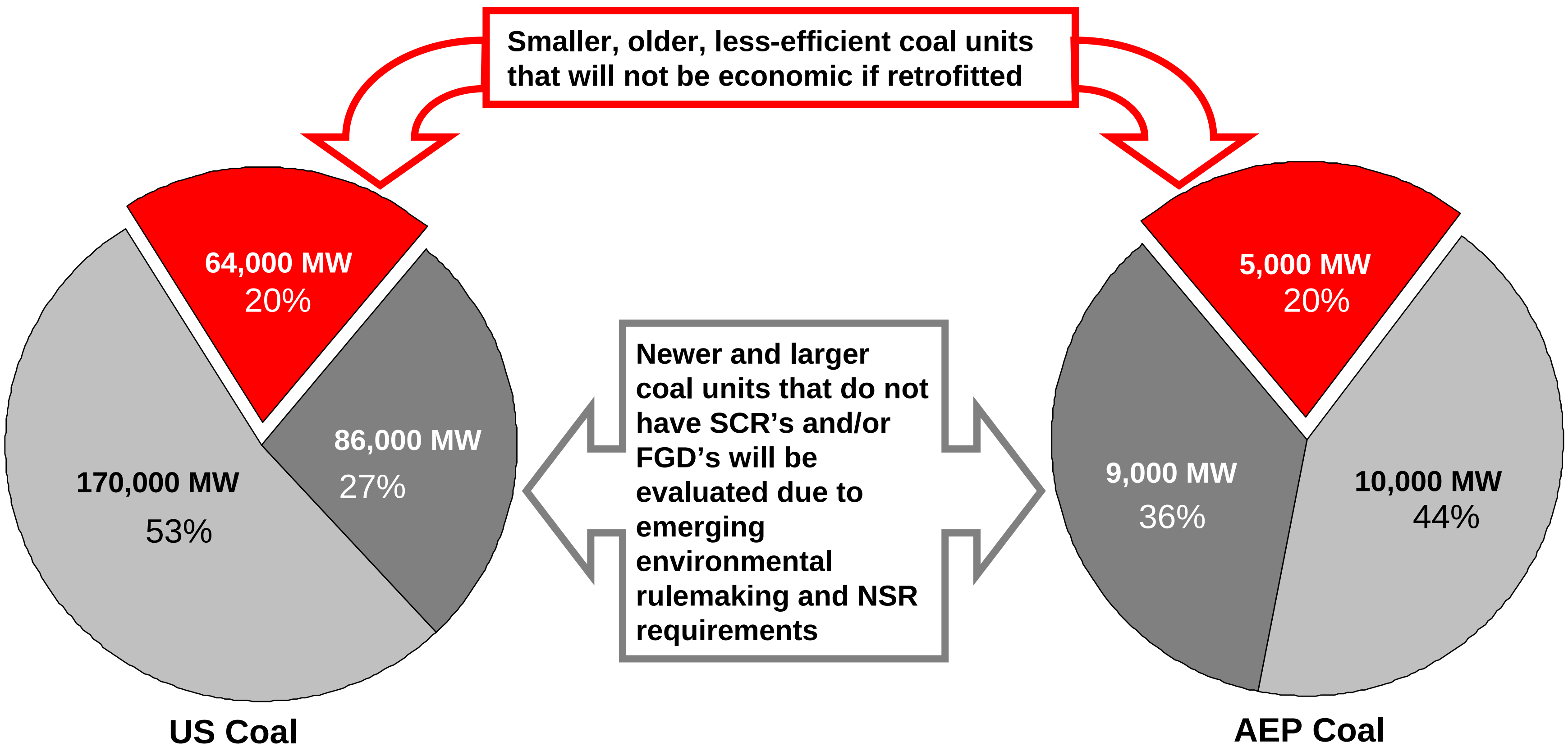
Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

CCS Candidates

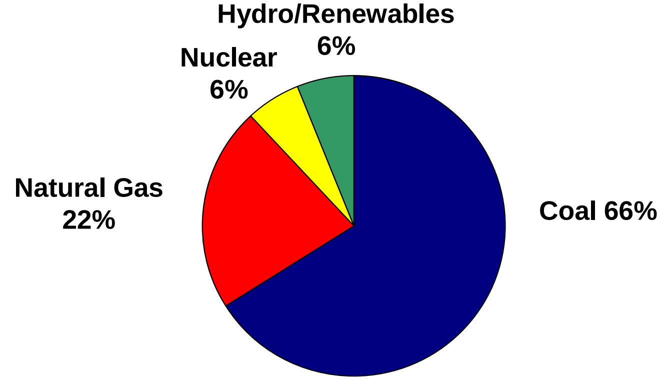


Nearly 50% of U.S. coal plants are exposed

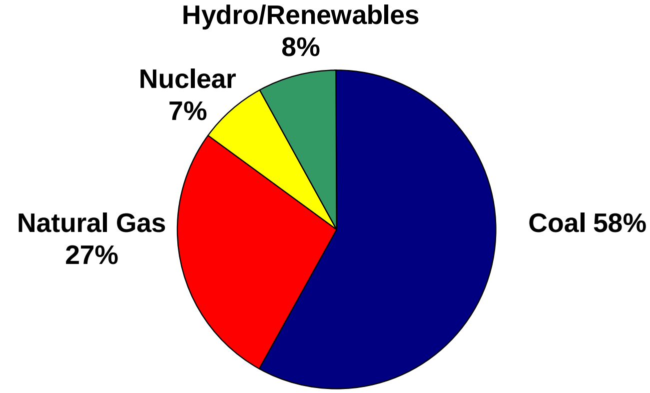
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of "partially exposed" units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



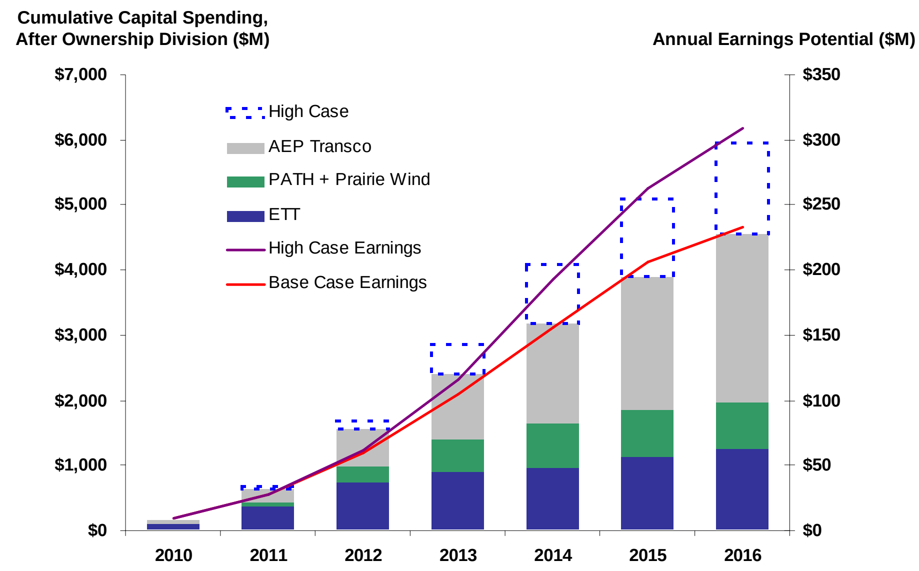
Capacity - 2009



Projected Capacity - 2017

Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on one CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - **Ohio application was approved by PUCO on December 29, 2010**
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Pursuing regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

ETT: An Operating Utility

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Electric Transmission Texas

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

Prairie Wind Transmission, LLC

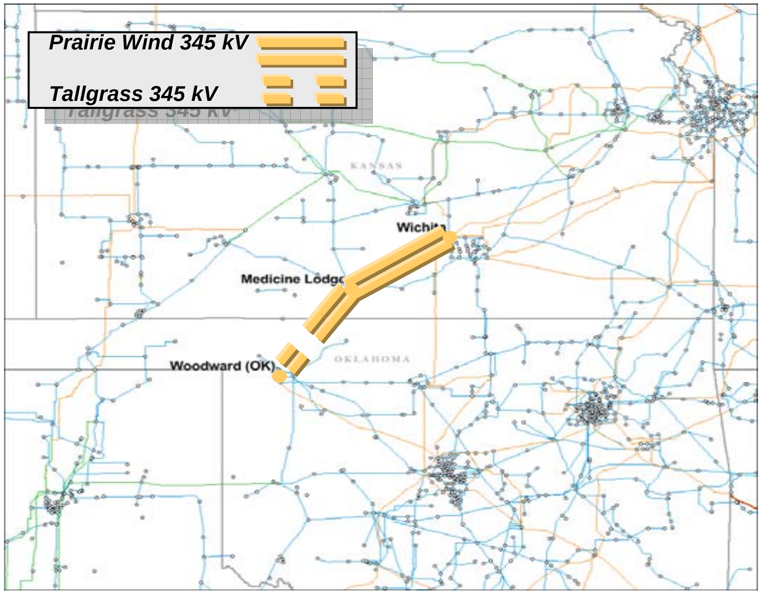
<u>Project Description</u>: 110 miles of EHV transmission lines extending from Wichita, KS to the KS/OK border

Overview:

- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost $225 million and be in-service by 2013-2014
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC was issued to Westar July 2010. Currently working on a novation of the NTC to Prairie Wind. As a Transmission Owner, Prairie Wind will be entitled to collect revenue upon the novation of the Notice to Construct.
  - Currently approved at 345 kV.

Key Challenges:

- Siting and Routing



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

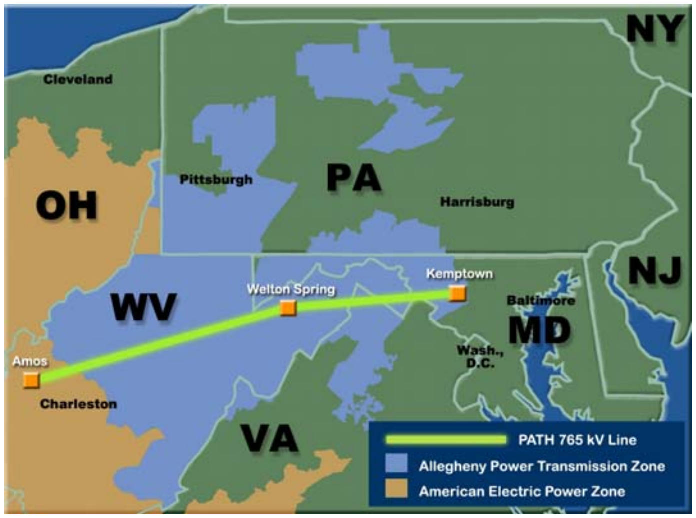
Prairie Wind Transmission
A joint venture between Westar Energy and ETA

Update on PATH, LLC

Project Description: 276 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new Welton Spring substation in Hardy County, WV, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- FERC order issued on November 19, 2010 set the 14.3% ROE for hearing
- Total estimated cost of entire line is $2.1 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.4 billion. AEP share is approximately $700 million
- Estimated completion date: June 1, 2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

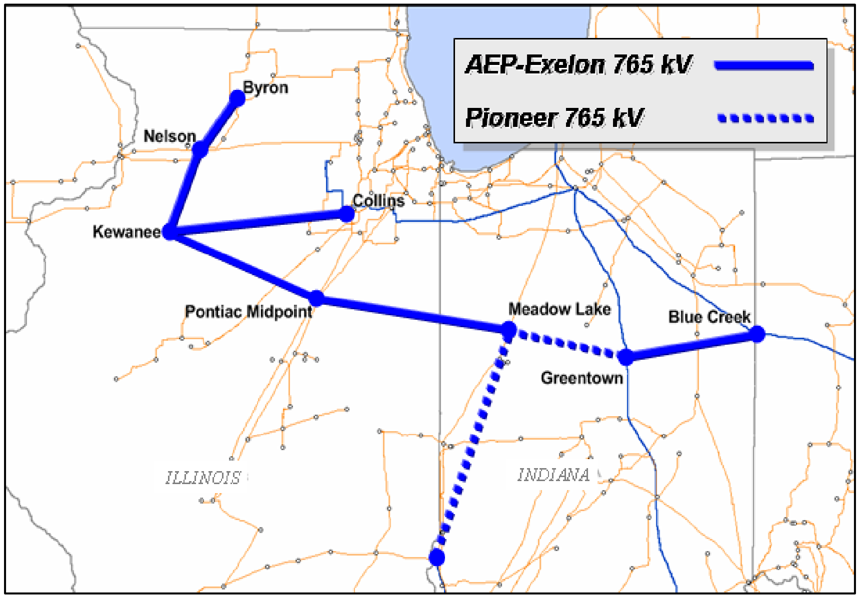
Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia, and Maryland
  - CPCN applications are filed and accepted in all three states
  - PJM released a draft 2011 Load Forecast that could affect the required in-service date for PATH
  - PATH filed motions in all three states in December 2010 for a delay in the procedural schedule to allow for the filing of supplemental need testimony to reflect the 2011 PJM Load Forecast

PATH
Potomac-Appalachian Transmission Highline

RITELine Project

- AEP, ETA and Exelon Corporation executed a Memorandum of Understanding on October 26, 2010 for the development of the Reliability Interregional Transmission Extension Line (“RITELine”) project

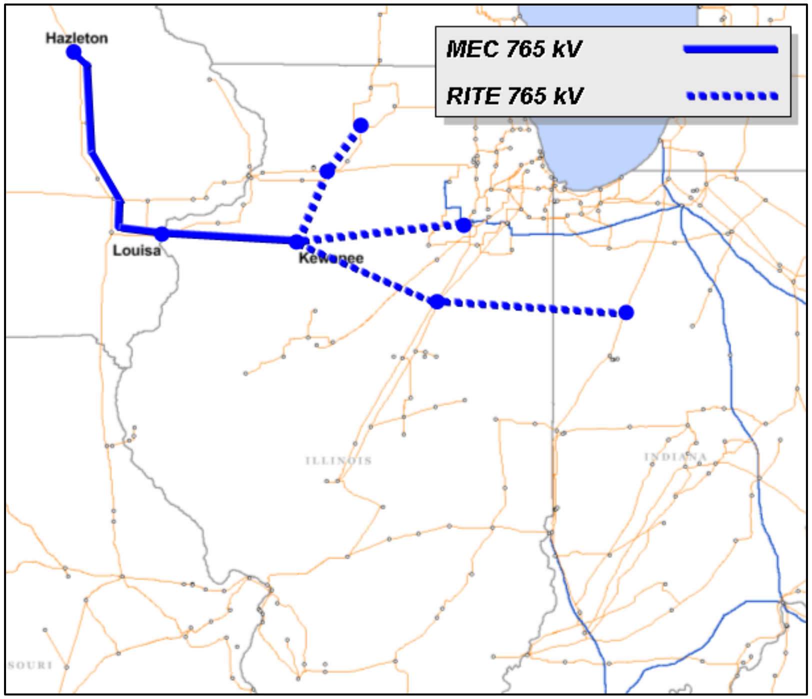


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- Estimated Project Cost: $1.6 billion
- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV line)
- Extends approximately 420 miles from the Byron Substation in Illinois to the Blue Creek substation at the Ohio/Indiana border and from Kewanee to the Collins Substation in Illinois

MEC Project

- ETA and MidAmerican Energy Company executed a Memorandum of Understanding on October 28, 2010 for the development of the MEC project



- Estimated Project Cost: $650 million
- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV)
- Extends approximately 180 miles from the Kewanee Substation in Illinois to the Louisa substation in Iowa and northwest to the Hazelton substation

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 130 of 9556

AEP AMERICAN ELECTRIC POWER®

RBC
Office Visit
March 22, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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AEP Ohio ESP Filing – Core Policy Issues

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

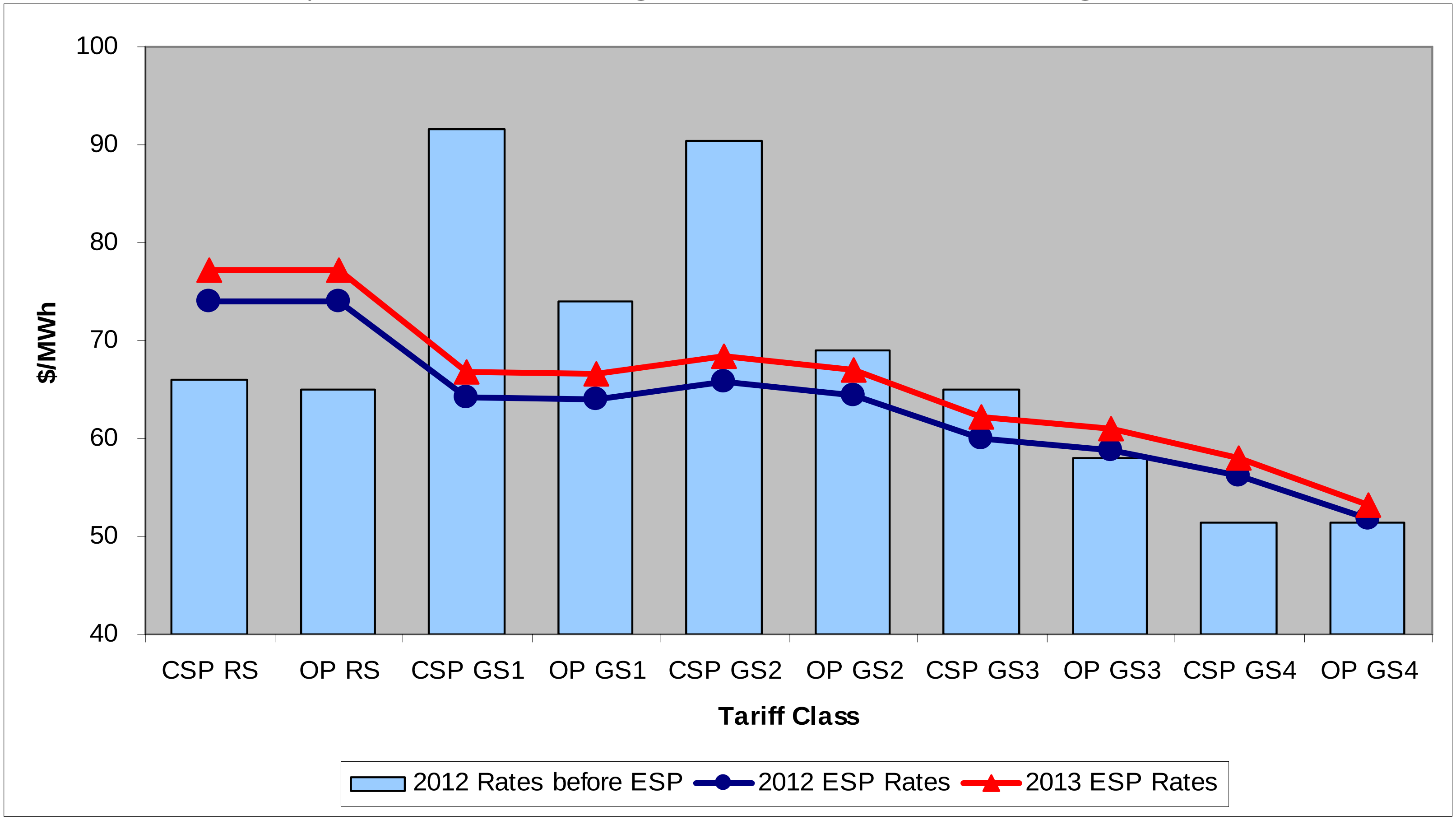
	2012			2013			2014		
	Revenue	$/MWh	%	Revenue	$/MWh	%	Revenue	$/MWh	%
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline

ESP → FAC → Distribution Case → **Recovery & Risk Mitigation**

Regulatory Activity	1Q10 – 4Q12 (Jan 2010 – Dec 2012)
Merger of CSP & OP	PUCO Application; FERC Application; Expected Closure
Proposed ESP (2012-2014)	ESP Application Filed; Proposed ESP Rates & Mechanisms in Place
Distribution Case $93.2MM base case filed Feb 28, 2011	Distribution Base Case Notification Filed; Rates May Be Implemented Subject to Refund
Capacity Charge (FRR) Filing	FERC Filing; FERC Ordered adherence to PUCO mechanism; Filing for FERC Rehearing due by 2/2/11; PUCO Opens Investigation; AEP files motion & memorandum to stay the reply comment period & establish procedural schedule; PUCO grants motion for extension
Trans. Cost Recovery Rider	Annual Filing; Annual Filing; Annual Filing
Environmental Rider	Annual Filing; Annual Filing; Annual Filing
FAC Filings	(Qtrly); Annual Audit; Annual Audit; Annual Audit
Sporn 5 Cost Recovery Request	Sporn 5 Closure Cost Recovery Application Filed
Annual SEET Filing Dates	1st SEET Annual Filing (FY2009); SEET Order Received; 2nd SEET Annual Filing (FY2010); 3rd SEET Annual Filing (FY2011)

AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Procedural Schedule - tbd

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

AEP AMERICAN® ELECTRIC POWER

Goldman Sachs
Office Visit

Columbus, OH
March 29, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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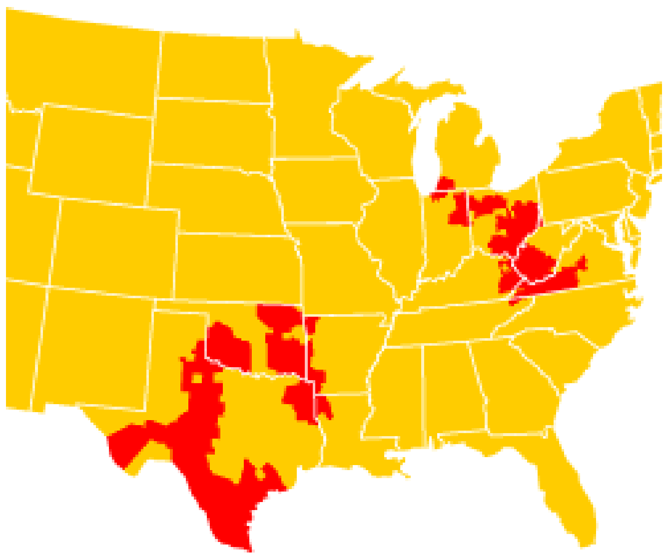
Table of Contents

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



AEP Fast Facts

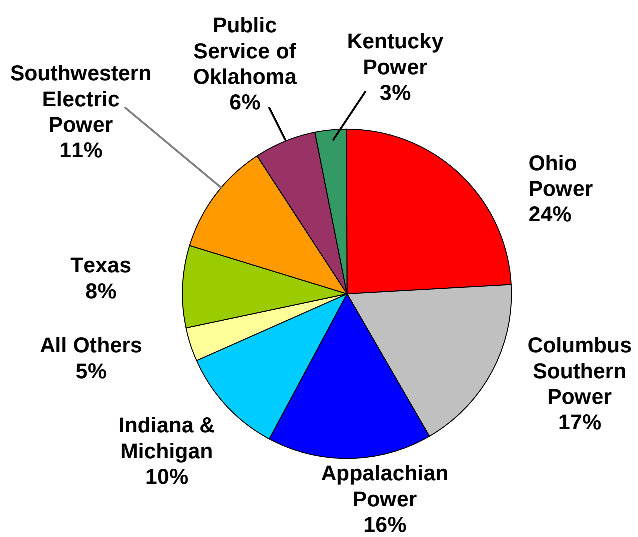
5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$16.7B Market Capitalization
BBB/Baa2/BBB credit rating

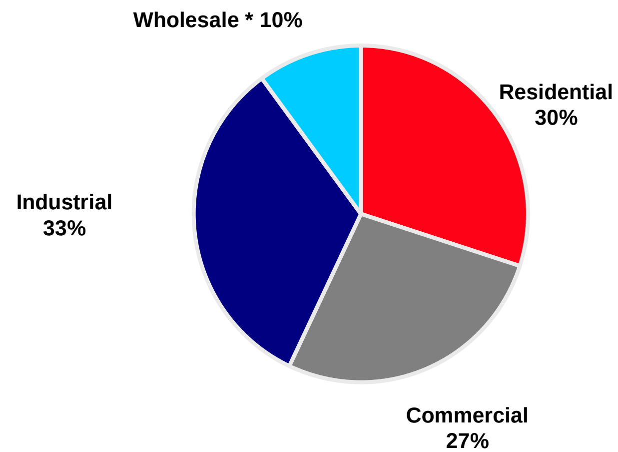
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load

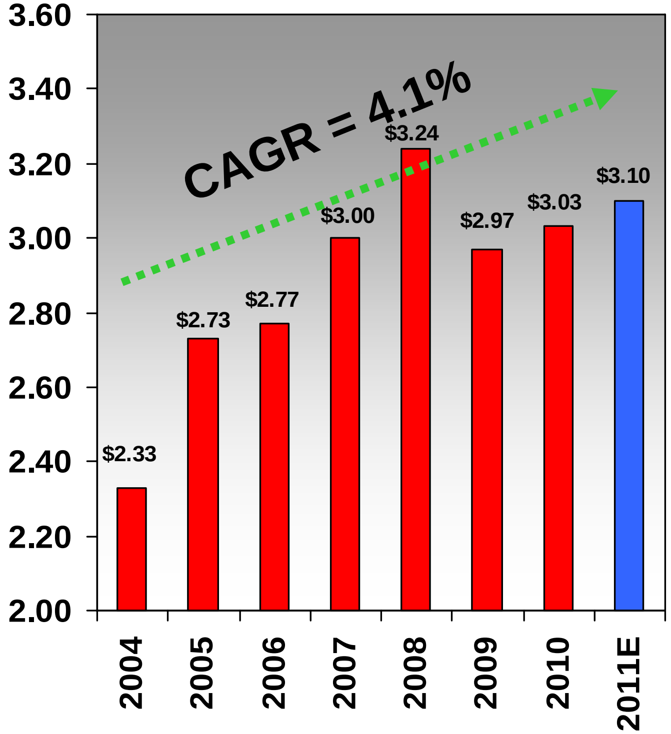


** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	**# of customers**
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

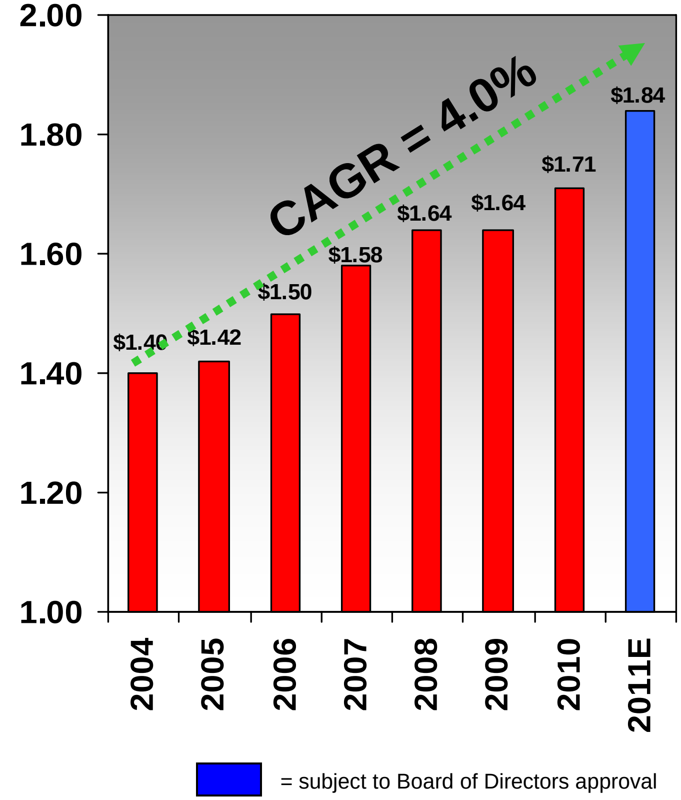
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

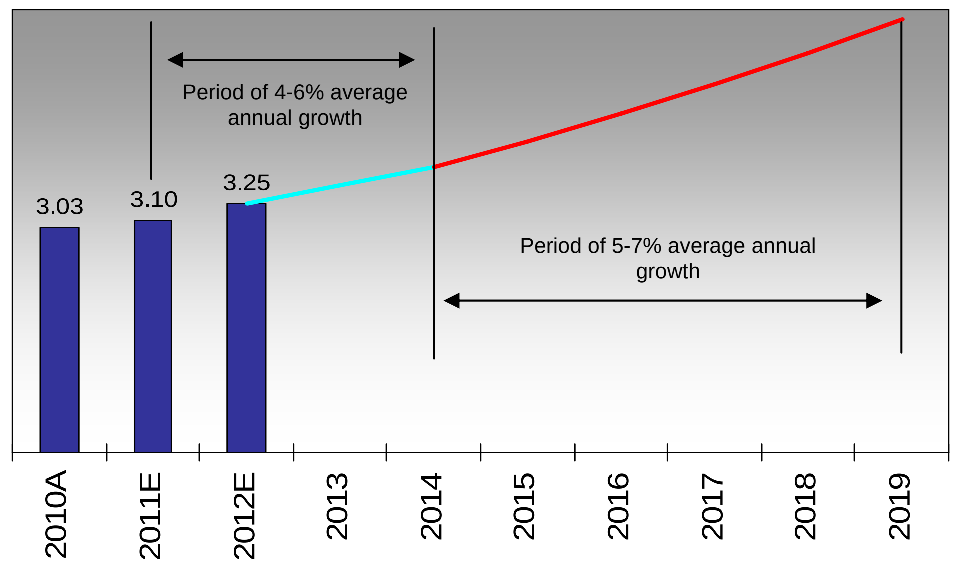


- Quarterly dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Detailed Ongoing Earnings Guidance

AEP®

2010A: $3.03

2011E: $3.00 - $3.20

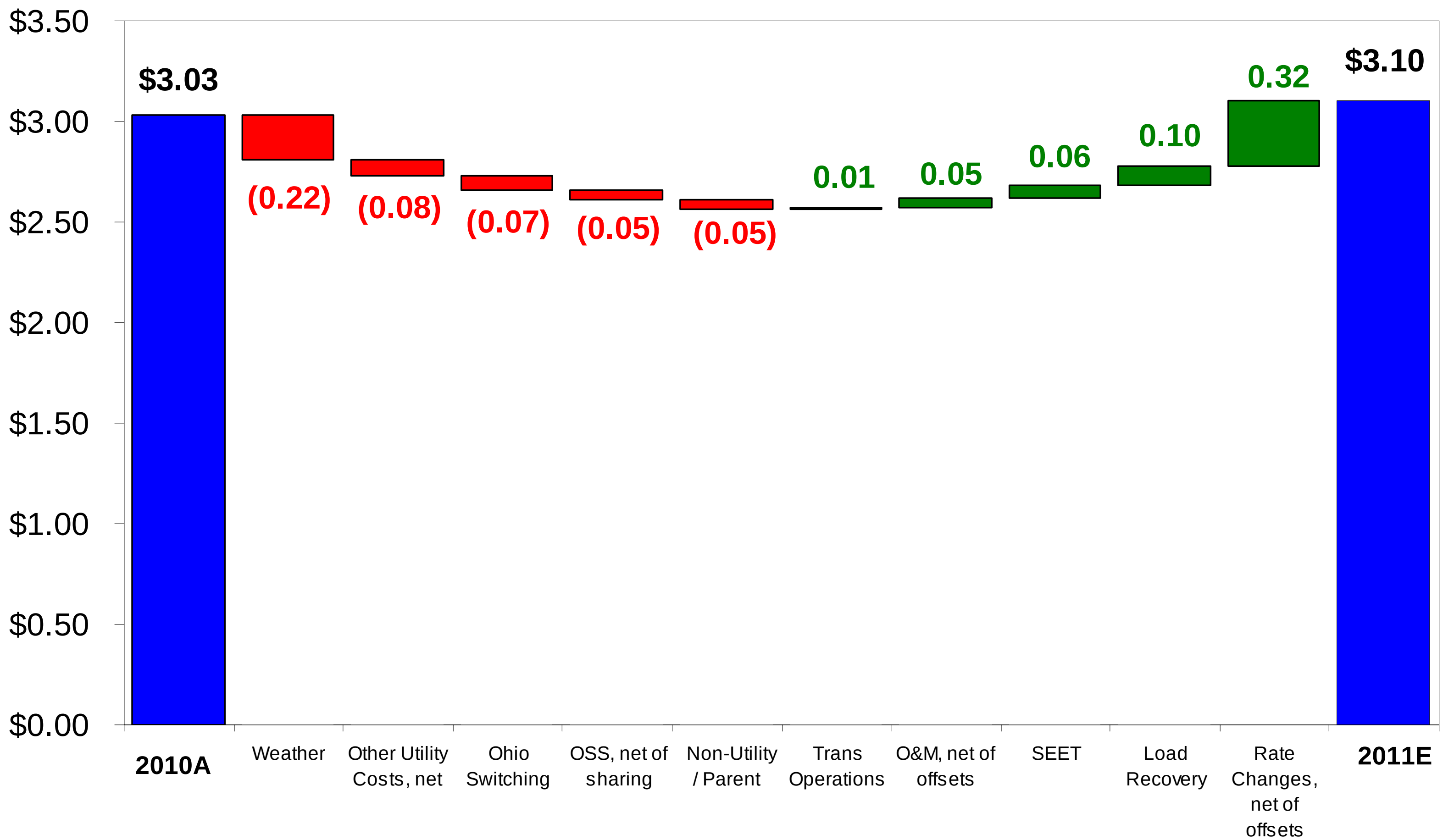
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

8

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

2011 Earnings Drivers

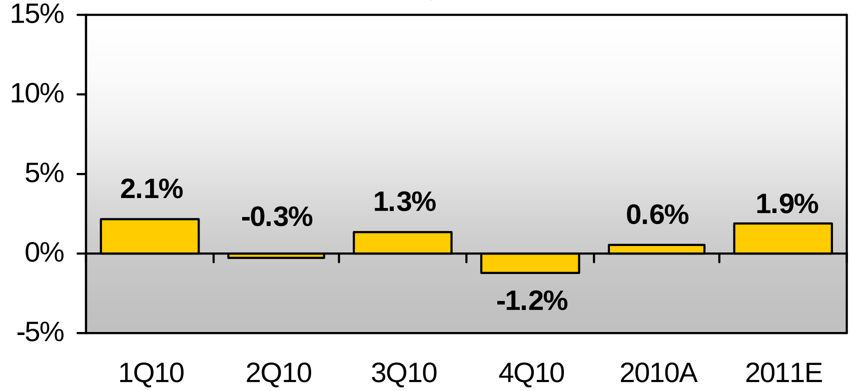


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

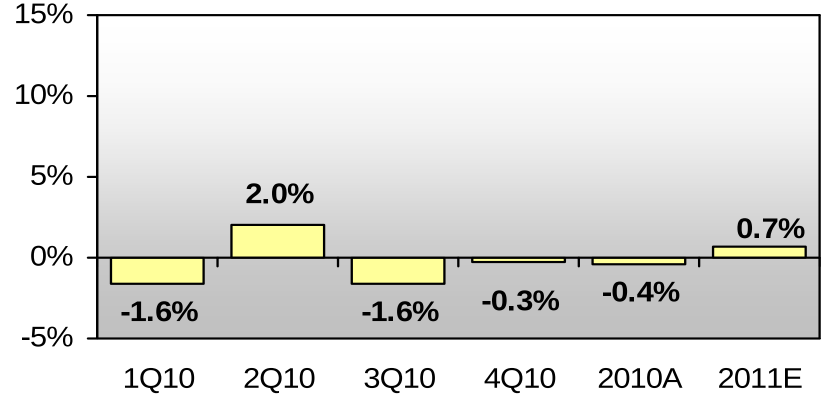
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

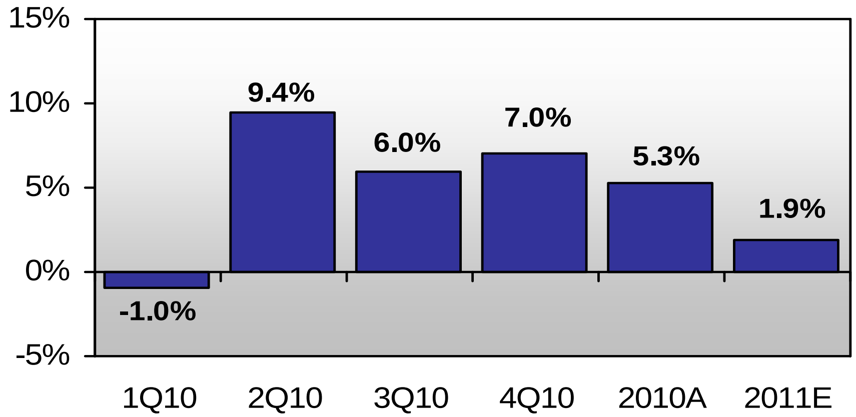
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



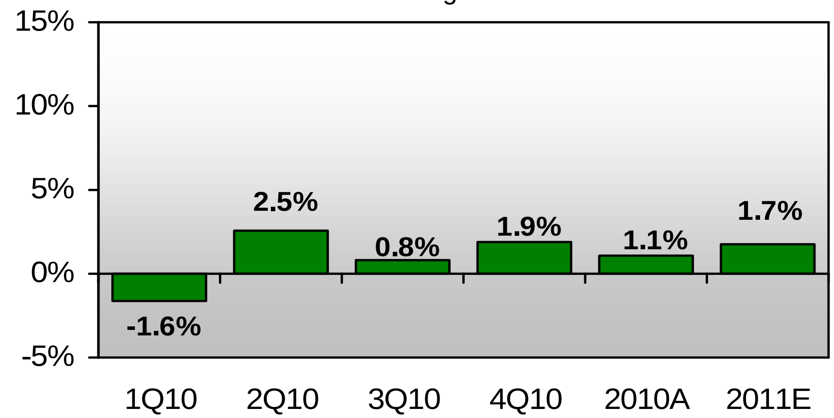
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

AEP®

$ in millions

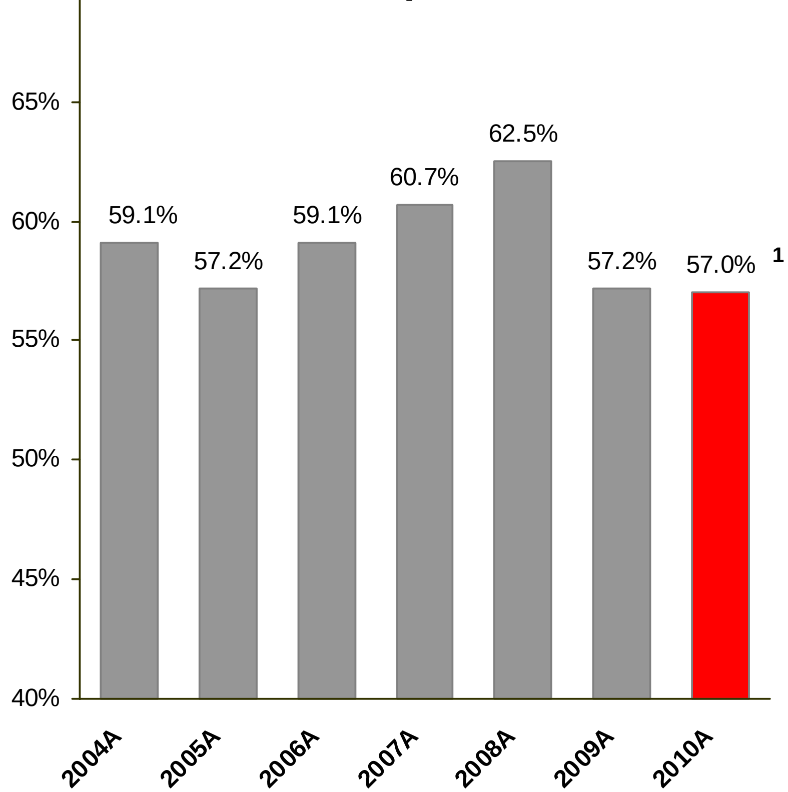
		2010A		2011E
Cash From Operations				
Income from Continuing Operations	$	1,218	$	1,499
Depreciation & Amortization		1,641		1,611
Pension Funding		(500)		(150)
Other Cash Flow Items		659		834
Litigation Resolution [1]		-		(449)
Working Capital [2]		279		7
Cash From Operations	$	3,297	$	3,352
Investing Activities				
Construction Expenditures		(2,318)		(2,644)
Other Investing Activity		(184)		(205)
Total Investing Activities	$	(2,502)	$	(2,849)
Financing Activities				
Dividends		(824)		(892)
Net Debt Issued/(Retired)[1]		(160)		234
Common Equity		93		150
Other Financing Activities		(100)		(72)
Total from Financing Activities	$	(991)	$	(580)
Beginning Cash Balance	$	490	$	294
Ending Cash Balance	$	294	$	217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity

Total Debt/Capitalization



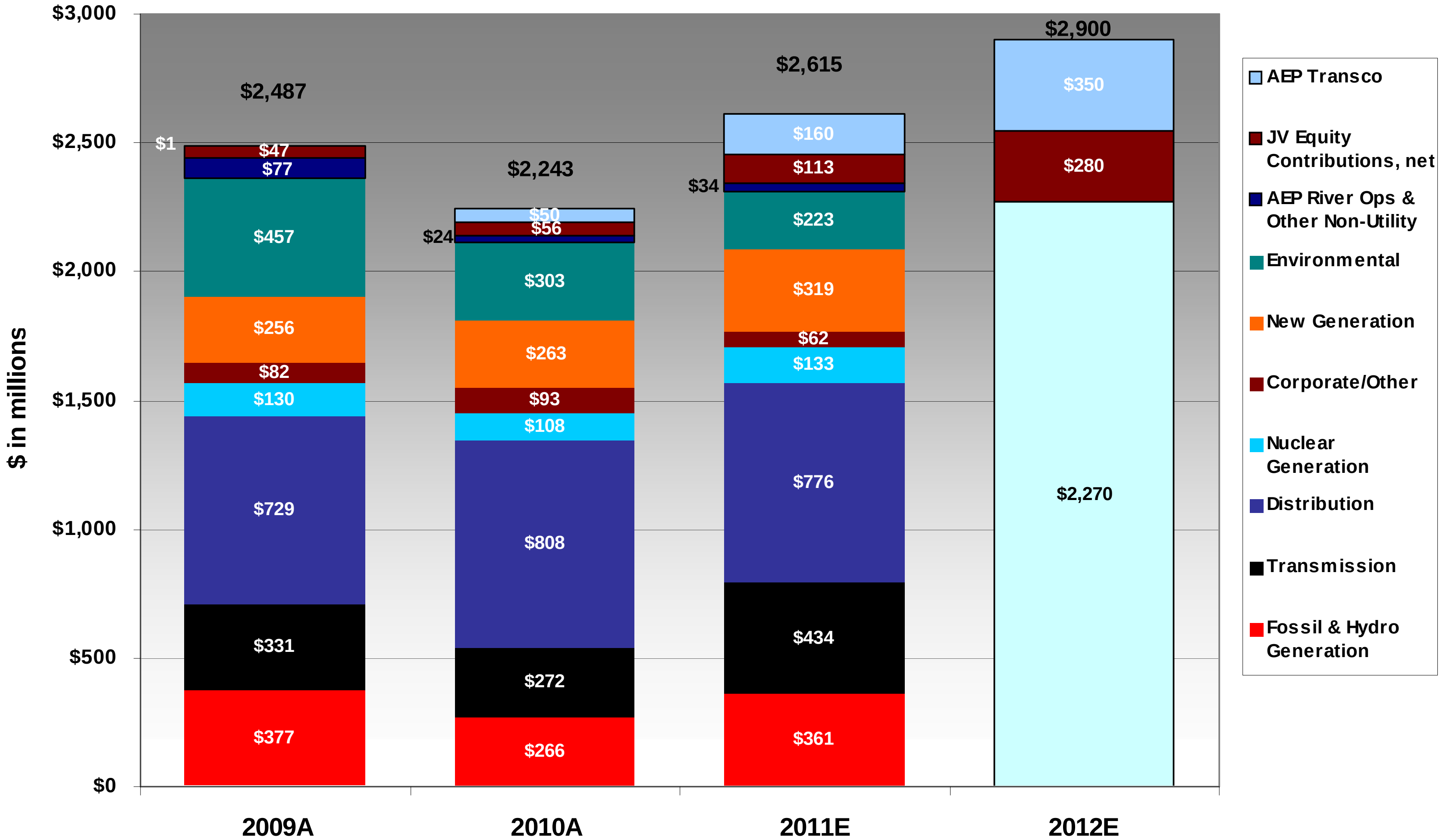
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Capital Expenditures

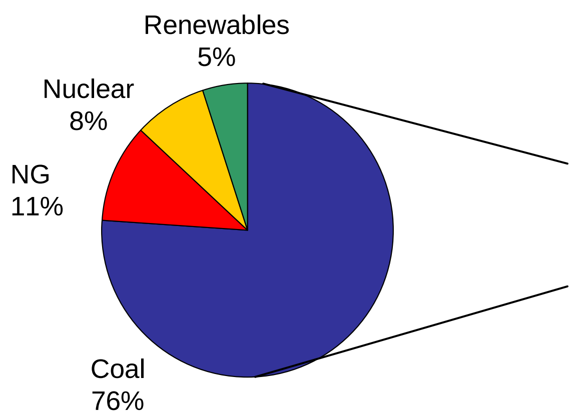


Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



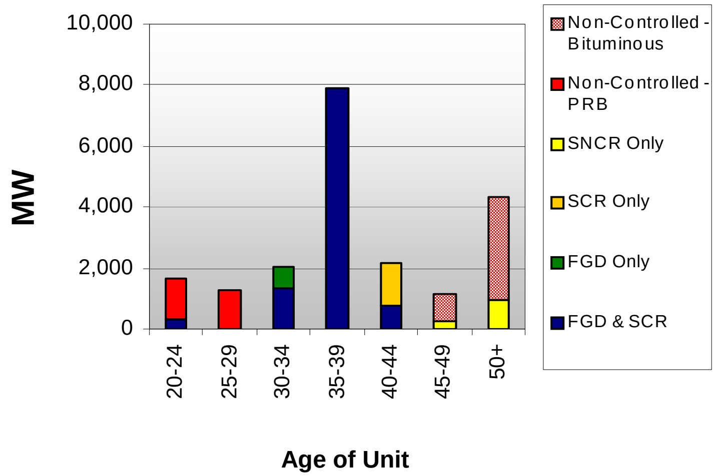
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost

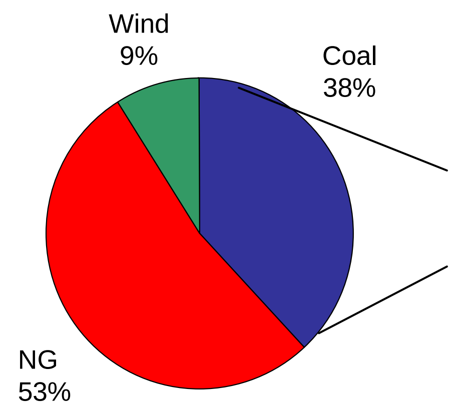
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton

Coal Unit Age & Installed Controls



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind



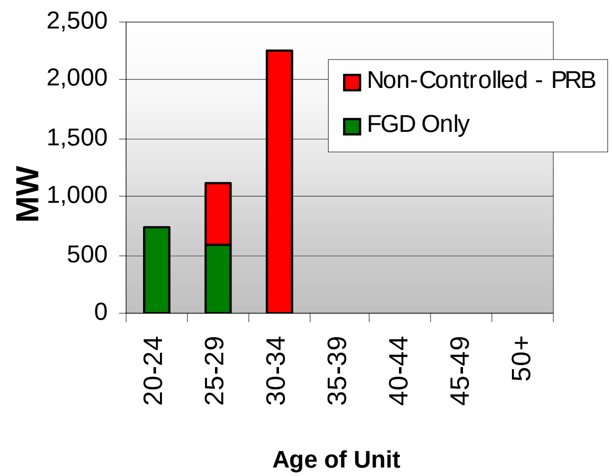
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

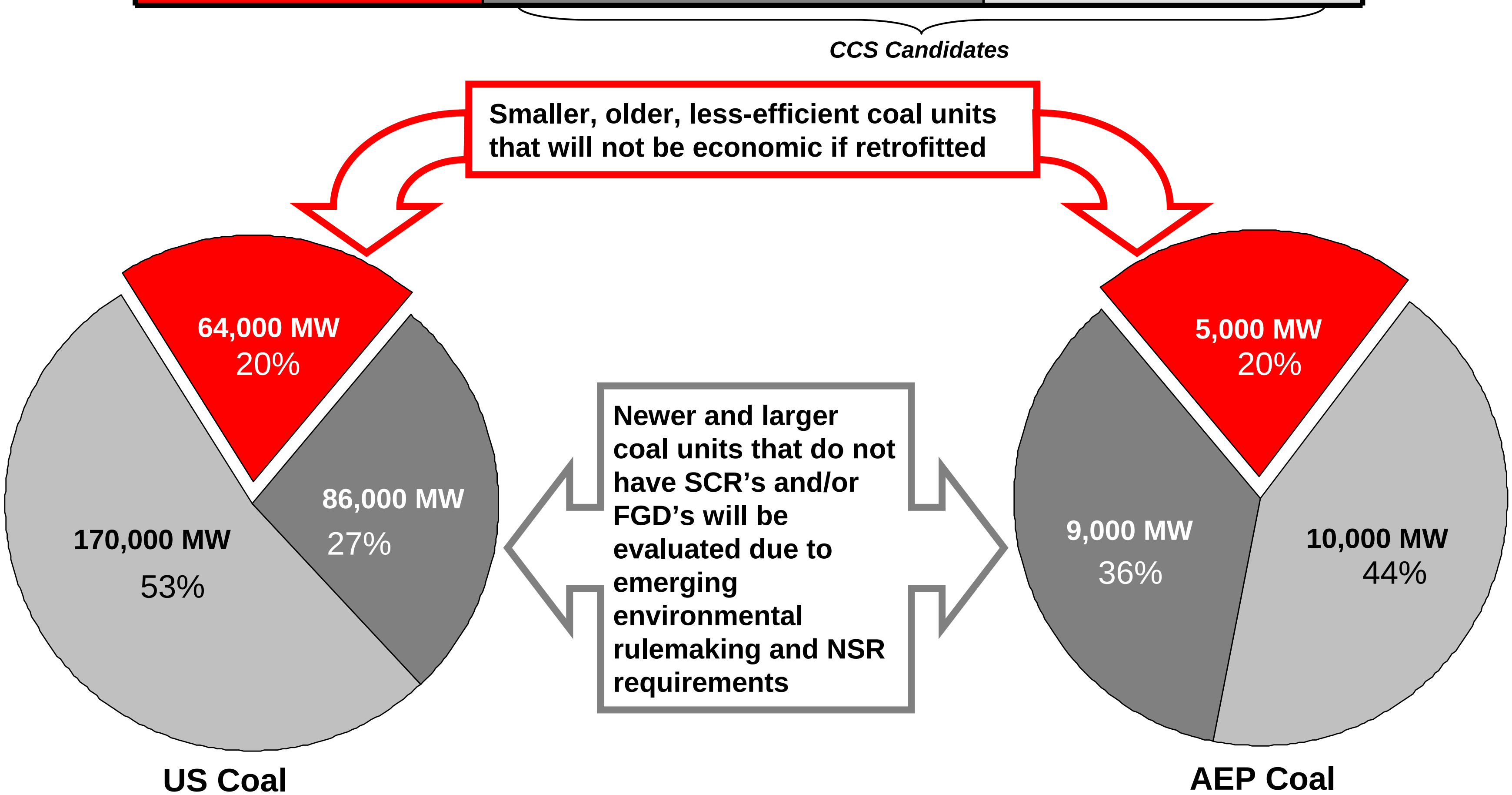
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

Coal Unit Age & Installed Controls



Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*



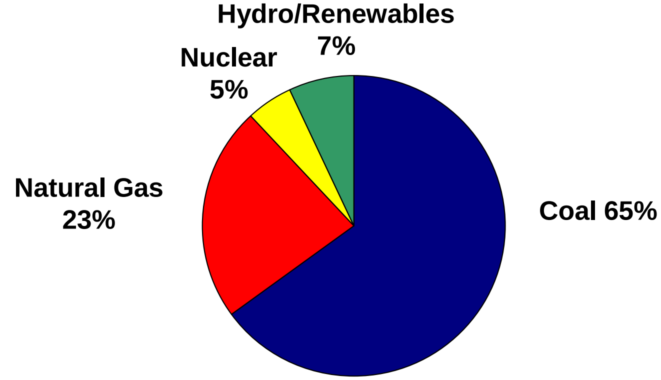
Nearly 50% of U.S. coal plants are exposed

Environmental Project Status Report

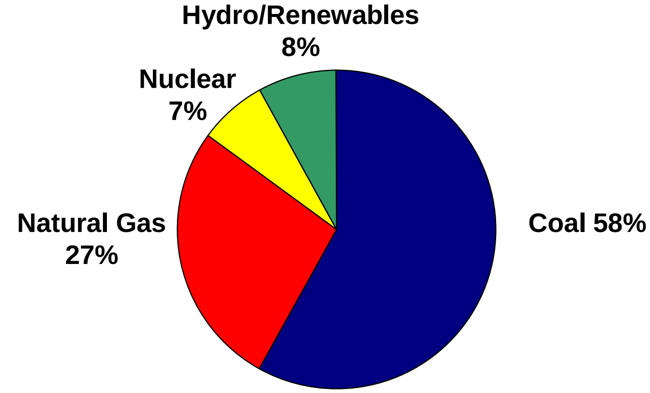
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (under construction)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®

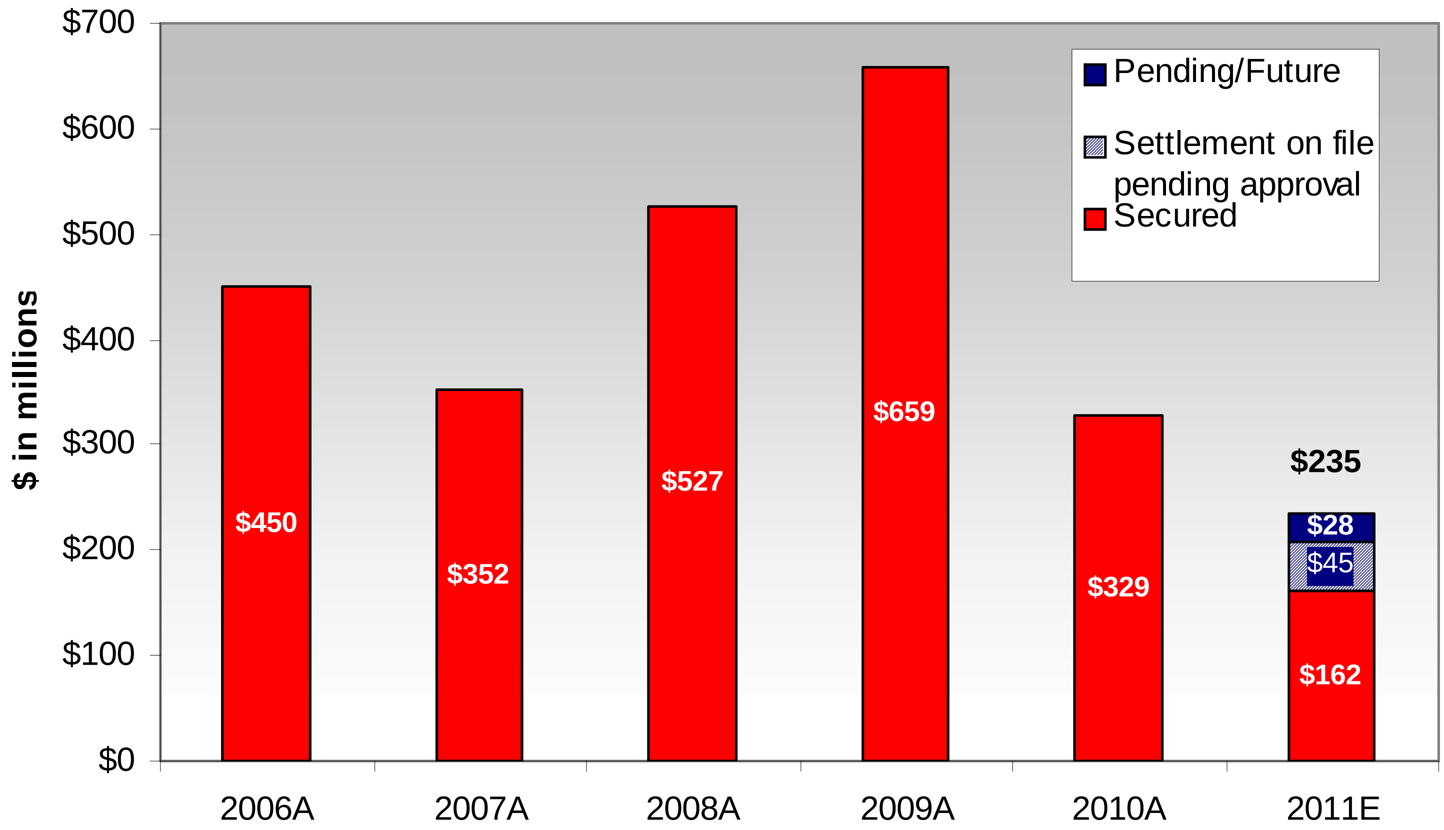


Capacity - 2010



Projected Capacity - 2017

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09) ($ in millions)

Rate Base	$ 2,639.6
Rate of Return	8.28%
Operating Income Requirement	$ 218.6
Adjusted Operating Income	$ 86.0
Difference	$ 132.6
Revenue Conversion Factor	1.6872
Total Revenue Requirement	$ 223.8
Elimination of Construction Surcharge	$ (68.3)
	$ 155.5

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Procedural Schedule - tbd

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

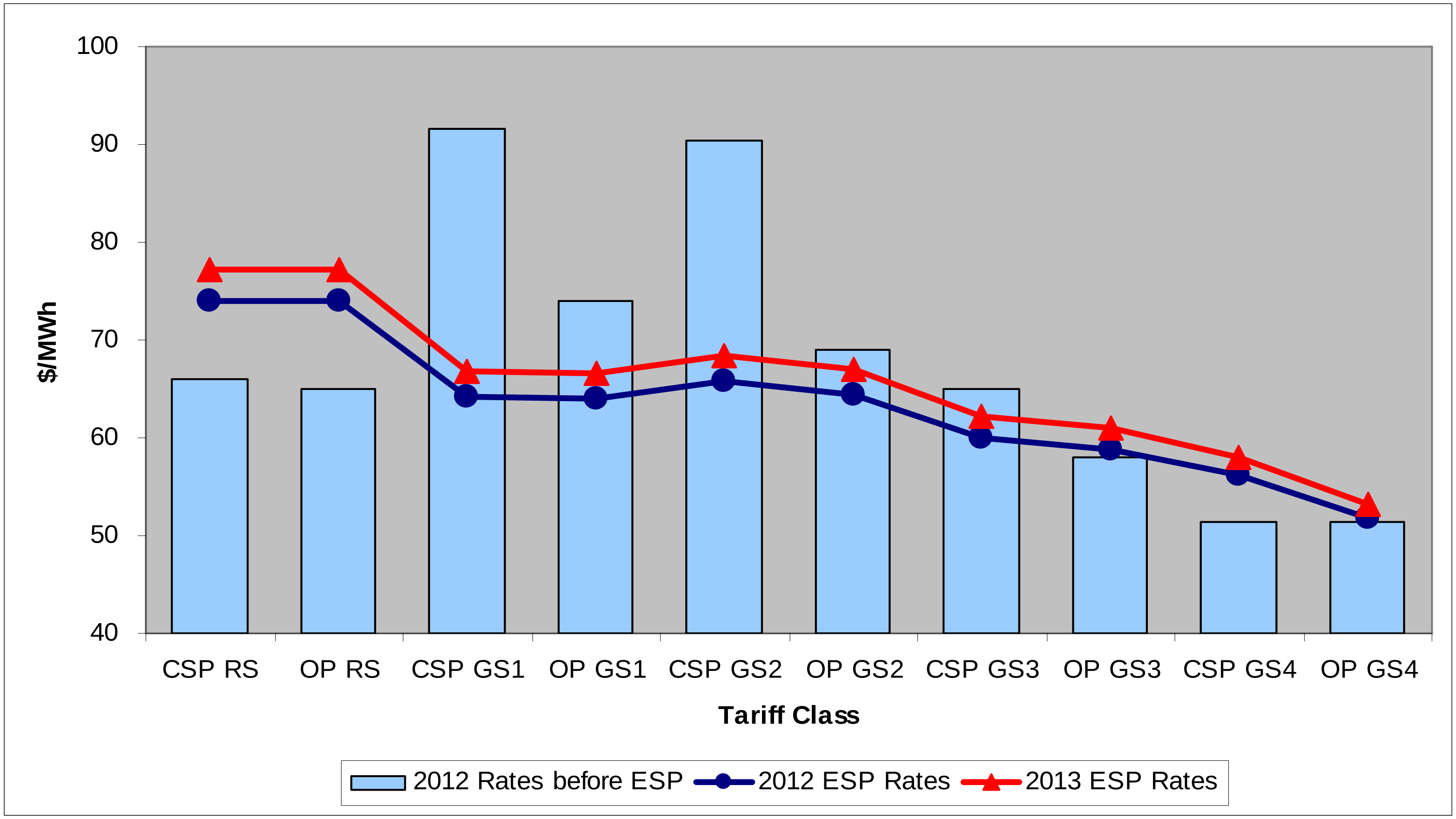
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

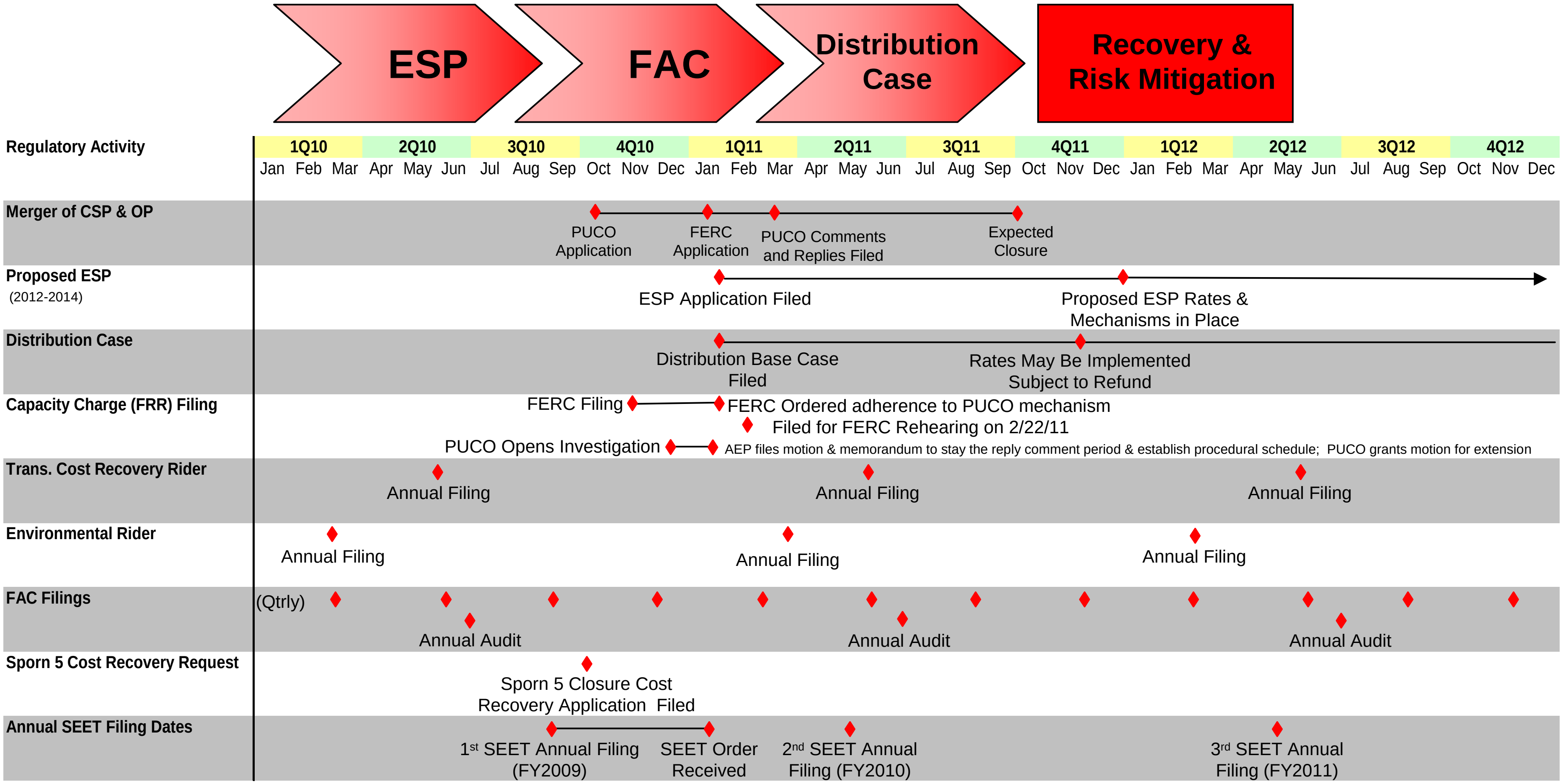
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

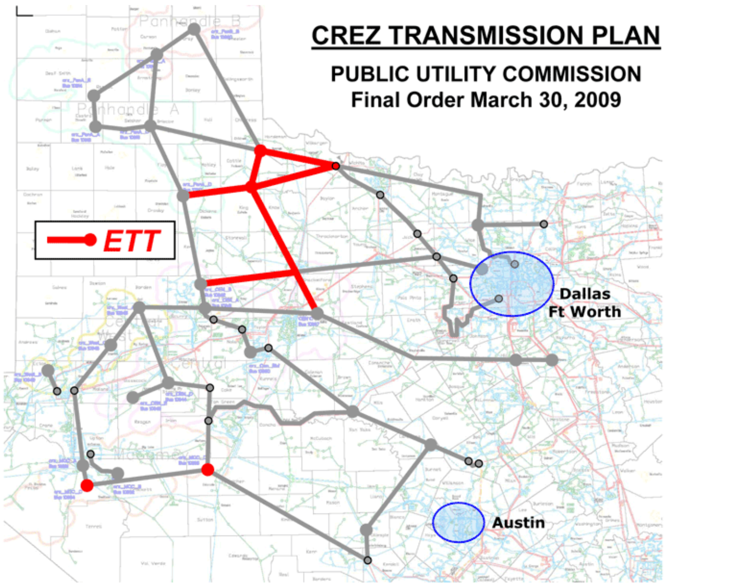
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

ETT
Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  – Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  – Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  – PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

AEP®

Filing Status Update:

- ***Ohio** (filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia** (filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia** (withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

$160M capital spend forecasted for 2011

Joint Venture Strategy: Long-term

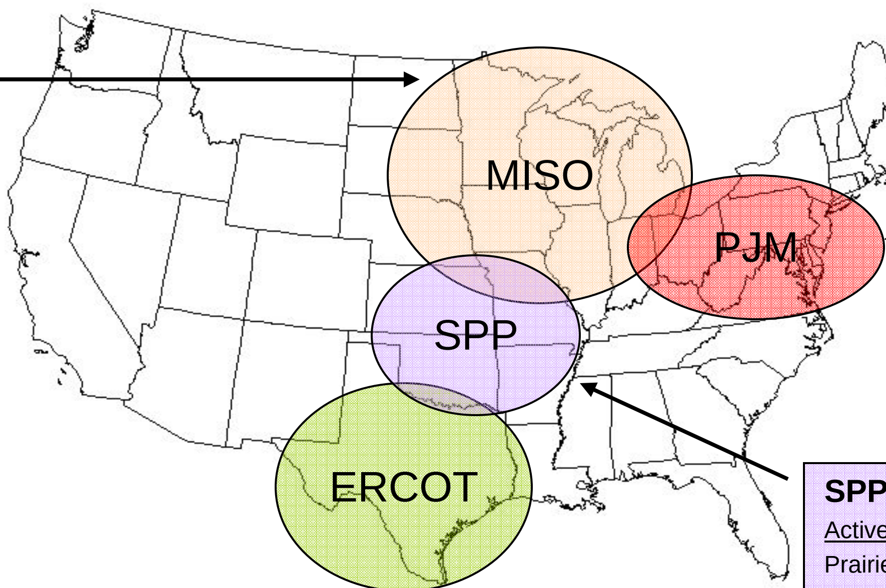
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

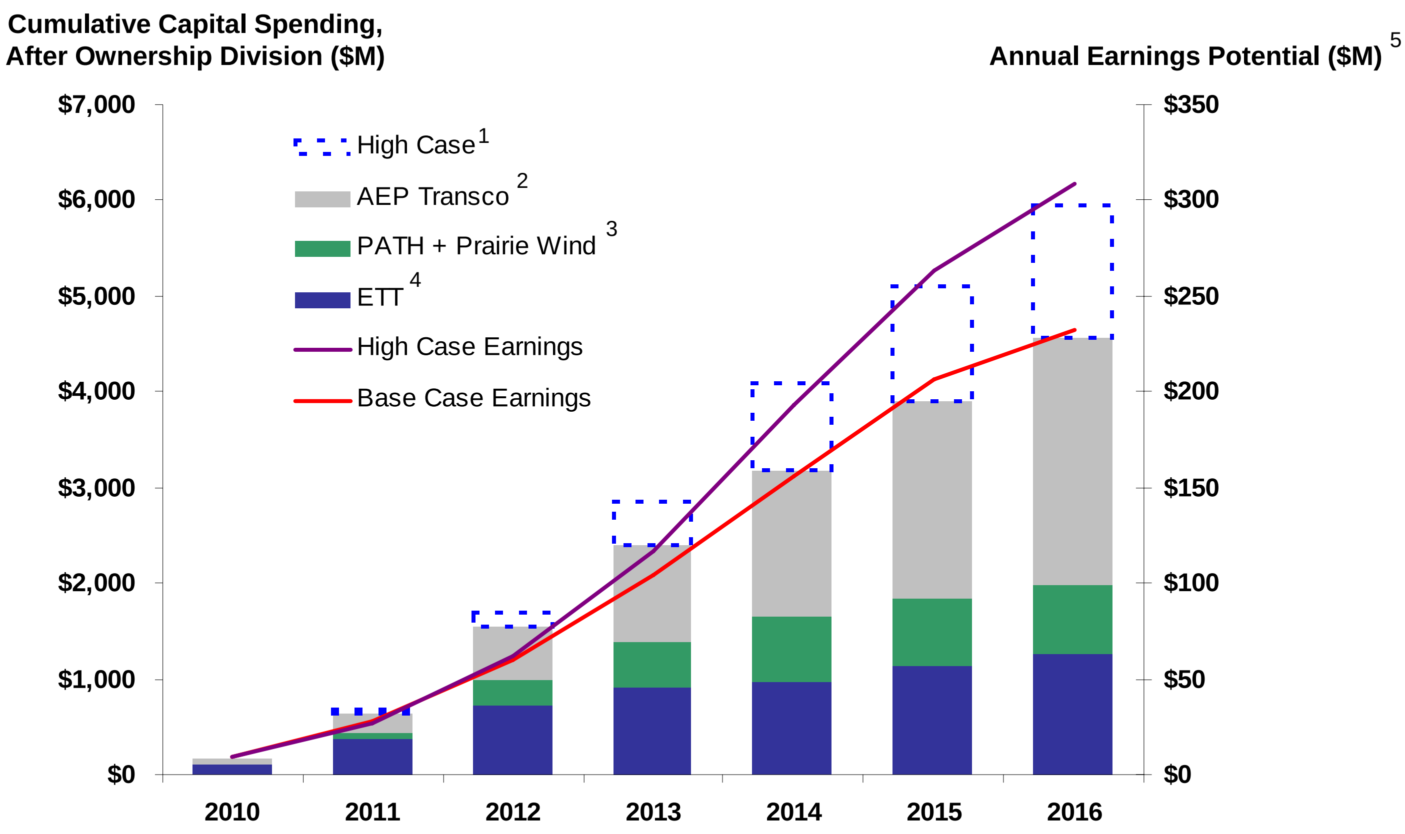
Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

AEP AMERICAN® ELECTRIC POWER

Wells Fargo
Office Visit
Columbus, OH
March 30, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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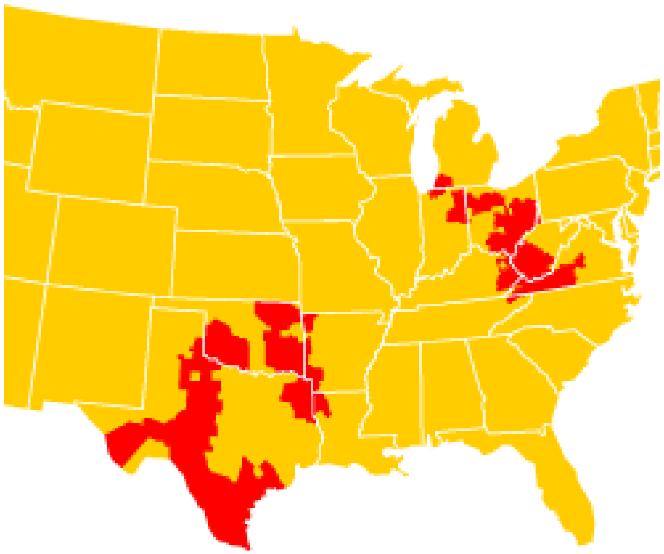
AEP®

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



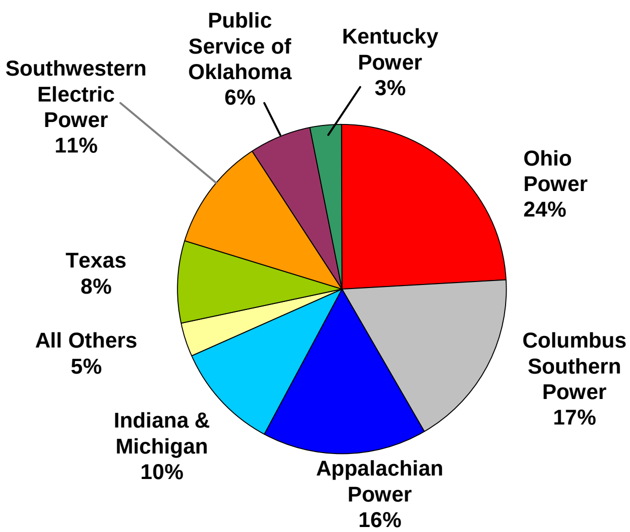
AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

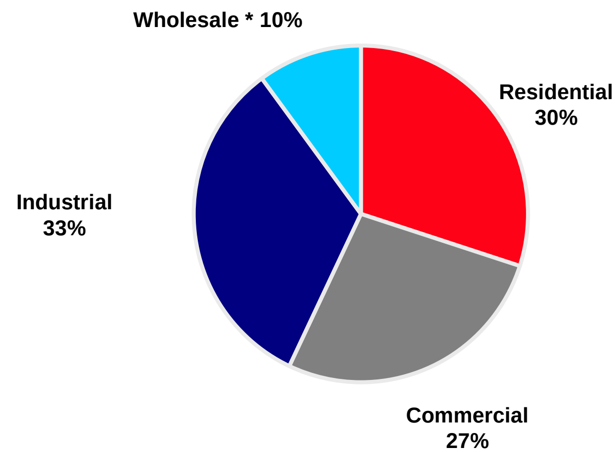
$16.7B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

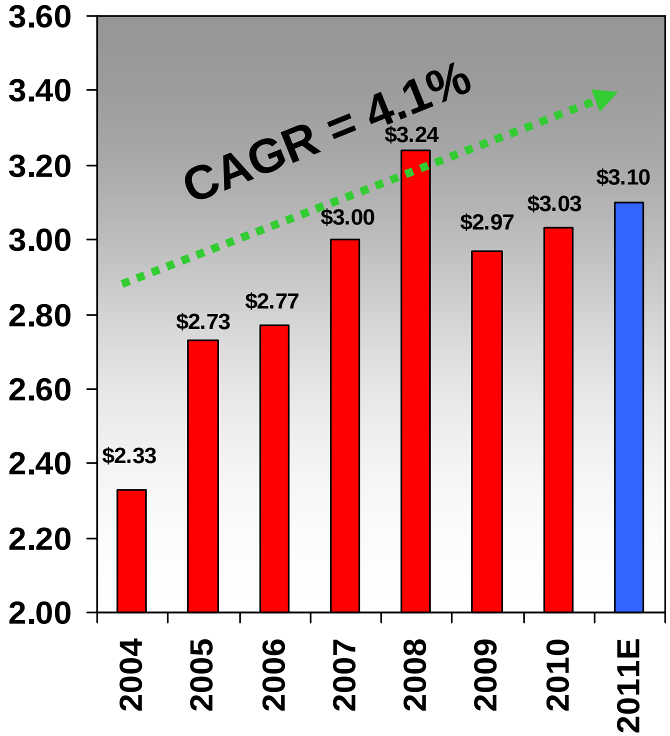
Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

AEP®

On-Going EPS History Since 2004

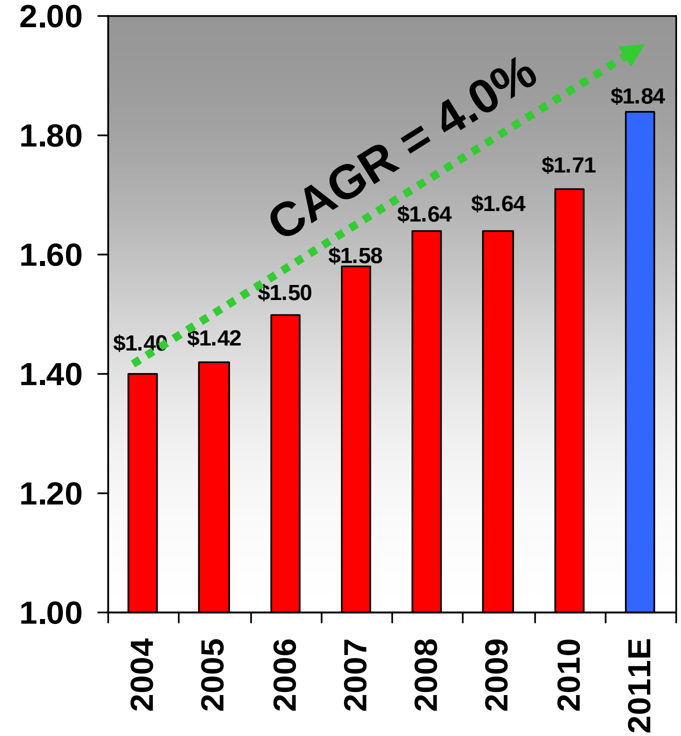
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



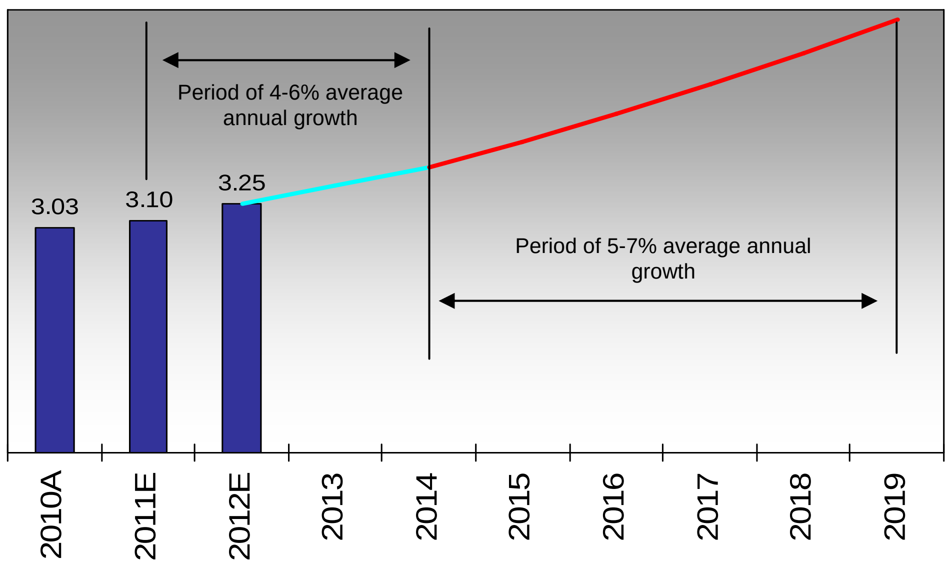
= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Detailed Ongoing Earnings Guidance

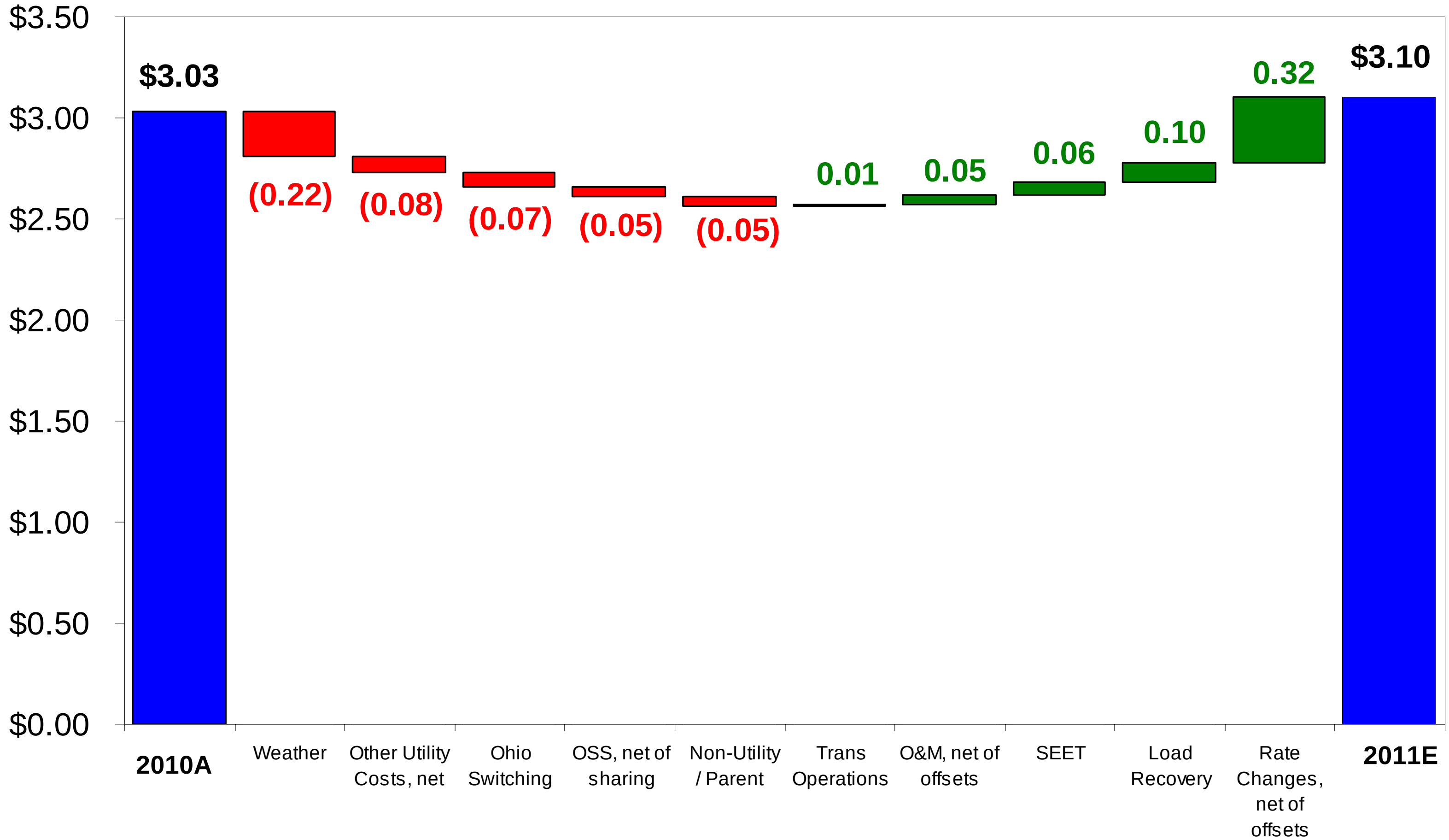
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

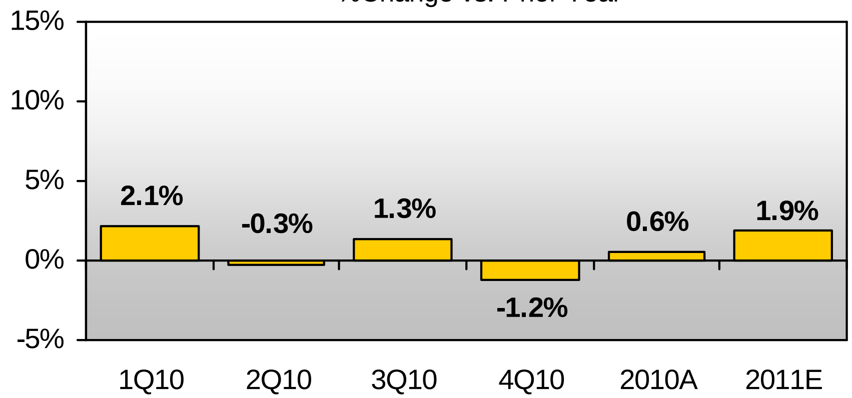


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

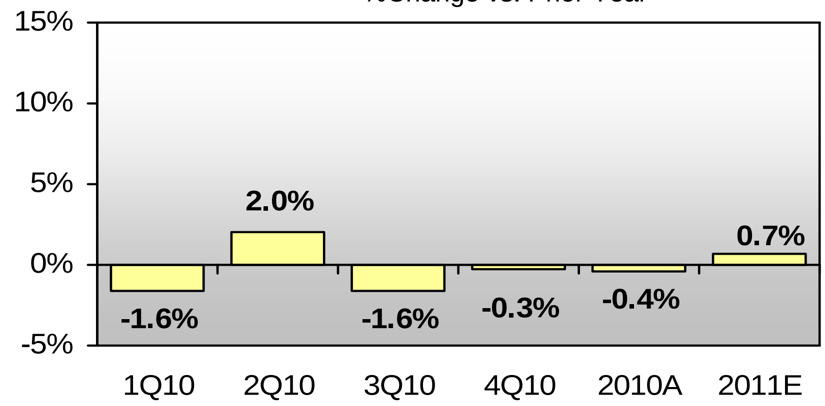
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

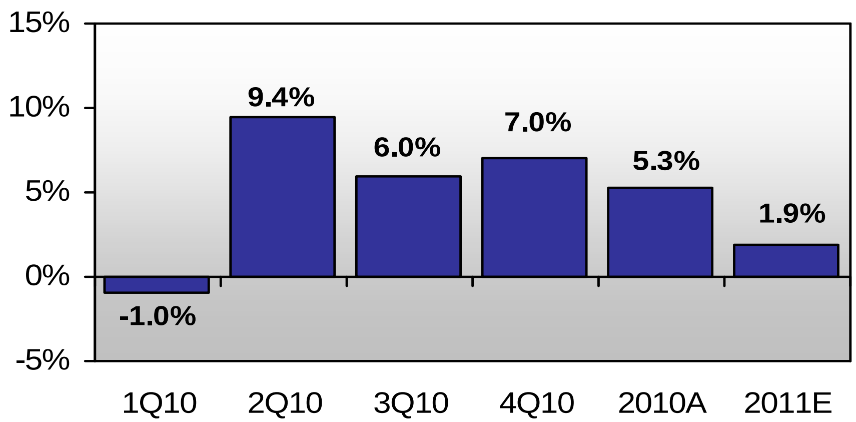
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



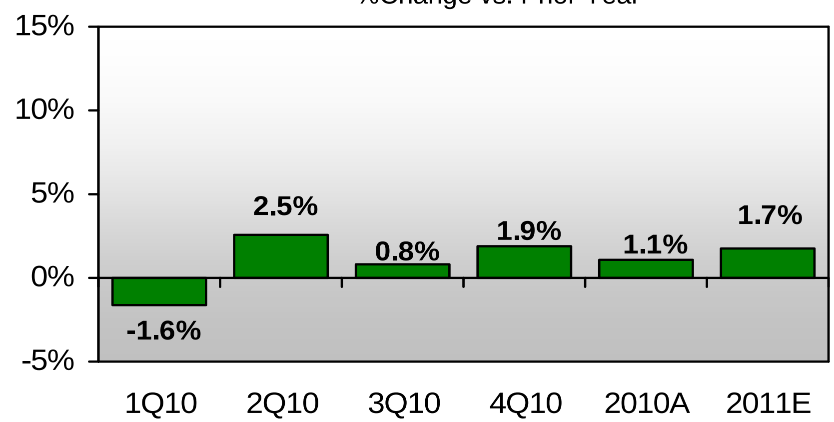
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

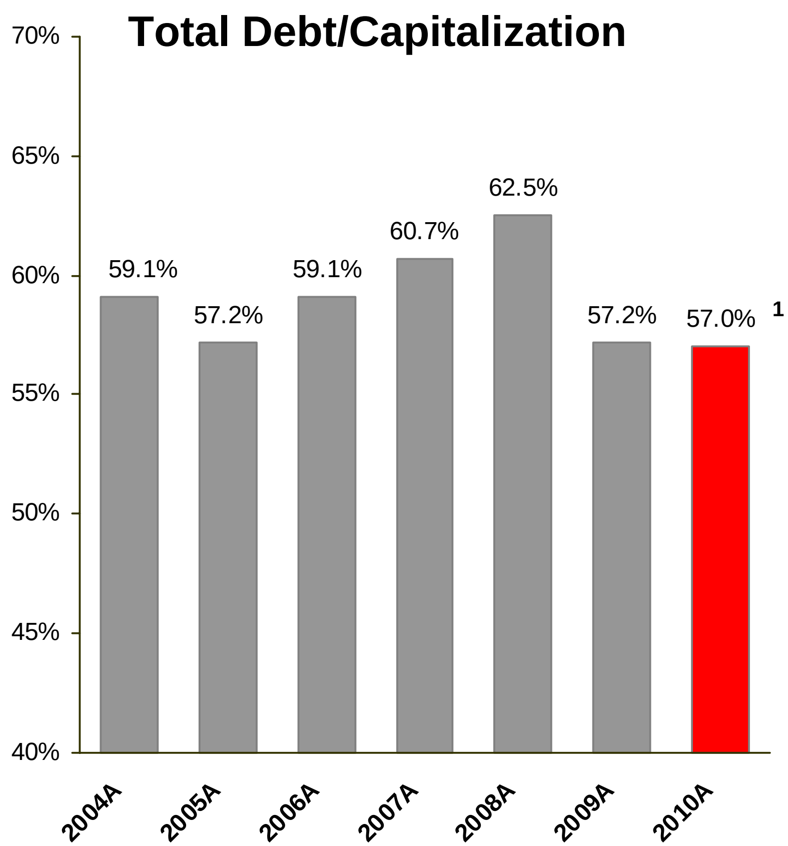
Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



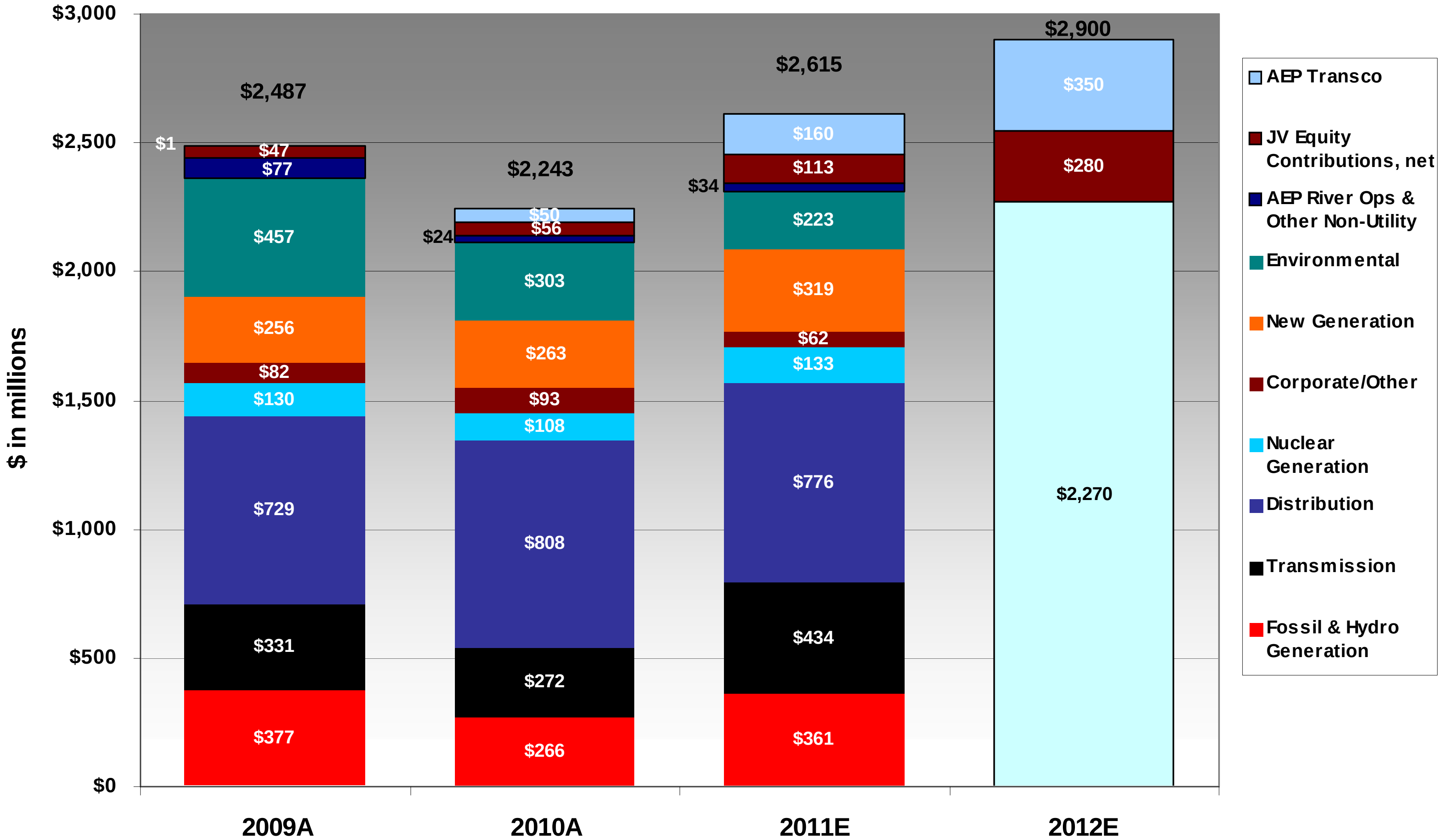
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

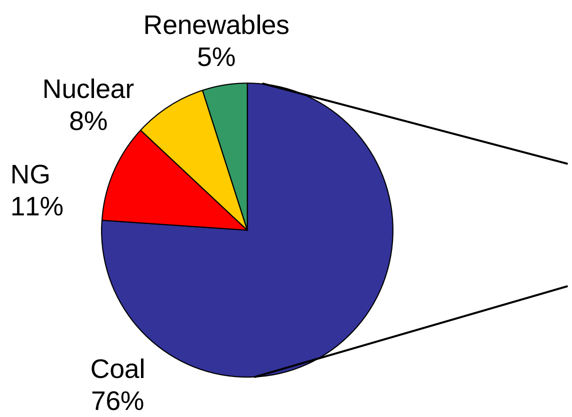
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

AEP Generation Capacity

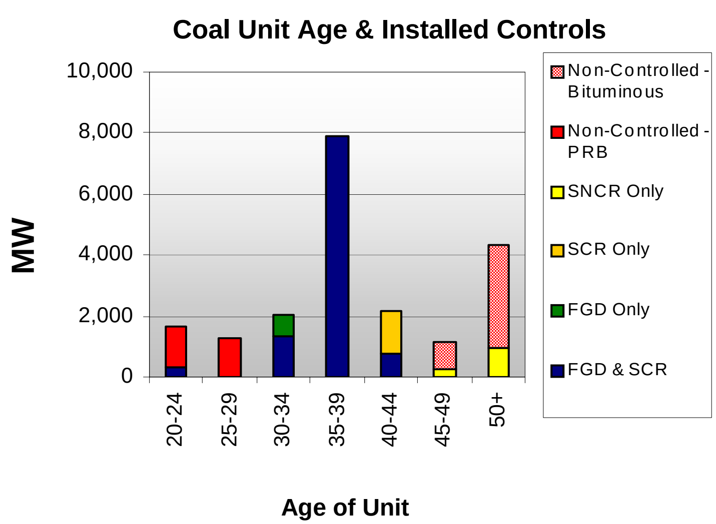
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



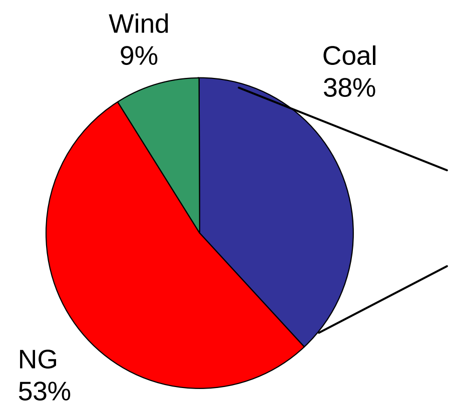
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



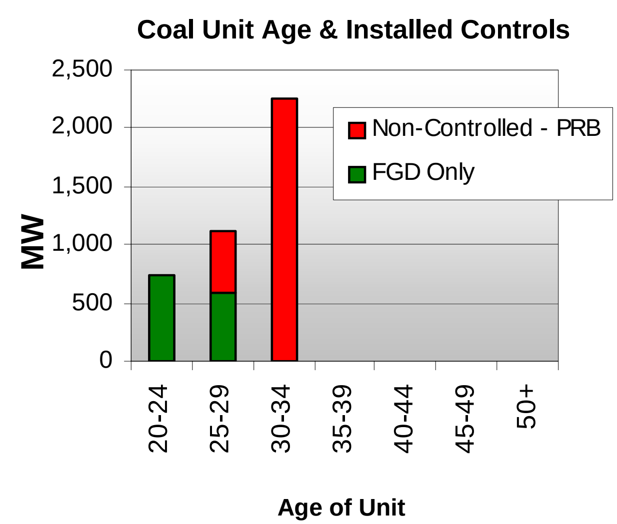
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

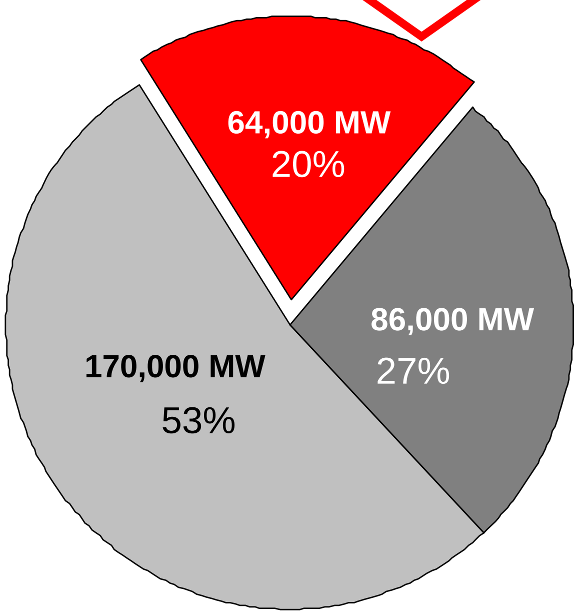


Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

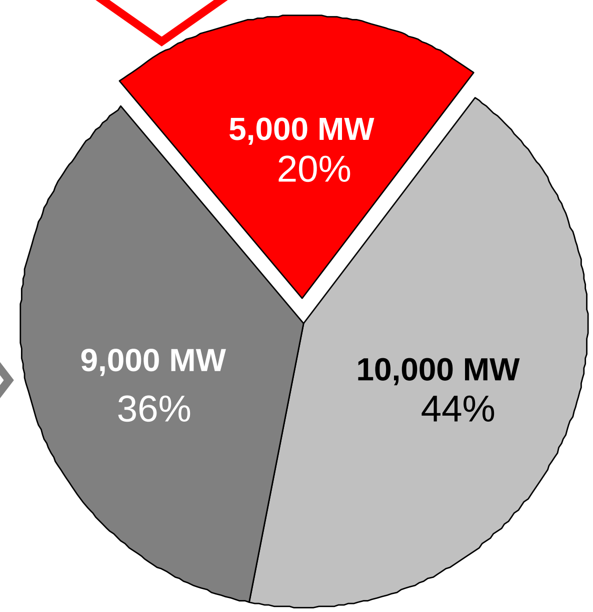
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements



AEP Coal

Nearly 50% of U.S. coal plants are exposed

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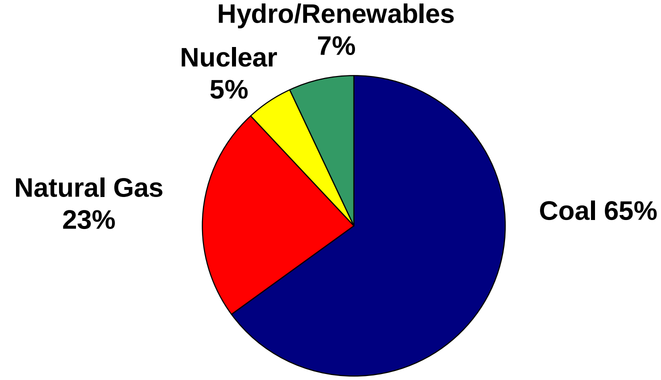
Environmental Project Status Report

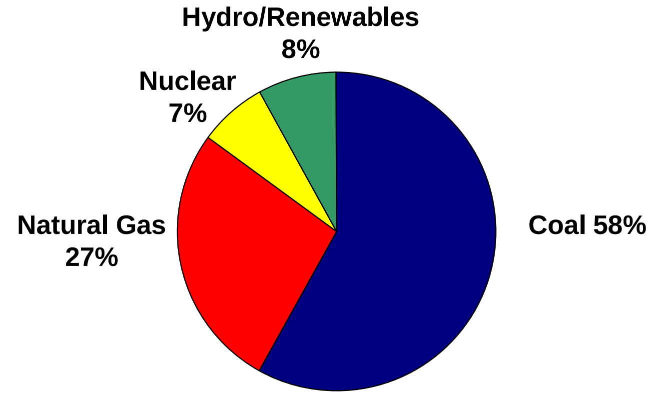
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (under construction)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®

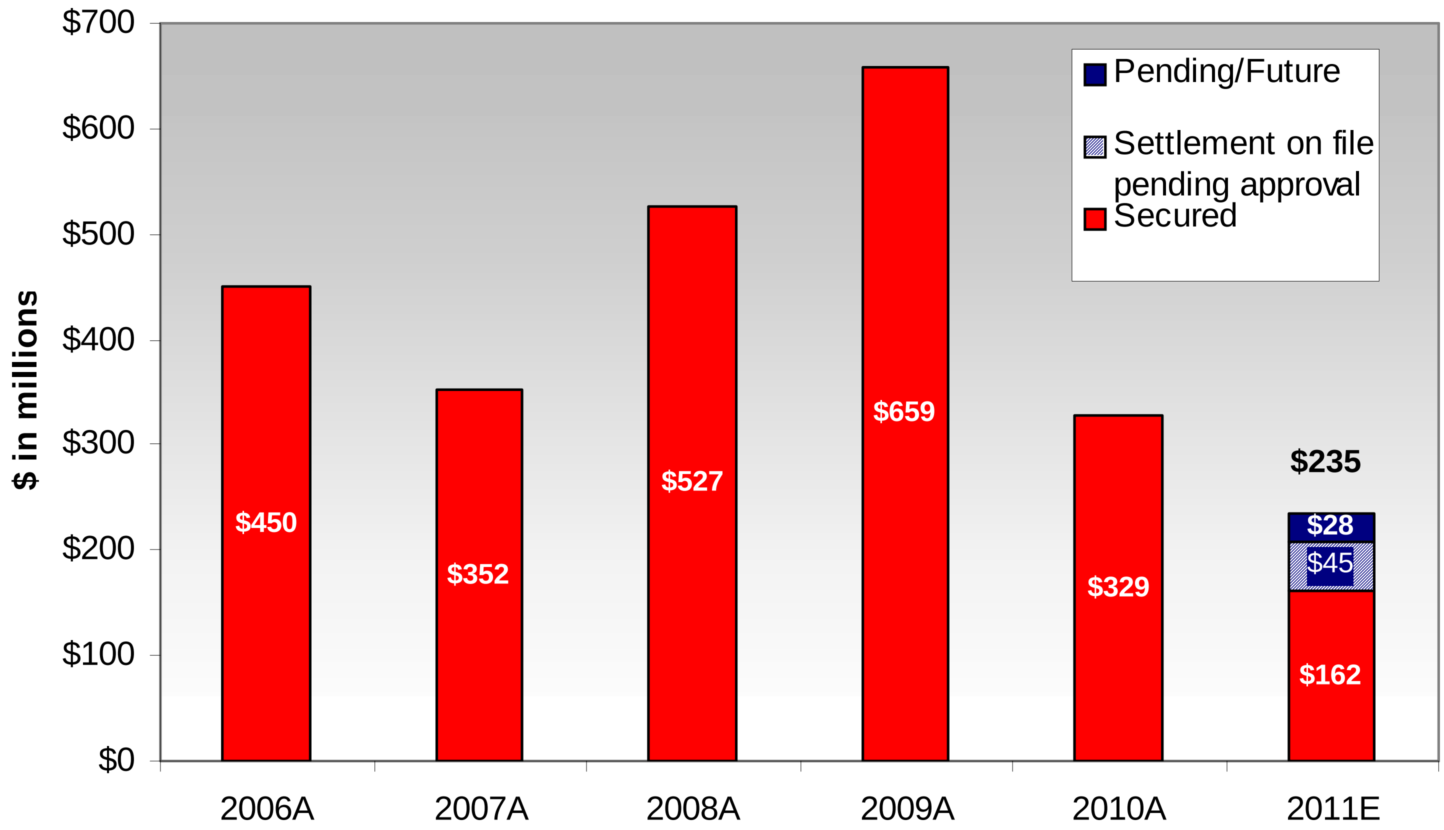


Capacity - 2010



Projected Capacity - 2017

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

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AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

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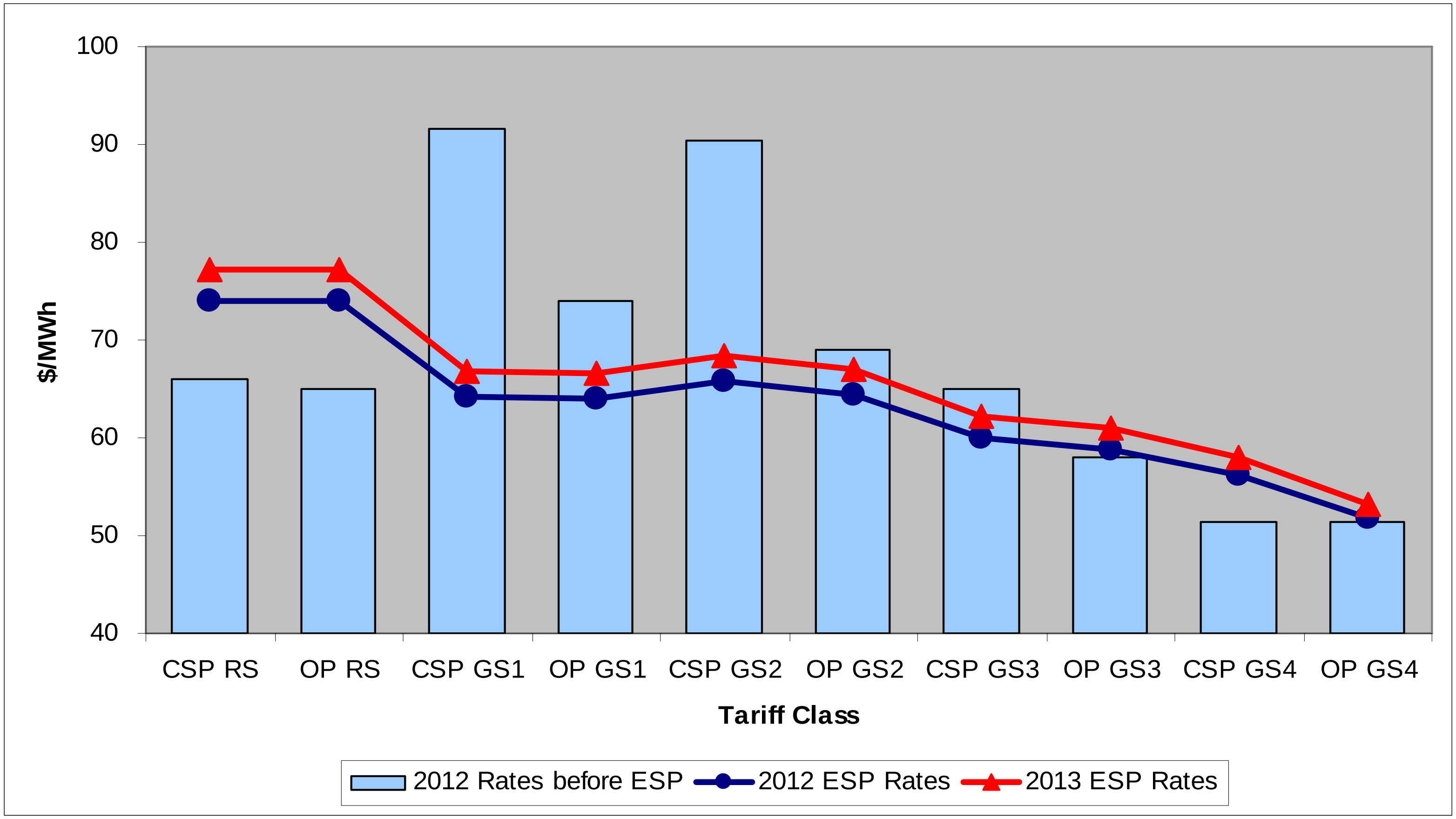
Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

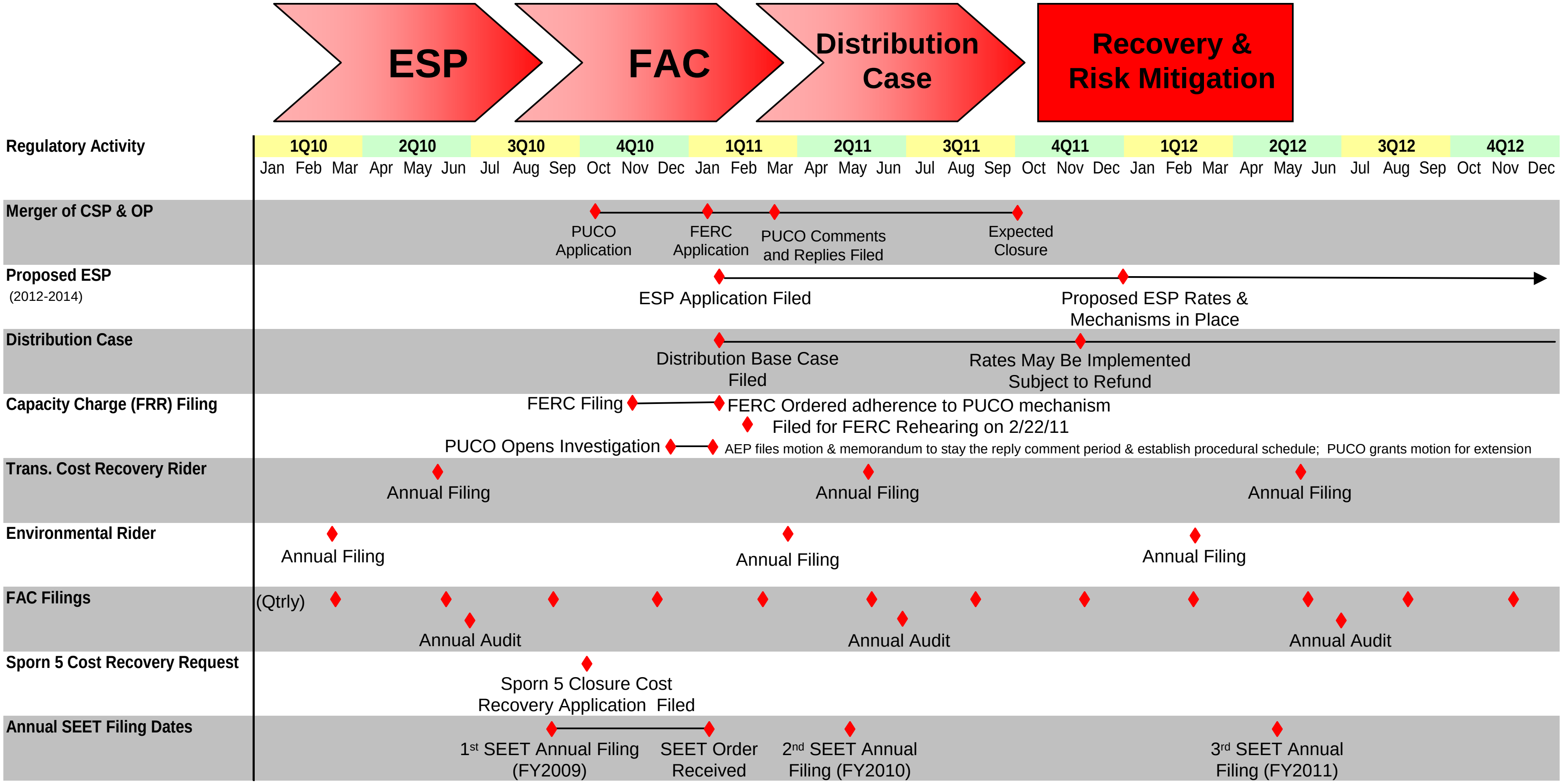
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

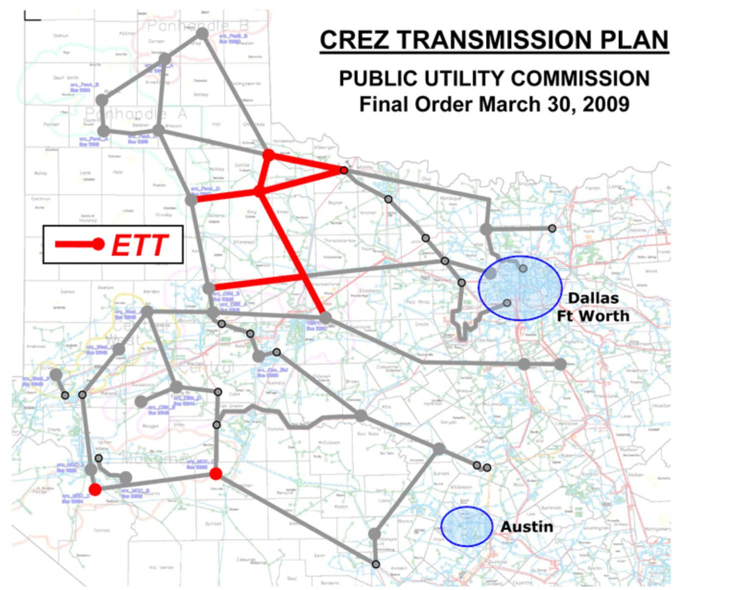
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **<u>Additional Projects in the Pipeline ~$1.6 B:</u>**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **<u>Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:</u>**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

Filing Status Update:

- ***Ohio*** *(filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia*** *(filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia*** *(withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

$160M capital spend forecasted for 2011

Joint Venture Strategy: Long-term

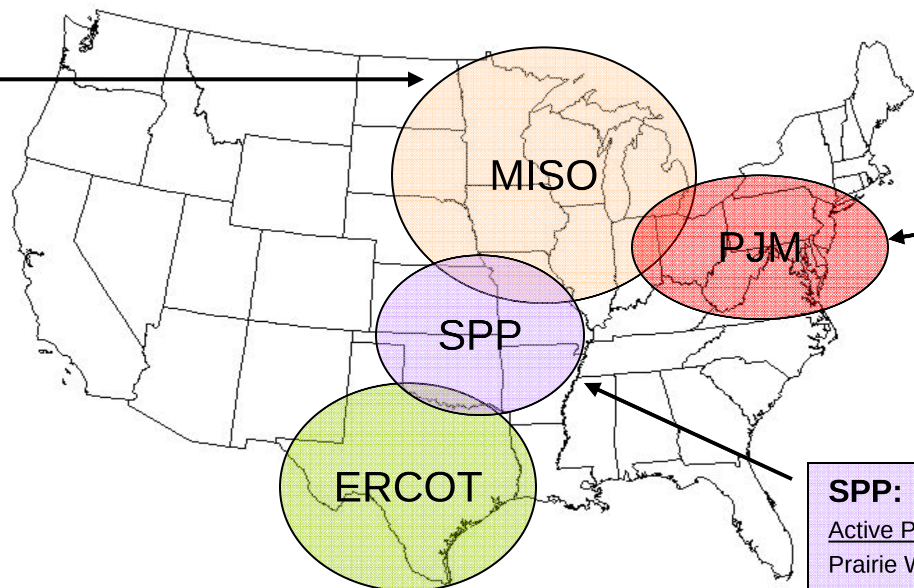
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

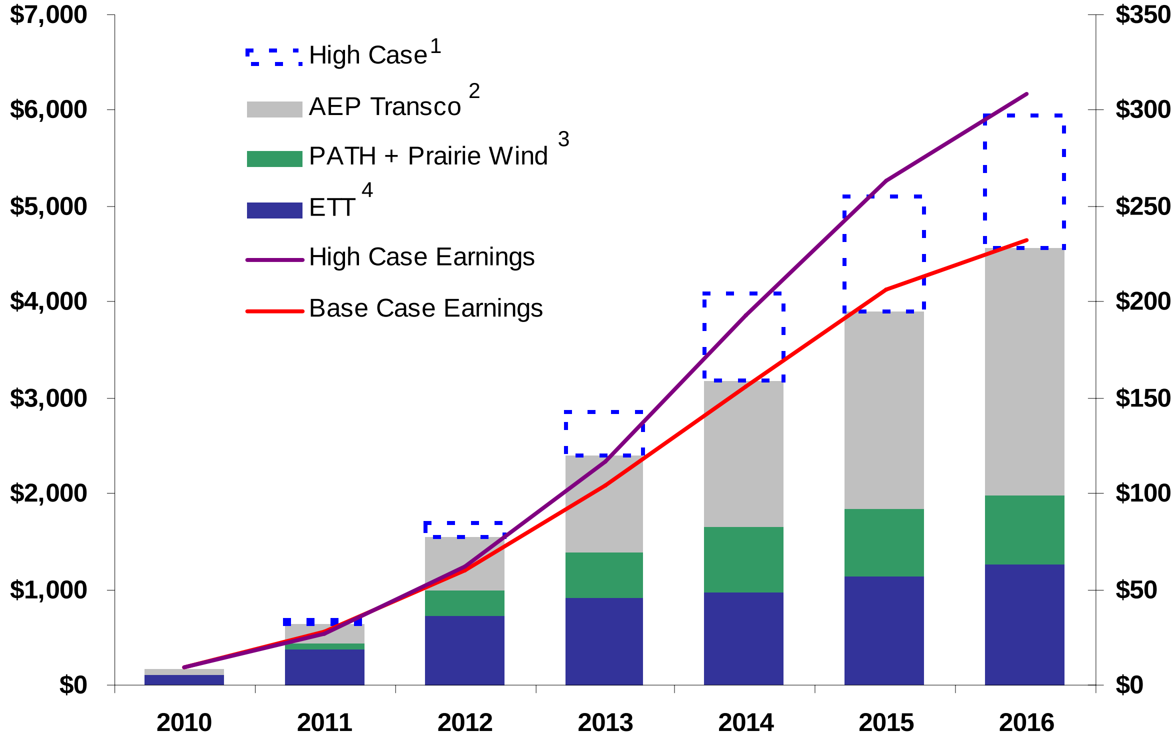
Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.

Cumulative Capital Spending, After Ownership Division ($M)

Annual Earnings Potential ($M) [5]



1 High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

2 AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

3 PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

4 ETT (50% ownership) includes CREZ and additional projects

5 Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

AMERICAN ELECTRIC POWER

Capital Group Office Visit

May 5, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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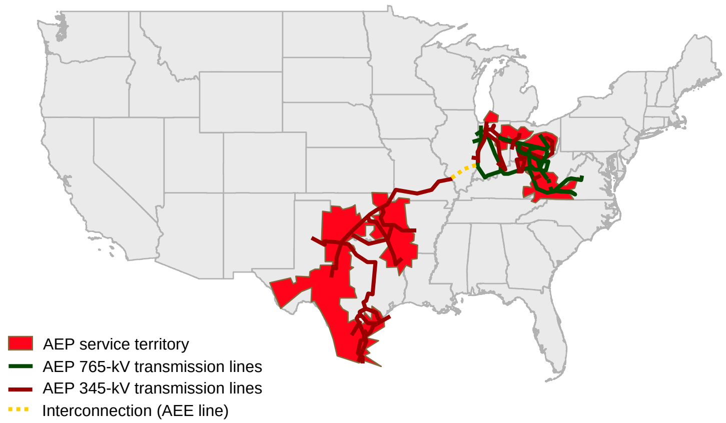
Premier Regulated Utility Platform

Overview

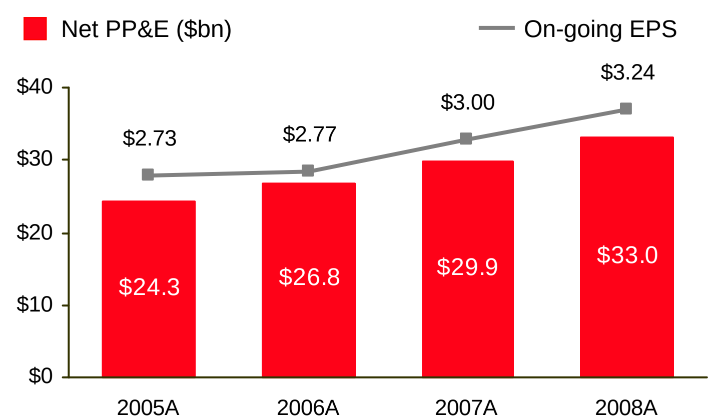


AEP's Leadership Position

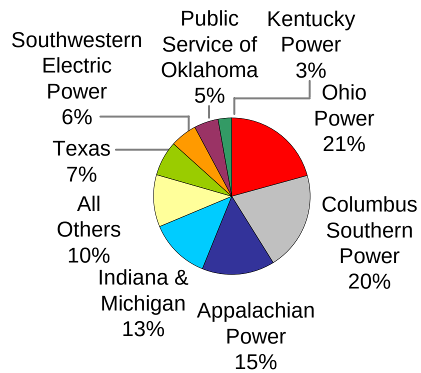
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

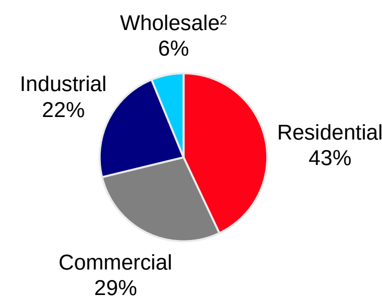
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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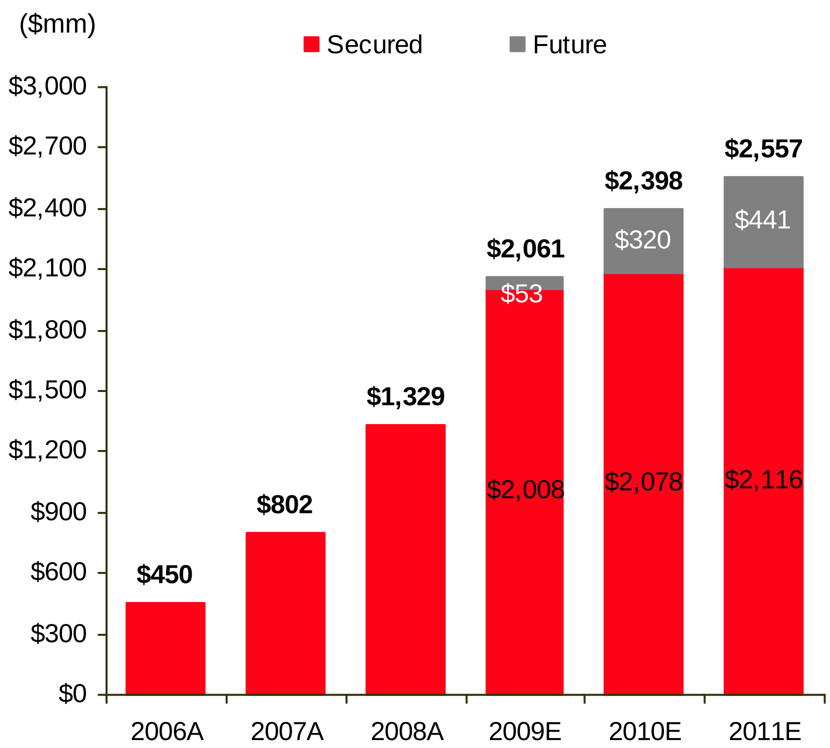
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $70mm and $38mm was secured for 2010 and 2011, respectively, as of March 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
  - ✓ Texas ($7MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
(Incl. OVEC of $68.8M)								
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9	*
Required Rate of Return		7.00%	
Required Operating Income	$	42.6	
Adjusted Operating Income	$	27.3	
Difference	$	15.3	
Revenue Conversion Factor		1.65	
Revenue Deficiency	$	25.2	
Generation Recovery Rider	$	28.7	
Total Required Rate Relief	$	53.9	

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop "transmission superhighway" to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America's power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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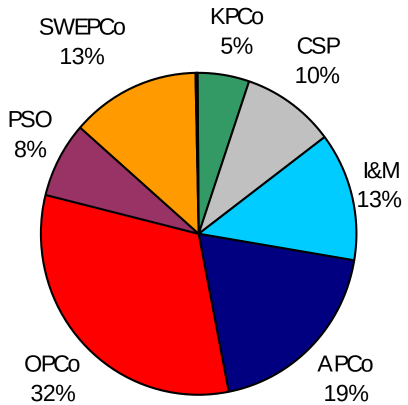
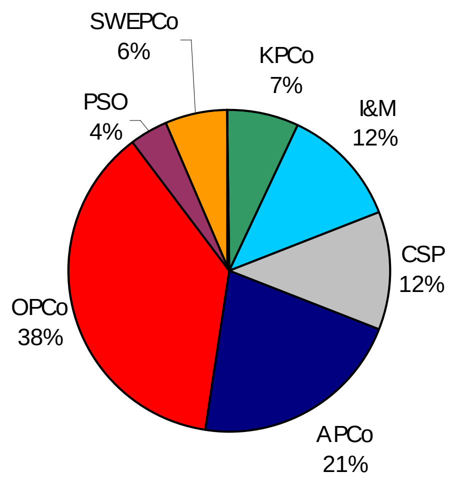
CO_2 Cost Recovery – Should Follow SO_2 & NOx

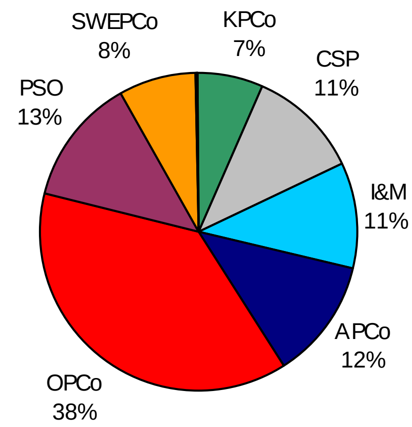
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



2008 AEP System NOx Emissions
248k tons



- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2012
Amos 2	800	☑	In-service	☑	Projected 2013
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☑	Projected 2015
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2015
Northeastern 4	450		N/A	☑	Projected 2015
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2013

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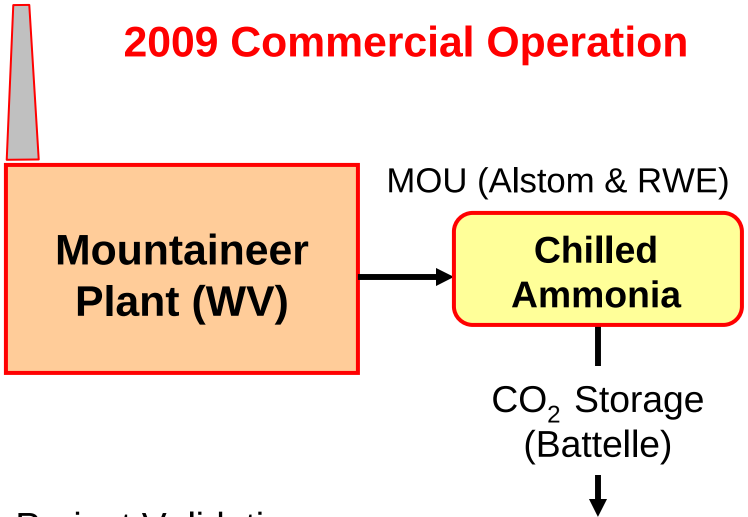
Carbon Capture & Storage

2009 Commercial Operation



<u>Project Validation</u>

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**

<u>Represents Post-Combustion Capture</u>

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

<u>Key Issues for CCS Development in the U.S.</u>

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – AEP self-reported impacts to jurisdictional wetlands in March 2009. Work continues outside the jurisdictional areas. Hearing on the air permit appeal is scheduled for June 2009.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

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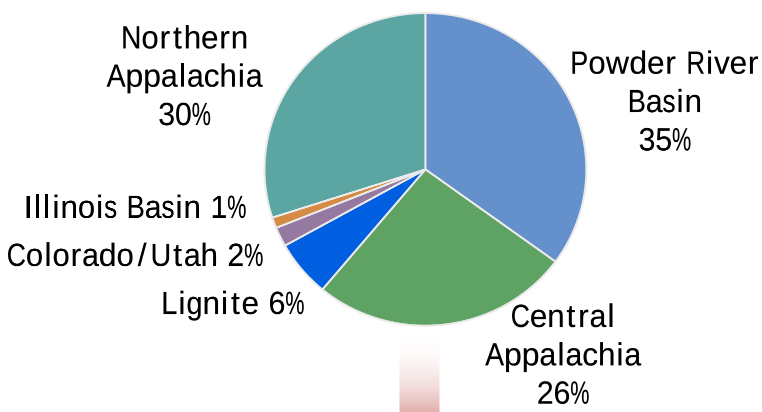
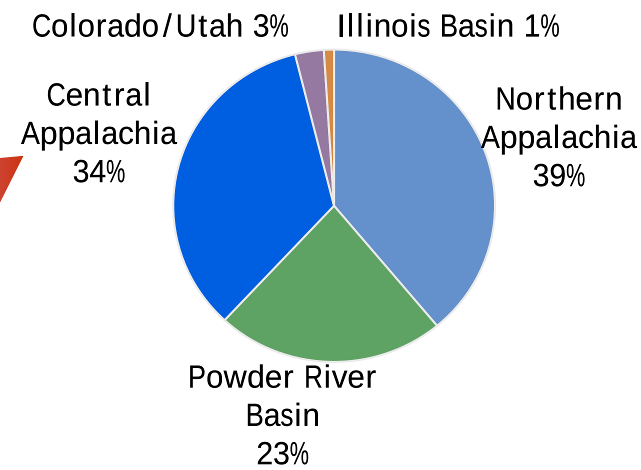
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

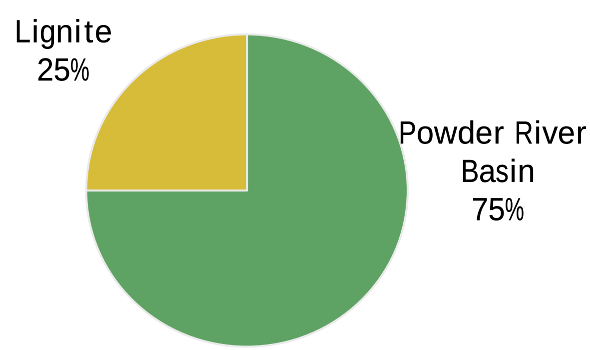
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

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p.14

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

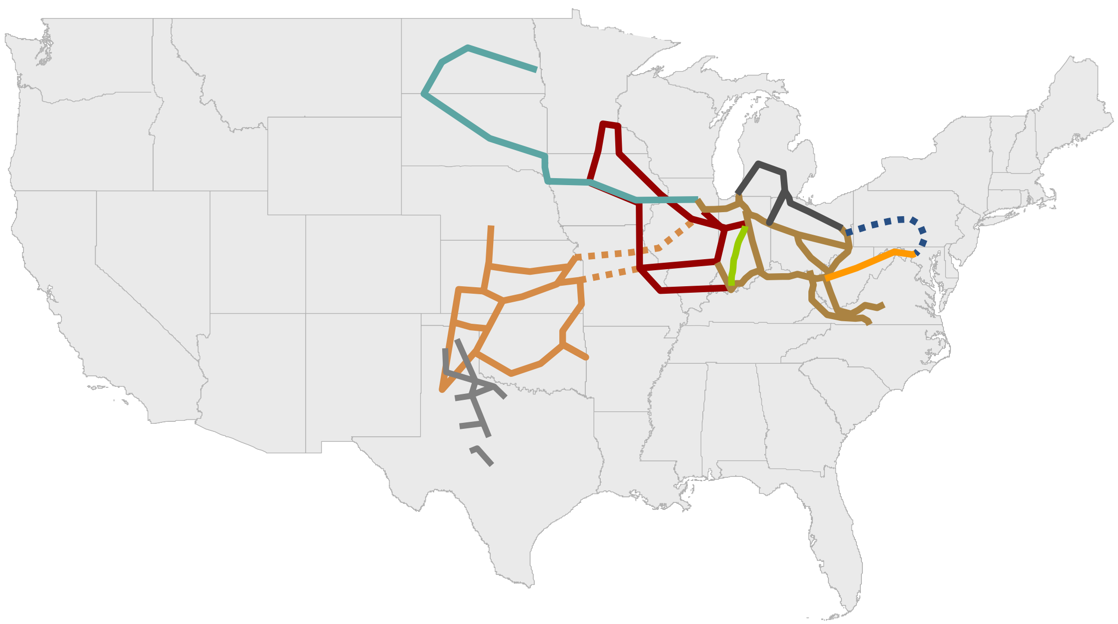
Pioneer	COD: 2015
240 miles of 765 kV	
Partner: Duke Energy (50%)	
Estimated Cost: $1 billion	
ROE: 12.54%	

PATH-WV	COD: 2014
275 miles of 765 kV	
Partner: Allegheny Energy (50%)	
Estimated Cost: $1.2 billion	
ROE: 14.3%	

Tallgrass	COD: 2013-14
170 miles of 765 kV	
Partners: OG&E (50%) & MidAmerican Energy (25%)	
Estimated Cost: $500 million	
ROE: 12.8%	

Prairie Wind	COD: 2013-14
230 miles of 765 kV	
Partners: Westar Energy (50%) & MidAmerican Energy (25%)	
Estimated Cost: $600 million	
ROE: 12.8%	

ETT	COD: 2013
345 kV in ERCOT	
Partner: MidAmerican Energy (50%)	
Estimated Cost: $400 million	
ROE: 9.96%	



Future Projects:

EHV Michigan	COD: ~2020
700 miles of 765 kV	
Partner: ITC	

PJM Projects	
Enhance existing 765/345 kV	

Hartland	COD: ~2020
1000+ miles of 765 kV	
Partner: Hartland Wind LLC	

MISO Vision Plan	
765 kV Backbone	

SPP Overlay	COD: 2013-14
765 kV Backbone	

ETT	COD: ~2018
345 kV in ERCOT	
Additional CREZ spend of $750-$850 million	

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

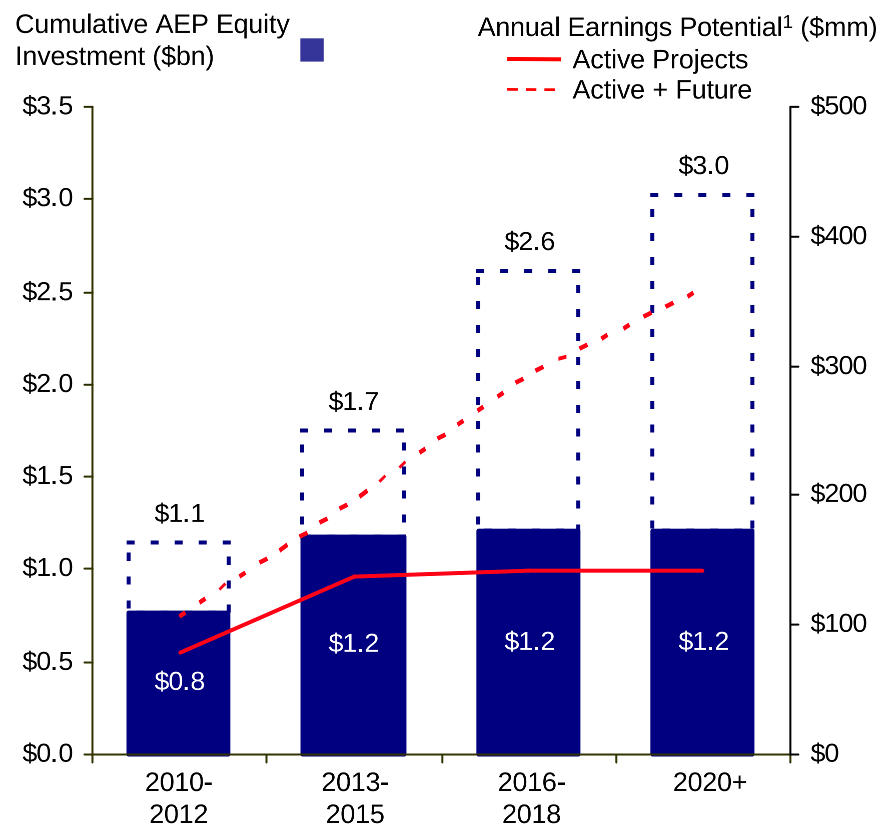
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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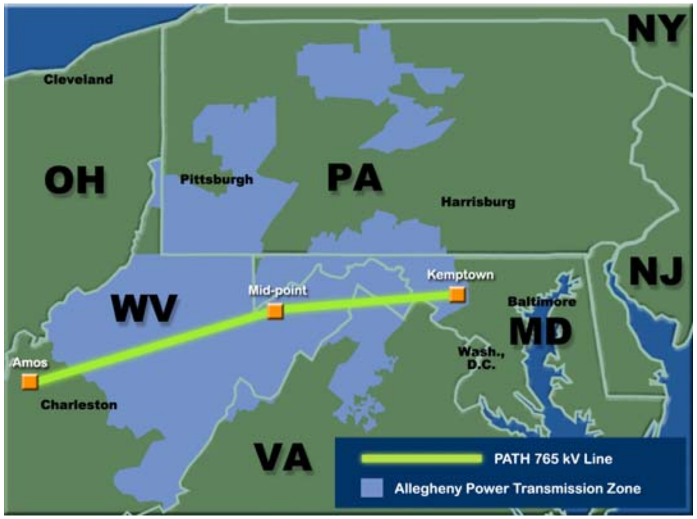
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



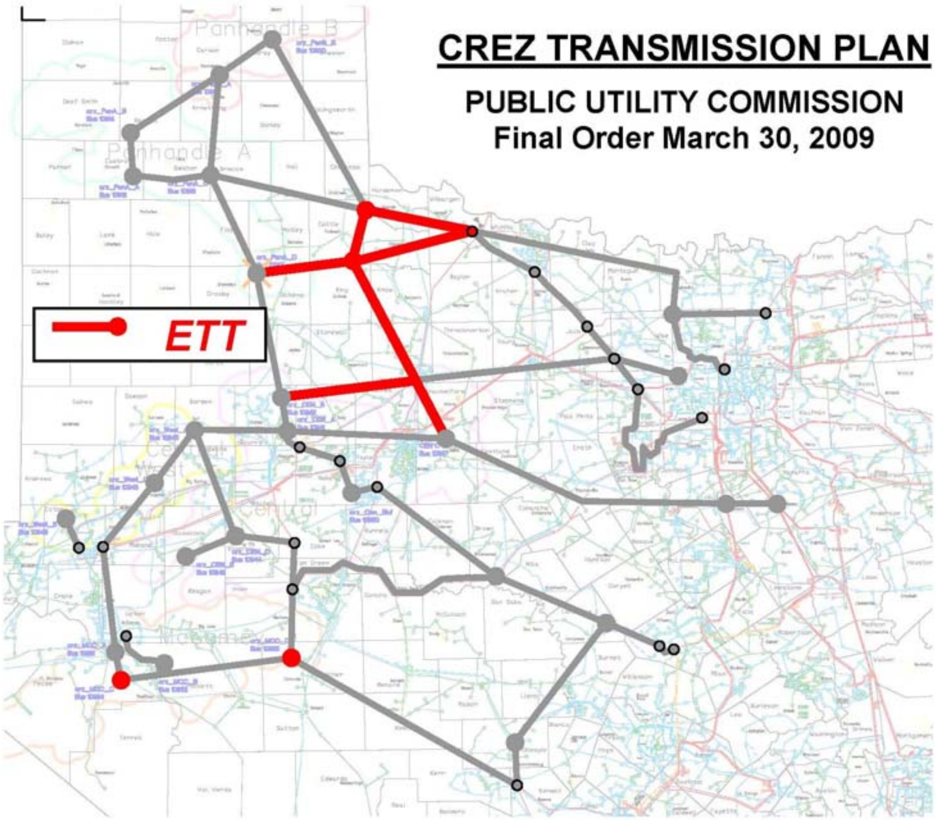
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AMERICAN ELECTRIC POWER

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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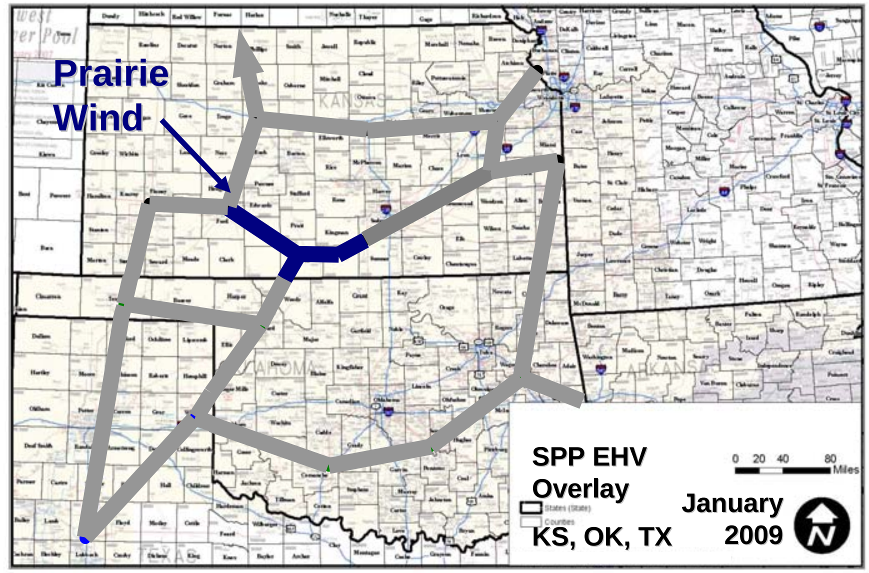
Electric Transmission Texas

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

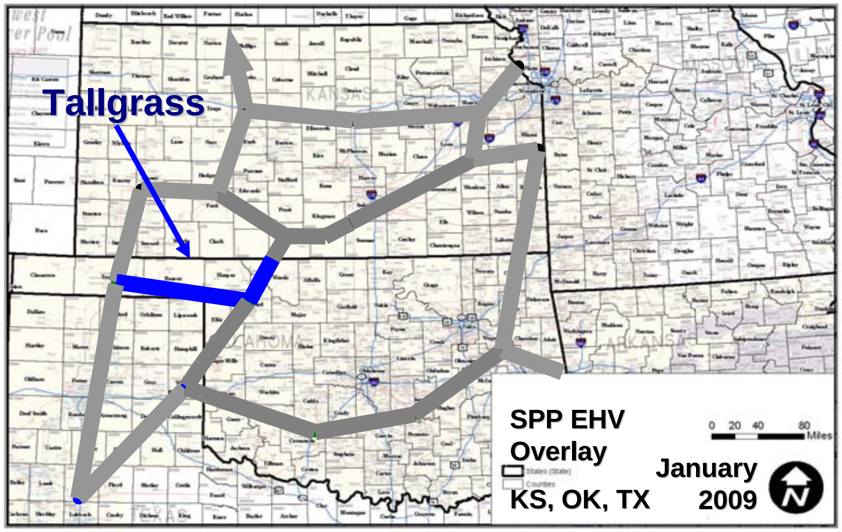
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Competing ITC Great Plains project

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013.
- AEP's ownership of the joint venture is 25%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received in December 2008:
  - ❑ Cash return on CWIP and 12.8% incentive ROE
  - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
  - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval

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Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

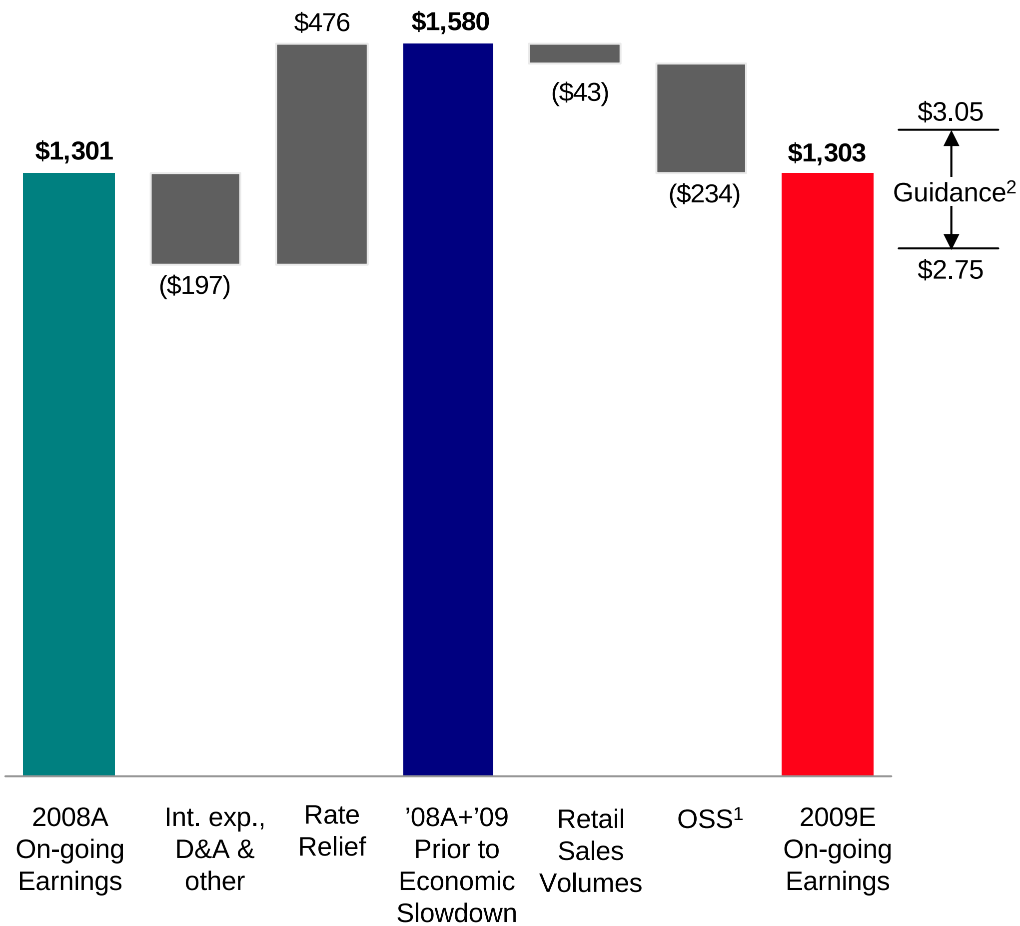
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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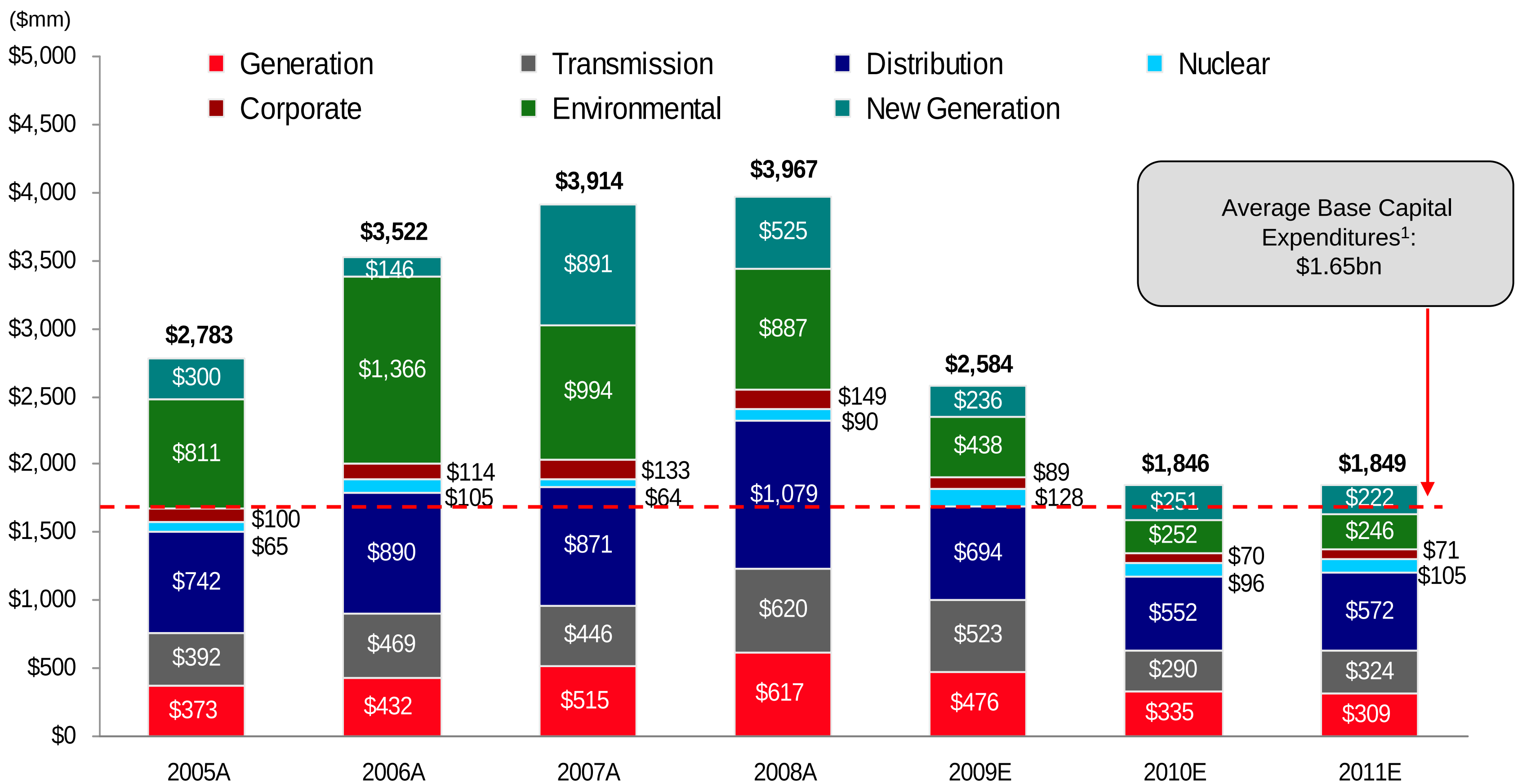
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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Capital Investment Funding Plan

$ in millions

		Actual 2008		Projection 2009
Planned Capital Investment (Excluding AFUDC)	$	(3,967)	$	(2,584)
Planned Transmission Initiatives (JV Equity Contributions)		0		(49)
Dividend on Common Stock		(660)		(755)
Cash Sources (Uses)				
Cash from Operations		2,576		2,514
Proceeds from Sale of Assets		90		172
Common Stock Issued		159		1,763
Change in Debt, Net		2,266		(773)
Other		(231)		(498)
Change in Cash		233		(210)
Ending Cash Balance	$	411	$	201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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AEP is a Compelling Investment

- Market leading assets and operations
- Attractive pipeline of growth capital opportunities
- Successful regulatory management supports earnings continuity
- Strengthened balance sheet, liquidity and credit profile
- Diversified earnings growth and attractive dividend

Norges Bank Office Visit
June 5, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Contents

- Legislative Proposals and Prospects
- Summary Findings
  - Emissions
  - Costs and Electricity Rate Impacts
  - Compliance Strategy
- New Generation (USC and IGCC)
- Carbon Capture and Sequestration Plans

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Legislative Proposals Evaluated

Senate Bills Analyzed

- *Two bills within the Senate were analyzed:*
  - *Lieberman-Warner (L-W) - leading bill; may be voted on in June 2008*
  - *Bingaman-Specter (B-S) - introduced June 2007; "moderate" alternative to L-W*

- *Each bill is built on a similar platform:*
  - *Cap-and-Trade program covering multiple GHGs*
  - *Significant auction of allowances (increasing over time) to fund technology development, low-income price relief and other initiatives*
  - *Financial incentives and bonus allowances for Carbon Capture and Sequestration (CCS)*
  - *Include AEP-IBEW language on international linkage*

- *AEP publicly supports the Bingaman-Specter bill.*

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Bill Comparison

Key Provisions for AEP

	Bingaman-Specter (S. 1766) "The Low Carbon Economy Act of 2007"	Lieberman-Warner (S. 2191) "America's Climate Security Act of 2007"
GHG Emission Cap Levels	2012: 2012 levels (28% above 1990 levels) 2020: 2006 levels (17% above 1990 levels) 2030: cap equal to 1990 levels	2012: 2005 levels (16% above 1990 levels) 2020: 1990 levels 2030: 22% reduction from 1990 levels
Cost Containment	"Safety Valve" allowances can be bought at $12 per metric ton of CO_2 in 2012, rising annually by 5% in real terms.	No "Safety Valve." Regulated cos. can "borrow." "Carbon Market Efficiency Board" created to ensure efficient allowance market.
Offsets	Unlimited use of domestic offsets. Allows President to establish program for international offset development.	Domestic offsets limited to 15% of compliance obligation. No international offsets unless developing countries cap emissions (unlikely).
CCS Bonus Allowances	CCS (Carbon Capture and Sequestration) receive bonus allowances.	CCS (Carbon Capture and Sequestration) receive bonus allowances.
Allowance Allocation (AEP Share)	2012: 76% of AEP share of cap "allocated" 2020: 64% of AEP share of cap "allocated" 2030: 36% of AEP share of cap "allocated"	2012: 62% of AEP share of cap "allocated" 2020: 54% of AEP share of cap "allocated" 2030: 18%of AEP share of cap "allocated"

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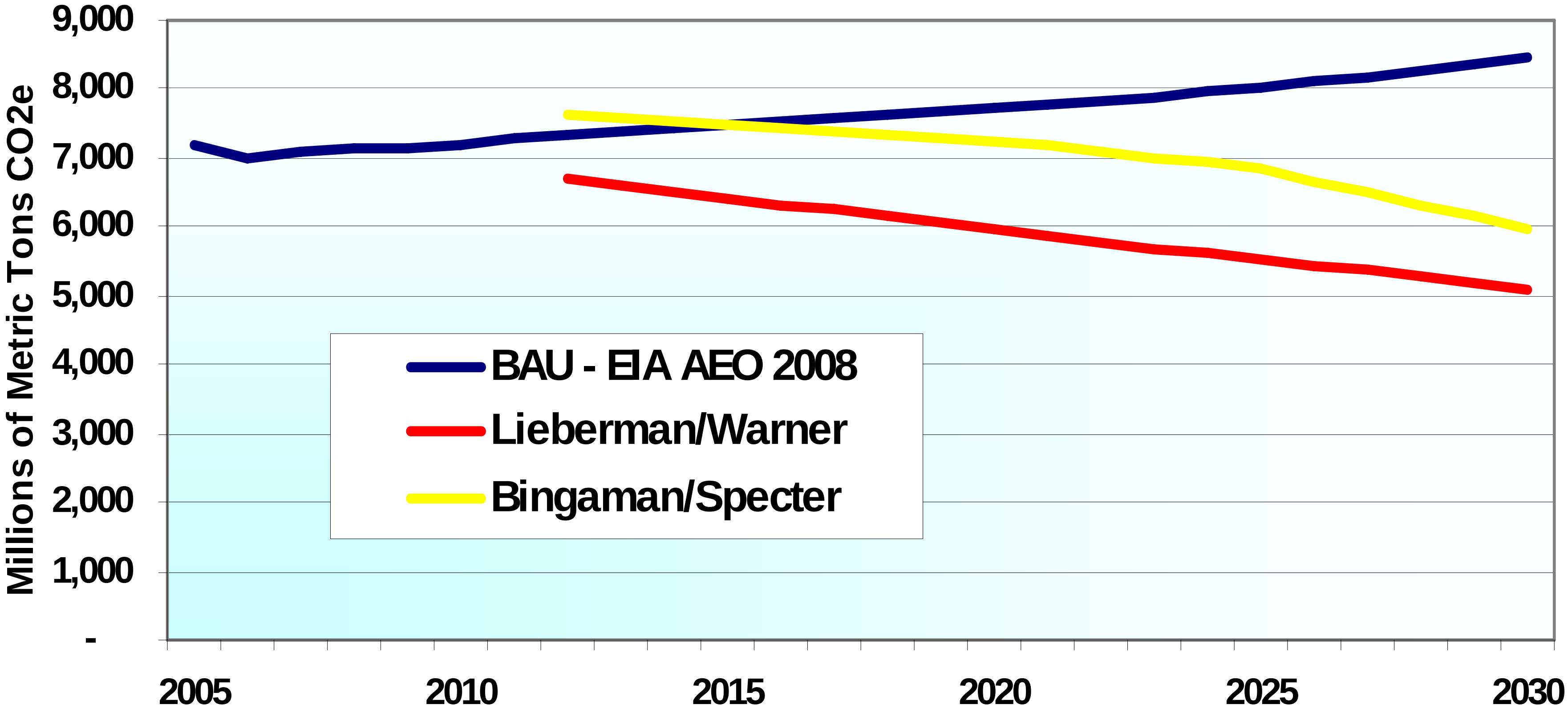
US GHG Emissions & Caps



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Summary Findings

Modeling and Major Assumptions

- ***AEP utilized its proprietary Multi-Emissions Compliance Optimization (MECO) model to analyze the impacts of the two bills on AEP's emissions, costs and compliance investments between 2008-2030.***
- ***This model incorporates a wide variety of technology choices and off-system GHG reduction options in determining a least cost path in meeting the CO_2 reduction requirements of the bills. Major assumptions for fuel, capital and O&M costs for technology choices, and electricity demand is based on AEP's current Integrated Resource Plan (IRP).***
- ***Major assumptions specific to the bills include:***
  - ***Annual emission caps (based on AEP's pro-rata share of required reductions).***
  - ***Offsets (though no international offsets effectively allowed in Lieberman-Warner).***
  - ***Allocation of "free" allowances and CCS Bonus Allowances (based on bill specifics). The balance of allowances needed to meet the emission caps were assumed to be bought from the auction at estimated market prices.***
- ***Overall, AEP was assumed to be able to aggressively:***
  1. ***Deploy new CCS technology***
  2. ***Add large amounts of new wind and biomass***
  3. ***Develop offset projects at "cost" in meeting the caps***

For additional information on compliance options and major assumptions please refer to Caveats and Uncertainties on page 24.

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Summary Findings

- ***L-W requires AEP to reduce its CO_2 by 32 MM Tons (or more than 20%) by 2020. By 2030, reductions total 70 MM Tons or almost 50% below projected levels. In contrast, B-S requires about half the reductions as L-W during 2012-2030.***
- ***L-W is expected to cost more than double B-S given earlier and larger GHG reductions. Total NPV costs of L-W = $27 Billion; B-S = $10 Billion.***
- ***L-W will cost almost $4 billion annually by 2020 and more than $12 billion/yr by 2030. AEP customers will pay 24% more in electric rates by 2020, and 58% more by 2030. This will increase a typical residential bill by more than $800 per year.***
- ***Coal with CCS is projected to play a large role in abating emissions under either bill. By 2020, in both bills, AEP is projected to install 3 GW (5 large projects) of CCS. By 2030, 7.5 GW (about 12 large projects) are projected to be installed under L-W.***
- ***<u>About two-thirds</u> of the costs and rate impacts of the bills are due to projected allowances purchases from the auction, NOT from compliance investments. A sensible allocation program that provides allocations to utilities instead of auctions would avoid these unnecessary rate impacts.***

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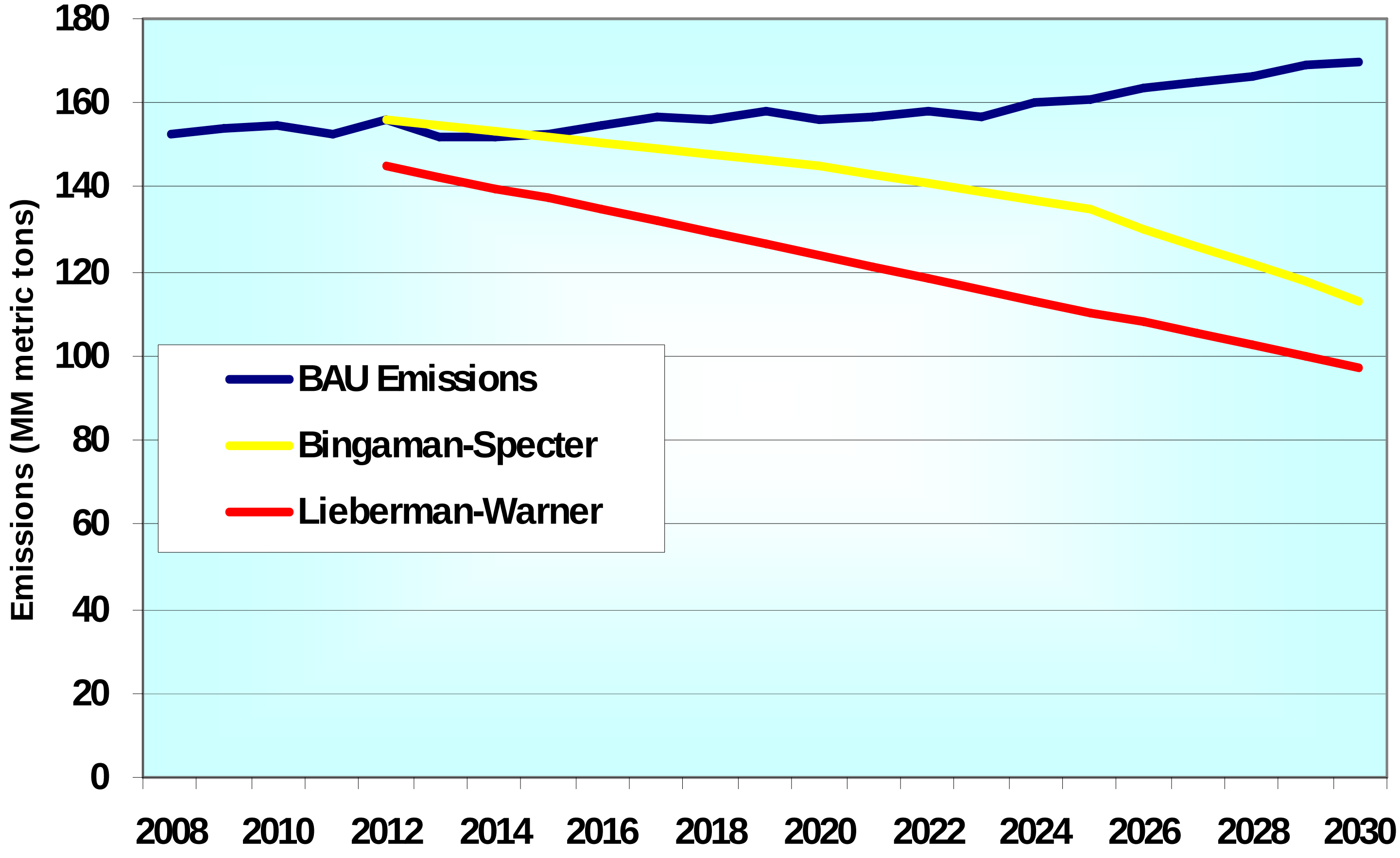
AEP CO_2 Emissions & Caps



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AEP CO_2 Emissions

- ***Despite continuing growth in demand for electric services, AEP's projected BAU emissions growth (e.g. without legislation) remains relatively flat between now and 2020. This reflects:***
  - ***End use energy efficiency due to AEP's gridSMART[SM] program and Federal standards under the most recent Energy Bill reducing system electricity demand growth to only ~0.8 % per year by 2020.***
  - ***Planned retirements of a number of older, less efficient coal fired units (5 GW or ~20% of AEP's total coal) between 2010 and 2023.***
  - ***AEP's voluntary commitment to reduce its CO_2 emissions by 5 MM Tons per year by 2011. This includes addition of 1000 MW of wind, continuing improvement in supply efficiency, emission offset projects and forestry.***

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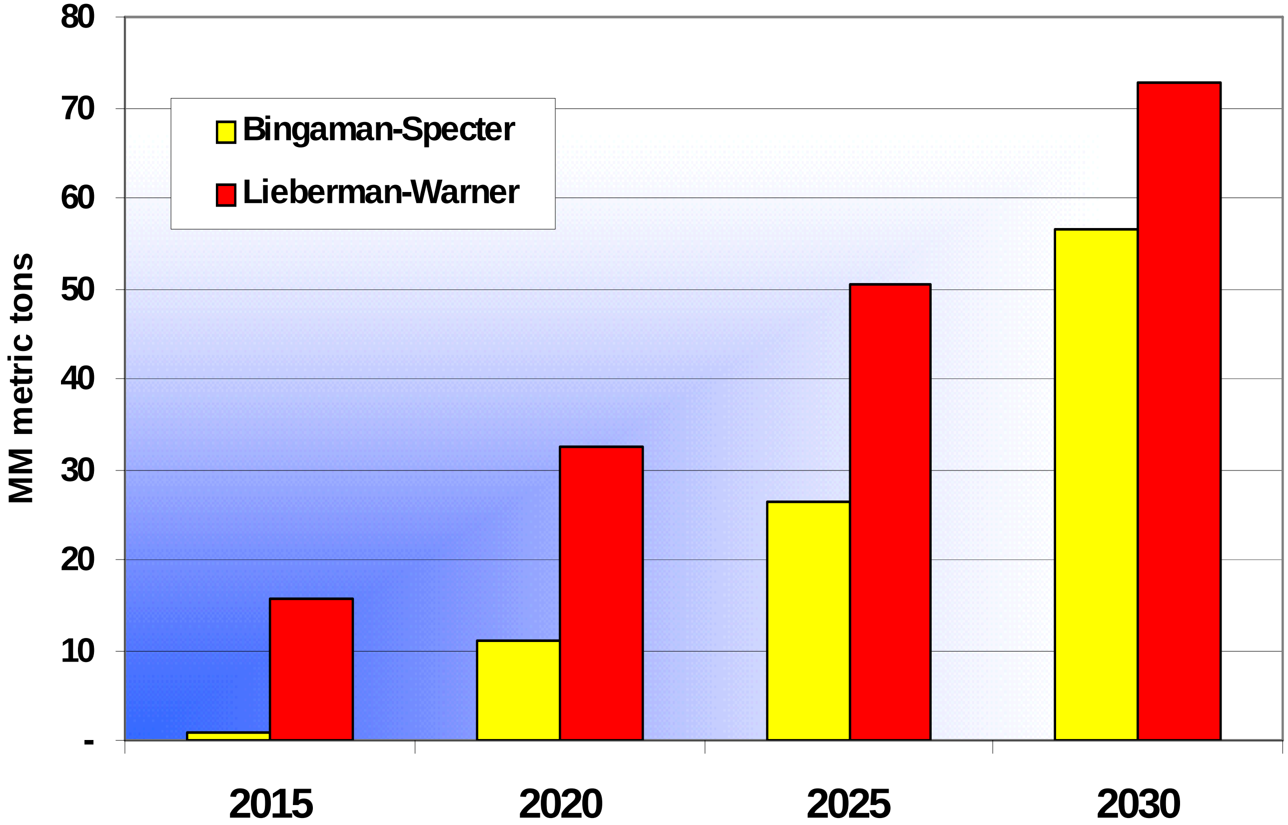
AEP Annual Emission Reductions

Based on current BAU projections



AEP is required to reduce emissions more substantially and sooner under L-W than B-S, with three times the reductions in 2020 and twice the reductions in 2025.

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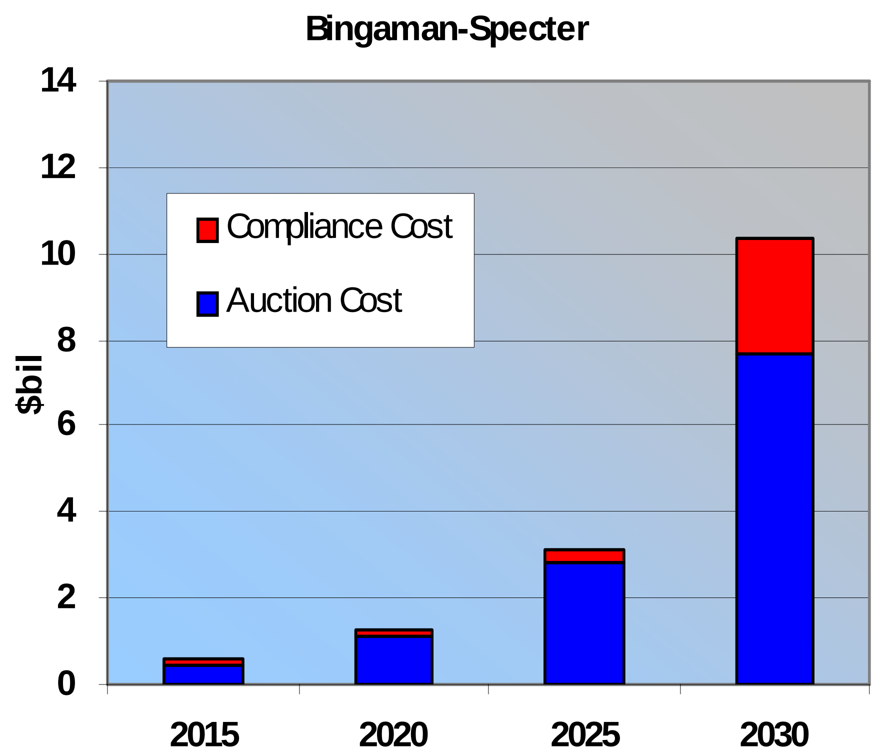
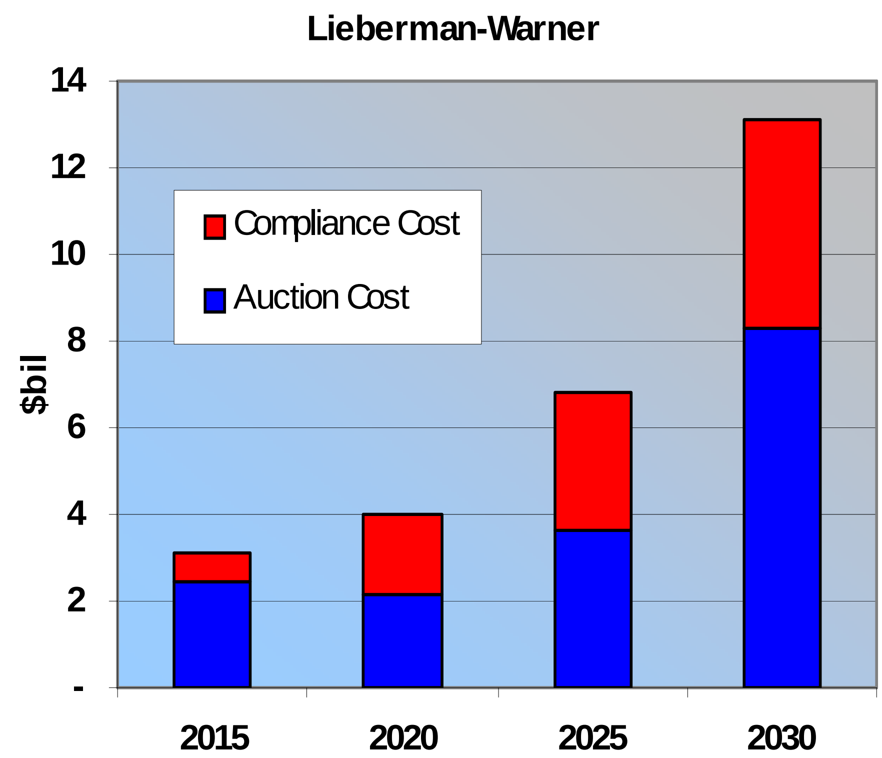
Annual AEP Cost Increases

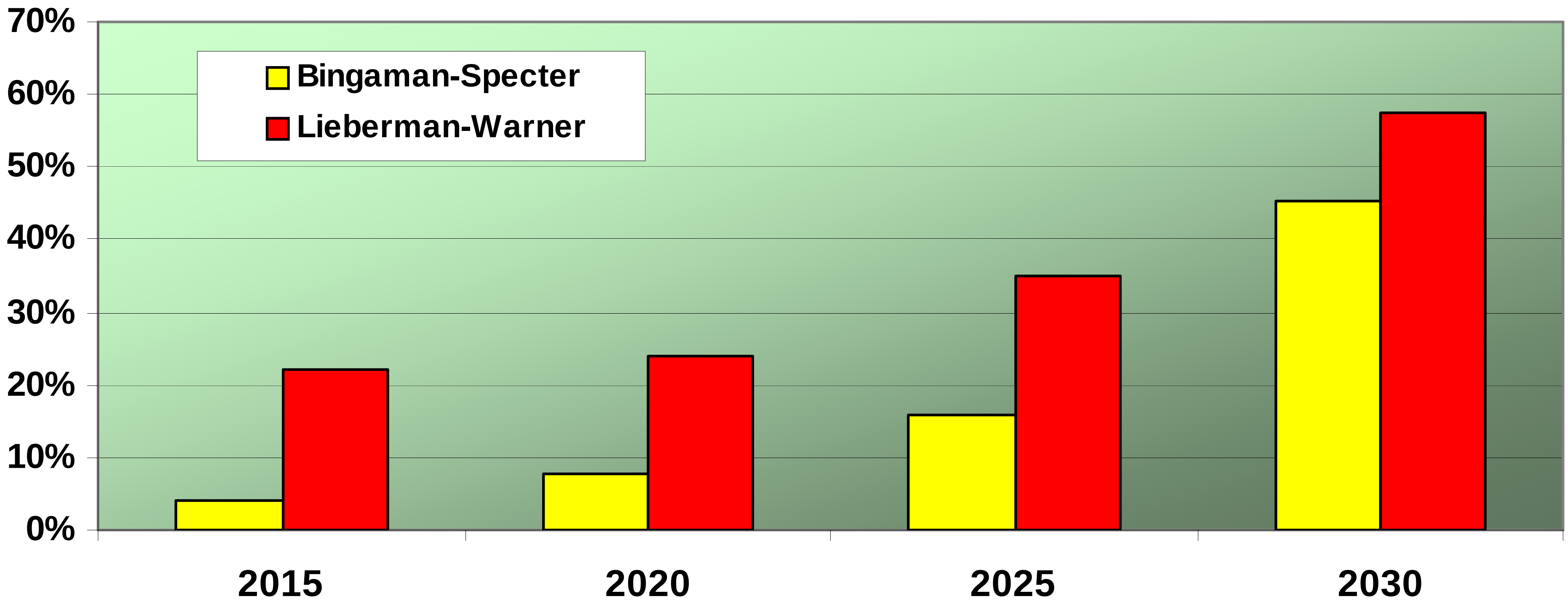




Consistent with the greater CO_2 reductions, the cost impacts of Lieberman-Warner are much greater, particularly during 2015-2025 than Bingaman-Specter. Auction purchases account for more than two-thirds of total costs.

AEP Average "Levelized" Rate Increase

(Average across all customer classes)



Electricity rate impacts are directly proportional to AEP's compliance costs and purchases from allowance auctions (shown on p. 17). Because auction costs dominate total costs, rate increases would be much lower with a large "no-cost" allocation of allowances.

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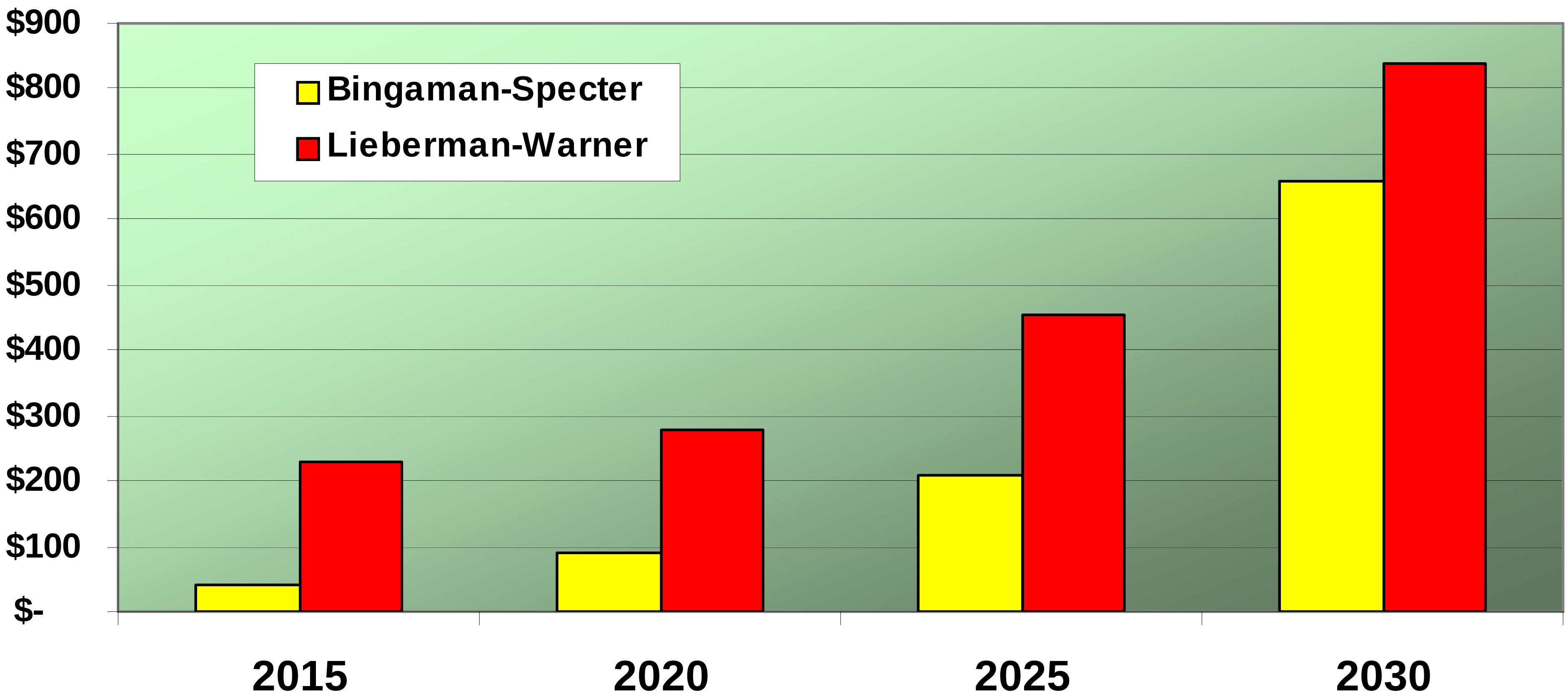
Annual Cost Per Residential Customer*



Assumes average monthly usage of 1,000 kWh

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Low and Zero CO_2 Technology Deployment

	Bingaman-Specter (MW)		Lieberman-Warner (MW)	
	2020	2030	2020	2030
CCS	2,900	3,800	2,900	7,500
New Nuclear	-	-	-	1,700
Wind*	1,800	4,800	4,800	4,800
New Biomass	-	500	-	800
Biomass Cofiring	-	600	1,100	2,200

***Total includes both existing and planned AEP-owned generation and wind purchase power agreements (PPAs).**

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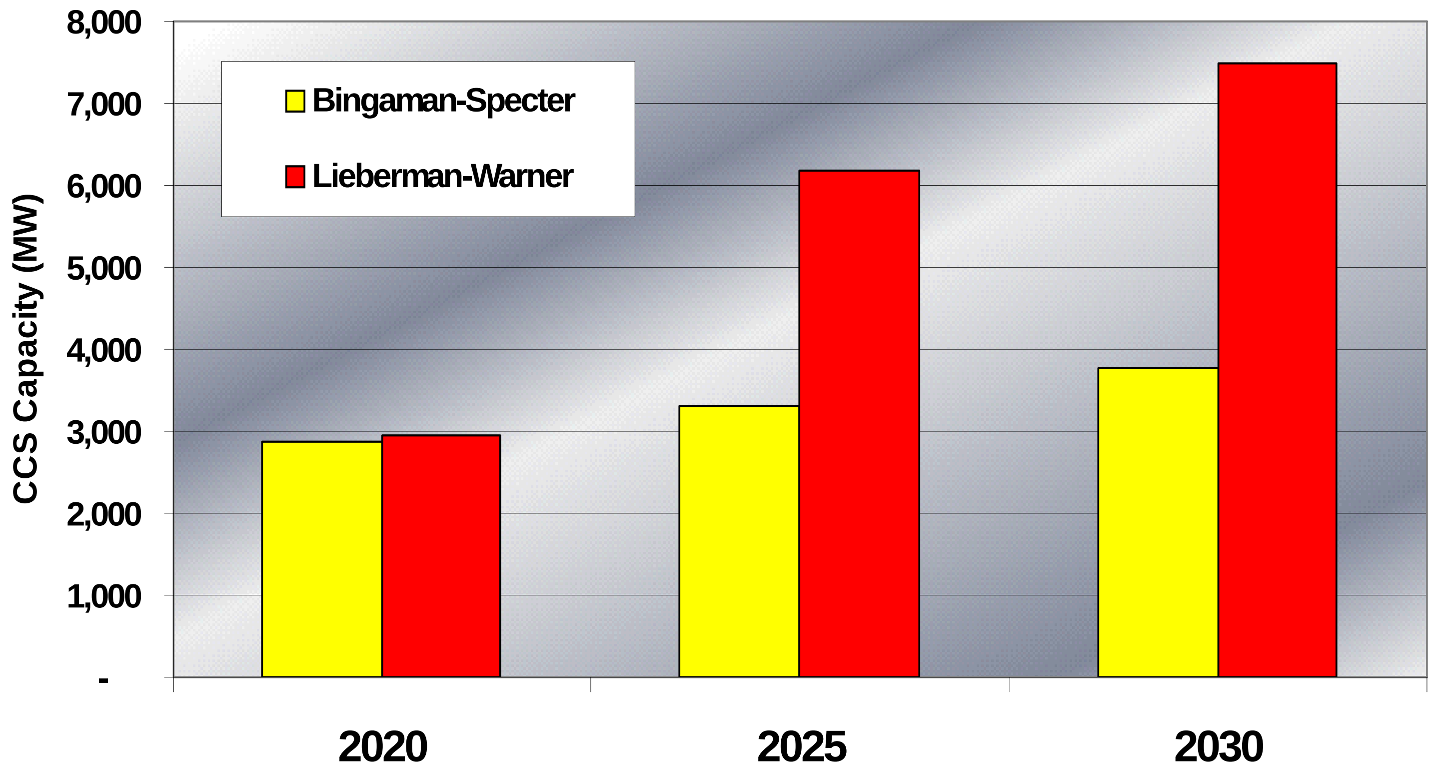
Projected CCS Installations



- ***Early CCS driven by CCS bonus allowances but limited by constraints on number of projects that can be put in-service.***
- ***Later CCS retrofits in L-W driven solely by need for very substantial emission reductions.***

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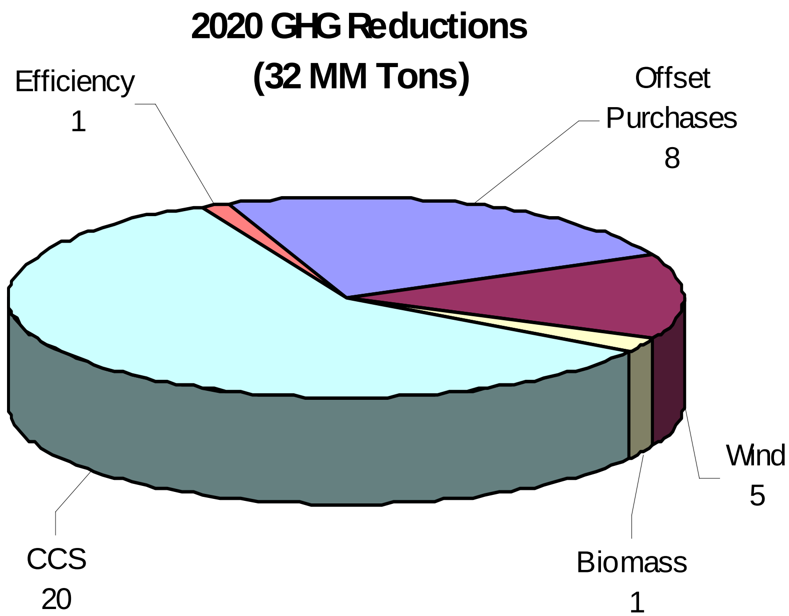
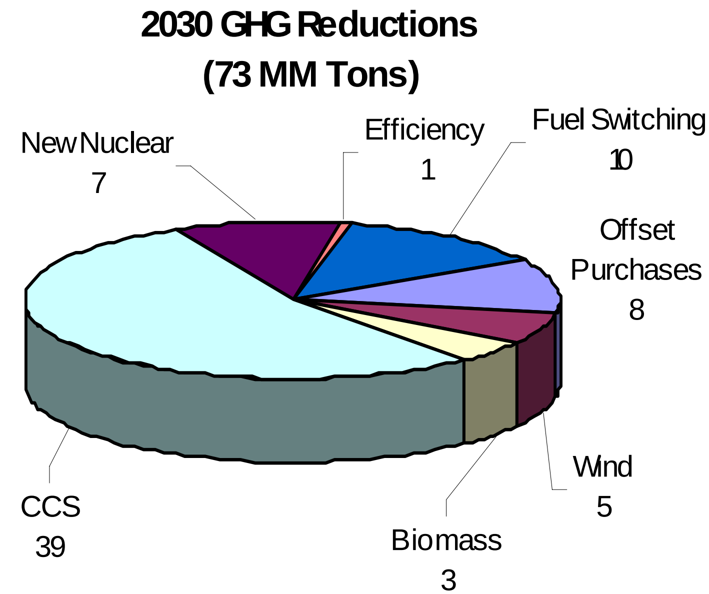
CO_2 Compliance Under Lieberman-Warner





- ***A mix of technologies is needed to meet reductions targets through 2020. However, most of the reductions come from CCS given the bonus allowance incentives and the bill's limitations on offsets.***
- ***Post-2020, most of the additional reductions come from additional CCS. New nuclear, additional dedicated biomass plants, and greater use of natural gas account for the remainder of the increase.***

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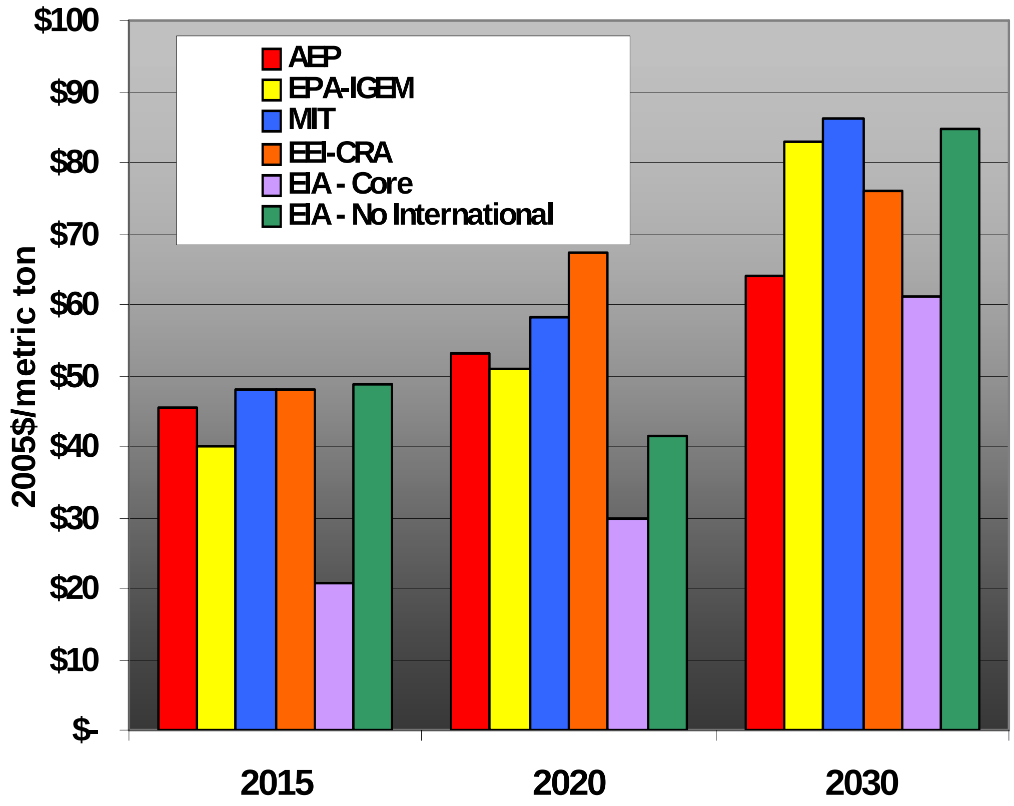
AEP Analysis Comparison w/ Other Studies

- *AEP price forecast is within the range of most other forecasts, though MIT and CRA-EEI studies are higher.*
- *EIA "core" case is generally considered unrealistically low as it includes very large amounts of international offsets (not allowed in L-W) and huge amounts of new nuclear.*
- *If market prices are in fact higher, AEP might reduce more, avoiding some auction purchases, though with higher auction prices, AEP costs and rate impacts would be higher.*
- *There is SUBSTANTIAL uncertainty in the costs and price projections in these studies.*



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Caveats and Uncertainties

- *The analysis assumes that CCS technology can be aggressively deployed by 2015-2020. To the extent, regulatory, financial and institutional obstacles prevent this from occurring, costs would be substantially higher than reported herein.*
- *AEP is assumed to receive CCS bonus allowances for all CCS technology installed. However, the total amount of bonuses are limited in L-W, so allowances received will hinge on the actions of other electric companies. Sensitivity analysis was conducted with and without the inclusion of the bonus allowances.*
- *The analysis incorporates the impacts of energy efficiency given increasing electricity prices. However, this impact is difficult to project given the interplay between price-induced AEP system reductions and possible increased or decreased demands from wholesale markets. Further, CO_2 policies could accelerate electrification of the US economy as industries and transportation move away from fossil fuels and towards electro-technologies (such as PHEV).*
- *Allowance market prices will affect electricity rate impacts and auction costs substantially. To the extent prices are higher (as in the MIT and CRA studies), costs and rate impacts for AEP under L-W would be greater.*
- *The analysis examines the 2008-2030 period. To the extent impacts were modeled over a longer horizon (e.g. thru 2050), they would tend to increase near term GHG reductions as allowances are banked to meet more stringent targets after 2030. This would result in much higher cost impacts during 2012-30 period.*

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AEP Leadership in Technology: IGCC and USC

<u>NEW ADVANCED GENERATION</u>

***IGCC** -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade*

***USC** -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100^{o}F) coal plant in U.S (AR)*

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CO_2 Capture Techniques

- Post-Combustion Capture
  - ***Conventional or Advanced Amines, Chilled Ammonia***
    - ***Amine technologies commercially available in other industrial applications***
    - ***Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches***
    - ***High parasitic demand***
      - ***Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%***
    - ***Amines require very clean flue gas***

- Modified-Combustion Capture
  - ***Oxy-Coal***
    - ***Technology not yet proven at commercial scale***
    - ***Creates stream of very high CO_2 concentration***
    - ***High parasitic demand, >25%***

- Pre-Combustion Capture
  - ***IGCC with Water-Gas Shift***
    - ***Most of the processes commercially available in other industrial applications***
      - ***Have never been integrated together***
    - ***Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale***
    - ***Creates stream of very high CO_2 concentration***
    - ***Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal***

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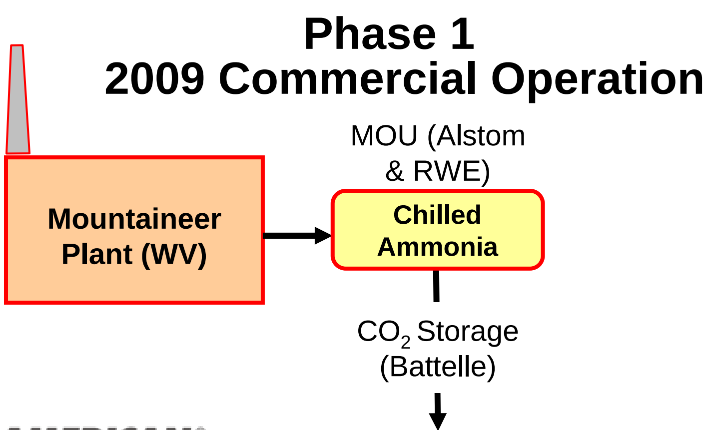
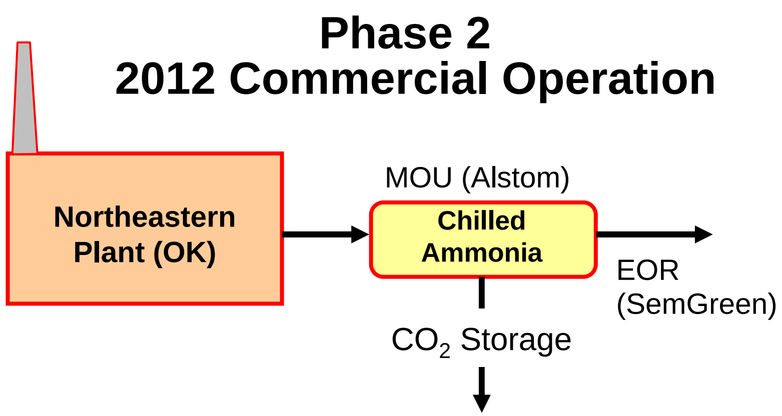
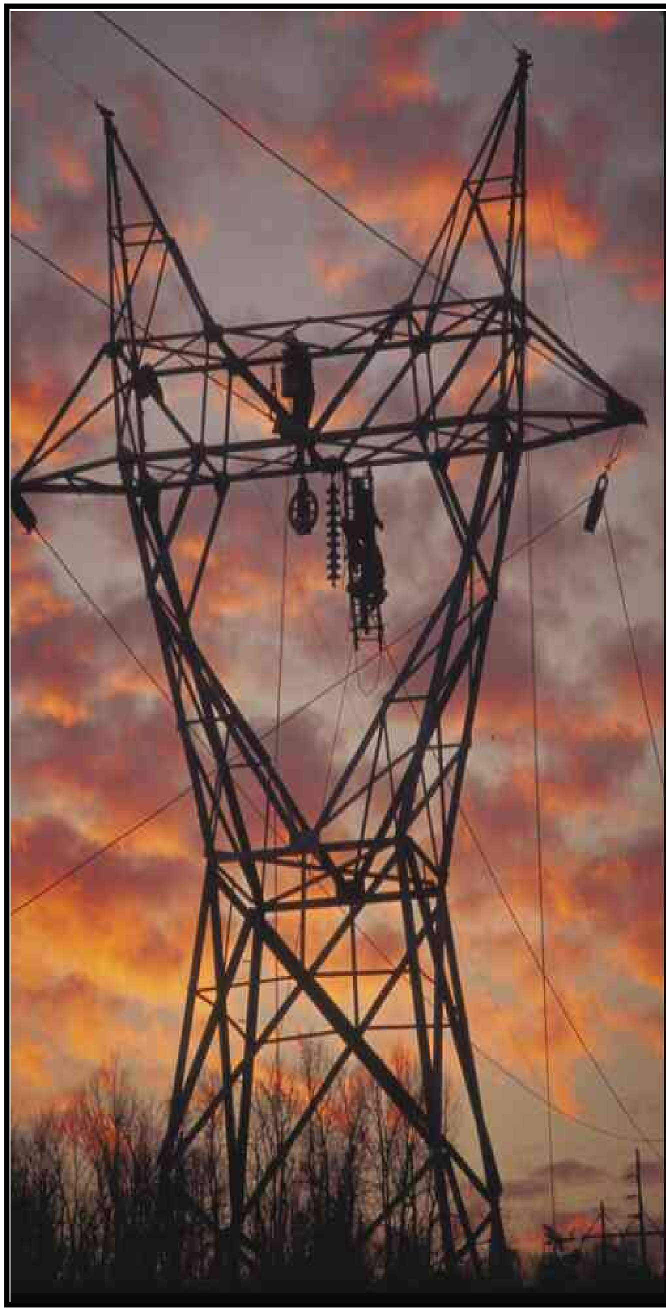
AEP's Carbon Capture & Storage Initiative

- *In March 2007, AEP announced a major new carbon capture and storage initiative:*
  - *Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.*
    - *The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.*
    - *The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.*







Alliance Bernstein Office Visit

June 17, 2008

Columbus, OH

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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I-765™ Transmission: Investment Opportunities

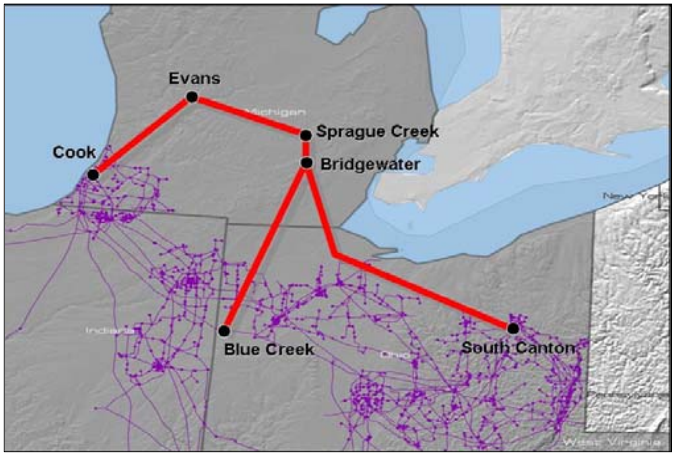
AEP is Advancing the Development of a National Interstate Today

PATH
Potomac-Appalachian Transmission Highline

PATH Project (PJM)

ETT
Electric Transmission Texas

ETT (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

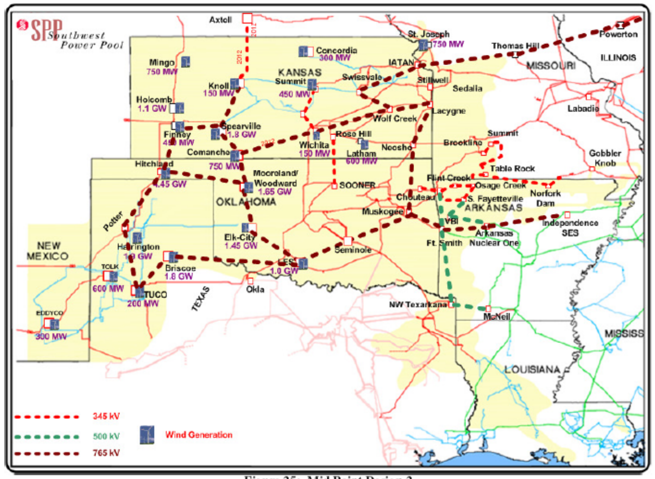


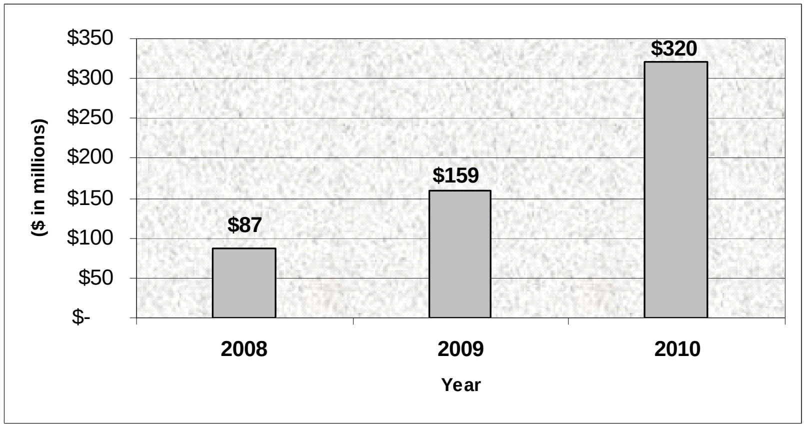
Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

AEP

Transmission – Investments and Earnings Contributions

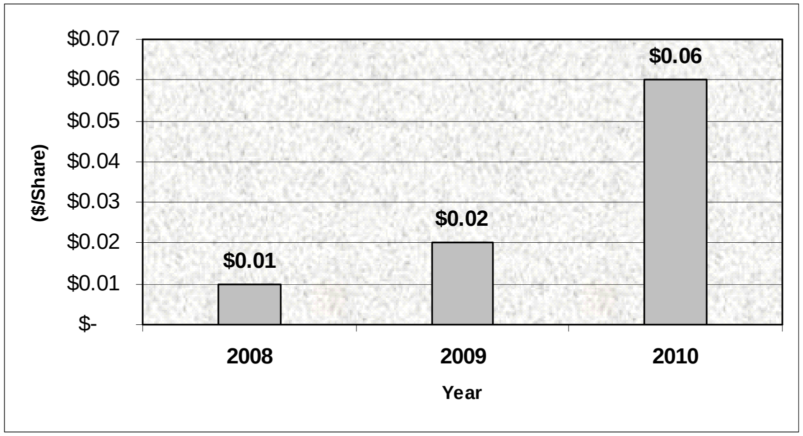
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

Electric Transmission Texas

Projected Transmission EPS Contributions*



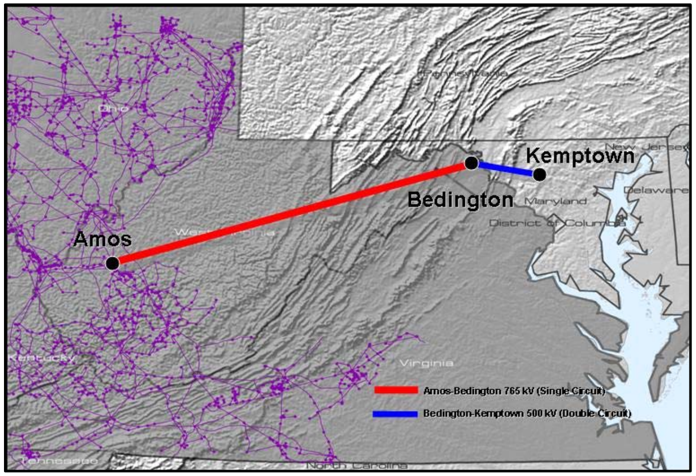
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Potomac-Appalachian Transmission Highline

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

PATH
Potomac-Appalachian Transmission Highline

- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
- To that end, ETA recently signed an agreement with Westar forming Prairie Wind Transmission, LLC proposing to build the first segment of the 765-kv Overlay Plan in SPP

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I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ### *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ### *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

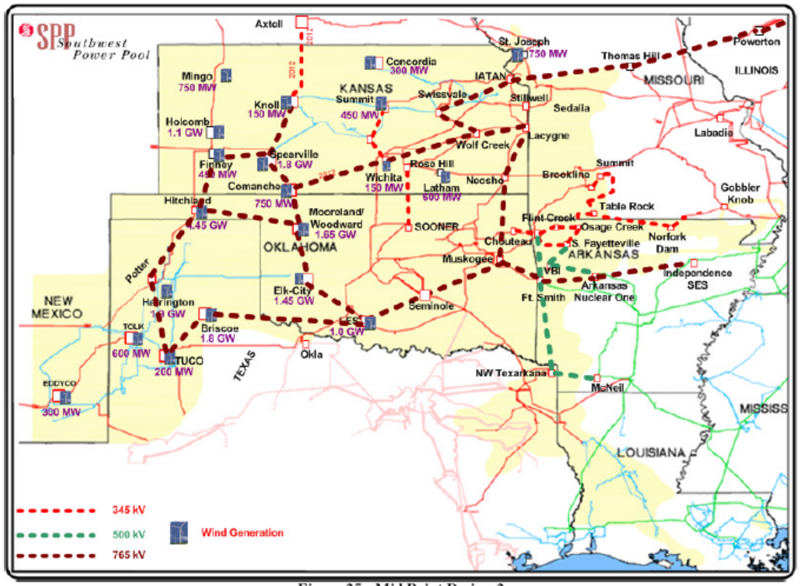

Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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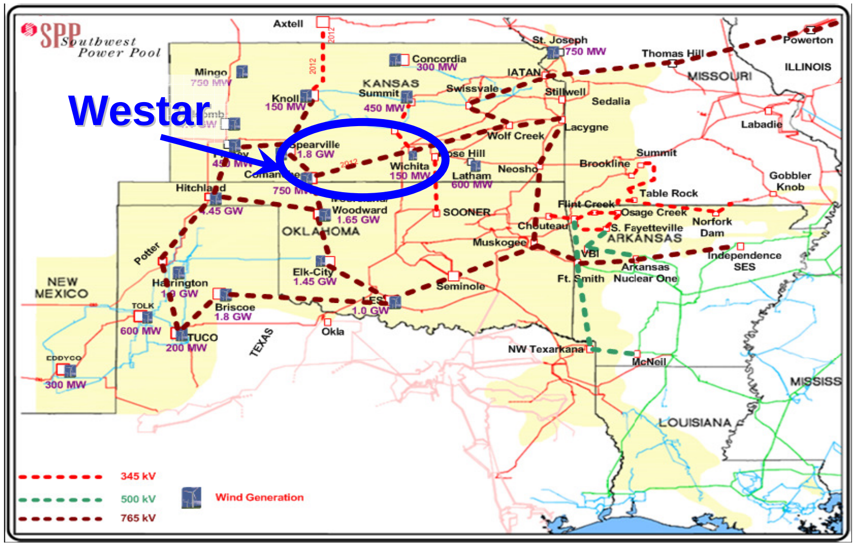
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



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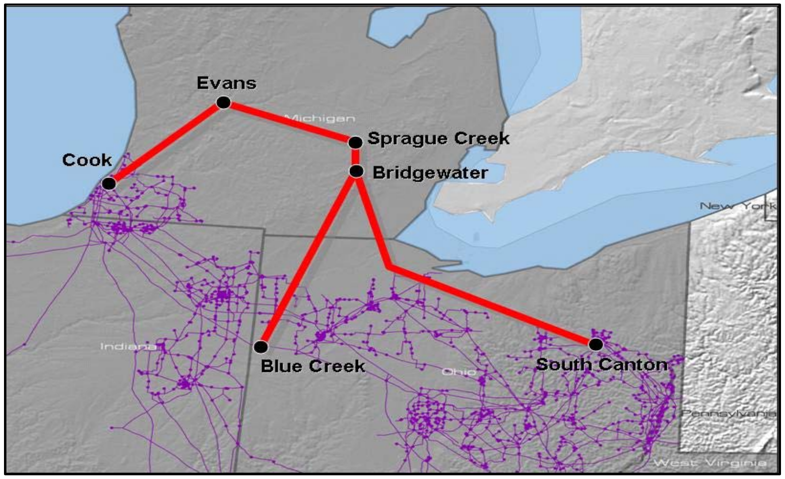
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



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UBS Analyst Visit

Columbus, Ohio

June 18, 2009

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STRONG
FLEXIBLE
ADAPTABLE

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AMERICAN ELECTRIC POWER

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AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

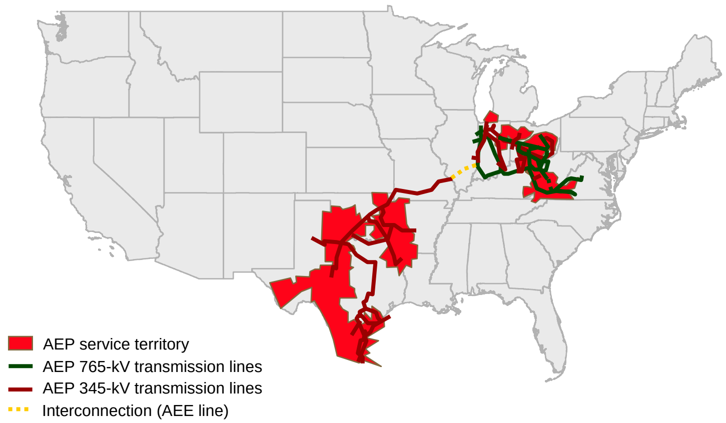
- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

Premier Regulated Utility Platform

Overview

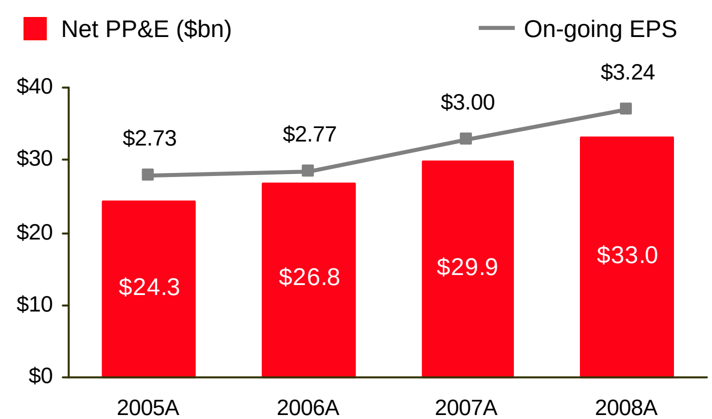


AEP's Leadership Position

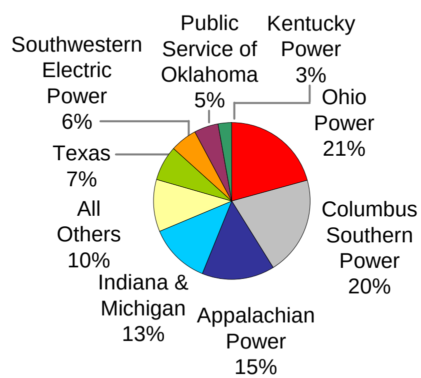
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

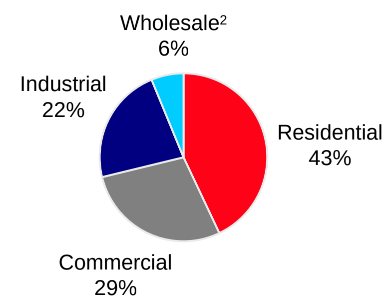
Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] Source: Company filings
[2] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

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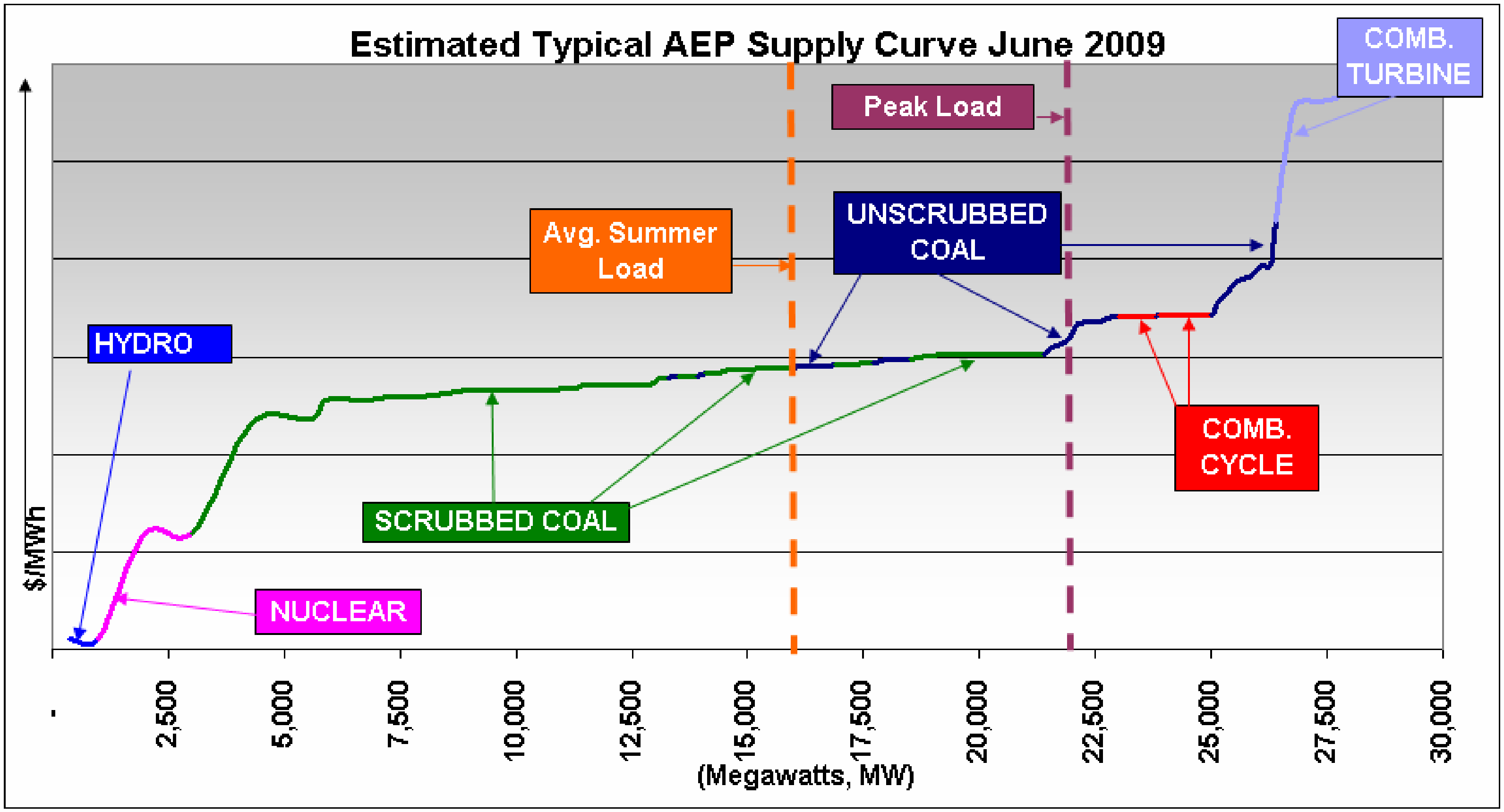
AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



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Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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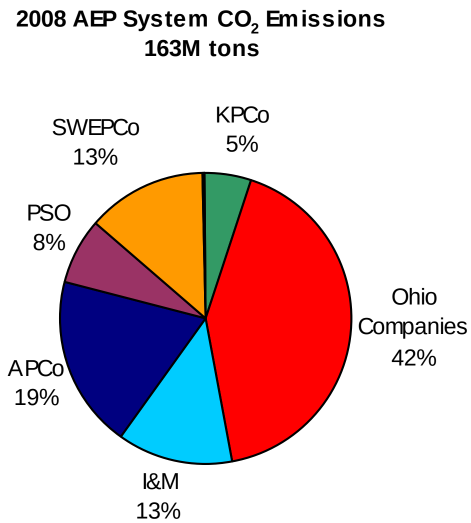
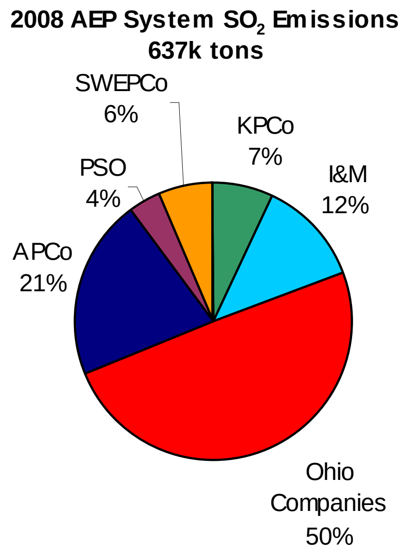
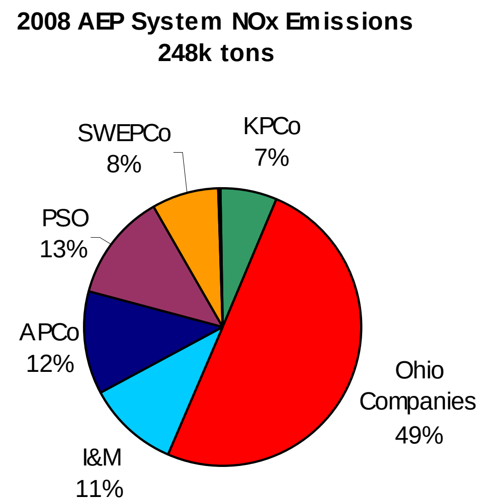
CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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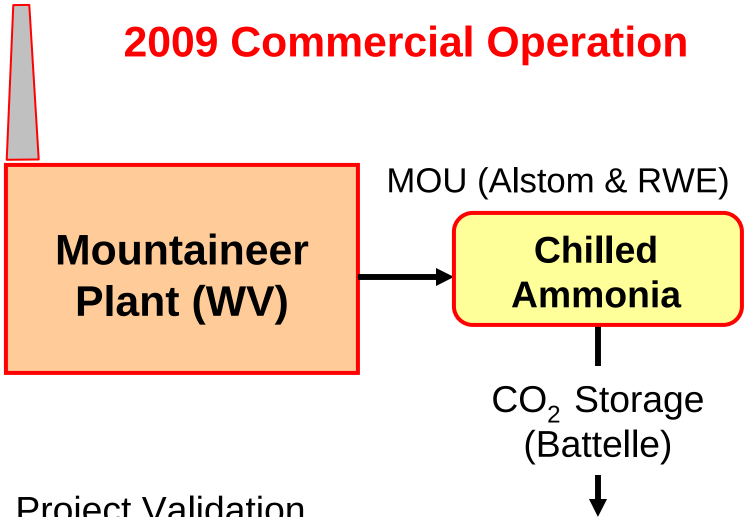
Carbon Capture & Storage

2009 Commercial Operation



<u>Project Validation</u>

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**
- **Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection**

<u>Represents Post-Combustion Capture</u>

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

<u>Key Issues for CCS Development in the U.S.</u>

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – AEP self-reported impacts to jurisdictional wetlands in March 2009. Work continues outside the jurisdictional areas. Hearing on the air permit appeal is scheduled for June 2009.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

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DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path

- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity

- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues

- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.

- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

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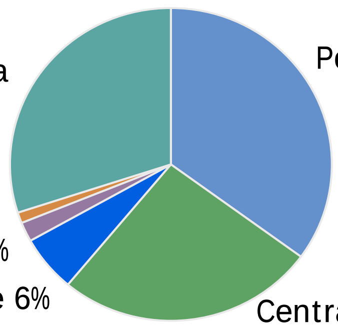
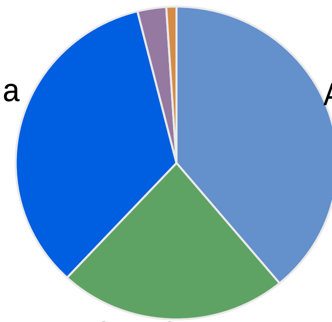
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

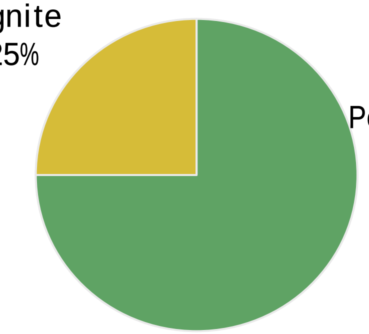
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

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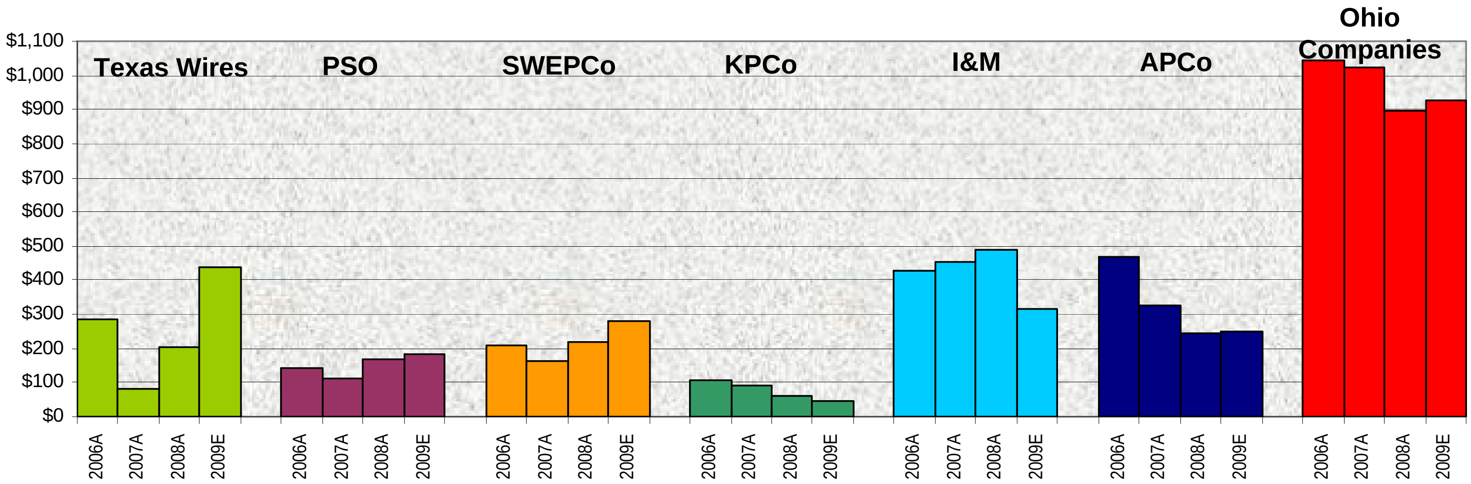
Cash Flow and Capex by Operating Company

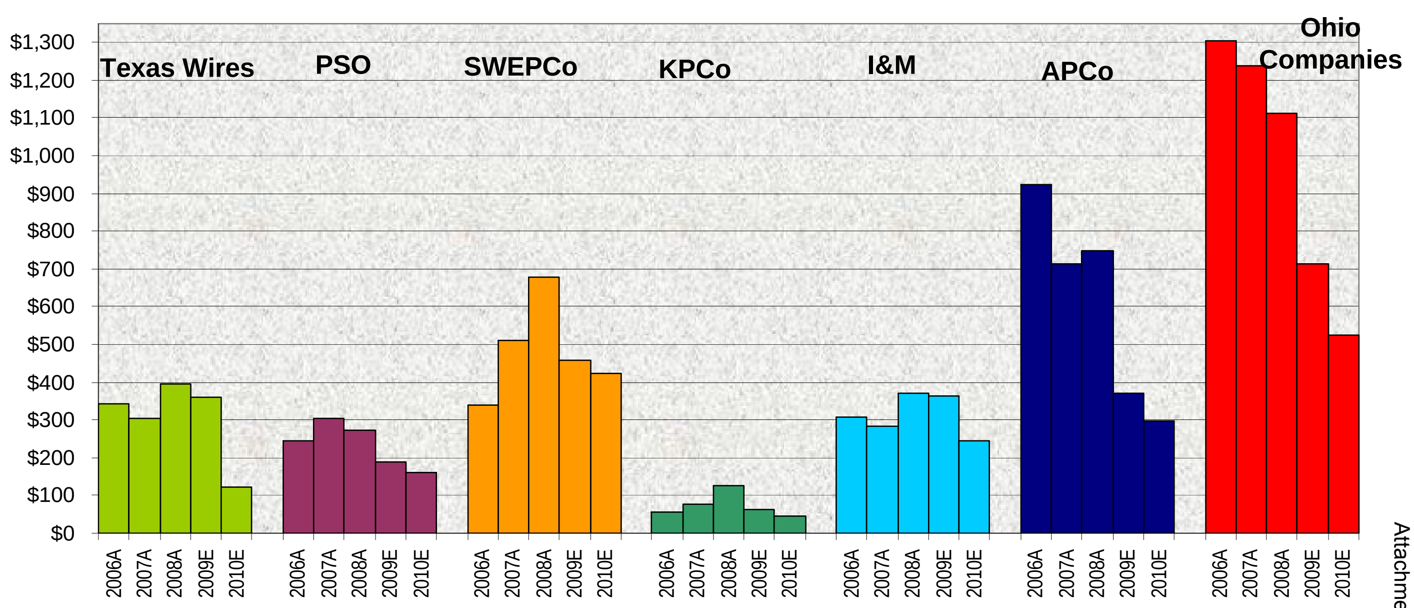


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER

Overview of 2009 Guidance

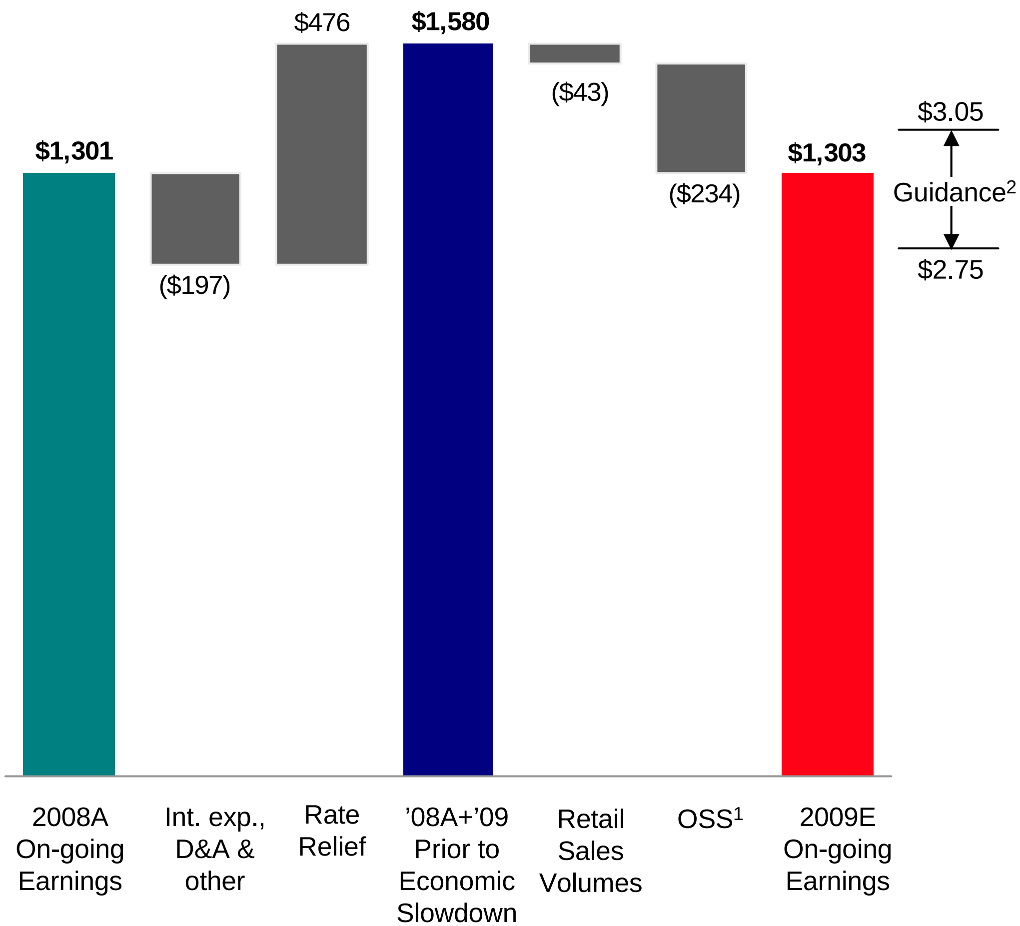
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax

[1] Net of sharing

[2] Assumes 2009 average shares outstanding ~ 450 million

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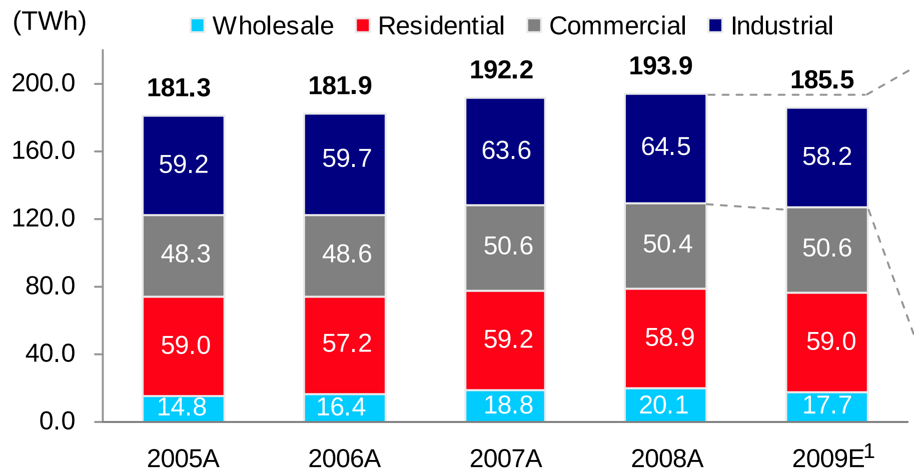
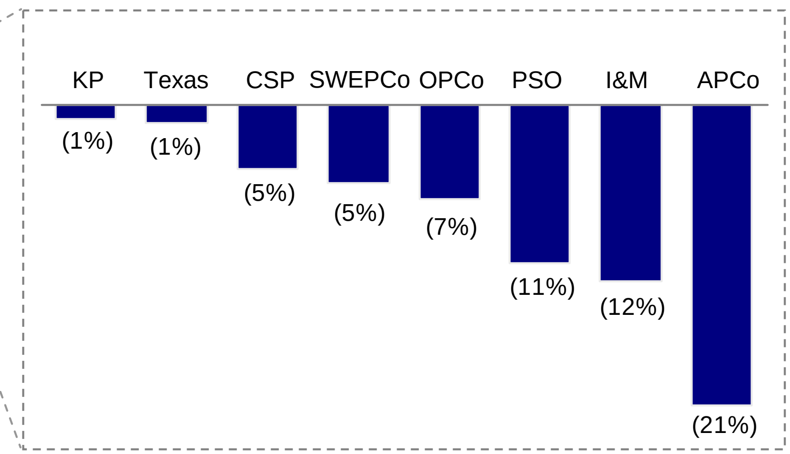
Key Drivers of Revised 2009 Guidance: Retail Sales

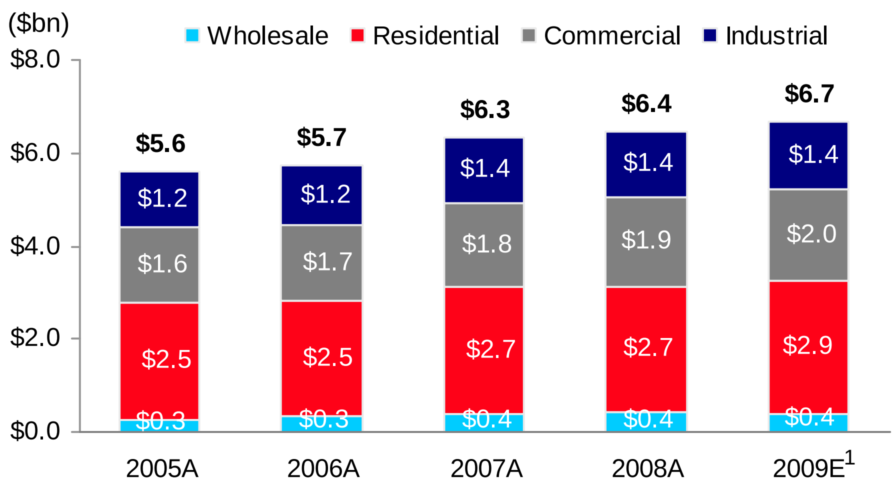
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

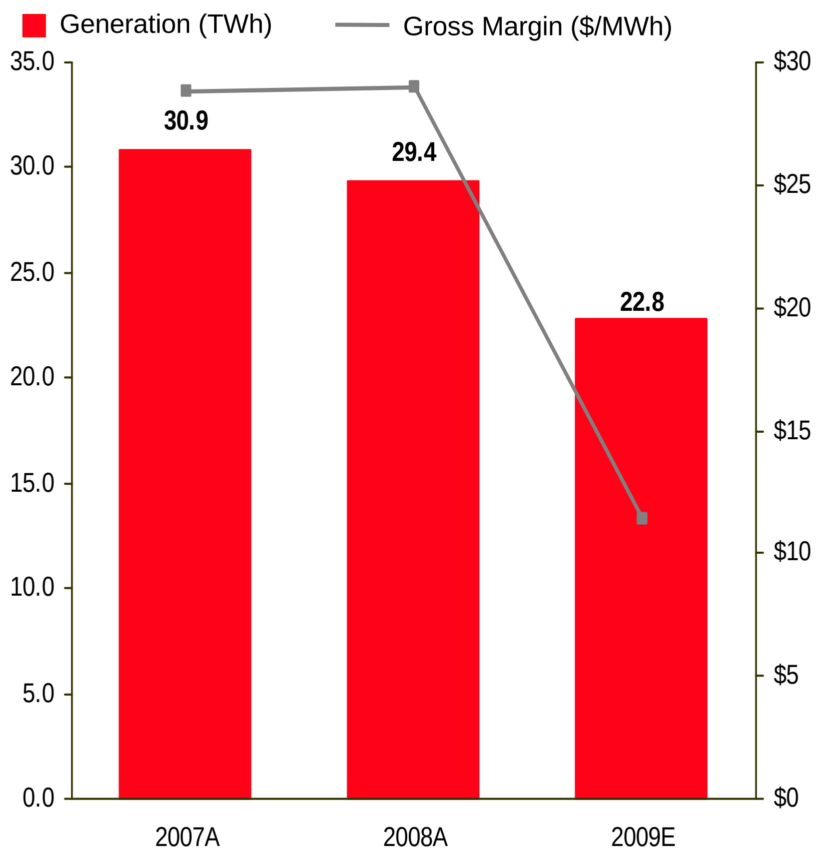
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

AEP AMERICAN ELECTRIC POWER

[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

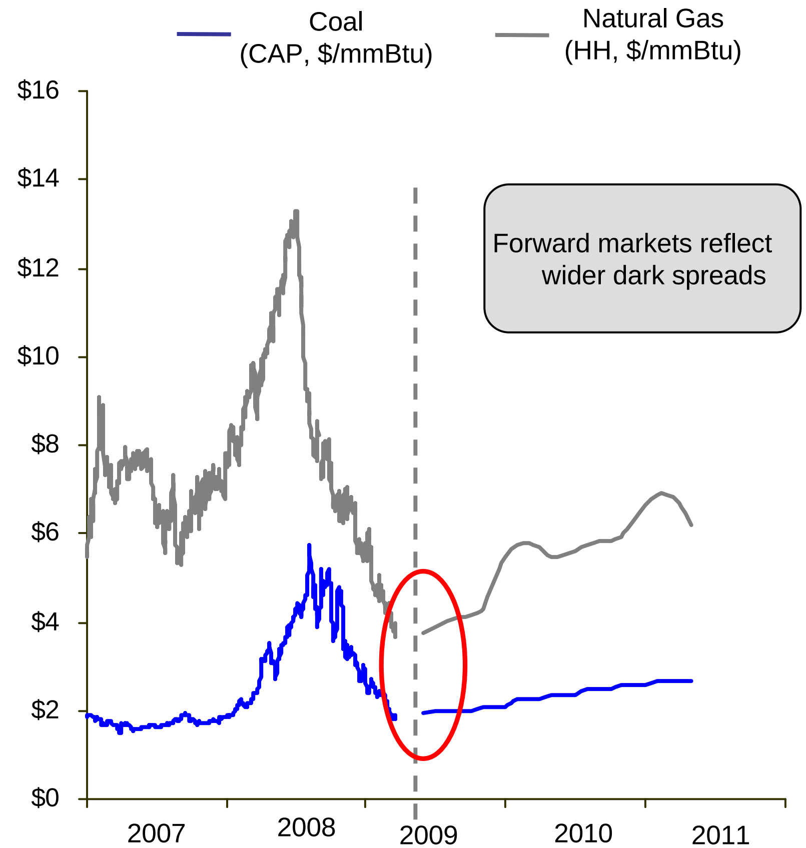
Key Drivers of Revised 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices

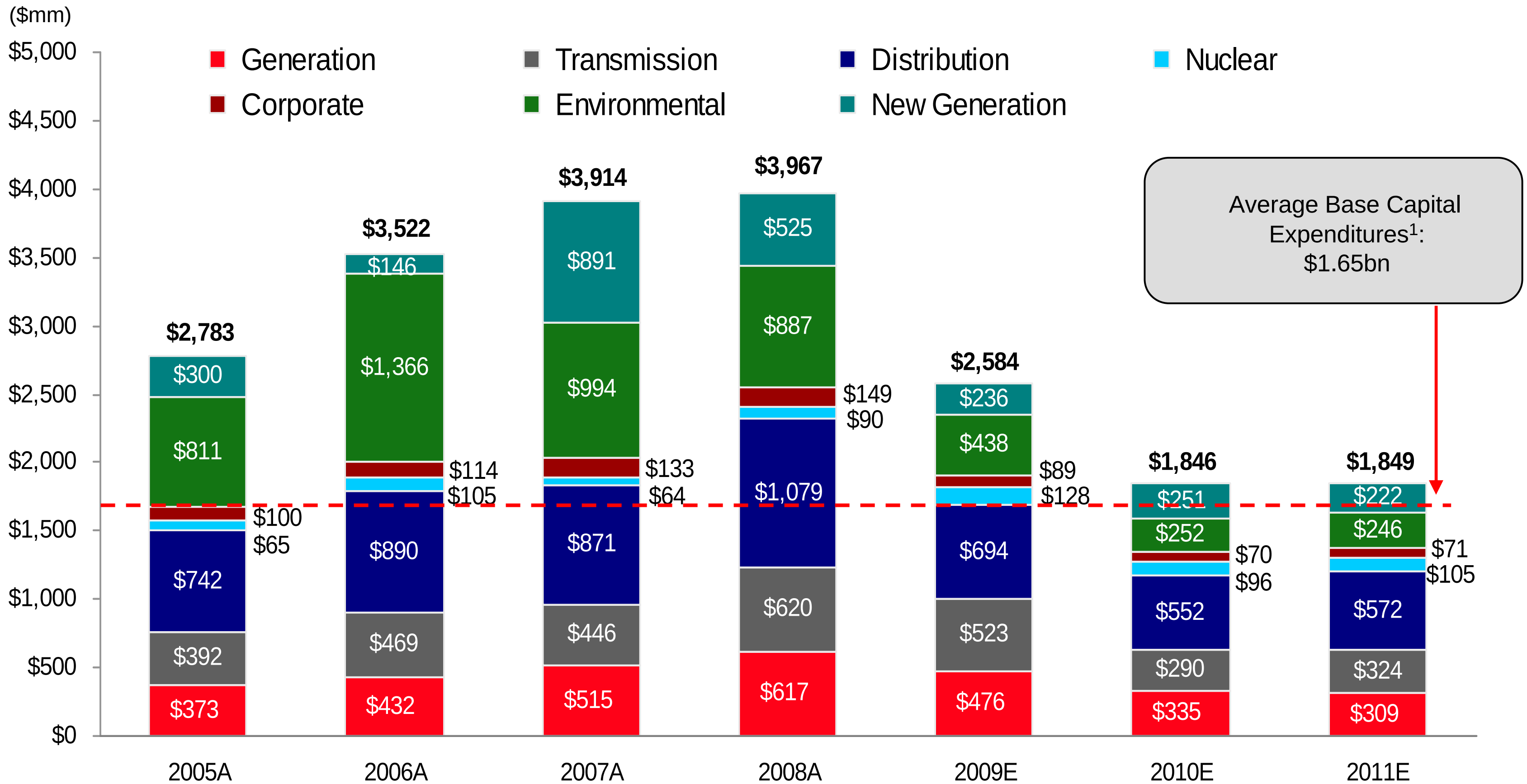


Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

AEP AMERICAN ELECTRIC POWER

Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

AEP AMERICAN ELECTRIC POWER

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

AEP AMERICAN ELECTRIC POWER

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN
FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

AEP AMERICAN ELECTRIC POWER

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	R	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)
(as of March 31, 2009)

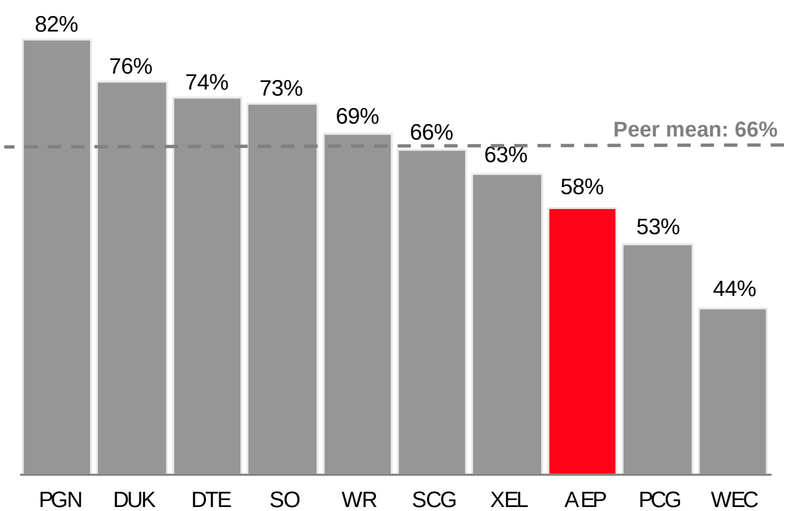
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ 150	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ 70	$ 679	$ -
Public Service of Oklahoma	$ 50	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 270	$ 1,791	$ 625

AEP AMERICAN ELECTRIC POWER

Dividend Overview

- We have paid 395 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

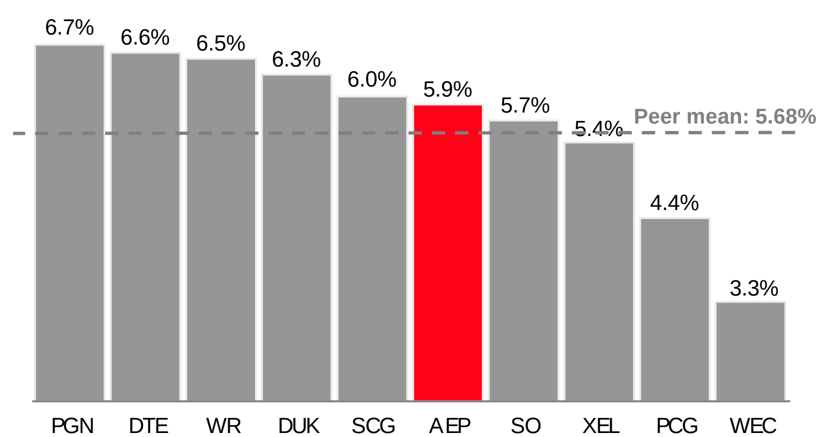
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 6/12/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 6/12/09

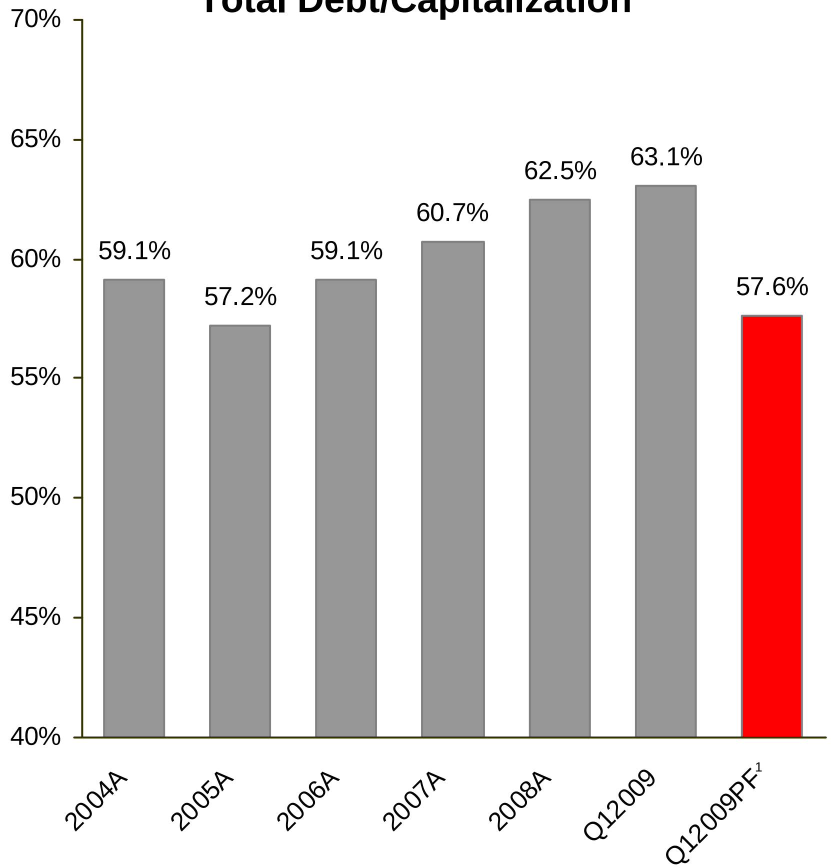
AEP AMERICAN ELECTRIC POWER

Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	**04/20/2009**	**Maturity**
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)[1]	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

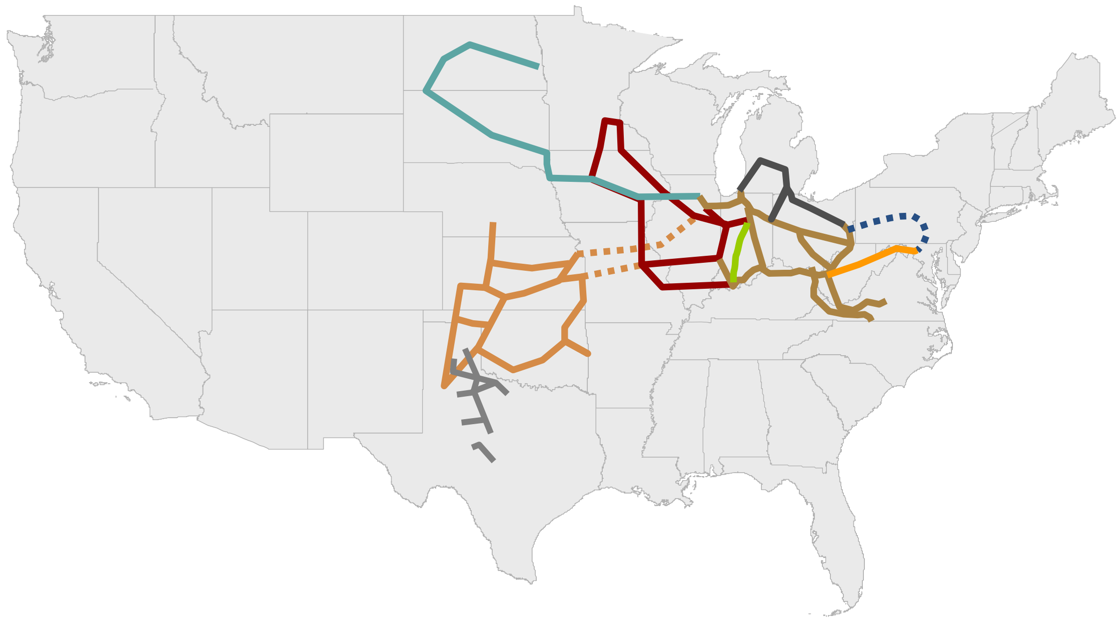
Pioneer COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV COD: 2014
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind COD: 2013
- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT COD: 2013
- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan COD: ~2020
- 700 miles of 765 kV

PJM Projects
- Enhance existing 765/345 kV

Hartland COD: ~2020
- 1000+ miles of 765 kV

MISO Vision Plan
- 765 kV Backbone

SPP Overlay COD: 2013-14
- 765 kV Backbone

ETT COD: ~2018
- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

AEP AMERICAN ELECTRIC POWER

Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

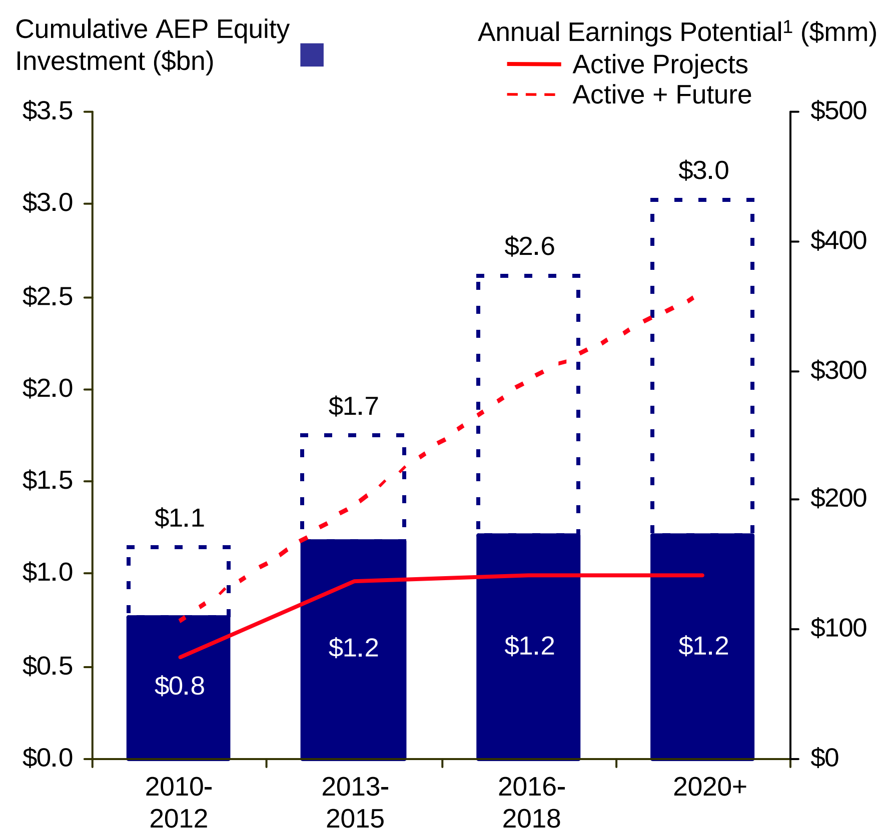
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects

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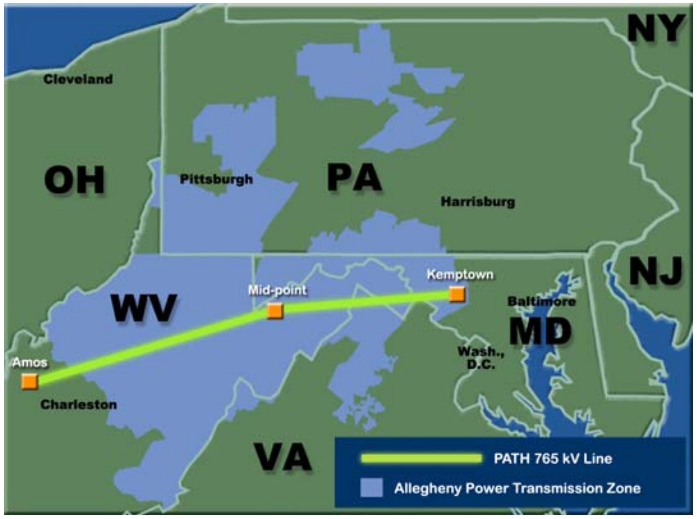
EHV Transmission in PJM: PATH

<u>Project Description:</u> 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



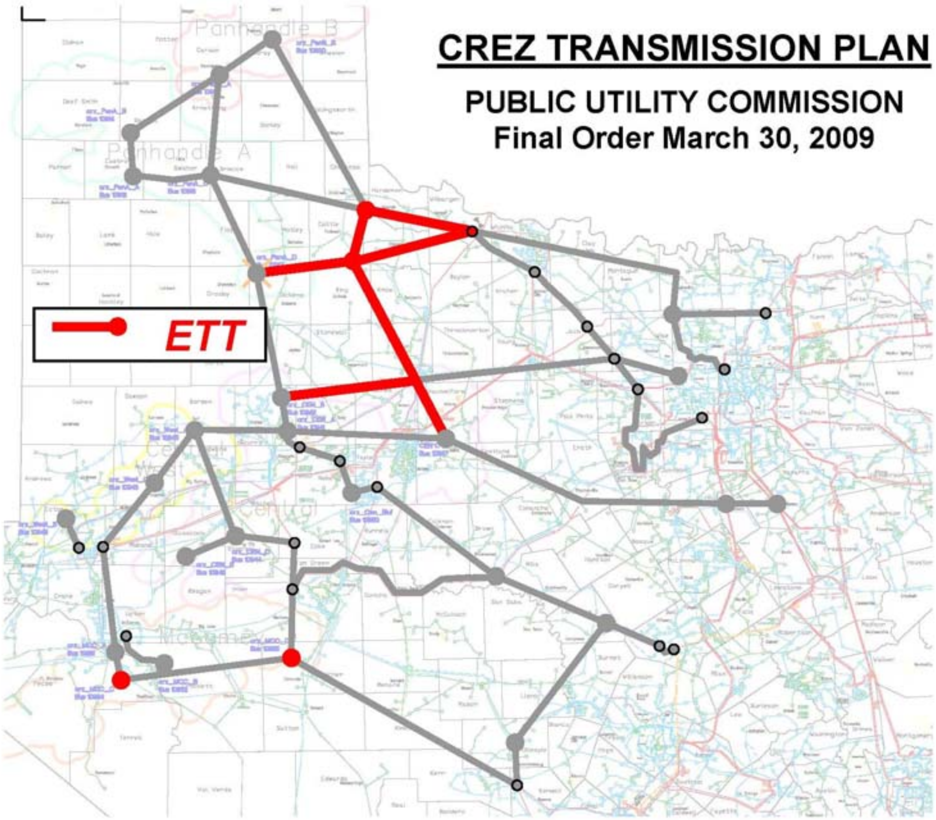
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AMERICAN ELECTRIC POWER

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT Electric Transmission Texas

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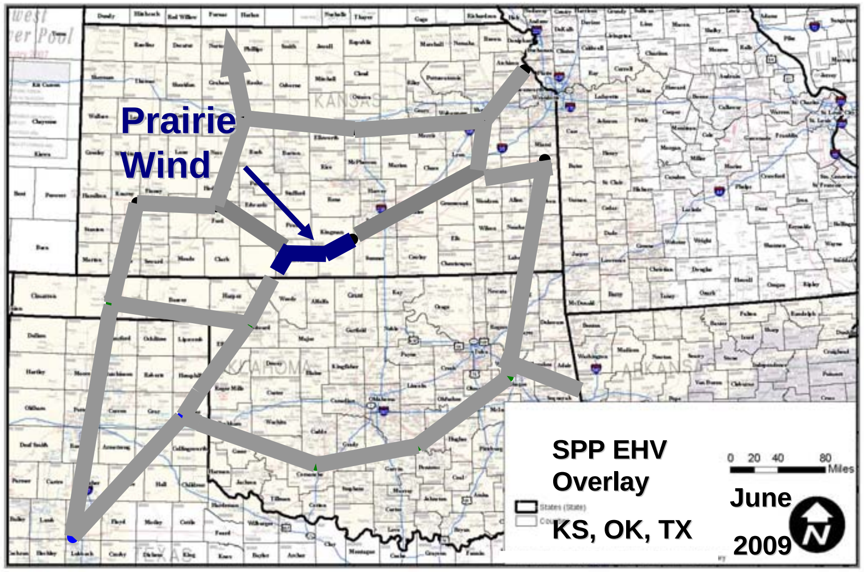
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement approval by the KCC is still pending.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



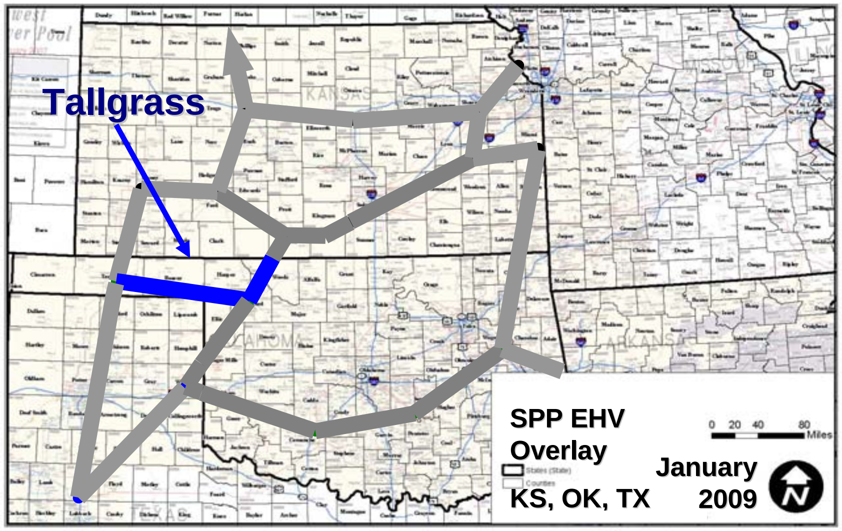
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

AEP AMERICAN® ELECTRIC POWER

Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

Barclays Office Visit
Columbus, Ohio
July 5, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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Detailed Ongoing Earnings Guidance

2010A: $3.03

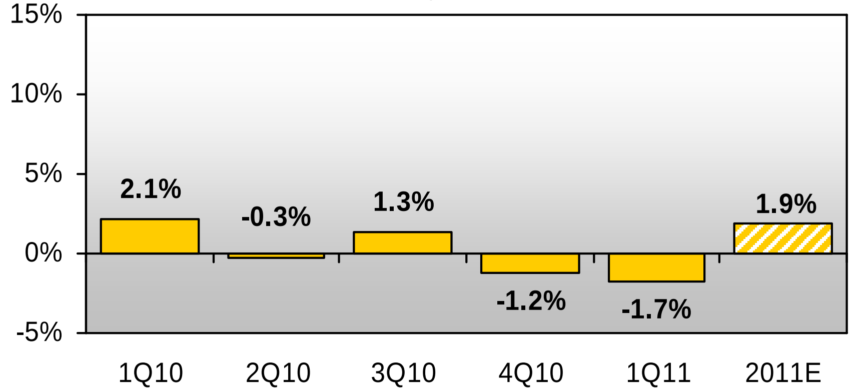
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

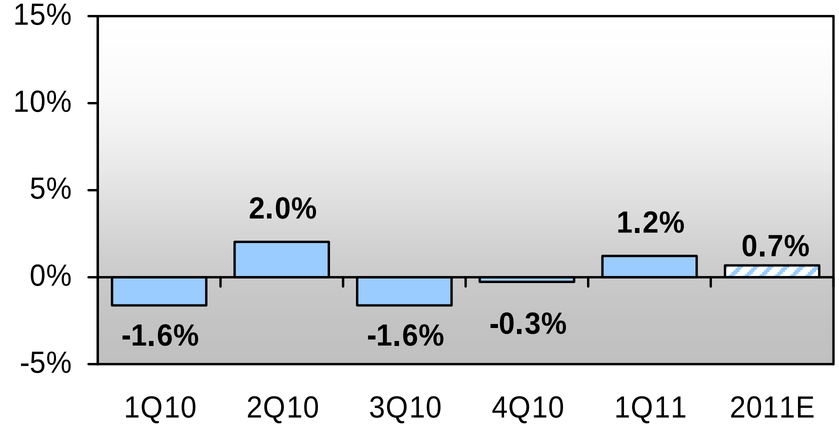
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

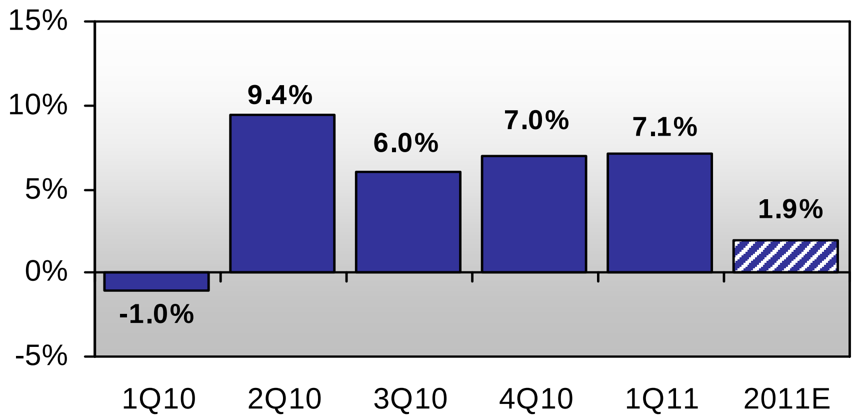
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



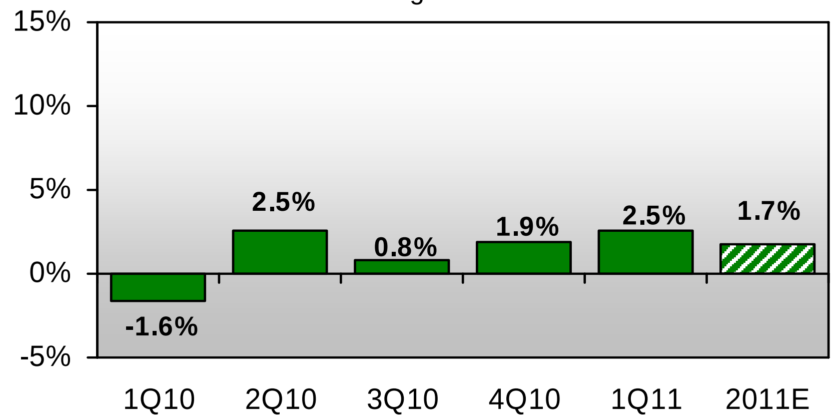
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



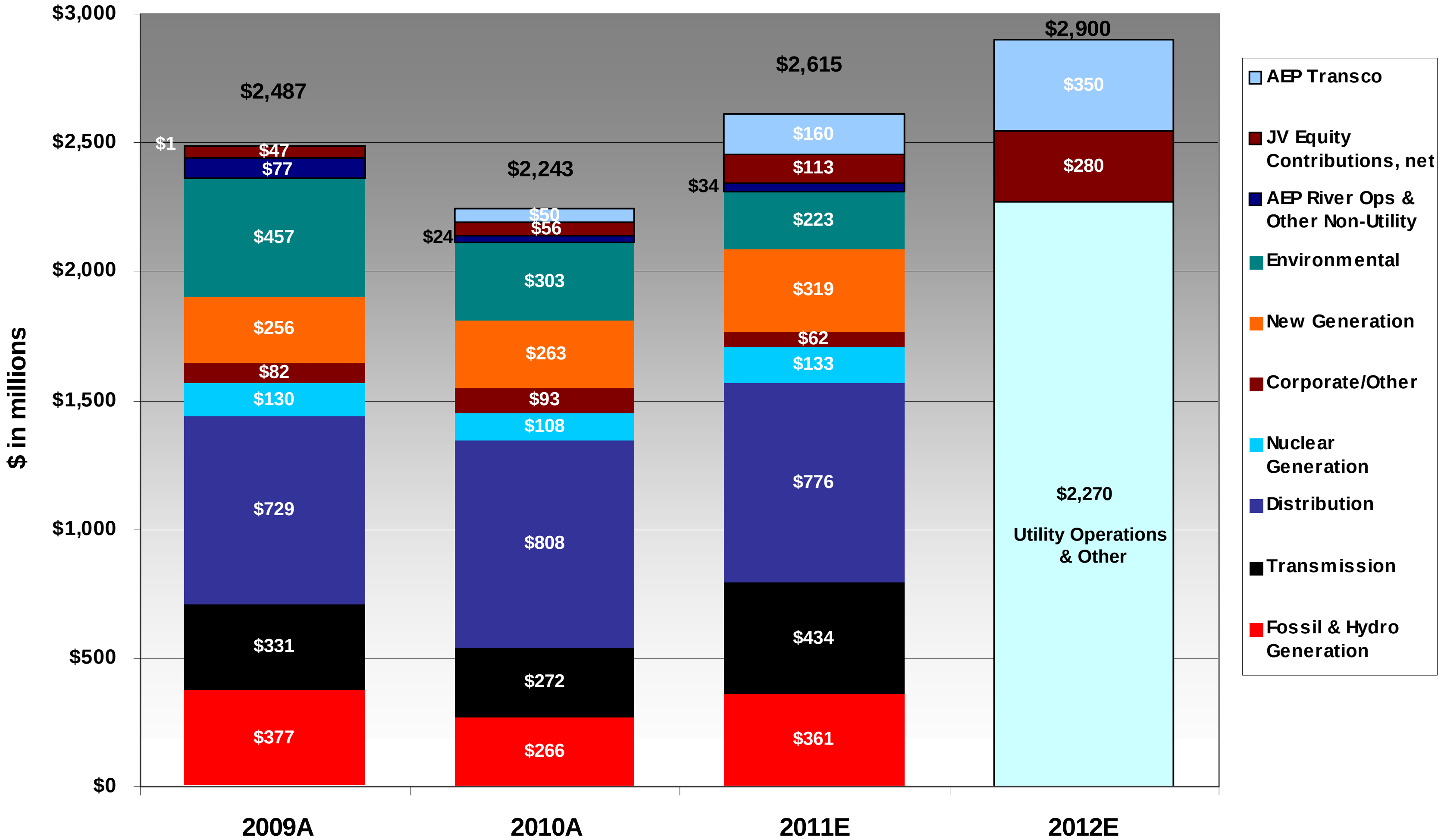
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

7

Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

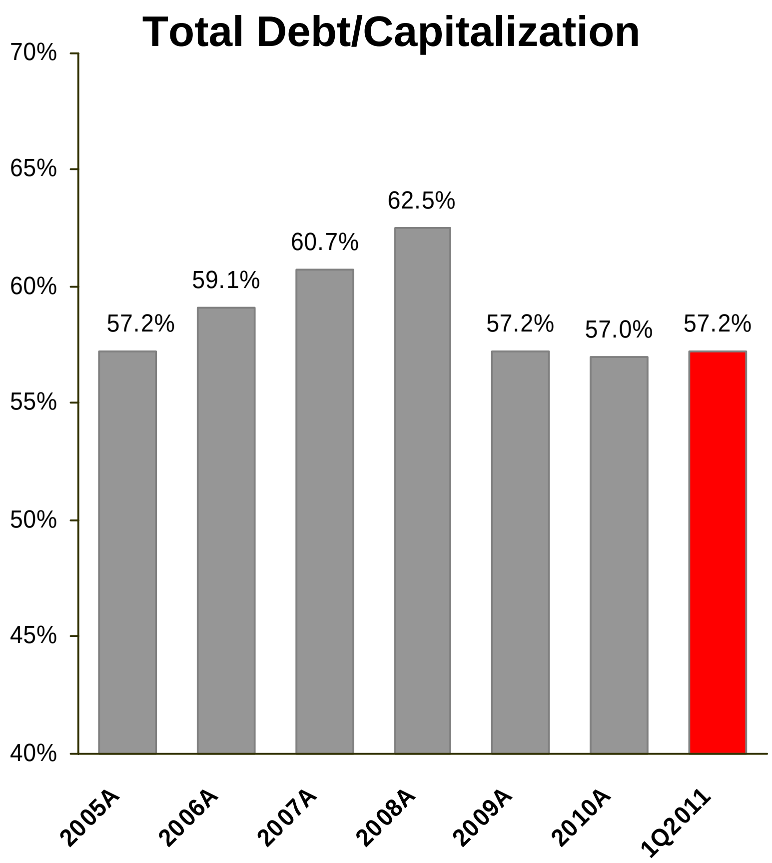
Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

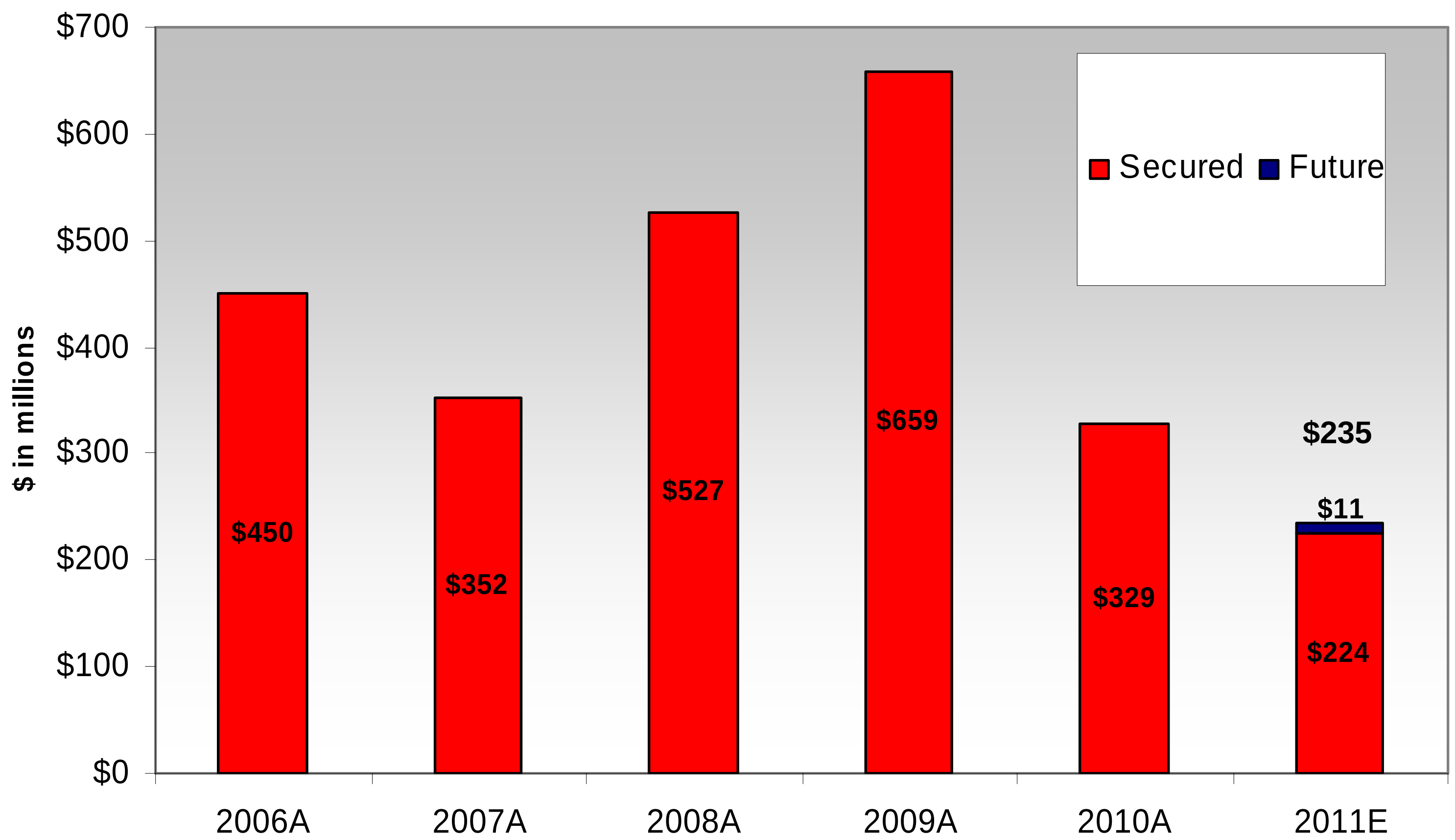


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 03/31/11	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Future rate cases includes formula rates and trackers in various jurisdictions not yet approved

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 312 of 9556

Summary Rate Case Information

I&M Michigan Base Rate Case (Docket# U-16801)

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. An order is expected by mid-year 2012.

Projected Capital Structure - Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule - TBD

Required Rate Relief - Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – July 29; Hearing August 15**

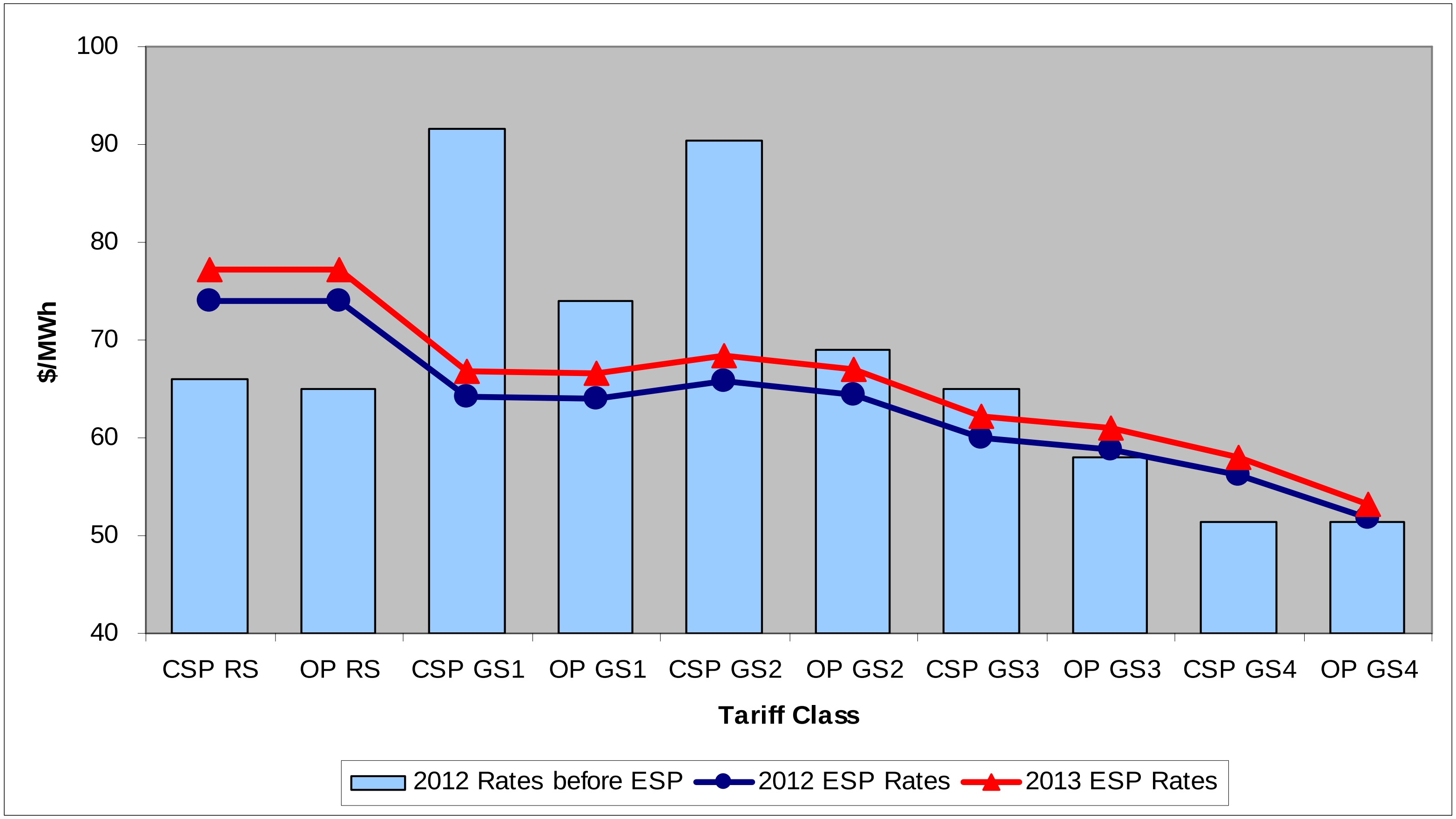
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

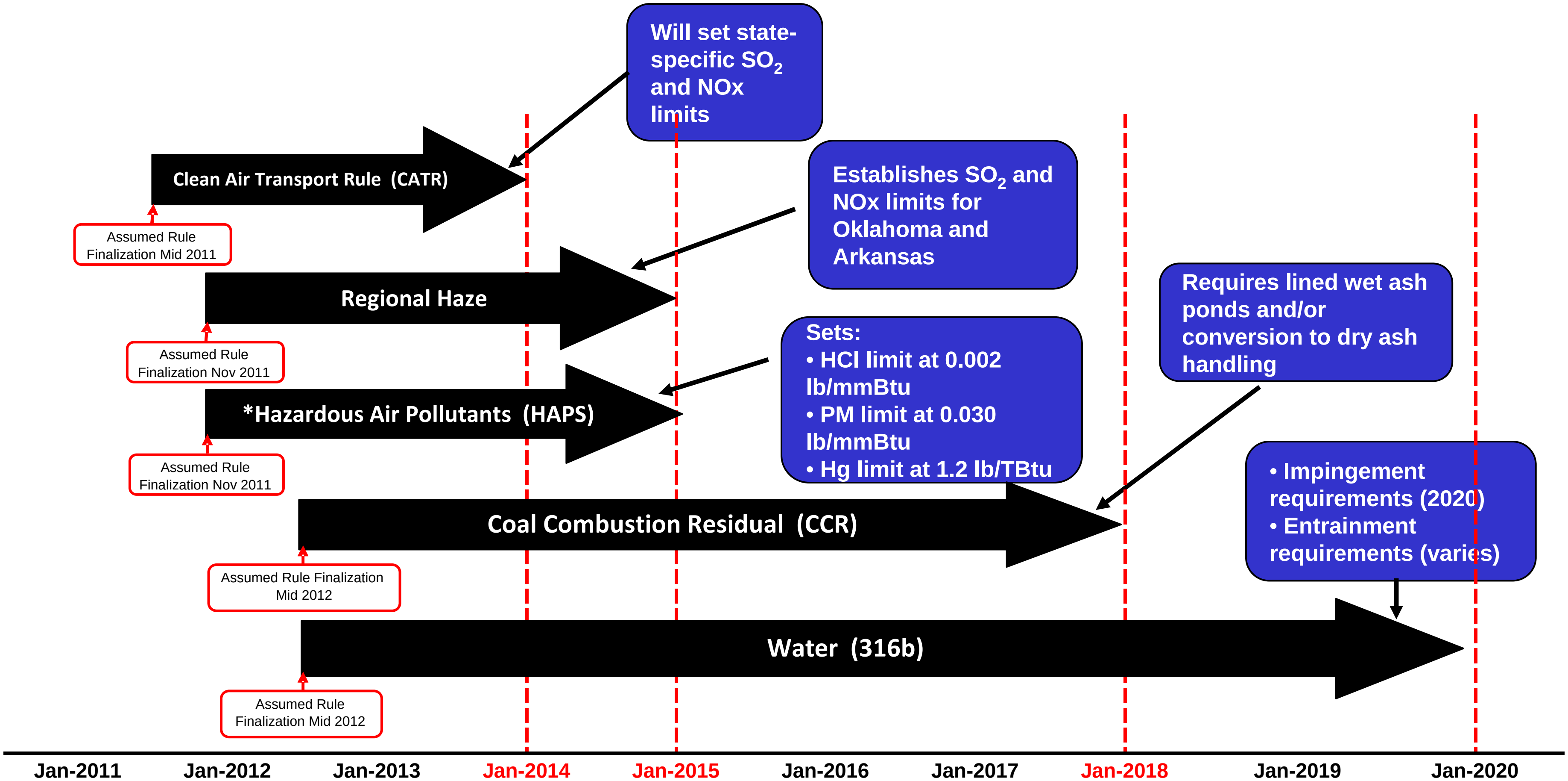
OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Anticipated environmental regulations and compliance deadlines



* **Units that will be retrofit are eligible for a one year compliance extension from the EPA**

Retrofits/New Generation

AEP®

- The tables below represent our estimated \$6 - \$8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
Conesville 5	400	SCR, DSI			
Conesville 6	400	SCR, DSI			
Muskingum River 5	510	Refuel with Natural Gas			
Gavin 1	1320	FGD upgrade			
Gavin 2	1320	FGD upgrade			
Zimmer 1	330	FGD upgrade			
Total Expected Cost			**2,100**	**2,800**	*
Clinch River 1	211	Refuel with Natural Gas			
Clinch River 2	211	Refuel with Natural Gas			
Dresden	580	New Natural Gas			
Total Expected Cost			**580**	**765**	**
Rockport 1	1320	FGD, SCR			
Rockport 2	1320	FGD, SCR			
Tanners Creek 4	500	DSI, ACI			
Total Expected Cost			**1,240**	**1,670**	***
Big Sandy 1	640	New Natural Gas			
Total Expected Cost			**400**	**525**	

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be \$366 million for the Dresden plant once completed; \$343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 1	470	FGD, ACI, Baghouse		
	Northeastern 2	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total Expected Cost			**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total Expected Cost			**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total Expected Cost			**80**	**100**

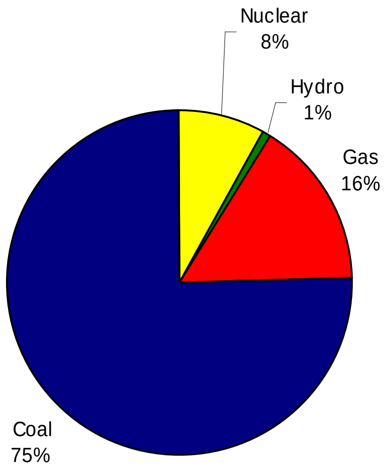
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Total MW	**2,485**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,856**	

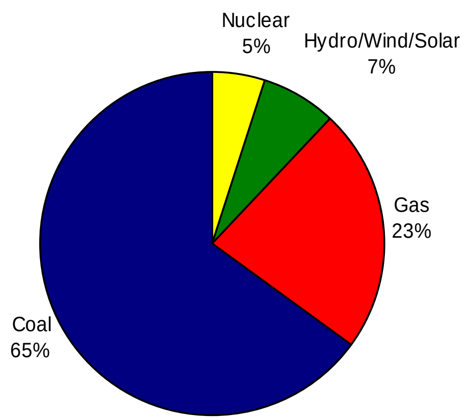
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

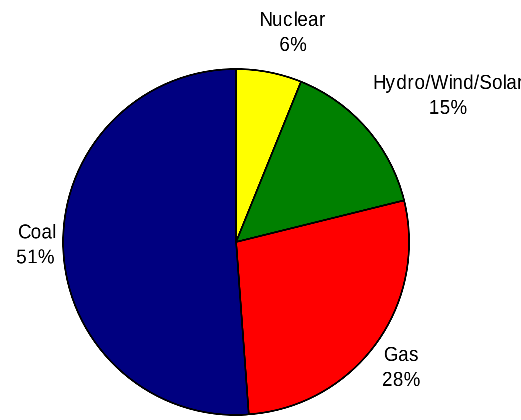
1990 AEP Generating Capacity by Fuel
37,428 total MW's



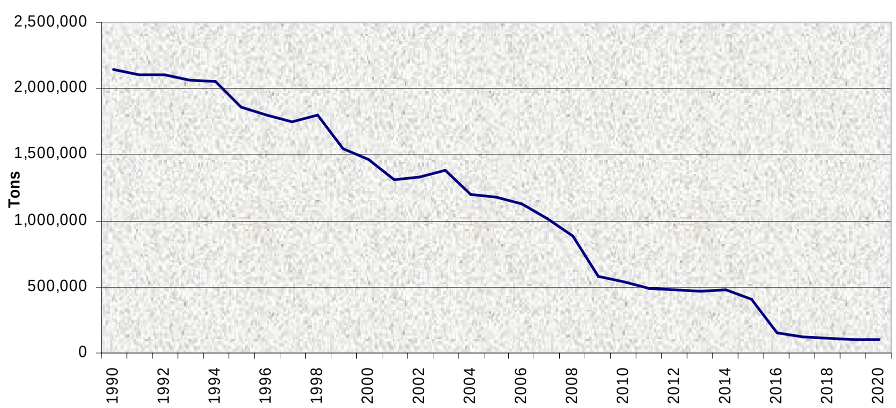
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons

- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

KPSC Case No. 2011-00401
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Dated January 13, 2012
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Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

Current rate base is $412 million; expected to grow as follows:

2011: $473 million

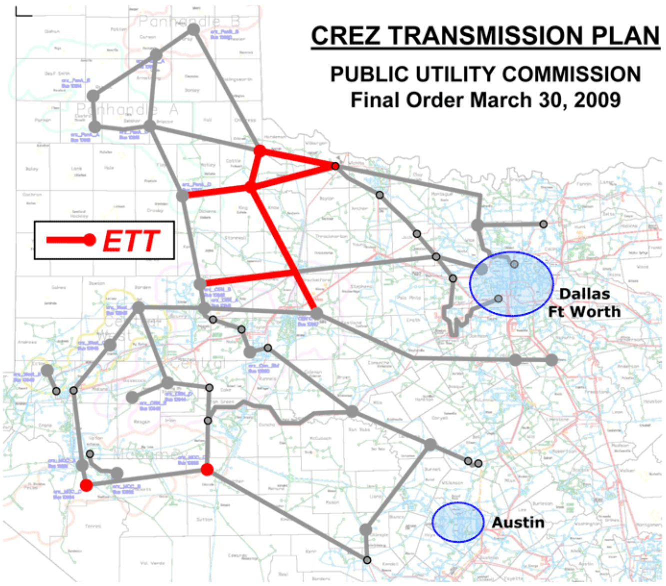
2012: $778 million

2013: $1,352 million

Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

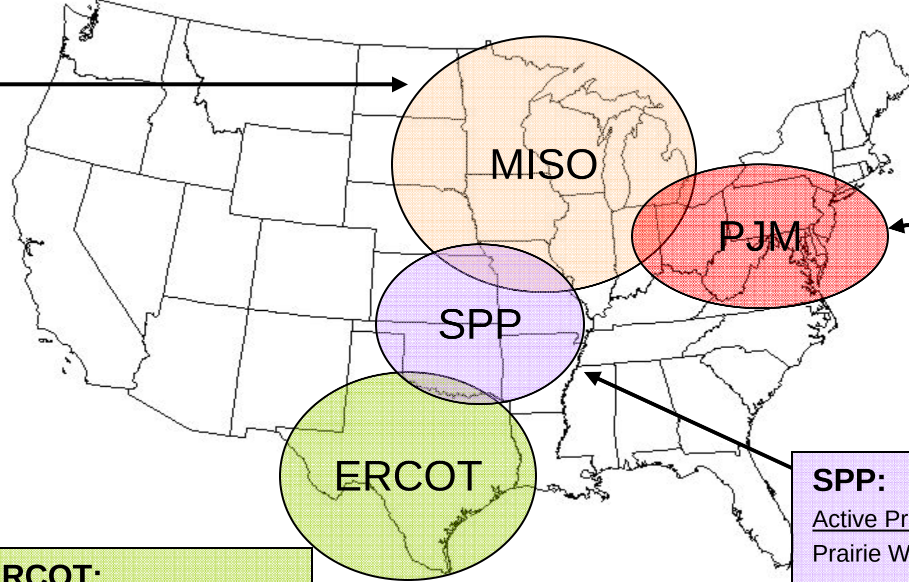
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration

PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational



SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

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Credit Suisse Analyst Visit

Columbus, Ohio

July 13, 2009

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STRONG
FLEXIBLE
ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

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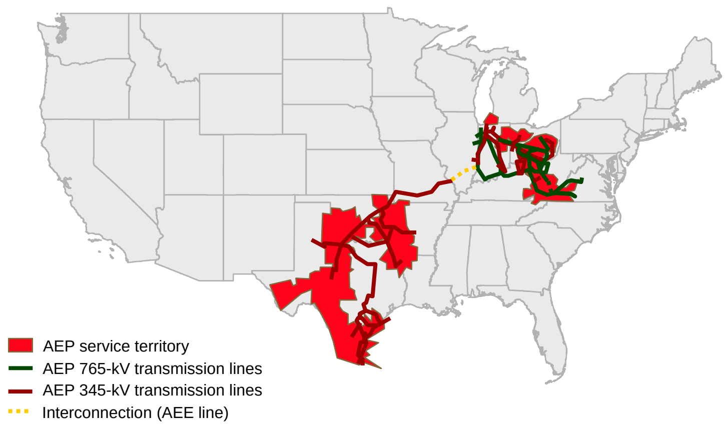
Premier Regulated Utility Platform

Overview



AEP's Leadership Position

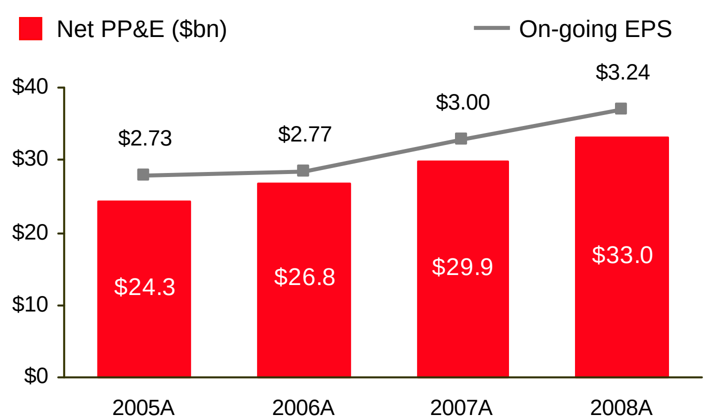
Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

Generation owned[1] (GW)	
SO	42.6
AEP	40.6 *
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

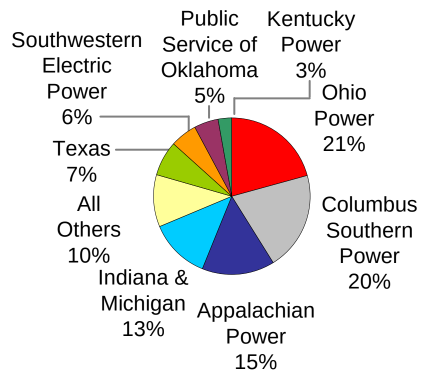
Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

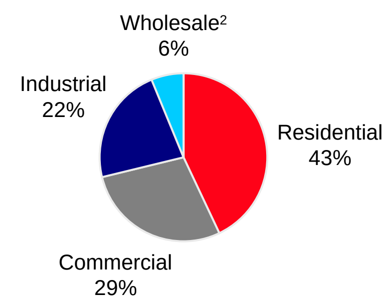
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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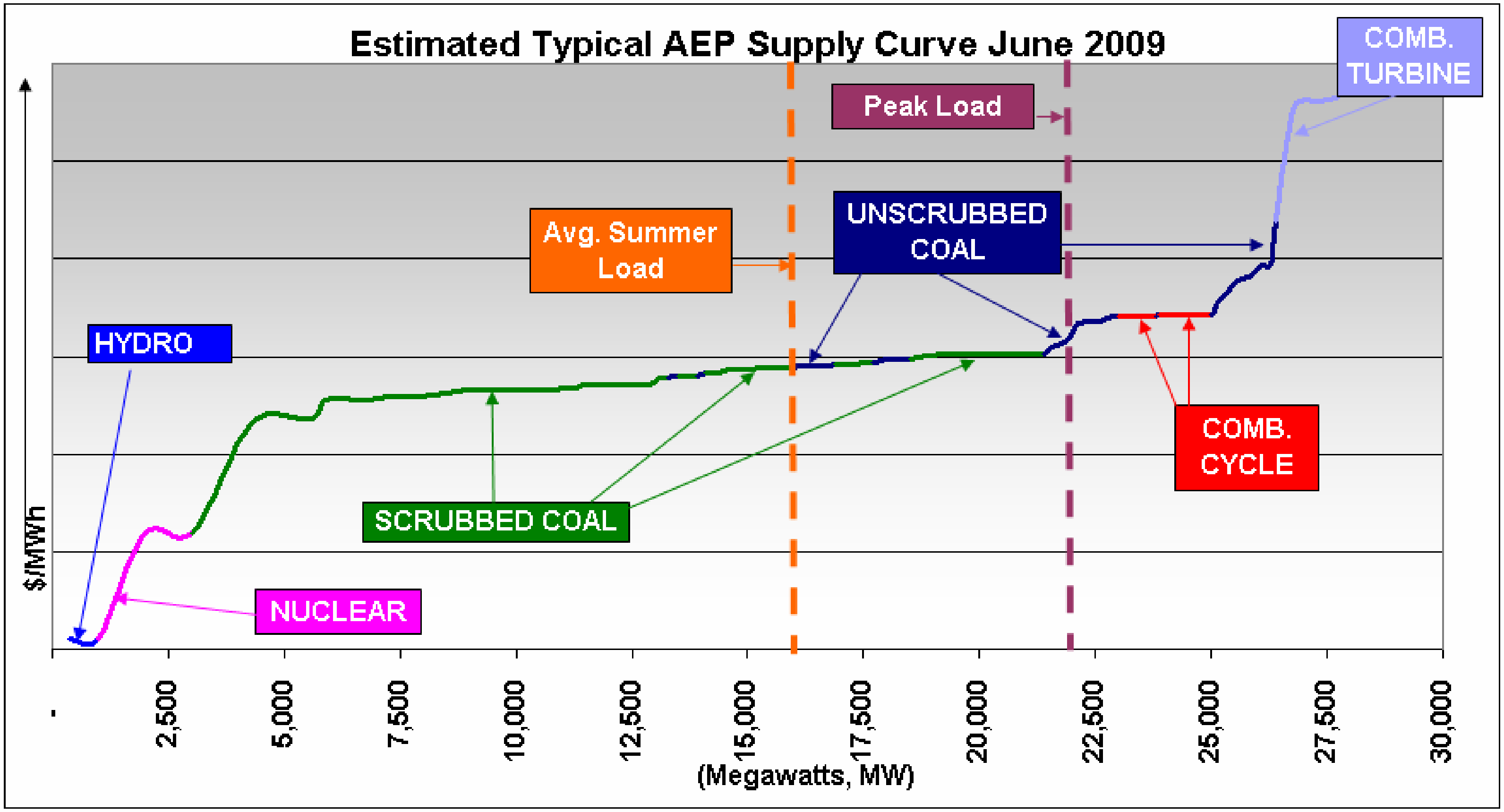
1

AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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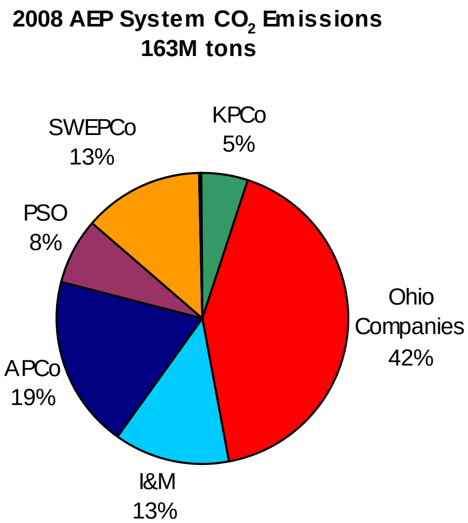
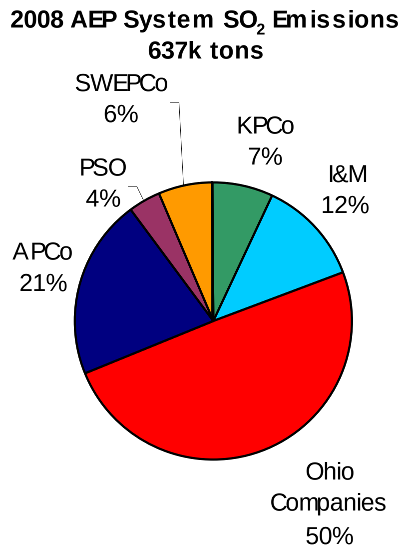
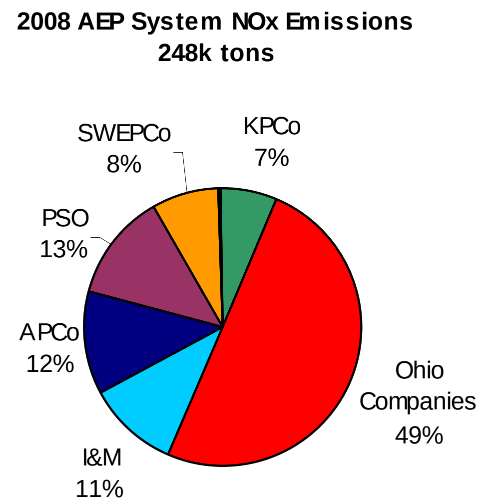
CO_2 Cost Recovery – Should Follow SO_2 & NOx

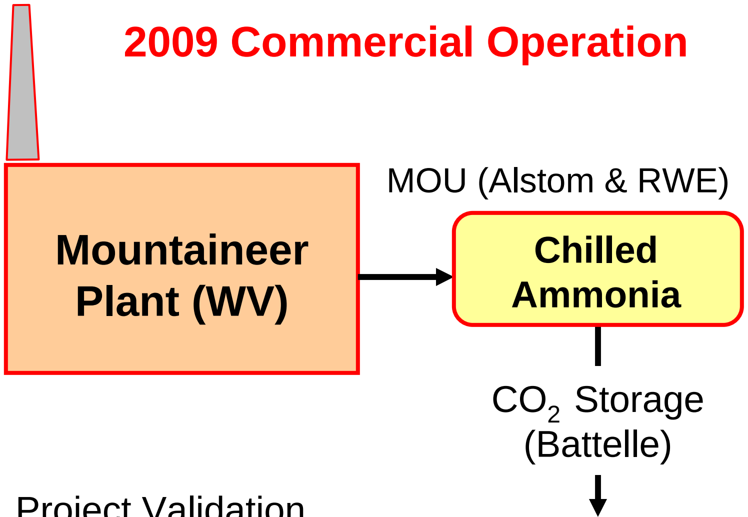






- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

Carbon Capture & Storage



Project Validation

- Alstom "Chilled Ammonia" Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Geologic storage for CO_2
- Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the 'economic' hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B [(1)]	Coal	Ultra-supercritical	600 [(1)]	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – Arkansas Court of Appeals overturned APSC decision granting CECPN & AEP filed appeal to Supreme Court. Air permit appeal hearings were held in June, and decision expected by year end. Construction continues.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

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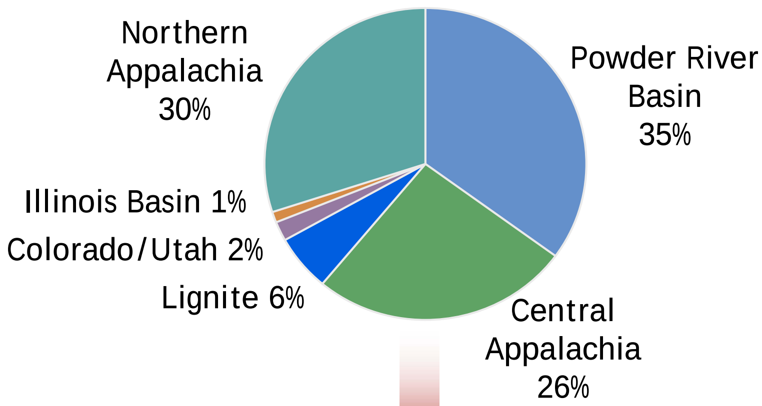
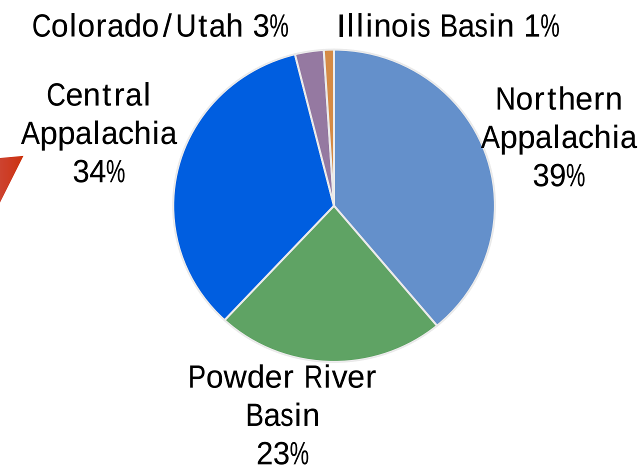
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

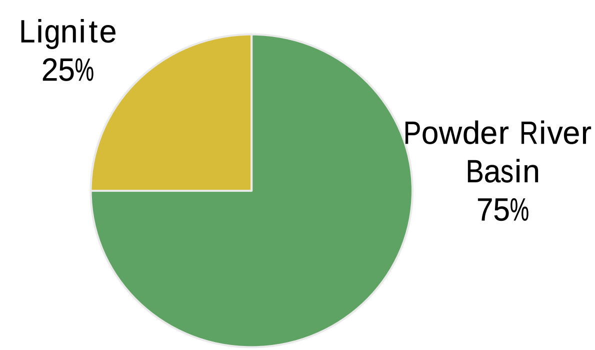
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

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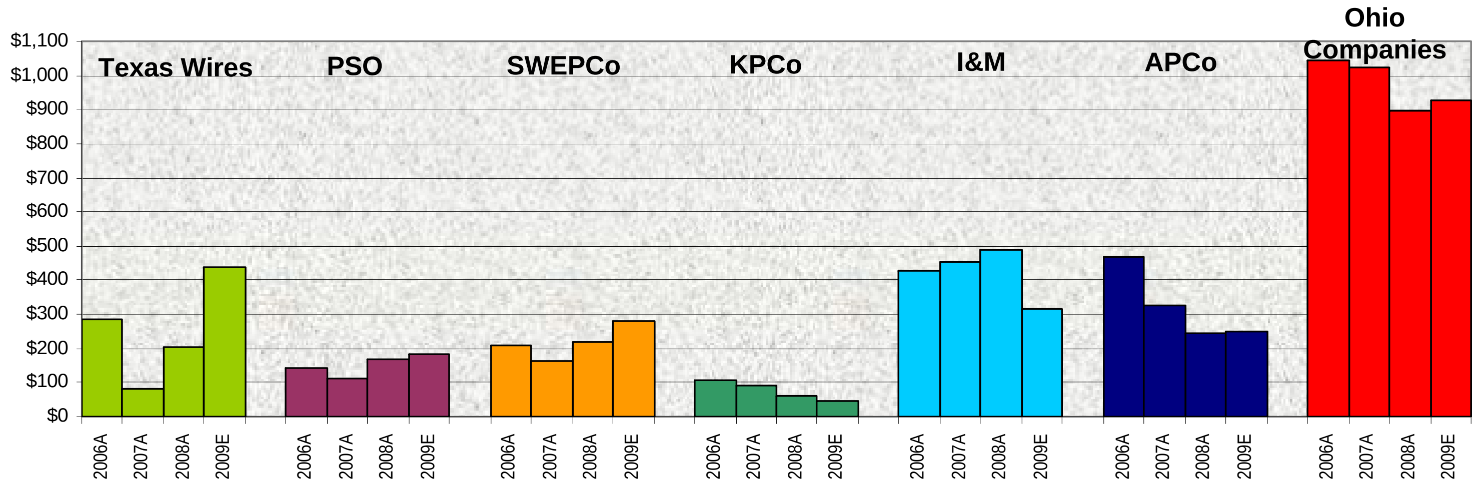
Cash Flow and Capex by Operating Company

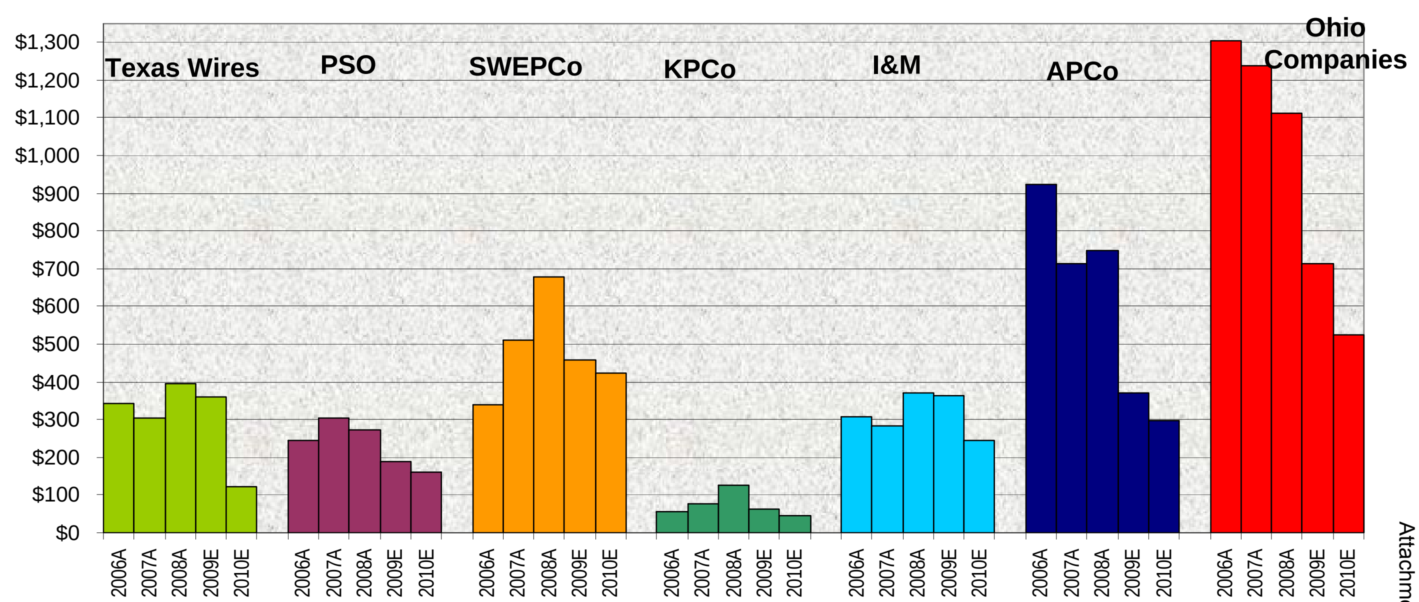


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

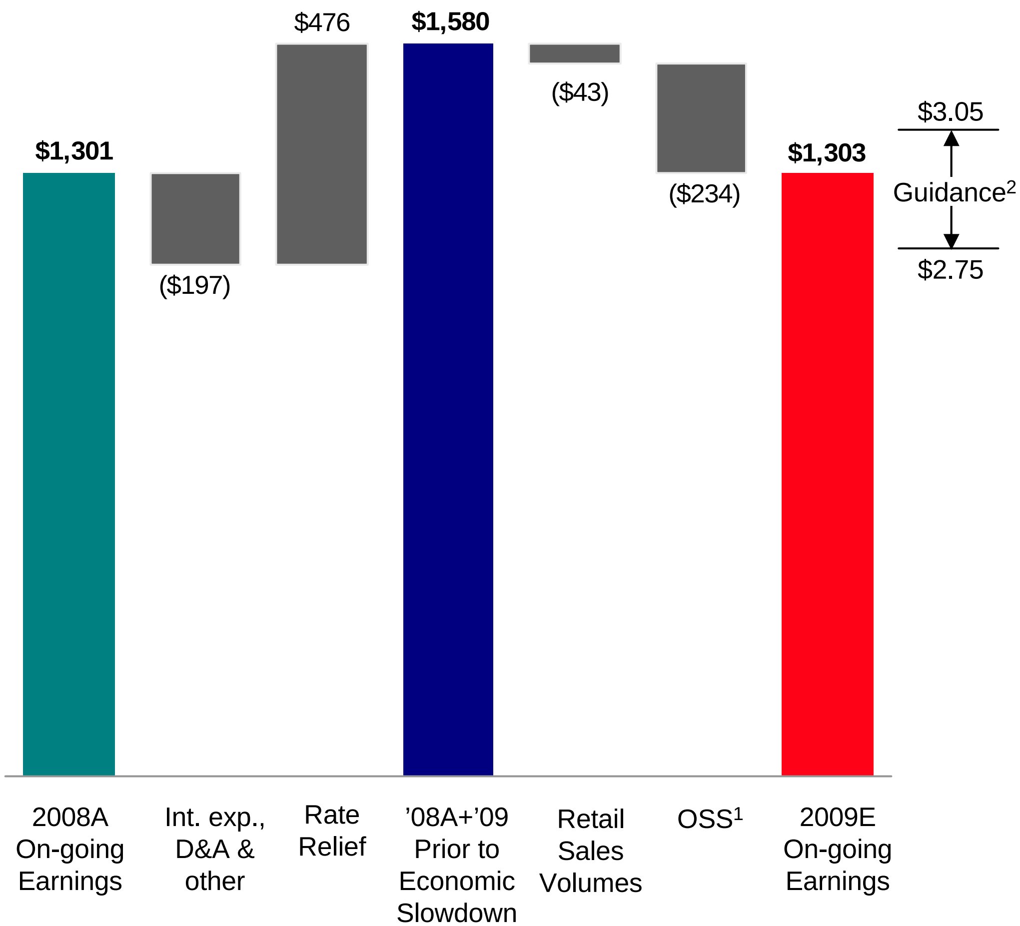
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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Sierra Club's First Set of Data Requests
Dated January 13, 2012
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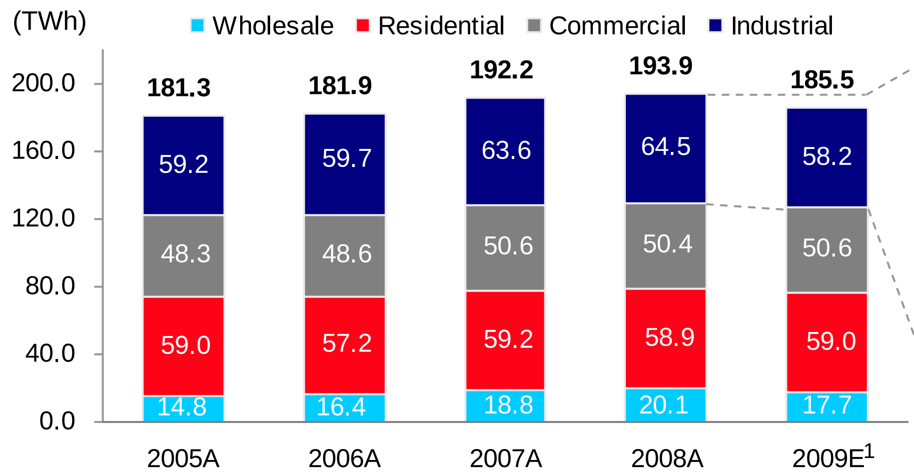
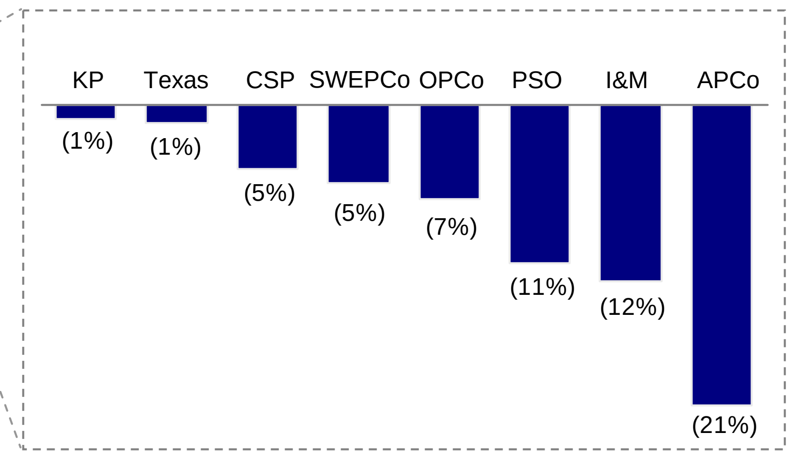
Key Drivers of Revised 2009 Guidance: Retail Sales

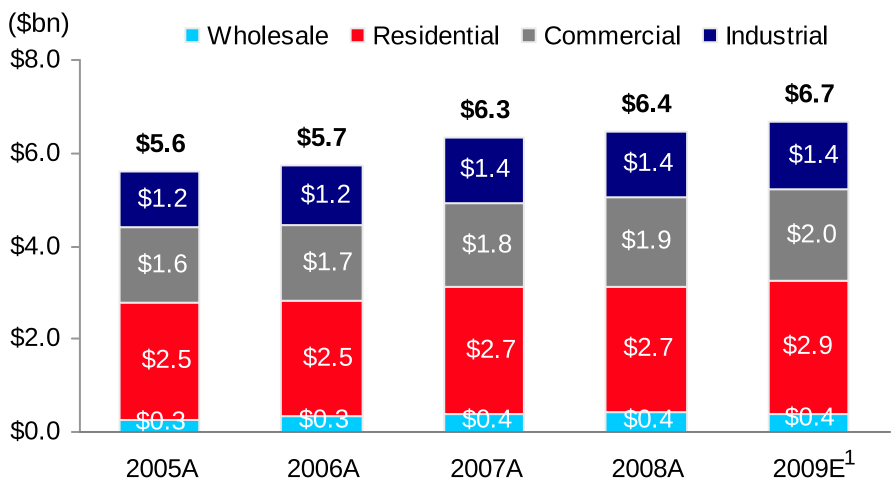
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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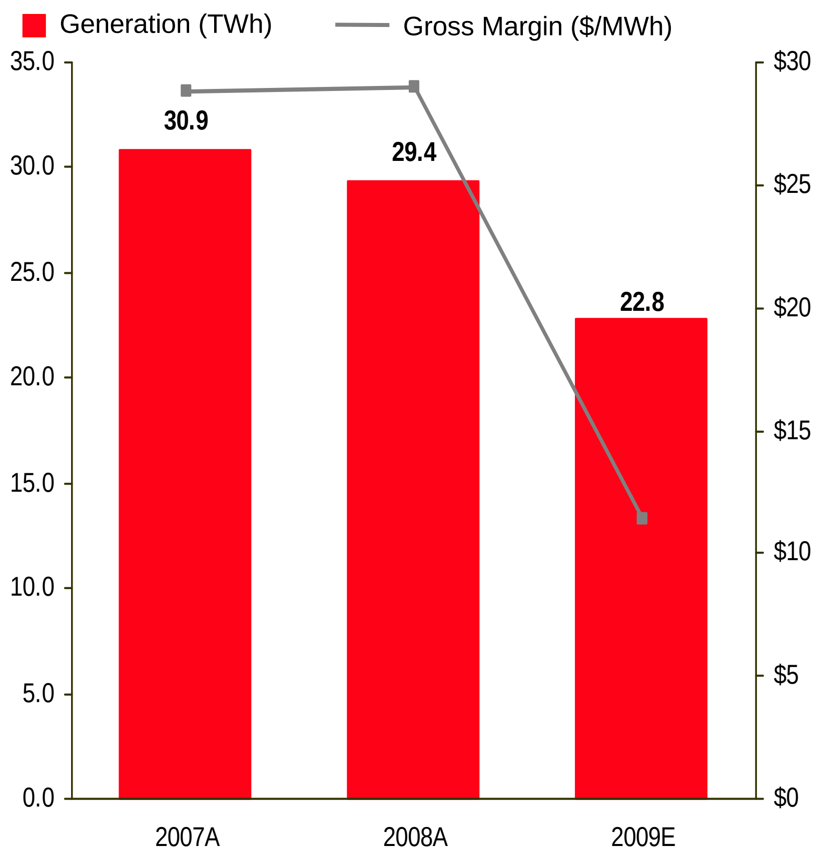
[1] *2009E assumes normalized weather*
[2] *Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables*

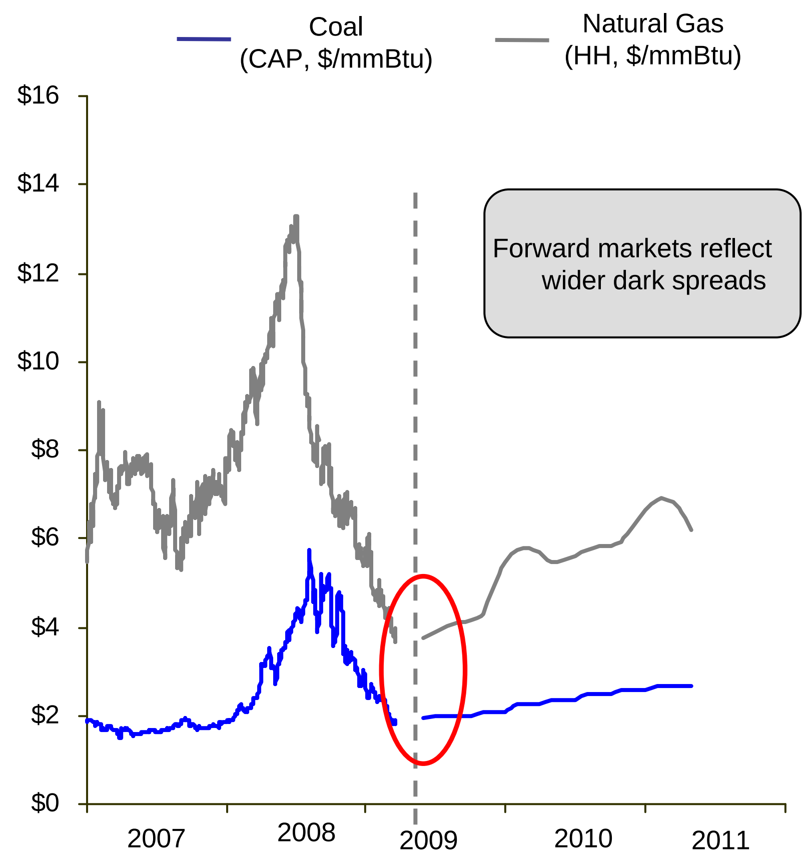
Key Drivers of Revised 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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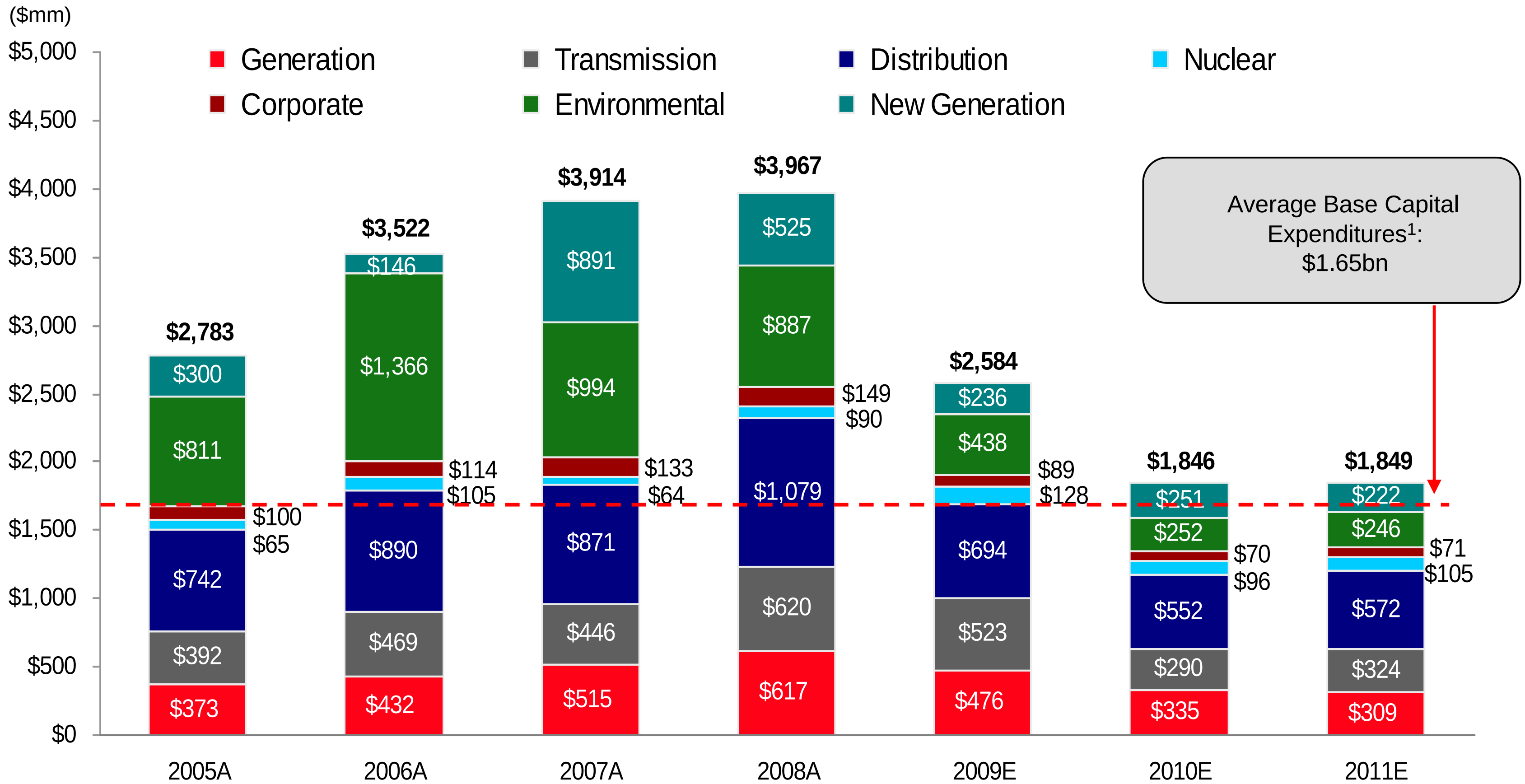
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN
FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

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Long-term Debt Maturity Profile

($ in millions)
(as of March 31, 2009)

Year		2009		2010		2011
AEP, Inc.	$	-	$	490	$	-
AEP Generating Company	$	-	$	-	$	130
Appalachian Power	$	150	$	200	$	250
Columbus Southern Power	$	-	$	150	$	-
Kentucky Power	$	-	$	-	$	-
Indiana Michigan Power	$	-	$	-	$	-
Ohio Power	$	70	$	679	$	-
Public Service of Oklahoma	$	50	$	150	$	75
Southwestern Electric Power	$	-	$	-	$	50
Texas Central Company	$	-	$	122	$	120
Texas North Company	$	-	$	-	$	-
Total	$	270	$	1,791	$	625

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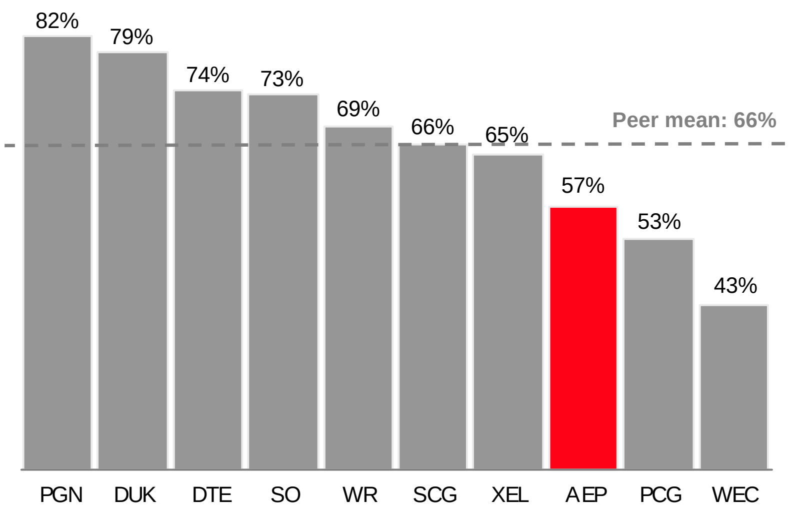
Dividend Overview

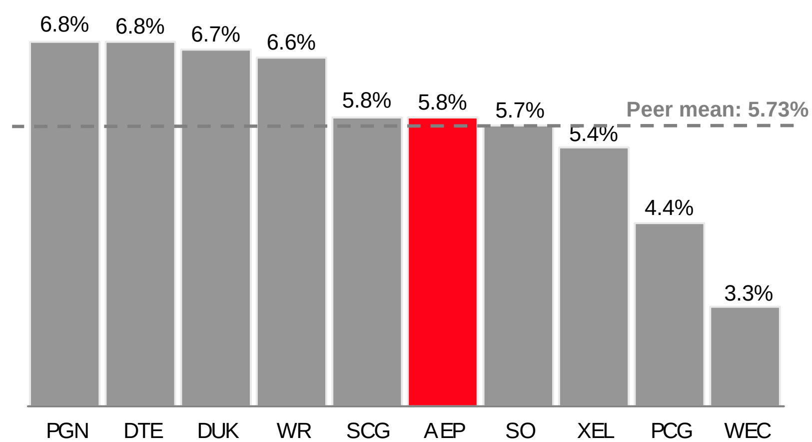
- We have paid 396 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 7/8/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 7/8/09

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Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

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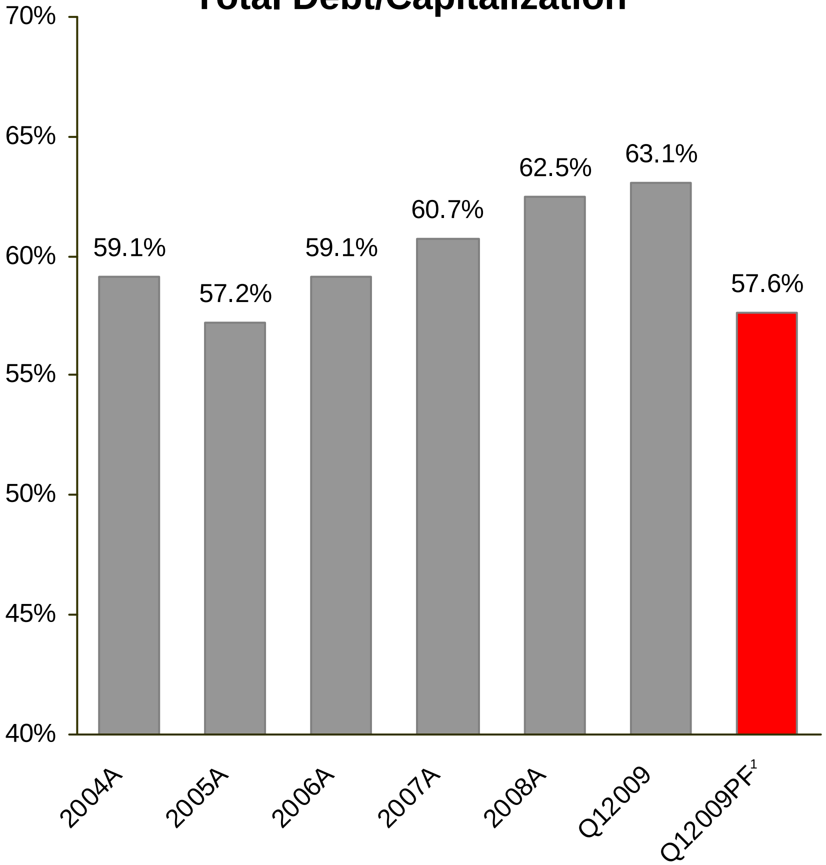
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	04/20/2009	Maturity
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)[1]	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

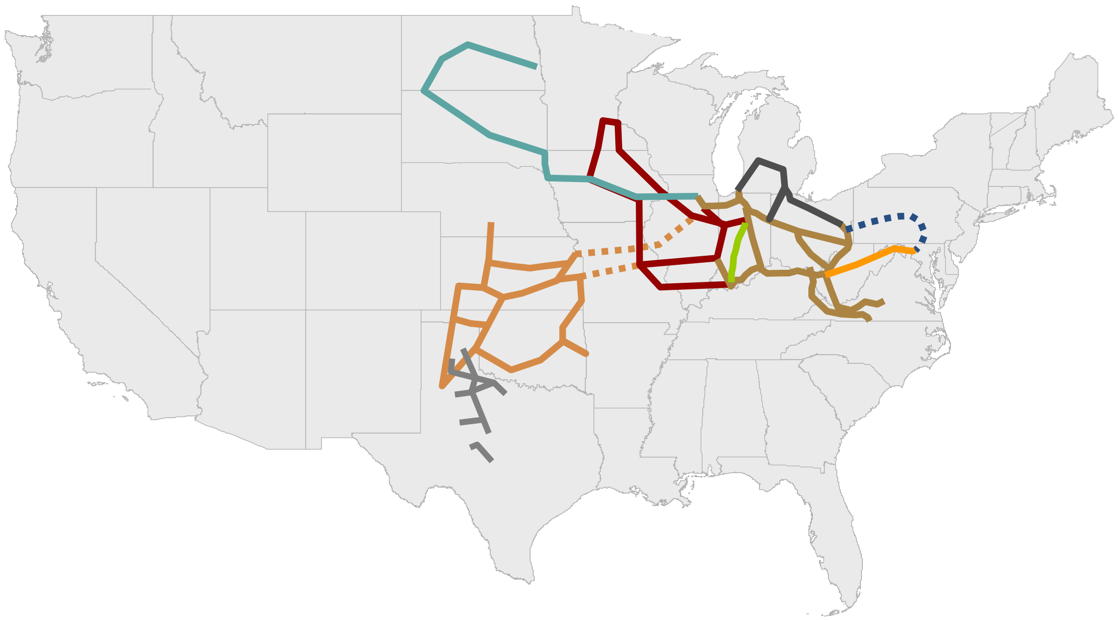
Pioneer — **COD: 2015**
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV — **COD: 2014**
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass — **COD: 2013-14**
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind — **COD: 2013**
- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT — **COD: 2013**
- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan — **COD: ~2020**
- 700 miles of 765 kV

PJM Projects
- Enhance existing 765/345 kV

Hartland — **COD: ~2020**
- 1000+ miles of 765 kV

MISO Vision Plan
- 765 kV Backbone

SPP Overlay — **COD: 2013-14**
- 765 kV Backbone

ETT — **COD: ~2018**
- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

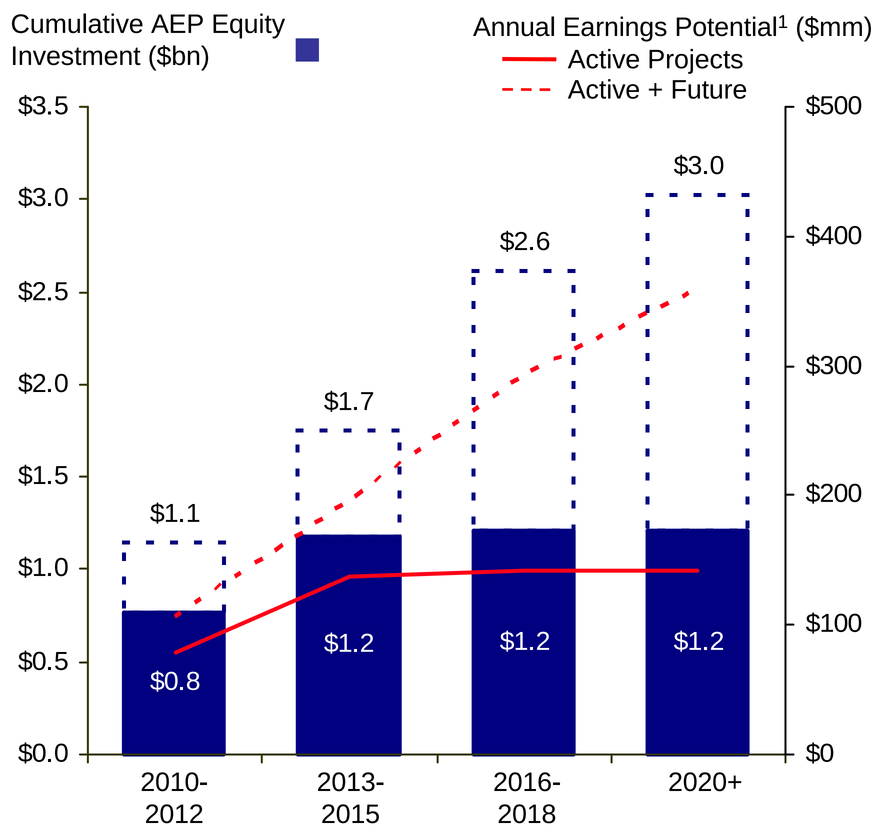
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives

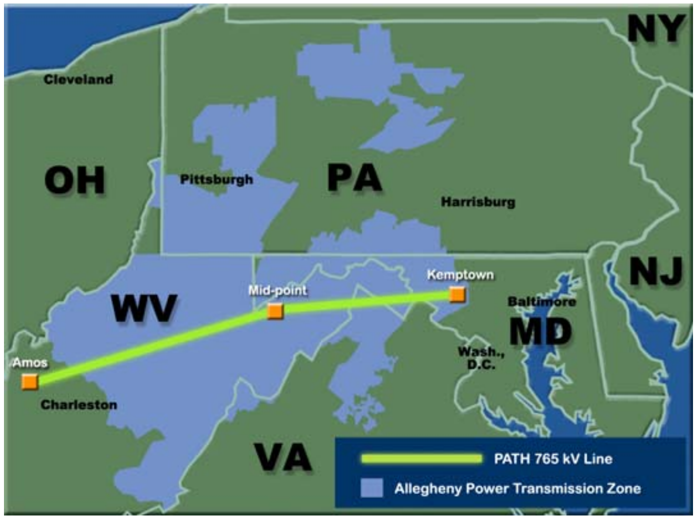


[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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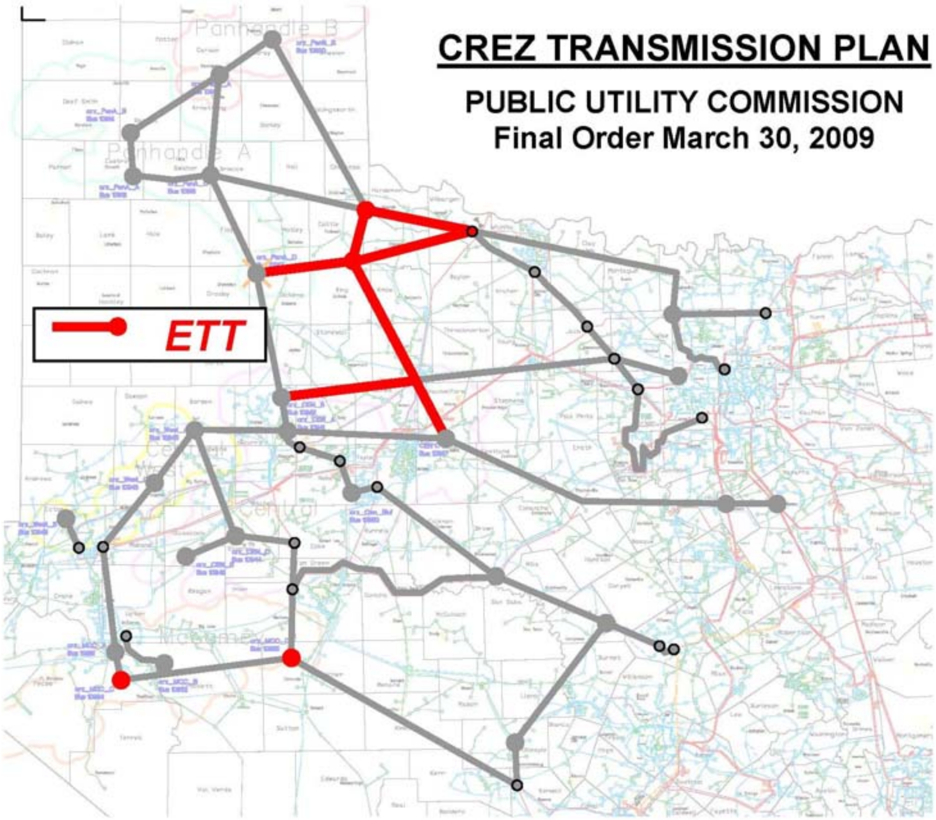
Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

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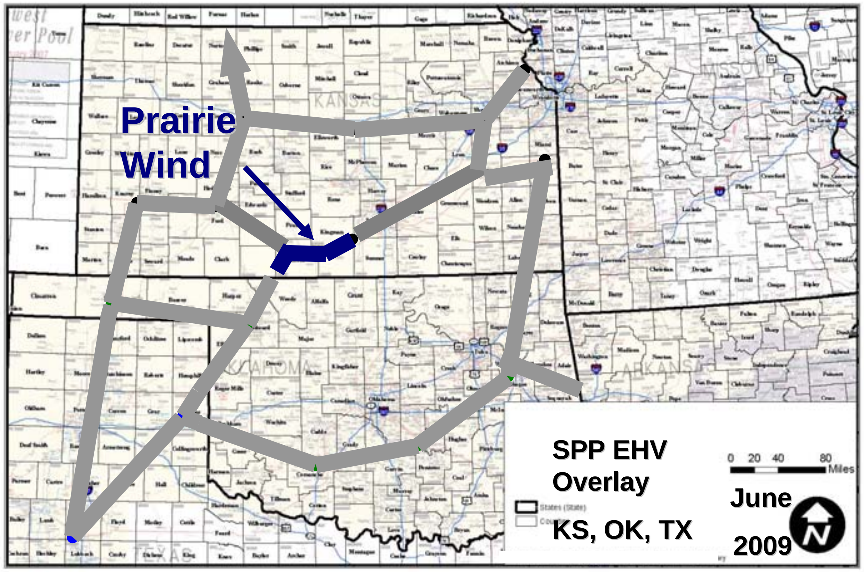
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement approval by the KCC is still pending.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

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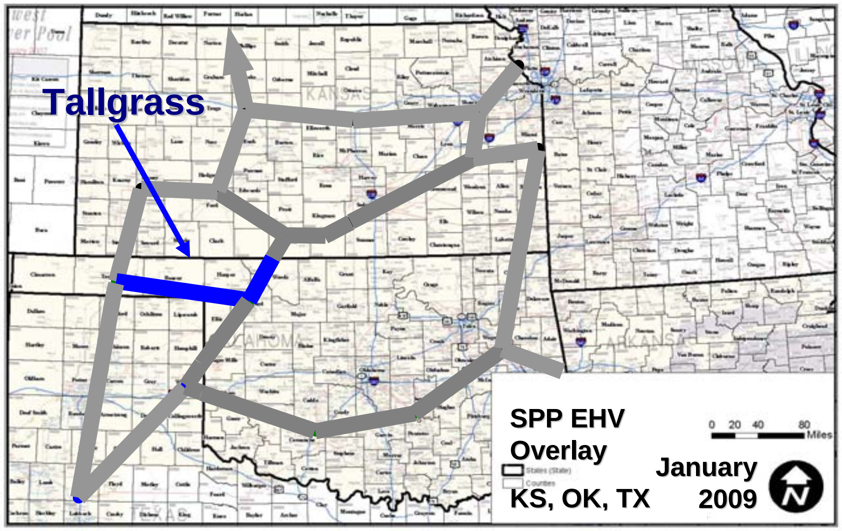
Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

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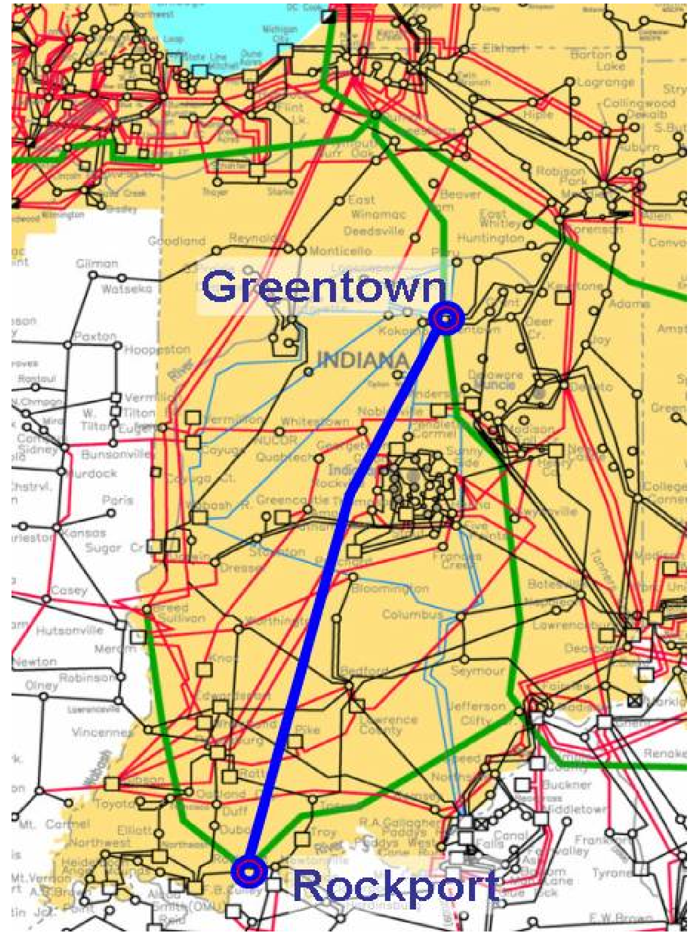
Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

<u>Project Description:</u> 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost \$5-\$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

American Electric Power, Inc.

Luminus Management

August 8, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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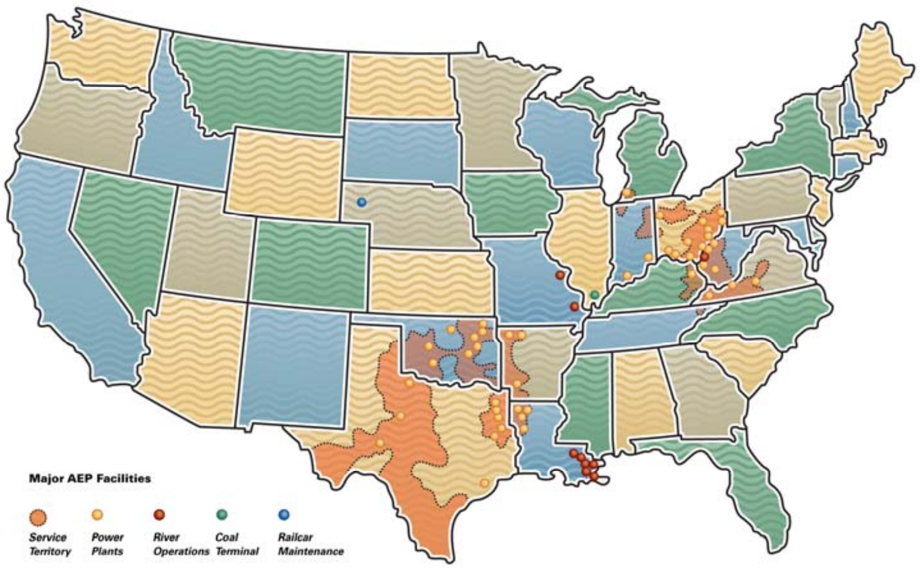
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

- 20,000 employees

AEP Enjoys Significant Presence Throughout The Energy Value Chain

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Strategic Direction

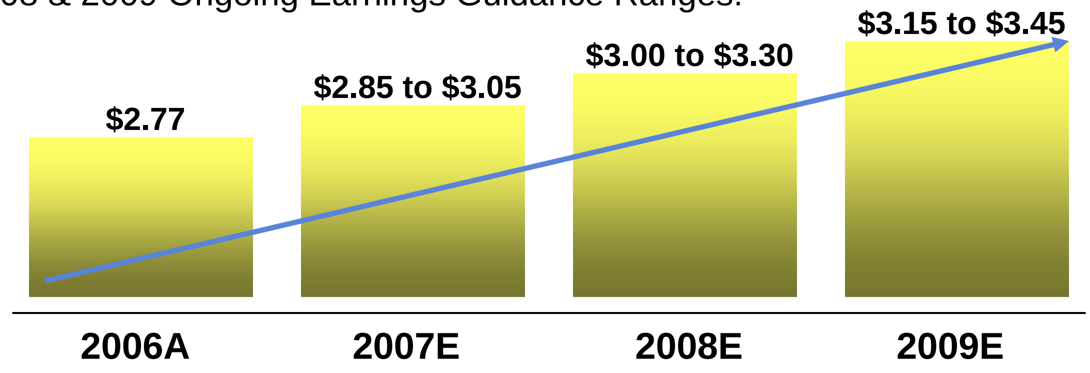
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

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Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

AEP®

New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

AEP OHIO – Post-2008

- Continued dialogue with fellow utilities
- Potential proposal from the governor's office sometime this summer
- Potential legislation crafted late 2007/early 2008
- The price of electricity in Ohio is going up to be more reflective of what is happening in the markets
- 'Stair-step' in a rate increase that is bigger than the current RSPs of 3% and 7%
- We will pursue recording the shortfall between the stair-step level and market prices as a regulatory asset – along with securitization at a legislative level

It Is Our Hope That We Can Craft A Reasonable Compromise That Will Allow Us To Achieve At Or Near Market Prices Without Causing Rate Shock To Our Customers And The Ohio Economy

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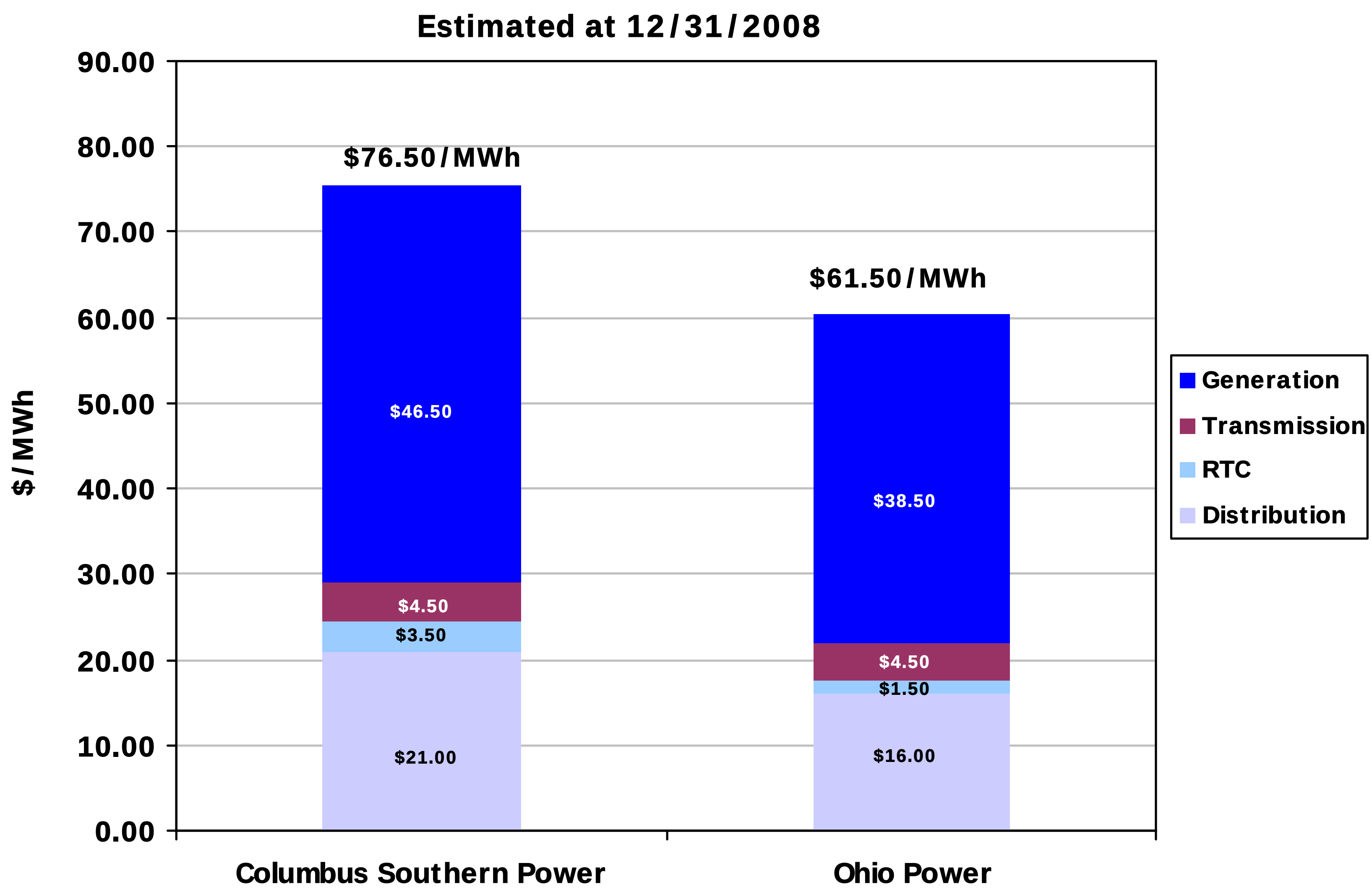
Average Unbundled AEP Ohio Rates



Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325	Note: Excludes AFUDC and recently announced CO_2 and transmission projects
2007 Including Lawrenceburg	**$3,867**	*Includes Lawrenceburg purchase $325MM in 2007

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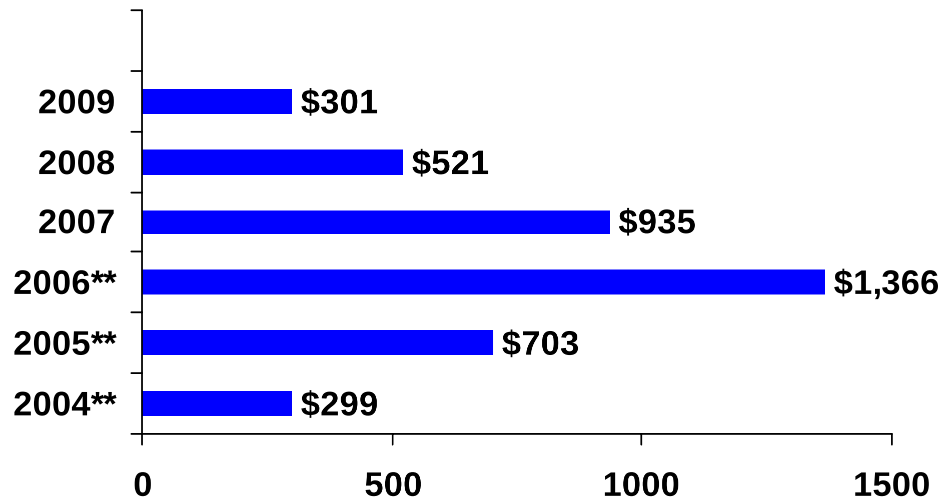
Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

$4.1 Billion Environmental Investment

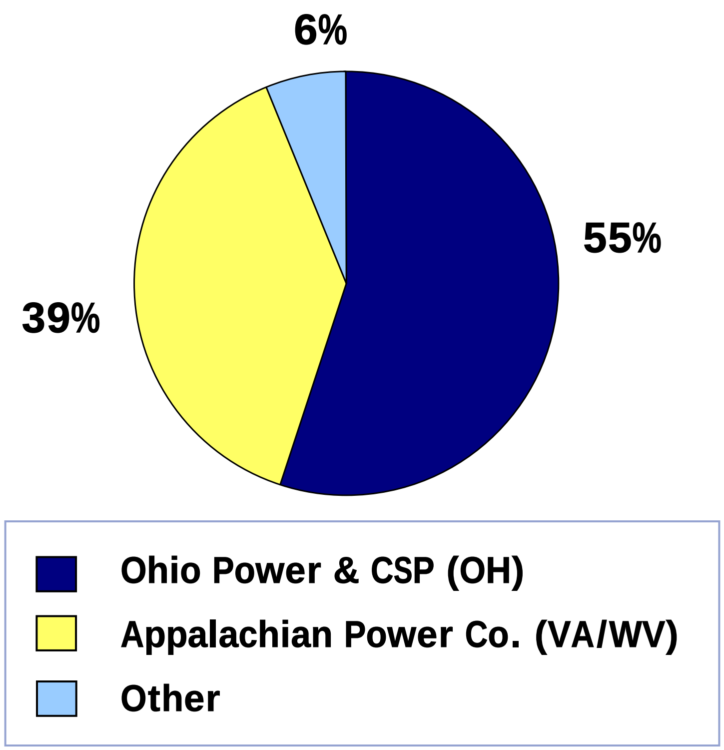
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



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Majority Of 2006 & 2007 Dollars Will Be Invested In Ohio & APCo

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
<u>East Plants</u>					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
<u>CCD Plants</u>					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
<u>West Plants</u>					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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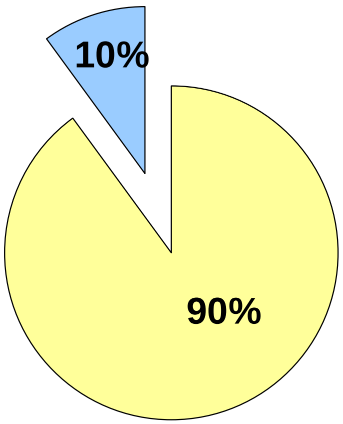
Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



- Actuals To Date & Firm Costs
- Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Pullman Power – Stack Supplier
- Babcock Power – SCR
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

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AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

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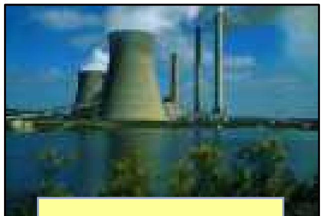
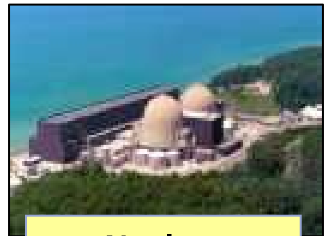
Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

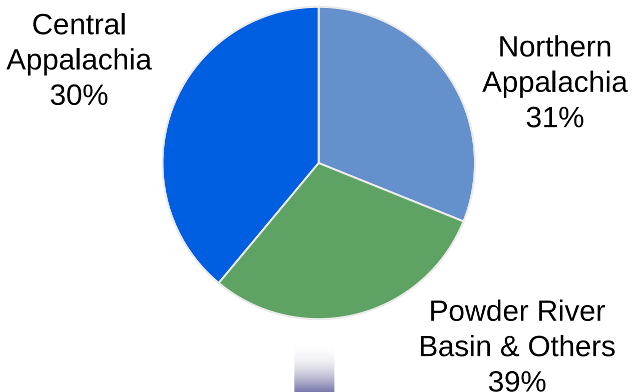
NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

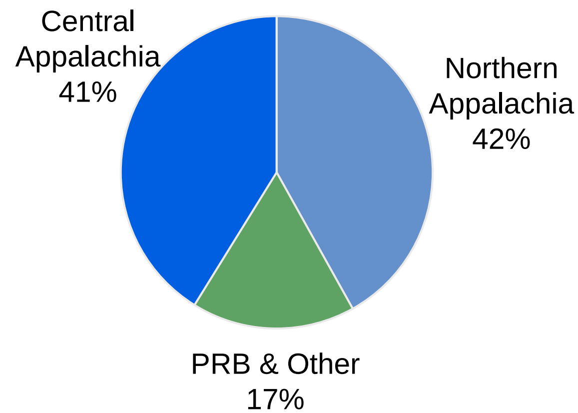
Total AEP System



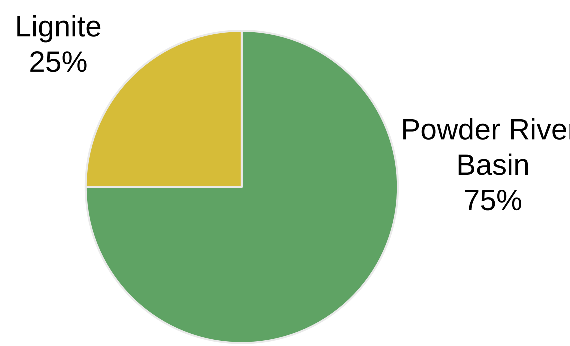
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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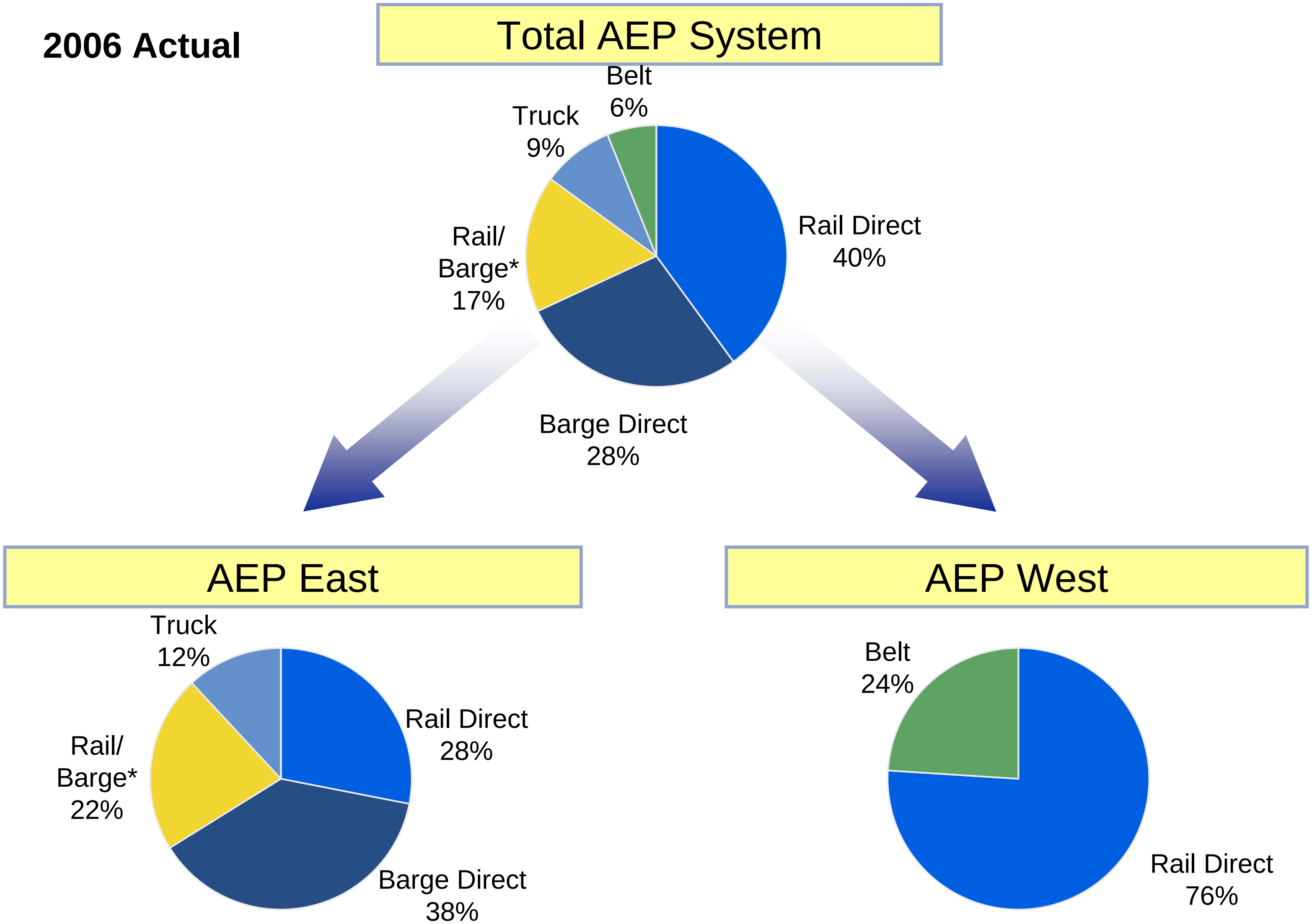
Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

–821 MW combined-cycle gas plant
–$220MM purchase price
–Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

–505 MW simple-cycle gas plant
–$100MM purchase price
–APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

–480 MW simple-cycle gas plant
–$102MM purchase price
–Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

–1140 MW combined-cycle gas plant
–$325MM purchase price
–AEG completed purchase on May 16, 2007

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Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (2)	Coal	Ultra-supercritical	600 (2)	2011
PSO	Red Rock	Oklahoma	$1.8 B (3)	Coal	Ultra-supercritical	900 (3)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW were declared in commerical operation on July 12, 2007.
(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(3) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
- Air permit approval expected in August 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

- Used and Useful Determination filed in February 2006 – Hearings concluded July 31, 2007 and order is expected in September 2007
- Air permit approval expected in October 2007
- Regulatory Recovery
  - Order expected in PSO rate case filing in July 2007 – filing included request for CWIP treatment for new projects
- Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

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IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

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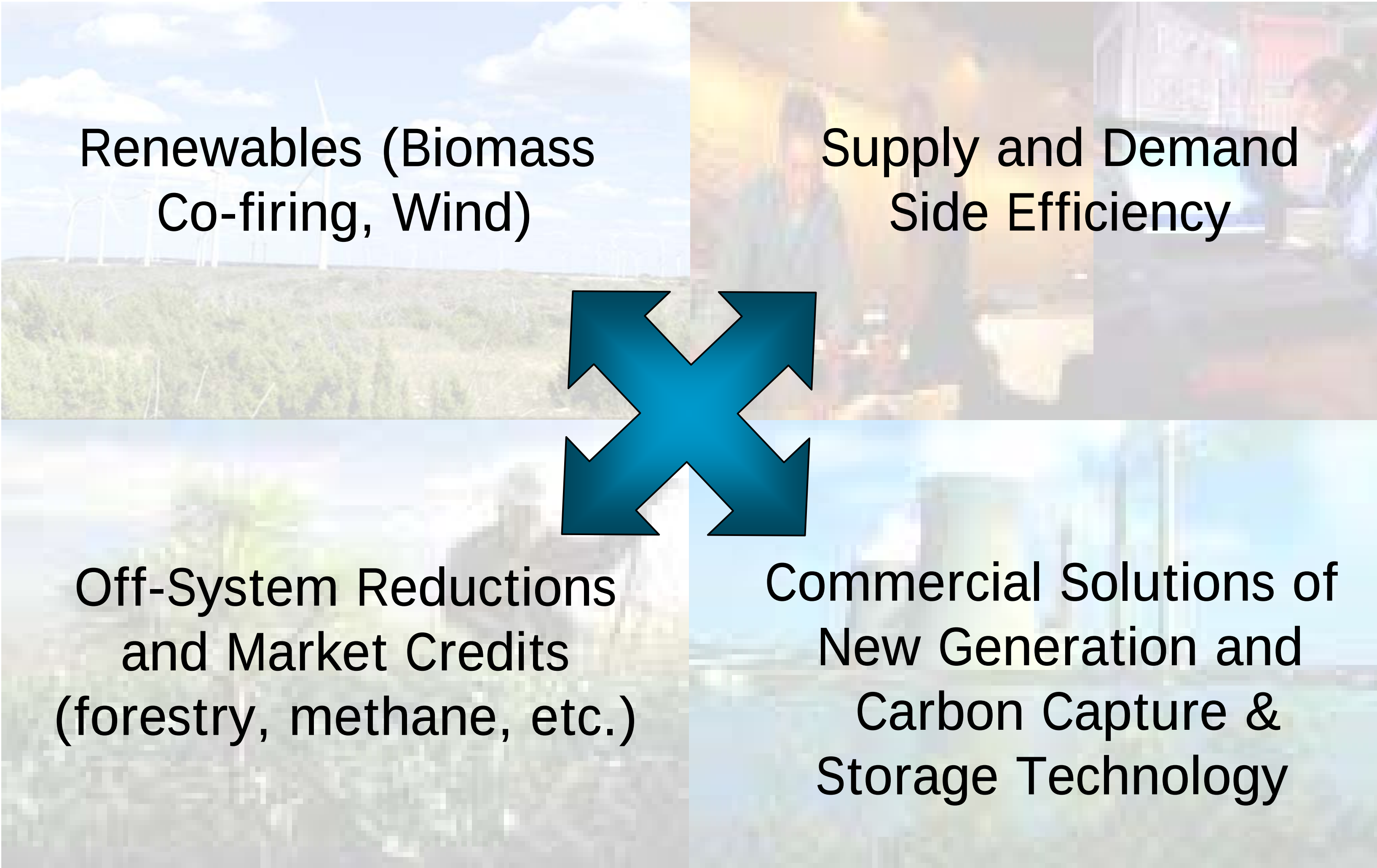
AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

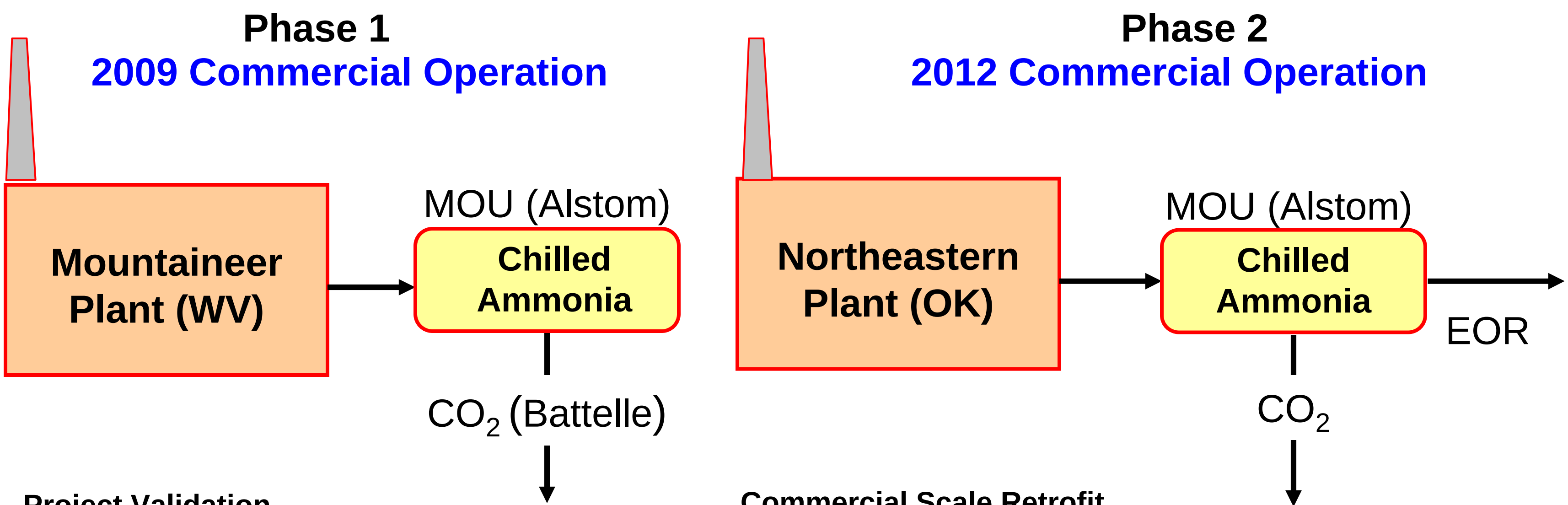
- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- **~ $3 billion I-765 Project in PJM**
- **~ $2 billion 765-kV study with ITC in Michigan**
- **~ $3 billion project filed with SPP**
- **~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)**

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution and timing dependent on ownership structure, capitalization, ROE and date assets are put in-service

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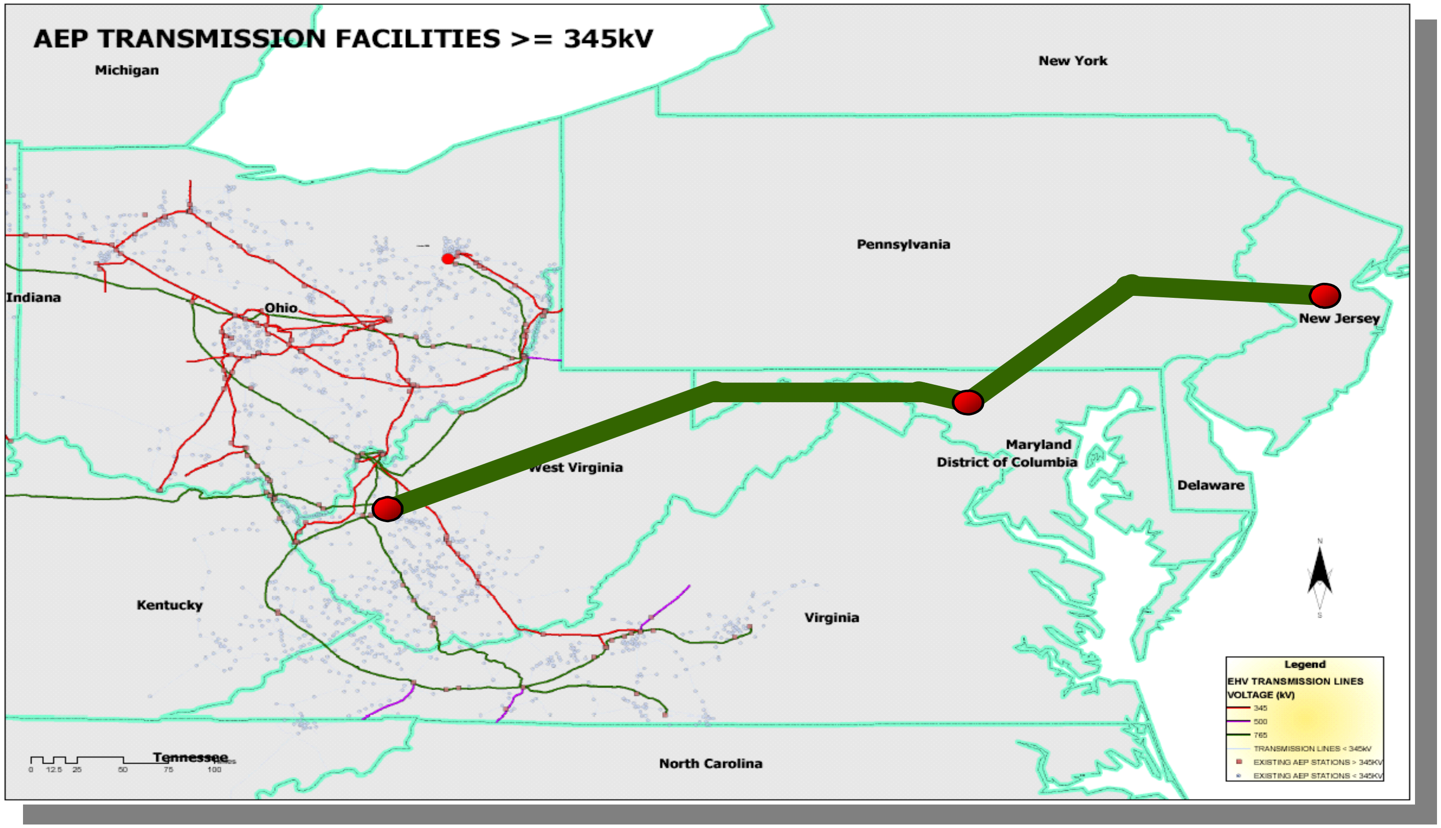
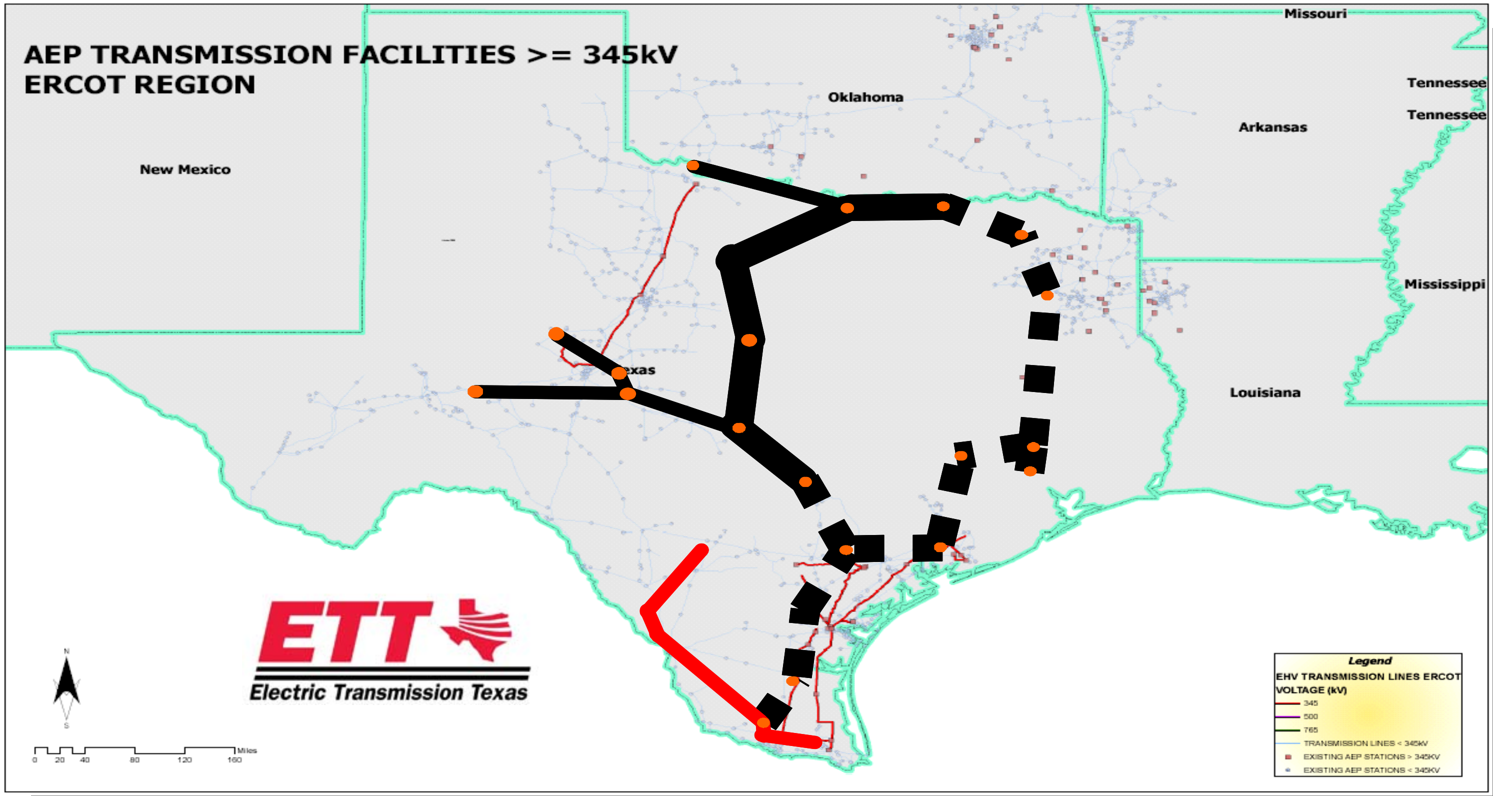
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765-PJM



- JV with Allegheny to build a 290 mile West Virginia – Maryland line (Approved by PJM in June 2007). Total estimated cost of $1.8 billion (AEP portion appprox. $600 million). (Second leg which would continue to New Jersey still under consideration by PJM.)
- Enhances Midwest-Mid-Atlantic reliability and improves power transfer capability by 5000 MW.
- Reduces network line losses by 280 MW.

765-ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets.
- AEP exploring ERCOT transmission investment opportunity, including 420 miles of 765-kV initially.
- Up to 4000MW improved transfer capability.

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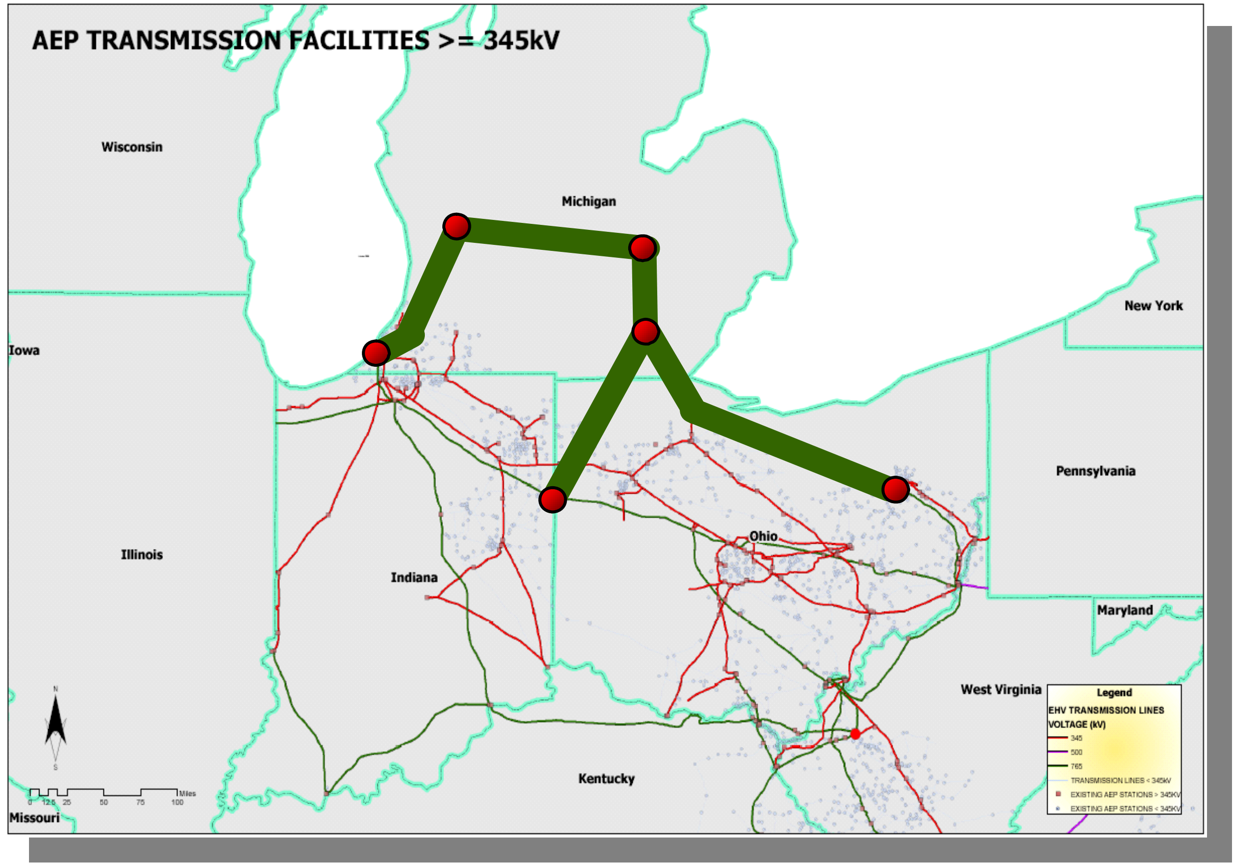
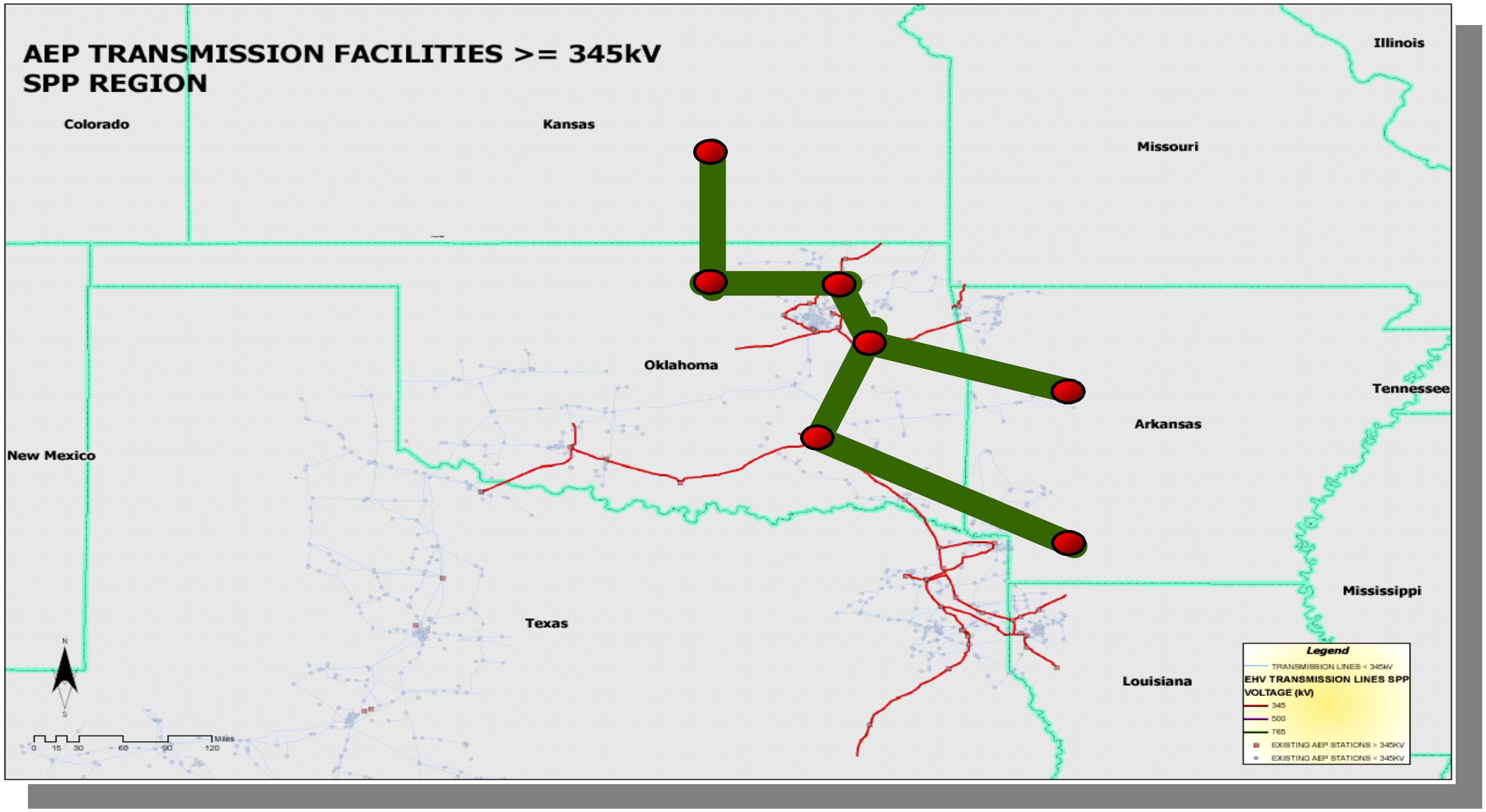
765-Michigan



- Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of 700 miles of 765-kV lines in Ohio and Michigan. Completed study should be available in the third quarter of 2007.
- Over 3000MW improved transfer capability.
- Reduces network line losses by 250 MW.

765-SPP



- In July 2006, AEP submitted a conceptual project to SPP for six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, with a proposed construction period of 2012-17.
- SPP issued its EHV Overlay Study in June 2007 reviewing 345 kV, 500 kV, and 765 kV potential projects in SPP. An alternative, which includes a 765-kV line in Oklahoma and Kansas connecting the east to PJM, was chosen as the preferred alternative.

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New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - **40% equity / 60% debt capital structure requested at the PUCT follows Texas' precedent for T&D companies' filings**
  - **Equity – 50% AEP / 50% MidAmerican Energy**
  - **AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary**
  - **Debt – Initially bank financing**
  - **Initial funding in 3Q07 after regulatory approvals**

- AEP I-765$_{TM}$ Interstate Project
  - **Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project**
  - **JV portion of the I-765$_{TM}$ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007**
  - **Equity – 50% AEP / 50% Allegheny**
  - **AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary**
  - **Operations to commence in the second half of 2007**
  - **I-765$_{TM}$ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007**

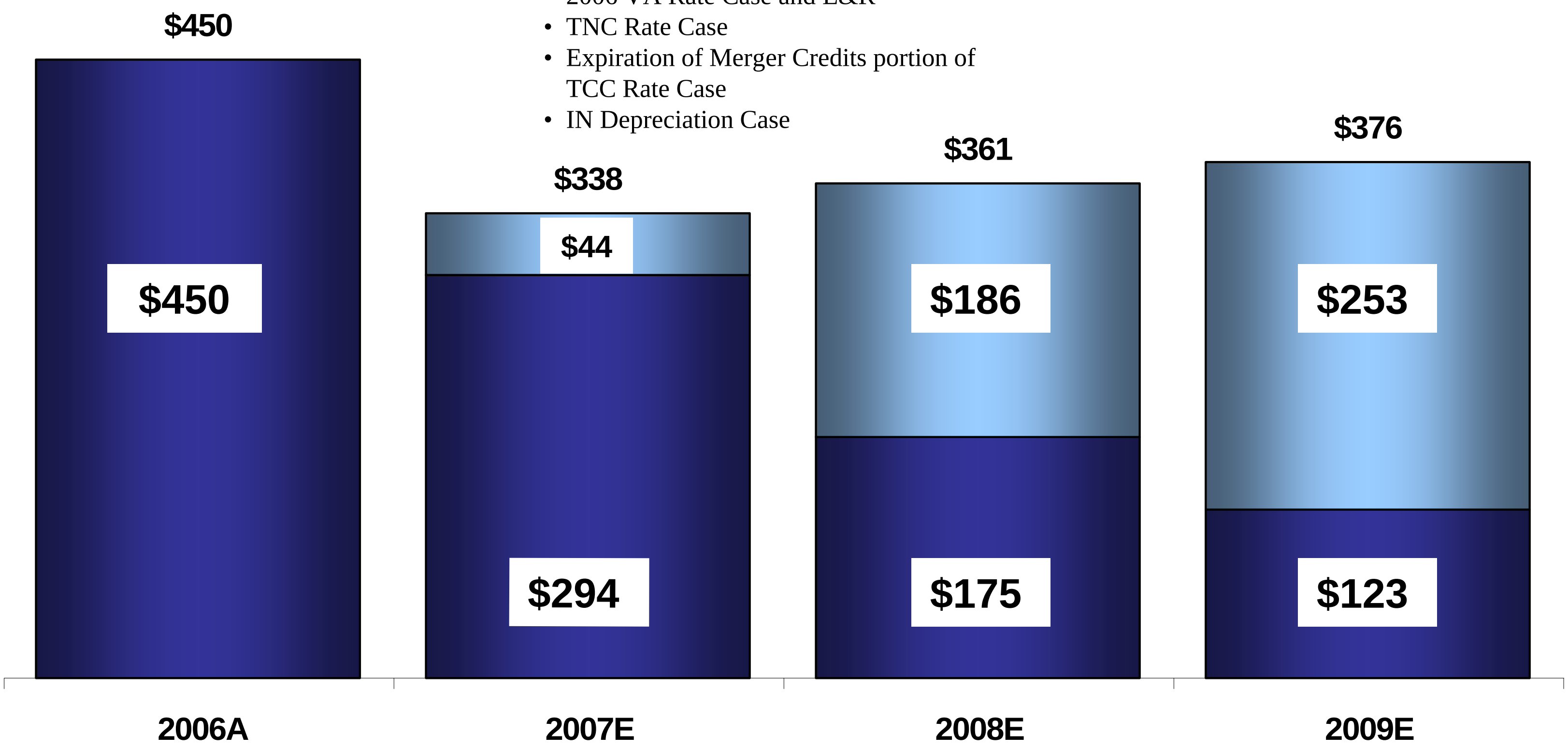
- Other Transmission Projects
  - **Equity percentage of capital structure will target FERC precedents**
  - **Equity ownership percentage will vary by project**
  - **Will seek FERC transmission incentives:**
    - **Incentive ROE**
    - **Return on CWIP**
    - **Abandonment recovery**
    - **Expensing pre-construction expenses**

Incremental Rate Relief Composition

$ Millions

Secured
- OH RSP
- 2006 WV Rate Case, including ENEC
- 2006 Kentucky Rate Case
- FERC & OH OATT
- 2006 VA Rate Case and E&R
- TNC Rate Case
- Expiration of Merger Credits portion of TCC Rate Case
- IN Depreciation Case

Pending/Future
- PSO Rate Case - $49.6 increase requested
- TCC Rate Case - $49.9 increase requested
- SWEPCo proceedings
- Cases yet to be filed



Rate Relief Is A Critical Element To AEP's Financial Success

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓$54.8 million covers increased costs related to coal and purchased power
  - ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings - Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

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Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
August 2007	Final order expected

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* Figures are rounded

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule is subject to IURC approval.

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Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- No procedural schedule has been set but Virginia legislation requires a decision within nine months.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for PSO's Used and Useful Determination and OG&E's cost recovery were held July 9-31, 2007.
- We await an ALJ report in August 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings will begin August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for September 27-28, 2007.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		2006 Performance Driver	2006 Actual ($ millions)	2007 Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

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Capital Investment Is Funded By Cash From Operations And Debt Issuances

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

AMERICAN ELECTRIC POWER

Nationwide Insurance Analyst Visit

Columbus, Ohio

August 12, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

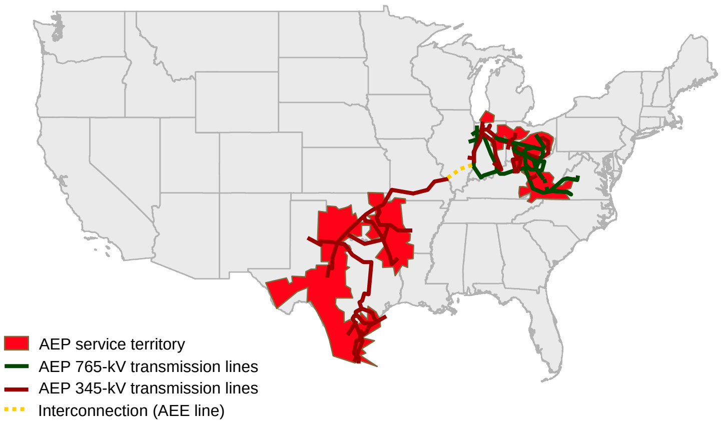
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview



AEP's Leadership Position

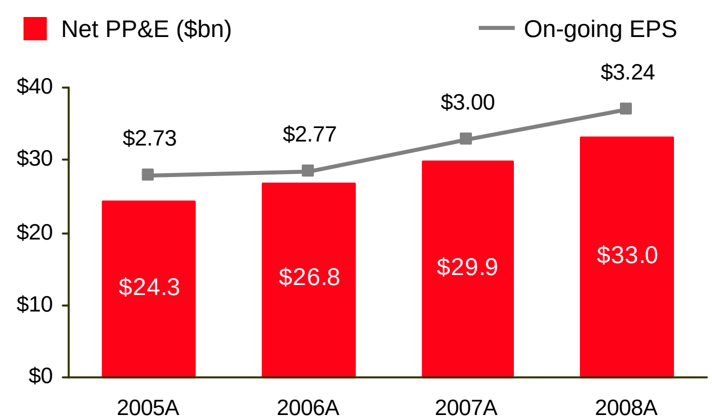
Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

Generation owned[1] (GW)	
SO	42.6
AEP	40.6 *
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

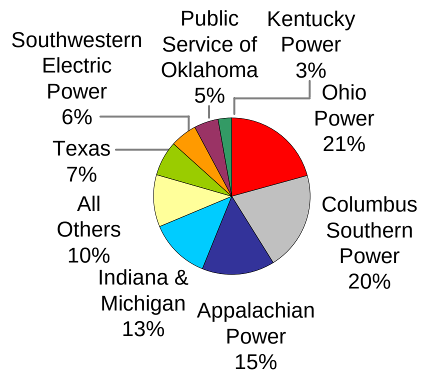
Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

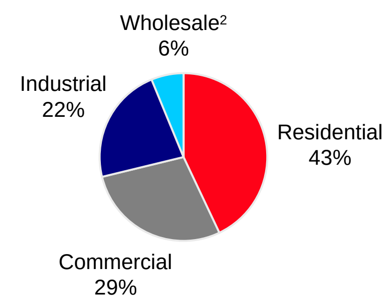
Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- Highly diversified regulated utility earnings contribution
- Balanced customer mix

[1] Source: Company filings
[2] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

AEP AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

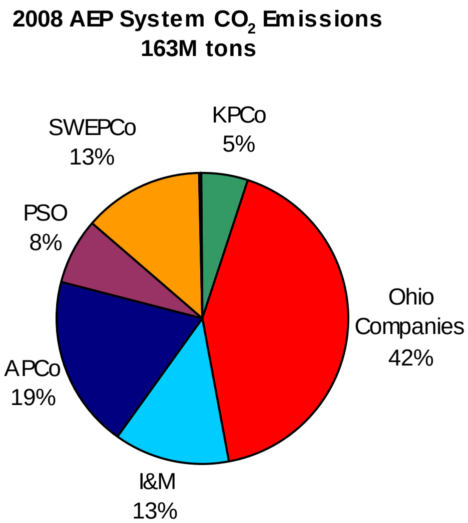
Renewable Energy

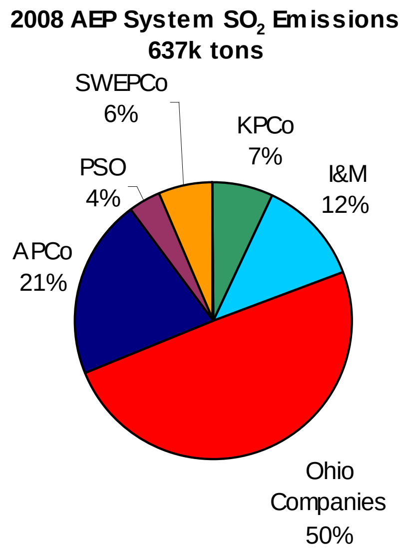
- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

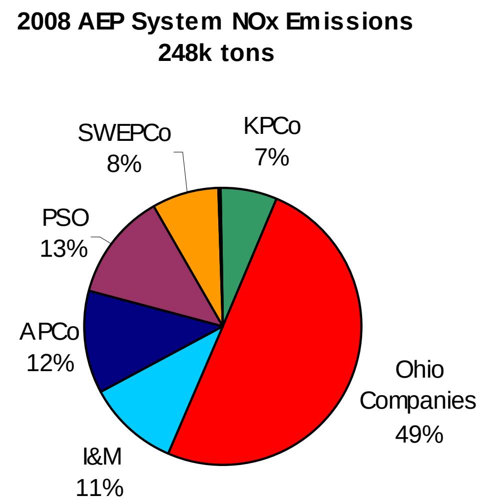
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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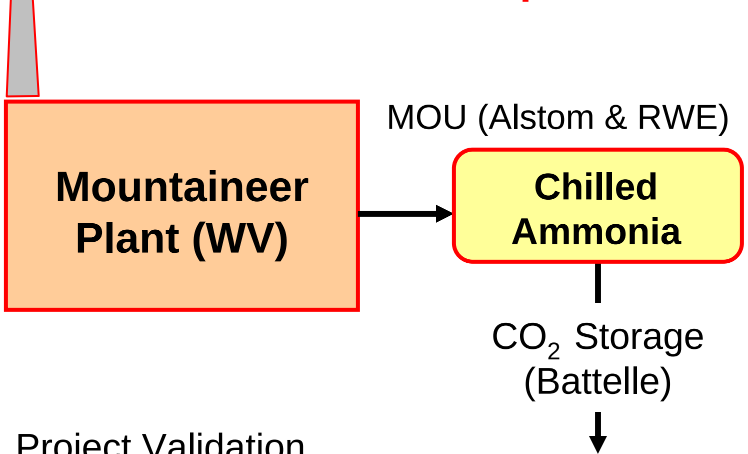
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- Alstom "Chilled Ammonia" Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Geologic storage for CO_2
- Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the 'economic' hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

AMERICAN ELECTRIC POWER

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1.2 billion in capital investment.

- Turk – In June 2009, the Arkansas Court of Appeals overturned APSC decision granting CECPN & AEP filed appeal to Supreme Court. Air permit appeal hearings were held in June 2009 and a decision is expected by year end. Construction continues.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

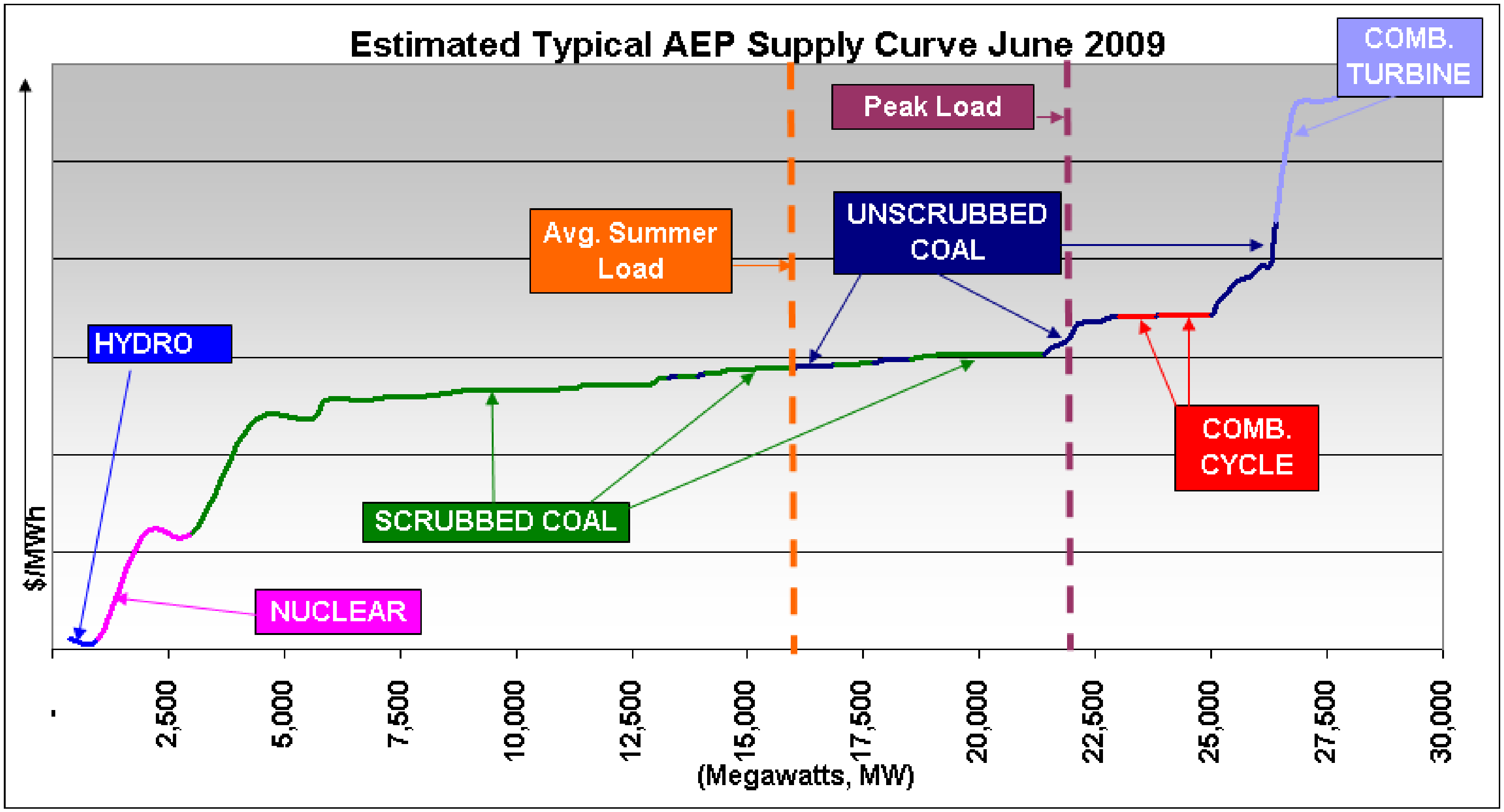
DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 2009 YTD, approximately 40% of the insurance payments ($40MM) were used to offset increased fuel costs to customers

AEP AMERICAN ELECTRIC POWER

AEP Supply Stack

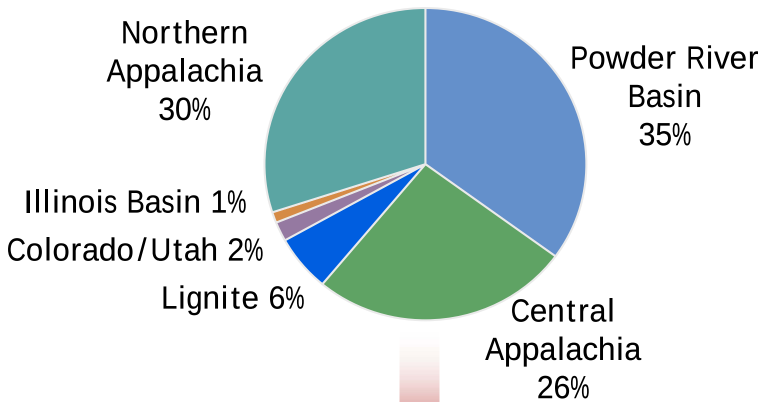
- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



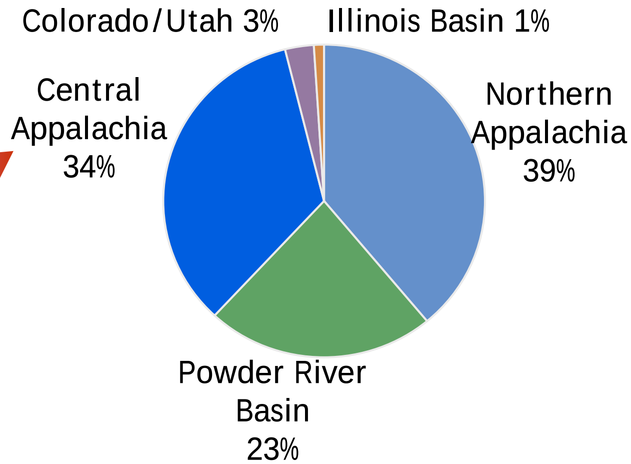
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

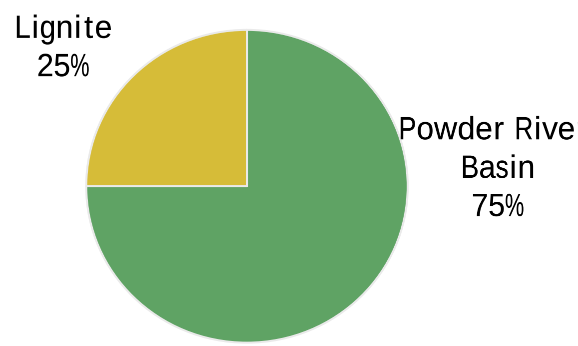
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

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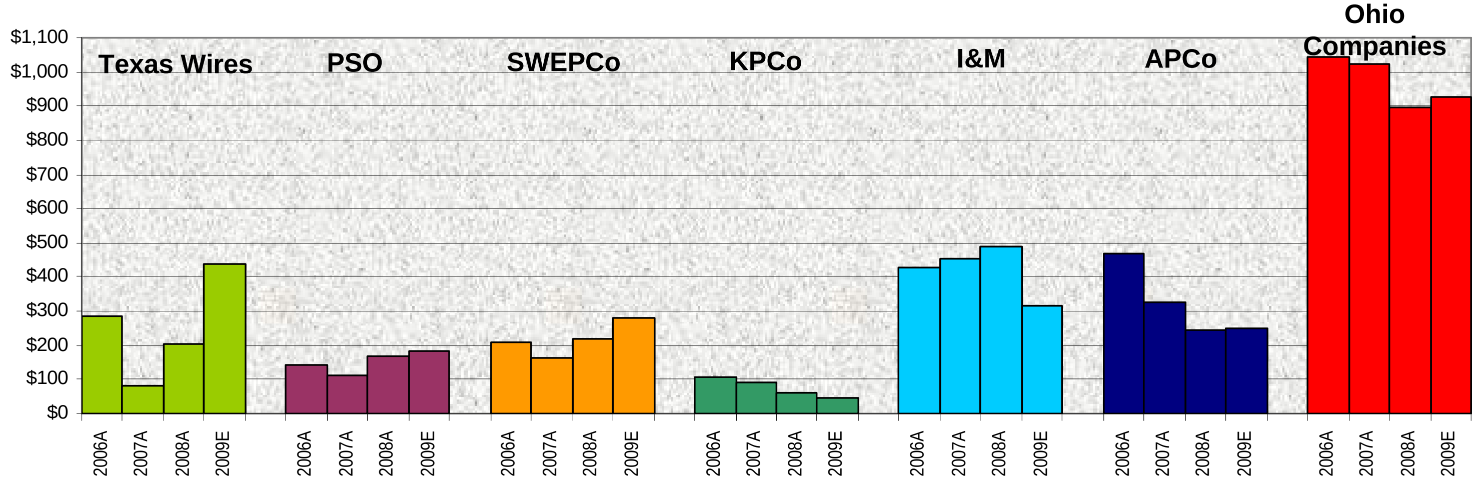
Cash Flow and Capex by Operating Company

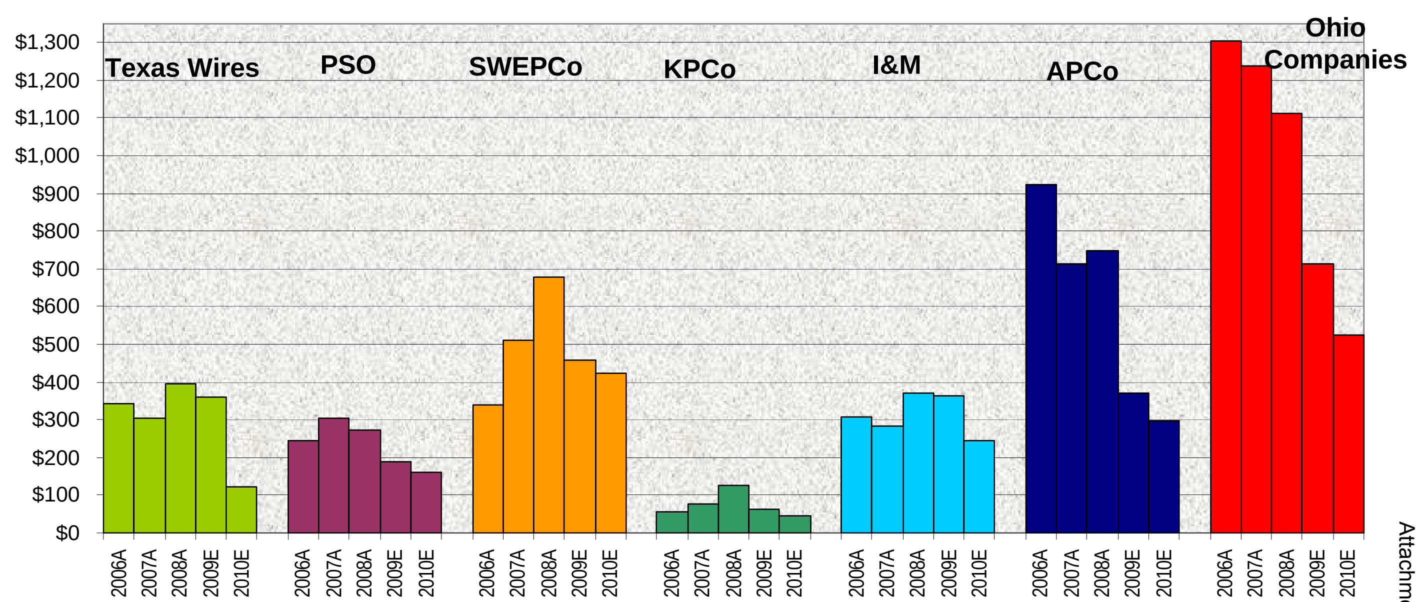


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER

Overview of 2009 Guidance

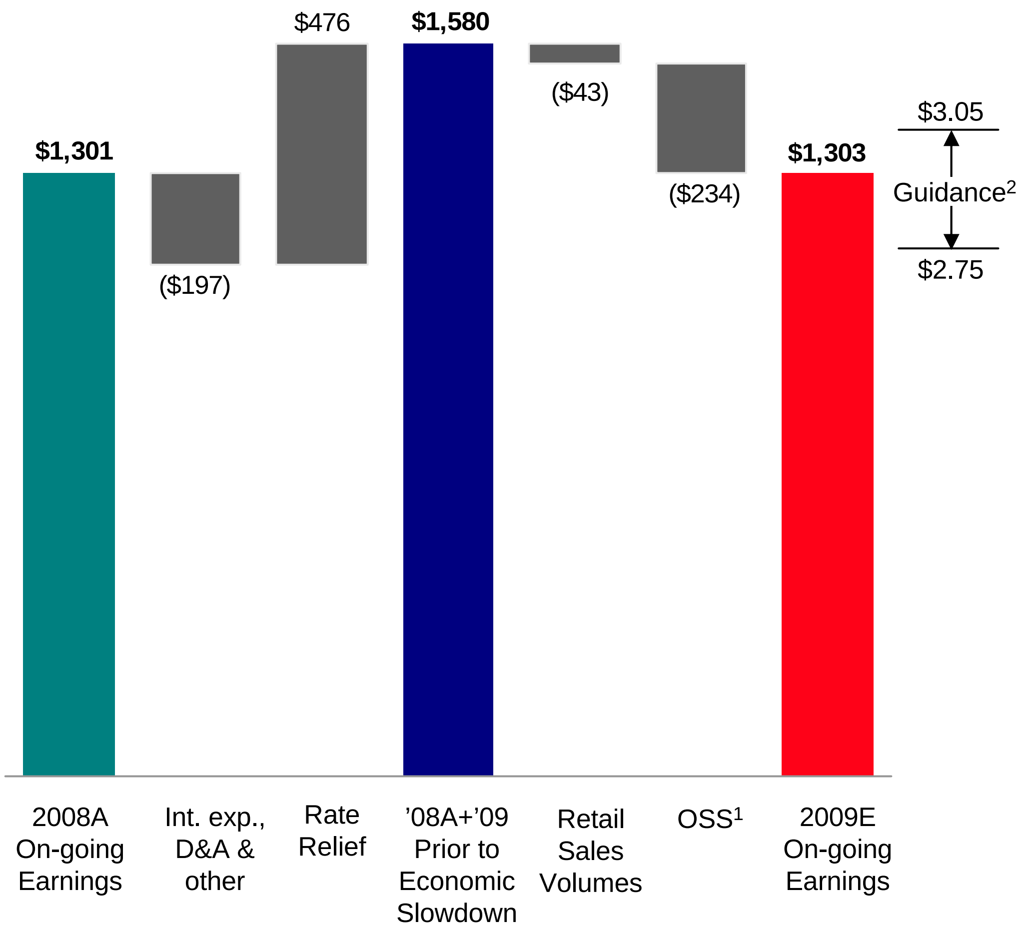
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

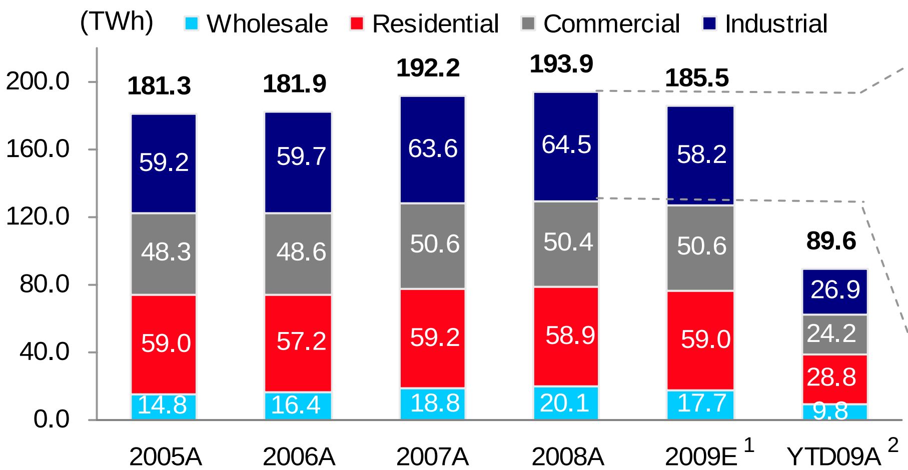
2008A-2009E Earnings Bridge ($mm)



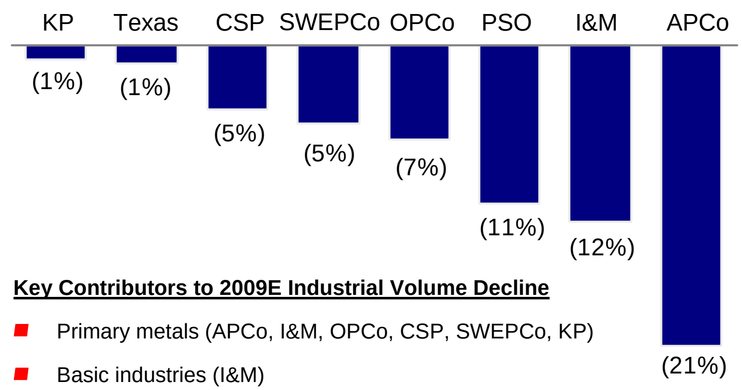
Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

Key Drivers of 2009 Guidance: Retail Sales

Retail Load by Customer Class



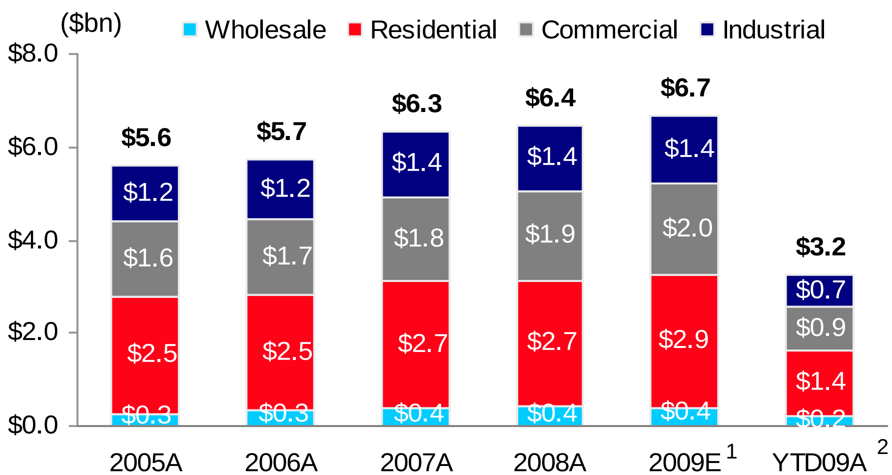
Forecast Drop in 2009 Industrial Sales

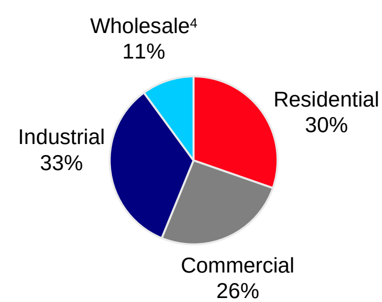


Key Contributors to 2009E Industrial Volume Decline

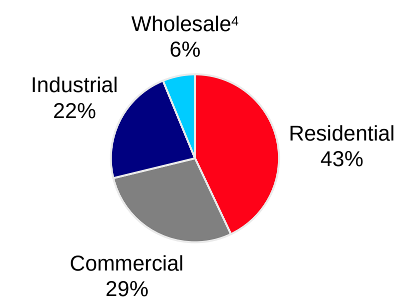
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

Retail Base Revenue[3] by Customer Class





2008 Retail Load = 193.9 TWh



2008 Retail Base Revenue [3] = $6.4bn

[1] 2009E assumes normalized weather
[2] YTD09A represents actual results through June 30, 2009

[3] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables
[4] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

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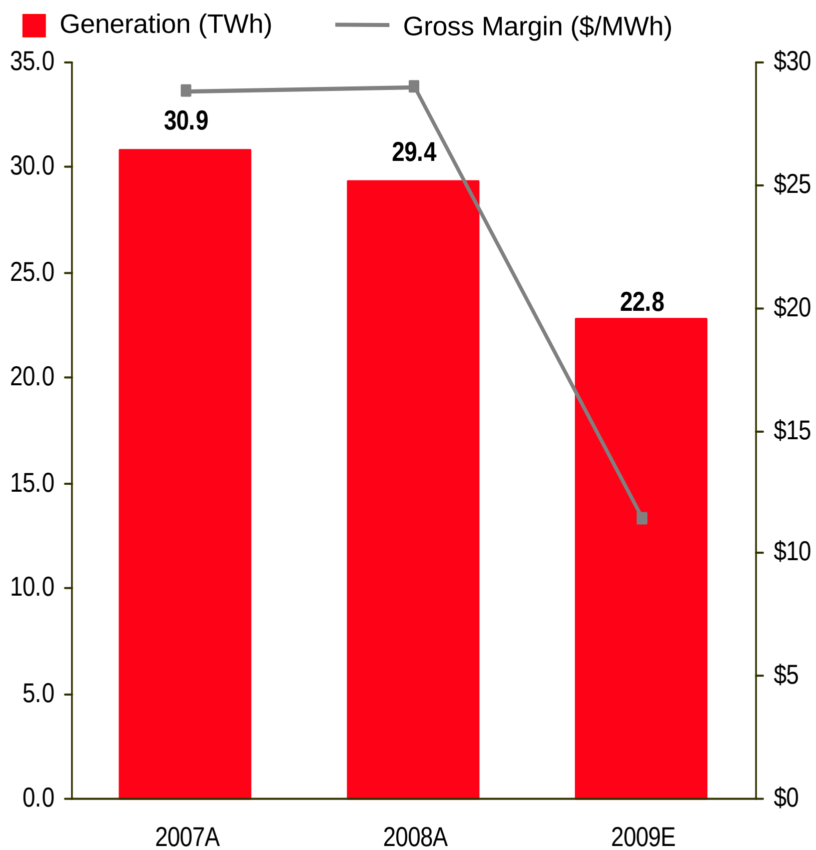
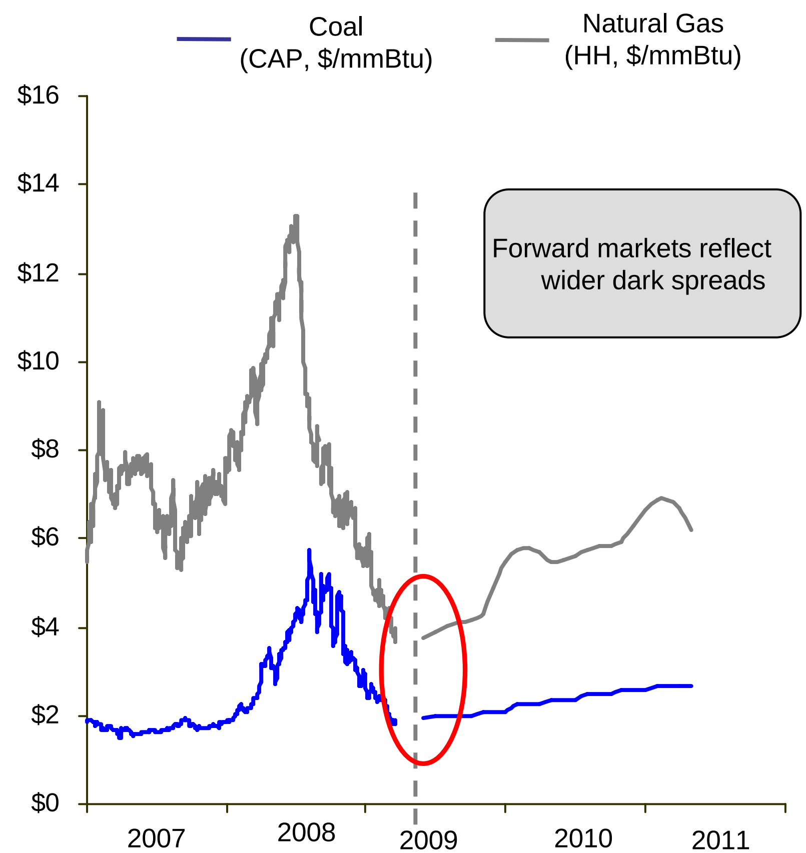
Key Drivers of 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices

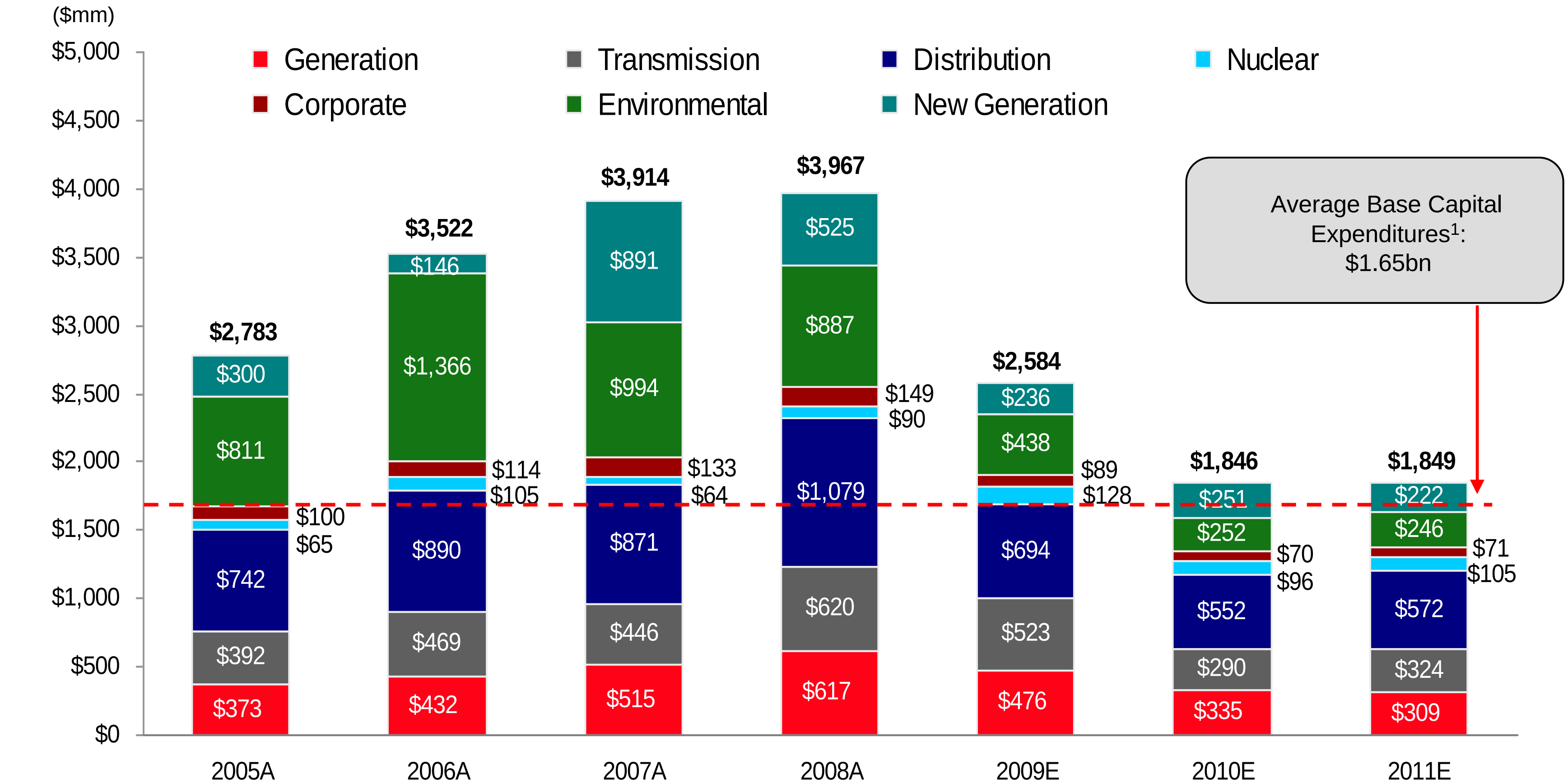


Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

AMERICAN ELECTRIC POWER

Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

AEP AMERICAN ELECTRIC POWER

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

AEP AMERICAN ELECTRIC POWER

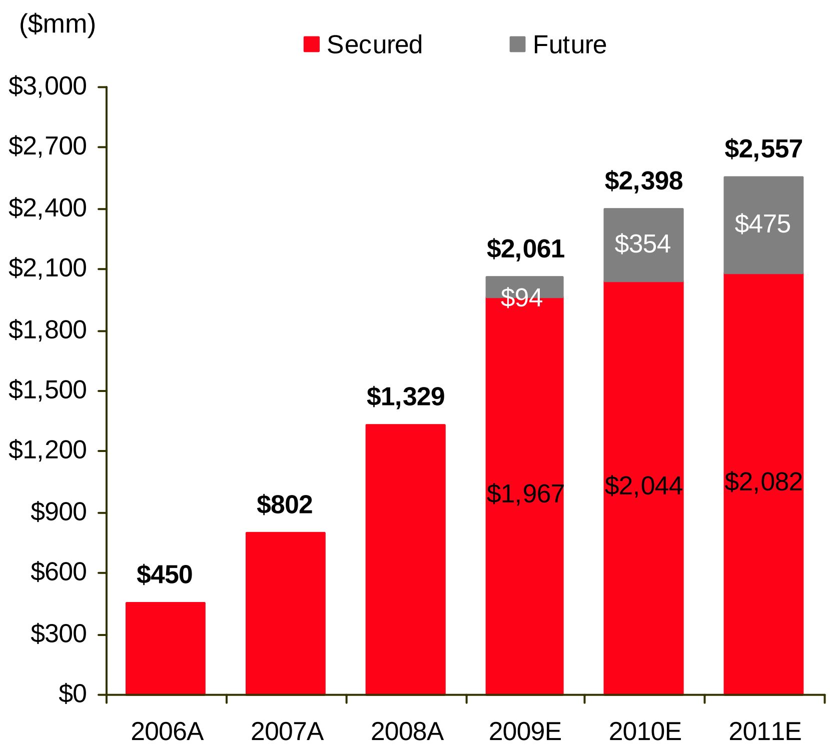
Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

AMERICAN ELECTRIC POWER

Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $77mm and $38mm was secured for 2010 and 2011, respectively, as of July 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
  - ✓ APCo VA ($169MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

AEP AMERICAN ELECTRIC POWER

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Rehearing Order	2010 ESP Appl.	2010 PUCO Rehearing Order	2011 ESP Appl.	2011 PUCO Rehearing Order	Cumulative ESP Appl.	Cumulative PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case

On July 15, 2009 APCo filed a pre-biennial base rate case with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $169.2 million. (Docket #: PUE-2009-00030) A procedural schedule is pending from the VSCC. A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position* (11/30/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.015%	1.365%	0.00%
Long-Term Debt	56.007%	6.383%	3.57%
Preferred Stock	0.280%	4.352%	0.01%
Common Equity	43.665%	13.350%	5.83%
Other Items	0.033%	9.421%	0.00%
Total	100.00%		9.42%

*AEP will refile by August 14, 2009 using an end-of-test-year capital structure per the recent Virginia SCC decision in case No. PUE-2009-00019.

Procedural Schedule TBD

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4*
Rate of Return		9.42%
Operating Income Requirement	$	193.8
Adjusted Operating Income	$	90.9
Difference	$	102.9
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	169.2

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

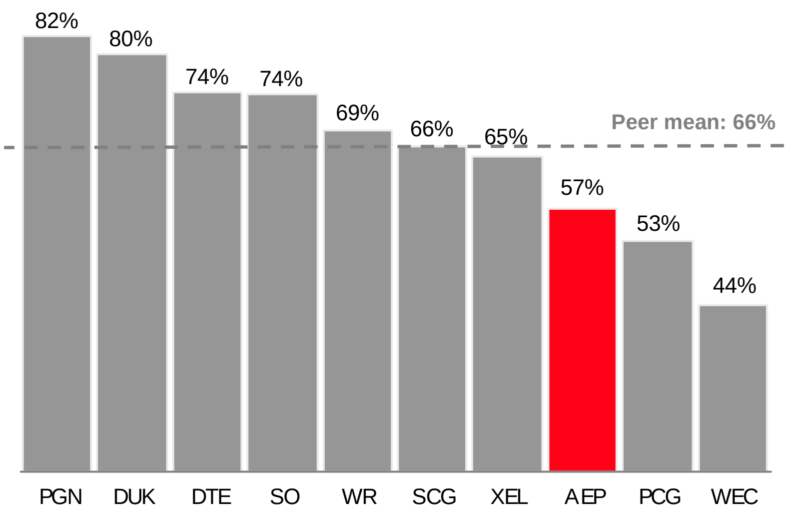
($ in millions)
(as of June 30, 2009)

Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

Dividend Overview

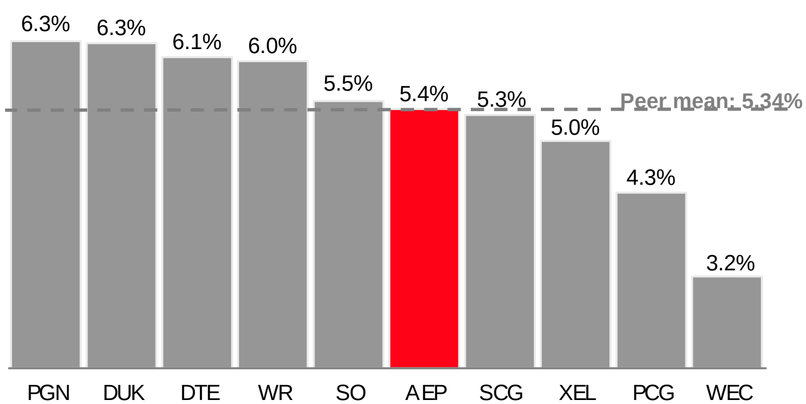
- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 7/28/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 7/28/09

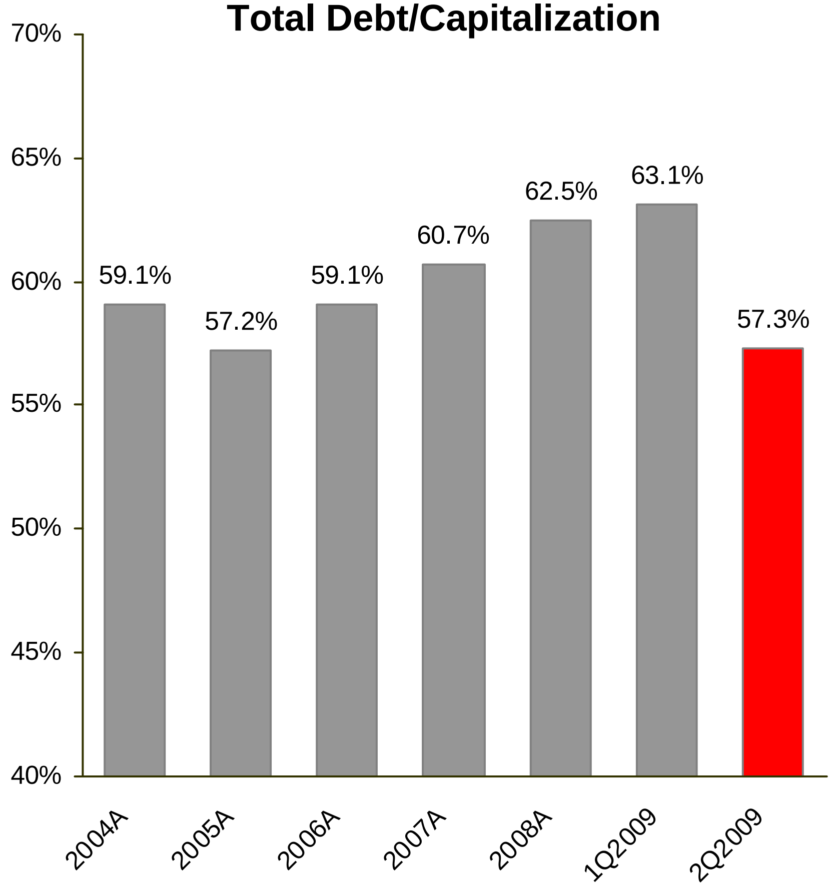
AEP AMERICAN ELECTRIC POWER

Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 6/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

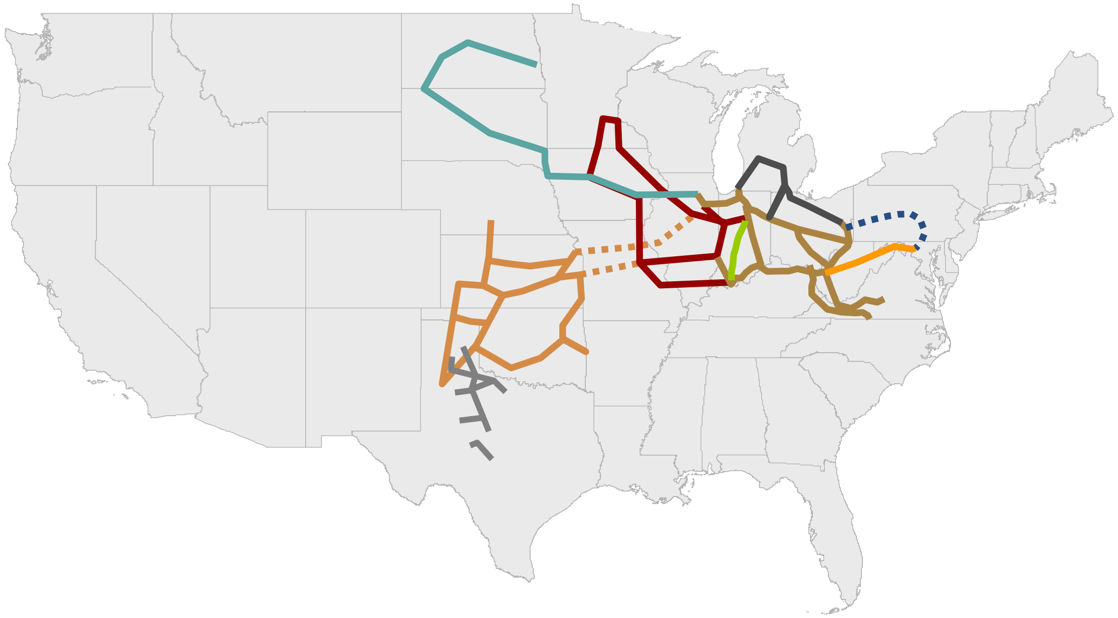
Pioneer	COD: 2015
■ 240 miles of 765 kV	
■ Partner: Duke Energy (50%)	
■ Estimated Cost: $1 billion	
■ ROE: 12.54%	

PATH-WV	COD: 2014
■ 275 miles of 765 kV	
■ Partner: Allegheny Energy (50%)	
■ Estimated Cost: $1.2 billion	
■ ROE: 14.3%	

Tallgrass	COD: 2013-14
■ 170 miles of 765 kV	
■ Partners: OG&E (50%) & MidAmerican Energy (25%)	
■ Estimated Cost: $500 million	
■ ROE: 12.8%	

Prairie Wind	COD: 2013
■ 110 miles of 765 kV	
■ Partners: Westar Energy (50%) & MidAmerican Energy (25%)	
■ Estimated Cost: $400 million	
■ ROE: 12.8%	

ETT	COD: 2013
■ 345 kV in ERCOT	
■ Partner: MidAmerican Energy (50%)	
■ Estimated Cost: $400 million	
■ ROE: 9.96%	



Future Projects:

EHV Michigan	COD: ~2020
■ 700 miles of 765 kV	

PJM Projects	
■ Enhance existing 765/345 kV	

Hartland	COD: ~2020
■ 1000+ miles of 765 kV	

MISO Vision Plan	
■ 765 kV Backbone	

SPP Overlay	COD: 2013-14
■ 765 kV Backbone	

ETT	COD: ~2018
■ 345 kV in ERCOT	
■ Additional CREZ spend of $750-$850 million	

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

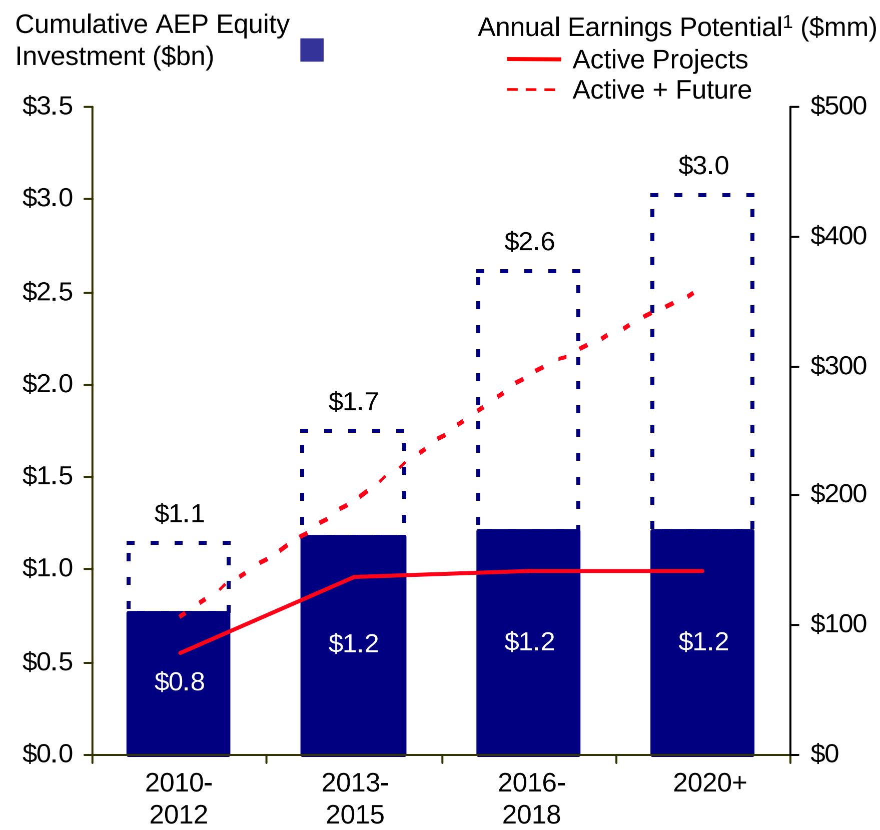
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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EHV Transmission in PJM: PATH

<u>Project Description:</u> 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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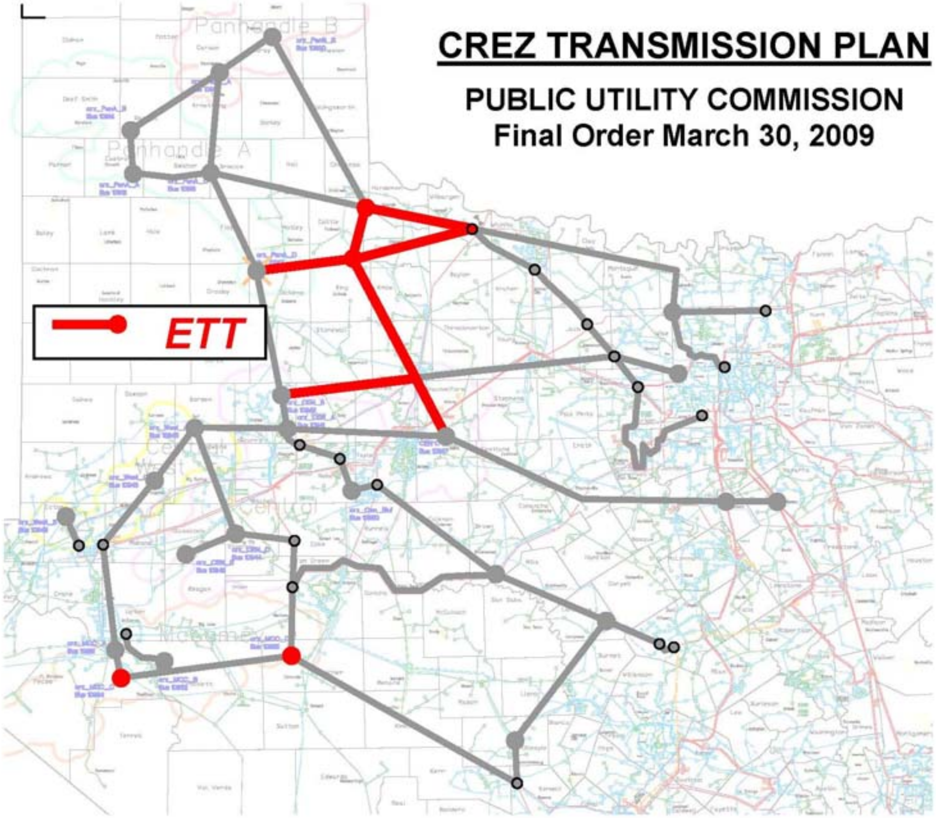
Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



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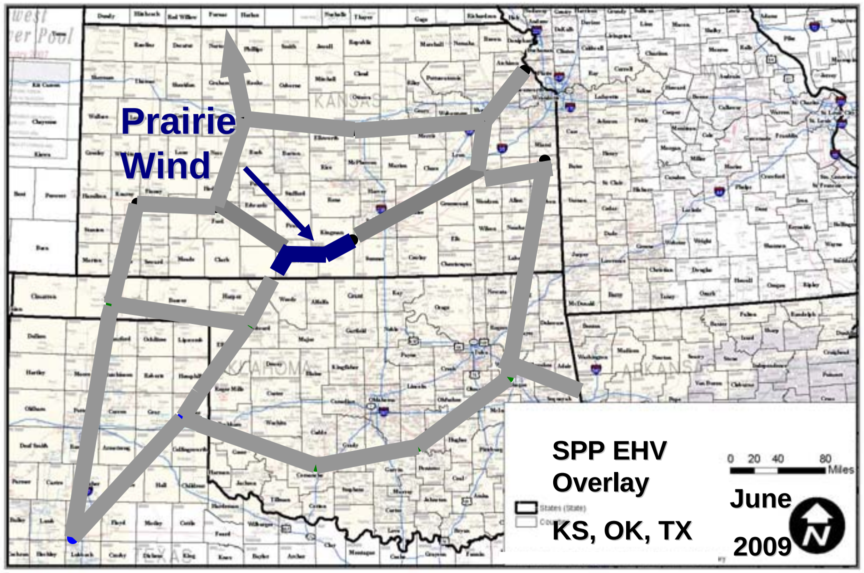
AEP AMERICAN ELECTRIC POWER

ETT Electric Transmission Texas

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

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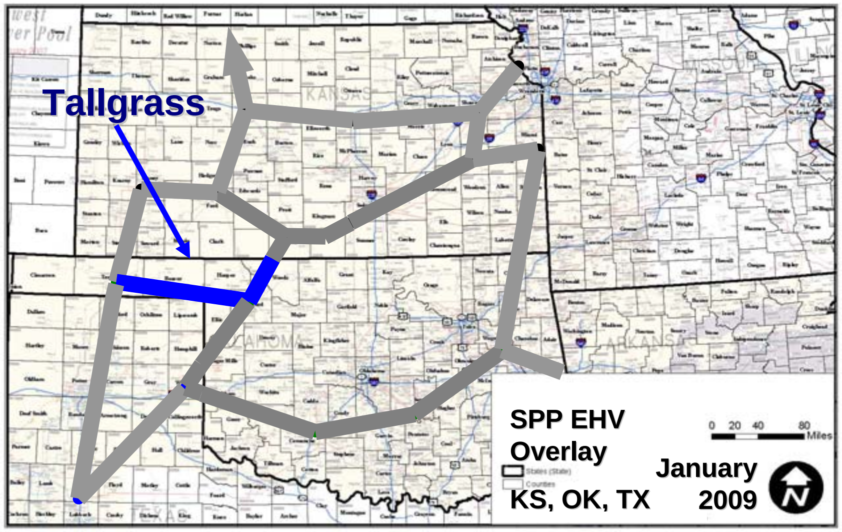
Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

AEP AMERICAN ELECTRIC POWER

Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

American Electric Power, Inc.

S.A.C. Capital Management

August 14, 2007

AEP®

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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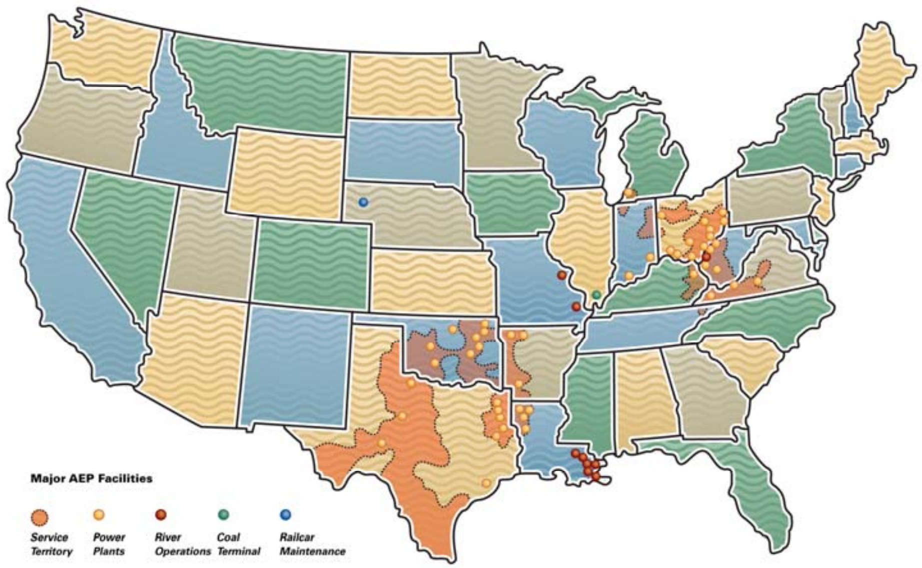
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

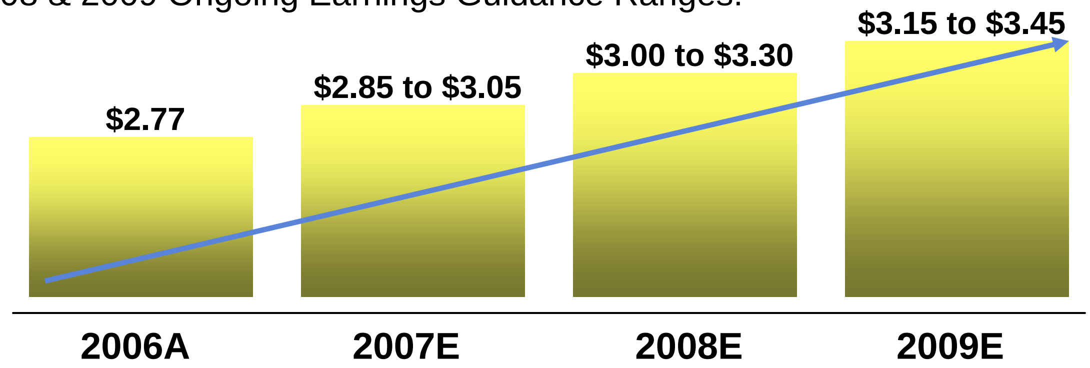
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

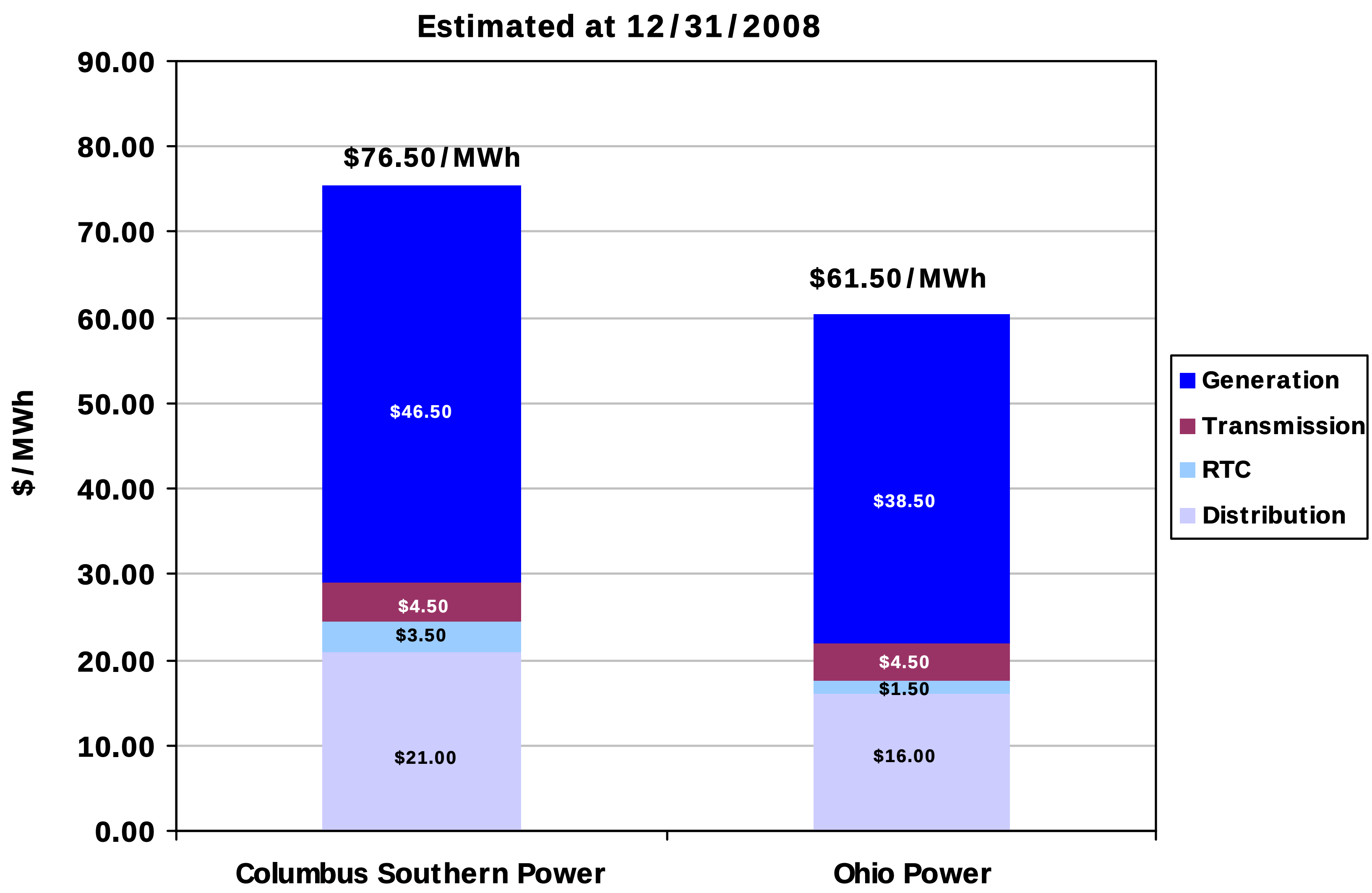
New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

AEP OHIO – Post-2008

- Continued dialogue with fellow utilities
- Potential proposal from the governor’s office sometime this summer
- Potential legislation crafted late 2007/early 2008
- The price of electricity in Ohio is going up to be more reflective of what is happening in the markets
- ‘Stair-step’ in a rate increase that is bigger than the current RSPs of 3% and 7%
- We will pursue recording the shortfall between the stair-step level and market prices as a regulatory asset – along with securitization at a legislative level

It Is Our Hope That We Can Craft A Reasonable Compromise That Will Allow Us To Achieve At Or Near Market Prices Without Causing Rate Shock To Our Customers And The Ohio Economy

Average Unbundled AEP Ohio Rates



Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

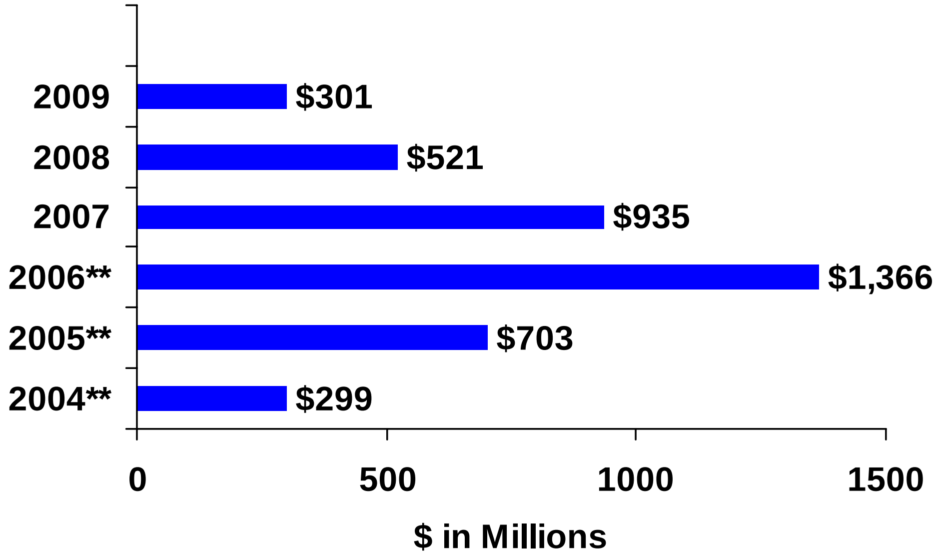
*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

AEP®

$4.1 Billion Environmental Investment

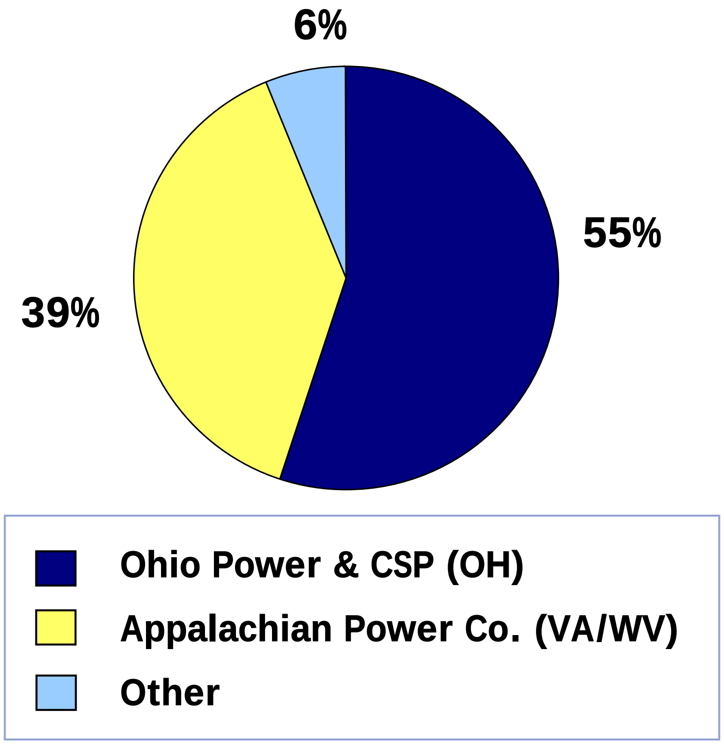
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



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Majority Of 2006 & 2007 Dollars Will Be Invested In Ohio & APCo

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
<u>East Plants</u>					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
<u>CCD Plants</u>					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
<u>West Plants</u>					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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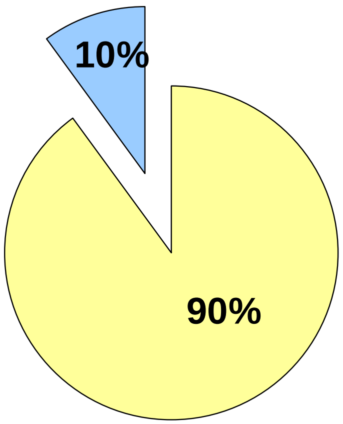
Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

•B&W/Alstom – FGD Spray Tower
•B&V/Chyioda – FGD Jet Bubbling Reactor
•Pullman Power – Stack Supplier
•Babcock Power – SCR
•Black & Veatch – Architect/Engineering
•Sargent & Lundy – Architect/Engineering

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

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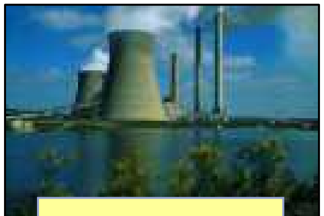
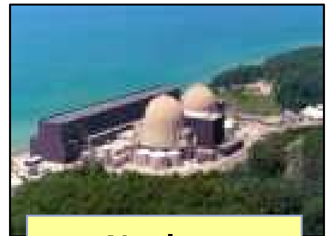
AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Domestic Generation Fleet

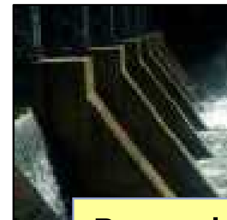
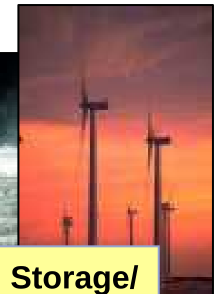


Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

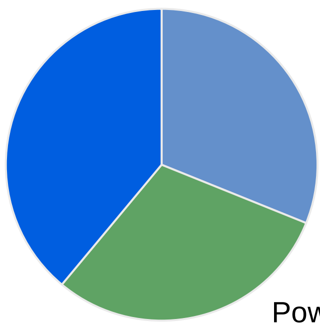
RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

AEP®

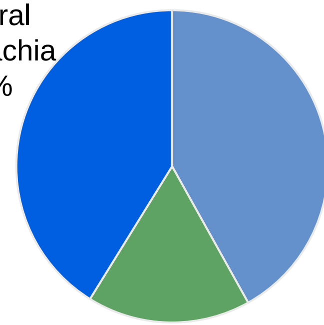
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

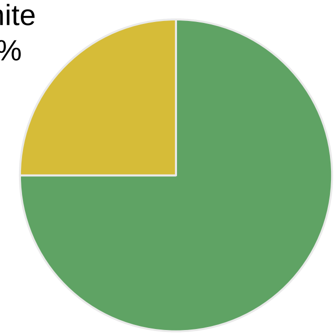
Total AEP System



AEP East



AEP West



Coal Stats:

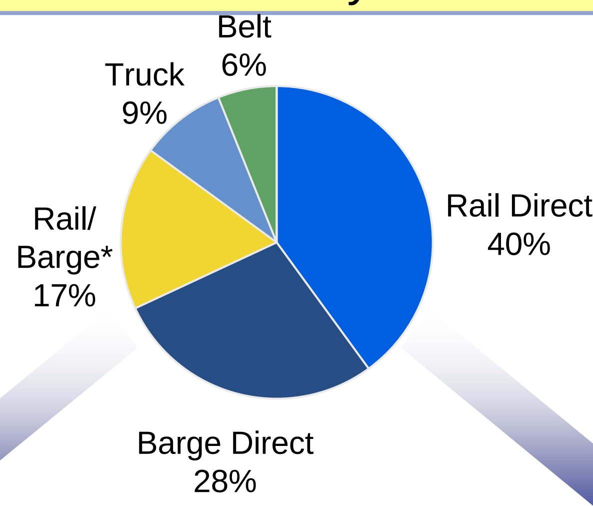
- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP®

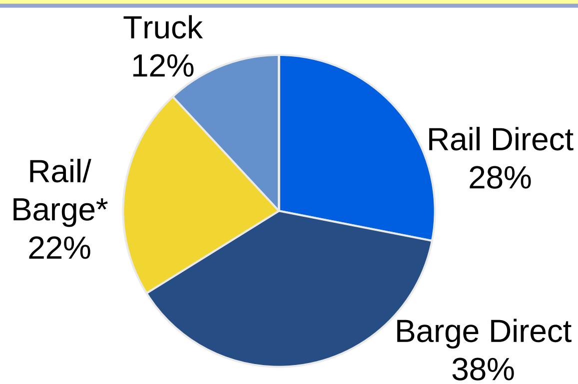
Coal Delivery

2006 Actual

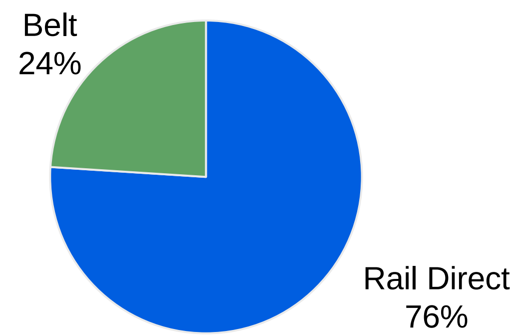
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

– 821 MW combined-cycle gas plant
– $220MM purchase price
– Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

– 505 MW simple-cycle gas plant
– $100MM purchase price
– APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

– 480 MW simple-cycle gas plant
– $102MM purchase price
– Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

– 1140 MW combined-cycle gas plant
– $325MM purchase price
– AEG completed purchase on May 16, 2007

AEP®

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 [(1)]	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B [(2)]	Coal	Ultra-supercritical	600 [(2)]	2011
PSO	Red Rock	Oklahoma	$1.8 B [(3)]	Coal	Ultra-supercritical	900 [(3)]	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review [(4)]	Coal	IGCC	630	2017

(1) 150MW were declared in commerical operation on July 12, 2007.
(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(3) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

AEP ®

New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
- Air permit approval expected in August 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

- Used and Useful Determination filed in February 2006 – Hearings concluded July 31, 2007 and order is expected in September 2007
- Air permit approval expected in October 2007
- Regulatory Recovery
  - Order expected in PSO rate case filing in July 2007 – filing included request for CWIP treatment for new projects
- Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

AEP®

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

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IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

Highlights of Bingaman-Specter Proposal

“Low Carbon Economy Act of 2007”

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

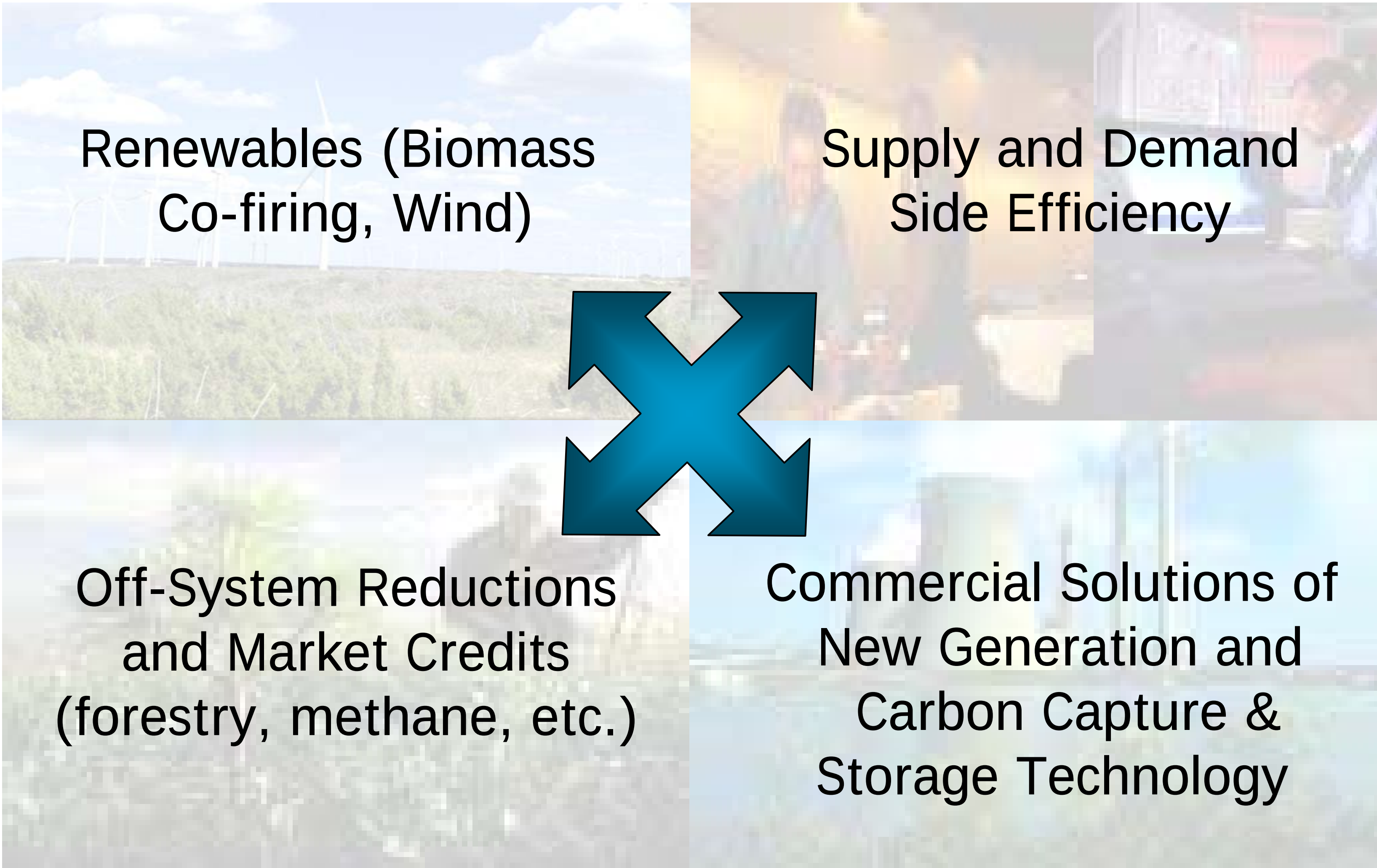
AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

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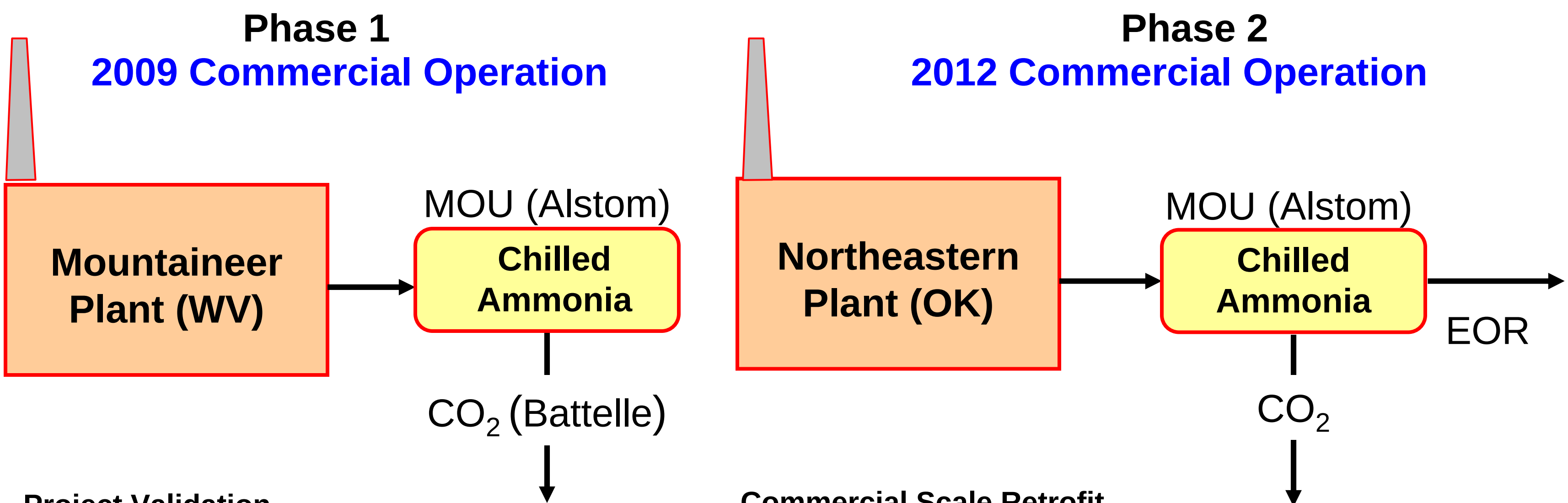
Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

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Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

7

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

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Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

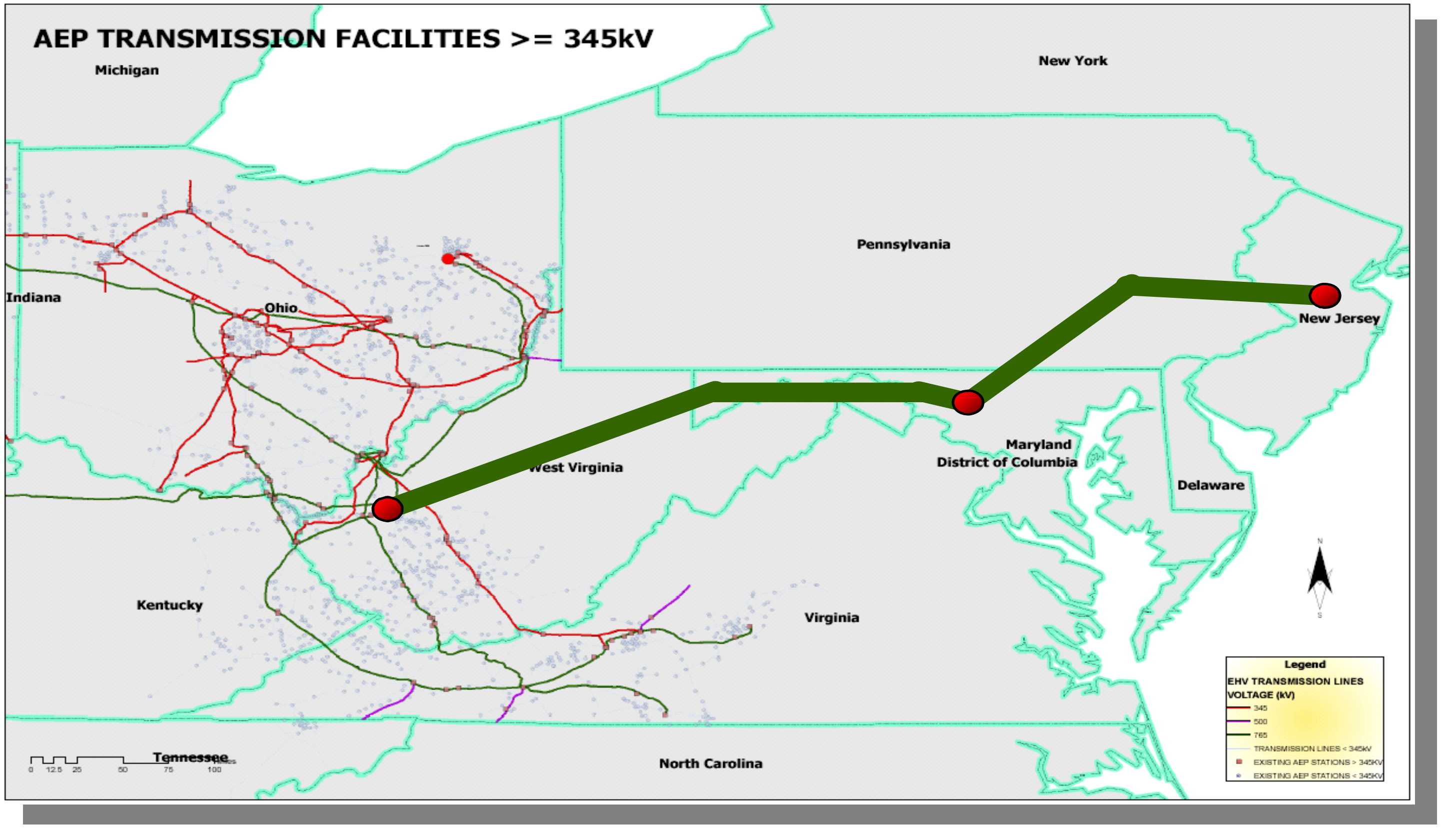
Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution and timing dependent on ownership structure, capitalization, ROE and date assets are put in-service

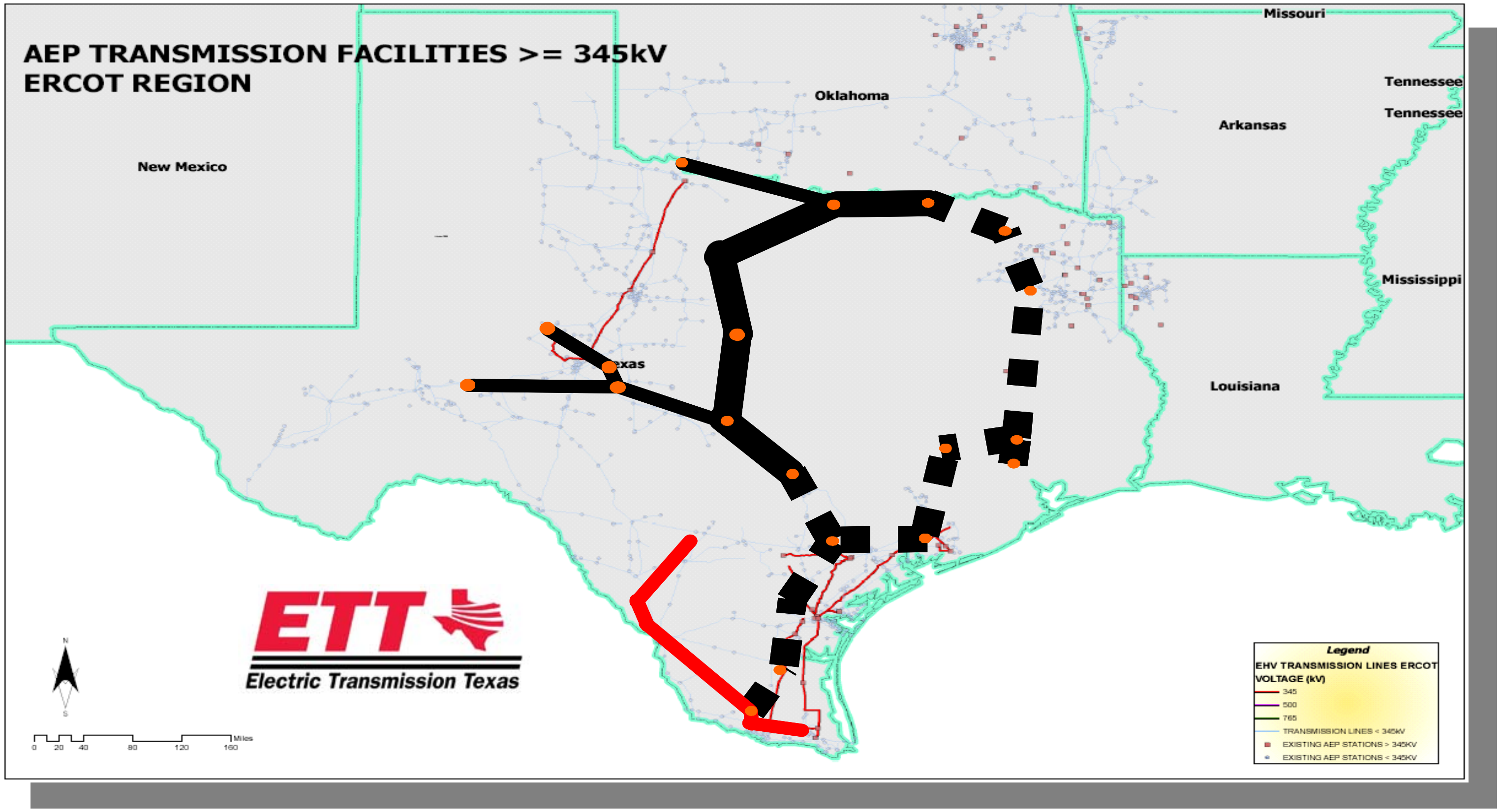
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765-PJM



- JV with Allegheny to build a 290 mile West Virginia – Maryland line (Approved by PJM in June 2007). Total estimated cost of $1.8 billion (AEP portion appprox. $600 million). (Second leg which would continue to New Jersey still under consideration by PJM.)
- Enhances Midwest-Mid-Atlantic reliability and improves power transfer capability by 5000 MW.
- Reduces network line losses by 280 MW.

765-ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets.
- AEP exploring ERCOT transmission investment opportunity, including 420 miles of 765-kV initially.
- Up to 4000MW improved transfer capability.

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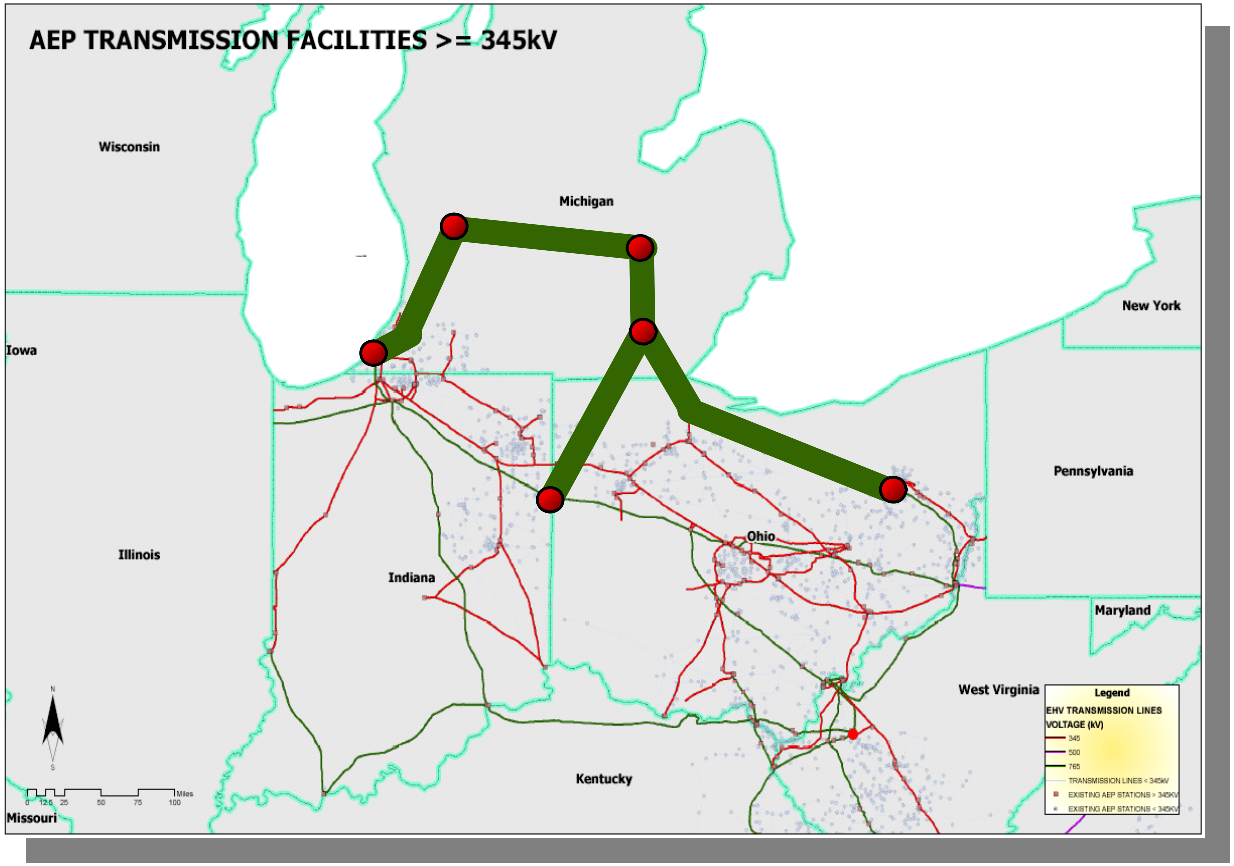
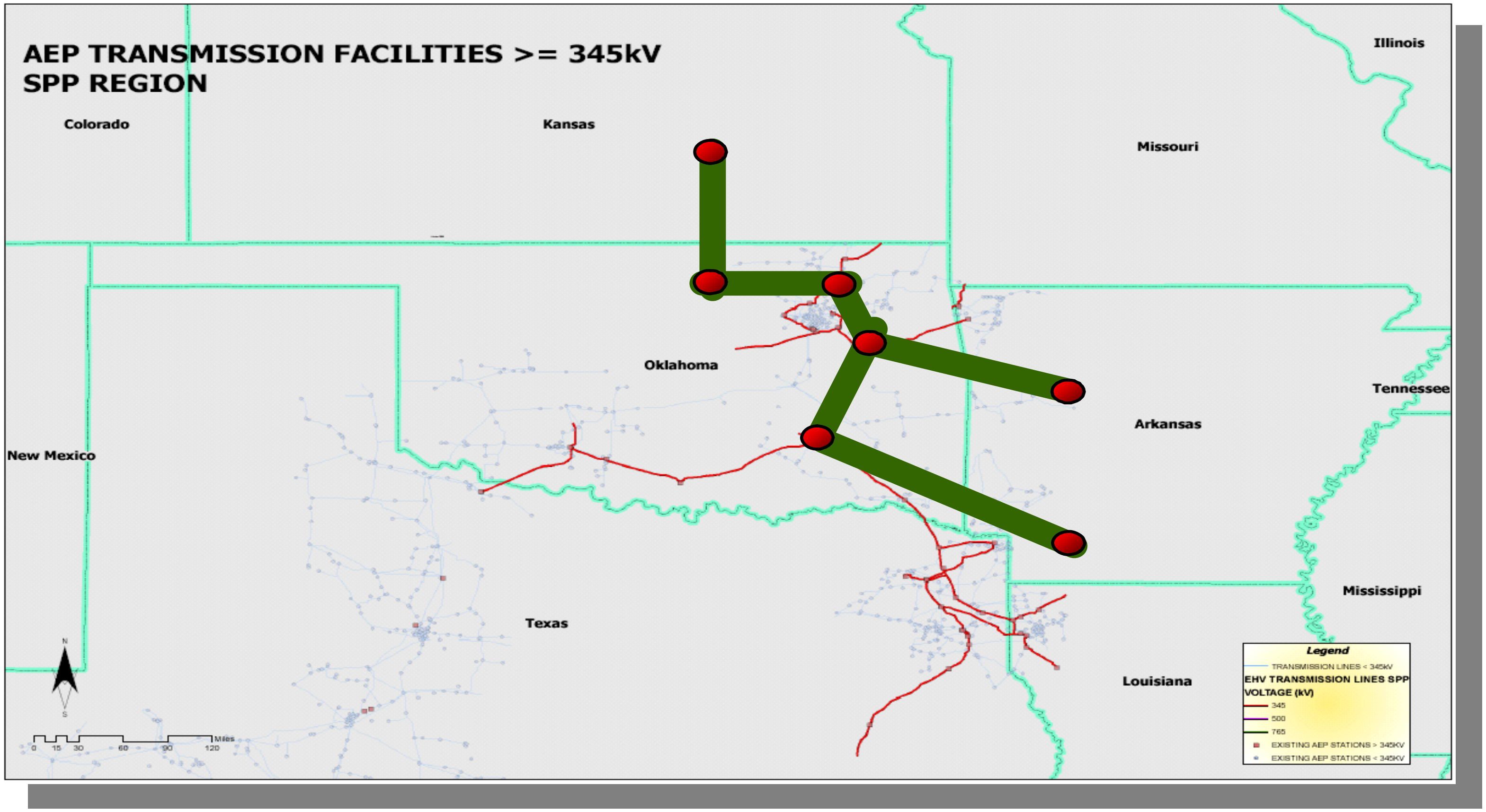
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 482 of 9556

765-Michigan



- Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of 700 miles of 765-kV lines in Ohio and Michigan. Completed study should be available in the third quarter of 2007.
- Over 3000MW improved transfer capability.
- Reduces network line losses by 250 MW.

765-SPP



- In July 2006, AEP submitted a conceptual project to SPP for six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, with a proposed construction period of 2012-17.
- SPP issued its EHV Overlay Study in June 2007 reviewing 345 kV, 500 kV, and 765 kV potential projects in SPP. An alternative, which includes a 765-kV line in Oklahoma and Kansas connecting the east to PJM, was chosen as the preferred alternative.

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New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - **40% equity / 60% debt capital structure requested at the PUCT follows Texas' precedent for T&D companies' filings**
  - **Equity – 50% AEP / 50% MidAmerican Energy**
  - **AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary**
  - **Debt – Initially bank financing**
  - **Initial funding in 3Q07 after regulatory approvals**

- AEP I-765$_{TM}$ Interstate Project
  - **Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project**
  - **JV portion of the I-765$_{TM}$ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007**
  - **Equity – 50% AEP / 50% Allegheny**
  - **AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary**
  - **Operations to commence in the second half of 2007**
  - **I-765$_{TM}$ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007**

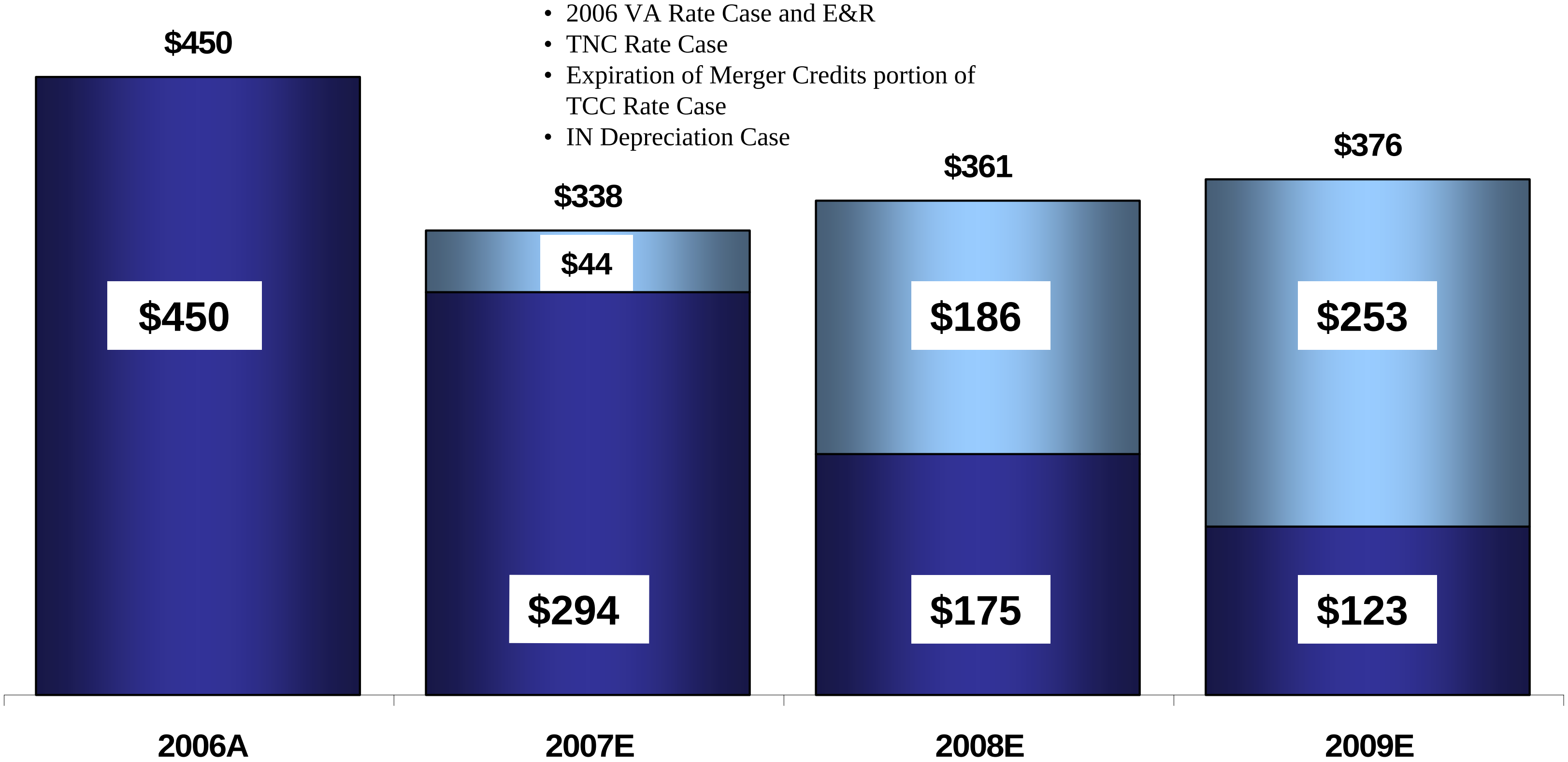
- Other Transmission Projects
  - **Equity percentage of capital structure will target FERC precedents**
  - **Equity ownership percentage will vary by project**
  - **Will seek FERC transmission incentives:**
    - **Incentive ROE**
    - **Return on CWIP**
    - **Abandonment recovery**
    - **Expensing pre-construction expenses**

Incremental Rate Relief Composition

$ Millions

Secured
- OH RSP
- 2006 WV Rate Case, including ENEC
- 2006 Kentucky Rate Case
- FERC & OH OATT
- 2006 VA Rate Case and E&R
- TNC Rate Case
- Expiration of Merger Credits portion of TCC Rate Case
- IN Depreciation Case

Pending/Future
- PSO Rate Case - $49.6 increase requested
- TCC Rate Case - $49.9 increase requested
- SWEPCo proceedings
- Cases yet to be filed



Rate Relief Is A Critical Element To AEP's Financial Success

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Page 486 of 9556

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓$54.8 million covers increased costs related to coal and purchased power
  - ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

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In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings - Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

KPSC Case No. 2011-00401
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Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
August 2007	Final order expected

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule is subject to IURC approval.

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Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- No procedural schedule has been set but Virginia legislation requires a decision within nine months.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for PSO's Used and Useful Determination and OG&E's cost recovery were held July 9-31, 2007.
- We await an ALJ report in August 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings will begin August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for September 27-28, 2007.

AEP®

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	**Senior Unsecured**	**Business Profile**	**Senior Unsecured**	**Senior Unsecured**
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

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We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

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Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

AEP®

Capital Investment Is Funded By Cash From Operations And Debt Issuances

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

AEP®

AEP AMERICAN® ELECTRIC POWER

Fixed Income Meetings
Philadelphia, PA
August 17, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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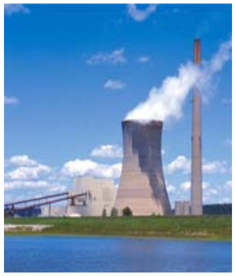
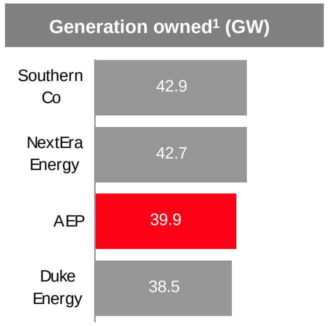
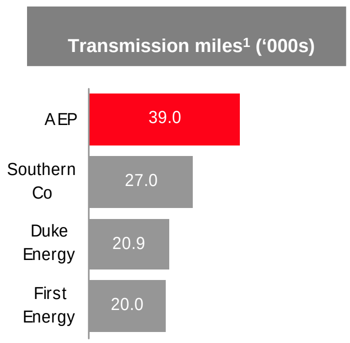
American Electric Power



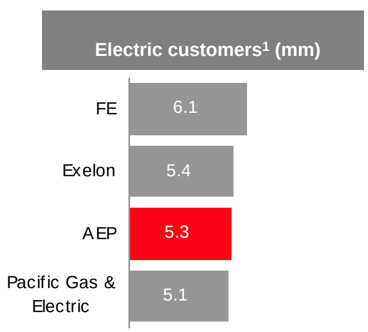
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

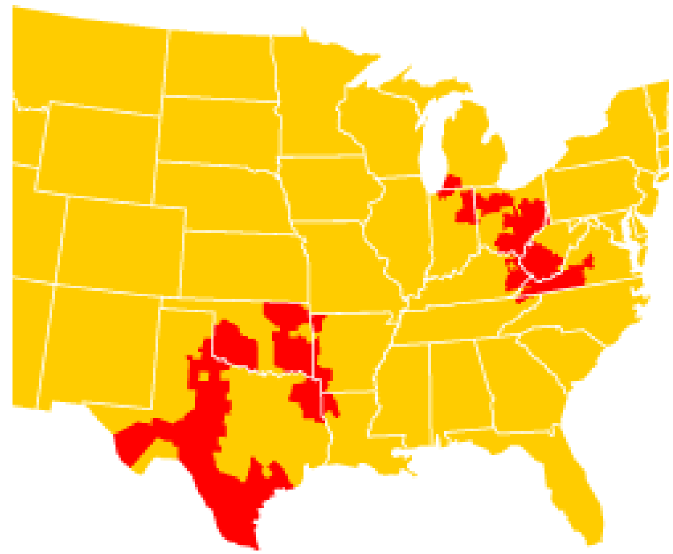


One of the largest U.S. electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

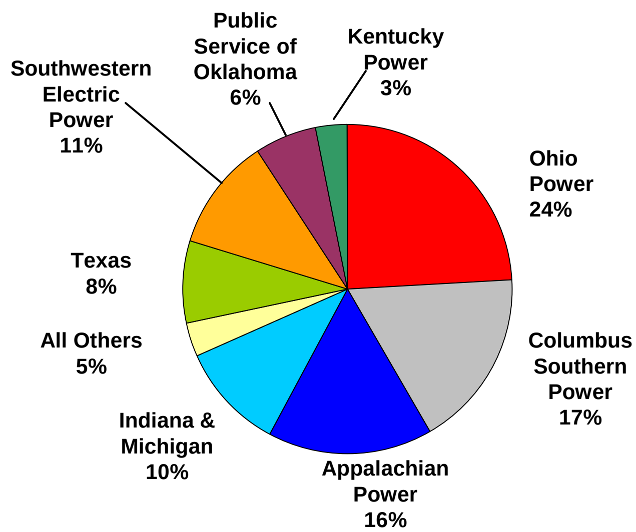
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.2B Market Capitalization
BBB/Baa2/BBB credit rating

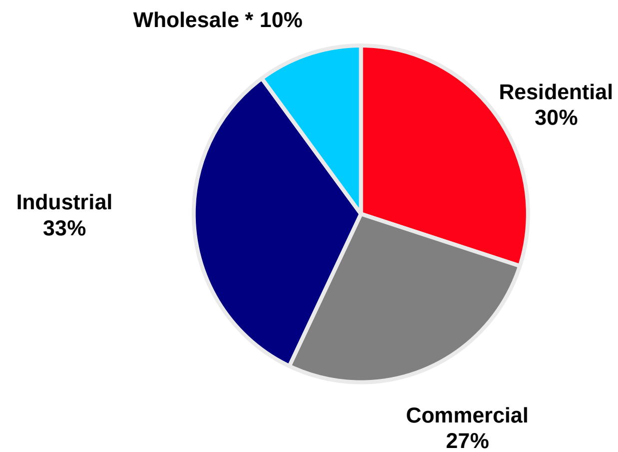
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load

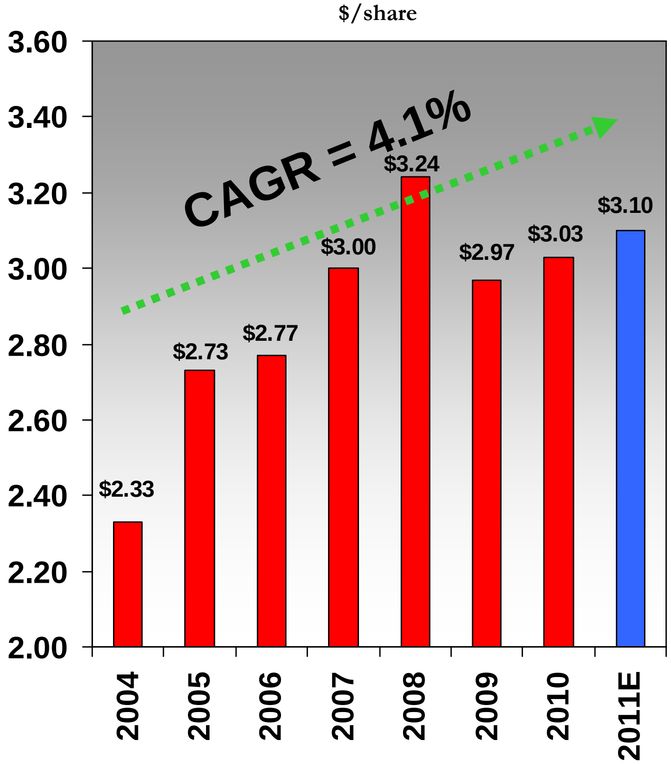


* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

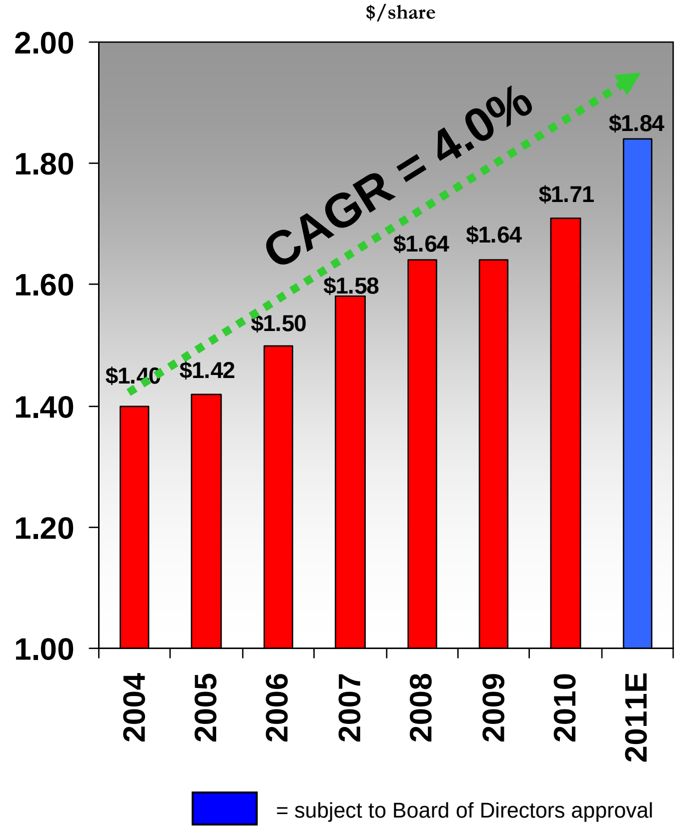
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004



- Quarterly dividend increased 12% in 2010
- 405th consecutive quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield over 5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

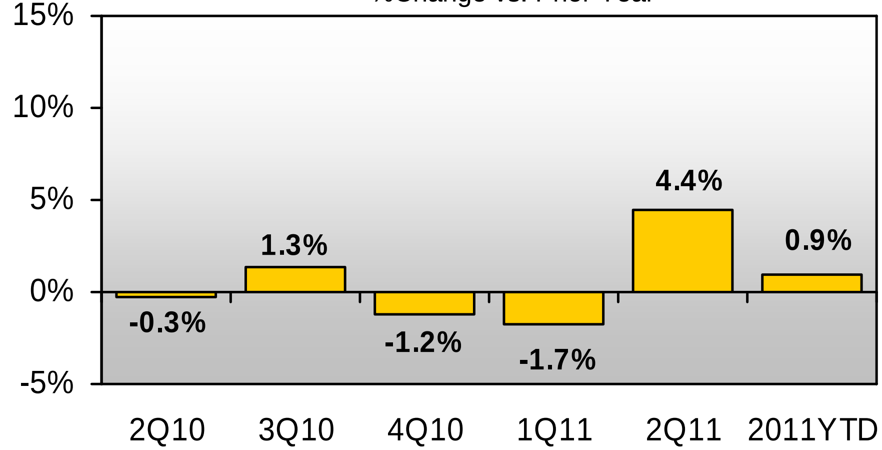
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

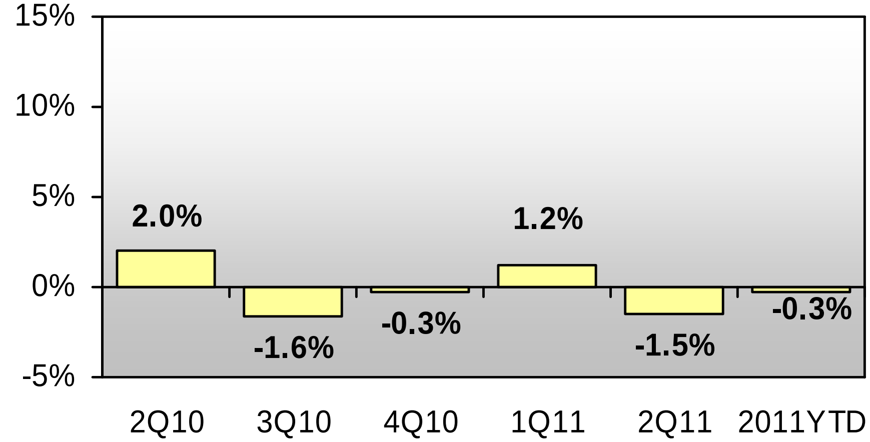
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

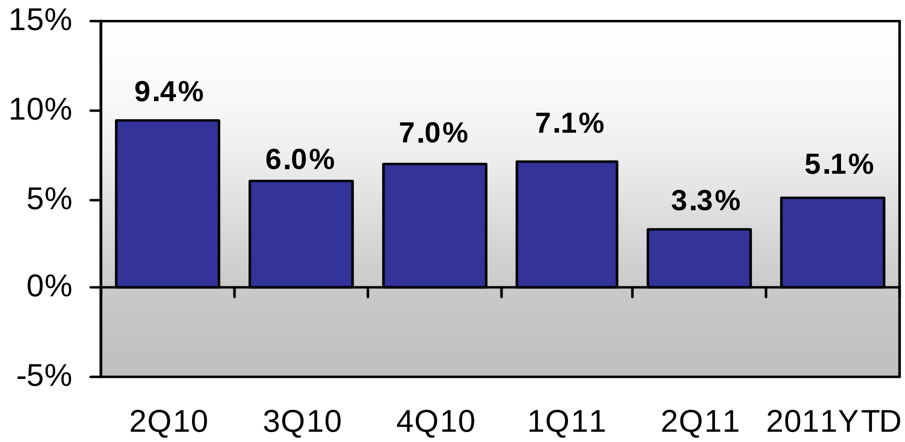
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



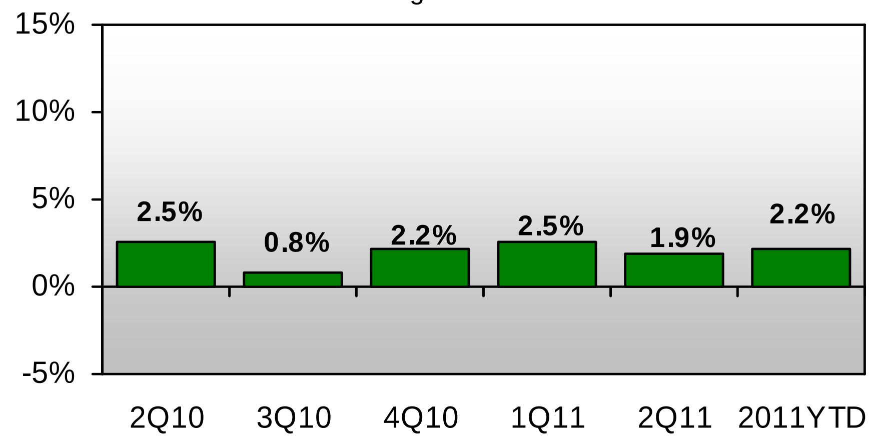
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



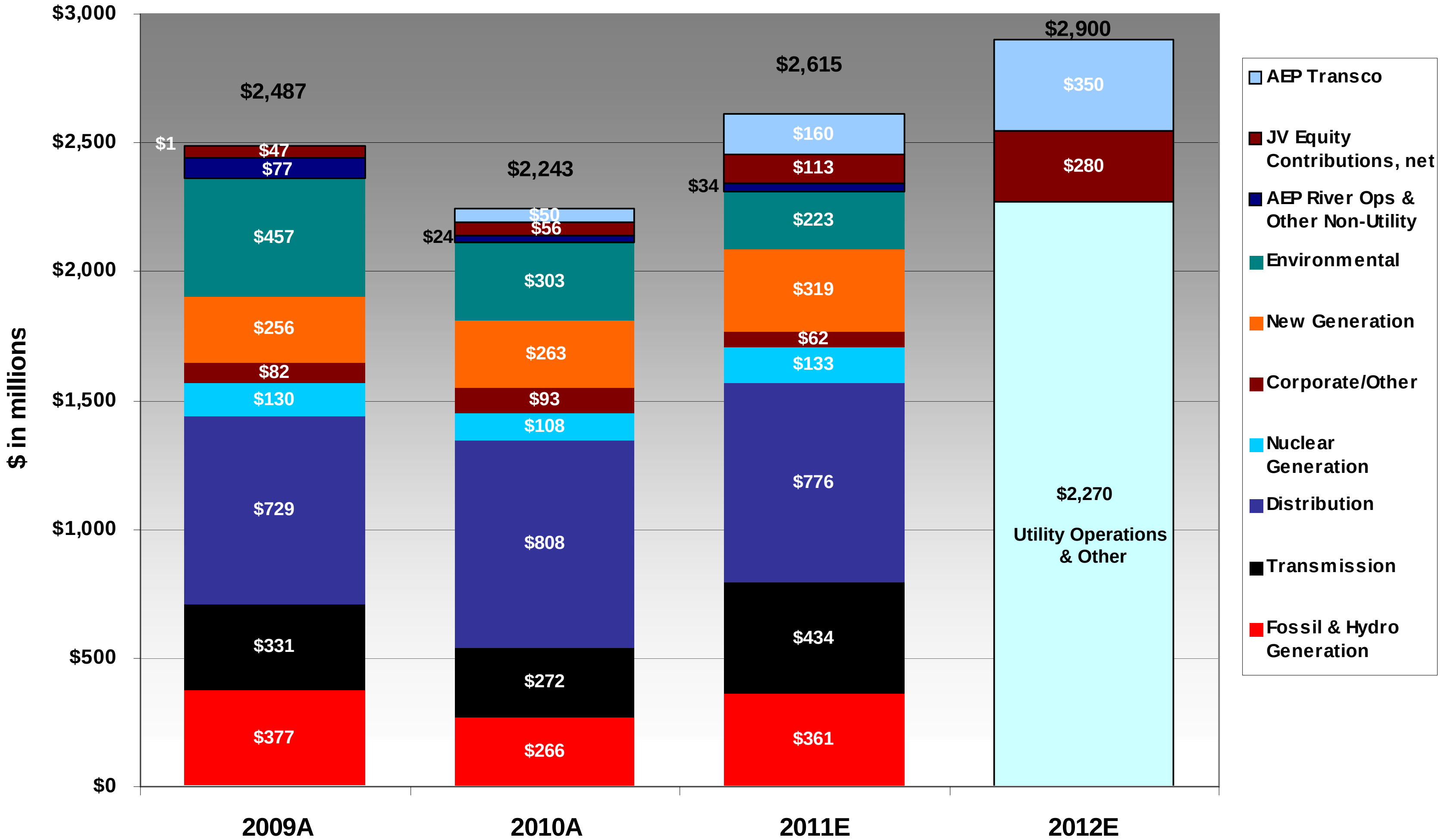
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

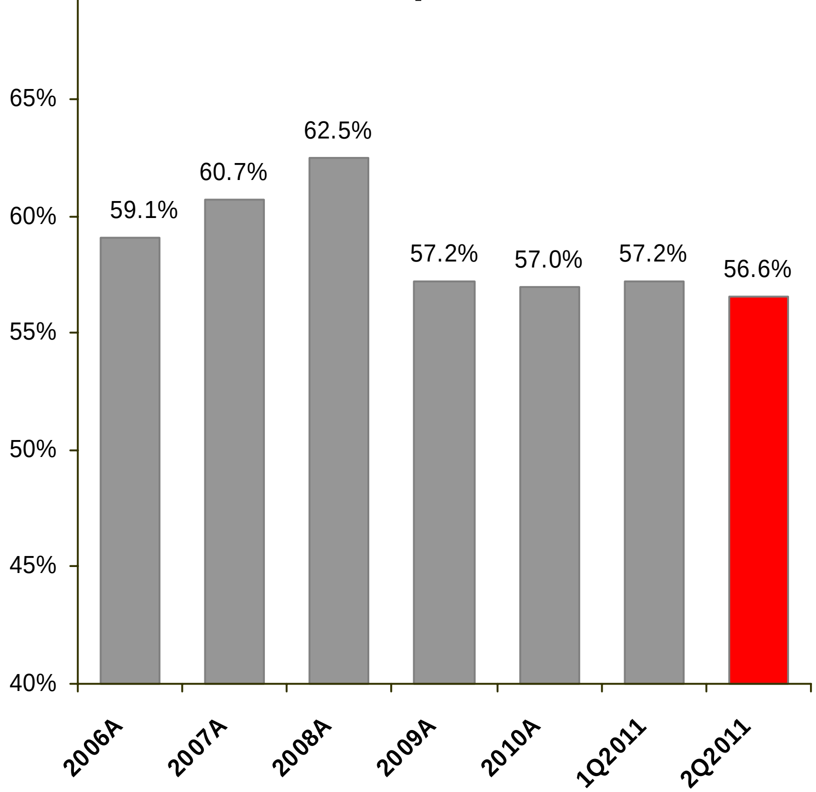
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

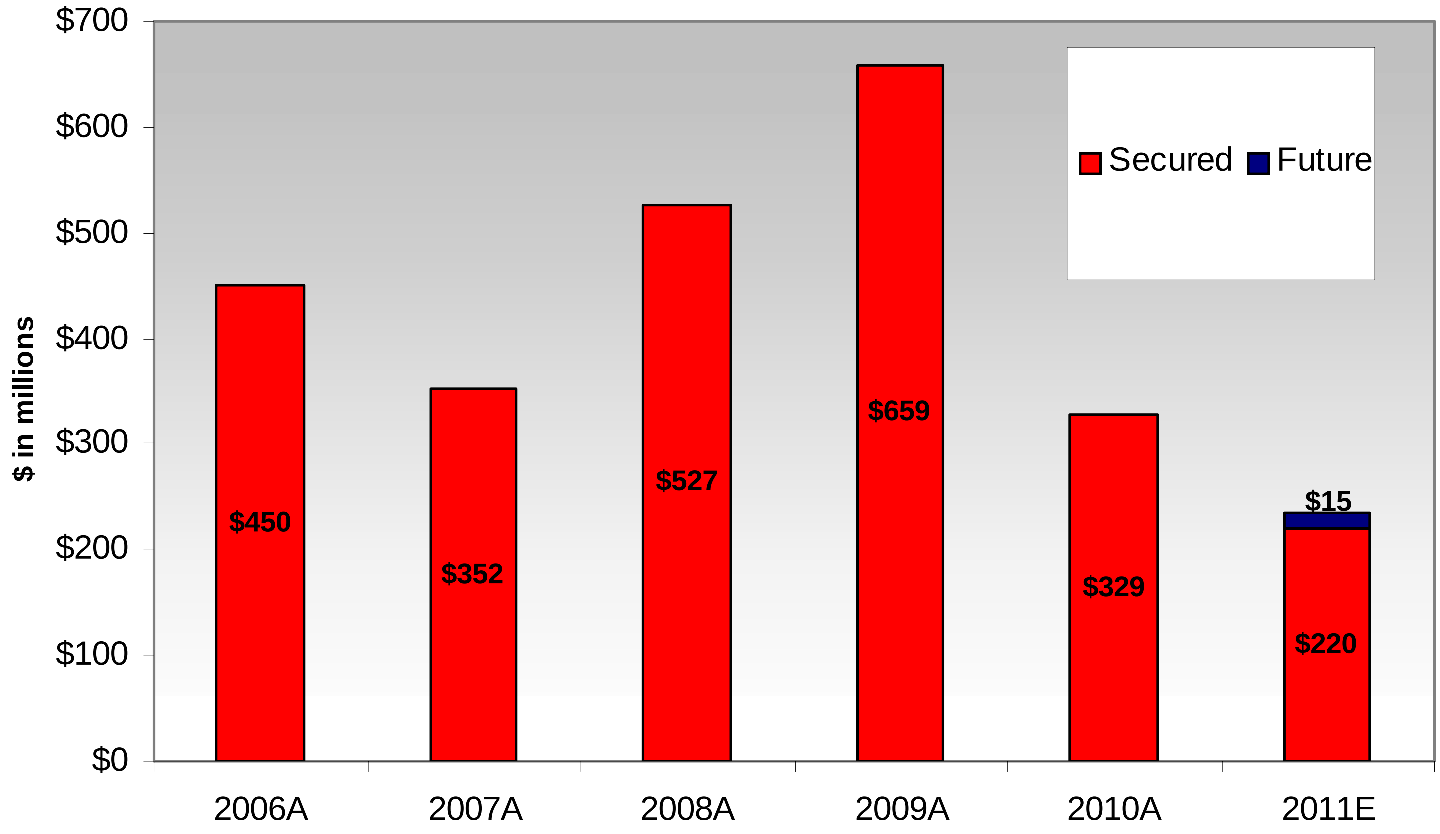
Liquidity Summary (unaudited)		Actual	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	**Cost Rate**	**Weighted Return**
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	**Cost Rate**	**Weighted Return**
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Summary Rate Case Information

AEP®

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase). (Docket #:) A procedural schedule is pending from the VSCC.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed . APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 25; Staff testimony – August 4; Hearing – August 29**

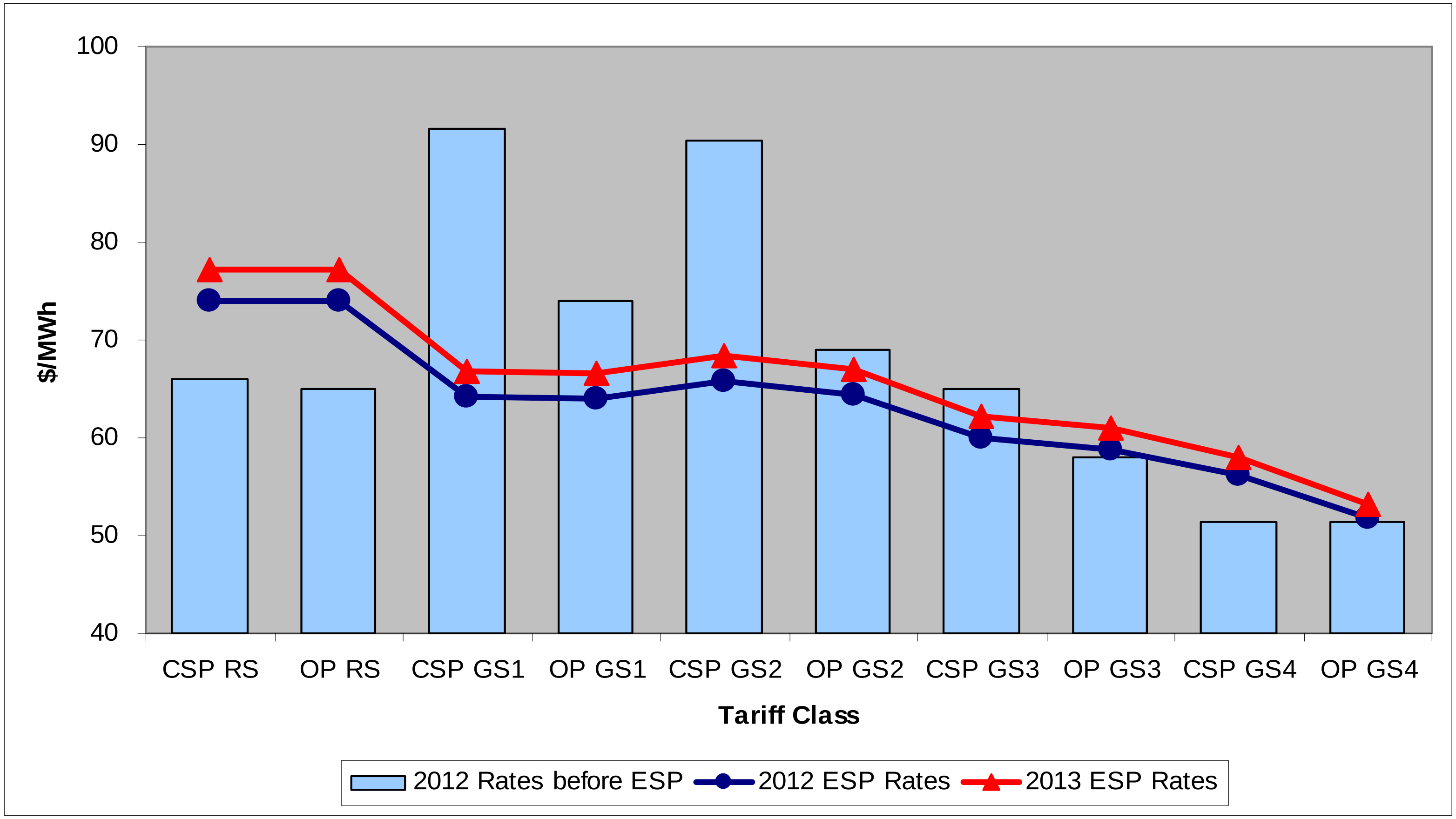
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

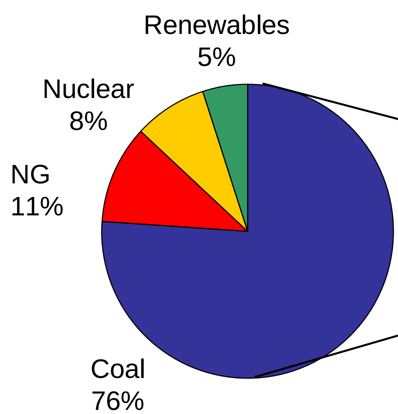
List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

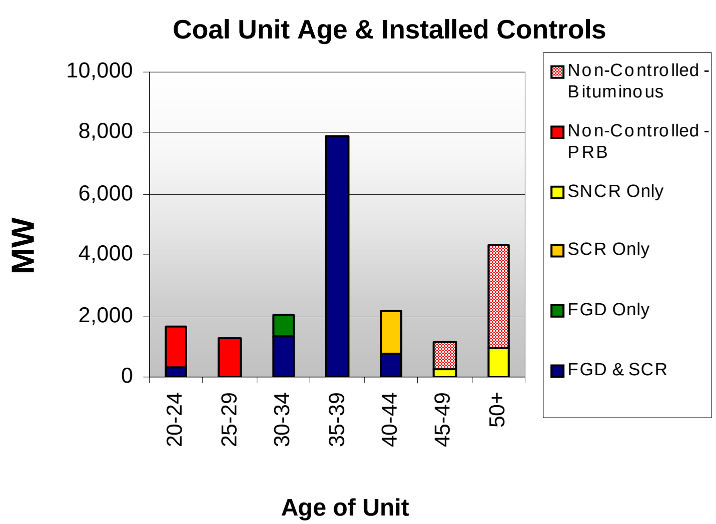


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

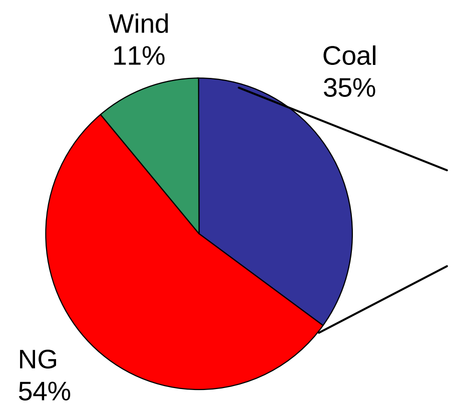
Avg. Delivered Cost

2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

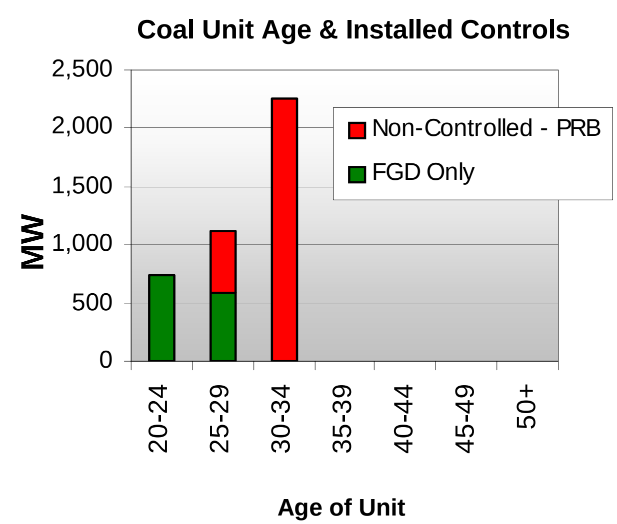


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 522 of 9556

Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

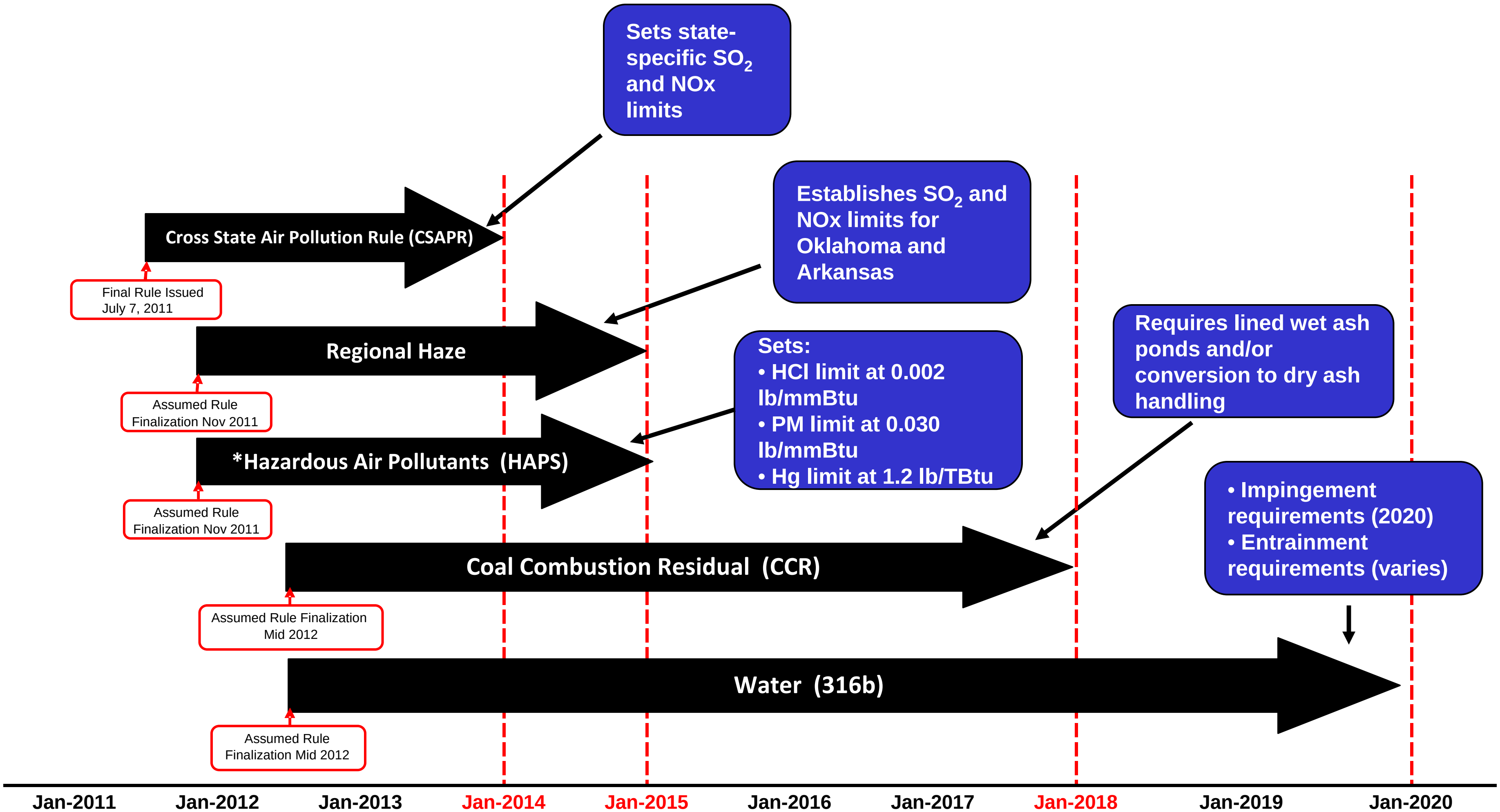
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP’s share approximately $1.4 billion (excluding AFUDC) and will begin commercial operation in 4Q2012.

- $1.2 billion capitalized expenditures through 6/30/11. SWEPCO’s contractual commitments $157MM.

Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5	510	Refuel with Natural Gas			
	Gavin 1	1320	FGD upgrade			
	Gavin 2	1320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	*
APCO	Clinch River 1	211	Refuel with Natural Gas			
	Clinch River 2	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	**
I&M	Rockport 1	1320	FGD, SCR			
	Rockport 2	1320	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670**	***
KPCO	Big Sandy 1	640	New Natural Gas			
	Total MW	**640**	**Total Expected Cost**		**525**	

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

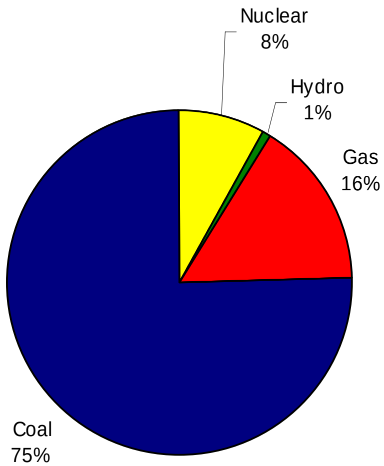
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

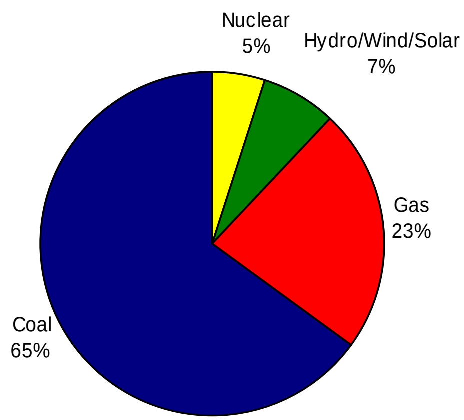
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

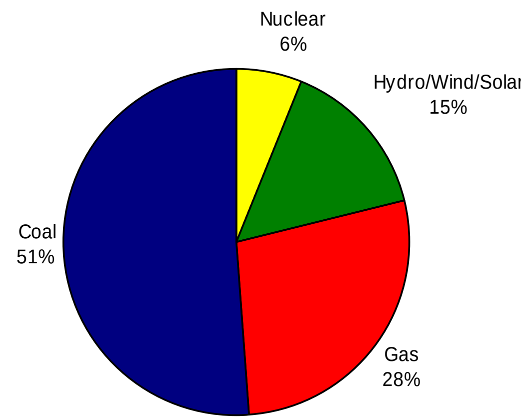
1990 AEP Generating Capacity by Fuel
37,428 total MW's



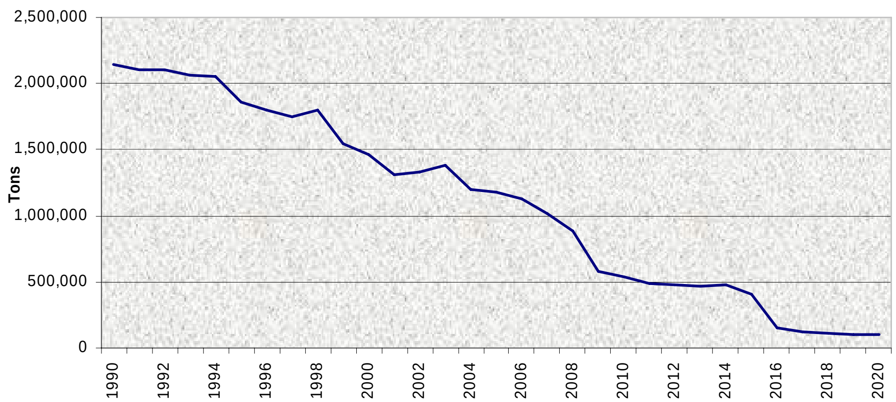
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons

- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

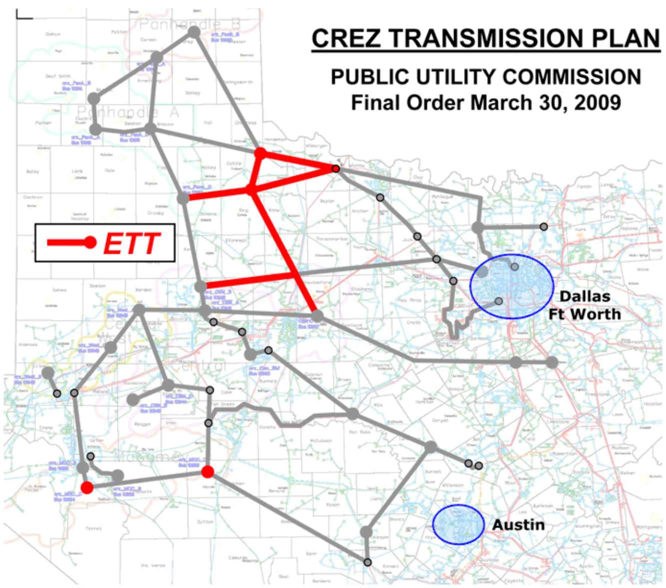
Growing Rate Base:

Current rate base is $412 million; expected to grow as follows:

2011: $482 million
2012: $778 million
2013: $1,352 million

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

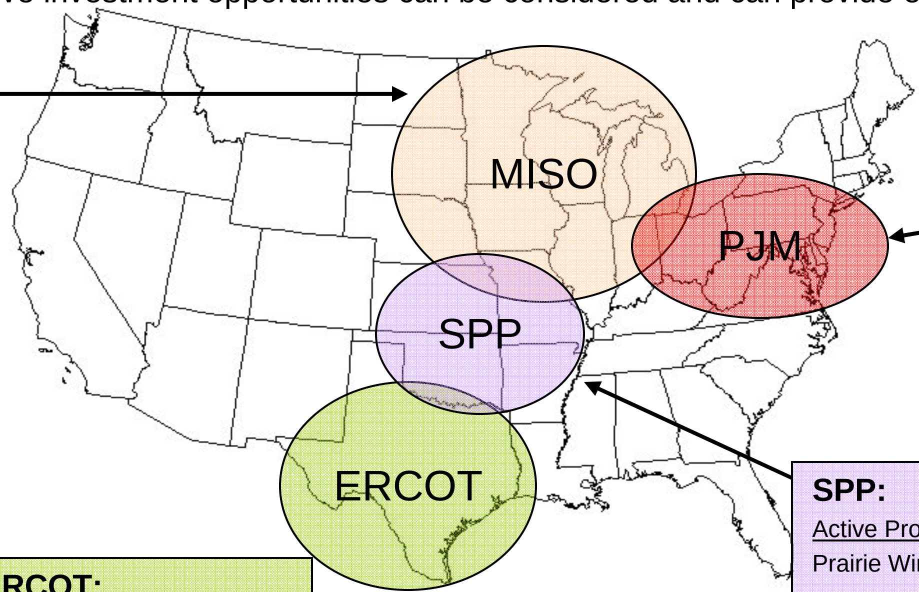
- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

American Electric Power Company, Inc.

Duquesne Capital Management

Highbridge Capital Management

September 18, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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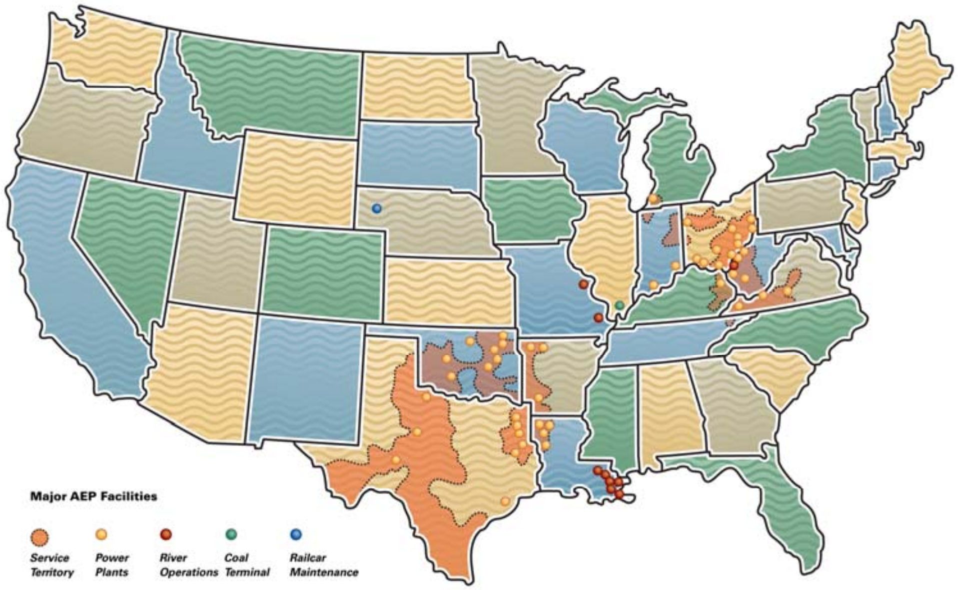
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

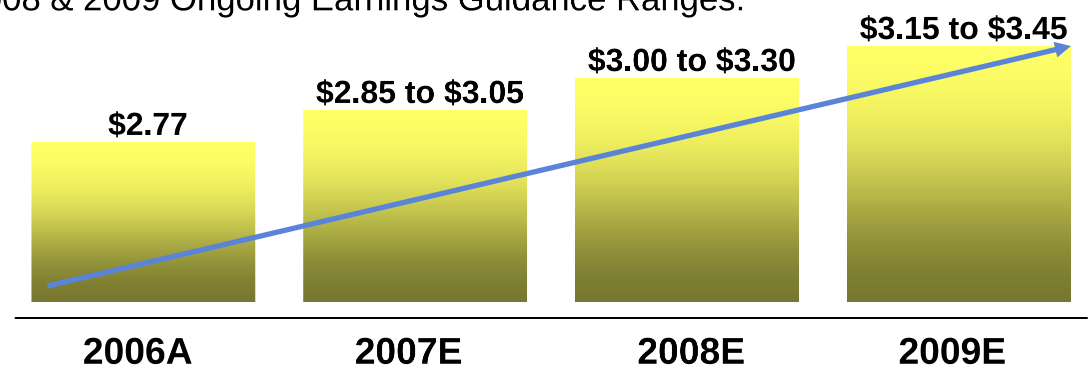
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

6

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden	$85
2007 Including Lawrenceburg	**$3,952**

Note: Excludes AFUDC and previously announced CO_2 and transmission projects

*Includes Lawrenceburg and Dresden purchases in 2007

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Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

Environmental Investment

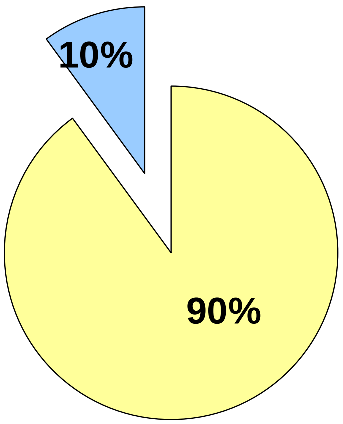
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2009
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☐	Delayed
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5 & 6	750		N/A	☑	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Pullman Power – Stack Supplier
- Babcock Power – SCR
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

First-Mover Advantage:

- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- AEP capital costs for a scrubber average approximately $250/kW
- We have since seen a 30-60% increase in material costs and a 15% increase in labor rates
- An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

AEP Customers and Shareholders Benefit From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

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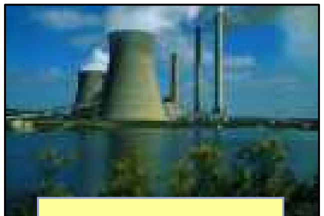
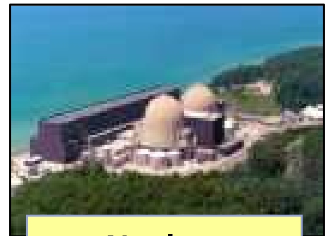
Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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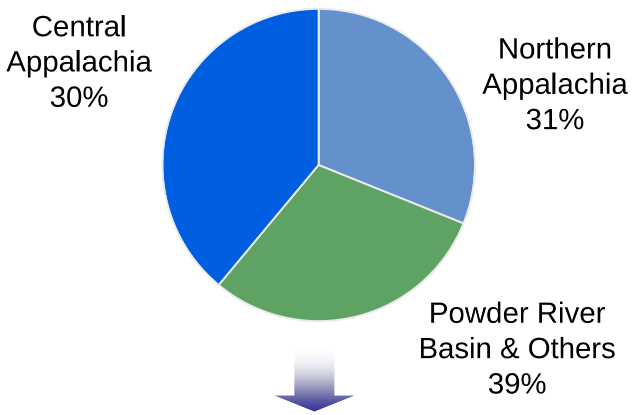
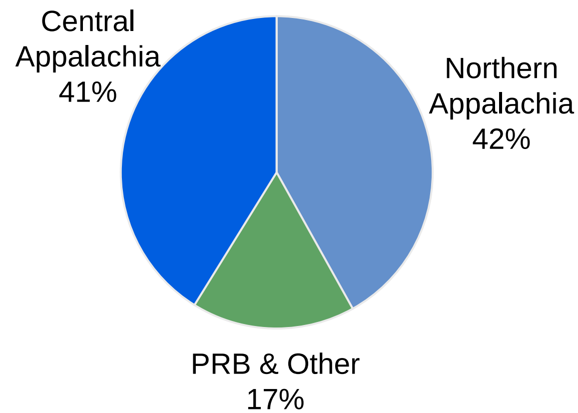
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

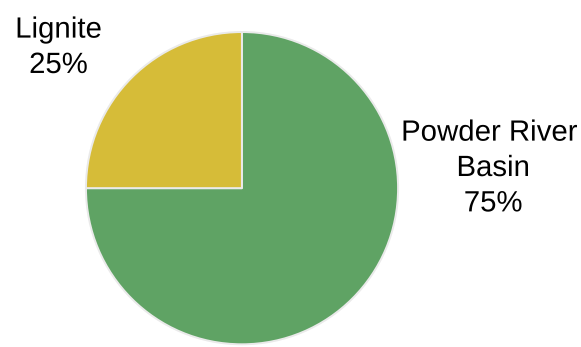
Total AEP System



AEP East



AEP West



Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

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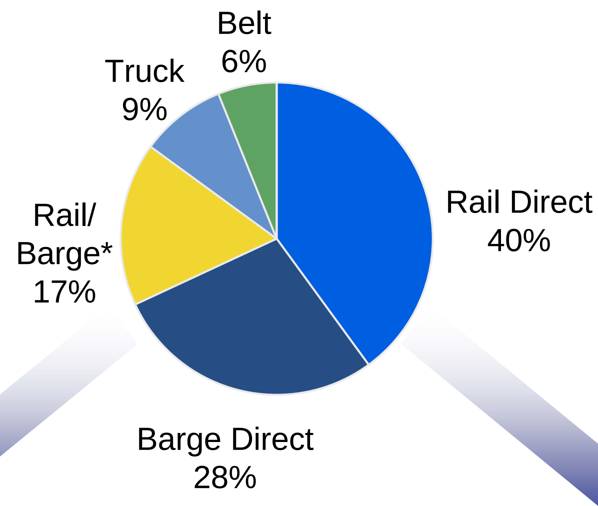
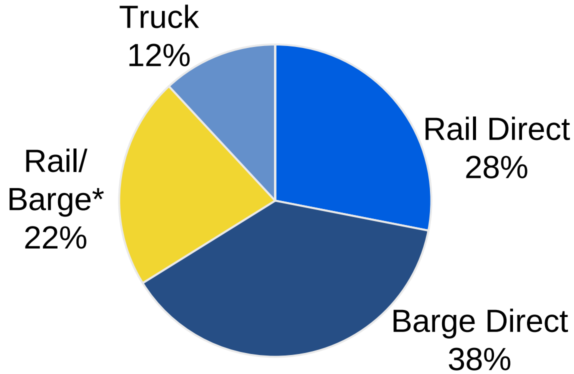
Coal Delivery

2006 Actual

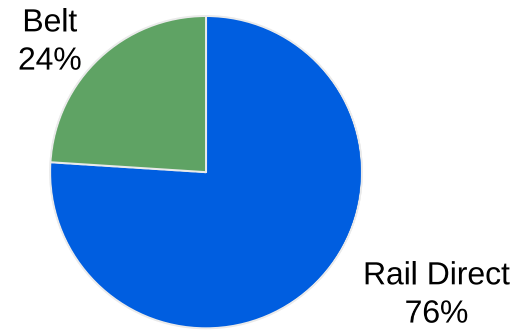
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

- –821 MW combined-cycle gas plant
- –$220MM purchase price
- –Columbus Southern Power completed purchase on September 28, 2005
- –$268/kW

Lawrenceburg

- –1140 MW combined-cycle gas plant
- –$325MM purchase price
- –AEG completed purchase on May 16, 2007
- –$295/kW

2,946 MW of gas-fired generation added since 2005

Darby

- –480 MW simple-cycle gas plant
- –$102MM purchase price
- –Columbus Southern Power completed purchase on April 25, 2007
- –$227/kW

Ceredo

- –505 MW simple-cycle gas plant
- –$100MM purchase price
- –APCo completed purchase on December 15, 2005
- –$198/kW

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Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

3

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis.
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

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New Ultra-Supercritical Coal Facility

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected in the fourth quarter of 2007
- Air permit approval expected in Fall 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings commenced September 11, 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - West Virginia filing made in June 2007 – included request for cash recovery mechanism
  - Virginia filing made in July 2007 requesting cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- New Technology Generation – IGCC and USC
- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

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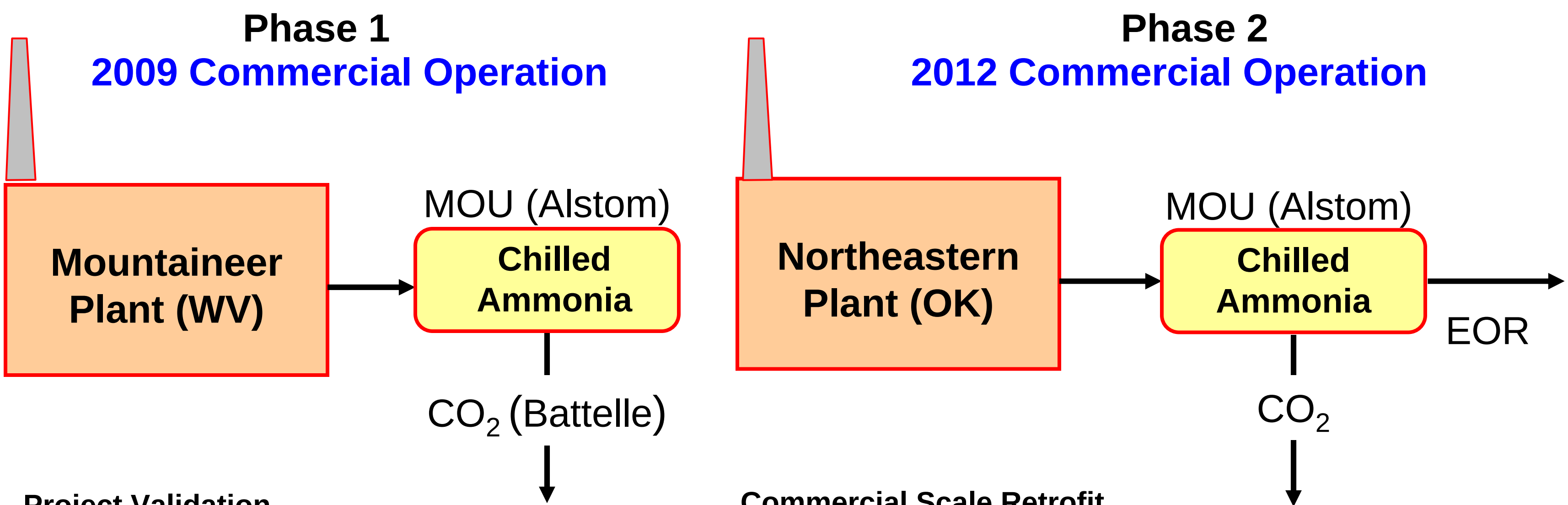
Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom “Chilled Ammonia” Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP’s Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

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Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

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Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities
~ $3 Billion I-765™ Project in PJM
~ $2.6 Billion 765-kV Project in Michigan with ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

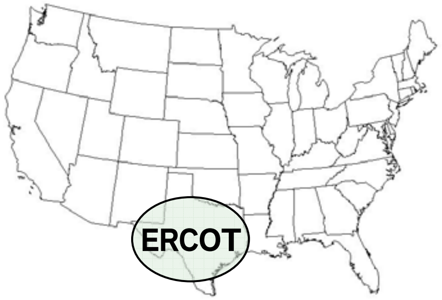
2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Building the next US interstate system for enhanced reliability and market efficiency.

Electric Transmission Texas (ETT) Status Update

ETT: Delivering power for Texas' future

- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP.
  - Investment opportunities can be offered by either partner.



- *Transaction Status*
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in October 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

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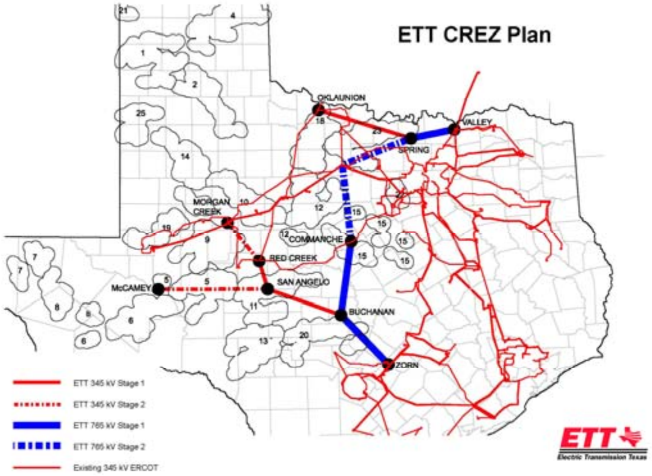
CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - $1.5 billion investment Phase 1 – 2012*
  - $1.5 billion investment Phase 2 – 2015*

  * Before ownership division.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

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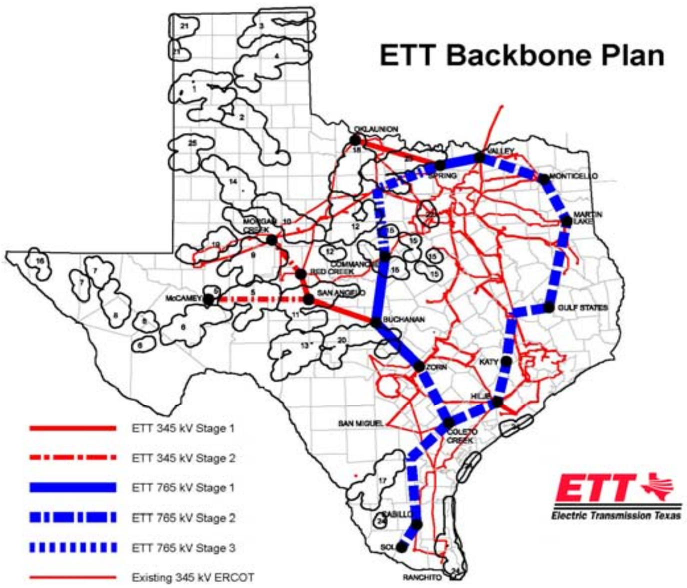
CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).



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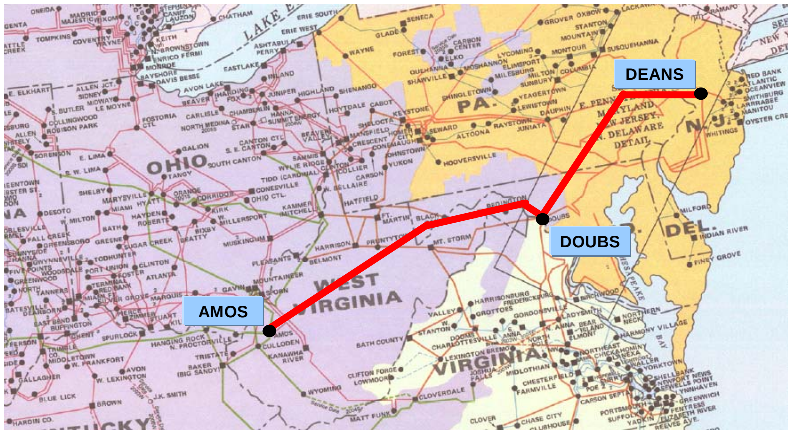
PJM I-765™ Original Proposal

Execution in Action

- *Overview*
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM approved)
  - FERC declaratory order approved July 2006
- *Benefits*
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation



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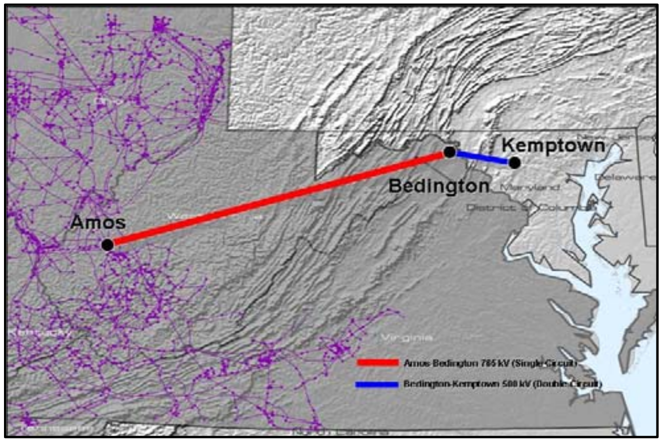
PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture (Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries) to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share control of Amos – Bedington line and contribute equally to this portion of the project
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - I-765™ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor (draft) issued in April 2007
- *Key Regulatory Activity Completed*
  - PJM approved plan June 2007
- *Key Next Steps*
  - PATH to Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



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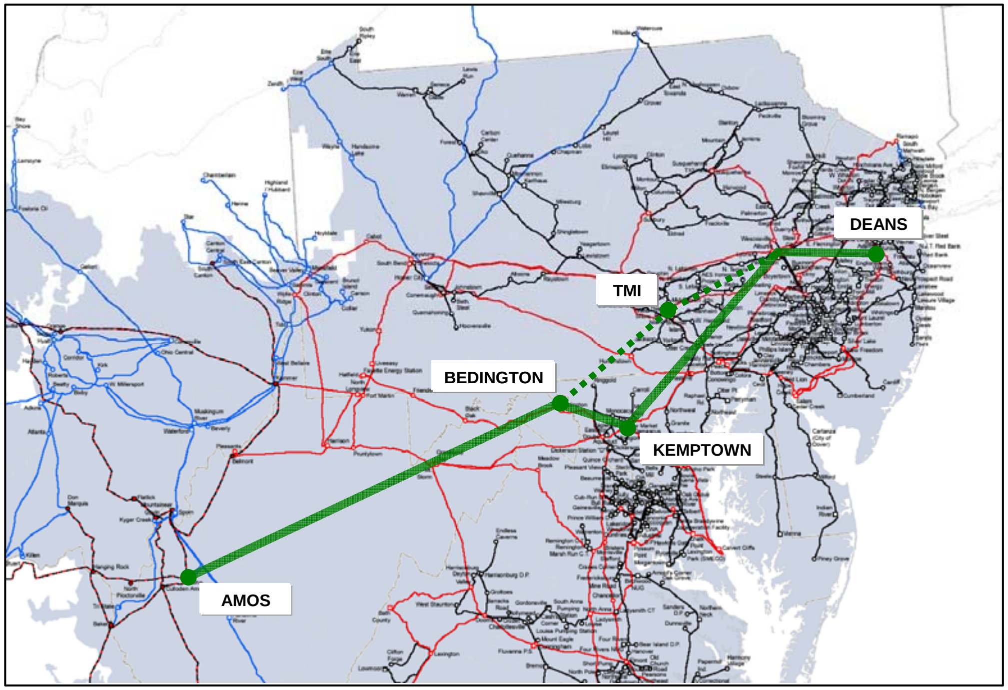
PJM I-765™

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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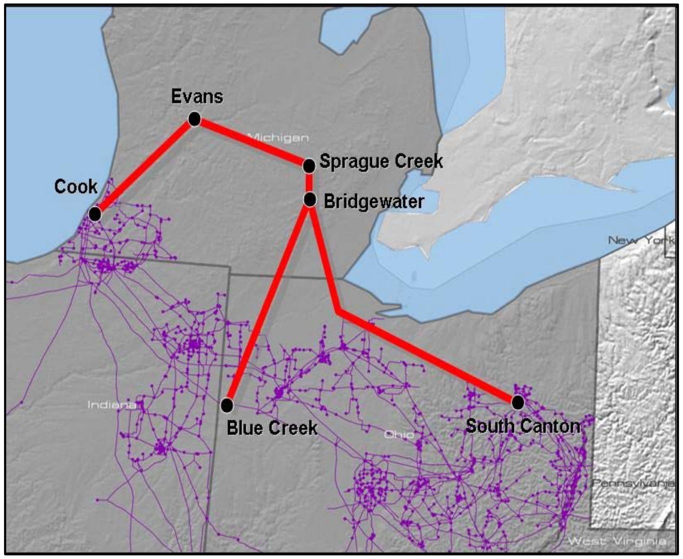
Michigan I-765™

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - PJM/MISO notified of results of technical study- Summer 2007
  - Public release of study- September 2007
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - JV formation – 2007
  - MISO and PJM review/approval – Winter 2008
  - FERC Filing - Fall 2008
  - Siting approval – Fall 2010
  - Estimated completion – Fall 2015



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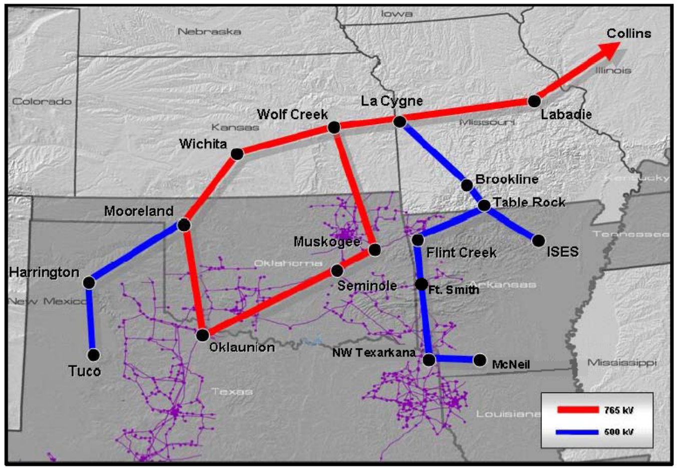
SPP I-765™

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
- *Benefits*
  - 4000 MW improved transfer capability
- *Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017



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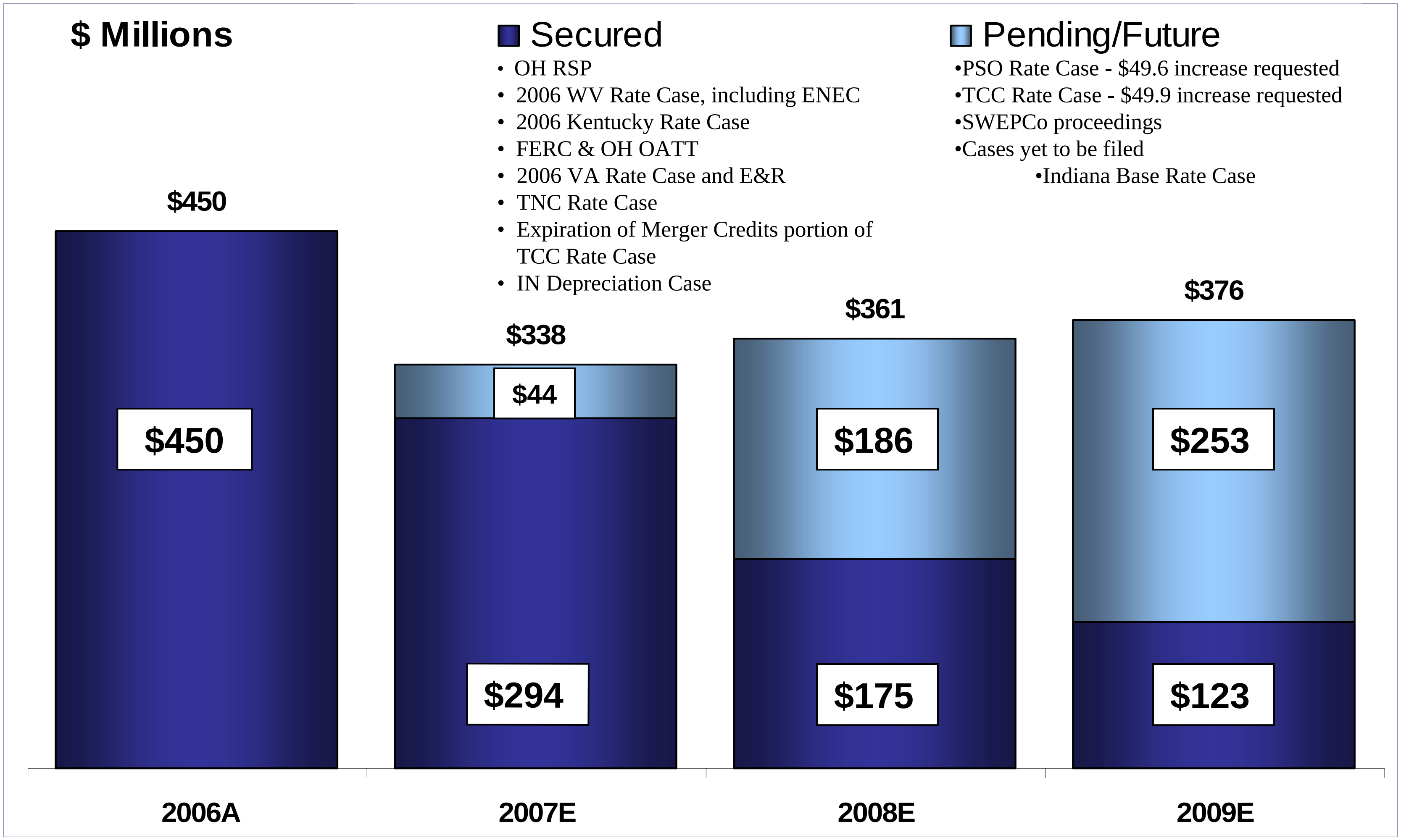
Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

2007 Regulatory Activity Completed

Appalachian Power - Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power - West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓ $54.8 million covers increased costs related to coal and purchased power
  - ✓ $28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓ Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power - Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings – Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

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Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
September 2007	Final order expected

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.

Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the 4th quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff , which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings commenced August 20, 2007. Decision expected by year end.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected by year end.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for October 17, 2007. Decision expected by year end.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

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Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital Investment Is Funded By Cash From Operations And Debt Issuances

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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American Electric Power Company, Inc.

Lehman Ohio Tour

September 21, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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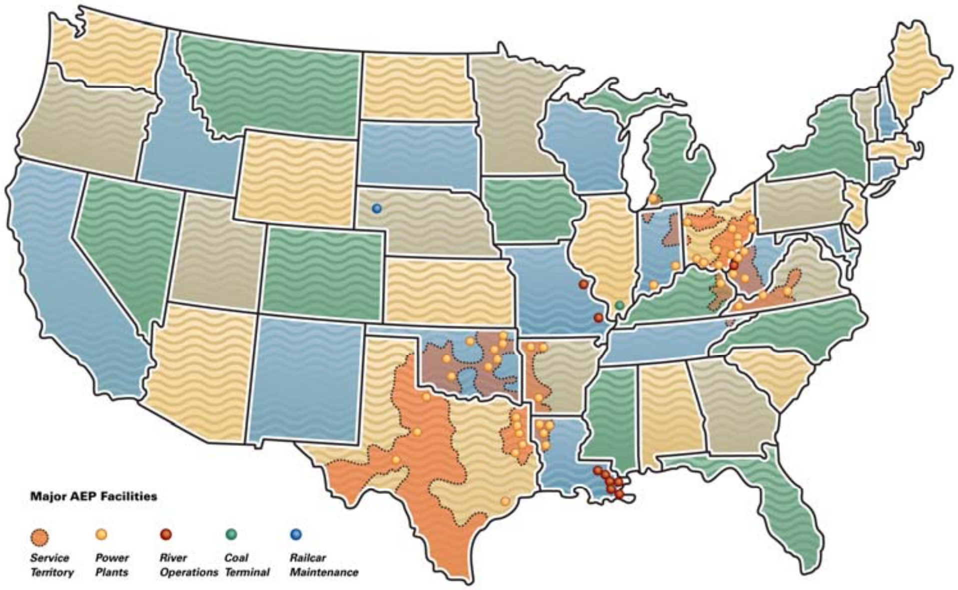
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 582 of 9556

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

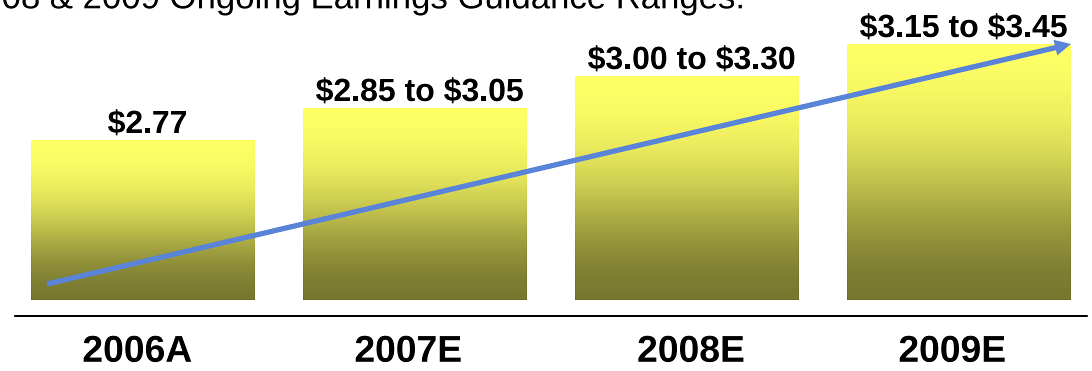
Deliver value to investors and cost effective service to our customers

AEP®

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

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Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden	$85
2007 Including Lawrenceburg	**$3,952**

Note: Excludes AFUDC and previously announced CO_2 and transmission projects

*Includes Lawrenceburg and Dresden purchases in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

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Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
<u>East Plants</u>					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
<u>CCD Plants</u>					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
<u>West Plants</u>					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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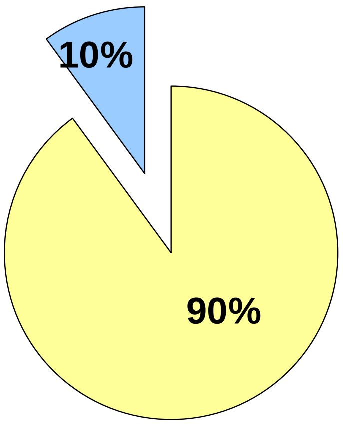
Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Pullman Power – Stack Supplier
- Babcock Power – SCR
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

First-Mover Advantage:

- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- AEP capital costs for a scrubber average approximately $250/kW
- We have since seen a 30-60% increase in material costs and a 15% increase in labor rates
- An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

AEP Customers and Shareholders Benefit From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

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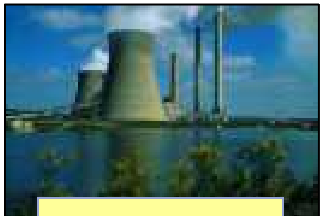
Domestic Generation Fleet

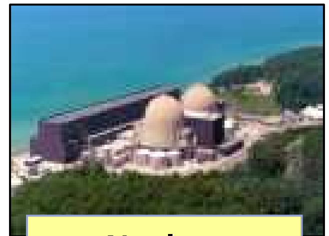


Coal/Lignite

67%

Nat. Gas/Oil

24%



Nuclear

6%

Pumped Storage/ Hydro/Wind

3%

AEP's Generation Fleet

38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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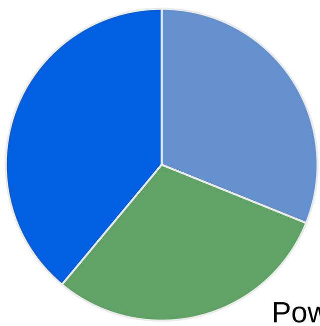
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

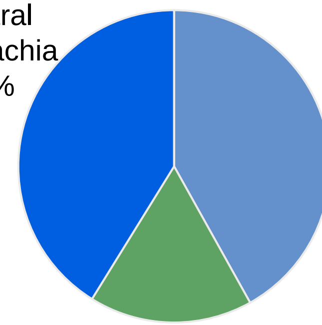
Total AEP System



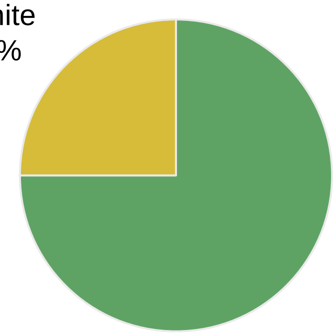
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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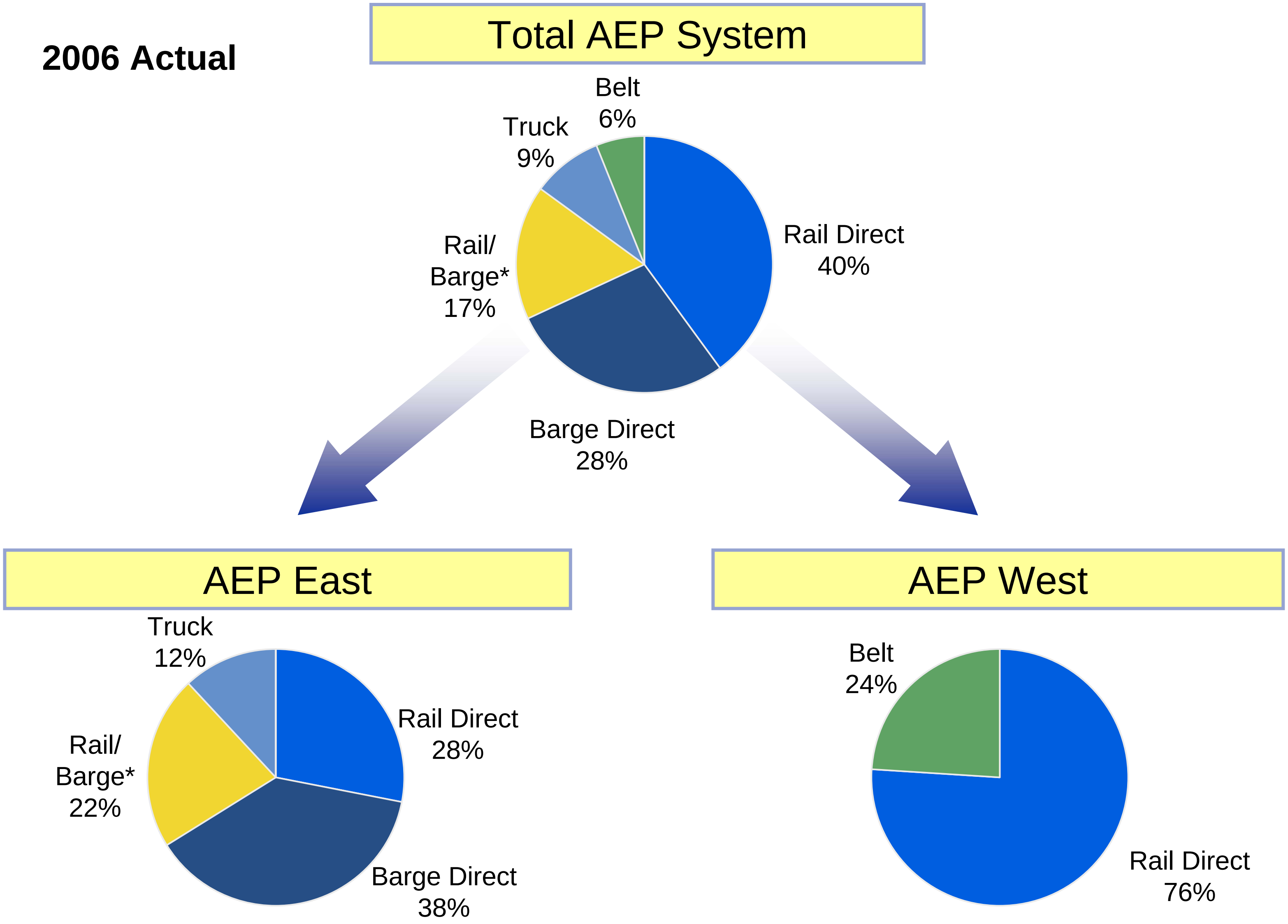
Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on September 28, 2005
- $268/kW

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007
- $295/kW

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007
- $227/kW

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on December 15, 2005
- $198/kW

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Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis.
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facility

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected in the fourth quarter of 2007
- Air permit approval expected in Fall 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings commenced September 11, 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM

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Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - West Virginia filing made in June 2007 – included request for cash recovery mechanism
  - Virginia filing made in July 2007 requesting cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

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Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

7

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

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IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

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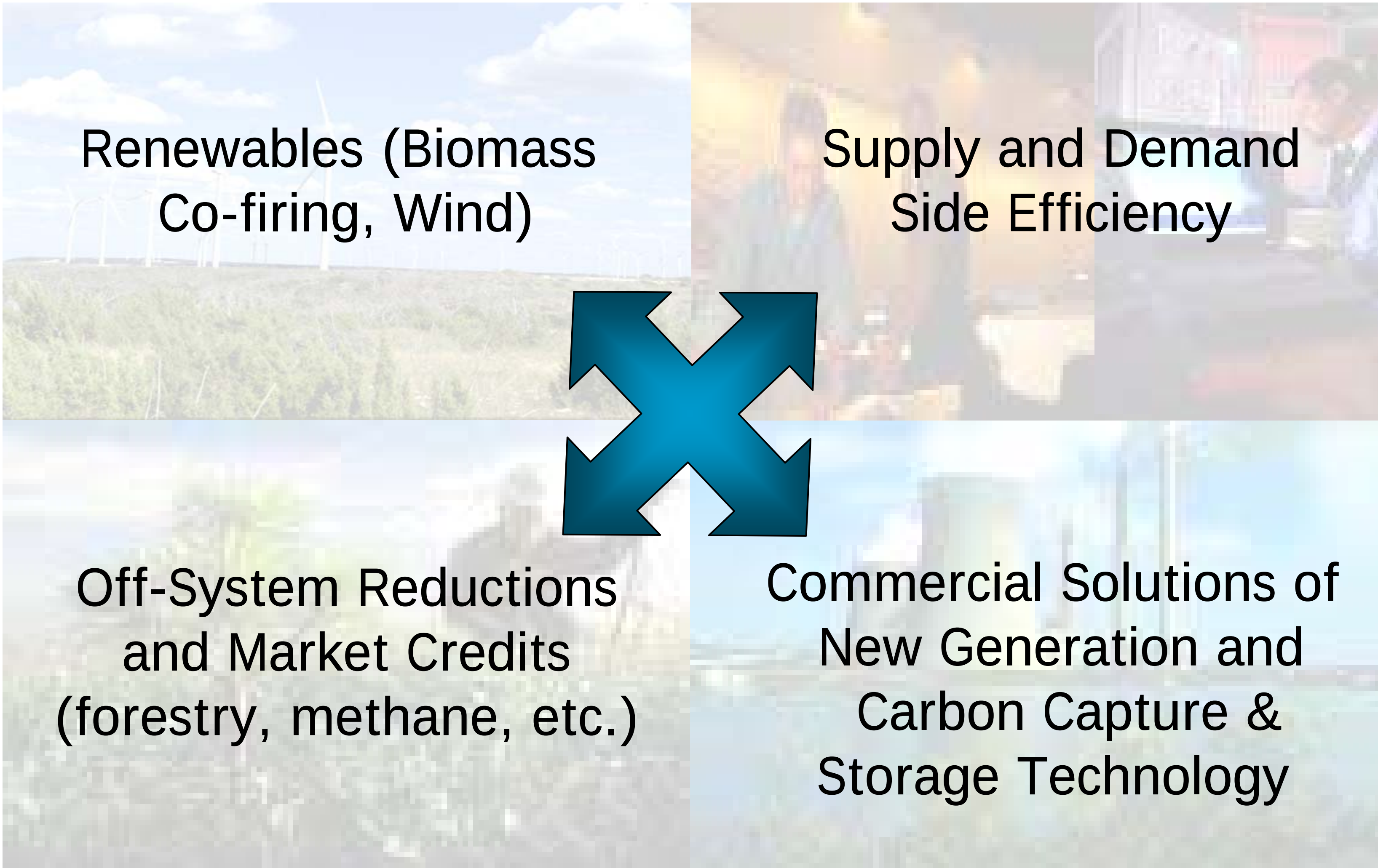
AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- New Technology Generation – IGCC and USC
- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

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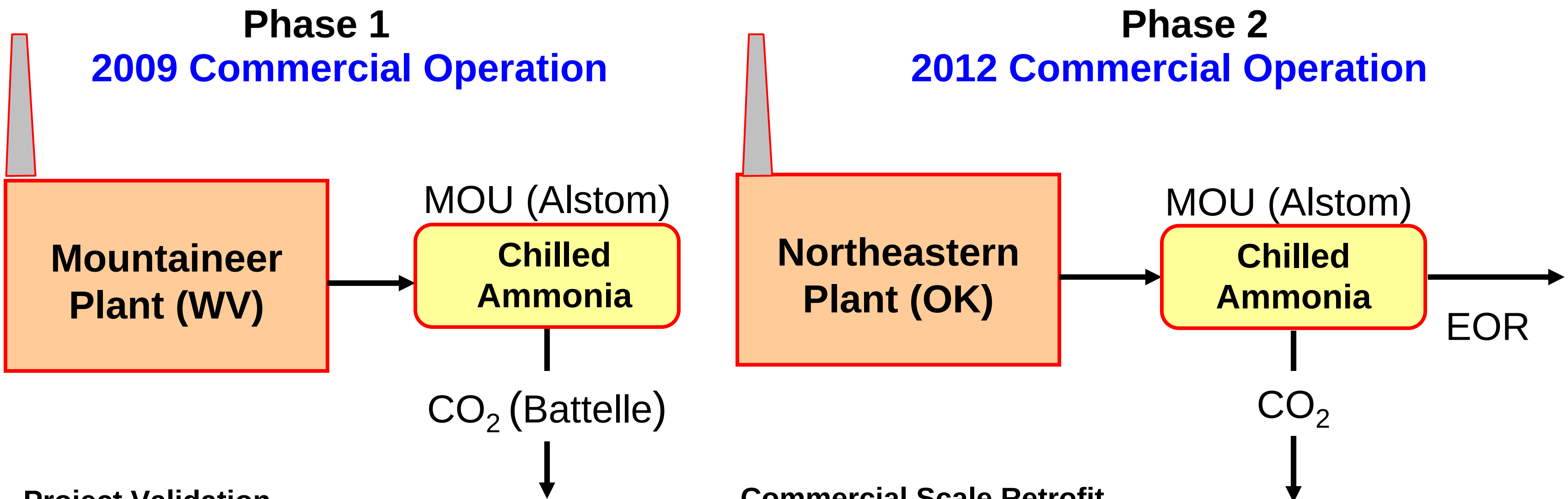
Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom “Chilled Ammonia” Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP’s Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

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Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

- ~ $3 Billion I-765™ Project in PJM
- ~ $2.6 Billion 765-kV Project in Michigan with ITC
- ~ $3 Billion Project filed with SPP
- ~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

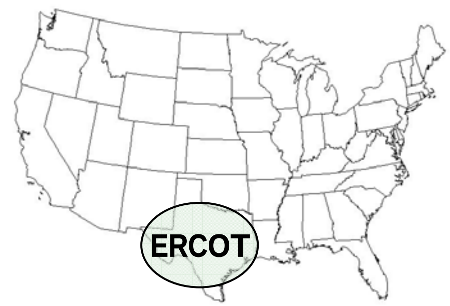
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

Building the next US interstate system for enhanced reliability and market efficiency.

Electric Transmission Texas (ETT) Status Update

ETT: Delivering power for Texas' future

- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP.
  - Investment opportunities can be offered by either partner.



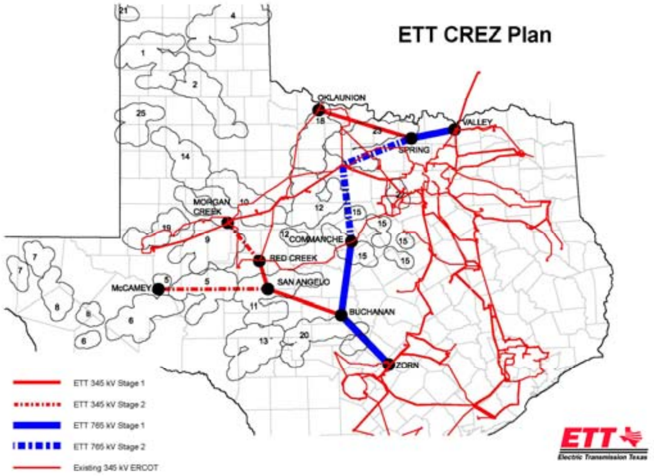
- *Transaction Status*
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in October 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - $1.5 billion investment Phase 1 – 2012*
  - $1.5 billion investment Phase 2 – 2015*

  * Before ownership division.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

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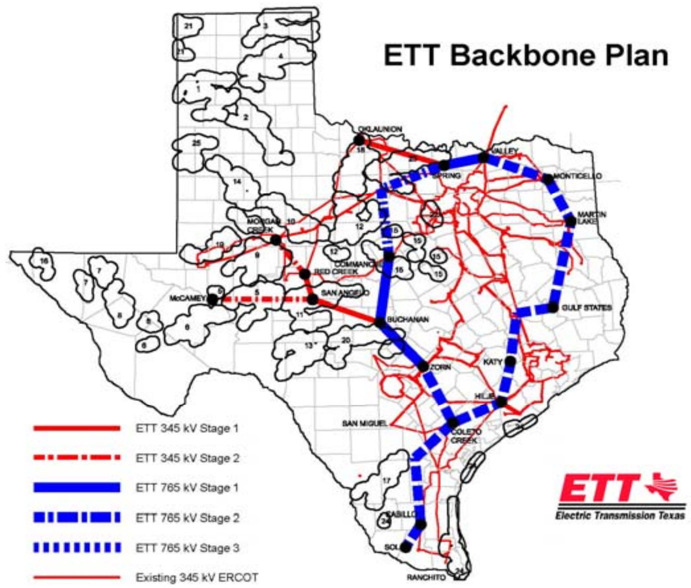
CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).



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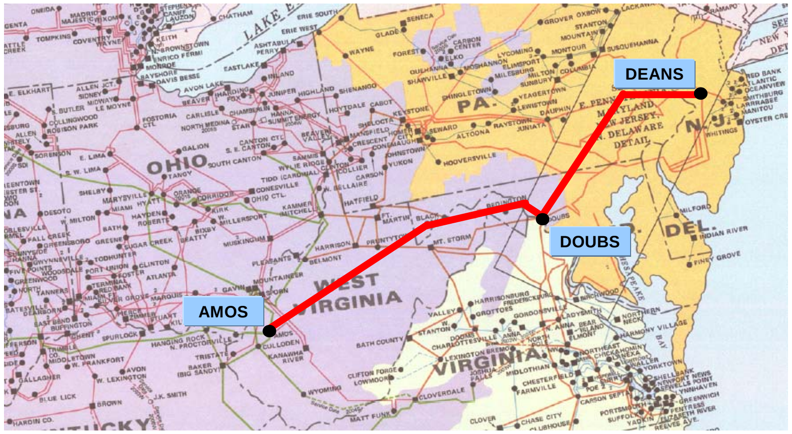
PJM I-765™ Original Proposal

Execution in Action

- *Overview*
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM approved)
  - FERC declaratory order approved July 2006
- *Benefits*
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation



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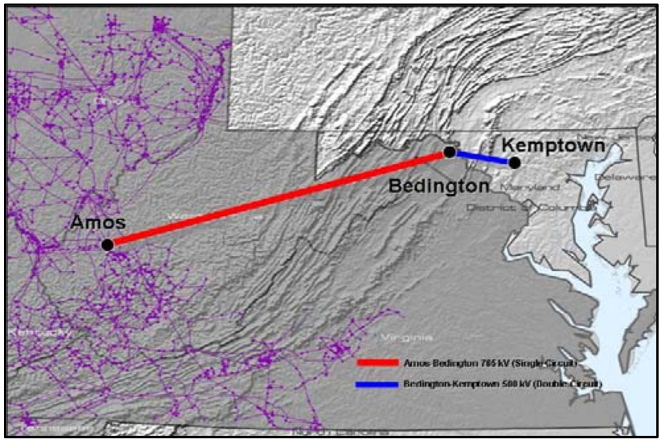
PATH

Execution in Action

- ### *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture (Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries) to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
- ### *Funding Plans/Transaction Structure*
  - AEP and Allegheny share control of Amos – Bedington line and contribute equally to this portion of the project
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - I-765™ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor (draft) issued in April 2007
- ### *Key Regulatory Activity Completed*
  - PJM approved plan June 2007
- ### *Key Next Steps*
  - PATH to Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



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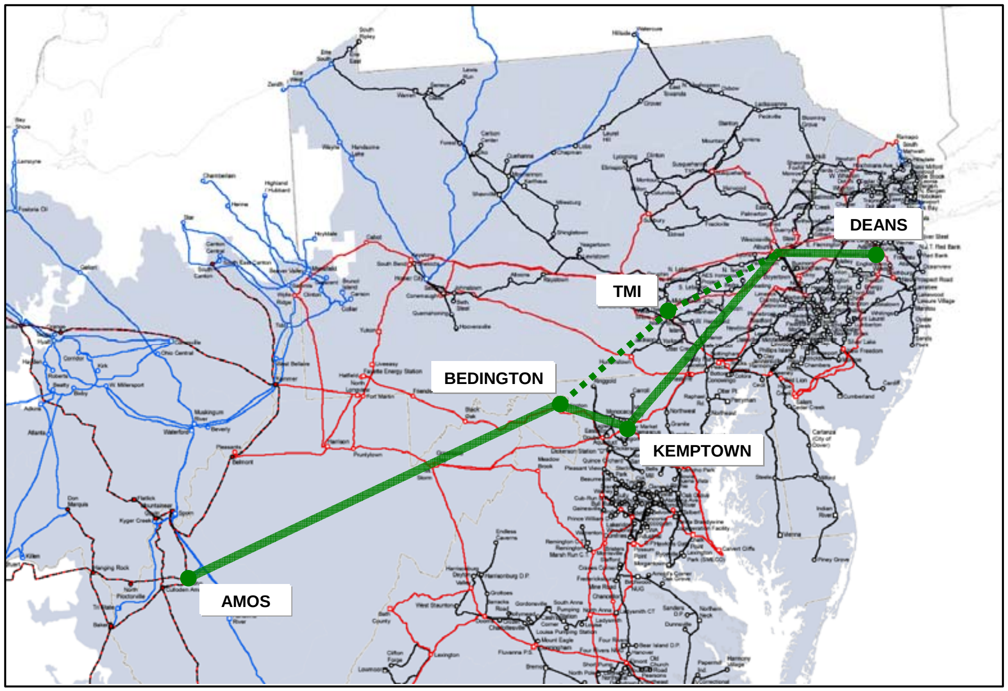
AEP®

PJM I-765™

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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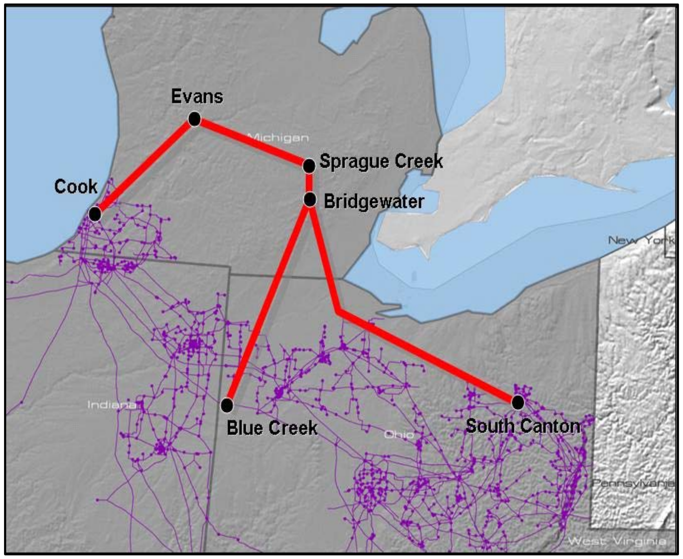
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 611 of 9556

Michigan I-765™

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - PJM/MISO notified of results of technical study- Summer 2007
  - Public release of study- September 2007
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - JV formation – 2007
  - MISO and PJM review/approval – Winter 2008
  - FERC Filing - Fall 2008
  - Siting approval – Fall 2010
  - Estimated completion – Fall 2015



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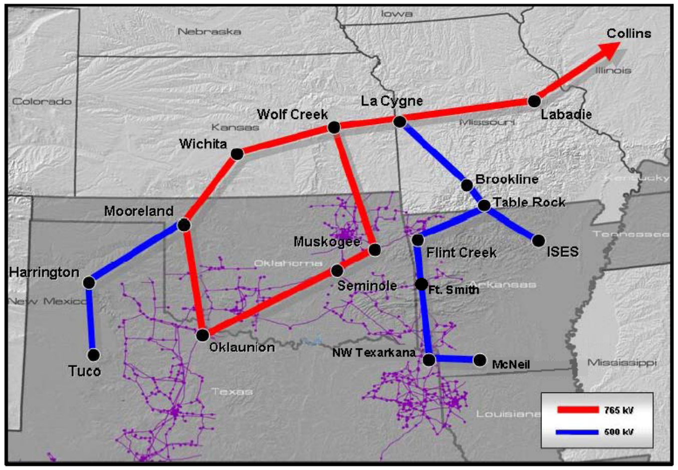
SPP I-765™

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
- *Benefits*
  - 4000 MW improved transfer capability
- *Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017



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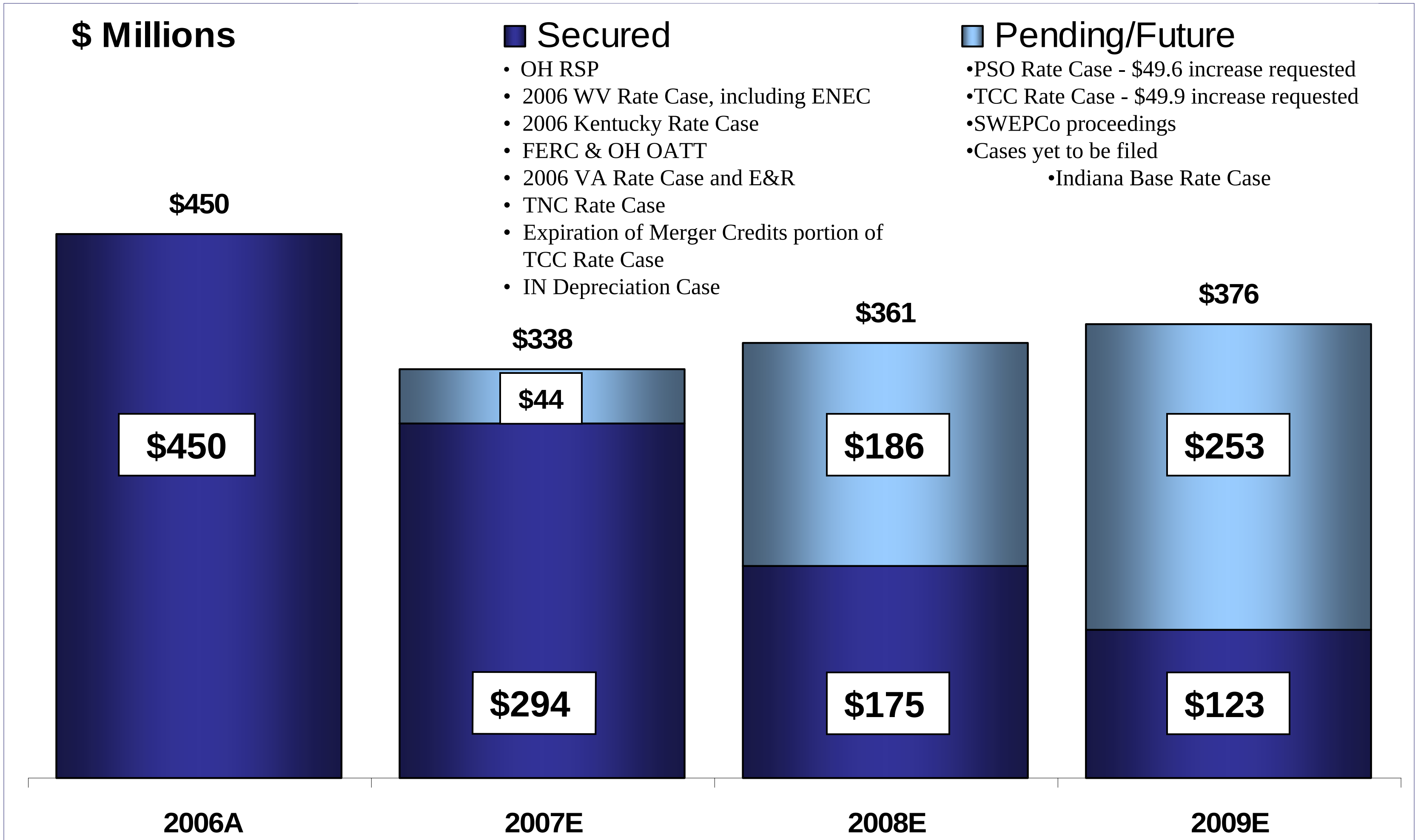
Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓ $54.8 million covers increased costs related to coal and purchased power
  - ✓ $28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓ Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

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In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings – Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

AEP®

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in October 2007

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
September 2007	Final order expected

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.

Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the 4th quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff , which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings commenced August 20, 2007. Decision expected by year end.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected by year end.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for October 17, 2007. Decision expected by year end.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

AEP®

We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

AEP®

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual 2006	Projection 2007	Projection 2008	Projection 2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

AEP®

Capital Investment Is Funded By Cash From Operations And Debt Issuances

AEP AMERICAN® ELECTRIC POWER

Better Investing
Chicago Investor Expo 2010
Chicago, Il
September 25, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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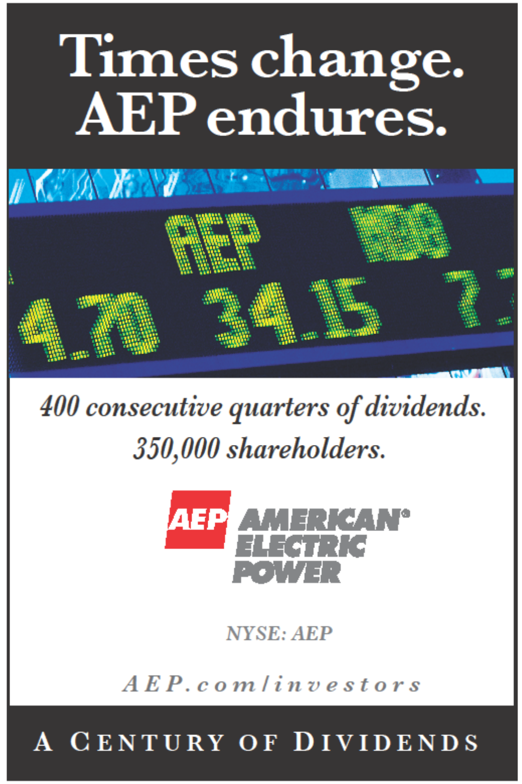
We are Proud of our Record….



Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 4.7%[1]**
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 22 analysts
- 13 Buy Ratings
- 8 Hold Ratings
- 1 Sell Rating

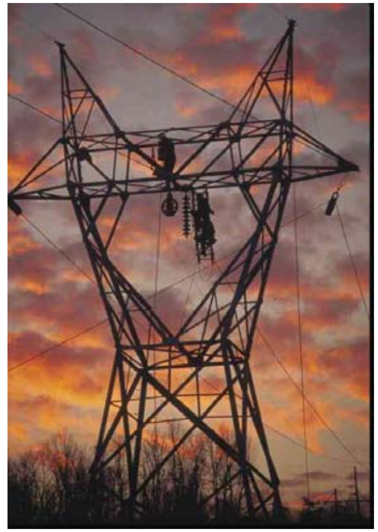
Attractive total return potential

[1] yield percentage based on AEP closing price of $36.43 on 09/22/2010

Industry Leadership

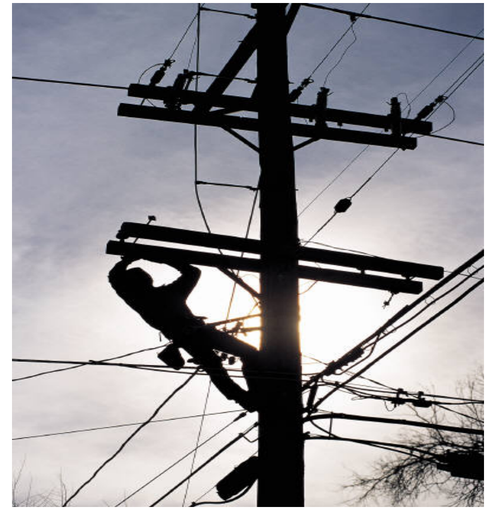
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

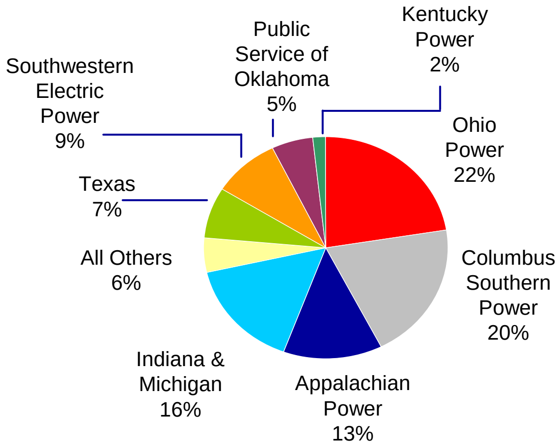
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

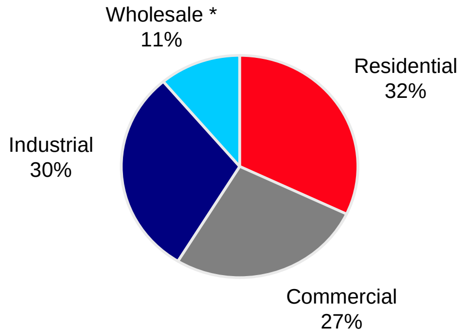
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

2010 Ongoing Earnings Guidance

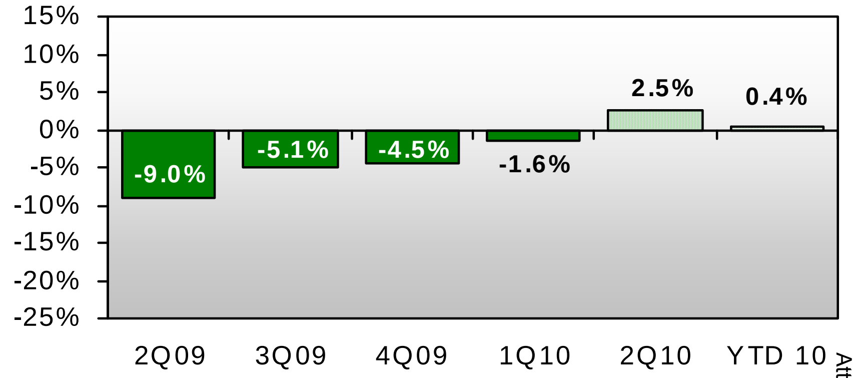
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- Rate recovery from returns on capital investment
- Load recovery
- Increase in off-system sales volumes and/or prices
- O&M discipline and cost cutting initiatives

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: -0.3%
Commercial: 2.0%
Industrial: 9.4%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

8

Transcription Investment Opportunities

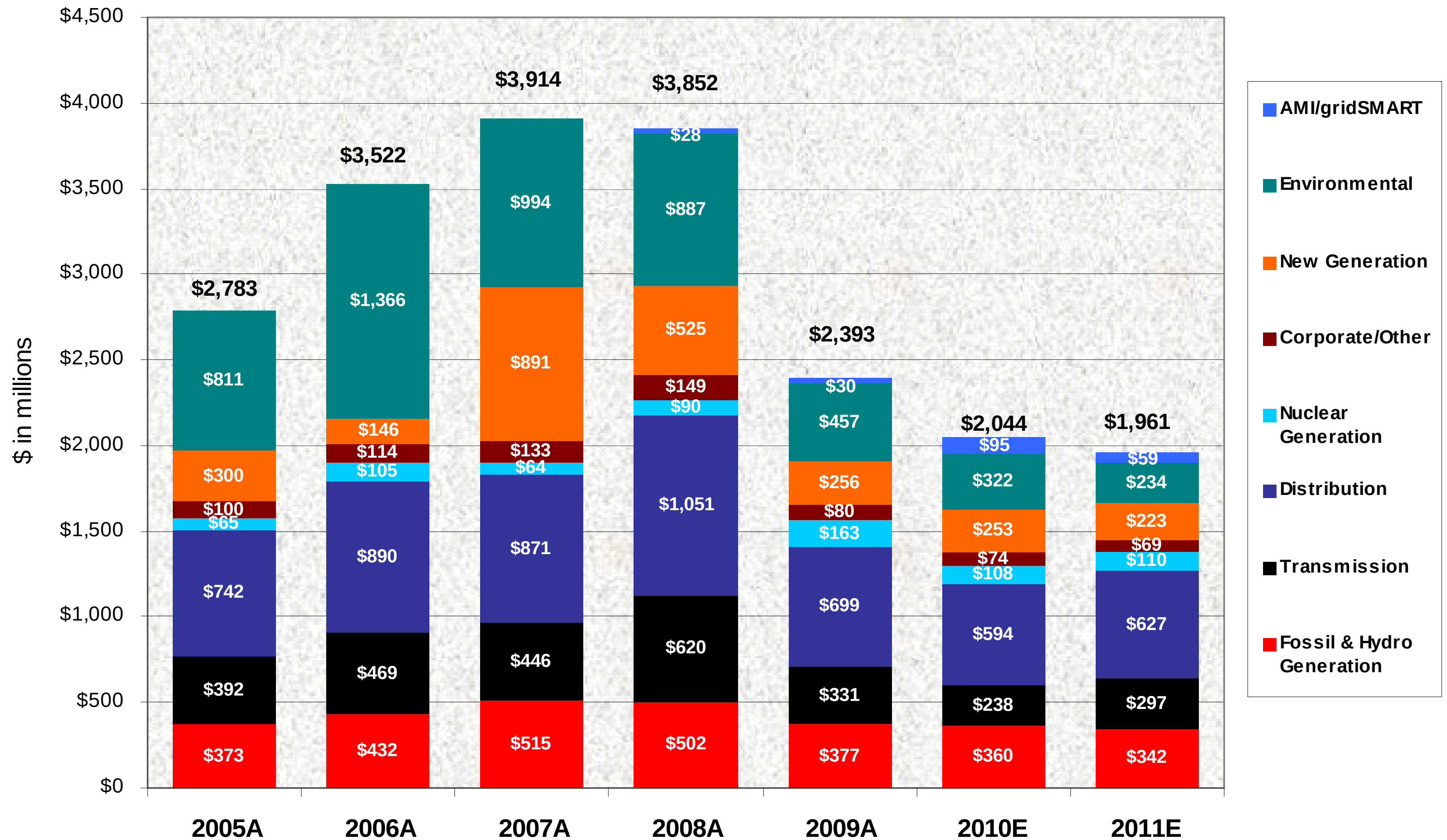
- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - In service assets $0.4 billion
  - CREZ opportunity $1.1 billion est. in service 2010-2013
  - Other ETT projects $1.6 billion est. in service 2010-2017

- **AEP Transmission Company (Transco): Within our existing footprint**
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually

- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 637 of 9556

Dividend Overview

- We paid our 401st consecutive quarterly dividend to shareholders on September 10, 2010

- Annual Dividend - $1.68/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December

- Attractive yield of 4.7% as of September 22, 2010

- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
- Strong Value and Total Return Proposition

Mountaineer Plant (WV)

October 5, 2005

KPSC Case No. 2011-00401
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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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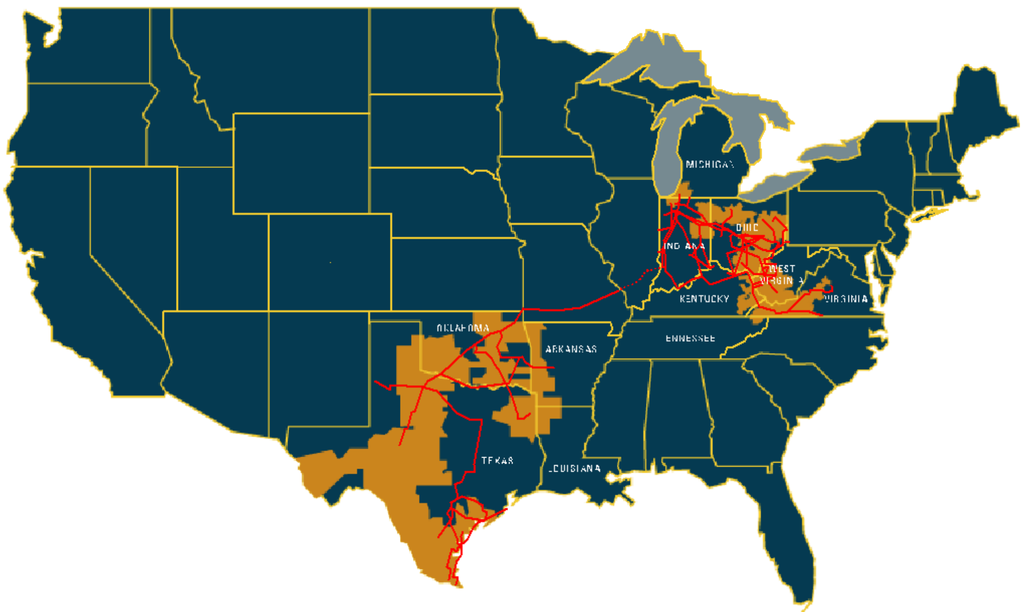
Asset Portfolio

Strength & Scale in Assets & Operations



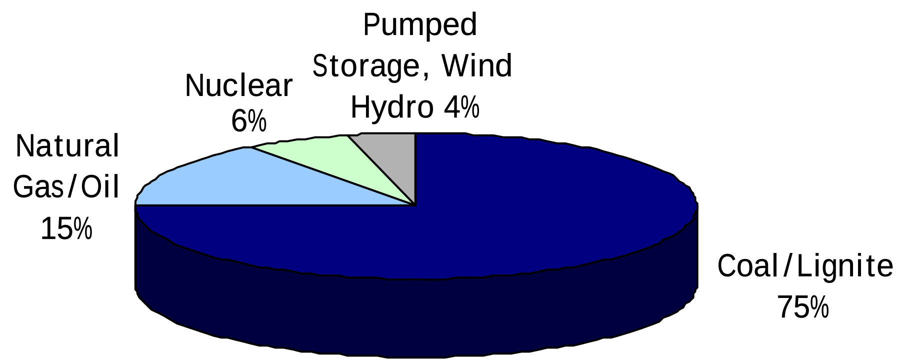
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- ➢ 35,500 MW Domestic Capacity
- ➢ 85% System Availability Factor YE 2004
- ➢ 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity). Also excludes the Waterford and Ceredo generating facilities.

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Environmental Investment

AEP's Environmental Compliance Strategy

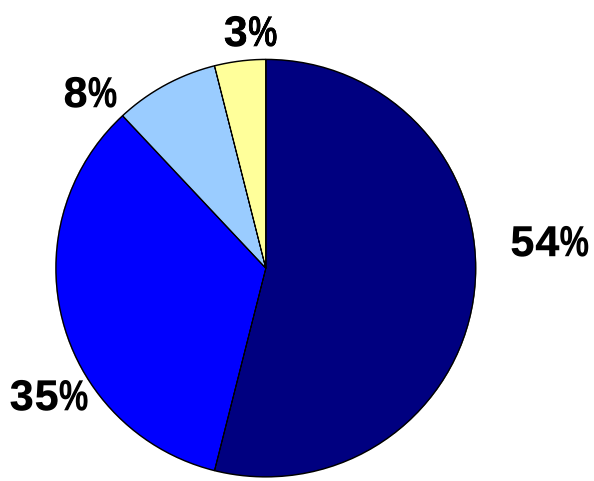
NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Much of this investment will be for:**
  - **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
  - **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
  - **SCR and FGD systems together offer co-benefit of mercury capture.**
  - **Sale of gypsum (by-product) avoids future landfill costs.**
  - **Provides fuel flexibility.**

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

$4.1 Billion Environmental Investment: Spending by Company

Projected Environmental Investment Allocation



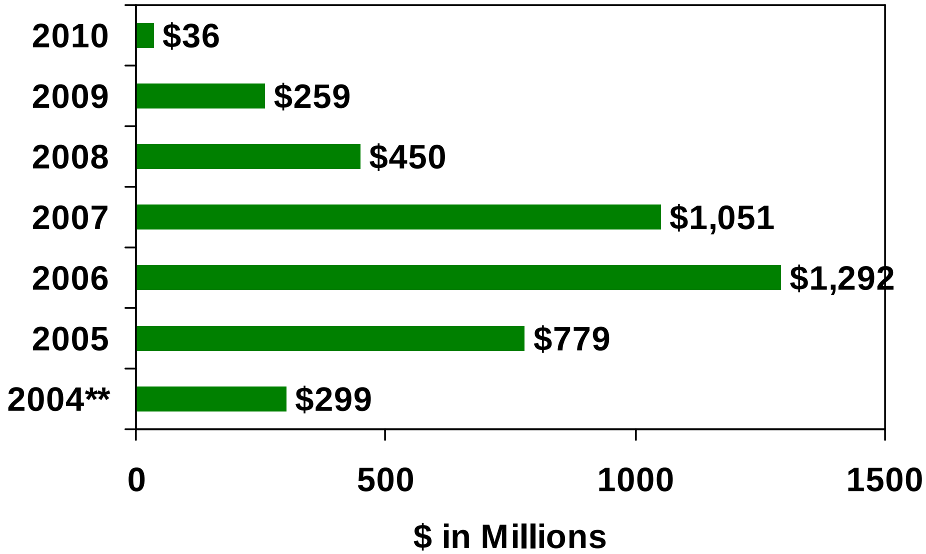
- Ohio Power & CSP (OH)
- Appalachian Power Co. (VA/WV)
- Kentucky Power Co. (KY)
- Other

Funding the Environmental Investments

- **Ohio**: 54% ($2.2 billion)
  - Approved annual generation increases 2006-2008
    - CSP – 3% annually
    - OP – 7% annually
- **Virginia/West Virginia**: 35% ($1.4 billion)
  - VA: Annual rate relief through Environmental & Reliability cost recovery mechanism; Two rate case opportunities through 2010
  - WV: General rate increase filed 8/26/05 including environmental, reliability & fuel recovery
- **Kentucky**: 8% ($319 million)
  - Automatic surcharge mechanism

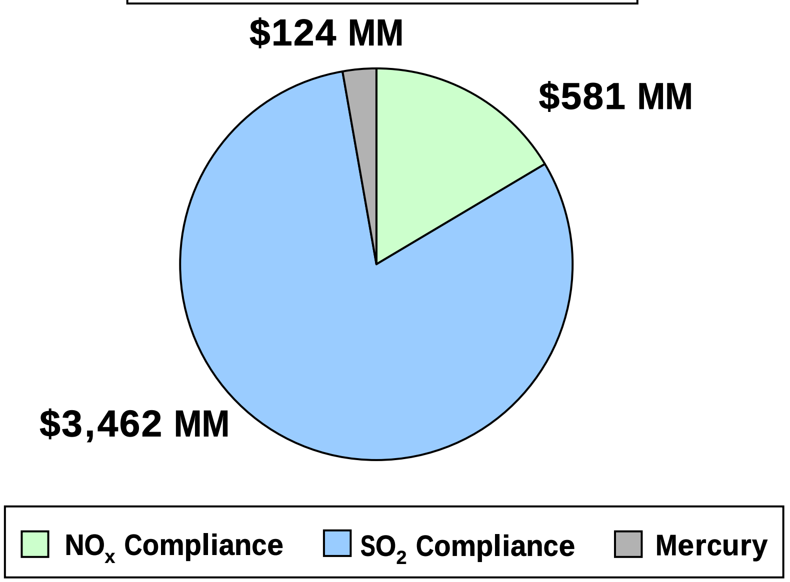
Environmental Investment: $4.1 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 billion for NOx

$1.5 billion for SO_2

Future Programs

$2.1 Billion:

$1.9 billion for SO_2

$0.2 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Investment

FGD

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Planned or Under Construction

2006 - 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

SCR

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

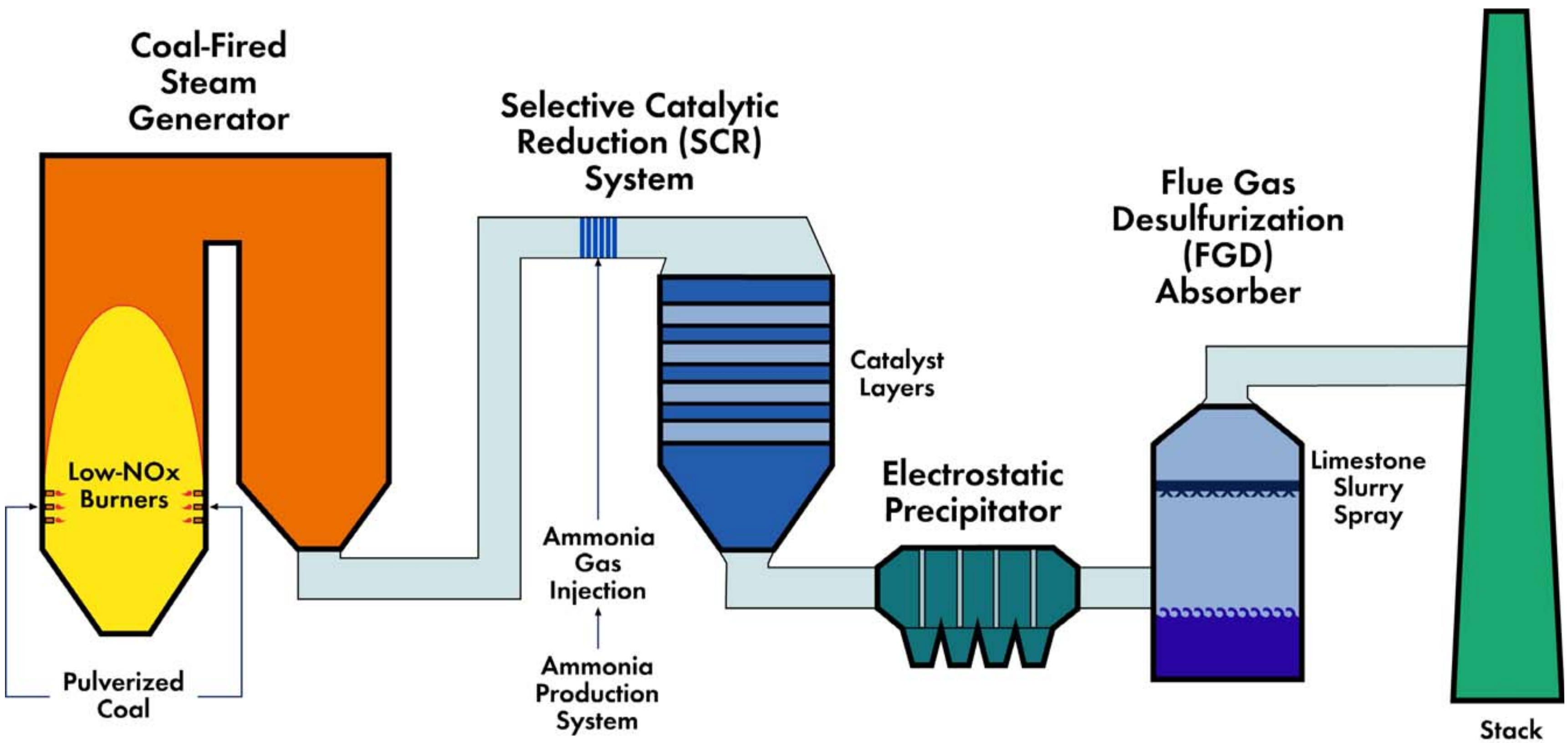
Planned or Under Construction

2006 - 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

The Flue Gas Stream



Investing in IGCC

Investing in IGCC

Ohio IGCC Procedural Schedule

- **August 16, 2005: Evidentiary Hearings Concluded**
- **September 20, 2005: Initial Briefs Due**
- **October 11, 2005: Reply Briefs Due**

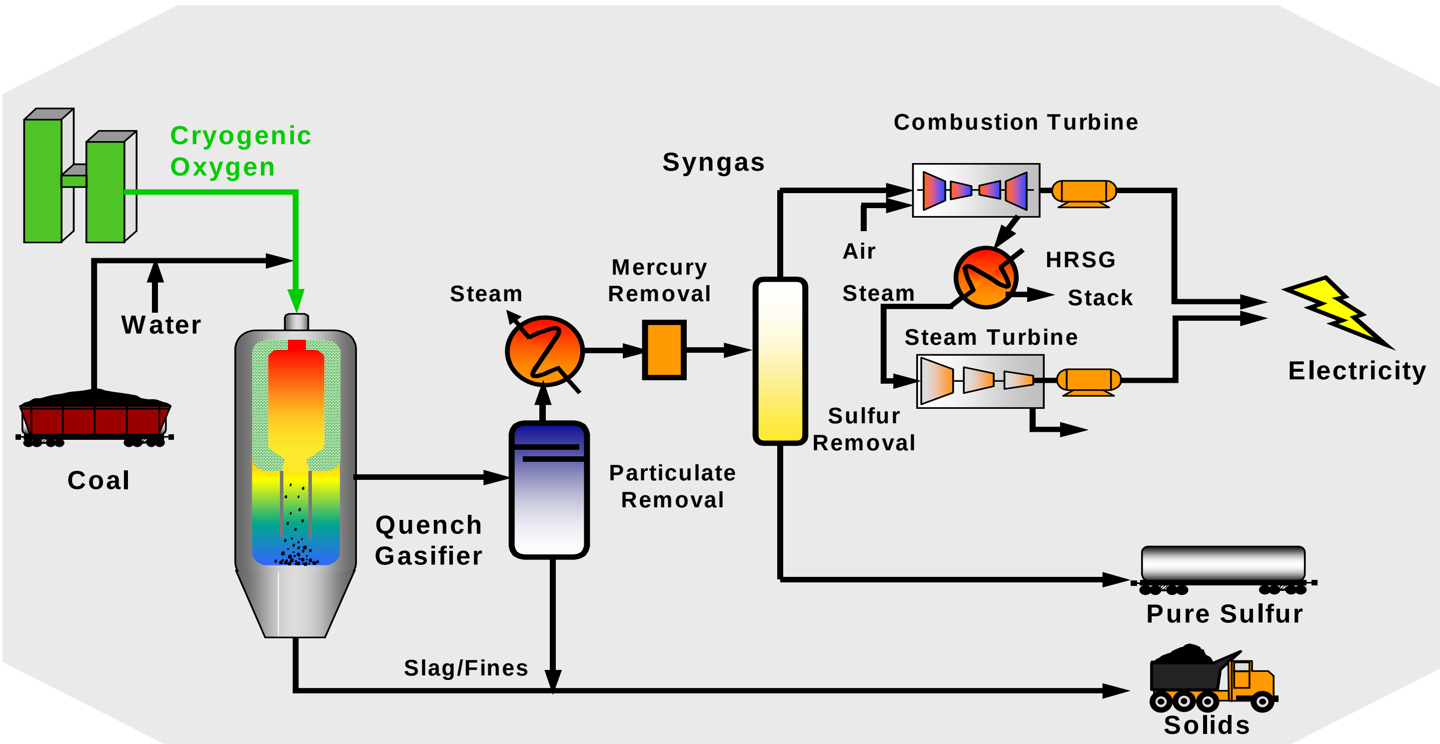
Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.
** Total plant cost include land, overheads, AFUDC, etc.
*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- Secure cost recovery plan
- Finalize site selection
- Negotiate with suppliers

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

AEP AMERICAN® ELECTRIC POWER

Morgan Stanley Office Visit

November 17, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Detailed Ongoing Earnings Guidance

2010A: $3.03

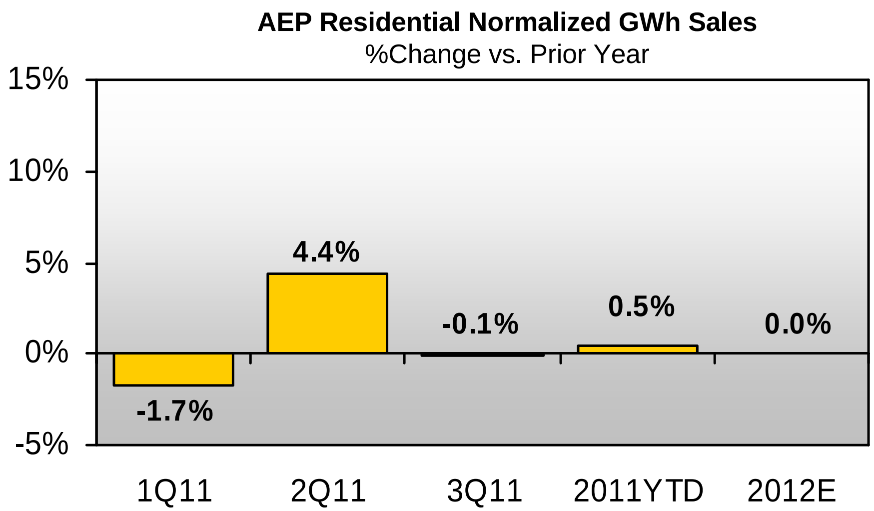
2011E: $3.07 - $3.17

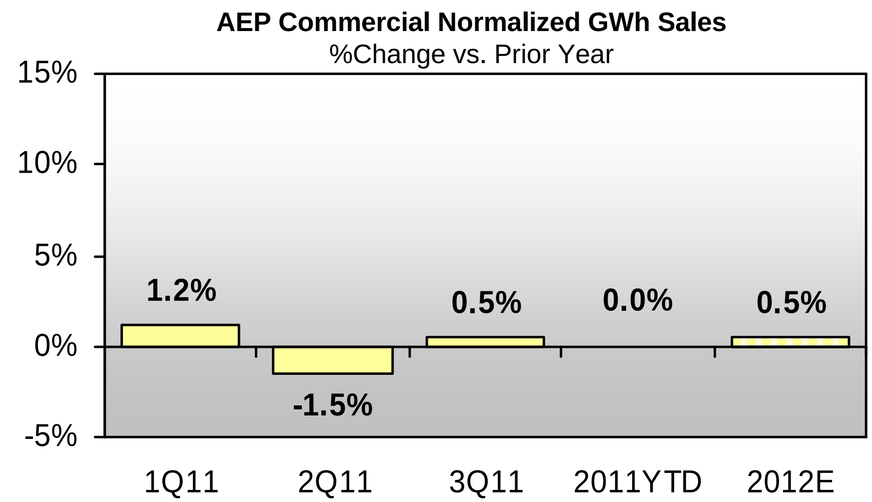
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

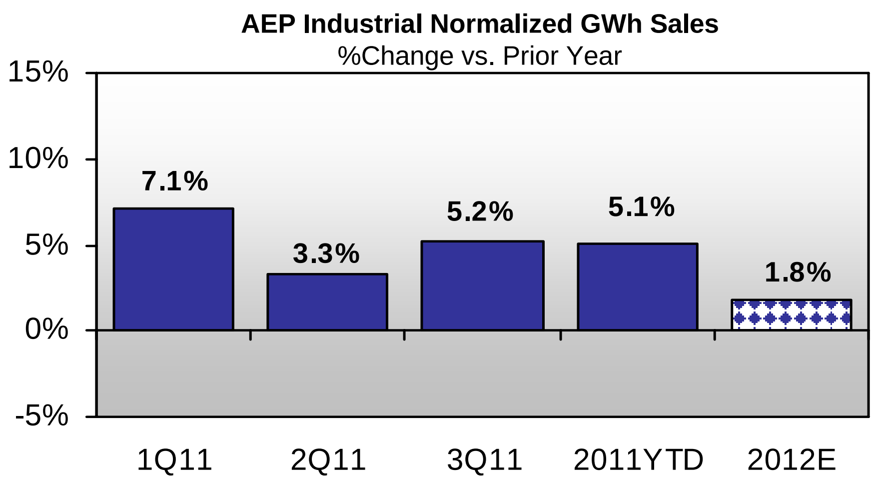
		2010 Performance Driver	2010 Actual ($ millions)	2011 Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

**original guidance given 01/28/2011*

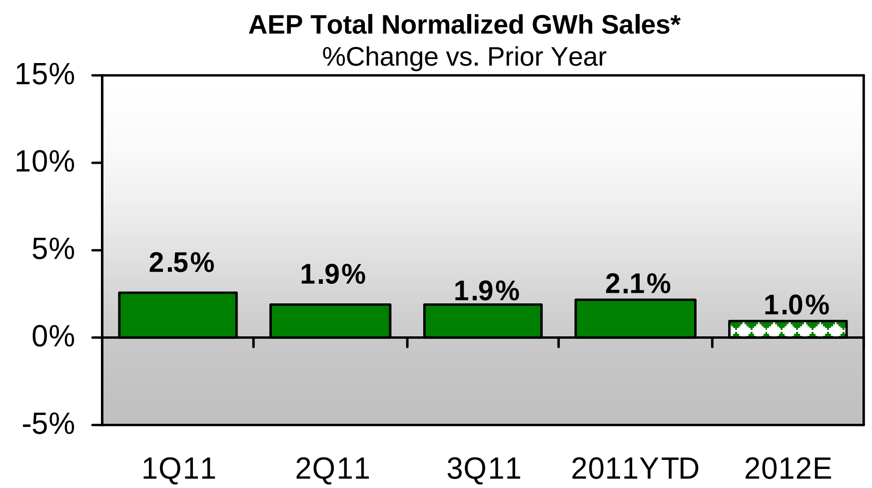
Normalized Load Trends







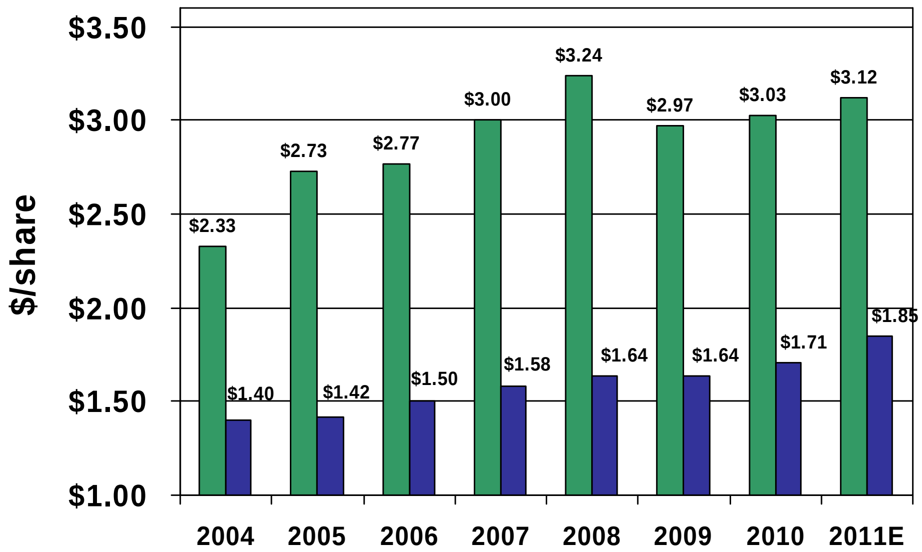
Note: Chart represents connected load



*includes firm wholesale load

Earnings and Dividend Growth

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

Dividend payout ratio target of 50–60%

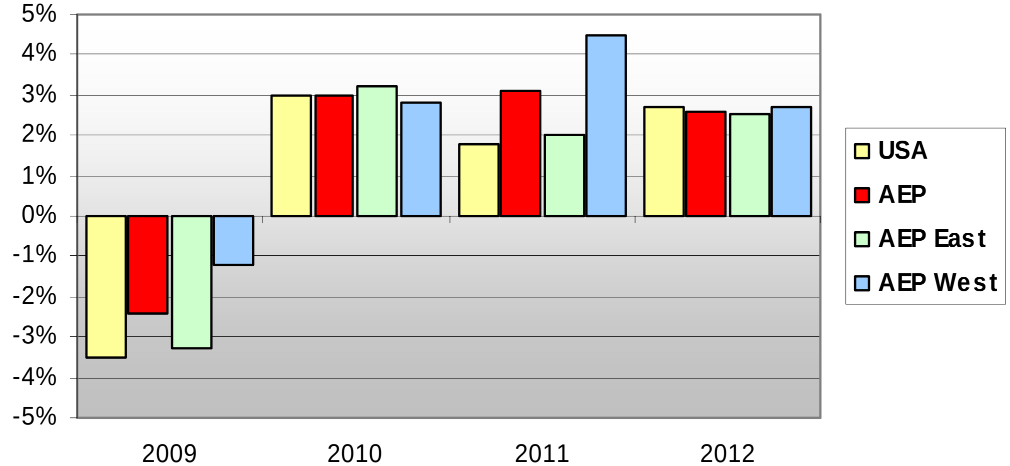
2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

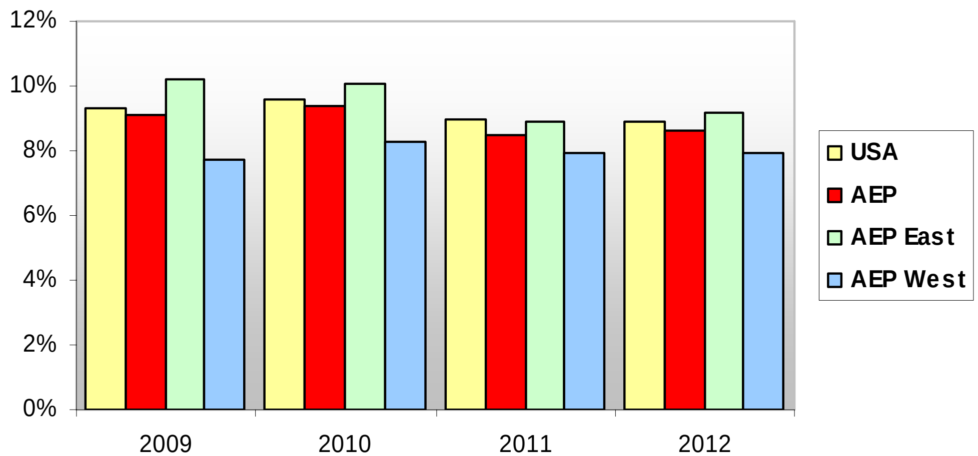
Economic Conditions/Load

- AEP's GDP growth at 3.1% in 2011 has been better than the US at 1.8%
- AEP West region continues to experience stronger growth than AEP East

Annual GDP Growth



Annual Unemployment Rate



- AEP East unemployment remains higher than AEP West
- AEP Total unemployment has started to improve relative to the US

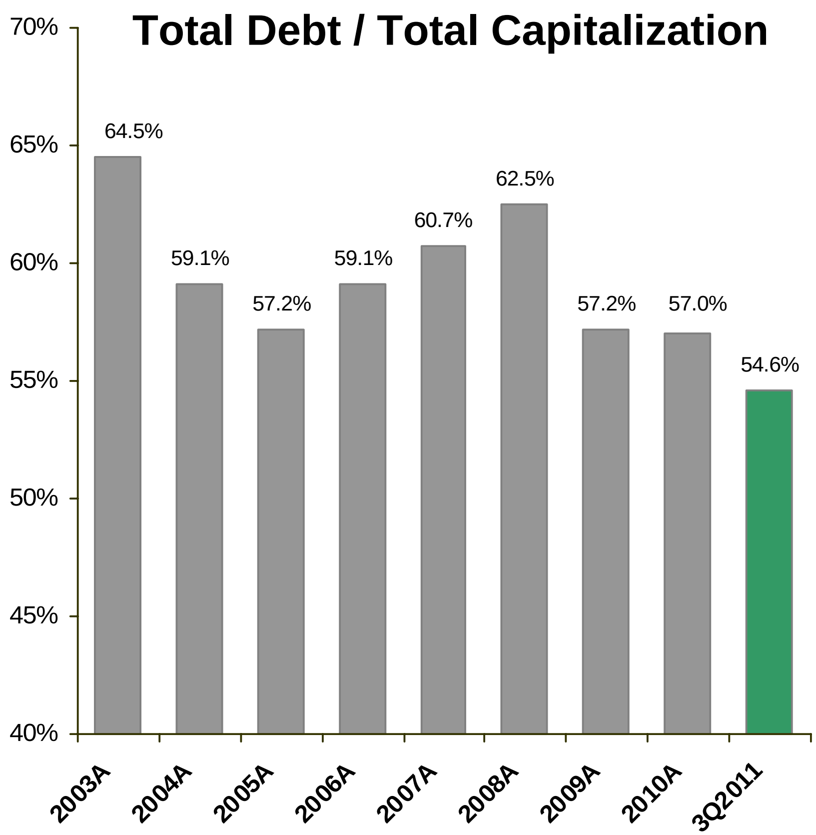
Sensitivities for 2012

EPS Sensitivities

Major Drivers		
Driver	**Driver Change**	**EPS Effect**
Average Load Growth	1%	$0.10
Off System Sales, net of sharing	10%	$0.05
Utility O&M	1%	$0.04
Capital Spending	$250M	$0.02

Operating Company Returns		
Company	**% Earnings Contribution**	**EPS Effect of 1% ROE Change**
AEP Ohio	42%	$0.10
APCo (incl WPCo)	16%	$0.06
SWEPCO	11%	$0.04
I&M	10%	$0.04
AEP Texas	8%	$0.02
PSO	6%	$0.02
KPCo	3%	$0.01
Other	4%	$0.02

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.50%	15%- 20%

Note: Credit statistics represent the 12 month trailing as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 664 of 9556

TCC Remand Case – PUCT Docket No. 39722

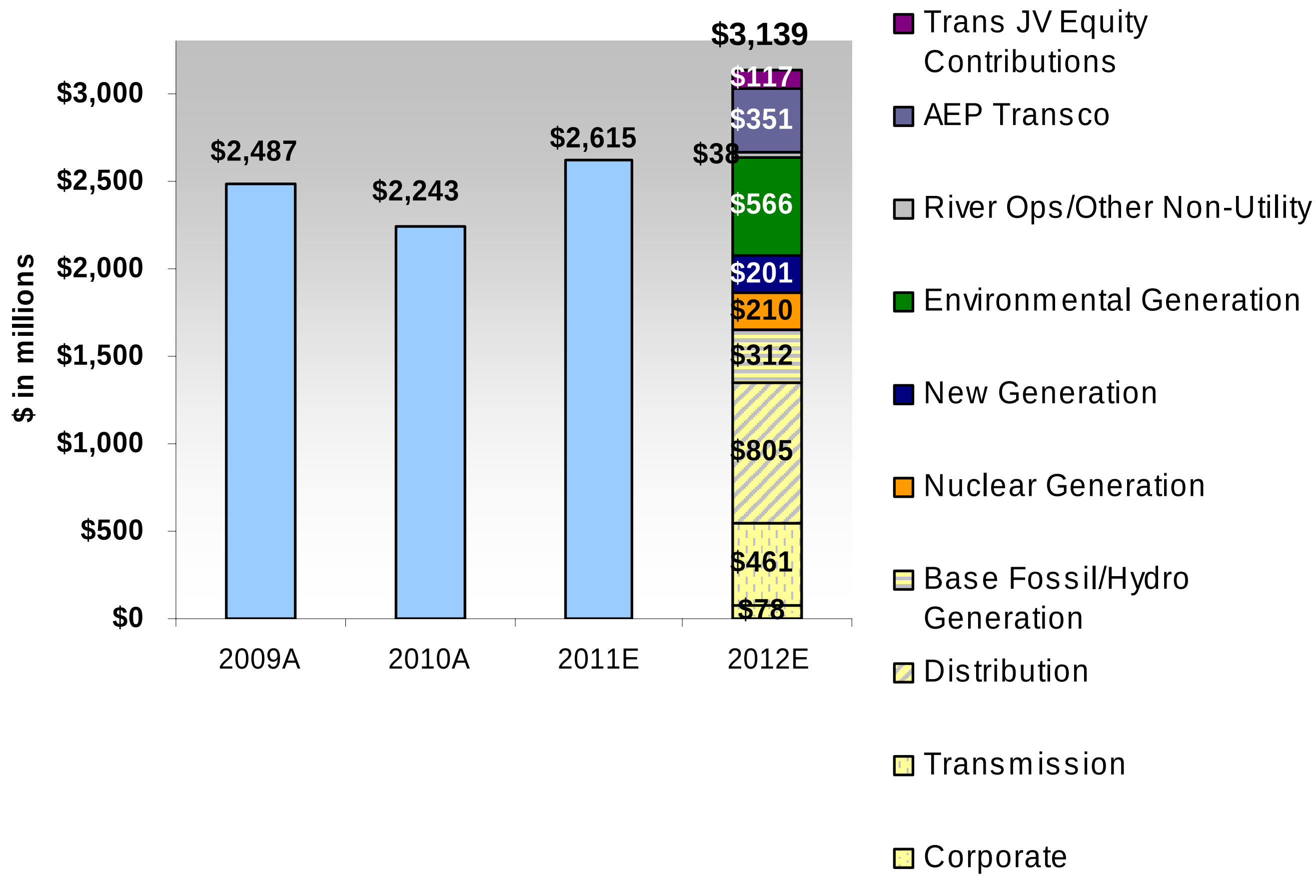
- In July 2011, the Supreme Court of Texas reversed the PUCT's decision of the disallowance of capacity auction costs. This opened the docket for TCC to file on October 10, 2011, an application to confirm the capacity auction true-up balance.
- TCC's filing requested a capacity auction true-up balance of $1.2B, which includes the capacity principal balance of $421M plus interest thru March 31, 2012. Interest is based on a carrying charge rate of 11.795%, which was the rate in effect at the time of the original PUC decision. Based on the Commission's Preliminary Order in the case, the capacity auction true-up balance would be approximately $817M inclusive of a carrying charge rate of 7.47%(based on ruling that modified the rate in 2007).
- The regulatory hearing is scheduled to take place November 29-30, 2011. A filing for a securitization order will occur soon after an order is issued on the remand case. TCC expects to issue the securitization bonds in the first quarter of 2012.
- TCC recorded a $425MM net-of-tax favorable special item related to this case in 3Q2011, ($421MM principal & $234MM interest, less related taxes). AEP also recorded $28MM on-going interest YTD in 3Q2011.
- Upon securitization, TCC will begin recognizing the equity component of the carrying cost prorated over the life of the securitization bonds (estimated to be $116MM, based on the PUCT preliminary order).
- Filing also seeks order to resolve tax normalization issues.

Pension and OPEB Estimate

- Investment returns for our pension plan remain slightly positive for the year despite volatility in the market, OPEB funds are slightly negative year to date.
- With very low short term interest rates, it is beneficial to pre-fund a portion of the required contributions to the plan.
- After making a discretionary contribution of $300 million by year end, cash contributions to the pension will total $450 million for 2011.
- We do not expect any required cash contributions to the pension for 2012, although we may make additional discretionary contributions.
- We expect combined pension and OPEB expense to increase $88M from 2011 to 2012 ($62MM O&M, pre-tax and $26MM capitalized).
- Discount rates are 5.05% for pension and 5.25% for OPEB for 2011, and are currently estimated to be 4.35% and 4.60% for 2012 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

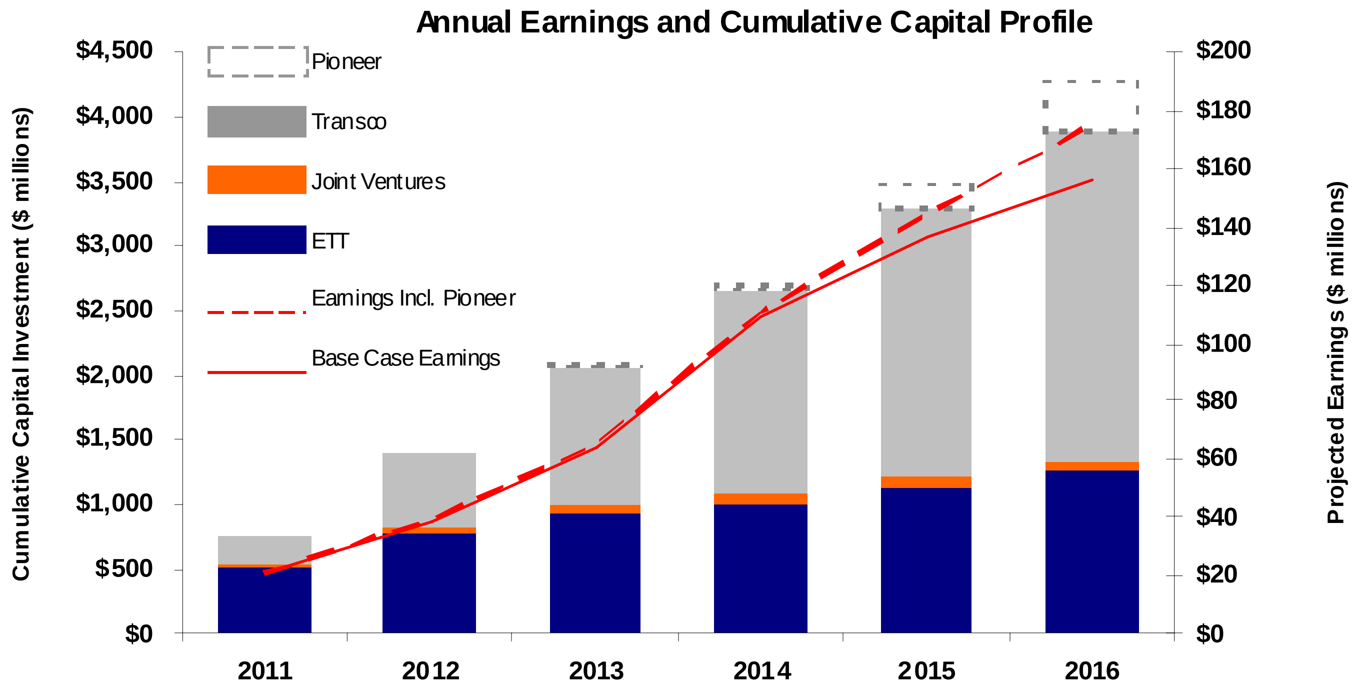
Capital Allocation

2012 AEP System Capital $3.1B



Major projects include: Turk Plant, Reliability upgrades, ETT contributions and Transco growth

Transmission Earnings & Capital Profile



[1] High Case includes AEP's share of Pioneer (50% ownership)

[2] Transco base case includes approximately $21MM in 2012 capital spend that is dependent upon state approval of Arkansas and Kentucky

[3] Joint Ventures include: PATH (50% ownership) assuming an ongoing suspension and Prairie Wind (25% ownership) assuming construction at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 11-13% for FERC projects; 60/40 debt/equity capitalization and 9.96% ROE (through 2013) and 55/45 debt/equity capitalization and 10% ROE (2014 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission Investment Opportunities

AEP®

ETT – Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:** Current rate base is $482 million; expected to grow as follows:
  - 2011: $495 million
  - 2012: $750 million
  - 2013: $1,200 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $210 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

ROE Optimization

ROE by Jurisdiction		
Jurisdiction	**Authorized ROE**	**Sep 2011 Proforma ROE***
AEP Ohio	NA	13.51%
APCO – Virginia APCO – West Virginia Wheeling	10.53% 10.00% 10.00%	6.88%
I&M – Indiana I&M – Michigan	10.50% 10.35%	8.24%
SWEPCO – Louisiana SWEPCO – Arkansas SWEPCO – Texas	10.57% 10.25% 10.33%	10.05%
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule

Intervenor Testimony Due	October 24, 2011
Prehearing Conference	November 2, 2011
Hearing Commences	November 14, 2011

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Historical Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Summary Rate Case Information

AEP®

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).

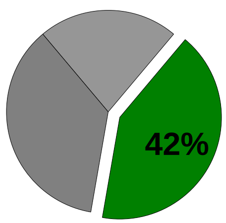
- Various legal challenges are on-going related to the plant (see 10-Q).

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

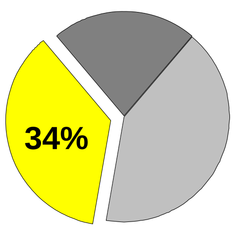
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

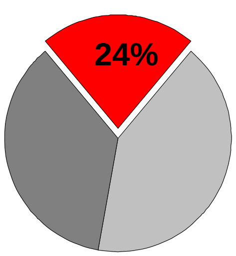
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	Has FGD
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Lawrenceburg **	1,186	2004	NG Combined Cycle
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	4,921		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**13,432**		

* May need FGD upgrades

** CSP has a PPA with AEGCo for the Lawrenceburg Plant. The contract extends through 2017, with a two-year optional renewal.

Total Ohio Generation	13,432 MW
Less units slated for retirement	2,500 MW
Total remaining portfolio	10,932 MW
Remaining Portfolio:	
Coal	77%
Has FGD & SCR - 83%	
Has FGD; may require SCR - 10%	
May be replaced with gas - 7%	
Natural gas & hydro units	23%
	100%

AEP AMERICAN ELECTRIC POWER®

DIAM Asset Management Office Visit

December 2, 2010
Columbus, OH

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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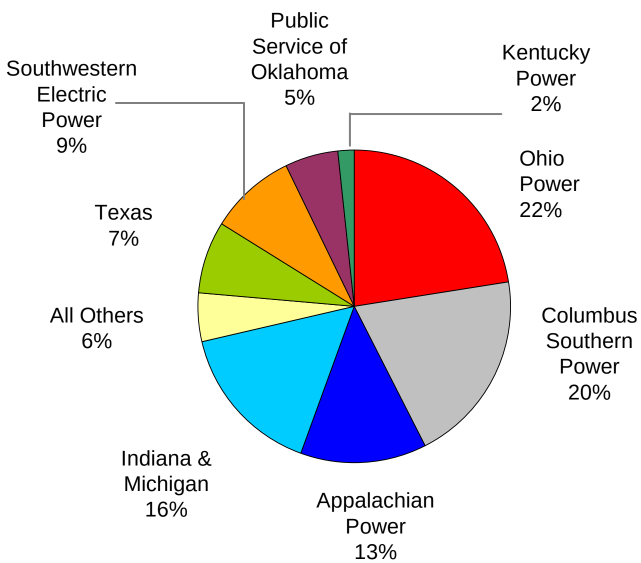
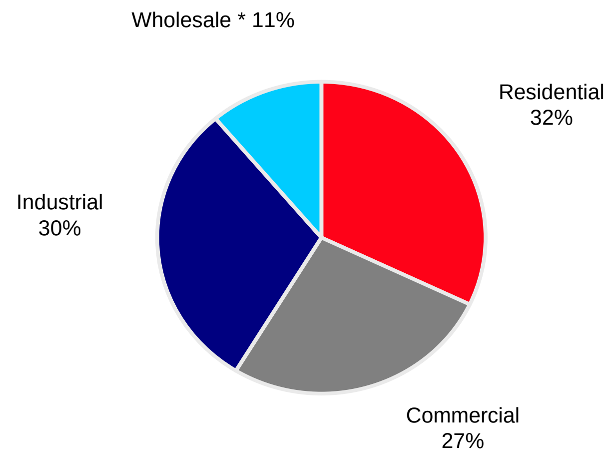
Highly Diversified Regulated Utility Platform

2009 Earnings Contribution



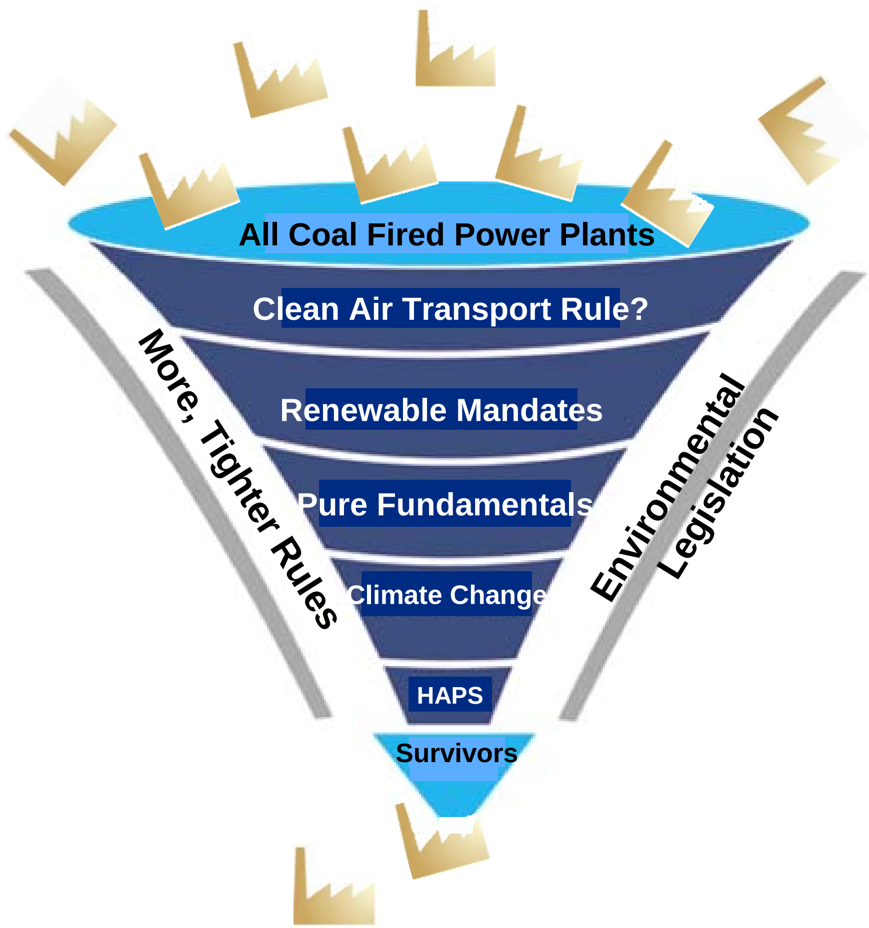
2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

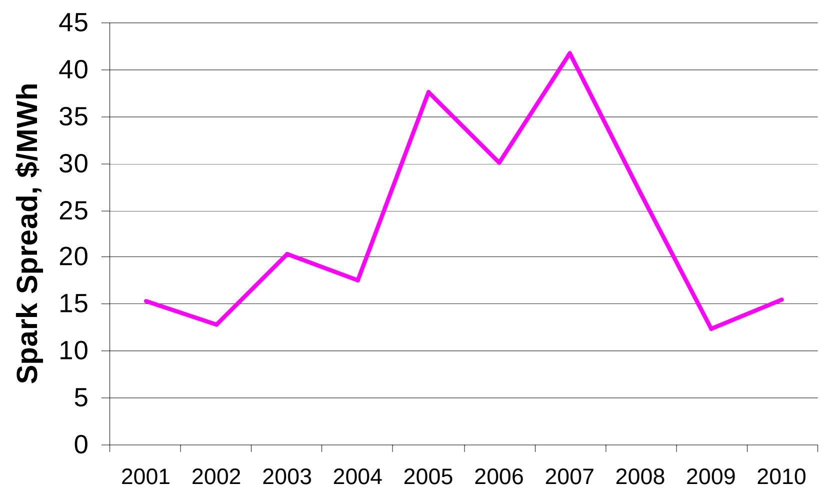
Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

The Pressure on Coal Generation



Dark Spread Compression

NYMEX coal



<u>Key EPA Actions Pending</u>

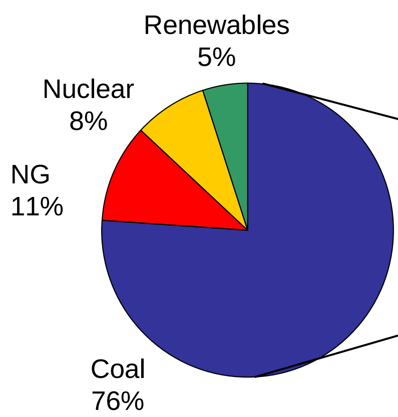
- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in Spring 2011

The threshold level for coal is being defined

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

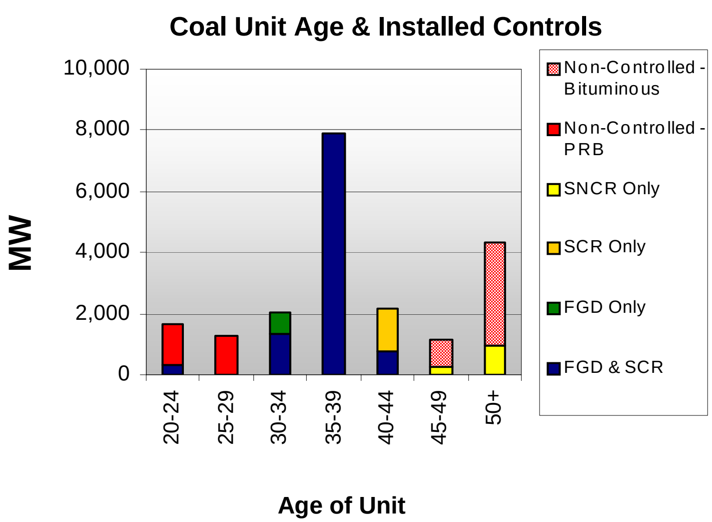


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

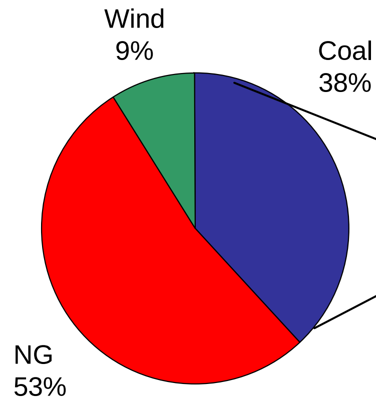
Avg. Delivered Cost
2009A - \$56/ton
2010E - \$52/ton
2011E[1] - \$51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

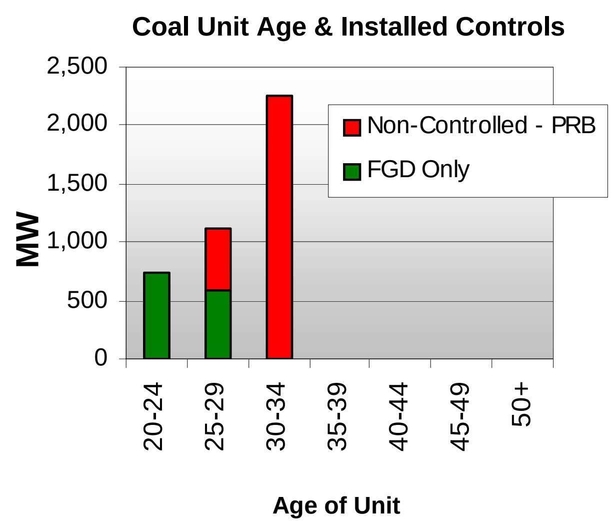


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - \$29/ton
2010E - \$29/ton
2011E[1] - \$29/ton

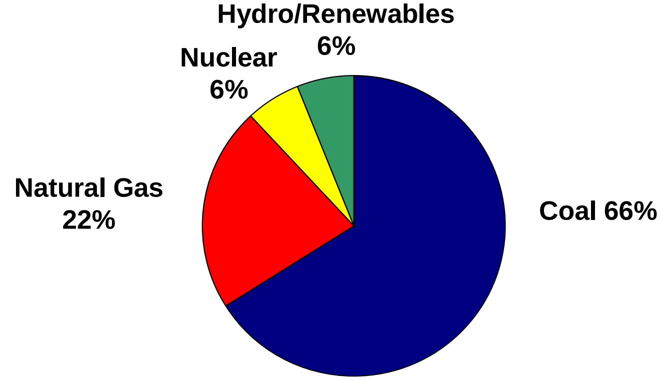
[1] Represents cost of committed position (90%)



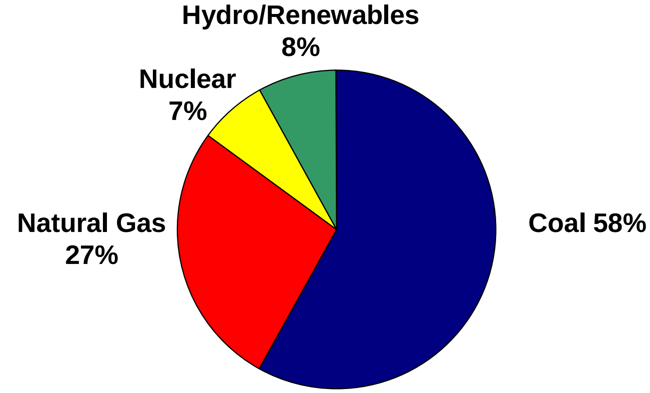
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

Transmission as a Growth Engine

AEP®

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

ETT Electric Transmission Texas

ETA ELECTRIC TRANSMISSION AMERICA, LLC

PATH Potomac-Appalachian Transmission Highline

Prairie Wind Transmission A joint venture between Westar Energy and ETA

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

ETT: An Operating Utility

AEP®

ETT Electric Transmission Texas

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	Anticipated 10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - Ohio application for public utility status pending; approval expected in 2010
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

Progress on Joint Ventures in 2010

PATH:

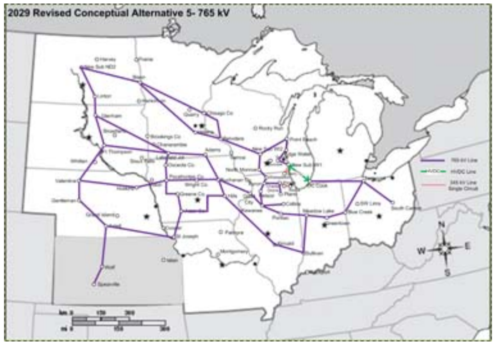
- Re-filed for certification in VA
- Letter from PJM confirmed the 2015 in-service date
- PJM Board reaffirmed need on December 1, 2010
- FERC approved formula rate (14.3% ROE), subject to rehearing

Prairie Wind:

- Approved by SPP as a Priority Project (Notice To Construct rcv'd)
- Cost allocation approved by SPP and FERC
- FERC approved formula rate (12.8% ROE)
- In-service date is 2013-2014

Pipeline of Future Projects:

- Pioneer
  - FERC approved formula rate (12.54% ROE)
  - Awaiting RTO project approval; MISO included Pioneer in its proposed EHV plan
- Tallgrass
  - Will move forward if approved at 765 kV
- Smart Transmission Study
  - Comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Two New Anchor Projects

ETA – MidAmerican Energy Co: MEC Project

Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

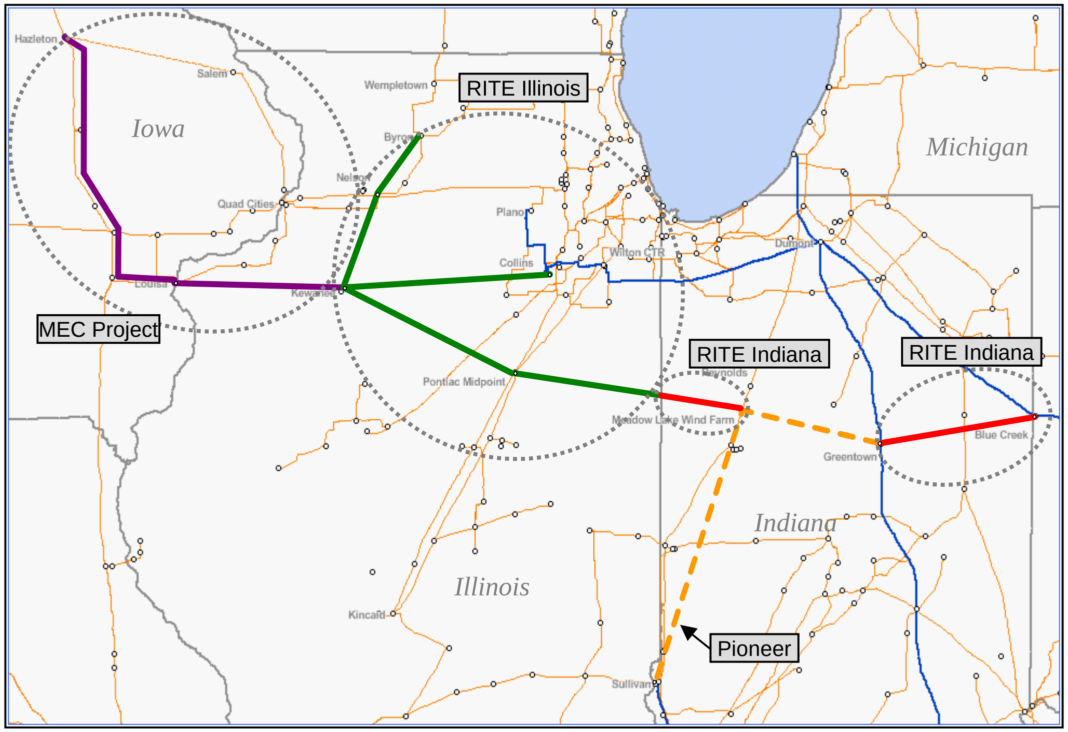
ETA – AEP - Exelon: The RITE Line

Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

AEP Total Investment:

~$500M



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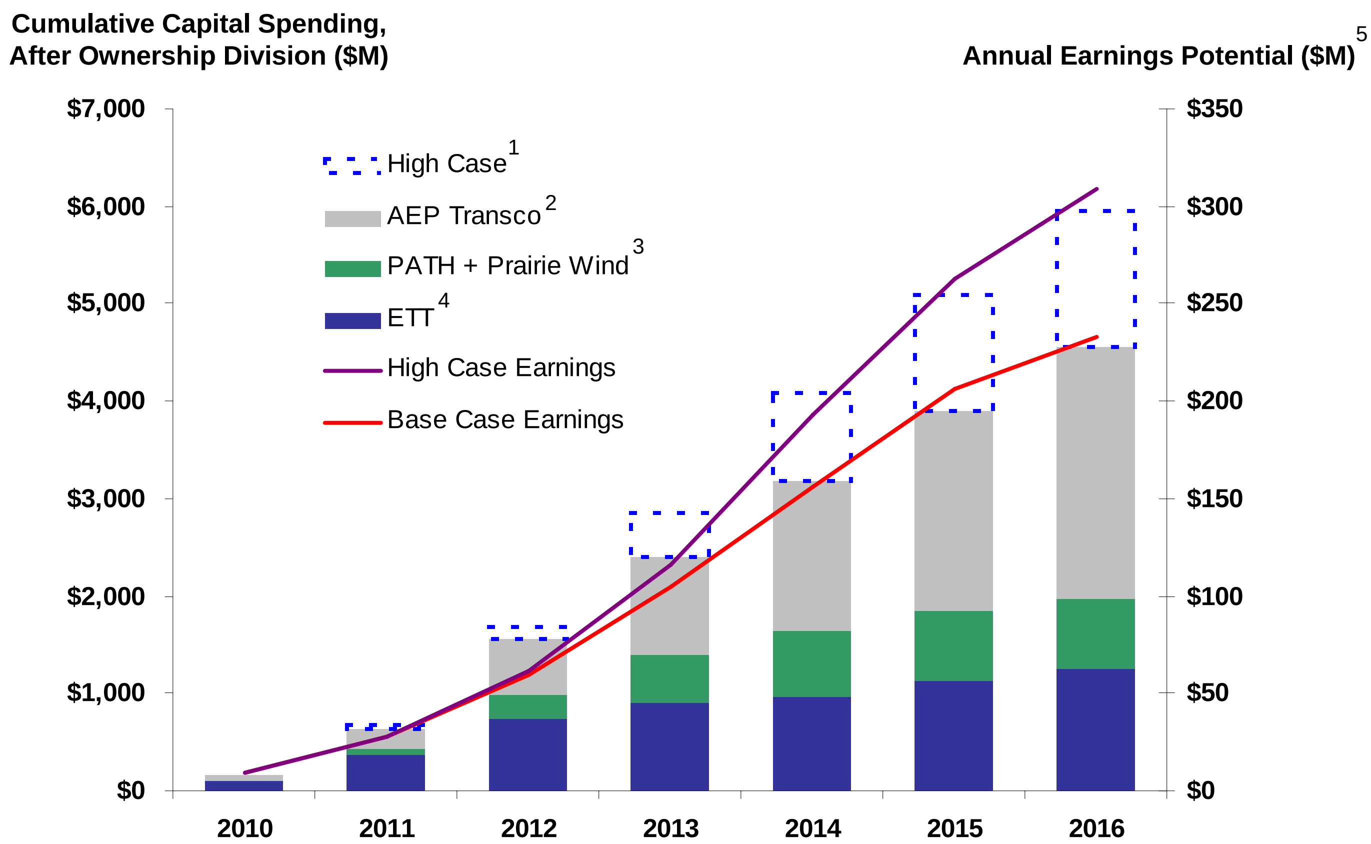
Capital Investment and Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

Capital for Growth

- Increased capital budget by $150M for 2011 to $2.6B
- Announced capital budget plan of $2.9B for 2012

Return of Capital to Shareholders

- 9.5% increase in quarterly dividend to $0.46/share declared by the board of directors on October 26th
- Future dividend increases will grow with earnings

Capital to Reduce Risk

- Voluntarily funding pension $500M in 2010
- Allocating an additional $150M of funding for pension in 2011

Detailed Ongoing Earnings Guidance

2010E: $2.95 - $3.05

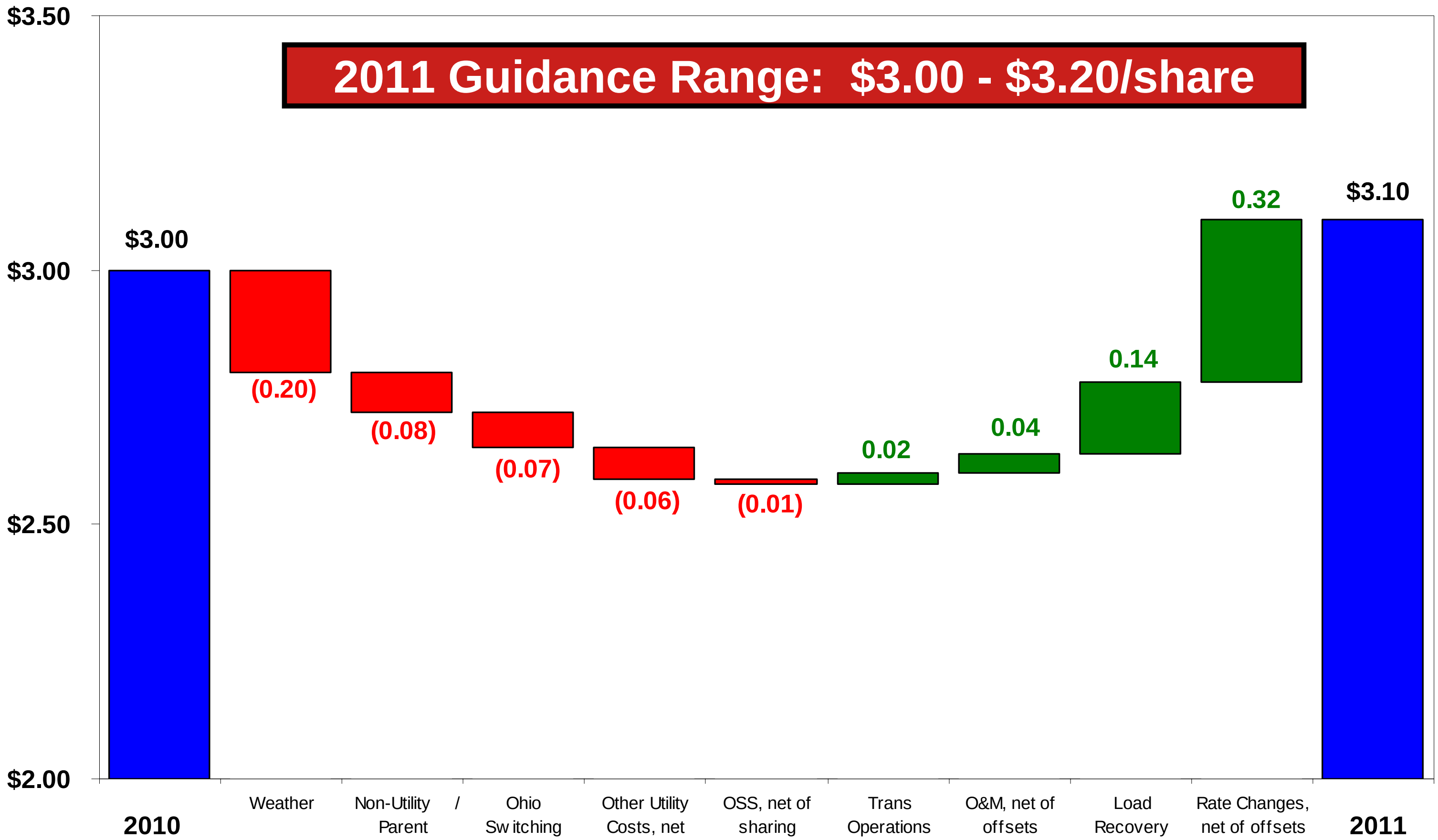
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Projection

		Performance Driver	2010 Projection ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		51
18	Generation & Marketing		20		2
19	Parent & Other On-Going Earnings		(22)		(53)
20	ON-GOING EARNINGS		1,439		1,496

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2011 Earnings Drivers



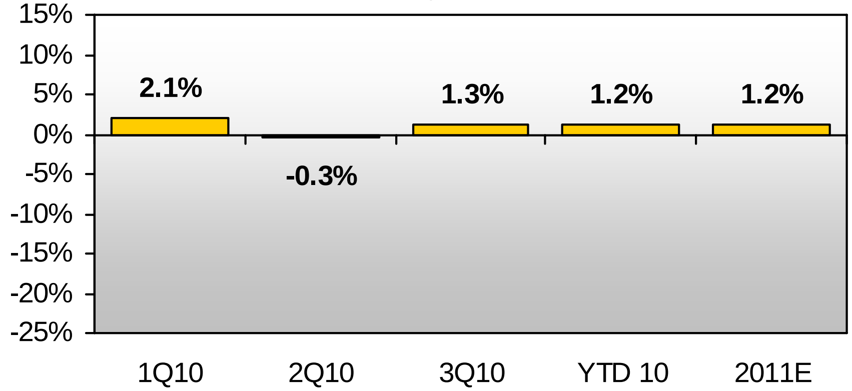
- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

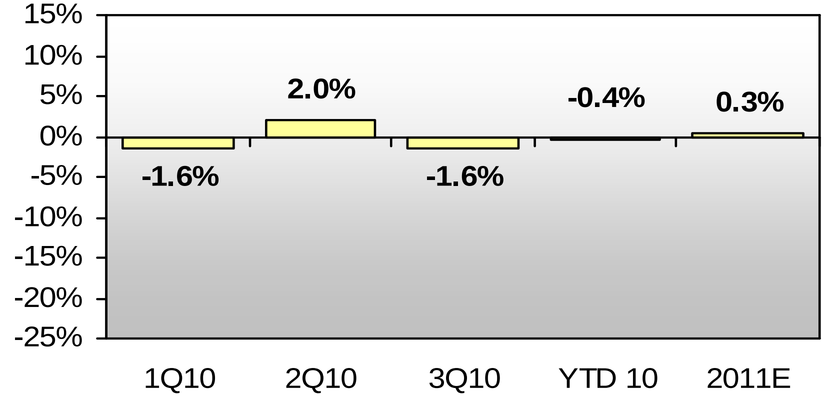
2012 EPS Target: $3.25/share

Normalized Load Trends

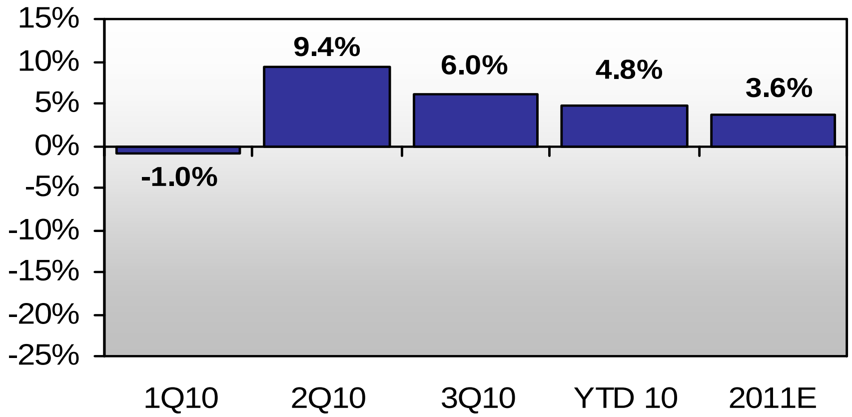
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



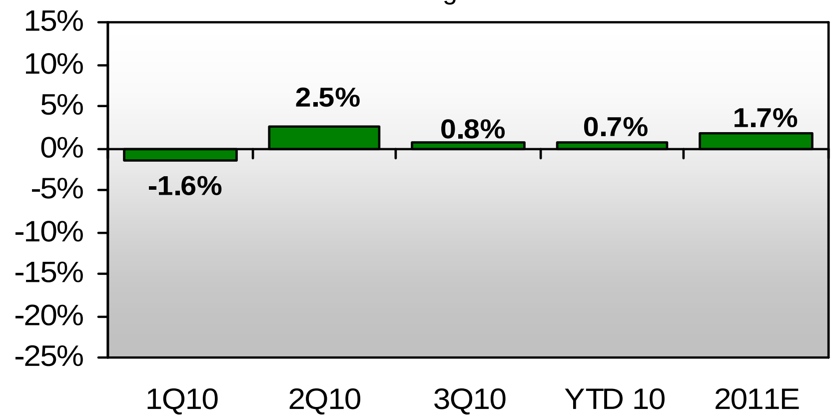
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year

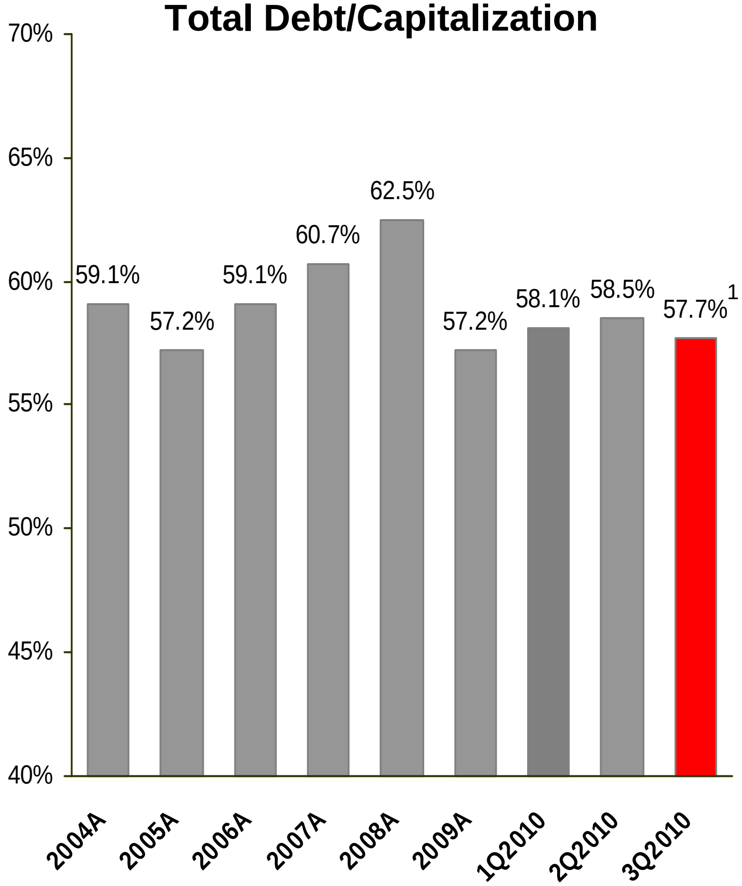


*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

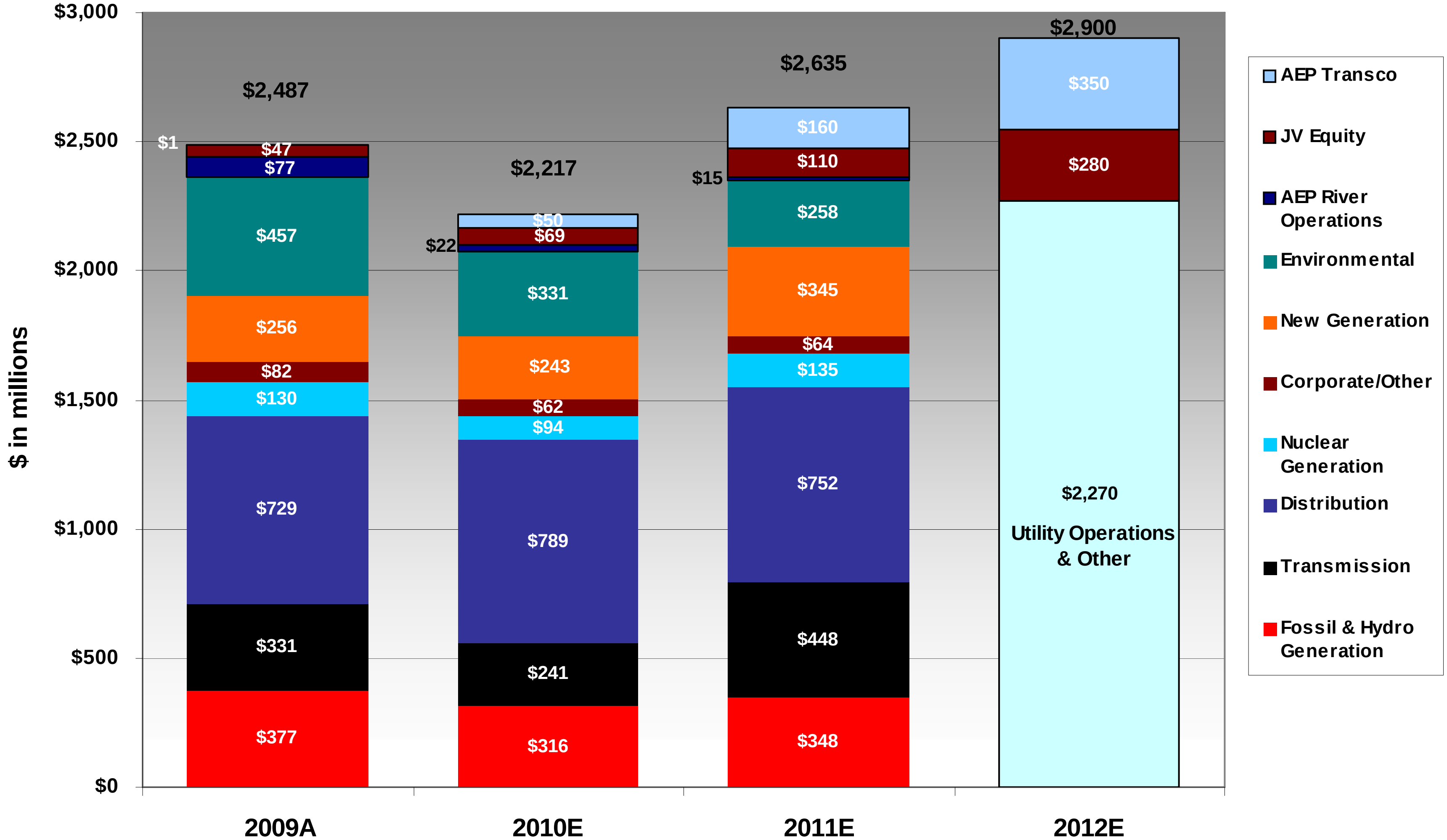
Cash Flow Guidance

AEP®

	$ in millions	
	2010E	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,205	$ 1,499
Depreciation & Amortization	1,654	1,588
Pension Funding	(500)	(150)
Other Cash Flow Items	653	234
Working Capital[1]	(218)	424
Cash From Operations	$ 2,794	$ 3,595
Investing Activities		
Construction Expenditures	(2,217)	(2,635)
Other Investing Activity	(352)	(265)
Total Investing Activities	$ (2,569)	$ (2,900)
Financing Activities		
Dividends	(826)	(893)
Net Debt Issued/(Retired)[1]	190	48
Common Equity	121	150
Total from Financing Activities	$ (515)	$ (695)
Beginning Cash Balance	$ 490	$ 200
Ending Cash Balance	$ 200	$ 200

[1] 2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Capital Expenditures



KPSC Case No. 2011-00401
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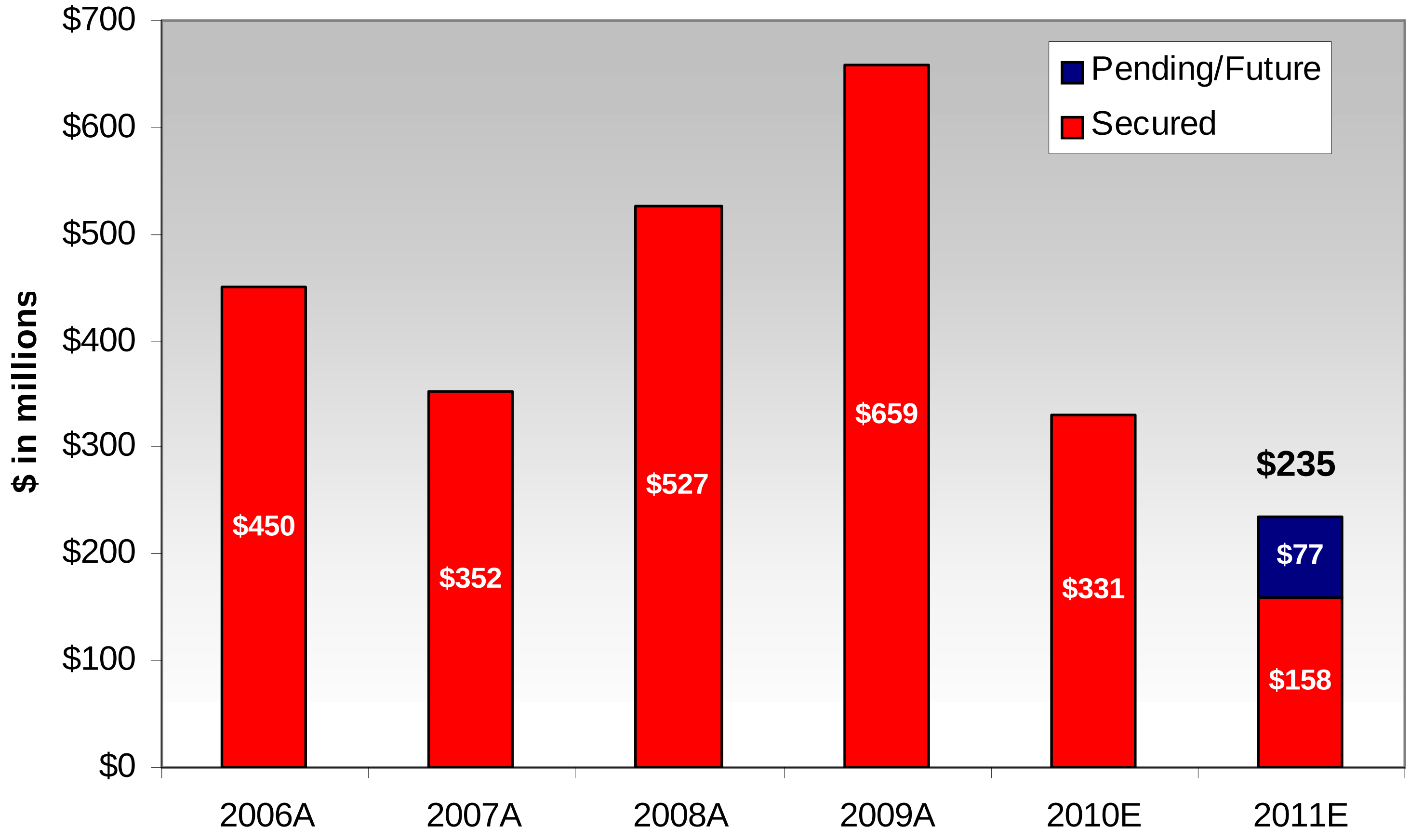
Rate Changes



Note: Rate changes in this chart excludes revenues with offsetting costs

Active or pending rate cases include Oklahoma, West Virginia and others yet to be filed

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011. Staff and Intervenor testimony recommended increases in the range of $41MM--$57MM.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

PSO General Rate Case – Docket #201000050

On July 9, 2010, PSO filed a base rate case with the Oklahoma Corporation Commission requesting a net increase of $52.4 million, comprised of a $82.7 million base rate increase and a $30.3 million decrease in the capital investment rider. The requested ROE is 11.50%. A settlement agreement was filed on Nov. 19, 2010 resulting in no change to current rates and a 10.15% ROE. Hearing scheduled December 6, 2010, with rates going into effect February 2011.

Actual Capital Structure – Company Position (2/28/10)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	53.86%	6.52%	3.51%
Common Equity	45.84%	11.50%	5.27%
Preferred Stock	0.30%	4.02%	0.01%
Total	100.00%		8.79%

Procedural Schedule

October 26, 2010	Staff & Intervenor testimony due
November 16, 2010	Rebuttal testimony due
December 6, 2010	Settlement hearing
January 5, 2011	Rates Effective, Subject to Refund

Required Rate Relief – Company Position (2/28/10)

($ in millions)

Rate Base	$	1,687.2
Rate of Return		8.79%
Operating Income Requirement	$	148.3
Adjusted Operating Income	$	97.9
Difference	$	50.4
Revenue Conversion Factor		1.6391
Total Revenue Requirement	$	82.7
Elimination of Capital Investment Rider	$	(30.3)
	$	52.4

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,467MM	10.50%	54/46	1/14/2009
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

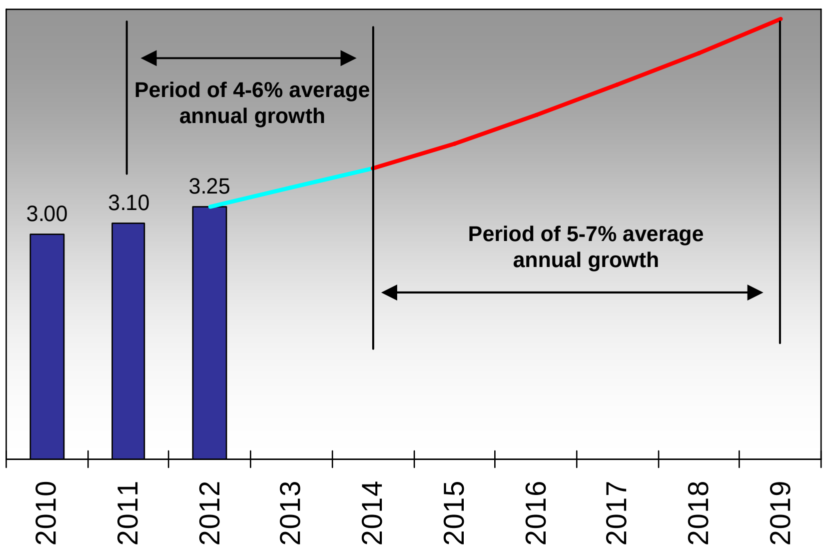
* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

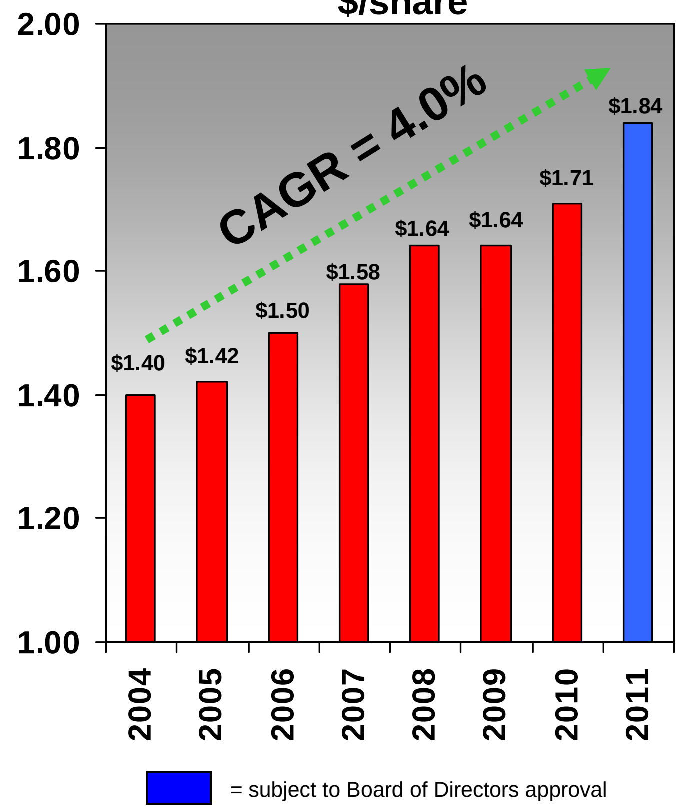
Value Proposition

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004
$/share



- <u>9.5% increase</u> in quarterly dividend to $0.46/share declared on October 26th
- <u>402nd consecutive</u> quarterly dividend will be paid December 10, 2010
- 50-60% payout ratio target
- Current yield about 5%

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Norges Bank Investment Management

Columbus Office Visit

Friday, December 5, 2008

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This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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2008 & 2009 Ongoing Earnings Guidance

2008 EPS: $3.15 - $3.25

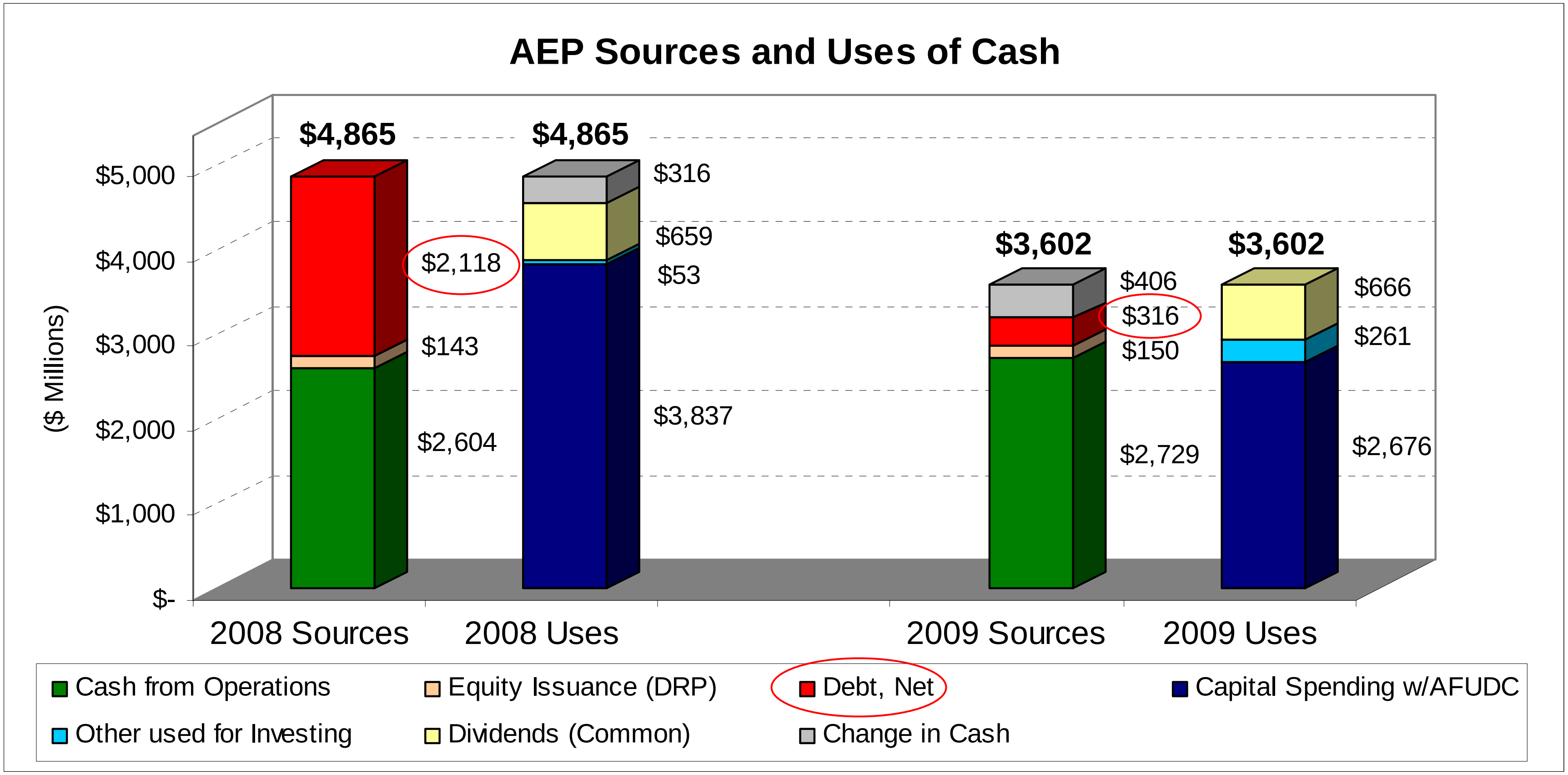
2009 EPS: $3.00 - $3.40

American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance ($ millions)	2008 Original Guidance EPS	2009 Guidance ($ millions)	2009 Guidance EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Depreciation & Amortization	(1,451)		(1,546)	
Taxes Other than Income Taxes	(779)		(790)	
Interest Exp & Preferred Dividend	(839)		(929)	
Other Income & Deductions	127		120	
Income Taxes	(602)		(641)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations:				
AEP River Operations	57	0.14	62	0.15
Generation & Marketing	20	0.05	13	0.03
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

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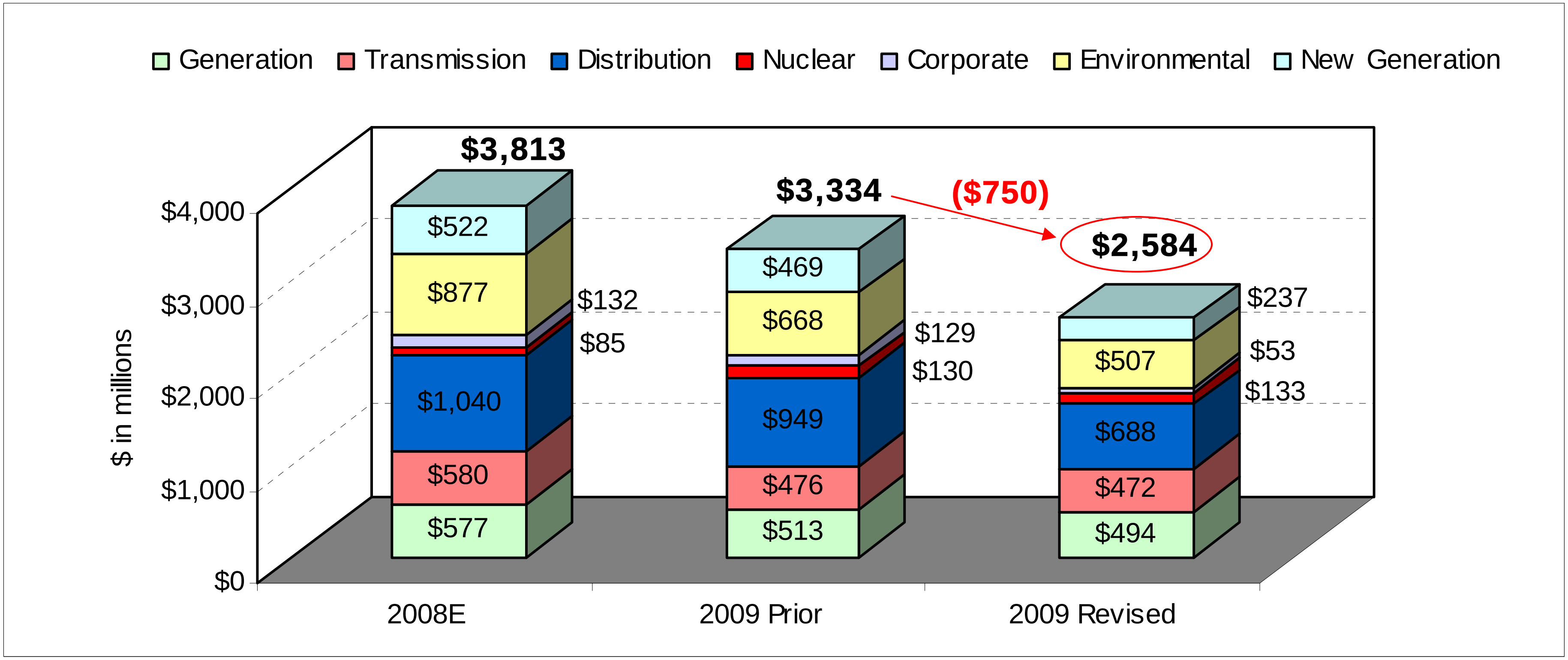
2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

Liquidity

Liquidity Summary (unaudited)	Actual 10/28/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	1,366	
Less		
Draw on Credit Facilities	(1,969)	
Commercial Paper Outstanding	(178)	
Letters of Credit Issued	(439)	
Net Available Liquidity	**$2,699**	

AEP's liquidity position is $2.7 billion as of 10/28/08.

Capitalization

Capital Structure	Actual 12/31/2007			Actual 9/30/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,993	-	14,993	16,007		16,007
Short-term Debt	660	-	660	1,302		1,302
Preferred Stock Not Subject to Mandatory Redemption	-	61	61		61	61
Common Equity	-	10,079	10,079		10,917	10,917
Total Capitalization per Balance Sheet	**15,654**	**10,139**	**25,793**	**17,309**	**10,978**	**28,286**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***61.2%***	***38.8%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
less: Cash and Marketable Securities	(178)	-	(178)	(781)	-	(781)
Capital and Operating Leases	1,522	-	1,163	1,470	-	1,470
Securitization Bonds	(2,257)	-	(2,257)	(2,132)	-	(2,132)
Receivables Securitization	507	-	507	555	-	555
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(263)	-	(263)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	1
Total Adjusted Capitalization	**14,969**	**10,139**	**25,108**	**15,999**	**11,136**	**27,135**
% of Adjusted Capitalization [1]	***59.6%***	***40.4%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Credit Adjusted Ratios:						
FFO Interest Coverage			**4.3**			**4.7**
FFO to Total Debt			**19.6%**			**21.5%**

Our goal remains a maximum 60/40 debt-to-capital ratio on an adjusted basis.

Long-term Debt Maturity Profile

($ in millions)

Year	2008 (1)		2009		2010	
AEP, Inc.	$	-	$	-	$	490
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	-	$	150	$	150
Columbus Southern Power	$	-	$	-	$	150
Kentucky Power	$	30	$	-	$	-
Indiana Michigan Power	$	50	$	-	$	-
Ohio Power	$	37	$	82	$	600
Public Service of Oklahoma	$	-	$	50	$	150
Southwestern Electric Power	$	-	$	-	$	-
Texas Central Company(2)	$	-	$	-	$	203
Texas North Company	$	-	$	-	$	-
Total	$	117	$	282	$	1,743

(1) Maturities remaining as of September 30, 2008

(2) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Ratings current as of October 17, 2008

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
AEP, Inc. Short Term Rating	**P2**	**S**	**A2**	**S**	**F2**	**S**
AEP Texas Central Company	**Baa2**	**N**	**BBB**	**S**	**BBB+**	**S**
AEP Texas North Company	**Baa1**	**S**	**BBB**	**S**	**A-**	**S**
Appalachian Power Company	**Baa2**	**N**	**BBB**	**S**	**BBB+**	**N**
Columbus Southern Power Company	**A3**	**S**	**BBB**	**S**	**A-**	**S**
Indiana Michigan Power Company	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
Kentucky Power Company	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
Ohio Power Company	**A3**	**N**	**BBB**	**S**	**BBB+**	**S**
Public Service Company of Oklahoma	**Baa1**	**S**	**BBB**	**S**	**BBB+**	**S**
Southwestern Electric Power Company	**Baa1**	**N**	**BBB**	**S**	**BBB+**	**S**

Pension and OPEB Estimate

- The Pension plan and OPEB funds investment returns are each down about 25% YTD as of October 16, 2008. The drop in assets is mitigated slightly by a corresponding decrease in plan liability caused by a higher discount rate (from 6% to 7% for pensions and from 6.25% to 7.25% for OPEB).
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- As of October 16, 2008, we expect 2009 pension expense to increase $10MM over 2008 and the estimated OPEB expense to increase $30MM year over year.
- These increases are reflected in our current guidance.
- We are currently not expecting any mandatory contributions to pension in 2009.

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- SWEPCo Stall Plant Filings in Arkansas
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART^{SM} Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony was filed October 31, Staff testimony was filed November 7 and the public hearing commenced on November 17, 2008. We anticipate an order in the first quarter of 2009.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $125.6 million ($80.1 million in base revenues and $45.6 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	1,999.1 *
Rate of Return		8.10%
Operating Income Requirement	$	161.9
Pro-Forma Operating Income	$	113.1
Difference	$	48.8
Revenue Conversion Factor		1.64
Revenue Deficiency	$	80.1
Reliability Enhancement Tracker	$	28.4
DSM / EE Tracker	$	4.4
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	44.4
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	125.6

* rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

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Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure – Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief – Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Regulatory Activity Underway

SPP OATT Formula Rate Filing (Docket #:ER07-1069-000)

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Regulatory Activity Underway

PJM OATT Formula Rate Filing (Docket #:ER08-1329-000)

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$507MM and the new revenue requirement requested is \$606MM. Approximately \$31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to March 1, 2009, with rates subject to refund.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is pending.

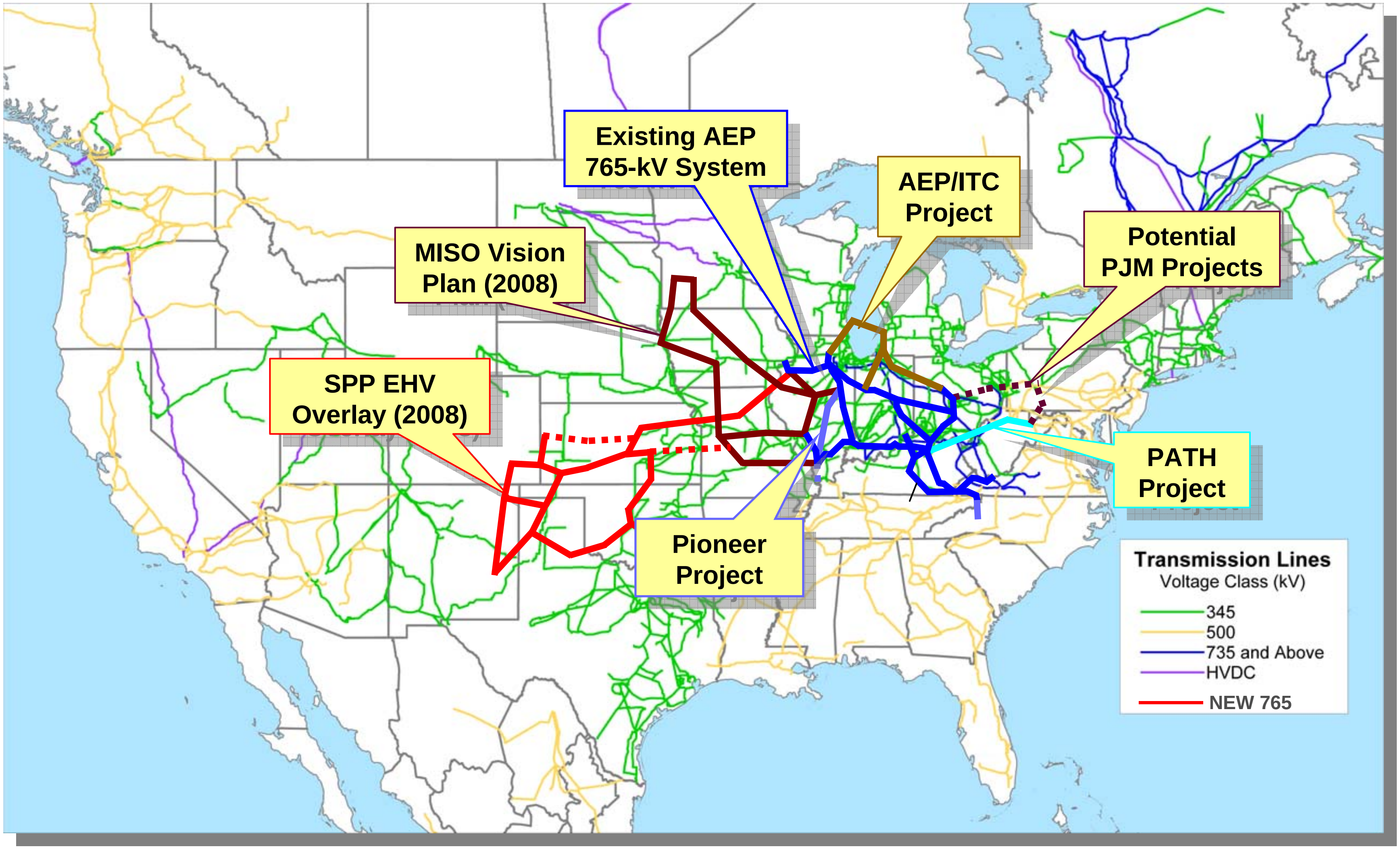
Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- PSC approval was granted on September 10, 2008.
- Air permit received on March 20, 2008.

Texas

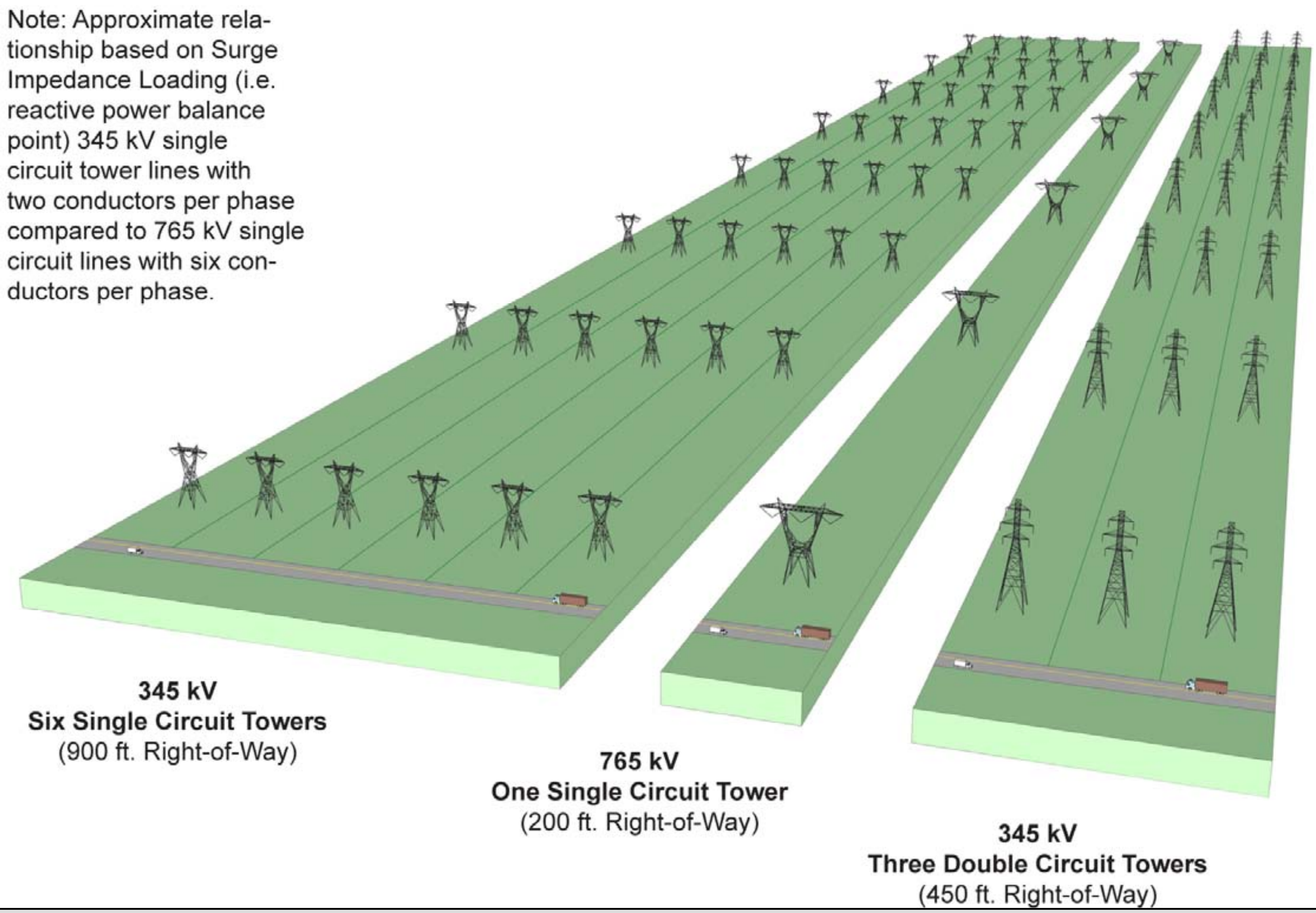
- PUCT order approving plant was issued on March 8, 2007.

Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

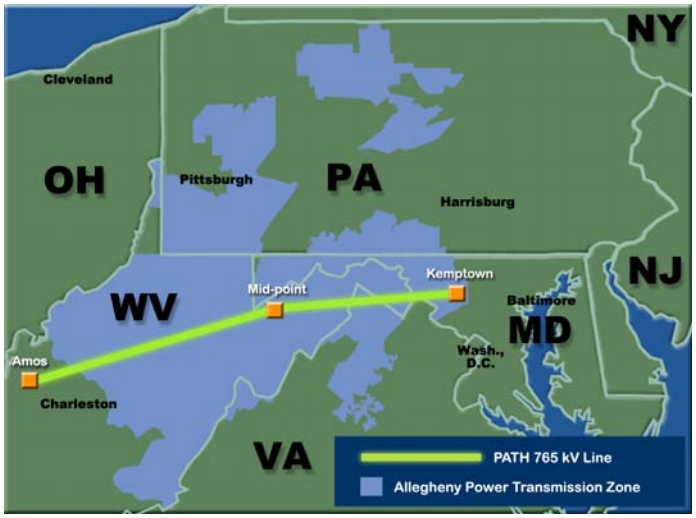
765 Right-of-Way Comparison



From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

EHV Transmission in PJM: PATH

- ***PATH Progress to Date***
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
  - In October 2008, PJM announced a reconfiguration of the PATH line which will eliminate the connection with the Bedington substation and the twin-circuit 500-kV lines from Bedington to Kemptown, and include a new mid-point substation near existing PATH alternative routes
    - The reconfiguration is a result of constraints identified as a result of comprehensive siting studies; interaction with government agencies; public input; and a desire to identify a solution that reduces line mileage and minimizes the impact on communities and the environment.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
- ***Key Challenges***
  - CPCN and Siting Approval from WV and MD



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MidAmerican Energy Holdings Company

Electric Transmission Texas Update

- 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
- ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
- Services provided by AEP and investment opportunities can be offered by either partner
- Total initial investment of $70 million before ownership division
- In October 2008, the District Court found that the PUCT exceeded its authority by granting ETT a CCN. This decision is currently under appeal and ETT believes the ultimate outcome will validate its utility status.

Electric Transmission America Update

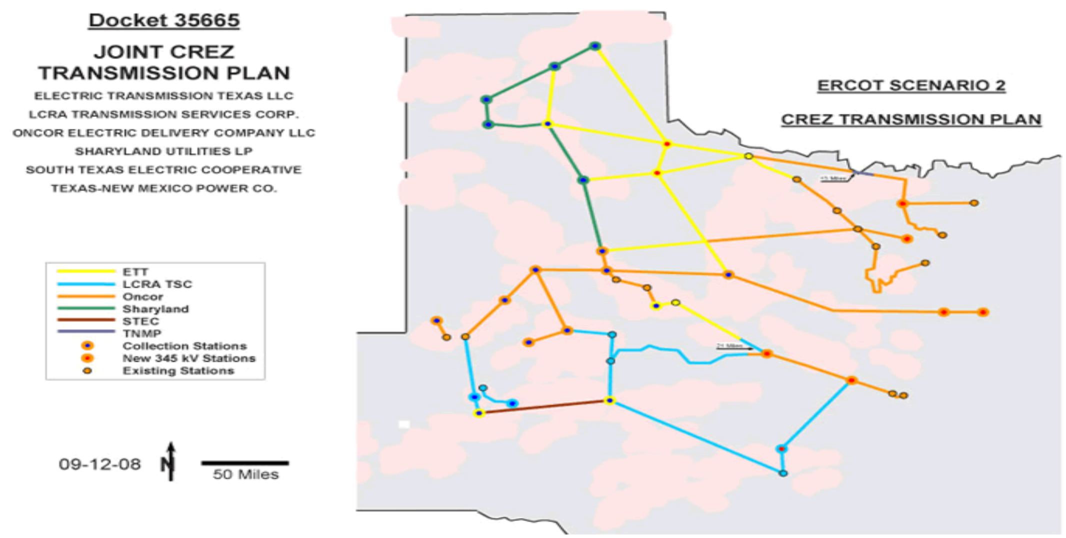
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - In 2008, ETA signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

❑ *Overview*

- ❑ In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the CREZ facilities approved by the Commission.
- ❑ ETT's requested share of the coordinated plan is approximately $1.5 billion. Staff testimony in October 2008 recommended ETT's share at $1.2 billion.
- ❑ The filing calls for completion of the plan by 2012.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

❑ *Next Steps*

- ❑ PUCT hearings – December 2008
- ❑ Selection of transmission providers – 1Q 2009

ETT
Electric Transmission Texas

EHV Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development

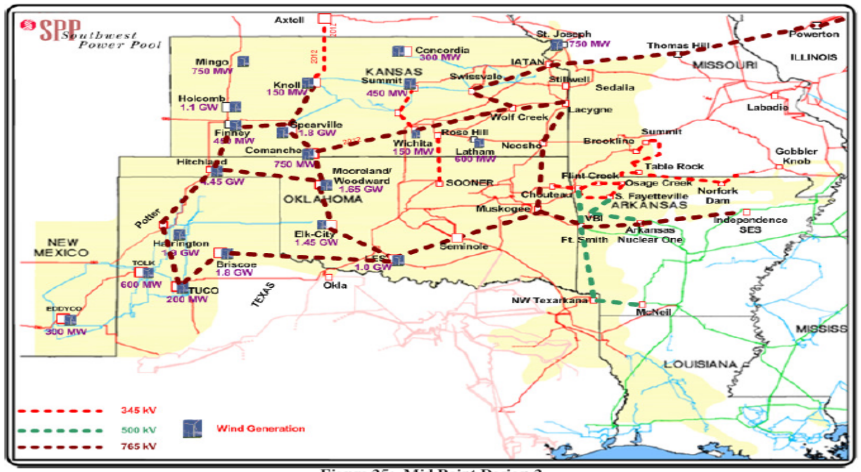


Figure 25: Mid Point Design 2

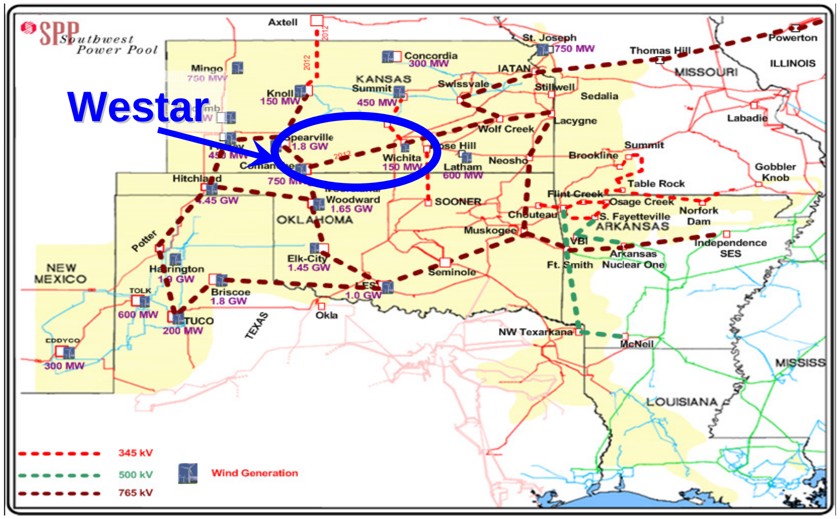
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC order received in December 2008 approving:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

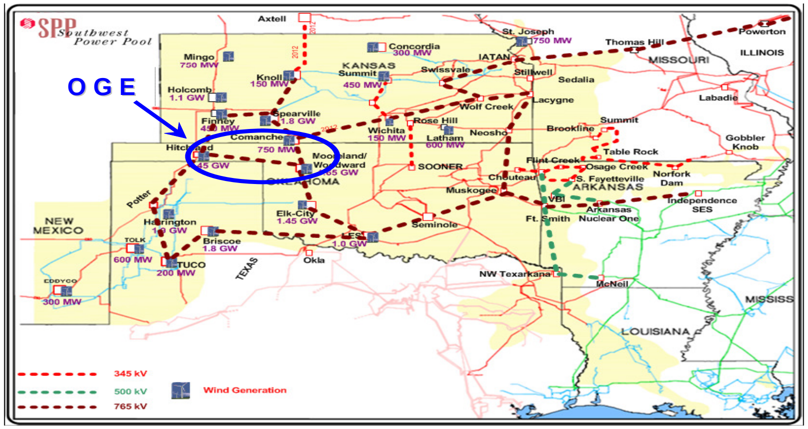
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

❑ *Overview*

- ❑ In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- ❑ TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- ❑ The project will promote wind development in the western half of Oklahoma.
- ❑ Project is expected to cost approximately $500 million and be in-service by 2013.
- ❑ AEP's ownership of the joint venture is 25%.
- ❑ Other responsibilities will be handled by the partners or outsourced.
- ❑ FERC order received in December 2008 approving:
  - ❑ Cash return on CWIP and 12.8% incentive ROE
  - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
  - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

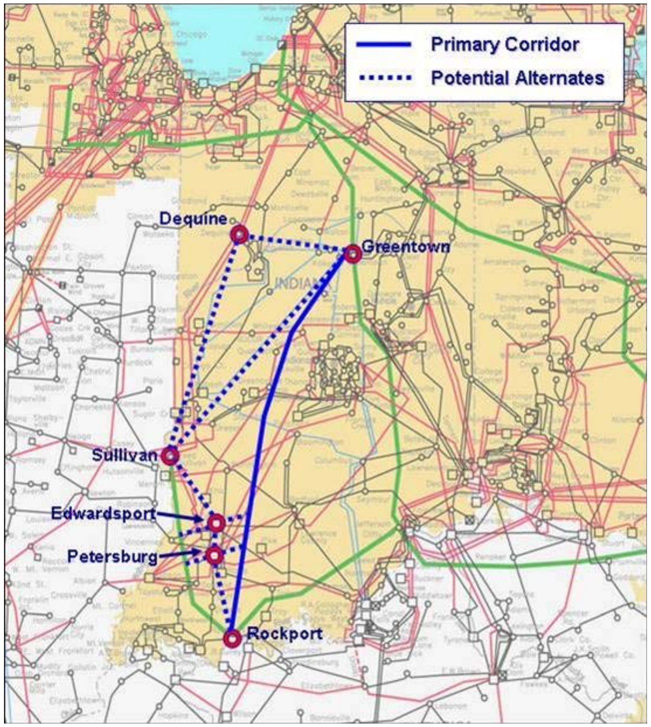
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

❑ *Key Challenges*

- ❑ Cost allocation which enables the development of "system solutions"
- ❑ RTO Approval

Pioneer Transmission, LLC

- ***Overview***
  - In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
  - PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
  - The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
  - Project is expected to cost approximately $1 billion and be in-service by 2015.
  - AEP's ownership of the joint venture is 50%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC formula rate filing submitted in October 2008 requesting:
    - Cash return on CWIP and 13.5% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



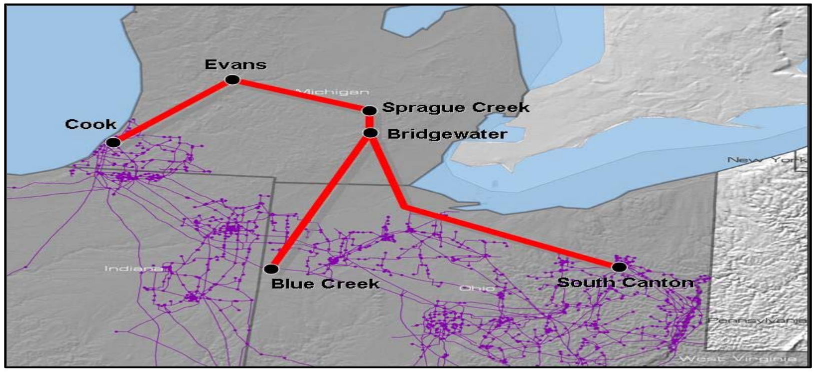
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Siting

EHV Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- ***Overview***
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (in 2007$, before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- ***Benefits***
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTOs Approvals



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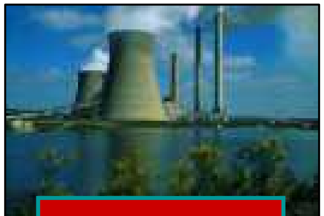
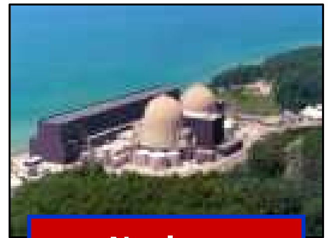
Domestic Generation Fleet

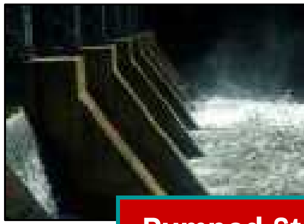


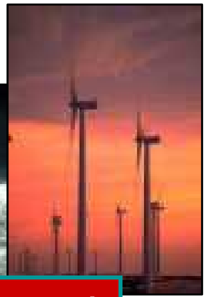
Coal/Lignite
66%

Nat. Gas/Oil
23%



Nuclear
6%





Pumped Storage/
Hydro/Wind
5%

AEP's Generation Fleet
38,721* MW Capacity

* Includes 270 MW of mothballed/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

AMERICAN ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date
AEG	Dresden	Ohio	$309 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600(1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

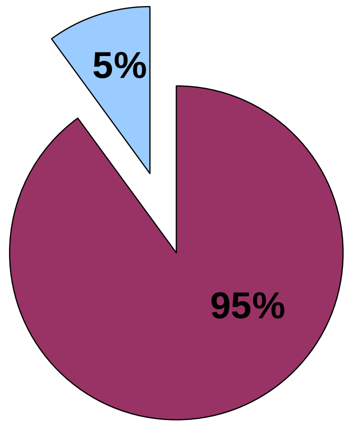
Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2013
Northeastern 3	450		N/A	☑	Projected 2014
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,646 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors - AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



- Actuals To Date & Firm Costs
- Estimated Cost Exposure*

Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $162/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

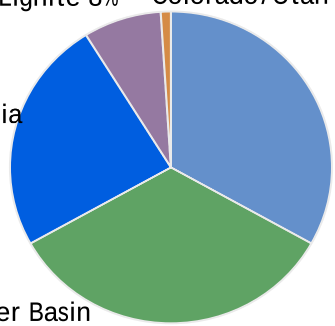
- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $262/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

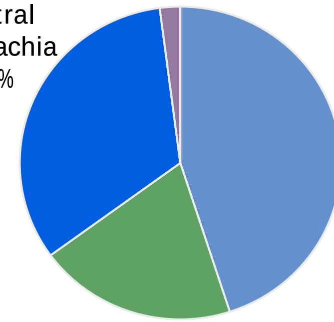
Total AEP System



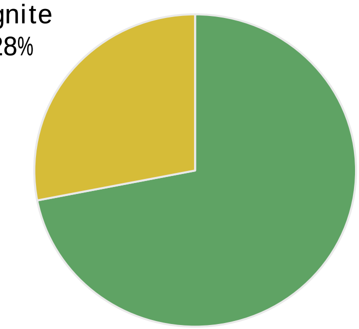
Coal Stats:

- 100% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 28% price increase in 2008 based on 2007 actual results.

AEP East



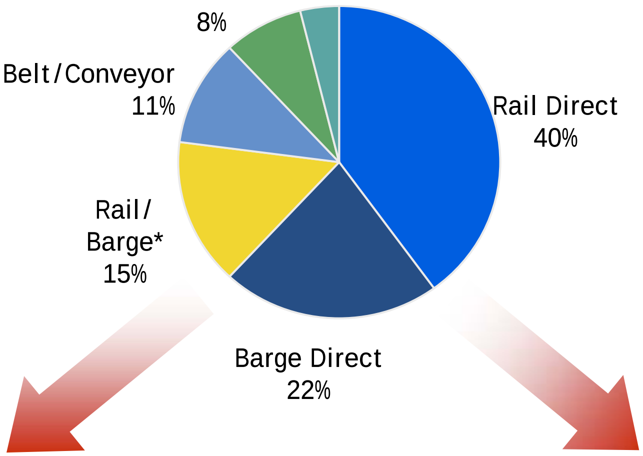
AEP West



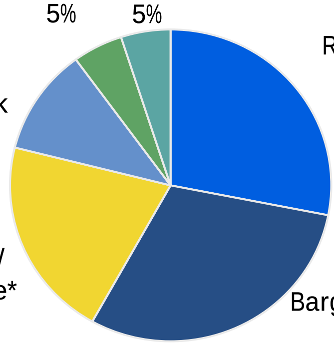
Coal Delivery

Total AEP System

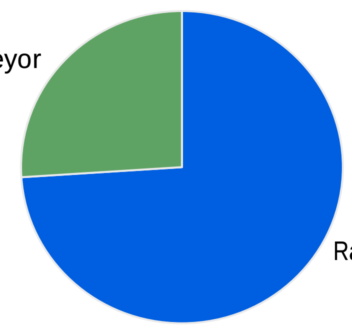
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

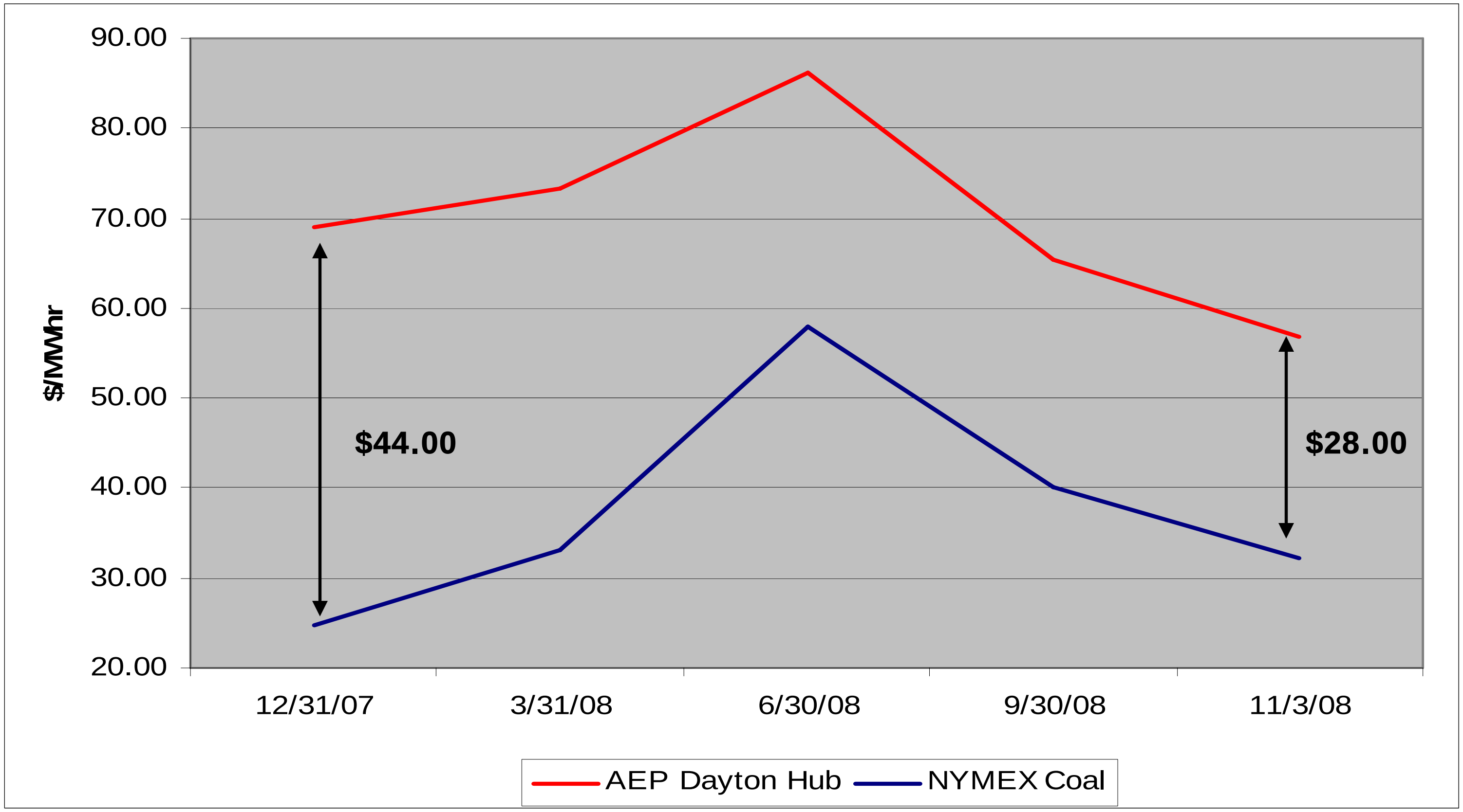
AEP River Operations

- Full-service Inland Waterways carrier
  - 2,900 hopper barges
  - 60+ towboats/20 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

Inland Waterway Routes For AEP River Operations

Dark Spread Comparison

NYMEX Coal vs. AEP-Dayton Hub Peak Electricity



Coal Purchases:
2009: 95+%
2010: 85+%

Del. Coal Prices:
2007A: $36.58/ton
2008E: $46.82/ton

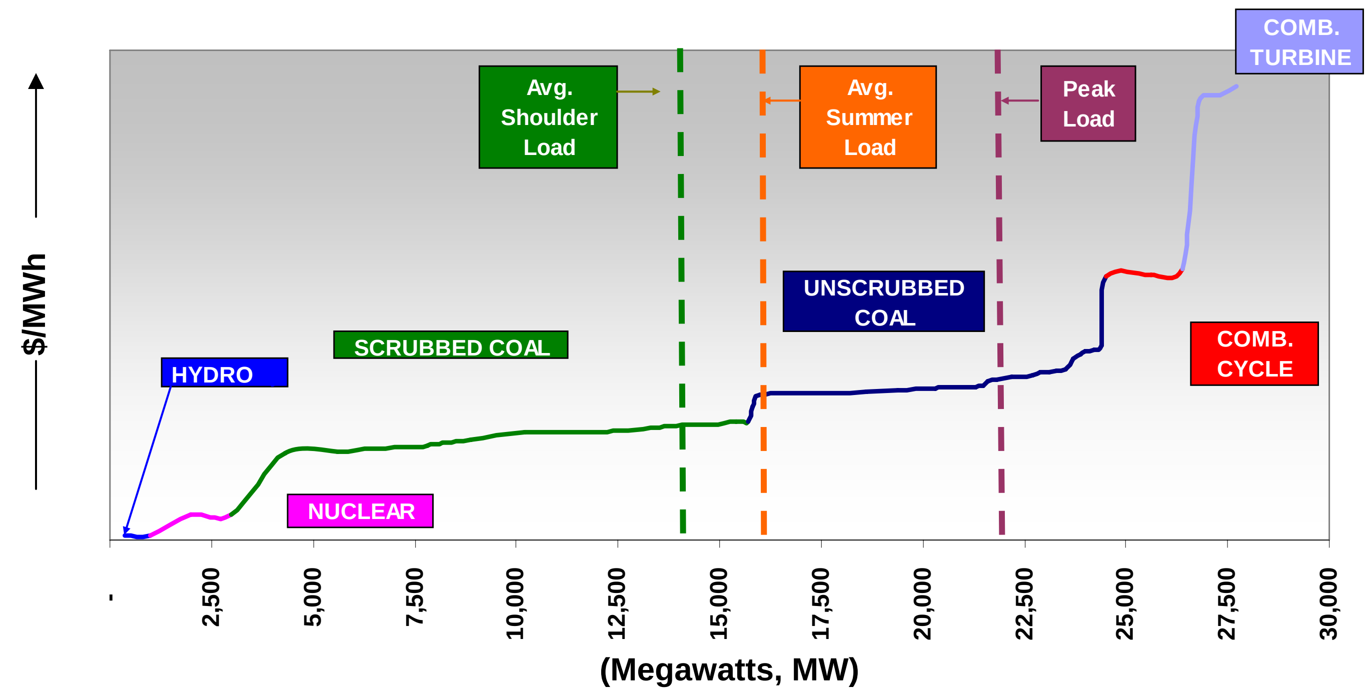
2009 estimated
increase: 12%-15%

- Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- 10,000 heat rate used for conversion
- Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.

Typical AEP Supply Stack



With the loss of Cook 1 this fall season, a planned outage on a scrubbed coal unit was cancelled, leaving the supply stack in roughly the same position for off-system sales

AEP AMERICAN® ELECTRIC POWER

Sanford Bernstein & Client Visit
AEP Headquarters
Columbus, OH
December 14, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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AEP AMERICAN ELECTRIC POWER®

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AEP AMERICAN® ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity
- $6.4 billion utility capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AMERICAN® ELECTRIC POWER

AEP Supports Climate Legislation

Key Design Elements:

- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program -** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program -** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues -** Full, free allocation to electric sector and "Low" auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

AEP AMERICAN® ELECTRIC POWER

AEP's Near-Term CO_2 Reduction Commitment

Existing Programs

- Existing plant efficiency improvements
- Renewable Energy
  - 1785 MWs of Wind
  - 722 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr
  - Over 63MM trees planted through 2008
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
2003-2010: 48 MMT Total

New Program Additions (by 2011)

- 1000 additional MWs of Renewable through PPAs
- Domestic Offsets (methane, forestry): About 2MM tons/yr
- Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr
- Additional actions: Energy efficiency and biomass: 0.3MM tons/yr

New Technology Additions

- New Generation – Ultra Super Critical
- Carbon Capture and Storage (CCS) for existing fleet
  - Chilled Ammonia

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/Year
Longer Term - New Technology

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Mountaineer CCS Update

PROJECT STATUS

- September 2 – successfully captured CO_2
- October 1 - began underground injection and storage
- October 30 – facility dedicated

NEXT STEPS

- Monitor the CO_2 behavior once underground
- Assess the parasitic load impact of the equipment on the plant
- DOE funding requested for 50% of commercial phase of project ($334MM); project expected to be operational between 2012 and 2015

PROJECT DESCRIPTION

- Alstom's chilled ammonia process captures CO_2 from a 20 MWe slipstream of flue gas at AEP's Mountaineer plant located in New Haven, WV
- Captured CO_2, transformed to a semi-liquid state, is pumped into sandstone or dolomite layers approximately 1.5 miles underground. Caprock will hold the CO_2 in place permanently.

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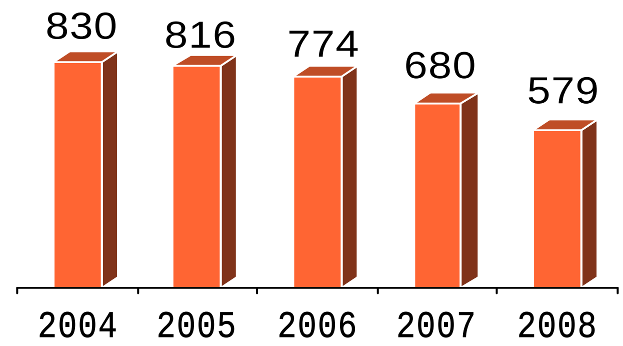
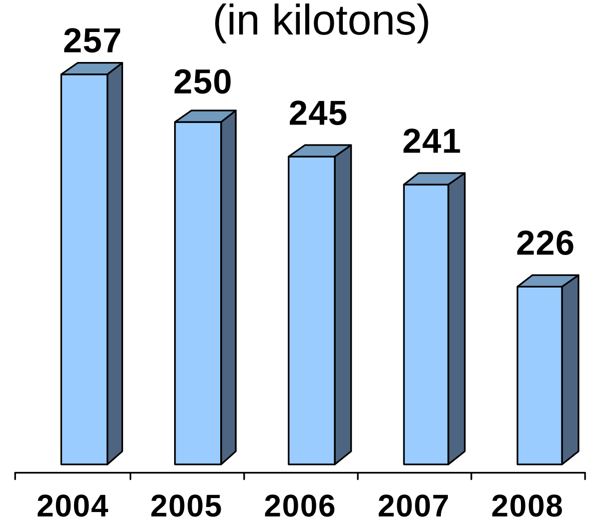
Environmental Program

- Environmental retrofits keep coal plants viable in order to take advantage of vast domestic fuel resources
- Scrubbers and SCRs reduce emissions of SO_2, NOx and Mercury
- Environmental technology installed on existing plants delays the premature retirement of those plants, thereby keeping low cost generation assets available to the market
- Since 2004, we have invested $4.4 billion in environmental retrofits to meet obligations required by environmental regulations

Annual SO_2 Emissions
(in kilotons)



Annual NOx Emissions
(in kilotons)



New Generation Projects

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

John W. Turk Jr. Ultra-Supercritical Coal Plant

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $386 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

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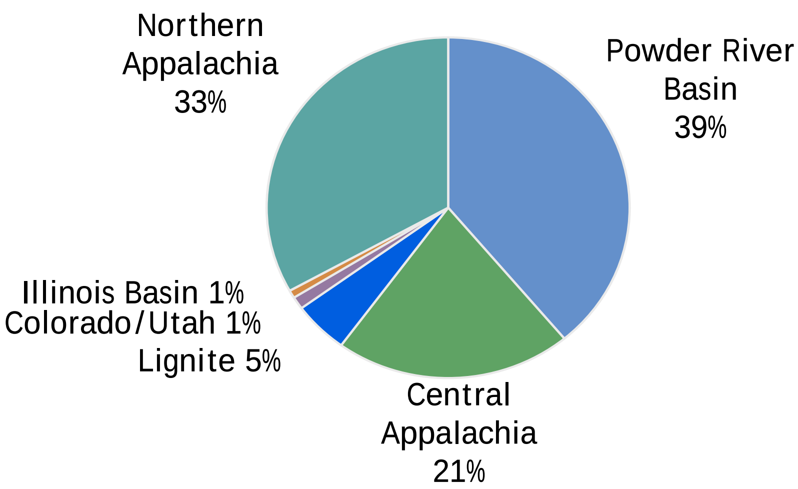
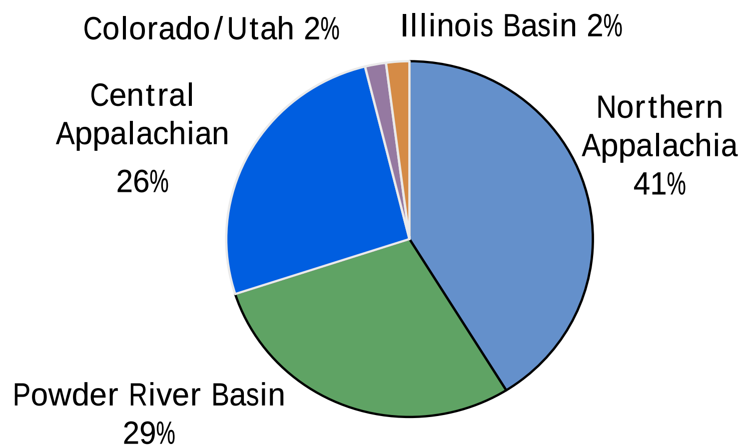
Coal Procurement - 2010 Projected

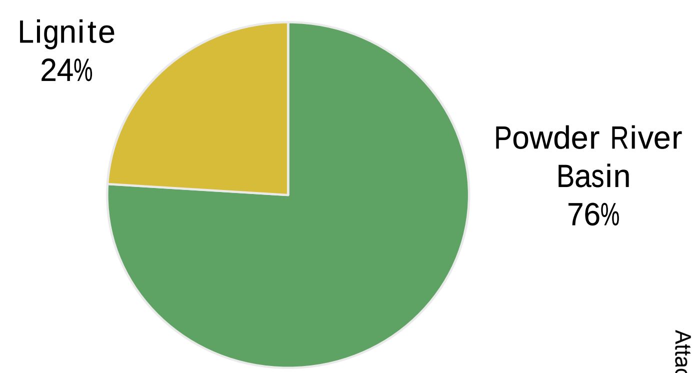
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009 and 98% for 2010
- Avg. delivered price ~ $47/ton in 2008
- Approximate 10% price increase in 2009 ~ $51/ton
- Approximate 10% price decrease in 2010 ~$46/ton

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030)

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

12/12/2009	Rates effective, subject to refund
12/28/2009	Intervenor testimony due
1/27/2010	Staff testimony due
2/17/2010	Rebuttal testimony due
3/16/2010	Evidentiary hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case

On August 28, 2009 SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. (Docket# 37364) An order is expected in July, 2010.

Projected Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

2/8/2010	Intervenor testimony due
2/15/2010	Staff testimony due
3/1/2010	SWEPCO rebuttal testimony due
3/15/2010	Evidentiary hearing commences
4/30/2010	Rates in Effect Subject to Refund

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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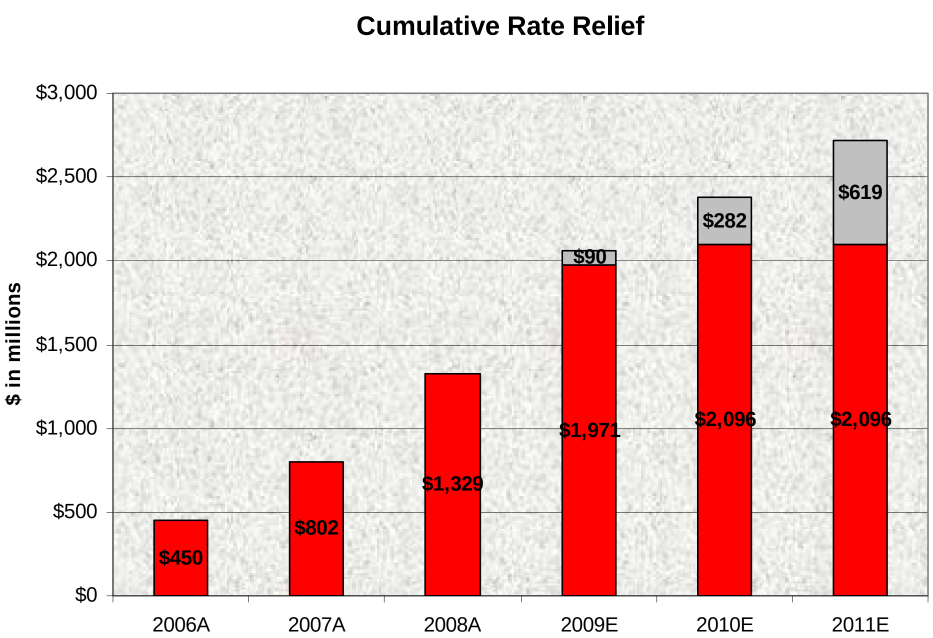
Investment in Utility Platform

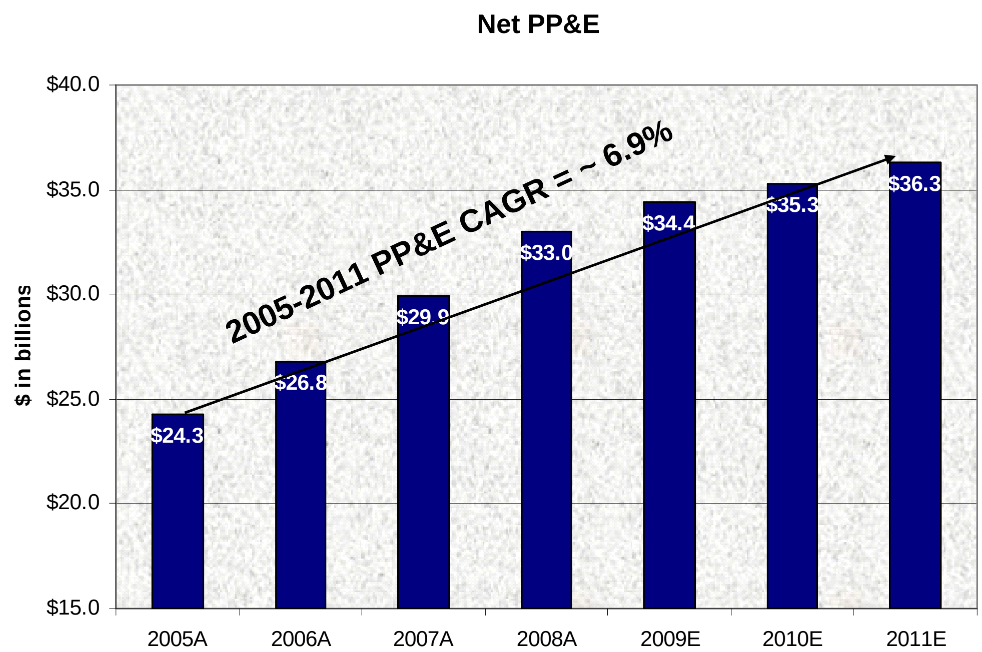
Track Record of Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$317[1]	$337

[1] *$125mm was secured for 2010 as of November 30, 2009*

Growth in Net PP&E



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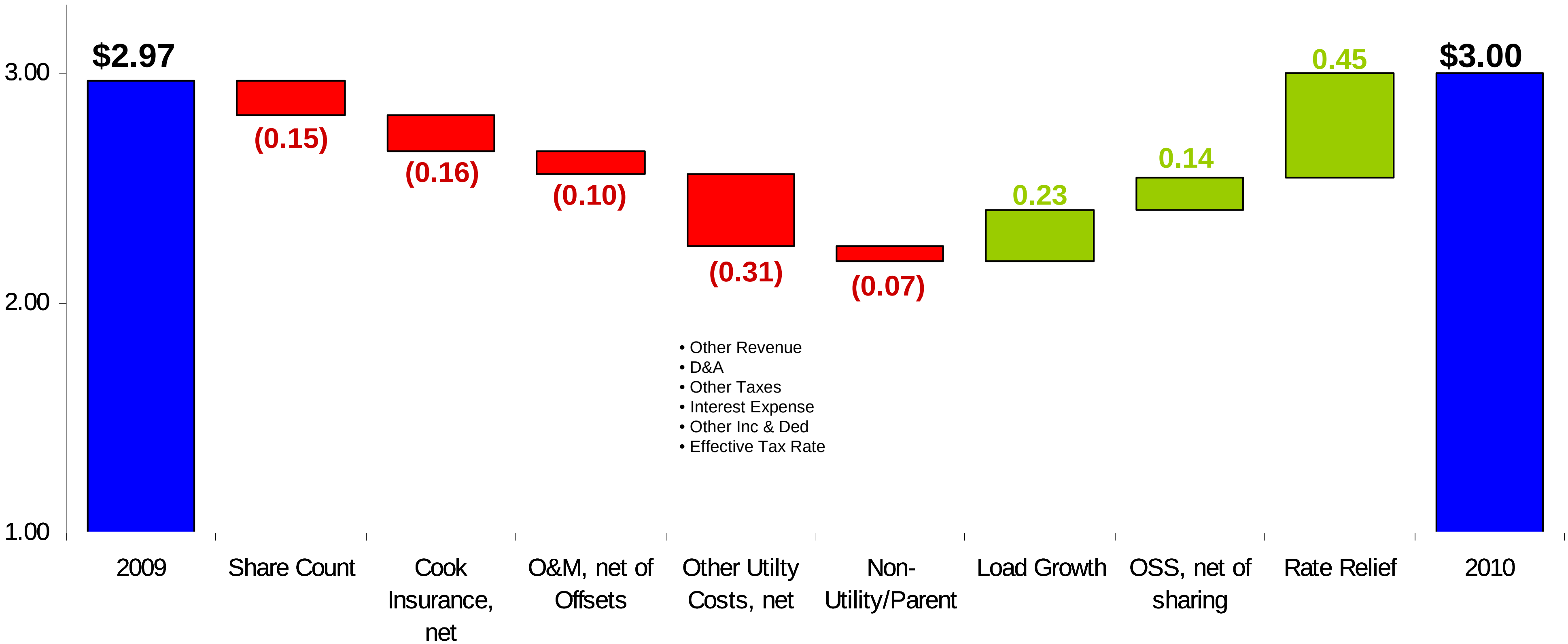
2010 Earnings Drivers



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Detailed Ongoing Earnings Guidance

2009E: $2.90 - $3.05

American Electric Power
2009 Guidance vs. 2010 Guidance

2010E: $2.80 - $3.20

		Performance Driver	2009 Guidance ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,754 GWh @ $ 38.4 /MWhr =	2,562	68,249 GWh @ $ 42.1 /MWhr =	2,873
2	Ohio Companies	47,284 GWh @ $ 57.8 /MWhr =	2,733	47,922 GWh @ $ 61.9 /MWhr =	2,968
3	West Regulated Integrated Utilities	39,112 GWh @ $ 29.8 /MWhr =	1,166	41,495 GWh @ $ 31.3 /MWhr =	1,298
4	Texas Wires	27,208 GWh @ $ 21.1 /MWhr =	575	27,510 GWh @ $ 21.9 /MWhr =	602
5	Off-System Sales (Net of Sharing)	13,525 GWh @ $ 16.7 /MWhr =	226	23,992 GWh @ $ 13.4 /MWhr =	322
6	Transmission Revenue - 3rd Party		356		353
7	Other Operating Revenue		779		554
8	Utility Gross Margin		8,397		8,970
9	Operations & Maintenance		(3,309)		(3,546)
10	Depreciation & Amortization		(1,582)		(1,625)
11	Taxes Other than Income Taxes		(768)		(791)
12	Interest Exp & Preferred Dividend		(924)		(986)
13	Other Income & Deductions		124		168
14	Income Taxes		(597)		(742)
15	Utility Operations On-Going Earnings		1,341		1,448
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		36		2
	Non-Utility Operations On-Going Earnings		83		45
19	Parent & Other On-Going Earnings		(64)		(58)
20	ON-GOING EARNINGS		1,364		1,444

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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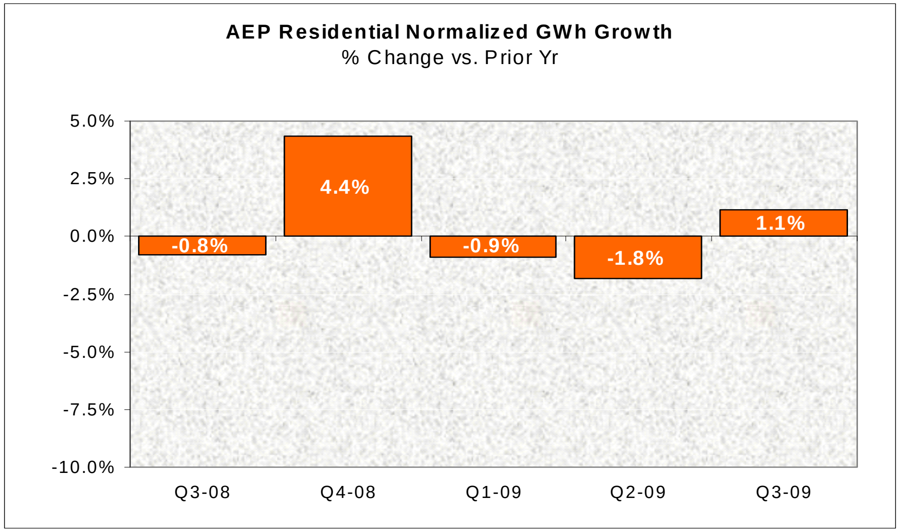
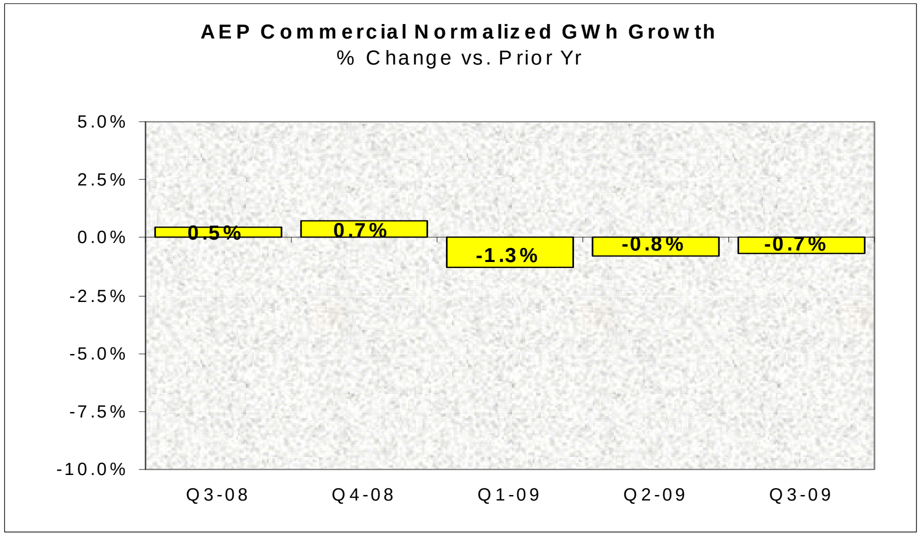
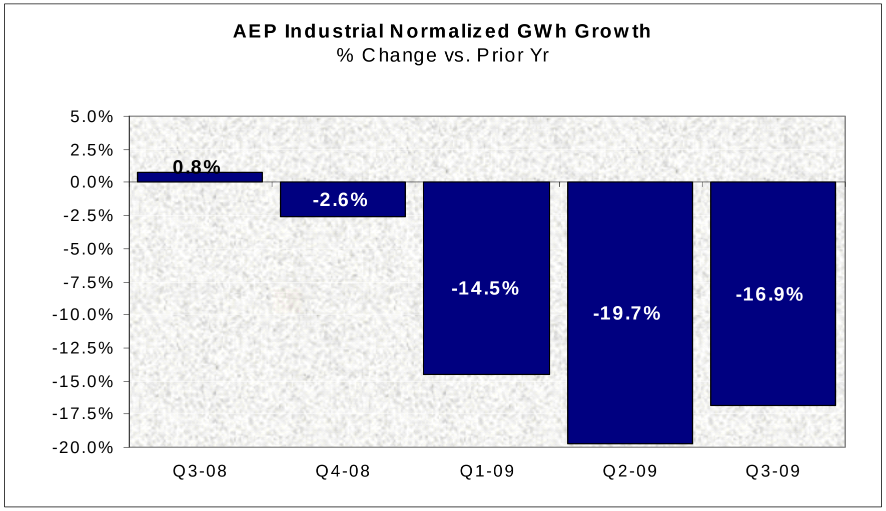
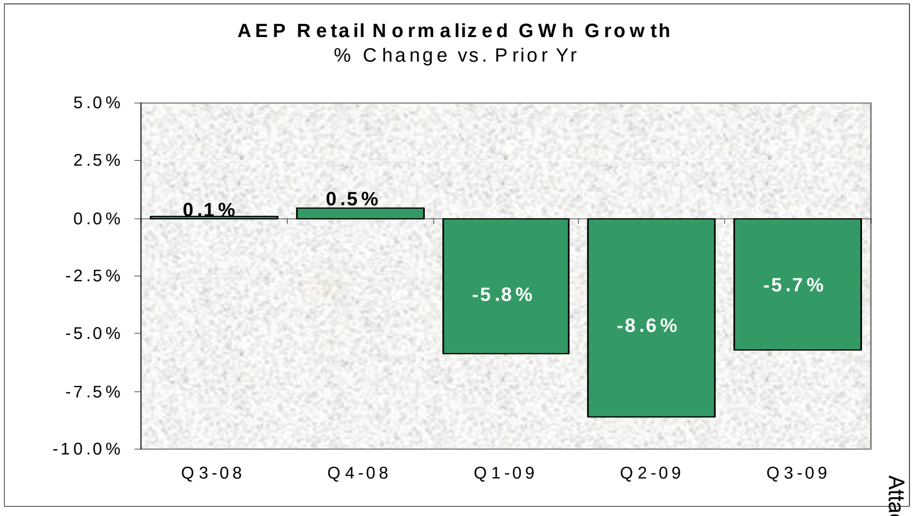
12-Month Normalized Retail Load Trends









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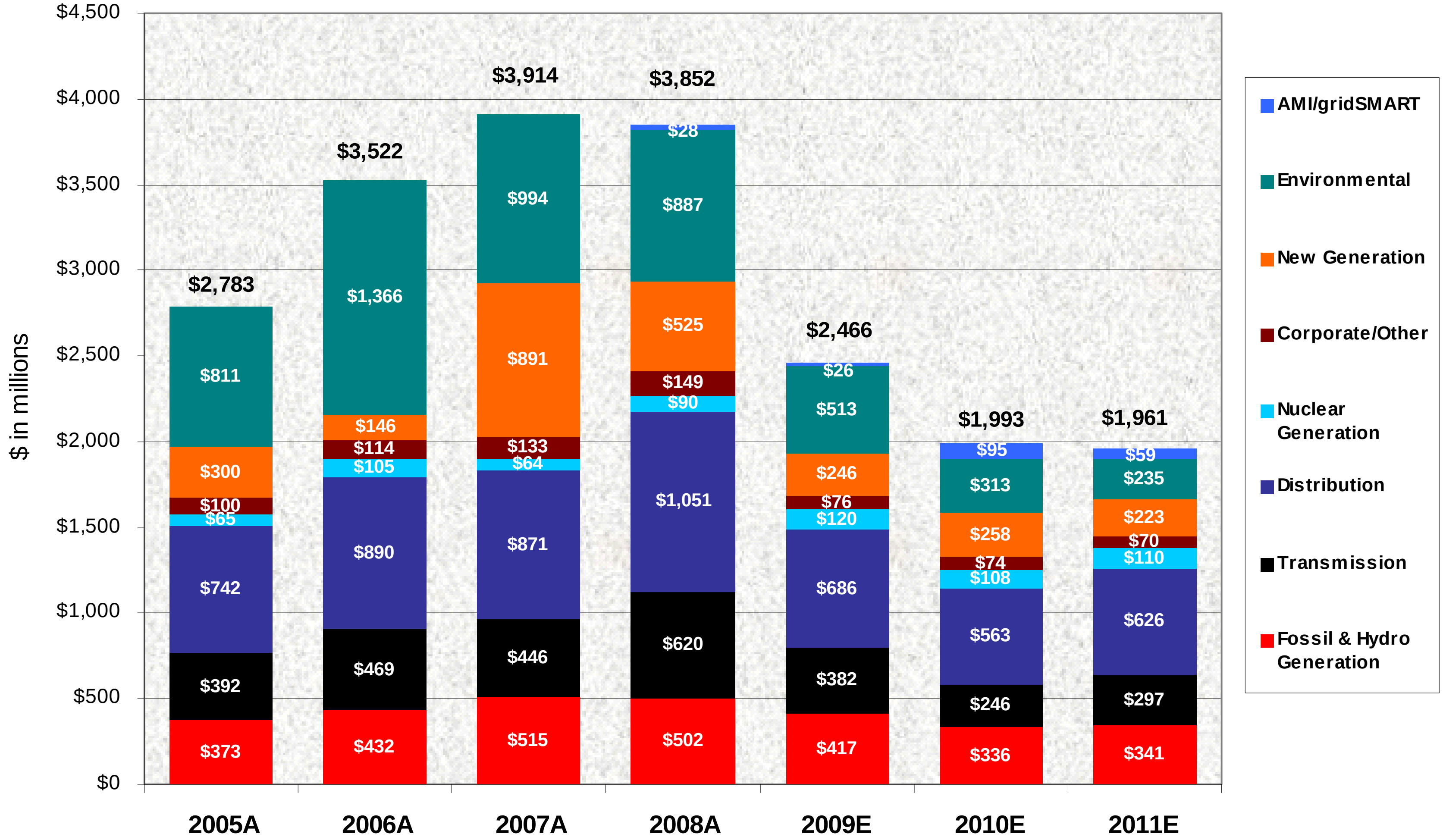
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

AEP AMERICAN ELECTRIC POWER

Multi-Year Capital Investment Funding Plan

	Actual 2008	Projection 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (3,967)	$ (2,885) *	$ (2,127)
Transmission Initiatives (JV Equity Contributions)	0	(49)	(93)
Dividend on Common Stock	(660)	(759)	(790)
Cash Sources (Uses)			
Cash from Operations	2,576	2,263	3,259
Proceeds from Sale of Assets	90	258	-
Common Stock Issued	159	1,744	150
Change in Debt, Net	2,266	(346)	(127)
Other	(231)	(436)	(274)
Change in Cash	233	(210)	(2)
Ending Cash Balance	$ 411	$ 201	$ 199

* - 2009 capital expenditure projection includes $340MM of construction-related accounts payable at 12/31

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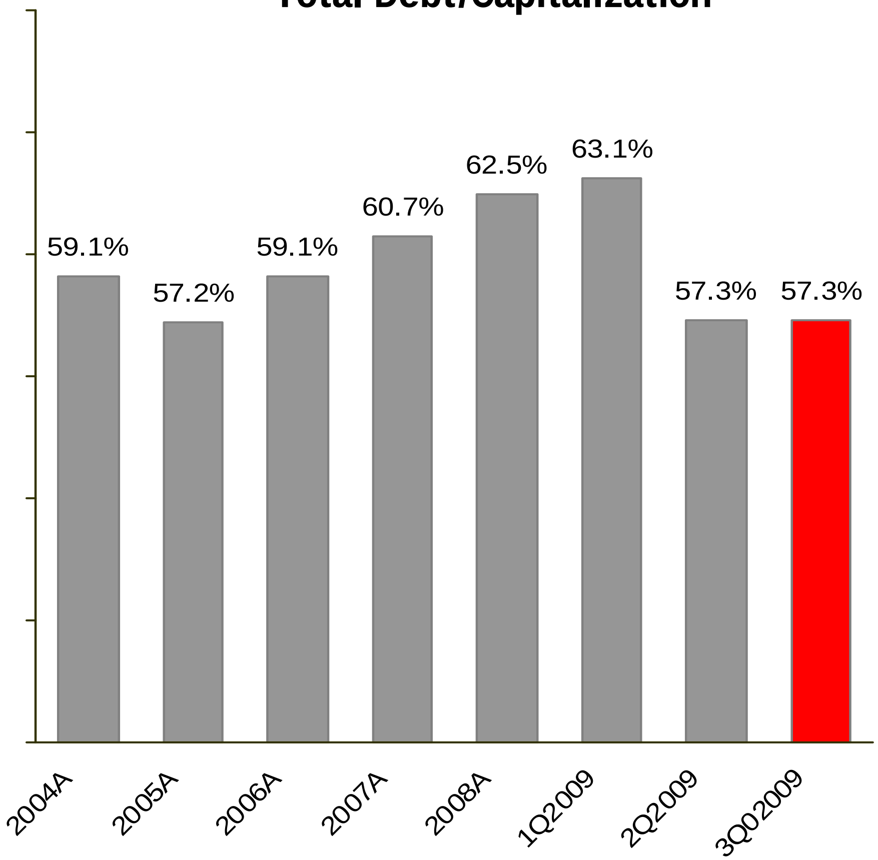
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

AEP AMERICAN ELECTRIC POWER®

AEP Credit Ratings

Ratings current as of September 30, 2009

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ 490	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 45
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 680	$ -	$ -
Public Service of Oklahoma	$ 150	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company[1]	$ 66	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,735	$ 623	$ 415

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)
Data as of September, 30 2009

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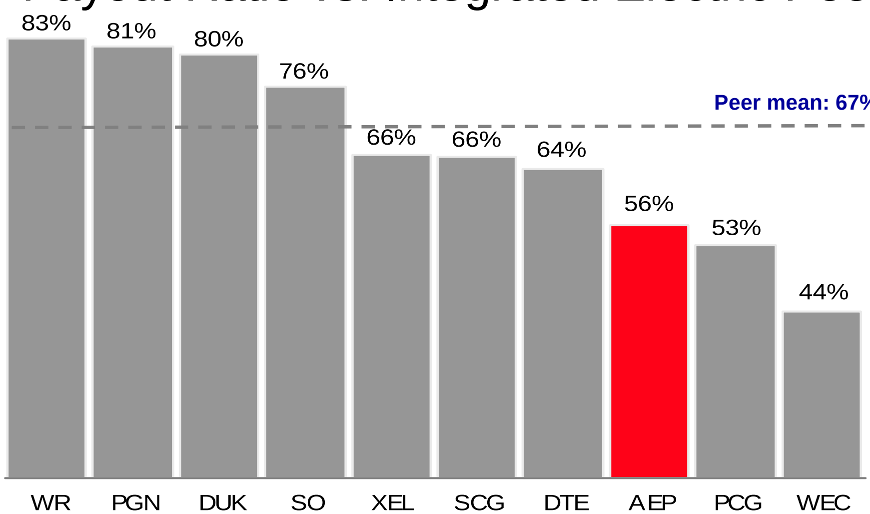
Dividend Overview

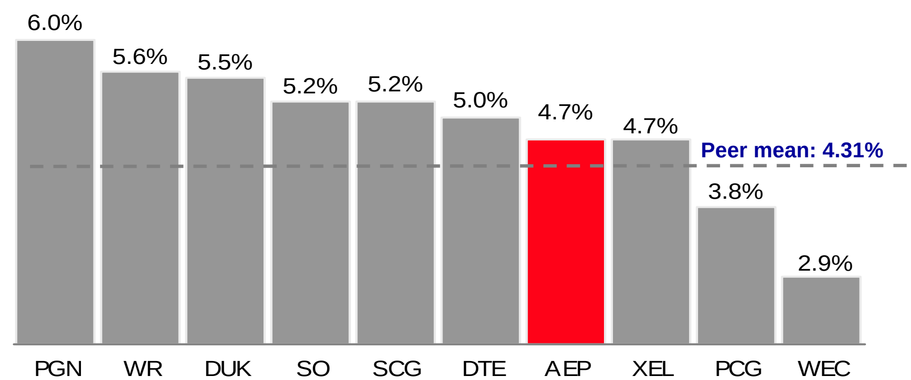
- We have paid 398 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 12/9/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 12/9/09

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Transmission Investment Opportunities

- **ETT: Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B in the next decade

- **Transco: Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM

- **Joint Ventures: Outside of our footprint, with ETA or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

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Transco

- **Transco will be used to develop significant new on-system, AEP-owned investment**
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- **Next steps:**
  - Obtain state utility status where required and join PJM and SPP as a transmission owner
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in service in 2010
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

AEP AMERICAN ELECTRIC POWER

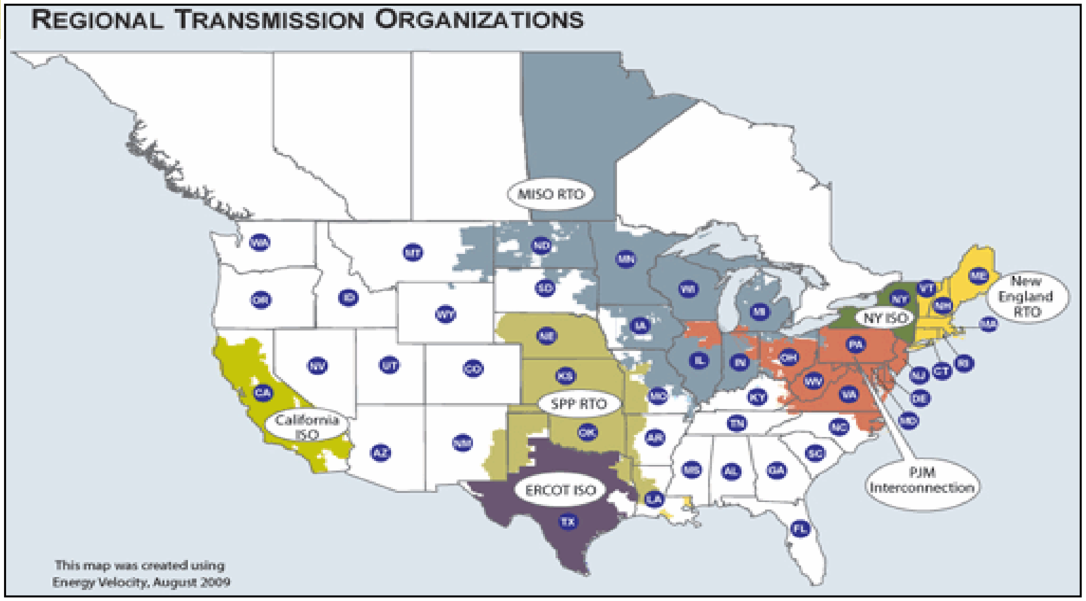
JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind — COD: 2013-14	**ETT** — COD: 2010-2013	**PATH-WV** — COD: 2014	**Pioneer** — COD: 2015
❑ *110 miles of 765 kV* ❑ *Partners: Westar (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $400 million* ❑ *ROE: 12.8%*	❑ *345 kV ERCOT Expansion* ❑ *Partner: MidAmerican Energy (50%)* ❑ *Estimated Cost: $600 million+* ❑ *ROE: 9.96%*	❑ *275 miles of 765 kV* ❑ *Partner: Allegheny Energy (50%)* ❑ *Estimated Cost: $1.2 billion* ❑ *ROE: 14.3%*	❑ *240 miles of 765 kV* ❑ *Partner: Duke Energy (50%)* ❑ *Estimated Cost: $1 billion* ❑ *ROE: 12.54%*

Tallgrass — COD: 2013-14

- ❑ *170 miles of 765 kV*
- ❑ *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- ❑ *Estimated Cost: $500 million*
- ❑ *ROE: 12.8%*



FUTURE DEVELOPMENT

SMARTransmission Study

- ❑ *Interregional EHV & Wind Integration Study*
- ❑ *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** — COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
❑ *Regional Expansion of 765 kV Backbone*	❑ *Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)* ❑ *Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)*	❑ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	❑ *700 miles of Proposed 765 kV*

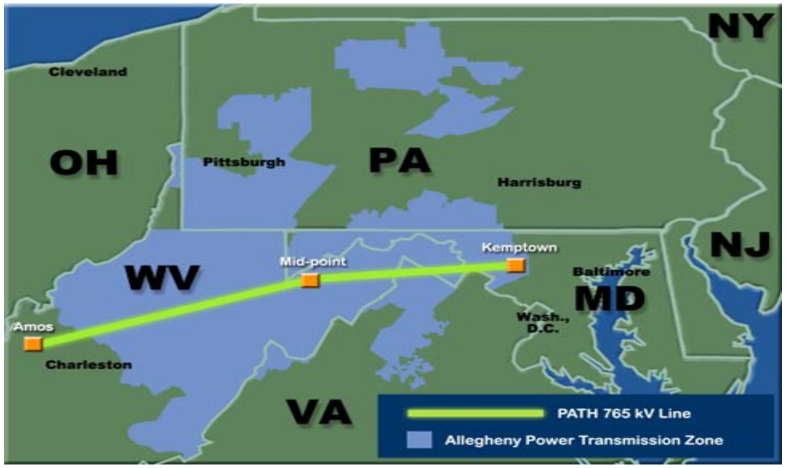
AEP AMERICAN® ELECTRIC POWER

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009 with a decision expected February, 2011.
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
- Estimated completion date: 2014

PATH
Potomac-Appalachian Transmission Highline

AEP AMERICAN® ELECTRIC POWER

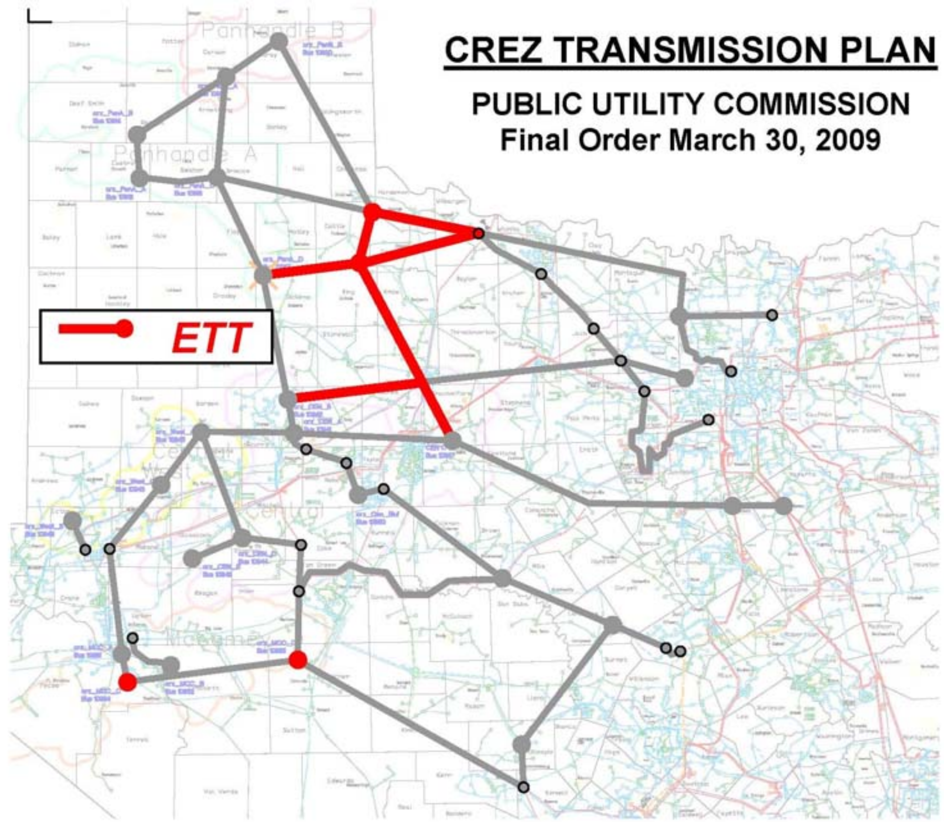
Texas CREZ Project

Overview

- On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
- Staging to occur in separate docket and consider timing of wind projects and congestion.
- PUCT established 2 categories based on priorities. ETT has no first priority lines.
- PUCT issued a final order assigning transmission service providers on March 30, 2009.
- ETT's share of CREZ investment is approx. $840MM of $4.9B total of which AEP's ownership is 50%.
- The filing calls for completion of the plan by 2013.

Next Steps

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



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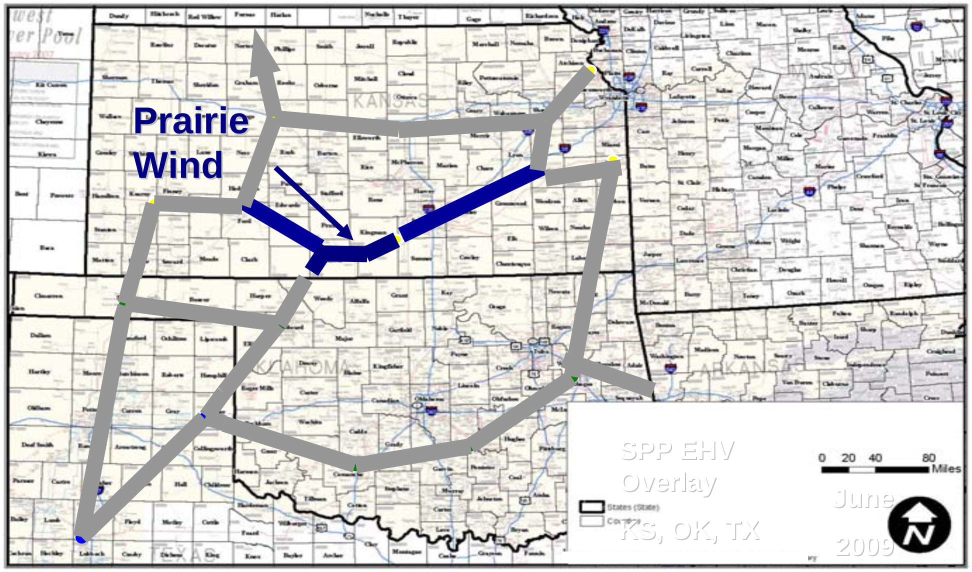
ETT
Electric Transmission Texas

AEP AMERICAN ELECTRIC POWER

Prairie Wind Transmission, LLC

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- Following a settlement agreement with ITC both entities agreed to split the mileage and costs of building the 765-kV transmission superhighway. The newly revised project is expected to cost approximately $400 million and be in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- RTO Approval

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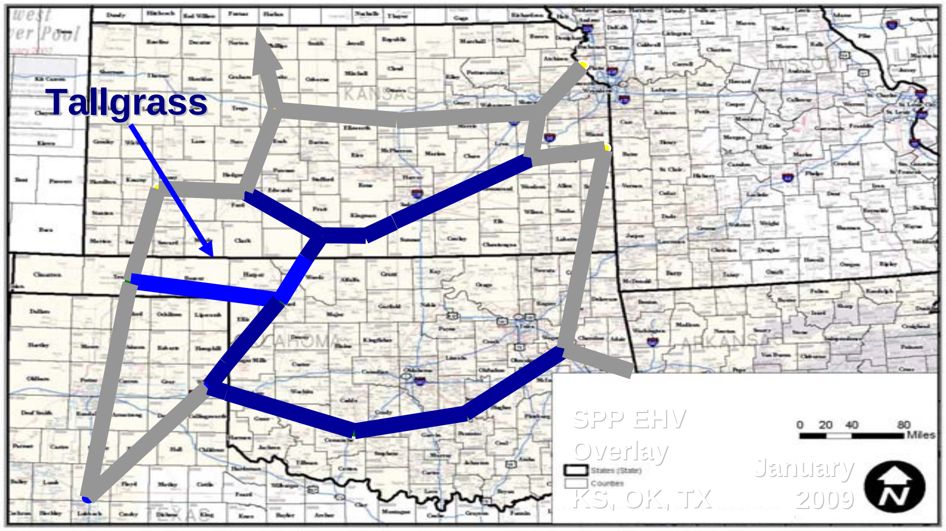
Tallgrass Transmission, LLC

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

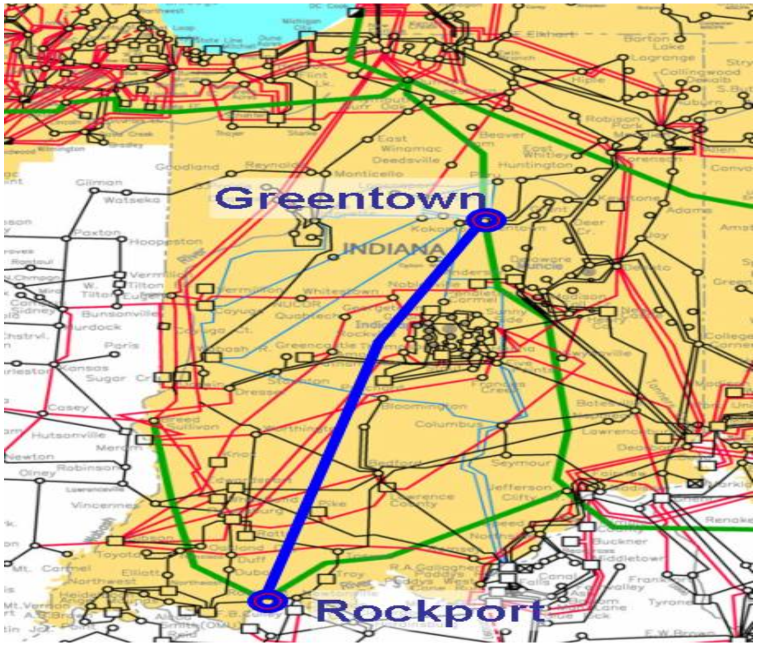
- RTO Approval

AEP AMERICAN® ELECTRIC POWER

Pioneer Transmission, LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

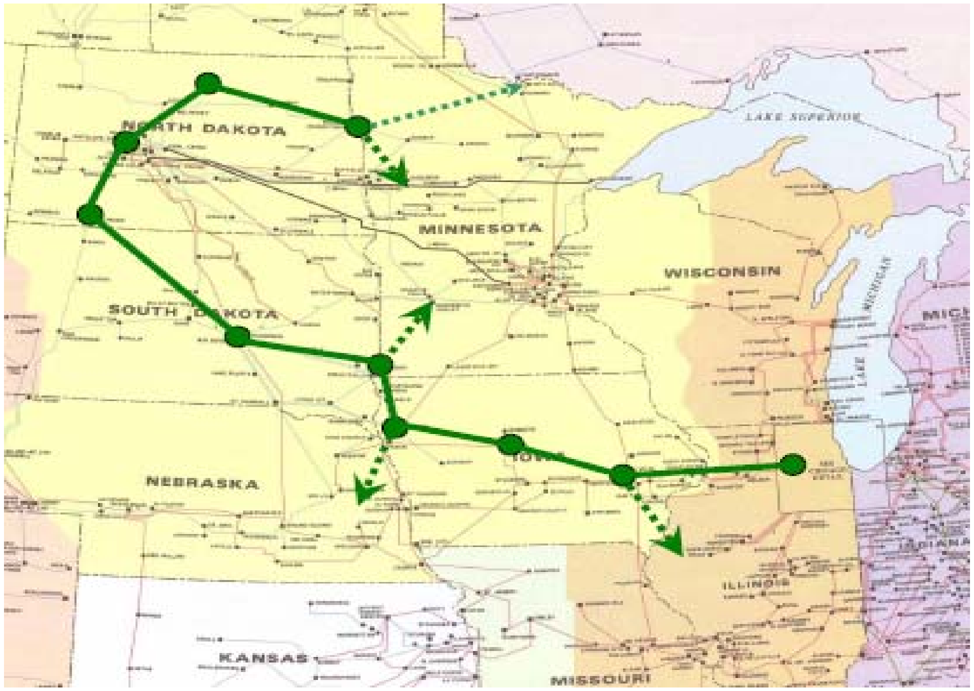
- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

AEP AMERICAN® ELECTRIC POWER

Upper Midwest EHV Development—SMART Study

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Announced SMARTransmission Study in August 2009.**
  - Participants include ETA, Exelon, ATC, Northwestern, MidAmerican and Xcel
  - Study due to be completed in early 2010 and will include “overlay” options and quantification of economic benefits.
- **Near Term Risks**
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including incentives
- **Mitigation**
  - Collaborative approach involving impacted utilities, RTOs, commissions and others

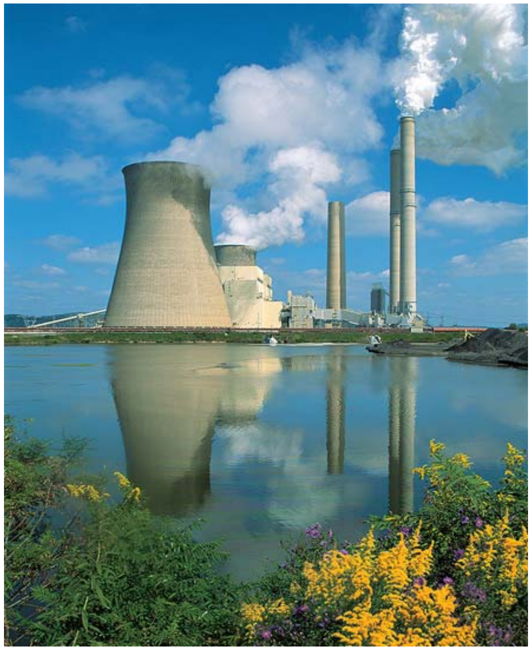


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

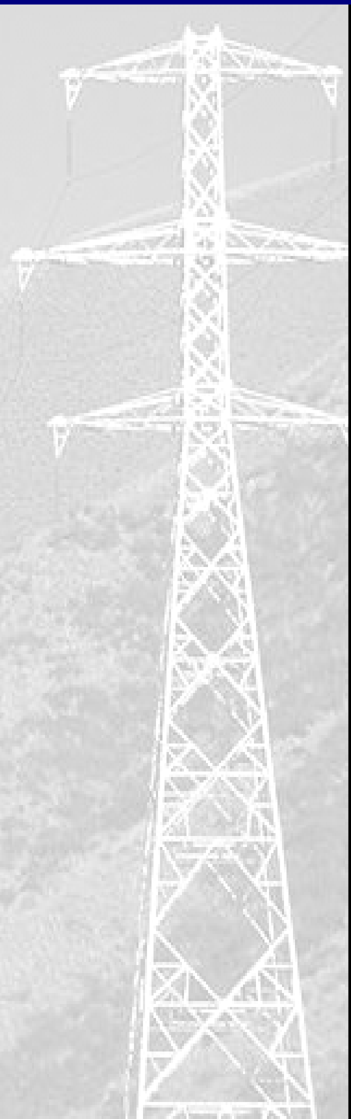
Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment
- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



General JM Gavin Plant (OH)

AEP AMERICAN ELECTRIC POWER



1Q05 Earnings Release Presentation

April 28, 2005

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Quarterly Highlights

- 1Q05 GAAP Earnings $0.90 Per Share, Ongoing $0.88 Per Share
- Reaffirm 2005 Earnings Guidance of $2.30 - $2.50 Per Share
- PJM Activity Update
- Regulatory Update
  - PSO Settlement
  - TCC Wires Case Status
  - IGCC Filing in Ohio
  - FERC Transmission Case Filed

1Q05 Earnings Performance

	$ millions			Earnings Per Share		
	1st Qtr 2004	1st Qtr 2005	Change	1st Qtr 2004	1st Qtr 2005	Change
Utility Operations	304	343	39	0.77	0.87	0.10
Investments	(6)	15	21	(0.02)	0.04	0.06
Parent Company	(9)	(14)	(5)	(0.02)	(0.03)	(0.01)
AEP On-Going Earnings	289	344	55	0.73	0.88	0.15

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q05 Utility Operations Performance

		2004 Actual		2005 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	750		709	
2	Ohio Cos.	512		491	
3	Texas Wires	99		101	
4	Texas Supply / REP	99		79	
5	Off-System Sales	169		162	
6	Other Wholesale Transactions	5		4	
7	Transmission Revenue - 3rd Party	124		93	
8	Other Operating Revenue	65		70	
9	Total Gross Margin	1,823		1,709	
10	Operations & Maintenance	(706)		(685)	
11	Depreciation & Amortization	(310)		(318)	
12	Taxes Other than Income Taxes	(182)		(186)	
13	Interest Exp & Preferred Dividend	(166)		(144)	
14	Other Income & Deductions	10		133	
15	Income Taxes	(165)		(166)	
16	Net Earnings Utility Operations	304	0.77	343	0.87

1Q 2005 Performance Drivers

Weather Impact: Negative $0.02 vs. normal
Negative $0.02 vs. prior yr.

- *Decreased margins reflecting increased fuel and unfavorable weather; partially offset by growth in retail customers & industrial demand*
- *Texas Supply margins down due to divestiture of assets and the cessation of RMR and Centrica supply contracts*
- *Lower transmission revenues due to elimination of T&O rates*
- *Lower O&M expenses largely due to timing differences*
- *Decreased interest expense reflecting refinancings completed in 2004*
- *Other Income & Deductions line includes: (1) $70 MM of Centrica earnings sharing; (2) return on environmental additions in Ohio ($26 MM); and (3) carrying costs on TX stranded costs ($22 MM)*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

First Quarter: Cash Flow from Operations

($ millions)	1st Quarter 2005	1st Quarter 2004
Operating Activities		
Net Income -- Reported	**$ 355**	**$ 282**
Discontinued Operations	(1)	7
Continuing Earnings	**354**	**289**
Depreciation, Amortization & Deferred Taxes	218	266
Pension Contributions	(102)	-
Changes in Mark-to-Market	27	(59)
Changes in Components of Working Capital	371	345
Other Assets & Liabilities	(195)	56
Cash Flow from Operations	**673**	**897**

Cash flow from operations was $673 million for the 1st quarter of 2005

First Quarter: Cash Flow from Investing Activities

($ millions)	1st Quarter 2005	1st Quarter 2004
Investing Activities		
Capital Expenditures	(465)	(305)
Investment in Discontinued Ops (net)	-	7
Change in Other Cash Deposits (net)	(9)	63
Assets Sales Proceeds & Other Inv (net)	1,159	48
Cash (Used) by Investing Activities	**685**	**(187)**

Cash flow from investing activities was $685 million for the 1st quarter of 2005

First Quarter: Cash Flow from Financing Activities

($ millions)	1st Quarter 2005	1st Quarter 2004
Financing Activities		
Common Shares Issued/(Retired), net	(417)	10
Long-term Debt Issuances/(Retirements), net	70	(341)
Short-term Debt Increase/(Decrease), net	31	(103)
Other Financing	-	-
Dividends Paid	(138)	(138)
Preferred Stock Retirement	(66)	(4)
Cash (Used for) Financing	**(520)**	**(576)**

Cash flow used for financing activities was $520 million for the 1st quarter of 2005

Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

Adjusted debt-to-cap of 59.0% at 3/31/05

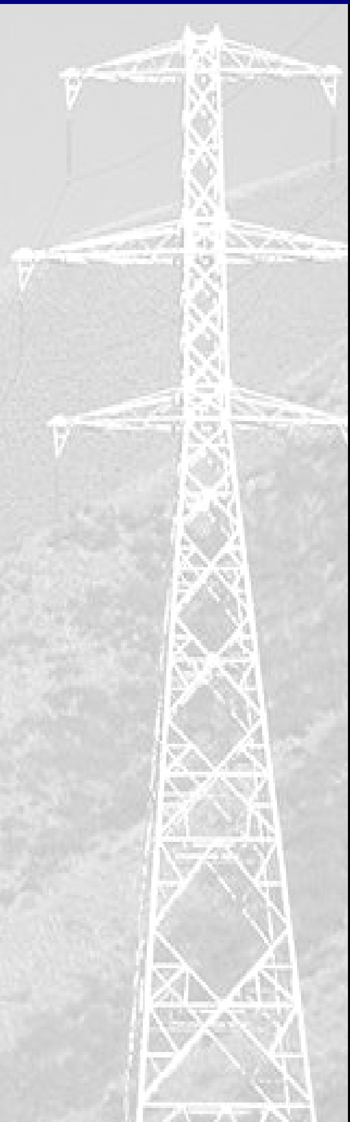
QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2005 Actual vs 1st Quarter 2004 Actual

		2004 Actual			2005 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	25,742 GWh @ $ 29.1 /MWhr =	750		26,055 GWh @ $ 27.2 /MWhr =	709	
2	Ohio Cos.	12,456 GWh @ $ 41.1 /MWhr =	512		12,349 GWh @ $ 39.8 /MWhr =	491	
3	Texas Wires	5,490 GWh @ $ 18.0 /MWhr =	99		5,519 GWh @ $ 18.3 /MWhr =	101	
4	Texas Supply / REP	5,224 GWh @ $ 19.0 /MWhr =	99		2,474 GWh @ $ 31.9 /MWhr =	79	
5	Off-System Sales	7,248 GWh @ $ 23.3 /MWhr =	169		7,637 GWh @ $ 21.2 /MWhr =	162	
6	Other Wholesale Transactions		5			4	
7	Transmission Revenue - 3rd Party		124			93	
8	Other Operating Revenue		65			70	
9	Total Gross Margin		1,823			1,709	
10	Operations & Maintenance		(706)			(685)	
11	Depreciation & Amortization		(310)			(318)	
12	Taxes Other than Income Taxes		(182)			(186)	
13	Interest Exp & Preferred Dividend		(166)			(144)	
14	Other Income & Deductions		10			133	
15	Income Taxes		(165)			(166)	
16	Net Earnings Utility Operations		304	0.77		343	0.87
	INVESTMENTS:						
17	AEPES		(10)			10	
18	Other		4			5	
19	Total Investments		(6)	(0.02)		15	0.04
20	Parent Company		(9)	(0.02)		(14)	(0.03)
21	ON-GOING EARNINGS		289	0.73		344	0.88
	Shares outstanding (in millions)		395			393	

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.



1Q06 Earnings Release Presentation

April 27, 2006

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Highlights

- 1Q06 GAAP Earnings $0.97 Per Share, Ongoing $0.96 Per Share
- Reaffirm 2006 Earnings Guidance of $2.50 - $2.70 Per Share
- Asset Divestiture Activity - Bajio
- Regulatory Update
  - PUCO Approval to Recover IGCC Pre-Construction Costs
  - West Virginia Rate Settlement
  - TCC Stranded Cost True-up Case
  - Virginia Environmental & Reliability Filing
  - I&M Depreciation Filing

1Q06 Earnings Performance

	$ millions			Earnings Per Share		
	1st Qtr 2005	1st Qtr 2006	Change	1st Qtr 2005	1st Qtr 2006	Change
Utility Operations	343	365	22	0.87	0.93	0.06
Investments	12	15	3	0.03	0.04	0.01
Parent Company	(14)	(2)	12	(0.03)	(0.01)	0.02
AEP On-Going Earnings	341	378	37	0.87	0.96	0.09

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q06 Utility Operations Performance

		2005 Actual		2006 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities - East	524		564	
2	Ohio Companies	468		517	
3	Regulated Integrated Utilities - West	178		195	
4	Texas Wires	101		106	
5	Off-System Sales	247		223	
6	Transmission Revenue - 3rd Party	101		101	
7	Other Operating Revenue	142		136	
8	Total Gross Margin	1,761		1,842	
9	Operations & Maintenance	(733)		(727)	
10	Depreciation & Amortization	(318)		(333)	
11	Taxes Other than Income Taxes	(186)		(187)	
12	Interest Exp & Preferred Dividend	(144)		(154)	
13	Other Income & Deductions	129		110	
14	Income Taxes	(166)		(186)	
15	Net Earnings Utility Operations	343	0.87	365	0.93

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q 2006 Performance Drivers

Weather Impact: Negative $0.06 vs. normal
Negative $0.04 vs. prior yr.

- *Increased margins reflecting customer growth, new muni & coop power supply contracts, usage and price; Ohio RSP ($49MM); Buckeye Emissions allowances gains ($9.4MM); slightly offset by weather.*

- *Lower off system sales due to lower volumes and margins (sale of STP) and trading contribution.*

- *Increased amortization expense associated with amortization of regulatory assets primarily at the Ohio Companies .*
- *Interest expense increase due to higher debt balances and interest rates.*
- *Other Income & Deductions decline due to lower carrying costs for the Ohio companies ($19MM).*
- *Income taxes increase driven by higher pretax income.*

1Q06 Cash Flow

A Century of Firsts

($ millions)	Year-to-Date 2005	Year-to-Date 2006
Operating Activities		
Net Income -- Reported	**$ 355**	**$ 381**
Discontinued Operations	(1)	(3)
Continuing Earnings	**354**	**378**
Depreciation, Amortization & Deferred Taxes	232	273
Pension Contributions	(102)	-
Changes in Mark-to-Market	27	(9)
Changes in Components of Working Capital	340	(123)
Other Assets & Liabilities	(184)	71
Cash Flow from Operations	**667**	**590**
Investing Activities		
Capital Expenditures	(434)	(772)
Proceeds on Sale of Assets	1,184	111
Change in Other Cash Deposits (net)	94	(46)
Other Investong (net)	(2)	(50)
Cash (Used) by Investing Activities	**842**	**(757)**
Financing Activities		
Common Shares Issued/(Retired), net	(417)	5
Long-term Debt Issuances/(Retirements)	70	(87)
Short-term Debt Increase/(Decrease), net	(5)	216
Other Financing	(12)	54
Dividends Paid	(138)	(146)
Preferred Stock Retirement	(66)	-
Cash (Used for) Financing	**(568)**	**42**
Cash From Continuing Operations	**$ 941**	**$ (125)**
Beginning Cash & Cash Equivalent Balances	320	401
Ending Cash & Cash Equivalent Balances	1,261	276

1Q 2006 Cash Flow Drivers

- *Changes in working capital had a negative cash effect of $123MM primarily as a result of an increase in fuel inventories and decreased customer deposits.*
- *$71MM positive cash effect partly due to deferred fuel recovery at PSO and SWEPCo.*
- *Cash outlay of $772MM in 1Q06 for capital investment. FY 2006 guidance assumes $3.7 billion in capital investment.*
- *1Q06 primary asset sale proceeds: Centrica sharing ($70MM) and Bajio ($29MM); 1Q05 primary asset sale proceeds: HPL ($1B) & Centrica sharing ($70MM);*
- *Portion of HPL sale proceeds used to repurchase shares in 1Q05.*
- *Capex in 1Q06 was funded with short-term debt ahead of long-term debt financing.*
- *Ending cash balance for 1Q06 of $276MM. 2006 guidance assumes year-end cash balance of $326MM.*

Capitalization

A Century of Firsts

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

Adjusted debt-to-cap of 57.5% at 3/31/06

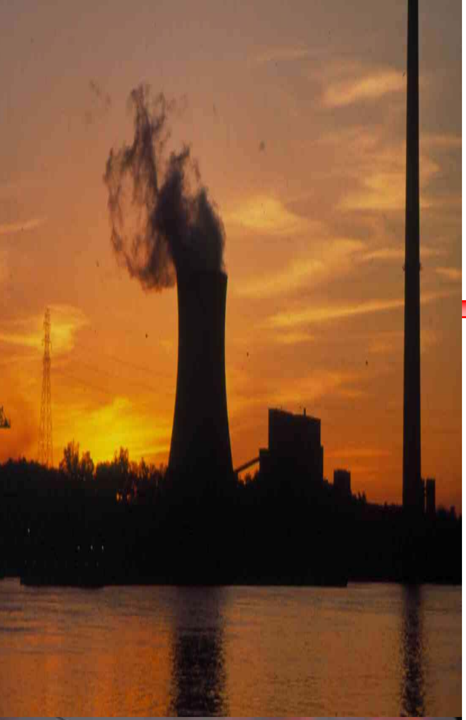
QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2006 Actual vs 1st Quarter 2005 Actual

		2005 Actual Performance Driver	2005 Actual ($ millions)	2005 Actual EPS	2006 Actual Performance Driver	2006 Actual ($ millions)	2006 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	17,184 GWh @ $ 30.5 /MWhr =	524		18,092 GWh @ $ 31.2 /MWhr =	564	
2	Ohio Companies	12,349 GWh @ $ 37.9 /MWhr =	468		11,529 GWh @ $ 44.8 /MWhr =	517	
3	Regulated Integrated Utilities - West	8,871 GWh @ $ 20.1 /MWhr =	178		8,922 GWh @ $ 21.9 /MWhr =	195	
4	Texas Wires	5,519 GWh @ $ 18.3 /MWhr =	101		5,546 GWh @ $ 19.1 /MWhr =	106	
5	Off-System Sales	10,112 GWh @ $ 24.4 /MWhr =	247		8,514 GWh @ $ 26.2 /MWhr =	223	
6	Transmission Revenue - 3rd Party		101			101	
7	Other Operating Revenue		142			136	
8	Total Gross Margin		1,761			1,842	
9	Operations & Maintenance		(733)			(727)	
10	Depreciation & Amortization		(318)			(333)	
11	Taxes Other than Income Taxes		(186)			(187)	
12	Interest Exp & Preferred Dividend		(144)			(154)	
13	Other Income & Deductions		129			110	
14	Income Taxes		(166)			(186)	
15	Net Earnings Utility Operations		343	0.87		365	0.93
	INVESTMENTS:						
16	AEPES		10			(1)	
17	Other		2			16	
18	Total Investments		12	0.03		15	0.04
19	Parent Company		(14)	(0.03)		(2)	(0.01)
20	ON-GOING EARNINGS		341	0.87		378	0.96
	Shares Outstanding (in millions)			393			3[illegible]4

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.



1Q07 Earnings Release Presentation

AMERICAN ELECTRIC POWER

April 26, 2007

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

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First Quarter 2007 Highlights

- **1Q 2007 GAAP and Ongoing Earnings $0.68 per share**
- **Reaffirming 2007 Ongoing Earnings Guidance Range of $2.85 to $3.05 per share**
- **2007 Regulatory Update**
  - **Indiana**
    - Depreciation Case
  - **Virginia**
    - General Base Rate Case Filing
    - Re-regulation
  - **Texas**
    - TNC & TCC Wires Base Rate Case Filings
  - **Oklahoma**
    - General Base Rate Case Filing
  - **Ohio**
    - 4% Generation Increase Filing
    - Withdrawal of Distribution Reliability Plan
  - **FERC: Regional Rate Design Proceedings**
  - **Transmission Project Updates**
    - **Electric Transmission Texas LLC**
    - **I-765 - JV announced with Allegheny**
    - **Michigan 765-kV study with ITC**
    - **SPP Investment Potential**

1Q07 Ongoing Earnings

	$ millions			Earnings Per Share		
	1st Qtr 2006	1st Qtr 2007	Change	1st Qtr 2006	1st Qtr 2007	Change
Utility Operations	365	253	(112)	0.93	0.63	(0.30)
Non-Utility Operations	25	14	(11)	0.06	0.04	(0.02)
Parent & Other	(12)	4	16	(0.03)	0.01	0.04
AEP On-Going Earnings	378	271	(107)	0.96	0.68	(0.28)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

28-cent Decrease Driven by Increased O&M and Reduced Off-System Sales, Partially Offset by Continued Rate Relief

1Q07 Utility Operations Performance

		2006 Actual		2007 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	564		604	
2	Ohio Companies	517		603	
3	West Regulated Integrated Utilities	195		200	
4	Texas Wires	106		114	
5	Off-System Sales	222		181	
6	Transmission Revenue - 3rd Party	101		72	
7	Other Operating Revenue	135		140	
8	Utility Gross Margin	1,840		1,914	
9	Operations & Maintenance	(717)		(828)	
10	Depreciation & Amortization	(340)		(383)	
11	Taxes Other than Income Taxes	(187)		(184)	
12	Interest Exp & Preferred Dividend	(154)		(179)	
13	Other Income & Deductions	109		39	
14	Income Taxes	(186)		(126)	
15	Utility Operations On-Going Earnings	365	0.93	253	0.63

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q 2007 Performance Drivers

- *Retail Sales (lines 1-4):*
  - *Rate relief primarily in OH, WV, VA and KY - $93MM*
  - *Positive load growth - $34MM*
  - *Favorable weather - $40MM*
  - *Slightly offset by lower FTR income - ($27MM)*
- *Off-System Sales (line 5):*
  - *Lower margins in the East due to lower plant availability, primarily associated with scrubber tie-ins*
- *Transmission Revenue (line 6):*
  - *Lower due to absence of SECA revenues in 1Q07*
- *Other Operating Revenue (line 7):*
  - *Securitization revenue related to the October 2006 Texas securitization (offset in lines 10 and 12), partially offset by lower contribution from emission allowance sales*
- *Operations & Maintenance (line 9):*
  - *Increased due to plant outages and removal expense, storm costs and increased vegetation management*
- *Depreciation & Amortization (line 10):*
  - *Increased primarily due to increased depreciable asset base and increased amortization of regulatory assets related to the Texas securitization and the APCo E&R deferrals.*
- *Interest Expense (line 12):*
  - *Increased due to increased long term debt outstanding, including Texas securitization bonds issued in October 2006, and higher interest rates, partially offset by AFUDC-debt of $27MM in 2007 and $17MM in 2006*
- *Other Income & Deductions (line 13):*
  - *Decreased due to Centrica sharing payment of $20MM in 2007 vs. $70MM in 2006 and reduced carrying charges of $22MM primarily due to the Texas securitization in October 2006; includes AFUDC-equity of $8MM in 2007 and $6MM in 2006*
- *Income Taxes (line 14):*
  - *Down primarily due to decreased income; effective tax rate for utility operations of 33.2% in 2007 and 33.8% in 2006*

1Q 2007 Cash Flow

($ millions)	2006	2007
Operating Activities		
Net Income -- Reported	**$ 381**	**$ 271**
Discontinued Operations	(3)	-
Continuing Earnings	**378**	**271**
Depreciation, Amortization & Deferred Taxes	266	323
Changes in Components of Working Capital	(123)	(248)
Other Assets & Liabilities	62	5
Cash Flows From Operating Activities	**583**	**351**
Investing Activities		
Capital Expenditures	(765)	(907)
Proceeds on Sale of Assets	111	68
Change in Other Temporary Cash Investments (net)	(46)	237
Other Investing (net)	(50)	(26)
Cash Flows Used for Investing Activities	**(750)**	**(628)**
Financing Activities		
Common Shares Issued/(Retired), net	5	54
Long-term Debt Issuances/(Retirements)	(87)	198
Short-term Debt Increase/(Decrease), net	216	157
Other Financing	54	(19)
Dividends Paid	(146)	(155)
Cash Flows From (Used for) Financing Act.	**42**	**235**
Cash From Continuing Operations	**$ (125)**	**$ (42)**
Beginning Cash & Cash Equivalent Balances	401	301
Ending Cash & Cash Equivalent Balances	276	259

1Q 2007 Cash Flow Drivers

Operating Activities

- *Changes in Working Capital largely driven by G&A-type items*

Investing Activities

- *Cash outlay of $907 million for 1Q 2007 capital investment. FY 2007 guidance assumes $3.9 billion in capital investment, including new generation purchases*
- *2007 primary asset sale proceeds: Centrica sharing ($20MM) and TCC's share of Oklaunion ($43MM); 2006 primary asset sale proceeds: Centrica sharing ($70MM) and Bajio ($29MM)*
- *Other Temporary Cash Investments were partially utilized in 1Q07 to support cash needs. The balance was unusually high at December 31, 2006 due to investments purchased with the proceeds from the Texas securitization in 4Q06*

Financing Activities

- *Common stock issuance of $54MM primarily related to the exercise of stock options during 2007*
- *Ending cash balance for Q1 2007 of $259MM. 2007 guidance assumes year-end cash balance of $205MM*

Capitalization

Capital Structure	Actual 12/31/2006			Actual 3/31/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	13,882	-	13,882
Short-term Debt	18	-	18	175	-	175
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,539	9,539
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**14,057**	**9,600**	**23,657**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.4%***	***40.6%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(27)	-	(27)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(251)	-	(251)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**12,659**	**9,600**	**22,259**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***56.9%***	***43.1%***	***100.0%***

Adjusted debt-to-cap of 56.9% at 3/31/07

QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2007 Actual vs 1st Quarter 2006 Actual

		2006 Performance Driver	2006 Actual ($ millions)	2006 Actual EPS	2007 Performance Driver	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	18,092 GWh @ $ 31.2 /MWhr =	564		19,212 GWh @ $ 31.4 /MWhr =	604	
2	Ohio Companies	11,529 GWh @ $ 44.8 /MWhr =	517		12,585 GWh @ $ 47.9 /MWhr =	603	
3	West Regulated Integrated Utilities	8,923 GWh @ $ 21.9 /MWhr =	195		9,674 GWh @ $ 20.7 /MWhr =	200	
4	Texas Wires	5,546 GWh @ $ 19.1 /MWhr =	106		5,831 GWh @ $ 19.6 /MWhr =	114	
5	Off-System Sales	8,514 GWh @ $ 26.1 /MWhr =	222		5,665 GWh @ $ 32.0 /MWhr =	181	
6	Transmission Revenue - 3rd Party		101			72	
7	Other Operating Revenue		135			140	
8	**Utility Gross Margin**		1,840			1,914	
9	Operations & Maintenance		(717)			(828)	
10	Depreciation & Amortization		(340)			(383)	
11	Taxes Other than Income Taxes		(187)			(184)	
12	Interest Exp & Preferred Dividend		(154)			(179)	
13	Other Income & Deductions		109			39	
14	Income Taxes		(186)			(126)	
15	**Utility Operations On-Going Earnings**		365	0.93		253	0.63
	NON-UTILITY OPERATIONS:						
16	MEMCO		21	0.05		15	0.04
17	Generation & Marketing		4	0.01		(1)	
18	**Non-Utility Operations On-Going Earnings**		25			14	
19	**Parent & Other On-Going Earnings**		(12)	(0.03)		4	0.01
20	**ON-GOING EARNINGS**		378	0.96		271	0.68
	Shares outstanding (in millions)			394			[illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

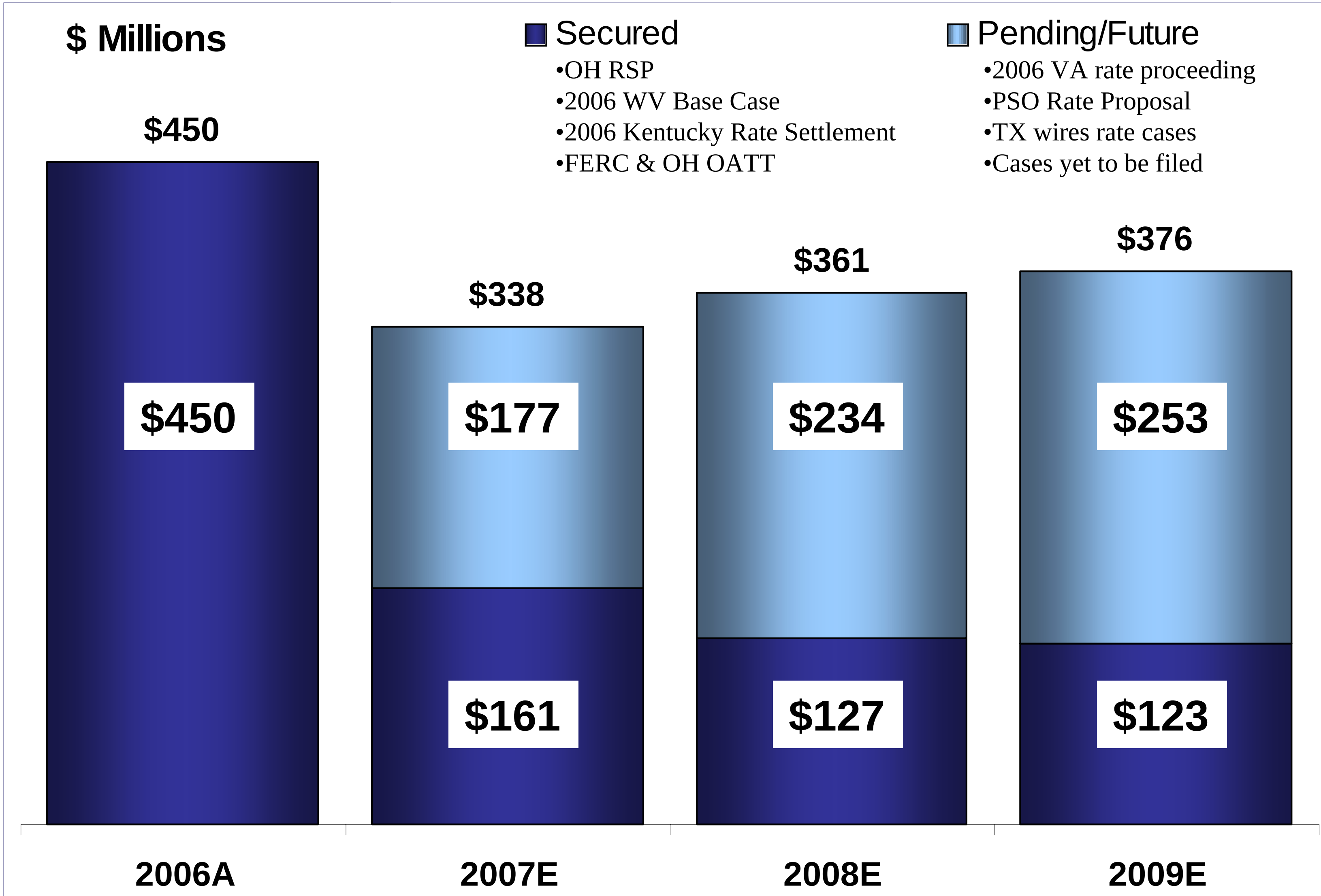
American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 803 of 9556

Incremental Rate Relief Composition



KPSC Case No. 2011-00401
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Item No. 1
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Retail Performance

	Load Growth (weather normalized)
	Q1 07 vs. Q1 06
East Regulated Integrated Utilities	3.3%
Ohio Companies	5.5%
West Regulated Integrated Utilities	3.9%
Texas Wires	1.9%
Impact on EPS	$0.08

	Degree Days
	Q1 07 vs. Q1 06
East Cooling	13
West Cooling *	13
East Heating	360
West Heating *	244
Impact on EPS	$0.07

* West statistics represent PSO/SWEPCo customer base only

Retail Performance

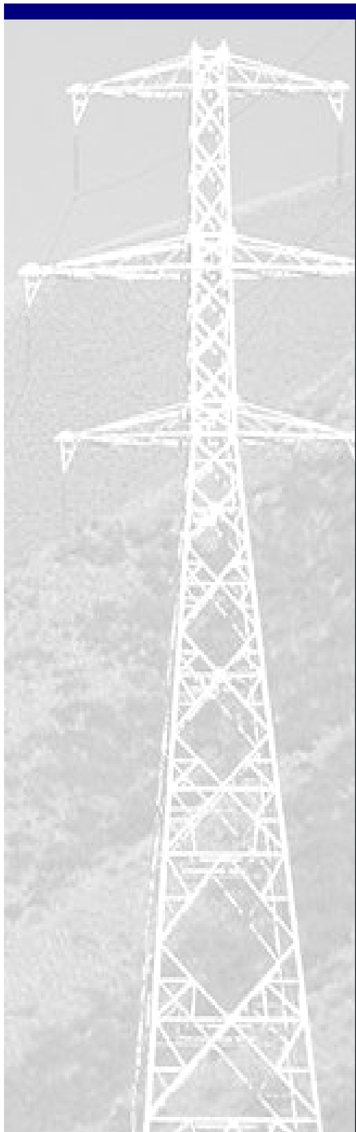
	Rate Relief (in millions)
	Q1 07 vs. Q1 06
East Regulated Integrated Utilities	$57
Ohio Companies	$35
West Regulated Integrated Utilities	$1
Texas Wires	$0
AEP System Total	$93
Impact on EPS	$0.15

Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.



1Q08 Earnings Release Presentation

April 24, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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First Quarter 2008 Highlights

- 1Q08 GAAP Earnings $1.43 per share; Ongoing Earnings $1.02 per share
- Reaffirming 2008 Ongoing Earnings Guidance Range of $3.10 to $3.30 per share
- Ohio developments
- Incremental Rate Relief - $481MM of $518MM for 2008 secured
  - Positive PSO storm settlement outcome
- New Generation
  - Turk Plant
  - IGCC
- Transmission
  - Favorable FERC order on the PATH project authorizing a 14.3% ROE

Continued track record of financial and operational excellence

1Q08 Performance

1Q08 Earnings Release

American Electric Power
Financial Results for 1st Quarter 2008 Actual vs 1st Quarter 2007 Actual

		2007 Actual ($ millions)	2007 Actual EPS	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	604		594	
2	Ohio Companies	603		696	
3	West Regulated Integrated Utilities	200		223	
4	Texas Wires	114		122	
5	Off-System Sales	181		221	
6	Transmission Revenue - 3rd Party	72		80	
7	Other Operating Revenue	140		145	
8	**Utility Gross Margin**	1,914		2,081	
9	Operations & Maintenance	(828)		(747)	
10	Depreciation & Amortization	(383)		(355)	
11	Taxes Other than Income Taxes	(184)		(194)	
12	Interest Exp & Preferred Dividend	(179)		(210)	
13	Other Income & Deductions	39		41	
14	Income Taxes	(126)		(207)	
15	**Utility Operations On-Going Earnings**	253	0.63	409	1.02
16	**Transmission Operations On-Going Earnings**	-	0.00	1	0.00
	NON-UTILITY OPERATIONS:				
17	MEMCO	15	0.04	7	0.02
18	Generation & Marketing	(1)	-	1	-
19	**Non-Utility Operations On-Going Earnings**	14		8	
20	**Parent & Other On-Going Earnings**	4	0.01	(8)	(0.02)
21	**ON-GOING EARNINGS**	271	0.68	410	1.02

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q08 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Minimal weather impact of $(3)MM versus prior year and $3MM versus normal; $0.00 per share vs. normal and vs. prior year*
  - *Rate relief $77MM; (APCo, Ohio RSPs, PSO & Texas Wires)*
  - *Positive load growth including new customers; $54MM*
  - *Offset by:*
    - *Unrecovered PJM marginal losses; $12MM*
    - *Increased OSS sharing; $16MM*
- *Off-System Sales (line 5):*
  - *Favorable due to higher prices and volumes, primarily due to higher plant availability in 1Q08*
- *Operations & Maintenance (line 9):*
  - *Decrease primarily attributed to PSO storm settlement booked in 1Q08, offset slightly by the Red Rock write-off*
- *Depreciation & Amortization (line 10):*
  - *Decrease primarily attributed to decreased depreciation in Indiana, Michigan, Texas, Virginia and Oklahoma related to approved rate proceedings in 2007 and lower regulatory asset amortization at the Ohio Companies*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 33.6% in 2008 and 33.2% in 2007*

2008 Cash Flow

($ millions)	2007	2008
Operating Activities		
Net Income -- Reported	**$ 271**	**$ 573**
Discontinued Operations	-	-
Continuing Earnings	**271**	**573**
Depreciation, Amortization & Deferred Taxes	339	427
Changes in Components of Working Capital	(247)	(74)
Other Assets & Liabilities	(12)	(298)
Cash Flows From Operating Activities	**351**	**628**
Investing Activities		
Capital Expenditures	(907)	(778)
Proceeds on Sale of Assets	68	18
Change in Other Temporary Cash Investments, net	237	(15)
Other Investing, net	(26)	(119)
Cash Flows Used for Investing Activities	**(628)**	**(894)**
Financing Activities		
Common Shares Issued, net	54	45
Long-term Debt Issuances, net	198	627
Short-term Debt Increase/(Decrease), net	157	(251)
Other Financing	(19)	(14)
Dividends Paid	(155)	(164)
Cash Flows From Financing Activities	**235**	**243**
Cash From Continuing Operations	**$ (42)**	**$ (23)**
Beginning Cash & Cash Equivalent Balances	301	178
Ending Cash & Cash Equivalent Balances	**$ 259**	**$ 155**

2008 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by changes in accrued taxes and accounts receivable/payable.
- Changes in other assets and liabilities largely driven by changes in regulatory and other non-current assets.

Investing Activities

- Cash outlay of $778 million for 1Q08 capital investment.
- 2008 asset sale proceeds relate to miscellaneous utility property sales; 2007 asset sale proceeds relate to Centrica sharing $20MM and TCC's sale of its share of Oklaunion $46MM.
- Change in Other Temporary Cash Investments was unusually large during 1Q07 due to receipt of the Texas securitization funds in 4Q06. The 2008 activity is a more normalized amount.
- Change in Other Investing primarily relates to the purchase of nuclear fuel of $99MM in 1Q08.

Financing Activities

- 2008 common share issuances of $45MM primarily due to issuances through the dividend reinvestment program.
- Changes in long and short term debt driven by capital funding requirements.

Capitalization

Capital Structure	Actual 12/31/2007			Actual 3/31/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,994	-	14,994	15,636	-	15,636
Short-term Debt	660	-	660	409	-	409
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	10,079	10,079	-	10,489	10,489
Total Capitalization per Balance Sheet	**15,654**	**10,140**	**25,794**	**16,045**	**10,550**	**26,595**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***60.3%***	***39.7%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
Rockport Unit 2 Off-balance Sheet Lease	1,163	-	1,183	1,163	-	1,163
Securitization Bonds	(2,257)	-	(2,257)	(2,183)	-	(2,183)
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(261)	-	(261)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	-
Total Adjusted Capitalization	**14,282**	**10,140**	**24,442**	**14,606**	**10,708**	**25,314**
% of Adjusted Capitalization	***58.5%***	***41.5%***	***100.0%***	***57.7%***	***42.3%***	***100.0%***

Adjusted debt-to-cap of 57.7% at 3/31/08

Questions

1Q08 Earnings

	$ millions			Earnings Per Share		
	1st Qtr 2007	1st Qtr 2008	Change	1st Qtr 2007	1st Qtr 2008	Change
Utility Operations	253	409	156	0.63	1.02	0.39
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	14	8	(6)	0.04	0.02	(0.02)
Parent & Other	4	(8)	(12)	0.01	(0.02)	(0.03)
AEP On-Going Earnings	271	410	139	0.68	1.02	0.34
Special Items	0	163	163	0.00	0.41	0.41
Reported Earnings (GAAP)	271	573	302	0.68	1.43	0.75

Quarterly Performance Comparison

American Electric Power

Financial Results for 1st Quarter 2008 Actual vs 1st Quarter 2007 Actual

		2007 Actual Performance Driver	2007 Actual ($ millions)	2007 Actual EPS	2008 Actual Performance Driver	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	19,212 GWh @ $ 31.5 /MWhr =	604		19,542 GWh @ $ 30.4 /MWhr =	594	
2	Ohio Companies	12,585 GWh @ $ 47.9 /MWhr =	603		13,901 GWh @ $ 50.0 /MWhr =	696	
3	West Regulated Integrated Utilities	9,674 GWh @ $ 20.7 /MWhr =	200		9,869 GWh @ $ 22.6 /MWhr =	223	
4	Texas Wires	5,831 GWh @ $ 19.5 /MWhr =	114		5,823 GWh @ $ 21.0 /MWhr =	122	
5	Off-System Sales	5,665 GWh @ $ 32.0 /MWhr =	181		8,160 GWh @ $ 27.1 /MWhr =	221	
6	Transmission Revenue - 3rd Party		72			80	
7	Other Operating Revenue		140			145	
8	**Utility Gross Margin**		1,914			2,081	
9	Operations & Maintenance		(828)			(747)	
10	Depreciation & Amortization		(383)			(355)	
11	Taxes Other than Income Taxes		(184)			(194)	
12	Interest Exp & Preferred Dividend		(179)			(210)	
13	Other Income & Deductions		39			41	
14	Income Taxes		(126)			(207)	
15	**Utility Operations On-Going Earnings**		253	0.63		409	1.02
16	**Transmission Operations On-Going Earnings**		-	0.00		1	0.00
	NON-UTILITY OPERATIONS:						
17	MEMCO		15	0.04		7	0.02
18	Generation & Marketing		(1)	-		1	-
19	**Non-Utility Operations On-Going Earnings**		14			8	
20	**Parent & Other On-Going Earnings**		4	0.01		(8)	(0.02)
21	**ON-GOING EARNINGS**		271	0.68		410	1.02

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q08 Earnings Release

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Detailed Ongoing Earnings Guidance

2007 Actual: $3.00

2008E: $3.10 - $3.30

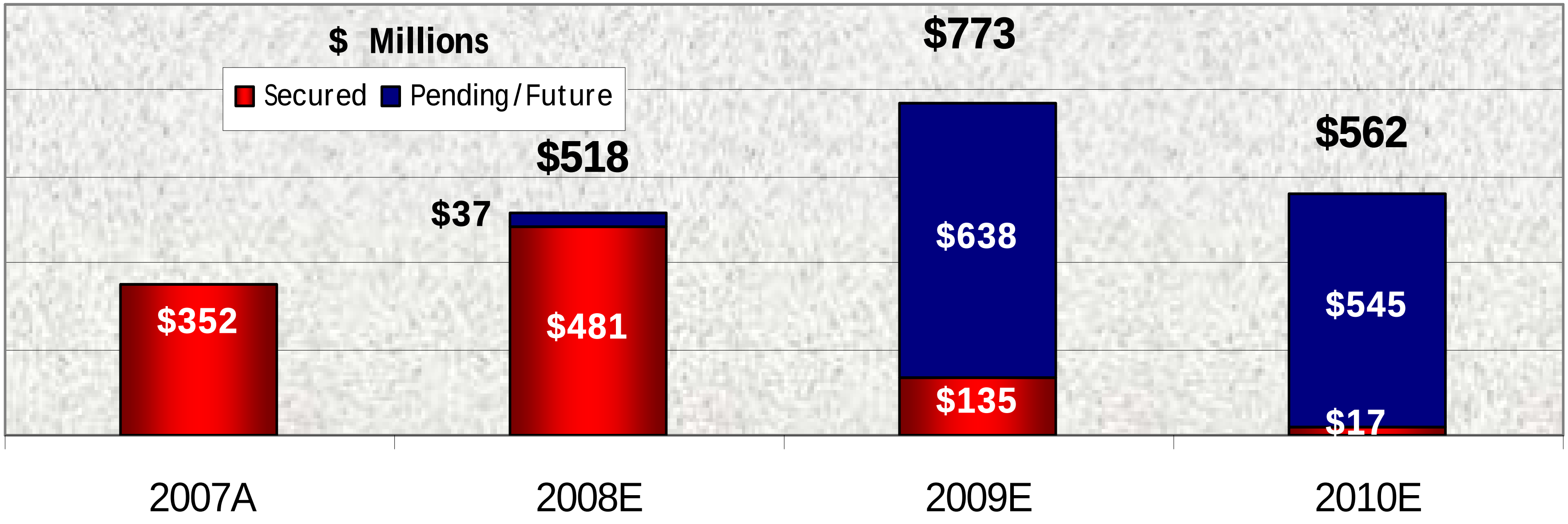
American Electric Power
2007 Actual vs 2008 Guidance

		2007 Performance Driver	2007 Actual ($ millions)	2008 Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q08 Earnings Release

Incremental Rate Relief



- 93% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan.

- 2008 Pending: 2008 TCC/TNC TCRF filings, other cases yet to be filed including Virginia base case.

Secured $481MM of $518MM for 2008

1Q08 Retail Performance

	Load Growth (weather normalized) 1Q08 vs. 1Q07
East Regulated Integrated Utilities	2.5%
Ohio Companies	7.9%
West Regulated Integrated Utilities	1.1%
Texas Wires	1.7%
Impact on EPS	$0.08

	Degree Days 1Q08 vs. 1Q07
East Cooling	-14
West Cooling *	-30
East Heating	8
West Heating *	47
Impact on EPS	$0.00

* West statistics represent PSO/SWEPCo customer base only

1Q08 Retail Performance (Con't)

	Rate Relief (in millions)
	1Q08 vs. 1Q07
East Regulated Integrated Utilities	$16
Ohio Companies	$44
West Regulated Integrated Utilities	$8
Texas Wires	$9
AEP System Total	$77
Impact on EPS	$0.12

1Q08 Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	1Q 2008	1Q 2007	1Q 2008	1Q 2007	1Q 2008	1Q 2007
East:	**67.54%**	**67.58%**	**85.32%**	**81.69%**	**9.38%**	**8.02%**
Coal:	77.99%	72.13%	82.69%	78.52%	10.03%	8.71%
Super-Critical*	78.48%	72.37%	81.47%	76.59%	10.42%	7.84%
Sub-Critical*	76.47%	71.39%	86.46%	84.52%	8.87%	11.17%
Gas**	2.10%	1.61%	97.11%	94.04%	N/A	N/A
Hydro	7.73%	13.32%	82.50%	88.47%	15.78%	17.89%
Nuclear	94.01%	102.03%	93.42%	99.98%	2.27%	0.00%
SPP:	**38.99%**	**41.89%**	**83.31%**	**86.29%**	**4.92%**	**4.21%**
Coal:	75.09%	76.55%	79.70%	81.67%	2.66%	2.96%
Super-Critical	84.53%	81.99%	85.96%	84.65%	3.52%	2.90%
Sub-Critical	71.64%	74.50%	77.31%	80.55%	2.30%	2.98%
Gas	16.51%	18.62%	85.55%	89.40%	7.40%	5.71%
Texas:						
Coal	**57.48%**	**42.21%**	**65.93%**	**42.20%**	**4.20%**	**40.48%**
AEP System	**60.79%**	**61.23%**	**84.61%**	**82.24%**	**8.48%**	**7.70%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run less frequently, this factor gauges performance based on period hours instead of service hours. (1Q08 = 0.81% / 1Q07 = 4.32%)

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1Q11 Earnings Release Presentation

April 21, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives..

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First Quarter 2011 Highlights

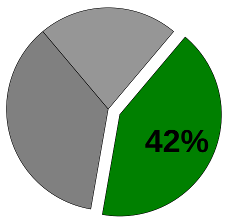
- **Financial Performance**
  - Delivered GAAP earnings of $0.73 and on-going earnings of $0.82/share
  - Reaffirming 2011 earnings guidance of $3.00 to $3.20 per share
    - Maintain 2012 point estimate of $3.25 per share
- **Regulatory Plan**
  - Rate proceedings – $200M of $235M secured (85%)
  - Ohio
- **Environmental Update**
  - Transport Rule
  - Mercury and HAP MACT
  - Coal Ash Rule
  - 316(b) Rule

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($Millions) (1)

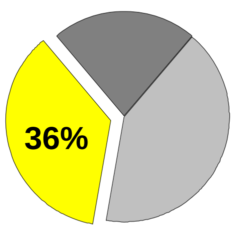
Least Exposed



Operating Company	MW
APCo	4,220
CSPCo	1,277
Ohio Power	4,820
	10,317

Proposed Rules		Low		High
Water Rules (2)	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules (3)	$	766	$	1,046

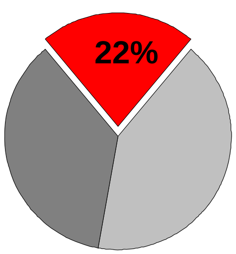
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High (4)
Water Rules (2)	$	26	$	46
CCR Rules	$	357	$	726
Air Rules (3) (5)	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

1Q11 Performance

AEP®

First Quarter Reconciliation

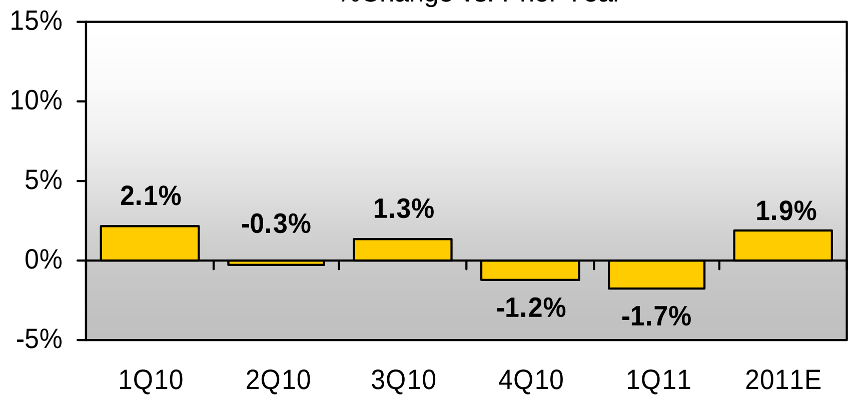
	EPS	Ongoing Earnings ($ in millions)
1Q10	$ 0.76	$365
Weather	$ (0.03)	
Retail Margin	$ (0.02)	
Non-Utility Operations, net	$ (0.01)	
Off-System Sales	$ 0.02	
Operations & Maintenance	$ 0.04	
Rate Changes	$ 0.06	
1Q11	$ 0.82	$392

1Q11 Performance Drivers

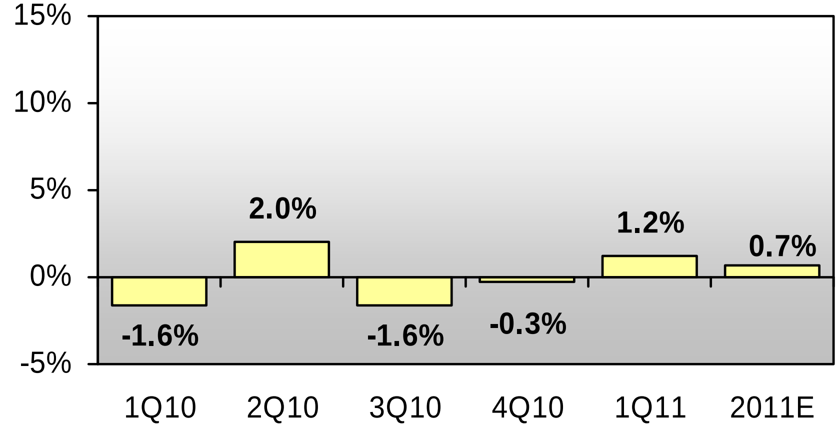
- Weather was unfavorable by $20M vs. prior year, favorable $20M vs. normal
- Retail Margin down $17M due to lower residential utilization, offset by increased industrial usage
- Non-Utility Operations/Parent decreased $4M, primarily driven by Generation and Marketing
- Off-System Sales, net of sharing, were favorable by $12M due to higher volumes and capacity payments
- O&M expense net of offsets decreased $30M primarily due to lower storm restoration expenses and cost savings initiatives
- Rate Changes net of offsets of $44M from multiple operating jurisdictions

Normalized Load Trends

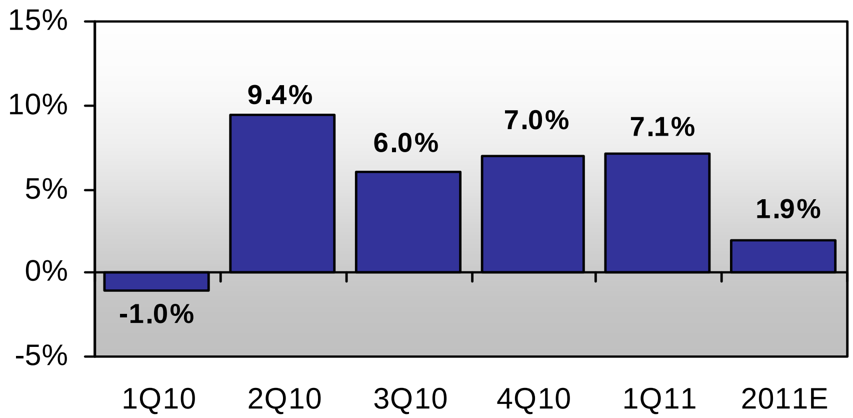
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



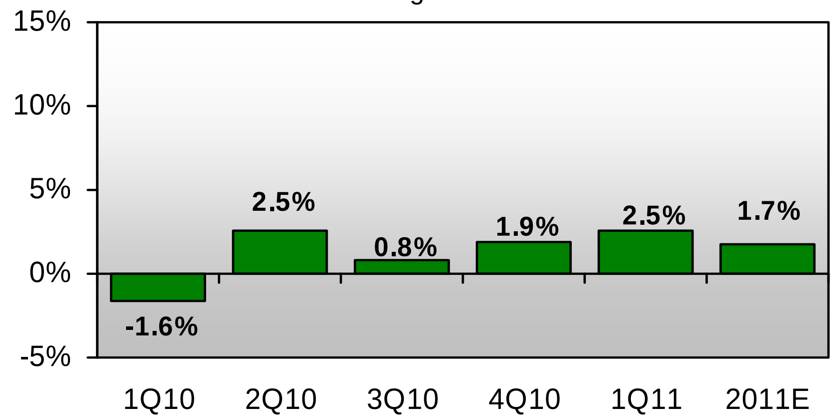
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year

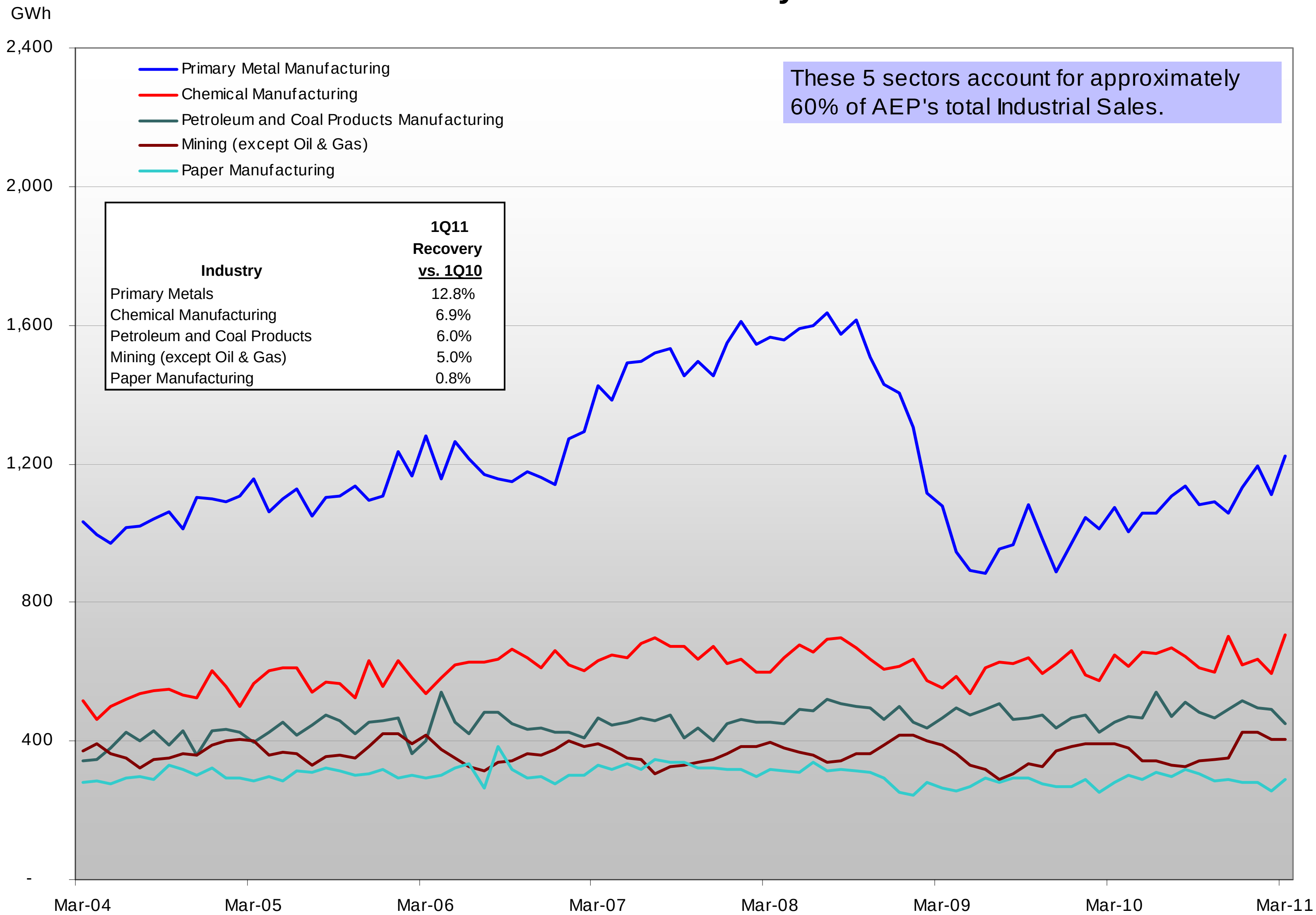


*includes firm wholesale load

Note: Chart represents connected load

Industrial Sales Volumes

AEP Industrial GWh by Sector



Industry	1Q11 Recovery vs. 1Q10
Primary Metals	12.8%
Chemical Manufacturing	6.9%
Petroleum and Coal Products	6.0%
Mining (except Oil & Gas)	5.0%
Paper Manufacturing	0.8%

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Reaffirming Guidance

2011 Guidance: $3.00 - $3.20 per share

2012 Point Estimate: $3.25 per share

2011 Earnings Drivers

- Recovering Economy
- Rate changes (85% secured)
- Continued O&M discipline - decrease net of offsets
- Customer switching – Ohio
- Off-system sales

2012 Earnings Drivers

- Recovering Economy
- Rate changes: Ohio Distribution, VA and cases not yet announced
- Continued O&M discipline
- Reasonable AEP-Ohio Outcome

Questions

1Q11 Earnings

AEP®

	$ millions			Earnings Per Share		
	1st Qtr 2010	1st Qtr 2011	Change	1st Qtr 2010	1st Qtr 2011	Change
Utility Operations	$ 361	$ 389	$ 28	$ 0.75	$ 0.81	$ 0.06
Transmission Operations	1	4	3	0.00	0.01	0.01
Non-Utility Operations	14	8	(6)	0.03	0.02	(0.01)
Parent & Other	(11)	(9)	2	(0.02)	(0.02)	0.00
AEP On-Going Earnings	365	392	27	0.76	0.82	0.06
Medicare D Subsidy	(21)	0	21	(0.04)	0.00	0.04
Cost Reduction Initiative	0	9	9	0.00	0.02	0.02
Carbon Capture - APCo WV	0	(26)	(26)	0.00	(0.06)	(0.06)
Litigation Settlement - Enron Bankruptcy	0	(22)	(22)	0.00	(0.05)	(0.05)
Special Items Total	(21)	(39)	(18)	(0.04)	(0.09)	(0.05)
Reported Earnings (GAAP)	$ 344	$ 353	$ 9	$ 0.72	$ 0.73	$ 0.01

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Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2011 Actual vs 1st Quarter 2010 Actual

		2010 Actual			2011 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	18,575 GWh @ $ 42.2 /MWhr =	784		18,152 GWh @ $ 41.7 /MWhr =	757	
2	Ohio Companies	12,584 GWh @ $ 54.3 /MWhr =	683		13,305 GWh @ $ 53.7 /MWhr =	715	
3	West Regulated Integrated Utilities	9,790 GWh @ $ 27.7 /MWhr =	271		9,903 GWh @ $ 29.6 /MWhr =	293	
4	Texas Wires	6,107 GWh @ $ 24.5 /MWhr =	150		6,314 GWh @ $ 23.5 /MWhr =	149	
5	Off-System Sales	4,745 GWh @ $ 15.6 /MWhr =	74		5,428 GWh @ $ 15.8 /MWhr =	86	
6	Transmission Revenue - 3rd Party		94			102	
7	Other Operating Revenue		123			125	
8	Utility Gross Margin		2,179			2,227	
9	Operations & Maintenance		(834)			(835)	
10	Depreciation & Amortization		(398)			(393)	
11	Taxes Other than Income Taxes		(203)			(209)	
12	Interest Exp & Preferred Dividend		(236)			(233)	
13	Other Income & Deductions		38			48	
14	Income Taxes		(185)			(216)	
15	Utility Operations On-Going Earnings		361	0.75		389	0.81
16	Transmission Operations On-Going Earnings		1	-		4	0.01
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		4	0.01		7	0.02
18	Generation & Marketing		10	0.02		1	-
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(14)			(11)	
20	Other Investments		3			2	
21	Parent & Other On-Going Earnings		(11)	(0.02)		(9)	(0.02)
22	ON-GOING EARNINGS		365	0.76		392	0.82

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q 2011 Cash Flow

($ millions)	2010	2011
Operating Activities		
Net Income -- Reported	**$ 346**	**$ 355**
Depreciation, Amortization & Deferred Taxes	501	711
Pension Contributions	(38)	-
Application of New Accounting Guidance: Securitized Debt for	(656)	-
Changes in Components of Working Capital	1	(32)
Over/(Under) Fuel Recovery, Net	(97)	(27)
Other Assets & Liabilities	(55)	34
Litigation Settlement - Enron Bankruptcy	-	(211)
Cash Flows From Operating Activities	**2**	**830**
Investing Activities		
Capital Expenditures	(609)	(540)
Proceeds on Sale of Assets	139	69
Change in Other Temporary Cash Investments, net	110	103
Acquisition of Assets	(7)	(216)
Other Investing, net	(63)	(29)
Cash Flows Used for Investing Activities	**(430)**	**(613)**
Financing Activities		
Common Shares Issued, net	26	31
Long-term Debt Issuances, net	15	237
Short-term Debt Increase/(Decrease), net	280	87
Receivables	656	-
Other Financing	(24)	(18)
Dividends Paid	(197)	(223)
Cash Flows From (Used for) Financing Activities	**756**	**114**
Cash From Continuing Operations	**$ 328**	**$ 331**
Beginning Cash & Cash Equivalent Balances	490	294
Ending Cash & Cash Equivalent Balances	**$ 818**	**$ 625**

1Q 2011 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by coal inventory and accrued taxes.

Investing Activities

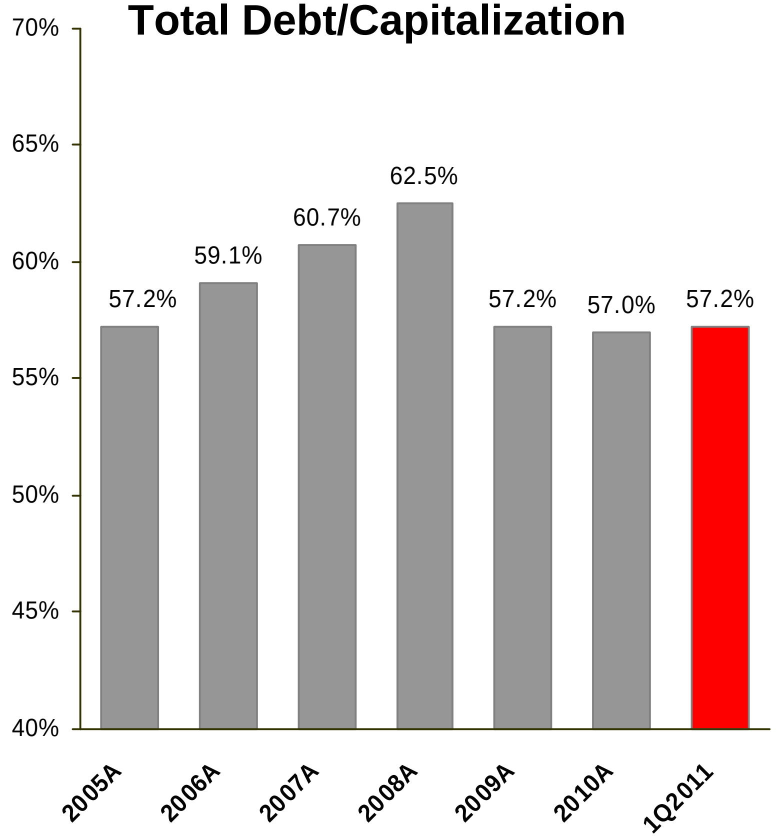
- Cash outlay for 2011 YTD capital investment.
- Asset Acquisition represents the receipt of title to the natural gas in the Bammel storage facility in conjunction with the Enron Bankruptcy settlement.

Financing Activities

- Changes in long-term debt driven by pre-funding of APCo April 2011 maturity.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 03/31/11**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	1Q11 vs. 1Q10
East Regulated Integrated Utilities	$23
Ohio Companies	$11
West Regulated Integrated Utilities	$10
Texas Wires	$0
AEP System Total	$44
Impact on EPS	$0.06

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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1Q11 Retail Performance

	Retail Load* (weather normalized)
	1Q11 vs. 1Q10
East Regulated Integrated Utilities	-0.8%
Ohio Companies	2.7%
West Regulated Integrated Utilities	7.0%
Texas Wires	1.4%
Impact on EPS	$0.02

*Excludes Firm Wholesale Load

	Weather Impact (in millions)
	1Q11 vs. 1Q10
East Regulated Integrated Utilities	($15)
Ohio Companies	$2
West Regulated Integrated Utilities	($9)
Texas Wires	$2
Impact on EPS	$0.03

May not foot due to rounding

Off System Sales Gross Margin Detail

1Q11

	1Q10 GWh	1Q10 Realization	1Q10 ($millions)	1Q11 GWh	1Q11 Realization	1Q11 ($millions)
OSS Physical Sales	4,745	$ 13.07	$ 62	5,428	$ 16.58	$ 90
Marketing/Trading	-		$ 38	-		$ 32
Pre-Sharing Gross Margin	4,745		$ 100	5,428		$ 122
Margin Shared			$ (26)			$ (36)
Net OSS			$ 74			$ 86

- Physical off-system sales margins exceeded last year by $28M
- Volumes up 14% versus last year
- AEP/Dayton Hub pricing: 3% decrease in liquidation prices
- Lower Trading & Marketing results by $6M

1Q11 vs. 1Q10

Q1 2011 Liquidations vs. Q1 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	38.96	37.95	(1.01)	-3%
PJM West	48.87	46.59	(2.28)	-5%
NiHub	35.58	34.05	(1.53)	-4%
CinHub	35.86	35.90	0.04	0%
SPP	38.21	28.87	(9.34)	-24%
Natural Gas ($/mmBtu)	5.15	4.16	(0.99)	-19%

Balance of 2011 Forwards vs. Balance of Year 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	37.59	36.30	(1.29)	-3%
PJM West	46.59	43.13	(3.46)	-7%
NiHub	33.13	30.06	(3.07)	-9%
CinHub	34.81	32.24	(2.57)	-7%
SPP	32.45	29.55	(2.90)	-9%
Natural Gas ($/mmBtu)	4.37	4.36	(0.01)	0%

AEP AMERICAN® ELECTRIC POWER

1Q10 Earnings Release Presentation

April 29, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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First Quarter 2010 Highlights

- **FINANCIAL PERFORMANCE**
  - Delivered GAAP earnings of $0.72 and on-going earnings of $0.76/share
  - Reaffirming 2010 guidance of $2.80 to $3.20/share
  - Moody's rating outlook changed to 'Stable' from 'Negative'
- **CORPORATE ACTIONS**
  - Declared 400th consecutive quarterly dividend and raised dividend 2.4%
  - Released Corporate Accountability Report - first integrated sustainability and annual report in the industry
  - Cost cutting initiatives underway
- **REGULATORY UPDATE**
  - Rate proceedings – $199MM of $320MM secured for 2010
  - Ohio SEET
  - Rate cases– Virginia and Kentucky
- **TRANSMISSION UPDATE**
- **FEDERAL LEGISLATION/EPA UPDATE**

1Q10 Performance

First Quarter Reconciliation

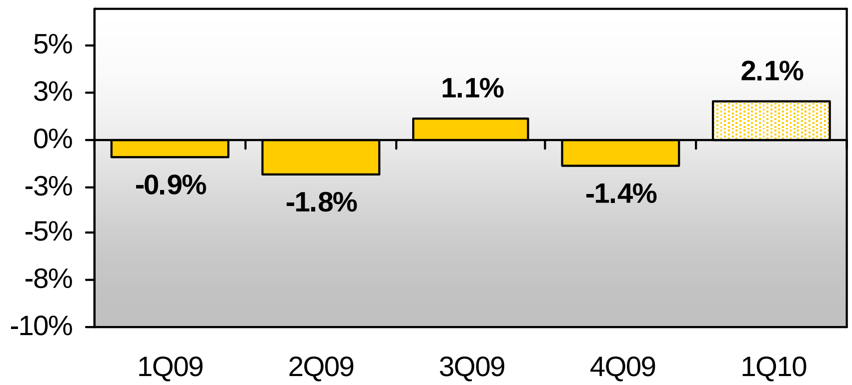
		EPS	Ongoing Earnings ($ in millions)
1Q09	$	0.89	$360
Share Count Effect	$	(0.13)	
Rate Changes	$	0.13	
Load	$	(0.06)	
Weather	$	0.06	
OSS	$	0.02	
Other Utility Operations, net	$	(0.11)	
Non-Utility Operations/Parent	$	(0.04)	
1Q10	$	0.76	$365

1Q10 Performance Drivers

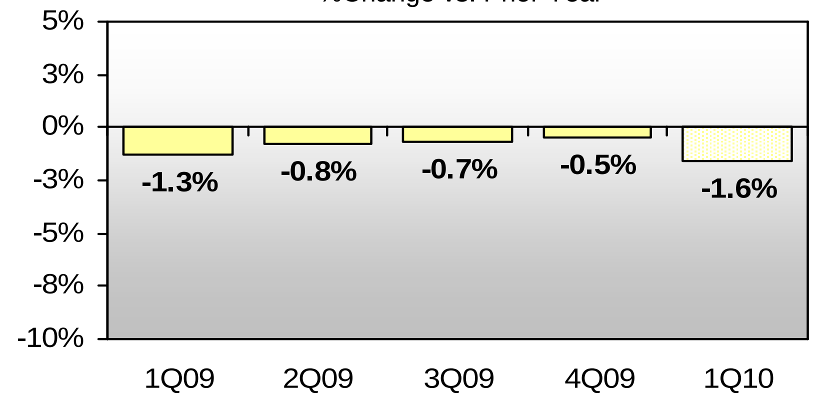
- Share count impact due to 71MM weighted average shares outstanding increase (407MM to 478MM) from equity offering and DRP
- Rate Changes of $81MM from multiple operating jurisdictions
- Load of $-36MM, primarily due to economic conditions
- Weather was favorable by $37MM vs. prior year, $40MM vs. normal
- OSS was favorable by $12MM due to enhanced generation availability and solid performance from the trading organization
- Other Utility Operations, net decreased approximately $70MM and primarily includes the absence of accidental outage insurance and higher interest expense, D&A and other taxes
- Non-utility operations decreased $14MM due to reduced deal flow in our Texas marketing business

Normalized Load Trends

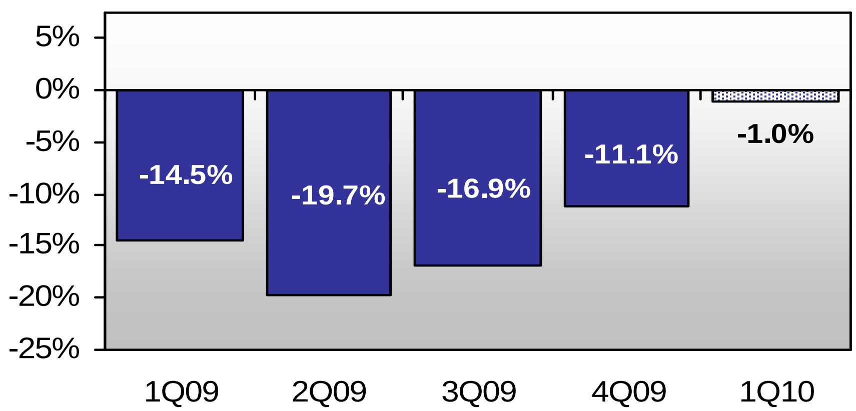
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



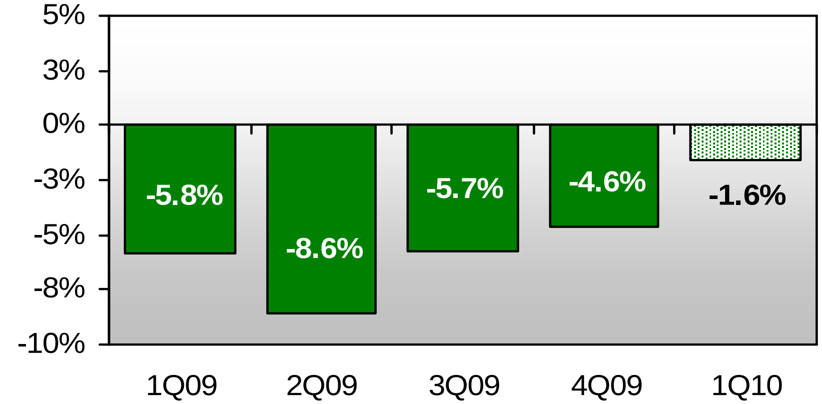
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



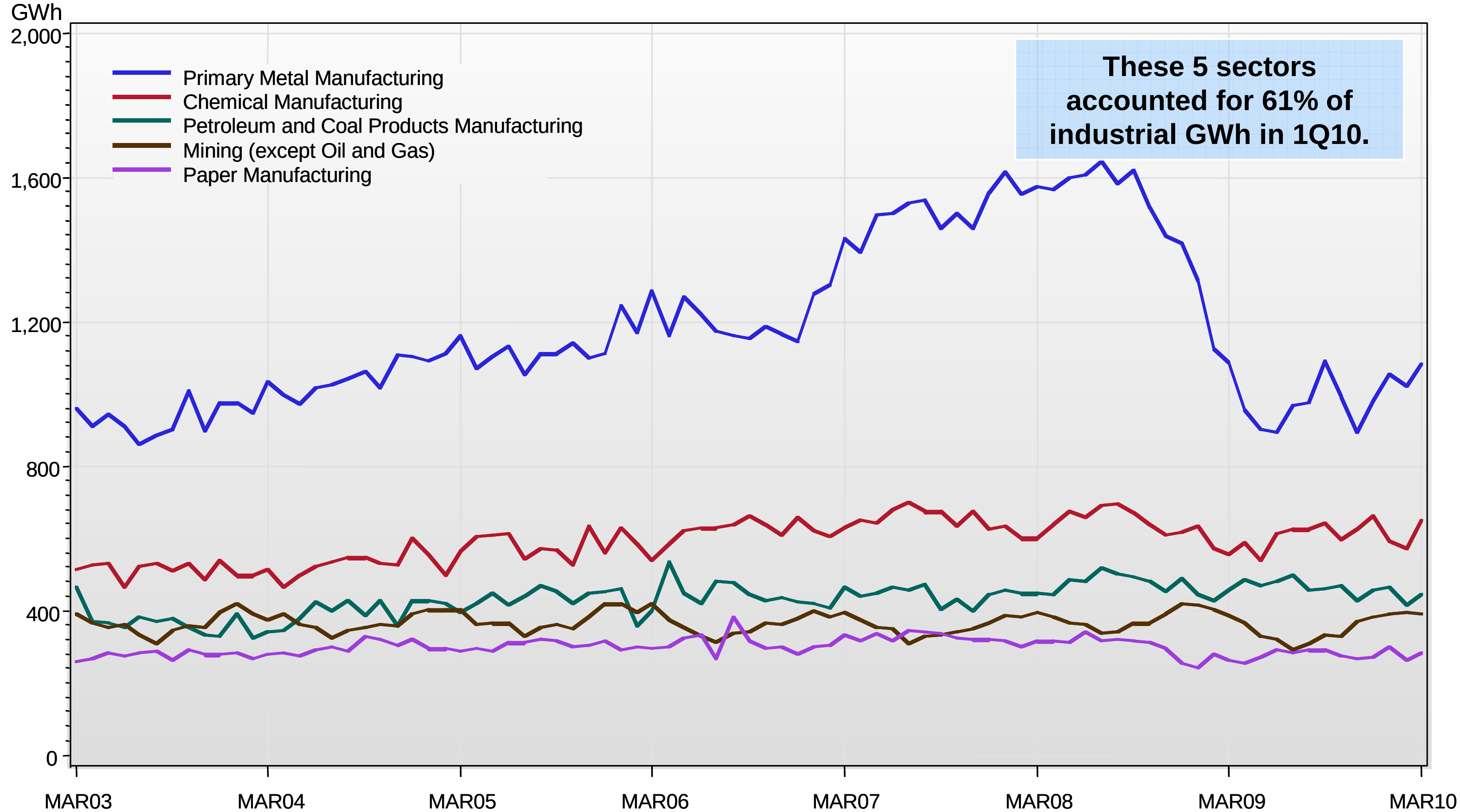
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Industrial Sales

AEP Industrial GWh by Sector



Off-System Sales

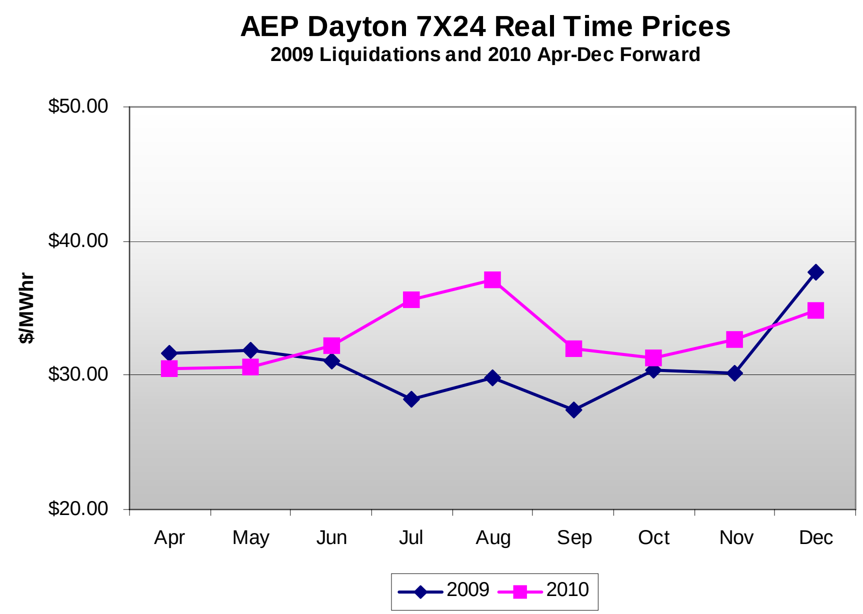
1Q10 vs. 1Q09

- 1Q10 AEP Off-system sales volumes were up approximately 83% over 1Q09
- 1Q10 AEP/Dayton Hub 7X24 prices (liquidations) were about 5% below 1Q09

Q1 2010 Liquidations vs. Q1 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	40.29	38.24	(2.05)	-5%
PJM West	49.19	44.52	(4.67)	-9%
NiHub	34.09	34.45	0.36	1%
CinHub	34.09	34.61	0.52	2%
SPP	29.71	38.21	8.50	29%
NG ($/mmBtu)	4.89	5.30	0.41	8%

Balance of Year



Balance of 2010 Forwards vs. Balance of Year 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	30.92	34.40	3.48	11%
PJM West	34.13	41.26	7.13	21%
NiHub	27.48	29.31	1.82	7%
CinHub	27.83	30.64	2.80	10%
SPP	28.92	31.40	2.48	9%
NG ($/mmBtu)	3.69	4.57	0.88	24%

Our Forward Looking Focus

- **Regulatory Proceedings**
- **Retail Load**
- **Off-System Sales**
- **O&M Cost Reduction**
- **2010 Earnings Guidance**
  $2.80 - $3.20 per share

Questions

1Q10 Earnings

	$ millions			Earnings Per Share		
	1st Qtr 2009	1st Qtr 2010	Change	1st Qtr 2009	1st Qtr 2010	Change
Utility Operations	$ 343	$ 361	$ 18	$ 0.84	$ 0.75	$ (0.09)
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	35	14	(21)	0.09	0.03	(0.06)
Parent & Other	(18)	(11)	7	(0.04)	(0.02)	0.02
AEP On-Going Earnings	360	365	5	0.89	0.76	(0.13)
Special Items	0	(21)	(21)	0.00	(0.04)	(0.04)
Reported Earnings (GAAP)	$ 360	$ 344	$ (16)	$ 0.89	$ 0.72	$ (0.17)

Quarterly Performance Comparison

American Electric Power

Financial Results for 1st Quarter 2010 Actual vs 1st Quarter 2009 Actual

		2009 Actual Performance Driver	2009 Actual ($ millions)	2009 Actual EPS	2010 Actual Performance Driver	2010 Actual ($ millions)	2010 Actual EPS
	UTILITY OPERATIONS:						
1	East Regulated Integrated Utilities	18,661 GWh @ $ 38.1 /MWhr =	710		18,575 GWh @ $ 42.2 /MWhr =	784	
2	Ohio Companies	13,134 GWh @ $ 48.7 /MWhr =	639		12,584 GWh @ $ 54.3 /MWhr =	683	
3	West Regulated Integrated Utilities	8,797 GWh @ $ 27.6 /MWhr =	243		9,790 GWh @ $ 27.7 /MWhr =	271	
4	Texas Wires	5,738 GWh @ $ 22.1 /MWhr =	127		6,107 GWh @ $ 24.5 /MWhr =	150	
5	Off-System Sales	2,592 GWh @ $ 23.8 /MWhr =	62		4,745 GWh @ $ 15.6 /MWhr =	74	
6	Transmission Revenue - 3rd Party		84			94	
7	Other Operating Revenue		206			123	
8	Utility Gross Margin		2,071			2,179	
9	Operations & Maintenance		(803)			(834)	
10	Depreciation & Amortization		(373)			(398)	
11	Taxes Other than Income Taxes		(194)			(203)	
12	Interest Exp & Preferred Dividend		(221)			(236)	
13	Other Income & Deductions		31			38	
14	Income Taxes		(168)			(185)	
15	Utility Operations On-Going Earnings		343	0.84		361	0.75
16	Transmission Operations On-Going Earnings		-	-		1	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		11	0.03		4	0.01
18	Generation & Marketing		24	0.06		10	0.02
	PARENT & OTHER:						
19	Parent & Other On-Going Earnings		(18)	(0.04)		(11)	(0.02)
20	**ON-GOING EARNINGS**		360	0.89		365	0.76

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q 2010 Cash Flow

($ millions)	2009	2010
Operating Activities		
Net Income -- Reported	**$ 360**	**$ 344**
Depreciation, Amortization & Deferred Taxes	543	501
Pension Contributions	-	(38)
Application of New Accounting Guidance: Securitized Debt for Receivables	-	(656)
Changes in Components of Working Capital	(468)	1
Over/(Under) Fuel Recovery, Net	(95)	(97)
Other Assets & Liabilities	(23)	(53)
Cash Flows From Operating Activities	**317**	**2**
Investing Activities		
Capital Expenditures	(897)	(609)
Proceeds on Sale of Assets	172	139
Change in Other Temporary Cash Investments, net	90	111
Acquisition of Nuclear Fuel	(76)	(38)
Other Investing, net	(16)	(33)
Cash Flows Used for Investing Activities	**(727)**	**(430)**
Financing Activities		
Common Shares Issued, net	48	26
Long-term Debt Issuances, net	854	14
Short-term Debt Increase/(Decrease), net	(1)	281
Application of New Accounting Guidance: Securitized Debt for Receivables	-	656
Other Financing	(23)	(24)
Dividends Paid	(169)	(197)
Cash Flows From Financing Activities	**709**	**756**
Cash From Continuing Operations	**$ 299**	**$ 328**
Beginning Cash & Cash Equivalent Balances	411	490
Ending Cash & Cash Equivalent Balances	**$ 710**	**$ 818**

1Q 2010 Cash Flow Drivers:

Operating Activities

- Application of new accounting guidance represents factored receivables.
- Changes in working capital largely driven by coal inventory, taxes payable and employee related expenses.

Investing Activities

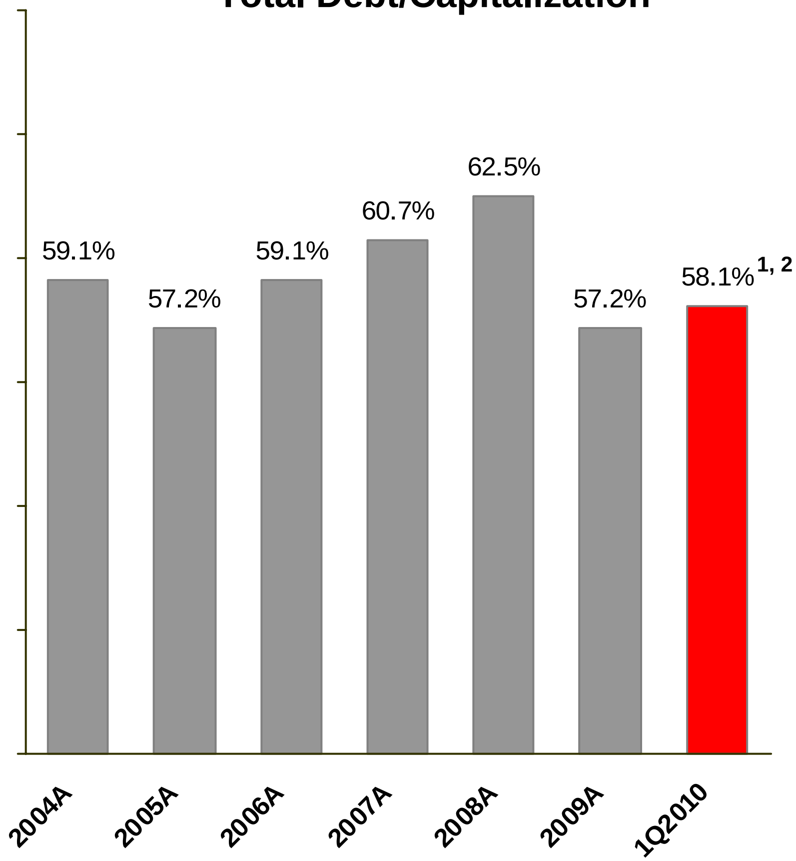
- Cash outlay for 2010 YTD capital investment.
- 2010 asset sale proceeds relate to the transfer of assets to ETT.

Financing Activities

- Changes in long-term debt driven by reduced capital funding requirements.
- Changes in short term debt relate to increased commercial paper activity.
- Application of new accounting guidance represents treatment of factored receivables as short-term debt.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $651 million are classified as short-term debt; The 1Q2010 debt/capitalization ratio would be 57.3%, excluding AEP Credit.

[2]: Ohio Power maturity of $400 million paid off on April 5, 2010

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 03/31/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	818	
Less		
Commercial Paper Outstanding	(399)	
Letters of credit issued	(652)	
Net Available Liquidity	**$3,348**	

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	1Q10 vs. 1Q09
East Regulated Integrated Utilities	$42
Ohio Companies	$27
West Regulated Integrated Utilities	$12
Texas Wires	$0
AEP System Total	$81
Impact on EPS	$0.13

1Q10 Retail Performance

	Load (weather normalized)
	1Q10 vs. 1Q09
East Regulated Integrated Utilities	-3.6%
Ohio Companies	-4.4%
West Regulated Integrated Utilities	4.6%
Texas Wires	2.1%
Impact on EPS	($0.06)

	Weather Impact (in millions)
	1Q10 vs. 1Q09
East Regulated Integrated Utilities	$16
Ohio Companies	$1
West Regulated Integrated Utilities	$14
Texas Wires	$6
Impact on EPS	$0.06

Off System Sales Gross Margin Detail

	1Q09			1Q10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	2,592	$ 16.98	$ 44	4,745	$ 13.07	$ 62
Marketing/Trading	-		$ 41	-		$ 38
Pre-Sharing Gross Margin	2,592		$ 85	4,745		$ 100
Margin Shared			$ (23)			$ (26)
Net OSS			$ 62			$ 74

AEP®

Fact Book

40th EEI Financial Conference

November 6-9, 2005
Hollywood, Florida

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Company Overview

- **AEP Company Overview**

Fall EEI 2005

Company Overview

American Electric Power Co, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Operating Companies	Electric Utility Subsidiaries
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

We have a significant presence throughout the domestic energy value chain. Our US electric assets include:

- More than 36,000 megawatts of generating capacity (one of the largest US generation portfolios with a significant cost advantage in many of our market areas);
- Approximately 39,000 circuit miles of transmission lines, including 2,026 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S., and
- 201,666 miles of overhead and underground distribution lines.

With our coal and transportation assets we:

- control over 7,000 railcars
- own and/or operate 2,230 hopper barges and 53 towboats
- operate one active coal-handling terminal with 20 millions tons of capacity

In addition we consume approximately 75 million tons of coal annually.

Our focus is our core domestic utility business operations. Over the past two years, we have successfully completed the planned divestiture of non-core assets with one exception, which we expect to complete in the near future:

- Mexico – Bajio Project: a 50% interest in a 600-megawatt natural gas-fired electric generation facility located near San Luis de la Pasz, Guanajuato, Mexico.

Company Overview

Business Strategy

AEP's strategy is to focus on domestic utility operations in the U.S. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. We will achieve economic advantage by designing, building, improving and operating low-cost, environmentally compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We will maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We will operate our competitive generating assets to maximize our productivity and profitability after meeting our native-load requirements.

In summary, our business strategy calls for us to:

Operations

- Invest in technology that improves the environment of the communities in which we operate
- Maximize the value of our transmission assets through membership in PJM, ERCOT and SPP
- Continue maintaining and improving the quality of distribution service
- Optimize generation assets by increasing availability and consequently increasing sales

Regulation

- Focus on the regulatory process to fully recover our costs and earn a fair return while providing fair and reasonable rates to our customers while fulfilling our commitment to invest in environmental projects at our generating plants and
- Recover stranded costs associated with our Texas generation assets in compliance with the law

Financial

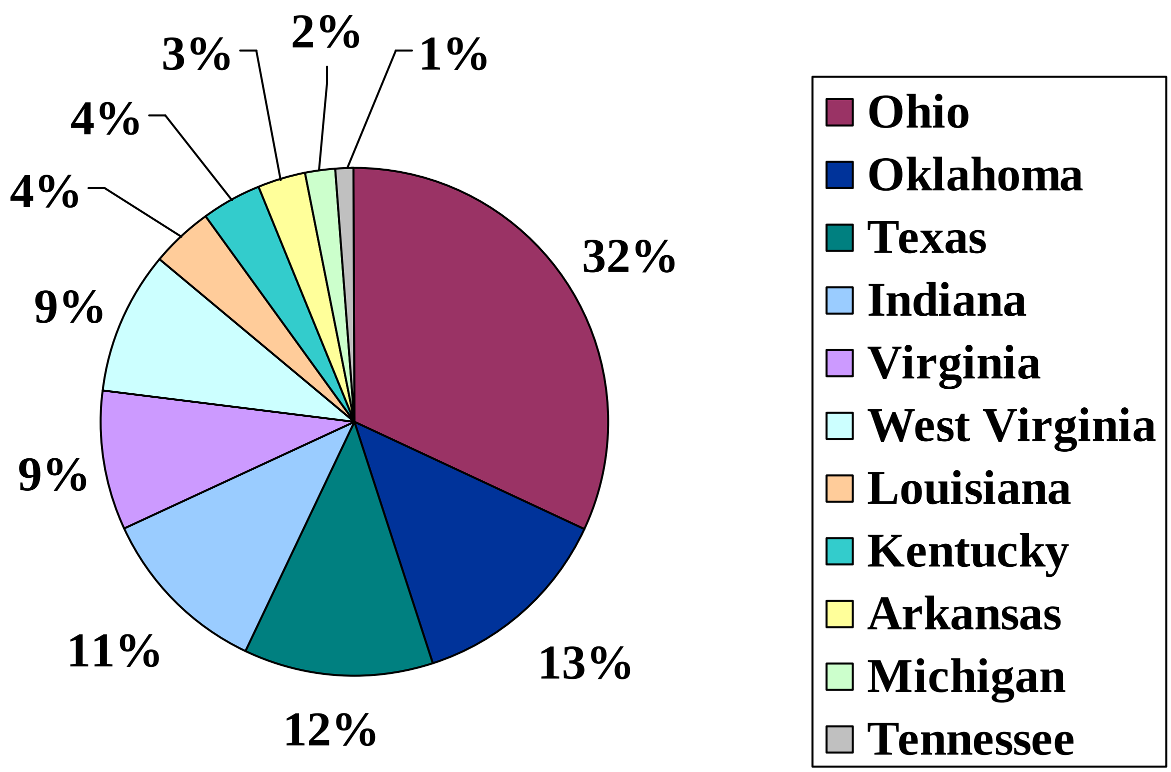
- Operate only those unregulated investments that are consistent with our energy expertise and risk tolerance and that provide reasonable prospects for a fair return and moderate growth
- Continue to improve credit quality and maintain acceptable levels of liquidity
- Achieve moderate but steady growth

2004 Retail Revenue

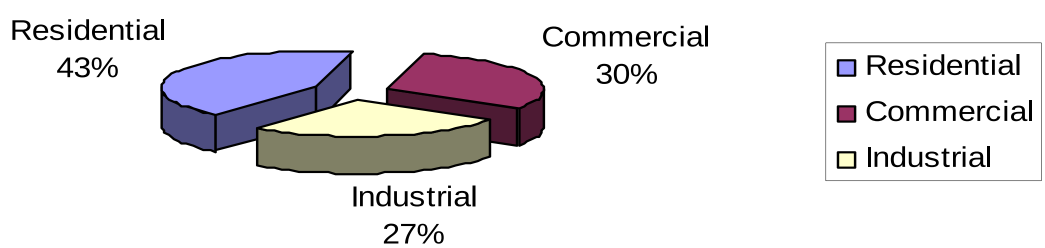
Customer Profile

AEP's service territory encompasses approximately 5 million customers in 11 states: Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

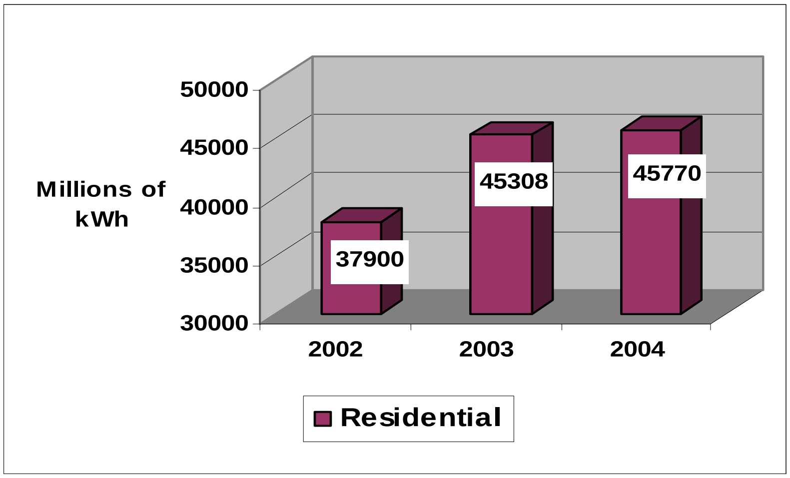
Retail Revenue Composition by State



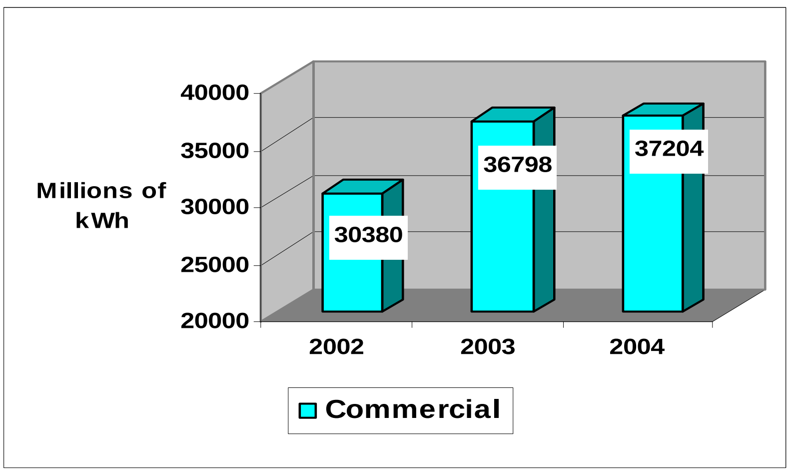
Retail Revenue Composition by Customer Class



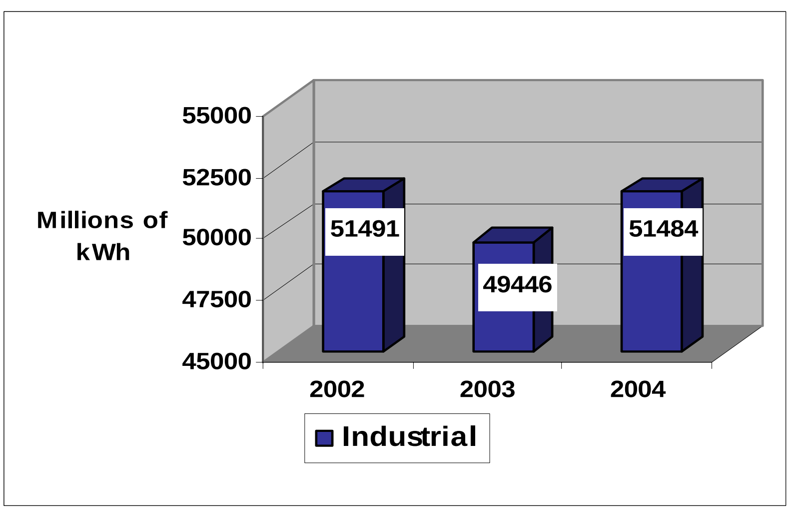
Utility Operations - Load



2 Yr. Compound Annual Load Growth at 9.9%



2 Yr. Compound Annual Load Growth at 10.7%



2 Yr. Compound Annual Load Growth Flat

Note: Figures do not include Texas Retail and Miscellaneous Other

Utility Operations

Generation

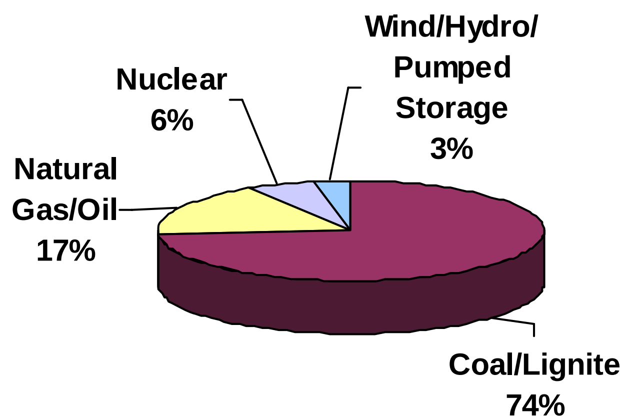
AEP has approximately 36,000 megawatts of generating capacity in 3 power pools. AEP owns all or portions of 70 major generating plants, which include coal/lignite, natural gas, nuclear, wind projects and hydroelectric facilities.

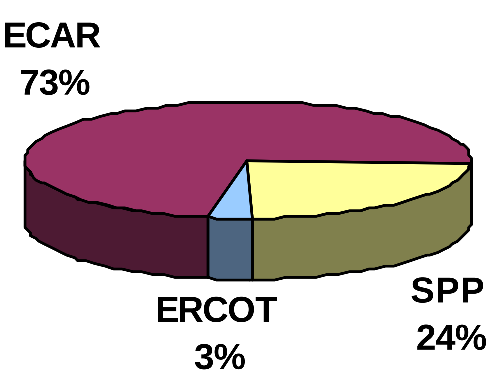
AEP operates generating capacity in its internal power pool under an economic dispatch system[1]. AEP's power pool's competitive, largely coal-based production costs are among the lowest in the nation. AEP's power production costs are also kept relatively low by its reliance primarily on fossil fuel (gas and coal), with only a small overall nuclear dependence.

As shown in the chart below, about 74% of AEP's generating capacity is coal-fired, 17% gas, 6% nuclear, with hydro, wind and pumped storage sources accounting for the balance.

AEP Capacity By Fuel Source & Region [2]

Fuel Source





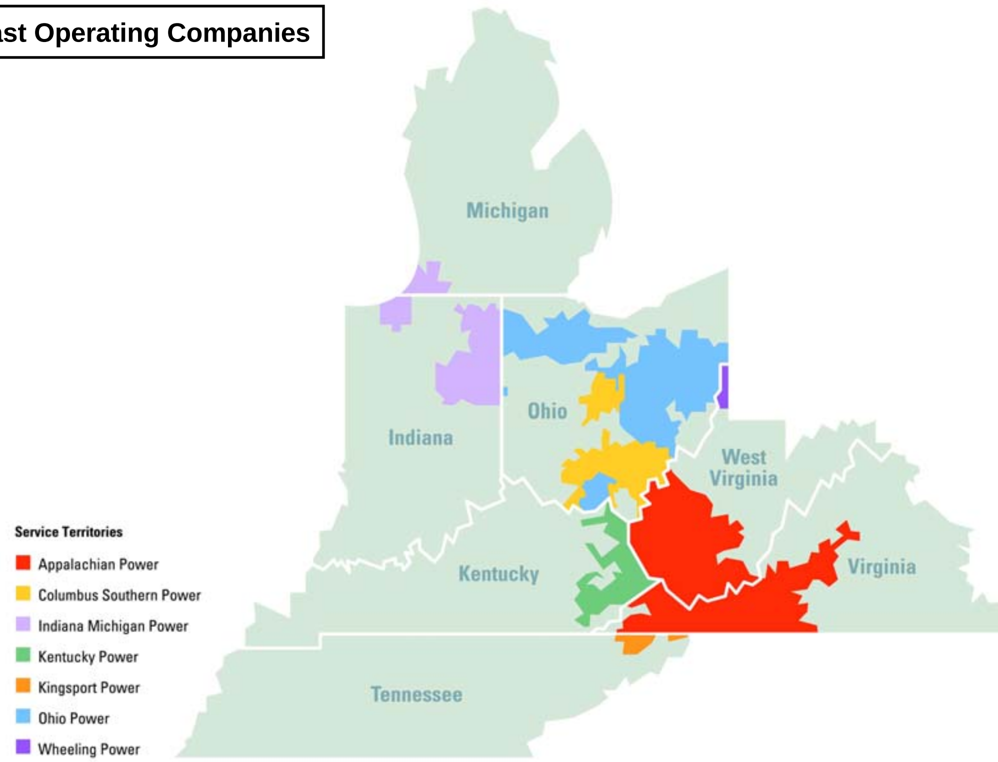
Regional Presence

[1] Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.

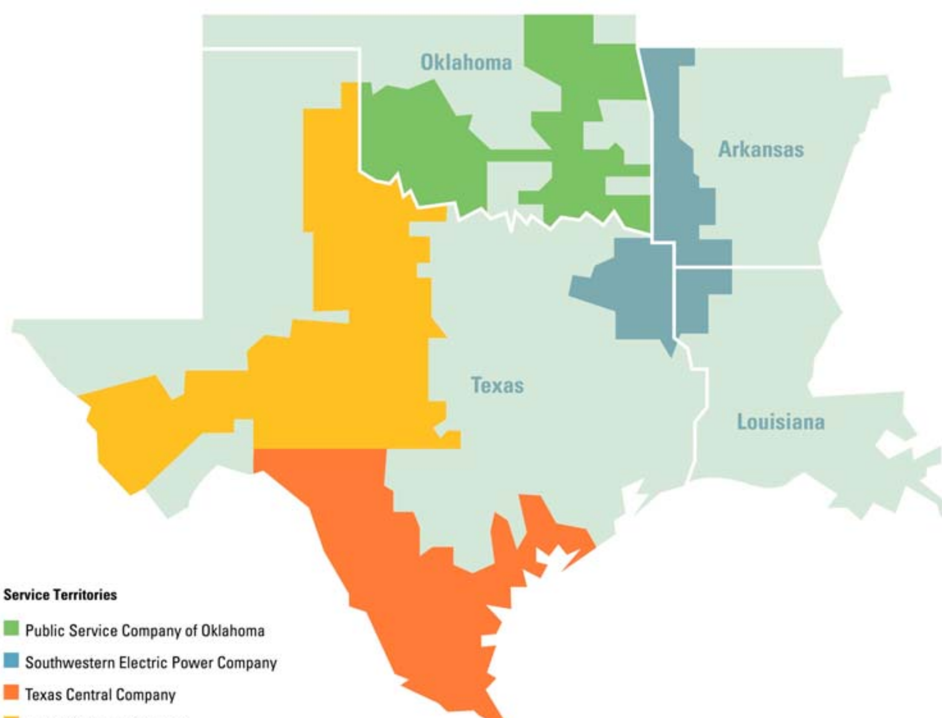
[2] Excludes 1,015 MW of mothballed and/or decommissioned generating capacity.

AEP Service Territory

AEP East Operating Companies



AEP West Operating Companies



Utility Operations

PROPERTY, PLANT, & EQUIPMENT DETAIL ($ MILLIONS)

Property Plant and Equipment	Original Cost	AEP Accumulated D&A	Net Utility Plant
Electric:			
Production	$ 16,487	$ 8,050	$ 8,437
Transmission	6,400	2,265	4,135
Distribution	10,564	3,056	7,508
Other	3,072	1,313	1,759
Construction Work in Progress	1,676	-	1,676
Total	$ 38,199	$ 14,684	$ 23,515

Source: Company Information as of 09/30/05

Operating Company Overview

- **AEP East Regional Utilities**
- **AEP West Regional Utilities**

Fall EEI 2005

Organizational Structure

- CEO
  Mike Morris
  - President
    AEP Utilities
    Carl English
    - EVP
      AEP Utilities East
      Holly Koeppel
      - President
        Ohio
        Kevin Walker
      - President
        Appalachian Power
        Dana Waldo
      - President
        Indiana Michigan Power
        Marsha Ryan
      - President
        Kentucky Power
        Tim Mosher
    - EVP
      AEP Utilities West
      Tom Hagan
      - President
        Texas
        Charles Patton
      - President
        SWEPCO
        Nick Akins
      - President
        Public Service of Oklahoma
        Stuart Solomon

SENIOR MANAGEMENT CLOSE TO CUSTOMERS AND REGULATORS

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AEP East Regional Utilities

AEP Ohio

President and Chief Operating Officer: Kevin Walker

Thumbnail profile and history:
AEP Ohio encompasses the AEP service territories within the state of Ohio and the Wheeling W.Va., area. AEP Ohio serves the customers of Ohio Power Company (organized in 1907) and Columbus Southern Power Company (organized in 1937) and Wheeling Power Company (organized in 1883) in northern West Virginia.

Principal industries served include metals, rubber & plastic products, stone, clay, glass & concrete products, petroleum, refining & chemicals, food processing, & paper.

AEP Ohio covers a service territory of 11,327 square miles, and currently has 1,468 employees.

Operating Information

Total Customers:	
• **Residential**	**1,276,000**
• **Commercial**	**167,000**
• **Industrial**	**11,000**
• **Other**	**<u>3,000</u>**
Total	**1,457,000**
Generating Capacity*	**11,992 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**92.5%**
• **Natural Gas**	**7.1%**
• **Hydro:**	**0.4%**
Transmission Miles	**9,100**
Distribution Miles	**44,000**

*** includes Conesville Units 1 & 2 (250 MW) that will be retired 12/31/05**

Financial Information

(In thousands, rounded)

2004 Revenue		**$3,670,000**
% of AEP retail		**32%**
2004 Net Income		**$349,000**
2004 Capital Ex.		**$495,000**
As of June 30, 2005:		
Total Assets		**$8,857,000**
Net Plant Assets		**$6,591,000**
Cash		**$1,040**
<u>CSP</u>		
Debt	**$988,000**	**(52%)**
Equity	**$919,000**	**(48%)**
<u>OP</u>		
Debt	**$1,793,000**	**(52%)**
Equity	**$1,643,000**	**(48%)**

AEP Ohio

Ohio Generation Production Statistics – 2002 - 2004				
Production Stat	**2002**	**2003**	**2004**	**Three Year Average**
MWh Produced	62,579,034	68,343,616	66,205,844	65,709,498
Coal Consumption (tons burned)	25,711,346	26,421,721	26,664,636	26,265,901

Operating Information

2004 retail sales in megawatt-hours	45,242,351
2004 firm wholesale sales in megawatt-hours	2,045,905
Average cost per kilowatt-hour (residential)	6.63 cents (OPCo) 7.58 cents (CSP)
2004 System Peak	5,059 megawatts (OPCo-Aug 3) 3,623 megawatts (CSP-July 23)

Ohio Plants

Name	Location	Megawatt Capacity	Fuel
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,510	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	627	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	48	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

AEP Ohio

OHIO UTILITIES

Ohio	Customers
AEP Ohio (OPCo, CSP & WPCo)	**1,457,000**
First Energy	1,322,754
Cinergy (CG&E)	650,533
DP&L	503,729

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.66**
AEP (CSP)	**75.51**
Cinergy (CG&E)	79.62
FE (CEI)	112.80
FE (Ohio Ed)	114.94
FE (Toledo Ed)	115.21

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

AEP-OHIO MAJOR INDUSTRIAL CUSTOMERS

Century Aluminum Co.
The Timken Co.
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Wheeling Pittsburgh
Globe Metallurgical, Inc
PPG Industries, Inc.
CONSOL Energy
Owens Corning Fiberglas Corp.
Marathon Ashland Petroleum LLC

OPCo:

- **Top 10 customers = 37% of industrial sales**
- **Metropolitan areas account for 46% of ultimate sales**
- **130 persons per square mile (U.S. = 98)**

CSP:

- **Top 10 customers = 34% of industrial sales**
- **Metropolitan areas account for 84% of ultimate sales**
- **195 persons per square mile (U.S. = 98)**

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commssioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000. Term expires April 2005. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and chair of the Fuel Source Advisory Council, member of the National Coal Council, and member of the Technical Advisory Committee of the Ohio Coal Development Office.

Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves on the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring.

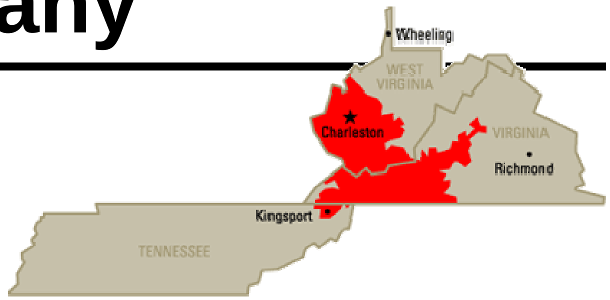
Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

AEP Regulatory Status

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSP and OPCo (the Ohio Companies). The plans provided, among other things, for CSP and OPCo to raise their generation rates by 3% and 7% respectively, in 2006, 2007 and 2008 and provided for additional generation rate increases of up to 4% per year based on the Ohio Companies supporting the need for additional revenues. Distribution rates in effect at 12/31/05 are frozen for OPCo and CSP until 12/31/07 and 12/31/08, respectively.

Transmission rates are currently regulated by FERC as reflected in the OATT. CSP and OPCO do not have an active fuel clause (fuel costs are embedded in unbundled G rates).

Appalachian Power Company



President and Chief Operating Officer: Dana Waldo

Thumbnail profile and history: Appalachian Power (APCo), organized in 1926, is headquartered in Charleston, W.Va., and provides service to AEP customers in West Virginia, Virginia, and Tennessee. APCo also serves customers for Tennessee-based Kingsport Power Company.

Principal industries served include coal mining, primary metals, chemicals & textile mill products.

APCo currently has 2,433 employees, and covers a service territory of 19,914 square miles.

Total Customers:

• **Residential**	**836,000**
• **Commercial**	**129,000**
• **Industrial**	**5,000**
• **Other**	**7,000**
Total	**977,000**
Generating Capacity*	**5,873 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**86%**
• **Hydro/Pump:**	**14%**
Transmission Miles	**6,700**
Distribution Miles	**50,000**

*** Excludes 516 MW Ceredo (expected to close 1Q06)**

(APCo in thousands, rounded)

2004 Revenue		**$1,948,000**
% of AEP retail		**18%**
2004 Net Income		**$150,000**
2004 Capital Ex.		**$452,000**
As of June 30, 2005:		
Total Assets		**$5,544,000**
Net Plant Assets		**$4,266,000**
Cash		**$1,281**
Debt	**$1,905,000**	**(55%)**
Equity	**$1,585,000**	**(45%)**

Appalachian Power Company

APCo Generation Production Statistics – 2002 - 2004				
Production Stat	**2002**	**2003**	**2004**	**Three Year Average**
MWh Produced	33,733,247	32,901,943	29,551,752	32,062,314
Coal Consumption (tons burned)	13,072,219	13,015,569	11,604,352	12,564,810

Operating Information

2004 retail electric sales in megawatt-hours	28,420,661
2004 firm wholesale sales in megawatt-hours	2,526,949
Average cost per kilowatt-hour (residential)	5.38 cents
2004 System Peak	7,080 (December 20)

Appalachian Power Plants

Name	Location	Megawatt Capacity	Fuel
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power Company

APPALACHIAN AREA UTILITIES

West Virginia	Customers
APCo	432,961
Allegheny	475,000

Virginia	Customers
APCo	497,762
Dominion Virginia	2,050,604
Allegheny	88,473
Conectiv	22,094

Tennessee	Customers
APCo	45,803

TYPICAL BILL COMPARISON*

West Virginia	
APCo	55.28
AEP – Wheeling	60.54
Allegheny	70.09

Virginia	
ODPCo	55.88
APCo	56.71
Allegheny	68.09
Dominion Virginia	87.18
Conectiv	92.88

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report.

APPALACHIAN POWER COMPANY MAJOR INDUSTRIAL CUSTOMERS

Consol Energy
Massey Energy Company
Roanoke Electric Steel
Georgia-Pacific Corporation
The Dow Chemical Co., Inc.
Arch Coal, Inc.
Greif Brothers Corporation
Dan River Inc. – Headquarters
Alpha Natural Resources, LLC (previously Pittston)
Peabody Group

- **Top 10 Customers = 26% of industrial sales**
- **Metropolitan areas account for 37% of ultimate sales**
- **90 persons per square mile (U.S. = 98)**

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Regulatory Information

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Wheeling Power Co. **Appalachian Power Co.**

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R**: 1 **D:** 2

<u>Qualifications for Commissioners</u>

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

<u>Commissioners</u>

Edward H. Staats, (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office.

R. Michael Shaw, Commissioner (Rep.), since mid 2003, term expires June 2009. Attorney, former state legislator.

Jon W. McKinney, Chairman (Dem.), since 2005, term expires June, 2011. Formerly served as plant manager of Flexsys' Nitro, W Va operations, chairman of Chemical Industry Committee for W Va, board member of W Va Chamber of Commerce, W Va Manufacturer's Association, Chemical Alliance Zone, W Va Roundtable & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power filed a joint application on August 26, 2005 seeking increases in base rates/charges, reinstatement of a fuel clause mechanism and establishment of a T&D reliability tracker.

Regulatory Information

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3 **Appointed/Elected** Elected **Term:** 6 years **Political Makeup: R:** 2 **D:** 1

Qualifications for Commssioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires February 2010. Attorney, counsel to the Speaker of the House.

Clinton Miller, (Rep.), since 1996, current term expires 2006. Law degree from Washington & Lee University Law School. Lawyer, in private practice. Served as a county Commonwealth's Attorney. Member of the Virginia House of Delegates from 1972 to 1995. Current Chairman.

AEP Regulatory Status

APCo filed an Environmental and Reliability rate case on July 1, 2005, seeking recovery of and return on incremental environmental and T&D costs.

Regulatory Information

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected**: Appointed	**Term:** 6 years	**Political Makeup: R:** 1 **D:** 3

<u>Qualifications for Commssioners</u>

The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all currently expire in June 2008; after 2008, terms will be staggered.

<u>Commissioners</u>

Deborah T. Tate, (Rep.), since 2002; current term expires June 2008. Attorney, juvenile and family law, probate and estate**.** Served as Director of the State and Local Policy Center at Vanderbilt University. Served as an Assistant to the Governor and a member of Senior Staff. J.D. degrees from the University of Tennessee.

Patrick Miller, (Dem.), since 2002; current term expires June 2008. Fiscal Analyst, Fiscal Review Committee. Legislative Liaison, Tennessee Supreme Court. Served as Chief of Staff to the Lt. Governor and Speaker of the Senate. J.D., Nashville School of Law.

Sara Kyle, Director (Dem.), since 1996; current term expires June 2008. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving director and only holdover from the previous Public Service Commission. Law degree from Middle Tennessee State University.

Ron Jones, Chairman, (Dem.), since 2002: current term expires June 2008. Sixteen year veteran of utility regulation, Director Jones served the first ten years with the Tennessee Public Service Commission staff and the next six with the TRA as a Senior Policy Advisor. Completed several regulatory studies programs at Michigan State University, Graduate School of Business.

AEP Regulatory Status

No deregulation legislation, no base rate freeze or cap. Tennessee has an active fuel clause.

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Indiana Michigan Power

President and Chief Operating Officer:
Marsha Ryan

Thumbnail profile and history:
Indiana Michigan Power (I&M), organized in 1925, is headquartered in Fort Wayne, Ind., and encompasses the AEP service territories in Indiana and Michigan.

Principal industries served include primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber, plastic products and chemicals and allied products.

I&M currently has 2,627 employees and has a service territory of 8,255 square miles.

Total Customers:

• **Residential**	**506,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**579,000**
Generating Capacity	**5,768 MW**
(includes AEG Rockport)	

Generating Capacity by Fuel Mix:

• **Coal:**	**62.5%**
• **Nuclear:**	**37.1%**
• **Hydro:**	**0.4%**

Transmission Miles	**5,300**
Distribution Miles	**19,600**

(In thousands, rounded)

2004 Revenue		**$1,662,000**
% of AEP retail		**13%**
2004 Net Income		**$133,000**
2004 Capital Ex.		**$177,000**

As of June 30, 2005:

Total Assets		**$4,943,000**
Net Plant Assets		**$2,985,000**
Cash		**$538**
Debt	**$1,316,000**	**(54%)**
Equity	**$1,130,000**	**(46%)**

Indiana Michigan Power

I&M Generation Production Statistics – 2002 – 2004				
Production Stat	**2002**	**2003**	**2004**	**Three-Year Avg.**
MWh Produced	29,625,450	28,075,125	21,258,001	29,652,858
Coal Consumption (tons burned)	7,053,828	7,189,655	7,186,066	7,143,183
Uranium (grams)	2,957,879	2,344,487	2,903,041	2,735,135

Operating Information	
2004 retail electric sales in megawatt-hours	18,611,660
2004 firm wholesale sales in megawatt-hours	2,211,218
Average cost per kilowatt-hour (residential)	6.64 cents
2004 System Peak	4,051 MW (July 22)

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES

Indiana	Customers
I&M	**452,931**
IP & L	446,614
NIPSCO	433,825
Cinergy (PSI)	733,265
SIGECO	133,492

Michigan	Customers
I&M	**125,596**
CMS (Consumers)	1,700,024
DTE (Detroit Edison)	2,132,409

TYPICAL BILL COMPARISON*

Indiana	
I&M	**68.35**
IP & L	68.91
Cinergy (PSI)	79.20
SIGECo	87.54
NIPSCo	100.72

Michigan	
I&M	**60.86**
Consumers Energy	83.18
Detroit Edison	93.80

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report.

INDIANA MICHIGAN POWER MAJOR INDUSTRIAL CUSTOMERS

Steel Dynamics Inc.
Mittal Steel
Air Products & Chemicals
BOC Gases
Saint Gobain Corporation USA
New Energy Corporation
Ball State University
Guide Indiana
Michelin North America, Inc.
Honeywell International, Inc.

- **Top 10 customers = 33% of industrial sales**
- **Metropolitan area accounts for 80% of ultimate sales**
- **217 persons per square mile (U.S. = 98)**

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup: R**:3 **D:** 2

<u>Qualifications for Commissioners</u>

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At lease one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

<u>Commissioners</u>

David L. Hardy, Chairman (Rep.), since September 2005, current term will expire April 2006. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include: negotiation, contracts, litigation, finance and administration. He has 35 years regulatory experience at the state and federal levels.

Larry S. Landis, Commissioner (Rep.), since December 2002, current term ends January 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.

David W. Hadley, Commissioner (Dem.), since 2000; current term ends January 2006. Executive officer for Indiana AFL-CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.

Greg Server, Commissioner (Rep.), since September 2005, current term ends in April 2009. Former state senator since 1981 and before that served in the Indiana House or Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.

David E. Ziegner, Commissioner (Dem.), since 1990, current term ends April 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

Indiana's base rates are frozen through 6-30-07. Interim fuel factors set through June 2007. Corporate Separation Agreement settled in July 2005.

Regulatory Information

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R**:1 **D:** 2

<u>Qualifications for Commissioners</u>

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

<u>Commissioners</u>

<u>J. Peter Lark, Chair, (Dem)</u> since July 2003: current term expires July 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney.

<u>Laura Chappelle, Commissioner, (Rep.)</u> since 2001: current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney.

<u>Monica Martinez, Commissioner, (Dem)</u> since 2005, current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues.

AEP Regulatory Status

Customer choice began 1/02. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active fuel clause.

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Thumbnail profile and history: Kentucky Power, organized in 1919, is headquartered in Frankfort, Ky., and represents all customers in the service territory of AEP subsidiary, Kentucky Power Company.

Kentucky Power currently has 348 employees and encompasses a service territory of 6,625 square miles.

Total Customers:	
• Residential	144,000
• Commercial	28,000
• Industrial	2,000
• Other	1,000
Total	175,000
Generating Capacity	1,060 MW
Generating Capacity by Fuel Mix:	
• Coal:	100%
Transmission Miles	1,200
Distribution Miles	10,000

(In thousands, rounded)

2004 Revenue		$451,000
% of AEP retail		4%
2004 Net Income		$26,000
2004 Capital Ex.		$38,000
As of June 30, 2005:		
Total Assets		$1,265,000
Net Plant Assets		$965,000
Cash		$237
Debt	$488,000	(60%)
Equity	$331,000	(40%)

Kentucky Power

Kentucky Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2002**	**2003**	**2004**	**Three-Year Average**
MWh Produced	5,752,802	6,170,931	6,550,509	6,158,081
Coal Consumption (tons burned)	2,299,076	2,513,524	2,607,559	2,473,386

Operating Information

2004 retail electric sales in megawatt-hours	6,976,594
2004 firm wholesale sales in megawatt-hours	94,936
2004 average cost per kilowatt-hour (residential)	5.50 cents
2004 System Peak	1,615 MW (Dec 20)

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	Customers
KPCo	**175,000**
Kentucky Utilities	485,253
LG & E	384,139

KENTUCKY POWER MAJOR INDUSTRIAL CUSTOMERS

Marathon Ashland Petroleum
AK Steel Holding Corporation
Massey Energy Company
James River Coal Co.
Air Products & Chemicals
TECO Energy, Inc.
MG Industries, Inc. NAN
Consol Energy
Alliance Coal, LLC
KES Acquisition Company LLC.

TYPICAL BILL COMPARISON*

Kentucky	
Kentucky Utilities	50.70
KPCo	**57.81**
LG&E	65.25
CIN	68.17

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report.

- **Top 10 customers = 72% of industrial sales**
- **Metropolitan areas account for 33% of ultimate sales**
- **65 persons per square mile (U.S. = 98)**

Regulatory Information

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup:** R: 3
<u>Qualifications for Commissioners</u> Three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.			
<u>Commissioners</u> **Mark Goss (Chair) (Rep.),** since 2004; current term expires July 2007. Attorney in private practice. **Teresa Hill (V. Chair.) (Rep.),** since 2005; current term expires July 2009. Served on the Governor's Executive Staff. She is an attorney. **Greg Coker (Rep.),** since 2004 (serving pending confirmation); current term expires July 2008. Formally V.P. External Affairs at ALLTEL; public policy positions at Bell South.			

AEP Regulatory Status

Kentucky has an environmental surcharge to recover approved environmental costs. Kentucky has an active fuel clause. Kentucky is a regulated state. On 9/26/05, KPCo filed a base rate case requesting a $64.8 million annual increase. The Company expects the effective date to be approximately 4/1/06.

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Thumbnail profile and history: Public Service Company of Oklahoma (PSO), organized in 1913, is headquartered in Tulsa, Okla., and serves all of AEP's Oklahoma customers. Principal industries served include natural gas & oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing & timber products, glass, chemicals, cement, plastics, telecommunications & rubber goods.

PSO currently has 1,635 employees, and a service territory of 30,000 square miles.

Total Customers:		
• Residential		441,000
• Commercial		58,000
• Industrial		7,000
• Other		7,000
Total		513,000
Generating Capacity		4,153 MW
Generating Capacity by Fuel Mix:		
• Coal:	25%	
• Natural Gas:	75%	
Transmission Miles		3,600
Distribution Miles		21,000

(In thousands, rounded)		
2004 Revenue		$1,047,000
% of AEP retail		13%
2004 Net Income		$38,000
2004 Capital Ex.		$82,000
As of June 30, 2005:		
Total Assets		$2,083,000
Net Plant Assets		$1,781,000
Cash		$778
Debt	$571,000	(52%)
Equity	$535,000	(48%)

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2002 - 2004				
Production Stat	**2002**	**2003**	**2004**	**Three-Year Average**
MWh Produced	15,047,242	14,845,846	12,512,486	14,135,191
Coal Consumption (tons burned)	4,604,433	4,678,950	4,093,436	4,458,940

Operating Information

2004 retail electric sales in megawatt-hours	16,987,554
2004 firm wholesale sales in megawatt-hours	96,816
Average cost per kilowatt-hour (residential)	7.01 cents
2004 System Peak	3,773 MW (July 14)

Oklahoma Power Plants

Name	Location	Megawatt Capacity	Fuel
Tulsa	Tulsa, Oklahoma	338	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	Customers
PSO	**513,000**
OG&E	674,000

PUBLIC SERVICE COMPANY OF OKLAHOMA MAJOR INDUSTRIAL CUSTOMERS

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
AMR Corporation
Sunoco Inc.
Visteon Corp.
Buzzi Unicem USA
Sinclair Oil Corp.
Terra Nitrogen Company, L.P.

TYPICAL BILL COMPARISON*

Oklahoma	
PSO	**68.57**
Empire District	74.46
OG&E	75.83
SPSCo	79.68

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report.

- **Top 10 customers = 48% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **46 persons per square mile (U.S. = 98)**

Regulatory Information

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected:** Elected	**Term**: 6 years	**Political Makeup:** R: 3

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

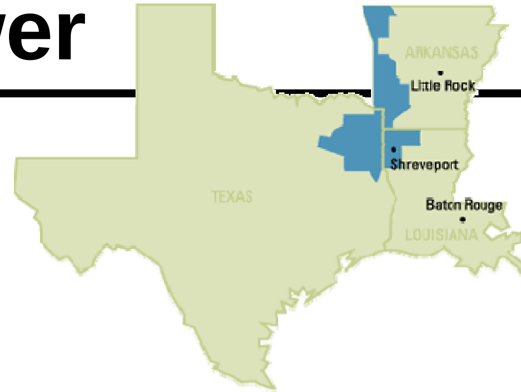
Denise A. Bode, Vice-Chairman (Rep.), since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

Bob Anthony, Commissioner (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

AEP Regulatory Status

As required by the OCC, PSO filed a general rate case October 31, 2003, which was settled in May 2005 and was essentially earnings neutral. Oklahoma has an active fuel clause. In December 2002, the Commission Staff filed for a fuel review. The two key issues are a prior period fuel under-recovery and the determination and allocation of trading margins. The procedural schedule is currently suspended, so no hearing date is set. Oklahoma passed then set aside deregulation legislation. It's unlikely that deregulation legislation will be enacted at any time in the foreseeable future in this state.

Southwestern Electric Power



President and Chief Operating Officer: Nick Akins

Thumbnail profile and history:
Southwestern Electric Power Company (SWEPCo), organized in 1912, is headquartered in Shreveport, La., and encompasses the AEP service territories in Louisiana, Arkansas and East Texas, which is the Texas service territory that participates in the Southwest Power Pool (SPP).

Principal industries include natural gas & oil production, petroleum refining, pulp & paper manufacturing, chemicals, food processing, & metal refining.

SWEPCo had 1,492 employees at 12/31/2004, and a service territory of 25,000 square miles.

Total Customers:	
• **Residential**	**374,000**
• **Commercial**	**60,000**
• **Industrial**	**7,000**
• **Other**	**<u>1,000</u>**
Total	**442,000**
Generating Capacity	**4,487 MW**
Generating Capacity by Fuel Mix:	
• **Coal/Lignite:**	**60%**
• **Natural Gas:**	**40%**
Transmission Miles	**3,500**
Distribution Miles	**19,100**

(In thousands, rounded)

2004 Revenue		**$1,087,000**
% of AEP retail		**11%**
2004 Net Income		**$89,000**
2004 Capital Ex.		**$103,000**
As of June 30, 2005:		
Total Assets		**$2,788,000**
Net Plant Assets		**$2,184,000**
Cash		**$4,591**
Debt	**$951,000**	**(55%)**
Equity	**$776,000**	**(45%)**

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2002**	**2003**	**2004**	**Three-Year Average**
MWh Produced	21,134,399	20,539,365	20,071,578	20,581,780
Coal Consumption (tons burned)	12,902,336	12,536,179	13,032,475	12,823,663

Operating Information

2004 retail electric sales in megawatt-hours	16,320,183
2004 firm wholesale sales in megawatt-hours	5,168,428
Average cost per kilowatt-hour (residential)	6.30 cents
2004 System peak	4,485 MW (July 15)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES

Arkansas	Customers
SWEPCO	**107,220**
Entergy AR	667,763

Louisiana	Customers
SWEPCO	**169,080**
CLECO	264,851

Texas	Customers
SWEPCO	**165,726**

TYPICAL BILL COMPARISON*

Arkansas	
SWEPCO	**64.08**
Empire District	65.19
OG&E	74.07
ETR	85.26

Louisiana	
SWEPCO	**61.30**
CLECO	83.21
Entergy Gulf St	86.45
Entergy LA	88.12
Entergy NO	93.36

Texas	
SWEPCO	**62.79**
SPSCo	75.48
ETR	93.02
TXU	102.11
EP	106.64

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report.

SOUTHWESTERN ELECTRIC POWER MAJOR INDUSTRIAL CUSTOMERS

Lone Star Steel Company
DOMTAR
International Paper Company
General Motors Corp.
Calumet Lubricants
Cooper Tire & Rubber Company
Pilgrim Pride Corp.
Big Three Industrial Gases
Alumax Mill Product, Inc.
Glad Manufacturing

- **Top 10 customers = 39% of industrial sales**
- **Metropolitan areas account for 71% of ultimate sales**
- **76 persons per square mile (U.S. = 98)**

Regulatory Information

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup:** R: 3

Qualifications for Commissioners

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

Commissioners

Sandra Hochstetter, Chairman (Rep.), since 1999; current term ends in 2005. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.

Randy Bynum, Commissioner (Rep.), since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.

Daryl E. Bassett, Commissioner (Rep.), since 2004; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

AEP Regulatory Status

Arkansas has an active fuel pass-through clause. Arkansas passed then repealed deregulation legislation.

Regulatory Information

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Elected	**Term**: 6 years	**Political Makeup**: **R**: 2 **D**: 3

<u>Qualifications for Commissioners</u>

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

<u>Commissioners</u>

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

James M. Field, (Rep.), since 1996; current term ends December 2006. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

AEP Regulatory Status

On October 15, 2002 SWEPCO submitted a revenue filing required by the LPSC as part of its merger order. In April 2004 SWEPCO provided a detailed financial information update for the test year ended 2003 showing a revenue deficiency of $.9 million. LPSC is in final stages of conducting depositions of Company witnesses. Louisiana has an active fuel pass-through clause.

Regulatory Information

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Company **Texas North Company** **Southwestern Electric Power Company**

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: R: 3

<u>**Qualifications for Commissioners**</u> To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.
<u>**Commissioners**</u> **Barry T. Smitherman, Commissioner, (Rep.),** since April 2004, current term expires August 2007. Attorney; Assistant DA; Public Finance Investment Banker. **Julie Parsley, Commissioner (Rep.),** since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University. **Paul Hudson, Chairman (Rep.),** since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUC as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO and TNC-SPP areas). Texas SWEPCO has an active fuel pass-through clause.

AEP Texas

President and Chief Operating Officer: Charles Patton

Thumbnail profile and history:
AEP Texas, headquartered in Corpus Christi, serves transmission and distribution consumers of AEP's two electric utility operating companies in ERCOT - AEP Texas Central Company (TCC), organized in 1916 and AEP Texas North Company (TNC), organized in 1923.

Principal industries served include oil & gas extraction, food processing, apparel, metal refining, chemical & petroleum refining, plastics machinery equipment, several military installations & correctional facilities.

This region had 1,135 employees at 12/31/2004; it covers 97,000 square miles.

Total Customers:
(Based on electric meters)

• **Residential**	**717,000**
• **Commercial**	**133,000**
• **Industrial**	**100**
Total	**850,100**
Generating Capacity	**981 MW***

(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

• **Coal:**	**43.9%**
• **Gas:**	**24.5%**
• **Wind:**	**31.6%**

Transmission Miles	**9,500**
Distribution Miles	**38,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

(In thousands, rounded)

2004 Revenue		
TCC		**$1,175,000**
TNC		**$492,000**
2004 Net Income		
TCC		**$174,000**
TNC		**$48,000**
2004 Capital Ex.		**$158,000**
As of June 30, 2005:		
Total Assets		**$6,254,000**
Net Plant Assets		**$2,588,000**
<u>TCC</u>		
LT Debt	**$1.673,000**	**(59%)**
Equity	**$1,153,000**	**(41%)**
<u>TNC</u>		
LT Debt	**$277,000**	**(46%))**
Equity	**$319,000**	**(54%)**

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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AEP Texas

MAJOR INDUSTRIAL CUSTOMERS

Texas Central Company

Valero Energy Corp.
Koch Industries, Inc.
Air Liquide America, LP
El Paso Energy Corp. (Javelina Co.)
Equistar Chemicals LP
Citgo Petroleum Corp.
Conoco Phillips Co.
Hoescht Celanese
Formosa Utl Ven Ltd.
Aluminum Co. of America

Texas North Company

Chevron Texaco Corp.
Occidental Permian Ltd.
Kinder Morgan
Crown Cork & Seal Co., Inc
Rhodia, Inc.
Shell Oil Products US (Equilon)
Ethicon, Inc.
Tyson Foods Inc. (Wright Brand)
ConocoPhillips Co.
Aethon 1 LP

TCC:

- **Top 10 customers = 85% of industrial sales ($)**
- **Metropolitan areas account for 73% ultimate sales**
- **51 persons per square mile (U.S. = 98)**

TNC:

- **Top 10 customers = 33% industrial sales ($)**
- **Metropolitan areas account for 53% ultimate sales**
- **8 persons per square mile (U.S. = 98)**

Texas Power Plants (excluding mothballed and decommissioned plants)

Name	Location	Megawatt Capacity	Fuel
Oklaunion (TNC)	Vernon, Texas	377	Coal
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal
Desert Sky Wind farm (IPP)	Iraan, Texas	160	Wind
Trent Wind Farm (IPP)	Trent, Texas	150	Wind
Sweeny (IPP Cogneration) *(Own 50% of total 480MW capacity)*	Old Ocean, Texas	240	Gas

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: **R:3**

<u>Qualifications for Commissioners</u>

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

<u>Commissioners</u>

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor’s office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor’s Association Task Force on Electric Infrastructure; Western Governor’s Association Working Group on Cross Border Energy Issues. Master’s degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master’s in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

AEP Regulatory Status

Operations for TCC and TNC have been functionally separated. TCC is pursuing recovery of regulated assets and stranded costs pursuant to the Texas restructuring act (SB7). PUCT hearings on the TCC stranded cost true-up case were completed October 4. Announcement of a decision by commissioners is anticipated in December. TCC is seeking approval of true-up balances of approximately $2.4 billion--$2 billion in stranded costs and associated carrying costs since the start of retail choice in 2002 and approximately $400 million in other true-up amounts including carrying costs. In August, the PUCT issued a decision regarding the TCC rate case, which resulted in a net decrease of $8.8 million in base rates charged to retail electric providers and wholesale transmission customers. However, due to implementation of revised depreciation rates resulting in a lower depreciation expense of approximately $9 million a year, as well as an increase in an AEP/CSW merger-related rate rider of $7.2 million, TCC will see a positive impact of approximately $11 million in pre-tax earnings. Retail competition has been delayed by the PUCT in the Southwest Power Pool (SPP) area of Texas (including SWEPCO and TNC-SPP areas).

Regulation

- **Jurisdictional Outlook**
- **TCC Stranded Cost Recovery**

Fall EEI 2005

Regulation Update

AEP East Companies

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05. Hearings and briefs are done. Awaiting a PUCO order.
- Hearings complete on CSP’s possible acquisition of Mon Power’s Ohio service territory. Commission order pending.

West Virginia (Regulated)
- Base rates not frozen
- No active fuel clause
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- On 8-26-05 AP & WP filed with the WVPSC for a $183 million revenue increase to be phased in over a four-year period beginning in mid 2006. The filing consists of a general rate case, reinstatement of the ENEC, to implement scheduled incremental rate increases for major clean air & transmission investments, and the implementation of a system reliability tracker mechanism.
- On 8-31-05 AP and Reliant jointly filed with the WVA PSC for approval to purchase the Ceredo generating station.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause
- On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental costs for environmental compliance and T&D System reliability (E&R) of $62.1 million based on actual costs through early 2005 and projected costs through June 2006, effective on an interim basis beginning 8-1-05. In an order dated 10-14-05, the Commission denied the Company’s request for interim rate treatment and ruled that the Company may only seek to include actually incurred costs (i.e., no projected future costs) in the E & R cost recovery filing. The Commission has scheduled hearings to begin 2-7-06 .

Kentucky (Regulated)
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- On 9-26-05 the Company filed a base rate case requesting a $64.8 million annual increase. The Company expects the effective date to be approximately 4-1-06.

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulation Update

AEP West Companies

Texas (Regulated) • SWEPCO Texas retail competition delayed until at least 2007. PUC Chairman believes the precursors for full and open competition are not yet in place and will not exist prior to 2009. The Chairman committed to the Texas Legislature that the commission would consider maintaining the current status of competition in the SWEPCO Texas (and SPP portion of TNC) areas in future proceedings. • Bi-annual fuel clause adjustment opportunity **Texas ERCOT Area (Restructured)** • TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested). Hearings concluded 10-4-05. TCC anticipates a Commission ruling in December. • TCC wires rate case PUCT approved final order on July 15. Final order results in slight rate decrease with a positive earnings impact. Rates were effective on 9-6-05. • TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing is final and appeals were filed in state and federal court in August 2005. • TNC true-up order approved in May 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC. The results of the true-up case were filed in TNC's Competition Transition Charge (CTC) proceeding in August 2005. • TNC final fuel reconciliation (July 00-Dec. 01). Final order received 10-18-04. District Court affirmed PUC on 9-9-05. TNC will appeal. In September 2005, the U.S. District Court enjoined the commissioners from violating federal law on its allocation of off-system sales margins.	**Oklahoma (Regulated)** • On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval. Staff submitted testimony supporting an annual cap of $23.68 million up from the $11.81 million cap currently in place. The ALJ has recommended approval of the Staff proposed rider cap. The ALJ recommendation also allows for the recovery of return, depreciation, taxes, etc. associated with converting overhead distribution lines to underground. It is now pending a Commission decision. • Annual Fuel Clause • 2001 Fuel review case •Hearings scheduled for Sept. 2005 have now been continued to a later date to be determined. Scope expanded to cover 2002-2004 margin allocation issue. Intervenors have submitted testimony which would substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error. • 2003 Fuel review case Scope has been expanded to include a prudence review. • 2004 Fuel review case Staff has now filed for a review of PSO's 2004 fuel costs.
Louisiana (Regulated) • Base rates not frozen • Currently under a merger required financial review • Fuel clause, adjusted monthly	**Arkansas (Regulated)** • Base rates not frozen • Fuel clause, adjusted annually

Components of TCC's Net True-up Regulatory Asset

	30-Sep-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 892	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(49)	(10)
Net Stranded Generation Costs	1,092	1,136
Carrying Costs on Stranded Generation Plant Costs	218	225
Net Stranded Generation Costs Designated for Securitization	1,310	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	114	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(210)	(212)
Net Other Recoverable True-up Amounts	326	287
Total Recorded Net True-up Regulatory Asset	$ 1,636	$ 1,648

- **Carrying charge calculated using pre-tax cost of capital of 11.79%**
- **Debt Component: 8.12% - $332 million recognized as income thru 9/30/05**
  - **Carrying charges for 2005 expected to be $87 million**
- **Equity Component: $177 million to be recognized in income as collected**

TCC SEEKING STRANDED COST RECOVERY OF $2.4 BILLION

Timeline For Recovery

May 27, 2005	True-up filings made with the PUCT; this a 150-day process with possible extension; filed for recovery of $2.4 billion.
Dec 2005	PUCT True-up decision, if not extended.
Jan/Feb 2006	TCC request for a financing order to enable it to securitize stranded costs.
Feb/Mar 2006	TCC request to reflect other true-up items (capacity auction true-up, final fuel balance and retail clawback amounts) in CTC (Competition Transition Charge). This must be filed within 60 days of final order and appealable order in true-up proceeding.
3Q 2006	Possible issuance of securitization bonds, if no appeal of TCC true-up order, or by unanimous agreement of all intervening parties.
4Q 2006	CTC charge approved by the PUCT (recovery of other true-up amounts begin).

Generation & Optimization

- Units
- Generation Statistics
- Fuel Statistics
- Transportation Assets

Fall EEI 2005

Domestic Generation

Generation Capacity*

COMPANY	MW
APCO**	5,873
I&M	4,468
KPCO	1,060
PSO	4,153
SWEPCO	4,487
AEG	1,300
CSP	3,472
OPCO	8,520
TCC	54
TNC***	377
OVEC Capacity****	981
Domestic IPPs	550
Total	**35,294**

*Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).
**Excludes 516 MW Ceredo generating plant, given that the sale has not yet closed
*** Excludes 1,015 MW of mothballed and/or decommissioned generation
**** AEP owns a 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE.

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
AEP GENERATING COMPANY					
Rockport	1	IN	ECAR	Steam - Coal	1,300
APPALACHIAN POWER COMPANY					
Buck	3	VA	ECAR	Hydro	8.5
Byllesby	4	VA	ECAR	Hydro	21.6
Claytor	4	VA	ECAR	Hydro	75
Leesville	2	VA	ECAR	Hydro	50
London	3	WV	ECAR	Hydro	14.4
Marmet	3	WV	ECAR	Hydro	14.4
Niagara	2	VA	ECAR	Hydro	2.4
Reusens	5	VA	ECAR	Hydro	12.5
Winfield	3	WV	ECAR	Hydro	14.8
Smith Mountain	5	VA	ECAR	Pumped Storage	586
Amos	2	WV	ECAR	Steam - Coal	2,033
Clinch River	3	VA	ECAR	Steam - Coal	705
Glen Lyn	2	VA	ECAR	Steam - Coal	335
Kanawha River	2	WV	ECAR	Steam - Coal	400
Mountaineer	1	WV	ECAR	Steam - Coal	1,300
Sporn	2	WV	ECAR	Steam - Coal	300
Ceredo (1)	6	WV	ECAR	Natural Gas	516
					5,872.6
COLUMBUS SOUTHERN POWER COMPANY					
Beckjord (CCD)	1	OH	ECAR	Steam - Coal	53
Conesville (CCD)(2)	6	OH	ECAR	Steam - Coal	1,510
Picway	1	OH	ECAR	Steam - Coal	100
Stuart (CCD)	4	OH	ECAR	Steam - Coal	627
Zimmer (CCD)	1	OH	ECAR	Steam - Coal	330
Waterford	4	OH	ECAR	Natural Gas	852
					3,472
INDIANA MICHIGAN POWER COMPANY					
Berrien Springs	3	MI	ECAR	Hydro	7.2
Buchanan	5	MI	ECAR	Hydro	4.1
Constantine	4	MI	ECAR	Hydro	1.2
Elkhart	3	IN	ECAR	Hydro	3.4
Mottville	4	MI	ECAR	Hydro	1.7
Twin Branch	6	IN	ECAR	Hydro	4.8
Rockport	1	IN	ECAR	Steam - Coal	1,307.5
Tanners Creek	4	IN	ECAR	Steam - Coal	995
Cook	2	MI	ECAR	Steam - Nuclear	2,143
					4,467.9

(1) Ceredo plant is excluded from the APCo MW count, given that the sale has not yet closed
(2) Conesville plant will retire units 1&2 at the end of 2005, resulting in a reduced MW capacity of 1260

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
KENTUCKY POWER COMPANY					
Big Sandy	2	KY	ECAR	Steam - Coal	1,060.0
OHIO POWER COMPANY					
Racine	2	OH	ECAR	Hydro	47.5
Amos	1	WV	ECAR	Steam - Coal	867
Cardinal	1	OH	ECAR	Steam - Coal	600
Gavin	2	OH	ECAR	Steam - Coal	2,600
Kammer	3	WV	ECAR	Steam - Coal	630
Mitchell	2	WV	ECAR	Steam - Coal	1,600
Muskingum River	5	OH	ECAR	Steam - Coal	1,425
Sporn	3	WV	ECAR	Steam - Coal	750
					8,519.5

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)	
PUBLIC SERVICE COMPANY OF OKLAHOMA						
Tulsa	2	OK	SPP	Steam - Nat Gas	330	
Tulsa	3	OK	SPP	Oil	8	
Riverside	2	OK	SPP	Steam - Nat Gas	917	
Riverside	1	OK	SPP	Oil	2.8	
Northeastern (1&2)	4	OK	SPP	Steam - Nat Gas	940	
Northeastern	1	OK	SPP	Oil	2.8	
Southwestern	3	OK	SPP	Steam - Nat Gas	472	
Southwestern	1	OK	SPP	Oil	2	
Comanche	3	OK	SPP	Steam - Nat Gas	273	
Comanche	2	OK	SPP	Oil	4	
Weleetka	3	OK	SPP	Steam - Nat Gas	163	
Weleetka	2	OK	SPP	Oil	4	
Northeastern (3&4)	2	OK	SPP	Steam - Coal	925	
Northeastern	1	OK	SPP	Oil	1.2	
Oklaunion	1	TX	ERCOT	Steam - Coal	108	
					4,152.7	
TEXAS CENTRAL COMPANY						
Oklaunion (1)	1	TX	ERCOT	Steam - Coal	54	
					54	
SOUTHWESTERN ELECTRIC POWER COMPANY						
Arsenal Hill	1	LA	SPP	Steam - Nat Gas	110	
Lieberman	4	LA	SPP	Steam - Nat Gas	269	
Knox Lee	4	TX	SPP	Steam - Nat Gas	486	
Wilkes	3	TX	SPP	Steam - Nat Gas	882	
Lone Star	1	TX	SPP	Steam - Nat Gas	50	
Welsh	3	TX	SPP	Steam - Coal	1,584	
Flint Creek	1	AR	SPP	Steam - Coal	264	
Pirkey	1	TX	SPP	Steam - Lignite	580	
Dolet Hills	1	LA	SPP	Steam - Lignite	262	
					4,487	
TEXAS NORTH COMPANY(2)						
Paint Creek	4	TX	ERCOT	Steam - Nat Gas	231	Mothballed
Rio Pecos	3	TX	ERCOT	Steam - Nat Gas	140	Mothballed
San Angelo	2	TX	ERCOT	Steam - Nat Gas	123	Mothballed
Fort Phantom	2	TX	ERCOT	Steam - Nat Gas	362	Mothballed
Oak Creek	1	TX	ERCOT	Steam - Nat Gas	85	Mothballed
Abilene	1	TX	ERCOT	Steam - Nat Gas	18	Mothballed
Lake Pauline	2	TX	ERCOT	Steam - Nat Gas	35	Mothballed
Ft. Stockton	1	TX	ERCOT	Steam - Nat Gas	5	Mothballed
Vernon	4	TX	ERCOT	Oil	8	Mothballed
Oklaunion	1	TX	ERCOT	Steam - Coal	377	
Presidio	2	TX	ERCOT	Oil	2	Mothballed
Ft. Davis	12	TX	ERCOT	Wind	6	Decommissioned
					377	

(1) TCC's share of the Oklaunion plant is currently under negotiation for sale

(2) Excludes 1,015 MW of mothballed and/or decommissioned generation

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
DOMESTIC INDEPENDENT POWER PROJECTS					
Trent Mesa	100	TX	ERCOT	Wind	150
Sweeny	4	TX	ERCOT	Natural Gas	240
Indian Mesa	107	TX	ERCOT	Wind	160
					550

Generation Statistics

	3rd. Qtr. Capacity Factor	3rd. Qtr. Equivalent Availability Factor	3rd. Qtr. Equivalent Forced Outage Rate	3rd. Qtr. Net Generation	YTD Generation
AEP East	74.03%	88.95%	8.31%	41,265,054	115,668,803
Coal*	75.83%	88.16%	8.82%	36,878,437	102,922,745
Hydro**	-5.33%	78.19%	23.64%	(98,866)	(98,866)
Nuclear	94.80%	97.68%	2.32%	4,485,483	12,844,924
AEP SPP	57.15%	92.87%	5.05%	10,345,981	25,399,600
Coal***	83.59%	93.09%	6.16%	6,187,886	16,791,955
Gas	38.86%	92.71%	4.12%	4,158,095	8,607,645
AEP Texas	80.57%	84.63%	13.39%	1,592,523	4,472,275
Coal****	80.57%	84.63%	13.39%	958,901	2,710,119
Nuclear*****	[redacted]				1,762,156
AEP System	70.07%	89.82%	7.63%	53,203,559	145,540,678

Notes: *Includes 20,795 MW, which includes AEP's share of CCD units. Does not include Cardinal 2 & 3 or the Mone units.

**Includes Smith Mountain only including pumping. Does NOT include AEP run-of-river units.

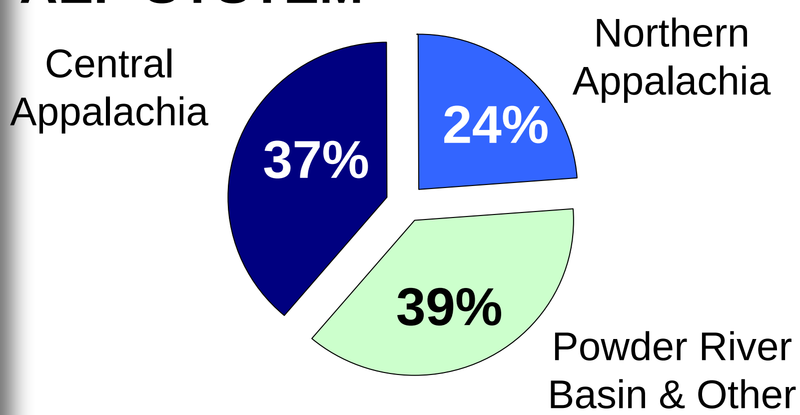
***Does not include Dolet Hills. Pirkey and Flint Creek are reported as owned.

****Oklaunion reported as owned.

*****South Texas Project generation reported through 5/18/05.

Coal Procurement

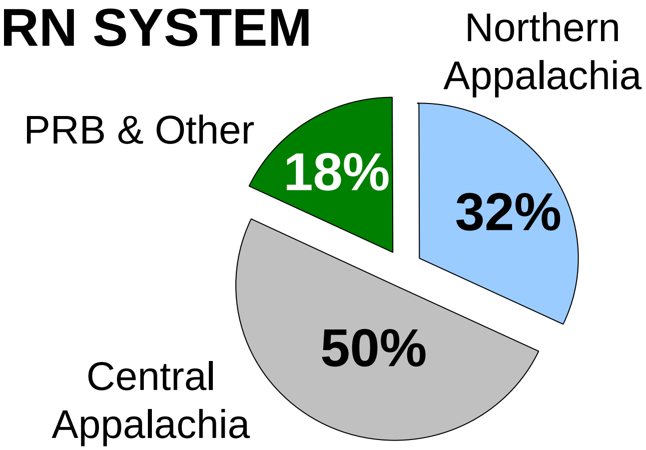
AEP SYSTEM



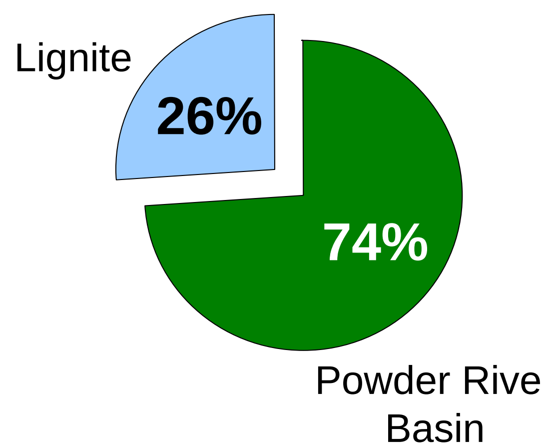
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 12%-14% price increase in 2005
  - Increase being pressured by strong burn
  - PRB deliveries will impact results

EASTERN SYSTEM

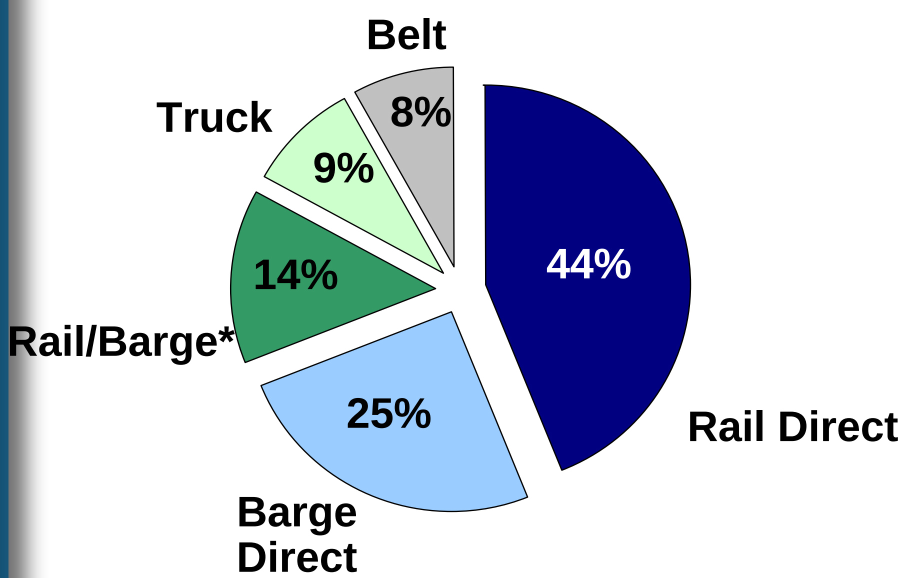


WESTERN SYSTEM

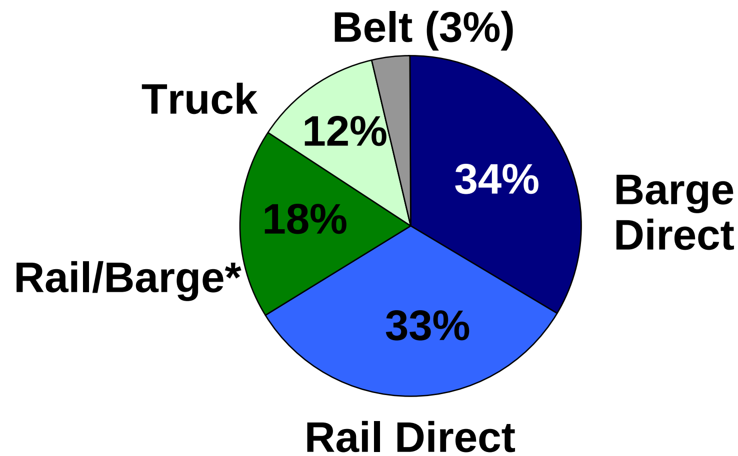


Coal Delivery Mix

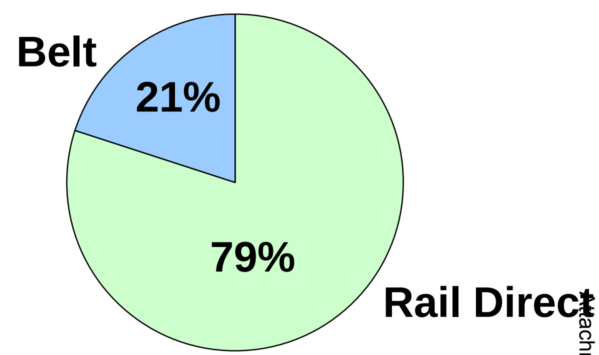
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



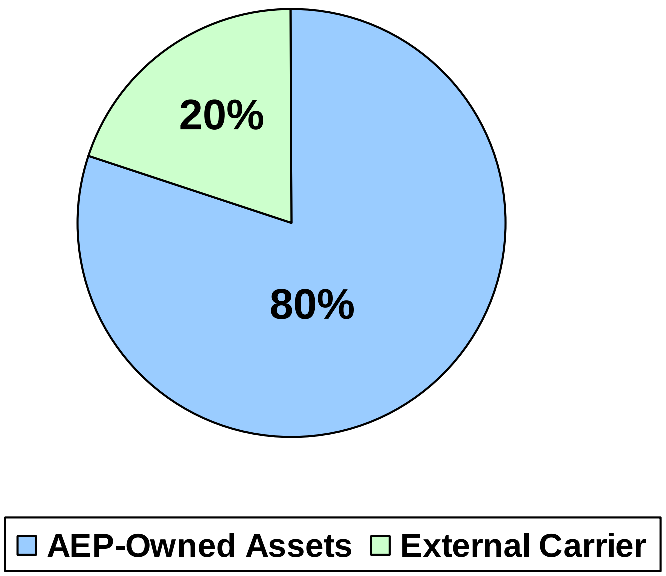
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



AEP's substantial coal transportation assets include:

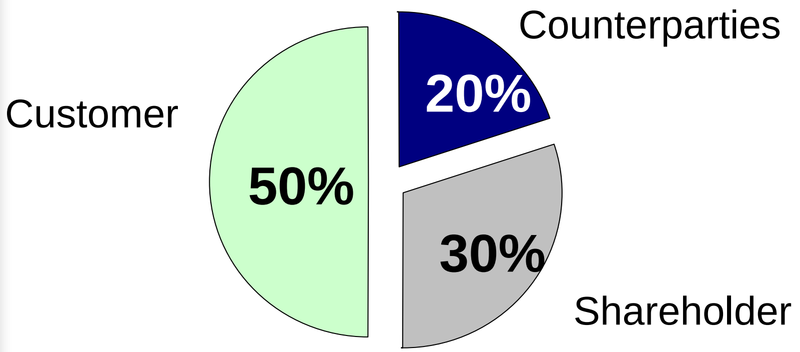
- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

* Represents close approximations

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM



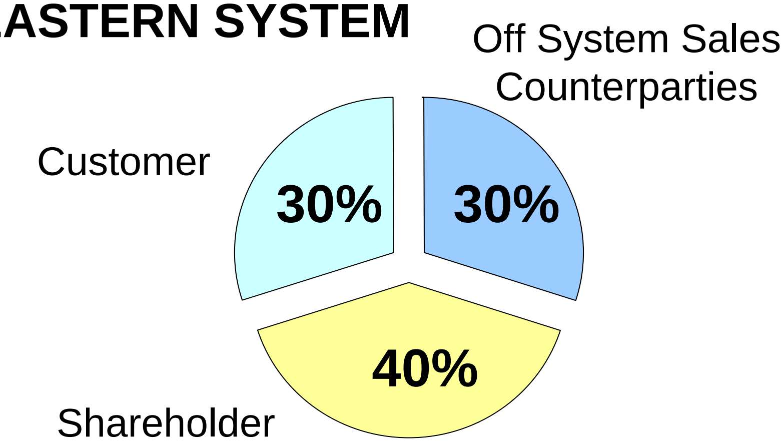
Fuel Cost Recovery

(on average)

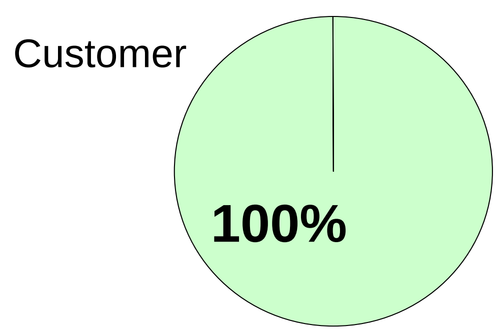
- ➢Fuel recovery varies by jurisdiction
- ➢70% of fuel cost is recoverable across the AEP System
- ➢Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



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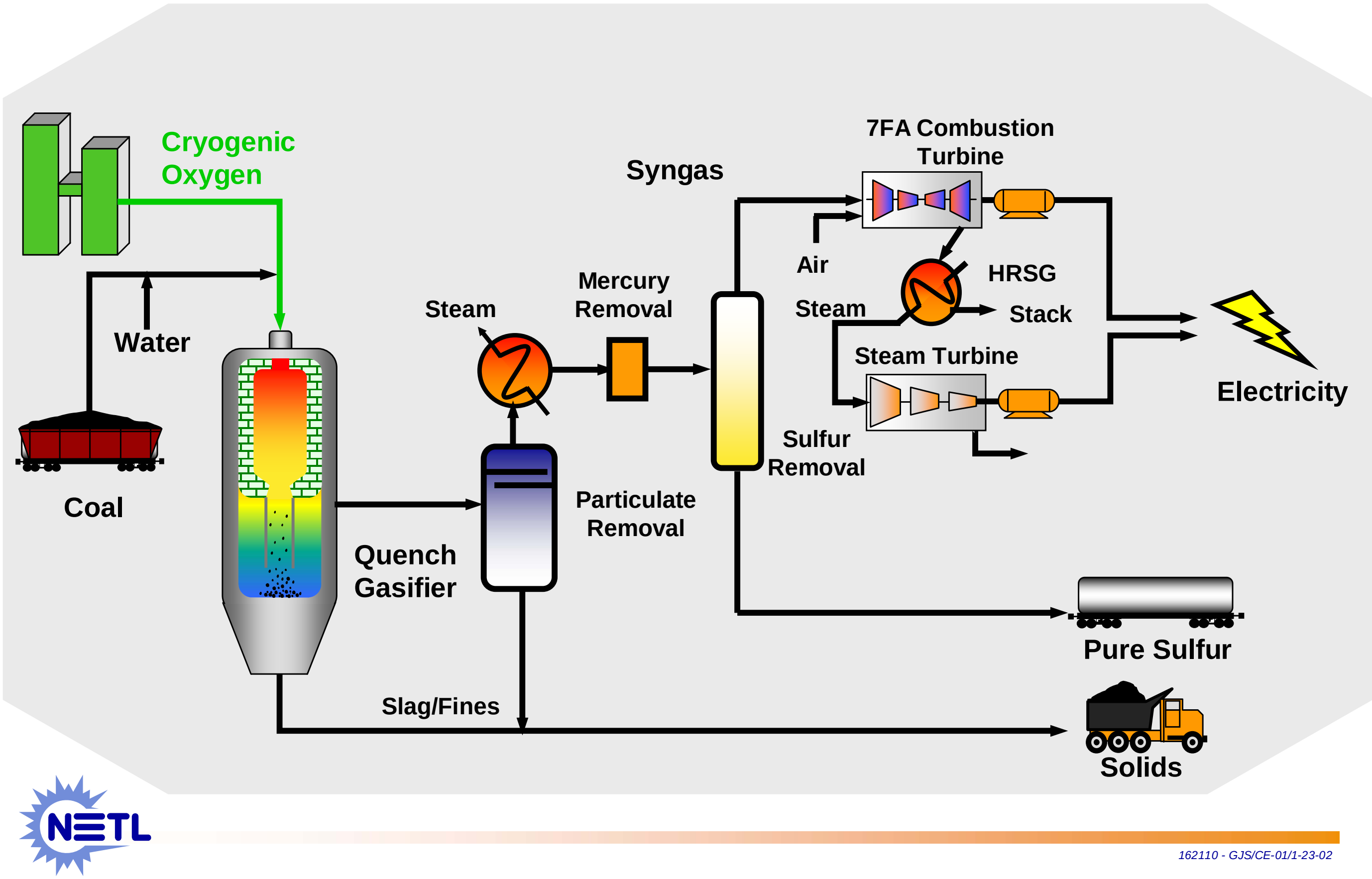
AEP®

IGCC Overview

- **Investing in IGCC**

Fall EEI 2005

Looking to the Future - IGCC



AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing in IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8690	8700	7200
Total Plant Cost ($/kW)	1290	1550	440
Fuel cost ($/MWh)	14	14	53
Cost of Electricity (without CO2 Capture) ($/MWh)	52	56	75
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	96	79	143

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost includes the cost to engineer, procure and construct plant. It does not include escalation, owner's costs, transmission upgrades, or AFUDC.
- Assumes Northern Appalachian Coal price of $36/ton for PC and IGCC and natural gas price of $7.34/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 40% for NGCC.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Siting and Permitting Process

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

Mason County, WV
- Adjacent to AEP's Mountaineer plant

Meigs County, OH
- In the Great Bend area

Lewis County, KY
- In the Carrs area near Vanceburg

PJM EVALUATION PERFORMED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

Recovery Application Filed with PUCO

March 18, 2005: CSP and OPCO filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant if built in Ohio.

Initial Cost Recovery Filing

Phase 1

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $18 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction
- Approximately $237.5 Million

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.033 Billion cost of plant over its operating life.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH

Next Steps

2005:

- **Secure cost recovery plan**
  - **Final Order expected by end of 2005 for Ohio IGCC filing**
- **Finalize site selection**
- **Negotiate with suppliers**

2005—2007: Obtain permits and finalize engineering and procurement

2007—2010: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

AMERICAN ELECTRIC POWER

NEWS from AEP

September 29, 2005

AEP selects GE and Bechtel to design clean-coal power plant

General Electric and Bechtel alliance to begin front-end engineering and design process for AEP's proposed IGCC plant

AEP has signed an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process for a commercial-scale, integrated gasification combined cycle (IGCC) clean-coal plant in the 600-megawatt range. This will be the first such engineering and design agreement undertaken for an IGCC plant of this scale.

"We're thrilled to be moving forward with our goal of building the next generation of coal-fueled power plants that offer enhanced environmental performance. We need additional generation, and we believe an IGCC plant, over its expected lifespan, offers the right, environmentally responsible, cost-effective option for our customers," said Mike Morris, AEP's chairman, president and chief executive officer.

"At AEP, we've worked for more than a decade to help push clean-coal generation from theory to commercial viability and now to mainstream use. Our success with this project -- ramping up the technology to build the first large-scale, baseload IGCC plant in the country -- will help our industry continue to rely on our nation's vast domestic coal reserves to generate much-needed, affordable electricity with less environmental impact," Morris said.

The front-end engineering design process is a detailed process that leads to a more accurate determination of the costs for a construction project. For AEP's proposed IGCC plant, the front-end engineering design process will require 10 to 12 months. Then, based on the status of regulatory proceedings, and engineering and cost targets, AEP would hope to move forward with awarding contracts for final engineering, procurement and construction.

AEP announced Aug. 31, 2004, its intent to build approximately 1,200 megawatts of commercial-scale, baseload IGCC generation. AEP Ohio filed for cost recovery March 18, 2005, with the Public Utilities Commission of Ohio (PUCO) to build an IGCC plant in Meigs County, Ohio. AEP Ohio hopes to have a decision from the PUCO by the end of 2005. AEP is moving forward with the front-end engineering design process for the IGCC technology in order to remain on schedule to complete an IGCC plant in 2010. AEP intends to build at least another 600 megawatts of IGCC generation in its eastern operating area by 2013. A location for additional IGCC generation has not been determined.

IGCC plants turn coal into a synthesis gas and eliminate most of the sulfur dioxide, nitrogen oxides, mercury and other emissions before the gas is used to fuel a combustion turbine generator. The hot exhaust gases are then used to heat steam to drive a steam turbine generator. The technology uses less water and has lower emissions than a conventional coal-fired plant with currently required emission control equipment. Additionally, IGCC design allows for potential capture and sequestration of carbon dioxide (CO_2) at a lower cost than conventional coal-fired plants.

Environmental Overview

Fall EEI 2005

Environmental – Multi-Emissions Reductions

Coal-fired power plants continue to face a variety of environmental requirements over the next decade. Most of the regulations and potential policies are aimed at reducing air emissions, primarily nitrogen oxides (NOx), sulfur dioxide (SO_2), mercury (Hg) and carbon dioxide (CO_2). The regulations and proposals address a variety of public health and/or ecosystem issues such as acid rain, regional haze, ozone transport, fine particulates, fish contaminated with mercury, eutrophication of water bodies, and global climate change. In addition, the industry is embroiled in an enforcement initiative by the EPA, the Justice Department, and some states and environmental groups alleging that companies violated the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs of the Clean Air Act through their power plant maintenance practices. Environmental regulations historically take a piecemeal approach to achieving air quality objectives that creates uncertainty for affected sources, results in unnecessary expenditures, lacks flexibility, often results in litigation that delays air quality improvements, and can seriously harm U.S. energy security.

Multi-Emissions Legislation: AEP continues to believe that a comprehensive, flexible, coordinated multi-emissions control strategy should be developed and implemented over the next 15-20 years for SO_2, NOx and Hg to address and resolve these air quality issues. Doing so could provide regulatory certainty to utilities for a significant period of time, lower compliance costs, accomplish air quality objectives, and maintain diversity of fuel for electricity production. In response to these pressures and motivated by a desire for regulatory certainty, the electric utility industry has been and continues to advocate enactment of federal multi-emission legislation. This is despite the aggressive reductions required under such legislation.

Early in 2005, President Bush's "Clear Skies Initiative" was reintroduced by Senators Inhofe and Voinovich as the Clear Skies bill (S-131). The bill (after initial markup) was a multi-emissions control proposal that would reduce NOx, SO_2, and Hg emissions, utilizing an emissions trading program for each pollutant. The bill requires reductions in two phases—by 2010 (2008 for NOx) about a 50% reduction in NOx and SO_2 emissions and about a 30% reduction in Hg emissions, and by 2016, 70% reductions in SO_2, NOx and Hg. In addition to significantly reducing emissions in two phases, the legislation would eliminate or modify existing Clean Air Act programs, including the NSR and PSD rules as they affect existing electric generating units. However, the bill failed to get out of Committee and further action on the legislation is unlikely. Regrettably, the legislation polarized the Congress along partisan lines and the environmental community has done an effective job of criticizing the legislation, albeit on specious grounds.

Environmental – Multi-Emissions Reductions

Multi-Emissions Regulations: During the course of 2005, EPA finalized two rules: the Clean Air Interstate Rule (CAIR), and the Clean Air Mercury Rule (CAMR). These rules would require approximately the same amount of reductions as the Clear Skies proposal in two phases: 2010 (2009 for NOx) and 2015 (2018 for Hg) also utilizing an emissions trading. While the industry and AEP are generally supportive of these regulations, they do not provide the same degree of regulatory certainty and eliminate unnecessary provisions or modify the Clean Air Act to the same degree as Clear Skies legislation.

In July 2005, EPA finalized a third rule: the Clean Air Visibility Rule (CAVR) which addresses the implementation of emission controls for SO_2 and NOx to deal with regional haze in Class I areas (e.g. national parks, forests and other pristine areas). CAVR requires Best Available Retrofit Technology (BART) – defined as scrubbers and meeting low NOx emission rates---to be required and ultimately installed at those affected facilities. EPA is urging states that are part of the CAIR region (most of the states except for the Western US) to adopt the CAIR rule as compliant with CAVR (thus not requiring BART at power plants within that state). However, in the other non-CAIR states (i.e. The West and Southwestern US) most of the currently unscrubbed coal fired plants will probably be required to install scrubbers and meet lower NOx limits.

Greenhouse Gas Policies: The President has committed the nation to reduce the greenhouse gas (GHG) intensity of the economy (GHG emissions per $ GDP) by 18% over the next ten years through voluntary programs, and called for an improved federal emissions reporting program for tracking progress toward this goal. Regional U.S. initiatives to reduce greenhouse gas emissions and specifically CO_2 emissions have also begun in states outside of AEP's service territory including the Northeastern States (i.e. the Regional Greenhouse Gas Initiative or RGGI) and the West Coast.

AEP continues to meet its voluntary greenhouse gas commitments through its participation agreement with the Chicago Climate Exchange,(as well as it participation in EPA's Climate Leaders). Under these agreements, the company has agreed to reduce its greenhouse gas emissions by 1,2, 3 and 4 percent respectively during the four year period (2003-2006) below its average emission level for 1998-2001. Recently,we agreed to extend this commitment period for further voluntary reductions during the 2007-2010 period.

Environmental Glossary

Clean Air Scientific Advisory Committee (CASAC) - Created by the Clean Air Act amendments in 1977, this committee of independent experts on air pollution reports to the U.S. Environmental Protection Agency Administrator. The committee is charged with reviewing the scientific knowledge of air pollution and its effects, without regard to costs.

Micron - One millionth of a meter. For example, human hair is about 70 microns thick. $PM_{2.5}$ is approximately 1/30th the thickness of a human hair.

National Ambient Air Quality Standards (NAAQS) - Establish maximum allowable concentrations in outdoor air for six pollutants: particulate matter, ozone, sulfur dioxide, nitrogen oxide, carbon monoxide, and lead. The Clean Air Act requires EPA to review NAAQS every five years. EPA is required to set standards "to protect public health ...allowing an adequate margin of safety."

Ozone - Ozone is a form of oxygen which is a colorless gas with a unique odor. Ozone occurs naturally in the earth's upper atmosphere where it shields against ultraviolet radiation from the sun. In the lower atmosphere, ozone is formed by the combination of nitrogen oxides and hydrocarbons in the presence of sunlight. This ozone is a major component of smog. The current NAAQS for maximum allowable ozone is 0.12 parts per million measured over a one-hour period, with three exceedances over three years permitted.

Particulate Matter - Particles of matter suspended in the atmosphere. EPA currently regulates concentrations of particulate matter that are 10 microns and smaller in diameter. The current allowable maximum concentration of particulate matter is 150 micrograms (ug) per cubic meter averaged over 24 hours. The annual average of 24 hour readings is required to be less than 50 ug/m^3.

PM_{10} - Particulate matter that is 10 microns or less in diameter.

$PM1_{2.5}$ - Particulate matter that is 2.5 microns or less in size.

Primary Particles - This is particle matter that is emitted directly into the atmosphere, including dust from construction, farming and roads, volcanic ash, sea salt, tire and brake dust, diesel soot and wood smoke. Primary particles are the dominant form of particulate matter in the West and arid Southwest. Primary particles tend to settle out of the atmosphere in a relatively short time.

Secondary Particles - These particles are formed when gases, such as sulfur oxides, nitrogen oxides and volatile organic carbon, react in the atmosphere to form solid or liquid particles of sulfates, nitrates and organic carbon particles. These particles are generally 2.5 microns and smaller in size. Secondary particles dominate in the eastern United States. Secondary particles tend to remain suspended in the atmosphere and can be transported over long distances by prevailing winds.

Precursor - The forerunners that lead to the formation of a pollutant. The precursors of ozone are nitrogen oxides and hydrocarbons, which combine in the presence of sunlight to form ozone. The precursors of fine particular matter are sulfur oxides, nitrogen oxides and volatile organic compounds which combine with ammonia in the atmosphere to form sulfate and nitrate particles.

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:
  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

Much of this investment will be for:

- **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
- **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
- **SCR and FGD systems together offer co-benefit of mercury capture.**
- **Sale of gypsum (by-product) avoids future landfill costs.**
- **Provides fuel flexibility.**

REPRESENTS THE BEST AND LEAST-COST COMPLIANCE PATH TO IMPROVE ENVIRONMENTAL PERFORMANCE ON A FLEET BASIS, WHILE CONTINUING TO PROVIDE A RELIABLE SUPPLY OF POWER TO CUSTOMERS AT A REASONABLE PRICE AND A SOLID RETURN FOR INVESTORS

Environmental Installations

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD: **2006 – 2010**

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

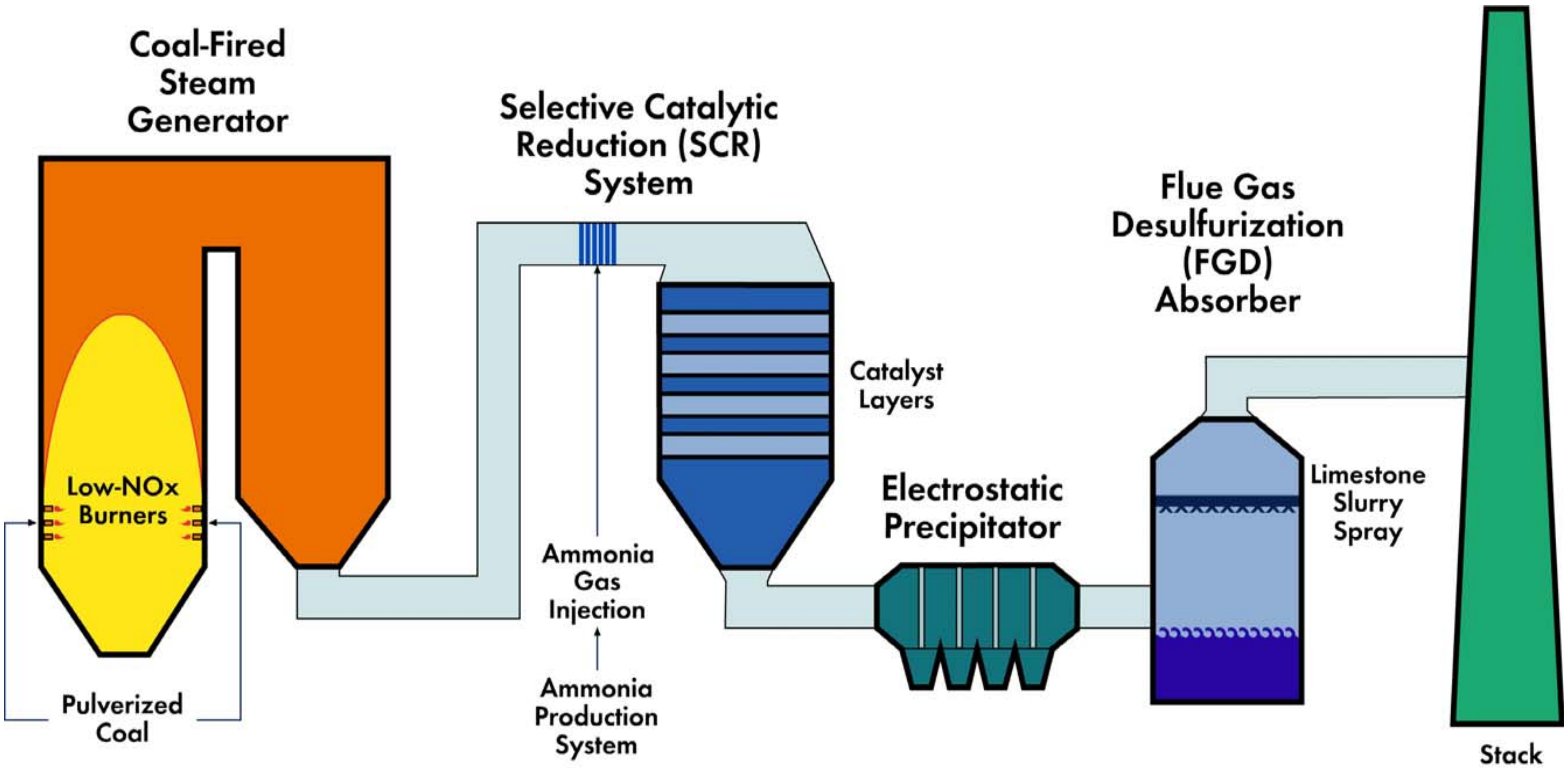
SCR: **2006 – 2009**

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

The Flue Gas Stream



Flue Gas Desulfurization (FGD)

Sulfur Dioxide

The Clean Air Act Amendments of 1990 and more recently the Clean Air Interstate Rule provide flexibility for cost–effective compliance in reducing sulfur dioxide (SO_2) emission. AEP continuously evaluates the alternatives for meeting those requirements, including fuel switching at some plants and the purchase of excess allowances from other facilities.

<u>What is SO_2?</u>

- A gas that forms when the sulfur in coal is burned or oxidized,
- dissolves easily in water and water vapor in the air to form sulfates, and
- with nitrogen oxides, is a major precursor of acidic deposition (acid rain).

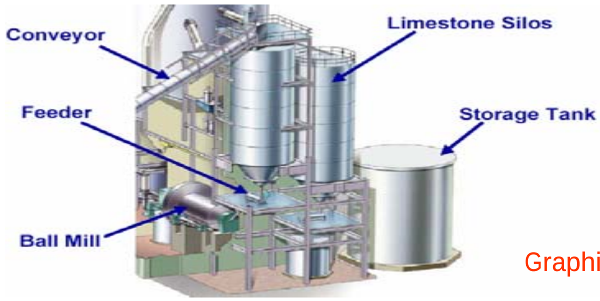
The SO_2 Solution

- AEP has initiated a program of flue gas desulfurization system installations to help it meet current and anticipated SO_2 emission standards from coal-fired power plants.
- AEP believes that installing FGD (scrubber) systems at carefully selected power plants is the best, most cost effective option for all stakeholders, while effectively providing the required environmental benefits.
- Scrubbers use mechanical and chemical processes to reduce SO_2 emissions by 98+%.

FGD Material

- Specific characteristics of FGD material vary from one installation to another.
- The FGD material from a wet scrubber system is gypsum that can be made for sale and used in drywall.
- AEP has made arrangements with BPB, a wallboard manufacturer to accept the gypsum produced at Mitchell as well as other AEP facilities.
- FGD material that is not marketed can be safely managed in landfills.
- Although this is considered a benign material, AEP will take steps to protect groundwater from leaching of the landfilled material, prevent dust and control runoff.

How an FGD Works



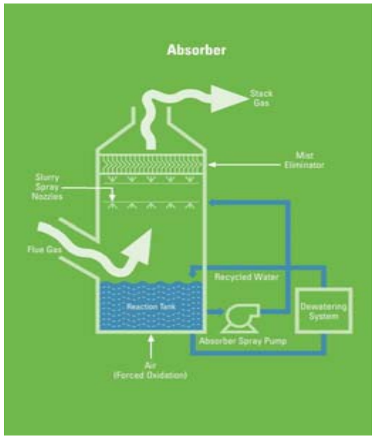
Graphic: Alstom Power, Inc.

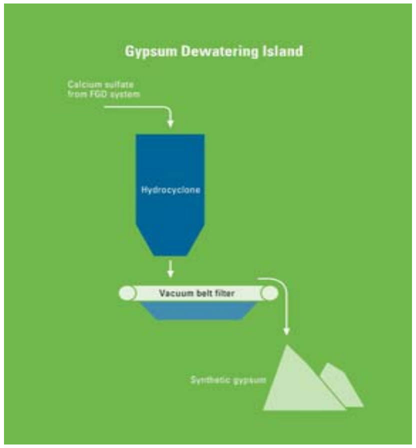
Reducing Agent Preparation

- Limestone, a plentiful supply, low cost raw material is crushed in ball mill pulverizers.
- The crushed limestone and water mix to form a slurry.

Sulfur Removal (Spray Tower)

- Exhaust gas is routed through absorber vessels where it is sprayed with the slurry.
- SO_2 reacts with the slurry and forms calcium sulfate or gypsum.
- The calcium sulfate falls to a tank in the lower part of the vessel.
- Blowers inject air to force oxidation of the product.





Dewatering

Hydrocyclones wring out much of the water to produce gypsum: the water is re-circulated.

The Plume

- Scrubbers increase the amount of water vapor emitted through the stack.
- As a result, the physical characteristics of the plume change so that it is
  - more visible,
  - less buoyant and
  - more saturated.

Selective Catalytic Reduction (SCR)

Nitrogen Oxide

U.S. EPA regulations have required many electric utilities in the United States, including AEP, to reduce nitrogen oxide (NOx) emissions.

AEP installed reduction systems prior to its compliance date and thus earned early reduction credits.

What is NOx?

- During combustion, nitrogen in coal combines at high temperatures with the nitrogen and oxygen that comprise air to form nitrogen oxides.
- When NOx combines with Volatile Organic Compounds in the presence of summer temperatures and sunlight, ozone is produced.
- Ground level ozone at levels above EPA's air quality standards can cause potential health problems for some people.

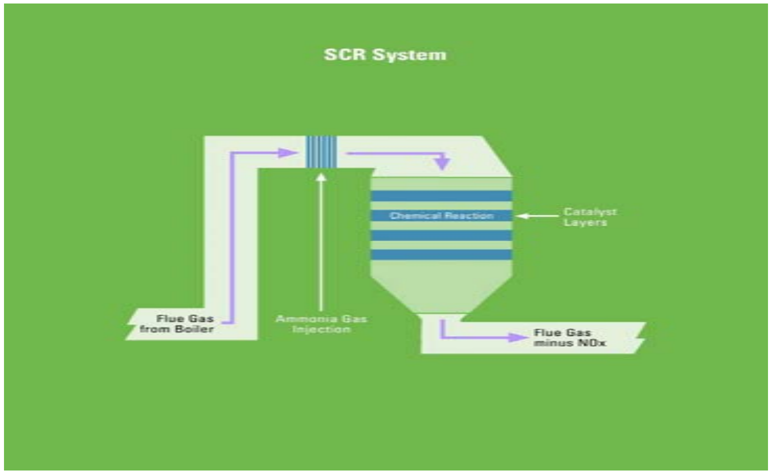
The NOx Solution

- In the 1990s, AEP invested more than $160 million to install low-NOx burners on some units.
- Low-NOx burners control the way coal is burned to reduce formation of NOx.
- Low-NOx burners on the AEP system reduced NOx emissions by approximately 30% per year below uncontrolled levels; however, these reductions are not sufficient to comply with new regulations.

What a selective catalytic reduction system (SCR) does:

- Reduces nitrogen oxide emissions by up to 90%.
- Uses ammonia as the reducing agent (re-agent) to assist the changing of chemical compounds.
- Employs a catalyst to convert NOx to nitrogen and water that are released to the atmosphere.
- Rather than transport and store anhydrous ammonia, AEP coal-fired facilities use urea to produce ammonia as needed.
- SCRs have been designed for modular construction to reduce outage time.

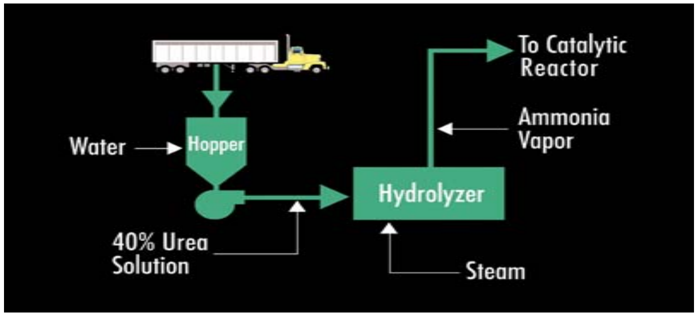
How an SCR Works



- Steam is used to drive the ammonia gas from the urea mixture.
- The ammonia gas is piped into the flue gas ahead of the SCR.

On Site Ammonia Production

- AEP helped develop the process for converting urea to ammonia.
- Anhydrous ammonia is neither transported nor stored.
- Uses urea, a stable, white granular powder under atmospheric conditions, typically used as fertilizer and not classified as toxic.



In the Reactor Vessel

- The ammonia reacts with the flue gas as it passes over the catalyst, forming nitrogen gas and water vapor.
- The harmless nitrogen and water vapor are released into the atmosphere.

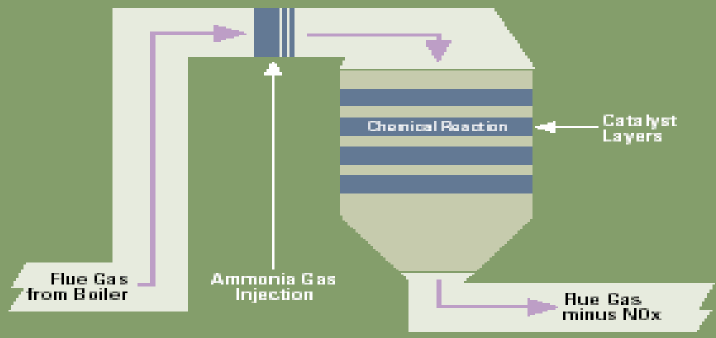
Selective Catalytic Reduction System (SCR)

How an SCR works

An SCR uses ammonia gas to create a chemical reaction that converts nitrogen oxide into nitrogen and water. Here's how:

- AEP uses urea, a harmless compound often used as fertilizer, delivered to the plant site where it is mixed with water.
- The urea mixture is then cracked by the use of steam to drive off the ammonia as a gas.
- The ammonia gas is piped into the flue gas ahead of the SCR.
- The ammonia reacts with the NOx in the flue gas as it passes over the catalyst resulting in the formation of nitrogen gas and water vapor.
- The nitrogen and water vapor are released into the atmosphere.

SCR System



What is NOx?

During combustion, nitrogen in coal and nitrogen and oxygen in air combine at high temperature to form a group of molecules: nitrogen oxides (NOx). Nitrogen oxides (NO, N2O, NO2) convert to nitric compounds when exposed to the air. These eventually can fall to earth as acid rain.

NOx has been cited as one of the precursors of ozone at ground level. When NOx combines with Volatile Organic Compounds, or VOCs, in the presence of summer temperatures and sunlight, ozone is produced. Ozone in higher levels of the atmosphere protects the earth from ultraviolet radiation. But ground-level ozone can cause regional haze and potential health problems for some people.

The U.S. Environmental Protection Agency (EPA) has adopted new regulations requiring many electric utilities in the United States, including AEP, to further reduce NOx emissions.

What an SCR does

A Selective Catalytic Reduction system (SCR) uses a chemical reaction to convert NOx back into harmless nitrogen and water vapor, reducing NOx emissions by up to 90 percent.

At the present time, SCR technology is the best available technology for making significant reductions in NOx emissions. While SCRs are rather new in the U.S., they are common in Europe.

On-site urea to ammonia

AEP's SCR units use an on-site ammonia production system for the SCRs' ammonia supply. This means that ammonia gas for SCR use is not shipped to or stored at the plant. Instead, urea is transported to and stored near the plant and is used to create ammonia gas on an as-needed basis. Under atmospheric conditions urea is a stable white, granular powder that is not classified as toxic. It is common to see this granular urea in lawn fertilizers.

SCRs at AEP

At present, AEP has installed or is installing SCR technology at more than 20 coal-fired generating units in the eastern U.S.

Facts at a glance

- SCRs reduce nitrogen oxide (NOx) emissions. Nitrogen oxides are a precursor to ozone at ground level.
- Despite increases in power generation using coal, NOx emissions have decreased 35% in the past 30 years.
- SCRs typically remove up to 90 percent of NOx emissions.

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AEP AMERICAN ELECTRIC POWER

Mercury

Mercury

In March 2004, the U.S. EPA issued rules requiring coal-fired power plants to reduce mercury emissions. EPA's rule caps emissions at 38 tons in 2010 and 15 tons in 2018 for overall reduction of 70%.

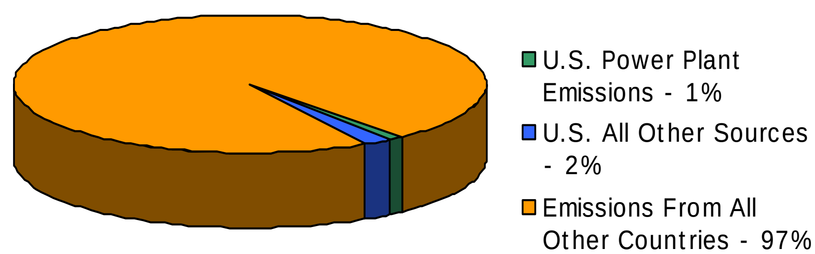
EPA also established an emission-trading program similar to that used for SO_2.

The U.S. is the first nation to regulate utility mercury emissions.

What is Mercury?

- Mercury emissions originate from numerous natural and man-made sources.
- Emissions generally remain in the atmosphere for a substantial period of time.
- More than 60% of mercury deposited in the U.S. originates outside of the country.
- U.S. power plants release less than 2% of the global total of human-caused mercury emissions and less than 1% of the total natural and human-caused mercury emissions.

1999 Global Mercury Emissions



Source: Based on Pacyna, J., Munthe J., Presentation at Workshop on Mercury, Brussels, March 29-30, 2004

The Mercury Solution

There are three forms of mercury – elemental, oxidized and particulate mercury

- **FGD systems take advantage of the high solubility of the oxidized portion of mercury and readily capture oxidized mercury.**
- **Elemental mercury passes through an FGD system uncaptured.**
- **The SCR catalyst may oxidize some or most of the elemental mercury, making it available for removal in the FGD system. As a result, the presence of an SCR can significantly increase the amount of mercury an FGD system can capture.**
- **Particulate mercury is effectively removed in existing particulate control devices. The presence of an SCR or FGD has not been shown to impact particulate mercury.**

AEP's Experience with Mercury Reduction

- AEP anticipates achieving most of its required phase-one mercury reductions through the co-benefits of installing FGD and SCR systems for SO_2 and NOx control.
- Extensive tests of the effectiveness of these combined technologies at Gavin Plant found mercury emissions reductions of 85% to 90%.
- Results could vary from plant to plant depending upon the exact characteristics of the coal being burned and other operating factors.
- These Hg emission reductions are only part of AEP's on-going strategy to comply with the EPA finalized CAMR. Other AEP facilities will be retrofit in the near future with similar SCR and/or FGD equipment to provide additional co-benefit mercury reductions. Other mercury specific control retrofits may also be needed in our environmental compliance program.

Energy Delivery

Fall EEI 2005

Transmission Detail

Transmission Plant Detail By Operating Company

As of September 30, 2005
(in millions $)

	Transmission Plant Original	Accum. D&A	Net Transmission Plant
ECAR			
AEP Generating Co.	$ -	$ -	$ -
Appalachian Power Co.	1,266	479	787
Columbus Southern Power Co.	446	189	257
Indiana Michigan Power Co.	1,025	402	623
Kentucky Power Co.	386	118	268
Ohio Power Co.	999	404	595
All other non-registrants	60	25	35
ERCOT			
AEP Texas Central Co.	811	202	609
AEP Texas North Co.	289	97	192
SPP			
Public Service Co. of Oklahoma	477	152	325
Southwestern Electric Power Co.	641	197	444
TOTAL	$ 6,400	$ 2,265	$ 4,135

Transmission Line Circuit Miles Detail

Operating Company Level

(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
APCo	644	97	383	106	0	3,281	0	43	1,077	791	0	230	0	**6,652**
CSP	0	0	884	0	0	824	0	0	469	0	59	0	0	**2,236**
I&M	615	0	1,614	0	0	1,663	0	0	705	0	0	744	0	**5,341**
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	**30**
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
OPCo	509	0	909	0	0	2,463	0	0	2,168	0	0	366	112	**6,527**
PSO	0	0	579	34	8	2,123	10	0	812	0	0	0	0	**3,566**
SWEPCo	0	0	660	0	228	1,171	42	0	1,402	0	0	0	0	**3,503**
TCC	0	0	641	0	0	2,568	0	0	1,779	0	0	0	0	**4,987**
TNC	0	0	222	0	0	1,579	14	0	2,699	0	0	0	0	**4,514**
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	**288**
Total	**2,026**	**113**	**5,909**	**140**	**282**	**16,166**	**67**	**43**	**11,746**	**846**	**59**	**1,370**	**112**	**38,879**

State Level

(Circuit Miles)

State	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
Arkansas	0	0	28	0	228	168	42	0	461	0	0	0	0	**927**
Indiana	599	0	1,380	0	0	1,424	0	0	406	0	0	596	0	**4,405**
Kentucky	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
Louisiana	0	0	105	0	0	245	0	0	230	0	0	0	0	**580**
Michigan	16	0	234	0	0	239	0	0	299	0	0	148	0	**936**
Ohio	509	0	1,793	0	0	3,287	0	0	2,637	0	59	366	112	**8,763**
Oklahoma	0	0	625	34	8	2,148	10	0	812	0	0	0	0	**3,638**
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	**275**
Texas	0	0	1,343	0	0	4,879	14	0	5,189	0	0	0	0	**11,425**
W. Virginia	352	17	323	0	0	1,593	0	43	456	743	0	89	0	**3,617**
Virginia	292	96	69	15	0	1,708	0	0	709	48	0	141	0	**3,078**
Total	**2,026**	**113**	**5,909**	**140**	**282**	**16,166**	**67**	**43**	**11,746**	**846**	**59**	**1,370**	**112**	**38,879**

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Distribution Line Detail

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,487	KGPCO	1,487
Virginia	29,241	KYPCO	9,653
W. Virginia	20,913	APCO	48,690
Kentucky	9,653	OPCO	25,995
Ohio	42,966	CSP	16,971
Michigan	5,088	I&M	19,573
Indiana	14,485	WPC	1,464
Texas	45,236	TCC	27,983
Oklahoma	21,084	TNC	9,622
Arkansas	4,264	PSO	21,084
Louisiana	7,249	SWEPCO	19,144
Total	**201,666**	**Total**	**201,666**

* Includes approximately 25,000 of underground circuit miles

Financial Update

- Capitalization
- Liquidity Position
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Fall EEI 2005

Capitalization

Capital Structure	Actual 9/30/05		
	Debt	**Equity**	**Total**
Balance Sheet Capitalization			
Long-term Debt	11,742	-	11,742
Short-term Debt	15	-	15
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	8,985	8,985
Total Capitalization per Balance Sheet	**11,757**	**9,046**	**20,803**
% of Capitalization per Balance Sheet	***56.5%***	***43.5%***	***100.0%***
Adjustments			
Preferred Stock Subject to Mandatory Redemption	-	-	-
Defeased First Mortgage Bonds	(19)	-	(19)
Off-balance Sheet Leases	1,227	-	1,227
Securitization Bonds	(648)	-	(648)
Spent Nuclear Fuel Trust	(234)	-	(234)
Equity Credit for Equity Units	-	-	-
Total Adjusted Capitalization	**12,085**	**9,046**	**21,130**
% of Adjusted Capitalization	***57.2%***	***42.8%***	***100.0%***

Liquidity

Liquidity Summary	Actual Sep-05	
($ in millions)	**Amount**	**Maturity**
5-Year R/C Facility	1,500	Mar-10
3-Year R/C Facility	1,000	May-07
3-Year L/C Facility	200	Sep-06
Total Credit Facilities	**2,700**	
Plus		
Total Cash & Cash Equivalents	**849**	
Less		
Commercial Paper Outstanding	-	
Amount Drawn on Bank Loans	-	
Amount Issued (L/C Facility)	150	
Net Available Liquidity	**3,399**	

R/C=Revolving Credit
L/C=Letter of Credit

AEP'S LIQUIDITY POSITION STANDS AT $3.4 BILLION

AEP Credit Ratings

Company	Moody's Senior Unsecured	Moody's Senior Secured	Moody's Outlook
American Electric Power Company, Inc.[1]	Baa2	-	S
AEP, Inc. Short Term Rating[2]	P2	-	S
AEP Texas Central Company	Baa2	Baa1	S
AEP Texas North Company	Baa1	A3	S
AEP Utilities, Inc.	-	-	-
Appalachian Power Company	Baa2	Baa1	S
Columbus Southern Power Company	A3	NR	S
Indiana Michigan Power Company	Baa2	NR	S
Kentucky Power Company	Baa2	NR	S
Ohio Power Company	A3	NR	S
Public Service Company of Oklahoma	Baa1	A3	S
Southwestern Electric Power Company	Baa1	A3	S

Company	Fitch Senior Unsecured	Fitch Senior Secured	Fitch Outlook
American Electric Power Company, Inc.[1]	BBB	-	S
AEP, Inc. Short Term Rating[2]	F2	-	S
AEP Texas Central Company	A-	A	S
AEP Texas North Company	A-	A	S
AEP Utilities, Inc.	-	-	-
Appalachian Power Company	BBB+	A-	S
Columbus Southern Power Company	A-	NR	S
Indiana Michigan Power Company	BBB	NR	S
Kentucky Power Company	BBB	NR	S
Ohio Power Company	BBB+	NR	S
Public Service Company of Oklahoma	A-	A	S
Southwestern Electric Power Company	A-	A	S

(1) Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2

(2) Moody's upgraded the AEP, Inc. short term rating from P3 to P2

Company	S&P Business Profile	S&P Senior Unsecured	S&P Senior Secured	S&P Outlook
American Electric Power Company, Inc.[1]	6	BBB	-	S
AEP, Inc. Short Term Rating[2]	N/A	A2	-	S
AEP Texas Central Company	3	BBB	BBB	S
AEP Texas North Company	3	BBB	BBB	S
AEP Utilities, Inc.	N/A	BBB	BBB	S
Appalachian Power Company	5	BBB	BBB	S
Columbus Southern Power Company	4	BBB	NR	S
Indiana Michigan Power Company	6	BBB	NR	S
Kentucky Power Company	5	BBB	NR	S
Ohio Power Company	4	BBB	NR	S
Public Service Company of Oklahoma	5	BBB	A-	S
Southwestern Electric Power Company	5	BBB	A-	S

Long-term Debt Maturity Profile

Year	2005[1]	2006	2007
AEP Inc.	$ -	$ 395,860,000	$ 345,000,000
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 100,000,000	$ 342,500,000
Columbus Southern Power	$ 36,000,000	$ -	$ -
Kentucky Power	$ -	$ -	$ 322,964,000
Indiana Michigan	$ -	$ 300,000,000	$ -
Ohio Power Company	$ -	$ -	$ -
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ -	$ 6,215,000	$ 94,000,000
Texas Central Company	$ -	$ -	$ -
Texas North Company	$ 37,609,000	$ -	$ 8,151,000
Total	**$ 73,609,000**	**$ 802,075,000**	**$ 1,112,615,000**

(1) Maturities remaining as of Sept 30th, 2005

Debt Schedules

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$40,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond (defeased)	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bond	5.010%	01/15/2008	$133,913,828
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.783%		$647,791,682

** TCC's first mortgage bonds were defeased in May, 2004.*

Debt Schedules

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	6.375%	10/01/2005	$37,609,000
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.723%		$317,426,600

Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
First Mortgage Bond	6.800%	03/01/2006	$100,000,000
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Weighted Average or Total	4.728%		$2,079,783,600

Debt Schedules

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2020	$43,695,000
Senior Notes	6.850%	10/03/2005	$36,000,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Weighted Average or Total	5.238%		$890,245,000

Debt Schedules

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Weighted Average or Total	4.893%		$1,095,083,600

Debt Schedules

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Notes Payable (JMG)	6.810%	03/31/2008	$14,634,147
Notes Payable (JMG)	6.270%	03/31/2009	$31,500,000
Notes Payable (JMG)	7.490%	04/15/2009	$70,000,000
Notes Payable (JMG)	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	4.457%		$1,623,130,347

Debt Schedules

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Debt Schedules

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	04/23/2011	$28,389,522
Notes Payable	Floating	06/30/2008	$14,021,168
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,215,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/10/2008	$113,403,000
Weighted Average or Total	4.739%		$707,063,290

40th EEI Financial Conference

November 8, 2005

Westin Diplomat Resort & Spa

Hollywood, Florida

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Framework for 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
  - New Generation
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Dividend Action

- **Announced $0.02 increase in quarterly dividend to $0.37 per share**

- **Future dividend action**
  - Long-term payout ratio target of 60-65%
  - Dividend growth rate to parallel company's annual long-term earnings growth rate

REPRESENTS 6% INCREASE IN ANNUAL DIVIDEND

Summary of Major 2006 Earnings Drivers

- Load growth of 2.5%
- $300MM new rate recovery in progress
- Rising fuel costs of 10-12%
- Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- Decline in utility operations O&M
- Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Regulatory Activity Underway

- TCC Stranded Cost Recovery True-up Filing Submitted
- FERC Transmission Case
- APCo Filing for Recovery of E&R Costs in Virginia & Fuel Clause Increase
- APCo & WPCo Base Rate & Fuel Clause Filing in West Virginia
- Kentucky Base Rate Filing

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

2006 Earnings Guidance

Projected Earnings Per Share

	2005E	2006E
Utility Operations	$ 2.75	$ 2.66
Investments	0.00	(0.02)
Parent Company	(0.15)	(0.04)
Ongoing Earnings	$ 2.60 *	$ 2.60 *

2006 ONGOING EARNINGS GUIDANCE RANGE: $2.50 to $2.70

* Represents mid-point of stated ongoing earnings guidance range.

Utility Operations

		2005 Projection			2006 Projection	
	Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
UTILITY OPERATIONS:						
Gross Margin:						
1 Regulated Integrated Utilities - East	65,270 GWh @ $ 31.5 /MWhr =	2,059		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2 Ohio Companies	48,203 GWh @ $ 39.6 /MWhr =	1,909		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3 Regulated Integrated Utilities - West	40,316 GWh @ $ 22.8 /MWhr =	919		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4 Texas Wires	26,387 GWh @ $ 17.3 /MWhr =	455		26,803 GWh @ $ 17.0 /MWhr =	456	
5 Off System Sales	41,207 GWh @ $ 20.0 /MWhr =	823		37,186 GWh @ $ 16.1 /MWhr =	600	
6 Transmission Revenue - 3rd Party		400			285	
7 Other Operating Revenue		487			515	
8 Total Gross Margin		7,052			7,283	
9 Operations & Maintenance		(3,140)			(3,045)	
10 Depreciation & Amortization		(1,295)			(1,332)	
11 Taxes Other than Income Taxes		(739)			(761)	
12 Interest Exp & Preferred Dividend		(598)			(688)	
13 Other Income & Deductions		271			153	
14 Income Taxes		(481)			(563)	
15 Net Earnings Utility Operations		1,070	2.75		1,047	2.66

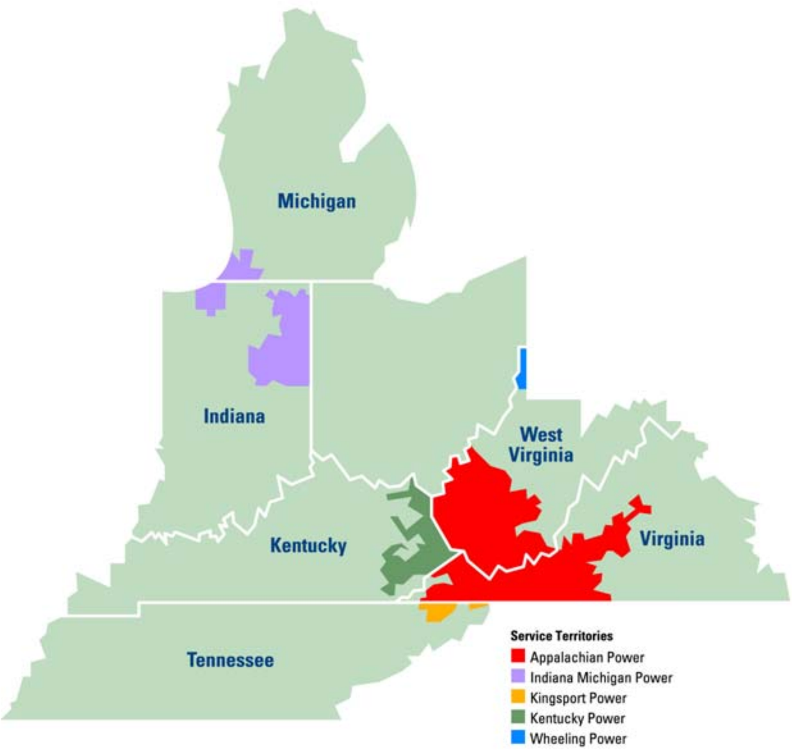
Note: Totals may not foot due to rounding.

GROSS MARGIN IMPROVEMENT OFFSET BY AN INCREASE IN OPERATING & INTEREST COSTS

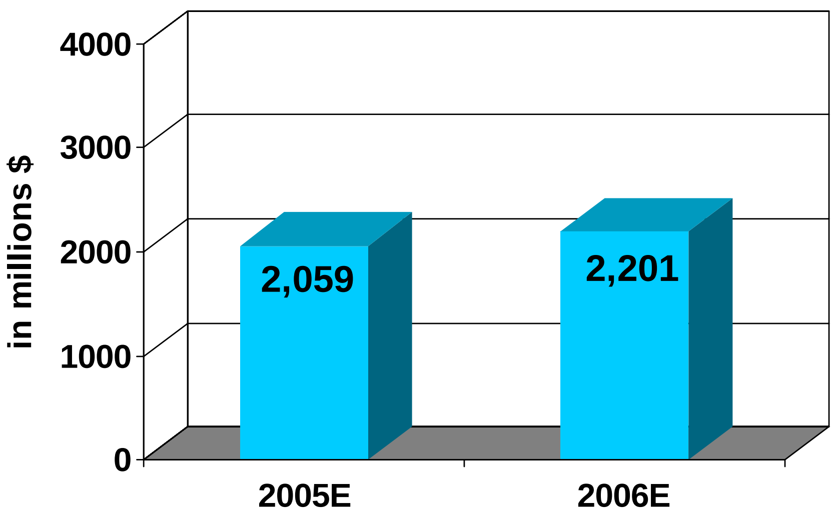
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 – Confidential
Page 975 of 9556

Utility Operations

East Integrated Companies



Gross Margin



Earnings Drivers

Load Growth	134
Rate Changes	103
Fuel Cost	(53)
Emissions & Consumables	(19)
Other	(23)
	142

$142 MILLION INCREASE IN GROSS MARGIN FOR 2006

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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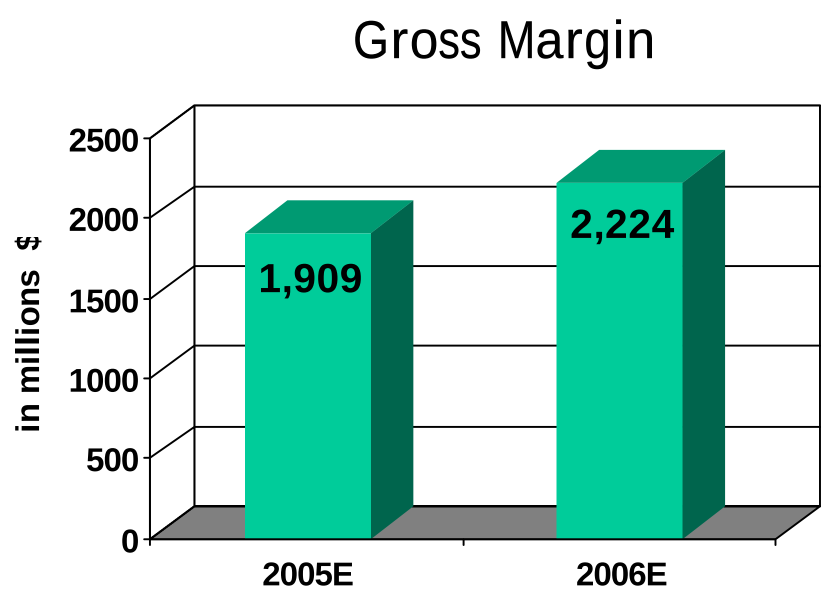
Utility Operations

Ohio Companies

- Ohio Power Service Territory
- Columbus Southern Power Service Territory



Earnings Drivers

Load Growth	58
Fuel Cost	(13)
Rate Stabilization Plan	258
Emissions & Consumables	(15)
Other	27
	315

$315 MILLION INCREASE IN GROSS MARGIN FOR 2006

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 – Confidential
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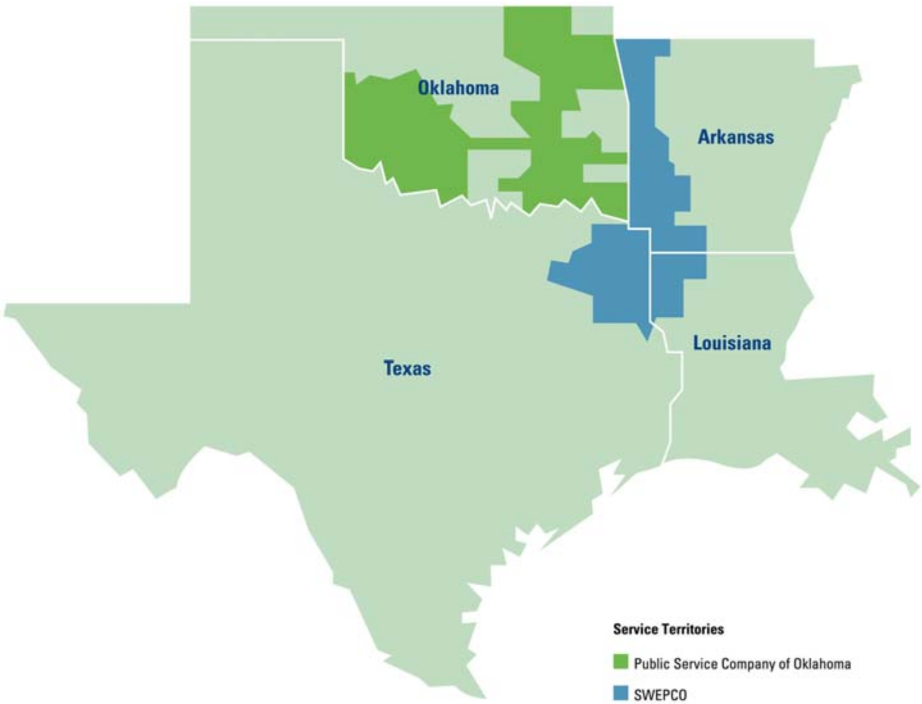
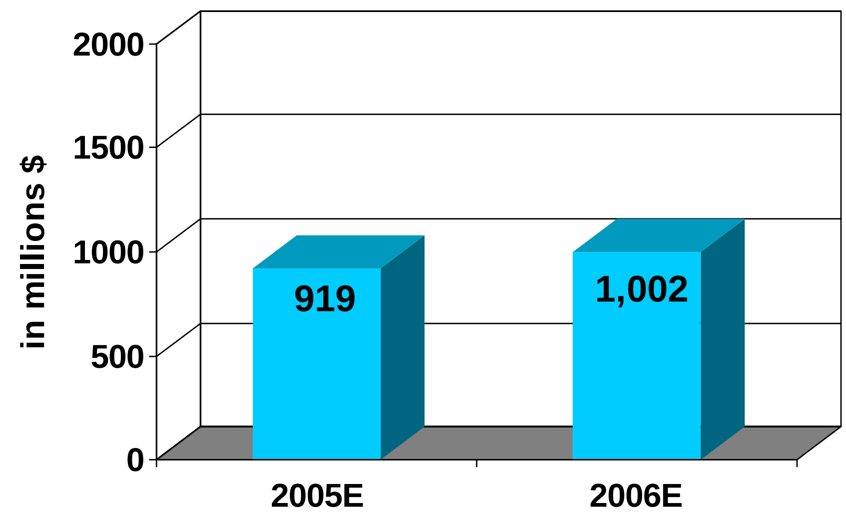
Utility Operations

West Integrated Companies



Gross Margin

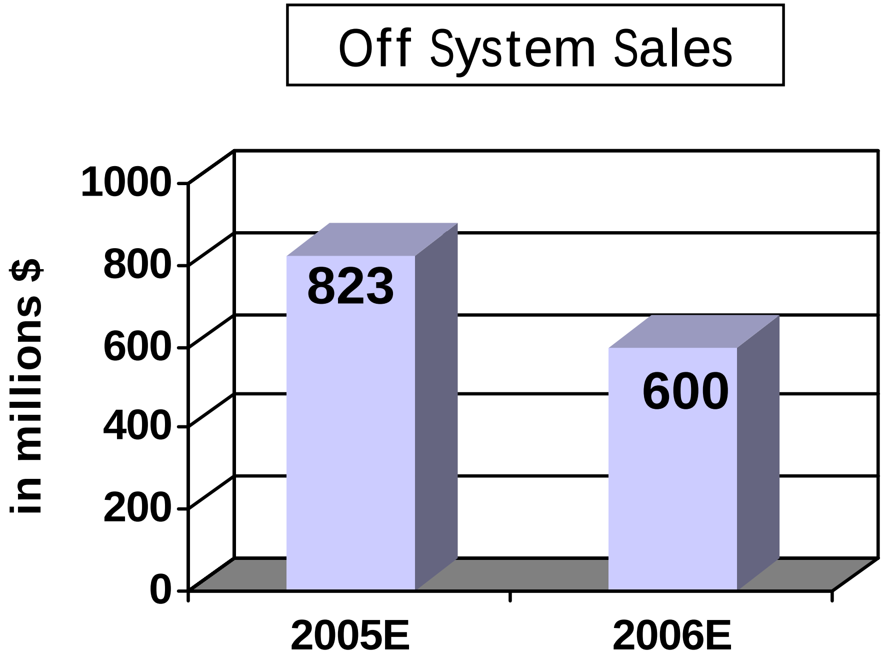


Earnings Drivers

Load Growth	15
Rate Changes	17
Margin Sharing, re: Fuel Clause	51
	83

$83 MILLION INCREASE IN GROSS MARGIN FOR 2006

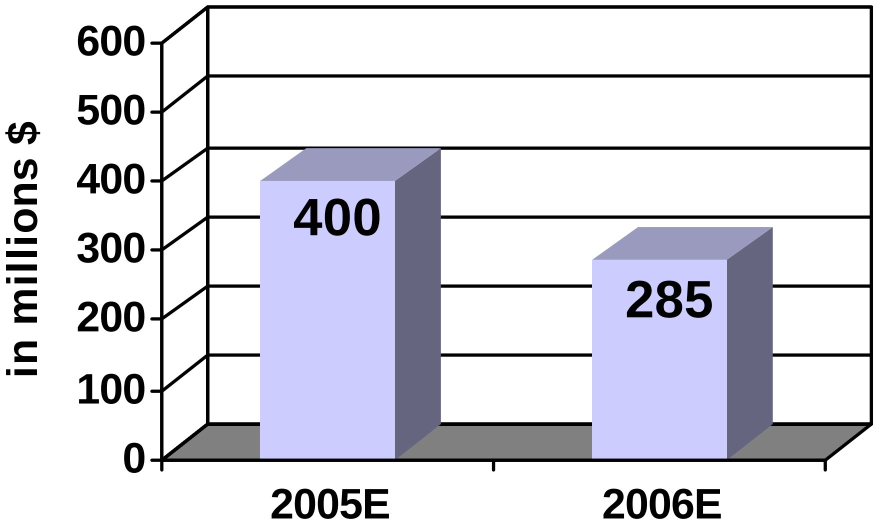
Utility Operations



DECLINE IN OFF SYSTEM SALES GROSS MARGIN DRIVEN BY SALE OF TCC GENERATION, INCREASED PLANNED OUTAGE RATES, & INCREASED RETAIL LOAD

Utility Operations

Transmission Revenues – 3rd Party



Earnings Drivers

Cessation of SECA Rates	(128)
ECAR Zonal Rate Change	22
Other	(9)
	(115)

Offset to Decline in Trans Revenues

(Captured on lines 1 & 2)

Ohio OATT	49
APCO ENEC in WV	9
	58

CESSATION OF SECA RATES WILL BE LARGELY OFFSET BY ECAR ZONAL RATE CHANGE, OHIO OATT ADJUSTMENT, & REACTIVATION OF ENEC IN WEST VIRGINIA

Utility Operations

Expense Drivers

Operations & Maintenance		
Labor, including fringes	48	
Sale of STP	38	$95 million decrease
Other	9	
	95	
Depreciation & Amortization		
Plant additions	(53)	
Change in depreciation rates	90	$37 million increase
Amortizations (TCC Securitization*, Ohio regulatory asset**, Other)	(74)	
	(37)	
Taxes		
Taxes Other than Income Taxes	(22)	
Change in Pre-Tax Income	(21)	$104 million increase
Q4 Accrual True-ups	(15)	
COLI benefit (2005)	(7)	
Flow-through & permanent timing differences	(39)	
	(104)	
Interest Expense & Pref. Dividends		
Securitized Debt	(23) *	
Debt (construction funding)	(67)	$90 million increase
	(90)	
Total	(136)	

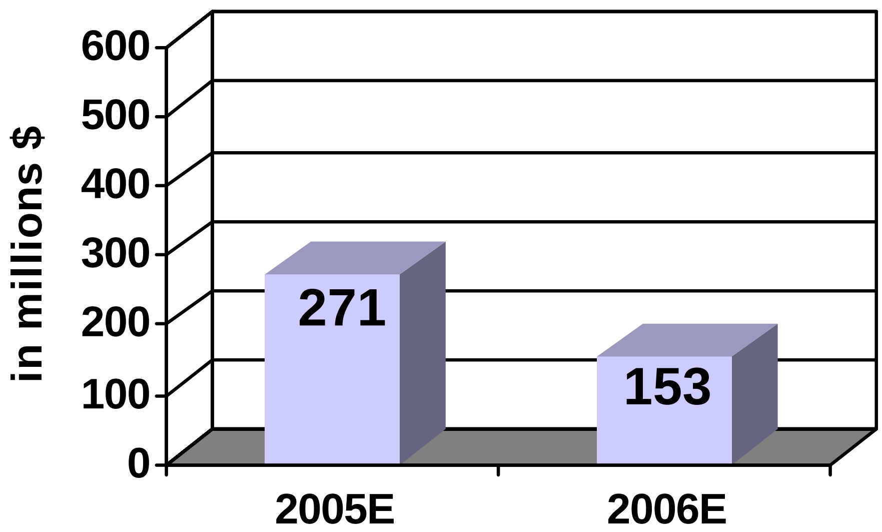
•Offset by TCC wires charge to cover securitization bonds issued 9/06

****Offset by cash Ohio POLR charge which begins 1/1/06**

UTILITY OPERATIONS EXPENSES TO RISE $136MM IN 2006

Utility Operations

Other Income & Deductions

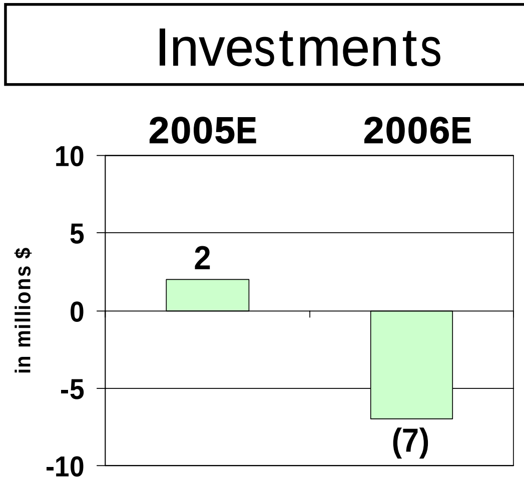


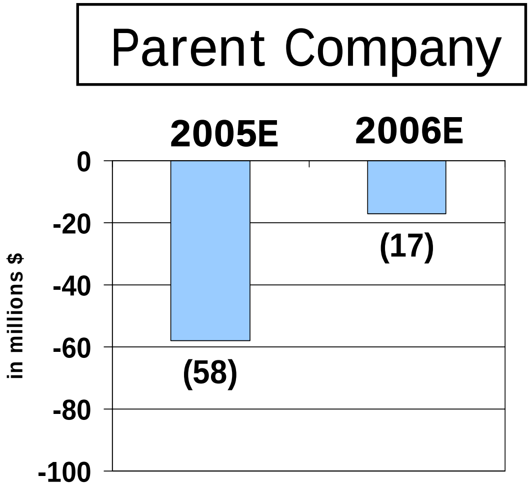
Earnings Drivers	
Reduction in Carrying Charges	
Ohio Companies*	(74)
Texas Central Company**	(12)
Reduction in Centrica Sharing	(20)
Other	(12)
	(118)

*Offset by cash POLR Rider Revenue
**TCC Carrying Charges decline upon issuance of securitization bonds 9/06

$118MM DECLINE IN OTHER INCOME & DEDUCTIONS DUE TO REDUCTION IN CARRYING CHARGES AND CENTRICA SHARING

Investments & Parent Company





Investment Drivers:

- Misc. true-ups that provided positive impact in 2005 not repeated in 2006
- Ongoing loss from Dow

Parent Company Drivers:

- 2005 included debt call premiums to retire $550MM of LTD
- Reduction in outstanding debt drives decline in interest expense in 2006

$32 MILLION IMPROVEMENT IN CONTRIBUTION FROM INVESTMENTS & PARENT COMPANY

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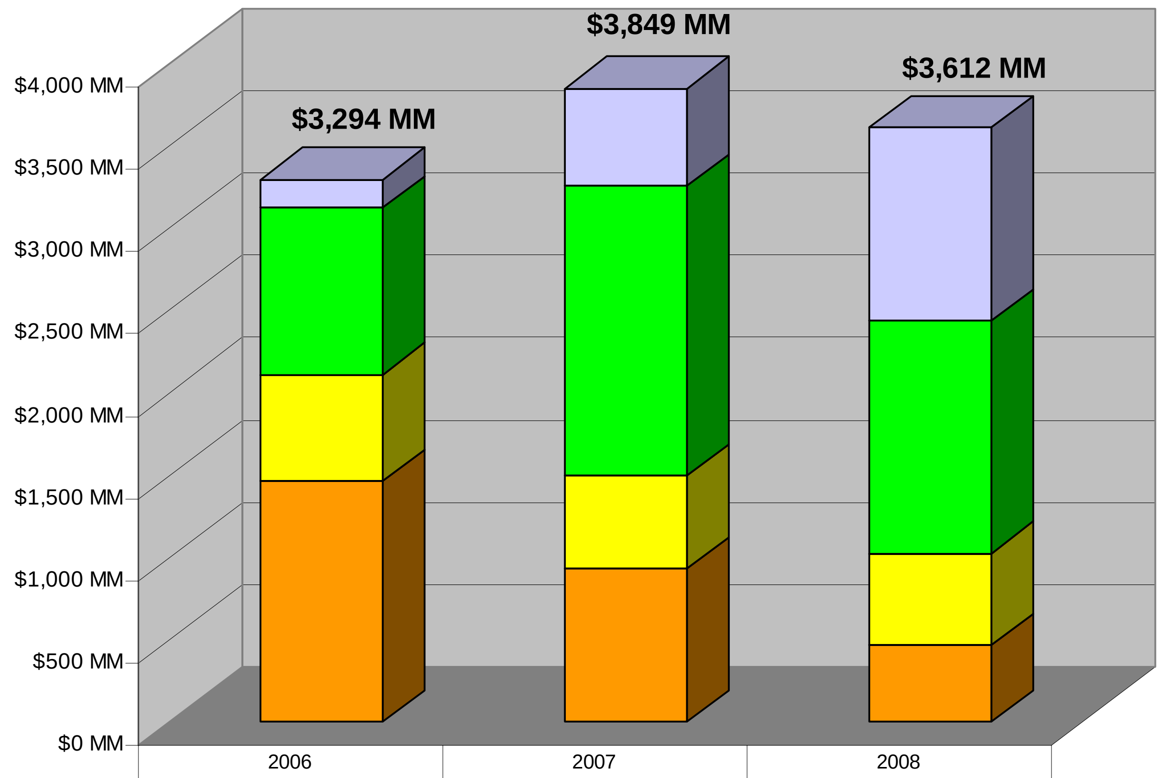
Capital Investment Forecast



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$168 MM	$593 MM	$1,176 MM
Ongoing Infrastructure Replacement/ Economically Justified	$1,016 MM	$1,757 MM	$1,412 MM
Mandated T&D	$646 MM	$568 MM	$554 MM
Environmental Compliance	$1,464 MM	$931 MM	$470 MM

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

($ in millions)	Actual 2004	Projection 2005	2006	2007	2008
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,656)	$ (2,110)	$ (1,499)	$ (1,024)
Discretionary Cap Ex Predicated on Rate Recovery &/or Cash Generated	n/a	n/a	$ (1,184)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,656)	$ (3,294)	$ (3,849)	$ (3,612)
Dividend on Common	$ (554)	$ (554)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,597	$ 1,666	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,357	$ 1,628	$ -	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan in 2007 & 2008)	$ 16	$ (33)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,230)	$ (6)	$ 2,129	$ 1,658	$ 1,697
Other	$ (72)	$ (67)	$ (31)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (556)	$ (21)	$ 167	$ (366)	$ 0
Ending Cash Balance	$ 420	$ 399	$ 566	$ 200	$ 200

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Projected Cash Flow

($ in millions)	2005 Guidance	2006 Guidance
Beginning Cash Balance	**$ 420**	**$ 399**
Cash from Operations:		
Income from Continuing Operations	1,014	1,023
Depreciation and Amortization	1,328	1,363
Pension Funding in Excess of Expense	(353)	(126)
TCC Carrying Charge	(51)	(66)
Other	(271)	(249)
Total from Operations	**$ 1,666**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,656)	(3,294)
AFUDC Debt	(27)	(37)
Asset Sales	1,628	-
Other	(8)	9
Total from Investing	**$ (1,063)**	**$ (3,322)**
Cash from Financing:		
Common Equity	(33)	-
Net Long Term Debt Issued/(Retired)	7	2,140
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(554)	(582)
Other Financing Activities	35	(3)
Total from Financing	**$ (624)**	**$ 1,544**
Net Change in Cash	**$ (21)**	**$ 167**
Ending Cash Balance	**$ 399**	**$ 566**

PROJECTED CASH ON HAND OF $399 MILLION AT YEAR END 2005

Capital Structure

Capital Structure	Actual 9/30/05		
$ in millions	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	11,742	-	11,742
Short-term Debt	15	-	15
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	8,985	8,985
Total Capitalization per Balance Sheet	**11,757**	**9,046**	**20,803**
% of Capitalization per Balance Sheet	***56.5%***	***43.5%***	***100.0%***
Adjustments			
Preferred Stock Subject to Mandatory Redemption	-	-	-
Defeased First Mortgage Bonds	(19)	-	(19)
Off-balance Sheet Leases	1,227	-	1,227
Securitization Bonds	(648)	-	(648)
Spent Nuclear Fuel Trust	(234)	-	(234)
Equity Credit for Equity Units	-	-	-
Total Adjusted Capitalization	**12,085**	**9,046**	**21,130**
% of Adjusted Capitalization	***57.2%***	***42.8%***	***100.0%***

Note: Totals may not foot due to rounding.

ADJUSTED DEBT/CAPITALIZATION: 57.2%

Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

- *Outcome of pending regulatory proceedings*
  - *Texas, Ohio, Virginia, West Virginia, Indiana, Kentucky, FERC*
- *Wholesale market volatility*
- *Plant availability*
- *Rising fuel costs*
- *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

Appendix

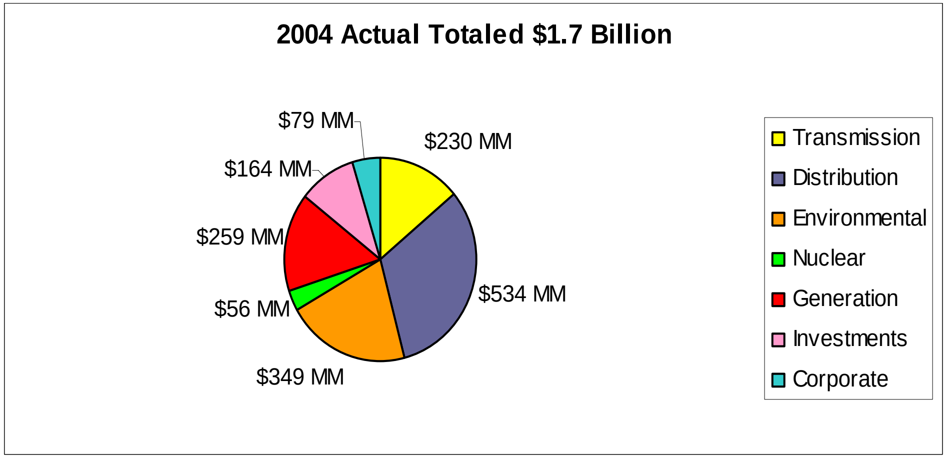
Earnings Guidance Range
$2.55 to $2.65 for 2005
$2.50 to $2.70 for 2006

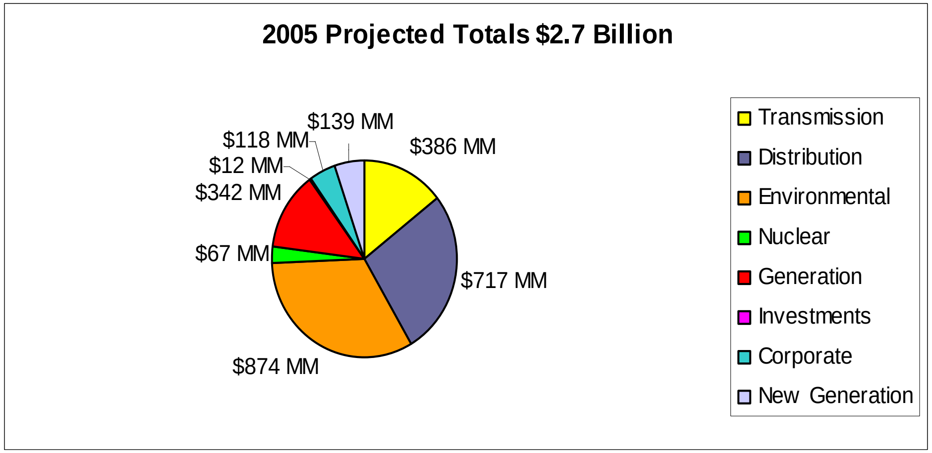
		2005 Projection			2006 Projection		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,270 GWh @ $ 31.5 /MWhr =	2,059		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,203 GWh @ $ 39.6 /MWhr =	1,909		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,316 GWh @ $ 22.8 /MWhr =	919		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,387 GWh @ $ 17.3 /MWhr =	455		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off System Sales	41,207 GWh @ $ 20.0 /MWhr =	823		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		400			285	
7	Other Operating Revenue		487			515	
8	Total Gross Margin		7,052			7,283	
9	Operations & Maintenance		(3,140)			(3,045)	
10	Depreciation & Amortization		(1,295)			(1,332)	
11	Taxes Other than Income Taxes		(739)			(761)	
12	Interest Exp & Preferred Dividend		(598)			(688)	
13	Other Income & Deductions		271			153	
14	Income Taxes		(481)			(563)	
15	Net Earnings Utility Operations		1,070	2.75		1,047	2.66
16	Investments		2	0.00		(7)	(0.02)
17	Parent Company		(58)	(0.15)		(17)	(0.04)
18	ON-GOING EARNINGS		1,014	2.60		1,023	2.60

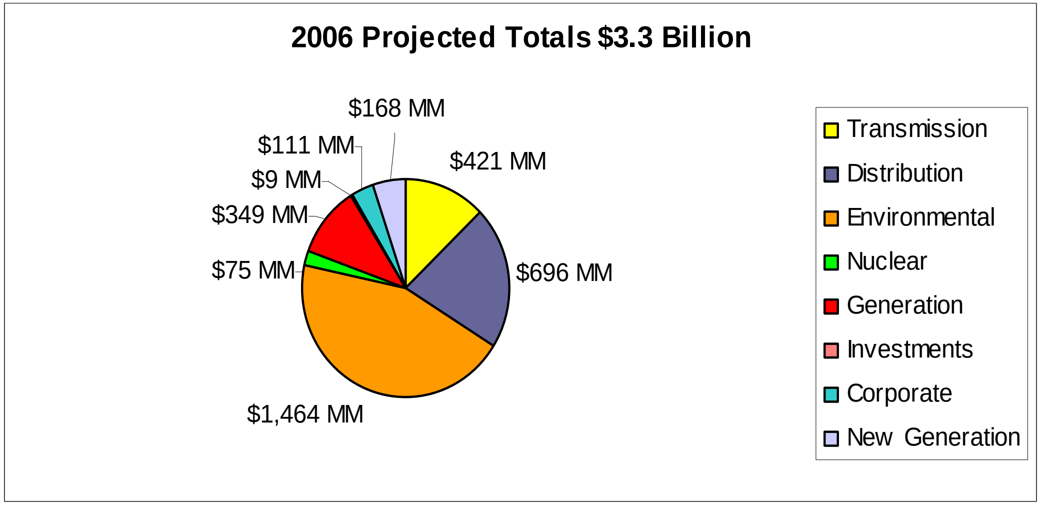
Shares Outstanding 390MM 393MM

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Capital Investment 2004-2006

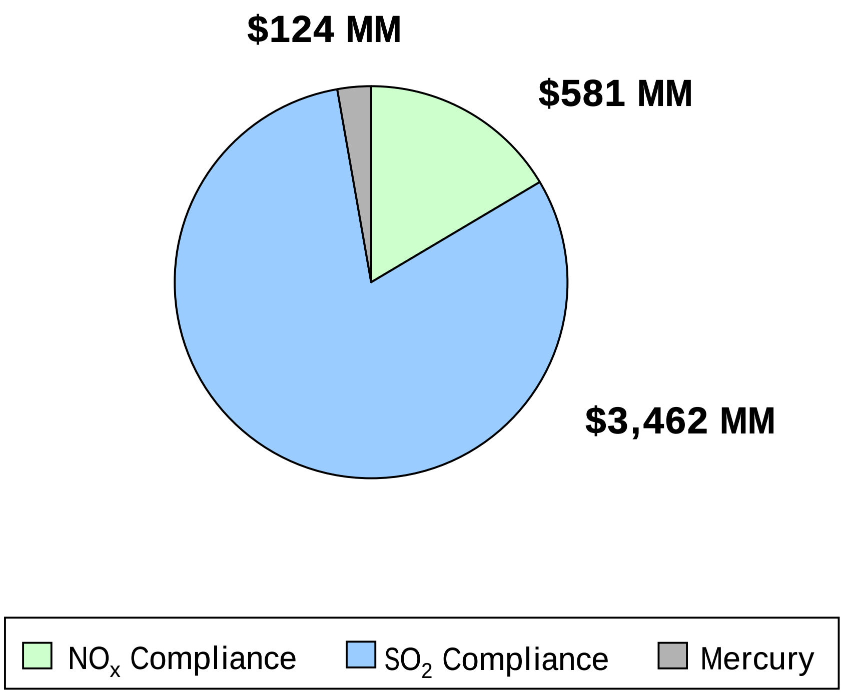






Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

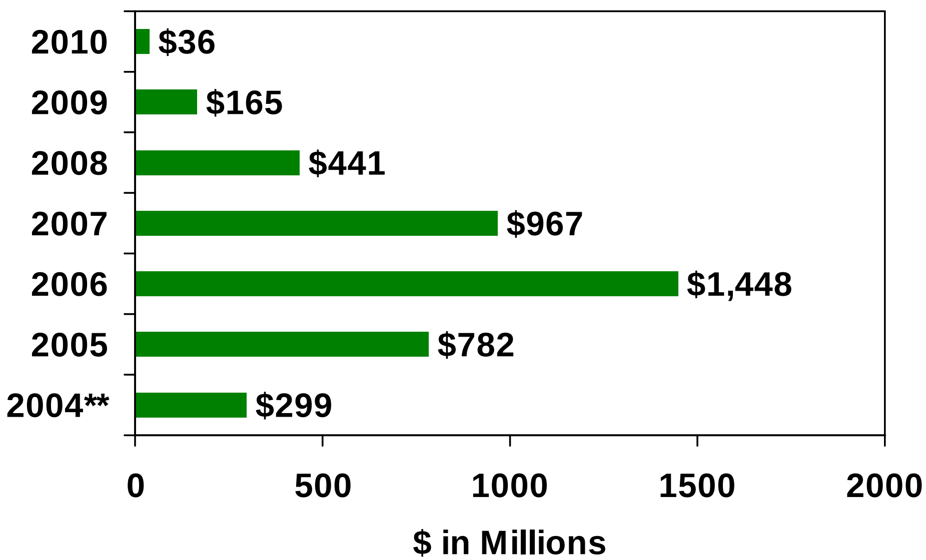
$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

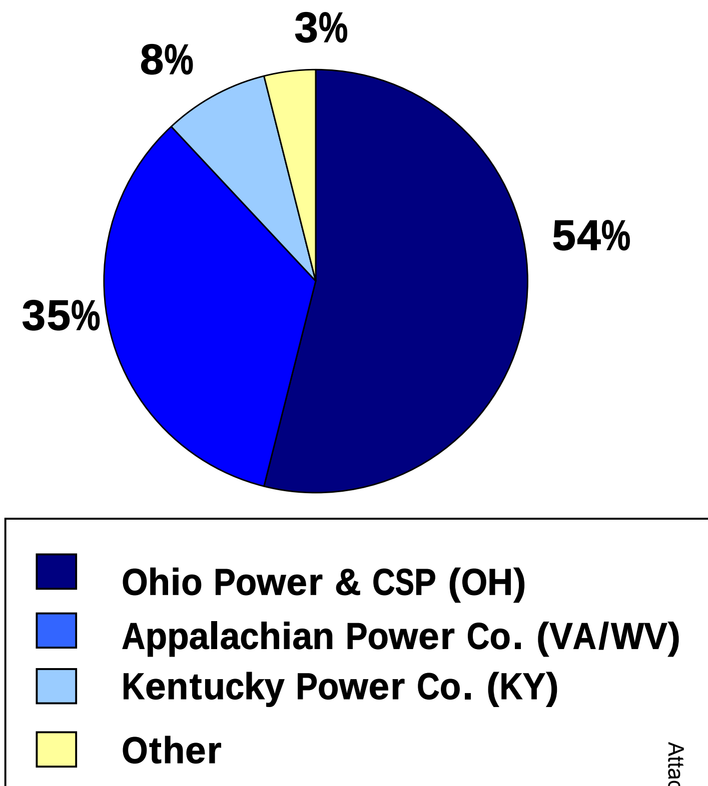
$4.1 Billion Environmental Investment

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Projected Environmental Investment Allocation



MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Funding the Environmental Investment

Ohio: 54% ($2.2 billion)

- Approved annual increases 2006-2008
  - CSP – 3% annually
  - OP – 7% annually

Virginia/West Virginia: 35% ($1.4 billion)

- VA: Annual Rate Relief through Environmental & Reliability cost recovery mechanism
  - Two rate case opportunities through 2010

- WV: General rate increase filed 8/26/05 including environmental, reliability & fuel recovery

Kentucky: 8% ($319 million)

- Automatic surcharge mechanism

THE INCREASES IN RATES TOGETHER WITH TRADITIONAL CASH FLOW FROM OPERATIONS, ASSET SALE PROCEEDS, AND A PORTION OF THE TCC STRANDED COST SECURITIZATION PROCEEDS POSITION US TO FUND THE ENVIRONMENTAL INVESTMENT PROGRAM WITHOUT MATERIAL LEVERAGING

41st EEI Financial Conference

2006 Fact Book

November 5-8, 2006
Las Vegas, NV

Table of Contents

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Company Overview

- **AEP Company Overview**

Fall EEI 2006

Company Overview

OUR FOCUS IS OUR CORE

DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Co, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions	Electric Utility Subsidiaries
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT

THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- More than 36,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 207,632 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 7,000 railcars
- own and/or operate over 2,300 hopper barges and 53 towboats
- operate one active coal-handling terminal with 20 millions tons of capacity

We consume approximately 75 million tons of coal annually.

Company Strategy

Business Strategy

AEP's mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to focus on our core utility business operations. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. Our plan entails designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Strategic Direction

Deliver value to our investors

- **Invest in our established utility business**
- **Achieve continued environmental improvements of existing facilities**
- **Buy or build additional generation to meet franchise service obligations**
- **Upgrade our energy delivery infrastructure**
- **Achieve adequate returns on all assets**

AEP Service Territory

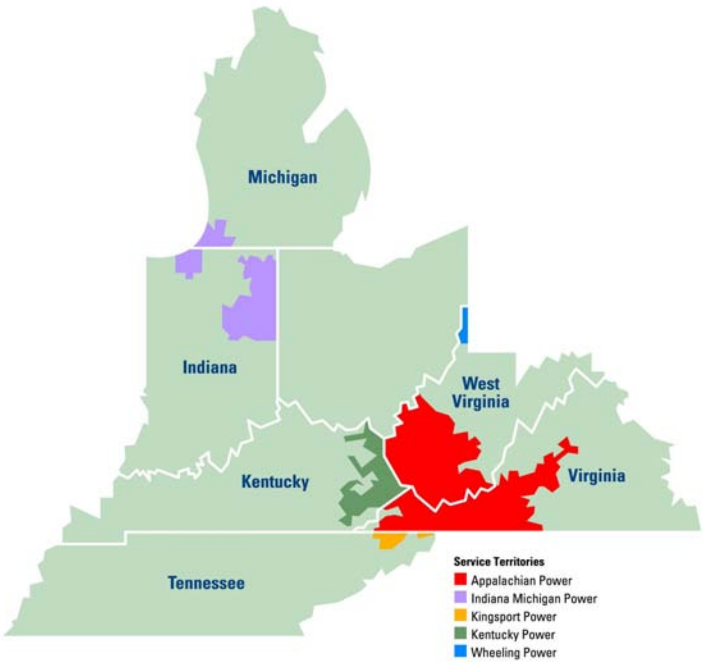
AEP EAST OPERATING COMPANIES

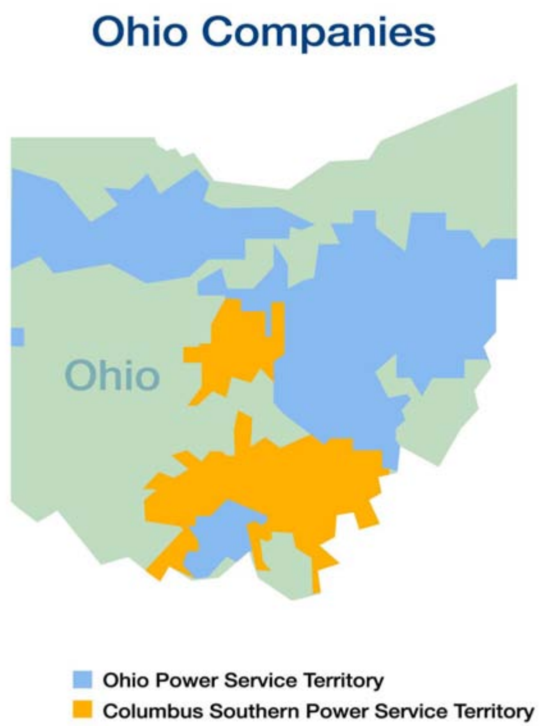
EAST REGULATED UTILITIES

- Appalachian Power Company
- Indiana Michigan Power Company
- Kingsport Power Company
- Kentucky Power Company
- Wheeling Power Company

AEP OHIO

- Columbus Southern Power Company
- Ohio Power Company





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AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

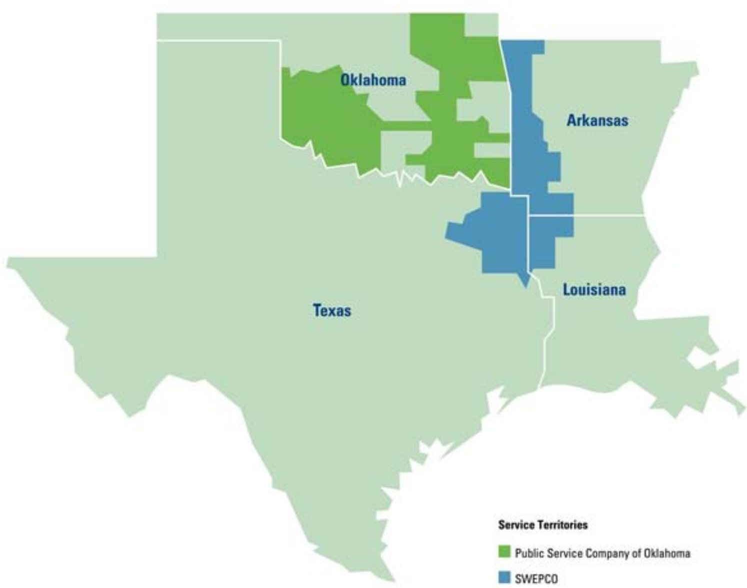
Public Service Company of Oklahoma

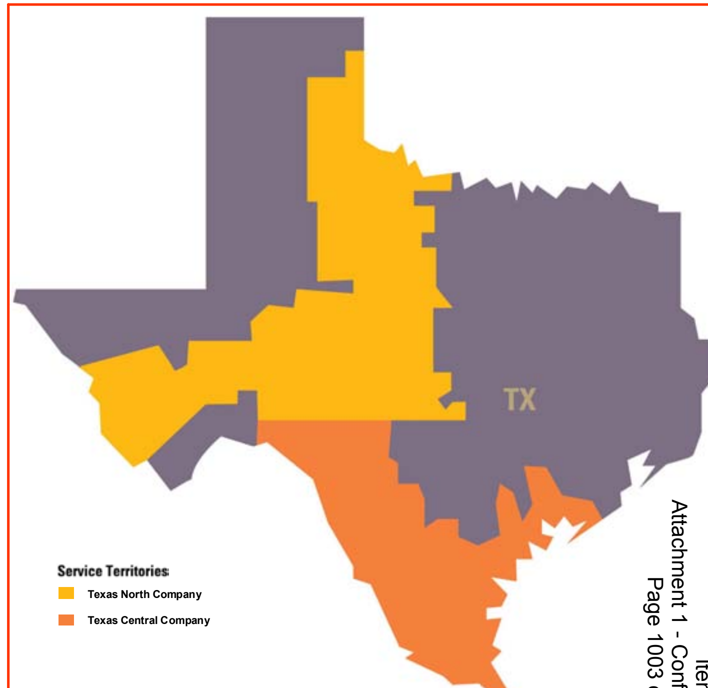
Southwestern Electric Power Company

AEP TEXAS

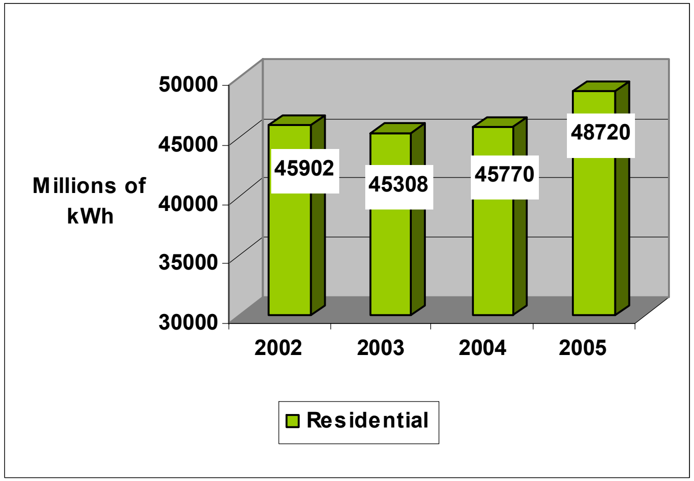
Texas Central Company

Texas North Company



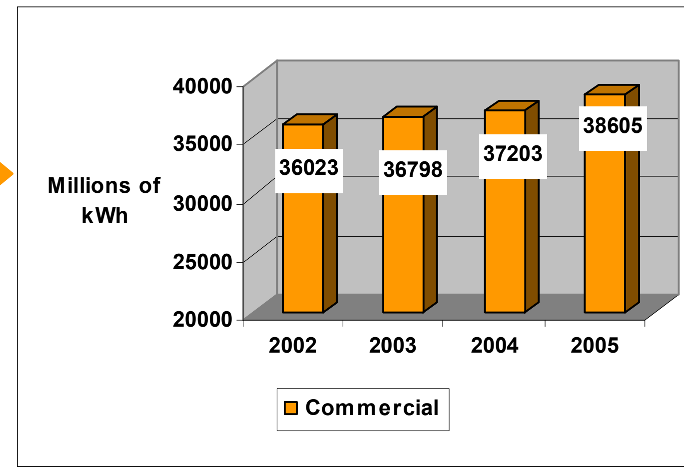


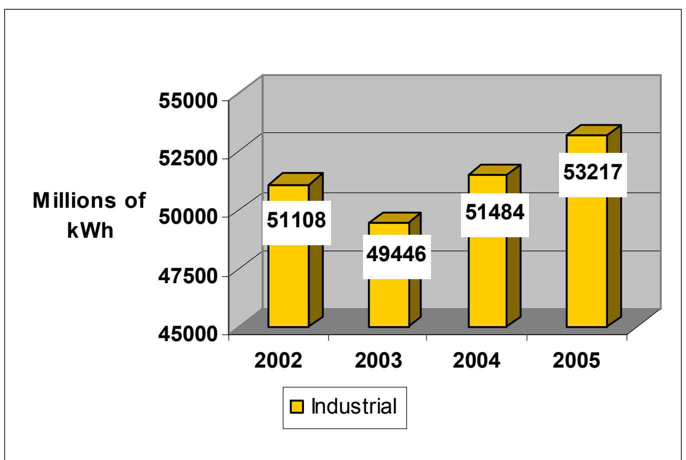
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 2.01%

3 Yr. Compound Annual Commercial Load Growth at 2.33%





3 Yr. Compound Annual Industrial Load Growth at 1.36%

Note: Figures do not include Texas Retail and Miscellaneous Other

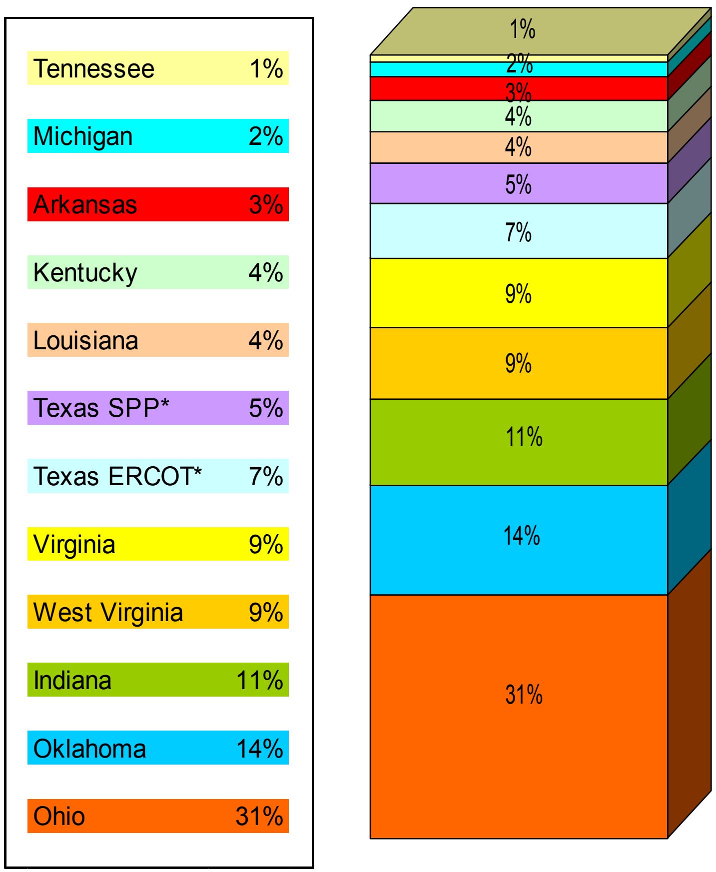
2005 Retail Revenue

CUSTOMER PROFILE

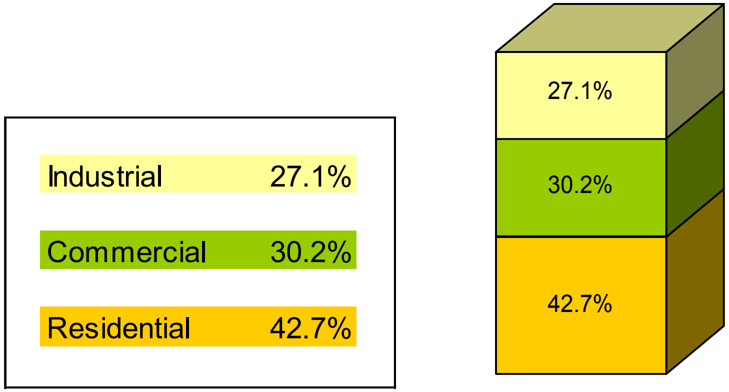
AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

PERCENTAGE OF AEP SYSTEM RETAIL REVENUES



Retail Revenue Composition by Customer Class**



Source: Form 10-K
*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.
**Note: Figures do not include Other Retail Sales

Utility Operations

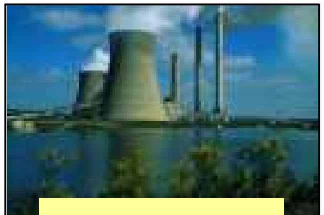
Generation

AEP has approximately 36,000 megawatts of generating capacity in 3 power pools. AEP owns all or portions of 70 major generating plants, which include coal/lignite, natural gas, nuclear, wind projects and hydroelectric facilities.

AEP operates generating capacity in its internal power pool under an economic dispatch system[1]. AEP's power pool's competitive, largely coal-based production costs are among the lowest in the nation. AEP's power production costs are also kept relatively low by its reliance primarily on fossil fuel (gas and coal), with only a small overall nuclear dependence.

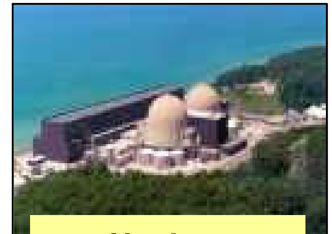
[1] Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.

Domestic Generation Fleet



Coal/Lignite
72%

Nat. Gas/Oil
19%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
35,660 MW Capacity*

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.50%	62.53%

NERC Regional Presence

RFC (formerly ECAR)	73%
SPP	24%
ERCOT	3%

* Excludes 1,013 MW of mothballed / decommissioned / retired generating capacity.

Utility Operations

PROPERTY, PLANT & EQUIPMENT DETAIL ($ MILLIONS)

Property Plant and Equipment	Original Cost	AEP Accumulated D&A	Net Utility Plant
Electric:			
Production	$ 16,712	$ 8,130	$ 8,582
Transmission	6,952	2,469	4,483
Distribution	11,179	3,303	7,876
Other (including coal mining & nuclear fuel)	3,277	1,279	1,998
Work in Progress	2,848	(35)	2,883
Total	**$ 40,968**	**$ 15,146**	**$ 25,822**

Source: Company information as of 9/30/06

Operating Company Overview

- AEP East Regional Utilities
- AEP West Regional Utilities

Fall EEI 2006

Organizational Structure

- **CEO**
  Mike Morris
  - **President**
    AEP Utilities
    Carl English
    - **EVP**
      AEP Utilities East
      Bob Powers
      - **President** **Ohio** **Kevin Walker**
      - **President** **Appalachian Power** **Dana Waldo**
      - **President** **Indiana Michigan Power** **Helen Murray**
      - **President** **Kentucky Power** **Tim Mosher**
    - **EVP**
      AEP Utilities West
      Tom Hagan
      - **President** **Texas** **Charles Patton**
      - **President** **SWEPCO** **Venita McCellon-Allen**
      - **President** **Public Service of Oklahoma** **Stuart Solomon**


Mike


Carl


Bob


Tom


Kevin


Dana


Helen


Tim


Charles


Venita


Stuart

SENIOR MANAGEMENT CLOSE TO CUSTOMERS AND REGULATORS

AEP East Regional Utilities

Appalachian Power Company

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

Total Customers as of 12/31/05*:

• **Residential**	**801,000**
• **Commercial**	**126,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**938,000**

Generating Capacity	**6,409 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**79.5%**
• **Hydro/Pump:**	**12.5%**
• **Nat Gas**	**8.0%**

Transmission Miles	**6,800**
Distribution Miles	**49,000**

*** Source: 2005 FERC FORM 1**

Principal industries served:
Coal mining
Primary metals
Chemicals
Textile mill products

Appalachian Power Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,947,075	1,360,131	3,307,206	1,995,658	1,427,502	3,423,160	2,345,511	1,821,484	4,166,995
% of Capitalization Per Balance Sheet	58.9%	41.1%	100.0%	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%
Adjusted Capitalization	1,947,075	1,360,131	3,307,206	2,004,550	1,418,610	3,423,160	2,354,403	1,812,593	4,166,996
% of Adjusted Capitalization	58.9%	41.1%	100.0%	58.6%	41.4%	100.0%	56.5%	43.5%	100.0%
FFO Interest Coverage			5.6			5.0			3.7
FFO Total Debt			27.2%			19.7%			12.4%

2005 Financial Data* (in thousands)

Revenue	$	2,176,000
% of AEP Retail		17%
Net Income	$	131,000
Capital Expenditures	$	589,000

2006 Asset Data** (in thousands)

	As of 09/30/06	
Total Assets	$	6,755,000
Net Plant Assets	$	5,314,000
Cash	$	1,249

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 928,000	$ 780,000	$ 559,000	$ 455,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Appalachian Power Company

APPALACHIAN AREA UTILITIES[1]

West Virginia	Customers
APCo	**433,615**
Allegheny	485,295

Virginia	Customers
APCo	**496,994**
Dominion Virginia	2,131,281
Allegheny	92,878
Kentucky Utilities	29,801
Conectiv	21,529

Tennessee	Customers
APCo	**45,840**

TYPICAL BILL COMPARISON[2]

West Virginia	
APCo	**55.28**
AEP – Wheeling	**55.28**
Monongahela	70.09
Potomac Edison	70.09

Virginia	
ODPCo	58.07
APCo	**61.39**
Dominion Virginia	87.18
Delmarva	103.13

***MAJOR CUSTOMERS**

Century Aluminum
Consol Energy
Massey Energy Company
Steel Dynamics
Georgia-Pacific Corporation
Greif Brothers Corporation
Arch Coal, Inc.
West Virginia Alloys, Inc
Peabody Group
State of WV

***Top 10 customers = 17.4% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

***APCO:**

- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

***Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005.

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Appalachian Power Company

APCo Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	32,901,943	29,551,752	32,949,364	31,801,020
Coal Consumption (tons burned)	13,015,569	11,604,352	13,187,986	12,602,636

Operating Information*

2005 retail electric sales in megawatt-hours	30,327,723
2005 firm wholesale sales in megawatt-hours	2,480,850
Revenue per kilowatt-hour sold (residential)	5.41 cents
2005 System Peak	6,978 (January 24)

Appalachian Power Plants

Name	Location	Megawatt Capacity	Fuel
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1320	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

*Source: FERC Form 1

Regulatory Information

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.
Wheeling Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R**: 1 **D:** 2
Qualifications for Commissioners The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.			
Commissioners **Edward H. Staats, (Dem.),** since 2003, term expires June 2009. Former Chief of Operations in the Governor's office. Former Chief Financial Officer of the W.V. Bureau of Employment Programs. Certified Public Accountant in West Virginia and Georgia. Bachelor's degree, West Virginia University.			
R. Michael Shaw, Commissioner (Rep.), since 2003, term expires June 2007. Served on Workers' Compensation Appeals Board from 1997 to 2001. Elected to the House of Delegates in 1972, served on Judiciary Committee. Elected to Senate in 1978 to 1982 and again in 1984 to 1988. Owns law practice.			
Jon W. McKinney, Chairman (Dem.), since 2005, term expires June 2011. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable & Thomas Memorial Hospital.			

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items.

Regulatory Information

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R**: 2 **D:** 1

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires 2010. Attorney, counsel to the Speaker of the House.

Judith Jagdmann, (Rep.), since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. APCO-VA's unbundled generation, transmission (which reflect FERC approved transmission rates) and distribution rates as well as its functional separation plan were approved by the VA SCC in December 2001. APCO-VA's base rates are capped at their mid-1999 levels until the end of the transition period (December 31, 2010), or sooner if the VA SCC finds that a competitive market for generation exists in Virginia. APCo-VA is permitted to seek two changes to its capped rates through December 31, 2010. In addition, APCo-VA is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution reliability and compliance with state or federal environmental laws or regulations. APCo-VA is entitled to adjustments to fuel rates through 2010 to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. APCO-VA recovers its generation capacity charges through capped base rates.

Regulatory Information

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: I**: 1 **D:** 3

Qualifications for Commissioners

The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all currently expire in June 2008; after 2008, terms will be staggered.

Commissioners

Eddie Roberson, Director (Ind.), since 2006; current term expires 2012. Former Chief of Public Services Division of PSC. Received Ph.D. in Public Administration from The Institute of Government at Tennessee State University in 1998.

Patrick Miller, Director (Dem.), since 2002; current term expires June 2008. Fiscal Analyst, Fiscal Review Committee. Legislative Liaison, Tennessee Supreme Court. Served as Chief of Staff to the Lt. Governor and Speaker of the Senate. J.D., Nashville School of Law.

Sara Kyle, Chairman (Dem.), since 1996; current term expires June 2008. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving director and only holdover from the previous Public Service Commission. Law degree from Middle Tennessee State University.

Ron Jones, Director, (Dem.), since 2002: current term expires June 2008. Sixteen year veteran of utility regulation, Director Jones served the first ten years with the Tennessee Public Service Commission staff and the next six with the TRA as a Senior Policy Advisor. Completed several regulatory studies programs at Michigan State University, Graduate School of Business. Received B.B.A. from Tennessee State University.

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Columbus Southern Power

President and Chief Operating Officer:
Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 square miles and at December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

Principal industries served:
Food processing
Chemicals
Primary metals
Electronic machinery
Paper products

Total Customers as of 12/31/05*:

• **Residential**	**635,000**
• **Commercial**	**72,000**
• **Industrial**	**3,000**
• **Other**	**300**
Total	**710,300**

Generating Cap	**3,215 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**73.5%**
• **Natural Gas**	**26.5%**
Transmission Miles	**2,400**
Distribution Miles	**17,200**

*** Source: 2005 FERC FORM 1**

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Capitalization Per Balance Sheet	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
Adjusted Capitalization	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Adjusted Capitalization	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
FFO Interest Coverage			7.7			6.2			5.8
FFO Total Debt			37.9%			28.7%			24.3%

2005 Financial Data* (in thousands)

Revenue	$ 1,542,000
% of AEP Retail	14%
Net Income	$ 134,000
Capital Expenditures	$ 164,000

2006 Asset Data** (in thousands)

	As of 09/30/06
Total Assets	$ 3,447,000
Net Plant Assets	$ 2,647,000
Cash	$ 1,251

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 319,000	$ 367,000	$ 523,000	$ 251,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	15,243,711	14,049,095	14,038,045	14,443,617
Coal Consumption (tons burned)	6,526,167	6,121,275	6,048,060	6,231,834

Operating Information*

2005 retail sales in megawatt-hours	18,277,372
2005 firm wholesale sales in megawatt-hours	0
Revenue per kilowatt-hour sold (residential)	7.56 cents
2005 System Peak	4,105 megawatts (July 25)

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,260	Coal
J. M. Stuart #*1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	620	Coal
Wm. H. Zimmer #*1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

*Source: FERC Form 1

Columbus Southern Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison = 162,117
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON[2]

Ohio	
AEP (OPCo)	**69.86**
AEP (CSP)	**83.07**
DP&L	93.09
Cinergy (CG&E)	102.74
FE (Ohio Ed)	112.99
FE (CEI)	116.02
FE (ToledoEd)	116.60

***MAJOR CUSTOMERS**

The Ohio State University
Eramet Marietta Inc
State of Ohio
E I duPont de Nemours HQ
Anheuser-Busch, Inc.
The Kroger Company
Nationwide Insurance Enterprise
OhioHealth
Federal Government
Ohio University

***Top 10 customers = 12.1% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

***CSP:**

- **Metropolitan areas account for 85% of ultimate sales**
- **222 persons per square mile (U.S. = 95)**

***Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Ohio Power

President and Chief Operating Officer:
Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCo covers a service territory of 6,675 square miles and at December 31, 2005, OPCo had 2,220 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Total Customers as of 12/31/05*:

• **Residential**	**609,000**
• **Commercial**	**90,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**709,000**

Generating Capacity	**8,540 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**99.5%**
• **Hydro:**	**.5%**

Transmission Miles	**6,500**
Distribution Miles	**26,200**

*** Source: 2005 FERC FORM 1**

Principal industries served:
Primary metals
Rubber and plastic products
Stone, clay, glass and concrete products
Petroleum refining
Chemicals

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,082,195	1,487,920	3,570,115	2,053,641	1,490,479	3,544,120	2,280,107	1,784,586	4,064,693
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	57.9%	42.1%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,082,195	1,487,920	3,570,115	2,061,962	1,482,159	3,544,121	2,288,427	1,776,267	4,064,694
% of Adjusted Capitalization	58.3%	41.7%	100.0%	58.2%	41.8%	100.0%	56.3%	43.7%	100.0%
FFO Interest Coverage			6.5			4.9			6.2
FFO Total Debt			28.3%			22.6%			23.8%

2005 Financial Data* (in thousands)

Revenue	$ 2,635,000
% of AEP Retail	17%
Net Income	$ 245,000
Capital Expenditures	$ 694,000

2006 Asset Data** (in thousands)

	As of 09/30/06
Total Assets	$ 6,566,000
Net Plant Assets	$ 5,325,000
Cash	$ 1,325

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 1,065,000	$ 746,000	$ 322,000	$ 391,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Ohio Power

Ohio Power Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	53,099,905	52,156,749	52,080,585	52,445,746
Coal Consumption (tons burned)	20,936,936	20,534,361	20,382,116	20,617,804

Operating Information*

2005 retail sales in megawatt-hours	28,929,494
2005 firm wholesale sales in megawatt-hours	2,225,194
Revenue per kilowatt-hour sold (residential)	6.56 cents
2005 System Peak	5,638 megawatts (Aug 12)

Ohio Power Plants

Name	Location	Megawatt Capacity	Fuel
Gen. JM Gavin #1,2	Cheshire, Ohio	2,620	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1,2	Racine, Ohio	48	Hydro

*Source: FERC Form 1

Ohio Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
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TYPICAL BILL COMPARISON[2]

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AEP (CSP)	**83.07**
DP&L	93.09
Cinergy (CG&E)	102.74
FE (Ohio Ed)	112.99
FE (CEI)	116.02
FE (ToledoEd)	116.60

***MAJOR CUSTOMERS**

The Timken Co.
Wheeling Pittsburgh – WHX HQ
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Century Aluminum Co.
Globe Metallurgical, Inc
Marathon Ashland Petroleum LLC
Owens Corning Fiberglas Corp.
Linde Gas LLC
Duke Energy Corp

***Top 10 customers = 21.5% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

***OPCo:**

- **Metropolitan areas account for 59% of ultimate sales**
- **137 persons per square mile (U.S. = 95)**

***Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005.

[2] Annualized typical bills are displayed in \$/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.
Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected: Appointed**	**Term: 5 Years**	**Political Makeup: R: 3 D: 0 I: 2**

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.) since 1995; term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.) since 1997; term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and chair of the Fuel Source Advisory Council, member of the National Coal Council, and member of the Technical Advisory Committee of the Ohio Coal Development Office.

Donald L. Mason, Commissioner, (Rep.) since 1998; term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves on the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master’s degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation.

AEP Regulatory Status

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSP and OPCo (the Ohio Companies). The plans provided, among other things, for CSP and OPCo to raise their generation rates by 3% and 7% respectively, in 2006, 2007 and 2008 and provided for additional generation rate increases of up to 4% per year based on the Ohio Companies supporting the need for additional revenues. Distribution rates in effect at 12/31/05 are frozen for OPCo and CSP until 12/31/07 and 12/31/08, respectively. Transmission rates are currently regulated by FERC as reflected in the OATT. CSP and OPCO do not have an active fuel clause (fuel costs are embedded in unbundled G rates).

Indiana Michigan Power

President and Chief Operating Officer:
Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2005, I&M had 2,633 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

Principal industries served:
Primary metals
Transportation equipment
Electrical and electronic machinery
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers as of 12/31/05*:

• **Residential**	**506,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**579,000**

Generating Capacity (includes AEG Rockport)	**5,768 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**62.4%**
• **Nuclear:**	**37.1%**
• **Hydro:**	**0.5%**

Transmission Miles	**5,300**
Distribution Miles	**19,700**

*** Source: 2005 FERC FORM 1**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,438,181	1,149,593	2,587,774	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%
Adjusted Capitalization	1,823,681	1,149,593	2,973,274	1,761,432	1,095,540	2,856,972	1,921,435	1,224,134	3,145,569
% of Adjusted Capitalization	61.3%	38.7%	100.0%	61.7%	38.3%	100.0%	61.1%	38.9%	100.0%
FFO Interest Coverage			4.0			4.1			4.7
FFO Total Debt			22.70%			23.20%			22.80%

2005 Financial Data* (in thousands)

Revenue	$	1,893,000
% of AEP Retail		13%
Net Income	$	146,000
Capital Expenditures	$	294,000

2006 Asset Data** (in thousands)

	As of 09/30/06	
Total Assets	$	5,274,000
Net Plant Assets	$	3,241,000
Cash	$	706

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 330,000	$ 267,000	$ 273,000	$ 365,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Indiana Michigan Power

I&M Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	28,075,125	21,258,001	31,535,226	26,956,117
Coal Consumption (tons burned)	7,189,655	7,186,066	7,011,370	7,129,030

Operating Information*

2005 retail electric sales in megawatt-hours	19,248,200
2005 firm wholesale sales in megawatt-hours	2,169,221
Revenue per kilowatt-hour sold (residential)	6.61 cents
2005 System Peak	4,193 MW (August 3)

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

*Source: FERC Form 1

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES[1]

Indiana	Customers
I & M	**452,050**
IP & L	458,796
NIPSCO	442,554
Cinergy (PSI)	747,696
SIGECO	135,449

Michigan	Customers
I & M	**124,583**
CMS (Consumers)	1,760,882
DTE (Detroit Edison)	2,144,655

TYPICAL BILL COMPARISON[2]

Indiana	
I & M	**69.63**
IP & L	72.73
PSI Energy	81.80
SIGECO	98.76

Michigan	
I & M – St. Joe	**60.00**
I & M – Three Rivers	**66.24**
Wisconsin Public Service	75.67
Consumers Energy	85.31
Northern States	90.11
WE Energies	102.73
Detroit Edison	104.48
Upper Peninsula	130.68

***MAJOR CUSTOMERS**

Steel Dynamics Inc
Mittal Steel Company
Air Products & Chemicals, Inc.
BOC Gases
Saint Gobain Corporation USA
Ball State University
New Energy Corporation
Michelin North America, Inc.
Guide Indiana
Dock Foundry

***Top 10 customers = 16.2% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

*** I & M:**

- **Metropolitan areas account for 68% of ultimate sales**
- **204 persons per square mile (U.S. = 95)**

*** Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005.

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 3 D: 2
Qualifications for Commissioners Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.			
Commissioners **David L. Hardy, Chairman (Rep.),** since 2005; current term will expire 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include negotiation, contracts, litigation, finance and administration. He has 35 years of regulatory experience at the state and federal levels.			
Larry S. Landis, Commissioner (Rep.),since 2002; current term ends 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.			
David W. Hadley, Commissioner (Dem.), since 2000; current term ends 2010. Executive officer for Indiana AFL-CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.			
Greg Server, Commissioner (Rep.),since 2005; current term ends 2009. Former state senator since 1981 and before that served in the Indiana House of Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.			
David E. Ziegner, Commissioner (Dem.), since 1990; current term ends 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.			

AEP Regulatory Status

I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, I&M's base rates are capped through June 30, 2007. Its fuel recovery rate is capped through that time period at a level that automatically increased in January 2006 and will do so again in January 2007.

Regulatory Information

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**
Qualifications for Commissioners The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.			
Commissioners **J. Peter Lark, Chairman (Dem.),** since 2003; current term expires 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney. Law degree from Western New England College School of Law in 1976.			
Laura Chappelle, Commissioner, (Rep.) , since 2001; current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney. J.D. from Thomas Cooley Law School in 1988.			
Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's degree, University of Michigan.			

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active fuel clause.

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers as of 12/31/05*:

• Residential	145,000
• Commercial	29,000
• Industrial	1,000
• Other	400
Total	175,400

Generating Capacity	1,060 MW
Generating Capacity by Fuel Mix:	
• Coal:	100%
Transmission Miles	1,200
Distribution Miles	9,700

* Source: 2005 FERC FORM 1

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Capitalization Per Balance Sheet	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
Adjusted Capitalization	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Adjusted Capitalization	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
FFO Interest Coverage			4.7			3.9			3.4
FFO Total Debt			20.4%			16.6%			14.0%

2005 Financial Data* (in thousands)

Revenue	$	531,000
% of AEP Retail		4%
Net Income	$	21,000
Capital Expenditures	$	57,000

2006 Asset Data** (in thousands)

	As of 09/30/06	
Total Assets	$	1,271,000
Net Plant Assets	$	993,000
Cash	$	479

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 54,000	$ 72,000	$ 104,000	$ 96,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Kentucky Power

Kentucky Power Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	6,170,931	6,550,509	7,345,624	6,689,021
Coal Consumption (tons burned)	2,513,524	2,607,559	2,926,253	2,682,445

Operating Information*

2005 retail electric sales in megawatt-hours	7,309,016
2005 firm wholesale sales in megawatt-hours	97,845
Revenue per kilowatt-hour sold (residential)	5.67 cents
2005 System Peak	1,685 MW (Jan 24)

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

*Source: FERC Form 1

Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	Customers[1]
KPCo	174,631
Kentucky Utilities	485,627
LG & E	389,196

TYPICAL BILL COMPARISON[2]

Kentucky	
Kentucky Utilities	55.04
KPCo	62.96
LG&E	63.98
CIN	68.54

***MAJOR CUSTOMERS**

Marathon Ashland Petroleum
AK Steel Holding Corporation
Massey Energy Company
James River Coal Co.
TECO Energy, Inc.
Air Products & Chemicals
KES Acquisition Company LLC.
Alliance Coal, LLC
Air Liquide America L.P.
Consol Energy

***Top 10 customers = 33.8% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

***KPCO:**

- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

***Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005.

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Regulatory Information

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 2	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R**: 2
Qualifications for Commissioners Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.			
Commissioners **Mark Goss, Chairman (Rep.),** since 2004; current term expires July 2007. Serves as member of NARUC. Board member for MISO and PJM. Former practicing attorney in private practice. J.D. from University of Tennessee College of Law.			
John W. Clay, (Rep.), since 2006; current term expires June 2009. Former deputy secretary of the Kentucky Environmental and Public Protection Cabinet. Served as executive director of the Office of Alcohol Beverage Control in the Department of Public Protection. B.A. from Georgetown College.			

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause.

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer:
Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2005, PSO had 1,176 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

Total Customers as of 12/31/05*:

• **Residential**	**441,000**
• **Commercial**	**57,000**
• **Industrial**	**7,000**
• **Other**	**8,000**
Total	**513,000**
Generating Capacity	**4,219 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**24.5%**
• **Natural Gas:**	**75.5%**

Transmission Miles	**3,600**
Distribution Miles	**21,200**

*** Source: 2005 FERC FORM 1**

Principal industries served:
Natural gas and oil production
Oil refining
Steel processing
Aircraft Maintenance
Paper manufacturing and timber products
Glass
Chemicals
Cement
Plastics
Aerospace manufacturing
Telecommunications
Rubber goods

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	607,162	488,275	1,095,437	601,095	534,517	1,135,612	646,954	553,858	1,200,812
% of Capitalization Per Balance Sheet	55.4%	44.6%	100.0%	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%
Adjusted Capitalization	607,162	488,275	1,095,437	603,726	531,886	1,135,612	649,585	551,228	1,200,813
% of Adjusted Capitalization	55.4%	44.6%	100.0%	53.2%	46.8%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			3.8			5.5			2.8
FFO Total Debt			20.4%			28.2%			9.5%

2005 Financial Data* (in thousands)

Revenue	$ 1,304,000
% of AEP Retail	14%
Net Income	$ 58,000
Capital Expenditures	$ 134,000

2006 Asset Data** (in thousands)

	As of 09/30/06
Total Assets	$ 2,498,000
Net Plant Assets	$ 1,908,000
Cash	$ 2,277

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 262,000	$ 311,000	$ 331,000	$ 440,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**3-Year Average**
MWh Produced	14,845,846	12,512,486	15,375,848	14,244,727
Coal Consumption (tons burned)	4,678,950	4,093,436	4,353,364	4,375,250

Operating Information*

2005 retail electric sales in megawatt-hours	17,782,561
2005 firm wholesale sales in megawatt-hours	45,172
Revenue per kilowatt-hour sold (residential)	7.55 cents
2005 System Peak	4,043 MW (July 22)

Oklahoma Power Plants

Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

*Source: FERC Form 1

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	**Customers[1]**
PSO	**507,214**
OG&E	668,766

TYPICAL BILL COMPARISON[2]

Oklahoma	
Empire District	76.71
PSO	**86.15**
OG&E	95.78

***MAJOR CUSTOMERS**

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Transok Inc
Federal Government
AMR Corporation
Sunoco Inc.
City of Tulsa
Republic Paperboard Inc

***Top 10 customers = 14.7% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

***PSO:**

- **Metropolitan areas account for 75% of ultimate sales**
- **46 persons per square mile (U.S. = 95)**

*** Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005.

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Regulatory Information

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R**: 3

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

Denise A. Bode, Vice Chairman (Rep.) since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

Bob Anthony Commissioner, (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established.

Southwestern Electric Power

President and Chief Operating Officer:
Venita McCellon-Allen

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2005, SWEPCo had 1,498 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

Total Customers as of 12/31/05*:

• **Residential**	**379,000**
• **Commercial**	**61,000**
• **Industrial**	**7,000**
• **Other**	**500**
Total	**447,500**

Generating Capacity **4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite:** **60%**
- **Natural Gas:** **40%**

Transmission Miles **3,500**

Distribution Miles **19,300**

*** Source: 2005 FERC FORM 1**

Principal industries served:

Natural gas and oil production
Petroleum refining
Manufacturing of pulp and paper
Chemicals
Food processing
Metal refining

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	890,675	701,360	1,592,035	806,494	773,318	1,579,812	774,245	787,077	1,561,322
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	51.0%	49.0%	100.0%	49.6%	50.4%	100.0%
Adjusted Capitalization	890,675	701,360	1,592,035	808,844	770,968	1,579,812	776,595	784,727	1,561,322
% of Adjusted Capitalization	55.9%	44.1%	100.0%	51.2%	48.8%	100.0%	49.7%	50.3%	100.0%
FFO Interest Coverage			4.1			5.7			3.8
FFO Total Debt			22.9%			31.4%			18.1%

2005 Financial Data* (in thousands)

Revenue	$ 1,405,000
% of AEP Retail	12%
Net Income	$ 74,000
Capital Expenditures	$ 156,000

2006 Asset Data** (in thousands)

	As of 09/30/06
Total Assets	$ 2,977,000
Net Plant Assets	$ 2,331,000
Cash	$ 2,796

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 315,000	$ 480,000	$ 565,000	$ 535,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2003 – 2005*				
	2003	**2004**	**2005**	**Three-Year Average**
MWh Produced	20,539,365	20,071,578	20,167,754	20,259,566
Coal Consumption (tons burned)	12,536,179	13,032,475	12,420,979	12,663,211

Operating Information*

2005 retail electric sales in megawatt-hours	17,069,455
2005 firm wholesale sales in megawatt-hours	5,554,340
Revenue per kilowatt-hour sold (residential)	6.92 cents
2005 System peak	4725 MW (Aug 23)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Lieberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

*Source: FERC Form 1

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES[1]

Arkansas	Customers
SWEPCO	**107,220**
Entergy AR	667,714

Louisiana	Customers
SWEPCO	**169,079**
CLECO	261,601

Texas	Customers
SWEPCO	**165,722**

TYPICAL BILL COMPARISON[2]

Arkansas	
SWEPCO	**72.90**
OG&E	81.83
Empire District	85.79
Entergy-Arkansas	93.50

Louisiana	
SWEPCO	**69.84**
Entergy LA	88.16
Entergy NO	95.06
CLECO	102.33
Entergy Gulf St	106.76

Texas	
SWEPCO	**67.31**
SPSCo	90.64
Entergy Gulf St	110.94
EP	117.76
TXU	157.73

***MAJOR CUSTOMERS**

Lone Star Steel Company
DOMTAR
Tyson Foods, Inc.
International Paper Company
Federal Government
Calumet Lubricants
Pilgrim's Pride Corp.
Wal-Mart Stores, Inc.
General Motors Corp.
Cooper Tire & Rubber Company

***Top 10 customers = 15.8% of retail sales volume**

*** Based on data 12 Months Ended Sept 2006**

*** SWEPCO:**

- **Metropolitan areas account for 74% of ultimate sales**
- **78 persons per square mile (U.S. = 95)**

*** Based on data YTD August 2006**

[1] Source: Energy Information Administration - Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for All Sectors by State and Utility – 2004 Report issued in December 2005

[2] Annualized typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the Winter 2006 EEI Typical Bills and Average Rates Report.

Regulatory Information

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R**: 3
Qualifications for Commissioners The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.			
Commissioners **Sandra Hochstetter, Chairman (Rep.),** since 1999; current term ends in 2011. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.			
Randy Bynum, Commissioner (Rep.), since 1999, Chairman since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.			
Daryl E. Bassett, Commissioner (Rep.), since 2003; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).			

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause.

Regulatory Information

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 3**
Qualifications for Commissioners The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.			
Commissioners **Jack A. Blossman, Jr. (Rep.),** since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.			
James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.			
Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.			
C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.			
Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.			

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause.

Regulatory Information

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.
Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R**: 3
Qualifications for Commissioners To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.			
Commissioners **Barry T. Smitherman, Commissioner, (Rep.),** since April 2004; current term expires August 2007. Attorney; Assistant DA; Public Finance Investment Banker.			
Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.			
Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUC as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.			

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO and TNC-SPP areas). SWEPCO-TX has an active fuel pass-through clause. TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules.

AEP Texas Central Company

President and Chief Operating Officer:
Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

Total Customers as of 12/31/05:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**

Generating Capacity	**54 MW***
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

•TCC's 54-MW share of the Oklaunion plant

Principal industries served:
Oil and gas extraction
Food processing
Apparel
Metal refining
Chemical and petroleum refining
Plastics
Machinery equipment

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data* (in thousands)

Revenue	$	793,000
% of AEP Retail		5%
Net Income (Loss)	$	(174,000)
Capital Expenditures	$	177,000

2006 Asset Data** (in thousands)

	As of 09/30/06	
Total Assets	$	4,869,000
Net Plant Assets	$	2,181,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 286,000	$ 249,000	$ 236,000	$ 239,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1053 of 9556

AEP Texas Central Company

Texas Central Company

***MAJOR CUSTOMERS**

Valero Energy Corp.
Koch Industries, Inc.
Air Liquide America, LP
El Paso Energy Corp.
Federal Government
Equistar Chemicals LP
HEB Grocery Company L P
Formosa Utl Ven Ltd.
Citgo Petroleum Corp.
Wal-Mart Stores, Inc.

***Top 10 customers = 18.5% of retail sales**

*** Based on data 12 Months Ended Sept 2006**

***TNC:**

- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Based on data YTD August 2006

Texas Central Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

AEP Texas North Company

President and Chief Operating Officer:
Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Total Customers as of 12/31/05:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
Total	**183,000**

Generating Capacity	**377 MW**
(excludes 1,013 MW mothballed plants)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**4,500**
Distribution Miles	**14,400**

Principal industries served:

Agriculture and the manufacturing or processing of Cotton seed products

Oil products

Precision and consumer metal products

Meat products

Gypsum products

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data* (in thousands)

Revenue	$ 459,000
% of AEP Retail	1%
Net Income	$ 33,000
Capital Expenditures	$ 63,000

2006 Asset Data** (in thousands)

	As of 09/30/06
Total Assets	$ 962,000
Net Plant Assets	$ 834,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008	2009
$ 72,000	$ 116,000	$ 173,000	$ 84,000

Sources: *2005 Form 10-K
**3Q06 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

AEP Texas North Company

Texas North Company

***MAJOR CUSTOMERS**

Chevron Texaco Corp.
Federal Government
Kinder Morgan Natural Gas Pipeline
Occidental Permian Ltd.
City of Abilene
Zoltek Corporation
Angelo State University
Txc
Kerr McGee Corp
Hendrick Med Ctr

***Top 10 customers = 13.8% of retail sales volumes**

*** Based on data 12 Months Ended Sept 2006**

***TNC:**

- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Based on data YTD August 2006

Texas North Power Plants (excluding 1,013MW of mothballed / retired/ decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulation

- **Jurisdictional Outlook**

Fall EEI 2006

Regulatory Activity Underway

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- Hearings held, awaiting Commission Order
- Hearing Examiner's recommendation received on September 22, 2006. APCo requested recovery of actual incurred environmental compliance and T&D System reliability costs incurred during the period July 1, 2004 through September 30, 2005 of $21.1 million. The Hearing Examiner agreed with the Va SCC staff approach indicating that rates could be established on a go-forward basis in the amount of $29 million, however, since interim rates went into effect subject to refund that included a going forward level of E&R recovery, no adjustment to rates was necessary.
- The Virginia Attorney General's office, in its reply brief, indicated that they disagreed with the Hearing Examiner's interpretation of the statute. If the Virginia SCC adopts the Hearing Examiner's findings, we will appeal the decision vigorously. We believe we will ultimately prevail in this case.

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, at which time $198.5 million went into effect subject to refund.
- October 24, 2006 - SCC Staff filed testimony recommending a $12.7MM rate increase, which includes a 9.9% return on equity and no off-system sales margin sharing.

<u>**Procedural Schedule**</u>

Nov 9, 2006	Company to file rebuttal testimony
Dec 6, 2006	Evidentiary Hearings to commence

Regulatory Activity Underway

FERC Regional Rate Design

Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service proved by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ rendered initial decision finding:
  - License Plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006 when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
- Briefs on Exceptions to the initial decision by all parties filed: Order expected by the Commission late 2006/early 2007

Seams Elimination Cost Adjustment Revenues

Seams Elimination Cost Allocations (SECA) Revenues

- August 2006 ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $111 million SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both
- Exceptions to initial decision filed Sept. 11, & Replies to exceptions filed Oct. 11: Order expected by the Commission in early 2007

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate, for certain specific incremental costs
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- $41 million annual increase in base rates
- Rates effective March 30, 2006

Regulatory Activity Completed

APCo & WPCo West Virginia Rate Case

Settlement approved July 2006

- $44MM initial overall increase in rates effective July 28, 2006 comprised of:
  - $56MM increase in ENEC for fuel & purchased power expenses;
  - $23MM special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry (WJF) 765kV line;
  - $18MM general base rate reduction based on ROE of 10.5%, of which $9MM relates to a reduction in depreciation expense (affects cash flows but not earnings);
  - $17MM credit to refund a portion of deferred prior over-recoveries of ENEC costs of $51MM, currently recorded in regulatory liabilities; therefore, this item impacts cash flows but has no effect on earnings
- Agreement also provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments and the costs of WJF
- Reinstatement of the ENEC mechanism effective July 1, 2006

CSP & OPCO Storm Related Service Restoration Cost Recovery

August 9, 2006 – PUCO issued ruling allowing CSP and OPCO to recover costs associated with service restoration activities during the back-to-back December 2004 and January 2005 ice storms.

- CSP Recovery - $11.9MM
- OP Recovery - $11.7MM

Rate Case Outcome Statistics

Company	Jurisdiction	Date of Final Order	Jurisdictional Rate Base ($ in MM)	ROE	Comments
APCo/WP	WV	7/26/2006	$1,658	10.50%	Settled case. Rate base, ROE and ROR per settlement agreement.
KPCo	KY	3/13/2006	$858 - Rate Base $853 - Capitalization	11.50%	Settled case. Rate base and ROE provided as filed by KPCo. Settlement agreement approved a 10.50% ROE for environmental surcharge filings. KY PSC requires use of total capitalization in rate filings.
PSO	OK	5/2/2005	$1,064	10.75%	Settled case. Rate base and ROE are estimated. A 10.75% ROE was found to be appropriate for AFUDC & affiliate transactions.
TCC	TX	8/15/2005	$862	10.125%	Settled case.

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. The Hearing Examiner's recommendation was received on September 22, 2006. APCo requested recovery of actual incurred environmental compliance and T&D System reliability costs incurred during the period July 1, 2004 through September 30, 2005 of $21.1 million. The Hearing Examiner agreed with the Va SCC staff approach indicating that rates could be established on a go-forward basis in the amount of $29 million, however, since interim rates went into effect subject to refund that included a going forward level of E&R recovery, no adjustment to rates was necessary. We will vigorously defend our position. Comments on the recommendation were filed October 13. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

*Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Note: During the course of the hearings, Staff updated their revenue requirement recommendation to $23.6 million.

Summary Rate Case Information

Virginia Base Rate Case

On May 4, 2006, Appalachian Power Co. filed a request with the Virginia SCC to increase base rates $225.8 million partially offset by a proposed credit to reflect sharing of $27.3 million in margins from off-system sales resulting in a net annual increase of $198.5MM. On May 30, 2006, the SCC suspended the effective date of the rates until 10/2/06, at which time $198.5 million went into effect subject to refund. Intervenor testimony was filed on October 4, 2006. On October 24, 2006, the SCC Staff filed testimony recommending a $12.7MM rate increase, which includes a 9.9% return on equity and no off-system sales margin sharing. Appalachian Power will file rebuttal testimony on November 9, 2006 and Evidentiary Hearings will commence on December 6, 2006.Docket # PUE-2006-00065

Capital Structure – Company vs. Staff

Capital Structure	Company Proposed in millions*		Staff Proposed in millions**	
Long-Term Debt	2,789	53.36%	2,552	55.33%
Short-Term Debt	121	2.31%	128	2.78%
Preferred Stock	18	0.34%	18	0.39%
Common Equity	2,286	43.74%	1,896	41.11%
ITC	13	0.25%	18	0.39%
Total	**5,227**	**100%**	**4,612**	**100%**

* Based on Company Projected Capital Structure at 09/30/07

** Based on Capital Structure at 06/30/06

Rate Base and ROE – Company vs. Staff

	Company Position	Staff Position
Rate Base (in millions)	2,345	1,975
ROE (Requested)	11.50%	9.90%

Generation & Optimization

- Units
- Generation Statistics
- Fuel Statistics
- Transportation Assets

Fall EEI 2006

Domestic Generation

Generation Capacity*

COMPANY	MW Capacity
AEP Generating Co	1,300
Appalachian Power Co	6,409
Columbus Southern Power	3,215
Indiana Michigan Power Co	4,468
Kentucky Power Co	1,060
Ohio Power Co	8,540
Public Service of Oklahoma	4,219
Southwestern Electric Power Co	4,487
Texas Central Co	54
Texas North Co**	377
OVEC Capacity***	981
Domestic IPPs	550
Total	**35,660**

*Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).
** Excludes 1,013 MW of mothballed / retired / decommissioned generation
*** AEP owns a 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE.

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
AEP GENERATING COMPANY					
Rockport	1	IN	RFC	Steam - Coal	1,300
APPALACHIAN POWER COMPANY					
Buck	3	VA	RFC	Hydro	8.5
Byllesby	4	VA	RFC	Hydro	21.6
Claytor	4	VA	RFC	Hydro	75
Leesville	2	VA	RFC	Hydro	50
London	3	WV	RFC	Hydro	14.4
Marmet	3	WV	RFC	Hydro	14.4
Niagara	2	VA	RFC	Hydro	2.4
Reusens	5	VA	RFC	Hydro	12.5
Winfield	3	WV	RFC	Hydro	14.8
Smith Mountain	5	VA	RFC	Pumped Storage	586
Amos	2	WV	RFC	Steam - Coal	2,033
Clinch River	3	VA	RFC	Steam - Coal	705
Glen Lyn	2	VA	RFC	Steam - Coal	335
Kanawha River	2	WV	RFC	Steam - Coal	400
Mountaineer	1	WV	RFC	Steam - Coal	1,320
Sporn	2	WV	RFC	Steam - Coal	300
Ceredo	6	WV	RFC	Natural Gas	516
					6,408.6
COLUMBUS SOUTHERN POWER COMPANY					
Beckjord (CCD)	1	OH	RFC	Steam - Coal	53
Conesville (CCD)	4	OH	RFC	Steam - Coal	1,260
Picway	1	OH	RFC	Steam - Coal	100
Stuart (CCD)	4	OH	RFC	Steam - Coal	620
Zimmer (CCD)	1	OH	RFC	Steam - Coal	330
Waterford	4	OH	RFC	Natural Gas	852
					3,215
INDIANA MICHIGAN POWER COMPANY					
Berrien Springs	3	MI	RFC	Hydro	7.2
Buchanan	5	MI	RFC	Hydro	4.1
Constantine	4	MI	RFC	Hydro	1.2
Elkhart	3	IN	RFC	Hydro	3.4
Mottville	4	MI	RFC	Hydro	1.7
Twin Branch	6	IN	RFC	Hydro	4.8
Rockport	1	IN	RFC	Steam - Coal	1,307.5
Tanners Creek	4	IN	RFC	Steam - Coal	995
Cook	2	MI	RFC	Steam - Nuclear	2,143
					4,467.9

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
KENTUCKY POWER COMPANY					
Big Sandy	2	KY	RFC	Steam - Coal	1,060.0
OHIO POWER COMPANY					
Racine	2	OH	RFC	Hydro	47.5
Amos	1	WV	RFC	Steam - Coal	867
Cardinal	1	OH	RFC	Steam - Coal	600
Gavin	2	OH	RFC	Steam - Coal	2,620
Kammer	3	WV	RFC	Steam - Coal	630
Mitchell	2	WV	RFC	Steam - Coal	1,600
Muskingum River	5	OH	RFC	Steam - Coal	1,425
Sporn	3	WV	RFC	Steam - Coal	750
					8,539.5

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)	
PUBLIC SERVICE COMPANY OF OKLAHOMA						
Tulsa	3	OK	SPP	Steam - Nat Gas	396	
Tulsa	3	OK	SPP	Oil	8	
Riverside	2	OK	SPP	Steam - Nat Gas	917	
Riverside	1	OK	SPP	Oil	2.8	
Northeastern (1&2)	4	OK	SPP	Steam - Nat Gas	940	
Northeastern	1	OK	SPP	Oil	2.8	
Southwestern	3	OK	SPP	Steam - Nat Gas	472	
Southwestern	1	OK	SPP	Oil	2	
Comanche	3	OK	SPP	Steam - Nat Gas	273	
Comanche	2	OK	SPP	Oil	4	
Weleetka	3	OK	SPP	Steam - Nat Gas	163	
Weleetka	2	OK	SPP	Oil	4	
Northeastern (3&4)	2	OK	SPP	Steam - Coal	925	
Northeastern	1	OK	SPP	Oil	1.2	
Oklaunion	1	TX	ERCOT	Steam - Coal	108	
					4,218.7	
SOUTHWESTERN ELECTRIC POWER COMPANY						
Arsenal Hill	1	LA	SPP	Steam - Nat Gas	110	
Lieberman	4	LA	SPP	Steam - Nat Gas	269	
Knox Lee	4	TX	SPP	Steam - Nat Gas	486	
Wilkes	3	TX	SPP	Steam - Nat Gas	882	
Lone Star	1	TX	SPP	Steam - Nat Gas	50	
Welsh	3	TX	SPP	Steam - Coal	1,584	
Flint Creek	1	AR	SPP	Steam - Coal	264	
Pirkey	1	TX	SPP	Steam - Lignite	580	
Dolet Hills	1	LA	SPP	Steam - Lignite	262	
					4,487	
TEXAS CENTRAL COMPANY						
Oklaunion (1)	1	TX	ERCOT	Steam - Coal	54	
					54	
TEXAS NORTH COMPANY						
Paint Creek	4	TX	ERCOT	Steam - Nat Gas	231	Retired
Rio Pecos	3	TX	ERCOT	Steam - Nat Gas	140	Retired
San Angelo	2	TX	ERCOT	Steam - Nat Gas	123	Mothballed
Fort Phantom	2	TX	ERCOT	Steam - Nat Gas	362	Mothballed
Oak Creek	1	TX	ERCOT	Steam - Nat Gas	85	Retired
Abilene	1	TX	ERCOT	Steam - Nat Gas	18	Retired
Lake Pauline	2	TX	ERCOT	Steam - Nat Gas	35	Retired
Ft. Stockton	1	TX	ERCOT	Steam - Nat Gas	5	Decommissioned
Vernon	4	TX	ERCOT	Oil	8	Decommissioned
Oklaunion	1	TX	ERCOT	Steam - Coal	377	
Ft. Davis	12	TX	ERCOT	Wind	6	Decommissioned
					377 (2)	

(1) TCC's share of the Oklaunion plant is currently under sale negotiations
(2) Excludes 1,013 MW of mothballed and/or decommissioned generation

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
DOMESTIC INDEPENDENT POWER PROJECTS					
Trent Mesa	100	TX	ERCOT	Wind	150
Sweeny	4	TX	ERCOT	Natural Gas	240
Indian Mesa	107	TX	ERCOT	Wind	160
					550

Generation Statistics

Region	Equivalent Capacity Factor 2004	Equivalent Capacity Factor 2005	Equivalent Availability Factor 2004	Equivalent Availability Factor 2005	Equivalent Forced Outage Rate 2004	Equivalent Forced Outage Rate 2005
AEP East	67.81%	66.52%	83.43%	84.27%	8.18%	7.90%
Coal*	67.57%	70.82%	82.64%	82.66%	8.77%	8.44%
Gas**	[redacted]	0.19%	[redacted]	96.09%	[redacted]	59.24%
Hydro***	-0.97%	-2.88%	93.90%	93.77%	1.09%	16.00%
Nuclear	89.09%	93.07%	88.71%	93.87%	4.11%	1.19%
AEP SPP	43.27%	47.10%	89.46%	85.81%	5.61%	5.97%
Coal****	77.95%	75.65%	85.85%	81.66%	4.89%	6.18%
Gas	16.38%	25.22%	92.25%	88.99%	6.68%	5.73%
AEP Texas	86.91%	74.90%	90.30%	78.61%	1.93%	7.47%
Coal	77.24%	71.59%	85.56%	77.00%	3.14%	8.78%
Nuclear*****	97.50%	84.48%	95.50%	83.28%	0.60%	3.52%
AEP System	62.43%	62.53%	85.19%	84.50%	7.38%	7.48%

Notes: *Includes 22,025 MW, which includes AEP's share of CCD units, and Cardinal 2 & 3.
**Waterford reported as of 10/1/2005. Ceredo reported as of 12/1/2005.
***Includes Smith Mountain only.
****Does not include Dolet Hills.
*****South Texas Project: Statistics reported through May 18th, 2005.

Net Generation Statistics

Net Generation By Operating Company (in MWhs)

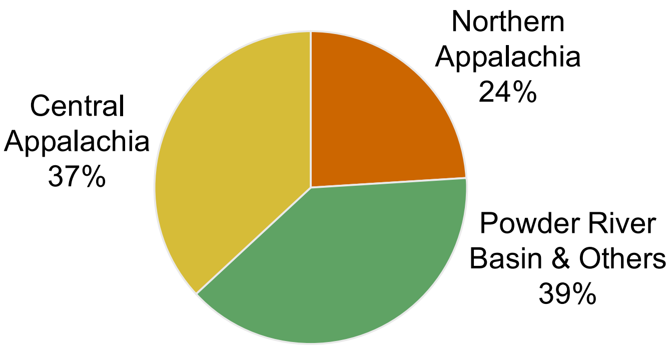
Operating Company	2004	2005
AEP Generating	8,514,555	8,969,041
Appalachain Power	29,551,752	32,949,364
Columbus Southern Power	14,049,095	14,038,045
Indiana Michigan Power	31,258,001	31,535,226
Kentucky Power	6,550,509	7,345,624
Ohio Power	52,156,944	52,080,585
Public Service of Oklahoma	12,512,501	15,375,848
Southwestern Electric Power	20,069,405	20,169,211
Texas Central Company	9,448,714	2,082,874
Texas North Company	3,263,320	2,342,693
AEP System Total Net Generation	**187,374,796**	**186,888,511**

Notes: Figures represent generation produced from AEP-owned assets only.

Coal Procurement

AEP purchases approx. 75 million tons of coal per year

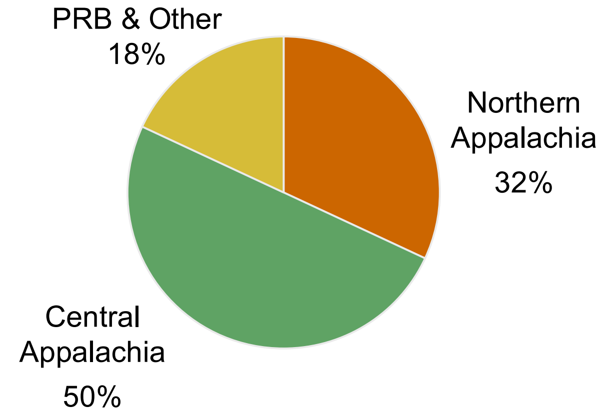
Total AEP System



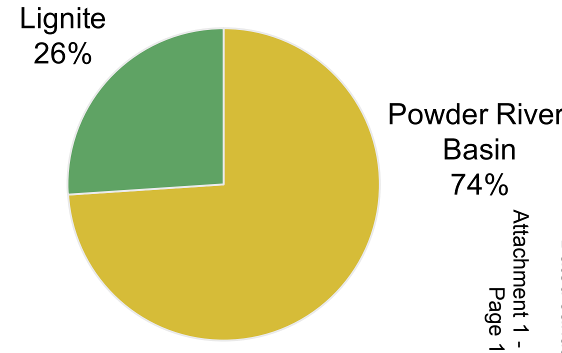
Coal Stats:

- Fully contracted for 2006; 95%+ contracted for 2007
- Avg. delivered price ~ $36.25/ton in 2006
- Approximate 6-8% price increase in 2007 -- ($38.80/ton)
  - Addition of Mountaineer & Mitchell scrubbers will allow for a greater mix of Northern Appalachian coal in 2007

AEP East



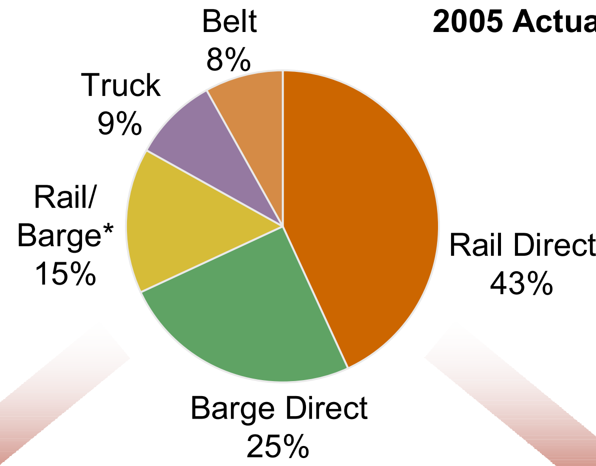
AEP West



Coal Delivery

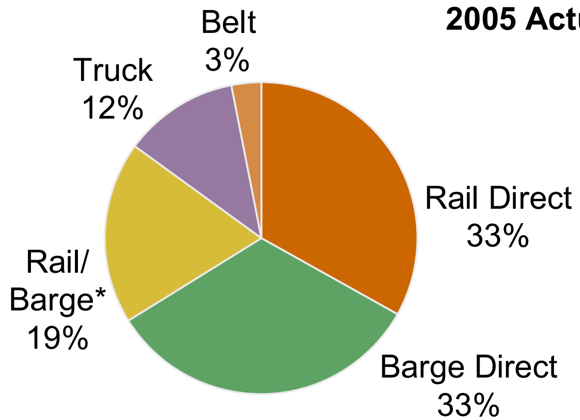
Total AEP System

2005 Actual



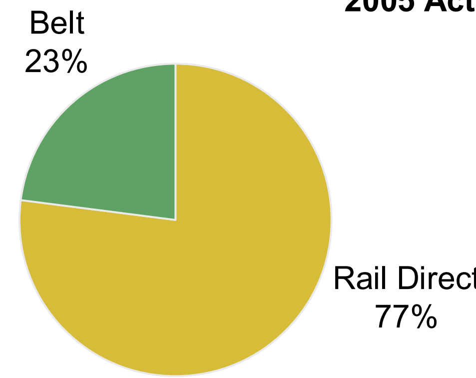
AEP East

2005 Actual



AEP West

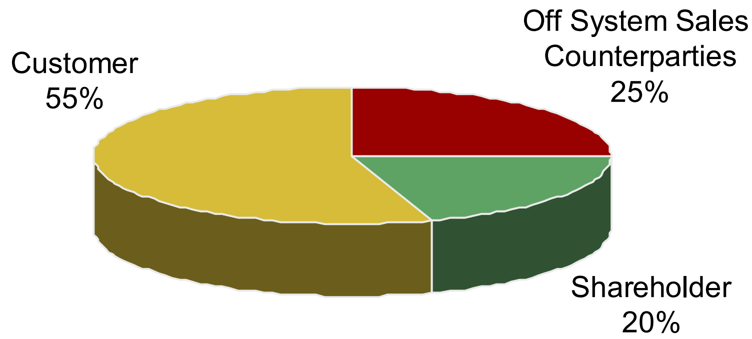
2005 Actual



* Reflects coal delivered to AEP plants transported through combination of rail and barge

Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- **Fuel recovery varies by jurisdiction**
- **80% of fuel cost is recoverable across the AEP System**
- **Active Fuel Clause Jurisdictions:**
  - **AEP EAST: APCo, I&M, KPCo, KGP, WP**
  - **AEP WEST: PSO, SWEPCO**

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

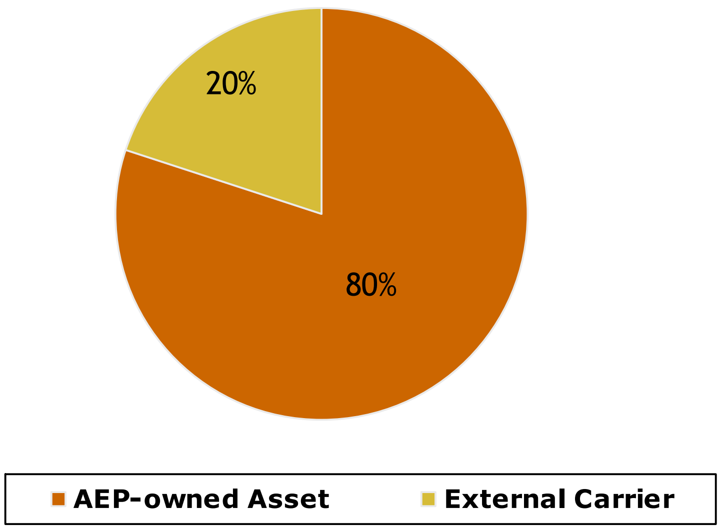
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Annually
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Semi-annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

New Generation

Fall EEI 2006

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of IGCC facilities dependent on regulatory approvals
- Certificates of Convenience and Necessity (CCN) applications filed in OH and WV and currently in process.

SWEPCO

- May 31, 2006- Announced plans to build $1.7 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling 320 MW at Tontitown, AR and combined-cycle gas plant totaling 480 MW at Arsenal Hill
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – expected SWEPCO investment will be approx. 75%
- Commercial operation dates between 2007 and 2011

PSO

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build a $1.8 billion 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

IGCC Overview

Fall EEI 2006

Integrated Gasification Combined Cycle

AEP IS COMMITTED TO IGCC TECHNOLOGY

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region.   AEP intends to seek regulatory recovery approvals in advance of building the plant.

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO_2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO_2 Capture ($/MWh)	94	87	137

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO_2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Regulatory Activity

Ohio IGCC Activity

March 18, 2005: CSP and OPCO filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant if built in Ohio.

October 2, 2006: Filed state environmental permit application with the Ohio Environmental Protection Agency

West Virginia IGCC Activity

January 11, 2006: Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

October 2, 2006: Filed state environmental permit application with the West Virginia Department of Environmental Protection

AEP WILL PIONEER CONSTRUCTION OF
FIRST COMMERCIAL SCALE IGCC PLANT IN THE WORLD

IGCC Activity in Ohio

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2012* (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2012* (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 filing – following completion of FEED study
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2012*:

- Design, construct and start-up plant

Construction of IGCC plant takes approximately 4 years from ground-breaking to start-up

***PROJECT TIMING DEPENDENT ON REGULATORY RECOVERY ASSURANCES**

IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMITTING PROCESS WILL TAKE 1 – 2 YEARS

Environmental Overview

Fall EEI 2006

Environmental – Multi-Emissions Reductions

Multi-Emissions Regulations: During the course of 2005, EPA finalized two rules: the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules require SO_2, NOx and Hg reductions in two phases: 2010 (2009 for NOx) and 2015 (2018 for Hg), also utilizing an emissions trading program. AEP is already well on the way towards compliance with these provisions with a substantial number of scrubber and SCR installations recently completed or underway.

While the industry and AEP are generally supportive of these regulations, they do not provide the same degree of regulatory certainty and eliminate unnecessary provisions or modify the Clean Air Act to the same degree as new Clear Skies legislation would have provided. However, passage of comprehensive Clear Skies legislation is not likely.

In July 2005, EPA finalized a third rule: the Clean Air Visibility Rule (CAVR), which addresses the implementation of emission controls for SO_2 and NOx to deal with regional haze in Class I areas (e.g. national parks, forests and other pristine areas). CAVR requires Best Available Retrofit Technology (BART) – defined as scrubbers and meeting low NOx emission rates -- to be required and ultimately installed at those affected facilities. The EPA is urging states that are part of the CAIR region (most of the states except for the Western US) to adopt the CAIR rule as compliant with CAVR (thus not requiring BART at power plants within that state). However, in the other non-CAIR states (i.e. The West and Southwestern US), most of the currently unscrubbed coal-fired plants will probably be required to install scrubbers and meet lower NOx limits.

Finally, in September 2006 EPA issued a final rule on PM (i.e. particulate matter), which tightened the PM-2.5 (i.e. fine particle) 24-hour standard, while retaining the current annual standard for PM-2.5. Precursors of fine particulates include SO_2, NOx and a variety of carbonaceous compounds. Though CAIR is expected to lead to increasing compliance with these new and existing standards, it is uncertain whether or not EPA will decide to reduce the utility SO_2 and/or the NOx emission limits further as part of a regional strategy in the longer term for compliance.

Environmental – Multi-Emissions Reductions

Greenhouse Gas Policies: The President has committed the nation to reduce the greenhouse gas (GHG) intensity of the economy (GHG emissions per $ GDP) by 18% over the next ten years through voluntary programs, and called for an improved federal emissions reporting program for tracking progress toward this goal. Regional U.S. initiatives to reduce greenhouse gas emissions and specifically CO_2 emissions have also begun in states outside of AEP's service territory including the Northeastern States (i.e. the Regional Greenhouse Gas Initiative or RGGI) and the West Coast (specifically California). A number of federal legislative proposals have been introduced in Congress over the past couple of years, which if passed, would require mandatory US GHG reductions in the future.

AEP does not support mandatory U.S. greenhouse gas (GHG) requirements unless they are part of a new international agreement that limits GHGs in the long term among all our major trading partners including developing countries such as China and India. Nonetheless, AEP has had a GHG strategy for a number of years, acknowledging the issue, accepting the science and believing in early proactive action. Our strategy includes:

1) Being proactive in the development of greenhouse gas policy through our support and membership within a variety of organizations (e,g, EPRI, Pew Center, the Business Roundtable, e8, IETA);

2) Being a leader in the development of technology through our support of research, development and deployment of new clean coal technology such as IGCC, being a major investor in the Future Gen project (the first near zero emitting IGCC coal plant in the U.S.), and through research in carbon capture and sequestration from coal plants;

3) Taking voluntary action now through our participation in Chicago Climate Exchange (CCX) , EPA Climate Leaders and SF-6 Program, Asia-Pacific Efficiency, DOE1605B, and Business Roundtable (BRT) Climate Resolve program among other efforts. We are making voluntary GHG reductions through our participation in CCX and are currently ahead of our reduction commitments.

4) Long-term planning (post-2010) to reduce or limit GHGs through:

- IGCC and FutureGen
- Retirement of less efficient capacity
- Emission offsets (e.g., forestry, SF-6)
- Renewables (e.g. biomass co-firing, wind)

Environmental Glossary

Clean Air Scientific Advisory Committee (CASAC) - Created by the Clean Air Act amendments in 1977, this committee of independent experts on air pollution reports to the U.S. Environmental Protection Agency Administrator. The committee is charged with reviewing the scientific knowledge of air pollution and its effects, without regard to costs.

Micron - One millionth of a meter. For example, human hair is about 70 microns thick. $PM_{2.5}$ is approximately 1/30th the thickness of a human hair.

National Ambient Air Quality Standards (NAAQS) - Establish maximum allowable concentrations in outdoor air for six pollutants: particulate matter, ozone, sulfur dioxide, nitrogen oxide, carbon monoxide, and lead. The Clean Air Act requires EPA to review NAAQS every five years. EPA is required to set standards "to protect public health ...allowing an adequate margin of safety."

Ozone - Ozone is a form of oxygen which is a colorless gas with a unique odor. Ozone occurs naturally in the earth's upper atmosphere where it shields against ultraviolet radiation from the sun. In the lower atmosphere, ozone is formed by the combination of nitrogen oxides and hydrocarbons in the presence of sunlight. This ozone is a major component of smog. The current NAAQS for maximum allowable ozone is 0.12 parts per million measured over a one-hour period, with three exceedances over three years permitted.

Particulate Matter - Particles of matter suspended in the atmosphere. EPA currently regulates concentrations of particulate matter that are 10 microns and smaller in diameter. The current allowable maximum concentration of particulate matter is 150 micrograms (ug) per cubic meter averaged over 24 hours. The annual average of 24 hour readings is required to be less than 50 ug/m^3.

PM_{10} - Particulate matter that is 10 microns or less in diameter.

$PM1_{2.5}$ - Particulate matter that is 2.5 microns or less in size.

Primary Particles - This is particle matter that is emitted directly into the atmosphere, including dust from construction, farming and roads, volcanic ash, sea salt, tire and brake dust, diesel soot and wood smoke. Primary particles are the dominant form of particulate matter in the West and arid Southwest. Primary particles tend to settle out of the atmosphere in a relatively short time.

Secondary Particles - These particles are formed when gases, such as sulfur oxides, nitrogen oxides and volatile organic carbon, react in the atmosphere to form solid or liquid particles of sulfates, nitrates and organic carbon particles. These particles are generally 2.5 microns and smaller in size. Secondary particles dominate in the eastern United States. Secondary particles tend to remain suspended in the atmosphere and can be transported over long distances by prevailing winds.

Precursor - The forerunners that lead to the formation of a pollutant. The precursors of ozone are nitrogen oxides and hydrocarbons, which combine in the presence of sunlight to form ozone. The precursors of fine particular matter are sulfur oxides, nitrogen oxides and volatile organic compounds which combine with ammonia in the atmosphere to form sulfate and nitrate particles.

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR was designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003-level emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

Clean Air Mercury Rule

- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTION AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Environmental Project Status Report

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 45% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 48% WILL BE SCRUBBED (FGD).

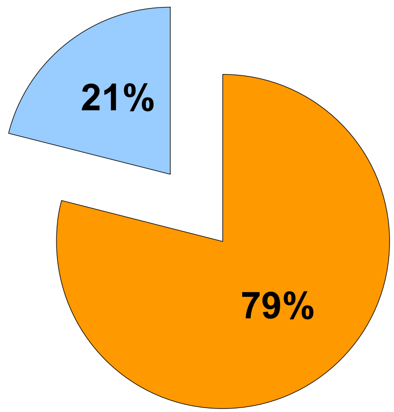
Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008-09
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1 & 2	1600	✓	Projected 2007	✓	Projected 2007
Mountaineer	1320	✓	In-service	✓	Projected 2007
Big Sandy 2	800	✓	In-service		Delayed
Conesville 5 & 6	750		N/A	✓	In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2007
Muskingum River 5	585	✓	In-service		Delayed
Pirkey	580		N/A	✓	In-service
Oklaunion	539*		N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262		N/A	✓	In-service

AEP's Total Coal Fleet Capacity = 25,746 MW

* Oklaunion's MW capacity represents combination of PSO, TCC & TNC ownership. TCC's 54 MW ownership of Oklaunion is currently under negotiation for sale.

Materials and Vendors – AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Actuals To Date & Firm Costs
Estimated Cost Exposure*

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

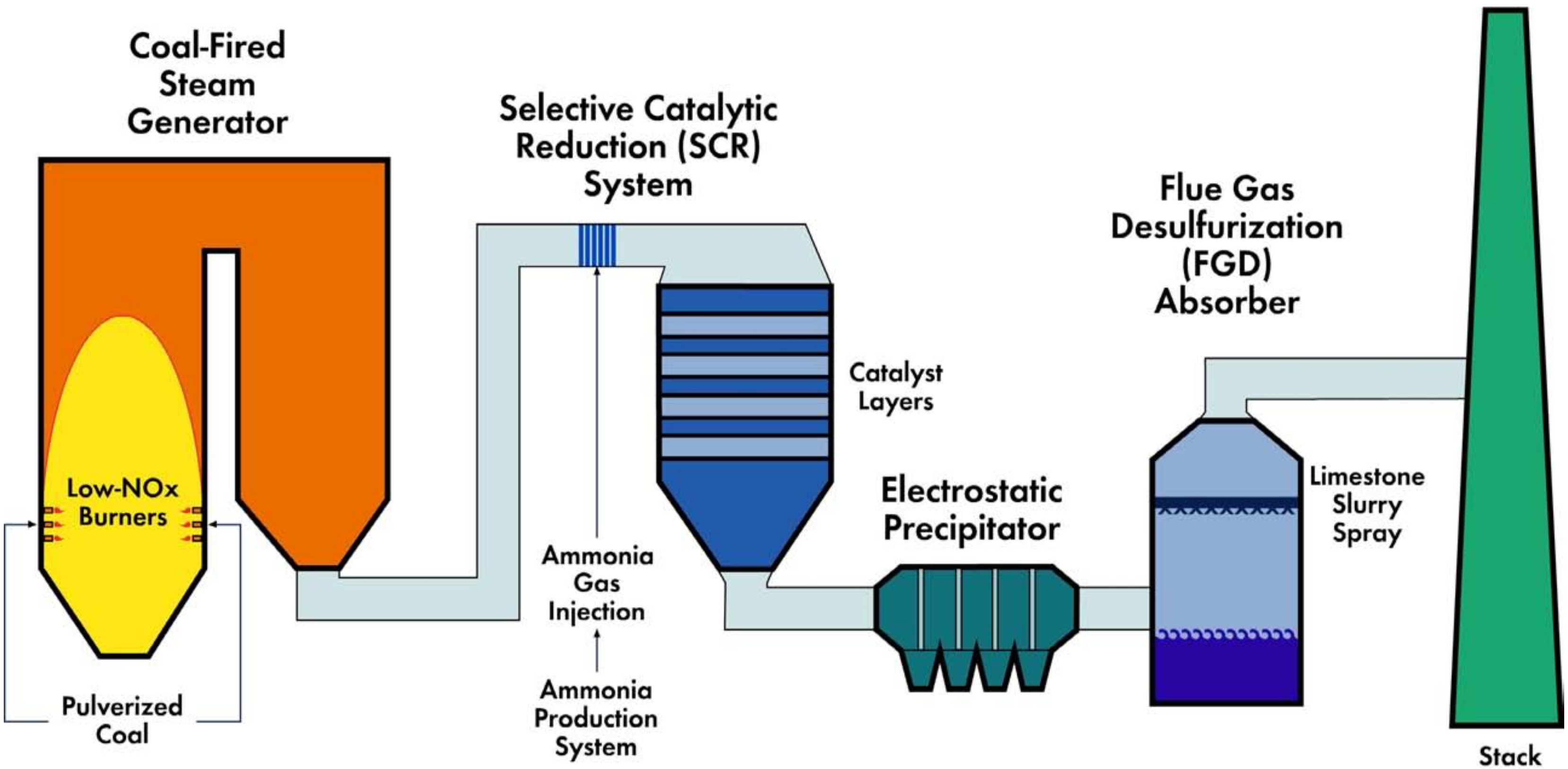
Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP BENEFITS FROM FIRST-MOVER ADVANTAGE THROUGH LOWER CONTRACTED PRICES COMPARED TO INDUSTRY

The Flue Gas Stream



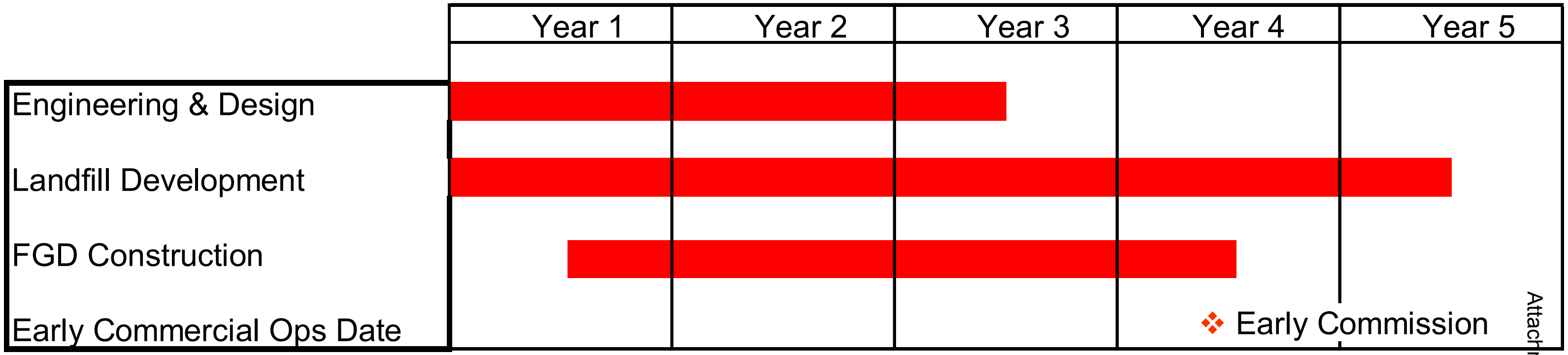
Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.
- Plant modifications increasing unit MW ratings are being implemented as part of the retrofit program
  - For example, Mountaineer turbine valve upgrades will increase unit output by ~30 - 45 MW
  - Similar upgrades will be implemented on other units

PLANT MODIFICATIONS WILL MITIGATE FGD AND SCR CAPACITY CONSUMPTION

Typical FGD Project Milestone Schedule

- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, Phase 3 Bid Construction at 30 – 60% design complete
- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path



Energy Delivery

Fall EEI 2006

Transmission Detail

Transmission Plant Detail By Operating Company

As of September 30, 2006
(in millions)

	Transmission Plant Original Cost	Accum. D&A	Net Transmission Plant
RFC (formerly ECAR)			
AEP Generating Co.	$ -	$ -	$ -
Appalachian Power Co.	1,596	510	1,086
Columbus Southern Power Co.	479	200	279
Indiana Michigan Power Co.	1,042	418	624
Kentucky Power Co.	392	124	268
Ohio Power Co.	1,016	418	598
All other non-registrants	40	26	14
ERCOT			
AEP Texas Central Co.	901	208	693
AEP Texas North Co.	325	139	186
SPP			
Public Service Co. of Oklahoma	499	158	341
Southwestern Electric Power Co.	662	268	394
TOTAL	$ 6,952	$ 2,469	$ 4,483

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
APCo	734	97	383	106	0	3,288	0	43	1,077	792	0	230	0	**6,750**
CSP	0	0	884	0	0	887	0	0	463	0	59	0	113	**2,406**
I&M	615	0	1,614	0	0	1,664	0	0	704	0	0	743.269	0	**5,341**
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	**30**
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
OPCo	509	0	909	0	0	2,463	0	0	2,167	0	0	366.12	112	**6,526**
PSO	0	0	579	34	8	2,123	10	0	812	0	0	0	0	**3,566**
SWEPCo	0	0	660	0	228	1,171	42	0	1,402	0	0	0	0	**3,503**
TCC	0	0	641	0	0	2,610	0	0	1,740	0	0	0	0	**4,991**
TNC	0	0	222	0	0	1,586	14	0	2,699	0	0	0	0	**4,521**
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	**288**
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**43**	**11,701**	**847**	**59**	**1,369**	**225**	**39,158**

State Level (Circuit Miles)

State	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
Arkansas	0	0	28	0	228	168	42	0	461	0	0	0	0	**927**
Indiana	599	0	1,380	0	0	1,425	0	0	405	0	0	595	0	**4,405**
Kentucky	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
Louisiana	0	0	105	0	0	245	0	0	230	0	0	0	0	**580**
Michigan	16	0	234	0	0	239	0	0	299	0	0	148	0	**936**
Ohio	509	0	1,793	0	0	3,350	0	0	2,631	0	59	366	225	**8,933**
Oklahoma	0	0	625	34	8	2,148	10	0	812	0	0	0	0	**3,638**
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	**275**
Texas	0	0	1,343	0	0	4,929	14	0	5,151	0	0	0	0	**11,436**
W. Virginia	384	17	323	0	0	1,601	0	43	456	744	0	89	0	**3,657**
Virginia	350	96	69	15	0	1,708	0	0	709	48	0	141	0	**3,136**
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**43**	**11,701**	**847**	**59**	**1,369**	**225**	**39,158**

Note: Transmission line circuit miles are current as of 12/31/05, with the exception of line mile additions for the Wyoming-Jacksons Ferry line (APCo) and the Monongahela Power assets (CSP).

Distribution Line Detail

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

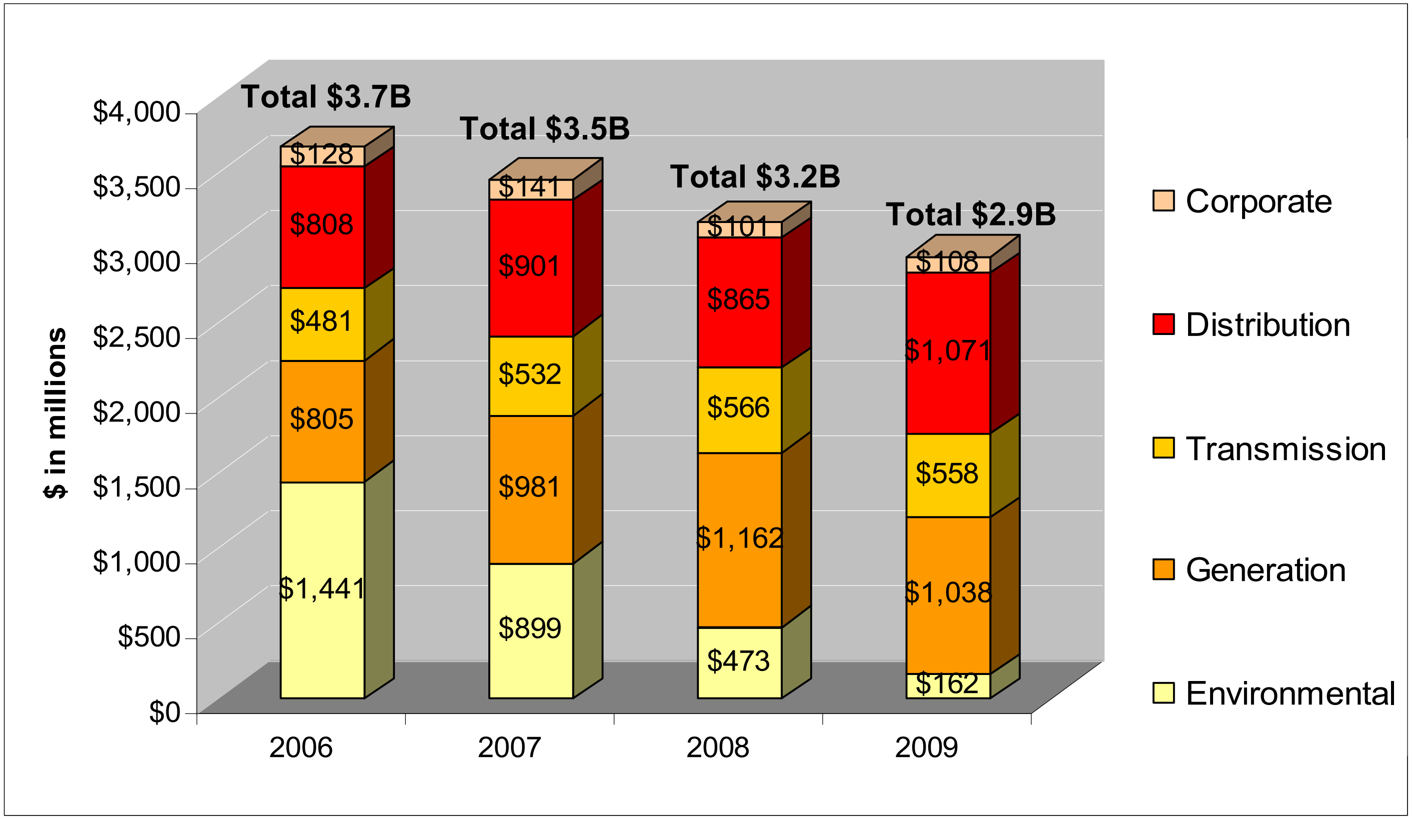
* Includes approximately 26,000 of underground circuit miles

Financial Update

- Capital Investment Forecast
- Earnings Guidance
- Capitalization
- Liquidity Position
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Fall EEI 2006

Multi-Year Capital Investment Forecast



Note: Excludes AFUDC

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1104 of 9556

Forecasted Capital Expenditures

($ IN THOUSANDS)

Company	2006	2007	2008	2009
AEP System*	**$ 3,663,000**	**$ 3,454,000**	**$ 3,167,000**	**$ 2,937,000**
APCo	$ 928,000	$ 780,000	$ 559,000	$ 455,000
CSPCo	$ 319,000	$ 367,000	$ 523,000	$ 251,000
I&M	$ 330,000	$ 267,000	$ 273,000	$ 365,000
KPCo	$ 54,000	$ 72,000	$ 104,000	$ 96,000
OPCo	$ 1,065,000	$ 746,000	$ 322,000	$ 391,000
PSO	$ 262,000	$ 311,000	$ 331,000	$ 440,000
SWEPCo	$ 315,000	$ 480,000	$ 565,000	$ 535,000
TCC	$ 286,000	$ 249,000	$ 236,000	$ 239,000
TNC	$ 72,000	$ 116,000	$ 173,000	$ 84,000

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2005	2006	2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (2,499)	$ (3,663)	$ (3,454)	$ (3,167)	$ (2,937)
Dividend on Common	$ (553)	$ (591)	$ (618)	$ (621)	$ (624)
Cash Sources					
Cash from Operations *	$ 1,877	$ 1,890	$ 2,232	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 1,246	$ 175	$ -	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ (25)	$ 45	$ 80	$ 80	$ 80
Change in Debt, Net	$ (91)	$ 661	$ 1,738	$ 1,176	$ 967
TCC securitization bond issuance	$ -	$ 1,740			
Other	$ 126	$ (268)	$ (95)	$ (67)	$ (69)
Cash Sources Less Capital Expenditures, Dividends & Other	$ 81	$ (11)	$ (117)	$ 43	$ 88
Ending Cash Balance	$ 401	$ 390	$ 273	$ 316	$ 404

Projected 2006-2009 Credit Metric Ranges

Debt to book capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Framework for Long-Range Performance

- **Introduction of 2007, 2008 & 2009 Earnings Guidance Ranges:**

2007 Range $2.85 to $3.05	2008 Range $3.00 to $3.30	2009 Range $3.15 to $3.45

- **Increased EPS Growth Range: 5-7% (2006-2009)**
  - Continued disciplined investment in utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
    - AEP Transmission Company
  - Seek rate recovery for new investments
  - Control costs
- **8-cent per share increase in annual dividend effective 4Q06**
- **Maintain credit ratings**
  - BBB/Baa2/BBB

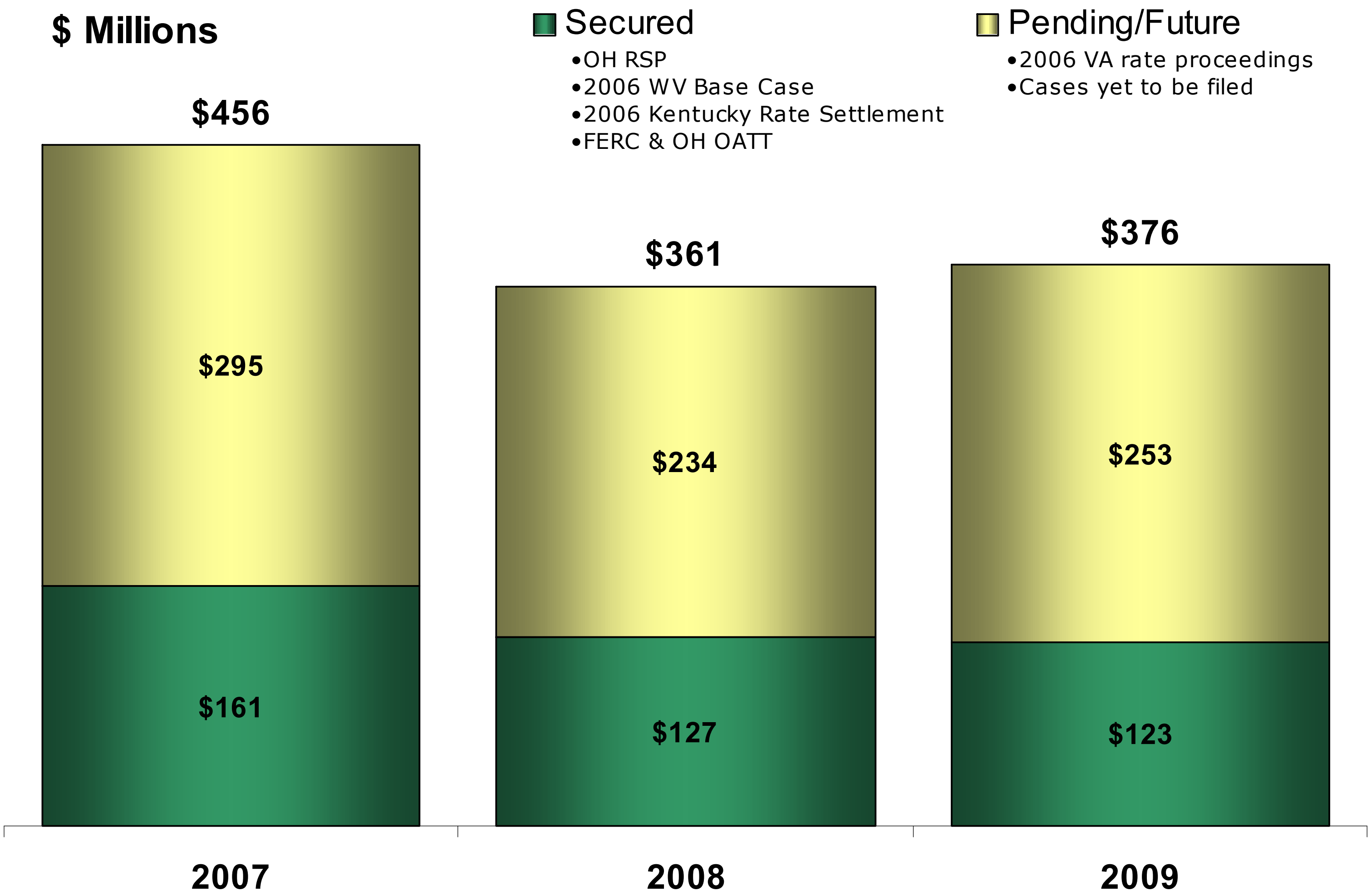
OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Summary of 5-7% Long-Range Growth Components

- **Energy sales growth of 1.5%**
  - Predicated on AEP's ability to economically dispatch at a high load capacity
- **Rate base investment**
  - Generation Plant Purchases & Build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- **Transmission company**
- **Commercial operations**
- **Regulatory strategy**
  - Achieve high returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

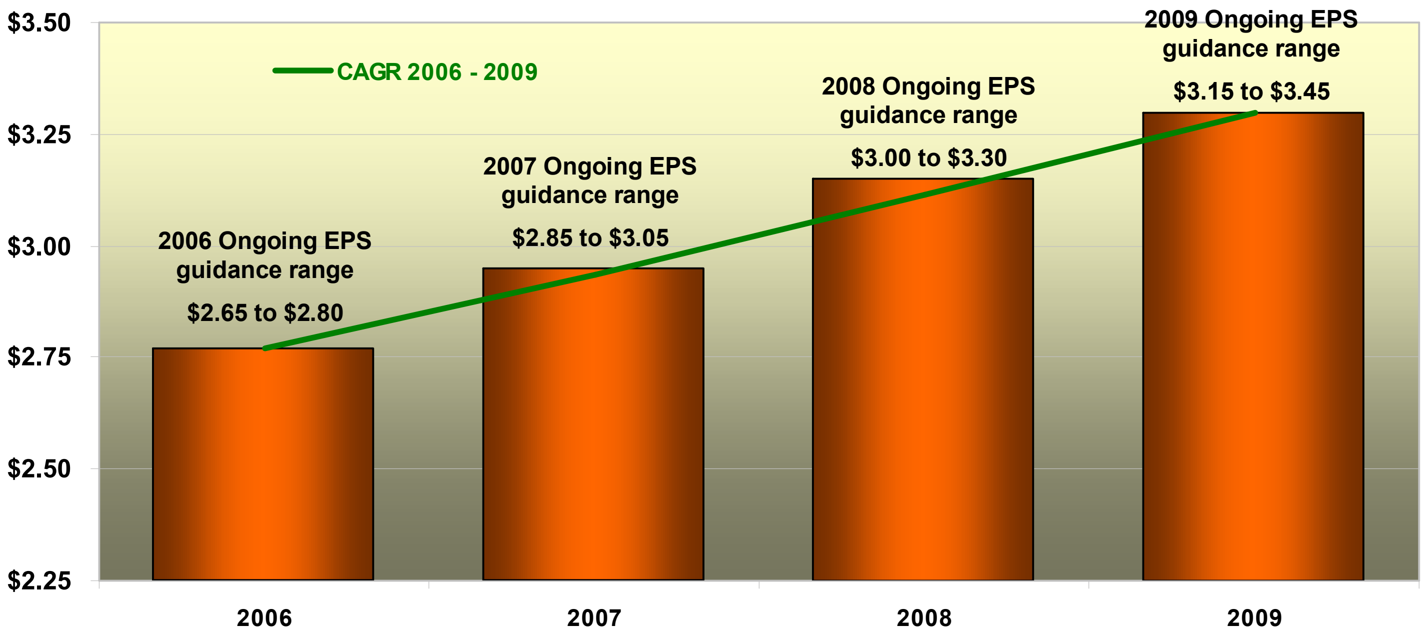
RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Incremental Rate Relief Composition



RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Long-Range EPS Expectations



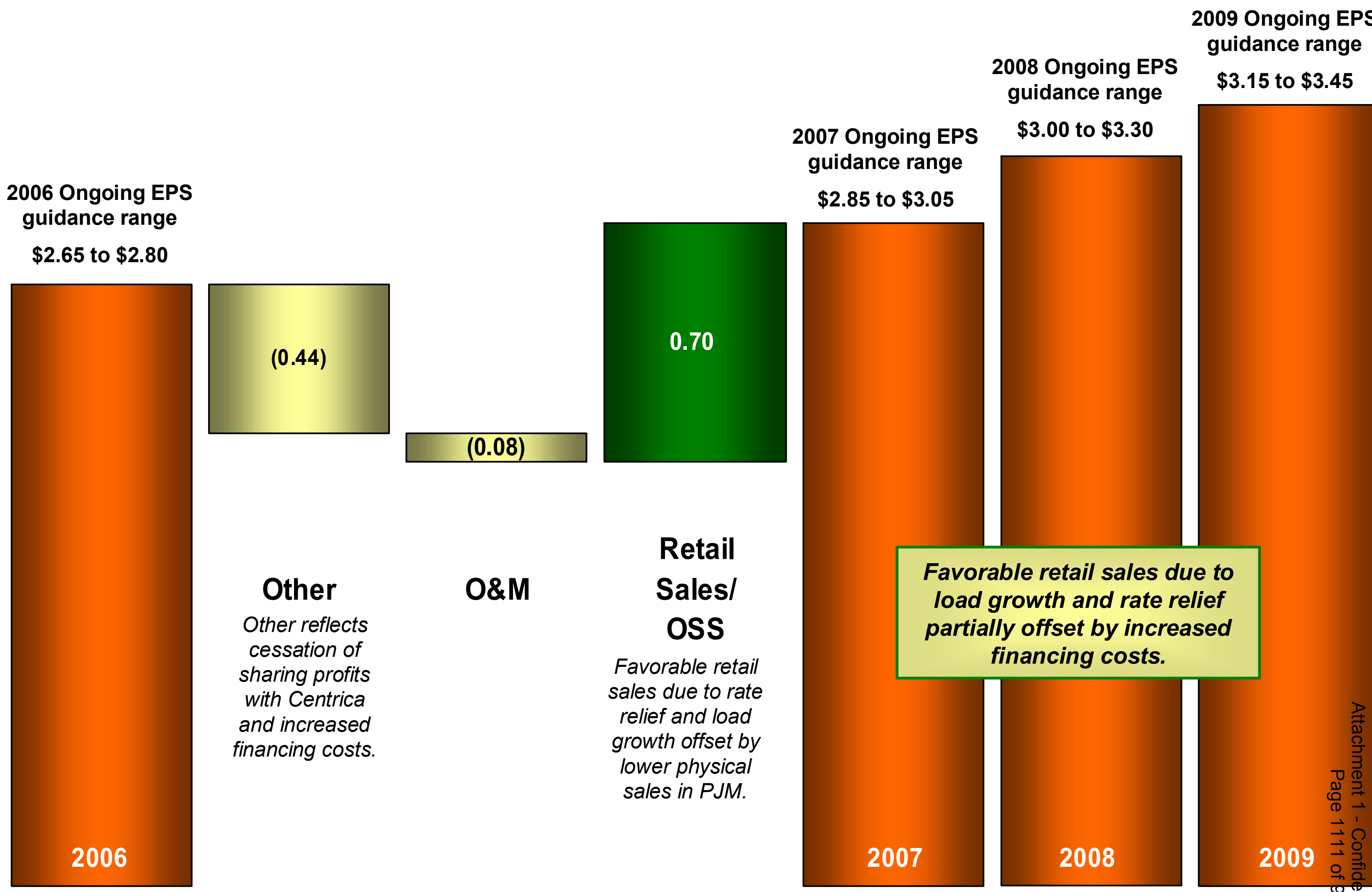
Long-Range Plan Highlights

- Committed to a 5-7% earnings growth range (2006-2009)
- 8-cent per share increase in the annual dividend commencing 4Q2006
- Continue capital investment in utility business to support earnings growth
- Fund investment program with new rate relief and debt
  - No common equity issuance (except through Dividend Reinvestment Program)
- Create joint venture to build our transmission company

COMMITTED TO 5-7% EARNINGS GROWTH

Composition of Long-Range EPS Drivers

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS



Earnings Guidance

2006 Ongoing Guidance: $2.65 to $2.80 Per Share
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Estimate vs. 2007 Estimate

		Performance Driver	2006 Estimate ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,321 GWh @ $ 30.9 /MWhr =	2,141	71,033 GWh @ $ 33.7 /MWhr =	2,392
2	Ohio Companies	46,083 GWh @ $ 46.6 /MWhr =	2,147	47,902 GWh @ $ 49.5 /MWhr =	2,371
3	West Regulated Integrated Utilities	41,264 GWh @ $ 24.9 /MWhr =	1,026	40,795 GWh @ $ 25.9 /MWhr =	1,058
4	Texas Wires	26,506 GWh @ $ 14.4 /MWhr =	383	26,834 GWh @ $ 16.4 /MWhr =	441
5	Off-System Sales	35,100 GWh @ $ 23.1 /MWhr =	811	30,742 GWh @ $ 21.9 /MWhr =	672
6	Transmission Revenue - 3rd Party		282		255
7	Other Operating Revenue		579		715
8	Utility Gross Margin		7,369		7,904
9	Operations & Maintenance		(3,241)		(3,292)
10	Depreciation & Amortization		(1,316)		(1,413)
11	Taxes Other than Income Taxes		(747)		(785)
12	Interest Exp & Preferred Dividend		(664)		(813)
13	Other Income & Deductions		199		91
14	Income Taxes		(551)		(567)
15	Utility Operations On-Going Earnings		1,049		1,125
16	Investments On-Going Earnings		45		48
17	Parent Company On-Going Earnings		(1)		(6)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

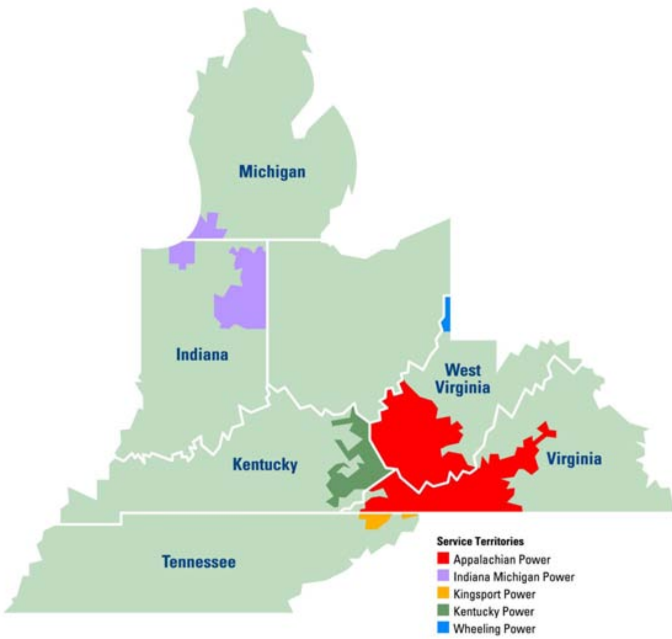
Summary of 2007 Earnings Guidance

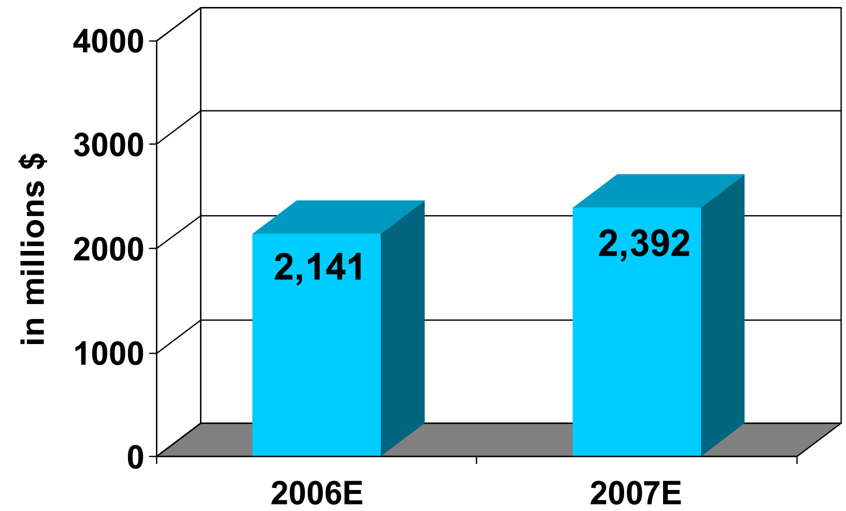
- Load growth of 1.5%
- Rate relief of $456MM ($161MM already secured)
- Improved performance at Investments
- Rising fuel costs of 6-8%
- Increased retail load & higher muni/co-op sales to impact off system sales contribution
- Higher financing costs
- Higher O&M (inflationary pressures)
- Lower contribution from Centrica sharing agreement

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS

Utility Operations

East Regulated Integrated Companies



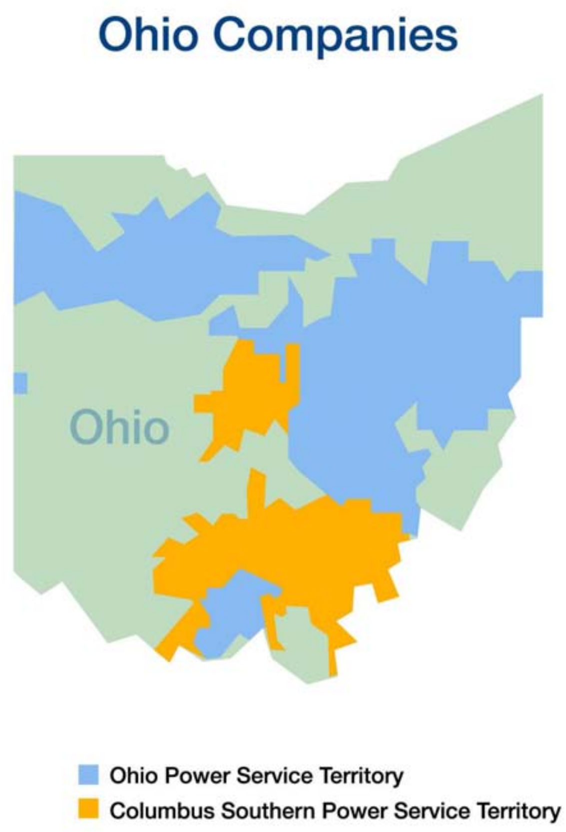


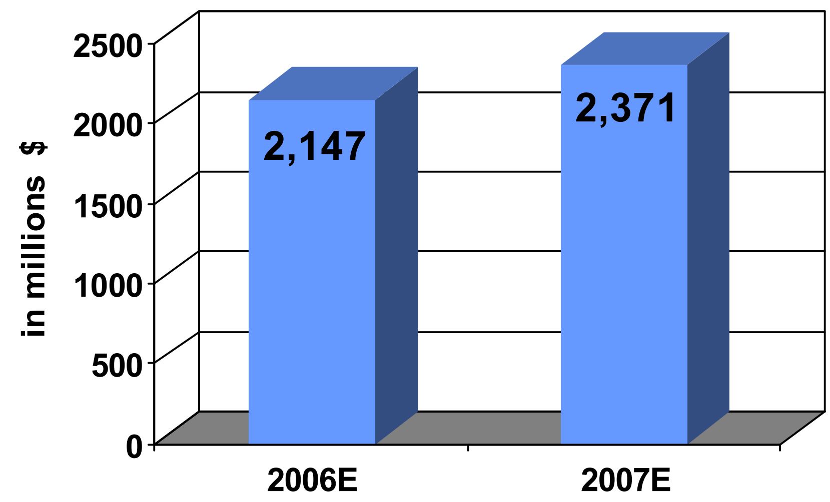
Earnings Drivers (in millions $)

Load Growth & Normal Weather	78
Rate Changes	175
Fuel Clause Activations	36
Capacity Settlement	(24)
Other	(14)
	251

$251 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations





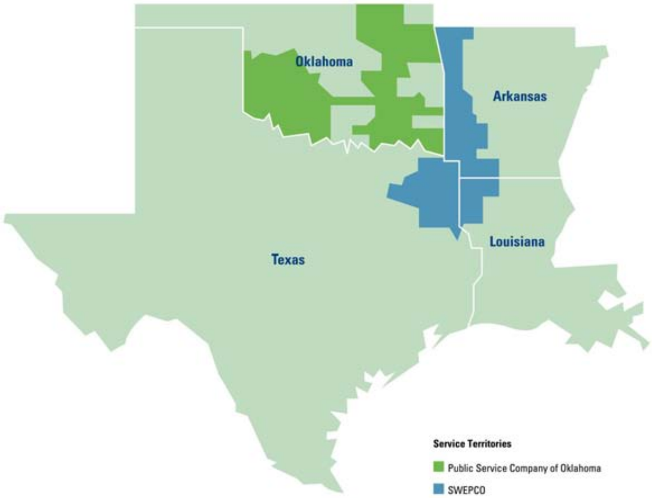
Earnings Drivers (in millions $)

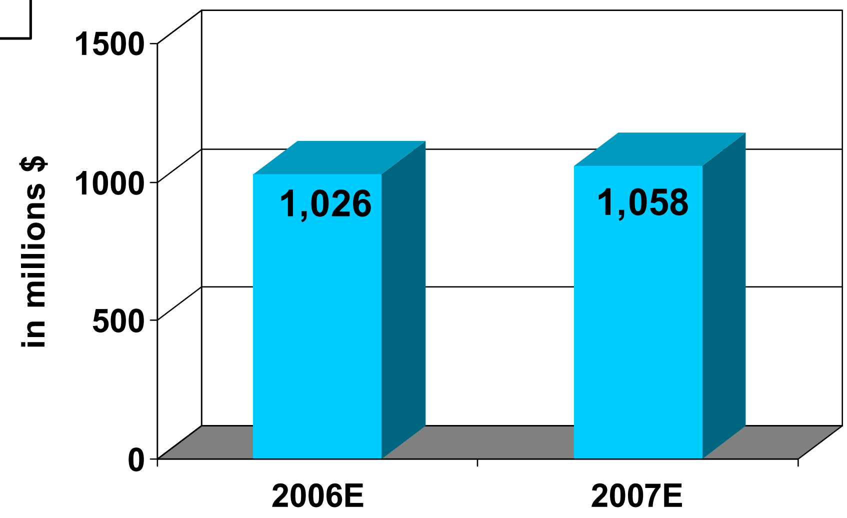
Load Growth & Normal Weather	94
Rate Relief	120
Fuel Costs	(13)
Capacity Settlement	24
Other	(1)
	224

$224 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations

West Integrated Companies





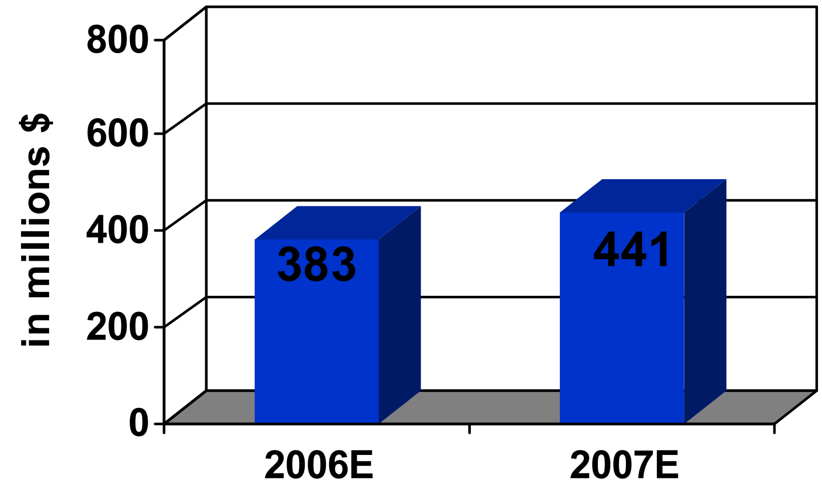
Earnings Drivers (in millions $)

Load Growth & Normal Weather	(22)
Rate Changes	38
Other	16
	32

$32 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations

Texas Wires

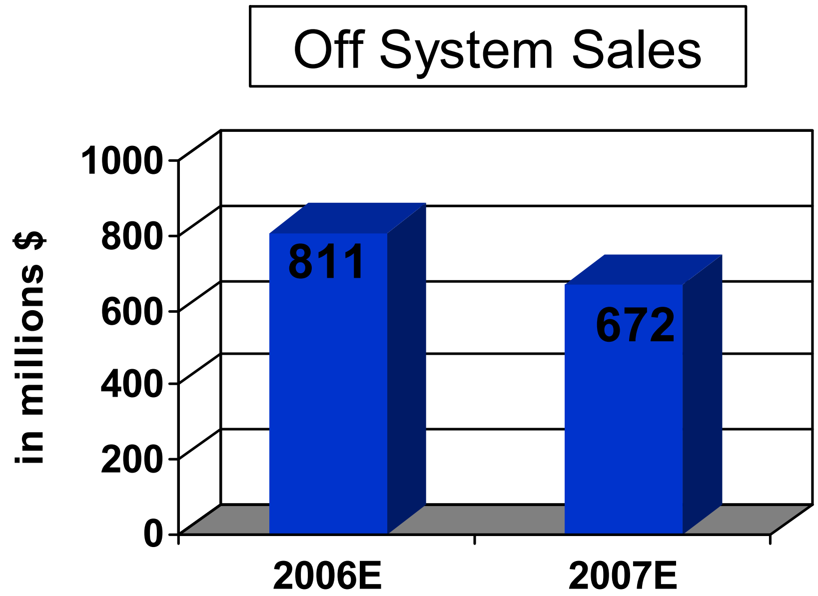


Earnings Drivers (in millions $)

Load Growth & Normal Weather	7
Rate changes	59
Other	(8)
	58

$58MM INCREASE IN GROSS MARGIN FOR 2007

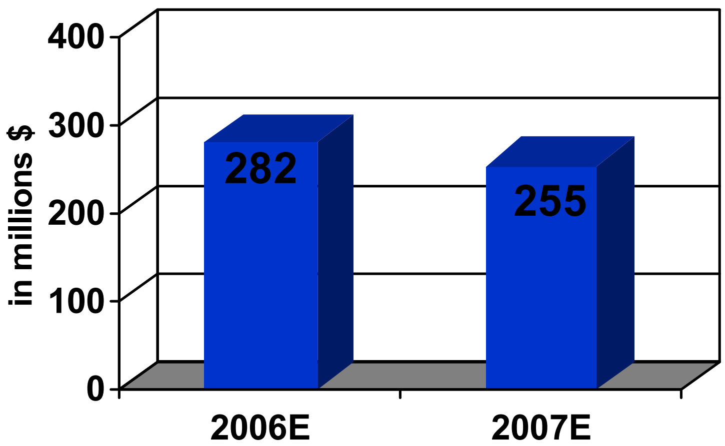
Utility Operations



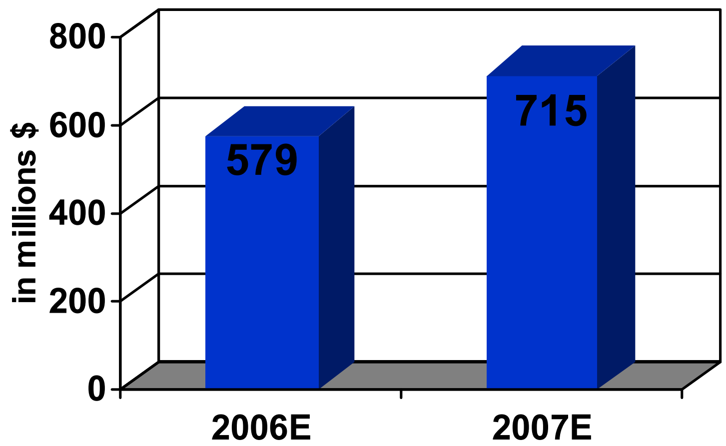
DECLINE IN OFF SYSTEM SALES GROSS MARGIN DRIVEN BY INCREASED RETAIL LOAD AND GROWING MUNI/CO-OP SALES CAPTURED ON LINES 1-3

Utility Operations

Transmission Revenues – 3rd Party



Other Operating Revenue



Earnings Drivers (in millions $)

PJM	(36)
ERCOT	11
SPP	(2)
	(27)

$27MM REDUCTION

Earnings Drivers (in millions $)

TX Securitization Revenue	114
Other	22
	136

$136MM INCREASE

Utility Operations

Expense Drivers

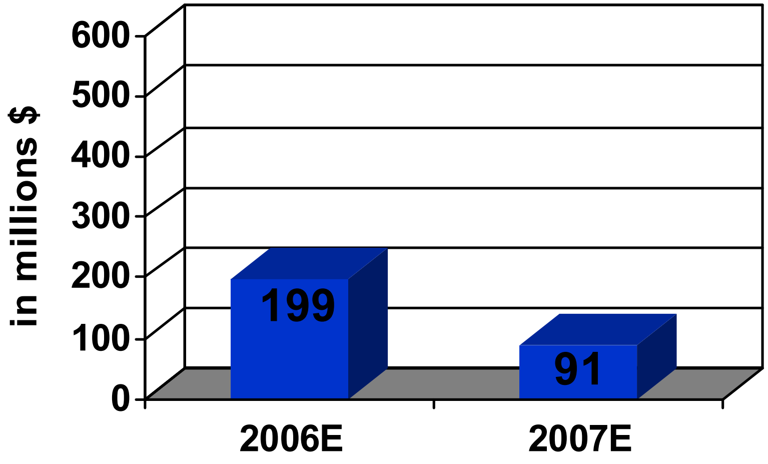
Operations & Maintenance	**(51)**	$51MM increase
Depreciation & Amortization		
Plant additions	(103)	
Change in depreciation rates	85	$97 MM increase
Amortizations (primarily TCC Securitization*)	(79)	
	(97)	
Taxes		
Taxes Other than Income Taxes	(38)	$54MM increase
Change in Pre-Tax Income	(16)	
	(54)	
Interest Expense & Pref. Dividends		
Securitized Debt*	(65)	$149MM increase
Debt (net increase)	(84)	
	(149)	
Total	**(351)**	

* TCC amortization and interest expenses associated with $1.7 billion securitization bond issuance in October are fully offset by higher revenues.

UTILITY OPERATIONS EXPENSES TO RISE $351MM IN 2007

Utility Operations

Other Income & Deductions

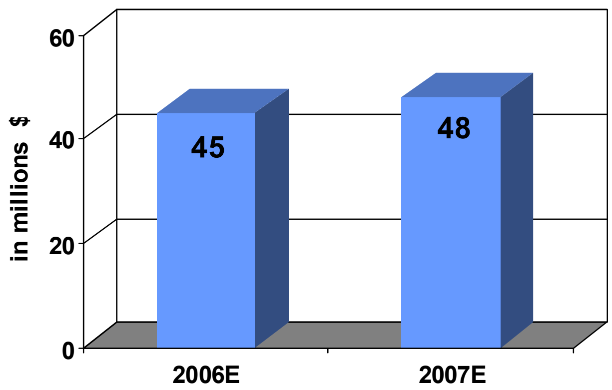


Earnings Drivers (in millions $)	
Centrica Sharing	(50)
TX Carrying Charges	(49)
Other	(9)
	(108)

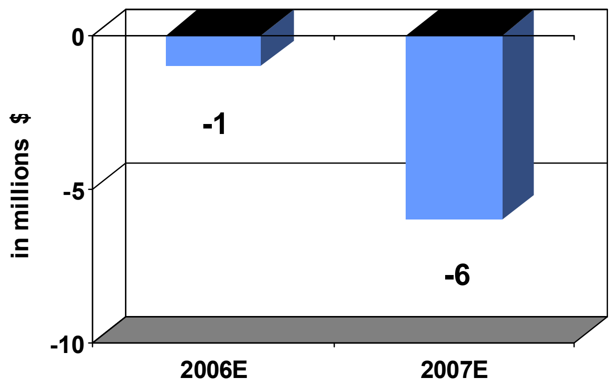
$108MM REDUCTION IN GROSS MARGIN FOR 2007

Investments & Parent Company

Investments



Parent Company



Investment Drivers:

- Slightly lower results from MEMCO
- Elimination of Dow somewhat offset by replacement debt

Parent Company Drivers:

- Increased borrowing at the Parent company

COMBINED PERFORMANCE FLAT YEAR-OVER-YEAR

Capitalization

Capital Structure	Actual 12/31/2005			Actual 9/30/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,763	-	12,763
Short-term Debt	10	-	10	23	-	23
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,524	9,524
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,786**	**9,585**	**22,371**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(21)	-	(21)
Off-balance Sheet Leases	1,213	-	1,213	1,199	-	1,199
Securitization Bonds	(648)	-	(648)	(596)	-	(596)
Spent Nuclear Fuel Trust	(228)	-	(228)	(244)	-	(244)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,694**	**13,154**	**9,555**	**22,709**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.9%***	***42.1%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.9% AS OF 9/30/06

Liquidity

Liquidity Summary	Actual 9/30/06	
($ in millions)	**Amount**	**Maturity**
5-Year Revolving Credit Facility	1,500	Mar-10
5-Year Revolving Credit Facility	1,500	May-11
Total Credit Facilities	**3,000**	
Plus		
Total Cash & Cash Equivalents	**259**	
Less		
Commercial Paper Outstanding	-	
Amount Drawn on Bank Loans	-	
Letters of Credit Issued	34	
Net Available Liquidity	**3,225**	

AEP'S LIQUIDITY POSITION STANDS AT $3.2 BILLION

2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
APCO	$780	$550 - $650 *	42-45%
CSP	$367	$0 - $50	44-46%
I&M	$267	$50	40-42% (b)
KPCo	$72	$300 - $400	42-44%
OPCo	$746	$350 - $450	44-46%
PSO	$311	$200 - $300	45-48%
SWEPCo	$480	$300 - $600	44-46%
TCC (c)	$249	$0	40%
TNC	$116	$150 - $250	40%

(a) Includes tax-exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

AEP Credit Ratings

Company	S&P			
	Business Profile	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	5	BBB	NR	S
AEP, Inc. Short Term Rating	N/A	A2	NR	S
AEP Texas Central Company	3	BBB	BBB	S
AEP Texas North Company	3	BBB	BBB	S
Appalachian Power Company	5	BBB	BBB	S
Columbus Southern Power Company	4	BBB	NR	S
Indiana Michigan Power Company	6	BBB	NR	S
Kentucky Power Company	5	BBB	NR	S
Ohio Power Company	4	BBB	NR	S
Public Service Company of Oklahoma	5	BBB	A-	S
Southwestern Electric Power Company	5	BBB	A-	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Company	Moody's		
	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc.	Baa2	NR	S
AEP, Inc. Short Term Rating	P2	NR	S
AEP Texas Central Company	Baa2	Baa1	S
AEP Texas North Company	Baa1	A3	S
Appalachian Power Company	Baa2	Baa1	S
Columbus Southern Power Company	A3	NR	S
Indiana Michigan Power Company	Baa2	NR	S
Kentucky Power Company	Baa2	NR	S
Ohio Power Company	A3	NR	S
Public Service Company of Oklahoma	Baa1	A3	S
Southwestern Electric Power Company	Baa1	A3	S

Company	Fitch		
	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc.	BBB	NR	S
AEP, Inc. Short Term Rating	F2	NR	S
AEP Texas Central Company	A-	A	S
AEP Texas North Company [2]	A-	A	N
Appalachian Power Company	BBB+	A-	S
Columbus Southern Power Company	A-	NR	S
Indiana Michigan Power Company	BBB	NR	S
Kentucky Power Company	BBB	NR	S
Ohio Power Company	BBB+	NR	S
Public Service Company of Oklahoma	A-	A	S
Southwestern Electric Power Company	A-	A	S

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

Long-term Debt Maturity Profile

Year	2006[1]	2007	2008
AEP Service Corp.	$ -	$ -	$ 38,000,000
AEP, Inc.	$ -	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Ohio Power Company	$ -	$ -	$ 46,005,488
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 6,070,000	$ 97,000,000	$ -
Texas Central Company	$ -	$ -	$ -
Texas North Company	$ -	$ 8,151,000	$ -
Total	$ 306,070,000	$ 1,115,615,000	$ 476,005,488

(1) Maturities remaining as of September 30, 2006

Debt Schedules

American Electric Power Service Corp	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.134%		$1,077,775,000

AEP Generating	Interest	Maturity	Amount
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Weighted Average or Total	4.150%		$45,000,000

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
First Mortgage Bond (defeased)*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes**	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.882%		$1,064,339,800
Securitization Bond	5.010%	01/15/2008	$81,649,042
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.851%		$595,526,896
Securitization Bond	4.980%	01/01/2010	$217,000,000
Securitization Bond	4.980%	07/01/2013	$341,000,000
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.136%		$1,739,700,000

** TCC's first mortgage bonds were defeased in May, 2004.*

*** TCC announced that its 5.50% Senior Notes due Feb. 15, 2013 will be redeemed on Nov. 13, 2006.*

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06, with the exception of $1,739,700,000 of securitization bonds issued on October 11, 2006.

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Debt Schedules

AEP Texas North	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.242%		$2,530,038,400

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.809%		$1,104,245,000

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,535,700
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Weighted Average or Total	5.810%		$1,220,082,400

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$8,780,488
Notes Payable	6.270%	03/31/2009	$25,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,737,500
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	5.868%		$2,225,766,088

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	5.465%		$676,621,700

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

Debt Schedules

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	4.470%	04/23/2011	$21,642,978
Notes Payable	6.360%	02/22/2007	$7,000,000
Notes Payable	7.030%	02/22/2012	$22,250,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,769,000
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.545%		$691,399,278

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/06.

42nd EEI Financial Conference

2007 Fact Book

Orlando, FL

November 4-7, 2007

AEP AMERICAN ELECTRIC POWER®

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Company Overview

Fall EEI 2007

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Company Overview

OUR FOCUS IS OUR CORE

DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Company, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions	Electric Utility Subsidiaries
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

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Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Approximately 38,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 210,685 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,300 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 millions tons of capacity

We consume approximately 76 million tons of coal annually.

Company Strategy

Business Strategy

AEP's mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to grow our core utility business at a moderate and steady rate through major investment in our current utility business supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated transmission company for the pursuit of new major interstate projects. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. Our plan entails designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Our Focus

Deliver value to our investors

- **Prepare for transition to market in Ohio**
- **Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management**
- **Enhance cash flow & earnings through rate recovery mechanisms**
- **Take advantage of AEP's size to bring economic savings to our customers while continuing to enhance shareholder value through regulatory-supported investment and operational excellence**

AEP Service Territory

AEP EAST OPERATING COMPANIES

EAST REGULATED UTILITIES

Appalachian Power Company

Indiana Michigan Power Company

Kingsport Power Company

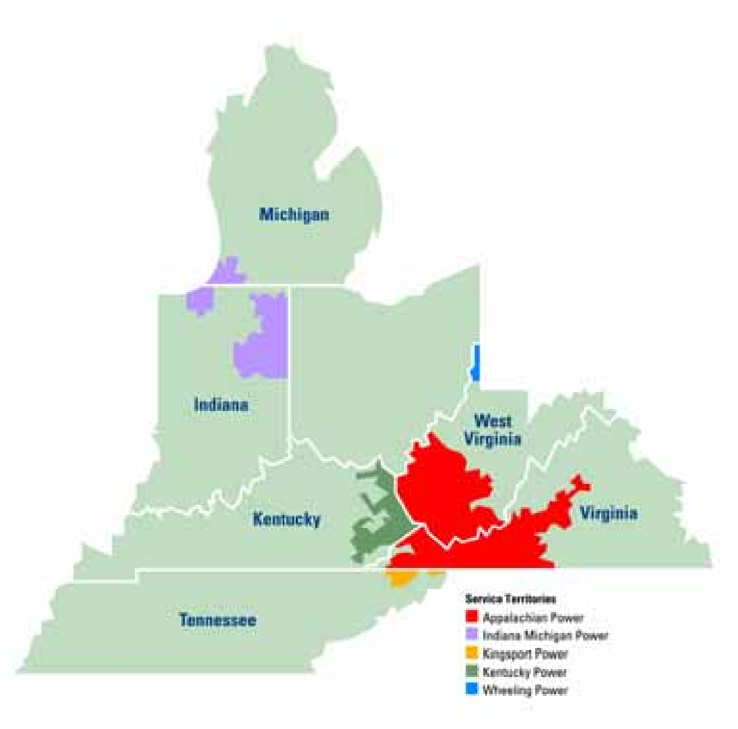
Kentucky Power Company

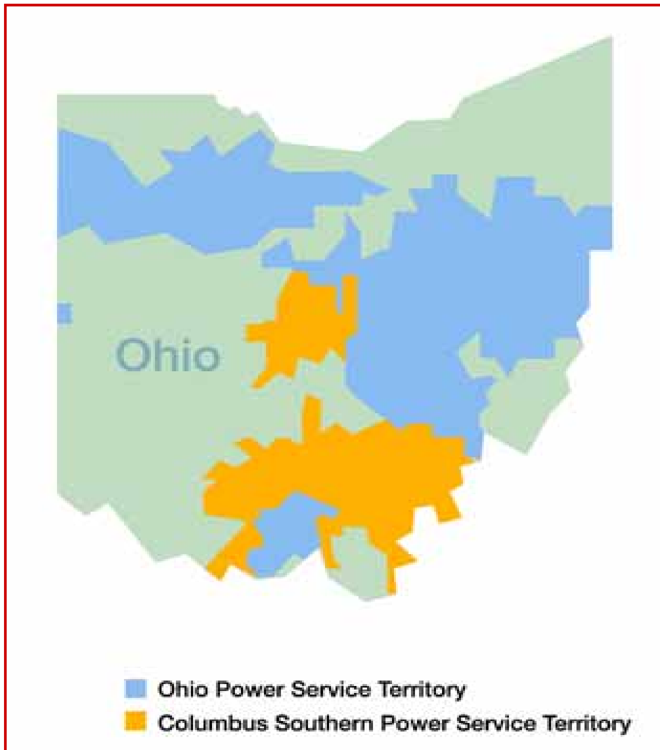
Wheeling Power Company

AEP OHIO

Columbus Southern Power Company

Ohio Power Company





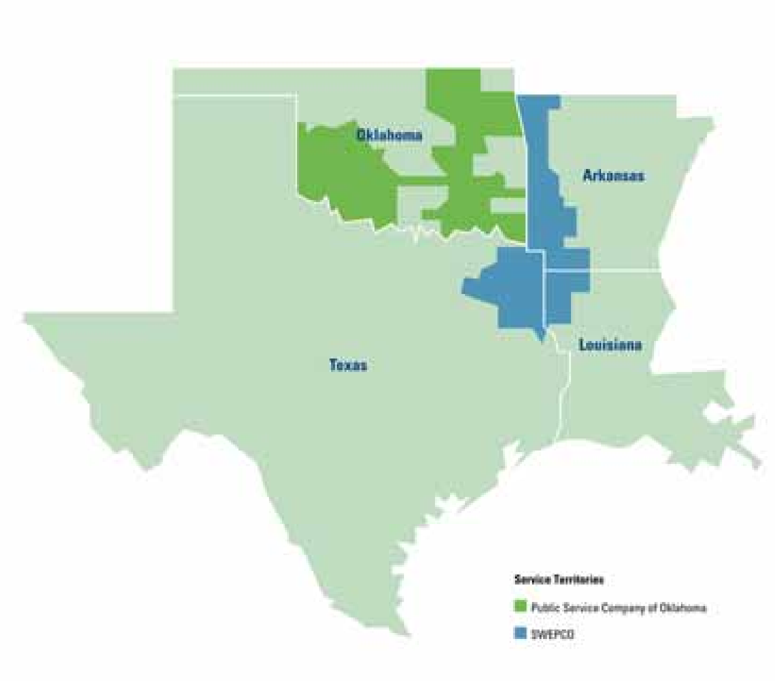
AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

Public Service Company of Oklahoma

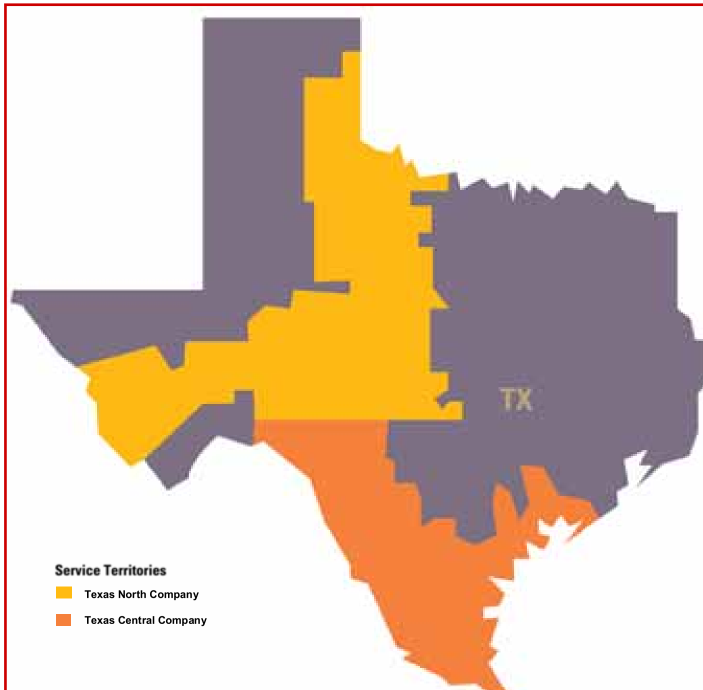
Southwestern Electric Power Company



AEP TEXAS

Texas Central Company

Texas North Company



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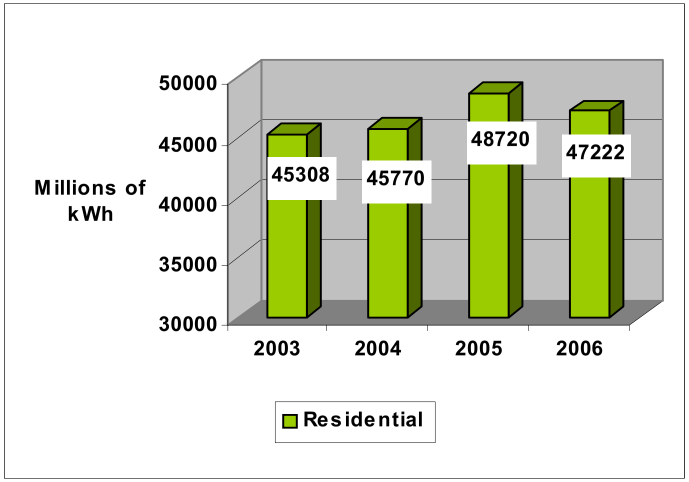
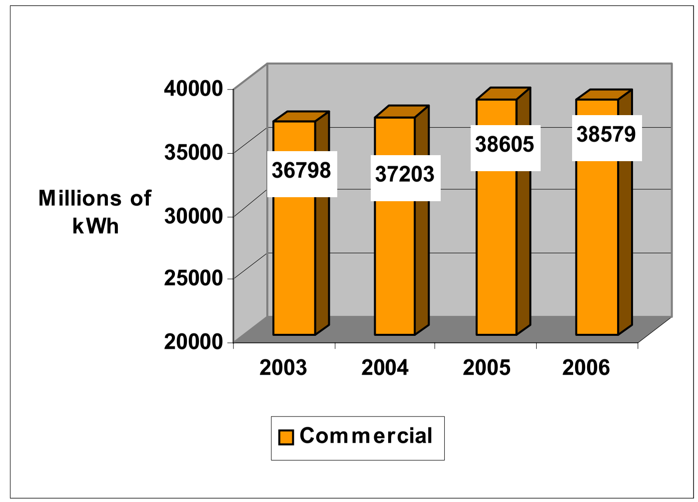
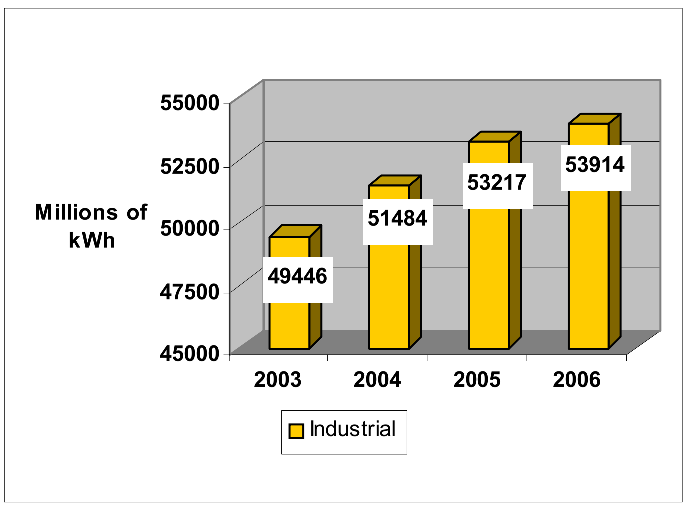
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 1.39%

3 Yr. Compound Annual Commercial Load Growth at 1.59%





3 Yr. Compound Annual Industrial Load Growth at 2.93%

Note: Figures do not include Texas Retail and Miscellaneous Other

2006 Retail Revenue

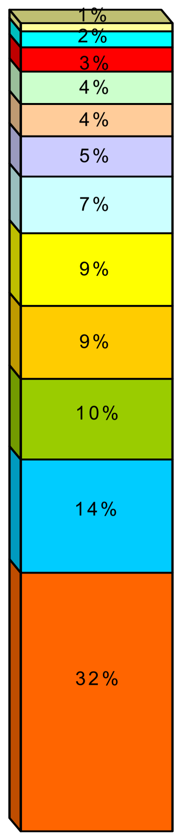
CUSTOMER PROFILE

AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

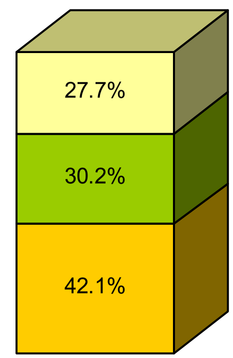
PERCENTAGE OF AEP SYSTEM RETAIL REVENUES

Tennessee	1%
Michigan	2%
Arkansas	3%
Kentucky	4%
Louisiana	4%
Texas SPP	5%
Texas ERCOT	7%
Virginia	9%
West Virginia	9%
Indiana	10%
Oklahoma	14%
Ohio	32%



Retail Revenue Composition by Customer Class**

Industrial	27.7%
Commercial	30.2%
Residential	42.1%



Source: Form 10-K
*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.
**Note: Figures do not include Other Retail Sales

Utility Operations

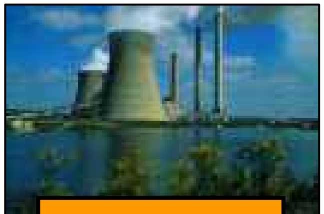
Generation

AEP has approximately 38,000 megawatts of generating capacity in 3 power pools. AEP owns all or portions of 60 major generating plants, which include coal/lignite, natural gas, nuclear, wind projects and hydroelectric facilities.

AEP operates generating capacity in its internal power pool under an economic dispatch system[1]. AEP's power pool's competitive, largely coal-based production costs are among the lowest in the nation. AEP's power production costs are also kept relatively low by its reliance primarily on fossil fuel (gas and coal), with only a small overall nuclear dependence.

[1] Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,168* MW Capacity

* Includes 1,022MW of mothballed/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.76%	63.18%
2006	82.62%	60.06%

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

Utility Operations

PROPERTY, PLANT & EQUIPMENT DETAIL ($ in Millions)

Property Plant and Equipment	Original Cost	AEP Accumulated D&A	Net Utility Plant
Electric:			
Production	$ 19,749	$ 8,920	$ 10,829
Transmission	7,354	2,303	5,051
Distribution	11,894	3,203	8,691
Other (including coal mining & nuclear fuel)	3,363	1,751	1,612
Work in Progress	2,809	(38)	2,847
Total	**$ 45,169**	**$ 16,139**	**$ 29,030**

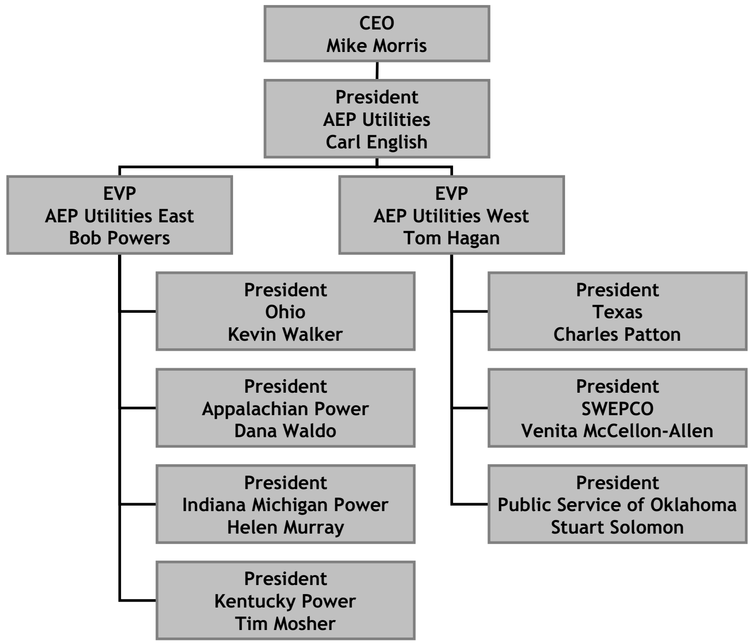
Source: Company information as of 9/30/07

Operating Company Overview

- Organizational Structure
- AEP East Regional Utilities
- AEP West Regional Utilities

Fall EEI 2007

Organizational Structure



Mike Carl Bob Tom

Kevin Dana Helen Tim Charles Venita Stuart

Senior management close to customers and regulators

AEP East Regional Utilities

Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers at 12/31/06:

• Residential	810,000
• Commercial	128,000
• Industrial	4,000
• Other	<u>7,000</u>
Total	949,000

Generating Capacity 6,297 MW

Generating Capacity by Fuel Mix:
- **Coal:** 80.8%
- **Hydro/Pump:** 10.8%
- **Nat Gas** 8.4%

Transmission Miles	6,731
Distribution Miles	49,413

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data * (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 7,483,217
Net Plant Assets	$ 5,953,651
Cash	$ 1,269

Estimated Capital Expenditures (in thousands)

2007	2008	2009	2010
$ 658,000	$ 720,000	$ 749,000	$ 579,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Appalachian Power

APCo Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Buck #1,2,3	Ivanhoe, Virginia	5	Hydro
Byllesby #1,2,3,4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	523	Nat Gas
Claytor #1,2,3,4	Radford, Virginia	28	Hydro
Clinch River #1,2,3	Carbo, Virginia	705	Coal
Glen Lyn #1,2	Glen Lyn, Virginia	335	Coal
Leesville #1,2	Leesville, Virginia	9	Hydro
Niagara #1,2	Roanoke, Virginia	1	Hydro
Reusens #1,2,3,4,5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1,2,3,4,5	Penhook, Virginia	586	Pump
John E. Amos #1,2 *(APCo owns 1/3 of Unit 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,320	Coal
Kanawha River #1,2	Glasgow, West Virginia	400	Coal
London #1,2,3	Montgomery, West Virginia	12	Hydro
Marmet #1,2,3	Marmet, West Virginia	11	Hydro
Philip Sporn #1,3	New Haven, West Virginia	300	Coal
Winfield #1,2,3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES *

West Virginia	Customers
APCo	434,504
Allegheny	492,354

Virginia	Customers
APCo	503,525
Dominion Virginia	2,171,253
Allegheny	95,665
Kentucky Utilities	29,900
Conectiv	21,930

Tennessee	Customers
APCo	45,960

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

West Virginia	
APCo	58.87
AEP - Wheeling	58.87
Allegheny	70.46

Virginia	
ODPCo	64.69
APCo	66.72 ***
Dominion Virginia	85.28
Conectiv	126.82

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

*** APCo Virginia rate adjusted for effect of rate case order received in May 2007.

- **Top 10 Customers = 49% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
CONSOL Energy (VA)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Dickenson-Russell Coal Co, LLC (VA)
Steel of WV, Inc. (WV)
Toyota Motor Manufacturing (WV)

(data for year ended December 2006)

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers at 12/31/06:		
• **Residential**		**662,000**
• **Commercial**		**76,000**
• **Industrial**		**4,000**
Total		**742,000**
Generating Capacity		**3,702 MW**
Generating Capacity by Fuel Mix:		
• **Coal**	**63.7%**	
• **Natural Gas**	**36.3%**	
Transmission Miles		**2,410**
Distribution Miles		**18,590**

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data * (in thousands)

Revenue	$ 1,807,000
% of AEP Retail	16%
Net Income	$ 185,000
Capital Expenditure	$ 307,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 3,706,066
Net Plant Assets	$ 2,984,663
Cash	$ 1,695

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 449,000	$ 393,000	$ 303,000	$ 262,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Columbus Southern Power

Columbus Southern Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Conesville #1,2,3,4 *(Unit #4 co-owned by DP&L.CG&E, CSP 43.5%)*	Conesville, Ohio	1,254	Coal
J. M. Stuart #1,2,3,4 *(Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer #1 *(Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #6 *(Co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	850	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	507	Nat Gas

Columbus Southern Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	1,416,992
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	75.39
AEP (CSP)	85.02
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products
(data for year ended December 2006)

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers at 12/31/06:	
• Residential	508,000
• Commercial	67,000
• Industrial	5,000
• Other	2,000
Total	582,000
Generating Capacity	5,801 MW
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• Coal:	62.5%
• Nuclear:	37.2%
• Hydro:	0.3%
Transmission Miles	5,341
Distribution Miles	19,871

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data * (in thousands)

Revenue	$ 1,977,000
% of AEP Retail	12%
Net Income	$ 121,000
Capital Expenditure	$ 325,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 5,511,474
Net Plant Assets	$ 3,384,061
Cash	$ 2,190

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 305,000	$ 341,000	$ 405,000	$ 341,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Indiana Michigan Power

I&M Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Rockport #1,2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1,2,3,4,5,6,7,8,9,10,11,12	Berrien Springs, Michigan	5	Hydro
Buchanan #1,2,3,4,5,6,7,8,9,10	Buchanan, Michigan	2	Hydro
Constantine #1,2,3,4	Constantine, Michigan	1	Hydro
Elkhart #1,2,3	Elkhart, Indiana	2	Hydro
Mottville #1,2,3,4	Mottville, Michigan	1	Hydro
Tanners Creek #1,2,3,4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1,2,3,4,5,6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1,2	Bridgman, Michigan	2,191	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I & M	453,788
IP & L	462,831
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECo	144,632

Michigan	Customers
I & M	125,588
Consumers Energy	1,779,184
Detroit Edison	2,156,214

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	
I & M	69.64
IP & L	76.00
Duke Indiana (PSI)	78.82
SIGECo	94.62

Michigan	
I & M	66.65
Consumers Energy	101.43
Detroit Edison	111.93

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

(data for year ended December 2006)

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers at 12/31/06:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**
Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,235**
Distribution Miles	**9,777**

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data * (in thousands)

Revenue	$ 586,000
% of AEP Retail	4%
Net Income	$ 35,000
Capital Expenditure	$ 78,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 1,466,241
Net Plant Assets	$ 1,015,100
Cash	$ 439

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 70,000	$ 122,000	$ 100,000	$ 119,000

Sources: * 2006 Form 10-K
** 3Q07 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Kentucky Power

Kentucky Power Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Big Sandy #1,2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY UTILITIES *

Kentucky	Customers
KPCo	175,255
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	58.57
LG&E	65.40
KPCo	69.40
Duke Kentucky	76.70

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company
(data for year ended December 2006)

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Total Customers at 12/31/06:	
• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**
Generating Capacity	**8,498 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**99.9%**
• **Hydro:**	**0.1%**
Transmission Miles	**6,528**
Distribution Miles	**26,276**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data * (in thousands)

Revenue	$	2,725,000
% of AEP Retail		16%
Net Income	$	229,000
Capital Expenditure	$	1,000,000

2007 Asset Data ** (in thousands)

	As of 9/30/07	
Total Assets	$	7,178,834
Net Plant Assets	$	6,053,900
Cash	$	12,726

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 799,000	$ 666,000	$ 525,000	$ 544,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Ohio Power

Ohio Power Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak - August 2nd	5,260 MW

Ohio Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1,2,3,4,5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2,4,5	New Haven, West Virginia	750	Coal
Kammer #1,2,3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1,2	Racine, Ohio	26	Hydro

Ohio Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	1,416,992
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	75.39
AEP (CSP)	85.02
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.
(data for year ended December 2006)

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers at 12/31/06:	
• **Residential**	**447,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**8,000**
Total	**520,000**
Generating Capacity	**4,281 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**23.8%**
• **Natural Gas:**	**76.2%**
Transmission Miles	**3,566**
Distribution Miles	**21,421**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data * (in thousands)

Revenue	$	1,442,000
% of AEP Retail		14%
Net Income	$	37,000
Capital Expenditure	$	240,000

2007 Asset Data ** (in thousands)

	As of 9/30/07	
Total Assets	$	2,705,629
Net Plant Assets	$	2,164,388
Cash	$	1,490

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 280,000	$ 266,000	$ 318,000	$ 511,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Tulsa #1,2,3	Tulsa, Oklahoma	423	Nat Gas, Oil
Riverside #1,2	Jenks, Oklahoma	931	Nat Gas, Oil
Northeastern #1,2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern #1,2,3	Anadarko, Oklahoma	477	Nat Gas, Oil
Comanche #1,2,3	Lawton, Oklahoma	289	Nat Gas, Oil
Weleetka #1,2,3	Weleetka, Oklahoma	199	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	911	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	511,924
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	70.73
PSO	73.67
OG&E	74.60

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

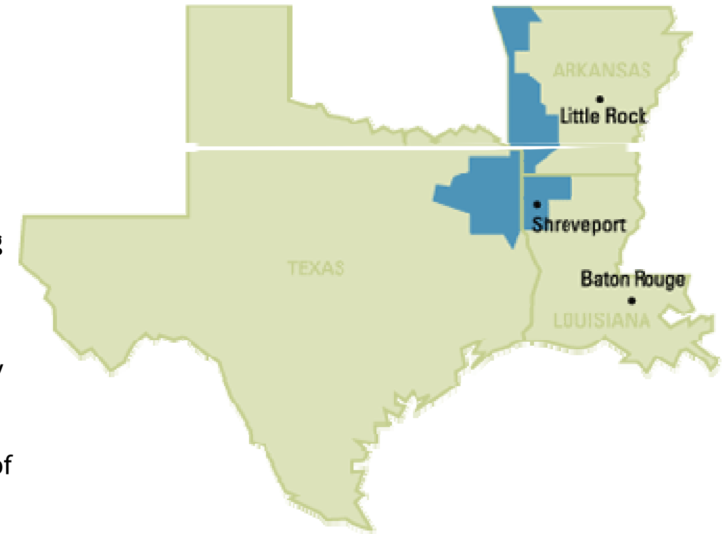
MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.
(data for year ended December 2006)

- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

Total Customers at 12/31/06:	
• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**456,000**
Generating Capacity	**4,687 MW**
Generating Capacity by Fuel Mix:	
• **Coal/Lignite:**	**57.7%**
• **Natural Gas:**	**42.3%**
Transmission Miles	**3,527**
Distribution Miles	**19,616**

PRINCIPAL INDUSTRIES SERVED:
Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data * (in thousands)

Revenue	$ 1,432,000
% of AEP Retail	11%
Net Income	$ 92,000
Capital Expenditure	$ 323,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 3,331,102
Net Plant Assets	$ 2,797,994
Cash	$ 1,852

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 582,000	$ 694,000	$ 651,000	$ 563,000

Sources: * 2006 Form 10-K
** 3Q07 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics - 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Mattison #3,4	Tontitown, Arkansas	176	Gas
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1,2,3,4	Mooringsport, Louisiana	278	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2,3,4,5	Longview, Texas	486	Gas
Wilkes #1,2,3	Avlinger, Texas	897	Gas
Welsh #1,2,3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	109,760
Entergy AR	672,890

Louisiana	Customers
SWEPCo	171,564
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	166,906
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	74.63
OG&E	77.70
Empire District	86.30
ETR	102.43

Louisiana	
SWEPCo	63.91
Entergy LA	99.63
Entergy Gulf St	100.81
Entergy NO	104.20
CLECO	110.19

Texas	
SWEPCo	60.80
SPSCo	80.91
ETR	114.79
EP	128.32
TXU	144.11

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

(data for 12 months ended December 2006)

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

(data for year ended December 2006)

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

(data for year ended December 2006)

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2006)

Total Customers at 12/31/06:
(Based on electric meters)

• Residential	630,000
• Commercial	102,000
• Industrial	5,000
• Other	1,000
Total	738,000
Transmission Miles	4,991
Distribution Miles	28,339

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data * (in thousands)

Revenue	$ 665,000
% of AEP Retail	5%
Net Income (Loss)	$ 42,000
Capital Expenditure	$ 270,000

2007 Asset Data ** (in thousands)

	As of 9/30/07
Total Assets	$ 5,148,741
Net Plant Assets	$ 2,348,756
Cash	$ 50

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 247,000	$ 197,000	$ 245,000	$ 234,000

Sources: * 2006 Form 10-K
** 3Q07 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:
Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

(data for year ended December 2006)

PRINCIPAL INDUSTRIES SERVED:
Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2006)

Total Customers at 12/31/06:
(Based on electric meters)

• Residential	148,000
• Commercial	30,000
• Industrial	5,000
• Other	6,000
Total	189,000

Generating Capacity	377 MW

Oklaunion Plant - Vernon, TX
(excludes 1,022 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal:** 100%

Transmission Miles	4,522
Distribution Miles	14,394

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data * (in thousands)

Revenue	$	329,000
% of AEP Retail		1%
Net Income	$	15,000
Capital Expenditure	$	70,000

2007 Asset Data ** (in thousands)

	As of 9/30/07	
Total Assets	$	997,124
Net Plant Assets	$	869,347
Cash	$	72

Estimated Capital Expenditures
(in thousands)

2007	2008	2009	2010
$ 106,000	$ 171,000	$ 134,000	$ 132,000

Sources: * 2006 Form 10-K
** 3Q07 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Regulation

- Regulatory Strategy
- Regulatory Activity Underway
- Regulatory Activity Completed
- Rate Case Filing Requirements
- GridSMART Regulatory Status
- Rate Base and ROE by Operating Company
- Commission Overviews

Fall EEI 2007

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Activity Underway

- Ohio Post 2008
- CSP and OPCo Filing for 4% Provision on Generation Rates
- I&M - Indiana Rate Petition
- APCo Filings – E&R and Fuel Factor Adjustments
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Regulatory Activity Underway

Ohio Post 2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on October 2, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote – October 31, 2007
- Presented to House Public Utilities Committee – November 2007; Hearing schedule extends to the end of January 2008.

AEP Ohio Application For 4% Provision On Generation Rate

- On October 24, 2007, CSP and OP filed an application pursuant to the RSP at the PUCO to recover costs associated with additional generation-related expenditures the companies are encountering related to environmental (CAIR, CAMR and NPDES – Clean Water Act) and PJM marginal losses.
- CSP and OP are requesting to implement the provision to recover $35.2MM and $11.9MM, respectively, from January through December 2008.

Regulatory Activity Underway

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.
- Hearings are expected in May 2008, and an order in the first quarter of 2009.

APCo E&R and Fuel Factor Adjustments

E&R:

- On July 16, 2007 a filing was made with the VA SCC requesting an additional $39MM be added to the current rider of $21MM. Therefore, at December 1, 2007, we will begin collecting $60MM.
- Intervenor testimony was filed on October 3, 2007, staff testimony filed on October 17, 2007, rebuttal testimony filed on October 24, 2007 and public hearings are expected to commence on November 5, 2007.

Fuel Factor:

- On July 16, 2007, a filing was made with the VA SCC requesting the termination of the OSS base credit and reflected 75% of OSS margins as a credit to fuel expense, consistent with new Virginia legislation. Implementation of the fuel factor was approved effective September 1, 2007, subject to review/refund.
- Intervenor testimony was filed on October 5, 2007, staff testimony filed on October 15, 2007, rebuttal testimony filed on October 22, 2007 and public hearings are expected to commence on November 8, 2007.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008. A request for rehearing was submitted on October 1, 2007.
- A technical conference was held on October 18, 2007. The purpose was to review and clarify the company's responses to discovery. A second technical conference is scheduled for November 6, 2007 with settlement meetings scheduled for November 15, 2007 and December 4, 2007.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony is scheduled for November 19, 2007.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings commenced August 20, 2007. Decision expected by year end.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected by year end.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in early 2008.

Regulatory Activity Completed

Company	Case	Order Date	Dollar Amount	ROE
APCo - Virginia	Base Rate Case	May 15, 2007	$24MM increase in annual base rates	10.0%
APCo - West Virginia	ENEC Filing	June 22, 2007	$29MM increase in annaul revenues	10.5%
I&M - Indiana	Depreciation Study	June 13, 2007	$69MM estimated decrease in annual depreciation expense	N/A
I&M - Michigan	Depreciation Study	September 25, 2007	$10MM estimated decrease in annual depreciation expense	N/A
CSP/OPCo	4% RSP	October 3, 2007	$23MM increase in annual generation rates	N/A
TNC	Base Rate Case	May 24, 2007	$12MM increase in annual pre-tax earnings	9.96%
TCC	Base Rate Case	October 17, 2007	$50MM increase in annual pre-tax earnings	9.96%
ETT	Utility Status/ROE	October 17, 2007	N/A	9.96%
PSO	Base Rate Case	October 9, 2007	$20MM increase in annual pre-tax earnings	10.0%

Incremental rate relief requirements for 2007 have been satisfied.

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Louisiana	Michigan	Ohio	Oklahoma	Texas	Virginia	West Virginia	FERC
General											
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	Yes	No	No
Period of Limitation (months)	--	15	--	--	--	--	--	--	See note 1	--	--
Pancaking Permitted?	No	No	No	Yes	No	Limited	Yes	No	No	No	Yes
Notice of Intent											
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	N/A	45	30	45	30	60	30	N/A
Case Components											
Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Partially Projected	Historical	Historical	Historical	Forecast Optional
Other											
Rates Effective Subject to Refund	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes
Approx # of Months after Filing to implement rates subject to refund	10	--	6	--	Varies	9	6	5	5	--	2 or 7

Note 1: One more opportunity exists for rate case opportunity between now and 12/31/08 prior to re-regulation conditions (1/1/09); however, post 1/1/09 no interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Regulatory framework inherently produces recovery and return lag.

GridSMART Implementation Regulatory Status

- **Indiana**
  - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and will administer a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana. Initial meter installation occurring in 2008.
  - Involved in an open DSM/EE docket working with the other utilities in the state.
- **Michigan**
  - Initial discussions underway regarding collaboration on a demand response/smart metering program. I&M has volunteered, subject to cost recovery, to conduct a smart grid pilot for all Michigan customers (125,000) pursuant to a Commission order requesting one or more smart grid pilots be conducted.
- **Kentucky**
  - Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.
- **Ohio**
  - Recent Governor remarks and draft legislation indicates modernization of Ohio's infrastructure is a high priority and sets demand and energy efficiency goals.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.
- **Arkansas**
  - The Arkansas commission approved our 'quick-start' programs, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-performance pilot that results in a payment to customers who curtail load upon request. Cost recovery began with the first billing cycle of November 2007.
  - Further discussion have been requested by the PSC regarding the GridSMART program and other alternatives the state may wish to pursue.
- **Oklahoma**
  - The OCC issued a notice of proposed rulemaking to establish rules promoting energy efficiency and establishing demand program requirements for Oklahoma utilities. Technical conferences and hearings are scheduled during the remainder of 2007.
  - In PSO's recent base rate case, the OCC ordered that PSO file a DSM/energy efficiency plan by December 8, 2007.
- **Texas**
  - Successful demand side management and energy efficiency programs have been in place in Texas since the 1990s.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.
  - PUCT has opened an energy efficiency rulemaking to address concurrent cost recovery, comprehensive potential and economic studies and the higher annual efficiency goals included in new legislation.

The pace of GridSMART implementation will be set by our regulators.

Rate Base & September 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	9/30/07 GAAP Earned ROE
APCo VA	$2.022MM	10.00%	10/2/2006	8.93%
APCo WV	$1.656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.87%
I&M-Indiana	$1.805MM	12.00%	11/19/1993	9.00%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSP	$1.558MM	12.46%	5/12/1992	21.77%
Ohio-OPCo	$2.183MM	12.81%	3/23/1995	12.70%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	1.28%
SWEPCo-LA	$434MM	11.10%	12/29/1999	5.97%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	8.10%
Texas-TNC	$530MM	9.96%	6/1/2007	10.71%

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 2 (one vacancy)	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 1
Qualifications for Commissioners The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.			
Commissioners **Paul Suskie, Chairman (Dem.),** since 2007; current term ends in 2013. Lawyer, North Little Rock, Arkansas City Attorney. Bachelor's attained at University of Central Arkansas. Juris Doctorate at University of Arkansas at Little Rock School of Law. NARUC member including Committee on Energy Resources and the Environment and Committee on Consumer Affairs.			
Daryl E. Bassett, Commissioner (Rep.), since 2003; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).			

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 3 D: 2**

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

Commissioners

David L. Hardy, Chairman (Rep.), since 2005; current term will expire April 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include negotiation, contracts, litigation, finance and administration. He has 35 years of regulatory experience at the state and federal levels. Bachelors degree and law degree from Indiana University.

Jeffrey L. Golc, Commissioner (Dem.), since 2007; current term will expire in 2009. Former public affairs manager for the Kroger Company. Previous Deputy Commissioner for the Indiana Bureau of Motor Vehicles and the Indiana Department of Workforce Development. Bachelors and Masters degrees in communications from Indiana University.

Larry S. Landis, Commissioner (Rep.), since 2002; current term ends June 2008. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.

Greg Server, Commissioner (Rep.), since 2005; current term ends 2009. Former state senator since 1981 and before that served in the Indiana House of Representatives from 1972 to 1980. Served as chair of Senate Commerce Committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility. Masters degrees in political science and counseling from Indiana State University.

David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2011. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and Advisory Council of the Electric Power Research Institute. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, I&M's fuel recovery and base rates were capped through June 30, 2007. Full fuel recovery commenced July 1, 2007 and company testimony in a full base rate case will be filed no later than January 31, 2008. The rate case will include requests for rider related to DSM, environmental and RTO costs.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 3

Qualifications for Commissioners

Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.

Commissioners

Mark Goss, Chairman (Rep.), since 2004; current term expires June 2011. Serves as member of NARUC and Chairman of the NARUC subcommittee on clean coal technology. Board member for MISO and Organization of PJM States, Inc.. Former practicing attorney in private practice. J.D. from University of Tennessee College of Law.

John W. Clay, Vice Chairman (Rep.), since 2006; current term expires June 2009. Former deputy secretary of the Kentucky Environmental and Public Protection Cabinet. Served as executive director of the Office of Alcohol Beverage Control in the Department of Public Protection. B.A. from Georgetown College. Certified Public Accountant and member of the AICPA.

Caroline Pitt Clark, Commissioner (Rep.), since 2007; current term expires June 2008. Criminal and civil attorney in private practice. Member of the Kentucky and American bar associations. Undergraduate degree in Political Science from Centre College; JD degree from the University of Kentucky College of Law.

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 3
Qualifications for Commissioners The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.			
Commissioners **Jack A. Blossman, Jr. (Rep.),** since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.			
James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.			
Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2010. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.			
C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.			
Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.			

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects.

Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: D: 2 I: 1
Qualifications for Commissioners The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.			
Commissioners **Orjiakor N. Isiogu, Chairman (Dem.),** since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.			
Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's degree, University of Michigan.			
Steven A. Transeth, Commissioner, (Ind.) , since 2007; current term expires July 2009. Former assistant director and legal counsel for the Michigan Legislative Service Bureau, which included drafting legislation and providing legal counsel to the Michigan Senate and House of Representatives. Lawyer, private practice and with the Ingham County Prosecuting Attorney's office.. J.D. from Thomas Cooley Law School.			

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active fuel clause and return on CWIP can be included in base rates.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 2 D: 1 I: 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee, National Governors' Association Electricity Task Force, Harvard Electricity Policy Group.

Ronda Hartman Fergus, Commissioner, (Rep.) since 1995; term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff. Member NARUC Committee on Consumer Affairs.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctor from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Donald L. Mason, Commissioner, (Rep.) since 1998; term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as the Chairman of the NARUC Gas Committee and serves on the NARUC Board of Directors and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master's degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation. Chair of the Board of Directors of the National Academy of Public Administration.

AEP Regulatory Status

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSP and OPCo (the Ohio Companies). The plans provided, among other things, for CSP and OPCo to raise their generation rates by 3% and 7% respectively, in 2006, 2007 and 2008 and provided for additional generation rate increases of up to 4% per year based on the Ohio Companies supporting the need for additional revenues. Distribution rates in effect at 12/31/05 are frozen for OPCo and CSP until 12/31/08. Transmission rates are currently regulated by FERC as reflected in the OATT. CSP and OPCO do not have an active fuel clause (fuel costs are embedded in unbundled G rates). Current legislative activity is underway regarding a new bill to replace Senate Bill 3, which was the original 1999 deregulation legislation.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 1

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

Bob Anthony Commissioner, (Rep.), since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.

Jim Roth, Commissioner, (Dem.), since 2007;appointed by the governor to fill the seat opened by the resignation of Commissioner Bode. Previously served various county governments for eight years. JD from Oklahoma City University School of Law.

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism and has rider mechanisms currently approved for vegetation management and the new peaking facilities expected to be in-service in December 2007.

Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: I: 1 D: 3
Qualifications for Commissioners The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all currently expire in June 2008; after 2008, terms will be staggered.			
Commissioners **Eddie Roberson, Chairman (Ind.),** since 2006; current term expires 2012. Former Chief of Public Services Division of PSC. Received Ph.D. in Public Administration from The Institute of Government at Tennessee State University in 1998.			
Patrick Miller, Director (Dem.), since 2002; current term expires June 2008. Fiscal Analyst, Fiscal Review Committee. Legislative Liaison, Tennessee Supreme Court. Served as Chief of Staff to the Lt. Governor and Speaker of the Senate. J.D., Nashville School of Law.			
Sara Kyle, Director (Dem.), since 1996; current term expires June 2008. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving director and only holdover from the previous Public Service Commission. Law degree from Middle Tennessee State University.			
Ron Jones, Director, (Dem.), since 2002: current term expires June 2008. Sixteen year veteran of utility regulation, Director Jones served the first ten years with the Tennessee Public Service Commission staff and the next six with the TRA as a Senior Policy Advisor. Completed several regulatory studies programs at Michigan State University, Graduate School of Business. Received B.B.A. from Tennessee State University.			

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.
Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Barry T. Smitherman, Commissioner, (Rep.), since April 2004; current term expires August 2013. Attorney; Assistant DA; Public Finance Investment Banker. Received law degree from the University of Texas School of Law

Julie Caruthers Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University. PUCT's SPP liaison. Member of Texas Energy Planning Council.

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUC as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State University.

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO and TNC-SPP areas). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base.

TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 1

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires 2010. Attorney, counsel to the Speaker of the House. Lawyer, private practice. Law degree from Georgetown.

Judith Williams Jagdmann, (Rep.), since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The opportunity for one rate case exists before December 31, 2008. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution system reliability and compliance with state or federal environmental laws or regulations (known as the E&R rider). APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.

Wheeling Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, Commissioner (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office. Former Chief Financial Officer of the Workers' Compensation Division of the W.V. Bureau of Employment Programs. Certified Public Accountant in West Virginia and Georgia. Bachelor's degree, West Virginia University.

Michael A. Albert, Chairman (Rep.), since 2007, term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005, term expires June 2011. Currently on the board of directors of the National Association of Regulatory Utility Commissioners and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction.

Generation & Optimization

- Units
- Generation Statistics
- Fuel/Transportation Statistics
- New Generation

Fall EEI 2007

Domestic Generation

Generation Capacity*

COMPANY	MW Capacity
AEP Generating Co	2,446
Appalachian Power Co	6,297
Columbus Southern Power	3,702
Indiana Michigan Power Co	4,501
Kentucky Power Co	1,060
Ohio Power Co	8,498
Public Service of Oklahoma	4,281
Southwestern Electric Power Co	4,687
Texas North Co**	1,399
OVEC Capacity***	986
Domestic IPPs	311
Total	**38,168**

*Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 1,022 MW of mothballed / retired / decommissioned generation

*** AEP owns a 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE.

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
AEP GENERATING COMPANY					
Rockport	1	IN	RFC	Steam - Coal	1,300
Lawrenceburg	6	IN	RFC	Natural Gas	1,146
					2,446
APPALACHIAN POWER COMPANY					
Buck	3	VA	RFC	Hydro	5
Byllesby	4	VA	RFC	Hydro	8
Claytor	4	VA	RFC	Hydro	28
Leesville	2	VA	RFC	Hydro	9
London	3	WV	RFC	Hydro	12
Marmet	3	WV	RFC	Hydro	11
Niagara	2	VA	RFC	Hydro	1
Reusens	5	VA	RFC	Hydro	6
Winfield	3	WV	RFC	Hydro	15
Smith Mountain	5	VA	RFC	Pumped Storage	586
Amos	2	WV	RFC	Steam - Coal	2,033
Clinch River	3	VA	RFC	Steam - Coal	705
Glen Lyn	2	VA	RFC	Steam - Coal	335
Kanawha River	2	WV	RFC	Steam - Coal	400
Mountaineer	1	WV	RFC	Steam - Coal	1,320
Sporn	2	WV	RFC	Steam - Coal	300
Ceredo	6	WV	RFC	Natural Gas	523
					6,297
COLUMBUS SOUTHERN POWER COMPANY					
Beckjord (CCD)	1	OH	RFC	Steam - Coal	53
Conesville (CCD)	4	OH	RFC	Steam - Coal	1,254
Picway	1	OH	RFC	Steam - Coal	100
Stuart (CCD)	4	OH	RFC	Steam - Coal	608
Zimmer (CCD)	1	OH	RFC	Steam - Coal	330
Waterford	4	OH	RFC	Natural Gas	850
Darby	6	OH	RFC	Natural Gas	507
					3,702
INDIANA MICHIGAN POWER COMPANY					
Berrien Springs	12	MI	RFC	Hydro	5
Buchanan	10	MI	RFC	Hydro	2
Constantine	4	MI	RFC	Hydro	1
Elkhart	3	IN	RFC	Hydro	2
Mottville	4	MI	RFC	Hydro	1
Twin Branch	6	IN	RFC	Hydro	4
Rockport	1	IN	RFC	Steam - Coal	1,300
Tanners Creek	4	IN	RFC	Steam - Coal	995
Cook	2	MI	RFC	Steam - Nuclear	2,191
					4,501

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
KENTUCKY POWER COMPANY					
Big Sandy	2	KY	RFC	Steam - Coal	**1,060**
OHIO POWER COMPANY					
Racine	2	OH	RFC	Hydro	26
Amos	1	WV	RFC	Steam - Coal	867
Cardinal	1	OH	RFC	Steam - Coal	600
Gavin	2	OH	RFC	Steam - Coal	2,600
Kammer	3	WV	RFC	Steam - Coal	630
Mitchell	2	WV	RFC	Steam - Coal	1,600
Muskingum River	5	OH	RFC	Steam - Coal	1,425
Sporn	3	WV	RFC	Steam - Coal	750
					8,498

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)	
PUBLIC SERVICE COMPANY OF OKLAHOMA						
Tulsa	3	OK	SPP	Steam - Nat Gas	415	
Tulsa	3	OK	SPP	Oil	8	
Riverside	2	OK	SPP	Steam - Nat Gas	928	
Riverside	1	OK	SPP	Oil	3	
Northeastern (1&2)	4	OK	SPP	Steam - Nat Gas	940	
Northeastern	1	OK	SPP	Oil	3	
Southwestern	3	OK	SPP	Steam - Nat Gas	475	
Southwestern	1	OK	SPP	Oil	2	
Comanche	3	OK	SPP	Steam - Nat Gas	285	
Comanche	2	OK	SPP	Oil	4	
Weleetka	3	OK	SPP	Steam - Nat Gas	195	
Weleetka	2	OK	SPP	Oil	4	
Northeastern (3&4)	2	OK	SPP	Steam - Coal	910	
Northeastern	1	OK	SPP	Oil	1	
Oklaunion	1	TX	ERCOT	Steam - Coal	108	
					4,281	
SOUTHWESTERN ELECTRIC POWER COMPANY						
Arsenal Hill	1	LA	SPP	Steam - Nat Gas	110	
Lieberman	4	LA	SPP	Steam - Nat Gas	278	
Knox Lee	4	TX	SPP	Steam - Nat Gas	486	
Wilkes	3	TX	SPP	Steam - Nat Gas	897	
Lone Star	1	TX	SPP	Steam - Nat Gas	50	
Mattison	2	AR	SPP	Natural Gas	176	
Welsh	3	TX	SPP	Steam - Coal	1,584	
Flint Creek	1	AR	SPP	Steam - Coal	264	
Pirkey	1	TX	SPP	Steam - Lignite	580	
Dolet Hills	1	LA	SPP	Steam - Lignite	262	
					4,687	
TEXAS CENTRAL COMPANY						
none						
TEXAS NORTH COMPANY						
Paint Creek	4	TX	ERCOT	Steam - Nat Gas	238	Retired
Rio Pecos	3	TX	ERCOT	Steam - Nat Gas	142	Retired
San Angelo	2	TX	ERCOT	Steam - Nat Gas	128	Mothballed
Fort Phantom	2	TX	ERCOT	Steam - Nat Gas	362	Mothballed
Oak Creek	1	TX	ERCOT	Steam - Nat Gas	85	Retired
Abilene	1	TX	ERCOT	Steam - Nat Gas	18	Retired
Lake Pauline	2	TX	ERCOT	Steam - Nat Gas	35	Retired
Ft. Stockton	1	TX	ERCOT	Steam - Nat Gas	6	Decommissioned
Vernon	4	TX	ERCOT	Oil	8	Decommissioned
Oklaunion	1	TX	ERCOT	Steam - Coal	377	
					1,399	

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
DOMESTIC INDEPENDENT POWER PROJECTS					
Trent Mesa	100	TX	ERCOT	Wind	150
Indian Mesa	107	TX	ERCOT	Wind	161
					311

Generation Statistics

Net Capacity Factor	2006	2005
AEP East	64.57%	68.58%
Coal*	70.34%	70.92%
Super Critical	73.36%	74.37%
Sub-Critical	61.00%	60.29%
Gas	2.58%	2.02%
Hydro**	10.68%	11.03%
Nuclear	83.55%	93.07%
AEP SPP	45.10%	45.81%
Coal***	76.87%	75.56%
Super Critical	83.77%	80.36%
Sub-Critical	74.24%	73.37%
Gas	23.33%	25.22%
AEP Texas	65.35%	70.89%
Coal****	65.35%	70.89%
AEP System	60.06%	63.18%

Equivalent Availability Factors	2006	2005
AEP East	81.80%	84.56%
Coal	80.29%	83.24%
Super Critical	80.55%	83.75%
Sub-Critical	79.49%	81.68%
Gas	92.84%	90.27%
Hydro	92.30%	92.23%
Nuclear	82.87%	92.70%
AEP SPP	86.25%	85.89%
Coal	82.87%	81.40%
Super Critical	86.76%	83.75%
Sub-Critical	81.27%	80.50%
Gas	88.56%	88.99%
AEP Texas	67.78%	77.00%
Coal	67.78%	77.00%
AEP System	82.62%	84.76%

Equivalent Forced Outage Rate (EFOR)	2006	2005
AEP East	8.54%	7.10%
Coal	9.37%	7.67%
Super Critical	8.31%	7.84%
Sub-Critical	12.63%	7.13%
Gas - See below		
Hydro	4.99%	9.85%
Nuclear	0.65%	1.19%
AEP SPP	6.79%	6.01%
Coal	3.86%	6.27%
Super Critical	5.50%	8.95%
Sub-Critical	3.31%	5.17%
Gas	9.73%	5.74%
AEP Texas	23.48%	8.78%
Coal	23.48%	8.78%
AEP System	8.45%	6.90%

Equivalent Forced Outage Factor (EFOF)	2006	2005
East Gas*****	0.39%	3.59%

* Includes AEP's share of CCD units and Cardinal 2&3. 2006 numbers do not include Conesville 1&2 (retired 12/31/05). Super critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** Does not include Dolet Hills.

**** Oklaunion reported as owned.

***** East Gas Units will now be evaluated using Equivalent Forced Outage Factor. Since these units are ran infrequently, this factor gauges their performance based on Period Hours instead of Service Hours.

Net Generation Statistics

Net Generation By Operating Company (in MWhs)

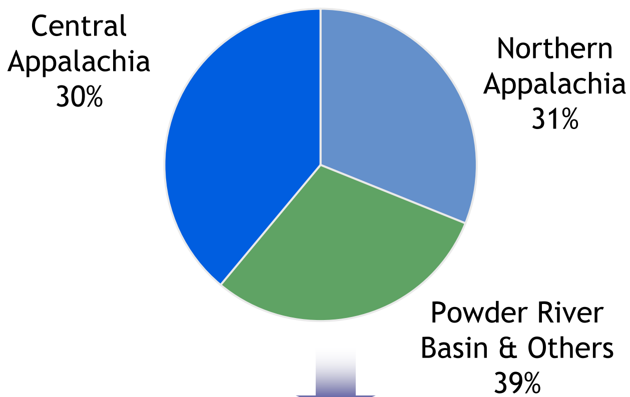
Operating Company	2005	2006
AEP Generating	8,969,041	10,276,134
Appalachian Power	32,949,364	31,494,581
Columbus Southern Power	14,038,045	14,134,232
Indiana Michigan Power	31,535,226	31,950,768
Kentucky Power	7,345,624	7,171,505
Ohio Power	52,080,585	49,341,134
Public Service of Oklahoma	15,375,848	15,139,848
Southwestern Electric Power	20,169,211	19,961,798
Texas Central Company	2,082,874	309,085
Texas North Company	2,342,693	2,160,348
AEP System Total Net Generation	186,888,511	181,939,433

Notes: Figures represent generation produced from AEP-owned assets only.

Coal Procurement

AEP burns approx. 76 million tons of coal per year

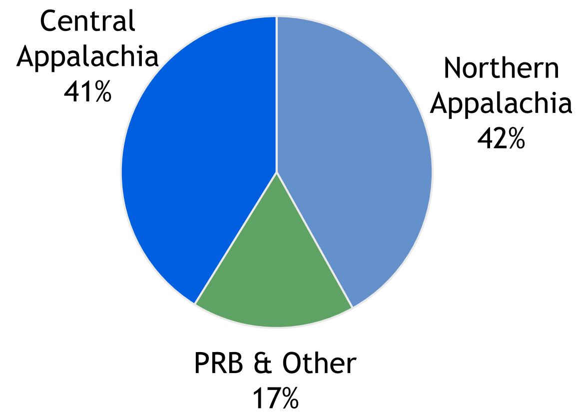
Total AEP System



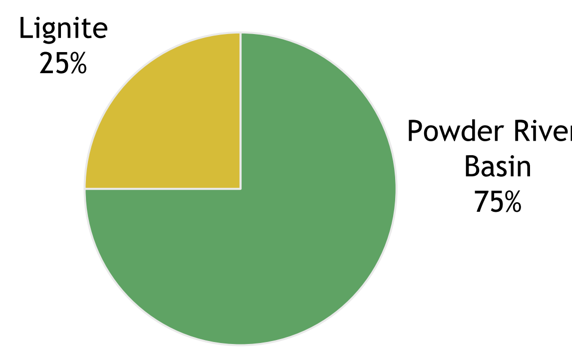
Coal Stats:

- Fully contracted for 2007; >93% for 2008
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-5% price increase in 2007 -- ($36.50 to $37.50/ton); 13% increase in 2008 based on anticipated 2007 actual results.
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

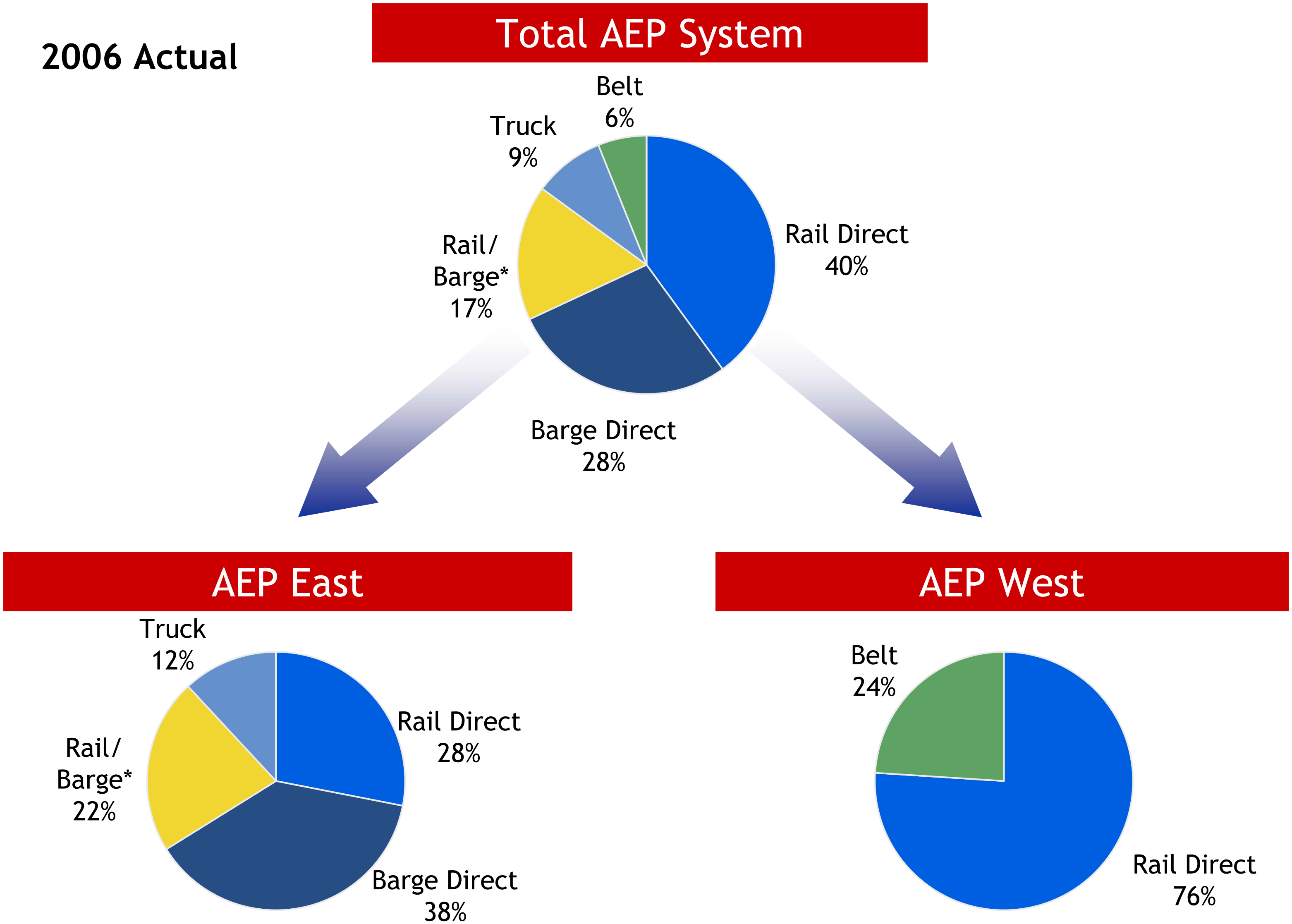


AEP West



Coal Delivery

2006 Actual

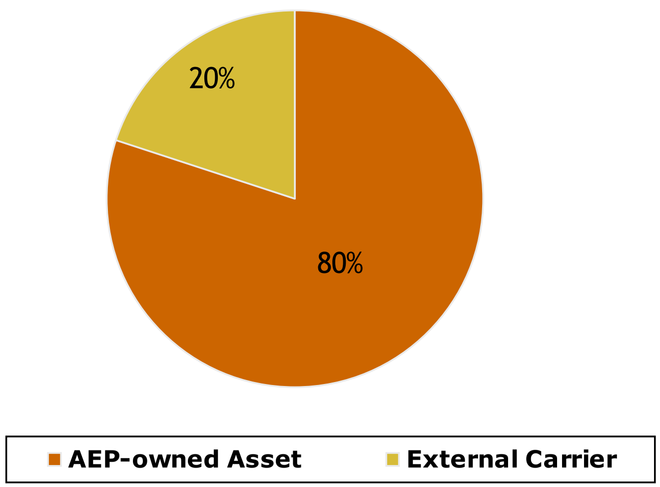


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2006 Actual



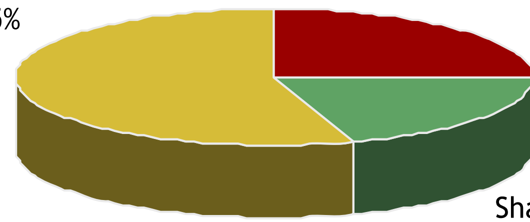
***Represents close approximations**

- Current Coal & Transportation Assets:
  - Control over 8,300 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity

AEP's transportation assets provide flexibility in a constrained delivery environment.

Fuel Recovery

AEP System



Fuel Cost Recovery (on average)

- **Fuel recovery varies by jurisdiction**
- **80% of fuel cost is recoverable across the AEP System**
- **Active Fuel Clause Jurisdictions:**
  - **AEP EAST: APCo, I&M, KPCo, KGP, WP**
  - **AEP WEST: PSO, SWEPCO**

Note: Fuel recovery percentages are based on estimates for 2007 fiscal year

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	N/A
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

We have fuel recovery in all jurisdictions except Ohio, where it is part of the RSP 3% (CSPCo) and 7% (OPCo) increases.

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis.
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. AEP intends to seek regulatory recovery approvals in advance of building the plant.

AEP is committed to IGCC technology.

Generation Technology Comparative Stats

US2006$	Eastern Bituminous		
	USC	IGCC	NGCC
Nominal Capacity (MW)	**618**	**629**	**530**
Capacity Factor (%)	**85%**	**85%**	**25%**
Total Plant Cost (EPC + Owner's Cost) ($/kW)	**$2,152**	**$2,717**	**$572**
Production Cost ($/MWh)	**$22**	**$22**	**$45**
Cost of Electricity, without CO_2 Capture ($/MWh)	**$72**	**$83**	**$87**
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	**$118**	**$108**	**$135**

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

Environmental Overview

- Multi-Emissions Reductions
- Environmental Glossary
- Current Environmental Regulations
    - Strategy
    - SCR/FGD Details
- Future Potential Greenhouse Gas Regulations
    - AEP's Position
    - CCS Projects

Fall EEI 2007

Multi-Emissions Reductions

Multi-Emissions Regulations: In 2005, the Federal EPA finalized two rules: the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules require sulfur dioxide (SO_2), nitrogen oxide (NOx) and mercury (Hg) reductions in two phases: 2010 (2009 for NOx) and 2015 (2018 for Hg), also utilizing an emissions trading program. AEP is well on the way towards compliance with these provisions with a substantial number of scrubber and selective catalytic reduction (SCR) installations recently completed or underway.

In July 2005, the Federal EPA finalized a third rule: the Clean Air Visibility Rule (CAVR), which addresses the implementation of emission controls for SO_2 and NOx to deal with regional haze in Class I areas (e.g. national parks, forests and other pristine areas). CAVR requires Best Available Retrofit Technology (BART) – defined as scrubbers and meeting low NOx emission rates -- ultimately installed at those affected facilities. The EPA is urging states that are part of the CAIR region (most of the states except for the Western US) to adopt the CAIR rule as compliant with CAVR (thus not requiring BART at power plants within that state). However, in the other non-CAIR states (i.e. The West and Southwestern US), most of the currently unscrubbed coal-fired plants will probably be required to install scrubbers and meet lower NOx limits.

Finally, in September 2006 the Federal EPA issued a final rule on particulate matter (PM), which tightened the PM-2.5 (i.e. fine particle) 24-hour standard, while retaining the current annual standard for PM-2.5. Precursors of fine particulates include SO_2, NOx and a variety of carbonaceous compounds. Though CAIR is expected to lead to increasing compliance with these new and existing standards, it is uncertain whether or not the Federal EPA will decide to reduce the utility SO_2 and/or the NOx emission limits further as part of a regional strategy in the longer term for compliance.

Multi-Emissions Reductions

Greenhouse Gas Policies: The President has committed the nation to reduce the greenhouse gas (GHG) intensity of the economy (GHG emissions per $ GDP) by 18% over the next ten years through voluntary programs, and called for an improved federal emissions reporting program for tracking progress toward this goal. Regional U.S. initiatives to reduce greenhouse gas emissions and specifically CO_2 emissions have also begun in states outside of AEP's service territory including the Northeastern States (i.e. the Regional Greenhouse Gas Initiative or RGGI) and the West Coast (specifically California). A number of federal legislative proposals have been introduced in Congress over the past couple of years, which if passed, would require mandatory US GHG reductions in the future.

AEP has had a GHG strategy for a number of years, acknowledging the issue, accepting the science and believing in early proactive action. Our strategy includes:

1) Being proactive in the development of greenhouse gas policy through our support and membership within a variety of organizations (e.g., EPRI, Pew Center, the Business Roundtable, e8, IETA);

2) Being a leader in the development of technology through our support of research, development and deployment of new clean coal technology such as IGCC, being a major investor in the Future Gen project (the first near zero emitting IGCC coal plant in the U.S.), and through research in carbon capture and sequestration from coal plants;

3) Taking voluntary action now through our participation in Chicago Climate Exchange (CCX) , EPA Climate Leaders and SF-6 Program, Asia-Pacific Partnership, DOE1605B, and Business Roundtable Climate Resolve program among other efforts. We are making voluntary GHG reductions through our participation in CCX and are currently ahead of our reduction commitments.

4) Long-term planning (post-2010) to reduce or limit GHGs through:

- New generation technology including Ultra-supercritical, IGCC and FutureGen
- Commercial solutions for carbon capture and storage technology
- Emissions offsets (e.g., forestry, domestic-methane)
- Renewables (e.g., wind, biomass co-firing)
- Supply and demand side efficiency

Environmental Glossary

Clean Air Scientific Advisory Committee (CASAC) - Created by the Clean Air Act amendments in 1977, this committee of independent experts on air pollution reports to the U.S. Environmental Protection Agency Administrator. The committee is charged with reviewing the scientific knowledge of air pollution and its effects, without regard to costs.

Micron - One millionth of a meter. For example, human hair is about 70 microns thick. $PM_{2.5}$ is approximately 1/30th the thickness of a human hair.

National Ambient Air Quality Standards (NAAQS) - Establish maximum allowable concentrations in outdoor air for six pollutants: particulate matter, ozone, sulfur dioxide, nitrogen oxide, carbon monoxide, and lead. The Clean Air Act requires EPA to review NAAQS every five years. EPA is required to set standards "to protect public health ...allowing an adequate margin of safety."

Ozone - Ozone is a form of oxygen which is a colorless gas with a unique odor. Ozone occurs naturally in the earth's upper atmosphere where it shields against ultraviolet radiation from the sun. In the lower atmosphere, ozone is formed by the combination of nitrogen oxides and hydrocarbons in the presence of sunlight. This ozone is a major component of smog. The current NAAQS for maximum allowable ozone is 0.12 parts per million measured over a one-hour period, with three exceedances over three years permitted.

Particulate Matter - Particles of matter suspended in the atmosphere. EPA currently regulates concentrations of particulate matter that are 10 microns and smaller in diameter. The current allowable maximum concentration of particulate matter is 150 micrograms (ug) per cubic meter averaged over 24 hours. The annual average of 24 hour readings is required to be less than 50 ug/m^3.

PM_{10} - Particulate matter that is 10 microns or less in diameter.

$PM1_{2.5}$ - Particulate matter that is 2.5 microns or less in size.

Primary Particles - This is particle matter that is emitted directly into the atmosphere, including dust from construction, farming and roads, volcanic ash, sea salt, tire and brake dust, diesel soot and wood smoke. Primary particles are the dominant form of particulate matter in the West and arid Southwest. Primary particles tend to settle out of the atmosphere in a relatively short time.

Secondary Particles - These particles are formed when gases, such as sulfur oxides, nitrogen oxides and volatile organic carbon, react in the atmosphere to form solid or liquid particles of sulfates, nitrates and organic carbon particles. These particles are generally 2.5 microns and smaller in size. Secondary particles dominate in the eastern United States. Secondary particles tend to remain suspended in the atmosphere and can be transported over long distances by prevailing winds.

Precursor - The forerunners that lead to the formation of a pollutant. The precursors of ozone are nitrogen oxides and hydrocarbons, which combine in the presence of sunlight to form ozone. The precursors of fine particular matter are sulfur oxides, nitrogen oxides and volatile organic compounds which combine with ammonia in the atmosphere to form sulfate and nitrate particles.

Current Environmental Regulations

Clean Air Interstate Rule

- Rule finalized March 2005
- Designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- Reductions from 2003-level emissions: ~73% SO_2 & ~61% NO_x
- Reductions occur in phases: Phase I (2009/2010); Phase II (2015)
- Established three cap & trade programs:

  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program

Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

Clean Air Visibility Rule

- Rule finalized March 2005
- Designed to address the Clean Air Act's best available retrofit technology (BART) requirements and applicability to plants built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants
- Final rule demonstrates that CAIR will result in more visibility improvements than BART
- States are allowed to substitute CAIR requirements in their SIPs for controls that would otherwise be required by BART
- For BART-eligible facilities located in states no subject to CAIR requirements for SO_2 and NO_x, additional controls will be required

Applicability to AEP

- Requires SO_2 reductions in Oklahoma and Arkansas
- Scrubbers (FGDs) will be installed at our Northeastern and Flint Creek plants by 2015

Clean Air Mercury Rule

- Rule finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a cap & trade structure to achieve mercury reductions

AEP will achieve significant mercury reduction as a co-benefit of SCR and FGD systems, but mercury specific control equipment will be needed on several units.

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, CAIR and CAMR.

Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

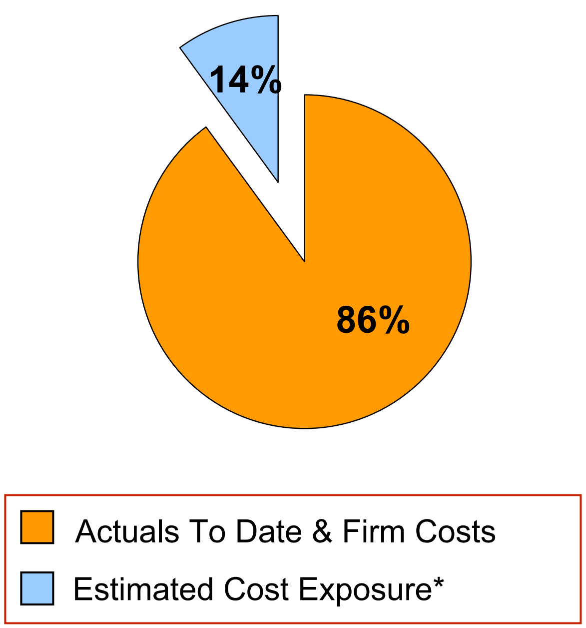
Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors – AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD retrofit for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.
- Plant modifications increasing unit MW ratings are being implemented as part of the retrofit program
  - For example, Mountaineer turbine valve upgrades will increase unit output by ~30 - 45 MW
  - Similar upgrades will be implemented on other units

Plant modifications will mitigate FGD and SCR capacity consumption.

Typical FGD Project Milestone Schedule

- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, Phase 3 Bid Construction at 30 – 60% design complete
- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path

Future Potential GHG Regulations

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

- **Key Components:**
  - **Start date for greenhouse-gas reductions is 2012**
  - **Goals: 2006 levels by 2020; 1990 levels by 2030**
  - **Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation**
  - **Support for allowance allocations**
  - **International action**

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- **Renewables**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

New Program Additions

- **Incremental Reduction quantity: 5MM tons/yr**
- **Timing: To take effect/receive credits by 2011**
- **Methods**
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- **Commercial solutions for existing fleet**
  - Chilled Ammonia
  - Oxy-Coal

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced.

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Mountaineer Plant (WV) → MOU (Alstom) **Chilled Ammonia**

CO_2 Storage (Battelle)

Phase 2
2012 Commercial Operation

Northeastern Plant (OK) → MOU (Alstom) **Chilled Ammonia** → EOR MOU (SemGreen)

CO_2 Storage

Project Validation

- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- Located at the AEP Mountaineer Plant in WV
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Approximate capture and storage cost $100 – $120M
- Alstom "Chilled Ammonia" Technology
- Geologic storage for CO_2

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2012
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit FGD Required: ~$225 – $300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion carbon solution provides pure CO_2 stream for capture.

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

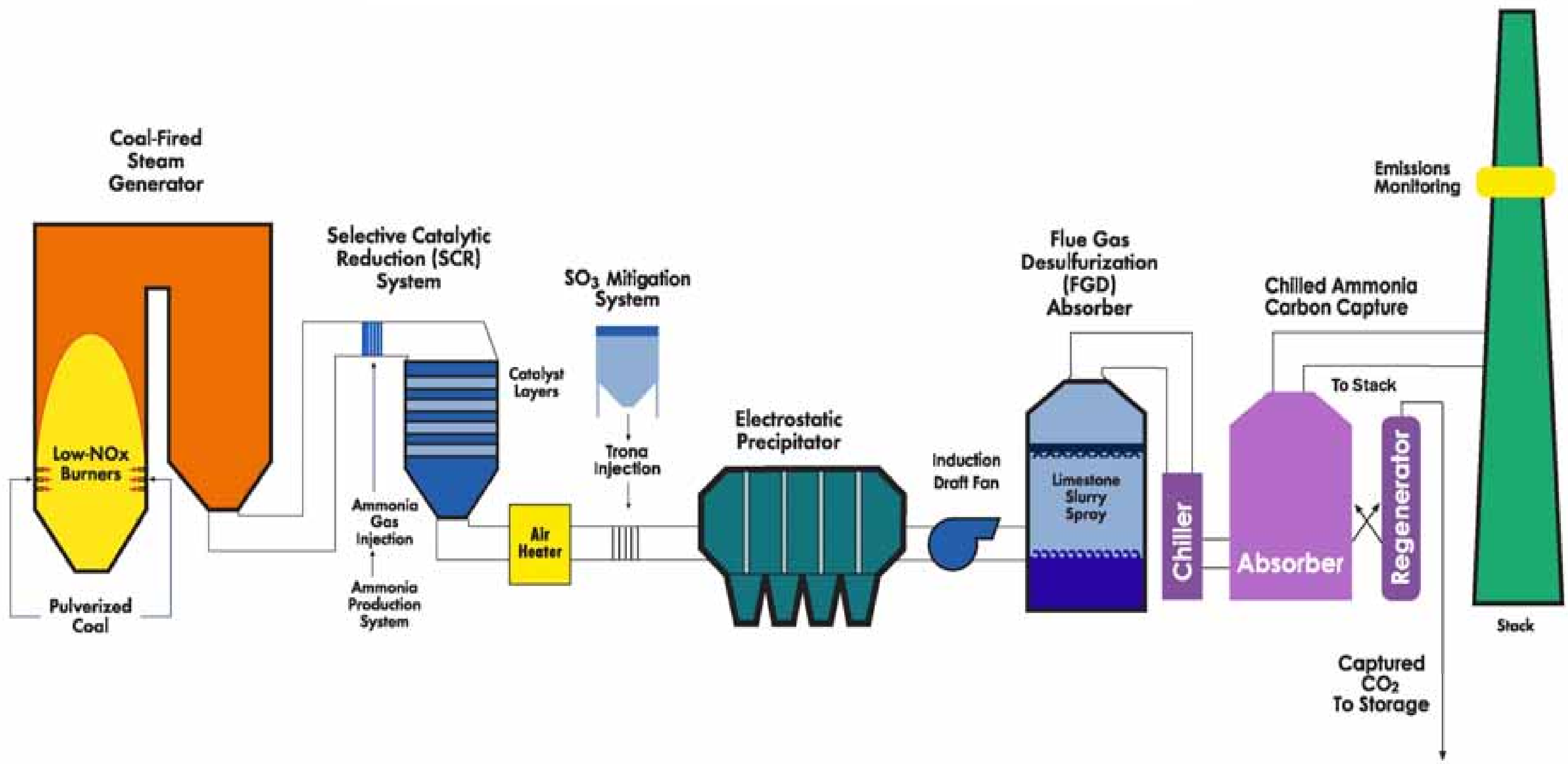
- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion conversion technology for existing coal fleet - longer lead time with enhanced viability and long term potential.

Environmental Control Systems



AEP's Carbon Capture & Storage Project

CCS Clean Energy for A Clean Environment

AEP's Carbon Capture & Storage Project

Leading the Way

AEP and Carbon Capture and Storage

AEP continues its heritage of advancing technology for the electric utility industry with leading-edge carbon capture and storage initiatives.

As an industry leader in climate action, AEP recognized more than a decade ago that the emissions of its coal-fueled fleet of power plants -- including carbon, a greenhouse gas emission associated with global climate change -- would have a significant impact on the future of the company.

AEP has faced the challenge with innovative, first-of-a-kind approaches designed to allow the continued use of coal to generate electricity in a carbon-constrained world.

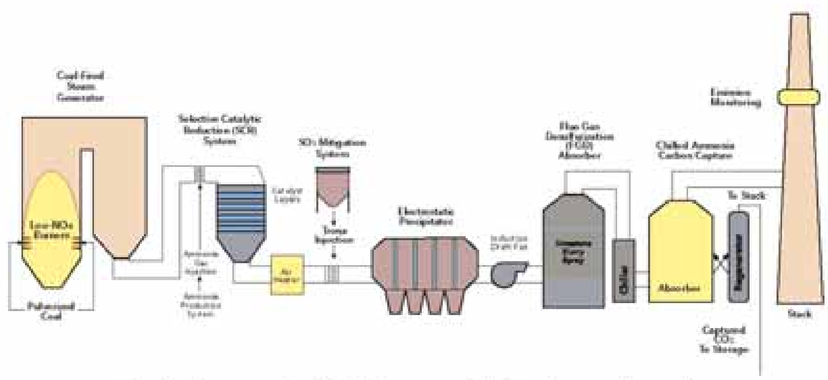
AEP and Carbon Capture and Storage

AEP's goal is to address the issue of climate change while maintaining a supply of affordable, reliable energy for customers that helps keep our economy and our nation secure and strong.

AEP will install Alstom's chilled ammonia process, a post-combustion technology, on two coal-fired power plants

- A technology validation project at Mountaineer Plant in West Virginia and
- Commercial scale installation at Northeastern Station in Oklahoma

The carbon capture project at Mountaineer Plant will be operational in early 2009. In addition, AEP will capture, compress and store underground at least 100,000 metric tons of carbon dioxide (CO_2) per year in deep geologic formations. The estimated $70 million project will operate three to five years.



CCS process occur after the flue gas exits the FGD system and before it enters the stack.

Commercial scale application of Alstom's chilled ammonia process at Northeastern will enter commercial operation in 2011. The installation will capture approximately 1.5 million metric tons of CO_2 per year. At Northeastern, AEP intends that the CO_2 will be used for enhanced oil recovery (EOR).

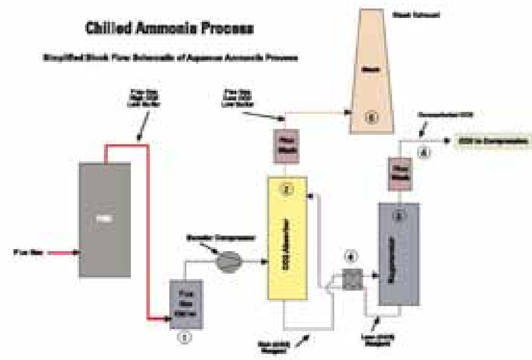
With these projects, AEP continues its leadership position with significant scale-up of technology to capture and store CO_2 emissions from a coal-fired plant.

AEP's Carbon Capture & Storage Project

Carbon Capture

With Alstom's chilled ammonia process

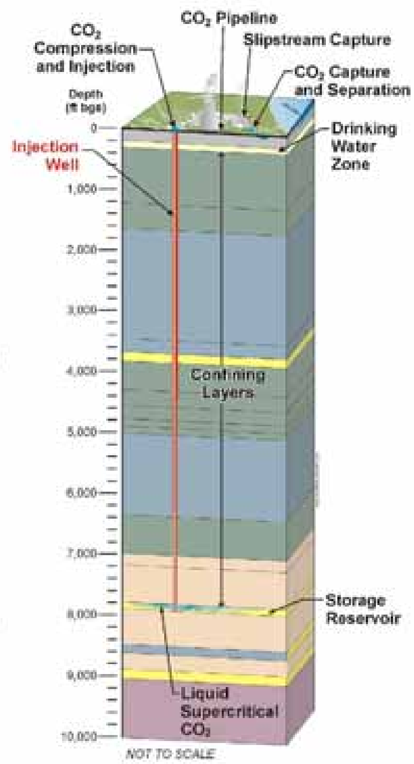
1. The flue gas is chilled to ~ 35°F
2. Ammonium carbonate absorbs CO_2 to make ammonium bicarbonate
3. Ammonium bicarbonate slurry is pumped to a regenerator for CO_2 removal, where the ammonium bicarbonate is converted back to ammonium carbonate and is reused to repeat the process.
4. Heat recovery ensures efficient operation of process.
5. The clean flue gas -- containing mainly nitrogen, excess oxygen and low concentration of CO_2 -- flows to the stack
6. CO_2 is sent to geologic storage in deep saline aquifers or EOR fields.



Carbon Storage

AEP will work with Battelle Memorial Institute to store captured carbon in deep saline aquifers on the Mountaineer Plant site. A characterization study was conducted here in 2003 - 04 and one well already exists. That study indicated that the geologic formations in this area are favorable for carbon storage.

For storage, the captured CO_2 is compressed into a liquid-like state and injected under pressure into saline aquifers in carefully chosen deep geologic formations of pourous sandstone or dolamite. The CO_2 is injected more than a mile underground and spreads through the pore space in the rock where it is effectively trapped from moving upward by layers of impermeable rock above the porous rock, much like oil and gas deposits are trapped for millions of years.



Other technologies – Oxy-coal

AEP also will conduct a retrofit feasibility study with Babcock & Wilcox of its Oxy-coal technology. Plans to retrofit an existing AEP plant for commercial-scale CO_2 capture using this pre-combustion technology will follow.

Oxy-coal combustion creates a flue gas that is primarily a concentrated stream of CO_2. In the Oxy-coal combustion process

- Combustion air is replaced with relatively pure oxygen.
- A portion of the CO_2-rich flue gas is returned to the burners, essentially substituting CO_2 for the nitrogen in the furnace.
- The fraction of the flue gas that is not re-circulated to the burners leaves the plant and is available for subsequent use or storage.
- A secondary benefit of Oxy-coal firing is the reduction of nitrogen oxide (NOx) emissions.

AEP AMERICAN ELECTRIC POWER

Energy Delivery

- Transmission Line Detail
- Distribution Line Detail

Fall EEI 2007

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
APCo	734	97	383	106	0	3,288	0	23	1,078	793	0	230	0	**6,731**
CSP	0	0	884	0	0	890	0	0	464	0	59	0	113	**2,410**
I&M	615	0	1,614	0	0	1,664	0	0	704	0	0	743	0	**5,341**
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	**30**
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,235**
OPCo	509	0	909	0	0	2,463	0	0	2,167	0	0	368	112	**6,528**
PSO	0	0	579	34	8	2,123	10	0	812	0	0	0	0	**3,566**
SWEPCo	0	0	660	0	228	1,192	42	0	1,405	0	0	0	0	**3,527**
TCC	0	0	641	0	0	2,610	0	0	1,740	0	0	0	0	**4,991**
TNC	0	0	223	0	0	1,586	14	0	2,699	0	0	0	0	**4,522**
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	**288**
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,311**	**67**	**23**	**11,705**	**848**	**59**	**1,371**	**225**	**39,169**

State Level (Circuit Miles)

State	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
Arkansas			28		228	168	42		461					**927**
Indiana	599		1,380			1,425			405			595		**4,405**
Kentucky	258		8		46	320			544	55		3		**1,235**
Louisiana			105			245			233					**583**
Michigan	16		234			239			299			148		**936**
Ohio	509	0	1,793	0	0	3,354	0	0	2,630	0	59	368	225	**8,937**
Oklahoma	0	0	625	34	8	2,148	10	0	812	0	0	0	0	**3,638**
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	**275**
Texas	0	0	1,344	0	0	4,950	14	0	5,151	0	0	0	0	**11,459**
W. Virginia	384	17	323	0	0	1,600	0	23	457	745	0	89	0	**3,638**
Virginia	349	96	69	15		1,708			709	48		141		**3,136**
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,311**	**67**	**23**	**11,705**	**848**	**59**	**1,371**	**225**	**39,169**

Note: Transmission line circuit miles are current as of 12/31/06

Distribution Line Detail

By State	Line Miles*		By Operating Company	Line Miles*
Tennessee	1,510	|	KGPCO	1,510
Virginia	29,769	|	KYPCO	9,777
W. Virginia	21,122	|	APCO	49,413
Kentucky	9,777	|	OPCO	26,276
Ohio	44,866	|	CSP	18,590
Michigan	5,185	|	I&M	19,871
Indiana	14,686	|	WPC	1,478
Texas	50,541	|	TCC	28,339
Oklahoma	21,421	|	TNC	14,394
Arkansas	4,391	|	PSO	21,421
Louisiana	7,417	|	SWEPCO	19,616
Total	**210,685**		**Total**	**210,685**

* Includes approximately 27,500 miles of underground circuit miles

Note: Distribution line circuit miles are current as of 12/31/06

Transmission Initiatives

- Electric Transmission Texas
- PJM Opportunities (I-765™ & PATH)
- Michigan 765-kV Opportunities
- SPP 765-kV Opportunities
- Electric Transmission America

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Electric Transmission Texas (ETT)

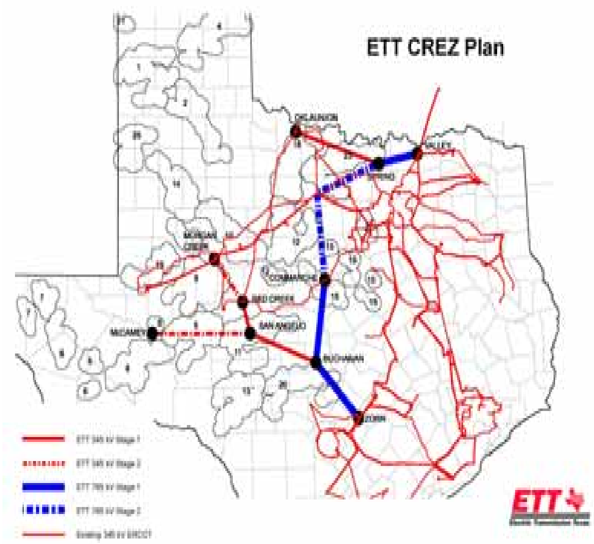
- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007
  - PUCT Recently Approved:
    - ROE of 9.96%
    - Establishment of Transmission Utility Status
  - Received FERC/PUCT approvals:
    - Asset transfer for TCC to ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

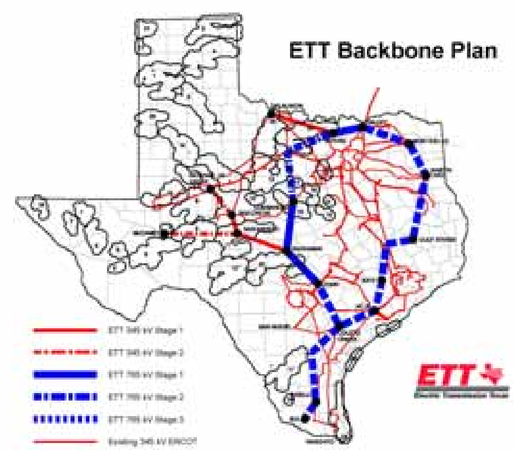
- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

- **Traditional ratemaking process through the PUCT will be utilized for investment cost recovery.**

ETT CREZ



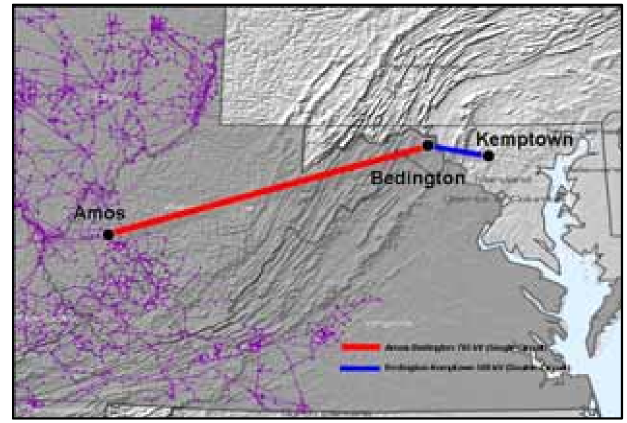
ETT Backbone



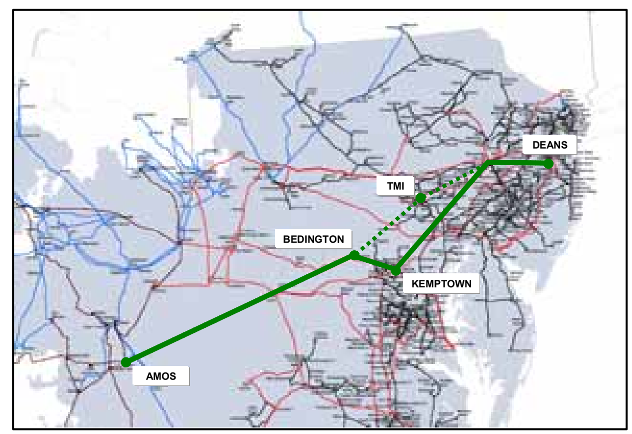
Transmission Project Updates - PJM

- ***I-765 TM in PJM Phase I Update***
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012
- ***Key Next Steps***
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Begin Routing Study – Fall 2007
  - State Filings – Fall 2008
  - Construction – Early 2010
  - Completion – Fall 2012
- ***I-765 TM in PJM Phase II Update***
  - Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
  - Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
  - Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.
- ***Regional Rate Design will be utilized for investment cost recovery.***

Phase I in PJM



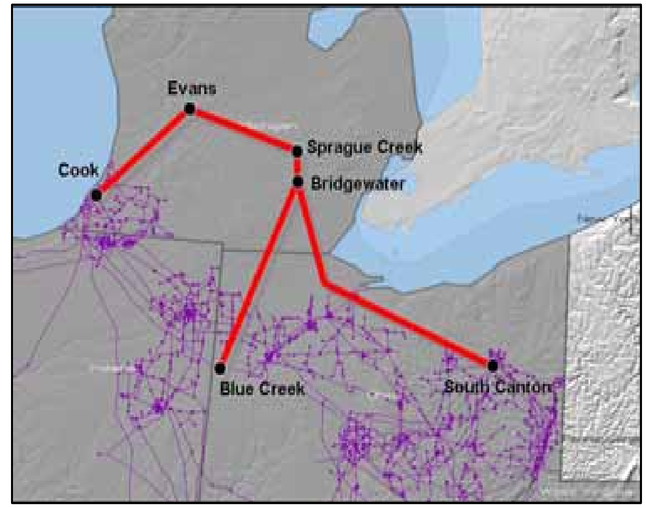
Phase II in PJM



Transmission Project Updates – cont'd

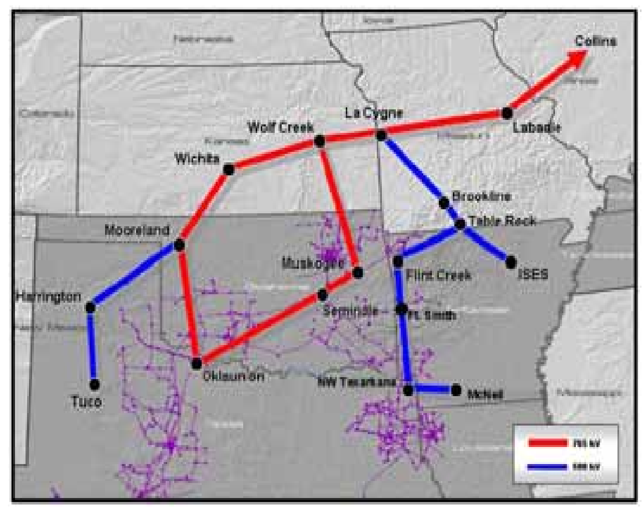
- ***765 - kV in Michigan - Key Next Steps***
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2015

Michigan



- ***765-kV in SPP - Key Next Steps***
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

Southwest Power Pool



- ***Regional Rate Design will be utilized for investment cost recovery.***

Electric Transmission America (ETA)

- ***Electric Transmission America (ETA)***
  - AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
  - Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
  - Projects taken on by the Joint Venture would entail transmission facilities:
    - 345 kV and above
    - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
    - Greater than $100 million
  - ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
  - ETA will look to collaborate with qualified partners in each particular region.

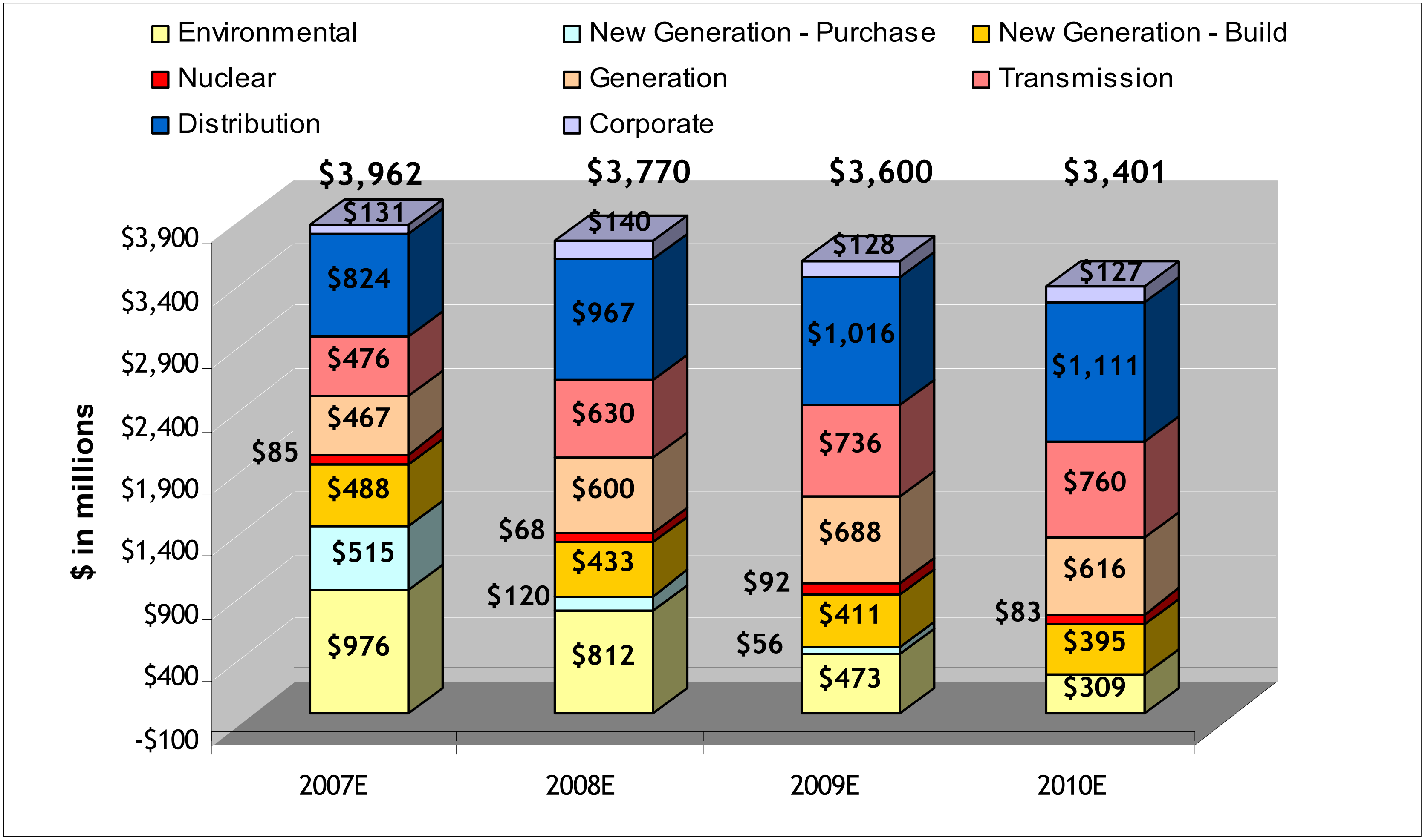
This JV reflects a natural progression and expansion of our partnership with MidAmerican.

Financial Update

- Capital Investment Forecast
- Earnings Guidance
- Capitalization
- Liquidity Position
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Fall EEI 2007

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital investment is funded from cash from operations and debt issuances.

Financial Forecast Highlights

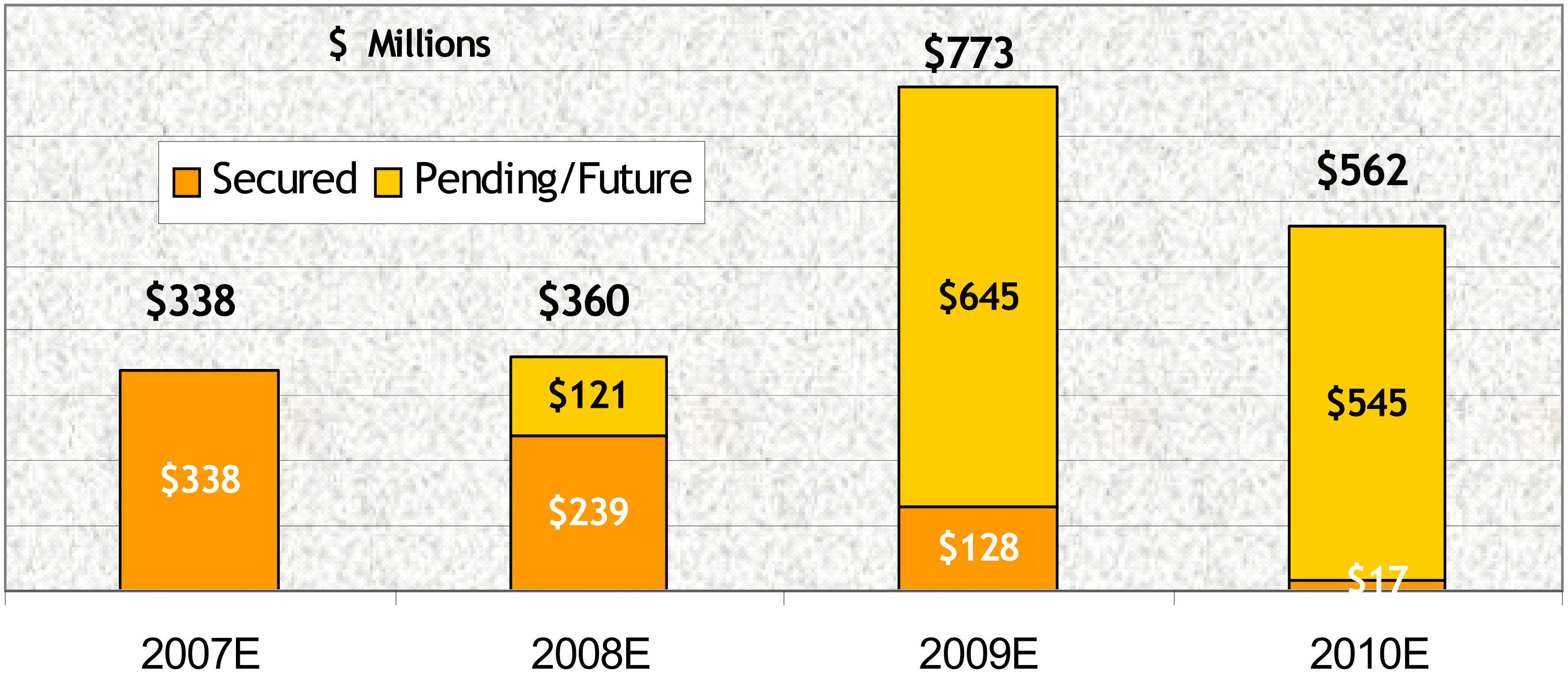
2007 Range $2.90 to $3.00	**2008 Range $3.05 to $3.25**
2009 Range $3.20 to $3.50	**2010 Range $3.45 to $3.80**

- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Ohio: Continue momentum toward market
  - Cost management
- 8-cent per share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Capital investment forecast

2007E: $3,962 MM	**2008E: $3,770 MM**
2009E: $3,600 MM	**2010E: $3,401 MM**

- Maintain credit ratings: BBB/Baa2/BBB

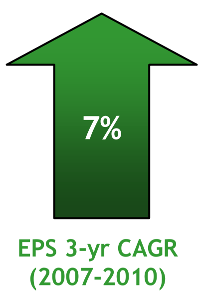
Incremental Rate Relief Assumptions

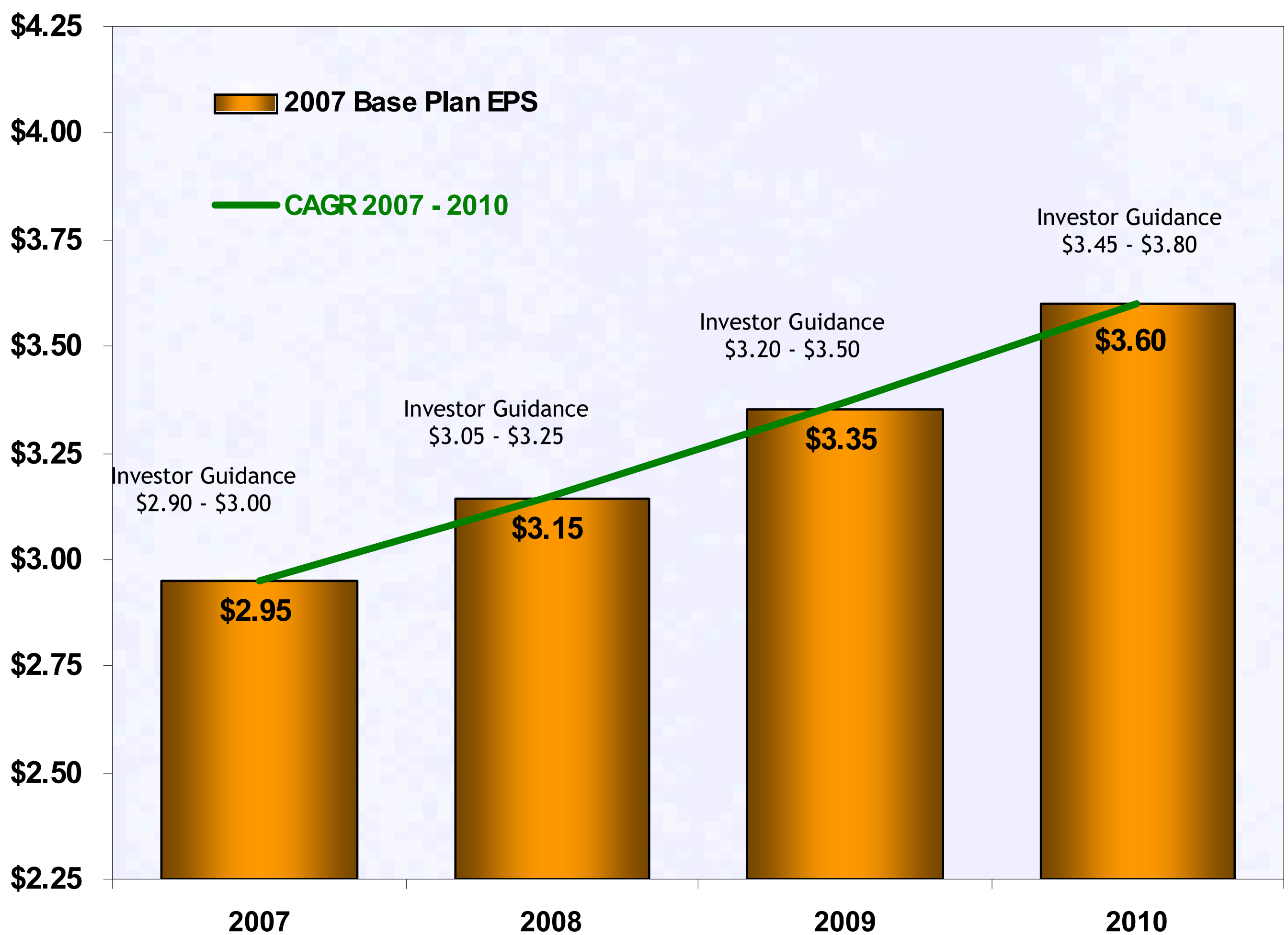


2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation and General Rate Case
TCC and TNC General Rate Cases

2007 - 2010 projected annual rate increases of 5.5%.

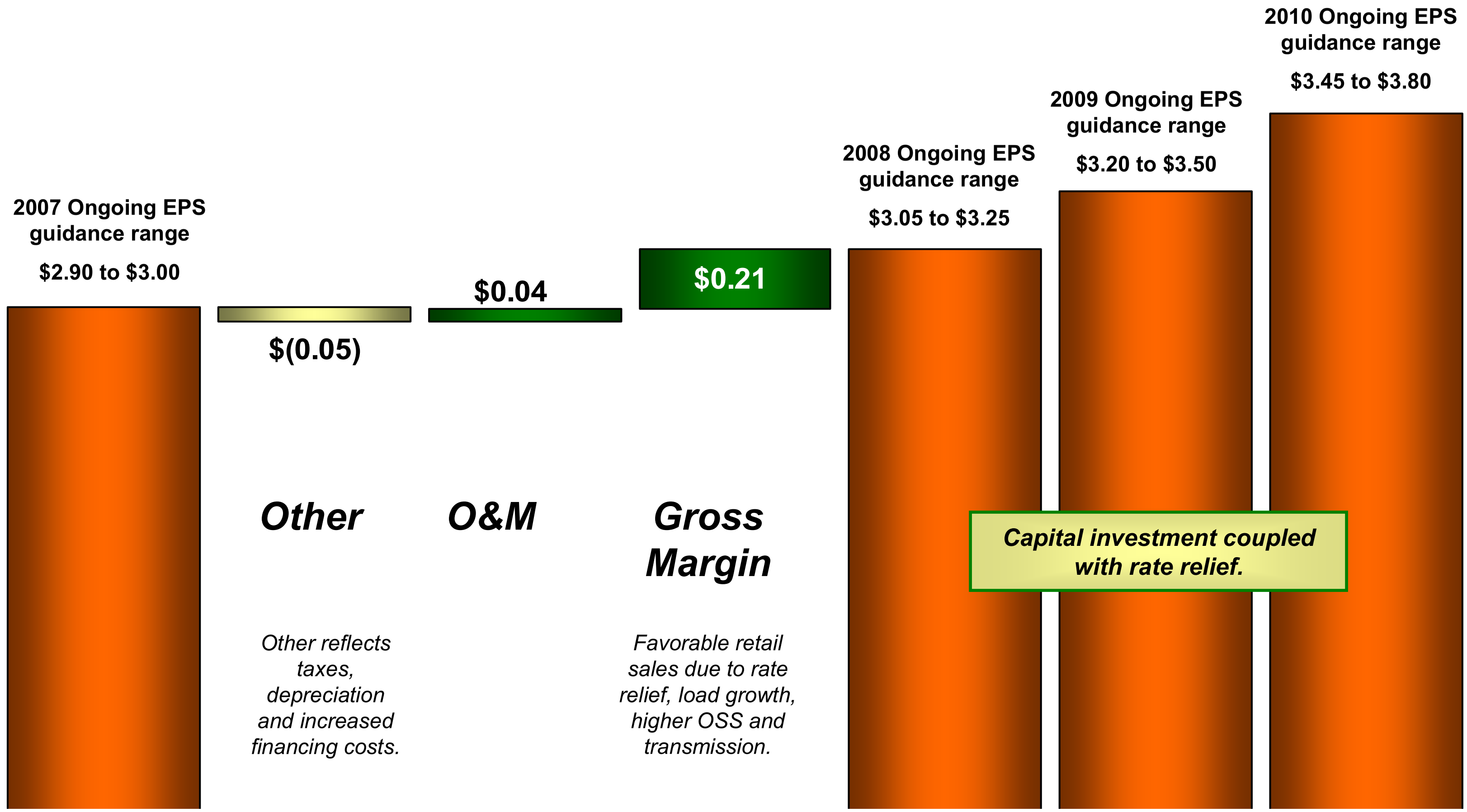
4-Year Earnings Range Forecast





5% to 9% earnings growth and recommendation of a 4Q07 dividend increase.

Long-Range Earnings Drivers



Traditional utility factors will drive earnings.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1282 of 9556

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		2007 Performance Driver	2007 Guidance ($ millions)	2008 Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Net Transmission Revenue		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

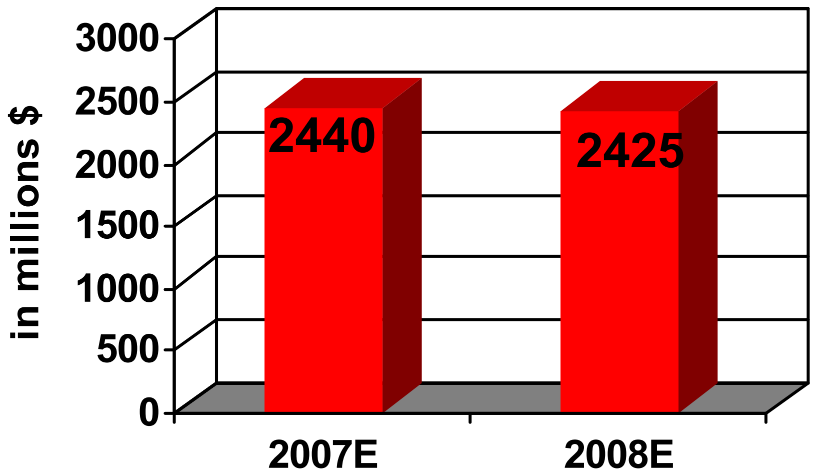
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

Summary of 2008 Earnings Guidance

- Load growth of 2.2%
- Rate relief of $360MM ($239MM already secured)
- Rising fuel costs of 13%
- Higher financing costs and taxes
- Lower contribution from Centrica sharing agreement

Traditional utility factors will drive earnings.

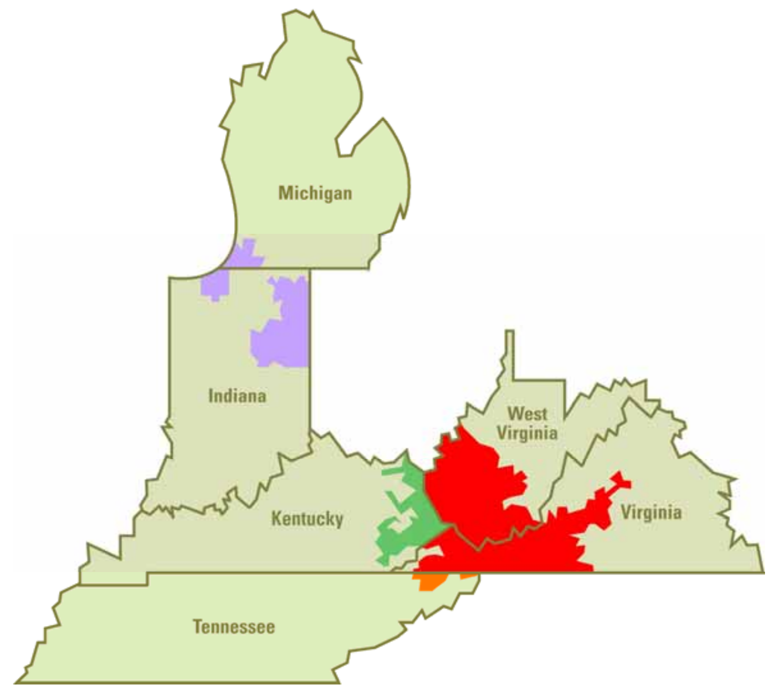
East Integrated Utilities



Earnings Drivers ($ in MM)

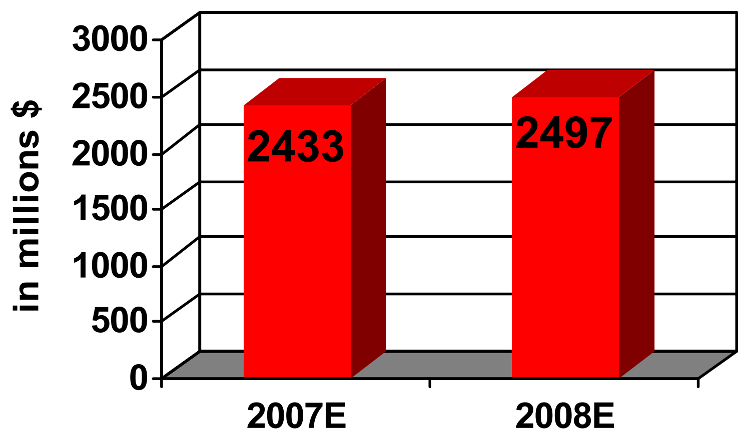
Load Growth	60
Rate Relief	93
Capacity Settlement*	(107)
Fuel	7
PJM & other variable costs	(69)

*Offset in Ohio Companies



$15 million decrease in gross margin for 2008

Ohio Companies



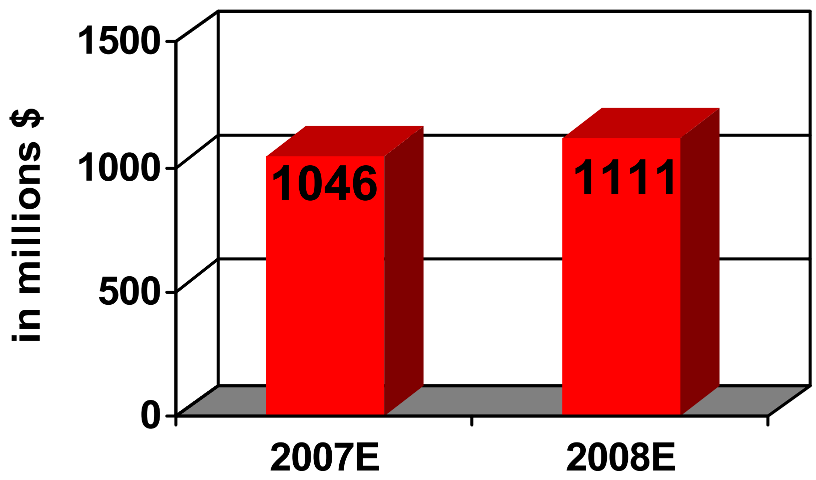
Earnings Drivers ($ in MM)

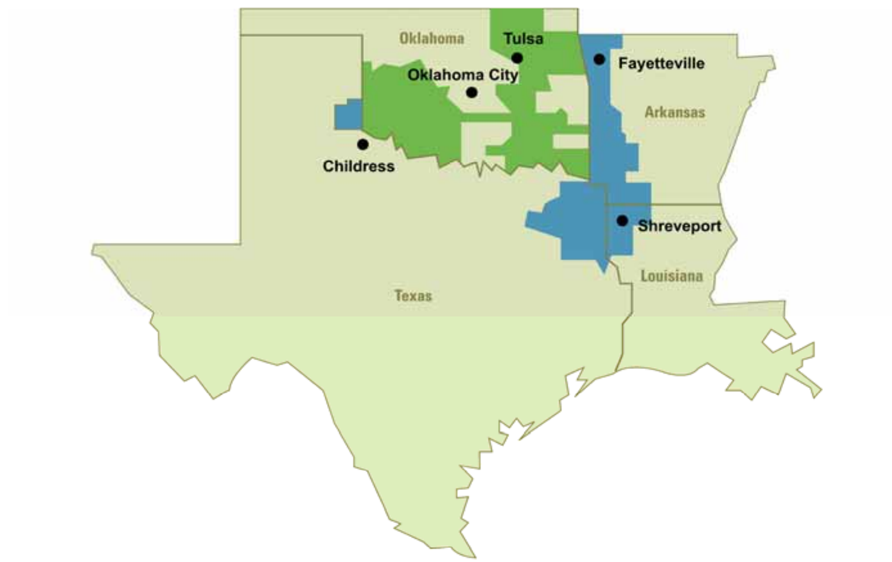
Load Growth	44
RSP Increase	120
Regulatory Asset Recovery (1)	(70)
Capacity Settlement (2)	107
Fuel	(94)
PJM & Other Variable Costs	(43)

(1) Offset in amortization - no earnings impact
(2) Offset in East Integrated Utilities

$64 million increase in gross margin for 2008

West Integrated Utilities

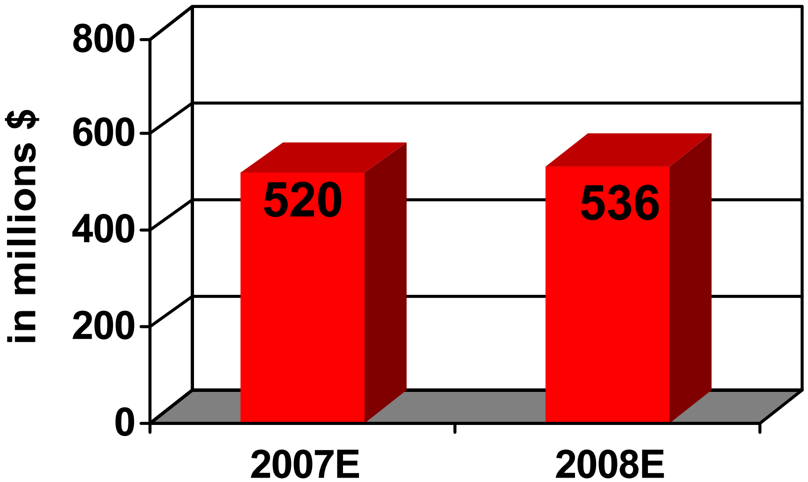


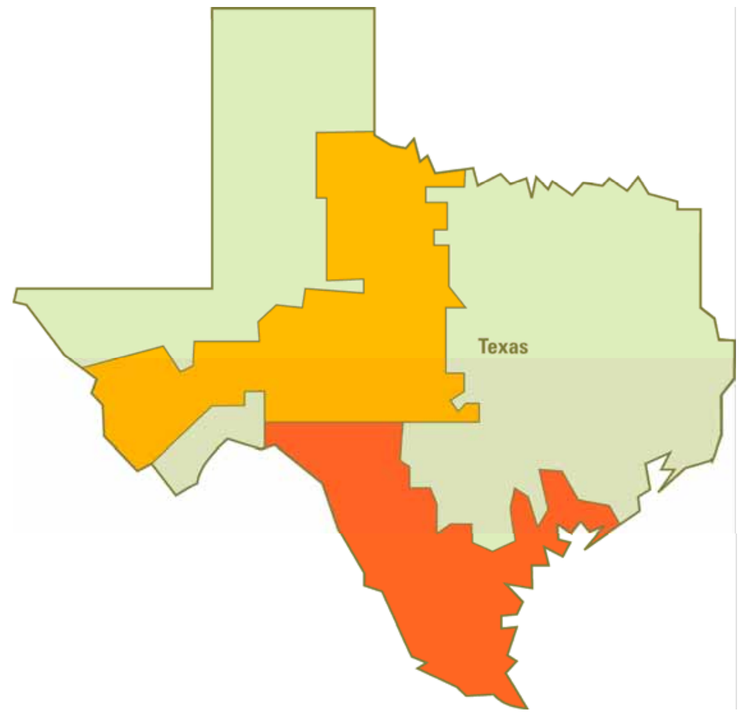


Earnings Drivers ($ in MM)	
Load Growth	22
Rate Relief	44
Other	(1)

$65 million increase in gross margin for 2008

Texas Wires



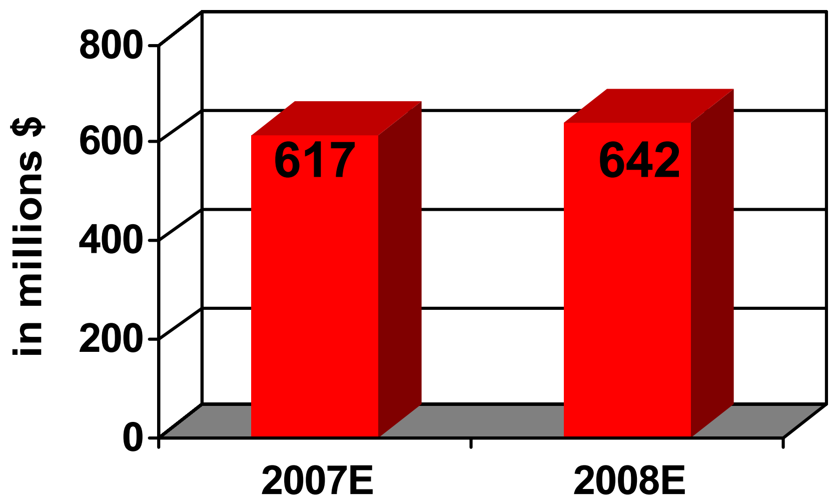


Earnings Drivers ($ in MM)

Load Growth	6
Rate Relief	10

$16 million increase in gross margin for 2008

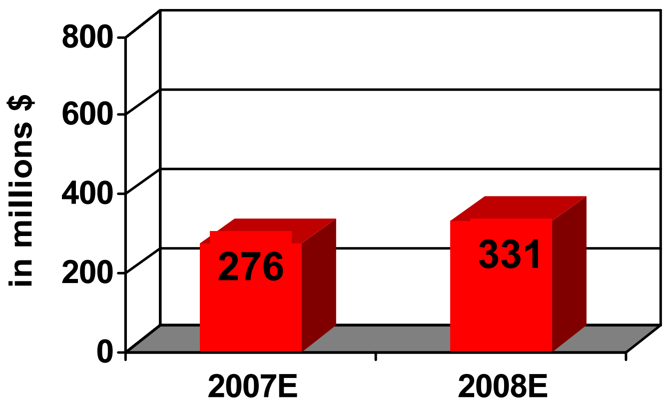
Off-System Sales



$25 million increase in gross margin for 2008, primarily driven by price assumptions

Net Transmission Revenue/Other Operating Revenue

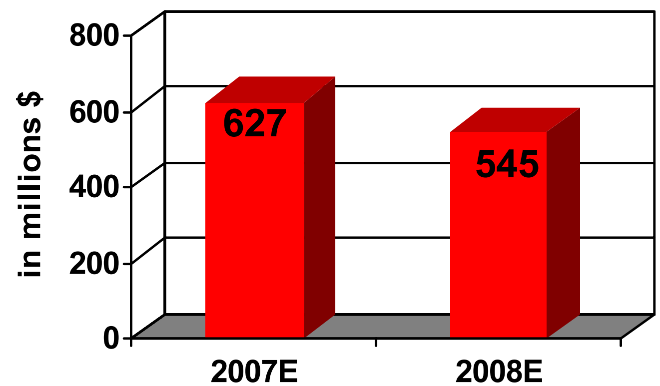
Net Transmission Revenue



Earnings Drivers ($ in MM)

PJM	11
ERCOT	24
SPP	20

Other Operating Revenue



Earnings Drivers ($ in MM)

Lower revenue from 3rd party work, offset by lower O&M	(45)
Higher eliminations due to full year of Lawrenceburg PPA, no earnings impact	(37)

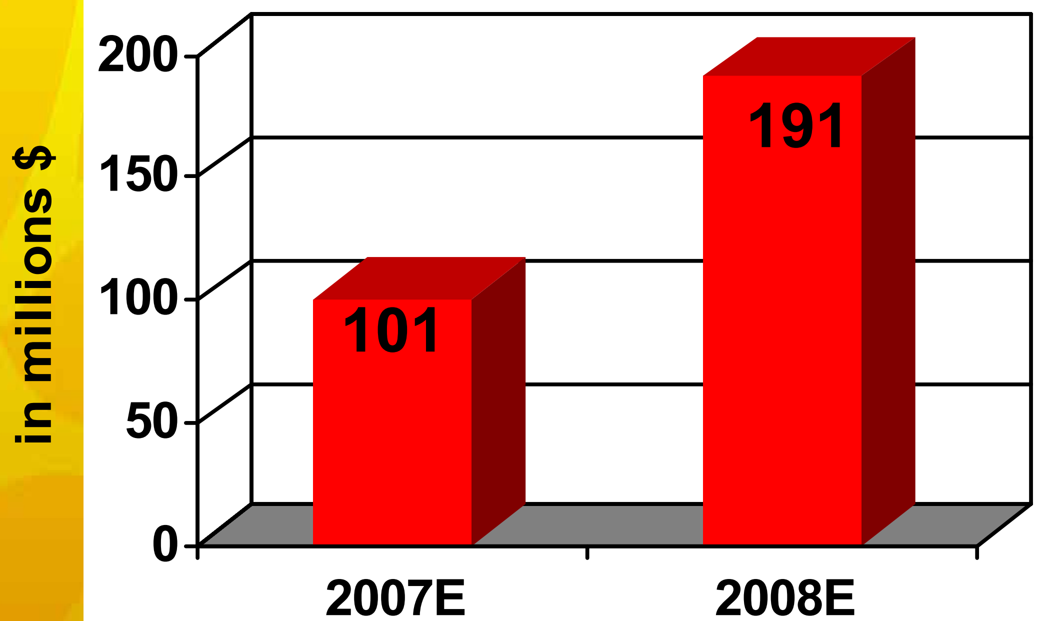
$55 million increase in Net Transmission Revenue for 2008
$82 million decrease in Other Operating Revenue for 2008

Utility Operations Segment Expense Drivers

Expense Drivers	$ in millions	
Operations & Maintenance	**25**	Continued Cost Control
Depreciation & Amortization		
Plant additions	(78)	
Change in depreciation rates	132	
Amortizations	(57)	
	(3)	IN, MI, TX and OK depreciation rate changes
Taxes		
Taxes Other than Income Taxes	(13)	
Change in Pre-Tax Income	(16)	
	(29)	Higher pre-tax income, offset by lower tax rate
Interest Expense & Pref. Dividends		
Debt (net increase)	(91)	
	(91)	Increased debt outstanding
Total	**(98)**	

$98 million increase in Utility Operations Segment expenses for 2008

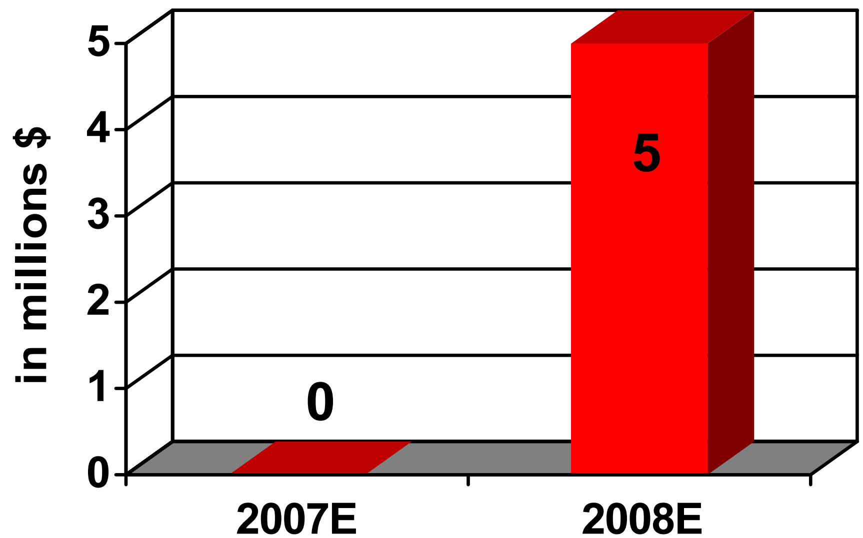
Other Income & Deductions



Earnings Drivers ($ in MM)	
APCo E&R Carrying Charges	80
Centrica Sharing	(20)
AFUDC Equity	24
Other	6

$90 million increase in other income/deduction, net for 2008

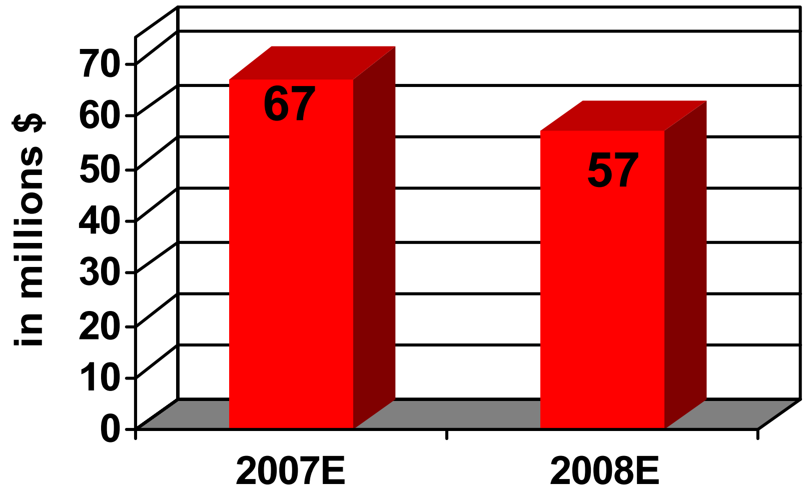
Transmission Operations



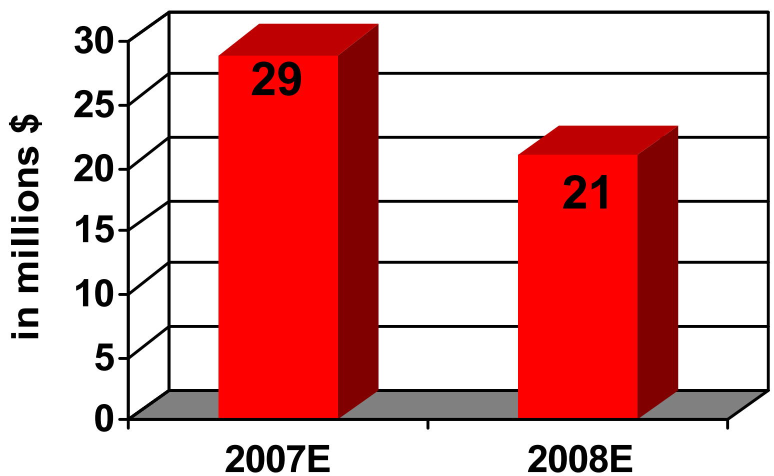
$5 million increase in equity earnings from ETT for 2008

Non-Utility Operations

MEMCO



Generation & Marketing



Earnings Drivers

MEMCO

Increasing costs

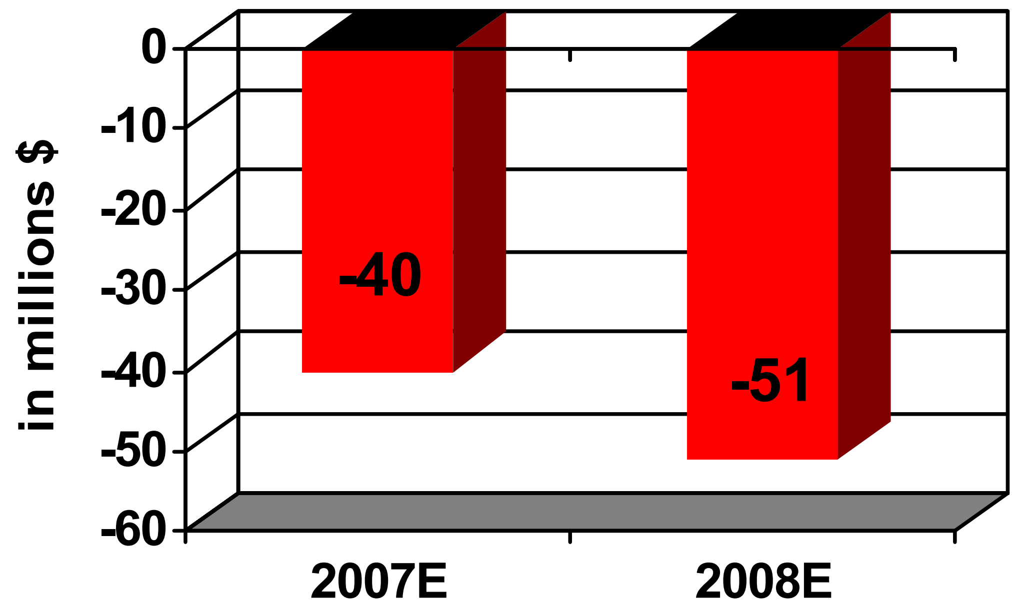
Reduced import/northbound traffic

Generation & Marketing

Divestiture of Sweeny in 4Q07

$18 million decrease in Non-Utility Operations for 2008

Parent & Other



$11 million decrease for 2008 due to increased interest expense, primarily related to the issuance of hybrid securities

Capitalization

Capital Structure	Actual 12/31/2006			Actual 9/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,777	-	14,777
Short-term Debt	18	-	18	587	-	587
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,908	9,908
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,364**	**9,969**	**25,333**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.6%***	***39.4%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,257)	-	(2,257)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(256)	-	(256)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,995**	**9,969**	**23,964**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.4%***	***41.6%***	***100.0%***

Adjusted debt-to-capital ratio was 58.4% as of 9/30/07.

Liquidity

Liquidity Summary	Actual 9/30/07	
($ in millions)	**Amount**	**Maturity**
5-Year Revolving Credit Facility (a)	1,500	Mar-11
5-Year Revolving Credit Facility (a)	1,500	Apr-12
Total Credit Facilities	**3,000**	
Plus		
Short-term Investments	0	
Total Cash & Cash Equivalents	196	
Total ST Investments, Cash & Cash Equivalents	**196**	
Less		
Commercial Paper Outstanding	559	
Amount Drawn on Bank Loans	-	
Letters of Credit Issued	69	
Net Available Liquidity	**2,568**	

(a) On March 20, 2007, both 5-Year Credit Facilities were amended to extend maturity to March 2011 and April 2012, respectively.

AEP's liquidity position stands at $2.6 billion as of 9/30/07.

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc.	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	BBB+	A-	N
AEP Texas North Company [1]	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) AEP Texas Central Company was downgraded and placed on negative outlook by Fitch in April 2007.

2008 Key Operating Company Highlights

Dependent on Actual Capital Investment ($ in millions)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEP, Inc.	$0	$500-600 (b)	n/a
AEG	$138	$100-150	40%
APCo	$720	$500-600	42-44%
CSP	$393	$250-350	45-47%
I&M	$341	$0	40-42% (c)
KPCo	$122	$100-200	41-43%
OPCo	$666	$100-200	44-46%
PSO	$266	$0	43-45%
SWEPCo	$694	$300-500	43-45%
TCC	$197	$0	40% (d)
TNC	$171	$100-150	40%

(a) Includes tax-exempt issuances
(b) represents hybrid securities
(c) Ratios include impact of Rockport 2 lease
(d) Excludes impact of securitization on the equity ratio

AEP will maintain the financial strength of its subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow.

Long-term Debt Maturity Profile

($ in millions)

Year	2007 [1]	2008	2009
AEP Service Corp.	$ -	$ 36	$ -
AEP, Inc.	$ -	$ -	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ 200	$ 200	$ 150
Columbus Southern Power	$ -	$ 112	$ -
Kentucky Power	$ 198	$ 30	$ -
Indiana Michigan Power	$ -	$ 50	$ 45
Ohio Power Company	$ -	$ 42	$ 100
Public Service of Oklahoma	$ -	$ -	$ 50
Southwestern Electric Power	$ -	$ 2	$ -
Texas Central Company	$ -	$ 48	$ -
Texas North Company	$ -	$ -	$ -
Total	$ 398	$ 520	$ 345

(1) Maturities remaining as of September 30, 2007

Debt Schedules

American Electric Power Service Corp	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

American Electric Power Inc	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	5.334%		$732,775,000

AEP Generating	Interest	Maturity	Amount
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Senior Notes	6.330%	06/28/2037	$218,181,900
Weighted Average or Total	5.957%		$263,181,900

Note: Debt schedules current as of 9/30/07.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
First Mortgage Bond (defeased)*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	5.200%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.771%		$688,687,300
Securitization Bond	5.010%	01/15/2008	$28,919,685
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.933%		$542,797,539
Securitization Bond	4.980%	01/01/2010	$191,502,599
Securitization Bond	4.980%	07/01/2013	$341,000,000
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.139%		$1,714,202,599

** TCC's first mortgage bonds were defeased in May 2004.*

Note: The weighted average coupon excludes all floating rate debt.
Debt schedules current as of 9/30/07.

Debt Schedules

AEP Texas North	Interest	Maturity	Amount
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.319%		$271,658,600

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	05/01/2037	$75,000,000
Preferred Stock	4.500%	NA	$17,752,000
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Senior Notes	5.650%	08/15/2012	$250,000,000
Senior Notes	6.700%	08/15/2037	$250,000,000
Weighted Average or Total	5.453%		$2,980,027,000

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/07.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	Floating	12/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Pollution Control Bond	Floating	08/01/2040	$44,500,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.809%		$1,148,745,000

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,533,500
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.798%		$1,320,080,200

Note: The weighted average coupon excludes all floating rate debt.
Debt schedules current as of 9/30/07.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Senior Notes	6.000%	09/15/2017	$325,000,000
Weighted Average or Total	5.650%		$627,964,000

Note: Debt schedules current as of 9/30/07.

Debt Schedules

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Notes Payable	6.810%	03/31/2008	$4,390,244
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,148,200
Preferred Stock	4.500%	NA	$9,737,300
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	Floating	04/05/2010	$400,000,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	5.829%		$2,680,372,644

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/07.

Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Preferred Stock	4.000%	NA	$4,454,800
Preferred Stock	4.240%	NA	$806,900
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	5.467%		$676,621,700

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$15,786,951
Notes Payable	Floating	06/30/2008	$2,250,000
Notes Payable	7.030%	02/22/2012	$20,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,767,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.336%		$832,471,551

Note: The weighted average coupon excludes all floating rate debt.
Debt schedules current as of 9/30/07.

AEP AMERICAN® ELECTRIC POWER

2008 Fact Book

43rd EEI Financial Conference

Phoenix, AZ

Table of Contents

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Company Overview

Company Overview

Fall EEI 2008

Company Overview

OUR FOCUS IS OUR CORE

DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Company, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions		Electric Utility Subsidiaries
AEP Ohio	→	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	→	Texas Central Company Texas North Company
Appalachian Power	→	Appalachian Power Kingsport Power
Indiana Michigan Power	→	Indiana Michigan Power
Kentucky Power	→	Kentucky Power
Public Service Company of Oklahoma	→	Public Service Company of Oklahoma
Southwestern Electric Power Co.	→	Southwestern Electric Power Co.

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Almost 39,000 megawatts of generating capacity in 3 RTOs (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 212,781 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 9.000 railcars
- own and/or operate over 2,900 hopper barges and 80 towboats
- operate one active coal-handling terminal with 20 millions tons of capacity

We consume approximately 76 million tons of coal annually.

Company Strategy

Business Strategy

AEP's mission is to bring comfort to our customers, support business and commerce and build strong communities. Our strategy to achieve our mission is to grow our core utility business at a moderate and steady rate through major investment in our current utility business supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated transmission company for the pursuit of new major interstate projects. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. Our plan entails designing, building, improving and operating low cost, environmentally-compliant, efficient sources of power and maximizing the volumes of power delivered from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Our Focus

Deliver value to our investors

- **Continue to invest in our core utility business to enable future earnings growth while improving both our earned and allowed ROEs across all operating companies**
- **Optimize the regulatory outcome for all operating companies**
- **Maximize the output of our generation fleet and optimize our off-system sales**
- **Continue to develop our transmission opportunities**
- **Continue active involvement in climate change policy**

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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AEP Service Territory

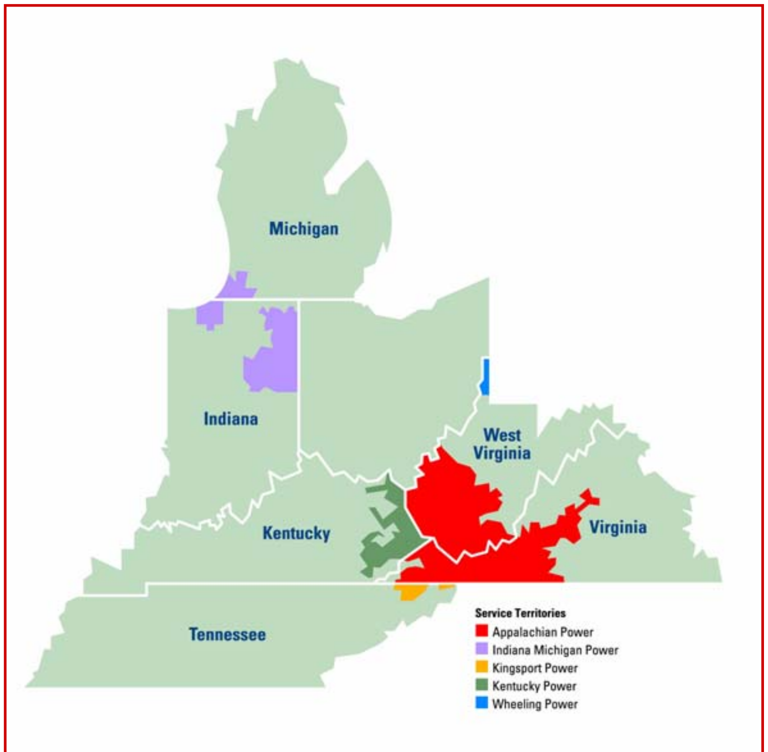
AEP EAST OPERATING COMPANIES

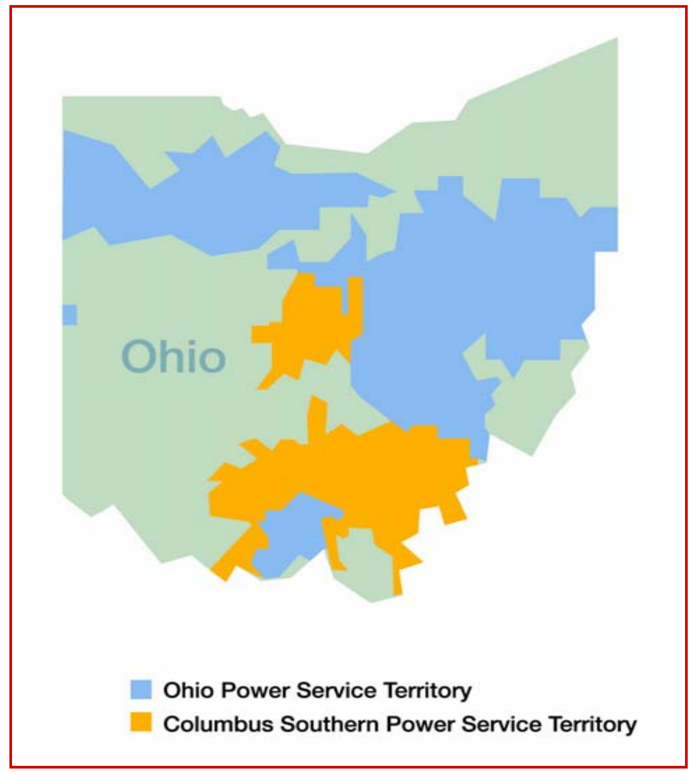
EAST REGULATED UTILITIES

Appalachian Power Company
Indiana Michigan Power Company
Kingsport Power Company
Kentucky Power Company
Wheeling Power Company

AEP OHIO

Columbus Southern Power Company
Ohio Power Company





AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

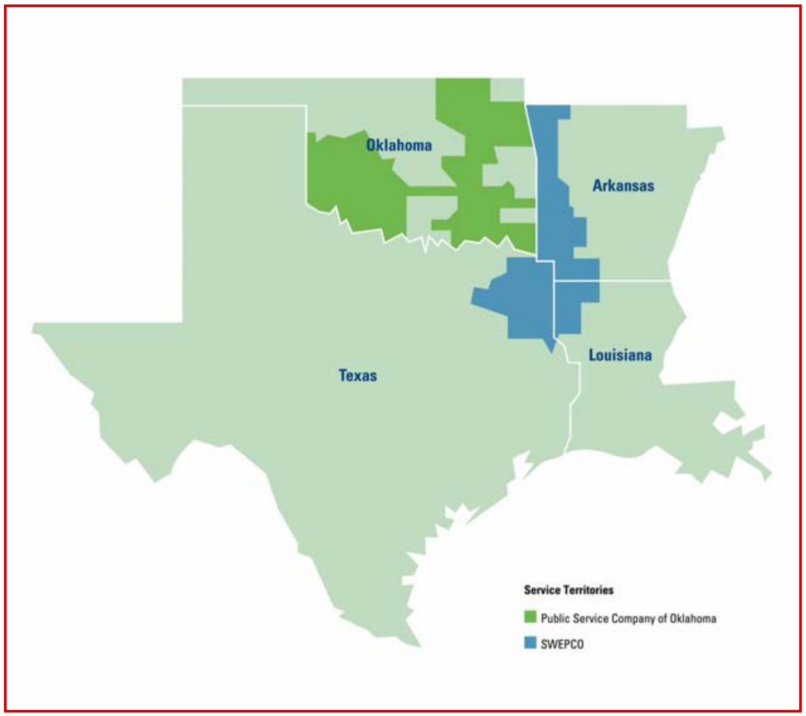
Public Service Company of Oklahoma

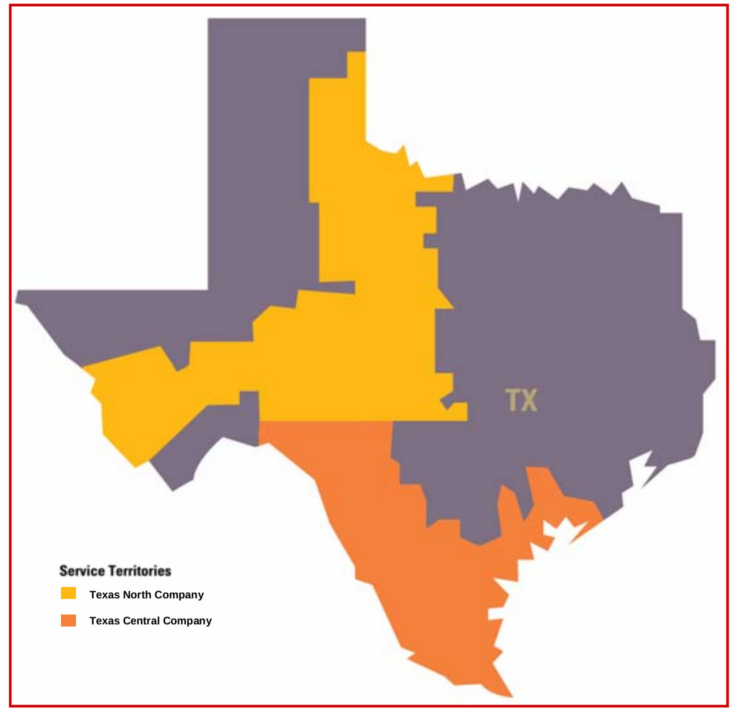
Southwestern Electric Power Company

AEP TEXAS

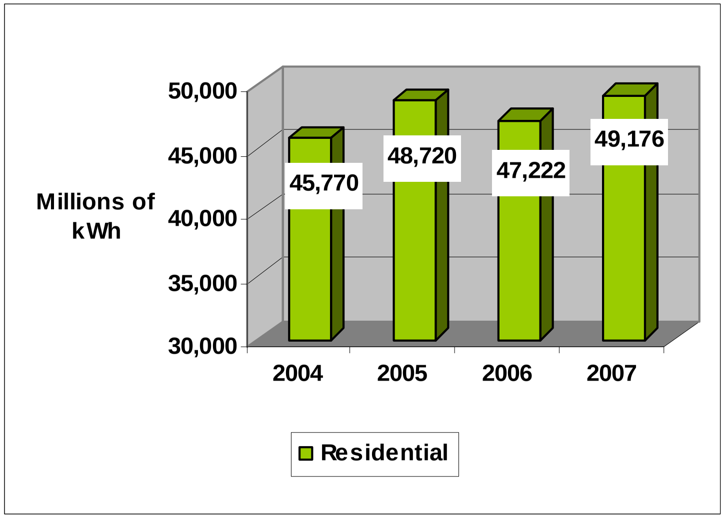
Texas Central Company

Texas North Company



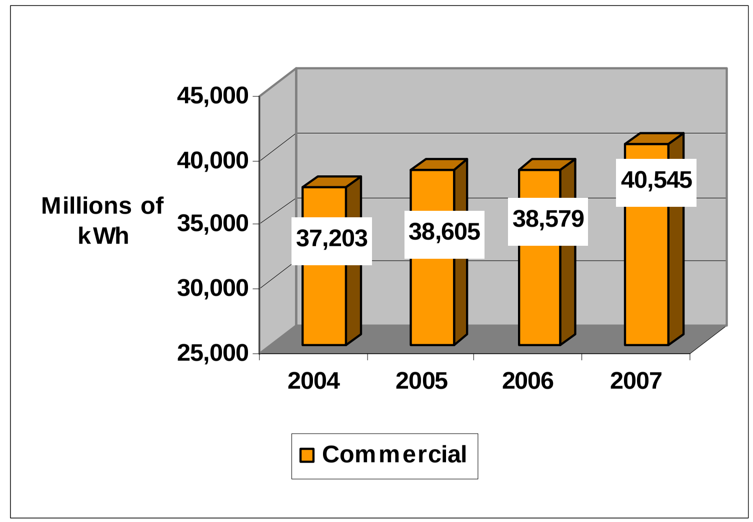


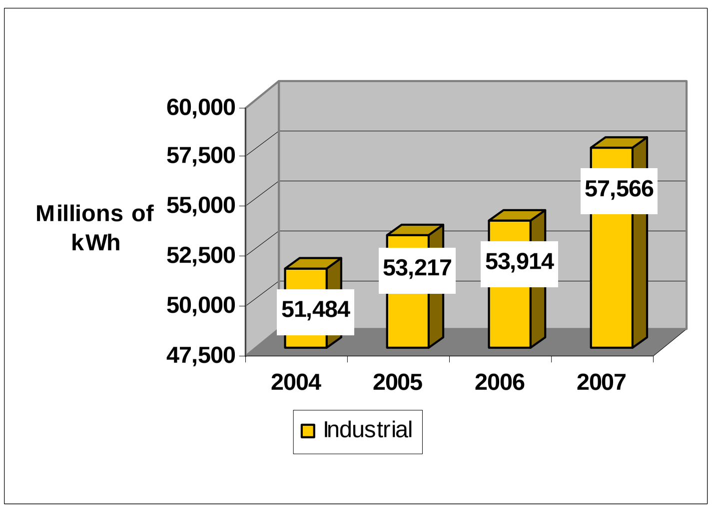
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 2.42%

3 Yr. Compound Annual Commercial Load Growth at 2.91%





3 Yr. Compound Annual Industrial Load Growth at 3.79%

Note: Figures do not include Texas Retail and Miscellaneous Other

2007 Retail Revenue

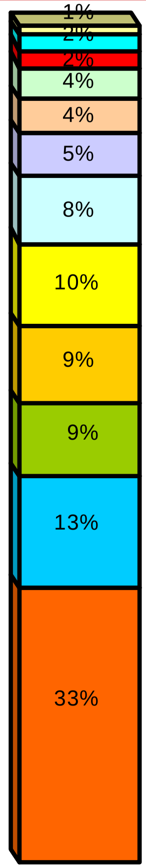
CUSTOMER PROFILE

AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

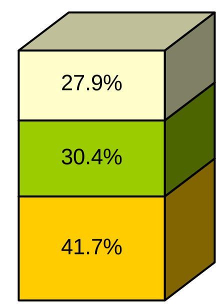
PERCENTAGE OF AEP SYSTEM RETAIL REVENUES

Tennessee	1%
Michigan	2%
Arkansas	2%
Kentucky	4%
Louisiana	4%
Texas SPP	5%
Texas ERCOT	8%
Virginia	9%
Indiana	9%
West Virginia	10%
Oklahoma	13%
Ohio	33%



Retail Revenue Composition by Customer Class**

Industrial	27.9%
Commercial	30.4%
Residential	41.7%



Source: Form 10-K
*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.
**Note: Figures do not include Other Retail Sales

Utility Operations

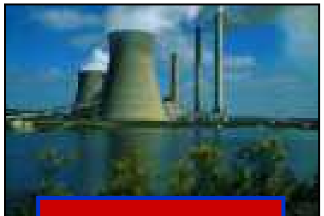
Generation

AEP has approximately 39,000 megawatts of generating capacity in 3 RTOs. AEP owns all or portions of 60 major generating plants, which include coal/lignite, natural gas, nuclear, wind projects and hydroelectric facilities.

AEP operates generating capacity in its internal power pool under an economic dispatch system[1]. AEP's power pool's competitive, largely coal-based production costs are among the lowest in the nation. AEP's power production costs are also kept relatively low by its reliance primarily on fossil fuel (gas and coal), with only a small overall nuclear dependence.

[1] Economic dispatch of a generating system utilizes the lowest-cost generating units to meet electric demand at any point in time.

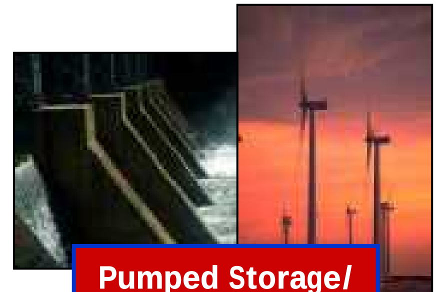
Domestic Generation Fleet



Coal/Lignite
69%

Nat. Gas/Oil
20%

Nuclear
6%



Pumped Storage/ Hydro/Wind
5%

AEP's Generation Fleet
38,721* MW Capacity

*** Includes 270 MW of mothballed/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
APCo	734	97	383	106	0	3,302	0	23	1,079	787	0	230	0	6,741
CSP	0	0	884	0	0	893	0	0	467	0	59	0	113	2,416
I&M	615	0	1,614	0	0	1,665	0	0	711	0	0	739	0	5,344
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	30
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	1,234
OPCo	509	0	909	0	0	2,464	0	0	2,169	0	0	365	112	6,528
PSO	0	0	579	34	8	2,149	10	0	812	0	0	0	0	3,592
SWEPCo	0	0	660	0	228	1,195	42	0	1,405	0	0	0	0	3,530
TCC	0	0	641	0	0	2,453	0	0	1,740	0	0	0	0	4,834
TNC	0	0	223	0	0	1,586	14	0	2,699	0	0	0	0	4,522
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	288
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,202**	**66**	**23**	**11,717**	**842**	**59**	**1,364**	**225**	**39,059**

State Level (Circuit Miles)

State	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
														0
Arkansas	0	0	28	0	228	168	42	0	461	0	0	0	0	927
Indiana	600	0	1,380	0	0	1,426	0	0	412	0	0	591	0	4,409
Kentucky	258	0	8	0	46	320	0	0	544	55	0	3	0	1,234
Louisiana	0	0	105	0	0	248	0	0	233	0	0	0	0	586
Michigan	16	0	234	0	0	239	0	0	299	0	0	148	0	936
Ohio	509	0	1,793	0	0	3,358	0	0	2,636	0	59	365	225	8,945
Oklahoma	0	0	625	34	8	2,174	10	0	812	0	0	0	0	3,663
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	275
Texas	0	0	1,345	0	0	4,793	14	0	5,151	0	0	0	0	11,303
W. Virginia	384	17	323	0	0	1,602	0	23	457	739	0	89	0	3,634
Virginia	349	96	69	15	0	1,720	0	0	709	48	0	141	0	3,147
Total	**2,116**	**113**	**5,910**	**140**	**282**	**16,202**	**66**	**23**	**11,717**	**842**	**59**	**1,364**	**225**	**39,059**

Note: Transmission line circuit miles are current as of 12/31/07

Distribution Line Detail

By State	Line Miles*		By Operating Company	Line Miles*
Tennessee	1,522			KGPCO	1,522
Virginia	30,005			KYPCO	9,848
W. Virginia	21,339			APCO	49,860
Kentucky	9,848			OPCO	26,396
Ohio	45,110			CSP	18,714
Michigan	5,247			I&M	20,089
Indiana	14,842			WPC	1,484
Texas	51,320			TCC	29,038
Oklahoma	21,622			TNC	13,772
Arkansas	4,442			PSO	21,622
Louisiana	7,484			SWEPCO	20,436
Total	**212,781**		**Total**	**212,781**

* Includes approximately 28,800 miles of underground circuit miles

Note: Distribution line circuit miles are current as of 12/31/2007

The Texas Panhandle Area was transferred from Texas North (Abilene District) to SWEPCO (Texarkana District) during 2007.

Musser Companies takeover included in APCO WVA mileage numbers.

Utility Operations

PROPERTY, PLANT & EQUIPMENT DETAIL ($ MILLIONS)

Property Plant and Equipment	Original Cost	AEP Accumulated D&A	Net Utility Plant
Electric:			
Production	$ 20,948	$ 9,200	$ 11,748
Transmission	7,734	2,417	5,317
Distribution	12,561	3,332	9,229
Other (including coal mining & nuclear fuel)	3,633	1,708	1,925
Work in Progress	3,516	(54)	3,570
Total	**$ 48,392**	**$ 16,603**	**$ 31,789**

Source: Company information as of 9/30/08

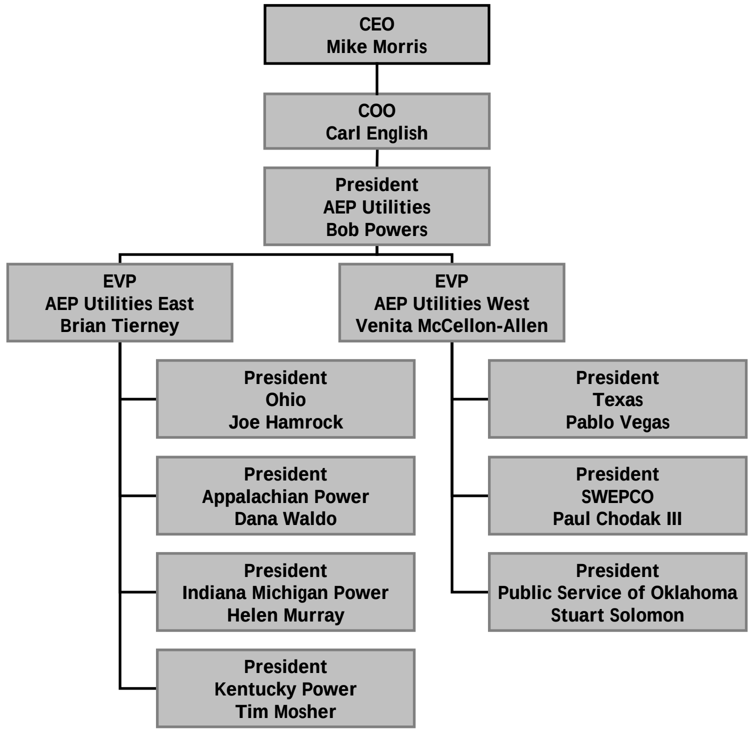
Operating Company Overview

Operating Company Overview

- **Organizational Structure**
- **AEP East Regional Utilities**
- **AEP West Regional Utilities**

Fall EEI 2008

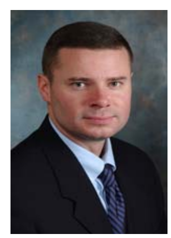
Organizational Structure




Mike


Carl


Bob


Brian

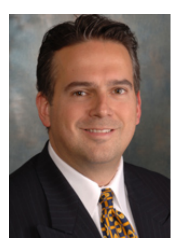

Venita


Joe


Dana


Helen


Tim


Pablo


Paul


Stuart

Senior management close to customers and regulators

AEP East Regional Utilities

Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 956,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2007, APCo and its wholly owned subsidiaries had 2,497 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers at 12/31/07:

• **Residential**	**815,000**
• **Commercial**	**130,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**956,000**

Generating Capacity	**6,290 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**80.9%**
• **Hydro/Pump:**	**10.8%**
• **Nat Gas:**	**8.3%**

Transmission Miles	**6,741**
Distribution Miles	**49,860**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576	3,122,556	2,099,784	5,222,340
% of Capitalization Per Balance Sheet	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%	59.8%	40.2%	100.0%
Adjusted Capitalization	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576	3,133,657	2,099,784	5,233,441
% of Adjusted Capitalization	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%	59.9%	40.1%	100.0%
FFO Interest Coverage			3.7			3.9			3.1
FFO Total Debt			12.4%			14.4%			12%

2007 Financial Data * (in thousands)

Revenue	$ 2,607,000
% of AEP Retail	18%
Net Income	$ 54,000
Capital Expenditure	$ 746,000

2008 Asset Data ** (in thousands)

	As of 9/30/08
Total Assets	$ 8,161,499
Net Plant Assets	$ 6,495,352
Cash	$ 1,987

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Appalachian Power

APCo Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three Year Average**
MWh Produced	32,949,364	31,494,581	32,588,773	32,344,239
Coal Consumption (tons burned)	13,187,986	12,619,910	12,828,218	12,878,704

Operating Information

2007 retail electric sales in megawatt-hours	33,875,411	2007 firm wholesale sales in megawatt-hours	3,435,670
Average cost per kilowatt-hour (residential)	6.36 cents	2007 System Peak – February 6	8,003 MW

Appalachian Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Buck #1,2,3	Ivanhoe, Virginia	5	Hydro
Byllesby #1,2,3,4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1,2,3,4	Radford, Virginia	28	Hydro
Clinch River #1,2,3	Carbo, Virginia	705	Coal
Glen Lyn #1,2	Glen Lyn, Virginia	335	Coal
Leesville #1,2	Leesville, Virginia	9	Hydro
Niagara #1,2	Roanoke, Virginia	1	Hydro
Reusens #1,2,3,4,5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1,2,3,4,5	Penhook, Virginia	586	Pump
John E. Amos #1,2 *(APCo owns 1/3 of Unit 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,320	Coal
Kanawha River #1,2	Glasgow, West Virginia	400	Coal
London #1,2,3	Montgomery, West Virginia	12	Hydro
Marmet #1,2,3	Marmet, West Virginia	11	Hydro
Philip Sporn #1,3	New Haven, West Virginia	300	Coal
Winfield #1,2,3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA

INVESTOR OWNED UTILITIES *

West Virginia	Customers
APCo	435,765
Allegheny	500,051

Virginia	Customers
APCo	509,315
Dominion Virginia	2,211,200
Allegheny	98,574
Kentucky Utilities	29,963
Potomac	22,282

Tennessee	Customers
APCo	46,208

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- **Top 10 Customers = 50% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

TYPICAL BILL COMPARISON **

West Virginia	$/month
APCo	64.55
AEP - Wheeling	64.55
Allegheny	72.52

Virginia	$/month
Old Dominion Power (Kentucky Utilities)	68.72
APCo	71.96
Dominion Virginia	88.69
Potomac	122.92

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
Felman Production (WV)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Steel of West Virginia (WV)
Goodyear Tire and Rubber (VA)
CNX Gas Company (VA)

(data for year ended December 2007)

Columbus Southern Power

President and Chief Operating Officer: Joe Hamrock

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 746,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2007, CSPCo had 1,265 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers at 12/31/07:

• Residential	666,000
• Commercial	77,000
• Industrial	3,000
Total	746,000

Generating Capacity		**3,701 MW**
Generating Capacity by Fuel Mix:		
• Coal	63.4%	
• Natural Gas	36.6%	
Transmission Miles		**2,416**
Distribution Miles		**18,714**

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035	1,393,423	1,164,277	2,557,700
% of Capitalization Per Balance Sheet	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%	54.5%	45.5%	100.0%
Adjusted Capitalization	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035	1,401,551	1,164,277	2,565,828
% of Adjusted Capitalization	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%	54.6%	45.4%	100.0%
FFO Interest Coverage			5.8			6.2			5.9
FFO Total Debt			24.3%			28.8%			26.9%

2007 Financial Data * (in thousands)

Revenue	$	2,043,000
% of AEP Retail		16%
Net Income	$	258,000
Capital Expenditure	$	338,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	3,949,104
Net Plant Assets	$	3,262,005
Cash	$	1,956

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Columbus Southern Power

Columbus Southern Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three Year Average**
MWh Produced	14,038,045	14,134,232	15,514,495	14,562,257
Coal Consumption (tons burned)	6,048,060	5,953,084	6,327,803	6,109,649

Operating Information

2007 retail sales in megawatt-hours	22,008,607
2007 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.81 cents
2007 System Peak – August 8	4,723 MW

Columbus Southern Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Conesville #1,2,3,4 *(Unit #4 co-owned by DP&L, Duke, CSP 43.5%)*	Conesville, Ohio	1,254	Coal
J. M. Stuart #*1,2,3,4 (Units co-owned by DP&L, Duke, CSP 26%)*	Aberdeen, Ohio	604	Coal
Wm. H. Zimmer #*1 (Co-owned by DP&L, Duke, CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #6 *(Co-owned by DP&L, Duke, CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	850	Nat Gas
J. M. Stuart #*1,2,3,4 (Units co-owned by DP&L, Duke, CSP 26%)*	Aberdeen, Ohio	3	Oil
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	507	Nat Gas

Columbus Southern Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	**1,449,636**
First Energy ***	1,820,036
Duke Energy Ohio	670,135
DP&L	513,074

** AEP Ohio - CSPCo = 739,424
OPCo = 710,212

*** First Energy - Toledo Edison = 265,028
CEI = 702,968
Ohio Edison = 852,040

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	**80.61**
AEP (CSP)	**93.78**
DP&L	98.54
Duke Energy Ohio	107.25
FE (CEI)	109.90
FE (Ohio Edison)	116.35
FE (Toledo Edison)	125.27

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Aluminum
Eramet Marietta, Inc.
Kraton Polymers
E I duPont de Nemours HQ
Glatfelter Company
Anheuser-Busch, Inc.
Griffin Wheel Company, Inc.

(data for year ended December 2007)

- **Top 10 customers = 59% of industrial sales**
- **Metropolitan areas account for 86% of ultimate sales**
- **238 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2007, I&M had 2,687 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Energy Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Energy Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers at 12/31/07:		
• **Residential**		**508,000**
• **Commercial**		**68,000**
• **Industrial**		**5,000**
• **Other**		**2,000**
Total		**583,000**
Generating Capacity		**5,821 MW**
Generating Capacity by Fuel Mix:		
• **Coal:**	**51.1%**	
• **Nuclear:**	**48.6%**	
• **Hydro:**	**0.3%**	
Transmission Miles		**5,344**
Distribution Miles		**20,089**

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total	2007 Debt	2007 Equity	2007 Total
Capitalization Per Balance Sheet	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829	1,612,491	1,393,779	3,006,270
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%	53.6%	46.4%	100.0%
Adjusted Capitalization	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238	2,049,215	1,393,779	3,442,994
% of Adjusted Capitalization	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%	59.5%	40.5%	100.0%
FFO Interest Coverage			4.7			4.8			4.8
FFO Total Debt			22.8%			23.9%			26.1%

2007 Financial Data * (in thousands)

Revenue	$ 2,043,000
% of AEP Retail	11%
Net Income	$ 137,000
Capital Expenditure	$ 295,000

2008 Asset Data ** (in thousands)

	As of 9/30/08
Total Assets	$ 5,935,699
Net Plant Assets	$ 3,702,117
Cash	$ 1,328

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Indiana Michigan Power

I&M Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Avg.**
MWh Produced	31,535,226	31,950,768	31,604,874	31,696,956
Coal Consumption (tons burned)	7,011,370	7,947,666	7,406,506	7,455,181

Operating Information

2007 retail electric sales in megawatt-hours	19,552,126
2007 firm wholesale sales in megawatt-hours	3,555,874
Average cost per kilowatt-hour (residential)	6.83 cents
2007 System Peak – August 7	4,528 MW

Indiana Michigan Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Rockport #1,2 (includes AEG)	Rockport, Indiana	2,620	Coal
Berrien Springs #1,2,3,4,5,6,7,8,9,10,11,12	Berrien Springs, Michigan	5	Hydro
Buchanan #1,2,3,4,5,6,7,8,9,10	Buchanan, Michigan	2	Hydro
Constantine #1,2,3,4	Constantine, Michigan	1	Hydro
Elkhart #1,2,3	Elkhart, Indiana	2	Hydro
Mottville #1,2,3,4	Mottville, Michigan	1	Hydro
Tanners Creek #1,2,3,4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1,2,3,4,5,6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1,2	Bridgman, Michigan	2,191	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN INVESTOR OWNED UTILITIES *

Indiana	Customers
I & M	**454,345**
IP & L	466,833
NIPSCO	450,819
Duke Energy Indiana	766,165
SIGECo	145,726

Michigan	Customers
I & M	**126,546**
Consumers Energy	1,792,469
Detroit Edison	2,166,478

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	$/month
I & M	**71.46**
IP & L	73.37
Duke Energy Indiana	89.19
SIGECo	116.10

Michigan	$/month
I & M	**66.09**
Consumers Energy	101.79
Detroit Edison	113.12

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

- **Top 10 Customers = 47% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **204 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

MAJOR CUSTOMERS:

Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corporation (MI)
New Energy Corp (IN)
Dock Foundry (MI)
White Pigeon Paper Company (MI)
IN TEK (IN)
The Minute Maid Company (MI)

(data for year ended December 2007)

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2007, KPCo had 471 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers at 12/31/07:	
• **Residential**	**144,000**
• **Commercial**	**30,000**
• **Industrial**	**1,500**
• **Other**	**500**
Total	**176,000**
Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,234**
Distribution Miles	**9,848**

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	493,030	347,841	840,871	477,604	369,651	847,255	467,526	386,969	854,495
% of Capitalization Per Balance Sheet	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%	54.7%	45.3%	100.0%
Adjusted Capitalization	493,030	347,841	840,871	477,604	369,651	847,255	469,770	386,969	856,739
% of Adjusted Capitalization	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%	54.8%	45.2%	100.0%
FFO Interest Coverage			3.4			3.9			3.8
FFO Total Debt			14.0%			17.7%			17.3%

2007 Financial Data * (in thousands)

Revenue	$	588,000
% of AEP Retail		4%
Net Income	$	32,500
Capital Expenditure	$	68,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	1,385,672
Net Plant Assets	$	1,096,852
Cash	$	455

Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Kentucky Power

Kentucky Power Generation Production Statistics - 2005-2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Average**
MWh Produced	7,345,624	7,171,505	7,533,223	7,350,117
Coal Consumption (tons burned)	2,926,253	2,854,537	2,950,296	2,910,362

Operating Information

2007 retail electric sales in megawatt-hours	7,114,506
2007 firm wholesale sales in megawatt-hours	100,249
2007 average cost per kilowatt-hour (residential)	6.71 cents
2007 System Peak – February 6	1,808 MW

Kentucky Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Big Sandy #1,2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY INVESTOR OWNED UTILITIES *

Kentucky	Customers
KPCo	175,572
Kentucky Utilities	497,939
LG & E	397,331

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	$/month
KPCo	67.89
Kentucky Utilities	73.67
LG&E	74.53
Duke Energy Kentucky	77.69

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:

Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Blue Diamond Coal Company
Perry County Coal Corporation
Consol of Kentucky, Inc.
Czar Coal Corporation

(data for year ended December 2007)

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **68 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

Ohio Power

President and Chief Operating Officer: Joe Hamrock

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2007, OPCo had 2,351 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Total Customers at 12/31/07:	
• **Residential**	**610,000**
• **Commercial**	**92,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**
Generating Capacity	**8,478 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**99.7%**
• **Hydro:**	**0.3%**
Transmission Miles	**6,528**
Distribution Miles	**26,396**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022	2,951,847	2,307,644	5,259,491
% of Capitalization Per Balance Sheet	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022	2,980,924	2,307,644	5,288,568
% of Adjusted Capitalization	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			6.2			6.2			4.5
FFO Total Debt			23.8%			19.7%			19.1%

2007 Financial Data * (in thousands)

Revenue	$	2,814,000
% of AEP Retail		16%
Net Income	$	268,000
Capital Expenditure	$	933,000

2008 Asset Data ** (in thousands)

		As of 9/30/08
Total Assets	$	7,684,833
Net Plant Assets	$	6,459,196
Cash	$	9,088

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)

Note: Capital Expenditure amounts exclude AFUDC

Ohio Power

Ohio Power Generation Production Statistics - 2005-2007				
Production Stat	**2005**	**2006**	**2007**	**Three Year Average**
MWh Produced	52,080,585	49,341,134	54,155,697	51,859,139
Coal Consumption (tons burned)	20,382,116	19,111,071	21,234,430	20,242,539

Operating Information

2007 retail sales in megawatt-hours	27,727,742
2007 firm wholesale sales in megawatt-hours	2,293,855
Average cost per kilowatt-hour (residential)	7.72 cents
2007 System Peak – August 23	5,485 MW

Ohio Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,640	Coal
Mitchell #1,2	Moundsville, West Virginia	1,560	Coal
Muskingum River #1,2,3,4,5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2,4,5	New Haven, West Virginia	750	Coal
Kammer #1,2,3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	580	Coal
Racine #1,2	Racine, Ohio	26	Hydro

Ohio Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	1,449,636
First Energy ***	1,820,036
Duke Energy Ohio	670,135
DP&L	513,074

** AEP Ohio - CSPCo = 739,424
OPCo = 710,212

***First Energy - Toledo Edison = 265,028
CEI = 702,968
Ohio Edison = 852,040

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	80.61
AEP (CSP)	93.78
DP&L	98.54
Duke Energy Ohio	107.25
FE (CEI)	109.90
FE (Ohio Edison)	116.35
FE (Toledo Edison)	125.27

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Ormet Primary Aluminum Corp.
Globe Metallurgical, Inc.
Premcor Refining Group, Inc.
Linde Glass, LLC
Owens Corning Fiberglass Corp.
Marathon Ashland Petroleum, LLC
Aristech Chemical Corp.

(data for year ended December 2007)

- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 60% of ultimate sales**
- **136 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 525,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2007, PSO had 1,255 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy, Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers at 12/31/07:	
• **Residential**	**451,000**
• **Commercial**	**59,000**
• **Industrial**	**7,000**
• **Other**	**8,000**
Total	**525,000**
Generating Capacity	**4,581 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**22.2%**
• **Natural Gas:**	**77.2%**
• **Oil:**	**0.6%**
Transmission Miles	**3,592**
Distribution Miles	**21,622**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	646,954	553,859	1,200,813	746,321	590,700	1,337,021	918,316	646,160	1,564,476
% of Capitalization Per Balance Sheet	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%	58.7%	41.3%	100.0%
Adjusted Capitalization	646,954	553,859	1,200,813	746,321	590,700	1,337,021	922,343	646,160	1,568,503
% of Adjusted Capitalization	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%	58.8%	41.2%	100.0%
FFO Interest Coverage			2.8			6.0			2.6
FFO Total Debt			9.5%			27.2%			9.2%

2007 Financial Data * (in thousands)

Revenue	$ 1,396,000
% of AEP Retail	13%
Net Loss	$ (24,000)
Capital Expenditure	$ 315,000

2008 Asset Data ** (in thousands)

	As of 9/30/08
Total Assets	$ 2,971,827
Net Plant Assets	$ 2,430,979
Cash	$ 2,244

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Average**
MWh Produced	15,375,848	15,139,848	14,439,801	14,985,166
Coal Consumption (tons burned)	4,353,364	4,421,396	4,102,943	4,292,568

Operating Information

2007 retail electric sales in megawatt-hours	17,910,740
2007 firm wholesale sales in megawatt-hours	10,536
Average cost per kilowatt-hour (residential)	8.10 cents
2007 System Peak – August 13	4,175 MW

Oklahoma Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Tulsa #1,2,3	Tulsa, Oklahoma	423	Nat Gas, Oil
Riverside #1,2,3,4	Jenks, Oklahoma	1,081	Nat Gas, Oil
Northeastern #1,2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern #1,2,3,4,5	Anadarko, Oklahoma	627	Nat Gas, Oil
Comanche #1,2,3	Lawton, Oklahoma	289	Nat Gas, Oil
Weleetka #1,2,3	Weleetka, Oklahoma	199	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	911	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA INVESTOR OWNED UTILITIES *

Oklahoma	Customers
PSO	**516,875**
OG&E	688,021

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	$/month
OG&E	74.21
PSO	**79.43**
Empire	90.89

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

MAJOR CUSTOMERS:

Anchor Stone
Weyerhaeuser Valliant Company
Sheffield Steel
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
American Airlines
Sun Refining
Terra Nitrogen
Sinclair
Explorer Pipeline Company

(data for year ended December 2007)

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 85)**

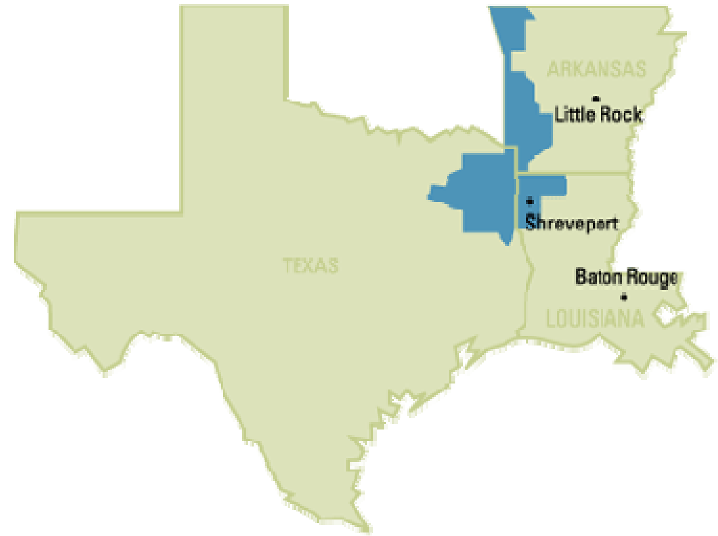
(data for 12 months ended December 2007)

Southwestern Electric Power

President and Chief Operating Officer: Paul Chodak III

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 467,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2007, SWEPCo had 1,578 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.



Total Customers at 12/31/07:		
• **Residential**		**394,500**
• **Commercial**		**65,000**
• **Industrial**		**7,000**
• **Other**		**500**
Total		**467,000**
Generating Capacity		**4,857 MW**
Generating Capacity by Fuel Mix:		
• **Coal:**	**38.0%**	
• **Natural Gas:**	**44.7%**	
• **Lignite:**	**17.3%**	
Transmission Miles		**3,530**
Distribution Miles		**20,436**

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Food processing
Primary metals

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	776,529	787,078	1,563,607	936,929	825,899	1,762,828	1,199,068	977,652	2,176,720
% of Capitalization Per Balance Sheet	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%	55.1%	44.9%	100.0%
Adjusted Capitalization	776,529	787,078	1,563,607	936,929	825,899	1,762,828	1,299,388	977,652	2,277,040
% of Adjusted Capitalization	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%	57.1%	42.9%	100.0%
FFO Interest Coverage			3.8			5.9			3.5
FFO Total Debt			18.1%			28.9%			13.7%

2007 Financial Data * (in thousands)

Revenue	$	1,483,000
% of AEP Retail		11%
Net Income	$	66,000
Capital Expenditure	$	505,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	4,126,456
Net Plant Assets	$	3,330,288
Cash	$	2,752

Sources: * 2007 Form 10-K
** 3Q08 Form 10-Q (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics - 2005 - 2007				
Production Stat	**2005**	**2006**	**2007**	**Three-Year Average**
MWh Produced	20,167,754	19,961,798	19,673,059	19,934,203
Coal/Lignite Consumption (tons burned)	12,420,979	12,180,786	12,393,538	12,331,768

Operating Information

2007 retail electric sales in megawatt-hours	17,287,236
2007 firm wholesale sales in megawatt-hours	5,771,986
Average cost per kilowatt-hour (residential)	7.52 cents
2007 System Peak – August 14	4,924 MW

SWEPCO Power Plants (Winter Capacity)			
Name	**Location**	**Nominal Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Mattison #1,2,3,4	Tontitown, Arkansas	346	Gas
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1,2,3,4	Mooringsport, Louisiana	278	Gas
Dolet Hills #1 *(Own 40%; operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2,3,4,5	Longview, Texas	486	Gas
Wilkes #1,2,3	Avlinger, Texas	897	Gas
Welsh #1,2,3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN INVESTOR OWNED UTILITIES *

Arkansas	Customers
SWEPCo	111,109
Entergy AR	681,298

Louisiana	Customers
SWEPCo	174,213
CLECO	265,556
Entergy	1,140,194

Texas	Customers
SWEPCo	168,180
El Paso	262,428
SPSCo	277,632
Entergy	382,202

* Customer counts are as of December 31, 2006 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	$/month
OG&E	63.04
SWEPCo	65.56
Empire District	76.18
Entergy AR	97.02

Louisiana	$/month
SWEPCo	66.39
Entergy LA	86.80
Entergy NO	101.20
Entergy Gulf St	104.56
CLECO	115.08

Texas	$/month
SWEPCo	60.11
SPSCo	83.55
El Paso	112.96
Entergy	113.36

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2008 Typical Bills and Average Rates Report as of January 1, 2008.

- **Top 10 customers = 54% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **80 persons per square mile (U.S. = 85)**

(data for 12 months ended December 2007)

MAJOR CUSTOMERS:

Lone Star Steel Company (TX)
Big Three Industrial Gas (TX)
UOP, LLC (LA)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Letourneau (TX)
Superior Industries (AR)
Tyson Foods, Inc. (AR)

(data for year ended December 2007)

AEP Texas Central Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 753,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2007, TCC had 1,195 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Refinery West
Formosa
Javelina Refinery
Equistar Bay City

(data for year ended December 2007)

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 37% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 85)**

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2007)

Total Customers at 12/31/07:
(Based on electric meters)

• **Residential**	**642,000**
• **Commercial**	**104,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**753,000**
Transmission Miles	**4,834**
Distribution Miles	**29,038**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total	2007 Debt	2007 Equity	2007 Total
Capitalization Per Balance Sheet	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651	2,937,553	465,115	3,402,668
% of Capitalization Per Balance Sheet	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%	86.3%	13.7%	100.0%
Adjusted Capitalization	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843	665,544	465,115	1,130,659
% of Adjusted Capitalization	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%	58.9%	41.1%	100.0%
FFO Interest Coverage			1.4			2.0			3.7
FFO to Total Debt			2.6%			13.0%			24.8%

2007 Financial Data * (in thousands)

Revenue	$	809,000
% of AEP Retail		7%
Net Income	$	59,000
Capital Expenditure	$	222,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	5,131,177
Net Plant Assets	$	2,487,543
Cash	$	203

Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

AEP Texas North Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 184,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2007, TNC had 373 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:

TXN
Zoltec Corporation
Tyson Foods, Inc.
Kinder Morgan
EBAA Iron

(data for year ended December 2007)

PRINCIPAL INDUSTRIES SERVED:

Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 37% industrial sales* ($)**
- **Metropolitan areas account for 60% ultimate sales**
- **8 persons per square mile (U.S. = 85)**
  - Industrial % is in terms of wires revenues

(data for 12 months ended December 2007)

Total Customers at 12/31/07:
(Based on electric meters)

• **Residential**	**144,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**<u>5,000</u>**
Total	**184,000**

Generating Capacity **377 MW**
Oklaunion Plant - Vernon, TX
(excludes 270 MW of decommissioned plants)

Generating Capacity by Fuel Mix:

• **Coal:**	**58.3%**
• **Gas:**	**40.5%**
• **Oil:**	**1.2%**

Transmission Miles	**4,522**
Distribution Miles	**13,772**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2005			2006			2007		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	276,845	316,276	593,121	276,936	308,705	585,641	302,386	334,244	636,630
% of Capitalization Per Balance Sheet	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%	47.5%	52.5%	100.0%
Adjusted Capitalization	276,845	316,276	593,121	268,785	308,705	577,490	303,682	334,244	637,926
% of Adjusted Capitalization	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%	47.6%	52.4%	100.0%
FFO Interest Coverage			5.0			3.7			4.7
FFO Total Debt			29.8%			17.4%			21.2%

2007 Financial Data * (in thousands)

Revenue	$	280,000
% of AEP Retail		1%
Net Income	$	39,000
Capital Expenditure	$	88,000

2008 Asset Data ** (in thousands)

	As of 9/30/08	
Total Assets	$	1,096,081
Net Plant Assets	$	954,938
Cash	$	214

Sources: * 2007 Annual Report
** 3Q08 Financial Statements (unaudited)
Note: Capital Expenditure amounts exclude AFUDC

Regulation

Regulation

- Regulatory Strategy
- Rate Case Filing Requirements
- Regulatory Activity Underway
- GridSMART Regulatory Status
- Rate Base and ROE by Operating Company
- Commission Overviews

Fall EEI 2008

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Louisiana	Michigan	Ohio	Oklahoma	Texas	Virginia	West Virginia	FERC
General											
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	Yes	No	No
Period of Limitation (months)	--	15	--	--	--	--	--	--	See note 1	--	--
Pancaking Permitted?	No	No	No	Yes	No	Limited	Yes	No	No	No	Yes
Notice of Intent											
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	N/A	45	30	45	30	60	30	N/A
Case Components											
Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Partially Projected	Historical	Historical	Historical	Forecast Optional
Other											
Rates Effective Subject to Refund	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes
Approx # of Months after Filing to implement rates subject to refund	10	--	6	--	Varies	9	6	5	5	--	2 or 7

Note 1: Post 1/1/09 no interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Regulatory framework inherently produces recovery and return lag.

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- SWEPCo Stall Plant Filings in Arkansas
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART℠ Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony was filed October 31, Staff testimony was filed November 7 and the public hearing commences on November 17, 2008. We anticipate an order in the first quarter of 2009.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $125.6 million ($80.1 million in base revenues and $45.6 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure – Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief – Company Position (9/30/07)
($ in millions)

Rate Base	$	1,999.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	161.9	
Pro-Forma Operating Income	$	113.1	
Difference	$	48.8	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	80.1	
Reliability Enhancement Tracker	$	28.4	
DSM / EE Tracker	$	4.4	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	44.4	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	125.6	

* rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2 *
Rate of Return		8.64%
Operating Income Requirement	$	133.5
Pro-Forma Operating Income	$	53.0
Difference	$	80.5
Revenue Conversion Factor		1.647045
Total Required Rate Relief	$	132.6

* rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates were effective on October 28, 2008, subject to refund with interest. On October 29, 2008, a settlement agreement was presented to the SCC for its consideration. The settlement allows for a revenue increase of $168MM based on a 10.2% ROE. We await a final order. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1	*
Rate of Return		8.52%	
Operating Income Requirement	$	205.7	
Adjusted Operating Income	$	79.2	
Difference	$	126.5	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	207.9	

* rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

SPP OATT Formula Rate Filing (Docket #:ER07-1069-000)

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing (Docket #:ER08-1329-000)

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to March 1, 2009, with rates subject to refund.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an application to purchase, operate, own and install peaking, intermediate and baseload generating facilities. The peaking facility has been addressed and the intermediate facility has been approved. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued its order approving construction of the plant on August 12, 2008, with a cost cap of $1.52 billion and a cap on carbon dioxide at $28/ton through 2030. This order is currently under appeal in Texas.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- ❑ Proceeding is pending.

Louisiana

- ❑ On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- ❑ PSC approval was granted on September 10, 2008.
- ❑ Air permit received on March 20, 2008.

Texas

- ❑ PUCT order approving plant was issued on March 8, 2007.

gridSMART℠ Evolution – AEP East

	State Policy	AEP Action Plans
AEP OHIO — A unit of American Electric Power	SSB 221 provides targets and provisions for DSM/EE programs and supports infrastructure modernization.	Filed an Electric Security Plan (2008) which includes a model city pilot in NE Columbus and addresses DSM/EE programs. New 2 MW NaS battery in Bluffton will demonstrate use of storage to enhance a sub-transmission system.
AEP APPALACHIAN POWER — A unit of American Electric Power	Legislative interest in Virginia beginning to drive regulatory activity in EE/DSM.	New 2 MW NaS battery in West Virginia will test dynamic islanding – supplying electricity while disconnected from the grid. AMR investments in Virginia and West Virginia will defer new AMI for several years. EE/DSM potential study initiated.
AEP KENTUCKY POWER — A unit of American Electric Power	Kentucky's commission rules regarding DSM/EE programs are the model we seek in other states.	Existing programs are focused on low-income weatherization and heat pump programs for mobile homes with favorable recovery. AMR investment will defer new AMI for several years.
AEP INDIANA MICHIGAN POWER — A unit of American Electric Power	Pending DSM filing in Indiana; rules being finalized. EE/DSM legislative goals recently established in Michigan.	Broadly focused South Bend Pilot includes AMI, distribution automation, demand response, pre-paid meters. NaS battery installation in IN in 2008 to demonstrate storage with intermittent wind.

The eastern states are evolving in their positions regarding demand side management, energy efficiency and AMI investments.

gridSMART^{SM} Evolution – AEP West

	State Policy	AEP Action Plans
AEP TEXAS – A unit of American Electric Power	Current legislation allows concurrent cost recovery of DSM/EE programs and performance incentives for exceeding goals. Legislature expecting distribution service providers in ERCOT to file plans for smart meter deployment.	Implementing aggressive DSM/EE programs to achieve legislatively mandated targets of 15% and 20% to reduce growth in demand in 2008 & 2009 respectively. A deployment plan for smart meters was initiated as of 10/31/08.
AEP PUBLIC SERVICE COMPANY OF OKLAHOMA – A unit of American Electric Power	DSM proceedings currently underway. Heavily involved with Commission regarding rulemaking. Favorable recovery provisions proposed.	Conducting Distribution Automation pilot in South Tulsa. In process of implementing quick start DSM/EE programs.
AEP SOUTHWESTERN ELECTRIC POWER COMPANY – A unit of American Electric Power	DSM/EE program costs are recoverable thru a rider in Texas and Arkansas and base rates in Louisiana. No current statutory support for AMI outside of Texas footprint.	Implementing aggressive EE/DSM programs to achieve targets of 15% and 20% (respectively) to reduce growth in demand in 2008 & 2009 in Texas. Continue quick-start DSM/EE in Arkansas. Submitted EE Potential Study to Louisiana Commission in October 2008.

Texas currently has the most progressive legislative stance with regards to supporting AMI. PSO and SWEPCo have active DSM/EE programs with Distribution Automation pilots proposed in each state.

Approved Rate Bases & ROEs and Current Rate Case Requests

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo-Virginia	$2,022MM	10.00%	10/2/2006
APCo-West Virginia	$1,656MM	10.50%	7/28/2006
Kentucky	$858MM	10.50%	3/31/2006
I&M-Indiana	$1,805MM	12.00%	11/19/1993
I&M-Michigan	$268MM	13.00%	4/1/1991
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo-Louisiana	$577MM	10.565% *	8/1/2008
SWEPCo-Arkansas	$408MM	10.75%	9/23/1999
SWEPCo-Texas	$474MM	15.70%	2/15/1983
TCC-Texas	$1,566MM	9.96%	6/1/2007
TNC-Texas	$530MM	9.96%	6/1/2007

*** - represents midpoint of the ROE range approved in the formula rate case settled in April 2008.**

Rate Case Requests on File

Jurisdiction	Requested Rate Base	Requested ROE
I&M - Indiana	$1,999MM	11.50%
PSO - Oklahoma	$1,545MM	11.25%
APCO - Virginia	$2,415MM	11.75%

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**
Qualifications for Commissioners The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.			
Commissioners **Paul Suskie, Chairman (Dem.),** since 2007; current term ends in 2013. Lawyer, North Little Rock, Arkansas City Attorney. Bachelor's attained at University of Central Arkansas. Juris Doctorate at University of Arkansas at Little Rock School of Law. NARUC member including Committee on Energy Resources and the Environment and Committee on Consumer Affairs.			
Daryl E. Bassett, Commissioner (Rep.), since 2003; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).			
Collette Honorable, Commissioner (Dem.), since 2008; current term ends in 2011. Commissioner Honorable is a member of NARUC and serves on the Electricity and Consumer Affairs Committees. She also serves on the Smart Grid Collaborative, a joint effort of NARUC and the FERC. Honorable obtained her Juris Doctorate from the University of Arkansas at Little Rock School of Law.			

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 3 D: 2**

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

Commissioners

David L. Hardy, Chairman (Rep.), since 2005; current term will expire April 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include negotiation, contracts, litigation, finance and administration. He has 35 years of regulatory experience at the state and federal levels. Bachelors degree and law degree from Indiana University.

Jeffrey L. Golc, Commissioner (Dem.), since 2007; current term will expire in 2009. Former public affairs manager for the Kroger Company. Previous Deputy Commissioner for the Indiana Bureau of Motor Vehicles and the Indiana Department of Workforce Development. Bachelors and Masters degrees in communications from Indiana University.

Larry S. Landis, Commissioner (Rep.), since 2002; current term ends June 2011. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.

Greg Server, Commissioner (Rep.), since 2005; current term ends 2009. Former state senator since 1981 and before that served in the Indiana House of Representatives from 1972 to 1980. Served as chair of Senate Commerce Committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility. Masters degrees in political science and counseling from Indiana State University.

David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2011. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and Advisory Council of the Electric Power Research Institute. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

I&M provides retail electric service in Indiana at bundled rates approved by the IURC. Rates are set on a cost-of-service basis with a fuel recovery mechanism. A current full base rate case is in process with a final order expected in the first half of 2009. The rate case includes requests for riders related to DSM, environmental, reliability, OSS and RTO costs.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 2 D:1**
Qualifications for Commissioners Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.			
Commissioners **David L. Armstrong, Chairman (Dem.),** since 2008; current term expires June 2011. Former practicing attorney in private practice. J.D. from University of Louisville Brandeis School of Law. Mr. Armstrong is also the former Mayor for the city of Louisville, KY (1999-2003).			
John W. Clay, Vice Chairman (Rep.), since 2006; current term expires June 2009. Former deputy secretary of the Kentucky Environmental and Public Protection Cabinet. Served as executive director of the Office of Alcohol Beverage Control in the Department of Public Protection. B.A. from Georgetown College. Certified Public Accountant and member of the AICPA.			
James W. Gardner, Commissioner (Rep.), since 2008; current term expires June 2012. Prior to joining the PSC Mr. Gardner was a partner at the law firm Henry Watz Gardner & Sellars PLLC where he specialized in bankruptcy law. JD degree from the University of Kentucky College of Law.			

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 3**

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2010. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects. A formula rate plan was implemented August 1, 2008.

Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: D: 2 I: 1**

Qualifications for Commissioners

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

Commissioners

Orjiakor N. Isiogu, Chairman (Dem.), since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.

Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's degree, University of Michigan.

Steven A. Transeth, Commissioner, (Ind.) , since 2007; current term expires July 2009. Former assistant director and legal counsel for the Michigan Legislative Service Bureau, which included drafting legislation and providing legal counsel to the Michigan Senate and House of Representatives. Lawyer, private practice and with the Ingham County Prosecuting Attorney's office.. J.D. from Thomas Cooley Law School.

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active fuel clause and return on CWIP can be included in base rates.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 1 D: 2 I: 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee, National Governors' Association Electricity Task Force, Harvard Electricity Policy Group.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctor from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Ronda Hartman Fergus, Commissioner, (Rep.) since 1995; term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff. Member NARUC Committee on Consumer Affairs.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master's degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation. Chair of the Board of Directors of the National Academy of Public Administration.

Cheryl Roberto, Commissioner, (Dem.) since 2008; term expires April 2013. Prior to joining the PUC, Roberto was director of the City of Columbus Public Utilities Department. Before entering the public sector, Commissioner Roberto worked as an assistant attorney general for the state of Ohio. Commissioner Roberto received her B.A. with honors from Kent State University and her Juris Doctorate from the Moritz College of Law at The Ohio State University.

AEP Regulatory Status

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSP and OPCo (the Ohio Companies). The plans provided, among other things, for CSP and OPCo to raise their generation rates by 3% and 7% respectively, in 2006, 2007 and 2008 and provided for additional generation rate increases of up to 4% per year based on the Ohio Companies supporting the need for additional revenues. Distribution rates in effect at 12/31/05 are frozen for OPCo and CSP until 12/31/08. Transmission rates are currently regulated by FERC as reflected in the OATT. SB221 allows that CSP and OPCo will have active fuel clauses effective January 1, 2009. An Electric Security Plan is currently on file with the PUCO for consideration before the end of 2008. The ESP requests a 15% rate increase for all CSP and OPCo customers.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 1**

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of Staff. Law degree from Oklahoma City University.

Bob Anthony, Commissioner, (Rep.), since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.

Jim Roth, Commissioner, (Dem.), since 2007;appointed by the governor to fill the seat opened by the resignation of Commissioner Bode; current term ends January 2011. Previously served various county governments for eight years. Juris Doctorate from Oklahoma City University School of Law.

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism and has rider mechanisms currently approved for vegetation management and the new peaking facilities in-service in 2008.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 3**

Qualifications for Commissioners

The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all expired in June 2008; terms are now staggered.

Commissioners

Tre Hargett, Chairman (Rep.), since 2008; current term expires 2012. Former Representative of House District 97. M.B.A. Memphis State University.

Mary W. Freeman, Director (Dem.), since 2008; current term expires June 2011. Prior legislative director for Governor Bredesen, executive assistant to State Representative Lois DeBerry. B.A. Tennessee State University.

Sara Kyle, Director (Dem.), since 1996; current term expires June 2012. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving director and only holdover from the previous Regulatory Authority. Law degree from Middle Tennessee State University.

Eddie Roberson, Ph.D, Director, (Dem.), since 2006; current term expires June 2010. Former Chief of Consumer Services Division of the Regulatory Authority; also served a year as the agency's Executive Director. Served two terms on the Chattanooga City School Board. Ph.D in Public Administration from Tennessee State University.

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.
Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 3**
Qualifications for Commissioners To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.			
Commissioners **Barry T. Smitherman, Chairman, (Rep.),** since April 2004; current term expires August 2013. Attorney; Assistant DA; Public Finance Investment Banker. Received law degree from the University of Texas School of Law.			
Kenneth W. Anderson, (Rep.) since September 2008; current term expires September 2011. Past Director of Governmental Appointments under Governor Perry. Prior to that Anderson served in private practice as a corporate attorney in the area of securities law and regulatory matters. He also served as a member of the Texas Securities Board from 1999-2006. Anderson holds a law degree from Southern Methodist University.			
Donna Nelson, Commissioner (Rep.), since August 2008; current term expires August 2009. Nelson served as a special assistant and advisor to Governor Perry on energy, telecommunications and cable budget and policy issues. She previously served as director of the PUC telecommunication's section and legal advisor to the PUC chairman. Nelson holds a law degree from Texas Tech University.			

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base.

TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 1**
Qualifications for Commissioners The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.			
Commissioners **Judith Williams Jagdmann, Chairperson, (Rep.),** since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.			
Mark C. Christie (Rep.), since 2004; current term expires 2010. Attorney, counsel to the Speaker of the House. Lawyer, private practice. Law degree from Georgetown.			
James C. Dimitri (Dem.), since 2008; current term expires 2014. Prior to being named Commissioner, Dimitri was in private practice in Richmond. From 1994 to 2000 he served as Senior Counsel, then General Counsel at the SCC. He was an assistant Attorney General from 1983 to 1987. Dimitri received his undergraduate degree in economics from the University of Virginia and his J.D. from the Boston University School of Law in 1976.			

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The opportunity for one rate case exists before December 31, 2008, which was filed May 30, 2008. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution system reliability and compliance with state or federal environmental laws or regulations (known as the E&R rider). APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.
Wheeling Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, Commissioner (Dem.), since 2003; term expires June 2009. Former Chief of Operations in the Governor's office. Former Chief Financial Officer of the Workers' Compensation Division of the W.V. Bureau of Employment Programs. Certified Public Accountant in West Virginia and Georgia. Bachelor's degree, West Virginia University.

Michael A. Albert, Chairman (Rep.), since 2007; term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005; term expires June 2011. Currently on the board of directors of the NARUC and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction.

Generation & Environmental

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- Generation Statistics
- New Generation
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- Future Potential Green House Gas Regulations

Fall EEI 2008

Domestic Generation

Generation Capacity*

COMPANY	**MW Capacity**
AEP Generating Co	2,466
Appalachian Power Co	6,290
Columbus Southern Power	3,701
Indiana Michigan Power Co	4,501
Kentucky Power Co	1,060
Ohio Power Co	8,478
Public Service of Oklahoma	4,581
Southwestern Electric Power Co	4,857
Texas North Co**	647
OVEC Capacity***	986
Domestic IPPs	311
Wind Purchase Power Agreements	843
Total	**38,721**

*Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 270 MW of mothballed / retired / decommissioned generation

*** AEP owns a 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE.

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
AEP Generating Company					
Rockport	1	IN	RFC	Steam - Coal	1,320
Lawrenceburg	6	IN	RFC		1,146
					2,466
Appalachian Power Company					
Buck	3	VA	RFC	Hydro	5
Byllesby	4	VA	RFC	Hydro	8
Claytor	4	VA	RFC	Hydro	28
Leesville	2	VA	RFC	Hydro	9
London	3	WV	RFC	Hydro	12
Marmet	3	WV	RFC	Hydro	11
Niagara	2	VA	RFC	Hydro	1
Reusens	5	VA	RFC	Hydro	6
Winfield	3	WV	RFC	Hydro	15
Smith Mountain	5	VA	RFC	Pumped Storage	586
Amos	2	WV	RFC	Steam - Coal	2,033
Clinch River	3	VA	RFC	Steam - Coal	705
Glen Lyn	2	VA	RFC	Steam - Coal	335
Kanawha River	2	WV	RFC	Steam - Coal	400
Mountaineer	1	WV	RFC	Steam - Coal	1,320
Sporn	2	WV	RFC	Steam - Coal	300
Ceredo	6	WV	RFC	Natural Gas	516
					6,290
Columbus Southern Power Company					
Beckjord (CCD)	1	OH	RFC	Steam - Coal	53
Conesville (CCD)	4	OH	RFC	Steam - Coal	1,254
Picway (CCD)	1	OH	RFC	Steam - Coal	100
Stuart (CCD)	4	OH	RFC	Steam - Coal	604
Stuart (CCD)	4	OH	RFC	Oil	3
Zimmer (CCD)	1	OH	RFC	Steam - Coal	330
Waterford	4	OH	RFC	Natural Gas	850
Darby	6	OH	RFC	Natural Gas	507
					3,701
Indiana Michigan Power Company					
Berrien Springs	12	MI	RFC	Hydro	5
Buchanan	10	MI	RFC	Hydro	2
Constantine	4	MI	RFC	Hydro	1
Elkhart	3	IN	RFC	Hydro	2
Mottville	4	MI	RFC	Hydro	1
Twin Branch	6	IN	RFC	Hydro	4
Rockport	1	IN	RFC	Steam - Coal	1,300
Tanners Creek	4	IN	RFC	Steam - Coal	995
Cook	2	MI	RFC	Steam - Nuclear	2,191
					4,501

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Kentucky Power Company					
Big Sandy	2	KY	RFC	Steam - Coal	**1,060**
Ohio Power Company					
Racine	2	OH	RFC	Hydro	26
Amos	1	WV	RFC	Steam - Coal	867
Cardinal	1	OH	RFC	Steam - Coal	580
Gavin	2	OH	RFC	Steam - Coal	2,640
Kammer	3	WV	RFC	Steam - Coal	630
Mitchell	2	WV	RFC	Steam - Coal	1,560
Muskingum River	5	OH	RFC	Steam - Coal	1,425
Sporn	3	WV	RFC	Steam - Coal	750
					8,478

Note: RFC regional reliability council was formerly known as ECAR

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Public Service Company of Oklahoma					
Tulsa	3	OK	SPP	Steam - Natural Gas	415
Tulsa	3	OK	SPP	Oil	8
Riverside	2	OK	SPP	Steam - Natural Gas	928
Riverside	2	OK	SPP	Steam - Natural Gas	150
Riverside	1	OK	SPP	Oil	3
Northeastern (1&2)	4	OK	SPP	Steam - Natural Gas	940
Northeastern	1	OK	SPP	Oil	3
Sothwestern	3	OK	SPP	Steam - Natural Gas	475
Sothwestern	2	OK	SPP	Steam - Natural Gas	150
Sothwestern	1	OK	SPP	Oil	2
Comanche	3	OK	SPP	Steam - Natural Gas	285
Comanche	2	OK	SPP	Oil	4
Weleetka	3	OK	SPP	Steam - Natural Gas	195
Weleetka	2	OK	SPP	Oil	4
Northeastern (3&4)	2	OK	SPP	Steam - Coal	910
Northeastern	1	OK	SPP	Oil	1
Oklaunion	1	TX	ERCOT	Steam - Coal	108
					4,581
Southwestern Electric Power Company					
Arsenal Hill	1	LA	SPP	Steam - Natural Gas	110
Lieberman	4	LA	SPP	Steam - Natural Gas	278
Knox Lee	4	TX	SPP	Steam - Natural Gas	486
Wilkes	3	TX	SPP	Steam - Natural Gas	897
Lone Star	1	TX	SPP	Steam - Natural Gas	50
Mattison	4	AR	SPP	Steam - Natural Gas	346
Welsh	3	TX	SPP	Steam - Coal	1,584
Flint Creek	1	AR	SPP	Steam - Coal	264
Pirkey	1	TX	SPP	Steam - Lignite	580
Dolet Hills	1	LA	SPP	Steam - Lignite	262
					4,857

Domestic Generation

Plant Name	Units	State	Regional Reliability Council	Fuel Type	Nominal Capacity (MW)
Texas Central Company					
none					
Texas North Company					
Paint Creek (Retired)	4	TX	ERCOT	Steam - Natural Gas	238
Abilene (Retired)	1	TX	ERCOT	Steam - Natural Gas	18
Ft. Stockton (Decommissioned)	1	TX	ERCOT	Steam - Natural Gas	6
Vernon (Decommissioned)	4	TX	ERCOT	Oil	8
Oklaunion	1	TX	ERCOT	Steam - Coal	377
					647
Domestic Independent Power Projects					
Trent Mesa	100	TX	ERCOT	Wind	150
Desert Sky	107	TX	ERCOT	Wind	161
					311
Long-Term Wind Purchase Power Agreements					
Southwest Mesa		TX	ERCOT	Wind	75
Weatherford		OK	SPP	Wind	147
Blue Canyon II		OK	SPP	Wind	151
Sleeping Bear		OK	SPP	Wind	95
Camp Grove		IL	RFC	Wind	75
Fowler Ridge		IN	RFC	Wind	100
Fowler Ridge		IN	RFC	Wind	100
Beech Ridge		WV	RFC	Wind	100
					843

Generation Statistics

Net Capacity Factors	2006	2007
AEP East	64.57%	64.26%
Coal	70.34%	71.89%
Super Critical*	73.36%	73.00%
Sub-Critical*	61.00%	68.44%
Gas	2.58%	7.27%
Hydro**	10.68%	7.85%
Nuclear	83.55%	90.86%
AEP SPP	45.10%	43.20%
Coal***	76.87%	77.45%
Super Critical*	83.77%	78.10%
Sub-Critical*	75.02%	77.21%
Gas	23.33%	20.65%
AEP Texas	65.35%	71.95%
Coal****	65.35%	71.95%
AEP System	60.06%	59.54%

Equivalent Availability Factors	2006	2007
AEP East	81.80%	81.09%
Coal	80.29%	78.73%
Super Critical*	80.55%	77.93%
Sub-Critical*	79.49%	81.23%
Gas	92.84%	90.19%
Hydro**	92.30%	86.42%
Nuclear	82.87%	89.68%
AEP SPP	86.25%	84.79%
Coal***	82.87%	82.35%
Super Critical*	86.76%	80.41%
Sub-Critical*	81.67%	83.09%
Gas	88.56%	86.39%
AEP Texas	67.78%	73.95%
Coal****	67.78%	73.95%
AEP System	82.62%	81.84%

Equivalent Forced Outage Rate (EFOR)	2006	2007
AEP East	8.54%	8.32%
Coal	9.37%	9.02%
Super Critical*	8.31%	8.81%
Sub-Critical*	12.63%	9.62%
Gas - See Below		
Hydro**	4.99%	11.61%
Nuclear	0.65%	1.25%
AEP SPP	6.79%	6.75%
Coal***	3.86%	5.49%
Super Critical*	5.50%	6.20%
Sub-Critical*	3.31%	5.23%
Gas	9.73%	8.04%
AEP Texas	23.48%	17.43%
Coal****	23.48%	17.43%
AEP System	8.45%	8.13%

Equivalent Forced Outage Factor (EFOF)	2006	2007
AEP East Gas*****	0.39%	1.23%

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** CF, EAF, and EFOR do not include Dolet Hills. Dolet Hills included in generation number as owned. Pirkey and Flint Creek reported as owned.

**** Oklaunion reported as owned.

***** East Gas Units evaluated using Equivalent Forced Outage Factor. Since these units are run less frequently, this factor gauges their performance based on Period Hours instead of Service Hours. EFOR uses Service Hours in the denominator, and EFOF uses Period Hours in the denominator.

Net Generation Statistics

Net Generation By Operating Company (in MWhs)

Operating Company	2006	2007
AEP Generating	10,276,134	9,027,362
Appalachian Power	31,494,581	32,588,773
Columbus Southern Power	14,134,232	15,514,495
Indiana Michigan Power	31,950,768	31,604,874
Kentucky Power	7,171,505	7,533,223
Ohio Power	49,341,134	54,155,697
Public Service of Oklahoma	15,139,848	14,439,801
Southwestern Electric Power	19,961,798	19,673,059
Texas Central Company	309,085	41,122
Texas North Company	2,160,348	2,309,566
AEP System Total Net Generation	181,939,433	186,887,972

Notes: Figures represent generation produced from AEP-owned assets only.

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date
AEG	Dresden	Ohio	$309 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600(1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1,110 million in capital investment.
The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

Environmental

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations and the NSR consent decree executed in October 2007.

Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Clean Air Interstate Rule

- Rule finalized March 2005
- Designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- Reductions from 2003-level emissions: ~73% SO_2 & ~61% NO_x
- Reductions occur in phases: Phase I (2009/2010); Phase II (2015)
- Established three cap & trade programs:
  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program
- On July 11, 2008 the D. C. Circuit Court issued a decision to remand and vacate CAIR, but the decision is not yet final
- EPA and others have requested rehearing, and the D. C. Circuit Court has requested further briefing on whether any party requested that the rule be vacated, and whether the rule should remain in place while EPA responds to the remand
- A final decision is expected shortly after the briefing is completed (November 2008)

Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

Clean Air Visibility Rule

- Rule finalized March 2005
- Designed to address the Clean Air Act's best available retrofit technology (BART) requirements and applicability to plants built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants
- Final rule demonstrates that CAIR will result in more visibility improvements than BART
- States are allowed to substitute CAIR requirements in their SIPs for controls that would otherwise be required by BART
- For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x, additional controls will be required

Applicability to AEP

- Requires SO_2 reductions in Oklahoma and Arkansas
- Scrubbers (FGDs) will be installed at our Northeastern and Flint Creek plants by 2015

Clean Air Mercury Rule

- Rule finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a cap & trade structure to achieve mercury reductions
- On February 8, 2008 the Supreme Court issued a decision to remand and vacate CAMR

AEP will achieve significant mercury reduction as a co-benefit of SCR and FGD systems, but mercury specific control equipment will be needed on several units.

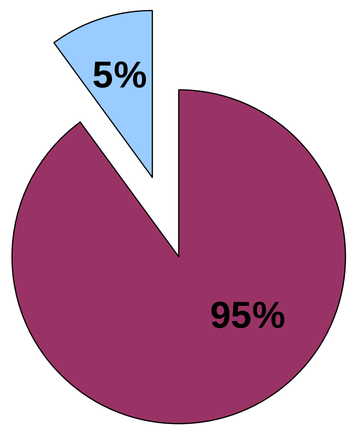
Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2012
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2013
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors - AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $162/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $262/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD retrofit for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.
- Plant modifications increasing unit MW ratings are being implemented as part of the retrofit program
  - For example, Mountaineer turbine valve upgrades will increase unit output by ~30 - 45 MW
  - Similar upgrades will be implemented on other units

Plant modifications will mitigate FGD and SCR capacity consumption.

Emission Limits

In compliance with our 2007 NSR settlement, the following limits are applicable to AEP's eastern generation fleet:

Eastern System-Wide Annual Tonnage Limitations for NO_x

Calendar Year	Limitation
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016 and each year thereafter	72,000 tons

Eastern System-Wide Annual Tonnage Limitations for SO_2

Calendar Year	Limitation
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019 and each year thereafter	174,000 tons

Emissions caps do not include any of the gas-fired units, or any new units AEP might build or purchase in the east.

AEP/CertainTeed Gypsum Wallboard Initiative

- CertainTeed Gypsum opened new wallboard manufacturing plant in March of 2008 adjacent to OPCo's Mitchell plant near Moundsville, WV
- Wallboard plant utilizes the gypsum produced from both the Mitchell and Cardinal power plants.
- Gypsum is the by-product of the recently completed FGD (i.e. scrubber) process.
- Key Project Benefits
  - Environmental stewardship program which eliminates the need for an expensive gypsum landfill at Mitchell.
  - Significant capital and annual O&M savings for Ohio ratepayers.
  - Wallboard is produced using greater than 96% recycled materials (i.e. gypsum, paper).
  - Created many new good paying jobs.
  - Strong/stable counterparty – CertainTeed is the #1 producer of wallboard in the world

Future Potential Green House Gas Regulations

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- **Renewables**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

New Program Additions

- **Incremental Reduction quantity: 5MM tons/yr**
- **Timing: To take effect/receive credits by 2011**
- **Methods**
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- **Commercial solutions for existing fleet**
  - Chilled Ammonia

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced.

Chilled Ammonia Technology Program

2009 Commercial Operation

Mountaineer Plant (WV) → MOU (Alstom & RWE) → **Chilled Ammonia** → CO_2 Storage (Battelle)

Project Validation

- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- Located at the AEP Mountaineer Plant in WV
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Alstom "Chilled Ammonia" Technology
- Geologic storage for CO_2

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Post-combustion carbon solution provides pure CO_2 stream for capture.

Coal

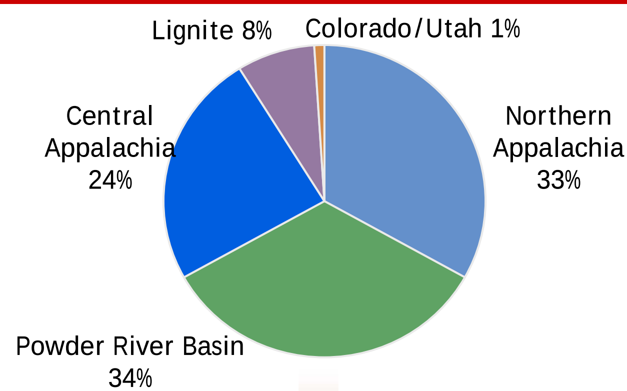
- Coal Procurement, Delivery & Transportation
- Fuel Recovery
- Coal Market Information

Fall EEI 2008

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

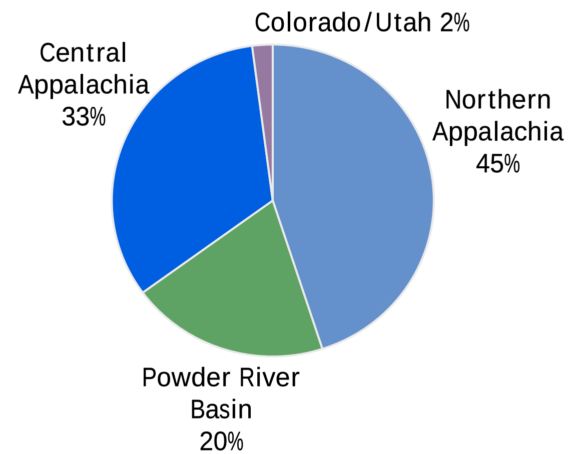
Total AEP System



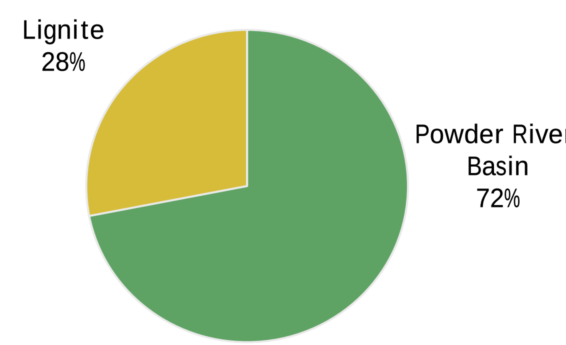
Coal Stats:

- 100% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 28% price increase in 2008 based on 2007 actual results.

AEP East



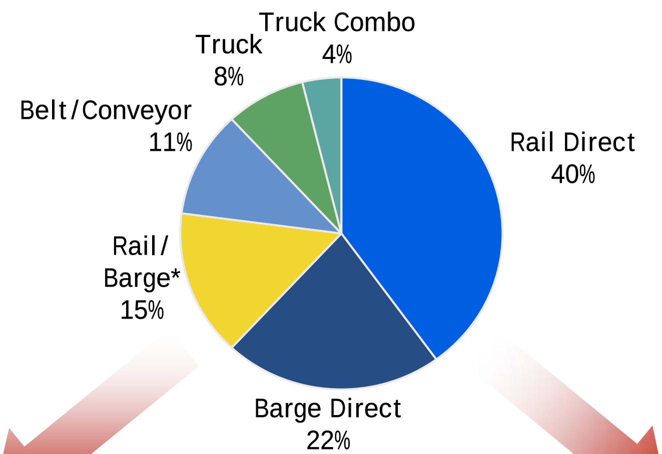
AEP West



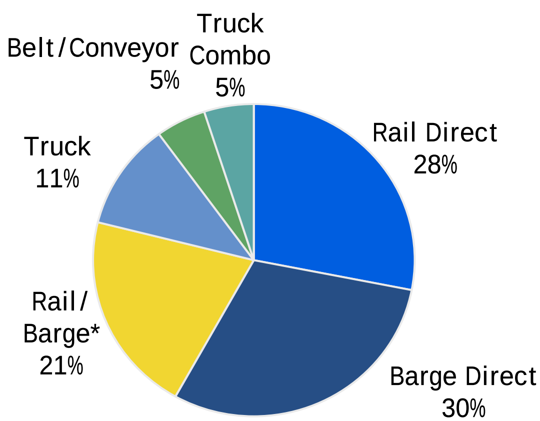
Coal Delivery

2007 Actual

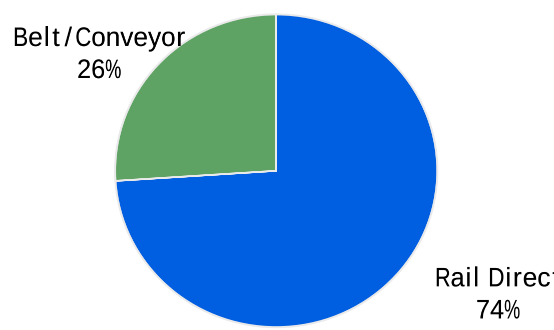
Total AEP System



AEP East



AEP West

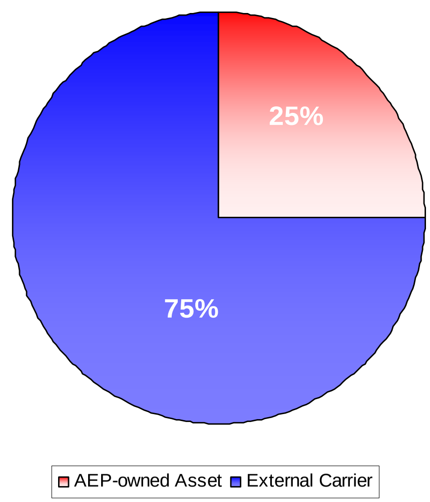


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2007 Actual

Coal Transportation to AEP Plants*



***Represents close approximations**

- Current Coal & Transportation Assets:
  - Control over 9,000 railcars
  - Own/lease and operate over 2,900 barges & 80 towboats/tugs
  - Coal handling terminal with 20 million tons of capacity

AEP's transportation assets provide flexibility in a constrained delivery environment.

AEP River Operations

- Full-service Inland Waterways carrier
  - 2,900 hopper barges
  - 60+ towboats/20 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations

  Barge cleaning and repair

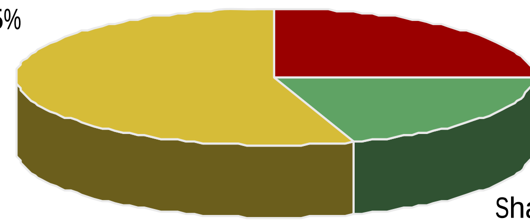
  Fleeting and shifting

  Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

Inland Waterway Routes For AEP River Operations

Fuel Recovery

AEP System



Fuel Cost Recovery (on average)

- **In response to Ohio Substitute Senate Bill 221, AEP Ohio filed an Electric Security Plan that would allow recovery of fuel costs from customers who do not switch their supplier. If adopted, AEP's fuel costs will be eligible for recovery in all AEP jurisdictions beginning in 2009.**
- **80% of fuel cost is recoverable across the AEP System**
- **Active Fuel Clause Jurisdictions:**
  - **AEP EAST: APCo, I&M, KPCo, KGP, WP**
  - **AEP WEST: PSO, SWEPCO**

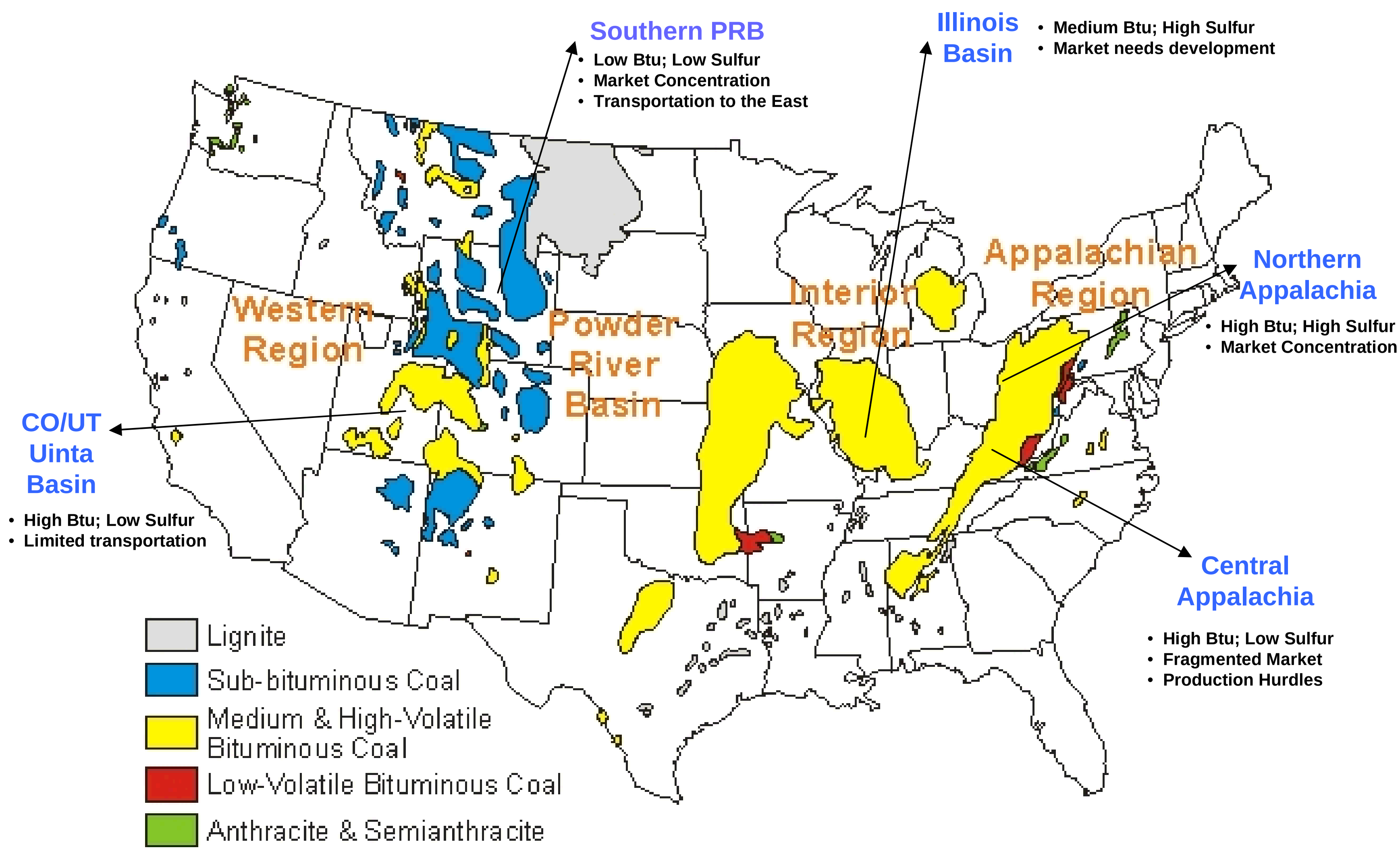
Note: Fuel recovery percentages are based on estimates for 2008 fiscal year

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Effective 1/1/09	TBD
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

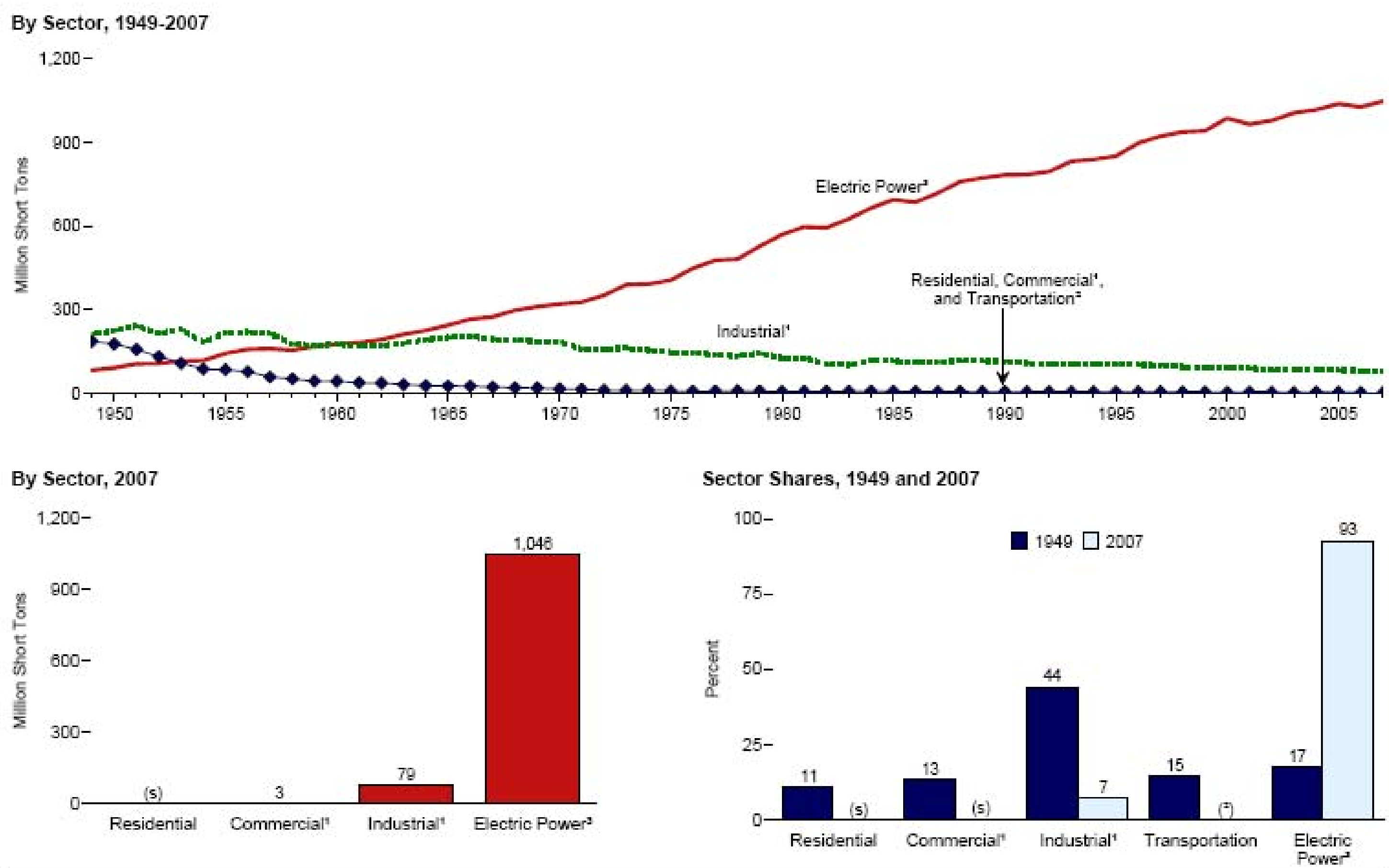
Effective January 1, 2009 we have fuel recovery in all jurisdictions.

Coal Producing Regions



Uses of Coal by Sector

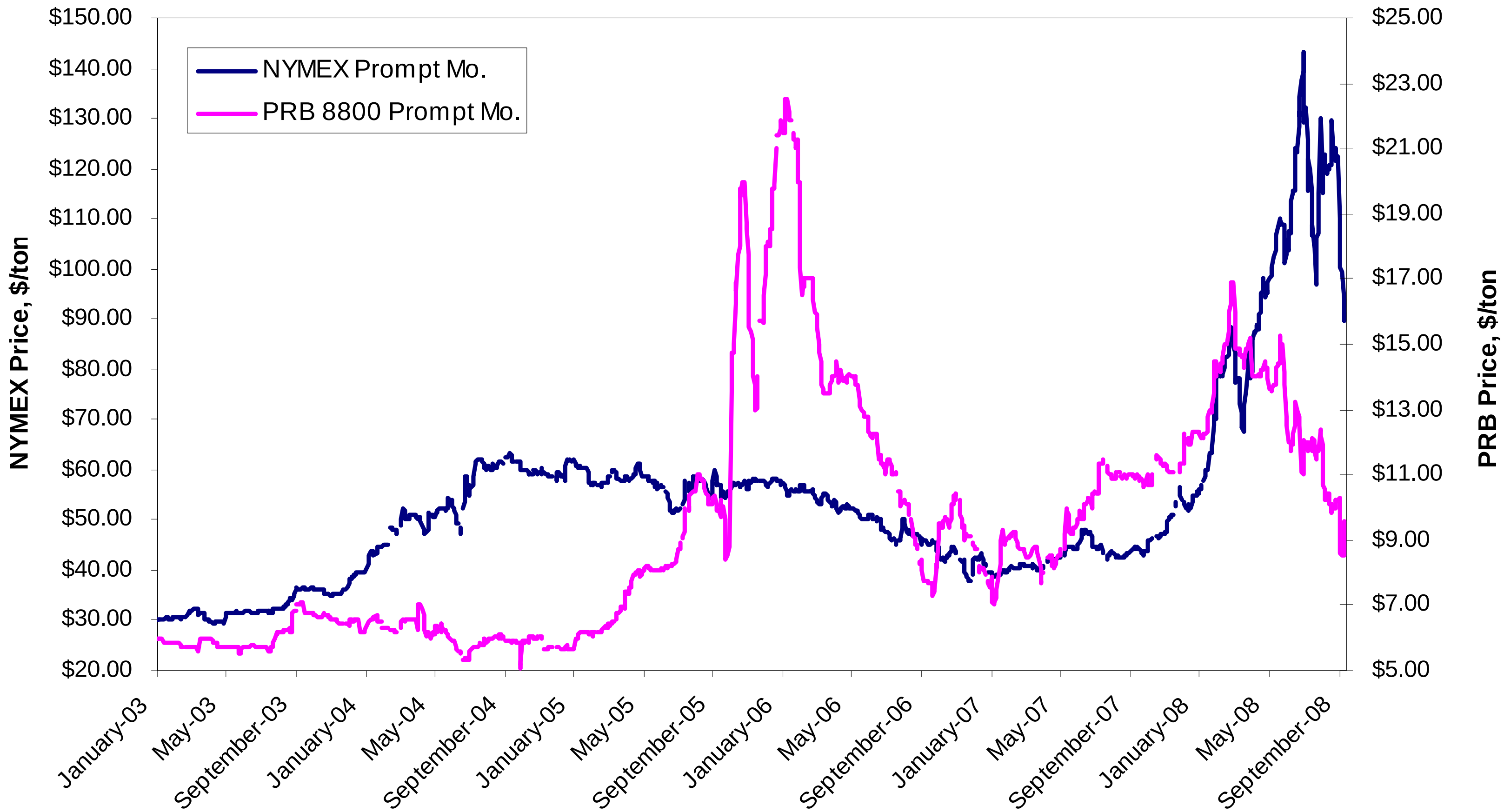
Figure 7.3 Coal Consumption by Sector



[1] Includes combined-heat-and-power (CHP) plants and a small number of electricity-only plants.
[2] For 1978 forward, small amounts of transportation sector use are included in "Industrial."
[3] Electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
(s)=Less than 0.5.
Source: Table 7.3.

Energy Information Administration / Annual Energy Review 2007

Domestic Coal Price Markers (FOB Mine)



Domestic Coal Market

Primary drivers for increasing coal prices in the US are:

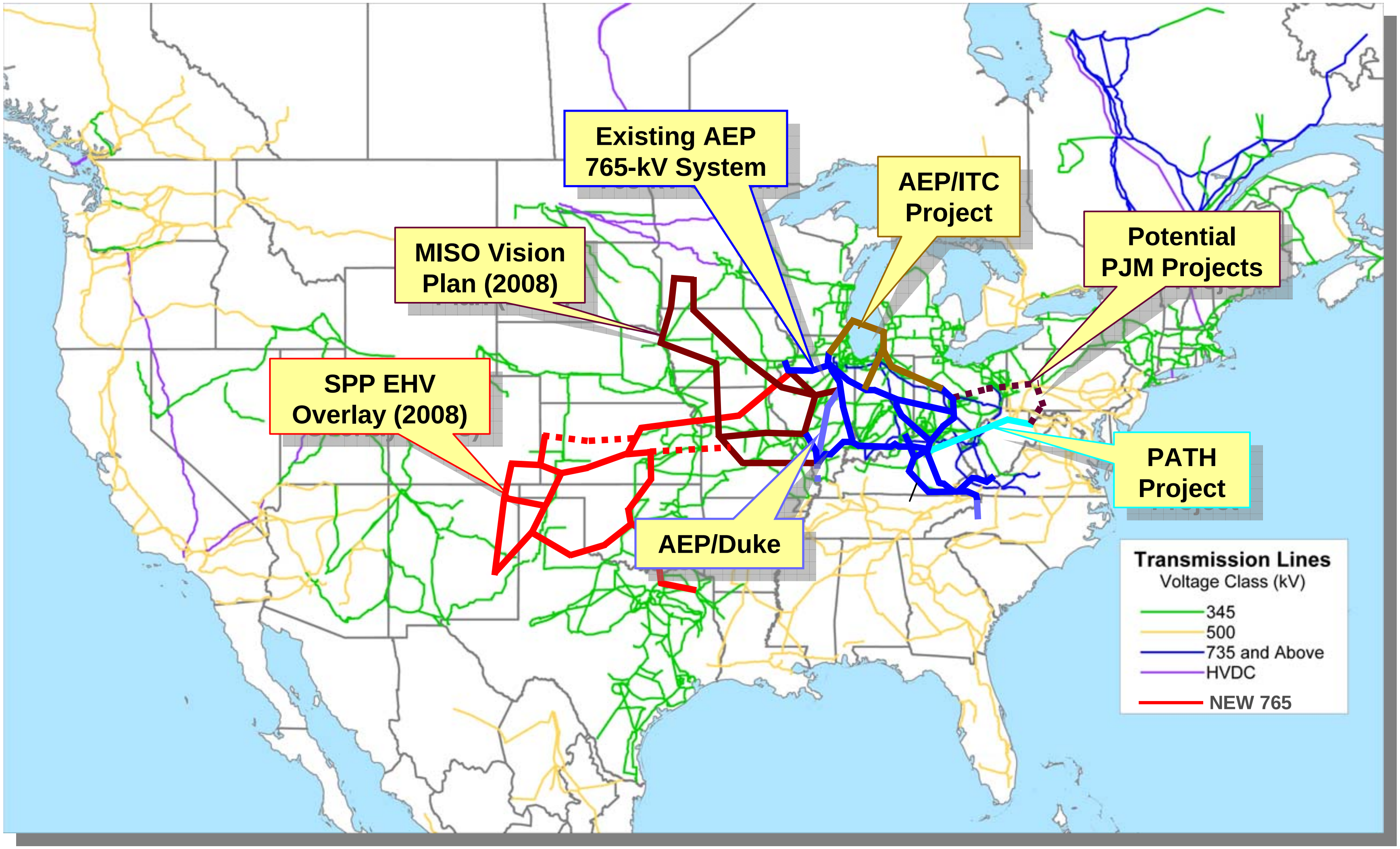
- ❑ Increase in the cost components to produce the product
- ❑ Declining productivity due to reserves, safety, etc.
- ❑ Declining eastern US coal production….particularly Central Appalachia
- ❑ Increasing global demand for coal….particularly Asia
- ❑ Inability to bring on new production quickly due to permitting and labor related issues
- ❑ High cost to mine in Central Appalachian region
- ❑ Capital required for new production
- ❑ Sustained pricing, how long?
- ❑ Increase in the international demand for US coal products
  - Dramatic increase in east coast and gulf coast US coal exports have lead to much higher priced markets in the US (82M exp; 28M imp)
  - Continued demand of metallurgical coal is drawing steam coal into the metallurgical coal market
  - Weak US Dollar

Transmission Initiatives

Transmission Initiatives

Fall EEI 2008

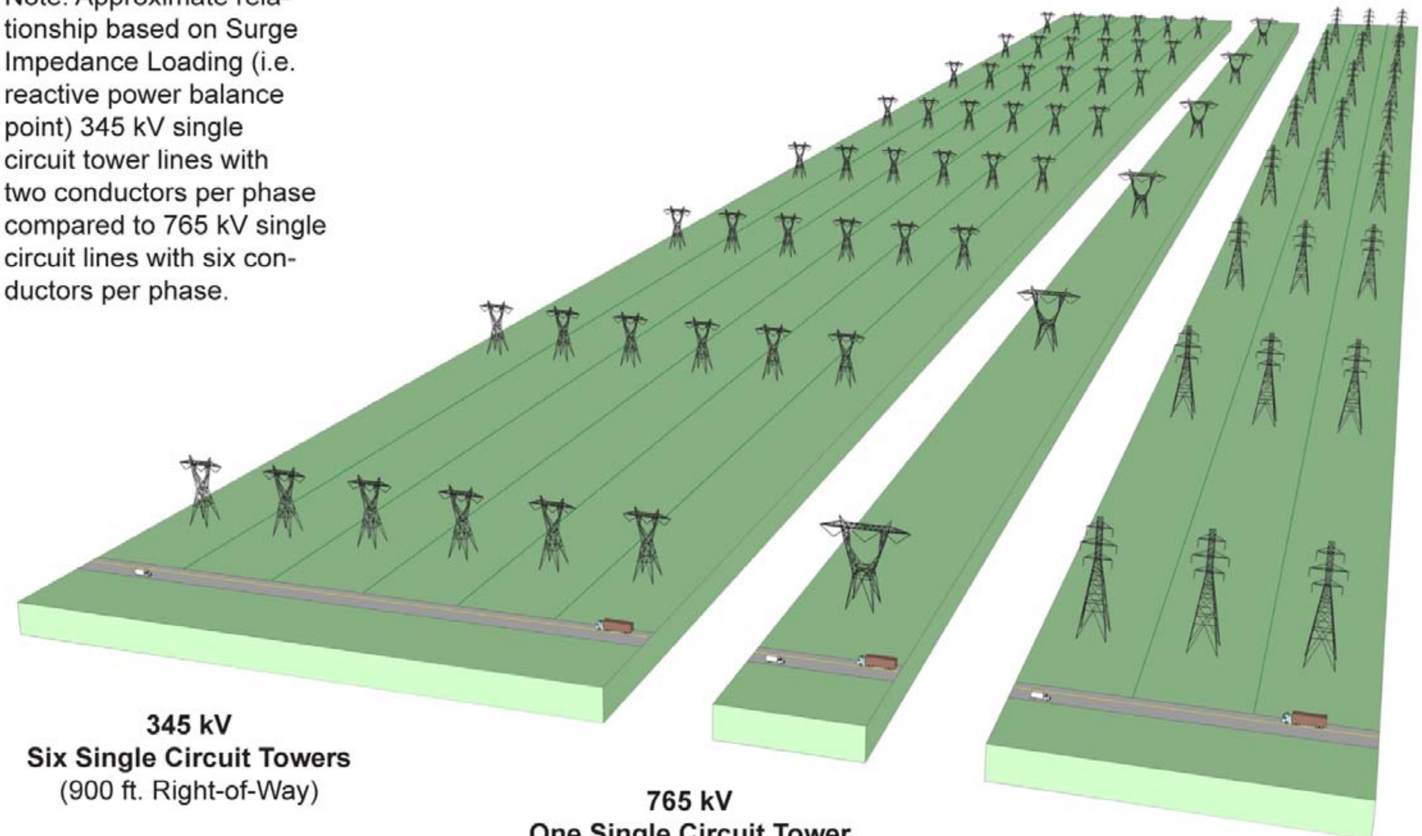
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

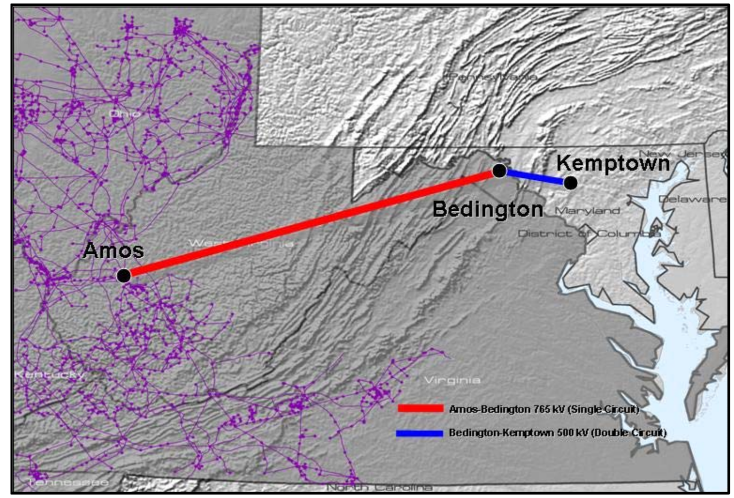
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

EHV Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
  - In October 2008, PJM announced a reconfiguration of the PATH line which will eliminate the connection with the Bedington substation and the twin-circuit 500-kV lines from Bedington to Kemptown, and include a new mid-point substation near existing PATH alternative routes
    - The reconfiguration is a result of constraints identified as a result of comprehensive siting studies; interaction with government agencies; public input; and a desire to identify a solution that reduces line mileage and minimizes the impact on communities and the environment.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
- *Key Challenges*
  - CPCN and Siting Approval from WV and MD



The ROW routes shown on this diagram are illustrative of the initial project approved by PJM, and not of the recently reconfigured line. As such, this map is not intended to depict the actual route that will eventually be selected.

Joint Ventures with MidAmerican Energy Holdings Company

Electric Transmission Texas Update

- 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
- ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
- Services provided by AEP and investment opportunities can be offered by either partner
- Total initial investment of $70 million before ownership division
- In October 2008, the District Court found that the PUCT exceeded its authority by granting ETT a CCN. This decision is currently under appeal and ETT believes the ultimate outcome will validate its utility status.

Electric Transmission America Update

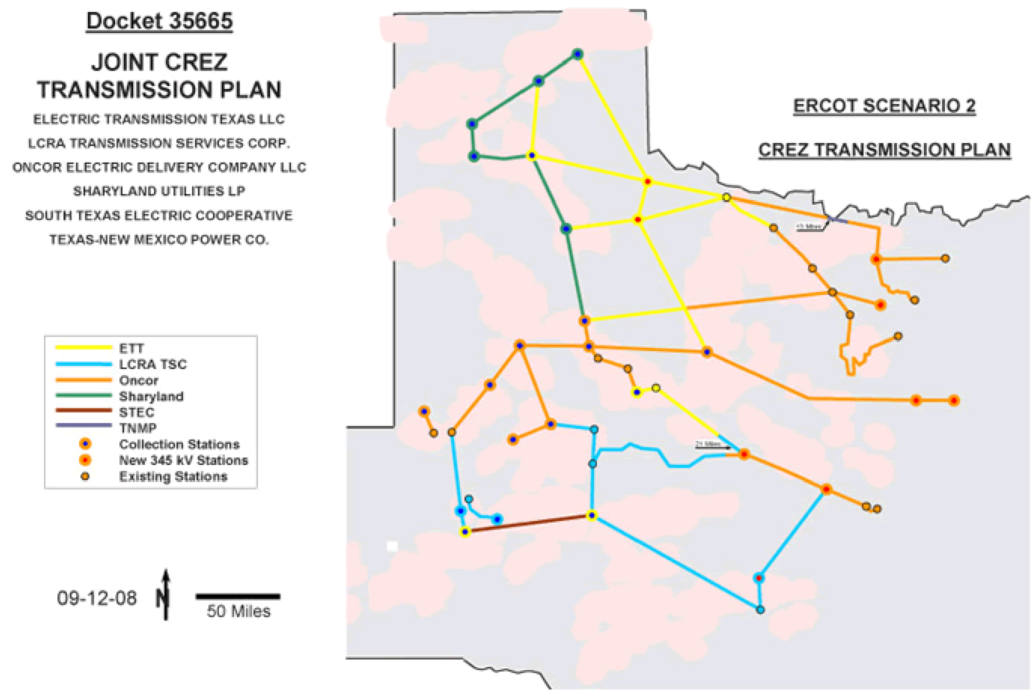
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - In 2008, ETA signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ❑ ***Overview***
  - ❑ In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the CREZ facilities approved by the Commission.
  - ❑ ETT's requested share of the coordinated plan is approximately $1.5 billion. Staff testimony in October 2008 recommended ETT's share at $1.2 billion.
  - ❑ The filing calls for completion of the plan by 2012.
- ❑ ***Next Steps***
  - ❑ PUCT hearings – December 2008
  - ❑ Selection of transmission providers – 1Q 2009

ETT
Electric Transmission Texas



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

EHV Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ❑ *Overview*
  - ❑ Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - ❑ Updated EHV Overlay Study completed by SPP – March 2008
- ❑ *Benefits*
  - ❑ Overall reliability reinforcement with improved voltage support throughout the SPP system
  - ❑ Significantly increased transfer capability
  - ❑ Provides access to new generation resources, especially renewables
  - ❑ Allows for effective interconnections for EHV system development

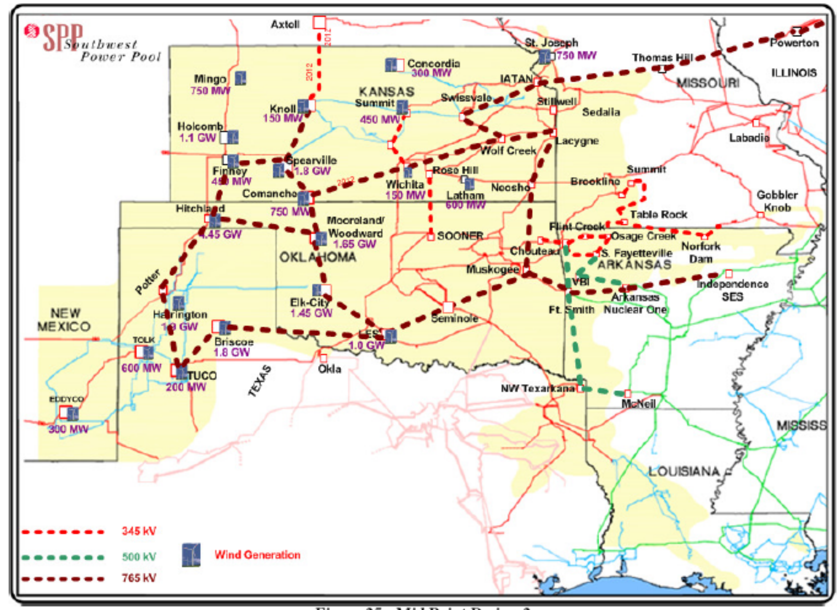


Figure 25: Mid Point Design 2

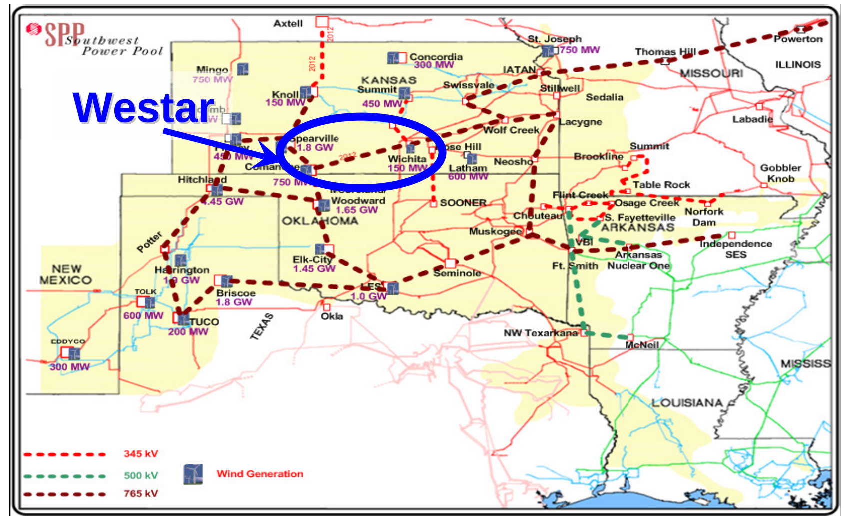
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ❑ *Overview*
  - ❑ In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - ❑ PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - ❑ The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - ❑ Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - ❑ AEP's ownership of the joint venture is 25%.
  - ❑ Kansas CPC filing submitted in May 2008.
  - ❑ FERC formula rate filing submitted in October 2008 requesting:
    - ❑ Cash return on CWIP and 13.3% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

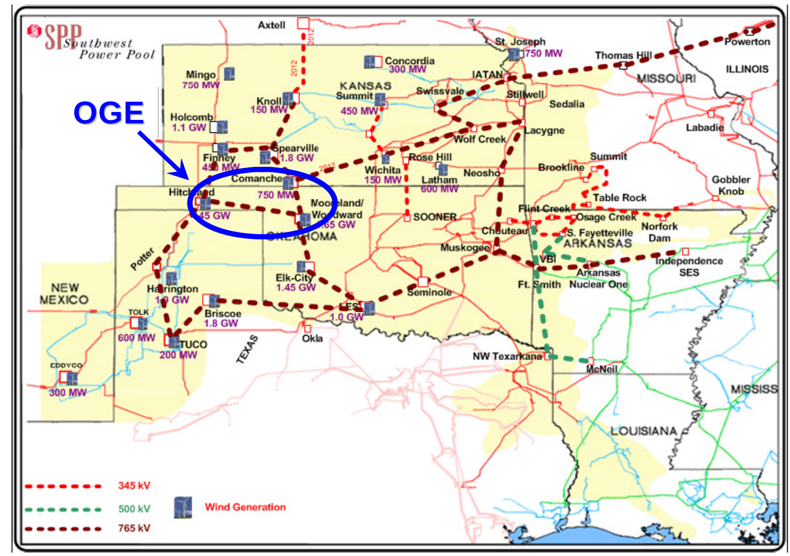
- ❑ *Key Challenges*
  - ❑ Cost allocation which enables the development of "system solutions"
  - ❑ RTO Approval

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1440 of 9556

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- *Overview*
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC formula rate filing submitted in October 2008:
    - Cash return on CWIP and 13.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



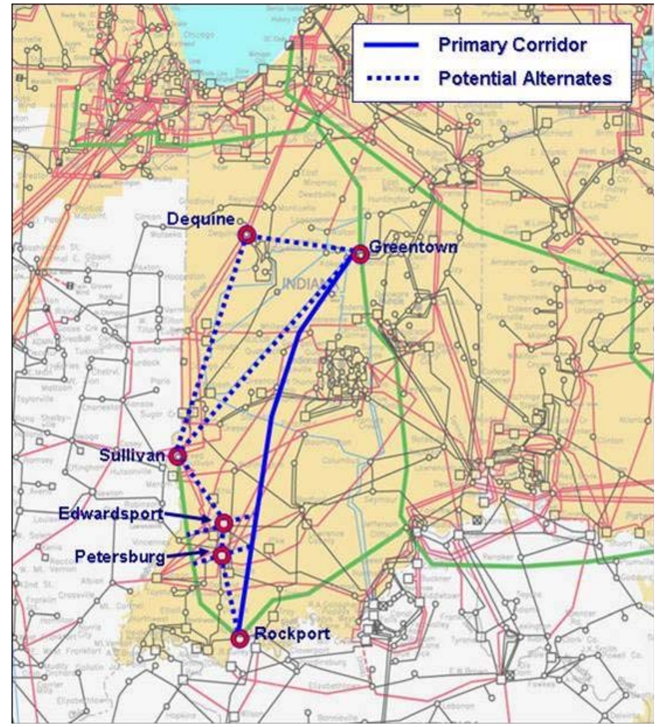
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Key Challenges*
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

Pioneer Transmission, LLC

- *Overview*
  - In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
  - PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
  - The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
  - Project is expected to cost approximately $1 billion and be in-service by 2015.
  - AEP's ownership of the joint venture is 50%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC formula rate filing submitted in October 2008 requesting:
    - Cash return on CWIP and 13.5% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



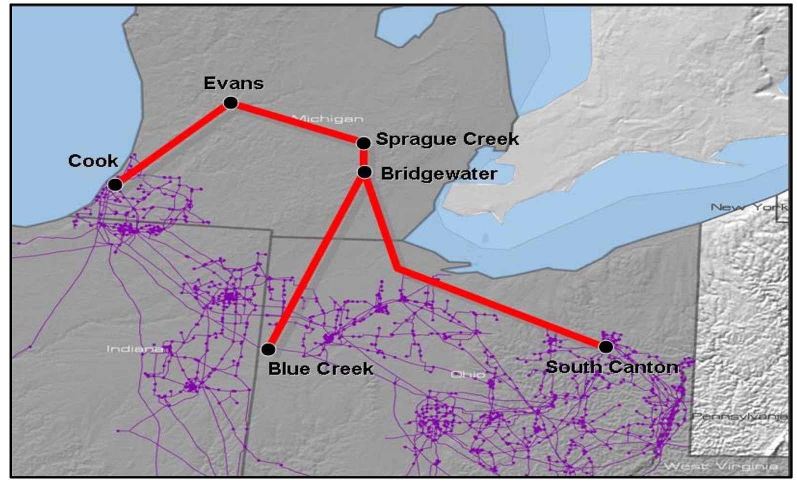
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

- *Key Challenges*
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Siting

EHV Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (in 2007$, before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Key Challenges*
  - Cost allocation which enables the development of "system solutions"
  - RTOs Approvals



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Financial Update

Financial Update

- **Capitalization**
- **Liquidity Position**
- **Credit Ratings**
- **Long-Term Debt Maturity Profile**
- **Debt Schedules**

Fall EEI 2008

Capitalization

Capital Structure	Actual 12/31/2007			Actual 9/30/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,993	-	14,993	16,007		16,007
Short-term Debt	660	-	660	1,302		1,302
Preferred Stock Not Subject to Mandatory Redemption	-	61	61		61	61
Common Equity	-	10,079	10,079		10,917	10,917
Total Capitalization per Balance Sheet	**15,654**	**10,139**	**25,793**	**17,309**	**10,978**	**28,286**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***61.2%***	***38.8%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
less: Cash and Marketable Securities	(178)	-	(178)	(781)	-	(781)
Capital and Operating Leases	1,522	-	1,163	1,470	-	1,470
Securitization Bonds	(2,257)	-	(2,257)	(2,132)	-	(2,132)
Receivables Securitization	507	-	507	555	-	555
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(263)	-	(263)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	1
Total Adjusted Capitalization	**14,969**	**10,139**	**25,108**	**15,999**	**11,136**	**27,135**
% of Adjusted Capitalization [1]	***59.6%***	***40.4%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Credit Adjusted Ratios:						
FFO Interest Coverage			**4.3**			**4.7**
FFO to Total Debt			**19.6%**			**21.5%**

Our goal remains a maximum 60/40 debt-to-capital ratio on an adjusted basis.

Liquidity

Liquidity Summary (unaudited)	Actual 10/28/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	1,366	
Less		
Draw on Credit Facilities	(1,969)	
Commercial Paper Outstanding	(178)	
Letters of Credit Issued	(439)	
Net Available Liquidity	**$2,699**	

AEP's liquidity position is $2.7 billion as of 10/28/08.

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Ratings current as of October 17, 2008

	Moody's		S&P		Fitch	
	Senior		Senior		Senior	
Company	Unsecured	Outlook	Unsecured	Outlook	Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	N	BBB	S	BBB+	S
AEP Texas North Company	Baa1	S	BBB	S	A-	S
Appalachian Power Company	Baa2	N	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	N	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	N	BBB	S	BBB+	S

Long-term Debt Maturity Profile

($ in millions)

Year	2008 (1)	2009	2010
AEP, Inc.	$ -	$ -	$ 490
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 150	$ 150
Columbus Southern Power	$ -	$ -	$ 150
Kentucky Power	$ 30	$ -	$ -
Indiana Michigan Power	$ 50	$ -	$ -
Ohio Power	$ 37	$ 82	$ 600
Public Service of Oklahoma	$ -	$ 50	$ 150
Southwestern Electric Power	$ -	$ -	$ -
Texas Central Company(2)	$ -	$ -	$ 203
Texas North Company	$ -	$ -	$ -
Total	$ 117	$ 282	$ 1,743

(1) Maturities remaining as of September 30, 2008

(2) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date

Debt Schedules

American Electric Power, Inc	Interest	Maturity	Amount
Junior Subordinated Debentures	8.750%	03/01/2063	$315,000,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	6.36%		$1,047,775,000

AEP Generating	Interest	Maturity	Amount
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Senior Notes	6.330%	06/28/2037	$210,909,170
Weighted Average or Total	5.947%		$255,909,170

Note: Debt schedules current as of 9/30/08.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
Pollution Control Bond	5.625%	10/01/2017	$40,890,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Pollution Control Bond	5.200%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	5.125%	06/01/2030	$120,265,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.609%		$670,106,300
Securitization Bond	5.560%	01/15/2010	$85,906,616
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	6.003%		$492,690,212
Securitization Bond	4.980%	01/01/2010	$116,771,724
Securitization Bond	4.980%	07/01/2013	$341,000,000
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.146%		$1,639,471,724

AEP Texas North	Interest	Maturity	Amount
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Senior Notes	5.890%	04/01/2018	$30,000,000
Senior Notes	6.760%	04/01/2038	$70,000,000
Weighted Average or Total	5.637%		$371,658,600

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/08.

Debt Schedules

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	4.850%	05/01/2019	$30,000,000
Pollution Control Bond	4.850%	05/01/2019	$40,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	02/01/2036	$75,000,000
Preferred Stock	4.500%	NA	$17,752,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	5.650%	08/15/2012	$250,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Senior Notes	6.700%	08/15/2037	$250,000,000
Senior Notes	7.000%	04/01/2038	$500,000,000
Weighted Average or Total	5.91%		$3,080,027,000

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/08.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	Floating	12/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Pollution Control Bond	4.850%	08/01/2040	$44,500,000
Pollution Control Bond	5.100%	11/01/2042	$56,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.050%	05/01/2018	$350,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.751%		$1,442,745,000

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	5.250%	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,533,500
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.778%		$1,275,080,200

Note: Debt schedules current as of 9/30/08.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	6.000%	09/15/2017	$325,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.966%		$430,000,000

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Notes Payable	6.270%	03/31/2009	$1,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,148,200
Preferred Stock	4.500%	NA	$9,737,300
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	Floating	04/05/2010	$400,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	5.750%	09/01/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	5.812%		$2,907,982,400

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/08.

Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Preferred Stock	4.000%	NA	$4,454,800
Preferred Stock	4.240%	NA	$806,900
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.625%	11/15/2037	$250,000,000
Weighted Average or Total	5.791%		$926,621,700

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$11,381,290
Notes Payable	4.470%	05/16/2011	$11,748,427
Notes Payable	7.030%	02/22/2012	$20,000,000
Notes Payable	6.370%	10/31/2024	$25,000,000
Pollution Control Bond	4.500%	07/01/2011	$41,135,000
Pollution Control Bond	4.950%	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,767,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Senior Notes	5.875%	03/01/2018	$300,000,000
Senior Notes	6.450%	01/15/2019	$400,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.708%		$1,562,564,317

Grand Total **$16,102,631,623**

Note: The weighted average coupon excludes all floating rate debt.

Debt schedules current as of 9/30/08.

AMERICAN ELECTRIC POWER

Fall EEI Conference

November 11, 2008

AEP AMERICAN ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

Michael G. Morris

Chairman, President & CEO

STRONG
FLEXIBLE
ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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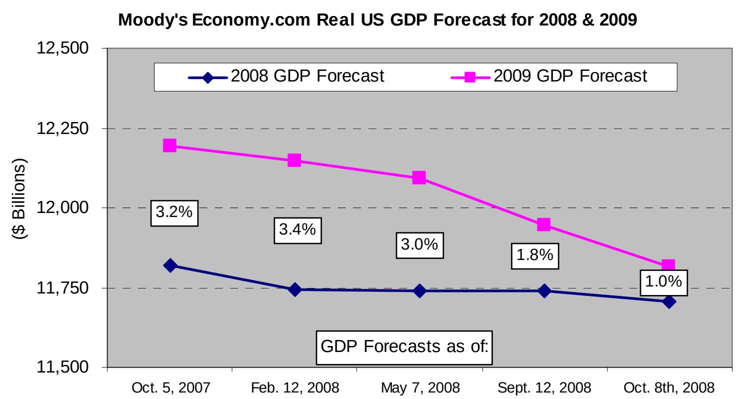
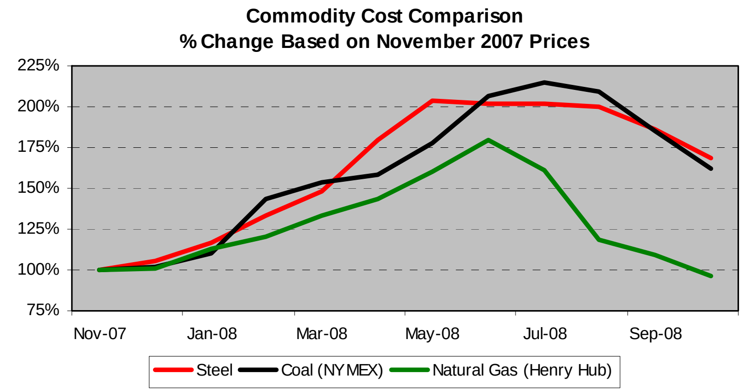
What Has Changed?

Slowed Economic Growth



Volatile Commodity Prices



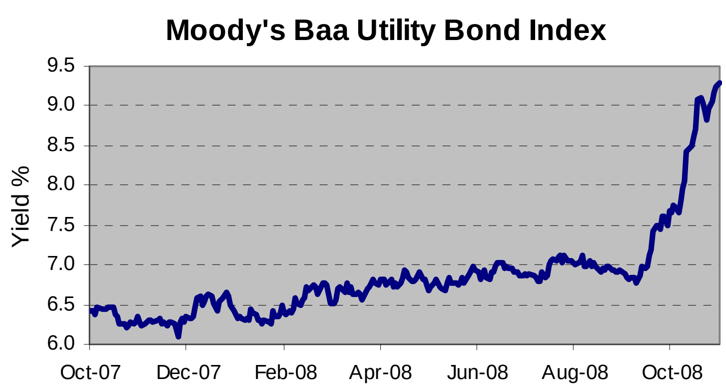
October '08 Prices

Steel: $903 / ton

Coal: $87.48 / ton

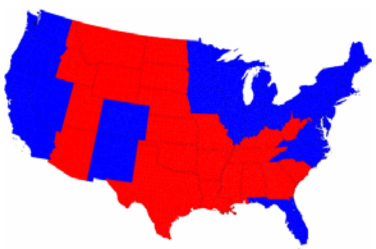
Gas: $6.75 / mmBtu

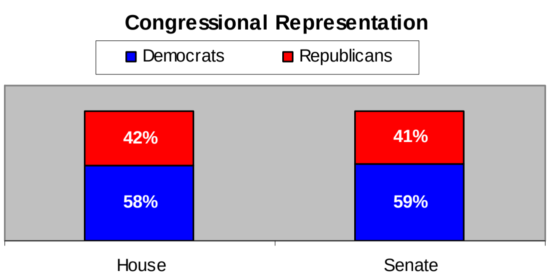
Crisis in Capital Markets



Election Results

Presidential Election Results:





In nearly every aspect, Fall 2008 has no resemblance of the conditions that surrounded AEP and the entire utility industry in Fall 2007.

Our Strategic Priorities Remain the Same

- ❑ "Keep the lights on"
  - Maintain our low-cost and reliable energy production and delivery system
  - Invest to replace aging infrastructure and ensure adequacy of capacity
  - Manage commodity costs
- ❑ Environmental priorities
  - Complete our $5.2 billion environmental controls program ($1.0 billion to be spent in 2009-2010)
  - Work to ensure a balanced and logical carbon legislation outcome
- ❑ Lead the development of America's high-voltage transmission system
- ❑ Collaborate with regulators to more closely match spending with rate recovery

AEP's strategic priorities remain the same, but the steps and timing may be different.

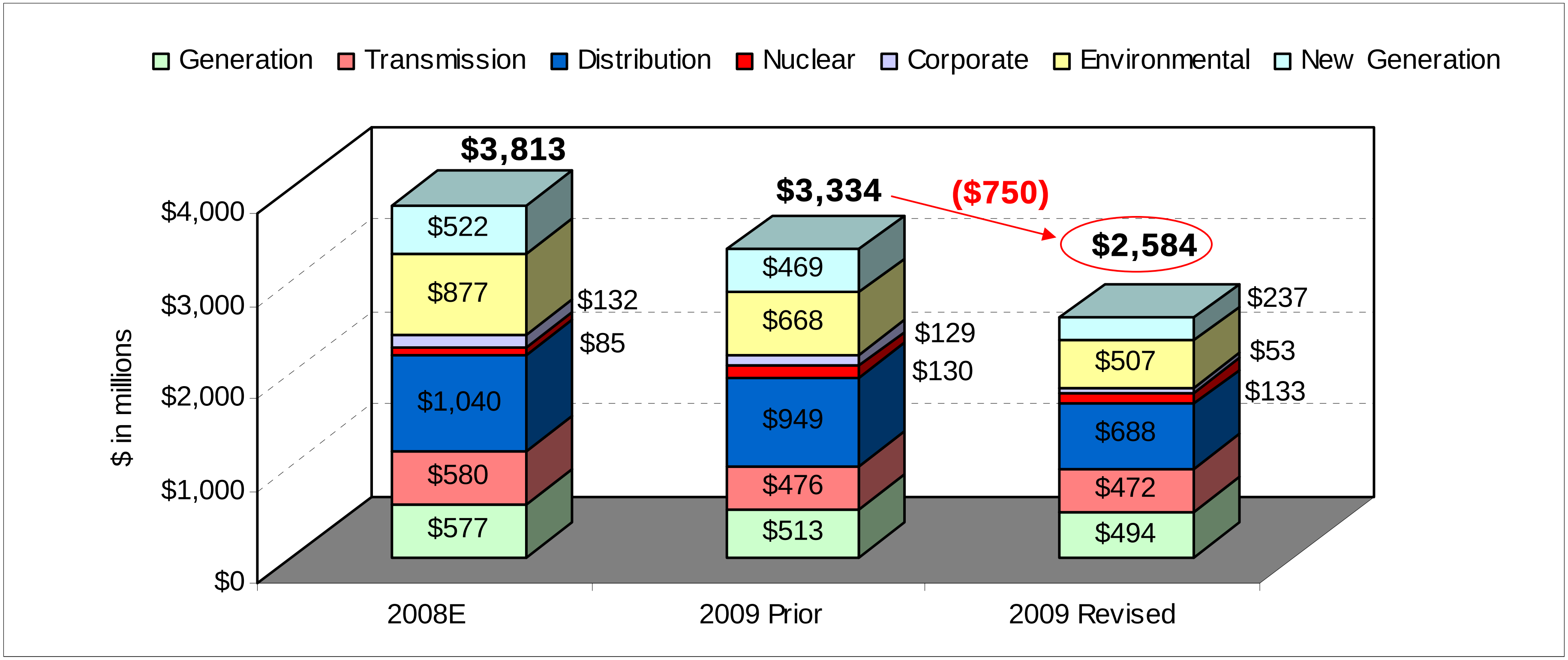
Management Priorities for 2009

- ❑ Secure rate relief in Ohio and other jurisdictions
- ❑ React to the current economic crisis
- ❑ Effectively manage our credit and liquidity
  - Cut capital budget by $750 million to $2.6 billion for 2009
  - Hold 2009 O&M spending flat at 2008 level of $3.3 billion
  - Choose opportunistic points to access capital markets and manage liquidity
- ❑ Maximize flexibility to respond to changing conditions

AEP has a strong reputation and track record for continued performance during difficult economic times.

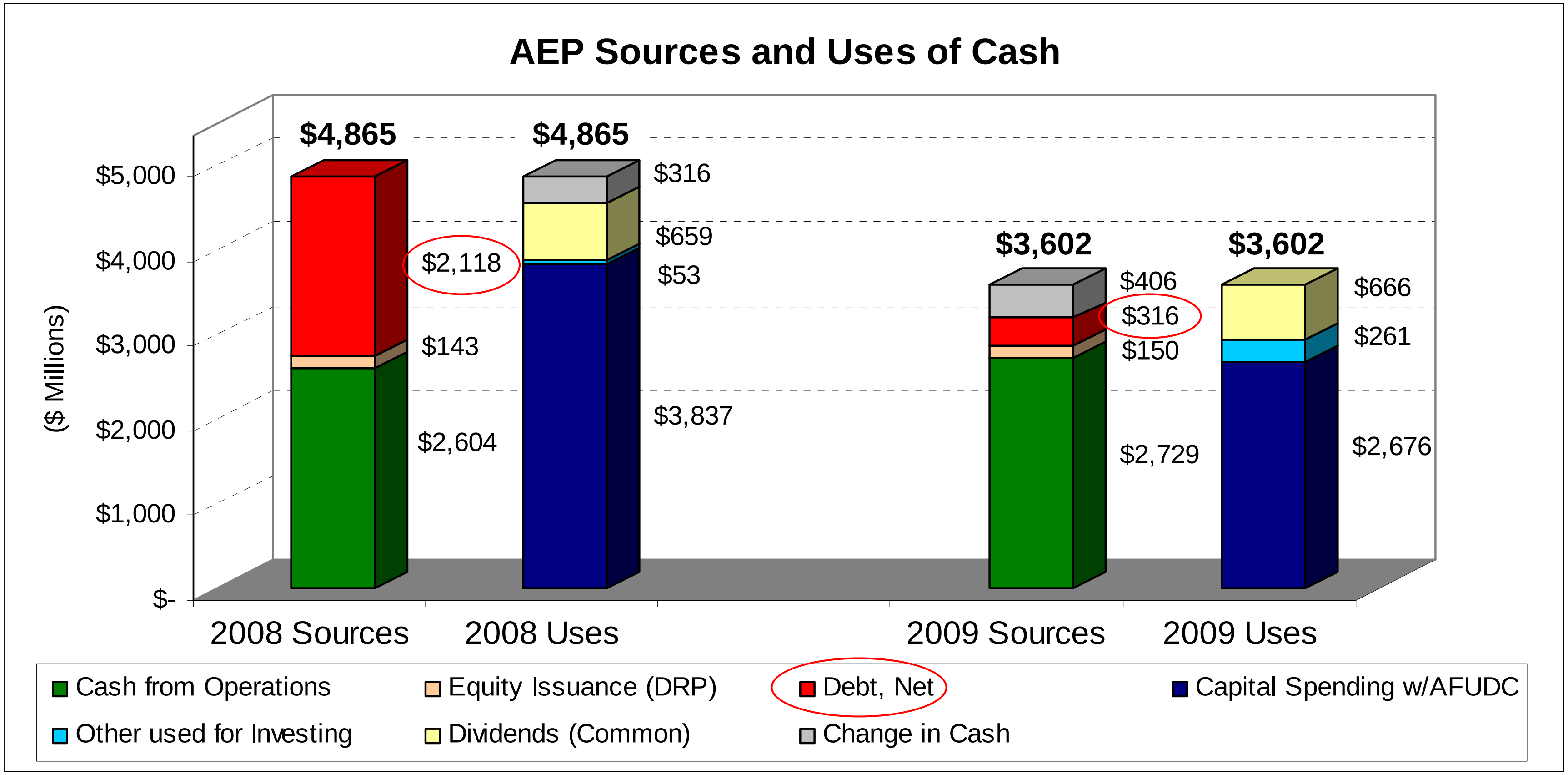
2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

2008 & 2009 Ongoing Earnings Guidance

2008E EPS: $3.15 - $3.25

2009E EPS: $3.00 - $3.40

American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance		2009 Guidance	
	($ millions)	EPS	($ millions)	EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Interest Exp & Preferred Dividend	(839)		(929)	
All Other Expenses, net	(2,705)		(2,857)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations	77	0.19	75	0.18
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

Continued Earnings Growth

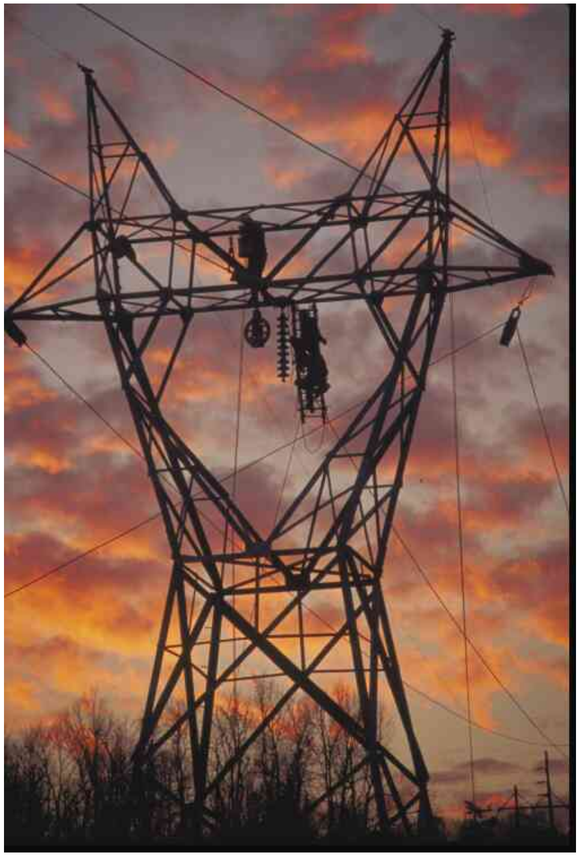
- ❑ Outcome for AEP Ohio still an important factor in determining 2009 results and beyond
- ❑ Active fuel recovery allowed in each jurisdiction
- ❑ Geographic diversity helps to mitigate the effect of the economic slowdown
- ❑ Joint venture strategy for transmission investment remains a long-term earnings growth catalyst
- ❑ Sustained capital investment in our traditional utility business aligned with regulatory return

Big Sandy Plant

Long-term earnings growth will continue at 4% to 6% per year.

Getting Ready for the Next Cycle

- ❑ Investing in the next generation of energy infrastructure
  - Approved new generation projects
  - High-voltage interstate transmission system
  - Advanced distribution infrastructure (gridSMART[SM])
- ❑ Focused on customer and regulatory relationships
- ❑ Improving financial metrics
- ❑ Committed to dividend policy consistent with past practices
- ❑ Leading the carbon policy debate



AEP is and will continue to be a financially sound, industry leader.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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AEP AMERICAN® ELECTRIC POWER

2009 Fact Book

44th EEI Financial Conference Hollywood, FL

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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AEP AMERICAN ELECTRIC POWER®

Company Overview

Company Overview

OUR FOCUS IS OUR CORE

DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Company, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions	Electric Utility Subsidiaries
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Over 39,000 megawatts of generating capacity in 3 RTOs (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 214,062 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 9,000 railcars
- own and/or operate almost 3,000 hopper barges, 58 towboats and 25 harbor boats
- operate one active coal-handling terminal with 20 millions tons of capacity

Historically, AEP consumes approximately 77 million tons of coal annually.

AEP Service Territory

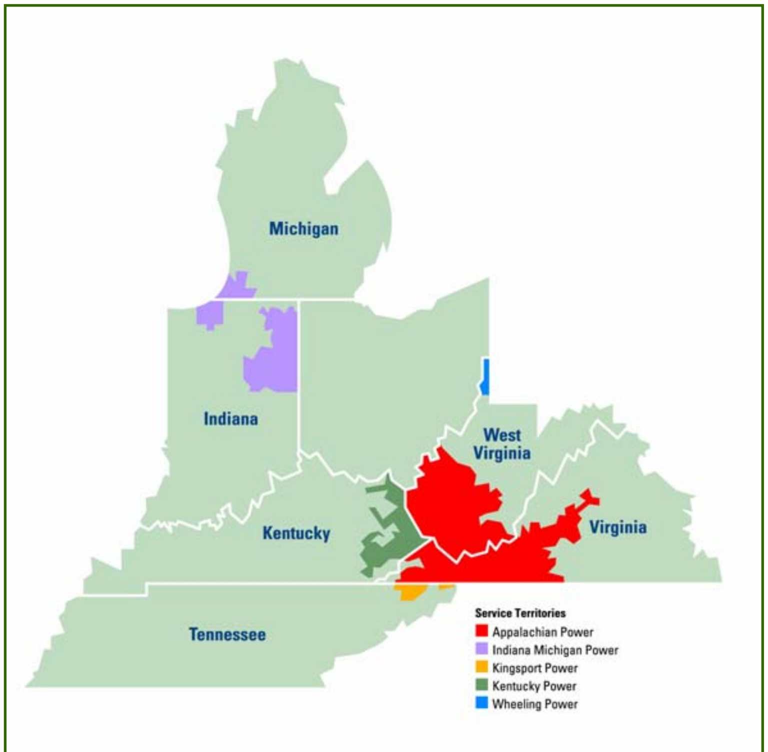
AEP EAST OPERATING COMPANIES

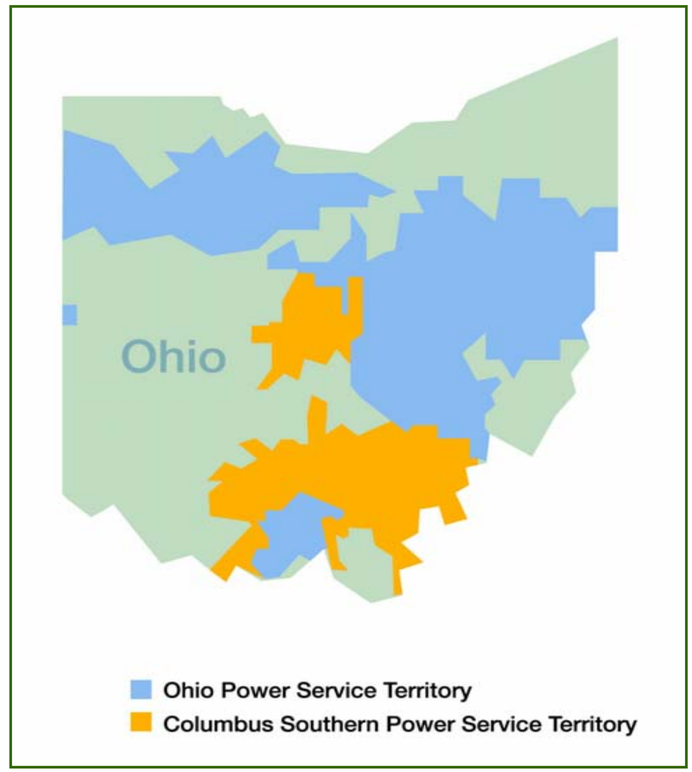
EAST REGULATED UTILITIES

- Appalachian Power Company (APCo)
- Indiana Michigan Power Company (I&M)
- Kingsport Power Company (KGPCo)
- Kentucky Power Company (KPCo)
- Wheeling Power Company (WPCo)

AEP OHIO

- Columbus Southern Power Company (CSPCo)
- Ohio Power Company (OPCo)





AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

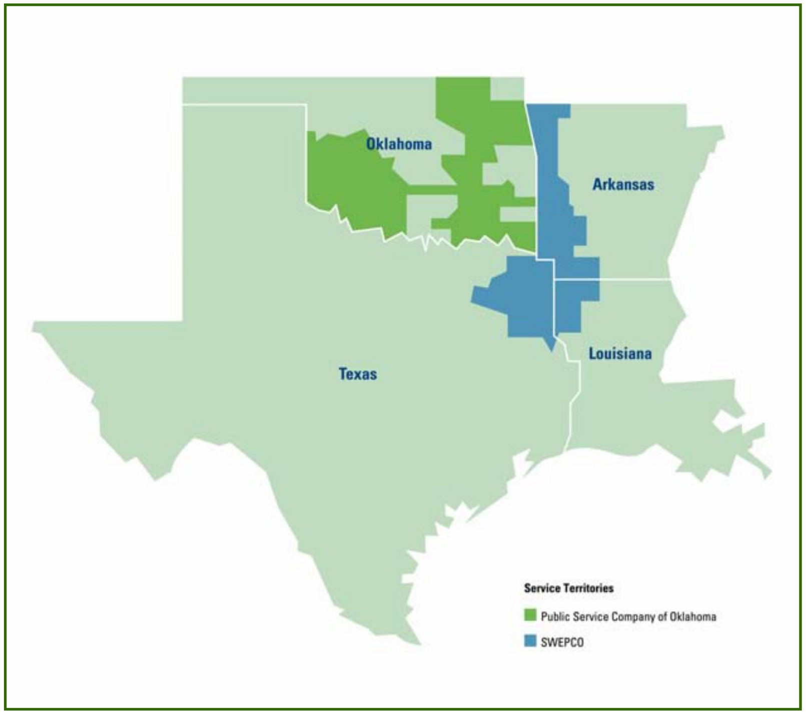
Public Service Company of Oklahoma (PSO)

Southwestern Electric Power Company (SWEPCO)

AEP TEXAS

Texas Central Company (TCC)

Texas North Company (TNC)



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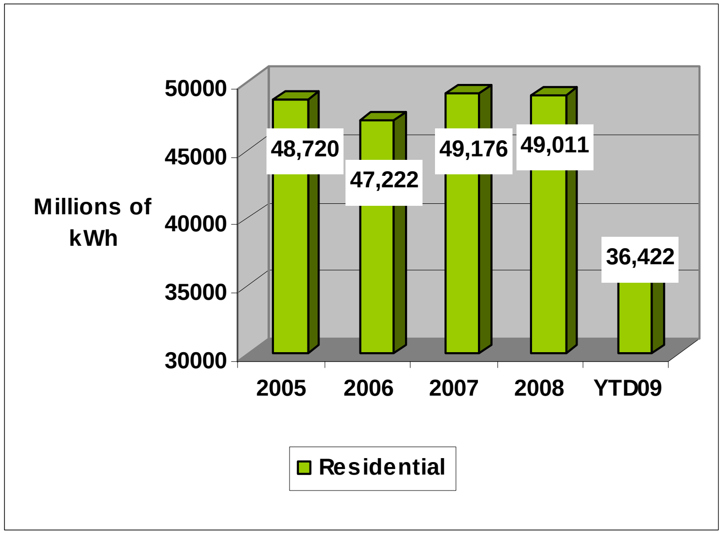
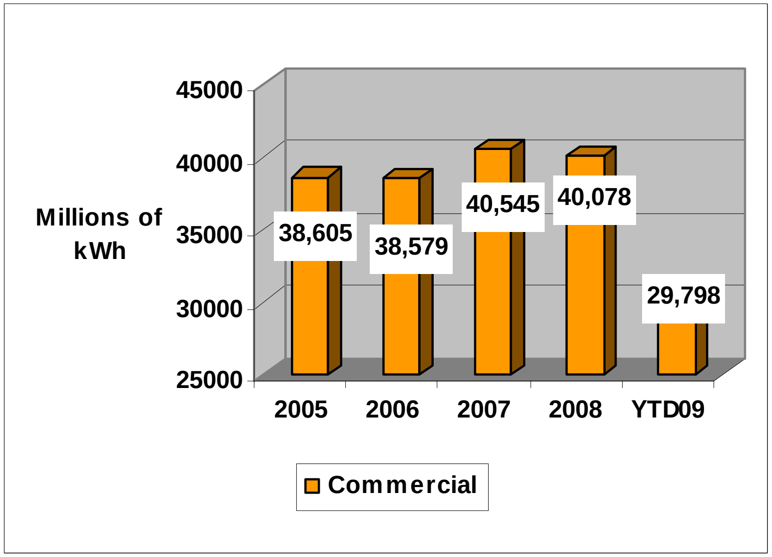
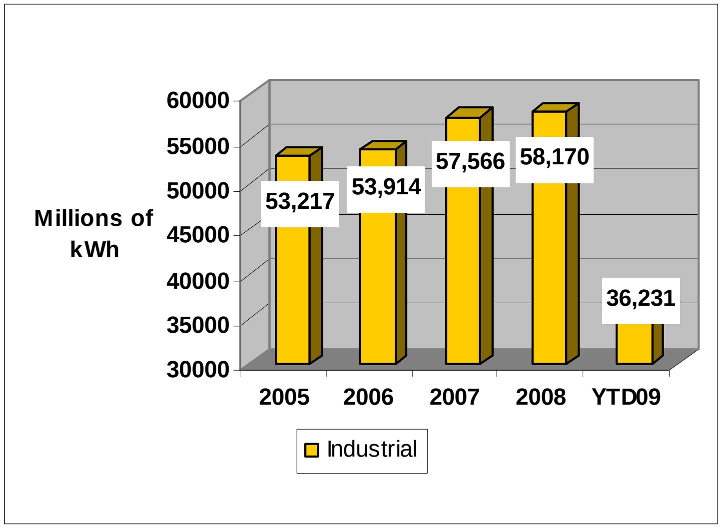
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 0.20%

3 Yr. Compound Annual Commercial Load Growth at 1.26%





3 Yr. Compound Annual Industrial Load Growth at 3.01%

Note: Figures do not include Texas Retail, Wholesale and Miscellaneous Other

2008 Retail Revenue

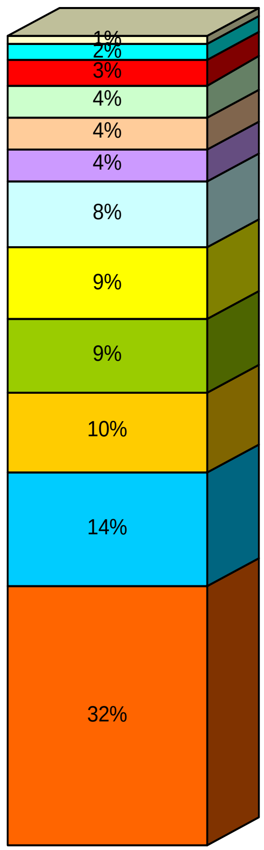
CUSTOMER PROFILE

AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

PERCENTAGE OF AEP SYSTEM RETAIL REVENUES

Tennessee	1%
Michigan	2%
Arkansas	3%
Kentucky	4%
Louisiana	4%
Texas SPP	4%
Texas ERCOT	8%
Indiana	9%
Virginia	9%
West Virginia	10%
Oklahoma	14%
Ohio	32%



Retail Revenue Composition by Customer Class**

Industrial	28.6%
Commercial	30.1%
Residential	41.3%

Top 10 Customers Across the AEP System By NAICS Code

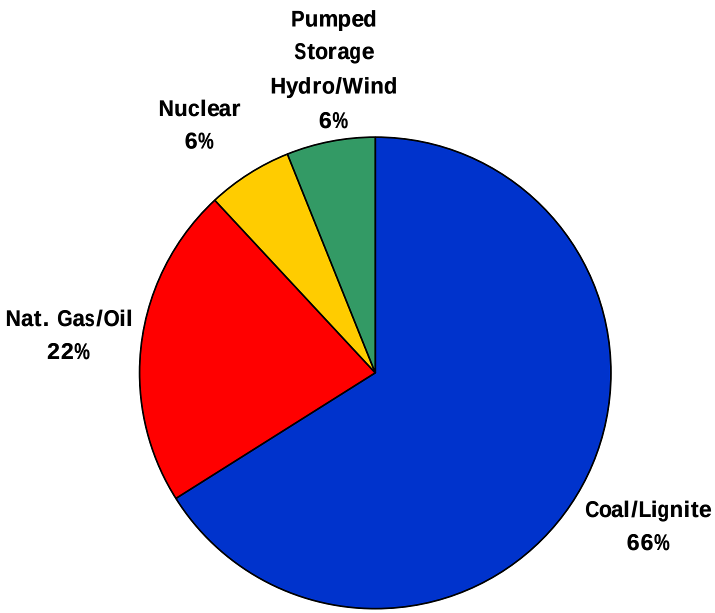
3330	PRIMARY SMELTING & REFINING OF NONFERROUS METALS
2800	CHEMICALS & ALLIED PRODUCTS
2911	PETROLEUM REFINING
2600	PAPERS & ALLIED PRODUCTS
2000	FOOD AND KINDRED PRODUCTS
3060	FABRICATED RUBBER PRODUCTS
1389	OIL & GAS FIELD SERVICES
3272/3281	STONE CLAY & CONCRETE PRODUCTS
1220	BITUMINOUS COAL & LIGNITE MINING
4900	ELECTRIC, GAS & SANITARY SERVICES

Source: Form 10-K

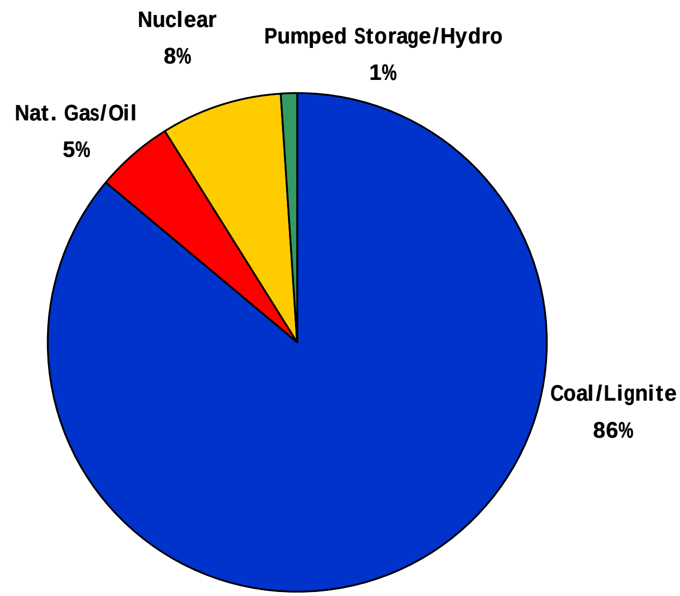
*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.

**Note: Figures do not include Other Retail Sales

Domestic Generation Fleet



2009 Generation Capacity by Fuel Type Based on 38,988 MW



2008 Generation Production by Fuel Type Based on 191,354,402 MWh

NERC Regional Presence

RFC	71%
SPP	26%
ERCOT	3%

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
APCo	734	97	383	106	0	3,338	0	23	1,096	789	0	230	0	6,796
CSPCo	0	0	884	0	0	893	0	0	467	0	59	0	113	2,416
I&M	615	0	1,614	0	0	1,668	0	0	707	0	0	739	0	5,343
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	30
KPCo	258	0	8	0	46	334	0	0	544	55	0	3	0	1,248
OPCo	509	0	909	0	0	2,444	0	0	2,169	0	0	365	112	6,508
PSO	0	0	579	34	8	2,175	11	0	812	0	0	0	0	3,619
SWEPCO	0	0	672	0	233	1,210	42	0	1,403	0	0	0	0	3,560
TCC	0	0	641	0	0	2,339	0	0	1,682	0	0	0	0	4,662
TNC	0	0	223	0	0	1,588	14	0	2,699	0	0	0	0	4,524
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	288
Total	**2,116**	**113**	**5,922**	**140**	**287**	**16,164**	**67**	**23**	**11,670**	**844**	**59**	**1,364**	**225**	**38,994**

State Level (Circuit Miles)

State	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
Arkansas	0	0	40	0	233	168	42	0	461	0	0	0	0	944
Indiana	600	0	1,380	0	0	1,426	0	0	409	0	0	591	0	4,406
Kentucky	258	0	8	0	46	334	0	0	544	55	0	3	0	1,248
Louisiana	0	0	105	0	0	260	0	0	230	0	0	0	0	595
Michigan	16	0	234	0	0	242	0	0	298	0	0	148	0	938
Ohio	509	0	1,793	0	0	3,337	0	0	2,637	0	59	365	225	8,925
Oklahoma	0	0	625	34	8	2,201	11	0	812	0	0	0	0	3,691
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	275
Texas	0	0	1,345	0	0	4,684	14	0	5,092	0	0	0	0	11,135
W. Virginia	384	17	323	0	0	1,624	0	23	457	741	0	89	0	3,658
Virginia	349	96	69	15	0	1,734	0	0	727	48	0	141	0	3,179
Total	**2,116**	**113**	**5,922**	**140**	**287**	**16,164**	**67**	**23**	**11,670**	**844**	**59**	**1,364**	**225**	**38,994**

Note: Transmission line circuit miles are current as of 12/31/08

Distribution Line Detail

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,529	KGPCo	1,529
Virginia	30,259	KPCo	9,899
W. Virginia	21,428	APCo	50,197
Kentucky	9,899	OPCo	26,458
Ohio	45,277	CSP	18,819
Michigan	5,277	I&M	20,170
Indiana	14,893	WPCo	1,490
Texas	51,661	TCC	29,322
Oklahoma	21,857	TNC	13,787
Arkansas	4,460	PSO	21,857
Louisiana	7,522	SWEPCO	20,534
Total	**214,062**	**Total**	**214,062**

* Includes approximately 29,800 miles of underground circuit miles

Year End 2008 data per Small World Graphics.

Operating Company Overview

- Organizational Structure
- AEP East Regional Utilities
- AEP West Regional Utilities

Organizational Structure

- CEO, Mike Morris
  - COO, Carl English
    - President, AEP Utilities, Bob Powers
      - EVP, AEP Utilities East, Venita McCellon-Allen
        - President, Ohio, Joe Hamrock
        - President, Appalachian Power, Dana Waldo
        - President, Indiana Michigan Power, Helen Murray
        - President, Kentucky Power, Tim Mosher
      - EVP, AEP Utilities West, Charles Patton
        - President, Texas, Pablo Vegas
        - President, SWEPCO, Paul Chodak III
        - President, Public Service of Oklahoma, Stuart Solomon


Mike


Carl


Bob


Venita


Charles


Joe


Dana


Helen


Tim


Pablo


Paul


Stuart

Senior management close to customers and regulators

AEP East Regional Utilities

Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 962,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2008, APCo and its wholly owned subsidiaries had 2,575 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary Metals
Coal Mining
Chemical
Paper Products

Total Customers at 12/31/08:

Residential	**819,000**
Commercial	**131,500**
Industrial	**4,500**
Other	**7,000**
Total	**962,000**

Generating Capacity **6,290 MW**

Generating Capacity by Fuel Mix:
- **Coal:** **80.9%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas:** **8.3%**

Transmission Miles **6,796**

Distribution Miles **50,197**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	3,122,556	2,099,784	5,222,340	3,369,400	2,394,343	5,763,743	3,604,148	2,757,358	6,361,506
% of Capitalization Per Balance Sheet	59.8%	40.2%	100.0%	58.5%	41.5%	100.0%	56.7%	43.3%	100.0%
FFO Interest Coverage			3.1			1.7			2.03 *
FFO Total Debt			11.8%			4.6%			6.4%*
							* - calculated on rolling 12-month avg.		

2008 Financial Data * (in thousands)

Revenue	$	2,889,000
% of AEP Retail		18%
Net Income	$	122,000
Capital Expenditures	$	697,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	9,342,067
Net Plant Assets	$	6,886,475
Cash	$	1,814

Operating Information***

2008 retail electric sales in megawatt-hours	34,209,668	2008 firm wholesale sales in megawatt-hours	3,489,529
2008 average cost per kilowatt-hour (residential)	5.77 cents	2008 System Peak – January 25	7,848 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

Appalachian Power

APPALACHIAN AREA

INVESTOR OWNED UTILITIES *

West Virginia	Customers
APCo	**437,496**
Allegheny	506,767

Virginia	Customers
APCo	**514,196**
Dominion Virginia	2,244,675
Allegheny	100,630
Kentucky Utilities	29,956
Potomac	22,496

Tennessee	Customers
APCo	**47,624**

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

West Virginia	$/month
APCo	**72.28**
AEP – Wheeling	**72.28**
Allegheny	83.33

Virginia	$/month
Old Dominion Power (Kentucky Utilities)	63.90
APCo	**91.49**
Potomac	91.60
Dominion Virginia	106.83

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009.

Top 10 Customers = 52% of industrial sales

Metropolitan areas account for 34% of ultimate sales

110 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

MAJOR CUSTOMERS:
CNX Gas Company (VA)
Greif Brothers Corporation (VA)
West Virginia Alloys (WV)
Alcan Rolled Products (WV)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Eastern Associated Coal Corp (WV)
Steel of West Virginia (WV)
Goodyear Tire and Rubber (VA)
Toyota Motor Manufacturing (WV)

(data for year ended December 2008)

AEP Ohio - Columbus Southern Power

President and Chief Operating Officer: Joe Hamrock

AEP Ohio-Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2008, CSPCo had 1,323 employees.

CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

Total Customers at 12/31/08:

Residential	**667,000**
Commercial	**78,000**
Industrial	**3,500**
Other	**500**
Total	**749,000**

Generating Capacity	**3,701 MW**

Generating Capacity by Fuel Mix:

- **Coal** **63.3%**
- **Natural Gas** **36.7%**

Transmission Miles	**2,416**
Distribution Miles	**18,819**

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals
Food Products
Rubber & Plastic Products
Fabricated Metals

AEP Ohio - Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,393,423	1,164,277	2,557,700	1,518,459	1,245,265	2,763,724	1,556,386	1,318,133	2,874,519
% of Capitalization Per Balance Sheet	54.5%	45.5%	100.0%	54.9%	45.1%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			5.9			5.24			5.09 *
FFO Total Debt			26.9%			26.3%			26.1% *
							* - calculated on rolling 12-month avg.		

2008 Financial Data * (in thousands)

Revenue	$	2,208,000
% of AEP Retail		16%
Net Income	$	237,000
Capital Expenditures	$	433,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	4,179,863
Net Plant Assets	$	3,439,650
Cash	$	1,204

Operating Information***

2008 retail sales in megawatt-hours	22,205,651
2008 firm wholesale sales in megawatt-hours	506,488
2008 average cost per kilowatt-hour (residential)	7.84 cents
2008 System Peak – June 9	4,406 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

AEP Ohio - Columbus Southern Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	1,456,053
First Energy ***	1,817,681
Duke Energy Ohio	675,108
DP&L	513,611

** AEP Ohio - CSPCo = 744,647
OPCo = 711,406

*** First Energy - Toledo Edison = 265,674
CEI = 696,301
Ohio Edison = 855,706

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	81.85
AEP (CSP)	96.29
DP&L	99.09
FE (CEI)	114.47
Duke Energy Ohio	116.70
FE (Ohio Edison)	122.04
FE (Toledo Edison)	130.92

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Aluminum
Eramet Marietta, Inc.
E I duPont de Nemours HQ
Kraton Polymers
Glatfelter Company
Anheuser-Busch, Inc.
Griffin Wheel Company, Inc.
Ross Products

(data for year ended December 2008)

Top 10 customers = 64% of industrial sales

Metropolitan areas account for 87% of ultimate sales

238 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2008, I&M had 2,879 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Energy Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Energy Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals and Allied Products
Transportation Equipment
Rubber and Miscellaneous Plastic Products
Fabricated Metals

Total Customers at 12/31/08:

Residential	**507,000**
Commercial	**68,000**
Industrial	**5,000**
Other	**2,000**
Total	**582,000**

Generating Capacity **5,821 MW***

Generating Capacity by Fuel Mix:

- **Coal:** **51.1%**
- **Nuclear:** **48.6%**
- **Hydro:** **0.3%**

Transmission Miles	**5,343**
Distribution Miles	**20,170**

* Includes AEGCo's share of Rockport of 1, 320MW

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,612,491	1,393,779	3,006,270	1,853,950	1,442,898	3,296,848	2,077,699	1,673,589	3,751,288
% of Capitalization Per Balance Sheet	53.6%	46.4%	100.0%	56.2%	43.8%	100.0%	55.4%	44.6%	100.0%
FFO Interest Coverage			4.8			4.4			4.5 *
FFO Total Debt			26.1%			22.0%			23.7% *
							* - calculated on rolling 12-month avg.		

2008 Financial Data * (in thousands)

Revenue	$ 2,166,000
% of AEP Retail	10%
Net Income	$ 132,000
Capital Expenditures	$ 352,000

2009 Asset Data ** (in thousands)

	As of 9/30/09
Total Assets	$ 6,826,753
Net Plant Assets	$ 4,063,726
Cash	$ 843

Operating Information***

2008 retail electric sales in megawatt-hours	18,942,835
2008 firm wholesale sales in megawatt-hours	4,552,202
2008 average cost per kilowatt-hour (residential)	6.17 cents
2008 System Peak – July 31	4,264 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

Indiana Michigan Power

INDIANA & MICHIGAN INVESTOR OWNED UTILITIES * TYPICAL BILL COMPARISON **

Indiana	Customers
I & M	**454,636**
IP & L	468,666
NIPSCO	454,471
Duke Energy Indiana	773,954
SIGECo	146,473

Indiana	$/month
I & M	**74.28**
IP & L	82.57
Duke Energy Indiana	98.33
NIPSCO	115.39
SIGECo	129.58

Michigan	$/month
I & M	**67.03**
Consumers Energy	109.97
Detroit Edison	120.07

Michigan	Customers
I & M	**127,245**
Consumers Energy	1,797,389
Detroit Edison	2,161,388

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009.

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

Top 10 Customers = 47% of industrial sales

Metropolitan areas account for 68% of ultimate sales

204 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

MAJOR CUSTOMERS:

Steel Dynamics Inc. (IN)
Dock Foundry (MI)
American Axle and Mfg. Co, Inc. (MI)
IN TEK (IN)
Whirlpool Corporation (MI)
Saint Gobain Corporation USA (IN)
White Pigeon Paper Company (MI)
Air Products & Chemicals, Inc. (IN)
The Minute Maid Company (MI)
New Energy Corp (IN)
Rexam Closure Systems, Inc. (MI)

(data for year ended December 2008)

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2008, KPCo had 480 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers at 12/31/08:

Residential	**144,000**
Commercial	**30,000**
Industrial	**1,500**
Other	**500**
Total	**176,000**

Generating Capacity	**1,060 MW**

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**1,248**
Distribution Miles	**9,899**

PRINCIPAL INDUSTRIES SERVED:

Petroleum Refining
Coal Mining
Primary Metals
Chemicals & Allied Products
Electric/Gas/Sanitary Services

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	467,526	386,969	854,495	549,954	398,008	947,962	548,680	431,042	979,722
% of Capitalization Per Balance Sheet	54.7%	45.3%	100.0%	58.0%	42.0%	100.0%	56.0%	44.0%	100.0%
FFO Interest Coverage			3.8			2.51			3.47 *
FFO Total Debt			17.3%			9.9%			16.3% *
							* - calculated on rolling 12-month avg.		

2008 Financial Data * (in thousands)

Revenue	$	666,000
% of AEP Retail		4%
Net Income	$	24,500
Capital Expenditures	$	130,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	1,474,143
Net Plant Assets	$	1,129,438
Cash	$	545

Operating Information***

2008 retail electric sales in megawatt-hours	7,241,902
2008 firm wholesale sales in megawatt-hours	100,098
2008 average cost per kilowatt-hour (residential)	6.58 cents
2008 System Peak – January 25	1,678 MW

Sources: * 2008 Annual Report
** 3Q09 Financial Statements (unaudited)
*** 2008 FERC Form 1

Kentucky Power

KENTUCKY INVESTOR OWNED UTILITIES *

Kentucky	Customers
KPCo	175,705
Kentucky Utilities	503,551
LG & E	400,703

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	$/month
Kentucky Utilities	71.72
LG&E	73.56
KPCo	84.29
Duke Energy Kentucky	88.66

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009.

MAJOR CUSTOMERS:

Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
KES Acquisition Company LLC
Air Products & Chemicals, Inc.
Perry County Coal Corporation
Blue Diamond Coal Company
McCoy Elkhorn Coal Corporation
Huntington Alloys
Czar Coal Corporation

(data for year ended December 2008)

Top 10 customers = 62% of industrial sales

Metropolitan areas account for 42% of ultimate sales

68 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

AEP Ohio - Ohio Power

President and Chief Operating Officer: Joe Hamrock

AEP Ohio- Ohio Power Company (OPCo)

AEP Ohio- Ohio Power Company (OPCo) (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2008, OPCo had 2,434 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Petroleum Refining
Rubber & Plastic Products
Chemicals & Allied Products
Stone, Clay, Glass and Concrete Products

Total Customers at 12/31/08:

Residential	**610,000**
Commercial	**92,500**
Industrial	**7,000**
Other	**2,500**
Total	**712,000**

Generating Capacity	**8,478 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.7%**
- **Hydro:** **0.3%**

Transmission Miles	**6,508**
Distribution Miles	**26,458**

AEP Ohio - Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,951,847	2,307,644	5,259,491	3,173,263	2,455,371	5,628,634	3,242,299	3,237,458	6,479,757
% of Capitalization Per Balance Sheet	56.1%	43.9%	100.0%	56.4%	43.6%	100.0%	50.0%	50.0%	100.0%
FFO Interest Coverage			4.5			3.1			3.56 *
FFO Total Debt			19.1%			13.3%			14.3% *
							* - calculated on 12-month rolling avg.		

2008 Financial Data * (in thousands)

Revenue	$ 3,097,000
% of AEP Retail	16%
Net Income	$ 230,000
Capital Expenditures	$ 706,000

2009 Asset Data ** (in thousands)

	As of 9/30/09
Total Assets	$ 8,736,817
Net Plant Assets	$ 6,699,698
Cash	$ 2,950

Operating Information

2008 retail sales in megawatt-hours	27,871,540
2008 firm wholesale sales in megawatt-hours	2,228,714
2008 average cost per kilowatt-hour (residential)	6.14 cents
2008 System Peak – June 9	5,458 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

AEP Ohio - Ohio Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	**1,456,053**
First Energy ***	1,817,681
Duke Energy Ohio	675,108
DP&L	513,611

** AEP Ohio - CSPCo = 744,647
OPCo = 711,406

*** First Energy - Toledo Edison = 265,674
CEI = 696,301
Ohio Edison = 855,706

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	**81.85**
AEP (CSP)	**96.29**
DP&L	99.09
FE (CEI)	114.47
Duke Energy Ohio	116.70
FE (Ohio Edison)	122.04
FE (Toledo Edison)	130.92

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Primary Aluminum Corp.
Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Lima Refining Corp.
Globe Metallurgical, Inc.
Linde Glass, LLC
Marathon Ashland Petroleum, LLC
Owens Corning Fiberglass Corp.
Aristech Chemical Corp.

(data for year ended December 2008)

Top 10 customers = 53% of industrial sales

Metropolitan areas account for 61% of ultimate sales

137 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 527,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2008, PSO had 1,279 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy, Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Paper Products
Oil and Gas Extraction
Stone, Clay and Glass Products
Primary Metals
Petroleum Refining

Total Customers at 12/31/08:

Residential	**453,000**
Commercial	**60,000**
Industrial	**7,000**
Other	**7,000**
Total	**527,000**

Generating Capacity **4,603 MW**

Generating Capacity by Fuel Mix:

- **Coal: 22.2%**
- **Natural Gas: 77.3%**
- **Oil: 0.5%**

Transmission Miles	**3,619**
Distribution Miles	**21,857**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	918,316	646,160	1,564,476	955,167	753,508	1,708,675	868,738	825,188	1,693,926
% of Capitalization Per Balance Sheet	58.7%	41.3%	100.0%	55.9%	44.1%	100.0%	51.3%	48.7%	100.0%
FFO Interest Coverage			2.6			4.3			5.22 *
FFO Total Debt			9.2%			27.2%			35.6% *
							* - calculated on rolling 12-month avg		

2008 Financial Data * (in thousands)

Revenue	$	1,656,000
% of AEP Retail		14%
Net Income	$	78,000
Capital Expenditures	$	286,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	3,084,811
Net Plant Assets	$	2,565,410
Cash	$	1,307

Operating Information***

2008 retail electric sales in megawatt-hours	17,753,458
2008 firm wholesale sales in megawatt-hours	9,229
2008 average cost per kilowatt-hour (residential)	8.01 cents
2008 System Peak – August 4	4,200 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

Public Service Company of Oklahoma

OKLAHOMA INVESTOR OWNED UTILITIES *

Oklahoma	Customers
PSO	522,419
OG&E	695,961

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	$/month
Empire	76.60
PSO	81.83
OG&E	84.88

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009.

MAJOR CUSTOMERS:

Sheffield Steel
Weyerhaeuser Valliant Company
Elkem Metals
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
American Airlines
Sinclair
Sun Refining
Republic Paperboard Inc.
Anchor Glass Container

(data for year ended December 2008)

Top 10 customers = 47% of industrial sales

Metropolitan areas account for 75% of ultimate sales

47 persons per square mile (U.S. = 80)

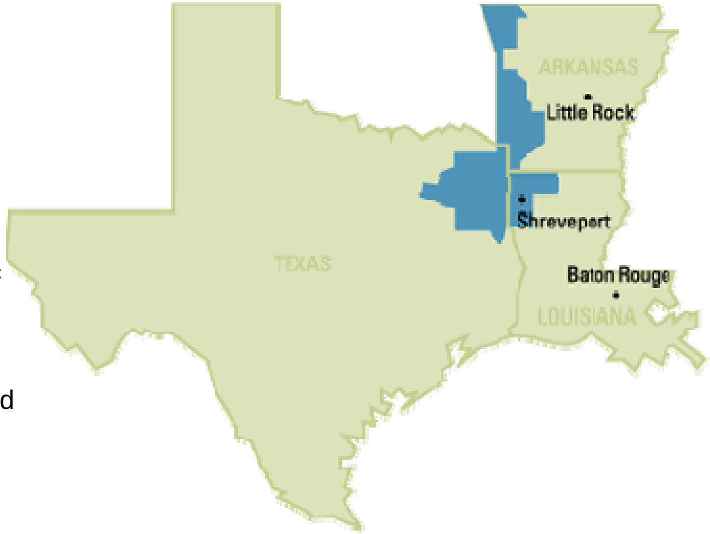
(data for 12 months ended December 2008)

Southwestern Electric Power

President and Chief Operating Officer: Paul Chodak III

Southwestern Electric Power Company (SWEPCO)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 471,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2008, SWEPCo had 1,641 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.



Total Customers at 12/31/08:	
Residential	**397,500**
Commercial	**66,000**
Industrial	**7,000**
Other	**500**
Total	**471,000**
Generating Capacity	**4,850 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**38.1%**
• **Natural Gas:**	**44.4%**
• **Lignite:**	**17.5%**
Transmission Miles	**3,560**
Distribution Miles	**20,534**

PRINCIPAL INDUSTRIES SERVED:

Food Processing
Pulp and Paper Manufacturing
Oil and Gas Extraction
Primary Metals
Petroleum Refining

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,199,068	977,652	2,176,720	1,487,847	1,253,626	2,741,473	1,480,425	1,517,624	2,998,049
% of Capitalization Per Balance Sheet	55.1%	44.9%	100.0%	54.3%	45.7%	100.0%	49.4%	50.6%	100.0%
FFO Interest Coverage			3.5			3.26			4.48 *
FFO Total Debt			13.7%			16.0%			24.2% *
							* - calculated on rolling 12-month avg		

2008 Financial Data * (in thousands)

Revenue	$ 1,555,000
% of AEP Retail	11%
Net Income	$ 93,000
Capital Expenditures	$ 692,000

2009 Asset Data ** (in thousands)

	As of 9/30/09
Total Assets	$ 4,528,910
Net Plant Assets	$ 3,830,618
Cash	$ 2,089

Operating Information

2008 retail electric sales in megawatt-hours	17,171,790
2008 firm wholesale sales in megawatt-hours	5,843,198
2008 average cost per kilowatt-hour (residential)	6.91 cents
2008 System Peak – August 4	4,950 MW

Sources: * 2008 Form 10-K
** 3Q09 Form 10-Q (unaudited)
*** 2008 FERC Form 1

Southwestern Electric Power

SOUTHWESTERN INVESTOR OWNED UTILITIES *

Arkansas	Customers
SWEPCo	**112,258**
Entergy AR	685,483

Louisiana	Customers
SWEPCo	**176,711**
CLECO	269,730
Entergy	1,148,958

Texas	Customers
SWEPCo	**175,823**
El Paso	267,993
SPSCo	278,156
Entergy	389,614

* Customer counts are as of December 31, 2007 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	$/month
OG&E	74.77
SWEPCo	**84.94**
Empire District	88.29
Entergy AR	112.70

Louisiana	$/month
SWEPCo	**73.27**
Entergy LA	91.43
Entergy Gulf St	97.64
Entergy NO	106.07
CLECO	119.63

Texas	$/month
SWEPCo	**61.16**
SPSCo	94.92
El Paso	126.48
Entergy	128.18

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2009.

Top 10 customers = 54% of industrial sales

Metropolitan areas account for 74% of ultimate sales

81 persons per square mile (U.S. = 80)

(data for 12 months ended December 2008)

MAJOR CUSTOMERS:

Lone Star Steel Company (TX)
International Paper Company (TX)
General Motors Corporation (LA)
Calumet Lubricants (LA)
Libbey Glass Inc. (LA)
Domtar, Inc (AR)
Pilgrim Pride Corporation (TX)
UOP, LLC (LA)
Cooper Tire & Rubber Company (AR)
Letourneau (TX)
Big Three Industrial Gas (TX)
Holox (AR)
Glad Manufacturing (AR)

(data for year ended December 2008)

AEP Texas Central Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas - Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 761,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2008, TCC had 1,201 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Javelina Refinery
Formosa
Koch Refinery West
Equistar Bay City

(data for year ended December 2008)

PRINCIPAL INDUSTRIES SERVED:

Petroleum Refining
Chemicals & Allied Products
Oil and Gas Extraction
Food Processing

Top 10 customers = 37% of industrial sales* ($)

Metropolitan areas account for 79% ultimate sales

57 persons per square mile (U.S. = 80)

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2008)

Total Customers at 12/31/08:
(Based on electric meters)

Residential	**649,000**
Commercial	**105,000**
Industrial	**5,000**
Other	**2,000**
Total	**761,000**
Transmission Miles	**4,662**
Distribution Miles	**29,322**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,937,553	465,115	3,402,668	2,901,590	519,964	3,421,554	2,757,921	597,881	3,355,802
% of Capitalization Per Balance Sheet	86.3%	13.7%	100.0%	84.8%	15.2%	100.0%	82.2%	17.8%	100.0%
FFO Interest Coverage			3.7			3.5			4.12 *
FFO to Total Debt			24.8%			19.9%			21.8% *
							* - calculated on rolling 12-month avg		

2008 Financial Data * (in thousands)

Revenue	$	837,000
% of AEP Retail		6%
Net Income	$	86,000
Capital Expenditures	$	267,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	5,270,961
Net Plant Assets	$	2,515,828
Cash	$	200

Sources: * 2008 Annual Report
** 3Q09 Financial Statements (unaudited)

AEP Texas North Company

President and Chief Operating Officer: Pablo Vegas

AEP Texas - Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 185,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2008, TNC had 370 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:

Zoltec Corporation
Oxy-Permian LTD
Kinder Morgan
Tyson Foods, Inc.
EBAA Iron
Georgia-Pacific LLC

(data for year ended December 2008)

PRINCIPAL INDUSTRIES SERVED:

Oil and Gas Extraction
Food Processing
Pipelines, except Natural Gas
Stone, Clay and Glass Production
Electric Equipment

Top 10 customers = 28% industrial sales* ($)

Metropolitan areas account for 58% ultimate sales

8 persons per square mile (U.S. = 80)

*Industrial % is in terms of wires revenues

(data for 12 months ended December 2008)

Total Customers at 12/31/08:
(Based on electric meters)

Residential	**145,000**
Commercial	**30,000**
Industrial	**5,000**
Other	**5,000**
Total	**185,000**

Generating Capacity **377 MW**
Oklaunion Plant – Vernon, TX
(excludes 270 MW of decommissioned plants)

Generating Capacity by Fuel Mix:

- **Coal:** **58.3%**
- **Gas:** **40.5%**
- **Oil:** **1.2%**

Transmission Miles	**4,524**
Distribution Miles	**13,787**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2007			2008			9/30/2009		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	302,386	334,244	636,630	397,651	325,825	723,476	409,342	324,747	734,089
% of Capitalization Per Balance Sheet	47.5%	52.5%	100.0%	55.0%	45.0%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			4.7			4.7			4.35 *
FFO Total Debt			21.2%			21.9%			19.8% *
							* - calculated on rolling 12-month avg.		

2008 Financial Data * (in thousands)

Revenue	$	278,000
% of AEP Retail		1%
Net Income	$	34,000
Capital Expenditures	$	133,000

2009 Asset Data ** (in thousands)

	As of 9/30/09	
Total Assets	$	1,192,244
Net Plant Assets	$	1,023,380
Cash	$	200

Sources: * 2008 Annual Report
** 3Q09 Financial Statements (unaudited)

Regulation

- Regulatory Strategy
- Rate Case Filing Requirements
- Regulatory Activity Underway
- Commission Overviews
- Rate Base and ROE by Operating Company

Regulatory Strategy: Reduce Lag

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers/Riders/Regulatory Adjustment Clauses
  - Federally-approved transmission costs
  - Fuel and emissions
  - Energy Efficiency Programs
- Formula rates
  - Including periodic true-ups and approved earnings bands
- Future test years
- Accelerated cost recovery/depreciation/replacement cost accounting
- Pre-Approvals
- Securitization
- Return on CWIP

The strategy: reduce the time between in-service dates and rate recovery

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Louisiana	Michigan	Ohio	Oklahoma	Texas	Virginia	West Virginia	FERC
General											
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	Yes	No	No
Period of Limitation (months)	--	15	--	--	--	--	--	--	See note 1	--	--
Pancaking Permitted?	No	No	No	Yes	No	Limited	No	No	No	No	Yes
Fuel Clause Renewal Frequency	Annually	Semi-Annually	Monthly	Monthly	Annually	Quarterly	Annually	Annually	Annually	Annually	Annually
Notice of Intent											
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	N/A	45	30	45	30	60	30	N/A
Case Components											
Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Partially Projected	Historical	Historical	Historical	Forecast Optional
Other											
Rates Effective Subject to Refund	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Approx # of Months after Filing to implement rates subject to refund	10	--	6	12	Varies	9	6	6	5	9	2 or 7

Note 1: No interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Regulatory framework inherently produces recovery and return lag.

Summary Rate Case Information

SWEPCO Arkansas General Rate Case

On February 19, 2009 SWEPCO filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) On September 17, 2009 SWEPCO, along with the general staff of the Arkansas PSC and State Attorney General filed a settlement agreement. The settlement requests a 10.25% ROE and a $17.8MM rate increase with a rate base of $612MM. The generation recovery rider has been amended to cover the return, depreciation and O&M expenses related to the Stall Plant once the unit is in-service.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Settlement hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030) A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

12/12/2009	Rates effective, subject to refund
12/28/2009	Intervenor testimony due
1/27/2010	Staff testimony due
2/17/2010	Rebuttal testimony due
3/16/2010	Evidentiary hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

SWEPCO Texas General Rate Case

On August 28, 2009 SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. (Docket# 37364) An order is expected in 2010.

Projected Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule TBD

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1521 of 9556

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**
Qualifications for Commissioners The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.			
Commissioners **Paul Suskie, Chairman (Dem.),** since 2007; current term ends in 2013. Lawyer, North Little Rock, Arkansas City Attorney. Bachelor's attained at University of Central Arkansas. Juris Doctorate at University of Arkansas at Little Rock School of Law. NARUC member including the Committee on Consumer Affairs and Electricity Committee.			
Olan Reeves, Commissioner (Rep.), since 2009; current term ends in 2015. Chairman of the Workers' Compensation Commission from January, 2003 until January, 2009. Prior to these appointments, Commissioner Reeves was Chief Legal Counsel to the Governor from 1998-2003 and served as the State Drug Director from 1996 to 1998. Reeves received his Juris Doctorate from the University of Arkansas School of Law in Fayetteville.			
Collette Honorable, Commissioner (Dem.), since 2007; current term ends in 2011. Commissioner Honorable is a member of NARUC and serves on the Consumer Affairs and Investment Committees. She also serves on the Smart Grid Collaborative, a joint effort of NARUC and the FERC. Honorable obtained her Juris Doctorate from the University of Arkansas at Little Rock School of Law.			

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 3 D: 2

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairperson.

Commissioners

David L. Hardy, Chairman (Rep.), since 2005; current term will expire April 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include negotiation, contracts, litigation, finance and administration. He has 35 years of regulatory experience at the state and federal levels. Bachelors degree and law degree from Indiana University.

Jeffrey L. Golc, Commissioner (Dem.), since 2007; current term will expire January 2010. Former public affairs manager for the Kroger Company. Previous Deputy Commissioner for the Indiana Bureau of Motor Vehicles and the Indiana Department of Workforce Development. Bachelors and Masters degrees in communications from Indiana University.

Larry S. Landis, Commissioner (Rep.), since 2002; current term ends December 2011. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.

Jim Atterholt, Commissioner (Rep.), since 2009; current term ends 2014. Prior to joining the Commission, he was the State Insurance Commissioner for more than four years where he also served as a member of the Governor's Cabinet. Atterholt worked as Director of Government Affairs for AT&T--Indiana from 2003 – 2004. Atterholt holds a Bachelors degree from the University of Wisconsin.

David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2011. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and chairman of the NARUC clean coal and carbon sequestration subcommittee. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

I&M provides retail electric service in Indiana at bundled rates approved by the IURC. Rates are set on a cost-of-service basis with a fuel recovery mechanism. I&M has trackers in place for PJM expenses, OSS sharing, clean coal technology, environmental and DSM.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 2 D:1**
Qualifications for Commissioners Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.			
Commissioners **David L. Armstrong, Chairman (Dem.),** since 2008; current term expires June 2011. Former practicing attorney in private practice. Board member of NARUC and serves on its Electricity Committee and the Subcommittee on Clean Coal Technology. J.D. from University of Louisville Brandeis School of Law. Mr. Armstrong is also the former Mayor for the city of Louisville, KY (1999-2003).			
James W. Gardner, Vice Chairman (Rep.), since 2008; current term expires June 2012. Prior to joining the PSC Mr. Gardner was a partner at the law firm Henry Watz Gardner & Sellars PLLC where he specialized in bankruptcy law. JD degree from the University of Kentucky College of Law.			
Charles Borders, Commissioner (Rep.), since 2009; current term expires June 2013. Before joining the PSC, Commissioner Borders served in the Kentucky Senate, representing the 18th District in northeast Kentucky since 1991. He most recently chaired the Appropriations and Revenue Committee and served on the committees on Education and Health and Welfare. Borders received his Bachelors and Masters degrees from Morehead State University.			

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 3 D: 2**
Qualifications for Commissioners The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.			
Commissioners **Lambert C. Bossiere, III (Chairman) (Dem.),** since 2005; current term ends December 2010. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.			
Eric Skrmetta, (Rep.), since 2009; current term ends December 2014. Practicing Attorney since 1985. Practicing Mediator since 1989. Republican State Central Committee District 81**.** Juris Doctorate Southern University Law School.			
Foster L. Campbell, (Dem.), since 2003; current term ends December 2014. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.			
James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.			
Clyde Holloway, (Rep.), since 2009; current term ends December 2010. Elected to Congress in 1987 and served in the United States House of Representatives until 1993. In October 2006 he received an appointment by President Bush as the USDA State Director of Rural Development where he served until 2009**.**			

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects. A formula rate plan was implemented August 1, 2008.

Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: D: 2 I: 1**
Qualifications for Commissioners The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.			
Commissioners **Orjiakor N. Isiogu, Chairman (Dem.),** since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.			
Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's and Master's degrees from University of Michigan.			
Steven A. Transeth, Commissioner, (Ind.) , since 2007; current term expires July 2015. Former assistant director and legal counsel for the Michigan Legislative Service Bureau, which included drafting legislation and providing legal counsel to the Michigan Senate and House of Representatives. Lawyer, private practice and with the Ingham County Prosecuting Attorney's office. J.D. from Thomas Cooley Law School.			

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. In 2008, legislation was enacted to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year. Michigan has an active fuel clause and return on CWIP can be included in base rates. Michigan currently has a mandatory renewable energy standard of 10% by 2015.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected: Appointed**	**Term: 5 Years**	**Political Makeup: R: 1 D: 2 I: 2**

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2014. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee, National Governors' Association Electricity Task Force, Harvard Electricity Policy Group.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctor from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Ronda Hartman Fergus, Commissioner, (Rep.) since 1995; term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff. Member NARUC Committee on Consumer Affairs.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master's degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation. Past President of the National Academy of Public Administration.

Cheryl Roberto, Commissioner, (Dem.) since 2008; term expires April 2013. Prior to joining the PUC, Roberto was director of the City of Columbus Public Utilities Department. Before entering the public sector, Commissioner Roberto worked as an assistant attorney general for the state of Ohio. Commissioner Roberto received her B.A. with honors from Kent State University and her Juris Doctorate from the Moritz College of Law at The Ohio State University.

AEP Regulatory Status

On March 18, 2009 the Ohio PUC approved an electric security plan allowing for revenue increases of 7% in 2009 and 6% in 2010 and 2011 for Columbus Southern Power and revenue increases of 8% in 2009, 7% in 2010 and 8% in 2011 for Ohio Power. Transmission rates are currently regulated by FERC as reflected in the OATT. SB221 allows that CSP and OPCo have active fuel clauses effective January 1, 2009. Ohio currently has a mandatory renewable energy standard of 25% by 2025.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 2 D: 1

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Bob Anthony, Chairman, (Rep.), since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned an M.Sc. from the London School of Economics, an M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.

Jeff Cloud, Commissioner (Rep.), since 2002; current term ends January 2015. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of Staff. Law degree from Oklahoma City University.

Dana Murphy, Commissioner, (Dem.), since 2008; current term expires January 2015. Member, NARUC. Murphy's prior experience includes working as an administrative law judge at the Commission. She has more than 20 years experience in the petroleum industry including owning and operating her own private law practice and working as a geologist in the Oklahoma petroleum industry. Juris Doctorate Oklahoma City University.

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism.

Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 3**
Qualifications for Commissioners The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six-year terms, which all expired in June 2008; terms are now staggered.			
Commissioners **Sara Kyle, Chairman (Dem.),** since 1996; current term expires June 2014. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving commissioner and only holdover from the previous Regulatory Authority. Law degree from Middle Tennessee State University.			
Mary W. Freeman, Director (Dem.), since 2008; current term expires June 2011. Prior legislative director for Governor Bredesen, executive assistant to State Representative Lois DeBerry. B.A. Tennessee State University.			
Kenneth Hill, Director (Rep.), since 2009; current term expires June 2015. At the time of his appointment to the TRA, Hill was Chief Executive Officer of AECC and served as General Manager of five radio stations reaching portions of East Tennessee and four surrounding states. Doctor of Religious Education, Andersonville Baptist Seminary.			
Eddie Roberson, Ph.D, Director, (Dem.), since 2006; current term expires June 2014. Former Chief of Consumer Services Division of the Regulatory Authority; also served a year as the agency's Executive Director. Served two terms on the Chattanooga City School Board. Ph.D in Public Administration from Tennessee State University.			

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.
Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 3**
Qualifications for Commissioners To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.			
Commissioners **Barry T. Smitherman, Chairman, (Rep.),** since April 2004; current term expires August 2013. Attorney; Assistant DA; Public Finance Investment Banker. Received law degree from the University of Texas School of Law.			
Kenneth W. Anderson, (Rep.) since September 2008; current term expires August 2011. Past Director of Governmental Appointments under Governor Perry. Prior to that Anderson served in private practice as a corporate attorney in the area of securities law and regulatory matters. He also served as a member of the Texas Securities Board from 1999-2006. Anderson holds a law degree from Southern Methodist University.			
Donna L. Nelson, Commissioner (Rep.), since August 2008; current term expires August 2015. Nelson served as a special assistant and advisor to Governor Perry on energy, telecommunications and cable budget and policy issues. She previously served as director of the PUC telecommunication's section and legal advisor to the PUC chairman. Nelson holds a law degree from Texas Tech University.			

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base. TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 1**
Qualifications for Commissioners The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.			
Commissioners **Mark C. Christie, Chairman (Rep.),** since 2004; current term expires 2010. Prior counsel to the Speaker of the House of delegates of the Virginia General Assembly. Lawyer, private practice. Law degree from Georgetown.			
Judith Williams Jagdmann, (Rep.), since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.			
James C. Dimitri (Dem.), since 2008; current term expires 2014. Prior to being named Commissioner, Dimitri was in private practice in Richmond. From 1994 to 2000 he served as Senior Counsel, then General Counsel at the SCC. He was an assistant Attorney General from 1983 to 1987. Dimitri received his undergraduate degree in economics from the University of Virginia and his J.D. from the Boston University School of Law.			

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to annual rate changes to recover the incremental costs it incurred through December 31, 2008 for transmission and distribution system reliability and compliance with state or federal environmental laws or regulations (known as the E&R rider). APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. Virginia currently has a voluntary renewable energy standard of 12% by 2022, which AEP intends to comply with.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.

Wheeling Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Michael A. Albert, Chairman (Rep.), since 2007; term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Edward H. Staats, Commissioner (Dem.), since 2003; term expired June 2009 and has not yet been renewed. Former Chief of Operations in the Governor's office. Former Chief Financial Officer of the Workers' Compensation Division of the W.V. Bureau of Employment Programs. Certified Public Accountant in West Virginia and Georgia. Bachelor's degree, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005; term expires June 2011. Currently on the board of directors of the NARUC and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction. West Virginia currently has a renewable energy standard of 25% by 2015.

Commission Overview

Federal Energy Regulatory Commission

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 5 Years**	**Political Makeup: R: 2 D: 2**

Qualifications for Commissioners

The Federal Energy Regulatory Commission (FERC) is composed of up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve five-year terms, and have an equal vote on regulatory matters. To avoid any undue political influence or pressure, no more than three commissioners may belong to the same political party.

Commissioners

Jon Wellinghoff, Chairman (Dem.), since 2006; term expires June 2013. Chairman Wellinghoff is an energy law specialist with more than 30 years experience in the field. Before joining FERC, he was in private practice and focused exclusively on client matters related to renewable energy, energy efficiency and distributed generation. While in the private sector, Chairman Wellinghoff represented an array of clients from federal agencies, renewable developers, and large consumers of power to energy efficient product manufacturers and clean energy advocacy organizations.

Suedeen G. Kelly, Commissioner (Dem.) since 2003; term expired June 2009. On September 21, 2009, Commissioner Kelly declined her reappointment by President Obama to a new term. She will continue to serve until the Senate confirms a replacement. Previously Kelly was a Professor of Law at the University of New Mexico School of Law, where she taught energy law, public utility regulation, administrative law and legislative process. She also worked with the law firm of Modrall, Sperling, Roehl, Harris & Sisk in Albuquerque from 2000 through 2003 and the law firm of Sheehan, Sheehan, and Stelzner from 1992 through 1999. In 2000, Ms. Kelly served as counsel to the California Independent System Operator. In 1999, she worked as a Legislative Aide to U.S. Senator Jeff Bingaman.

Phillip D. Moeller, Commissioner (Rep.), since 2006; term expires June 2010. From 1997 through 2000, Mr. Moeller served as an energy policy advisor to U.S. Senator Slade Gorton (R-Washington) where he worked on electricity policy, electric system reliability, hydropower, energy efficiency, nuclear waste, energy and water appropriations and other energy legislation. Before becoming a Commissioner, Mr. Moeller headed the Washington, D.C., office of Alliant Energy Corporation. Prior to Alliant Energy, Mr. Moeller worked in the Washington office of Calpine Corporation.

Mark Spitzer, Commissioner (Rep.), since 2006; term expires June 2011. Prior to becoming a commissioner Spitzer served as chairman of the Arizona Corporation Commission (ACC), where he focused on policies encouraging expansion of natural gas infrastructure, specifically distribution and storage; creating a demand side management policy; enhancing the ACC's renewables standard; and advancing consumer privacy concerns in telecommunications.

Approved Rate Bases & ROEs and Current Rate Base Requests

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo-Virginia	$2,424MM*	10.20%	11/17/2008
APCo-West Virginia	$1,656MM	10.50%	7/28/2006
Kentucky	$858MM	10.50%	3/31/2006
I&M-Indiana	$2,000MM	10.50%	3/4/2009
I&M-Michigan	$268MM	13.00%	4/1/1991
PSO-Oklahoma	$1,467MM	10.50%	1/14/2009
SWEPCO-Louisiana	$577MM	10.57% **	8/1/2008
SWEPCO-Arkansas	$408MM	10.75%	9/23/1999
SWEPCO-Texas	$474MM	15.70%	2/15/1983
TCC-Texas	$1,566MM	9.96%	10/17/2007
TNC-Texas	$530MM	9.96%	6/1/2007

*** represents assumed rate base interpreted from settlement**

**** represents midpoint of the ROE range approved in the formula rate case settled in April 2008.**

Rate Case Requests on File

Jurisdiction	Requested Rate Base	Requested ROE
SWEPCO -Arkansas	$612MM	10.25%
SWEPCO -Texas	$669MM	11.50%
APCO - Virginia	$2,057MM ***	13.35%

***Represents Generation and Distribution Rate Base Only

Generation & Environmental

- Units
- Generation Statistics
- New Generation
- Environmental
- Future Potential Green House Gas Regulations

Domestic Generation

Generation Capacity*

Company	**MW Capacity**
AEP Generating Co	2,446
Appalachian Power Co	6,238
Columbus Southern Power Co	3,611
Indiana Michigan Power Co	4,453
Kentucky Power Co	1,060
Ohio Power Co	8,498
Public Service of Oklahoma	4,465
Southwestern Electric Power Co	4,799
Texas North Co**	647
OVEC Capacity ***	986
Domestic IPPs	311
Long Term Wind Purchase Power Agreements	1,474
	38,988

* Capacity amounts represent the nominal capcaity (the number of MW expected to be produced on a routine basis).

** Includes 270MW of mothballed/retired/decommissioned generation

*** Represents AEP's 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE.

Coal/Lignite #	25,647	66%
Natural Gas/Oil	8,691	22%
Nuclear	2,143	6%
Wind/Hydro/Pumped Storage	2,507	6%
Total Generating Capacity	38,988	100%

Includes AEP's 43% ownership of OVEC

At the conclusion of our current environmental retrofit program, over 56% of our 25,647 MW coal-fired generation fleet will be equipped with SCRs and over 71% will be scrubbed (FGDs).

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
AEP Generating Company					
Rockport	1	IN	Steam - Coal	1,300	1984
Lawrenceburg	6	IN	Natural Gas	1,146	2004
				2,446	
Appalachian Power Company					
Buck	3	VA	Hydro	5	1912
Byllesby	4	VA	Hydro	8	1912
Claytor	4	VA	Hydro	28	1939
Leesville	2	VA	Hydro	9	1964
London	3	WV	Hydro	12	1935
Marmet	3	WV	Hydro	11	1935
Niagara	2	VA	Hydro	1	1906
Reusens	5	VA	Hydro	6	1904
Winfield	3	WV	Hydro	15	1938
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos	2	WV	Steam - Coal	2,033	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	335	1918
Kanawha River	2	WV	Steam - Coal	400	1953
Mountaineer	1	WV	Steam - Coal	1,320	1980
Sporn	2	WV	Steam - Coal	300	1950
Ceredo	6	WV	Natural Gas	464	2001
				6,238	
Columbus Southern Power Company					
Beckjord (CCD)	1	OH	Steam - Coal	53	1969
Conesville (CCD)	4	OH	Steam - Coal	1,254	1957
Picway	1	OH	Steam - Coal	100	1926
Stuart (CCD)	4	OH	Steam - Coal	604	1971
Stuart (CCD)	4	OH	Oil	3	1970
Zimmer (CCD)	1	OH	Steam - Coal	330	1991
Waterford	4	OH	Natural Gas	810	2003
Darby	6	OH	Natural Gas	457	2001
				3,611	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Indiana Michigan Power Company					
Berrien Springs	12	MI	Hydro	5	1908
Buchanan	10	MI	Hydro	2	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	2	1913
Mottville	4	MI	Hydro	1	1923
Twin Branch	6	IN	Hydro	4	1904
Rockport	1	IN	Steam - Coal	1,300	1984
Tanners Creek	4	IN	Steam - Coal	995	1951
Cook	2	MI	Steam - Nuclear	2,143	1975
				4,453	
Kentucky Power Company					
Big Sandy	2	KY	Steam - Coal	1,060	1963
Ohio Power Company					
Racine	2	OH	Hydro	26	1982
Amos	1	WV	Steam - Coal	867	1973
Cardinal	1	OH	Steam - Coal	600	1967
Gavin	2	OH	Steam - Coal	2,600	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell	2	WV	Steam - Coal	1,600	1971
Muskingum River	5	OH	Steam - Coal	1,425	1953
Sporn	3	WV	Steam - Coal	750	1950
				8,498	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Public Service Company of Oklahoma					
Tulsa	3	OK	Steam - Natural Gas	330	1923
Tulsa	3	OK	Oil	8	1967
Riverside (1&2)	2	OK	Steam - Natural Gas	917	1974
Riverside (3&4)	2	OK	Steam - Natural Gas	156	2008
Riverside	1	OK	Oil	3	1976
Northeastern (1&2)	4	OK	Steam - Natural Gas	940	1961
Northeastern	1	OK	Oil	3	1961
Sothwestern (1-3)	3	OK	Steam - Natural Gas	472	1952
Sothwestern (4&5)	2	OK	Steam - Natural Gas	156	2008
Sothwestern	1	OK	Oil	2	1962
Comanche	3	OK	Steam - Natural Gas	273	1973
Comanche	2	OK	Oil	4	1962
Weleetka	3	OK	Steam - Natural Gas	163	1975
Weleetka	2	OK	Oil	4	1963
Northeastern (3&4)	2	OK	Steam - Coal	925	1979
Northeastern	1	OK	Oil	1	1980
Oklaunion	1	TX	Steam - Coal	108	1986
				4,465	
Southwestern Electric Power Company					
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Lieberman	4	LA	Steam - Natural Gas	269	1947
Knox Lee	4	TX	Steam - Natural Gas	486	1950
Wilkes	3	TX	Steam - Natural Gas	882	1964
Lone Star	1	TX	Steam - Natural Gas	50	1954
Mattison	4	AR	Natural Gas	312	2007
Welsh	3	TX	Steam - Coal	1,584	1977
Flint Creek	1	AR	Steam - Coal	264	1978
Pirkey	1	TX	Steam - Lignite	580	1985
Dolet Hills	1	LA	Steam - Lignite	262	1986
				4,799	
Texas North Company					
Paint Creek (Retired)	4	TX	Steam - Natural Gas	238	1953
Abilene (Retired)	1	TX	Steam - Natural Gas	18	1949
Ft. Stockton (Decommissioned)	1	TX	Steam - Natural Gas	6	1958
Vernon (Decommissioned)	4	TX	Oil	8	1963
Oklaunion	1	TX	Steam - Coal	377	1986
				647	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Contract Initiated
Domestic Independent Power Projects					
Trent Mesa	100	TX	Wind	150	2001
Desert Sky	107	TX	Wind	161	2001
				311	
Long-Term Wind Purchase Power Agreements					
Southwest Mesa		TX	Wind	75	2005
South Trent		TX	Wind	102	2008
Weatherford		OK	Wind	148	2005
Blue Canyon II		OK	Wind	151	2005
Sleeping Bear		OK	Wind	95	2008
Camp Grove		IL	Wind	75	2008
Fowler Ridge I		IN	Wind	100	2009
Fowler Ridge III		IN	Wind	100	*
Beech Ridge		WV	Wind	100	*
Majestic		TX	Wind	80	*
Elk City		OK	Wind	99	*
Blue Canyon 5		OK	Wind	99	*
Fowler Ridge II		IN	Wind	150	*
Grand Ridge III		IL	Wind	100	*
				1,474	

* Under contract but not yet on-line, expected December 2009

Generation Statistics

Net Capacity Factors	2007	2008	YTD09
AEP East	64.26%	61.95%	50.82%
Coal	71.89%	72.11%	60.99%
Super Critical*	73.00%	75.75%	68.53%
Sub-Critical*	68.44%	60.86%	37.82%
Gas	7.27%	3.43%	5.27%
Hydro**	7.85%	5.79%	12.19%
Nuclear	90.86%	78.13%	39.14%
AEP SPP	43.20%	40.79%	40.20%
Coal***	77.45%	76.53%	77.80%
Super Critical*	78.10%	78.02%	84.55%
Sub-Critical*	77.21%	76.14%	75.07%
Gas	20.65%	19.09%	17.69%
AEP Texas	71.95%	72.52%	45.42%
Coal****	71.95%	72.52%	45.42%
AEP System	59.54%	57.10%	48.23%

Equivalent Availability Factors	2007	2008	YTD09
AEP East	81.09%	82.11%	77.84%
Coal	78.73%	81.19%	80.08%
Super Critical*	77.93%	81.71%	81.12%
Sub-Critical*	81.23%	79.57%	76.89%
Gas	90.19%	89.35%	85.93%
Hydro**	86.42%	86.68%	86.41%
Nuclear	89.68%	77.78%	38.97%
AEP SPP	84.79%	83.99%	83.77%
Coal***	82.35%	83.24%	84.78%
Super Critical*	80.41%	82.64%	88.48%
Sub-Critical*	83.09%	83.61%	83.22%
Gas	86.39%	84.45%	83.17%
AEP Texas	73.95%	84.47%	62.82%
Coal****	73.95%	84.47%	62.82%
AEP System	81.84%	82.58%	79.06%

Equivalent Forced Outage Rate (EFOR)	2007	2008	YTD09
AEP East	8.32%	9.78%	13.29%
Coal	9.02%	9.21%	8.06%
Super Critical*	8.81%	8.95%	6.24%
Sub-Critical*	9.62%	10.08%	15.24%
Gas - See Below			
Hydro**	11.61%	7.87%	23.70%
Nuclear	1.25%	15.34%	56.27%
AEP SPP	6.75%	7.00%	9.34%
Coal***	5.49%	6.08%	6.46%
Super Critical*	6.20%	3.83%	5.24%
Sub-Critical*	5.23%	6.73%	7.36%
Gas	8.04%	7.93%	12.16%
AEP Texas	17.43%	4.70%	6.96%
Coal****	17.43%	4.70%	6.96%
AEP System	8.13%	9.11%	12.28%

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** CF, EAF, and EFOR do not include Dolet Hills.

**** Oklaunion reported as owned.

***** East Gas Units evaluated using Equivalent Forced Outage Factor. Since these units are run less frequently, this factor gauges their performance based on Period Hours instead of Service Hours. EFOR uses Service Hours in the denominator, and EFOF uses Period Hours in the denominator.

Equivalent Forced Outage Factor (EFOF)	2007	2008	YTD09
AEP East Gas*****	1.23%	1.24%	3.40%

Generation & Coal Statistics

MWhs Produced

Operating Company	2006	2007	2008	Three Year Average
AEP Generating	10,276,134	9,027,362	10,622,505	9,975,334
Appalachian Power	31,494,581	32,588,773	31,868,466	31,983,940
Columbus Southern Power	14,134,232	15,514,495	14,866,609	14,838,445
Indiana Michigan Power	31,950,768	31,604,874	29,790,250	31,115,297
Kentucky Power	7,171,505	7,533,223	6,021,182	6,908,637
Ohio Power	49,341,134	54,155,697	55,039,733	52,845,521
Public Service of Oklahoma	15,139,848	14,439,801	14,874,023	14,817,891
Southwestern Electric Power	19,961,798	19,673,059	19,714,013	19,782,957
Texas Central Company	309,085	41,122	-	116,736
Texas North Company	2,160,348	2,309,566	2,310,091	2,260,002
AEP System Total Net Generation	181,939,433	186,887,972	185,106,872	184,644,759

Note: Figures represent generation produced from AEP-owned assets only.

Coal Comsumption in Tons

Operating Company	2006	2007	2008	Three Year Average
AEP Generating	5,291,881	4,545,828	5,463,904	5,100,538
Appalachian Power	12,619,910	12,828,218	13,030,442	12,826,190
Columbus Southern Power	5,953,084	6,327,803	6,318,996	6,199,961
Indiana Michigan Power	7,947,666	7,406,506	7,709,863	7,688,012
Kentucky Power	2,854,537	2,950,296	2,349,586	2,718,140
Ohio Power	19,111,071	21,234,430	22,436,865	20,927,455
Public Service of Oklahoma	4,421,396	4,102,943	4,135,223	4,219,854
Southwestern Electric Power	12,180,786	12,393,538	12,413,907	12,329,410
Texas North Company	1,356,264	1,416,422	1,444,187	1,405,624
AEP System Coal Usage	71,736,595	73,205,984	75,302,973	73,415,184

New Generation Projects

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

John W. Turk Jr. Ultra-Supercritical Coal Plant

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $378 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

Environmental

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations and the NSR consent decree executed in October 2007.

Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service		
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	In-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Emission Limits

In compliance with our 2007 NSR settlement,
the following limits are applicable to
AEP's eastern generation fleet:

Eastern System-Wide Annual Tonnage Limitations for NO_x	
Calendar Year	**Limitation**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016 and each year thereafter	72,000 tons

Eastern System-Wide Annual Tonnage Limitations for SO_2	
Calendar Year	**Limitation**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019 and each year thereafter	174,000 tons

Emissions caps do not include any of the gas-fired units, or any new units AEP might build or purchase in the east.

Future Potential Green House Gas Regulations

AEP Supports Reasonable Climate Legislation

Key Design Elements:

- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program –** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program –** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues –** Full, free allocation to electric sector and "Low" auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

AEP supports ***The American Clean Energy and Security Act of 2009*** **introduced by Rep. Waxman and Rep. Markey**

AEP's Near-Term CO_2 Reduction Commitment

Existing Programs

- Existing plant efficiency improvements
- Renewable Energy
  - 1785 MWs of Wind
  - 722 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr
  - Over 63MM trees planted through 2008
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions (by 2011)

- 1000 additional MWs of Renewable through PPAs
- Domestic Offsets (methane, forestry): About 2MM tons/yr
- Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr
- Additional actions: Energy efficiency and biomass: 0.3MM tons/yr

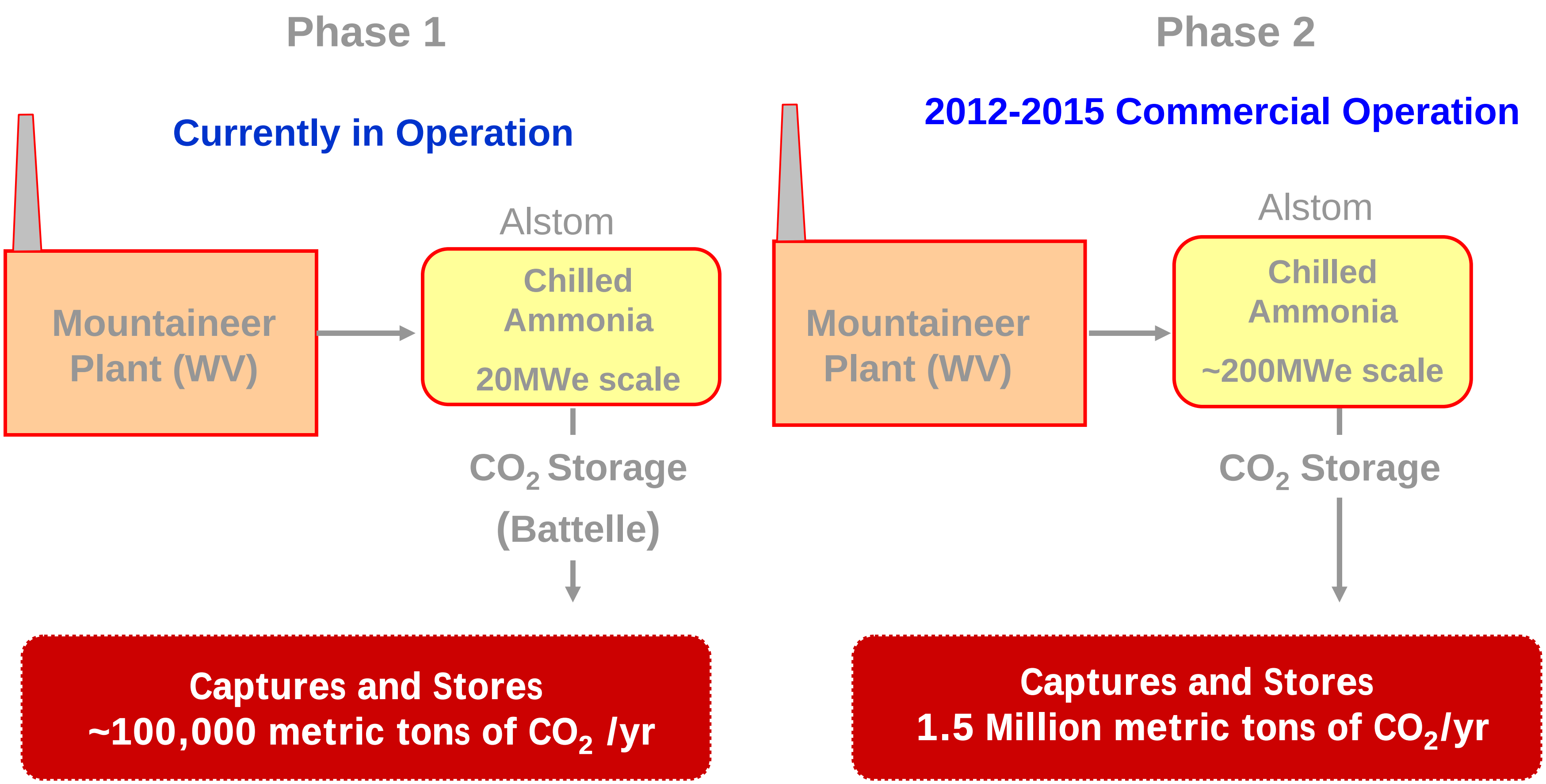
New Technology Additions

- New Generation – Ultra Super Critical
- Carbon Capture and Storage (CCS) for existing fleet
  - Chilled Ammonia

AEP's reductions/offsets of CO_2:
2003-2010: 48 MMT Total

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/Year
Longer Term - New Technology

AEP Leadership in New Technology: Chilled Ammonia CCS

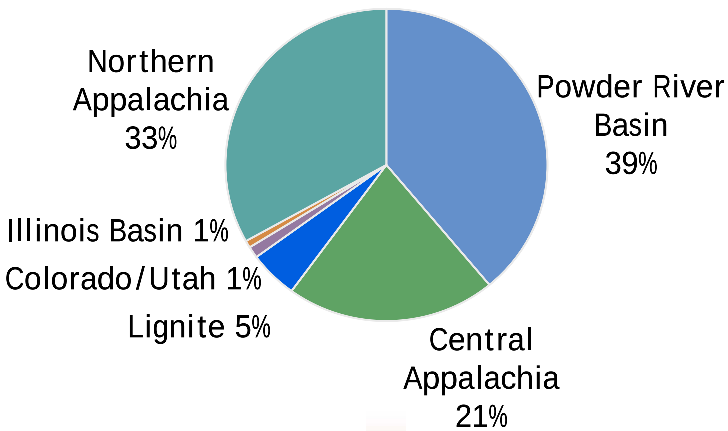


Coal

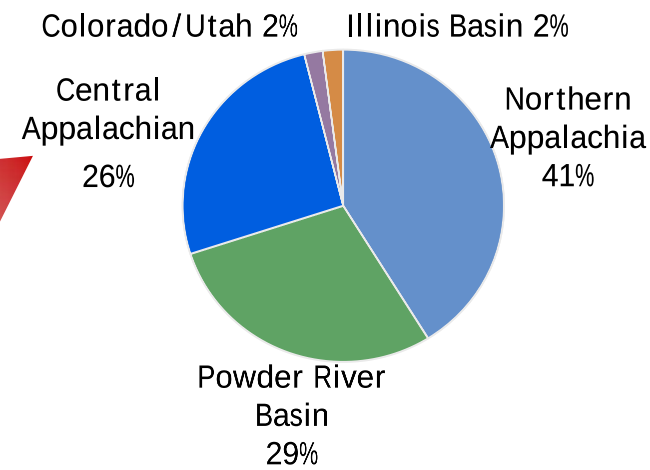
- Coal Procurement, Delivery & Transportation
- Fuel Recovery
- Coal Market Information

Coal Procurement – 2010 Projected

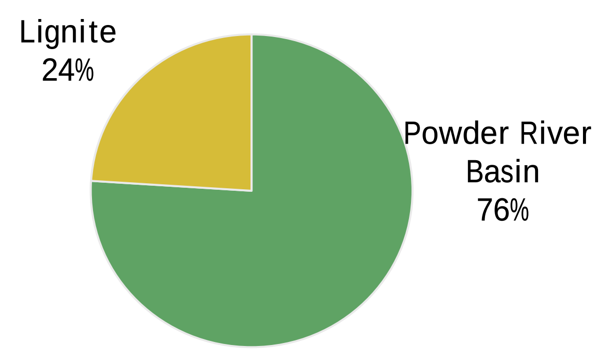
Total AEP System



AEP East



AEP West



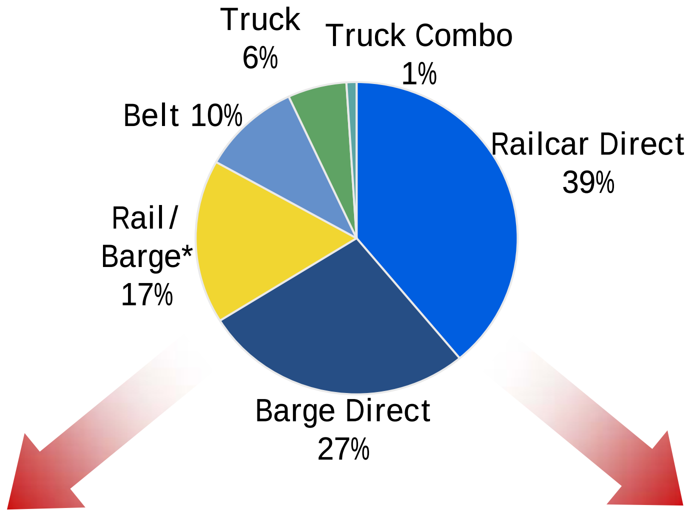
Coal Stats:

- 100% contracted for 2009 and 98% for 2010
- Avg. delivered price ~ $47/ton in 2008
- Approximate 10% price increase in 2009 ~ $51/ton
- Approximate 10% price decrease in 2010 ~$46/ton

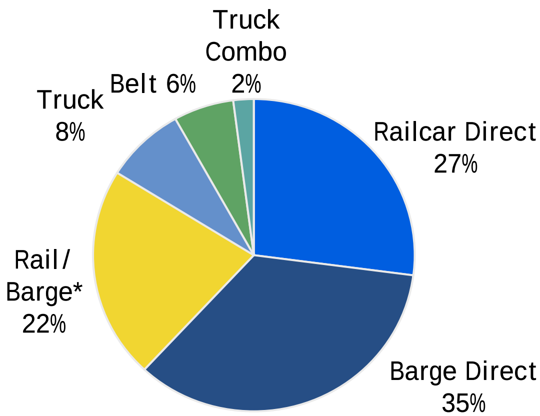
Coal Delivery

2008 Actual

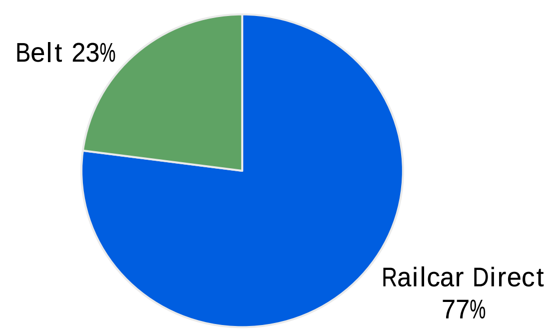
Total AEP System



AEP East



AEP West

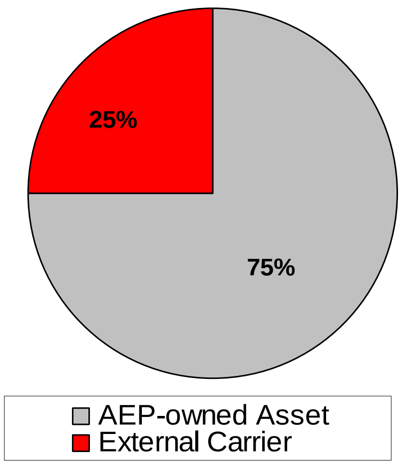


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2008 Actual

Coal Transportation to AEP Plants*



***Represents close approximations**

Current Coal & Transportation Assets:

- Control over 9,000 railcars
- Own/lease and operate over 2,978
- barges & 58 towboats & 25 harbor boats
- Coal handling terminal with 20 million tons of capacity

AEP's transportation assets provide flexibility in a constrained delivery environment.

AEP River Operations

- Full-service Inland Waterways carrier
  - 2,978 hopper barges
  - 58+ towboats/25 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

Inland Waterway Routes For AEP River Operations

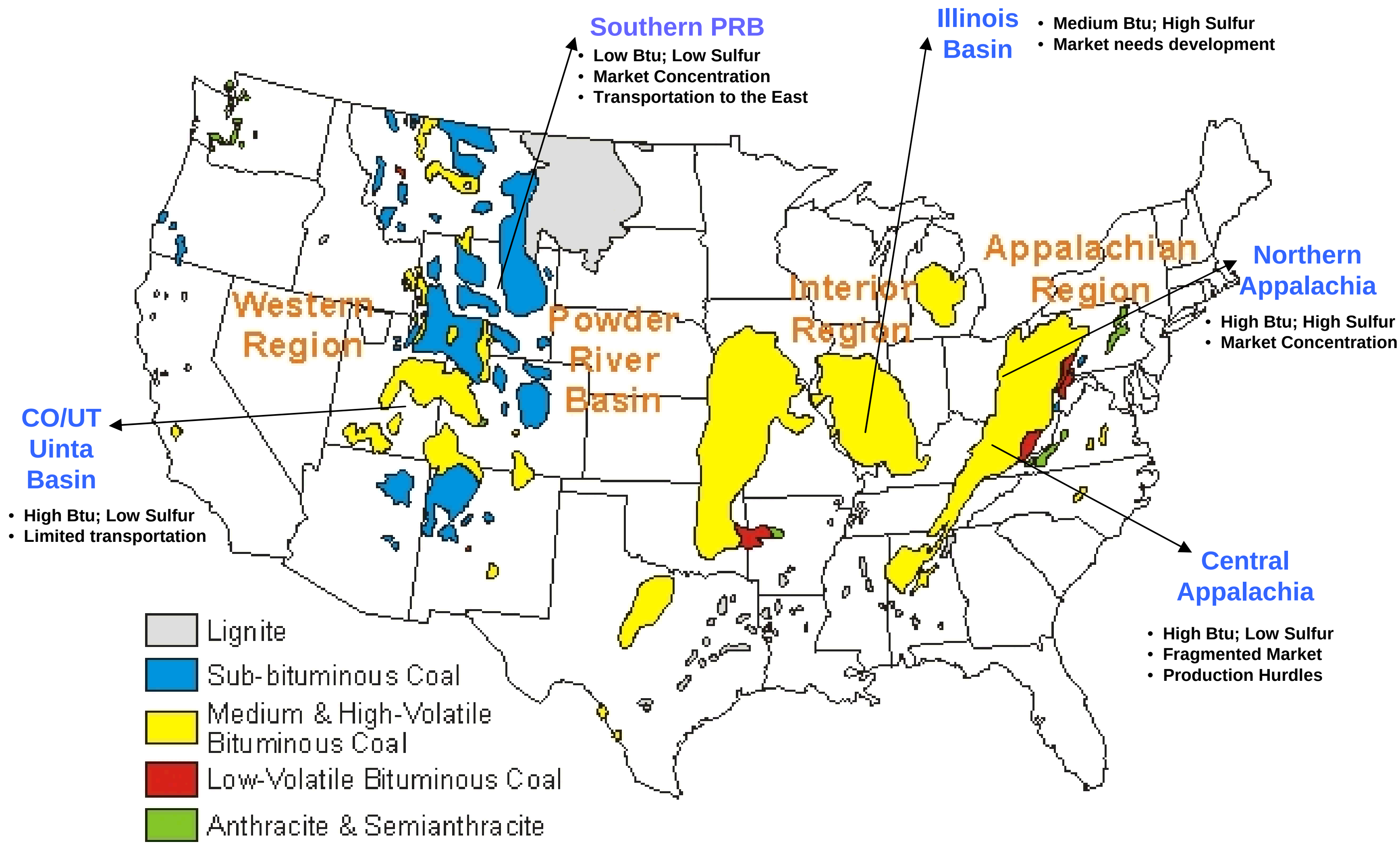
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1558 of 9556

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Yes	Quarterly
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Effective January 1, 2009 we have fuel recovery in all jurisdictions.

Coal Producing Regions



Transmission Initiatives

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

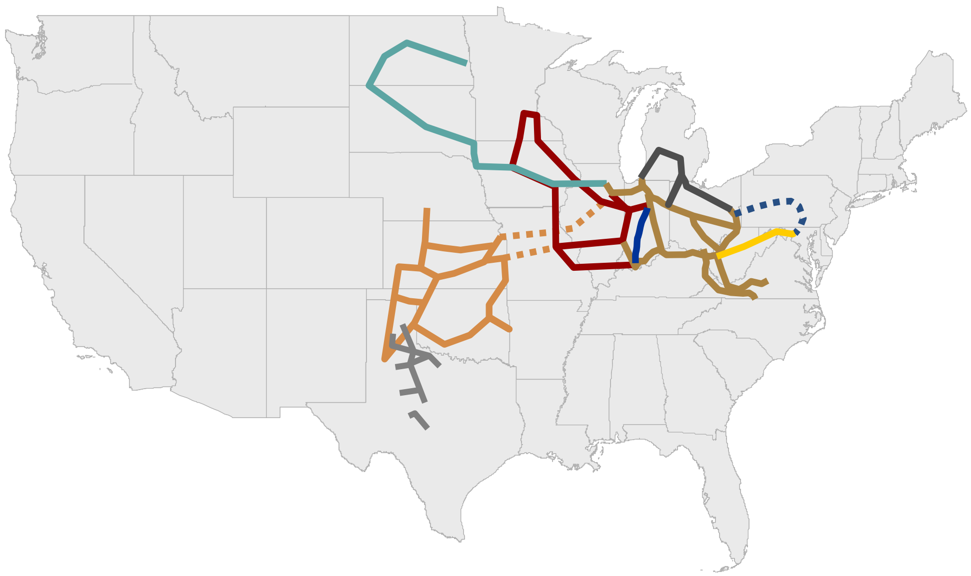
Pioneer — **COD: 2015**
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013**
- *110 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

ETT — **COD: 2013**
- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $420 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**
- *700 miles of 765 kV*

PJM Projects
- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**
- *1000+ miles of 765 kV*

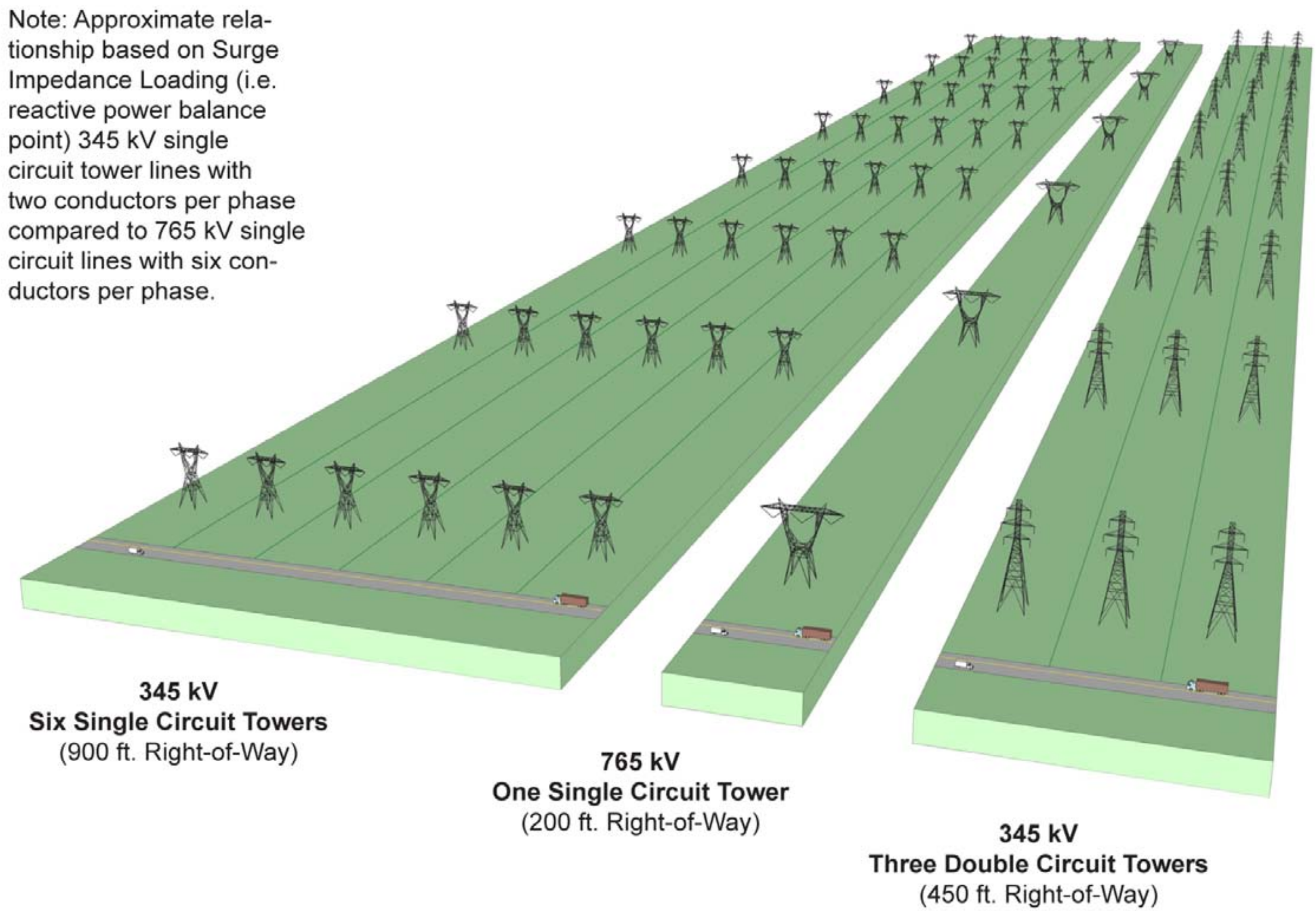
MISO Vision Plan
- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**
- *765 kV Backbone*

ETT — **COD: ~2018**
- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

765 Right-of-Way Comparison



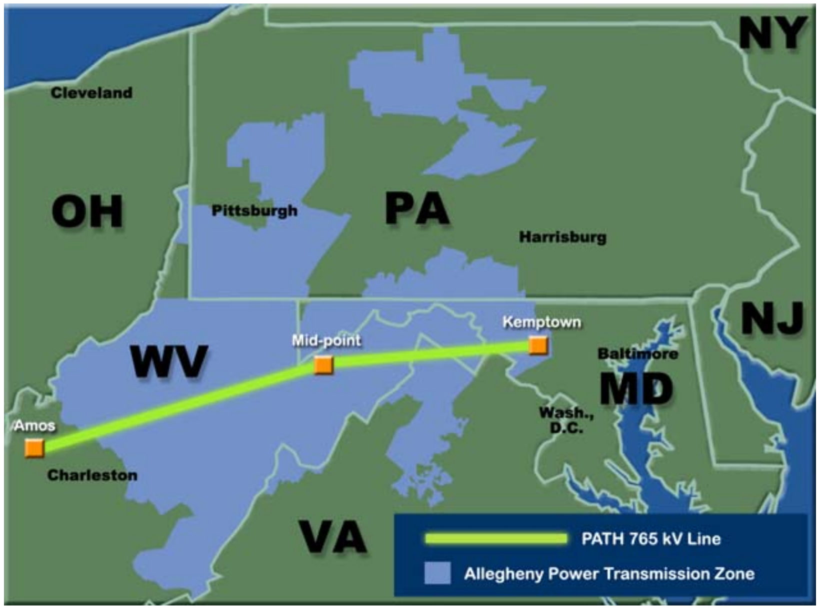
From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009 with a decision expected June, 2010.
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
- Estimated completion date: 2014

PATH
Potomac-Appalachian Transmission Highline

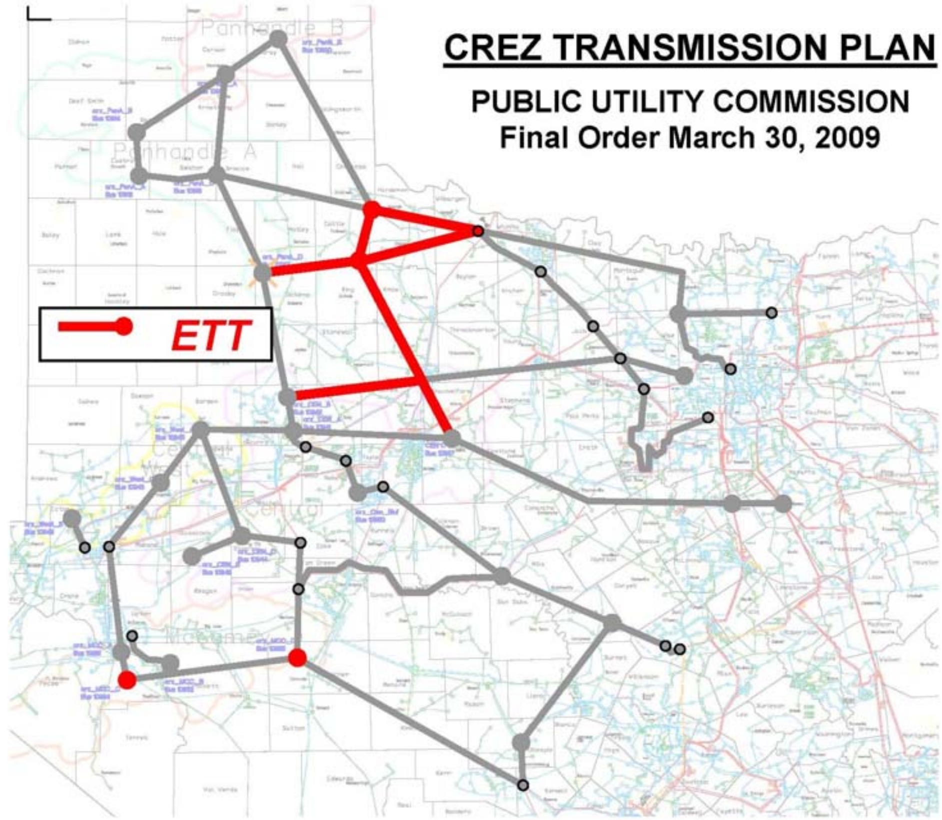
Texas CREZ Project

Status

- On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
- Staging to occur in separate docket and consider timing of wind projects and congestion.
- PUCT established 2 categories based on priorities. ETT has no first priority lines.
- PUCT issued a final order assigning transmission service providers on March 30, 2009.
- ETT's share of CREZ investment is approx. $840MM of $4.9B total of which AEP's ownership is 50%.
- The filing calls for completion of the plan by 2013.

Next Steps

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

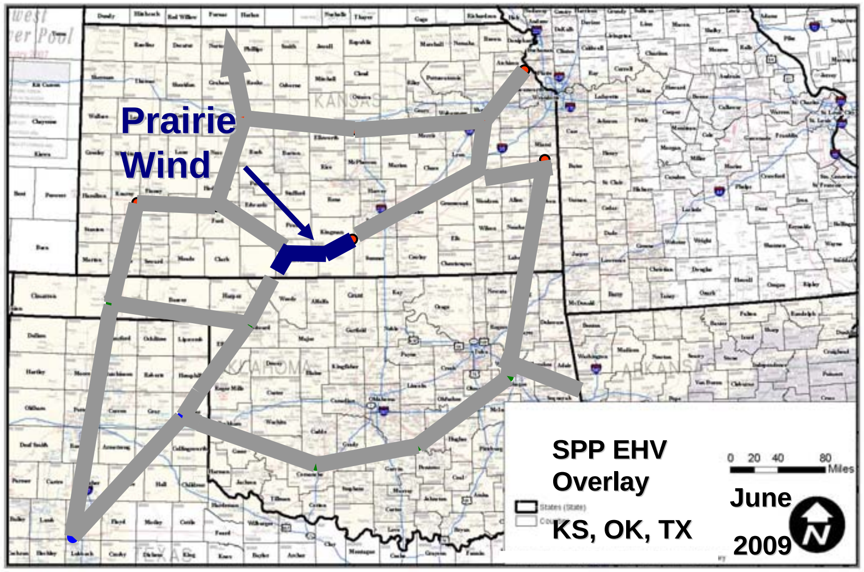
ETT Electric Transmission Texas

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- Following a settlement agreement with ITC both entities agreed to split the mileage and costs of building the 765-kV transmission superhighway. The newly revised project is expected to cost approximately $400 million and be in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

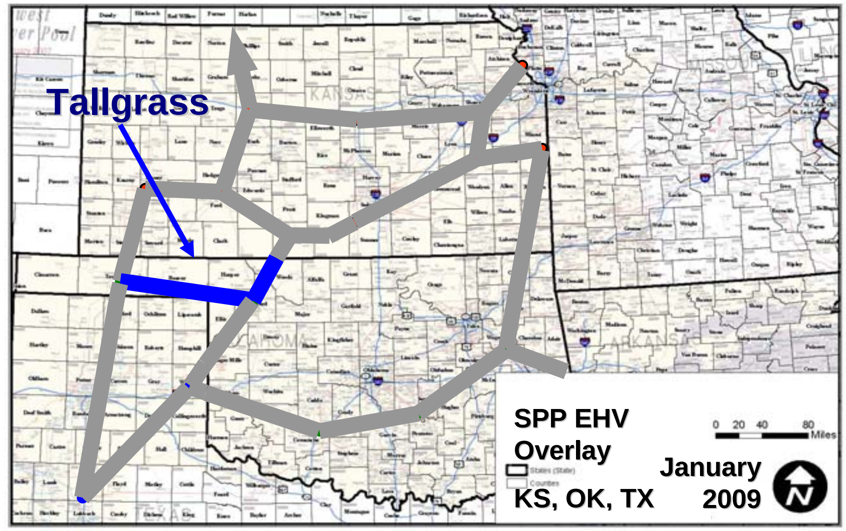
- Regional Cost allocation which enables the development of "system solutions"
- RTO Approval

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

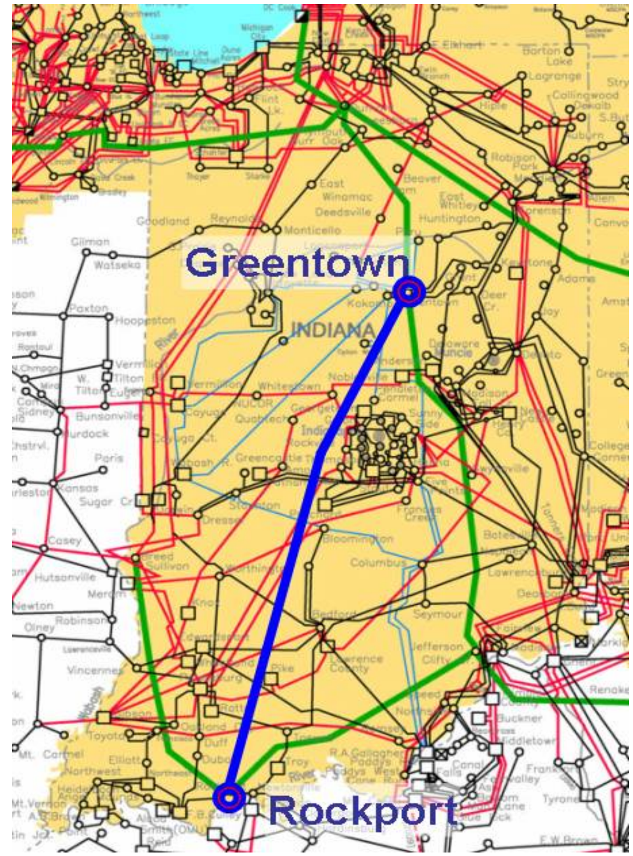
Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval

Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

Upper Midwest EHV Development – SMART Study

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Announced SMARTransmission Study in August 2009.**
  - Participants include ETA, Exelon, ATC, Northwestern, MidAmerican and Excel
  - Study due to be completed in early 2010 and will include “overlay” options and quantification of economic benefits.
- **Near Term Risks**
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including incentives
- **Mitigation**
  - Collaborative approach involving impacted utilities, RTOs, commissions and others

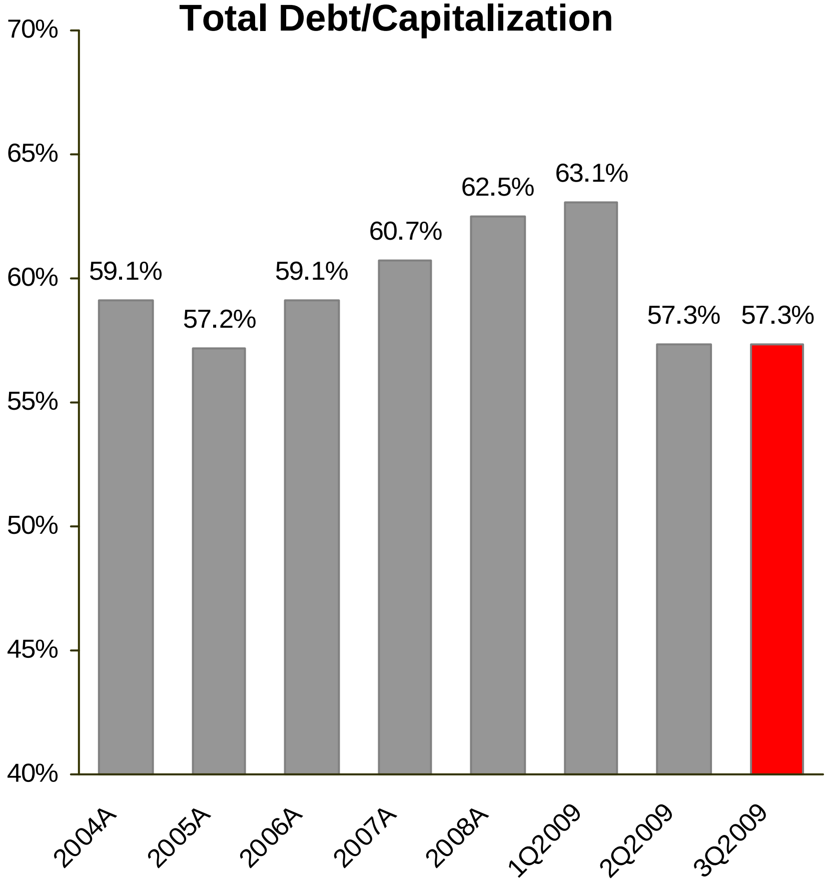
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Financial Update

- Capitalization and Liquidity Position
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

AEP Credit Ratings

Ratings current as of September 30, 2009

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

Long-term Debt Maturity Profile

($ in millions)

Year		2010		2011		2012
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	680	$	-	$	-
Public Service of Oklahoma	$	150	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company(1)	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,735	$	623	$	415

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)
Data as of September, 30 2009

Debt Schedules

American Electric Power, Inc	Interest	Maturity	Amount
Junior Subordinated Debentures	8.750%	03/01/2063	$315,000,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	6.36%		$1,047,775,000

AEP Generating	Interest	Maturity	Amount
Notes Payable	Floating	12/05/2011	$85,000,000
Pollution Control Bond	4.150%	7/1/2025[1]	$22,500,000
Pollution Control Bond	4.150%	7/1/2025[1]	$22,500,000
Senior Notes	6.330%	09/30/2037	$203,636,440
Weighted Average or Total	5.935%		$333,636,440

[1] Put date 7/15/2011

AEP Texas North	Interest	Maturity	Amount
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Senior Notes	5.500%	03/01/2013	$225,000,000
Senior Notes	5.890%	04/01/2018	$30,000,000
Senior Notes	6.760%	04/01/2038	$70,000,000
Weighted Average or Total	5.645%		$369,310,000

Note: Debt schedules current as of 9/30/09. The weighted average coupon excludes all floating rate debt.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
Pollution Control Bond	5.625%	10/01/2017	$40,890,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Pollution Control Bond	6.300%	11/01/2029	$100,635,000
Pollution Control Bond	5.200%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	5.125%	6/1/2030[2]	$120,265,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.711%		$764,820,000
Securitization Bond	5.560%	01/15/2010	$32,279,500
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	6.057%		$439,063,096
Securitization Bond	4.980%	01/01/2010	$33,257,770
Securitization Bond	4.980%	07/01/2013	$341,000,000
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.155%		$1,555,957,770

[2] Put date 6/01/2011

Note: Debt schedules current as of 9/30/09.

Debt Schedules

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	4.850%	05/1/2019[3]	$30,000,000
Pollution Control Bond	4.850%	05/1/2019[3]	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	02/01/2036	$75,000,000
Pollution Control Bond	7.125%	12/1/2038[4]	$50,000,000
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	5.650%	08/15/2012	$250,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	7.950%	01/15/2020	$350,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Senior Notes	6.700%	08/15/2037	$250,000,000
Senior Notes	7.000%	04/01/2038	$500,000,000
Weighted Average or Total	6.13%		$3,294,775,000

[3] Put date 9/04/2013

[4] Put date 6/01/2010

Note: Debt schedules current as of 9/30/09. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	3.875%	12/1/2038[5]	$60,000,000
Pollution Control Bond	5.800%	12/01/2038	$32,245,000
Pollution Control Bond	4.850%	8/1/2040[6]	$44,500,000
Pollution Control Bond	5.100%	11/1/2042[7]	$56,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.050%	05/01/2018	$350,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.674%		$1,442,745,000

[5] Put date 6/01/2014

[6] Put date 4/01/2012

[7] Put date 5/01/2013

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	5.250%	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	6.250%	06/1/2025[8]	$50,000,000
Pollution Control Bond	6.250%	06/1/2025[8]	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	7.000%	03/15/2019	$475,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	6.154%		$1,692,000,000

[8] Put date 6/2/2014

Note: Debt schedules current as of 9/30/09. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	6.000%	09/15/2017	$325,000,000
Senior Notes	7.250%	06/18/2021	$40,000,000
Senior Notes	8.030%	06/18/2029	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Senior Notes	8.130%	06/18/2039	$60,000,000
Weighted Average or Total	6.397%		$530,000,000

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Pollution Control Bond	7.125%	6/1/2041[9]	$79,450,000
Senior Notes	Floating	04/05/2010	$400,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	5.750%	09/01/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	5.375%	10/01/2021	$500,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	5.717%		$3,048,580,000

[9] Put date 6/01/2010

Note: Debt schedules current as of 9/30/09. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	5.250%	06/01/2014	$33,700,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.625%	11/15/2037	$250,000,000
Weighted Average or Total	5.844%		$871,360,000

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	7.030%	02/22/2012	$20,000,000
Notes Payable	6.370%	10/31/2024	$25,000,000
Notes Payable	4.470%	04/23/2011	$6,975,630
Pollution Control Bond	4.500%	07/01/2011	$41,135,000
Pollution Control Bond	4.950%	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Senior Notes	5.875%	03/01/2018	$300,000,000
Senior Notes	6.450%	01/15/2019	$400,000,000
Weighted Average or Total	5.763%		$1,428,310,630

Note: Debt schedules current as of 9/30/09. The weighted average coupon excludes all floating rate debt.

AEP AMERICAN® ELECTRIC POWER

2010 Fact Book

45th EEI
Financial Conference
Palm Desert, CA

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Company Overview

Company Overview

Company Overview

OUR FOCUS IS OUR CORE

DOMESTIC UTILITY BUSINESS OPERATIONS

American Electric Power Company, Inc. is one of the largest investor-owned electric public utility holding companies in the US. We provide generation, transmission and distribution services to over 5 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies.

We have seven regional operating companies for distribution and customer service operations that serve the customers of our eleven electric utility subsidiaries:

Regional Utility Divisions	**Electric Utility Subsidiaries**
AEP Ohio	Columbus Southern Power Ohio Power Wheeling Power
AEP Texas	Texas Central Company Texas North Company
Appalachian Power	Appalachian Power Kingsport Power
Indiana Michigan Power	Indiana Michigan Power
Kentucky Power	Kentucky Power
Public Service Company of Oklahoma	Public Service Company of Oklahoma
Southwestern Electric Power Co.	Southwestern Electric Power Co.

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT

THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Almost 39,000 megawatts of generating capacity in 3 RTOs (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Approximately 215,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 9,000 railcars
- own and/or operate approximately 3,000 hopper barges, 62 towboats and 27 harbor boats
- operate one active coal-handling terminal with 18 millions tons of capacity

AEP consumes approximately 70 million tons of coal annually.

AEP Service Territory

AEP EAST OPERATING COMPANIES

EAST REGULATED UTILITIES

Appalachian Power Company (APCo)

Indiana Michigan Power Company (I&M)

Kingsport Power Company (KGPCo)

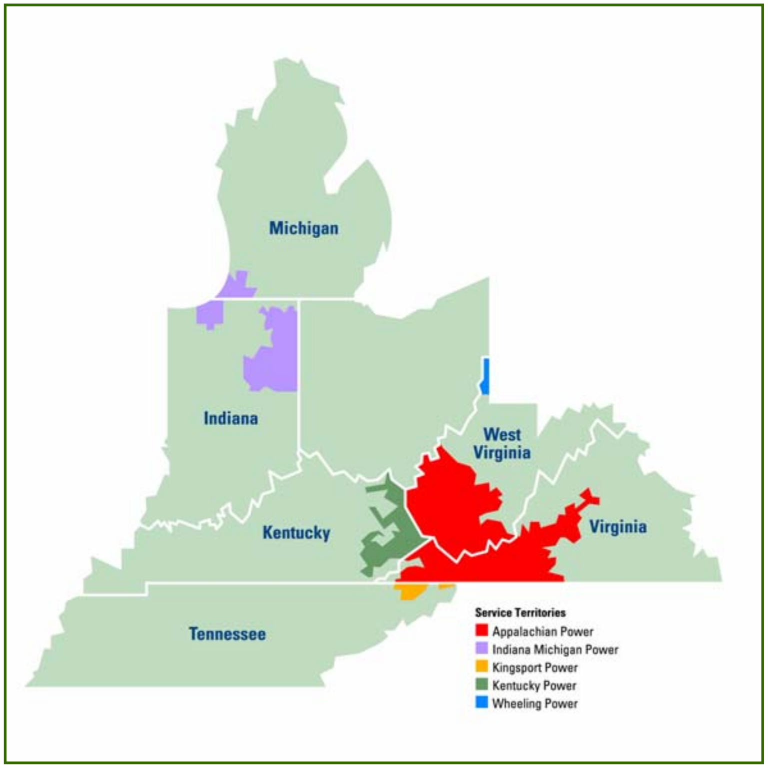
Kentucky Power Company (KPCo)

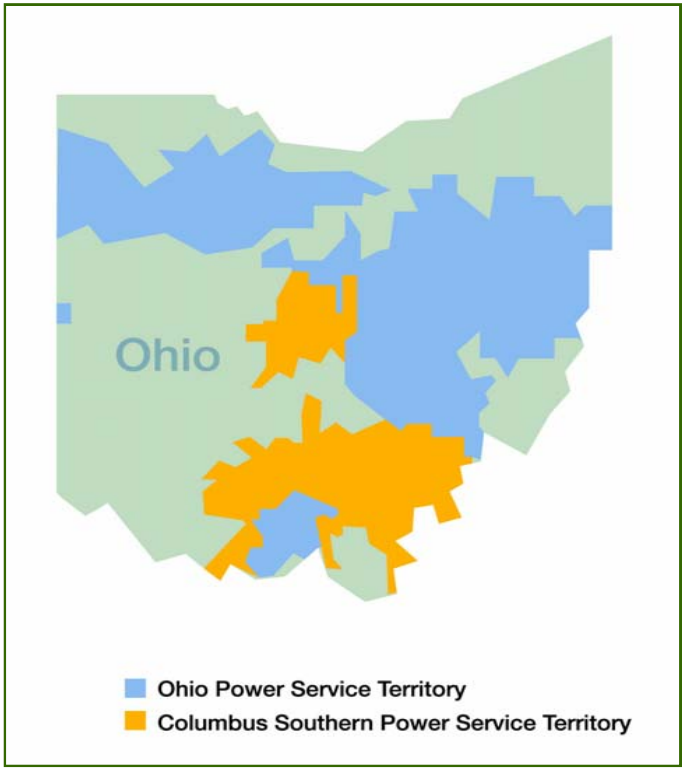
Wheeling Power Company (WPCo)

AEP OHIO

Columbus Southern Power Company (CSPCo)

Ohio Power Company (OPCo)





AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

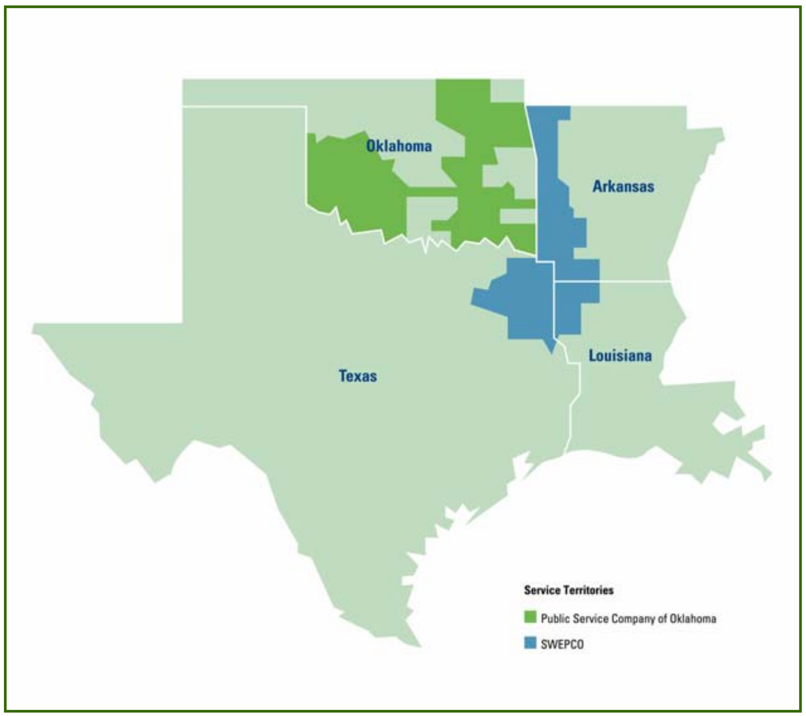
Public Service Company of Oklahoma (PSO)

Southwestern Electric Power Company (SWEPCO)

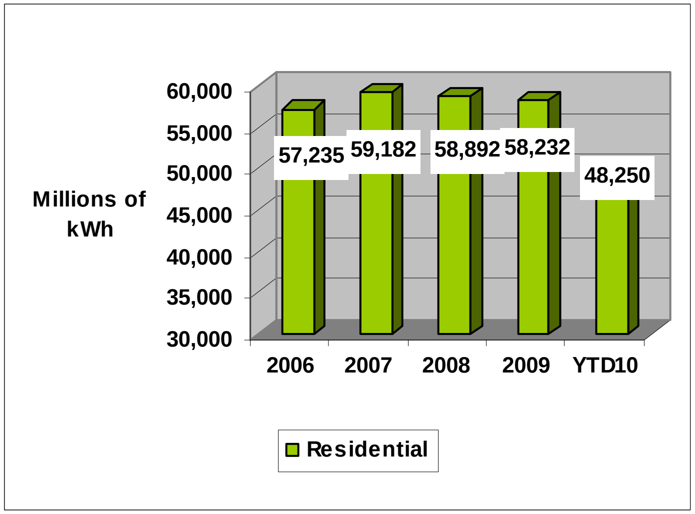
AEP TEXAS

Texas Central Company (TCC)

Texas North Company (TNC)

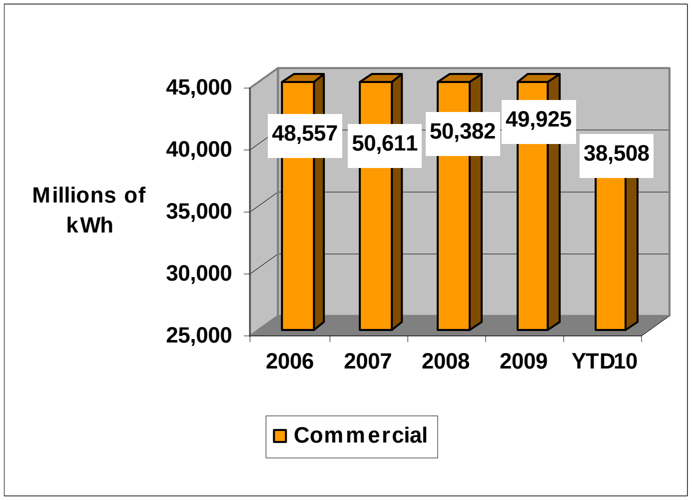


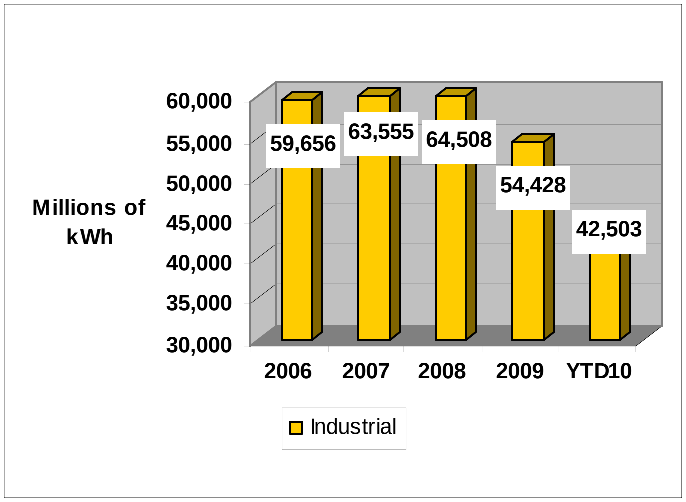
Utility Operations - Load



3 Yr. Compound Annual Residential Load Growth at 0.58%

3 Yr. Compound Annual Commercial Load Growth at 0.93%





3 Yr. Compound Annual Industrial Load Contraction at 3.01%

Note: Figures do not include Wholesale and Miscellaneous Other

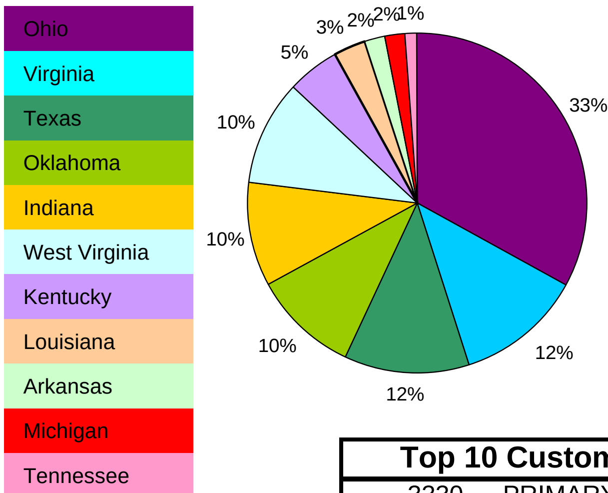
2009 Retail Revenue

CUSTOMER PROFILE

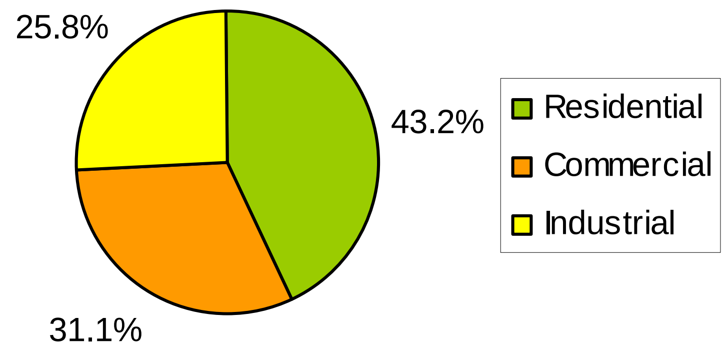
AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

Percentage of AEP System Retail Revenues



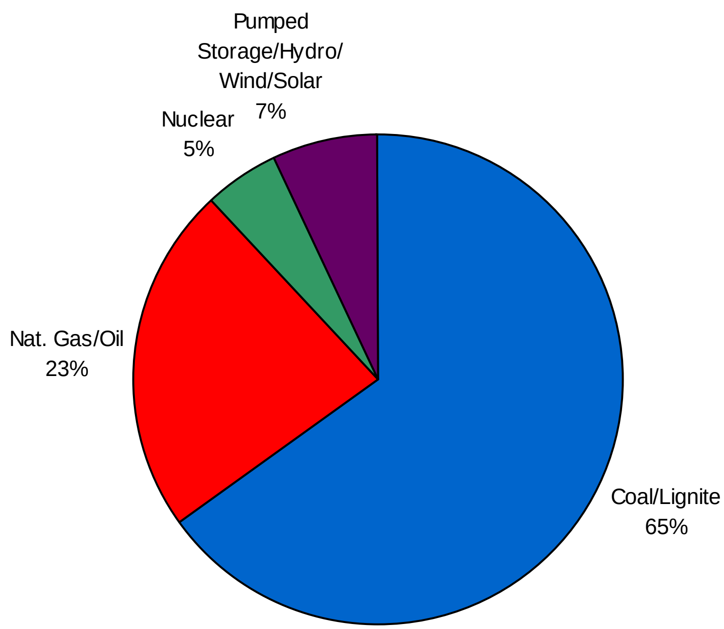
Retail Revenue Composition by Customer Class*



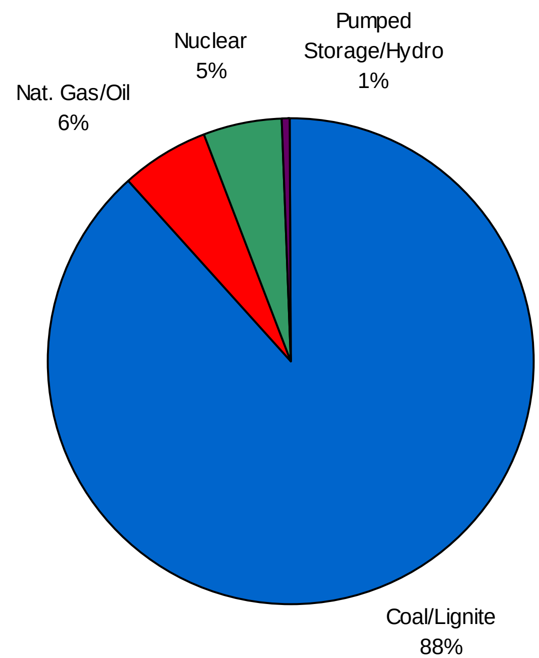
Top 10 Customers Across the AEP System By NAICS Code	
3330	PRIMARY SMELTING & REFINING OF NONFERROUS METALS
2800	CHEMICALS & ALLIED PRODUCTS
2911	PETROLEUM REFINING
1220	BITUMINOUS COAL & LIGNITE MINING
2600	PAPERS & ALLIED PRODUCTS
3060	FABRICATED RUBBER PRODUCTS
1389	OIL & GAS FIELD SERVICES
2000	FOOD & KINDRED PRODUCTS
3272/3281	STONE CLAY & CONCRETE PRODUCTS
3700	TRANSPORTATION EQUIPMENT

Source: Form 10-K.
*Note: Figures do not include Other Retail Sales

Domestic Generation Fleet



2010 Generation Capacity by Fuel Type Based on 39,910 MW



2009 Generation Production by Fuel Type Based on 160,276,948 MWh

NERC Regional Presence

RFC	71%
SPP	26%
ERCOT	3%

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
APCo	734	97	383	106	0	3,344	0	23	1,101	789	0	230	0	6,807
CSPCo	0	0	890	0	0	906	0	0	467	0	59	0	113	2,435
I&M	615	0	1,614	0	0	1,669	0	0	710	0	0	739	0	5,347
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	30
KPCo	258	0	8	0	46	335	0	0	544	55	0	3	0	1,249
OPCo	509	0	909	0	0	2,445	0	0	2,183	0	0	365	112	6,523
PSO	0	0	579	34	8	2,176	10	0	812	0	0	0	0	3,619
SWEPCO	0	0	672	0	233	1,320	56	0	1,503	0	0	0	0	3,784
TCC	0	0	626	0	0	2,332	0	0	1,671	0	0	0	0	4,629
TNC	0	0	223	0	0	1,497	0	0	2,599	0	0	0	0	4,319
WPCo	0	16	9	0	0	174	0	0	88	0	0	0	0	287
Total	**2,116**	**113**	**5,913**	**140**	**287**	**16,198**	**66**	**23**	**11,681**	**844**	**59**	**1,364**	**225**	**39,029**

State Level (Circuit Miles)

State	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
Arkansas	0	0	40	0	233	168	42	0	461	0	0	0	0	944
Indiana	599	0	1,380	0	0	1,426	0	0	414	0	0	591	0	4,410
Kentucky	258	0	8	0	46	335	0	0	544	55	0	3	0	1,249
Louisiana	0	0	105	0	0	260	0	0	230	0	0	0	0	595
Michigan	16	0	234	0	0	242	0	0	296	0	0	148	0	936
Ohio	509	0	1,799	0	0	3,350	0	0	2,650	0	59	365	225	8,957
Oklahoma	0	0	625	34	8	2,202	10	0	812	0	0	0	0	3,691
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	275
Texas	0	0	1,330	0	0	4,696	14	0	5,082	0	0	0	0	11,122
W. Virginia	385	17	323	0	0	1,630	0	23	458	741	0	89	0	3,666
Virginia	349	96	69	15	0	1,735	0	0	731	48	0	141	0	3,184
Total	**2,116**	**113**	**5,913**	**140**	**287**	**16,198**	**66**	**23**	**11,681**	**844**	**59**	**1,364**	**225**	**39,029**

Note: Transmission line circuit miles are current as of 12/31/09

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1594 of 9556

Distribution Line Detail

By State	Line Miles*		By Operating Company	Line Miles*
Tennessee	1,536	|	KGPCo	1,536
Virginia	30,426	|	KPCo	9,926
W. Virginia	21,529	|	APCo	50,460
Kentucky	9,926	|	OPCo	26,472
Ohio	45,348	|	CSP	18,876
Michigan	5,288	|	I&M	20,218
Indiana	14,930	|	WPCo	1,495
Texas	51,904	|	TCC	29,491
Oklahoma	21,951	|	TNC	13,815
Arkansas	4,471	|	PSO	21,951
Louisiana	7,568	|	SWEPCO	20,637
Total	**214,877**		**Total**	**214,877**

* Includes approximately 30,400 miles of underground circuit miles

Year End 2009 data per Small World Graphics.

Operating Company Overview

Operating Company Overview

- AEP East Regional Utilities
- AEP West Regional Utilities

AEP East Regional Utilities

Appalachian Power

President and Chief Operating Officer:
Charles Patton

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 959,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2009, APCo and its wholly owned subsidiaries had 2,577 employees. Among the principal industries served by APCo are paper and rubber products, coal mining, primary metals, textile mill products, and stone, clay and glass products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary Metals
Coal Mining
Chemical
Paper Products

Total Customers at 12/31/09:

Residential	**818,000**
Commercial	**130,000**
Industrial	**4,000**
Other	**7,000**
Total	**959,000**

Generating Capacity **6,287 MW**

Generating Capacity by Fuel Mix:

- **Coal: 81.0%**
- **Hydro/Pump: 10.8%**
- **Nat Gas: 8.2%**

Transmission Miles	**6,807**
Distribution Miles	**50,460**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	3,369,400	2,394,343	5,763,743	3,706,852	2,789,329	6,496,181	3,616,072	2,800,963	6,417,035
% of Capitalization Per Balance Sheet	58.5%	41.5%	100.0%	57.1%	42.9%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			1.7			3.02			3.39*
FFO Total Debt			4.6%			11.4%			13.8%*
							* - calculated on rolling 12-month avg.		

2009 Financial Data * (in thousands)

Revenue	$ 2,182,000
% of AEP Retail	21%
Net Income	$ 156,000
Capital Expenditures	$ 544,000

2010 Asset Data ** (in thousands)

	As of 9/30/10
Total Assets	$ 9,583,474
Net Plant Assets	$ 7,221,927
Cash	$ 2,201

Operating Information***

2009 retail electric sales in megawatt-hours	30,414,469	2009 firm wholesale sales in megawatt-hours	3,420,505
2009 average cost per kilowatt-hour (residential)	8.37 cents	2009 System Peak – (date) January 16	8,308 MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

Appalachian Power

APPALACHIAN AREA

INVESTOR OWNED UTILITIES *

West Virginia	Customers
APCo	**439,831**
Monongahela Power	381,193
Potomac Edison	130,304
AEP – Wheeling	**41,334**

Virginia	Customers
APCo	**518,043**
Dominion Virginia	2,268,601
Old Dominion Power	30,017
Potomac Edison	101,722

Tennessee	Customers
AEP - Kingsport	**46,961**

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

Top 10 Customers = 40% of industrial sales

Metropolitan areas account for 37% of ultimate sales

110 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

TYPICAL BILL COMPARISON **

West Virginia	$/month
APCo	**80.47**
AEP – Wheeling	**80.47**
Potomac Edison	91.78
Monongahela Power	91.78

Virginia	$/month
Old Dominion Power	91.64
Potomac Edison	95.75
Dominion Virginia	106.32
APCo	**114.03**

Tennessee	$/Month
AEP – Kingsport	**82.92**

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010.

MAJOR CUSTOMERS:
CNX Gas Company (VA)
Greif Brothers Corporation (VA)
Century Aluminum of West Virginia (WV)
WVA Manufacturing (WV)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Eastern Associated Coal Corp (WV)
Felman Production (WV)
Alcan Rolled Products (WV)
Consolidation Coal Company (VA)

(data for year ended December 2009)

AEP Ohio - Columbus Southern Power

President and Chief Operating Officer: Joe Hamrock

AEP Ohio-Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2009, CSPCo had 1,283 employees.

CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries services are primary metals, chemical and allied products, health services and electronic machinery. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

Total Customers at 12/31/09:

Residential	**667,000**
Commercial	**78,000**
Industrial	**3,500**
Other	**500**
Total	**749,000**

Generating Capacity **3,738 MW**

Generating Capacity by Fuel Mix:

- **Coal** **63.9%**
- **Natural Gas** **36.1%**

Transmission Miles	**2,435**
Distribution Miles	**18,876**

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals
Food Products
Rubber & Plastic Products
Fabricated Metals

AEP Ohio - Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,518,459	1,245,265	2,763,724	1,560,595	1,359,835	2,920,430	1,588,753	1,494,158	3,082,911
% of Capitalization Per Balance Sheet	54.9%	45.1%	100.0%	53.4%	46.6%	100.0%	51.5%	48.5%	100.0%
FFO Interest Coverage			5.24			5.31			5.17*
FFO Total Debt			26.3%			25.9%			24.0%*
							* - calculated on rolling 12-month avg.		

2009 Financial Data * (in thousands)

Revenue	$	1,735,000
% of AEP Retail		17%
Net Income	$	272,000
Capital Expenditures	$	303,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	4,414,230
Net Plant Assets	$	3,544,007
Cash	$	1,679

Operating Information***

2009 retail sales in megawatt-hours	20,673,469
2009 firm wholesale sales in megawatt-hours	498,182
2009 average cost per kilowatt-hour (residential)	10.26 cents
2009 System Peak – June 25	4,209 MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

AEP Ohio - Columbus Southern Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	1,458,111
First Energy ***	1,844,202
Duke Energy Ohio	677,178
DP&L	514,094

** AEP Ohio - CSPCo = 746,664
OPCo = 711,447

*** First Energy - Toledo Edison = 270,430
CEI = 701,554
Ohio Edison = 872,218

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	91.03
AEP (CSP)	106.09
FE (Toledo Edison)	110.55
DP&L	112.25
FE (Ohio Edison)	112.78
FE (CEI)	127.88
Duke Energy Ohio	135.69

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Aluminum
Eramet Marietta, Inc.
E I duPont de Nemours HQ
Kraton Polymers
Glatfelter Company
Anheuser-Busch, Inc.
Griffin Wheel Company, Inc.
Ross Products

(data for year ended December 2009)

Top 10 customers = 60% of industrial sales

Metropolitan areas account for 86% of ultimate sales

241 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

Indiana Michigan Power

President and Chief Operating Officer: Paul Chodak

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2009, I&M had 3,008 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. This lease extends through February 2010 and its termination is currently being litigated. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals and Allied Products
Transportation Equipment
Rubber and Miscellaneous Plastic Products
Fabricated Metals Products

Total Customers at 12/31/09:

Residential	**507,000**
Commercial	**69,000**
Industrial	**5,000**
Other	**2,000**
Total	**583,000**

Generating Capacity **5,821 MW***

Generating Capacity by Fuel Mix:

- **Coal:** **68.6%**
- **Nuclear:** **31.1%**
- **Hydro:** **0.3%**

Transmission Miles	**5,347**
Distribution Miles	**20,218**

* Includes AEGCo's share of Rockport of 1, 310MW

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,853,950	1,442,898	3,296,848	2,077,906	1,680,860	3,758,766	2,118,911	1,724,825	3,843,736
% of Capitalization Per Balance Sheet	56.2%	43.8%	100.0%	55.3%	44.7%	100.0%	55.1%	44.9%	100.0%
FFO Interest Coverage			4.4			5.91			5.22*
FFO Total Debt			22.0%			28.9%			25.5%*

* - calculated on rolling 12-month avg.

2009 Financial Data * (in thousands)

Revenue	$	991,000
% of AEP Retail		10%
Net Income	$	216,000
Capital Expenditures	$	333,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	7,101,587
Net Plant Assets	$	4,226,830
Cash	$	789

Operating Information***

2009 retail electric sales in megawatt-hours	17,642,645
2009 firm wholesale sales in megawatt-hours	4,513,856
2009 average cost per kilowatt-hour (residential)	7.67 cents
2009 System Peak – June 25	4,262MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

Indiana Michigan Power

INDIANA & MICHIGAN INVESTOR OWNED UTILITIES * TYPICAL BILL COMPARISON **

Indiana	Customers
I & M	**455,120**
IP & L	468,203
NIPSCO	456,302
Duke Energy Indiana	776,647
SIGECo	146,339

Indiana	$/month
IP & L	80.07
I & M	**85.49**
Duke Energy Indiana	97.16
NIPSCO	110.80
SIGECo	142.11

Michigan	$/month
I & M	**73.15**
Consumers Energy	108.80
Detroit Edison	129.05

Michigan	Customers
I & M	**127,648**
Consumers Energy	1,804,232
Detroit Edison	2,148,520

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010.

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

Top 10 Customers = 49% of industrial sales

Metropolitan areas account for 68% of ultimate sales

205 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

MAJOR CUSTOMERS:

Steel Dynamics Inc. (IN)
Dock Foundry (MI)
American Axle and Mfg. Co, Inc. (MI)
IN TEK (IN)
Whirlpool Corporation (MI)
Saint Gobain Corporation USA (IN)
White Pigeon Paper Company (MI)
Uniroyal Goodrich Tire Co. (IN)
The Minute Maid Company (MI)
New Energy Corp (IN)
Rexam Closure Systems, Inc. (MI)

(data for year ended December 2009)

Kentucky Power

President and Chief Operating Officer: Greg Pauley

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 175,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2009, KPCo had 478 employees. In addition to its AEP System interconnections, KPCo is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Petroleum Refining
Coal Mining
Primary Metals
Chemical & Allied Products
Electric/Gas/Sanitary Services

Total Customers at 12/31/09:

Residential	**143,500**
Commercial	**29,500**
Industrial	**1,500**
Other	**500**
Total	**175,000**

Generating Capacity	**1,078 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**1,249**
Distribution Miles	**9,926**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	549,954	398,008	947,962	549,207	431,784	980,991	548,847	434,919	983,766
% of Capitalization Per Balance Sheet	58.0%	42.0%	100.0%	56.0%	44.0%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			2.51			4.20			3.17*
FFO Total Debt			9.9%			19.9%			14.9%*
							* - calculated on rolling 12-month avg.		

2009 Financial Data * (in thousands)

Revenue	$	487,000
% of AEP Retail		5%
Net Income	$	24,000
Capital Expenditures	$	64,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	1,502,188
Net Plant Assets	$	1,135,618
Cash	$	621

Operating Information***

2009 retail electric sales in megawatt-hours	7,068,456
2009 firm wholesale sales in megawatt-hours	93,766
2009 average cost per kilowatt-hour (residential)	7.93cents
2009 System Peak – January 16	1,674 MW

Sources: * 2009 Annual Report
** 3Q10 Financial Statements (unaudited)
*** 2009 FERC Form 1

Kentucky Power

KENTUCKY INVESTOR OWNED UTILITIES *

Kentucky	Customers
KPCo	**175,646**
Duke Energy Kentucky	134,703
Kentucky Utilities	506,419
LG & E	400,699

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	$/month
Kentucky Utilities	73.57
LG&E	75.26
KPCo	**76.57**
Duke Energy Kentucky	80.02

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010.

MAJOR CUSTOMERS:

Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
KES Acquisition Company LLC
Air Products & Chemicals, Inc.
Perry County Coal Corporation
Blue Diamond Coal Company
McCoy Elkhorn Coal Corporation
Kentucky West Virginia Gas Co.
Czar Coal Corporation

(data for year ended December 2009)

Top 10 customers = 65% of industrial sales

Metropolitan areas account for 40% of ultimate sales

68 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

AEP Ohio - Ohio Power

President and Chief Operating Officer: Joe Hamrock

AEP Ohio- Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2009, OPCo had 2,391 employees. In addition to its AEP System interconnections, OPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Petroleum Refining
Rubber & Plastic Products
Chemicals & Allied Products
Stone, Clay Glass and Concrete Products

Total Customers at 12/31/09:

Residential	**608,000**
Commercial	**92,500**
Industrial	**7,000**
Other	**2,500**
Total	**710,000**

Generating Capacity	**8,508 MW**

Generating Capacity by Fuel Mix:

- **Coal: 99.7%**
- **Hydro: 0.3%**

Transmission Miles	**6,523**
Distribution Miles	**26.472**

AEP Ohio - Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	3,173,263	2,455,371	5,628,634	3,242,505	3,251,322	6,493,827	2,929,386	3,237,649	6,167,035
% of Capitalization Per Balance She	56.4%	43.6%	100.0%	49.9%	50.1%	100.0%	47.5%	52.5%	100.0%
FFO Interest Coverage			3.1			5.34			5.40*
FFO Total Debt			13.3%			22.1%			24.0%*
							* - calculated on 12-month rolling avg.		

2009 Financial Data * (in thousands)

Revenue	$	1,679,000
% of AEP Retail		16%
Net Income	$	306,000
Capital Expenditures	$	418,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	8,684,457
Net Plant Assets	$	6,647,889
Cash	$	1,354

Operating Information

2009 retail sales in megawatt-hours	24,936,379
2009 firm wholesale sales in megawatt-hours	2,149,774
2009 average cost per kilowatt-hour (residential)	8.69 cents
2009 System Peak – January 20	4,972 MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

AEP Ohio - Ohio Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	**1,458,111**
First Energy ***	1,844,202
Duke Energy Ohio	677,178
DP&L	514,094

** AEP Ohio - CSPCo = 746,664
OPCo = 711,447

*** First Energy - Toledo Edison = 270,430
CEI = 701,554
Ohio Edison = 872,218

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	**91.03**
AEP (CSP)	**106.09**
FE (Toledo Edison)	110.55
DP&L	112.25
FE (Ohio Edison)	112.78
FE (CEI)	127.88
Duke Energy Ohio	135.69

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Primary Aluminum Corp.
The Premcor Refining Group, Inc.
The Timken Company
Republic Engineered Products, LLC
Wheeling-Pittsburgh Steel Corp.
Globe Metallurgical, Inc.
Linde Gases, LLC
Marathon Ashland Petroleum, LLC
Owens Corning Sales, LLC.

(data for year ended December 2009)

Top 10 customers = 47% of industrial sales

Metropolitan areas account for 59% of ultimate sales

137 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 531,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2009, PSO had 1,281 employees. In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy, Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Paper Products
Oil & Gas Extraction
Transportation Equipment
Stone, Clay and Glass Products
Petroleum Refining

Total Customers at 12/31/09:

Residential	**457,000**
Commercial	**60,000**
Industrial	**7,000**
Other	**7,000**
Total	**531,000**

Generating Capacity	**4,465 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **23.1%**
- **Natural Gas:** **76.3%**
- **Oil:** **0.6%**

Transmission Miles	**3,619**
Distribution Miles	**21,951**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	955,167	753,508	1,708,675	968,121	817,000	1,785,121	993,667	853,764	1,847,431
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	54.2%	45.8%	100.0%	53.8%	46.2%	100.0%
FFO Interest Coverage			4.3			4.01			2.80*
FFO Total Debt			27.2%			18.7%			11.6%*
							* - calculated on rolling 12-month avg		

2009 Financial Data * (in thousands)

Revenue	$	998,000
% of AEP Retail		10%
Net Income	$	75,000
Capital Expenditures	$	175,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	3,227,713
Net Plant Assets	$	2,689,348
Cash	$	1,587

Operating Information***

2009 retail electric sales in megawatt-hours	16,955,308
2009 firm wholesale sales in megawatt-hours	6,623
2009 average cost per kilowatt-hour (residential)	7.36 cents
2009 System Peak – July 13	3,994 MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

Public Service Company of Oklahoma

OKLAHOMA INVESTOR OWNED UTILITIES *

Oklahoma	Customers
PSO	**525,801**
OG&E	702,603

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	$/month
PSO	**62.02**
Empire District	78.65
OG&E	86.89

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010.

MAJOR CUSTOMERS:

Sheffield Steel
Weyerhaeuser Valliant Company
Elkem Metals
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
American Airlines
Sinclair
Sun Refining
Marmac Resources
Terra Nitrogen

(data for year ended December 2009)

Top 10 customers = 45% of industrial sales

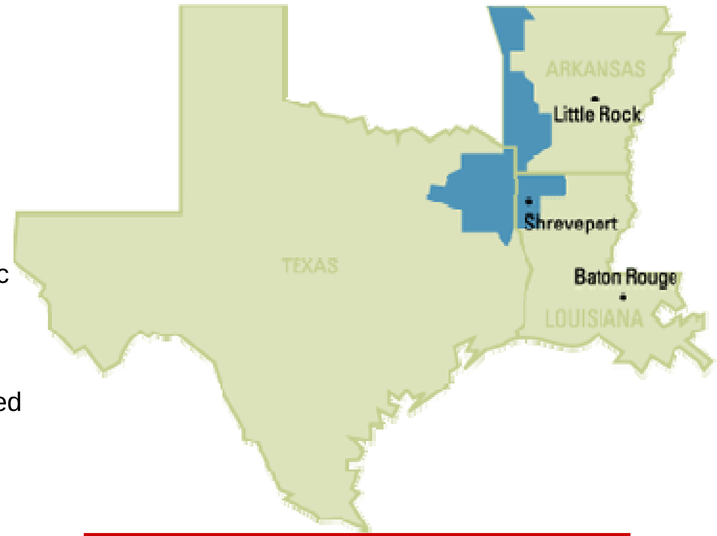
Metropolitan areas account for 76% of ultimate sales

48 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen



Southwestern Electric Power Company (SWEPCO)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 474,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2009, SWEPCo had 1,671 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets and to assume certain liabilities of Valley Electric Membership Corporation (VEMCO) for approximately $96 million, subject to regulatory approval by the LPSC and the APSC. VEMCO services approximately 30,000 member customers in eight parishes south of Shreveport, Louisiana. SWEPCo expects to complete the transaction in the second quarter of 2010.

PRINCIPAL INDUSTRIES SERVED:

Food Processing
Pulp and Paper Manufacturing
Oil and Gas Extraction
Chemicals and Allied Products
Petroleum Refining

Total Customers at 12/31/09:

Residential	**400,000**
Commercial	**66,500**
Industrial	**7,000**
Other	**500**
Total	**474,000**

Generating Capacity	**5,307 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **38.5%**
- **Natural Gas:** **44.0%**
- **Lignite:** **17.5%**

Transmission Miles	**3,784**
Distribution Miles	**20,637**

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,487,847	1,253,626	2,741,473	1,481,043	1,528,854	3,009,897	1,772,627	1,666,353	3,438,980
% of Capitalization Per Balance Sheet	54.3%	45.7%	100.0%	49.2%	50.8%	100.0%	51.5%	48.5%	100.0%
FFO Interest Coverage			3.26			4.14			3.34*
FFO Total Debt			16.0%			19.3%			14.3%*

* - calculated on rolling 12-month avg

2009 Financial Data * (in thousands)

Revenue	$ 1,039,000
% of AEP Retail	10%
Net Income	$ 114,000
Capital Expenditures	$ 597,000

2010 Asset Data ** (in thousands)

	As of 9/30/10
Total Assets	$ 5,079,134
Net Plant Assets	$ 4,215,158
Cash	$ 1,882

Operating Information

2009 retail electric sales in megawatt-hours	16,086,255
2009 firm wholesale sales in megawatt-hours	5,897,295
2009 average cost per kilowatt-hour (residential)	7.35 cents
2009 System Peak – July 13	4,750 MW

Sources: * 2009 Form 10-K
** 3Q10 Form 10-Q (unaudited)
*** 2009 FERC Form 1

Southwestern Electric Power

SOUTHWESTERN INVESTOR OWNED UTILITIES *

Arkansas	Customers
SWEPCo	**112,843**
Entergy AR	688,951
OG&E	64,284

Louisiana	Customers
SWEPCo	**178,634**
CLECO	271,663
Entergy	1,171,895

Texas	Customers
SWEPCo	**177,786**
El Paso	273,185
SPSCo	279,551
Entergy TX	396,885

* Customer counts are as of December 31, 2008 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	$/month
OG&E	57.37
SWEPCo	**73.20**
Empire District	87.44
Entergy AR	106.74

Louisiana	$/month
SWEPCo	**69.13**
Entergy Gulf St	83.97
Entergy NO	95.65
Entergy LA	100.21
CLECO	104.29

Texas	$/month
SWEPCo	**63.07**
SPSCo	80.48
Entergy TX	81.70
El Paso	113.16

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2010.

Top 10 customers = 50% of industrial sales

Metropolitan areas account for 76% of ultimate sales

82 persons per square mile (U.S. = 87)

(data for 12 months ended December 2009)

MAJOR CUSTOMERS:

Lone Star Steel Company (TX)
International Paper Company (TX)
General Motors Corporation (LA)
Calumet Lubricants (LA)
Libbey Glass Inc. (LA)
Domtar, Inc (AR)
Pilgrim Pride Corporation (TX)
Cooper Tire & Rubber Company (AR)
Letourneau Inc.(TX)
Big Three Industrial Gas (TX)
Tyson Foods AR)
Glad Manufacturing (AR)

(data for year ended December 2009)

AEP Texas Central Company

President and Chief Operating Officer: Wade Smith

AEP Texas - Texas Central Company

(TCC) (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 766,000 retail customers through REPs in southern Texas. Under the Texas Act, TCC has completed the final stage of exiting the generation business and has sold of all of its generation assets. At December 31, 2009, TCC had 1,174 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Javelina Refinery
Formosa
Koch Refinery West
Equistar Bay City

(data for year ended December 2009)

PRINCIPAL INDUSTRIES SERVED:

Petroleum Refining
Chemicals & Allied Products
Oil and Gas Extraction
Food Processing

Top 10 customers = 49% of industrial sales* ($)

Metropolitan areas account for 78% ultimate sales

58 persons per square mile (U.S. = 87)

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2009)

Total Customers at 12/31/09:
(Based on electric meters)

Residential	**654,000**
Commercial	**105,000**
Industrial	**5,000**
Other	**2,000**
Total	**766,000**

Transmission Miles	**4,629**
Distribution Miles	**29,491**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,901,590	519,964	3,421,554	2,757,966	600,749	3,358,715	2,610,238	624,527	3,234,765
% of Capitalization Per Balance Sheet	84.8%	15.2%	100.0%	82.1%	17.9%	100.0%	80.7%	19.3%	100.0%
FFO Interest Coverage			3.5			3.52			3.67*
FFO to Total Debt			19.9%			17.2%			18.9%*
							* - calculated on rolling 12-month avg		

2009 Financial Data * (in thousands)

Revenue	$	721,000
% of AEP Retail		7%
Net Income	$	82,000
Capital Expenditures	$	176,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	5,099,978
Net Plant Assets	$	2,566,203
Cash	$	200

Sources: * 2009 Annual Report
** 3Q10 Financial Statements (unaudited)

AEP Texas North Company

President and Chief Operating Officer: Wade Smith

AEP Texas - Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 185,000 retail customers through REPs in west and central Texas. TNC's remaining generating capacity that is not deactivated has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. At December 31, 2009, TNC had 368 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:

Zoltec Corporation
Sheridan Production Co.
Kinder Morgan
Tyson Foods, Inc.
EBAA Iron
Bandag, LLC.

(data for year ended December 2009)

PRINCIPAL INDUSTRIES SERVED:

Oil and Gas Extraction
Food Processing
Pipelines, except Natural Gas
Stone, Clay and Glass Production
Electric Equipment

Top 10 customers = 40% industrial sales* ($)

Metropolitan areas account for 57% ultimate sales

8 persons per square mile (U.S. = 87)

*Industrial % is in terms of wires revenues

(data for 12 months ended December 2009)

Total Customers at 12/31/09:
(Based on electric meters)

Residential	**145,000**
Commercial	**30,000**
Industrial	**5,000**
Other	**5,000**
Total	**185,000**

Generating Capacity **377 MW**
Oklaunion Plant – Vernon, TX
(excludes 270 MW of decommissioned plants)

Generating Capacity by Fuel Mix:

- **Coal:** **58.3%**
- **Gas:** **40.5%**
- **Oil:** **1.2%**

Transmission Miles	**4,319**
Distribution Miles	**13,815**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2008			2009			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	397,651	325,825	723,476	446,256	312,260	758,516	400,155	307,412	707,567
% of Capitalization Per Balance Sheet	55.0%	45.0%	100.0%	58.8%	41.2%	100.0%	56.6%	43.4%	100.0%
FFO Interest Coverage			4.7			3.41			3.75*
FFO Total Debt			21.9%			12.8%			15.7%*
							* - calculated on rolling 12-month avg.		

2009 Financial Data * (in thousands)

Revenue	$	115,000
% of AEP Retail		1%
Net Income	$	18,000
Capital Expenditures	$	94,000

2010 Asset Data ** (in thousands)

	As of 9/30/10	
Total Assets	$	1,150,479
Net Plant Assets	$	992,014
Cash	$	200

Sources: * 2009 Annual Report
** 3Q10 Financial Statements (unaudited)

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Regulation

Regulation

- Regulatory Strategy
- Rate Case Filing Requirements
- Regulatory Activity Underway
- Commission Overviews
- Approved Rate Base and ROE by Operating Company

Regulatory Strategy: Reduce Lag

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers/Riders/Regulatory Adjustment Clauses
  - Federally-approved transmission costs
  - Fuel and emissions
  - Energy efficiency programs
- Formula rates
  - Including periodic true-ups and approved earnings bands
- Future test years
- Accelerated cost recovery/depreciation/replacement cost accounting
- Pre-Approvals
- Securitization
- Return on CWIP

The strategy: reduce the time between in-service dates and rate recovery

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Louisiana	Michigan	Ohio	Oklahoma	Texas	Virginia	West Virginia	FERC
General											
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	Yes	No	No
Period of Limitation (months)	--	15	--	--	--	--	--	--	See note 1	--	--
Pancaking Permitted?	No	No	No	No	No	Limited	No	No	No	No	Yes
Fuel Clause Renewal Frequency	Annually	Semi-Annually	Monthly	Monthly	Annually	Quarterly	Annually	Tri-Annually	Annually	Annually	--
Notice of Intent											
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	N/A	45	30	45	30	60	30	N/A
Case Components											
Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Historical	Historical	Historical	Historical	Forecast Optional
Other											
Rates Effective Subject to Refund	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes
Approx # of Months after Filing to implement rates subject to refund	10	--	6	8	Varies	9	6	6	5	9	2 or 7

Note 1: No interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Regulatory framework inherently produces recovery and return lag.

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

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Summary Rate Case Information

PSO General Rate Case – Docket #201000050

On July 9, 2010, PSO filed a base rate case with the Oklahoma Corporation Commission requesting a net increase of $52.4 million, comprised of a $82.7 million base rate increase and a $30.3 million decrease in the capital investment rider. The requested ROE is 11.50%. Staff testimony supports a $0.3 million increase at an ROE of 10.04% and recommends continued collection of the $30.3 million capital investment rider.

Actual Capital Structure – Company Position (2/28/10)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	53.86%	6.52%	3.51%
Common Equity	45.84%	11.50%	5.27%
Preferred Stock	0.30%	4.02%	0.01%
Total	100.00%		8.79%

Procedural Schedule

October 26, 2010	Staff & Intervenor testimony due
November 16, 2010	Rebuttal testimony due
November 29, 2010	Settlement Conference
Debember 6-17, 2010	Hearing
January 5, 2011	Rates Effective, Subject to Refund

Required Rate Relief – Company Position (2/28/10)

($ in millions)

Rate Base	$	1,687.2
Rate of Return		8.79%
Operating Income Requirement	$	148.3
Adjusted Operating Income	$	97.9
Difference	$	50.4
Revenue Conversion Factor		1.6391
Total Revenue Requirement	$	82.7
Elimination of Capital Investment Rider	$	(30.3)
	$	52.4

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**

Qualifications for Commissioners

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Beebe has appointed all of the current commissioners.

Commissioners

Paul Suskie, Chairman (Dem.), since 2007; current term ends in 2013. Lawyer, North Little Rock, Arkansas City Attorney. Bachelor's attained at University of Central Arkansas. Juris Doctorate at University of Arkansas at Little Rock School of Law. NARUC member including the Committee on Consumer Affairs and Electricity Committee.

Olan Reeves, Commissioner (Rep.), since 2009; current term ends in 2015. Chairman of the Workers' Compensation Commission from January, 2003 until January, 2009. Prior to these appointments, Commissioner Reeves was Chief Legal Counsel to the Governor from 1998-2003 and served as the State Drug Director from 1996 to 1998. Reeves received his Juris Doctorate from the University of Arkansas School of Law in Fayetteville.

Collette Honorable, Commissioner (Dem.), since 2007; current term ends in 2011. Commissioner Honorable is a member of NARUC and serves on the Consumer Affairs and Investment Committees. She also serves on the Smart Grid Collaborative, a joint effort of NARUC and the FERC. Honorable obtained her Juris Doctorate from the University of Arkansas at Little Rock School of Law.

AEP Regulatory Status

SWEPCo-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 2 D: 2**
Qualifications for Commissioners Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairperson.			
Commissioners **Jim Atterholt, Chairman (Rep.),** since 2009; current term ends 2014. Prior to joining the Commission, he was the State Insurance Commissioner for more than four years where he also served as a member of the Governor's Cabinet. Atterholt worked as Director of Government Affairs for AT&T--Indiana from 2003 – 2004. Atterholt holds a Bachelors degree from the University of Wisconsin.			
Carolene R. Mays, Commissioner (Dem.), since 2010; current term will expire December 2013. Former publisher and president of the Indianapolis Recorder Newspaper and the Indiana Minority Business Magazine. From 2002 to 2008, served in the Indiana House of Representatives and sat on the committees for Small Business and Economic Development, Ways and Means and Public Health.			
Larry S. Landis, Commissioner (Rep.), since 2002; current term ends December 2011. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.			
David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2011. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and chairman of the NARUC clean coal and carbon sequestration subcommittee. Law degree from the Indiana University School of Law in Indianapolis.			

AEP Regulatory Status

I&M–Indiana provides retail electric service at bundled rates approved by the IURC. Rates are set on a cost-of-service basis with a fuel recovery mechanism. I&M–Indiana has trackers in place for PJM expenses, OSS sharing, clean coal technology, environmental and DSM.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 4 Years	Political Makeup: R: 2 D:1
Qualifications for Commissioners Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KPSC shall be of the same profession or occupation.			
Commissioners **David L. Armstrong, Chairman (Dem.),** since 2008; current term expires June 2011. Former practicing attorney in private practice. Board member of NARUC and serves on its Electricity Committee and the Subcommittee on Clean Coal Technology. J.D. from University of Louisville Brandeis School of Law. Mr. Armstrong is also the former Mayor for the city of Louisville, KY (1999-2003).			
James W. Gardner, Vice Chairman (Rep.), since 2008; current term expires June 2012. Prior to joining the PSC Mr. Gardner was a partner at the law firm Henry Watz Gardner & Sellars PLLC where he specialized in bankruptcy law. JD degree from the University of Kentucky College of Law.			
Charles Borders, Commissioner (Rep.), since 2009; current term expires June 2013. Before joining the PSC, Commissioner Borders served in the Kentucky Senate, representing the 18th District in northeast Kentucky since 1991. He most recently chaired the Appropriations and Revenue Committee and served on the committees on Education and Health and Welfare. Borders received his Bachelors and Masters degrees from Morehead State University.			

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 3 D: 2
Qualifications for Commissioners The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.			
Commissioners **Lambert C. Bossiere, III (Chairman) (Dem.),** since 2005; current term ends December 2010. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.			
Eric Skrmetta, (Rep.), since 2009; current term ends December 2014. Practicing Attorney since 1985. Practicing Mediator since 1989. Republican State Central Committee District 81**.** Juris Doctorate Southern University Law School.			
Foster L. Campbell, (Dem.), since 2003; current term ends December 2014. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.			
James M. Field, (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.			
Clyde Holloway, (Rep.), since 2009; current term ends December 2010. Elected to Congress in 1987 and served in the United States House of Representatives until 1993. In October 2006 he received an appointment by President Bush as the USDA State Director of Rural Development where he served until 2009**.**			

AEP Regulatory Status

SWEPCo-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects. A formula rate plan was implemented August 1, 2008 with annual true-ups required.

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Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: D: 2 I: 1**
Qualifications for Commissioners The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.			
Commissioners **Orjiakor N. Isiogu, Chairman (Dem.),** since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.			
Monica Martinez, Commissioner, (Dem.), since 2005; current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this, she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues. Bachelor's and Master's degrees from University of Michigan.			
Steven A. Transeth, Commissioner, (Ind.) , since 2007; current term expires July 2015. Former assistant director and legal counsel for the Michigan Legislative Service Bureau, which included drafting legislation and providing legal counsel to the Michigan Senate and House of Representatives. Lawyer, private practice and with the Ingham County Prosecuting Attorney's office. J.D. from Thomas Cooley Law School.			

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. In 2008, legislation was enacted to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year. I&M-Michigan has an active fuel clause and return on CWIP can be included in base rates. Michigan currently has a mandatory renewable energy standard of 10% by 2015.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 1 D: 2 I: 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.) , since 1999; term expires April 2014. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee, National Governors' Association Electricity Task Force, Harvard Electricity Policy Group.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctorate from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Steven D. Lesser, Commissioner, (Rep.) since 2010; term expires April 2015. Juris Doctorate from Capital University; previously served as PUCO chief of staff, assistant director of the legal department, deputy director of the transportation department and administrative law judge/attorney examiner in the legal department.

Valerie A. Lemmie, Commissioner, (Ind.) since 2006; term expires April 2011. Master's degree in Urban Affairs and Public Policy Planning, Washington University. Served as city manager for Cincinnati, Dayton, and Petersburg, Va. Scholar-in-residence at the Kettering Foundation. Past President of the National Academy of Public Administration.

Cheryl Roberto, Commissioner, (Dem.) since 2008; term expires April 2013. Prior to joining the PUC, Roberto was director of the City of Columbus Public Utilities Department. Before entering the public sector, Commissioner Roberto worked as an assistant attorney general for the state of Ohio. Commissioner Roberto received her B.A. with honors from Kent State University and her Juris Doctorate from the Moritz College of Law at The Ohio State University.

AEP Regulatory Status

On March 18, 2009 the Ohio PUC approved an electric security plan allowing for revenue increases of 7% in 2009 and 6% in 2010 and 2011 for Columbus Southern Power and revenue increases of 8% in 2009, 7% in 2010 and 8% in 2011 for Ohio Power. Transmission rates are currently regulated by FERC as reflected in the OATT. SB221 allows that CSP and OPCo have active fuel clauses effective January 1, 2009. Ohio currently has a mandatory renewable energy standard of 25% by 2025.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 3 D: 0**
Qualifications for Commissioners The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms. The election pattern was established when the Commission was created by the state constitution.			
Commissioners **Bob Anthony, Chairman, (Rep.),** since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned an M.Sc. from the London School of Economics, an M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.			
Jeff Cloud, Commissioner (Rep.), since 2002; current term ends January 2015. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of Staff. Law degree from Oklahoma City University.			
Dana Murphy, Commissioner, (Rep.), since 2008; current term expires January 2015. Member, NARUC. Murphy's prior experience includes working as an administrative law judge at the Commission. She has more than 20 years experience in the petroleum industry including owning and operating her own private law practice and working as a geologist in the Oklahoma petroleum industry. Juris Doctorate Oklahoma City University.			

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism.

Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 3**

Qualifications for Commissioners

The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six and three-year staggered terms. The chairmanship rotates every year in an agreed upon decision by the directors.

Commissioners

Sara Kyle, Director (Dem.), since 1996; current term expires June 2014. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving commissioner and only holdover from the previous Regulatory Authority. Law degree from Middle Tennessee State University.

Mary W. Freeman, Chairman (Dem.), since 2008; current term expires June 2011. Prior legislative director for Governor Bredesen, executive assistant to State Representative Lois DeBerry. B.A. Tennessee State University.

Kenneth Hill, Director (Rep.), since 2009; current term expires June 2015. At the time of his appointment to the TRA, Hill was Chief Executive Officer of AECC and served as General Manager of five radio stations reaching portions of East Tennessee and four surrounding states. Doctor of Religious Education, Andersonville Baptist Seminary.

Eddie Roberson, Ph.D, Director, (Dem.), since 2006; current term expires June 2014. Former Chief of Consumer Services Division of the Regulatory Authority; also served a year as the agency's Executive Director. Served two terms on the Chattanooga City School Board. Ph.D in Public Administration from Tennessee State University.

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Co.
Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 3**
Qualifications for Commissioners To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.			
Commissioners **Barry T. Smitherman, Chairman, (Rep.),** since April 2004; current term expires August 2013. Attorney; Assistant DA; Public Finance Investment Banker. Received law degree from the University of Texas School of Law.			
Kenneth W. Anderson Jr., (Rep.) since September 2008; current term expires August 2011. Past Director of Governmental Appointments under Governor Perry. Prior to that Anderson served in private practice as a corporate attorney in the area of securities law and regulatory matters. He also served as a member of the Texas Securities Board from 1999-2006. Anderson holds a law degree from Southern Methodist University.			
Donna L. Nelson, Commissioner (Rep.), since August 2008; current term expires August 2015. Nelson served as a special assistant and advisor to Governor Perry on energy, telecommunications and cable budget and policy issues. She previously served as director of the PUC telecommunication's section and legal advisor to the PUC chairman. Nelson holds a law degree from Texas Tech University.			

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base. TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 1**
Qualifications for Commissioners The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.			
Commissioners **Mark C. Christie, (Rep.),** since 2004; current term expires 2016. Prior counsel to the Speaker of the House of delegates of the Virginia General Assembly. Lawyer, private practice. Law degree from Georgetown.			
Judith Williams Jagdmann, (Rep.), since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.			
James C. Dimitri, Chairman (Dem.), since 2008; current term expires 2014. Prior to being named Commissioner, Dimitri was in private practice in Richmond. From 1994 to 2000 he served as Senior Counsel, then General Counsel at the SCC. He was an assistant Attorney General from 1983 to 1987. Dimitri received his undergraduate degree in economics from the University of Virginia and his J.D. from the Boston University School of Law.			

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. Virginia currently has a voluntary renewable energy standard of 12% by 2022, which AEP intends to comply with.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.
Wheeling Power Co.

Commissioners

Number: 3	Appointed/Elected: Appointed	Term: 6 Years	Political Makeup: R: 1 D: 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Michael A. Albert, Chairman (Rep.), since 2007; term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Ryan B. Palmer, Commissioner (Dem.), since 2010; term expired June 2015. Served as Deputy General Counsel to West Virginia Governor Joe Manchin, III; as Attorney/Advisor to Commissioner Charlotte R. Lane of the United States International Trade Commission and Law Clerk to the Honorable W. Craig Broadwater of the United States District Court, Northern District of West Virginia. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005; term expires June 2011. Currently on the board of directors of the NARUC and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction. West Virginia currently has a renewable energy standard of 25% by 2015.

Commission Overview

Federal Energy Regulatory Commission

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 2 D: 3

Qualifications for Commissioners

The Federal Energy Regulatory Commission (FERC) is composed of up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve five-year terms, and have an equal vote on regulatory matters. To avoid any undue political influence or pressure, no more than three commissioners may belong to the same political party.

Commissioners

Jon Wellinghoff, Chairman (Dem.), since 2006; term expires June 2013. Chairman Wellinghoff is an energy law specialist with more than 30 years experience in the field. Before joining FERC, he was in private practice and focused exclusively on client matters related to renewable energy, energy efficiency and distributed generation. While in the private sector, Chairman Wellinghoff represented an array of clients from federal agencies, renewable developers, and large consumers of power to energy efficient product manufacturers and clean energy advocacy organizations.

Mark Spitzer, Commissioner (Rep.) since 2006: term expires June 2011. Prior to becoming a commissioner, Spitzer served as chairman of the Arizona Corporation Commission (ACC), where he focused on policies encouraging expansion of natural gas infrastructure, specifically distribution and storage: creating a demand side management policy: enhancing the ACC's renewables standard: and advancing consumer privacy concerns in telecommunications.

Sheryl A. LaFleur, Commissioner (Dem.) since 2010; term expires June 2014. Retired in 2007 as executive vice president and acting CEO of National Grid USA, responsible for the delivery of electricity to 3.4 million customers in the Northeast. Her previous positions at National Grid and its predecessor New England Electric System included COO, president of New England distribution and general counsel. She practiced law in Boston earlier in her career, and has been a community and nonprofit leader

John R. Norris, Commissioner (Dem.) since 2010: term expires June 2012. Most recently served as Chief of Staff to Secretary Tom Vilsack of the U.S. Department of Agriculture. Prior to joining the USDA, he served as Chairman of the Iowa Utilities Board (IUB) from 2005 to 2009. During his tenure as IUB Chairman, Commissioner Norris served on the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee and was Co-Chair of the 2009 National Electricity Delivery Forum

Phillip D. Moeller, Commissioner (Rep.), since 2006; term expires June 2015. From 1997 through 2000, Mr. Moeller served as an energy policy advisor to U.S. Senator Slade Gorton (R-Washington) where he worked on electricity policy, electric system reliability, hydropower, energy efficiency, nuclear waste, energy and water appropriations and other energy legislation. Before becoming a Commissioner, Mr. Moeller headed the Washington, D.C., office of Alliant Energy Corporation. Prior to Alliant Energy, Mr. Moeller worked in the Washington office of Calpine Corporation.

Approved Rate Bases & ROEs and Current Rate Base Requests

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo-Virginia	$2,060MM*	10.53%	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	7/28/2006
KPCo-Kentucky	$995MM	10.50%	6/30/2010
I&M-Indiana	$2,000MM	10.50%	3/4/2009
I&M-Michigan	$595MM	10.35%	10/14/2010
PSO-Oklahoma	$1,467MM	10.50%	1/14/2009
SWEPCo-Louisiana	$649MM	10.57%**	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	11/25/2009
SWEPCo-Texas	$665MM	10.33%	4/15/2010
TCC-Texas	$1,566MM	9.96%	10/17/2007
TNC-Texas	$530MM	9.96%	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

Rate Case Requests on File

Jurisdiction	Requested Rate Base	Requested ROE
APCO - West Virginia	$2,640MM	11.75%
PSO - Oklahoma	$1,687MM	11.50%

Generation &
Environmental

Generation & Environmental

- Units
- Generation Statistics
- OSS Sharing Summary
- New Generation
- Environmental
- Future Potential Green House Gas Regulations

Domestic Generation

Generation Capacity*

Company	MW Capacity
AEP Generating Co	2,496
Appalachian Power Co	6,287
Columbus Southern Power Co	3,738
Indiana Michigan Power Co	4,511
Kentucky Power Co	1,078
Ohio Power Co	8,508
Public Service of Oklahoma	4,465
Southwestern Electric Power Co	5,307
Texas North Co**	647
OVEC Capacity ***	980
Domestic IPPs	311
Long Term Renewable Purchase Power Agreements	1,582
	39,910

* Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 270MW of mothballed/retired/decommissioned generation

*** Represents AEP's 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE.

Coal/Lignite #	25,736	65%
Natural Gas/Oil	9,371	23%
Nuclear	2,191	5%
Wind/Hydro/Pumped Storage	2,612	7%
Total Generating Capacity	39,910	100%

Includes AEP's 43% ownership of OVEC

At the conclusion of our current environmental retrofit program, over 56% of our 25,736 MW coal-fired generation fleet will be equipped with SCRs and over 71% will be scrubbed (FGDs).

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
AEP Generating Company					
Rockport	1	IN	Steam - Coal	1,310	1984
Lawrenceburg	6	IN	Natural Gas	1,186	2004
				2,496	
Appalachian Power Company					
Buck	3	VA	Hydro	5	1912
Byllesby	4	VA	Hydro	8	1912
Claytor	4	VA	Hydro	28	1939
Leesville	2	VA	Hydro	9	1964
London	3	WV	Hydro	12	1935
Marmet	3	WV	Hydro	11	1935
Niagara	2	VA	Hydro	1	1906
Reusens	5	VA	Hydro	3	1904
Winfield	3	WV	Hydro	15	1938
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos	2	WV	Steam - Coal	2,033	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	335	1918
Kanawha River	2	WV	Steam - Coal	400	1953
Mountaineer	1	WV	Steam - Coal	1,320	1980
Sporn	2	WV	Steam - Coal	300	1950
Ceredo	6	WV	Natural Gas	516	2001
				6,287	
Columbus Southern Power Company					
Beckjord (CCD)	1	OH	Steam - Coal	53	1969
Conesville (CCD)	4	OH	Steam - Coal	1,302	1957
Picway	1	OH	Steam - Coal	100	1926
Stuart (CCD)	4	OH	Steam - Coal	600	1971
Stuart (CCD)	4	OH	Oil	3	1970
Zimmer (CCD)	1	OH	Steam - Coal	333	1991
Waterford	4	OH	Natural Gas	840	2003
Darby	6	OH	Natural Gas	507	2001
				3,738	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Indiana Michigan Power Company					
Berrien Springs	12	MI	Hydro	5	1908
Buchanan	10	MI	Hydro	2	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	2	1913
Mottville	4	MI	Hydro	1	1923
Twin Branch	6	IN	Hydro	4	1904
Rockport	1	IN	Steam - Coal	1,310	1984
Tanners Creek	4	IN	Steam - Coal	995	1951
Cook	2	MI	Steam - Nuclear	2,191	1975
				4,511	
Kentucky Power Company					
Big Sandy	2	KY	Steam - Coal	1,078	1963
Ohio Power Company					
Racine	2	OH	Hydro	26	1982
Amos	1	WV	Steam - Coal	867	1973
Cardinal	1	OH	Steam - Coal	595	1967
Gavin	2	OH	Steam - Coal	2,640	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell	2	WV	Steam - Coal	1,560	1971
Muskingum River	5	OH	Steam - Coal	1,440	1953
Sporn*	3	WV	Steam - Coal	750	1950
				8,508	

*Application on file with PUCO to retire Sporn Unit 5 at the end of 2010. (450MW)

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Public Service Company of Oklahoma					
Tulsa	3	OK	Steam - Natural Gas	330	1923
Tulsa	3	OK	Oil	8	1967
Riverside (1&2)	2	OK	Steam - Natural Gas	917	1974
Riverside (3&4)	2	OK	Steam - Natural Gas	156	2008
Riverside	1	OK	Oil	3	1976
Northeastern (1&2)	4	OK	Steam - Natural Gas	940	1961
Northeastern	1	OK	Oil	3	1961
Southwestern (1-3)	3	OK	Steam - Natural Gas	472	1952
Southwestern (4&5)	2	OK	Steam - Natural Gas	156	2008
Southwestern	1	OK	Oil	2	1962
Comanche	3	OK	Steam - Natural Gas	273	1973
Comanche	2	OK	Oil	4	1962
Weleetka	3	OK	Steam - Natural Gas	163	1975
Weleetka	2	OK	Oil	4	1963
Northeastern (3&4)	2	OK	Steam - Coal	925	1979
Northeastern	1	OK	Oil	1	1980
Oklaunion	1	TX	Steam - Coal	108	1986
				4,465	
Southwestern Electric Power Company					
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Lieberman	4	LA	Steam - Natural Gas	269	1947
Knox Lee	4	TX	Steam - Natural Gas	486	1950
Wilkes	3	TX	Steam - Natural Gas	882	1964
Lone Star	1	TX	Steam - Natural Gas	50	1954
Stall	1	LA	Natural Gas	508	2010
Mattison	4	AR	Natural Gas	312	2007
Welsh	3	TX	Steam - Coal	1,584	1977
Flint Creek	1	AR	Steam - Coal	264	1978
Pirkey	1	TX	Steam - Lignite	580	1985
Dolet Hills	1	LA	Steam - Lignite	262	1986
				5,307	
Texas North Company					
Paint Creek (Retired)	4	TX	Steam - Natural Gas	238	1953
Abilene (Retired)	1	TX	Steam - Natural Gas	18	1949
Ft. Stockton (Decommissioned)	1	TX	Steam - Natural Gas	6	1958
Vernon (Decommissioned)	4	TX	Oil	8	1963
Oklaunion	1	TX	Steam - Coal	377	1986
				647	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Contract Initiated
Domestic Independent Power Projects					
Trent Mesa	100	TX	Wind	150	2001
Desert Sky	107	TX	Wind	161	2001
				311	
Long-Term Renewable Purchase Power Agreements					
Southwest Mesa		TX	Wind	75	2005
South Trent		TX	Wind	102	2008
Weatherford		OK	Wind	147	2005
Blue Canyon II		OK	Wind	151	2005
Sleeping Bear		OK	Wind	95	2008
Camp Grove		IL	Wind	75	2008
Fowler Ridge I		IN	Wind	100	2009
Fowler Ridge III		IN	Wind	100	2009
Beech Ridge		WV	Wind	100	2009
Majestic		TX	Wind	80	2009
Elk City		OK	Wind	99	2010
Blue Canyon 5		OK	Wind	99	2009
Fowler Ridge II		IN	Wind	150	2009
Grand Ridge III		IL	Wind	100	2009
Wyandot Solar		OH	Solar	10	2010
Minco		OK	Wind	99	*
				1,582	

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1656 of 9556

Generation Statistics

Net Capacity Factors	2008	2009	YTD SEPT 10
AEP East	61.96%	50.61%	55.84%
Coal	72.11%	60.49%	62.26%
Super Critical*	75.76%	68.02%	70.14%
Sub-Critical*	60.86%	37.39%	38.21%
Gas	3.43%	3.98%	8.03%
Hydro**	5.95%	12.44%	9.96%
Nuclear	78.13%	43.38%	88.12%
AEP SPP	40.82%	38.48%	43.84%
Coal***	76.53%	74.31%	78.22%
Super Critical*	78.02%	83.01%	73.06%
Sub-Critical*	76.14%	69.44%	80.03%
Gas	19.15%	17.03%	23.89%
AEP Texas	72.67%	51.70%	66.95%
Coal****	72.67%	51.70%	66.95%
AEP System	57.11%	47.75%	53.10%

Equivalent Availability Factors	2008	2009	YTD SEPT 10
AEP East	82.11%	76.18%	76.45%
Coal	81.19%	77.65%	74.01%
Super Critical*	81.71%	79.35%	77.02%
Sub-Critical*	79.57%	72.44%	64.80%
Gas	89.35%	85.38%	82.47%
Hydro**	86.68%	84.47%	84.27%
Nuclear	77.78%	43.23%	87.92%
AEP SPP	83.99%	81.08%	82.77%
Coal***	83.24%	80.50%	84.81%
Super Critical*	82.64%	86.65%	76.12%
Sub-Critical*	83.61%	76.49%	87.79%
Gas	84.45%	81.43%	81.59%
AEP Texas	84.47%	69.47%	78.75%
Coal****	84.47%	69.47%	78.75%
AEP System	82.58%	77.26%	78.00%

Equivalent Forced Outage Rate (EFOR)	2008	2009	YTD SEPT 10
AEP East	9.78%	13.05%	10.41%
Coal	9.21%	8.05%	11.36%
Super Critical*	8.95%	6.35%	9.41%
Sub-Critical*	10.08%	14.90%	18.85%
Gas - See Below			
Hydro**	7.87%	20.83%	8.37%
Nuclear	15.34%	52.99%	2.64%
AEP SPP	7.00%	10.10%	10.07%
Coal***	6.08%	6.92%	6.87%
Super Critical*	3.83%	5.39%	9.74%
Sub-Critical*	6.73%	7.93%	5.76%
Gas	7.93%	13.17%	12.66%
AEP Texas	4.70%	4.96%	9.92%
Coal****	4.70%	4.96%	9.92%
AEP System	9.11%	12.26%	10.32%

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** CF, EAF, and EFOR do not include Dolet Hills.

**** Oklaunion reported as owned.

***** East Gas Units evaluated using Equivalent Forced Outage Factor. Since these units are run less frequently, this factor gauges their performance based on Period Hours instead of Service Hours. EFOR uses Service Hours in the denominator, and EFOF uses Period Hours in the denominator.

Equivalent Forced Outage Factor (EFOF)	2008	2009	YTD SEPT 10
AEP East Gas*****	1.24%	2.55%	2.74%

Generation & Coal Statistics

MWh Produced

Operating Company	2007	2008	2009	Three Year Average
AEP Generating	9,027,362	10,622,505	9,914,827	9,854,898
Appalachian Power	32,588,773	31,868,466	23,615,041	29,357,427
Columbus Southern Power	15,514,495	14,866,609	12,012,080	14,131,061
Indiana Michigan Power	31,604,874	29,790,250	20,478,701	27,291,275
Kentucky Power	7,533,223	6,021,182	6,262,165	6,605,523
Ohio Power	54,155,697	55,039,733	47,700,622	52,298,684
Public Service of Oklahoma	14,439,801	14,874,023	13,967,928	14,427,251
Southwestern Electric Power	19,673,059	19,714,013	18,563,548	19,316,873
Texas North Company	2,309,566	2,310,091	1,608,890	2,076,182
Texas Central Company	41,122	-	-	13,707
AEP System Total Net Generation	186,887,972	185,106,872	154,123,802	175,372,882

Note: Figures represent generation produced from AEP-owned assets only.

Coal Consumption in Tons

Operating Company	2007	2008	2009	Three Year Average
AEP Generating	4,545,828	5,463,904	5,061,232	5,023,655
Appalachian Power	12,828,218	13,030,442	9,392,378	11,750,346
Columbus Southern Power	6,327,803	6,318,996	5,046,741	5,897,847
Indiana Michigan Power	7,406,506	7,709,863	6,395,162	7,170,510
Kentucky Power	2,950,296	2,349,586	2,512,559	2,604,147
Ohio Power	21,234,430	22,436,865	19,420,513	21,030,603
Public Service of Oklahoma	4,102,943	4,135,223	4,293,510	4,177,225
Southwestern Electric Power	12,393,538	12,413,907	11,583,949	12,130,465
Texas North Company	1,416,422	1,444,187	984,453	1,281,687
AEP System Total Net Generation	73,205,984	75,302,973	64,690,497	71,066,485

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $15,290,363, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	75% of profits are shared with ratepayers.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

New Generation Project – Turk Plant

- **John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.**
- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Environmental

Recent and Major Upcoming EPA Actions

- **Transport Rule – Proposed July 2010**
  - Governs power plant emissions of SO_2 and NOx that affect downwind fine particle and ozone concentrations
  - 2012 program start date with stringent second phase beginning in 2014
  - Limited interstate trading and no use of previously banked SO_2 allowances from CAIR program
  - 2014 SO_2 limits in AEP-East states will require almost all coal units to be scrubbed or retired/use gas
  - AEP believes an extension of the compliance deadlines is essential to allow states to develop implementation plans and give companies time to install the retrofits needed to comply

- **"Coal Ash" Rule – Proposed May 2010**
  - EPA proposed two different regulatory designations:
    - Solid waste – action required by ~2017
    - "Special" hazardous waste - action required by ~2018-2020
  - AEP supports regulation of coal ash under the Subtitle 'D Prime' option of the RCRA
  - Cost to AEP customers estimated at $3.9 billion by 2020 to comply with Subtitle D option

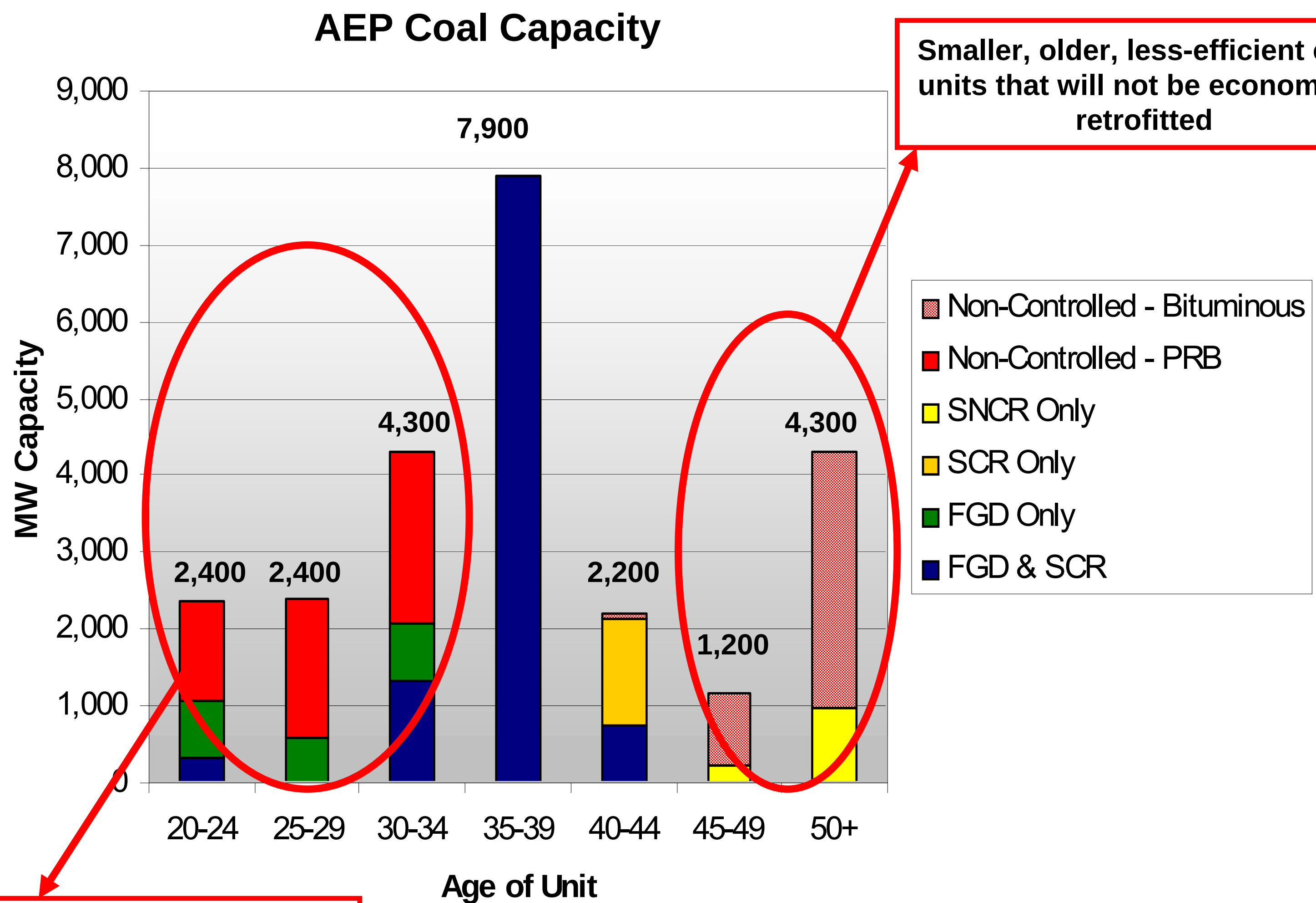
- **Mercury and other Hazardous Air Pollutants (HAPs) Rule**
  - Expect proposed rule in spring 2011, finalized in late 2011; likely compliance year - 2015
  - Could require major pollution control retrofits at most U.S. coal plants (FGD, baghouses, etc.)

Cumulative effects of EPA proposed rules and carbon legislation/regulation are a major concern for utility resource planning

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Plant Retirements are Inevitable



Smaller, older, less-efficient coal units that will not be economic if retrofitted

Newer and larger coal units that do not have SCRs and/or FGDs will be evaluated due to emerging and existing environmental requirements

Emission Limits

In compliance with our 2007 NSR settlement,
the following limits are applicable to
AEP's eastern generation fleet:

Eastern System-Wide Annual Tonnage Limitations for NO_x

Calendar Year	Limitation
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016 and each year thereafter	72,000 tons

Eastern System-Wide Annual Tonnage Limitations for SO_2

Calendar Year	Limitation
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019 and each year thereafter	174,000 tons

Emissions caps do not include any of the gas-fired units, or any new units AEP might build or purchase in the east.

Future Potential Green House Gas Regulations

AEP Supports Reasonable Climate Legislation

Key Design Elements:

- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program –** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program –** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues –** Full, free allocation to electric sector and "Low" auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process

Carbon Capture and Storage project Mountaineer Plant - New Haven, WV

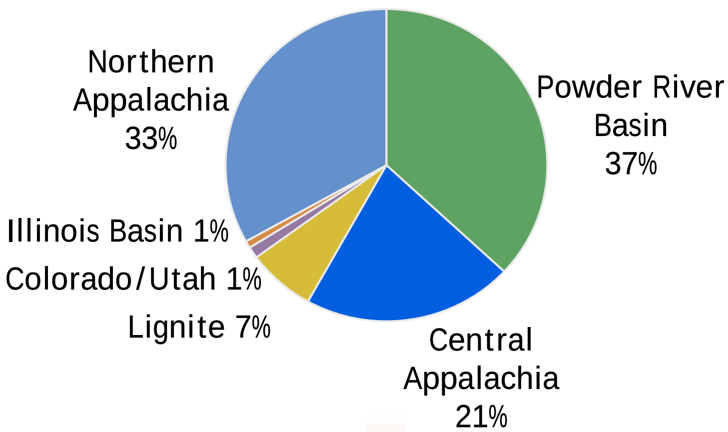
Coal

Coal

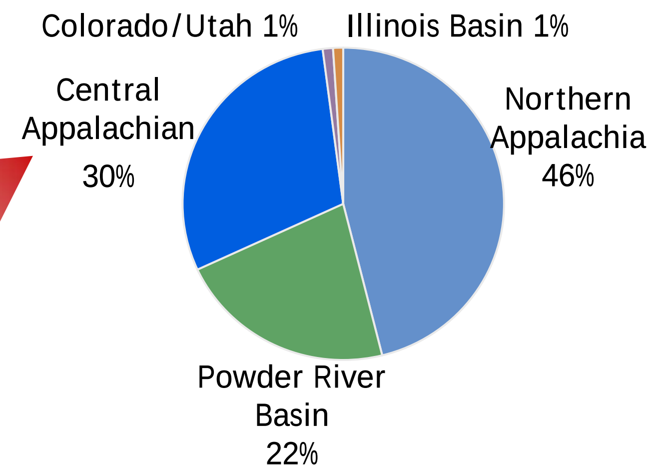
- Coal Procurement, Delivery & Transportation
- Fuel Recovery
- Coal Market Information

Coal Procurement – 2011 Projected

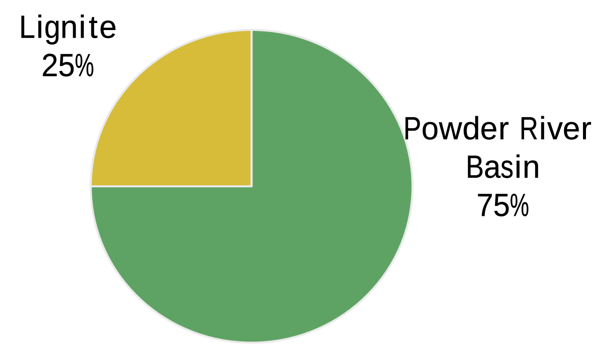
Total AEP System



AEP East



AEP West



Coal Stats:

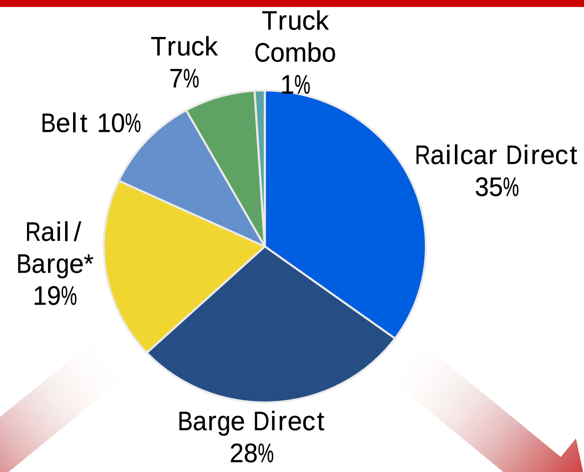
- 91% contracted for 2011 and 79% contracted for 2012*
- Avg. system delivered price ~ $46/ton in 2010*
  - East ~ $52/ton, West ~ $29/ton
- System price decrease of approximately 2% in 2011 ~ 45$/ton*
  - East ~ $51/ton, West ~ $29/ton

(*based on committed position information as of 10/1/10)

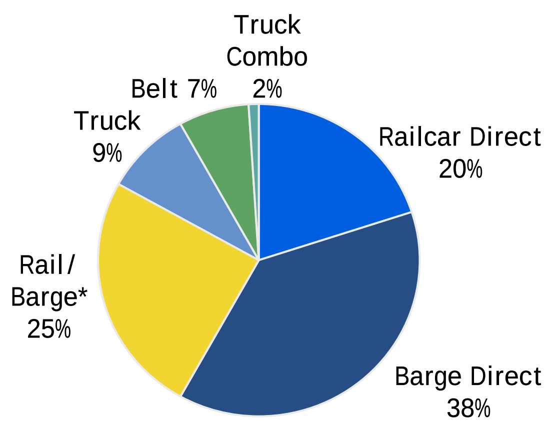
Coal Delivery

2009 Actual

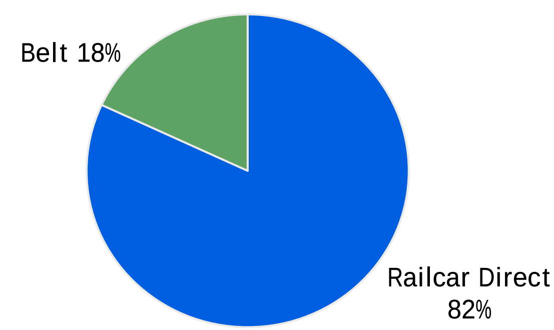
Total AEP System



AEP East



AEP West

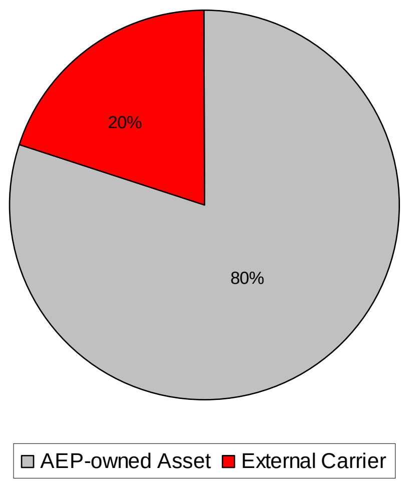


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2009 Actual

Coal Transportation to AEP Plants*



***Represents close approximations**

Current Coal & Transportation Assets:

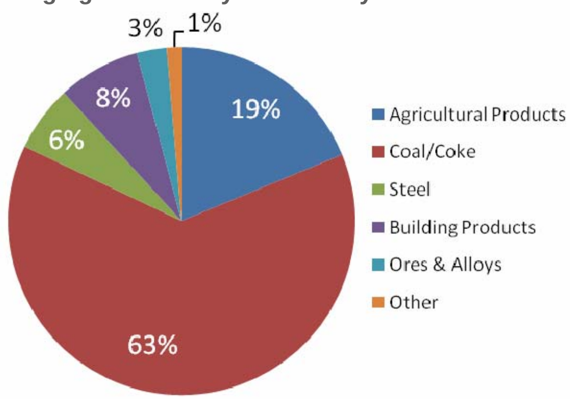
- Control over 9,000 railcars
- Own/lease and operate 3,212 barges, 62 towboats & 27 harbor boats
- Coal handling terminal with 18 million tons of capacity

AEP's transportation assets provide flexibility in a constrained delivery environment.

AEP River Operations

- Full-service Inland Waterways carrier
  - 3,212 hopper barges
  - 62 towboats and 27 tugs
- Tonnage & Commodity (2009):
  - Captive: (for AEP)-36MM tons of coal/ consumables
  - Commercial: 33MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Paducah, KY, Convent and Belle Chase, LA

Barging Volumes by Commodity

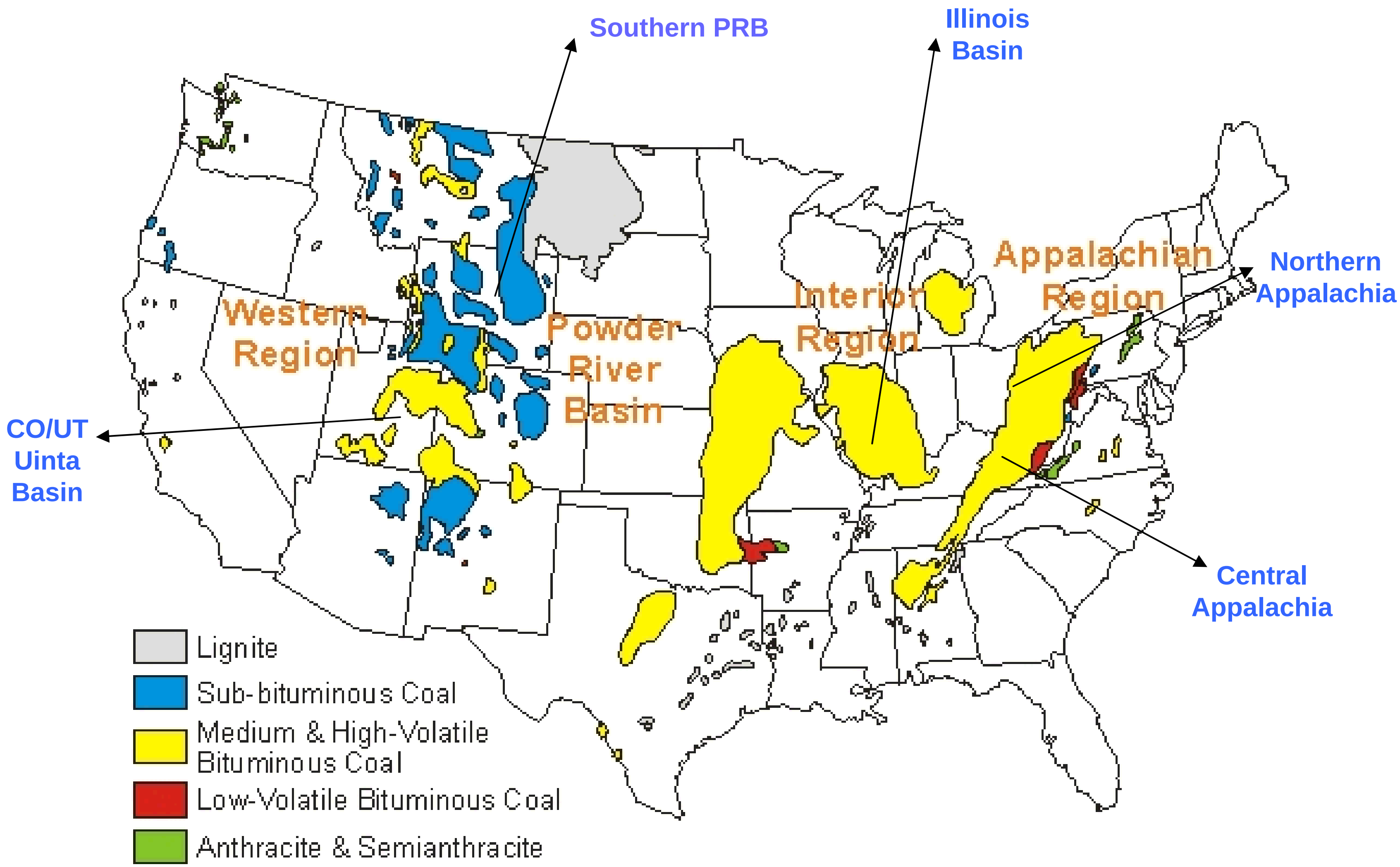


Inland Waterway Routes For AEP River Operations

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Yes	Quarterly
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Tri-Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Coal Producing Regions



Transmission Initiatives

Transmission Initiatives

JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14

- *75 - 110 miles of 345 kV**
- *Partners: Westar (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $162 - $225 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 345 kV**
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $337 million*
- *ROE: 12.8%*

* May revert to 765 kV depending on 2010 SPP ITP results

ERCOT

ETT — COD: 2010-2014

- *345 kV and below CREZ & ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Total Estimated Cost: $1.1 billion*
- *ROE: 9.96%*

PJM

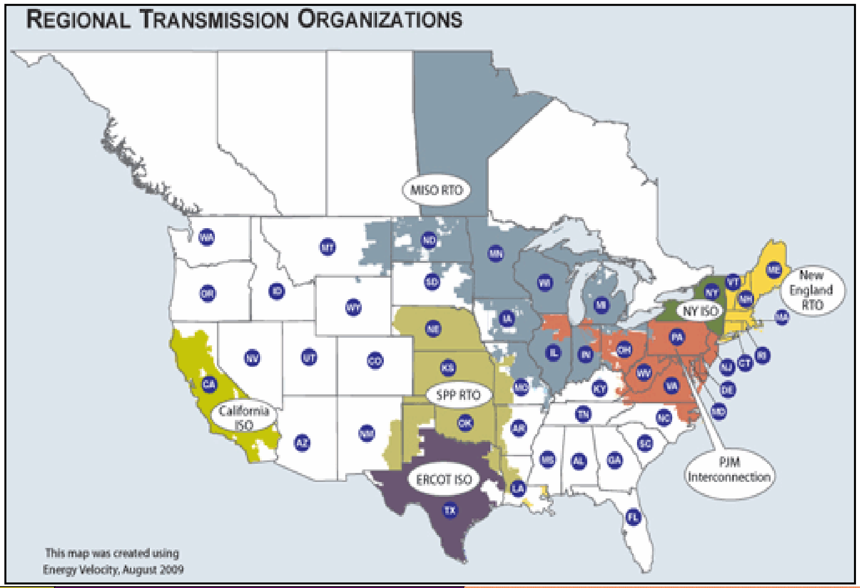
PATH-WV — COD: 2015

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: ~2015-2017

- *Up to 240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: up to $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Sponsors: ATC, ETA, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

PJM/MISO

SPP EHV Overlay

- *Regional Expansion of EHV Backbone*

SPP

ETT — COD: various

- *Other Projects*
  - *Total estimated cost: $1.6 billion (COD 2010-2020)*

ERCOT

PJM Expansion

- *Regional Expansion of EHV systems*

PJM

AEP Transmission Company (Transco)

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - Ohio application for public utility status pending; approval expected in 2010
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

765-kV Tower

Electric Transmission Texas, LLC

Overview:

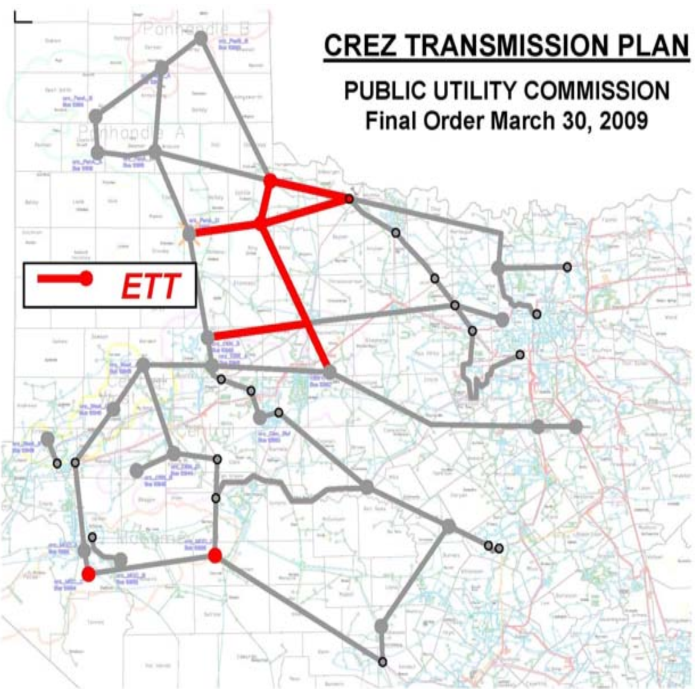
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that constructs and operates transmission projects within ERCOT. Total investment opportunity of more than $3 billion.
- Current rate base of $386 million
- Debt to equity ratio of 60/40
- Authorized ROE of 9.96%.

Opportunities:

- Future CREZ projects: approx. $1.1 billion
- Other future projects: approx. $1.6 billion

Next Steps:

- Perform engineering, procurement and construction work on assigned projects
- Development of other non-CREZ projects
- Continue to operate portfolio of in-service assets



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

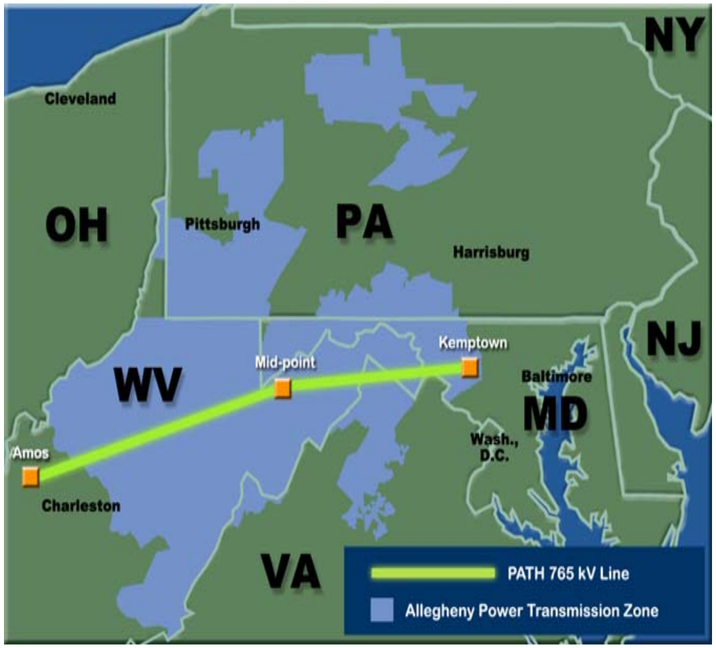
ETT Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $2.1 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.4 billion. AEP share is approximately $700 million.
- Estimated completion date: 2015.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

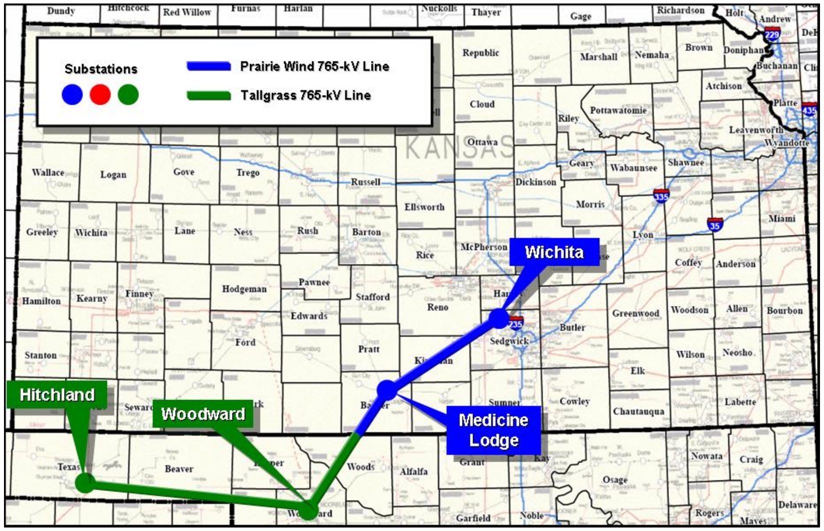
- Obtaining a CPCN in West Virginia,Virginia and Maryland.

PATH
Potomac-Appalachian Transmission Highline

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build up to 110 miles of EHV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost up to $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice to Construct received July 2010.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be up to $225 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

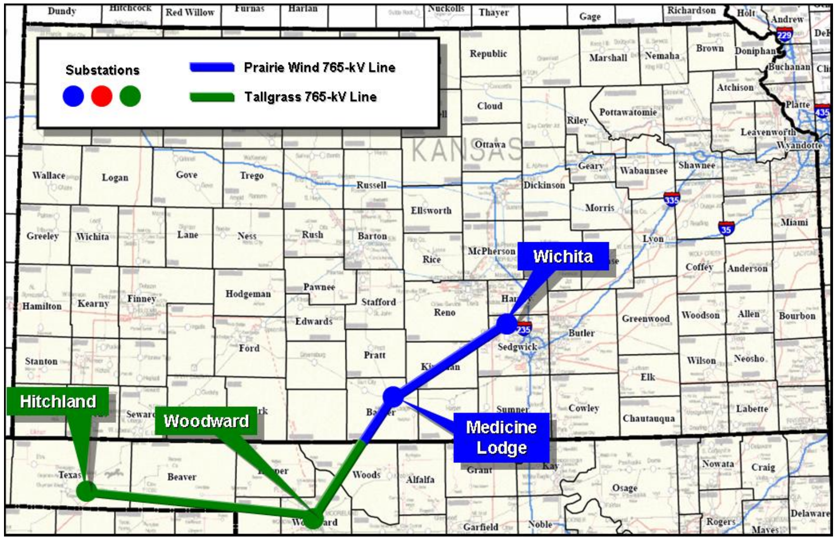
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of EHV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- The project is expected to cost up to $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect
    - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
    - Notice to Construct received July 2010.
    - Currently approved at 345 kV. Cost at 345 kV estimated to be $337 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

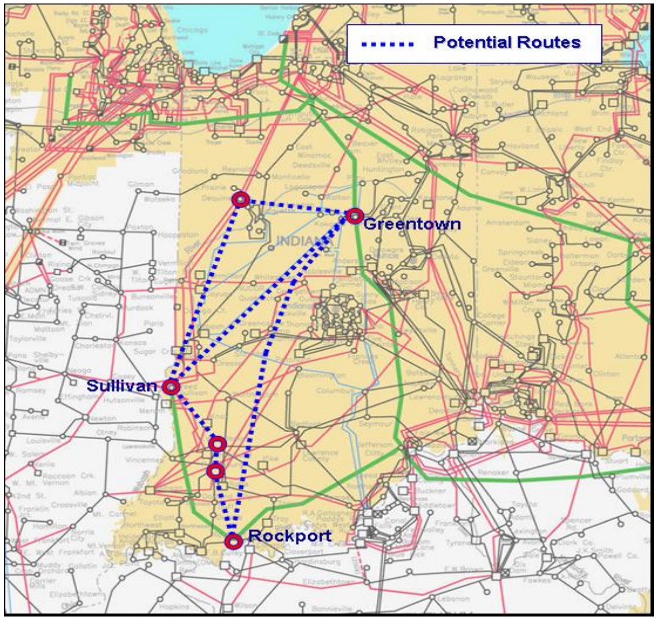
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build up to 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service between 2015-2017.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

SMARTransmission Initiative

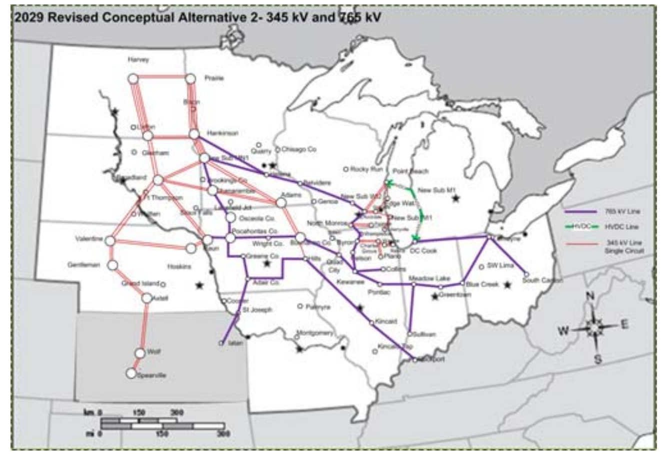
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

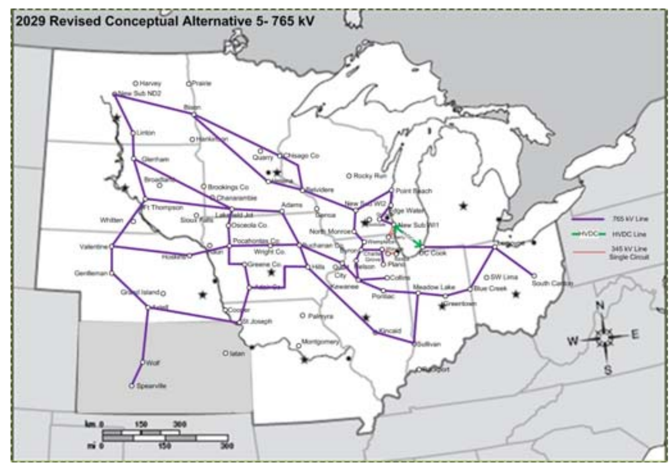
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 (technical) completed April 2010
- Phase 2 (economic) completed October 2010
- Studied two alternatives in Phase 2; one combination 345 kV & 765 kV and one primarily 765 kV

Next Steps:

- Investment structure
- Resolution of cost allocation issues between states, PJM, and MISO
- RTO technical approvals
- Favorable FERC formula rate including incentives





The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

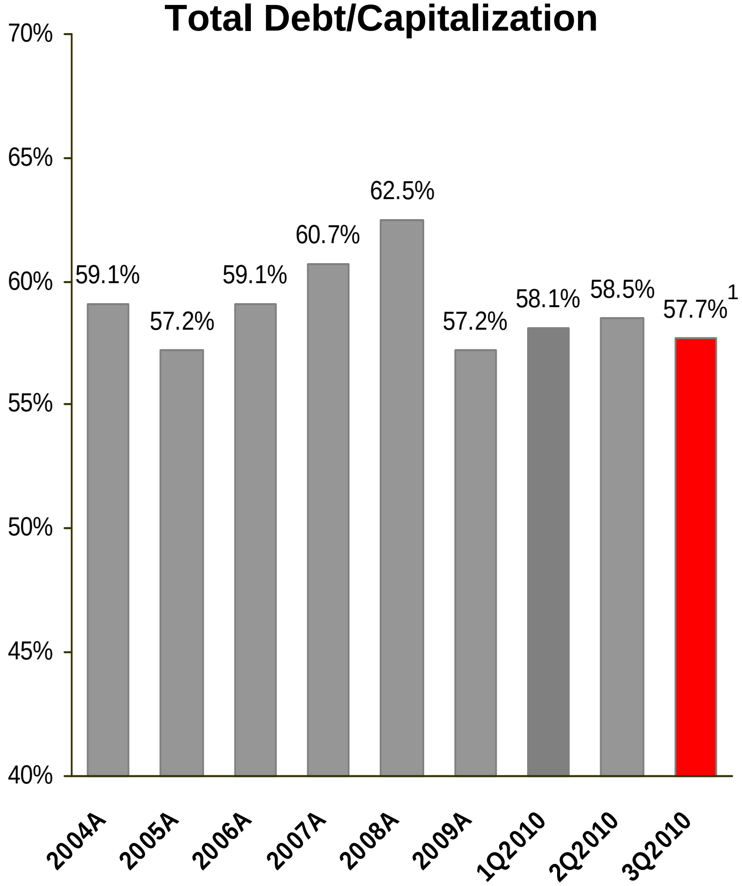
Financial Update

Financial Update

- Capitalization and Liquidity Position
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

AEP Credit Ratings

Ratings current as of September 30, 2010

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	-
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,636

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of September 30, 2010

Debt Schedules

American Electric Power, Inc	Interest	Maturity	Amount
Junior Subordinated Debentures	8.750%	03/01/2063	$315,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	7.23%		$557,775,000

AEP Generating	Interest	Maturity	Amount
Notes Payable	Floating	11/23/2011	$85,000,000
Pollution Control Bond	4.150%	07/01/2025[1]	$22,500,000
Pollution Control Bond	4.150%	07/01/2025[1]	$22,500,000
Senior Notes	6.330%	09/30/2037	$196,363,710
Weighted Average or Total	5.924%		$326,363,710

[1] Put date 7/15/2011

AEP Texas North	Interest	Maturity	Amount
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Senior Notes	5.500%	03/01/2013	$225,000,000
Senior Notes	5.890%	04/01/2018	$30,000,000
Senior Notes	6.760%	04/01/2038	$70,000,000
Weighted Average or Total	5.645%		$369,310,000

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
Pollution Control Bond	5.625%	10/01/2017	$40,890,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Pollution Control Bond	6.300%	11/01/2029	$100,635,000
Pollution Control Bond	5.200%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	5.125%	06/01/2030[2]	$120,265,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.711%		$764,820,000
Securitization Bond	5.960%	07/15/2013	$190,631,083
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	6.105%		$382,487,941
Securitization Bond	4.980%	07/01/2013	$283,000,263
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.166%		$1,464,700,263

[2] Put date 06/01/2011

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

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Debt Schedules

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	4.850%	05/01/2019[3]	$30,000,000
Pollution Control Bond	4.850%	05/01/2019[3]	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	02/01/2036	$75,000,000
Pollution Control Bond	5.375%	12/01/2038	$50,000,000
Pollution Control Bond	Floating	12/01/2042	$54,375,000
Pollution Control Bond	Floating	12/01/2042	$50,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	5.650%	08/15/2012	$250,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	3.400%	05/24/2015	$300,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	7.950%	01/15/2020	$350,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Senior Notes	6.700%	08/15/2037	$250,000,000
Senior Notes	7.000%	04/01/2038	$500,000,000
Weighted Average or Total	5.93%		$3,549,150,000

[3] Put date 09/04/2013

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	3.875%	12/01/2038[4]	$60,000,000
Pollution Control Bond	5.800%	12/01/2038	$32,245,000
Pollution Control Bond	4.850%	08/01/2040[5]	$44,500,000
Pollution Control Bond	5.100%	11/01/2042[6]	$56,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	Floating	03/16/2012	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.050%	05/01/2018	$350,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.674%		$1,592,745,000

[4] Put date 06/01/2014
[5] Put date 04/01/2012
[6] Put date 05/01/2013

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	5.250%	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	6.250%	06/01/2025[7]	$50,000,000
Pollution Control Bond	6.250%	06/01/2025[7]	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	7.000%	03/15/2019	$475,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	6.154%		$1,692,000,000

[7] Put date is 06/2/2014

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	6.000%	09/15/2017	$325,000,000
Senior Notes	7.250%	06/18/2021	$40,000,000
Senior Notes	8.030%	06/18/2029	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Senior Notes	8.130%	06/18/2039	$60,000,000
Weighted Average or Total	6.397%		$530,000,000

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	2.875%	12/01/2027[8]	$39,130,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Pollution Control Bond	3.250%	06/01/2041[9]	$79,450,000
Pollution Control Bond	3.125%	06/01/2043[10]	$86,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	5.750%	09/01/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	5.375%	10/01/2021	$500,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	5.468%		$2,734,580,000

[8] Put date 08/01/2014

[9] Put date 06/02/2014

[10] Put date 04/01/2015

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	5.250%	06/01/2014	$33,700,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	5.150%	12/01/2019	$250,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.625%	11/15/2037	$250,000,000
Weighted Average or Total	5.819%		$971,360,000

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	7.030%	02/22/2012	$20,000,000
Notes Payable	6.370%	10/31/2024	$25,000,000
Pollution Control Bond	4.500%	07/01/2011	$41,135,000
Pollution Control Bond	4.950%	03/01/2018	$81,700,000
Pollution Control Bond	3.250%	01/01/2019[11]	$53,500,000
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Senior Notes	5.875%	03/01/2018	$300,000,000
Senior Notes	6.450%	01/15/2019	$400,000,000
Senior Notes	6.200%	03/15/2040	$350,000,000
Weighted Average or Total	5.779%		$1,771,335,000

[11] Put date 01/02/2015

Note: Debt schedules current as of 9/30/10. The weighted average coupon excludes all floating rate debt.

AEP AMERICAN® ELECTRIC POWER

2011 Fact Book
46th EEI Financial Conference
Orlando, FL

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Company Overview

Company Overview

OUR FOCUS IS OUR CORE UTILITY BUSINESS OPERATIONS

Provide generation, transmission and distribution services to approximately 5.3 million customers in eleven states

Our electric assets include:

- Approximately 40,000 megawatts of generating capacity in 3 RTOs (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Approximately 220,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 9,000 railcars
- own and/or operate approximately 3,300 hopper barges, 62 towboats and 29 harbor boats
- operate one active coal-handling terminal with 18 millions tons of capacity

AEP consumes approximately 65-70 million tons of coal annually.

AEP Service Territory

AEP EAST OPERATING COMPANIES

EAST REGULATED UTILITIES

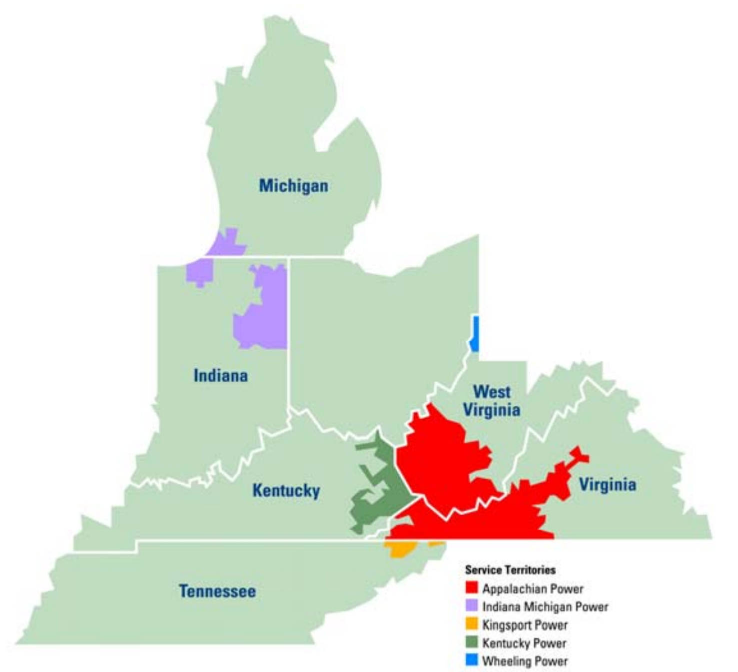
Appalachian Power Company (APCo)

Indiana Michigan Power Company (I&M)

Kingsport Power Company (KGPCo)

Kentucky Power Company (KPCo)

Wheeling Power Company (WPCo)

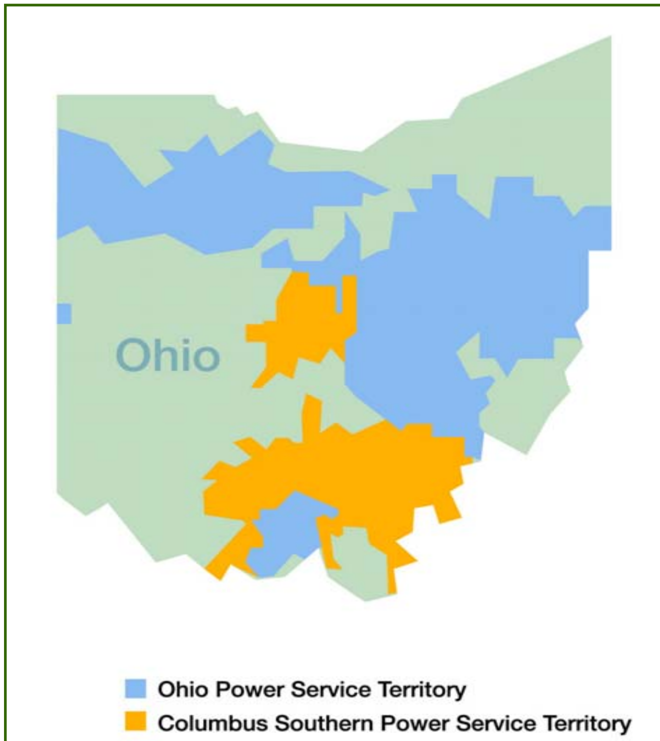


AEP OHIO

Columbus Southern Power Company (CSPCo)*

Ohio Power Company (OPCo)*

* - Stipulation on file with the PUCO, if approved, will result in the merger of these two companies by the end of 2011



AEP Service Territory

AEP WEST OPERATING COMPANIES

WEST REGULATED UTILITIES

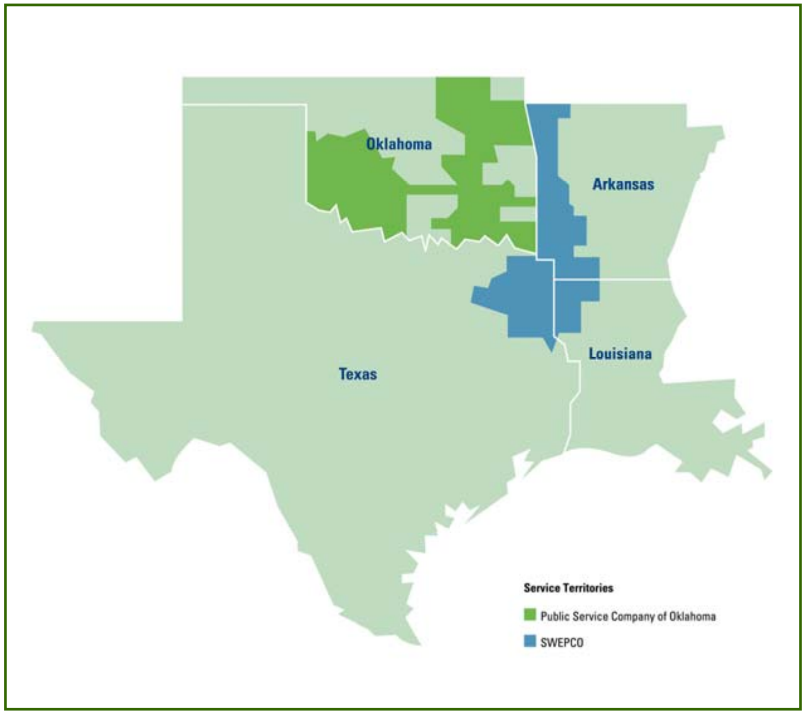
Public Service Company of Oklahoma (PSO)

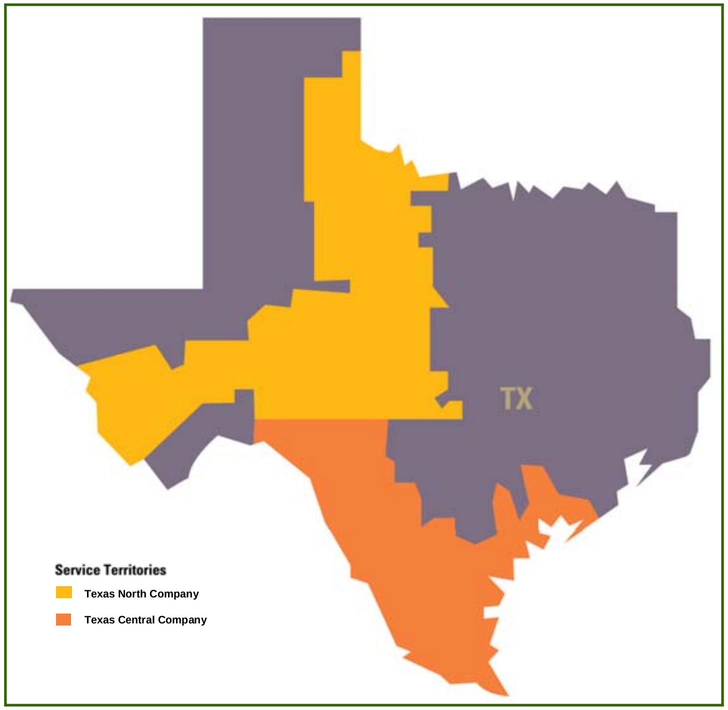
Southwestern Electric Power Company (SWEPCO)

AEP TEXAS

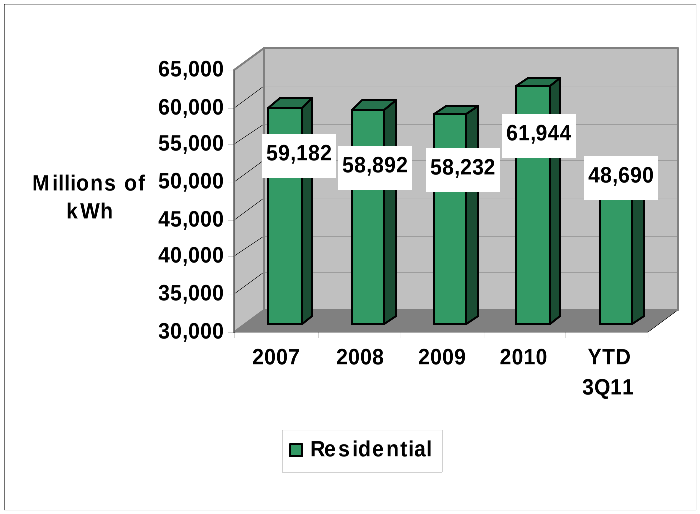
Texas Central Company (TCC)

Texas North Company (TNC)

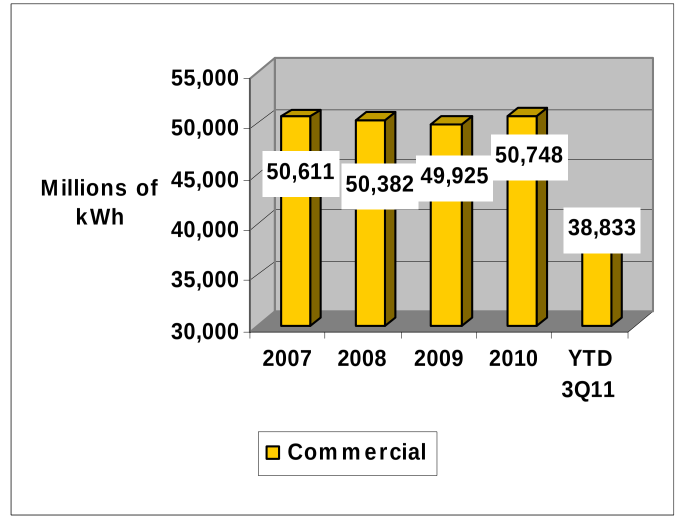




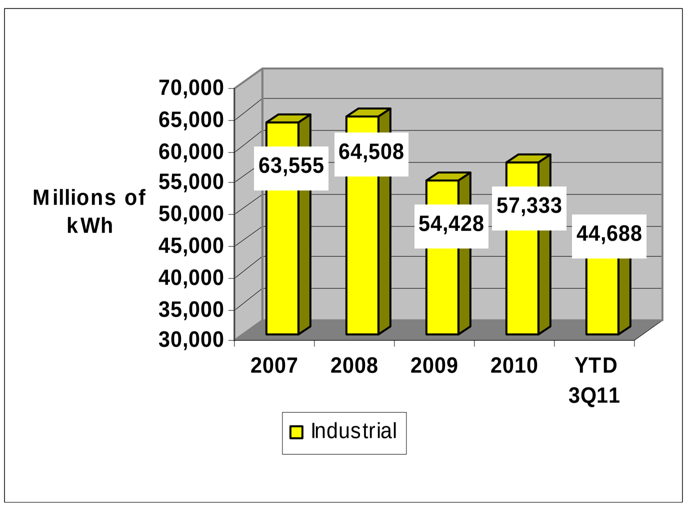
Utility Operations - Load



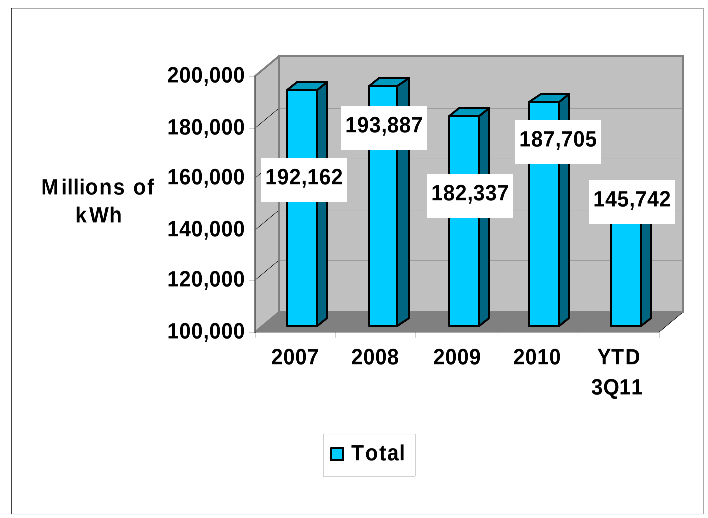
3 Yr. Compound Annual Residential Load Growth at 1.53%



3 Yr. Compound Annual Commercial Load Growth at 0.09%



3 Yr. Compound Annual Industrial Load Contraction at 3.38%



3 Yr. Compound Annual Load Contraction at 0.78%

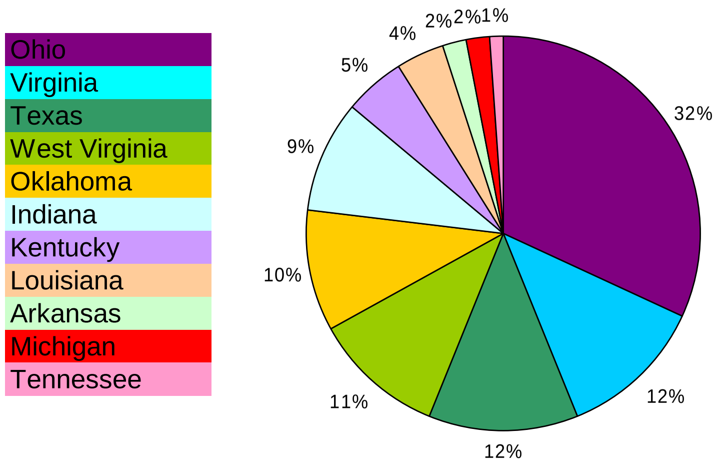
2010 Retail Revenue

CUSTOMER PROFILE

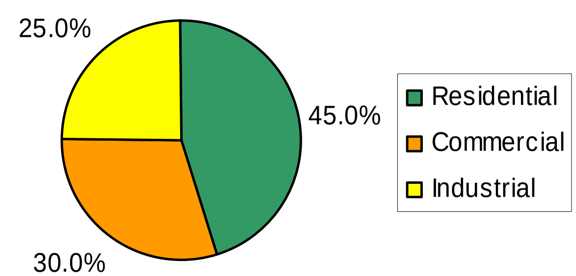
AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5.3 MILLION CUSTOMERS IN 11 STATES

Percentage of AEP System Retail Revenues



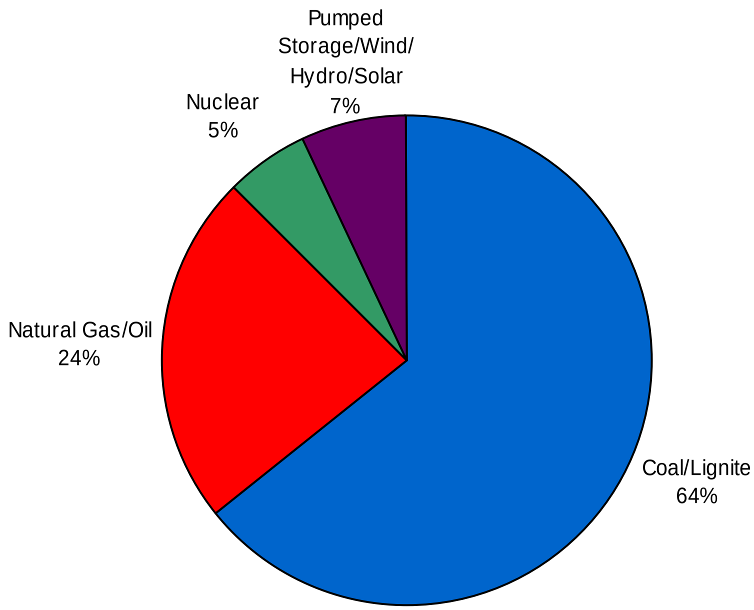
Retail Revenue Composition by Customer Class*

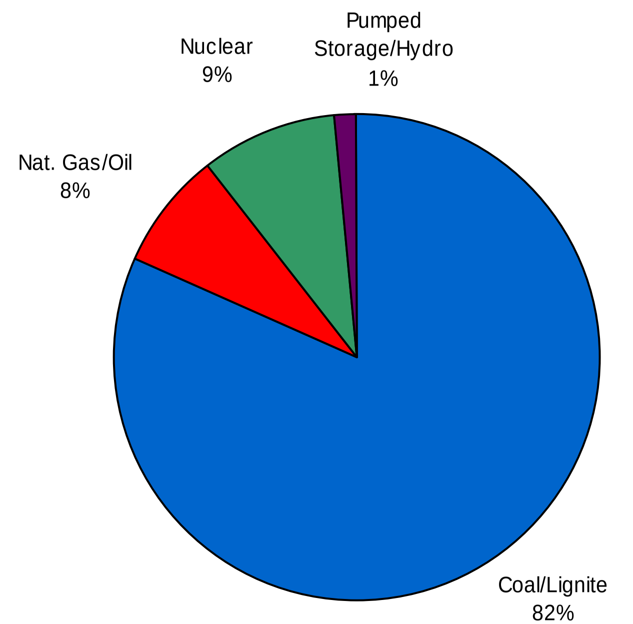


Top 10 Customers Across the AEP System By NAICS Code	
331	Primary Metal Manufacturing
325	Chemical Manufacturing
324	Petroleum and Coal Products Manufacturing
212	Mining (except Oil and Gas)
322	Paper Manufacturing
326	Plastics and Rubber Products Manufacturing
311	Food Manufacturing
336	Transportation Equipment Manufacturing
211	Oil and Gas Extraction
486	Pipeline Transportation

Source: Form 10-K.
*Note: Figures do not include Other Retail Sales

Domestic Generation Fleet





2011 Generation Capacity by Fuel Type Based on 40,167 MW

2010 Generation Production by Fuel Type Based on 173,228,109 MWh

NERC Regional Presence

RFC	71%
SPP	26%
ERCOT	3%

Transmission Line Circuit Miles Detail

Operating Company Level (Circuit Miles)

Operating Company	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
APCo	734	97	383	106	0	3,352	0	23	1,104	789	0	230	0	6,818
CSPCo	0	0	890	0	0	907	0	0	467	0	59	0	113	2,436
I&M	615	0	1,614	0	0	1,673	0	0	711	0	0	739	0	5,352
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	30
KPCo	258	0	8	0	46	335	0	0	545	55	0	3	0	1,250
OPCo	509	0	909	0	0	2,444	0	0	2,183	0	0	365	112	6,522
PSO	0	0	579	34	8	2,176	10	0	812	0	0	0	0	3,619
SWEPCO	0	0	672	0	233	1,342	56	0	1,502	0	0	0	0	3,805
TCC	0	0	626	0	0	2,332	0	0	1,671	0	0	0	0	4,629
TNC	0	0	223	0	0	1,498	0	0	2,599	0	0	0	0	4,320
WPCo	0	16	9	0	0	175	0	0	90	0	0	0	0	290
Total	**2,116**	**113**	**5,913**	**140**	**287**	**16,234**	**66**	**23**	**11,687**	**844**	**59**	**1,364**	**225**	**39,071**

State Level (Circuit Miles)

State	765kV	500kV	345kV	230kV	161kV	138kV	115kV	88kV	69kV	46kV	40kV	34.5kV	23kV	Total
Indiana	599	0	1,380	0	0	1,431	0	0	415	0	0	591	0	4,416
Michigan	16	0	234	0	0	242	0	0	296	0	0	148	0	936
Kentucky	258	0	8	0	46	335	0	0	545	55	0	3	0	1,250
Louisiana	0	0	105	0	0	260	0	0	230	0	0	0	0	595
Arkansas	0	0	40	0	233	190	42	0	461	0	0	0	0	966
Ohio	509	0	1,799	0	0	3,351	0	0	2,650	0	59	365	225	8,958
Oklahoma	0	0	625	34	8	2,202	10	0	812	0	0	0	0	3,691
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	275
Texas	0	0	1,330	0	0	4,696	14	0	5,081	0	0	0	0	11,121
W. Virginia	385	17	323	0	0	1,638	0	23	463	741	0	89	0	3,679
Virginia	349	96	69	15	0	1,735	0	0	731	48	0	141	0	3,184
Total	**2,116**	**113**	**5,913**	**140**	**287**	**16,234**	**66**	**23**	**11,687**	**844**	**59**	**1,364**	**225**	**39,071**

Note: Transmission line circuit miles are current as of 12/31/10

Distribution Line Detail

By State	Line Miles*	Operating Company	Line Miles*
Tennessee	1,544	KGPCo	1,544
Virginia	30,554	KPCo	9,973
W. Virginia	21,578	APCo	50,632
Kentucky	9,973	OPCo	26,478
Ohio	45,445	CSP	18,967
Michigan	5,299	I&M	20,236
Indiana	14,936	WPCo	1,499
Texas	52,159	TCC	29,689
Oklahoma	21,961	TNC	13,830
Arkansas	4,483	PSO	21,961
Louisiana**	7,623	SWEPCO **	20,746
Total	**215,555**	**Total**	**215,555**

* Includes approximately 30,800 miles of underground circuit miles
**SWEPCO (LA) mileage does not include the VEMCO (LA) service area of approximately 6,900 miles

Year End 2010 data per Small World Graphics.

Operating Company Overview

- AEP East Regional Utilities
- AEP West Regional Utilities

AEP East Regional Utilities

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Appalachian Power

President and Chief Operating Officer:
Charles Patton

Since July 2010
Previously EVP – AEP Utilities West and
President & COO – AEP Texas

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 957,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, APCo and its wholly owned subsidiaries had 2,186 employees. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal Mining
Primary Metals
Chemical Manufacturing
Paper Products
Pipeline Transportation

Total Customers at 12/31/10:

Residential	**814,000**
Commercial	**132,000**
Industrial	**4,000**
Other	**7,000**
Total	**957,000**

Generating Capacity **6,286 MW**

Generating Capacity by Fuel Mix:
- **Coal:** **81.0%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas:** **8.2%**

Transmission Miles	**6,818**
Distribution Miles	**50,632**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	3,706,852	2,789,329	6,496,181	3,689,472	2,839,426	6,528,898	3,726,069	2,967,829	6,693,898
% of Capitalization Per Balance Sheet	57.1%	42.9%	100.0%	56.5%	43.5%	100.0%	55.7%	44.3%	100.0%
FFO Interest Coverage			3.02			3.69			4.22*
FFO Total Debt			11.4%			15.4%			18.4%

* - calculated on rolling 12-month avg.

2010 Financial Data * (in thousands)

Total Revenue	$	3,275,000
% of AEP Retail		22%
Net Income	$	137,000
Capital Expenditures	$	534,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	10,185,661
Net Plant Assets	$	7,799,604
Cash	$	2,669

Operating Information***

2010 retail electric sales in megawatt-hours	31,978,163
2010 firm wholesale sales in megawatt-hours	3,544,173
2010 average cost per kilowatt-hour (residential)	9.31 cents
2010 System Peak – December 14	7,623 MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

Appalachian Power

APPALACHIAN AREA

INVESTOR OWNED UTILITIES *

West Virginia	Customers
APCo	**439,916**
Monongahela Power	383,621
Potomac Edison	131,495
AEP – Wheeling	**41,225**

Virginia	Customers
APCo	**519,898**
Dominion Virginia	2,285,525
Old Dominion Power	29,739
Potomac Edison	102,258

Tennessee	Customers
AEP - Kingsport	**47,028**

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

Top 10 Customers = 42% of industrial sales

Metropolitan areas account for 37% of ultimate sales

112 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

TYPICAL BILL COMPARISON **

West Virginia	$/month
APCo	**86.39**
AEP – Wheeling	**86.39**
Monongahela Power	95.88
Potomac Edison	95.88

Virginia	$/month
Old Dominion Power	76.67
APCo	**94.66**
Dominion Virginia	100.96

Tennessee	$/Month
AEP – Kingsport	**81.15**

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011.

MAJOR CUSTOMERS:
CNX Gas Company (VA)
Greif Brothers Corporation (VA)
Steel of WV, Inc. (WV)
WVA Manufacturing (WV)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Bayer Crop Science, LP (WV)
Felman Production (WV)
Alcan Rolled Products (WV)
The Goodyear Tire and Rubber Co. (VA)

(Data for year ended December 2010)

AEP Ohio - Columbus Southern Power

President and Chief Operating Officer:
Joe Hamrock

Since January 2008
Previously SVP and CIO AEP Shared Services

AEP Ohio-Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2010, CSPCo had 1,082 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for CSPCo to merge into OPCo, effective in October 2011. FERC approved the merger on July 1, 2011 and a decision is pending from the PUCO. There is a stipulation on file with the PUCO in the current ESP proceeding which would approve the merger of the two companies and facilitate corporate separation of generation from transmission and distribution in order to transition generation to market in 2015. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: Duke Energy Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary Metals
Chemical Manufacturing
Food Products
Rubber & Plastic Products
Fabricated Metals

Total Customers at 12/31/10:

Residential	**667,000**
Commercial	**78,000**
Industrial	**3,500**
Other	**500**
Total	**749,000**

Generating Capacity		**3,738 MW**
Generating Capacity by Fuel Mix:		
• **Coal**	**63.9%**	
• **Natural Gas**	**36.1%**	
Transmission Miles		**2,436**
Distribution Miles		**18,967**

AEP Ohio - Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,560,595	1,359,835	2,920,430	1,438,830	1,486,215	2,925,045	1,439,039	1,514,656	2,953,695
% of Capitalization Per Balance Sheet	53.4%	46.6%	100.0%	49.2%	50.8%	100.0%	48.7%	51.3%	100.0%
FFO Interest Coverage			5.31			6.01			7.04*
FFO Total Debt			25.9%			30.8%			35.1%

* - calculated on rolling 12-month avg.

2010 Financial Data * (in thousands)

Total Revenue	$	2,149,000
% of AEP Retail		16%
Net Income	$	230,000
Capital Expenditures	$	236,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	4,416,612
Net Plant Assets	$	3,595,523
Cash	$	1,851

Operating Information***

2010 retail sales in megawatt-hours	21,235,052
2010 average cost per kilowatt-hour (residential)	11.32 cents
2010 System Peak – July 23	4,364 MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

AEP Ohio - Columbus Southern Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	**1,458,891**
First Energy ***	1,735,759
Duke Energy Ohio	652,840
DP&L	514,167

** AEP Ohio - CSPCo = 748,730
OPCo = 710,161

*** First Energy -Toledo Edison = 256,874
CEI = 594,286
Ohio Edison = 884,599

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

MAJOR CUSTOMERS:

Ormet Aluminum
Eramet Marietta, Inc.
E I duPont de Nemours HQ
Kraton Polymers
General Mills
Metal Container Corporation
Glatfelter Company
Anheuser-Busch, Inc.
Griffin Wheel Company, Inc.
Ross Products

(Data for year ended December 2010)

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	**100.96**
FE (Toledo Edison)	111.15
FE (Ohio Edison)	113.19
AEP (CSP)	**115.74**
FE (CEI)	117.34
DP&L	123.43
Duke Energy Ohio	126.59

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011. Ohio rates represent POLR bundled residential rates.

Top 10 customers = 58% of industrial sales

Metropolitan areas account for 86% of ultimate sales

254 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

AEP Ohio - Ohio Power

President and Chief Operating Officer:
Joe Hamrock

Since January 2008
Previously SVP and CIO AEP Shared Services

AEP Ohio- Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 706,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, OPCo had 2,100 employees. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for CSPCo to merge into OPCo, effective in October 2011. FERC approved the merger on July 1, 2011 and a decision is pending from the PUCO. There is a stipulation on file with the PUCO in the current ESP proceeding which would approve the merger of the two companies and facilitate corporate separation of generation from transmission and distribution in order to transition generation to market in 2015. In addition to its AEP System interconnections, OPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Petroleum Refining
Rubber & Plastic Products
Chemical Manufacturing
Nonmetallic Mineral Products

Total Customers at 12/31/10:

Residential	**604,000**
Commercial	**93,000**
Industrial	**7,000**
Other	**2,000**
Total	**706,000**

Generating Capacity	**8,498 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.7%**
- **Hydro:** **0.3%**

Transmission Miles	**6,522**
Distribution Miles	**26,478**

AEP Ohio - Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2009			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	3,242,505	3,251,322	6,493,827	2,729,522	3,185,040	5,914,562	2,614,910	3,112,577	5,727,487
% of Capitalization Per Balance Sheet	49.9%	50.1%	100.0%	46.1%	53.9%	100.0%	45.7%	54.3%	100.0%
FFO Interest Coverage			5.34			5.29			6.14*
FFO Total Debt			22.1%			24.3%			28.4%

* - calculated on 12-month rolling avg.

2010 Financial Data * (in thousands)

Total Revenue	$	3,224,000
% of AEP Retail		16%
Net Income	$	311,000
Capital Expenditures	$	277,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	8,421,645
Net Plant Assets	$	6,477,955
Cash	$	1,409

Operating Information

2010 retail sales in megawatt-hours	26,199,753
2010 firm wholesale sales in megawatt-hours	2,356,358
2010 average cost per kilowatt-hour (residential)	9.70 cents
2010 System Peak – July 23	5,235 MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

AEP Ohio - Ohio Power

OHIO INVESTOR OWNED UTILITIES *

Ohio	Customers
AEP Ohio **	**1,458,891**
First Energy ***	1,735,759
Duke Energy Ohio	652,840
DP&L	514,167

** AEP Ohio - CSPCo = 748,730
OPCo = 710,161

*** First Energy -Toledo Edison = 256,874
CEI = 594,286
Ohio Edison = 884,599

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	$/month
AEP (OPCo)	**100.96**
FE (Toledo Edison)	111.15
FE (Ohio Edison)	113.19
AEP (CSP)	**115.74**
FE (CEI)	117.34
DP&L	123.43
Duke Energy Ohio	126.59

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Ormet Primary Aluminum Corp.
The Premcor Refining Group, Inc.
The Timken Company
Republic Engineered Products, LLC
Globe Metallurgical, Inc.
Linde Gase, LLC
Marathon Ashland Petroleum, LLC
Owens Corning Sales, LLC
Sunoco Inc
Texas Eastern Gas Pipeline Co.

(Data for year ended December 2010)

Top 10 customers = 48% of industrial sales

Metropolitan areas account for 59% of ultimate sales

139 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

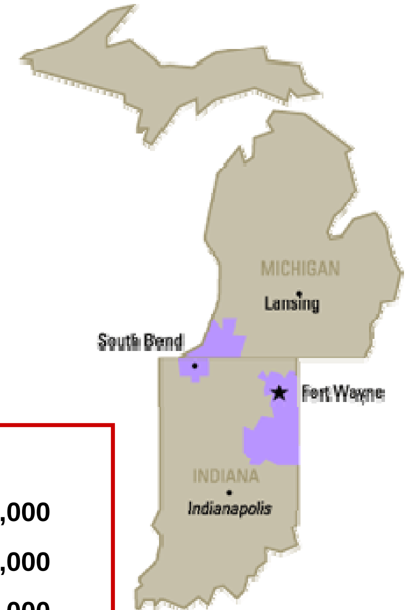
Indiana Michigan Power

President and Chief Operating Officer:
Paul Chodak

Since July 2010
Previously President and COO - SWEPCO

Indiana Michigan Power Company (I&M) (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2010, I&M had 2,705 employees. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Primary Metals
Chemical Manufacturing
Transportation Equipment
Plastics and Rubber Products
Fabricated Metals Products



Total Customers at 12/31/10:	
Residential	**507,000**
Commercial	**68,000**
Industrial	**5,000**
Other	**2,000**
Total	**582,000**
Generating Capacity	**5,821 MW***
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.1%**
• **Nuclear:**	**37.6%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,352**
Distribution Miles	**20,236**

* Includes AEGCo's share of Rockport of 1,310MW

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,077,906	1,680,860	3,758,766	2,046,995	1,702,421	3,749,416	1,985,733	1,771,310	3,757,043
% of Capitalization Per Balance Sheet	55.3%	44.7%	100.0%	54.6%	45.4%	100.0%	52.9%	47.1%	100.0%
FFO Interest Coverage			5.91			4.46			5.09*
FFO Total Debt			28.9%			19.0%			21.8%

* - calculated on rolling 12-month avg.

2010 Financial Data * (in thousands)

Total Revenue	$	2,196,000
% of AEP Retail		11%
Net Income	$	126,000
Capital Expenditures	$	333,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	7,193,759
Net Plant Assets	$	4,378,610
Cash	$	1,154

Operating Information***

2010 retail electric sales in megawatt-hours	18,720,509
2010 firm wholesale sales in megawatt-hours	4,815,224
2010 average cost per kilowatt-hour (residential)	8.20 cents
2010 System Peak – July 23	4,474MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

Indiana Michigan Power

INDIANA & MICHIGAN INVESTOR OWNED UTILITIES * TYPICAL BILL COMPARISON **

Indiana	Customers
I & M	**454,395**
IP & L	467,683
NIPSCO	455,645
Duke Energy Indiana	776,145
SIGECo	145,945

Indiana	$/month
I & M	**83.91**
IP & L	86.97
Duke Energy Indiana	105.37
NIPSCO	120.05
SIGECo	140.62

Michigan	$/month
I & M	**85.19**
Consumers Energy	118.60
Detroit Edison	134.58

Michigan	Customers
I & M	**127,820**
Consumers Energy	1,787,254
Detroit Edison	2,131,067

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011.

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

Top 10 Customers = 50% of industrial sales

Metropolitan areas account for 67% of ultimate sales

205 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

MAJOR CUSTOMERS:

Steel Dynamics Inc. (IN)
Dock Foundry (MI)
American Axle and Mfg. Co, Inc. (MI)
IN TEK (IN)
Whirlpool Corporation (MI)
Saint Gobain Corporation USA (IN)
White Pigeon Paper Company (MI)
Air Products & Chemicals. Inc. (IN)
The Minute Maid Company (MI)
BOC Gases (IN)

(Data for year ended December 2010)

Kentucky Power

President and Chief Operating Officer:
Greg Pauley

Since August 2010
Previously Director – Public Policy

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 174,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, KPCo had 417 employees. In addition to its AEP System interconnections, KPCo is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers at 12/31/10:	
Residential	**143,000**
Commercial	**29,000**
Industrial	**1,500**
Other	**500**
Total	**174,000**
Generating Capacity	**1,078 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,250**
Distribution Miles	**9,973**

PRINCIPAL INDUSTRIES SERVED:
Petroleum Refining
Coal Mining
Primary Metals
Chemical Manufacturing
Mining Support Activities

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	549,207	431,784	980,991	548,888	446,216	995,104	549,013	460,487	1,009,500
% of Capitalization Per Balance Sheet	56.0%	44.0%	100.0%	55.2%	44.8%	100.0%	54.4%	45.6%	100.0%
FFO Interest Coverage			4.20			3.48			3.97*
FFO Total Debt			19.9%			16.6%			19.9%

* - calculated on rolling 12-month avg.

2010 Financial Data * (in thousands)

Total Revenue	$	684,000
% of AEP Retail		5%
Net Income	$	35,000
Capital Expenditures	$	54,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	1,555,989
Net Plant Assets	$	1,148,757
Cash	$	809

Operating Information***

2010 retail electric sales in megawatt-hours	7,348,529
2010 firm wholesale sales in megawatt-hours	101,493
2010 average cost per kilowatt-hour (residential)	8.64 cents
2010 System Peak – January 8	1,543 MW

Sources: * 2010 Annual Report
** 3Q11 Financial Statements (unaudited)
*** 2010 FERC Form 1

Kentucky Power

KENTUCKY INVESTOR OWNED UTILITIES *

Kentucky	Customers
KPCo	**174,994**
Duke Energy Kentucky	134,819
Kentucky Utilities	510,875
LG & E	390,825

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	$/month
Kentucky Utilities	80.14
Duke Energy Kentucky	82.24
LG&E	85.90
KPCo	**99.98**

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011.

MAJOR CUSTOMERS:

Cattletsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
KES Acquisition Company LLC
Air Products & Chemicals, Inc.
Perry County Coal Corporation
Blue Diamond Coal Company
EQT Gathering, LLC
Air Liquide
Czar Coal Corporation

(Data for year ended December 2010)

Top 10 customers = 66% of industrial sales

Metropolitan areas account for 40% of ultimate sales

67 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

AEP West Regional Utilities

Public Service Company of Oklahoma

President and Chief Operating Officer:
Stuart Solomon

Since June 2004
Previously VP – Public Policy and Regulatory Services

Public Service Company of Oklahoma (PSO) (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 532,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2010, PSO had 1,150 employees. In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy, Inc. PSO is a member of SPP.

Total Customers at 12/31/10:	
Residential	**458,000**
Commercial	**60,000**
Industrial	**7,000**
Other	**7,000**
Total	**532,000**
Generating Capacity	**4,522 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**22.8%**
• **Natural Gas:**	**76.6%**
• **Oil:**	**0.6%**
Transmission Miles	**3,619**
Distribution Miles	**21,961**

PRINCIPAL INDUSTRIES SERVED:
Paper Products
Oil & Gas Extraction
Transportation Equipment
Plastics and Rubber Products
Petroleum Refining

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	968,121	817,000	1,785,121	1,062,568	847,354	1,909,922	945,735	897,817	1,843,552
% of Capitalization Per Balance Sheet	54.2%	45.8%	100.0%	55.6%	44.4%	100.0%	51.3%	48.7%	100.0%
FFO Interest Coverage			4.01			3.63			6.63*
FFO Total Debt			18.7%			15.7%			35.1%

* - calculated on rolling 12-month avg

2010 Financial Data * (in thousands)

Total Revenue	$ 1,274,000
% of AEP Retail	10%
Net Income	$ 73,000
Capital Expenditures	$ 195,000

2011 Asset Data ** (in thousands)

	As of 9/30/11
Total Assets	$ 3,322,920
Net Plant Assets	$ 2,755,321
Cash	$ 2,273

Operating Information***

2010 retail electric sales in megawatt-hours	17,916,962
2010 firm wholesale sales in megawatt-hours	7,147
2010 average cost per kilowatt-hour (residential)	7.95 cents
2010 System Peak – August 12	4,168 MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

Public Service Company of Oklahoma

OKLAHOMA INVESTOR OWNED UTILITIES *

Oklahoma	Customers
PSO	**529,267**
OG&E	709,302

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	$/month
Empire District	85.01
PSO	**85.13**
OG&E	88.11

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011.

MAJOR CUSTOMERS:

Weyerhaeuser Valliant Company
Transok, Inc.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
American Airlines
Sinclair
Sun Refining
Terra Nitrogen
Kelco
Anchor Glass Container

(Data for year ended December 2010)

Top 10 customers = 46% of industrial sales

Metropolitan areas account for 75% of ultimate sales

49 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

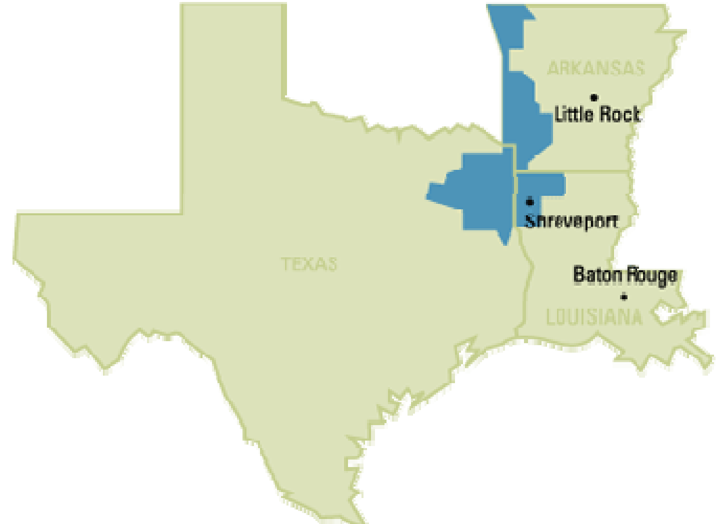
Southwestern Electric Power

President and Chief Operating Officer:
Venita McCellon-Allen

Since July 2010
Previously EVP – AEP Utilities East

Southwestern Electric Power Company (SWEPCO) (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2010, SWEPCo had 1,382 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:
Food Processing
Paper Manufacturing
Oil and Gas Extraction
Primary Metals
Chemical Manufacturing



Total Customers at 12/31/10:	
Residential	**441,500**
Commercial	**71,000**
Industrial	**7,000**
Other	**500**
Total	**520,000**

Generating Capacity		**5,319 MW**
Generating Capacity by Fuel Mix:		
• **Coal:**	**34.8%**	
• **Natural Gas:**	**49.4%**	
• **Lignite:**	**15.8%**	
Transmission Miles		**3,805**
Distribution Miles		**20,746**

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009 Debt	2009 Equity	2009 Total	2010 Debt	2010 Equity	2010 Total	9/30/2011 Debt	9/30/2011 Equity	9/30/2011 Total
Capitalization Per Balance Sheet	1,481,043	1,528,854	3,009,897	1,775,737	1,672,045	3,447,782	1,770,111	1,828,116	3,598,227
% of Capitalization Per Balance Sheet	49.2%	50.8%	100.0%	51.5%	48.5%	100.0%	49.2%	50.8%	100.0%
FFO Interest Coverage			4.14			3.49			4.05*
FFO Total Debt			19.3%			15.8%			20.1%

* - calculated on rolling 12-month avg

2010 Financial Data * (in thousands)

Total Revenue	$ 1,524,000
% of AEP Retail	10%
Net Income	$ 143,000
Capital Expenditures	$ 420,000

2011 Asset Data ** (in thousands)

	As of 9/30/11
Total Assets	$ 5,486,874
Net Plant Assets	$ 4,758,976
Cash	$ 5,784

Operating Information

2010 retail electric sales in megawatt-hours	17,813,088
2010 firm wholesale sales in megawatt-hours	6,393,436
2010 average cost per kilowatt-hour (residential)	7.80 cents
2010 System Peak – August 11	4,994 MW

Sources: * 2010 Form 10-K
** 3Q11 Form 10-Q (unaudited)
*** 2010 FERC Form 1

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1742 of 9556

Southwestern Electric Power

SOUTHWESTERN INVESTOR OWNED UTILITIES *

Arkansas	Customers
SWEPCo	**112,999**
Entergy AR	690,484
OG&E	64,595

Louisiana	Customers
SWEPCo	**180,372**
CLECO	273,432
Entergy	1,187,316

Texas	Customers
SWEPCo	**179,009**
El Paso	277,915
SPSCo	282,084
Entergy TX	400,948

* Customer counts are as of December 31, 2009 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	$/month
OG&E	66.27
SWEPCo	**72.09**
Empire District	88.74
Entergy AR	89.35

Louisiana	$/month
SWEPCo	**77.40**
Entergy LA	82.54
Entergy NO	88.35
Entergy Gulf St.	89.40
CLECO	112.81

Texas	$/month
SWEPCo	**70.01**
SPSCo	81.40
Entergy TX	105.44
El Paso	112.09

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2011.

Top 10 customers = 54% of industrial sales

Metropolitan areas account for 75% of ultimate sales

83 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

MAJOR CUSTOMERS:

Lone Star Steel Company (TX)
International Paper Company (TX)
General Motors Corporation (LA)
Calumet Lubricants (LA)
Pratt Paper (LA)
Domtar, Inc. (AR)
Pilgrim Pride Corporation (TX)
Cooper Tire & Rubber Company (AR)
Libbey Glass, Inc. (LA)
Big Three Industrial Gas (TX)
Tyson Foods (AR)
Glad Manufacturing (AR)

(Data for year ended December 2010)

AEP Texas Central Company

President and Chief Operating Officer:
Wade Smith

Since July 2010
Previously VP – Transmission Engineering & Project Services

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 775,000 retail customers through REPs in southern Texas. At December 31, 2010, TCC had 1,006 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Javelina Refinery
Formosa
Koch Refinery West
TXC

(Data for year ended December 2010)

PRINCIPAL INDUSTRIES SERVED:

Petroleum Refining
Chemical Manufacturing
Oil and Gas Extraction
Food Processing
Pipeline Transportation

Top 10 customers = 53% of industrial sales*

Metropolitan areas account for 78% ultimate sales

60 persons per square mile (U.S. = 87)

* Industrial % is in terms of wires revenues

(data for 12 months ended December 2009)

Total Customers at 12/31/10:
(Based on electric meters)

Residential	**663,000**
Commercial	**106,000**
Industrial	**5,000**
Other	**1,000**
Total	**775,000**
Transmission Miles	**4,629**
Distribution Miles	**29,689**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2010		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,757,966	600,749	3,358,715	2,610,274	626,743	3,237,017	2,390,677	1,098,114	3,488,791
% of Capitalization Per Balance Sheet	82.1%	17.9%	100.0%	80.6%	19.4%	100.0%	68.5%	31.5%	100.0%
FFO Interest Coverage			3.52			4.63			5.63*
FFO to Total Debt			16.7%			24.8%			34.0%

* - calculated on rolling 12-month avg

2010 Financial Data * (in thousands)

Total Revenue	$	892,000
% of AEP Retail		6%
Net Income	$	68,000
Capital Expenditures	$	178,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	5,627,098
Net Plant Assets	$	2,679,957
Cash	$	200

Sources: * 2010 Annual Report
** 3Q11 Financial Statements (unaudited)

AEP Texas North Company

President and Chief Operating Officer:
Wade Smith

Since July 2010
Previously VP – Transmission Engineering & Project Services

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 186,000 retail customers through REPs in west and central Texas. TNC's remaining generating capacity that is not deactivated has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. At December 31, 2010, TNC had 319 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Total Customers at 12/31/10:
(Based on electric meters)

Residential	**146,000**
Commercial	**30,000**
Industrial	**5,000**
Other	**5,000**
Total	**186,000**

Generating Capacity **377 MW**
Oklaunion Plant – Vernon, TX
(excludes 270 MW of deactivated plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,320**
Distribution Miles	**13,830**

MAJOR CUSTOMERS:

Zoltec Corporation
Sheridan Production Co.
Tyson Foods, Inc.
EBAA Iron
TXN

(Data for year ended December 2010)

PRINCIPAL INDUSTRIES SERVED:
Oil and Gas Extraction
Food Processing
Pipeline Transportation
Support Activities for Mining
Nonmetallic Mineral Products

Top 10 customers = 32% industrial sales*

Metropolitan areas account for 56% ultimate sales

8 persons per square mile (U.S. = 87)

(Data for 12 months ended December 2010)

*Industrial % is in terms of wires revenues

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2009			2010			9/30/2011		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	446,256	312,260	758,516	370,145	311,656	681,801	375,597	322,126	697,723
% of Capitalization Per Balance Sheet	58.8%	41.2%	100.0%	54.3%	45.7%	100.0%	53.8%	46.2%	100.0%
FFO Interest Coverage			3.40			5.4			6.02*
FFO Total Debt			12.6%			26.6%			30.7%

* - calculated on rolling 12-month avg.

2010 Financial Data * (in thousands)

Total Revenue	$	282,000
% of AEP Retail		1%
Net Income	$	24,000
Capital Expenditures	$	74,000

2011 Asset Data ** (in thousands)

	As of 9/30/11	
Total Assets	$	1,145,398
Net Plant Assets	$	1,024,050
Cash	$	200

Sources: * 2010 Annual Report
** 3Q11 Financial Statements (unaudited)

Regulation

- Rate Case Filing Requirements
- Recovery Mechanisms across Jurisdictions
- Regulatory Activity Underway
- Commission Overviews
- Approved Rate Base and ROE by Operating Company

Summary of Rate Case Filing Requirements

	Arkansas	Indiana	Kentucky	Lousiana	Michigan	Ohio	Oklahoma	Tennessee	Texas	Virginia	West Virginia	FERC
GENERAL												
Time Limitations Between Cases	No	Yes	No	No	No	No	No	No	No	Yes	No	No
Period of Limitation (Months)	--	15	--	--	--	--	--	--	--	Note 1	--	--
Pancaking Permitted	No	No	No	No	No	Limited	No	No	No	No	No	Yes
Fuel Clause Renewal Frequency	Annually	Semi-Annually	Monthly	Monthly	Annually	Quarterly	Annually	Annually	Tri-Annually	Annually	Annually	--
Notice of Intent												
Prior PSC Notice Required?	Yes	Yes	Yes	No	Optional	Yes	Yes	Yes	Yes	Yes	Yes	No
Notice Period (days)	60	Varies	28	n/a	45	30	45	30	30	60	30	No
CASE COMPONENTS												
Base Case Test Year	Partially Projected	Historical	Forecast Optional	Historical	Forecast Optional	Partially Projected	Historical	Historical	Historical	Historical	Historical	Forecast Optional
Other												
Rates Effective Subject to Refund	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes
Approx # of months after filing to implement rates subject to refund	10	--	6	8	Note 2	9	6	6	6	--	--	2 or 7

Note 1: No interim rates provided and rate cases must be filed no less than biennially; historical test year used.

Note 2: If no order is received within 180 days of the filing utility can implement interim rates, however they can not be implemented before the start of the test year.

Regulatory framework inherently produces recovery and return lag.

Recovery Mechanisms Across Jurisdictions

	SO_2 Allowances*	NO_x Allowances*	CO_2 Allowances	GHG Offsets	Environmental Investment	Energy Efficiency	Renewables	Purchased Power	OATT
AEP East									
Indiana	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**CCTR/BR**	**Rider**	**FAC**	**FAC/BR**	**PJM Tracker**
Kentucky	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**		**FAC**	**Base Rates**
Michigan	**PSCR**	**PSCR**	**PSCR**	**PSCR**	**Base Rates**	**Surcharge**	**PSCR/REP**	**PSCR**	**Base Rates**
Ohio	**FAC**	**FAC**	**FAC**	**FAC**	**SSO**	**Rider**	**FAC**	**FAC**	**TCRR**
Tennessee	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**			**FERC Tariff**	**PPAR**
Virginia	**ERAC**	**ERAC**	**ERAC**	**ERAC**	**ERAC/BR**	**RAC**	**RPSRAC**	**FAC/BR**	**TRAC**
West Virginia	**ENEC**	**ENEC**	**ENEC**	**ENEC**	**ENEC/BR**	**Rider**	**ENEC**	**ENEC**	**ENEC**
AEP West									
Arkansas	**ECR**	**ECR**	**FAC**	**FAC**	**Surch/BR**	**EECR**	**FAC**	**ECR/BR**	**Base Rates**
Louisiana	**EAC**	**EAC**	**Rider**	**Rider**	**Formula BR**		**FAC**	**EAC/FRP**	**Formula BR**
Oklahoma	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Rider**	**FAC**	**FAC/PPC**	**Base Rates**
Texas(SWP)	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**EECRF**	**FAC**	**FAC/BR**	**TCRF**

* - For certain jurisdictions where necessary, confirmation of the replacement of CAIR with CSAPR is occurring with applicable commissions

ECCR	Environmental Compliance Cost Rider
CCTR	Clean Coal Technology Rider
BR	Base Rates
FAC	Fuel Adjustment Clause
PSCR	Power Supply Cost Recovery Rider
REP	Renewable Energy Plan
SSO	Standard Service Offer
TCRR	Transmission Cost Recovery Rider
PPAR	Purchased Power Adjustment Rider
ERAC	Environmental Rate Adjustment Clause
RAC	Rate Adjustment Clause
RPSRAC	Renewable Portfolio Standard Rate Adjustment Clause
TRAC	Transmission Rate Adjustment Clause
ENEC	Expanded Net Energy Cost
ECR	Energy Cost Recovery Rider
EECR	Energy Efficiency Cost Rate
FRP	Formula Rate Plan
PPC	Purchased Power Capacity Rider
EECRF	Energy Efficiency Cost Recovery Rider
TCRF	Transmission Cost Recovery Factor

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Procedural Schedule

Intervenor Testimony Due	October 24, 2011
Prehearing Conference	November 2, 2011
Hearing Commences	November 14, 2011

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Historical Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$ 2,192.5
Rate of Return	8.14%
Operating Income Requirement	$ 178.5
Adjusted Operating Income	$ 102.8
Difference	$ 75.7
Revenue Conversion Factor	1.6650
Total Revenue Requirement	$ 126.0

Summary Rate Case Information

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

Commission Overview

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**

Qualifications for Commissioners

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Beebe has appointed all of the current commissioners.

Commissioners

Collette Honorable, Chairperson (Dem.), since 2007; current term ends in 2011. Commissioner Honorable is a member of NARUC and serves on the Consumer Affairs and Investment Committees. She also serves on the Smart Grid Collaborative, a joint effort of NARUC and the FERC. Honorable received her Juris Doctorate from the University of Arkansas at Little Rock School of Law.

Olan Reeves, Commissioner (Rep.), since 2009; current term ends in 2015. Chairman of the Workers' Compensation Commission from January, 2003 until January, 2009. Prior to these appointments, Commissioner Reeves was Chief Legal Counsel to the Governor from 1998-2003 and served as the State Drug Director from 1996 to 1998. Reeves received his Juris Doctorate from the University of Arkansas School of Law in Fayetteville.

Elana C. Wills, Commissioner (Dem.), since 2011; current term expires 2013. Served as an Associate Justice on the Arkansas Supreme Court by gubernatorial appointment from October 2008 – December 2010. Received her Juris Doctorate from the University of Arkansas School of Law in Fayetteville.

AEP Regulatory Status

SWEPCO-AR provides service at regulated bundled rates in Arkansas. Arkansas has an active fuel pass-through clause. Arkansas has an OSS margin sharing mechanism and allows CWIP in rate base for a plant that is placed in service within six months after the end of the test year.

Commission Overview

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 3 D: 2**

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four-year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At least one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The Governor appoints one of the five as chairperson.

Commissioners

Jim Atterholt, Chairman (Rep.), since 2009; current term ends April 2013. Prior to joining the Commission, he was the State Insurance Commissioner for more than four years where he also served as a member of the Governor's Cabinet. Atterholt worked as Director of Government Affairs for AT&T--Indiana from 2003 – 2004. Atterholt holds a Bachelors degree from the University of Wisconsin.

Kari A. E. Bennett, Commissioner (Rep.), since 2011;current term ends March 2014. Prior to joining the Commission, she was chief legal counsel of the Indiana Department of Natural Resources. From 2005 to 2007 she was Policy Director for Environments and Natural Resources for Indiana Governor Daniels. She graduated from Miami University of Ohio with a degree in environmental science and received her Juris Doctorate from the University of Minnesota.

Carolene R. Mays, Commissioner (Dem.), since 2010; current term ends December 2013. Former publisher and president of the Indianapolis Recorder Newspaper and the Indiana Minority Business Magazine. From 2002 to 2008, served in the Indiana House of Representatives and sat on the committees for Small Business and Economic Development, Ways and Means and Public Health.

Larry S. Landis, Commissioner (Rep.), since 2002; current term ends December 2011. Former president of a marketing and communications agency, VP Corporate Advertising, American Fletcher National Bank. Bachelor's degrees in political science and economics.

David E. Ziegner, Commissioner (Dem.), since 1990; current term ends April 2015. Lawyer, staff attorney for Legislative Services Agency, General Counsel for IURC. Member, NARUC Committee on Electricity and chairman of the NARUC clean coal and carbon sequestration subcommittee. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

I&M–Indiana provides retail electric service at bundled rates approved by the IURC. Rates are set on a cost-of-service basis with a fuel recovery mechanism. I&M–Indiana has trackers in place for PJM expenses, OSS sharing, clean coal technology, environmental and DSM. Indiana currently has a voluntary renewable standard goal of 10% by 2025.

Commission Overview

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 4 Years**	**Political Makeup: R: 2 D:1**

Qualifications for Commissioners

Typically three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KPSC shall be of the same profession or occupation.

Commissioners

David L. Armstrong, Chairman (Dem.), since 2008; current term expires June 2015. Former practicing attorney in private practice. Board member of NARUC and serves on its Electricity Committee and the Subcommittee on Clean Coal Technology. J.D. from University of Louisville Brandeis School of Law. Mr. Armstrong is also the former Mayor for the city of Louisville, KY (1999-2003).

James W. Gardner, Vice Chairman (Rep.), since 2008; current term expires June 2012. Prior to joining the PSC Mr. Gardner was a partner at the law firm Henry Watz Gardner & Sellars PLLC where he specialized in bankruptcy law. JD degree from the University of Kentucky College of Law.

Charles Borders, Commissioner (Rep.), since 2009; current term expires June 2013. Before joining the PSC, Commissioner Borders served in the Kentucky Senate, representing the 18th District in northeast Kentucky since 1991. He most recently chaired the Appropriations and Revenue Committee and served on the committees on Education and Health and Welfare. Borders received his Bachelors and Masters degrees from Morehead State University.

AEP Regulatory Status

KPCo provides service at regulated bundled rates in Kentucky. Kentucky has an environmental surcharge to recover approved environmental costs and it has an active fuel clause. Kentucky also has an OSS sharing mechanism and a monthly adjustment clause in place for DSM.

Commission Overview

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	Appointed/Elected: Elected	Term: 6 Years	Political Makeup: R: 3 D: 2

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

James M. Field, (Chairman) (Rep.), since 1996; current term ends December 2012. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Bachelor's and Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2016. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans. Member of NARUC.

Eric Skrmetta, (Rep.), since 2009; current term ends December 2014. Practicing Attorney since 1985. Practicing Mediator since 1989. Republican State Central Committee District 81**.** Juris Doctorate Southern University Law School.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2014. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

Clyde Holloway, (Rep.), since 2009; current term ends December 2016. Elected to Congress in 1987 and served in the United States House of Representatives until 1993. In October 2006 he received an appointment by President Bush as the USDA State Director of Rural Development where he served until 2009**.**

AEP Regulatory Status

SWEPCO-LA provides service at regulated bundled rates in Louisiana. Louisiana has an active fuel pass-through clause and an OSS margin sharing mechanism. Formula rate plans are permitted in Louisiana including a potential for a partial CWIP return on new generation projects. A formula rate plan was implemented August 1, 2008 with annual true-ups required. The current FRP expired in August 2011 an the company intends to file for an extension of the plan.

Commission Overview

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: D: 1 I: 1 R: 1**

Qualifications for Commissioners

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

Commissioners

John D. Quackenbush, Chairman (Rep), since 2011; current term expires July 2017. Former managing director and senior investment analyst at UBS Global Asset Management responsible for equity research of transportation, utilities and coal industries in the US and Canada. Undergraduate degree in business economics from Calvin College and master's degree in finance from Michigan State University.

Orjiakor N. Isiogu, Commissioner (Dem.), since 2007; current term expires July 2013. Former Director of the Telecommunications Division of the MPSC. Assistant Attorney General in Michigan since 1989. Undergraduate and law degree from Wayne State University.

Greg R. White, Commissioner, (Ind.) , since 2009; current term expires July 2015. Former legislative liaison for the MPSC and liaison for the MPSC to the Michigan Department of Energy, Labor and Economic Growth. Holds a bachelor of science from Michigan State University and master's of public administration from Grand Valley State University.

AEP Regulatory Status

Customer choice began January 2002. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. In 2008, legislation was enacted to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year. I&M-Michigan has an active fuel clause and return on CWIP can be included in base rates. Michigan currently has a mandatory renewable energy standard of 10% by 2015.

Commission Overview

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 2 D: 3

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as chairman, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Todd A. Snitchler, Chairman, (Rep.) , since 2011; term expires April 2014. Before joining the commission was elected to two terms in the Ohio House of Representatives. Past chairman and secretary of the Lake Township Chamber of Commerce. Received his B.S. from Grove City College in history and secondary education/social science and his law degree fro the University of Akron School of Law.

Paul A. Centolella, Commissioner, (Dem.) since 2007; term expires April 2012. Juris Doctorate from the University of Michigan. From 1992-2007, worked as a senior economist in the Energy Solutions Group of Science Applications International Corporation. Former senior policy advisor and senior utility attorney for the Office of the Ohio Consumers' Counsel.

Steven D. Lesser, Commissioner, (Dem.) since 2010; term expires April 2015. Juris Doctorate from Capital University; previously served as PUCO chief of staff, assistant director of the legal department, deputy director of the transportation department and administrative law judge/attorney examiner in the legal department.

Andre T. Porter, Commissioner, (Rep.) since 2011; term expires April 2016. Former attorney at Schottenstein Zox & Dunn. Sits on Capital University Board of Trustees and previously served on the Gahanna City Council. Received his undergraduate degree from Capital University and law degree from The Ohio State University Moritz College of Law.

Cheryl Roberto, Commissioner, (Dem.) since 2008; term expires April 2013. Prior to joining the PUC, Roberto was director of the City of Columbus Public Utilities Department. Before entering the public sector, Commissioner Roberto worked as an assistant attorney general for the state of Ohio. Commissioner Roberto received her B.A. with honors from Kent State University and her Juris Doctorate from the Moritz College of Law at The Ohio State University.

AEP Regulatory Status

The currently approved electric security plan expires in December 2011. Stipulation on file with the PUCO for the pending electric security plan filing which would merge the two Ohio companies, split the companies into a wires business and a generation business and take generation to market pricing in 2015. Transmission rates are currently regulated by FERC as reflected in the OATT. SB221 allows that CSP and OPCo have active fuel clauses effective January 1, 2009. Ohio currently has a mandatory renewable energy standard of 25% by 2025.

Commission Overview

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 3 D: 0**

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Bob Anthony, Commissioner, (Rep.), since 1989; current term expires January 2013. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned an M.Sc. from the London School of Economics, an M.A. from Yale University and an M.P.A. from the Kennedy School of Government at Harvard University.

Patrice Douglas, Commissioner, (Rep.), since 2011; current term ends January 2015. Served as president of SpiritBank and executive vice president of First Fidelity bank. Received her undergraduate degree from Oklahoma Christian and her juris doctorate from the University of Oklahoma.

Dana Murphy, Chairperson, (Rep.), since 2008; current term expires January 2015. Member, NARUC. Murphy's prior experience includes working as an administrative law judge at the Commission. She has more than 20 years experience in the petroleum industry including owning and operating her own private law practice and working as a geologist in the Oklahoma petroleum industry. Juris Doctorate Oklahoma City University.

AEP Regulatory Status

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. PSO has an OSS margin sharing mechanism. Oklahoma currently has a mandatory renewable energy standard of 15% by 2015.

Commission Overview

Tennessee Regulatory Authority

AEP Regulated Electric Utilities

Kingsport Power Co.

Commissioners

Number: 4	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**

Qualifications for Commissioners

The Tennessee Regulatory Authority (TRA) directors are appointed, one each, by the Governor, Lieutenant Governor (as Speaker of the Senate), Speaker of the House and one joint appointment by the three together, and are confirmed by the Tennessee General Assembly. The directors are appointed for six and three-year staggered terms. The chairmanship rotates every year in an agreed upon decision by the directors.

Commissioners

Sara Kyle, Director (Dem.), since 1996; current term expires June 2014. Former assistant public defender until she was elected to the Memphis City Court bench. The longest serving commissioner and only holdover from the previous Regulatory Authority. Law degree from Middle Tennessee State University.

Mary W. Freeman, Director (Dem.), since 2008; current term expired June 2011. Prior legislative director for Governor Bredesen, executive assistant to State Representative Lois DeBerry. B.A. Tennessee State University.

Kenneth C. Hill, Chairman (Rep.), since 2009; current term expires June 2015. At the time of his appointment to the TRA, Hill was Chief Executive Officer of AECC and served as General Manager of five radio stations reaching portions of East Tennessee and four surrounding states. Doctor of Religious Education, Andersonville Baptist Seminary.

AEP Regulatory Status

No deregulation legislation and no base rate freeze or cap. Tennessee has an active fuel clause.

Commission Overview

Public Utility Commission of Texas

AEP Regulated Electric Utilities

AEP Texas Central Co.
AEP Texas North Co.
Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 3 D: 0**

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Donna L. Nelson, Chairman (Rep.), since August 2008; current term expires August 2015. Nelson served as a special assistant and advisor to Governor Perry on energy, telecommunications and cable budget and policy issues. She previously served as director of the PUC telecommunication's section and legal advisor to the PUC chairman. Nelson holds a law degree from Texas Tech University.

Rolando Pablos (Rep.), since 2011; current term expires August 2013. Member of the State Bar of Texas, chair of the San Antonio Free Trade Alliance and a member and past board chair of the San Antonio Hispanic Chamber of Commerce. Received a bachelor's degree from St. Mary's University MBA from the University of Texas at San Antonio, a master's degree in hospitality management from the University of Houston and a law degree from St. Mary's University School of Law.

Kenneth W. Anderson Jr., (Rep.) since September 2008; current term expires August 2017. Past Director of Governmental Appointments under Governor Perry. Prior to that Anderson served in private practice as a corporate attorney in the area of securities law and regulatory matters. He also served as a member of the Texas Securities Board from 1999-2006. Anderson holds a law degree from Southern Methodist University.

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas (including SWEPCO). SWEPCO-TX has an active fuel pass-through clause as well as OSS margin sharing. In some circumstances, CWIP is allowed in rate base.

TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission riders provide annual recovery dependent on the level of transmission investment and ERCOT load growth rates. AFUDC is permitted in limited circumstances. Texas currently has a mandatory renewable energy standard of 5% by 2015.

Commission Overview

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected: Elected**	**Term: 6 Years**	**Political Makeup: R: 2 D: 1**

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Mark C. Christie, (Rep.), since 2004; current term expires 2016. Prior counsel to the Speaker of the House of delegates of the Virginia General Assembly. Lawyer, private practice. Law degree from Georgetown.

Judith Williams Jagdmann, Chairman, (Rep.), since 2006; current term expires 2012. Law degree from T.C. Williams School of Law at the University of Richmond. Served as Deputy Attorney General for Civil Litigation Division from 1998 to 2005. Attorney General for Commonwealth of Virginia from 2005 to 2006.

James C. Dimitri, (Dem.), since 2008; current term expires 2014. Prior to being named Commissioner, Dimitri was in private practice in Richmond. From 1994 to 2000 he served as Senior Counsel, then General Counsel at the SCC. He was an assistant Attorney General from 1983 to 1987. Dimitri received his undergraduate degree in economics from the University of Virginia and his J.D. from the Boston University School of Law.

AEP Regulatory Status

APCo-VA provides retail electric service in Virginia at unbundled rates. In 2007, the General Assembly passed legislation re-establishing retail rate regulation in the Commonwealth. The new legislation provides for biennial rate reviews beginning in 2009, sharing of off-system sales margins at a rate of a minimum of 25% retained by the company effective July 1, 2007 and a post-2008 rider for DSM, renewable programs and new generation. APCo-VA is entitled to adjustments to fuel rates to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. Virginia currently has a voluntary renewable energy standard of 12% by 2022.

Commission Overview

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Appalachian Power Co.

Wheeling Power Co.

Commissioners

Number: 3	**Appointed/Elected: Appointed**	**Term: 6 Years**	**Political Makeup: R: 1 D: 2**

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Michael A. Albert, Chairman (Rep.), since 2007; term expires June 2013. Served as a member in the Business Law Department of Jackson Kelly. President and Chairman of the board of directors of the Kanawha County Public Library. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Ryan B. Palmer, Commissioner (Dem.), since 2010; term expired June 2015. Served as Deputy General Counsel to West Virginia Governor Joe Manchin, III; as Attorney/Advisor to Commissioner Charlotte R. Lane of the United States International Trade Commission and Law Clerk to the Honorable W. Craig Broadwater of the United States District Court, Northern District of West Virginia. Bachelor's degree and Doctorate of Jurisprudence, West Virginia University.

Jon W. McKinney, Commissioner (Dem.), since 2005; term expired June 2011. Currently on the board of directors of the NARUC and second VP of the Mid-Atlantic Conference of Regulated Utilities Commissioners. Formerly served as plant manager of Flexsys' Nitro, W .V. operations, chairman of Chemical Industry Committee for W.V., board member of W.V. Chamber of Commerce, W.V. Manufacturer's Association, Chemical Alliance Zone, W.V. Roundtable, Advantage Valle, St. Francis Hospital & Thomas Memorial Hospital.

AEP Regulatory Status

APCo and Wheeling Power in WV provide retail electric service at bundled rates approved by the WV PSC. West Virginia has an active annual ENEC (Expanded Net Energy Cost) mechanism, which provides for a rate adjustment for fuel costs, among other items. West Virginia also has a special construction surcharge permitted, primarily related to environmental-related construction. West Virginia currently has a renewable energy standard of 25% by 2015.

Commission Overview

Federal Energy Regulatory Commission

Commissioners

Number: 5	Appointed/Elected: Appointed	Term: 5 Years	Political Makeup: R: 2 D: 3

Qualifications for Commissioners

The Federal Energy Regulatory Commission (FERC) is composed of up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve five-year terms, and have an equal vote on regulatory matters. To avoid any undue political influence or pressure, no more than three commissioners may belong to the same political party.

Commissioners

Jon Wellinghoff, Chairman (Dem.), since 2006; term expires June 2013. Chairman Wellinghoff is an energy law specialist with more than 30 years experience in the field. Before joining FERC, he was in private practice and focused exclusively on client matters related to renewable energy, energy efficiency and distributed generation. While in the private sector, Chairman Wellinghoff represented an array of clients from federal agencies, renewable developers, and large consumers of power to energy efficient product manufacturers and clean energy advocacy organizations.

Marc Spitzer, Commissioner (Rep.) since 2006: term expired June 2011. Prior to becoming a commissioner, Spitzer served as chairman of the Arizona Corporation Commission (ACC), where he focused on policies encouraging expansion of natural gas infrastructure, specifically distribution and storage: creating a demand side management policy: enhancing the ACC's renewables standard: and advancing consumer privacy concerns in telecommunications.

Sheryl A. LaFleur, Commissioner (Dem.) since 2010; term expires June 2014. Retired in 2007 as executive vice president and acting CEO of National Grid USA, responsible for the delivery of electricity to 3.4 million customers in the Northeast. Her previous positions at National Grid and its predecessor New England Electric System included COO, president of New England distribution and general counsel. She practiced law in Boston earlier in her career, and has been a community and nonprofit leader

John R. Norris, Commissioner (Dem.) since 2010: term expires June 2012. Most recently served as Chief of Staff to Secretary Tom Vilsack of the U.S. Department of Agriculture. Prior to joining the USDA, he served as Chairman of the Iowa Utilities Board (IUB) from 2005 to 2009. During his tenure as IUB Chairman, Commissioner Norris served on the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee and was Co-Chair of the 2009 National Electricity Delivery Forum

Phillip D. Moeller, Commissioner (Rep.), since 2006; term expires June 2015. From 1997 through 2000, Mr. Moeller served as an energy policy advisor to U.S. Senator Slade Gorton (R-Washington) where he worked on electricity policy, electric system reliability, hydropower, energy efficiency, nuclear waste, energy and water appropriations and other energy legislation. Before becoming a Commissioner, Mr. Moeller headed the Washington, D.C., office of Alliant Energy Corporation. Prior to Alliant Energy, Mr. Moeller worked in the Washington office of Calpine Corporation.

Approved Rate Bases & ROEs and Current Rate Base Requests

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Rate Case Requests on File

Jurisdiction	Requested Rate Base	Requested ROE
APCO - Virginia	$2,193MM	11.65%
I&M - Michigan	$681MM	11.15%
I&M - Indiana	$2,412MM	11.15%
OPCo - Ohio	$1,015MM	11.15%
CSP - Ohio	$911MM	11.15%

Generation & Environmental

- Units
- Generation Statistics
- OSS Sharing Summary
- New Generation
- Environmental

Domestic Generation

Generation Capacity*

Company	MW Capacity
AEP Generating Co	2,496
Appalachian Power Co	6,286
Columbus Southern Power Co	3,738
Indiana Michigan Power Co	4,511
Kentucky Power Co	1,078
Ohio Power Co	8,498
Public Service of Oklahoma	4,522
Southwestern Electric Power Co	5,319
Texas North Co**	647
OVEC Capacity ***	980
Domestic IPPs	311
Long Term Renewable Purchase Power Agreements	1,781
	40,167

* Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 270MW of deactivated

*** Represents AEP's 43.5% interest in Ohio Valley Electric Corporation (OVEC)

Coal/Lignite #	25,725	64%
Natural Gas/Oil	9,441	24%
Nuclear	2,191	5%
Wind/Hydro/Pumped Storage	2,810	7%
Total Generating Capacity	40,167	100%

Includes AEP's 43% ownership of OVEC

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
AEP Generating Company					
Rockport	1	IN	Steam - Coal	1,310	1984
Lawrenceburg	6	IN	Natural Gas	1,186	2004
				2,496	
Appalachian Power Company					
Buck	3	VA	Hydro	5	1912
Byllesby	4	VA	Hydro	8	1912
Claytor	4	VA	Hydro	28	1939
Leesville	2	VA	Hydro	9	1964
London	3	WV	Hydro	12	1935
Marmet	3	WV	Hydro	11	1935
Niagara	2	VA	Hydro	1	1906
Reusens	5	VA	Hydro	2	1904
Winfield	3	WV	Hydro	15	1938
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos (1&2)	2	WV	Steam - Coal	2,033	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	335	1918
Kanawha River	2	WV	Steam - Coal	400	1953
Mountaineer	1	WV	Steam - Coal	1,320	1980
Sporn	2	WV	Steam - Coal	300	1950
Ceredo	6	WV	Natural Gas	516	2001
				6,286	
Columbus Southern Power Company					
Beckjord (CCD)	1	OH	Steam - Coal	53	1969
Conesville (CCD)	4	OH	Steam - Coal	1,302	1957
Picway	1	OH	Steam - Coal	100	1926
Stuart (CCD)	4	OH	Steam - Coal	600	1971
Stuart (CCD)	4	OH	Oil	3	1970
Zimmer (CCD)	1	OH	Steam - Coal	333	1991
Waterford	4	OH	Natural Gas	840	2003
Darby	6	OH	Natural Gas	507	2001
				3,738	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Indiana Michigan Power Company					
Berrien Springs	12	MI	Hydro	5	1908
Buchanan	10	MI	Hydro	2	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	2	1913
Mottville	4	MI	Hydro	1	1923
Twin Branch	6	IN	Hydro	4	1904
Rockport	1	IN	Steam - Coal	1,310	1984
Tanners Creek	4	IN	Steam - Coal	995	1951
Cook	2	MI	Steam - Nuclear	2,191	1975
				4,511	
Kentucky Power Company					
Big Sandy	2	KY	Steam - Coal	1,078	1963
Ohio Power Company					
Racine	2	OH	Hydro	26	1982
Amos (3)	1	WV	Steam - Coal	867	1973
Cardinal	1	OH	Steam - Coal	595	1967
Gavin	2	OH	Steam - Coal	2,640	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell	2	WV	Steam - Coal	1,560	1971
Muskingum River	5	OH	Steam - Coal	1,440	1953
Sporn*	3	WV	Steam - Coal	740	1950
				8,498	

*Application on file with PUCO to retire Sporn Unit 5 (450MW)

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Year Plant Commissioned
Public Service Company of Oklahoma					
Tulsa	3	OK	Steam - Natural Gas	370	1923
Tulsa	3	OK	Oil	8	1967
Riverside (1&2)	2	OK	Steam - Natural Gas	909	1974
Riverside (3&4)	2	OK	Steam - Natural Gas	170	2008
Riverside	1	OK	Oil	3	1976
Northeastern (1&2)	4	OK	Steam - Natural Gas	922	1961
Northeastern	1	OK	Oil	3	1961
Southwestern (1-3)	3	OK	Steam - Natural Gas	467	1952
Southwestern (4&5)	2	OK	Steam - Natural Gas	170	2008
Southwestern	1	OK	Oil	2	1962
Comanche	3	OK	Steam - Natural Gas	260	1973
Comanche	2	OK	Oil	4	1962
Weleetka	3	OK	Steam - Natural Gas	197	1975
Weleetka	2	OK	Oil	4	1963
Northeastern (3&4)	2	OK	Steam - Coal	930	1979
Northeastern	1	OK	Oil	1	1980
Oklaunion	1	TX	Steam - Coal	102	1986
				4,522	
Southwestern Electric Power Company					
Arsenal Hill	1	LA	Steam - Natural Gas	107	1960
Lieberman	4	LA	Steam - Natural Gas	269	1947
Knox Lee	4	TX	Steam - Natural Gas	486	1950
Wilkes	3	TX	Steam - Natural Gas	882	1964
Lone Star	1	TX	Steam - Natural Gas	50	1954
Stall	1	LA	Natural Gas	523	2010
Mattison	4	AR	Natural Gas	312	2007
Welsh	3	TX	Steam - Coal	1,584	1977
Flint Creek	1	AR	Steam - Coal	264	1978
Pirkey	1	TX	Steam - Lignite	580	1985
Dolet Hills	1	LA	Steam - Lignite	262	1986
				5,319	

Domestic Generation

Plant Name	Units	State	Fuel Type	Nominal Capacity (MW)	Contract Initiated
Texas North Company					
Paint Creek (Deactivated)	4	TX	Steam - Natural Gas	238	1953
Abilene (Deactivated)	1	TX	Steam - Natural Gas	18	1949
Ft. Stockton (Deactivated)	1	TX	Steam - Natural Gas	6	1958
Vernon (Deactivated)	4	TX	Oil	8	1963
Oklaunion	1	TX	Steam - Coal	377	1986
				647	
Domestic Independent Power Projects					
Trent Mesa	100	TX	Wind	150	2001
Desert Sky	107	TX	Wind	161	2001
				311	
Long-Term Renewable Purchase Power Agreements					
Southwest Mesa		TX	Wind	75	2005
South Trent		TX	Wind	102	2008
Weatherford		OK	Wind	147	2005
Blue Canyon II		OK	Wind	151	2005
Sleeping Bear		OK	Wind	95	2008
Camp Grove		IL	Wind	75	2008
Fowler Ridge I		IN	Wind	100	2009
Majestic		TX	Wind	80	2009
Fowler Ridge III		IN	Wind	100	2009
Blue Canyon V		OK	Wind	99	2009
Grand Ridge II and III		IL	Wind	100	2009
Fowler Ridge II		IN	Wind	150	2009
Elk City		OK	Wind	99	2010
Wyandot Solar		OH	Solar	10	2010
Beech Ridge		WV	Wind	100	2009
Minco		OK	Wind	99	2010
Timber Road		OH	Wind	99	*
Wildcat		IN	Wind	100	**
				1,781	

* Under contract but not yet on-line, expected 2011
** Under contract but not yet on-line, expected 2012

Generation Statistics

Net Capacity Factors	2009	2010	YTD SEPT 11
AEP East	50.61%	53.94%	56.81%
Coal	60.49%	60.28%	61.23%
Super Critical*	68.02%	68.75%	67.93%
Sub-Critical*	37.39%	34.40%	40.81%
Gas	3.98%	9.27%	19.02%
Hydro**	12.44%	9.05%	9.70%
Nuclear	43.38%	81.52%	93.11%
AEP SPP	38.48%	42.11%	45.58%
Coal***	74.31%	77.63%	82.65%
Super Critical*	83.01%	73.86%	85.96%
Sub-Critical*	69.44%	78.94%	81.58%
Gas	17.03%	21.79%	25.27%
AEP Texas	51.70%	67.36%	69.75%
Coal****	51.70%	67.36%	69.75%
AEP System	47.75%	51.24%	54.19%

Equivalent Availability Factors	2009	2010	YTD SEPT 11
AEP East	76.18%	74.26%	76.23%
Coal	77.65%	71.97%	73.51%
Super Critical*	79.35%	75.84%	75.92%
Sub-Critical*	72.44%	60.14%	66.14%
Gas	85.38%	80.85%	80.79%
Hydro**	84.47%	86.65%	85.21%
Nuclear	43.23%	81.40%	92.43%
AEP SPP	81.08%	80.92%	85.93%
Coal***	80.50%	84.19%	88.50%
Super Critical*	86.65%	77.17%	88.79%
Sub-Critical*	76.49%	86.56%	88.35%
Gas	81.43%	79.05%	84.52%
AEP Texas	69.47%	81.42%	83.20%
Coal****	69.47%	81.42%	83.20%
AEP System	77.26%	75.95%	78.71%

Equivalent Forced Outage Rate (EFOR)	2009	2010	YTD SEPT 11
AEP East	13.05%	10.60%	11.98%
Coal	8.05%	11.16%	12.95%
Super Critical*	6.35%	9.08%	10.77%
Sub-Critical*	14.90%	19.60%	20.79%
Gas - See Below			
Hydro**	20.83%	9.30%	24.01%
Nuclear	52.99%	5.96%	2.14%
AEP SPP	10.10%	9.05%	4.66%
Coal***	6.92%	5.90%	1.44%
Super Critical*	5.39%	8.93%	1.17%
Sub-Critical*	7.93%	4.83%	1.78%
Gas	13.17%	11.75%	7.26%
AEP Texas	4.96%	8.53%	3.98%
Coal****	4.96%	8.53%	3.98%
AEP System	12.26%	10.18%	10.01%

Equivalent Forced Outage Factor (EFOF)	2009	2010	YTD SEPT 11
AEP East Gas*****	2.55%	3.53%	3.03%

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; sub-critical includes coal units with a net maximum capacity less than 450MW.

** Includes all AEP owned Hydro and Pumped Storage generation.

*** CF, EAF, and EFOR do not include Dolet Hills.

**** Oklaunion reported as owned.

***** East Gas Units evaluated using Equivalent Forced Outage Factor. Since these units are run less frequently, this factor gauges their performance based on Period Hours instead of Service Hours. EFOR uses Service Hours in the denominator, and EFOF uses Period Hours in the denominator.

Generation & Coal Statistics

MWh Produced

Operating Company	2008	2009	2010	Three Year Average
AEP Generating	10,622,505	9,914,827	10,362,410	10,299,914
Appalachian Power	31,868,466	23,615,041	22,287,975	25,923,827
Columbus Southern Power	14,866,609	12,012,080	12,521,147	13,133,279
Indiana Michigan Power	29,790,250	20,478,701	28,476,693	26,248,548
Kentucky Power	6,021,182	6,262,165	6,552,258	6,278,535
Ohio Power	55,039,733	47,700,622	48,768,500	50,502,952
Public Service of Oklahoma	14,874,023	13,967,928	14,376,653	14,406,201
Southwestern Electric Power	19,714,013	18,563,548	22,343,172	20,206,911
Texas North Company	2,310,091	1,608,890	2,098,311	2,005,764
AEP System Total Net Generation	185,106,872	154,123,802	167,787,119	169,005,931

Note: Figures represent generation produced from AEP-owned assets only.

Coal/Lignite Consumption in Tons

Operating Company	2008	2009	2010	Three Year Average
AEP Generating	5,463,904	5,061,232	4,850,666	5,125,267
Appalachian Power	13,030,442	9,392,378	8,932,179	10,451,666
Columbus Southern Power	6,318,996	5,046,741	5,107,920	5,491,219
Indiana Michigan Power	7,709,863	6,395,162	6,857,261	6,987,429
Kentucky Power	2,349,586	2,512,559	2,573,985	2,478,710
Ohio Power	22,436,865	19,420,513	20,139,568	20,665,649
Public Service of Oklahoma	4,135,223	4,293,510	3,917,577	4,115,437
Southwestern Electric Power	12,413,907	11,583,949	12,910,825	12,302,894
Texas North Company	1,444,187	984,453	1,258,369	1,229,003
AEP System Total Consumption	75,302,973	64,690,497	66,548,350	68,847,273

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana*	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $15,290,363, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	75% of profits are shared with ratepayers.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

*Request on file in cause 44075 to remove amounts built into base rates and to begin sharing on a 50/50 basis from the first dollar of margin.

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).
- Various legal challenges are on-going related to the plant (see 10-Q).

New Generation – Dresden Plant

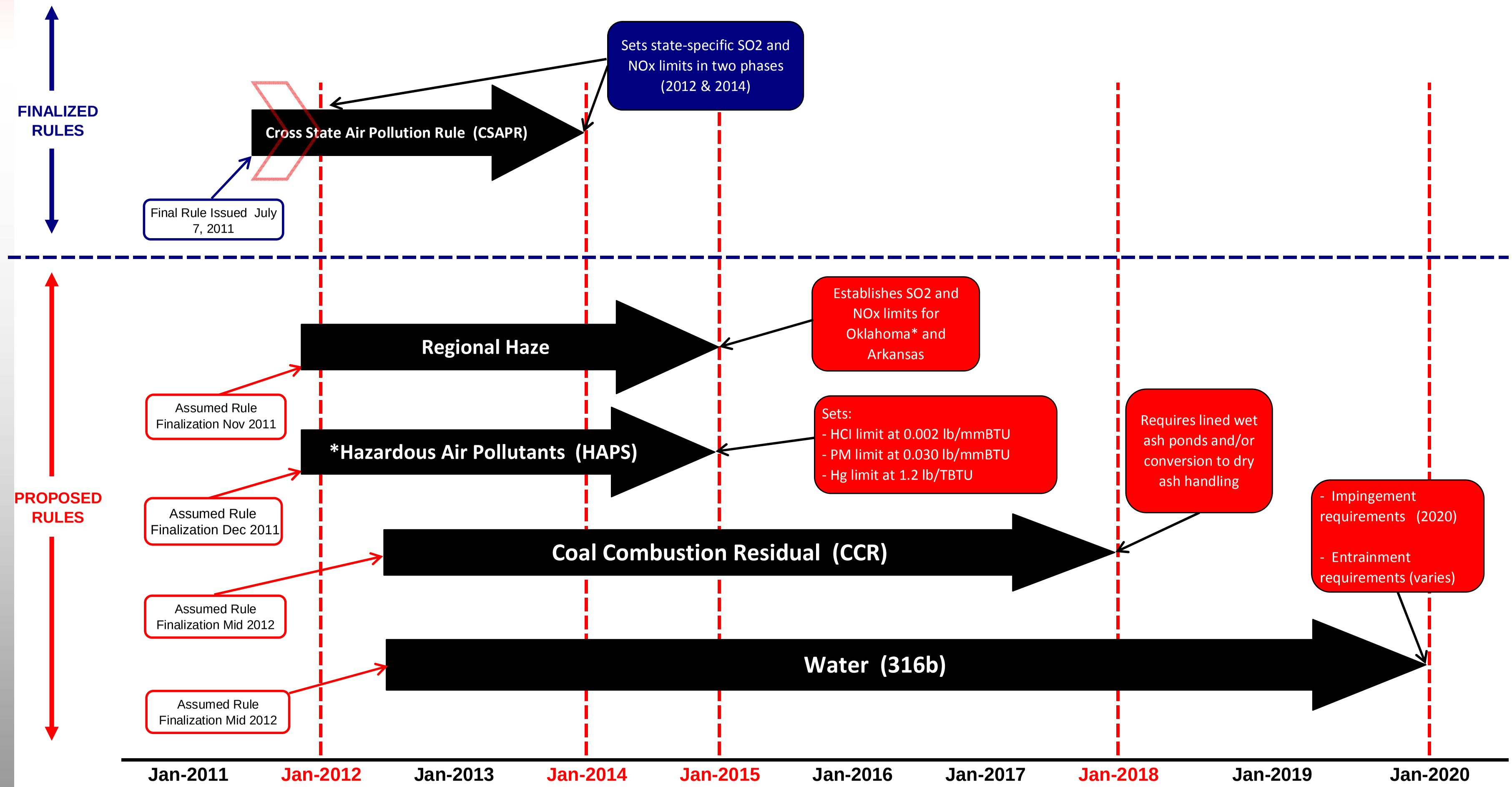
Dresden is an intermediate load 580-MW combined–cycle natural gas plant. Located in Dresden, Ohio.

- On September 19, 2007, AEG purchased the Dresden Facility from Dominion for approximately $85MM. Construction began on the Dresden plant in 2001, with major equipment necessary for its completion procured and on site.
- The plant is expected to be operational during the first quarter of 2012. When completed, the Dresden plant will be a nominal 580-megawatt natural gas-fired combined-cycle plant.

- Total capital invested is expected to be $366 million once completed.
- On February 28, 2011 in West Virginia and March 1, 2011 in Virginia, APCo filed requests to enter into affiliate transactions to transfer ownership of Dresden from AEG to APCo. The WV request was approved on June 30, 2011 and VA approved the transaction on July 20, 2011. The plant was transferred to APCo in August 2011.

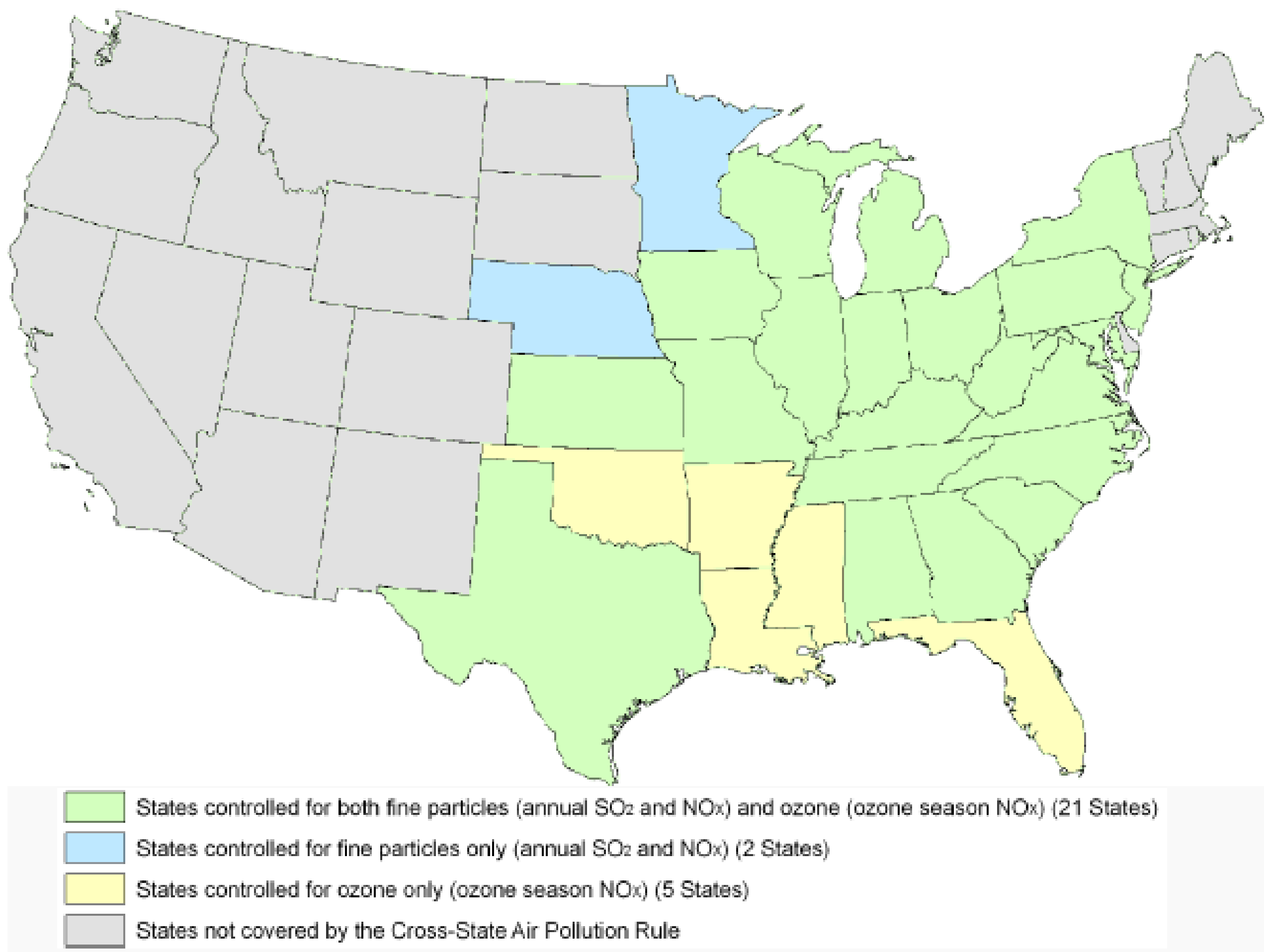
Environmental

EPA Regulatory Deadlines



* Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.

CSAPR: States Covered



Coverage of states changed slightly from the proposed rule. Most notably for AEP, Texas is now included in the SO_2 program while Louisiana is not.

CSAPR: State Budgets v. Historical Emissions

Percentage Reduction Required from 2010 Levels				
State	**2012 SO2**	**2014 SO2**	**2012 NOx**	**2012 S NOx**
Alabama	6%	4%	15%	15%
Arkansas	N/A	N/A	N/A	-16%
Florida	N/A	N/A	N/A	-23%
Georgia	-28%	-56%	2%	4%
Illinois	7%	-44%	-37%	-24%
Indiana	-31%	-61%	-3%	-5%
Iowa	2%	-28%	-15%	-13%
Kansas	-8%	-8%	-37%	-39%
Kentucky	-14%	-61%	-7%	-7%
Louisiana	N/A	N/A	N/A	-24%
Maryland	1%	-6%	-14%	-24%
Michigan	-6%	-41%	-19%	-26%
Minnesota	1%	1%	-5%	N/A
Mississippi	N/A	N/A	N/A	-24%
Missouri	-12%	-30%	-10%	-11%
Nebraska	1%	1%	-20%	N/A
New Jersey	-50%	-63%	-20%	-23%
New York	-38%	-55%	-19%	-21%
North Carolina	14%	-52%	-7%	-10%
Ohio	-46%	-76%	-12%	-16%
Oklahoma	N/A	N/A	N/A	-37%
Pennsylvania	-33%	-73%	-10%	-10%
South Carolina	-6%	-6%	18%	1%
Tennessee	25%	-50%	14%	2%
Texas	-32%	-32%	-7%	-6%
Virginia	-24%	-62%	-13%	-21%
West Virginia	34%	-31%	12%	4%
Wisconsin	-27%	-56%	2%	-6%

AEP Coal Generating States

Amounts based on October 6, 2011 EPA technical adjustments

On average, state budgets in the finalized Cross State Air Pollution (CSAPR) rule are significantly lower in 2012 and 2014 versus the proposed rule:

- 2012 SO_2 – 13% reduction
- 2014 SO_2 – 15% reduction
- 2012 Annual NOx – 7% reduction
- 2012 Seasonal NOx – 14% reduction

Significant reductions are required as early as January 2012 in many states. 32% and 46% reductions in SO_2 are required in TX and OH, respectively, and major seasonal NOx reductions are required in OK and LA.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1786 of 9556

CSAPR: 2012 AEP Allowance Allocations

Operating Company	State	SO_2 Allocation	Annual NOx Allocation	Seasonal NOx Allocation
APCO	West Virginia	43,870	15,760	6,243
	Virginia	12,948	3,962	1,564
	APCO Total	56,818	19,722	7,807
KPCO	Kentucky	15,325	5,324	2,229
	Indiana	6,182	2,333	970
	KPCO Total	21,507	7,657	3,199
AEP Ohio	Ohio	95,713	29,596	12,722
	West Virginia	37,494	13,448	5,699
	Indiana	4	74	51
	AEP Ohio Total	133,211	43,118	18,472
I&M	Indiana	47,386	17,879	7,582
	I&M Total	47,386	17,879	7,582
	AEP East Total	**258,922**	**88,376**	**37,060**

Operating Company	State	SO_2 Allocation	Annual NOx Allocation	Seasonal NOx Allocation
SWEPCO	Texas	30,545	9,373	4,475
	Arkansas	N/A	N/A	883
	Louisiana	N/A	N/A	729
	SWEPCO Total	30,545	9,373	6,087
PSO	Texas	685	349	159
	Oklahoma	N/A	N/A	5,314
	PSO Total	685	349	5,473
TNC	Texas	2,399	1,221	556
	TNC Total	2,399	1,221	556
	AEP West Total	**33,629**	**10,943**	**12,116**

Amounts based on October 6, 2011 EPA technical adjustments

Key Concerns with Proposed HAPs Rule

Implementation Concerns:

- Unrealistic three year compliance schedule
- Retrofit emission controls require >3 years to complete
- Significant capital investments required
- Proposed rule effectively eliminates coal as a future generation option

Grid Reliability Concerns:

- Significant number of units offline due to retirements and retrofit project outages
- Insufficient time to accommodate new generation development

Key AEP Recommendations:

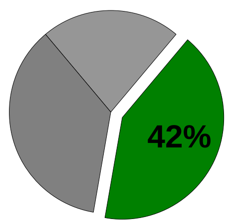
- Establish a subcategory for small, low-capacity factor units that would not have to meet the stringent limits so as to avoid premature retirements
- Utilize full range of regulatory flexibility to automatically extend compliance deadline and provide assurance at time of final rule that additional time is available

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

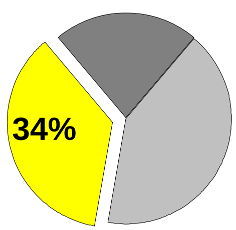
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

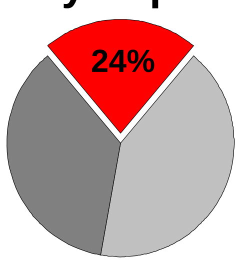
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078(5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

Emission Limits

In compliance with our 2007 NSR settlement, the following limits are applicable to AEP's eastern generation fleet:

Eastern System-Wide Annual Tonnage Limitations for NO_x

Calendar Year	Limitation
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016 and each year thereafter	72,000 tons

Eastern System-Wide Annual Tonnage Limitations for SO_2

Calendar Year	Limitation
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019 and each year thereafter	174,000 tons

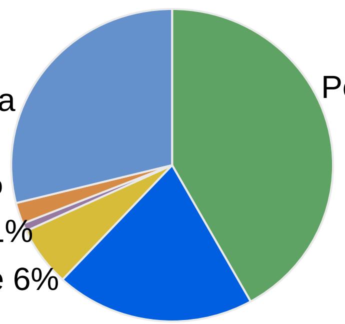
Emissions caps do not include any of the gas-fired units, or any new units AEP might build or purchase in the east.

Coal

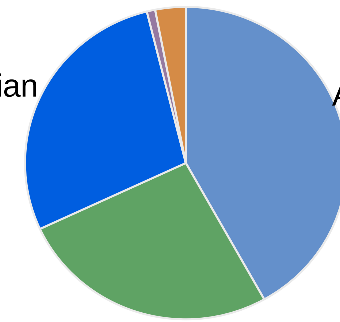
- Coal Procurement, Delivery & Transportation
- Fuel Recovery
- AEP River Operations
- Coal Market Information

Coal Procurement – 2012 Projected

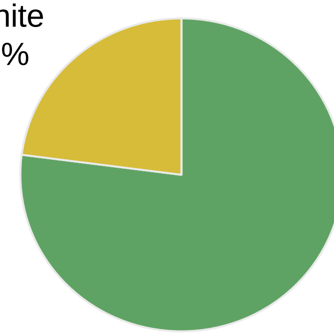
Total AEP System



AEP East



AEP West



Coal Stats:

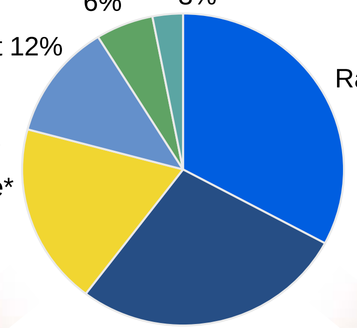
- 92% contracted for 2012 and 78% contracted for 2013*
- Avg. system delivered price ~ $47/ton in 2011**
  - East ~ $55/ton, West ~ $30/ton
- System price increase of approximate 4% in 2012 ~ $49/ton*
  - East ~ $56/ton, West ~ $31/ton

(*based on committed position information available as of 10/19/11 **based on coal receipts as of 9/30/2011)

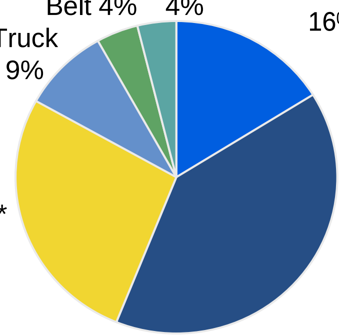
Coal Delivery

Total AEP System

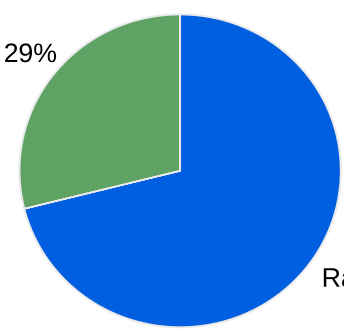
2010 Actual



AEP East



AEP West

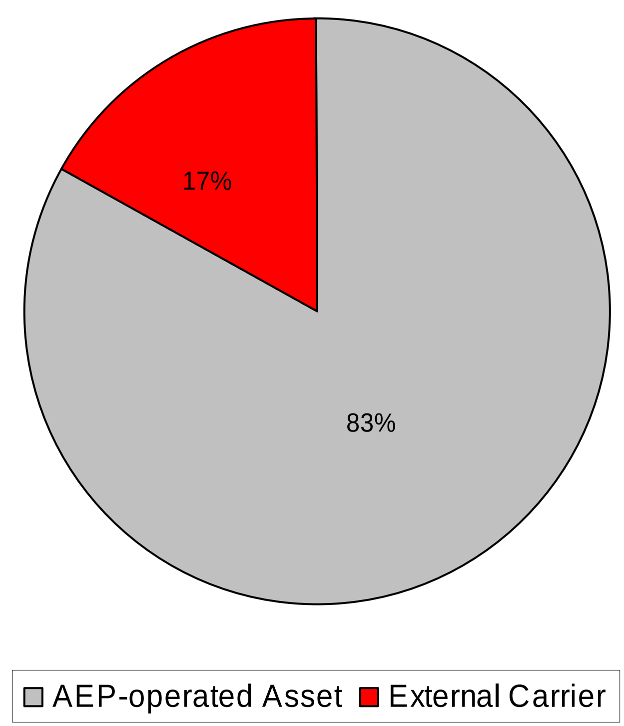


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2010 Actual

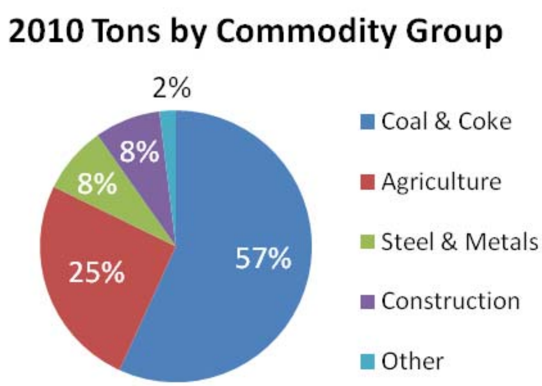
Coal Transportation to AEP Plants



AEP's transportation assets provide flexibility in a constrained delivery environment.

AEP River Operations

- Net Income
  - 2010: $37 Million
  - 2009: $47 Million
  - 2008: $55 Million
- Full-service Inland Waterways carrier
  - 3,300 hopper barges
  - 64 towboats and 26 tugs
- Tonnage & Commodity (2010):
  - Captive: (for AEP) 32MM tons of coal/ consumables
  - Commercial: 39MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Paducah, KY, Convent and Belle Chase, LA and Mobile, AL

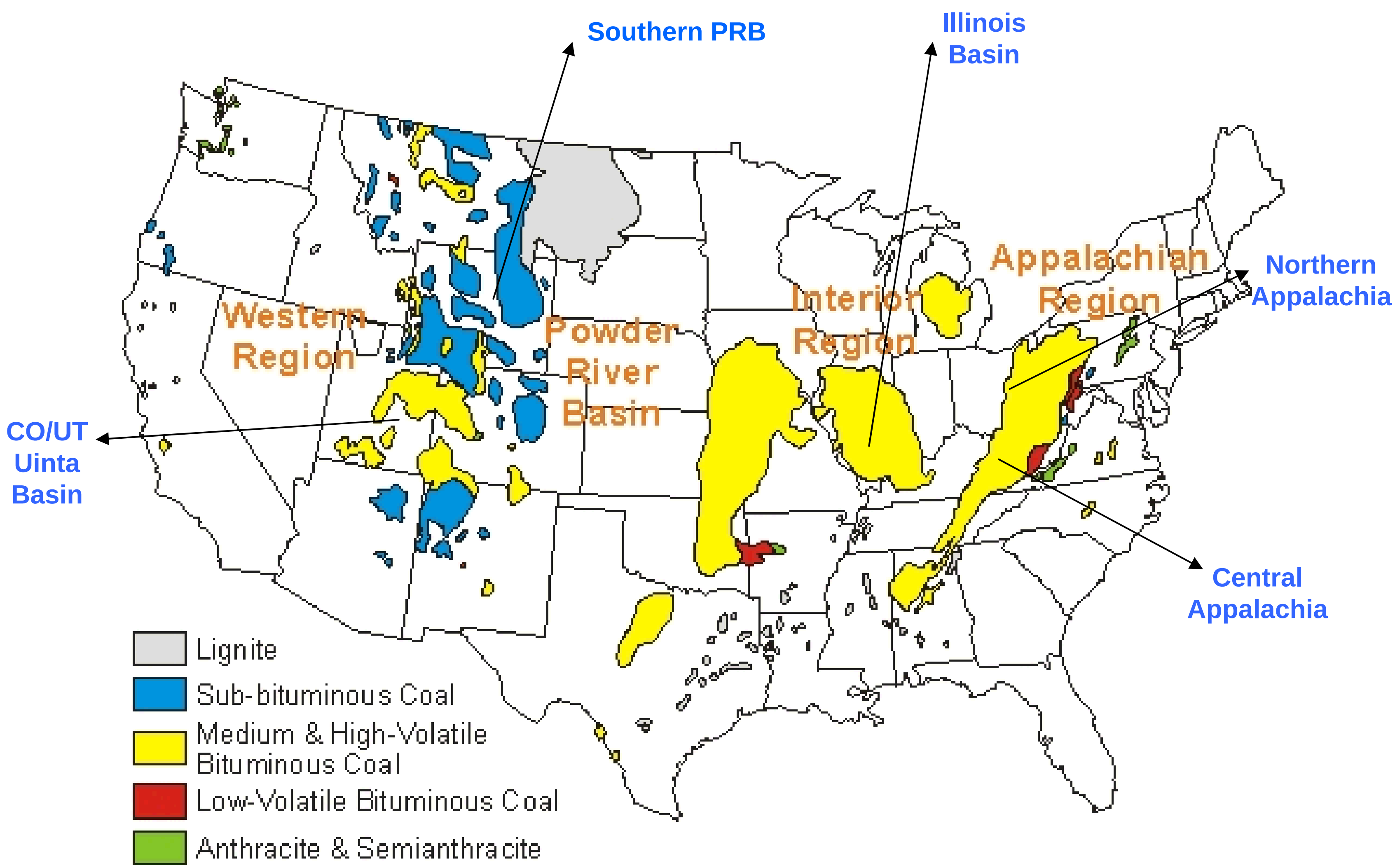


Inland Waterway Routes For AEP River Operations

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Yes	Quarterly
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Tri-Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Coal Producing Regions



Transmission Initiatives

AEP Transmission Company (Transco)

- FERC-approved formula rates
  - ROE: 11.49% in PJM and 11.2% in SPP
- $260 M invested in three states by the end of 2011 (OH, MI & OK)
- Baseline capital spending target for OH, MI & OK of $350M for 2012
- Pursuing regulatory approvals for other states (AR, LA, WV, VA, IN & KY)
  - Settlement filed in IN with approval expected in 2011
  - Outcomes expected in WV & KY in 2011
  - Proceedings in AR, LA and VA likely to extend into 2012
  - Additional capital spending opportunity in these states for 2012 and beyond

765-kV Tower

Electric Transmission Texas, LLC

Overview:

- ETT is a 50/50 JV owned by subsidiaries of AEP and MidAmerican Energy Holding Company that constructs and operates transmission projects within ERCOT. Total investment opportunity of more than $3 billion.
- Current rate base of $410 million
  - Potential rate base growth:

Year	Increase	Total Rate Base
2011	$72M	$482M
2012	$268M	$750M
2013	$450M	$1,200M
2014	$900M	$2,100M

- Debt to equity ratio of 60/40
- Authorized ROE of 9.96%

Current Portfolio:

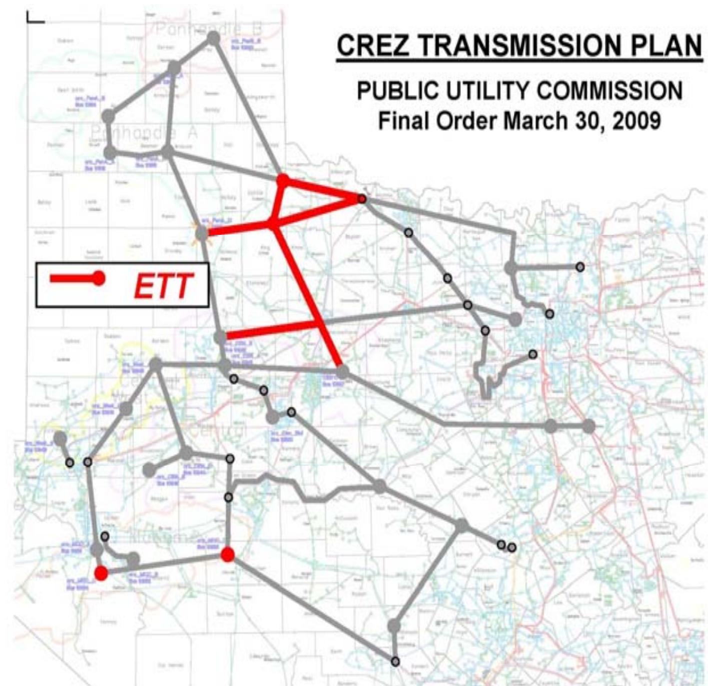
  - Plant In Service: $513M
  - CWIP: $307M

Opportunities:

- CREZ projects: approx. $1.2 billion
- Other Non-CREZ projects: approx. $1.3 billion

Next Steps:

- Perform engineering, procurement and construction work on assigned projects
- Development of other non-CREZ projects
- Continue to operate portfolio of in-service assets



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

Pioneer Transmission, LLC

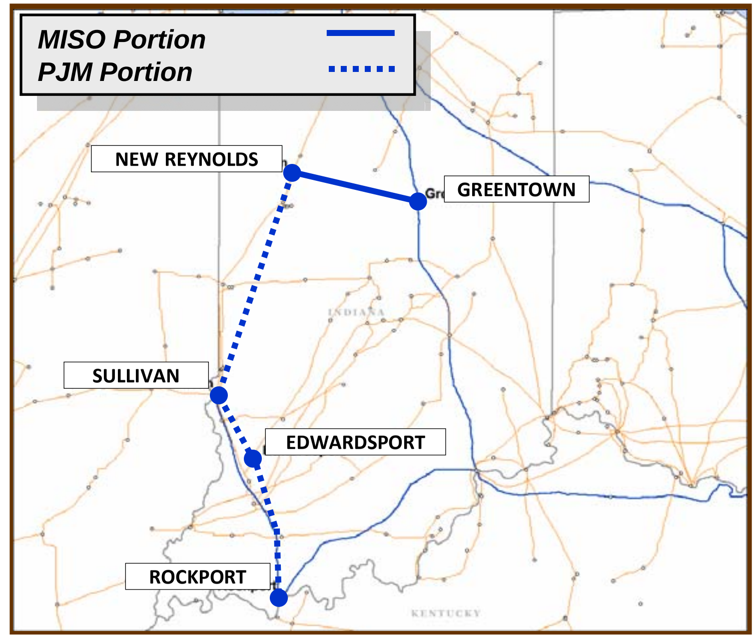
Project Description: 765 kV line extending 240 miles from Rockport (AEP) to Greentown (Duke) substation in Indiana.

Project Overview:

- 50/50 joint venture between AEP and Duke.
- LLC Agreement was executed in August 2008.
- Estimated project cost is $950 million.
- FERC 205 order issued March 2009.
  - ROE of 12.54%
  - 100% CWIP in rate base during development
  - Abandonment for prudently incurred costs
  - 50/50 hypothetical capital structure during construction
  - Establishment of deferred regulatory asset to recover pre-construction costs during the construction period
- In-service in phases between 2015-2018.

Project Status:

- It is anticipated that the Greentown to New Reynolds segment will be included in MISO's MVP portfolio that will be approved for construction by the MISO Board in December 2011.
- Pioneer is planning to file for Indiana utility status in 4Q 2011.



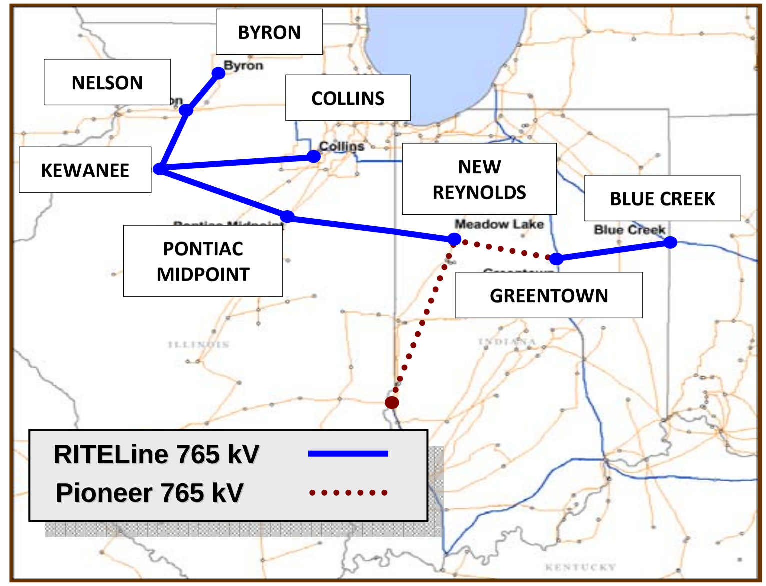
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

RITELine Transmission Development, LLC

Route Description: 765 kV line extends 420 miles from a new substation near Blue Creek on the IN/OH border west to Kewanee, IL and then north to Byron, IL. There is also a segment from Kewanee, IL to Collins, IL.

Project Overview:

- AEP and ETA executed LLC agreements with Exelon to form project companies in Illinois and Indiana in June 2011.
- Estimated project cost is $1.6 billion. The investment is shared 67% by Exelon, 22% by ETA* and 11% by AEP.
- FERC 205 order issued October 2011.
  - ROE of 11.43%
  - 100% CWIP in rate base during development
  - Abandonment for prudently incurred costs
  - 55/45 hypothetical equity to debt capital structure
  - Establishment of deferred regulatory asset to recover pre-construction costs during the construction period
- In-service in phases between 2015-2018.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Project Status:

- Continue advocacy with PJM to ensure inclusion in the 2012 - 2013 RTEP planning process

*ETA is a 50/50 Joint venture between subsidiaries of MidAmerican Energy Holding Company and AEP

Prairie Wind Transmission, LLC

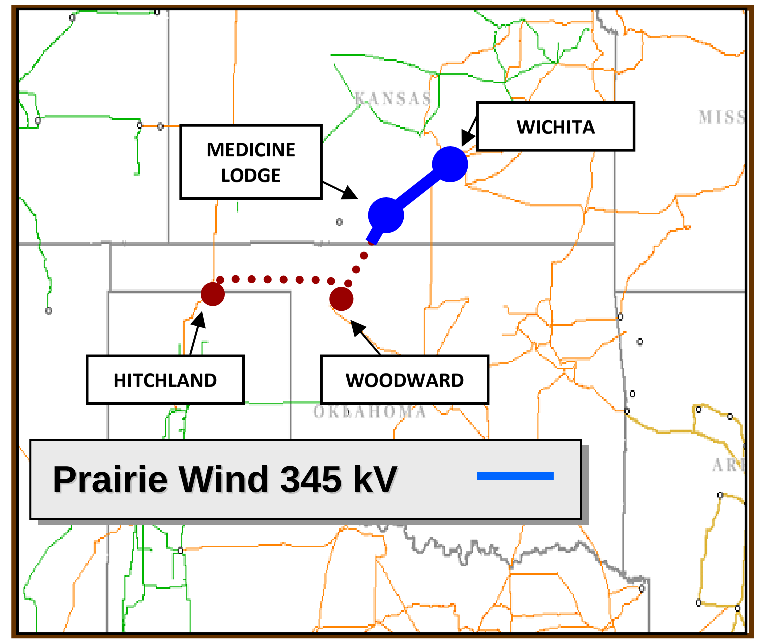
Route Description: Double circuit 345 kV line extends 110 miles from Westar's substation near Wichita to a new substation near Medicine Lodge, KS extending further south-southwest to the KS/OK border.

Project Overview:

- 50/50 joint venture between ETA and Westar Energy
- LLC agreement was executed in May 2008.
- FERC 205 order issued December 2008:
  - 12.8% incentive ROE
  - 100% CWIP in rate base during development
  - Abandonment for prudently incurred costs
  - 50/50 hypothetical capital structure during construction
  - Establishment of deferred regulatory asset to recover pre-construction costs during the construction period
- Estimated project cost is $225 million.
- In-service date is December 2014.

Project Status:

- Approved as SPP Priority Project in April 2010.
- Notice to Construct at double circuit 345 kV received July 2010
- Siting application approved in June 2011.
- Compliance filing to recover costs made in May 2011.
- Right-of-way acquisition underway.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Midwest Power Transmission, LLC

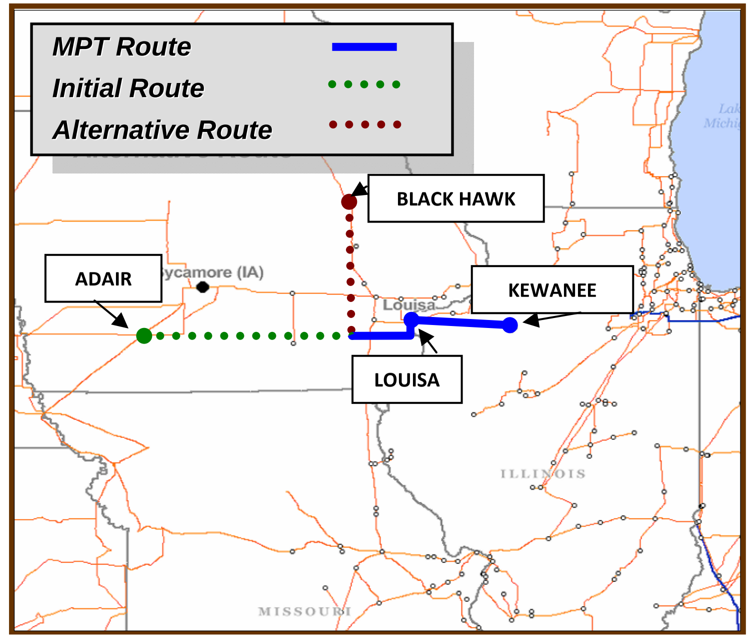
Project Description: 765 kV line extends 70 miles from Kewanee in Henry County to Louisa County in eastern Iowa. From Louisa County two routes are being considered: a route extending 195 miles to Adair County in southwestern Iowa (total of 265 miles) and an alternative route extending 165 miles to Black Hawk County in northeastern Iowa (total of 235 miles).

Project Overview:

- 50/50 joint venture between ETA and MidAmerican Energy Company.
- LLC Agreement was executed in August 2011.
- MPT line will strengthen the high voltage transmission system connecting Illinois and Iowa.
- Estimated project cost of the initial route is $865 million.
  - The estimated project cost of the alternative route is $650 million.
- In-service date is estimated to be 2019.
- FERC 205 Filing is expected in 4Q 2011.

Project Status:

- Economic and reliability transmission studies to support the FERC 205 filing are expected to be completed by 4Q 2011.



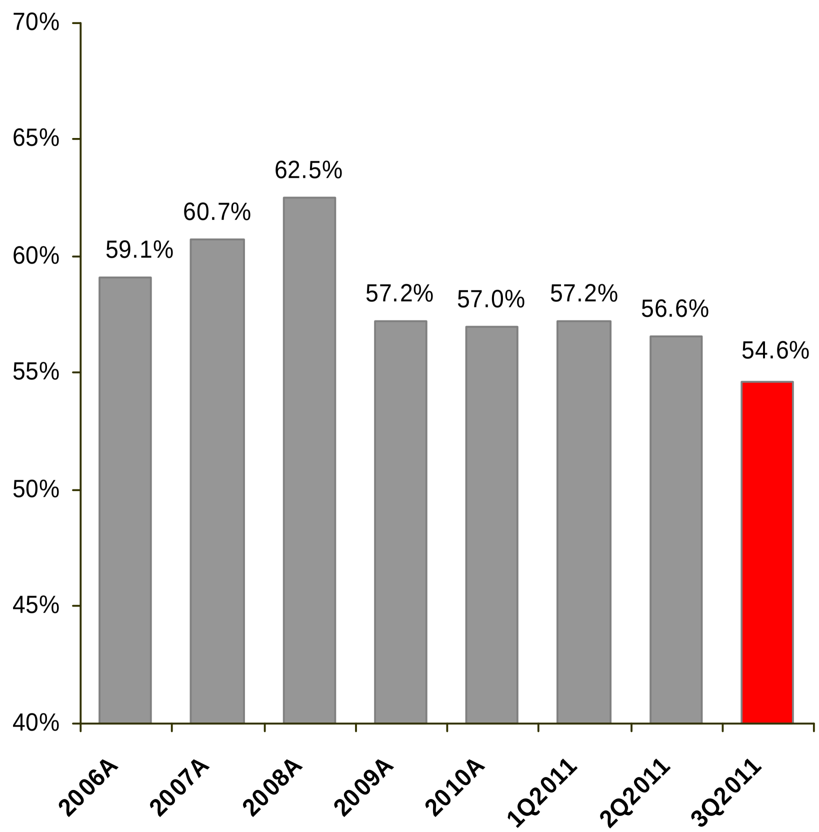
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Financial Update

- Capitalization and Liquidity Position
- Banking Group
- Credit Ratings
- Long-Term Debt Maturity Profile
- Debt Schedules

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		Actual	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

AEP Banking Group

		Credit Ratings Moodys/S&P/ Fitch
Domestic	**43.7%**	
JPMorgan Chase		Aa3 / A+ / AA-
Citibank		A3 / A / A+
Key Bank		A3 / BBB+ / A-
Wells Fargo		A1 / AA- / AA-
US Bank		Aa3 / A+ / AA-
SunTrust		Baa1 / BBB+ / A-
Bank of New York-Mellon		Aa2 / AA- / AA-
Goldman Sachs		A1 / A / A+
Morgan Stanley		A2 / A / A
PNC Bank		A3 / A / A+
Fifth Third		Baa1 / BBB / A-
Huntington		Baa2 / BBB / BBB+
Northern Trust		A1 / AA- / AA-
European	**27.8%**	
Credit Agricole		Aa2 / A+ / AA-
Royal Bank of Scotland		A1 / A / AA-
Barclays		A1 / A+ / AA-
Credit Suisse		Aa2 / A+ / AA-
BNP Paribas		Aa2 / AA / AA-
UBS		Aa3 / A+ / A+
Deutsche Bank		Aa3 / A+ / AA-
BBVA		Aa2 / AA / AA-
WestLB		A3 / BBB+ / A-
Asian	**17.4%**	
Bank of Tokyo-Mitsubishi		Aa3 / A / A
Mizuho		A1 / A / A
Sumitomo		Aa3 / A / AA-
Canadian	**11.1%**	
Scotia		Aa1 / AA- / AA-
Royal Bank of Canada		Aa1 / AA- / AA
Total		

Percentages based on participation in the two core credit facitilites, AEP Credit, stand-alone letters of credit and AEP's share of OVEC and ETT.
Ratings as of September 30, 2011

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	A-	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	N	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	P
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

Ratings current as of September 30, 2011

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013	2014	2015	2016
AEP, Inc.	-	-	-	-	$243	-
AEP Generating Company	-	-	-	$45	-	-
Appalachian Power	-	$315	$195	$204	$500	
Columbus Southern Power	-	$195	$306	$60	-	-
Indiana Michigan Power	-	$100	$126	$332	$176	-
Kentucky Power	-	-	-	-	-	-
Ohio Power	-	-	$550	$344	$86	$350
Public Service of Oklahoma	-	-	-	$34	-	$150
Southwestern Electric Power	-	$20	-	-	$304	-
Texas Central Company(1)	-	$60	$314	-	$250	$192
Texas North Company	-	-	$225	-	-	-
Total	-	$690	$1,717	$1,019	$1,558	$692

(1) Includes $756 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of September 30, 2011

Debt Schedules

American Electric Power, Inc	Interest	Maturity	Amount
Junior Subordinated Debentures	8.750%	03/01/2063	$315,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	7.23%		$557,775,000

AEP Generating	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2025[1]	$22,500,000
Pollution Control Bond	Floating	07/01/2025[1]	$22,500,000
Senior Notes	6.330%	09/30/2037	$189,090,980
Weighted Average or Total	6.330%		$234,090,980

[1] Put date 7/15/2014

AEP Texas North	Interest	Maturity	Amount
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Senior Notes	5.500%	03/01/2013	$225,000,000
Senior Notes	5.890%	04/01/2018	$30,000,000
Senior Notes	6.760%	04/01/2038	$70,000,000
Weighted Average or Total	5.645%		$369,310,000

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

Debt Schedules

AEP Texas Central	Interest	Maturity	Amount
Pollution Control Bond	5.625%	10/01/2017	$40,890,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Pollution Control Bond	6.300%	11/01/2029	$100,635,000
Pollution Control Bond	5.200%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	1.125%	06/01/2030[2]	$60,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.421%		$704,555,000
Securitization Bond	5.960%	07/15/2013	$130,670,070
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	6.133%		$322,526,928
Securitization Bond	4.980%	07/01/2013	$183,518,567
Securitization Bond	5.090%	07/01/2015	$250,000,000
Securitization Bond	5.170%	01/01/2018	$437,000,000
Securitization Bond	5.306%	07/01/2020	$494,700,000
Weighted Average or Total	5.179%		$1,365,218,567

[2] Put date 06/01/2012

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

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Debt Schedules

Appalachian Power Company	Interest	Maturity	Amount
Pollution Control Bond	4.850%	05/01/2019[3]	$30,000,000
Pollution Control Bond	4.850%	05/01/2019[3]	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	4.625%	11/01/2021	$17,500,000
Pollution Control Bond	2.000%	10/1/2022[4]	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/1/2036[5]	$50,275,000
Pollution Control Bond	Floating	02/1/2036[5]	$75,000,000
Pollution Control Bond	5.375%	12/01/2038	$50,000,000
Pollution Control Bond	2.000%	01/1/2041[6]	$65,350,000
Pollution Control Bond	Floating	12/1/2042[7]	$54,375,000
Pollution Control Bond	Floating	12/1/2042[7]	$50,000,000
Senior Notes	5.650%	08/15/2012	$250,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	3.400%	05/24/2015	$300,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	7.950%	01/15/2020	$350,000,000
Senior Notes	4.600%	03/30/2021	$350,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Senior Notes	6.700%	08/15/2037	$250,000,000
Senior Notes	7.000%	04/01/2038	$500,000,000
Weighted Average or Total	5.65%		$3,732,000,000

[3] Put date 09/04/2013
[4] Put date 10/01/2014
[5] Put date 03/17/2013
[6] Put date 08/01/2012
[7] Put date 03/24/2014

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Columbus Southern Power	Interest	Maturity	Amount
Pollution Control Bond	3.875%	12/01/2038[8]	$60,000,000
Pollution Control Bond	5.800%	12/01/2038	$32,245,000
Pollution Control Bond	4.850%	08/01/2040[9]	$44,500,000
Pollution Control Bond	5.100%	11/01/2042[10]	$56,000,000
Senior Notes	Floating	03/16/2012	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.050%	05/01/2018	$350,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.822%		$1,442,745,000

[8] Put date 06/01/2014
[9] Put date 04/01/2012
[10] Put date 05/01/2013

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Indiana Michigan Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019[11]	$25,000,000
Pollution Control Bond	Floating	11/01/2021[12]	$52,000,000
Pollution Control Bond	5.250%	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	6.250%	06/01/2025[13]	$50,000,000
Pollution Control Bond	6.250%	06/01/2025[13]	$50,000,000
Nuclear Fuel Lease	5.440%	10/01/2013	$49,274,327
Nuclear Fuel Lease	4.000%	10/13/2014	$56,946,886
Nuclear Fuel Lease	Floating	06/07/2015	$51,410,250
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	7.000%	03/15/2019	$475,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	6.068%		$1,699,631,464

[11] Put date is 03/22/2013

[12] Put date is 03/16/2013

[13] Put date is 06/02/2014

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

Debt Schedules

Kentucky Power	Interest	Maturity	Amount
Senior Notes	6.000%	09/15/2017	$325,000,000
Senior Notes	7.250%	06/18/2021	$40,000,000
Senior Notes	8.030%	06/18/2029	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Senior Notes	8.130%	06/18/2039	$60,000,000
Weighted Average or Total	6.397%		$530,000,000

Ohio Power Company	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/1/2014[14]	$50,000,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	2.875%	12/01/2027[15]	$39,130,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Pollution Control Bond	3.250%	06/01/2041[16]	$79,450,000
Pollution Control Bond	3.125%	06/01/2043[17]	$86,000,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	5.750%	09/01/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	5.375%	10/01/2021	$500,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Weighted Average or Total	5.482%		$2,419,580,000

[14] Put date 03/10/2013
[15] Put date 08/01/2014
[16] Put date 06/02/2014
[17] Put date 04/01/2015

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.

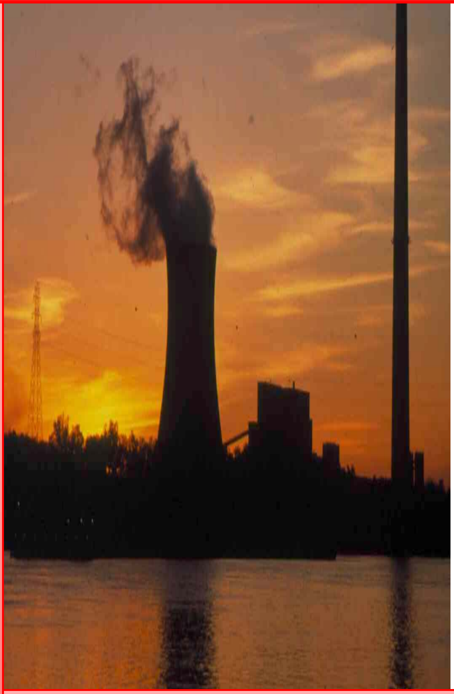
Debt Schedules

Public Service Company of Oklahoma	Interest	Maturity	Amount
Pollution Control Bond	5.250%	06/01/2014	$33,700,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Senior Notes	5.150%	12/01/2019	$250,000,000
Senior Notes	4.400%	02/01/2021	$250,000,000
Senior Notes	6.625%	11/15/2037	$250,000,000
Weighted Average or Total	5.494%		$946,360,000

Southwestern Electric Power Company	Interest	Maturity	Amount
Notes Payable	7.030%	02/22/2012	$20,000,000
Notes Payable	6.370%	10/31/2024	$25,000,000
Pollution Control Bond	4.950%	03/01/2018	$81,700,000
Pollution Control Bond	3.250%	01/01/2019[18]	$53,500,000
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Senior Notes	5.875%	03/01/2018	$300,000,000
Senior Notes	6.450%	01/15/2019	$400,000,000
Senior Notes	6.200%	03/15/2040	$350,000,000
Weighted Average or Total	5.809%		$1,730,200,000

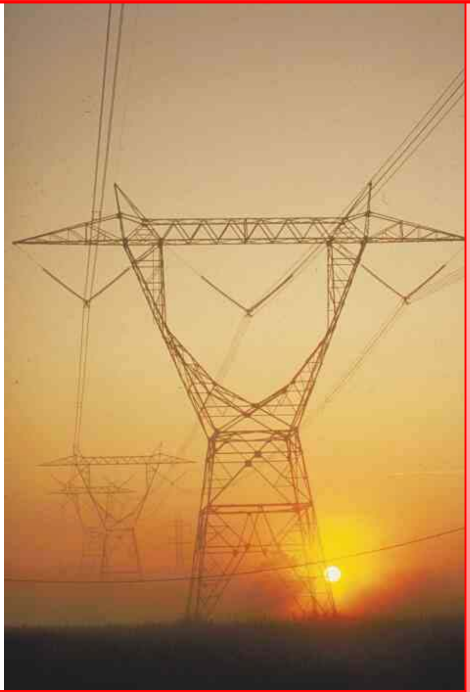
[18] Put date 01/02/2015

Note: Debt schedules current as of 9/30/11. The weighted average coupon excludes all floating rate debt.



2Q07 Earnings Release Presentation

July 31, 2007



AMERICAN ELECTRIC POWER

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This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Second Quarter 2007 Highlights

- 2Q 2007 GAAP Earnings of $0.45 per share; Ongoing Earnings of $0.64 per share
- YTD 2007 GAAP Earnings of $1.13 per share; Ongoing Earnings of $1.33 per share
- Reaffirming 2007 Ongoing Earnings Guidance Range of $2.85 to $3.05 per share
- Low Carbon Economy Act of 2007
- PJM's 2008/2009 RPM Capacity Auction
- Regulatory Update
  - **Ohio**
    - Post-2008 Plan
  - **Virginia**
    - Fuel, E&R and IGCC Filings
  - **Oklahoma**
    - General Base Rate Case Order
  - **Indiana**
    - Depreciation Case and Rate Petition
  - **Transmission Project Updates**
    - Electric Transmission Texas LLC Hearings
    - PATH JV
    - Michigan 765-kV study with ITC
    - SPP Overlay Study Released
  - **Generation Project Updates**
    - IGCC Filings in West Virginia and Virginia
    - Red Rock Proceedings concluded in Oklahoma
    - Turk Plant Filings in Arkansas, Louisiana and Texas Progressing
    - Commercial Operation Declaration for Mattison Plant on July 12, 2007 – 150 MW

2Q07 Performance

		2006 Actual		2007 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	471		453	
2	Ohio Companies	487		610	
3	West Regulated Integrated Utilities	272		229	
4	Texas Wires	121		131	
5	Off-System Sales	151		203	
6	Transmission Revenue - 3rd Party	49		71	
7	Other Operating Revenue	122		148	
8	Utility Gross Margin	1,673		1,845	
9	Operations & Maintenance	(796)		(770)	
10	Depreciation & Amortization	(346)		(365)	
11	Taxes Other than Income Taxes	(187)		(187)	
12	Interest Exp & Preferred Dividend	(161)		(207)	
13	Other Income & Deductions	44		27	
14	Income Taxes	(68)		(105)	
15	Utility Operations On-Going Earnings	159	0.40	238	0.60
	NON-UTILITY OPERATIONS:				
16	MEMCO	14	0.04	7	0.02
17	Generation & Marketing	2	0.01	15	0.03
18	Non-Utility Operations On-Going Earnings	16		22	
19	Parent and Other On-Going Earnings	(3)	(0.01)	(3)	(0.01)
20	ON-GOING EARNINGS	172	0.44	257	0.64

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q 2007 Performance Drivers

- *Weather Impact of $26MM:*
  - *Positive $0.03 vs. normal; Positive $0.04 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Positive load growth, including new customers - $86MM*
  - *Offset by Fuel and ENEC under-recovery ($32MM)*
- *Off-System Sales (line 5):*
  - *Increased due to higher margins*
- *Transmission Revenue (line 6):*
  - *Higher due to $18MM provision booked in 2Q06 for potential SECA refunds*
- *Other Operating Revenue (line 7):*
  - *Increase related to Texas securitization revenue*
- *Operations & Maintenance (line 9):*
  - *Decreased due to favorable insurance policyholder's surplus adjustments and lower storm restoration*
- *Depreciation & Amortization (line 10):*
  - *Increased asset base and amortization related to the Texas securitization and the Ohio RSPs*
- *Interest Expense (line 12):*
  - *Increased long term debt outstanding, including Texas securitization bonds issued in October 2006*
- *Other Income & Deductions (line 13):*
  - *Reduced carrying charges of $17MM primarily due to the Texas securitization in October 2006*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 30.6% in 2007 and 30.0% in 2006*

YTD 2007 Performance

		2006 Actual ($ millions)	2006 Actual EPS	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	1,035		1,057	
2	Ohio Companies	1,004		1,213	
3	West Regulated Integrated Utilities	467		429	
4	Texas Wires	227		244	
5	Off-System Sales	373		384	
6	Transmission Revenue - 3rd Party	151		143	
7	Other Operating Revenue	256		289	
8	Utility Gross Margin	3,513		3,759	
9	Operations & Maintenance	(1,513)		(1,598)	
10	Depreciation & Amortization	(686)		(748)	
11	Taxes Other than Income Taxes	(374)		(371)	
12	Interest Exp & Preferred Dividend	(315)		(386)	
13	Other Income & Deductions	153		66	
14	Income Taxes	(254)		(231)	
15	Utility Operations On-Going Earnings	524	1.33	491	1.24
	NON-UTILITY OPERATIONS:				
16	MEMCO	35	0.09	22	0.06
17	Generation & Marketing	6	0.02	14	0.03
18	Non-Utility Operations On-Going Earnings	41		36	
19	Parent and Other On-Going Earnings	(15)	(0.04)	1	-
20	ON-GOING EARNINGS	550	1.40	528	1.33

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2007 Performance Drivers

- *Weather Impact of $66MM:*
  - *Positive $0.04 vs. normal; Positive $0.11 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Rate relief primarily in OH, KY and TX - $103MM*
  - *Load growth, including new customers - $120MM*
  - *Slightly offset by lower FTR income - ($48MM) and*
  - *Fuel under-recovery ($29MM)*
- *Other Operating Revenue (line 7):*
  - *Increase related to Texas securitization revenue*
- *Operations & Maintenance (line 9):*
  - *Increased due to plant outages and maintenance, storm costs and increased vegetation management*
- *Depreciation & Amortization (line 10):*
  - *Increased asset base and amortization related to the Texas securitization and the Ohio RSPs*
- *Interest Expense (line 12):*
  - *Increased long term debt outstanding, including Texas securitization bonds issued in October 2006*
- *Other Income & Deductions (line 13):*
  - *Decreased Centrica sharing contribution of $20MM in 2007 vs. $70MM in 2006 and reduced carrying charges of $39MM primarily due to the Texas securitization in October 2006*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.0% in 2007 and 32.6% in 2006*

YTD 2007 Cash Flow

($ millions)	2006	2007
Operating Activities		
Net Income -- Reported	**$ 556**	**$ 451**
Discontinued Operations	(6)	(2)
Continuing Earnings	**550**	**449**
Depreciation, Amortization & Deferred Taxes	735	783
Extraordinary Loss, net of Taxes	-	79
Changes in Components of Working Capital	(183)	(285)
Other Assets & Liabilities	21	(57)
Cash Flows From Operating Activities	**1,123**	**969**
Investing Activities		
Capital Expenditures	(1,611)	(1,823)
Proceeds on Sale of Assets	118	74
Acquisitions of Assets	-	(427)
Change in Other Temporary Cash Investments (net)	(20)	101
Other Investing (net)	(59)	(52)
Cash Flows Used for Investing Activities	**(1,572)**	**(2,127)**
Financing Activities		
Common Shares Issued/(Retired), net	6	90
Long-term Debt Issuances/(Retirements)	405	874
Short-term Debt Increase/(Decrease), net	147	420
Other Financing	30	(44)
Dividends Paid	(291)	(311)
Cash Flows From Financing Activities	**297**	**1,029**
Cash From Continuing Operations	**$ (152)**	**$ (129)**
Beginning Cash & Cash Equivalent Balances	401	301
Ending Cash & Cash Equivalent Balances	**$ 249**	**$ 172**

YTD 2007 Cash Flow Drivers

Operating Activities

- *Changes in Working Capital largely driven by G&A-type items*

Investing Activities

- *Cash outlay of $1.8 billion for YTD 2007 capital investment.*
- *2007 primary asset sale proceeds: Centrica sharing ($20MM) and TCC's share of Oklaunion ($43MM); 2006 primary asset sale proceeds: Centrica sharing ($70MM) and Bajio ($29MM)*
- *2007 acquisitions consist of the Darby Plant for $102MM and Lawrenceburg for $325MM*
- *Other Temporary Cash Investments were partially utilized in 2007 to support cash needs. The balance was unusually high at December 31, 2006 due to investments purchased with the proceeds from the Texas securitization in 4Q06*

Financing Activities

- *Common stock issuance of $90MM primarily related to the exercise of stock options during 2007*

Ending cash balance for Q1 2007 of $259MM. 2007 guidance assumes year-end cash balance of $205MM

AEP®

Capitalization

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

Adjusted debt-to-cap of 58.3% at 6/30/07

QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 2nd Quarter 2007 Actual vs 2nd Quarter 2006 Actual

		2006 Actual			2007 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	15,782 GWh @ $ 29.8 /MWhr =	471		16,845 GWh @ $ 26.9 /MWhr =	453	
2	Ohio Companies	10,860 GWh @ $ 44.8 /MWhr =	487		12,030 GWh @ $ 50.7 /MWhr =	610	
3	West Regulated Integrated Utilities	10,016 GWh @ $ 27.2 /MWhr =	272		10,150 GWh @ $ 22.6 /MWhr =	229	
4	Texas Wires	6,915 GWh @ $ 17.5 /MWhr =	121		6,746 GWh @ $ 19.4 /MWhr =	131	
5	Off-System Sales	8,075 GWh @ $ 18.7 /MWhr =	151		7,168 GWh @ $ 28.3 /MWhr =	203	
6	Transmission Revenue - 3rd Party		49			71	
7	Other Operating Revenue		122			148	
8	**Utility Gross Margin**		1,673			1,845	
9	Operations & Maintenance		(796)			(770)	
10	Depreciation & Amortization		(346)			(365)	
11	Taxes Other than Income Taxes		(187)			(187)	
12	Interest Exp & Preferred Dividend		(161)			(207)	
13	Other Income & Deductions		44			27	
14	Income Taxes		(68)			(105)	
15	**Utility Operations On-Going Earnings**		159	0.40		238	0.60
	NON-UTILITY OPERATIONS:						
16	MEMCO		14	0.04		7	0.02
17	Generation & Marketing		2	0.01		15	0.03
18	**Non-Utility Operations On-Going Earnings**		16			22	
19	**Parent & Other On-Going Earnings**		(3)	(0.01)		(3)	(0.01)
20	**ON-GOING EARNINGS**		172	0.44		257	0.64

Shares outstanding (in millions) 394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance Comparison

American Electric Power

Financial Results for YTD June 2007 Actual vs YTD June 2006 Actual

			2006 Actual			2007 Actual	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	33,874 GWh @ $ 30.6 /MWhr =	1,035		36,057 GWh @ $ 29.3 /MWhr =	1,057	
2	Ohio Companies	22,389 GWh @ $ 44.8 /MWhr =	1,004		24,615 GWh @ $ 49.3 /MWhr =	1,213	
3	West Regulated Integrated Utilities	18,939 GWh @ $ 24.7 /MWhr =	467		19,825 GWh @ $ 21.6 /MWhr =	429	
4	Texas Wires	12,461 GWh @ $ 18.2 /MWhr =	227		12,577 GWh @ $ 19.4 /MWhr =	244	
5	Off-System Sales	16,589 GWh @ $ 22.5 /MWhr =	373		12,832 GWh @ $ 29.9 /MWhr =	384	
6	Transmission Revenue - 3rd Party		151			143	
7	Other Operating Revenue		256			289	
8	**Utility Gross Margin**		3,513			3,759	
9	Operations & Maintenance		(1,513)			(1,598)	
10	Depreciation & Amortization		(686)			(748)	
11	Taxes Other than Income Taxes		(374)			(371)	
12	Interest Exp & Preferred Dividend		(315)			(386)	
13	Other Income & Deductions		153			66	
14	Income Taxes		(254)			(231)	
15	**Utility Operations On-Going Earnings**		524	1.33		491	1.24
	NON-UTILITY OPERATIONS:						
16	MEMCO		35	0.09		22	0.06
17	Generation & Marketing		6	0.02		14	0.03
18	**Non-Utility Operations On-Going Earnings**		41			36	
19	**Parent & Other On-Going Earnings**		(15)	(0.04)		1	-
20	**ON-GOING EARNINGS**		550	1.40		528	1.33

Shares outstanding (in millions) 394 [illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

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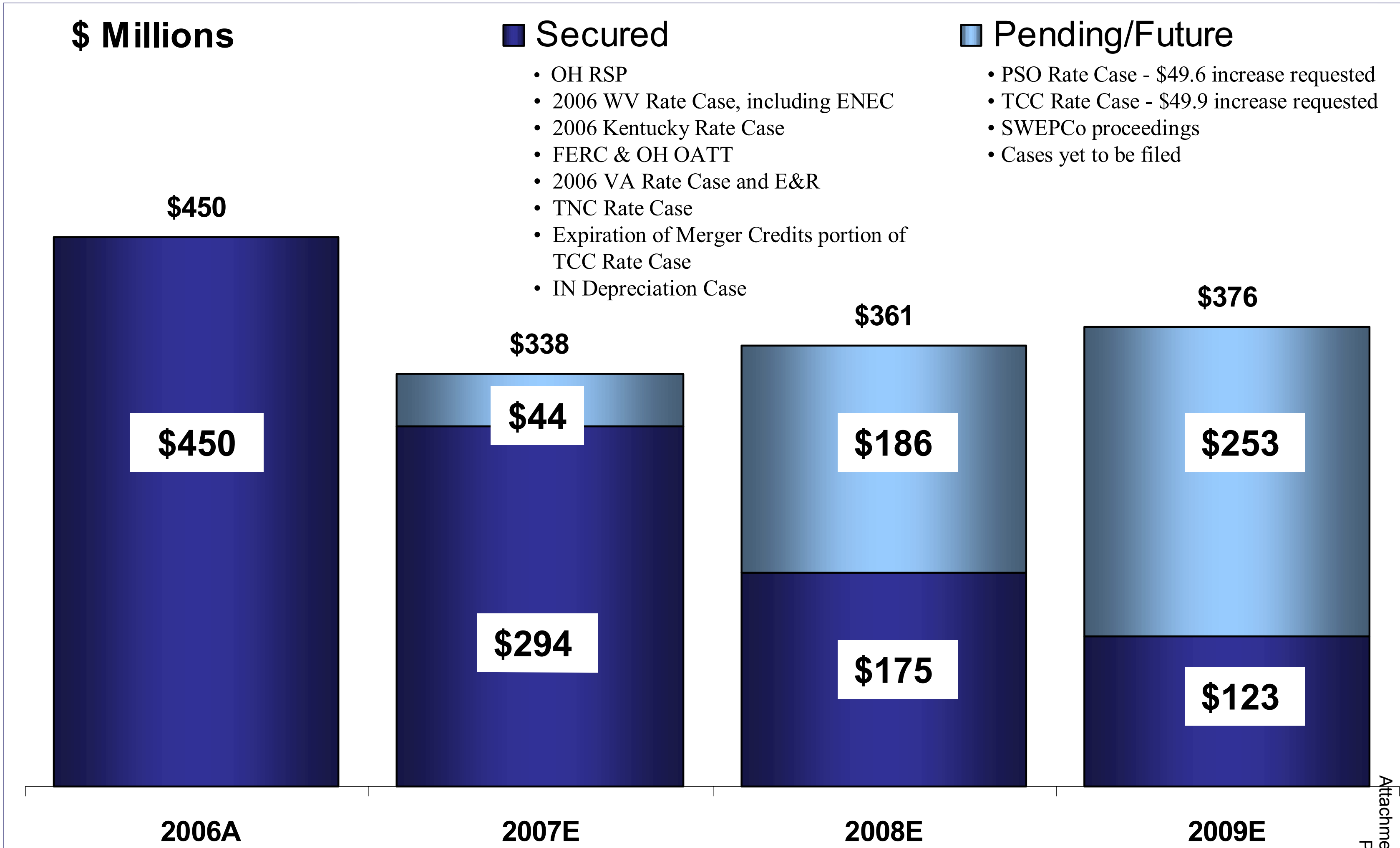
Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

2Q07 Retail Performance

	Load Growth (weather normalized)
	2Q 07 vs. 2Q 06
East Regulated Integrated Utilities	5.3%
Ohio Companies	10.9%
West Regulated Integrated Utilities	3.0%
Texas Wires	4.2%
Impact on EPS	$0.17

	Degree Days
	2Q 07 vs. 2Q 06
East Cooling	139
West Cooling *	(193)
East Heating	115
West Heating *	87
Impact on EPS	$0.04

* West statistics represent PSO/SWEPCo customer base only

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YTD Retail Performance

	Load Growth (weather normalized)
	YTD 6/30/07 vs. YTD 6/30/06
East Regulated Integrated Utilities	4.2%
Ohio Companies	8.1%
West Regulated Integrated Utilities	3.4%
Texas Wires	3.2%
Impact on EPS	$0.23

	Degree Days
	YTD 6/30/07 vs. YTD 6/30/06
East Cooling	153
West Cooling *	(180)
East Heating	476
West Heating *	331
Impact on EPS	$0.11

* West statistics represent PSO/SWEPCo customer base only

Retail Performance

	Rate Relief (in millions)
	2Q 07 vs. 2Q 06
East Regulated Integrated Utilities	$(37)
Ohio Companies	$36
West Regulated Integrated Utilities	$2
Texas Wires	$8
AEP System Total	$9
Impact on EPS	$0.01

	Rate Relief (in millions)
	YTD 6/30/07 vs. YTD 6/30/06
East Regulated Integrated Utilities	$20
Ohio Companies	$71
West Regulated Integrated Utilities	$4
Texas Wires	$8
AEP System Total	$103
Impact on EPS	$0.17

2Q07 Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	2Q 2007	2Q 2006	2Q 2007	2Q 2006	2Q 2007	2Q 2006
East:	**58.64%**	**61.14%**	**78.86%**	**76.84%**	**9.28%**	**11.91%**
Coal:	64.51%	65.98%	74.13%	73.95%	10.38%	13.11%
Super-Critical *	63.89%	70.10%	72.28%	77.00%	11.29%	8.38%
Sub-Critical *	66.61%	51.84%	79.82%	64.52%	7.71%	27.29%
Gas **	4.75%	1.42%	93.17%	99.06%	0.56%	0.01%
Hydro	10.00%	10.58%	91.85%	95.80%	10.96%	6.12%
Nuclear	98.17%	78.05%	99.91%	78.64%	0.00%	0.00%
SPP:	**40.61%**	**44.84%**	**81.38%**	**83.20%**	**8.83%**	**7.91%**
Coal:	71.56%	74.07%	76.68%	80.20%	6.02%	2.77%
Super-Critical *	53.68%	76.51%	56.17%	80.03%	15.12%	4.14%
Sub-Critical *	78.32%	73.14%	84.43%	80.26%	3.44%	2.24%
Gas	19.89%	24.93%	84.53%	85.27%	11.32%	12.13%
Texas:						
Coal	**84.67%**	**39.01%**	**86.13%**	**41.27%**	**11.48%**	**54.76%**
AEP System	**55.25%**	**57.38%**	**79.52%**	**77.78%**	**9.22%**	**11.84%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

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YTD Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	YTD 2007	YTD 2006	YTD 2007	YTD 2006	YTD 2007	YTD 2006
East:	**61.94%**	**65.03%**	**80.28%**	**81.45%**	**8.64%**	**9.25%**
Coal:	68.76%	69.90%	76.31%	78.95%	9.53%	10.24%
Super-Critical *	68.69%	72.99%	74.42%	80.14%	9.55%	7.66%
Sub-Critical *	69.02%	59.25%	82.16%	75.26%	9.49%	18.12%
Gas **	4.65%	0.80%	94.00%	97.14%	1.47%	0.08%
Hydro	11.65%	11.74%	90.17%	96.03%	14.62%	5.23%
Nuclear	100.08%	86.83%	99.94%	86.93%	0.00%	0.00%
SPP:	**41.25%**	**41.83%**	**83.84%**	**83.27%**	**6.67%**	**6.04%**
Coal:	74.04%	70.70%	79.16%	76.35%	4.48%	3.43%
Super-Critical *	67.75%	75.86%	70.33%	78.89%	8.20%	5.85%
Sub-Critical *	76.42%	68.74%	82.50%	75.38%	3.22%	2.43%
Gas	19.26%	22.16%	86.98%	88.04%	8.90%	8.53%
Texas:						
Coal	**63.82%**	**53.27%**	**64.29%**	**57.15%**	**23.77%**	**34.06%**
AEP System	**57.73%**	**59.95%**	**80.89%**	**81.50%**	**8.47%**	**9.07%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

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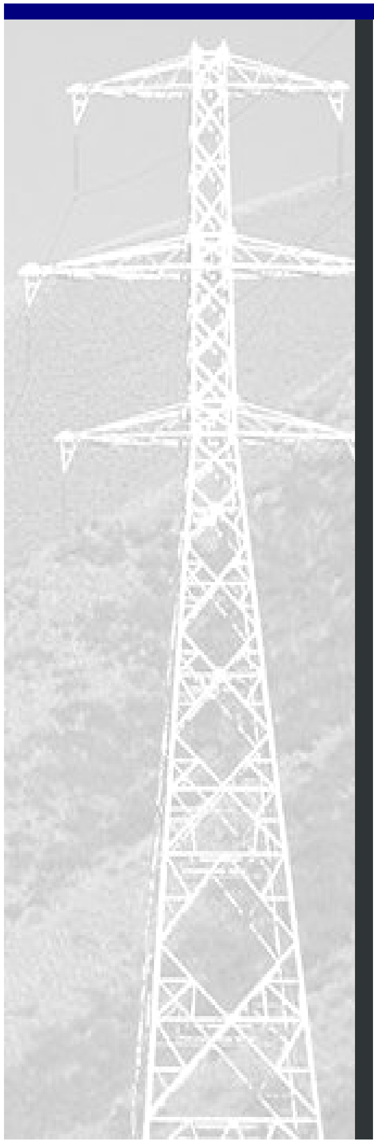

2Q09 Earnings Release Presentation

July 31, 2009

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Second Quarter 2009 Highlights

- 2Q09 GAAP Earnings $0.67 per share;
  2Q09 Ongoing Earnings $0.68
- 2009 YTD GAAP Earnings $1.54 per share;
  2009 YTD Ongoing Earnings $1.55
- Reaffirming 2009 Ongoing Earnings Guidance Range of $2.75 to $3.05 per share
- Ohio ESP Rehearing Order
- New Generation-Turk Plant
- Federal Legislation Update

2nd Quarter Earnings Results Keep Us in Our Targeted Earnings Range

Quarterly Performance Comparison

American Electric Power

Financial Results for 2nd Quarter 2008 Actual vs 2nd Quarter 2009 Actual

			2008 Actual			2009 Actual	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	16,881 GWh @ $ 31.3 /MWhr =	528		15,143 GWh @ $ 37.7 /MWhr =	571	
2	Ohio Companies	12,606 GWh @ $ 43.7 /MWhr =	551		10,914 GWh @ $ 62.4 /MWhr =	681	
3	West Regulated Integrated Utilities	10,339 GWh @ $ 24.9 /MWhr =	257		10,099 GWh @ $ 30.2 /MWhr =	305	
4	Texas Wires	7,132 GWh @ $ 18.8 /MWhr =	134		6,888 GWh @ $ 20.2 /MWhr =	139	
5	Off-System Sales	7,564 GWh @ $ 32.1 /MWhr =	243		3,619 GWh @ $ 24.4 /MWhr =	88	
6	Transmission Revenue - 3rd Party		82			90	
7	Other Operating Revenue		144			186	
8	Utility Gross Margin		1,939			2,060	
9	Operations & Maintenance		(840)			(805)	
10	Depreciation & Amortization		(365)			(388)	
11	Taxes Other than Income Taxes		(188)			(188)	
12	Interest Exp & Preferred Dividend		(218)			(228)	
13	Other Income & Deductions		49			24	
14	Income Taxes		(114)			(150)	
15	**Utility Operations On-Going Earnings**		263	0.66		325	0.69
16	**Transmission Operations On-Going Earnings**		-	-		1	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		3	0.01		1	-
18	Generation & Marketing		26	0.06		4	0.01
	PARENT & OTHER:						
19	Parent & Other On-Going Earnings		(12)	(0.03)		(10)	(0.02)
20	**ON-GOING EARNINGS**		280	0.70		321	0.68

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD Performance Comparison

American Electric Power

Financial Results for YTD June 2008 Actual vs YTD June 2009 Actual

		2008 Actual			2009 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	36,423 GWh @ $ 30.8 /MWhr =	1,122		33,804 GWh @ $ 37.3 /MWhr =	1,261	
2	Ohio Companies	26,507 GWh @ $ 47.0 /MWhr =	1,247		24,049 GWh @ $ 54.9 /MWhr =	1,320	
3	West Regulated Integrated Utilities	20,208 GWh @ $ 23.7 /MWhr =	480		19,162 GWh @ $ 28.4 /MWhr =	544	
4	Texas Wires	12,955 GWh @ $ 19.8 /MWhr =	256		12,626 GWh @ $ 21.1 /MWhr =	266	
5	Off-System Sales	15,799 GWh @ $ 29.4 /MWhr =	464		6,214 GWh @ $ 27.8 /MWhr =	173	
6	Transmission Revenue - 3rd Party		162			174	
7	Other Operating Revenue		289			393	
8	Utility Gross Margin		4,020			4,131	
9	Operations & Maintenance		(1,587)			(1,608)	
10	Depreciation & Amortization		(720)			(761)	
11	Taxes Other than Income Taxes		(382)			(382)	
12	Interest Exp & Preferred Dividend		(428)			(449)	
13	Other Income & Deductions		90			55	
14	Income Taxes		(321)			(318)	
15	**Utility Operations On-Going Earnings**		672	1.67		668	1.52
16	**Transmission Operations On-Going Earnings**		1	-		1	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		10	0.03		12	0.03
18	Generation & Marketing		27	0.07		28	0.06
	PARENT & OTHER:						
19	**Parent & Other On-Going Earnings**		(20)	(0.05)		(28)	(0.06)
20	**ON-GOING EARNINGS**		690	1.72		681	1.55

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2009 Cash Flow

($ millions)	2008	2009
Operating Activities		
Net Income -- Reported	**$ 858**	**$ 680**
Discontinued Operations	(1)	-
Continuing Earnings	**857**	**680**
Depreciation, Amortization & Deferred Taxes	1,123	1,193
Changes in Components of Working Capital	(253)	(717)
Extraordinary Loss	-	5
Other Assets & Liabilities	(526)	(304)
Cash Flows From Operating Activities	**1,201**	**857**
Investing Activities		
Capital Expenditures	(1,608)	(1,547)
Proceeds on Sale of Assets	69	240
Change in Other Temporary Cash Investments, net	80	11
Other Investing, net	(186)	(182)
Cash Flows Used for Investing Activities	**(1,645)**	**(1,478)**
Financing Activities		
Common Shares Issued, net	72	1,688
Long-term Debt Issuances, net	732	703
Short-term Debt Increase/(Decrease), net	45	(1,414)
Other Financing	(32)	(45)
Dividends Paid	(333)	(364)
Cash Flows From Financing Activities	**484**	**568**
Cash From Continuing Operations	**$ 40**	**$ (53)**
Beginning Cash & Cash Equivalent Balances	178	411
Ending Cash & Cash Equivalent Balances	**$ 218**	**$ 358**

YTD 2009 Cash Flow Drivers:

Operating Activities

- Increase in working capital largely driven by increased fuel inventories
- Changes in other assets and liabilities largely driven by changes in mark-to-market and fuel under recovery

Investing Activities

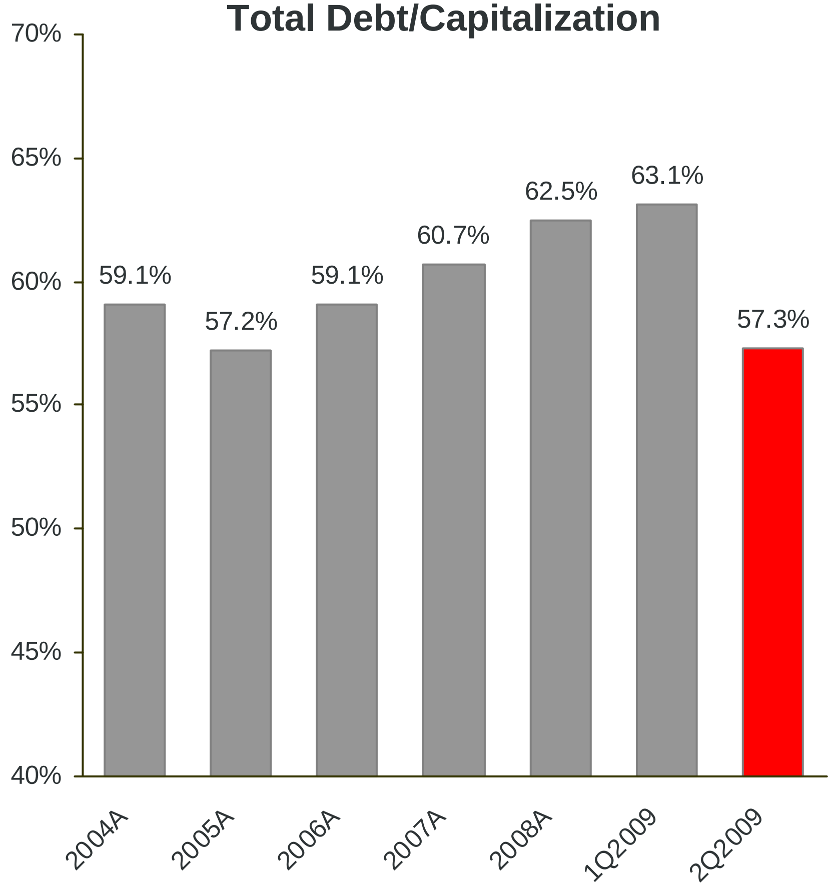
- Cash outlay of $1.5B for 2009 YTD capital investment
- 2009 asset sale proceeds primarily relate to the transfer of assets from TCC to ETT ($90MM) and the payments from the third-party owners of the Turk Plant ($104MM)
- Change in Other Investing primarily relates to the purchase of nuclear fuel of $152MM

Financing Activities

- 2009 common share issuances of $1,688MM primarily due to secondary equity offering completed in April
- Changes in short term debt relate to payments made on credit facilities from proceeds of the equity offering

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 6/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

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Questions

2Q09 Earnings

	$ millions			Earnings Per Share		
	2nd Qtr 2008	2nd Qtr 2009	Change	2nd Qtr 2008	2nd Qtr 2009	Change
Utility Operations	263	325	62	0.66	0.69	0.03
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	29	5	(24)	0.07	0.01	(0.06)
Parent & Other	(12)	(10)	2	(0.03)	(0.02)	0.01
AEP On-Going Earnings	280	321	41	0.70	0.68	(0.02)
Special Items	1	(5)	(6)	0.00	(0.01)	(0.01)
Reported Earnings (GAAP)	281	316	35	0.70	0.67	(0.03)

June YTD Earnings

	$ millions			Earnings Per Share		
	June YTD 2008	June YTD 2009	Change	June YTD 2008	June YTD 2009	Change
Utility Operations	672	668	(4)	1.67	1.52	(0.15)
Transmission Operations	1	1	0	0.00	0.00	0.00
Non-Utility Operations	37	40	3	0.10	0.09	(0.01)
Parent & Other	(20)	(28)	(8)	(0.05)	(0.06)	(0.01)
AEP On-Going Earnings	690	681	(9)	1.72	1.55	(0.17)
Special Items	164	(5)	(169)	0.41	(0.01)	(0.42)
Reported Earnings (GAAP)	854	676	(178)	2.13	1.54	(0.59)

Detailed Ongoing Earnings Guidance

2008 Actual: $3.24

2009E: $2.75-$3.05

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q09 Retail Performance

	Load Decline (weather normalized)
	2Q09 vs. 2Q08
East Regulated Integrated Utilities	-11%
Ohio Companies	-14%
West Regulated Integrated Utilities	-2%
Texas Wires	-5%
Impact on EPS	($0.10)

	Weather Impact
	2Q09 vs. 2Q08
East Regulated Integrated Utilities	$0.01
Ohio Companies	$0.00
West Regulated Integrated Utilities	$0.00
Texas Wires	$0.00
Impact on EPS	$0.02

Does not foot due to rounding

YTD Retail Performance

	Load Decline (weather normalized)
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	-8%
Ohio Companies	-10%
West Regulated Integrated Utilities	-5%
Texas Wires	-3%
Impact on EPS	($0.13)

	Weather Impact
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	$0.01
Ohio Companies	$0.00
West Regulated Integrated Utilities	$0.00
Texas Wires	$0.00
Impact on EPS	$0.01

Retail Performance

	Rate Relief (in millions)
	2Q09 vs. 2Q08
East Regulated Integrated Utilities	$72
Ohio Companies	$123
West Regulated Integrated Utilities	$28
Texas Wires	($8)
AEP System Total	$215
Impact on EPS	$0.30

	Rate Relief (in millions)
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	$147
Ohio Companies	$143
West Regulated Integrated Utilities	$48
Texas Wires	($13)
AEP System Total	$325
Impact on EPS	$0.48

Off System Sales Gross Margin Detail

	2Q08			2Q09		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	7,564	$ 27.23	$ 206	3,619	$ 6.91	$ 25
Oklaunion Payment	-		$ 10	-		$ 12
Marketing/Trading	-		$ 27	-		$ 52
Pre-Sharing Gross Margin	7,564		$ 243	3,619		$ 88

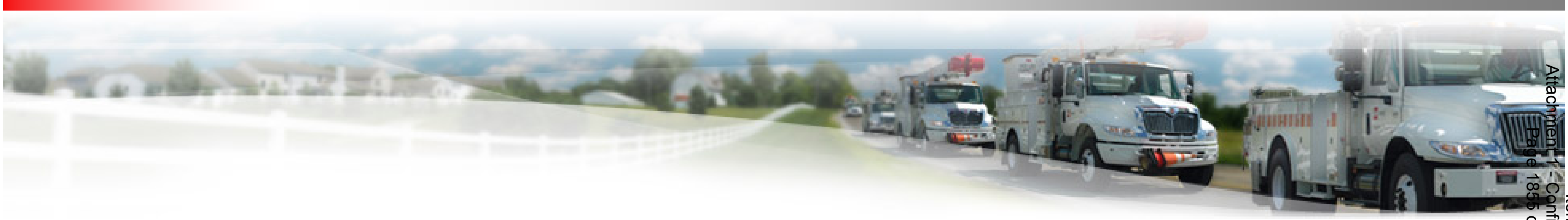
	YTD 2008			YTD 2009		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	15,800	$ 24.24	$ 383	6,214	$ 8.69	$ 54
Oklaunion Payment	-		$ 23	-		$ 26
Marketing/Trading	-		$ 58	-		$ 93
Pre-Sharing Gross Margin	15,800		$ 464	6,214		$ 173

Reduction in Pre-Sharing OSS Physical Sales primarily due to lower demand and significantly lower realized prices as a result of natural gas price contraction.

AMERICAN ELECTRIC POWER

2Q11 Earnings Release Presentation

July 29, 2011



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel..

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Second Quarter 2011 Highlights

- **Financial Performance**
  - Delivered GAAP and on-going earnings of $0.73 per share
  - Reaffirming 2011 earnings guidance of $3.00 to $3.20 per share
- **Positive Litigation Developments**
  - Texas Supreme Court Ruling
  - Turk Settlement
- **Regulatory Plan**
  - Rate proceedings – $220M secured
  - Open proceedings – Ohio, Virginia, Michigan
- **Environmental Update**
  - Cross-State Air Pollution Rule
  - Carbon Capture & Storage Project

2Q11 Performance

Second Quarter Reconciliation

		EPS	Ongoing Earnings ($ in millions)
2Q10	$	0.74	$355
Operations & Maintenance	$	(0.08)	
Other Costs, net	$	(0.04)	
Customer Switching	$	(0.04)	
Rate Changes	$	0.09	
Off-System Sales	$	0.05	
Weather	$	0.01	
2Q11	$	0.73	$352

EPS Based on 482MM shares in Q211

2Q11 Performance Drivers

- O&M expense net of offsets increased $56M primarily due to higher storm expenses
- Other Costs increased $34M, partially due to gain on sale of ICE shares in 2Q10 and increased other taxes
- Customer Switching in Ohio up $24M
- Rate Changes net of offsets of $66M from multiple operating jurisdictions
- Off-System Sales, net of sharing, were favorable by $37M due to higher volumes and higher power prices
- Weather was favorable by $5M vs. prior year, favorable $47M vs. normal

June YTD 2011 Performance

June YTD 2011 Reconciliation

		EPS	Ongoing Earnings ($ in millions)
2010	$	1.50	$720
Operations & Maintenance	$	(0.04)	
Other Costs, net	$	(0.05)	
Customer Switching	$	(0.06)	
Rate Changes	$	0.15	
Off-System Sales	$	0.07	
Weather	$	(0.02)	
2011	$	1.55	$744

EPS Based on 482MM shares in YTD11

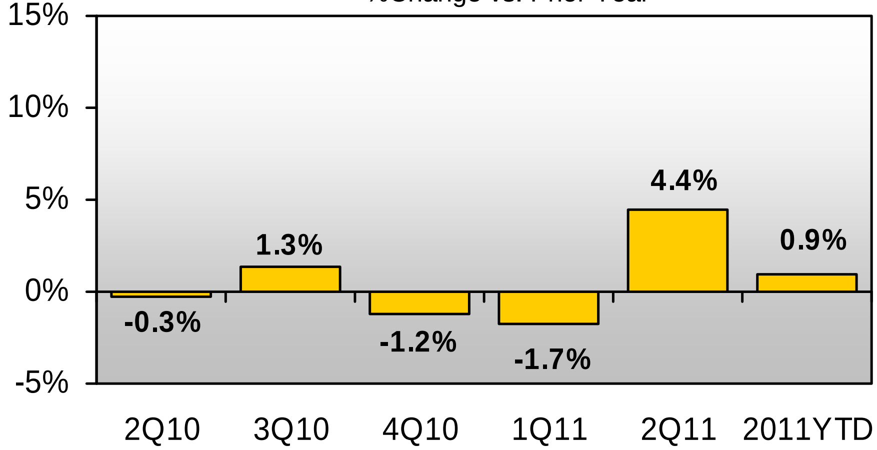
YTD 2011 Performance Drivers

- O&M increase of $30M, net of offsets, primarily due to higher storm expenses
- Other Costs, Net increased $35M primarily due to gain on sale of ICE shares in 2Q10 and increased taxes
- Customer Switching in Ohio up $43M from last year
- Rate Changes, net of offsets, of $110M from multiple operating jurisdictions
- Off-System Sales, net of sharing, were favorable by $49M due to higher volumes and higher power prices
- Weather was unfavorable by $15M vs. prior year, favorable $67M vs. normal

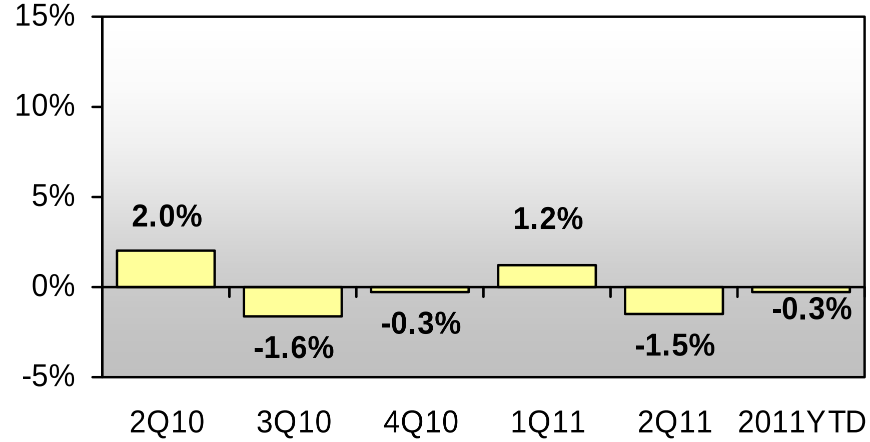
Normalized Load Trends

AEP®

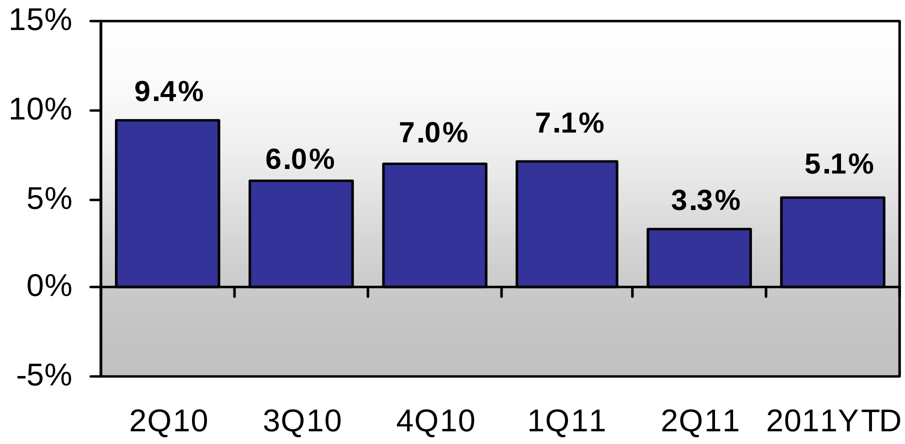
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



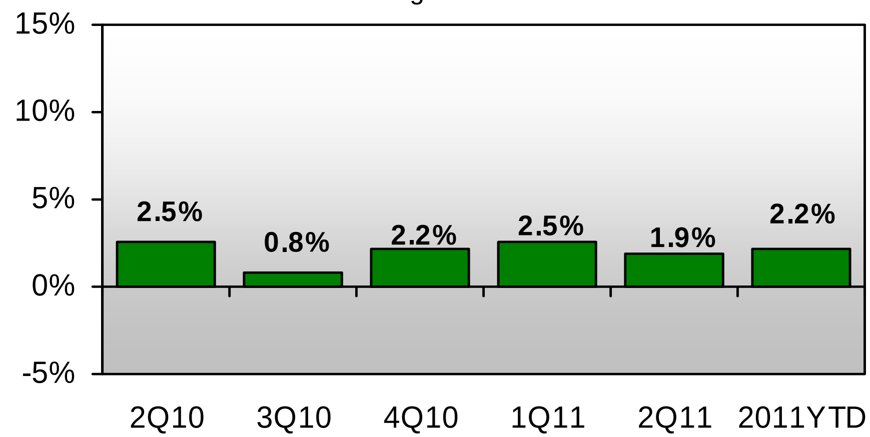
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year

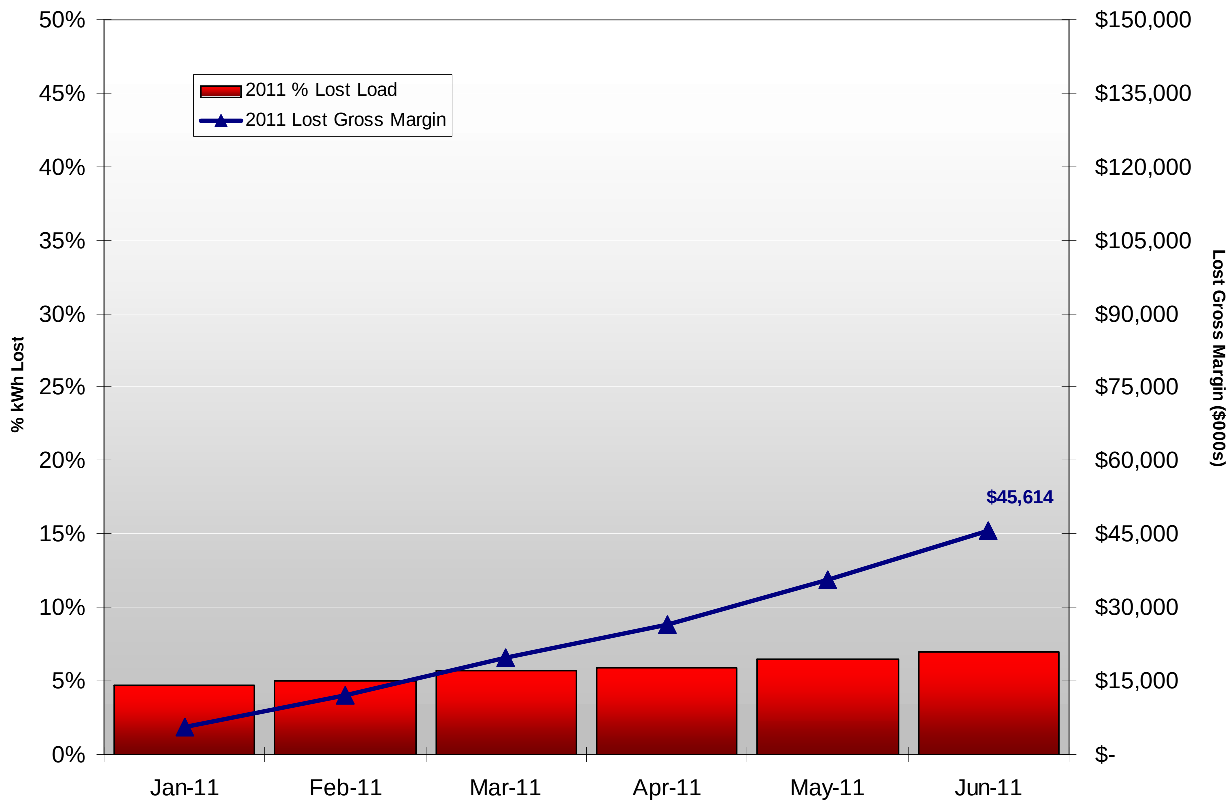


*includes firm wholesale load

Note: Chart represents connected load

Customer Switching

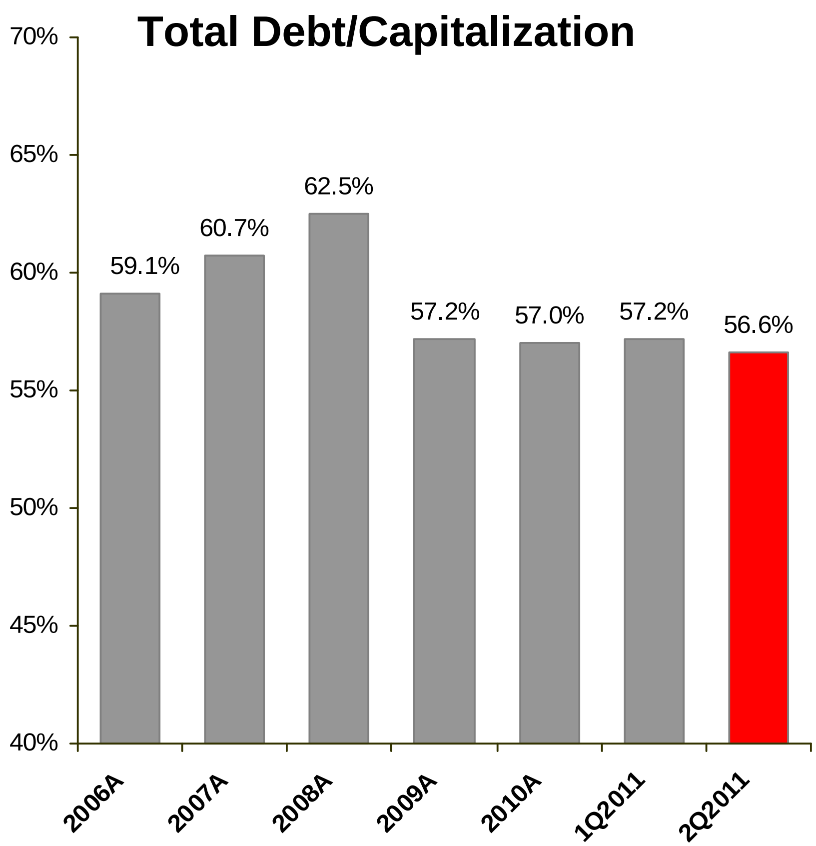
AEP-OH Customers Choosing Other Energy Providers



($ in millions)

	2Q11 Gross Margin Lost		YTD Gross Margin Lost		YTD % Lost Load
CSP	**$**	**23.8**	**$**	**42.8**	**14.8%**
OPCo	**$**	**2.2**	**$**	**2.8**	**0.8%**
Total	**$**	**26.0**	**$**	**45.6**	**6.9%**

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Questions

2Q11 Earnings

	$ millions			Earnings Per Share		
	2nd Qtr 2010	2nd Qtr 2011	Change	2nd Qtr 2010	2nd Qtr 2011	Change
Utility Operations	$ 348	$ 349	$ 1	$ 0.73	$ 0.73	$ -
Transmission Operations	-	6	6	-	0.01	0.01
Non-Utility Operations	7	10	3	0.01	0.02	0.01
Parent & Other	-	(13)	(13)	-	(0.03)	(0.03)
AEP On-Going Earnings	355	352	(3)	0.74	0.73	(0.01)
Cost Reduction Initiative	(185)	-	185	(0.39)	-	0.39
Carbon Capture - APCo VA	(34)	-	34	(0.07)	-	0.07
Special Items Total	(219)	0	219	(0.46)	-	0.46
Reported Earnings (GAAP)	$ 136	$ 352	$ 216	$ 0.28	$ 0.73	$ 0.45

Quarterly Performance Comparison

American Electric Power
Financial Results for 2nd Quarter 2011 Actual vs 2nd Quarter 2010 Actual

		2010 Actual			2011 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	15,523 GWh @ $ 41.2 /MWhr =	639		15,335 GWh @ $ 42.2 /MWhr =	648	
2	Ohio Companies	11,361 GWh @ $ 61.0 /MWhr =	693		11,831 GWh @ $ 55.6 /MWhr =	658	
3	West Regulated Integrated Utilities	10,325 GWh @ $ 33.3 /MWhr =	344		10,631 GWh @ $ 33.7 /MWhr =	358	
4	Texas Wires	7,075 GWh @ $ 21.5 /MWhr =	152		7,753 GWh @ $ 21.2 /MWhr =	164	
5	Off-System Sales	3,980 GWh @ $ 14.5 /MWhr =	58		7,188 GWh @ $ 13.3 /MWhr =	95	
6	Transmission Revenue - 3rd Party		88			101	
7	Other Operating Revenue		127			134	
8	Utility Gross Margin		2,101			2,158	
9	Operations & Maintenance		(780)			(853)	
10	Depreciation & Amortization		(394)			(398)	
11	Taxes Other than Income Taxes		(190)			(199)	
12	Interest Exp & Preferred Dividend		(237)			(227)	
13	Other Income & Deductions		41			41	
14	Income Taxes		(193)			(173)	
15	Utility Operations On-Going Earnings		348	0.73		349	0.73
16	Transmission Operations On-Going Earnings		-	-		6	0.01
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		-	-		(1)	-
18	Generation & Marketing		7	0.01		11	0.02
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(12)			(17)	
20	Other Investments		12			4	
21	Parent & Other On-Going Earnings		-	-		(13)	(0.03)
22	ON-GOING EARNINGS		355	0.74		352	0.73

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD Earnings

	$ millions			Earnings Per Share		
	June YTD 2010	June YTD 2011	Change	June YTD 2010	June YTD 2011	Change
Utility Operations	$ 709	$ 738	$ 29	$ 1.48	$ 1.54	$ 0.06
Transmission Operations	1	10	9	-	0.02	0.02
Non-Utility Operations	21	18	(3)	0.04	0.03	(0.01)
Parent & Other	(11)	(22)	(11)	(0.02)	(0.04)	(0.02)
AEP On-Going Earnings	720	744	24	1.50	1.55	0.05
Medicare D Subsidy	(21)	-	21	(0.04)	-	0.04
Cost Reduction Initiative	(185)	9	194	(0.39)	0.02	0.41
Litigation Settlement - Enron Bankruptcy	-	(22)	(22)	-	(0.06)	(0.06)
Carbon Capture -- APCo WV	-	(26)	(26)	-	(0.05)	(0.05)
Carbon Capture -- APCo VA	(34)	-	34	(0.07)	-	0.07
Special Items Total	(240)	(39)	201	(0.50)	(0.09)	0.41
Reported Earnings (GAAP)	$ 480	$ 705	$ 225	$ 1.00	$ 1.46	$ 0.46

YTD 2011 Performance Comparison

American Electric Power
Financial Results for YTD June 2011 Actual vs YTD June 2010 Actual

		2010 Actual Performance Driver	2010 Actual ($ millions)	2010 Actual EPS	2011 Actual Performance Driver	2011 Actual ($ millions)	2011 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	34,098 GWh @ $ 41.7 /MWhr =	1,423		33,487 GWh @ $ 42.0 /MWhr =	1,405	
2	Ohio Companies	23,945 GWh @ $ 57.5 /MWhr =	1,376		25,136 GWh @ $ 54.6 /MWhr =	1,373	
3	West Regulated Integrated Utilities	20,115 GWh @ $ 30.6 /MWhr =	615		20,534 GWh @ $ 31.7 /MWhr =	651	
4	Texas Wires	13,183 GWh @ $ 22.9 /MWhr =	302		14,067 GWh @ $ 22.2 /MWhr =	313	
5	Off-System Sales	8,724 GWh @ $ 15.1 /MWhr =	132		12,615 GWh @ $ 14.4 /MWhr =	181	
6	Transmission Revenue - 3rd Party		182			203	
7	Other Operating Revenue		250			259	
8	Utility Gross Margin		4,280			4,385	
9	Operations & Maintenance		(1,614)			(1,688)	
10	Depreciation & Amortization		(792)			(791)	
11	Taxes Other than Income Taxes		(393)			(408)	
12	Interest Exp & Preferred Dividend		(473)			(460)	
13	Other Income & Deductions		79			89	
14	Income Taxes		(378)			(389)	
15	Utility Operations On-Going Earnings		709	1.48		738	1.54
16	Transmission Operations On-Going Earnings		1	-		10	0.02
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		4	0.01		6	0.01
18	Generation & Marketing		17	0.03		12	0.02
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(26)			(28)	
20	Other Investments		15			6	
21	Parent & Other On-Going Earnings		(11)	(0.02)		(22)	(0.04)
22	ON-GOING EARNINGS		720	1.50		744	1.55

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD 2011 Cash Flow

($ millions)	2010	2011
Operating Activities		
Net Income -- Reported	**$ 480**	**$ 708**
Depreciation, Amortization & Deferred Taxes	1,139	1,464
Pension Contributions	(75)	(75)
Application of New Accounting Guidance: Securitized Debt for Receivables	(656)	-
Severance	269	-
Changes in Components of Working Capital	(453)	(151)
Over/(Under) Fuel Recovery, Net	(181)	(93)
Other Assets & Liabilities	59	90
Litigation Settlement - Enron Bankruptcy	-	(211)
Cash Flows From Operating Activities	**582**	**1,732**
Investing Activities		
Capital Expenditures	(1,104)	(1,113)
Proceeds on Sale of Assets	147	94
Change in Other Temporary Cash Investments, net	42	78
Acquisition of Assets	(41)	(224)
Other Investing, net	(36)	(115)
Cash Flows Used for Investing Activities	**(992)**	**(1,280)**
Financing Activities		
Common Shares Issued, net	42	49
Long-term Debt Issuances, net	(180)	(189)
Short-term Debt Increase, net	691	293
Application of New Accounting Guidance: Securitized Debt for Receivables	656	-
Other Financing	(52)	(36)
Dividends Paid	(399)	(446)
Cash Flows From (Used for) Financing Activities	**758**	**(329)**
Cash From Continuing Operations	**$ 348**	**$ 123**
Beginning Cash & Cash Equivalent Balances	490	294
Ending Cash & Cash Equivalent Balances	**$ 838**	**$ 417**

YTD 2011 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by coal inventory and accounts receivable/payable, net

Investing Activities

- Cash outlay for 2011 YTD capital investment.
- Asset Acquisition represents the receipt of title to the natural gas in the Bammel storage facility in conjunction with the Enron Bankruptcy settlement.

Financing Activities

- Changes in dividend payout represent 9.5% increase in the 4th quarter of 2010

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	2Q11 vs. 2Q10
East Regulated Integrated Utilities	$50
Ohio Companies	$10
West Regulated Integrated Utilities	$7
Texas Wires	$0
AEP System Total	$66
Impact on EPS	$0.09

	Rate Changes, net of trackers (in millions)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	$72
Ohio Companies	$20
West Regulated Integrated Utilities	$17
Texas Wires	$0
AEP System Total	$110
Impact on EPS	$0.15

2Q11 Retail Performance

	Retail Load* (weather normalized)
	2Q11 vs. 2Q10
East Regulated Integrated Utilities	(0.8%)
Ohio Companies	4.4%
West Regulated Integrated Utilities	2.2%
Texas Wires	3.7%
Impact on EPS	$0.00

*Excludes Firm Wholesale Load

	Weather Impact (in millions)
	2Q11 vs. 2Q10
East Regulated Integrated Utilities	($6)
Ohio Companies	($7)
West Regulated Integrated Utilities	$9
Texas Wires	$9
Impact on EPS	$0.01

May not foot due to rounding

YTD 2011 Retail Performance

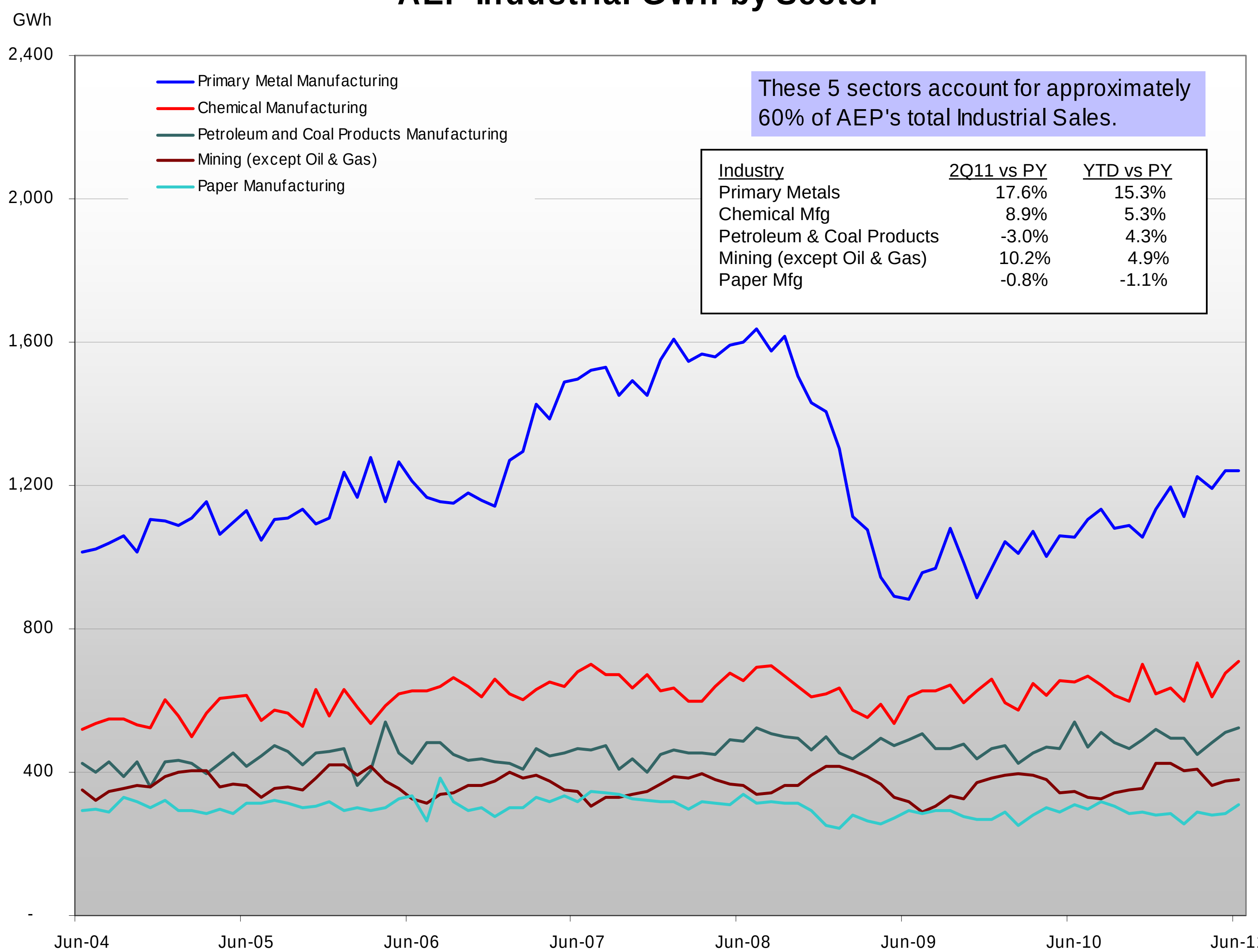
	Retail Load* (weather normalized)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	(0.8%)
Ohio Companies	3.5%
West Regulated Integrated Utilities	4.5%
Texas Wires	2.7%
Impact on EPS	$0.00

	Weather Impact (in millions)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	($21)
Ohio Companies	($5)
West Regulated Integrated Utilities	$0
Texas Wires	$11
Impact on EPS	$0.02

*Excludes Firm Wholesale Load

Industrial Sales Volumes

AEP Industrial GWh by Sector



Industry	2Q11 vs PY	YTD vs PY
Primary Metals	17.6%	15.3%
Chemical Mfg	8.9%	5.3%
Petroleum & Coal Products	-3.0%	4.3%
Mining (except Oil & Gas)	10.2%	4.9%
Paper Mfg	-0.8%	-1.1%

Off System Sales Gross Margin Detail

AEP®

2Q11

	2Q10			2Q11		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	3,980	$ 11.21	$ 45	7,188	$ 13.22	$ 95
Marketing/Trading	-		$ 31	-		$ 34
Pre-Sharing Gross Margin	3,980		$ 76	7,188		$ 129
Margin Shared			$ (18)			$ (34)
Net OSS			$ 58			$ 95

- Physical off-system sales margins exceeded last year by $50M
- Volumes up 81% versus last year
- Improved AEP/Dayton Hub pricing: 14% increase in liquidation prices
- Higher Trading & Marketing results by $3M

YTD11

	YTD10			YTD11		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	8,725	$ 12.22	$ 107	12,616	$ 14.66	$ 185
Marketing/Trading	-		$ 69	-		$ 66
Pre-Sharing Gross Margin	8,725		$ 176	12,616		$ 251
Margin Shared			$ (44)			$ (70)
Net OSS			$ 132			$ 181

- Physical off-system sales margins exceeded last year by $78M
- Volumes up 45% versus last year
- Improved AEP/Dayton Hub pricing: 5% increase in liquidation prices
- Lower Trading & Marketing results by $3M

Off-System Sales

2Q11 vs. 2Q10

Q2 2011 Liquidations vs. Q2 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	35.5	40.43	4.93	14%
PJM West	43.59	45.58	1.99	5%
NiHub	32.09	34.59	2.50	8%
CinHub	33.75	35.33	1.58	5%
SPP	31.85	29.29	(2.56)	-8%
Natural Gas ($/mmBtu)	4.30	4.35	0.05	1%

YTD11 vs. YTD10

YTD 2011 Liquidations vs. YTD 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	37.22	39.20	1.98	5%
PJM West	45.72	46.08	0.36	1%
NiHub	33.82	34.32	0.50	1%
CinHub	34.8	35.61	0.81	2%
SPP	35.01	29.08	(5.93)	-17%
Natural Gas ($/mmBtu)	4.72	4.26	(0.46)	-10%

Balance of 2011 Forwards vs. Balance of Year 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	37.94	39.77	1.83	5%
PJM West	47.45	46.99	(0.46)	-1%
NiHub	32.44	33.58	1.14	4%
CinHub	34.82	35.28	0.46	1%
SPP	29.94	31.61	1.67	6%
Natural Gas ($/mmBtu)	4.03	4.45	0.42	10%

Power forwards and NG futures as of July 14, 2011

2Q10 Earnings Release Presentation

July 30, 2010

A CENTURY OF DIVIDENDS • 1910 - 2010

"*Safe Harbor*" *Statement under the Private Securities Litigation Reform Act of 1995*

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Second Quarter 2010 Highlights

- **FINANCIAL PERFORMANCE**
  - Delivered GAAP earnings of $0.28 per share; special items include costs associated with the cost reduction initiative ($0.39) and carbon capture & storage R&D expense ($0.07)
  - Delivered on-going earnings of $0.74/share
  - Reaffirming 2010 guidance range of $2.80 to $3.20/share
- **REGULATORY UPDATE**
  - Rate proceedings – $301MM of $320MM secured for 2010
  - Ohio SEET
  - TURK Update
- **TRANSMISSION UPDATE**
- **FEDERAL LEGISLATION/EPA UPDATE**
- **OPERATING COMPANY REFINEMENTS**

2Q10 Performance

Second Quarter Reconciliation

		EPS	Ongoing Earnings ($ in millions)
2Q09	$	0.68	$321
Share Count Effect	$	(0.01)	
Rate Changes	$	0.03	
Retail Margin	$	0.05	
Firm Wholesale Margin	$	(0.03)	
Weather	$	0.05	
OSS	$	(0.02)	
Operations & Maintenance	$	0.07	
Other Utility Operations, net	$	(0.10)	
Non-Utility Operations/Parent	$	0.02	
2Q10	$	0.74	$355

2Q10 Performance Drivers

- Rate Changes net of offsets $22MM from multiple operating jurisdictions
- Retail Margin up $33MM, primarily due to industrial recovery
- Firm Wholesale Margin down $22MM due to the loss of two large wholesale customers
- Weather was favorable by $34MM vs. prior year, $43MM vs. normal
- OSS was unfavorable by $12MM due to lower profit from trading/marketing activities.
- O&M expense net of offsets decrease of $51MM due primarily to storm cost deferral at APCo and other G&A items
- Other Utility Operations, net decreased approximately $75MM and primarily includes the absence of accidental outage insurance and higher interest expense, D&A and taxes
- Non-Utility Operations/Parent increased $12MM due to a gain on sale of remaining ICE shares

June YTD 2010 Performance

June YTD 2010 Reconciliation

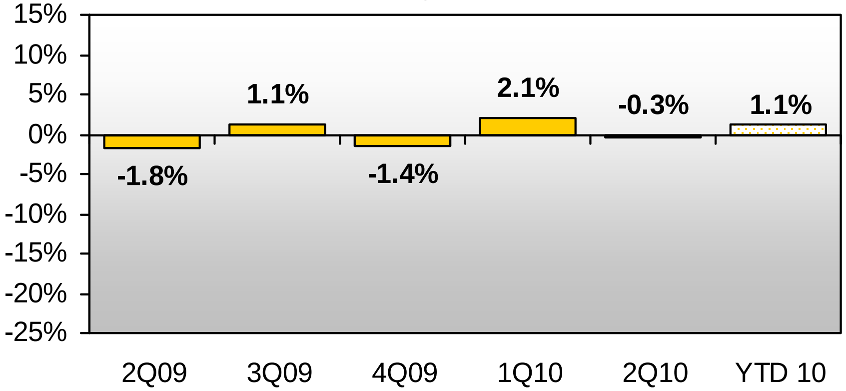
		EPS	Ongoing Earnings ($ in millions)
YTD09	$	1.55	$681
Share Count Effect	$	(0.14)	
Rate Changes	$	0.17	
Retail Margin	$	0.03	
Firm Wholesale Margin	$	(0.07)	
Weather	$	0.11	
OSS	$	-	
Operations & Maintenance	$	0.10	
Other Utility Operations, net	$	(0.24)	
Non-Utility Operations/Parent	$	(0.01)	
YTD10	$	1.50	$720

YTD 2010 Performance Drivers

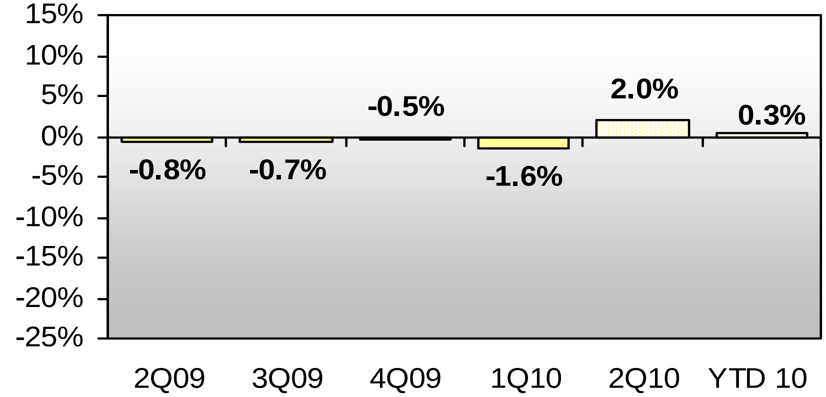
- Share count impact due to 39MM weighted average shares outstanding increase (440MM to 479MM) from equity offering and DRP
- Rate Changes net of offsets of $112MM from multiple operating jurisdictions
- Retail Margin up $21MM, due to recovery across all customer classes, primarily industrial
- Firm Wholesale Margin down $46MM due to the loss of two large wholesale customers
- Weather was favorable by $71MM vs. prior year, $83MM vs. normal
- OSS was flat with increased sales in the east offsetting decreased trading/marketing profits
- O&M decrease of $66MM net of offsets, primarily due to lower storm costs including the deferral of 2009 storm costs at APCo, and other G&A items
- Other Utility Operations, net decreased approximately $185MM and primarily includes the absence of accidental outage insurance related to the DC Cook nuclear plant and higher interest expense, D&A and taxes

Normalized Load Trends

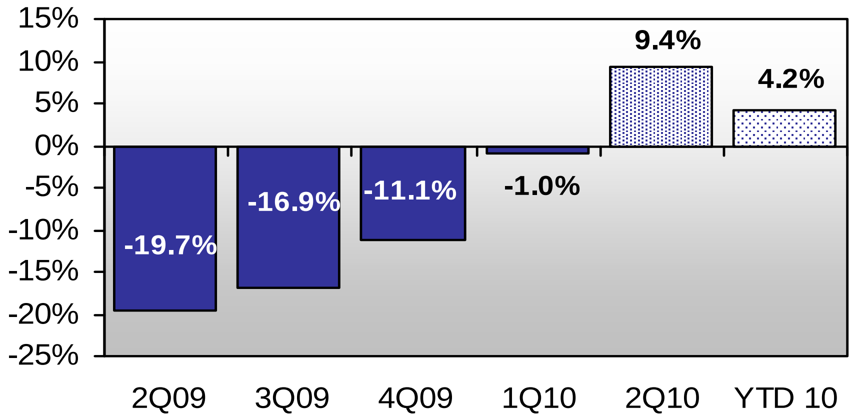
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



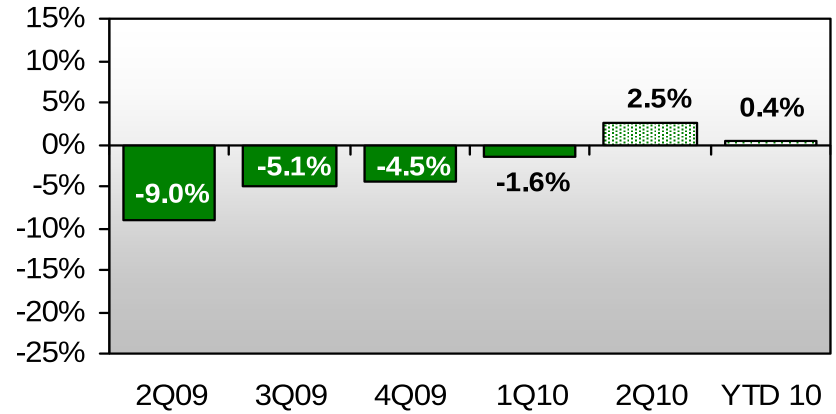
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



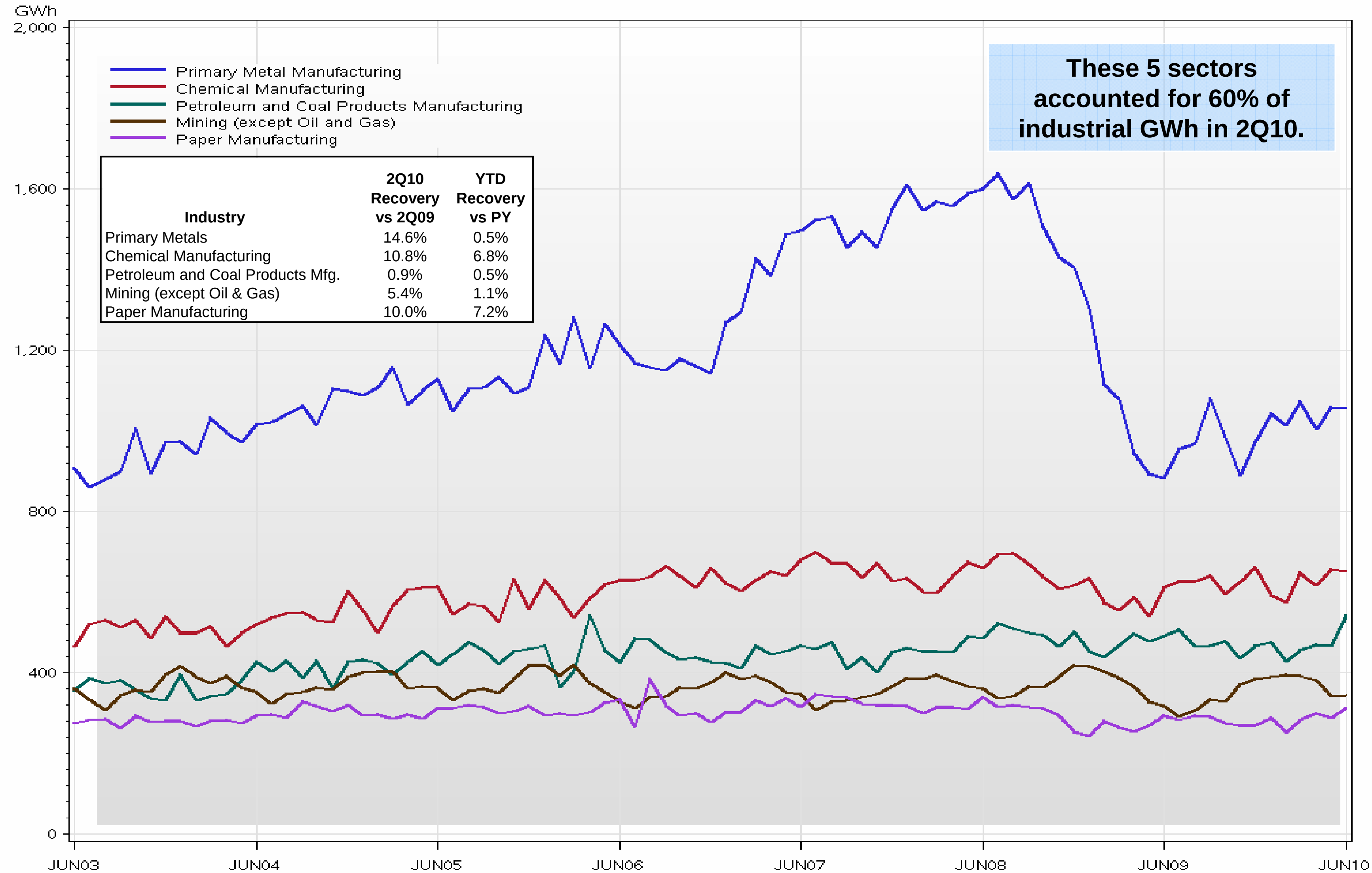
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Industrial Sales

AEP Industrial GWh by Sector



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

Off System Sales Gross Margin Detail

2Q10

	2Q09			2Q10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	3,622	$ 10.13	$ 37	3,980	$ 11.21	$ 45
Marketing/Trading	-		$ 52	-		$ 31
Pre-Sharing Gross Margin	3,622		$ 88	3,980		$ 76
Margin Shared			$ (19)			$ (18)
Net OSS			$ 70			$ 58

- Physical off-system sales margins exceeded last year by $8M
- Volumes up 10% versus last year led by a 37% increase in June
- Improved AEP/Dayton Hub pricing: 13% increase in liquidation prices
- Lower Trading & Marketing results by $20M

YTD10

	YTD09			YTD10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	6,213	$ 12.91	$ 80	8,724	$ 12.24	$ 107
Marketing/Trading	-		$ 93	-		$ 69
Pre-Sharing Gross Margin	6,213		$ 173	8,724		$ 176
Margin Shared			$ (42)			$ (44)
Net OSS			$ 131			$ 132

* May not foot due to rounding

- Physical off-system sales margins exceeded last year by $27M
- Volumes up 40% versus last year
- Improved AEP/Dayton Hub pricing: 5% increase in liquidation prices
- Lower Trading & Marketing results by $24M

Outlook

- Retail Load Volume & Margin recovery slower than previously anticipated
- Off-System Sales margin challenged by market prices
- Rate Changes on target for remainder of the year
- O&M Cost Reduction & Restructuring Program
  - Severance of 2,461 employees
- Operating Company Refinements
- 2010 Earnings Guidance $2.80 - $3.20 per share

Questions

2Q10 Earnings

	$ millions			Earnings Per Share		
	2nd Qtr 2009	2nd Qtr 2010	Change	2nd Qtr 2009	2nd Qtr 2010	Change
Utility Operations	$ 325	$ 348	$ 23	$ 0.69	$ 0.73	$ 0.04
Transmission Operations	1	0	(1)	0.00	0.00	0.00
Non-Utility Operations	5	7	2	0.01	0.01	0.00
Parent & Other	(10)	0	10	(0.02)	0.00	0.02
AEP On-Going Earnings	321	355	34	0.68	0.74	0.06
SWEPCO SFAS 71	(5)	0	5	(0.01)	0.00	0.01
Cost Reduction Initiative	0	(185)	(185)	0.00	(0.39)	(0.39)
Carbon Capture - APCo VA	0	(34)	(34)	0.00	(0.07)	(0.07)
Special Items Total	(5)	(219)	(214)	(0.01)	(0.46)	(0.45)
Reported Earnings (GAAP)	$ 316	$ 136	$ (180)	$ 0.67	$ 0.28	$ (0.39)

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 1886 of 9556

Quarterly Performance Comparison

American Electric Power
Financial Results for 2nd Quarter 2010 Actual vs 2nd Quarter 2009 Actual

		2009 Performance Driver	2009 Actual ($ millions)	2009 EPS	2010 Performance Driver	2010 Actual ($ millions)	2010 EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	15,143 GWh @ $ 38.8 /MWhr =	587		15,523 GWh @ $ 41.2 /MWhr =	639	
2	Ohio Companies	10,914 GWh @ $ 62.4 /MWhr =	681		11,361 GWh @ $ 61.0 /MWhr =	693	
3	West Regulated Integrated Utilities	9,752 GWh @ $ 31.4 /MWhr =	306		10,325 GWh @ $ 33.3 /MWhr =	344	
4	Texas Wires	6,888 GWh @ $ 20.2 /MWhr =	139		7,075 GWh @ $ 21.5 /MWhr =	152	
5	Off-System Sales	3,622 GWh @ $ 19.3 /MWhr =	70		3,980 GWh @ $ 14.5 /MWhr =	58	
6	Transmission Revenue - 3rd Party		90			88	
7	Other Operating Revenue		187			127	
8	Utility Gross Margin		2,060			2,101	
9	Operations & Maintenance		(805)			(780)	
10	Depreciation & Amortization		(388)			(394)	
11	Taxes Other than Income Taxes		(188)			(190)	
12	Interest Exp & Preferred Dividend		(227)			(237)	
13	Other Income & Deductions		23			41	
14	Income Taxes		(150)			(193)	
15	Utility Operations On-Going Earnings		325	0.69		348	0.73
16	Transmission Operations On-Going Earnings		1	-		-	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		1	-		-	-
18	Generation & Marketing		4	0.01		7	0.01
	PARENT & OTHER:						
19	Parent & Other On-Going Earnings		(10)	(0.02)		-	-
20	ON-GOING EARNINGS		321	0.68		355	0.74

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD 2010 Earnings

	$ millions			Earnings Per Share		
	June YTD 2009	June YTD 2010	Change	June YTD 2009	June YTD 2010	Change
Utility Operations	$ 668	$ 709	$ 41	$ 1.52	$ 1.48	$ (0.04)
Transmission Operations	1	1	0	0.00	0.00	0.00
Non-Utility Operations	40	21	(19)	0.09	0.04	(0.05)
Parent & Other	(28)	(11)	17	(0.06)	(0.02)	0.04
AEP On-Going Earnings	681	720	39	1.55	1.50	(0.05)
SWEPCO SFAS 71	(5)	0	5	(0.01)	0.00	0.01
Medicare D Subsidy	0	(21)	(21)	0.00	(0.04)	(0.04)
Cost Reduction Initiative	0	(185)	(185)	0.00	(0.39)	(0.39)
Carbon Capture -- APCo VA	0	(34)	(34)	0.00	(0.07)	(0.07)
Special Items Total	(5)	(240)	(235)	(0.01)	(0.50)	(0.49)
Reported Earnings (GAAP)	$ 676	$ 480	$ (196)	$ 1.54	$ 1.00	$ (0.54)

June YTD Performance Comparison

American Electric Power
Financial Results for YTD June 2010 Actual vs YTD June 2009 Actual

		2009 Performance Driver	2009 Actual ($ millions)	2009 Actual EPS	2010 Performance Driver	2010 Actual ($ millions)	2010 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	33,804 GWh @ $ 38.4 /MWhr =	1,298		34,098 GWh @ $ 41.7 /MWhr =	1,423	
2	Ohio Companies	24,049 GWh @ $ 54.9 /MWhr =	1,320		23,945 GWh @ $ 57.5 /MWhr =	1,376	
3	West Regulated Integrated Utilities	18,550 GWh @ $ 29.6 /MWhr =	549		20,115 GWh @ $ 30.6 /MWhr =	615	
4	Texas Wires	12,626 GWh @ $ 21.1 /MWhr =	266		13,183 GWh @ $ 22.9 /MWhr =	302	
5	Off-System Sales	6,213 GWh @ $ 21.1 /MWhr =	131		8,724 GWh @ $ 15.1 /MWhr =	132	
6	Transmission Revenue - 3rd Party		174			182	
7	Other Operating Revenue		393			250	
8	Utility Gross Margin		4,131			4,280	
9	Operations & Maintenance		(1,608)			(1,614)	
10	Depreciation & Amortization		(761)			(792)	
11	Taxes Other than Income Taxes		(382)			(393)	
12	Interest Exp & Preferred Dividend		(448)			(473)	
13	Other Income & Deductions		54			79	
14	Income Taxes		(318)			(378)	
15	Utility Operations On-Going Earnings		668	1.52		709	1.48
16	Transmission Operations On-Going Earnings		1	-		1	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		12	0.03		4	0.01
18	Generation & Marketing		28	0.06		17	0.03
	PARENT & OTHER:						
19	Parent & Other On-Going Earnings		(28)	(0.06)		(11)	(0.02)
20	ON-GOING EARNINGS		681	1.55		720	1.50

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD 2010 Cash Flow

($ millions)	2009	2010
Operating Activities		
Net Income -- Reported	**$ 676**	**$ 480**
Depreciation, Amortization & Deferred Taxes	1,193	1,139
Pension Contributions	-	(75)
Application of New Accounting Guidance: Securitized Debt for Receivables	-	(656)
Severance	-	269
Changes in Components of Working Capital	(717)	(453)
Over/(Under) Fuel Recovery, Net	(246)	(181)
Extraordinary Loss	5	-
Other Assets & Liabilities	(54)	59
Cash Flows From Operating Activities	**857**	**582**
Investing Activities		
Capital Expenditures	(1,547)	(1,104)
Proceeds on Sale of Assets	240	147
Change in Other Temporary Cash Investments, net	11	42
Acquisition of Nuclear Fuel	(152)	(41)
Other Investing, net	(30)	(36)
Cash Flows Used for Investing Activities	**(1,478)**	**(992)**
Financing Activities		
Common Shares Issued, net	1,688	42
Long-term Debt Issuances, net	703	(180)
Short-term Debt Increase/(Decrease), net	(1,414)	691
Application of New Accounting Guidance: Securitized Debt for Receivables	-	656
Other Financing	(45)	(52)
Dividends Paid	(364)	(399)
Cash Flows From Financing Activities	**568**	**758**
Cash From Continuing Operations	**$ (53)**	**$ 348**
Beginning Cash & Cash Equivalent Balances	411	490
Ending Cash & Cash Equivalent Balances	**$ 358**	**$ 838**

YTD 2010 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by coal inventory, taxes payable and employee related expenses.

Investing Activities

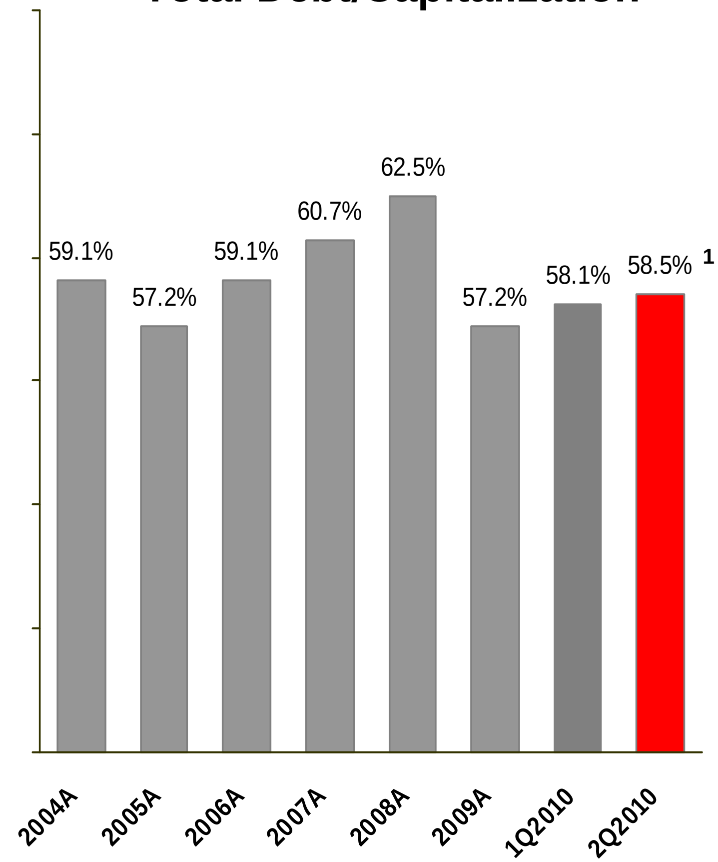
- Cash outlay for 2010 YTD capital investment.
- 2010 asset sale proceeds relate to the transfer of assets to ETT.

Financing Activities

- Changes in long-term debt driven by reduced capital funding requirements.
- Changes in short term debt relate to funding of severance activity.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: *Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.*

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	2Q10 vs. 2Q09
East Regulated Integrated Utilities	$15
Ohio Companies	-$6
West Regulated Integrated Utilities	$13
Texas Wires	$0
AEP System Total	$22
Impact on EPS	$0.03

	Rate Changes, net of trackers (in millions)
	YTD10 vs. YTD09
East Regulated Integrated Utilities	$57
Ohio Companies	$30
West Regulated Integrated Utilities	$25
Texas Wires	$0
AEP System Total	$112
Impact on EPS	$0.17

2Q10 Retail Performance

	Retail Load* (weather normalized) 2Q10 vs. 2Q09
East Regulated Integrated Utilities	**4.1%**
Ohio Companies	**2.6%**
West Regulated Integrated Utilities	**2.5%**
Texas Wires	**7.3%**
Impact on EPS	**$0.05**

*Excludes Firm Wholesale Load

	Weather Impact (in millions) 2Q10 vs. 2Q09
East Regulated Integrated Utilities	**$13**
Ohio Companies	**$14**
West Regulated Integrated Utilities	**$12**
Texas Wires	**($5)**
Impact on EPS	**$0.05**

YTD 2010 Retail Performance

	Retail Load* (weather normalized)
	YTD10 vs. YTD09
East Regulated Integrated Utilities	2.2%
Ohio Companies	-0.7%
West Regulated Integrated Utilities	2.7%
Texas Wires	4.8%
Impact on EPS	$0.03

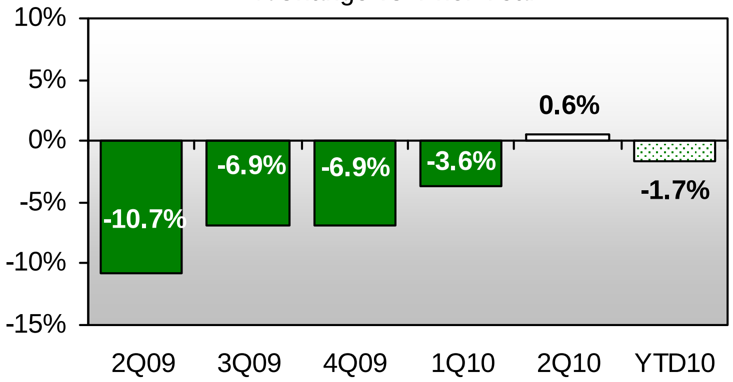
*Excludes Firm Wholesale Load

	Weather Impact (in millions)
	YTD10 vs. YTD09
East Regulated Integrated Utilities	$30
Ohio Companies	$15
West Regulated Integrated Utilities	$25
Texas Wires	$2
Impact on EPS	$0.11

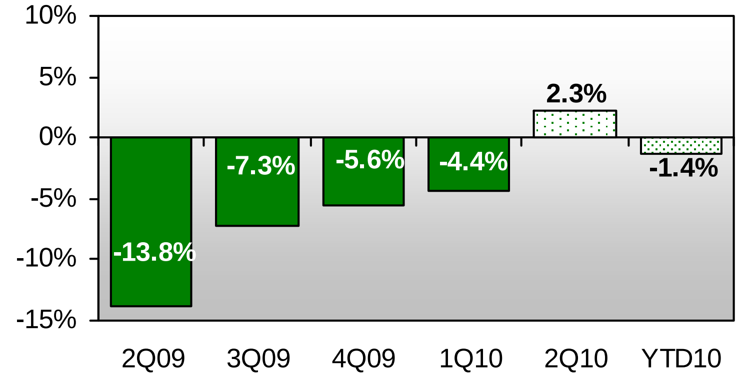
May not foot due to rounding

Normalized Load Trends by Region

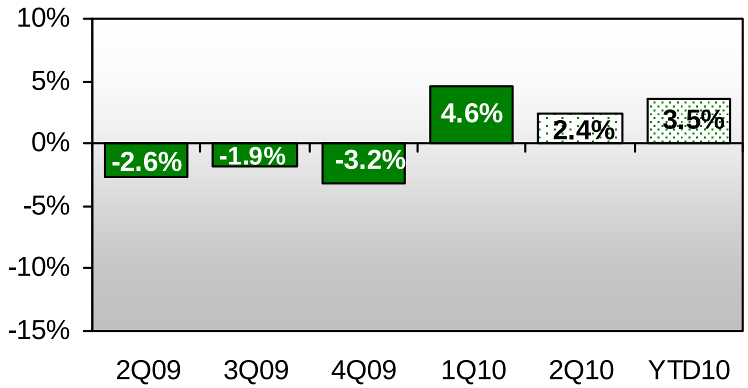
Reg East Total Normalized GWh Sales*
%Change vs. Prior Year



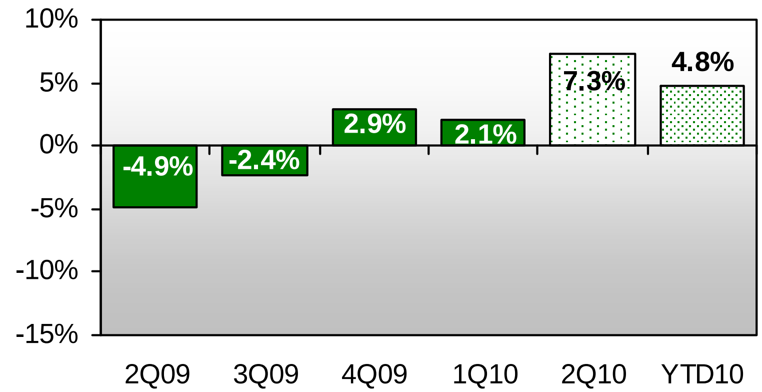
Ohio Total Normalized GWh Sales*
%Change vs. Prior Year



Reg West Total Normalized GWh Sales*
%Change vs. Prior Year



Texas Wires Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

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Off-System Sales

2Q10 vs. 2Q09

Q2 2010 Liquidations vs. Q2 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	31.44	35.50	4.06	13%
PJM West	33.68	43.59	9.91	29%
NiHub	25.68	32.09	6.41	25%
CinHub	27.59	33.75	6.16	22%
SPP	25.16	31.82	6.66	26%
Natural Gas ($/mmBtu)	3.69	4.30	0.61	17%

YTD10 vs. YTD09

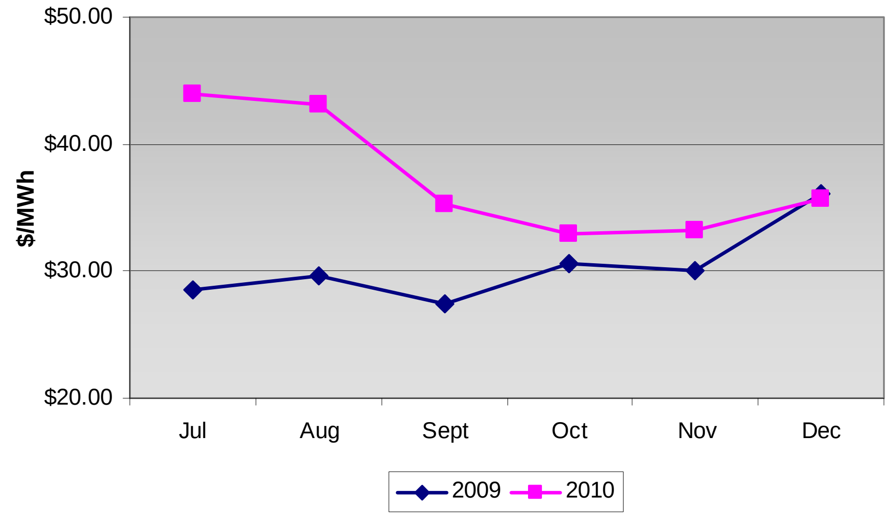
YTD 2010 Liquidations vs. YTD 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	35.61	37.22	1.61	5%
PJM West	41.84	45.71	3.86	9%
NiHub	30.14	33.82	3.67	12%
CinHub	31.31	34.8	3.49	11%
SPP	27.42	35	7.58	28%
Natural Gas ($/mmBtu)	4.13	4.72	0.59	14%

Balance of Year

AEP Dayton 7X24 Day Ahead Prices

2009 Liquidations and 2010 Jul-Dec Forward



Balance of 2010 Forwards vs. Balance of Year 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	30.40	37.38	7.11	23%
PJM West	35.71	47.37	11.66	33%
NiHub	27.25	33.17	5.92	22%
CinHub	27.64	33.88	6.24	23%
SPP	30.78	31.82	1.04	3%
Natural Gas ($/mmBtu)	3.71	4.64	0.93	25%

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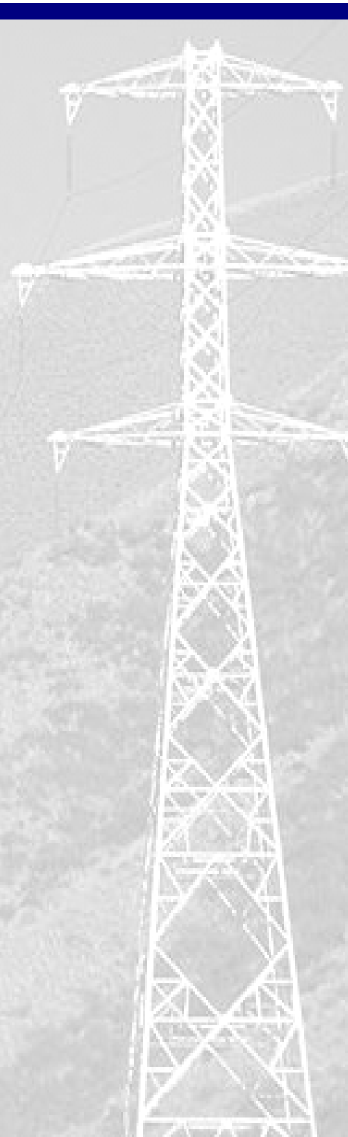

2Q05 Earnings Release Presentation

July 29, 2005

“Safe Harbor” Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Quarterly Highlights

- 2Q05 GAAP Earnings $0.58 Per Share, Ongoing $0.61 Per Share
- Reaffirm 2005 Earnings Guidance of $2.30 - $2.50 Per Share
- Environmental Investment Program Adjusted to $4.1b from $3.7b
- PJM Activity Update
- Asset acquisition activity
  - Waterford Gas Plant
  - Monongahela Power Customers
- Regulatory Update
  - TCC Stranded Cost Recovery True-up Filing Submitted
  - TCC Wires Case Settlement
  - FERC Transmission Case
  - APCo Filed for Recovery of E&R Costs in Virginia

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2Q05 Earnings Performance

	$ millions			Earnings Per Share		
	2nd Qtr 2004	2nd Qtr 2005	Change	2nd Qtr 2004	2nd Qtr 2005	Change
Utility Operations	184	262	78	0.46	0.68	0.22
Investments	(9)	(2)	7	(0.02)	0.00	0.02
Parent Company	(25)	(26)	(1)	(0.06)	(0.07)	(0.01)
AEP On-Going Earnings	150	234	84	0.38	0.61	0.23

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q05 Utility Operations Performance

		2004 Actual ($ millions)	2004 Actual EPS	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	750		706	
2	Ohio Cos.	469		511	
3	Texas Wires	106		113	
4	Texas Supply / REP	84		48	
5	Off-System Sales	112		150	
6	Other Wholesale Transactions	9		5	
7	Transmission Revenue - 3rd Party	119		98	
8	Other Operating Revenue	76		81	
9	Total Gross Margin	1,725		1,712	
10	Operations & Maintenance	(818)		(750)	
11	Depreciation & Amortization	(308)		(317)	
12	Taxes Other than Income Taxes	(176)		(170)	
13	Interest Exp & Preferred Dividend	(161)		(156)	
14	Other Income & Deductions	16		56	
15	Income Taxes	(94)		(113)	
16	Net Earnings Utility Operations	184	0.46	262	0.68

2Q 2005 Performance Drivers

Weather Impact: Positive $0.01 vs. normal
Positive $0.01 vs. prior yr

- *Decline at Reg Integ Utilities attributable to increased fuel costs partially offset by growth in retail customers and warmer weather; Fuel pressure at Ohio Cos. offset by cust. growth, weather & Buckeye Power emissions allowances*
- *Decrease in gross margin due to July 2004 plant divestitures and STP sale in May 2005 & expiration of Centrica supply contract*
- *Increased OSS margin due to stronger margins and increased sales volume*
- *Lower transmission revenues due to elimination of O&T rates*
- *Lower O&M expenses due to timing of maintenance projects, lower storm damage, and sale of TCC generation*
- *Decreased interest expense reflecting refinancings and lower debt balance*
- *Other Income & Deductions line includes: (1) carrying costs on OH environmental additions ($11MM) and (2) carrying costs on TX stranded costs ($20MM)*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

6 Months YTD Earnings Performance

	$ millions			Earnings Per Share		
	2nd Qtr 2004	2nd Qtr 2005	Change	2nd Qtr 2004	2nd Qtr 2005	Change
Utility Operations	488	605	117	1.23	1.56	0.33
Investments	(15)	13	28	(0.04)	0.03	0.07
Parent Company	(34)	(40)	(6)	(0.08)	(0.10)	(0.02)
AEP On-Going Earnings	439	578	139	1.11	1.49	0.38

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

6 Months YTD Utility Operations Performance

		2004 Actual ($ millions)	2004 Actual EPS	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	1,500		1,412	
2	Ohio Cos.	981		1,000	
3	Texas Wires	206		214	
4	Texas Supply / REP	183		127	
5	Off-System Sales	281		315	
6	Other Wholesale Transactions	13		8	
7	Transmission Revenue - 3rd Party	243		192	
8	Other Operating Revenue	141		153	
9	Total Gross Margin	3,548		3,421	
10	Operations & Maintenance	(1,524)		(1,435)	
11	Depreciation & Amortization	(618)		(635)	
12	Taxes Other than Income Taxes	(358)		(356)	
13	Interest Exp & Preferred Dividend	(326)		(300)	
14	Other Income & Deductions	25		189	
15	Income Taxes	(259)		(279)	
16	Net Earnings Utility Operations	488	1.23	605	1.56

YTD 2005 Performance Drivers

Weather Impact: Negative $0.01 vs. normal
Negative $0.01 vs. prior yr

- *Decline at Reg Integ Utilities attributable to higher fuel costs partially offset by growth in retail customers; Fuel pressure at Ohio Cos. offset by cust. growth & Buckeye Power emissions allowances*
- *Decrease in gross margin due to July 2004 plant divestitures and expiration of Centrica supply agreement*
- *Increased OSS margin due to higher power prices and slightly higher volumes*
- *Lower transmission revenues due to elimination of O&T rates*
- *O&M decrease primarily attributable to timing differences and reduced outage maintenance*
- *Decreased interest expense reflecting refinancings and lower debt balance*
- *Other Income & Deductions line includes: (1) $70MM Centrical sharing mechanism; (2) carrying costs on OH environmental additions ($37MM) and (3) carrying costs on TX stranded costs ($42MM)*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q05 YTD Cash Flow

($ millions)	Year-to-Date 2005	Year-to-Date 2004
Operating Activities		
Net Income -- Reported	**$ 576**	**$ 382**
Discontinued Operations	(4)	58
Continuing Earnings	**572**	**440**
Depreciation, Amortization & Deferred Taxes	572	714
Pension Contributions	(204)	(8)
Changes in Mark-to-Market	43	50
Changes in Components of Working Capital	293	3
Other Assets & Liabilities	(382)	74
Cash Flow from Operations	**894**	**1,275**
Investing Activities		
Capital Expenditures	(1,018)	(690)
Investment in Discontinued Ops (net)	-	-
Change in Other Cash Deposits (net)	-	1
Assets Sales Proceeds & Other Inv (net)	1,502	124
Cash (Used) by Investing Activities	**484**	**(565)**
Financing Activities		
Common Shares Issued/(Retired), net	(399)	11
Long-term Debt Issuances/(Retirements)	(380)	(743)
Short-term Debt Increase/(Decrease), net	27	188
Other Financing	-	-
Dividends Paid	(273)	(277)
Preferred Stock Retirement	(66)	(4)
Cash (Used for) Financing	**(1,091)**	**(825)**
Cash From Continuing Operations	**$ 287**	**$ (115)**
Beginning Cash & Cash Equivalent Balances	320	778
Ending Cash & Cash Equivalent Balances	607	663

Capitalization

Capital Structure	Actual 3/31/05			Actual 6/30/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,359	-	12,359	11,916	-	11,916
Short-term Debt	19	-	19	14	-	14
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,268	8,268	-	8,382	8,382
Total Capitalization per Balance Sheet	**12,378**	**8,329**	**20,707**	**11,930**	**8,443**	**20,373**
% of Capitalization per Balance Sheet	***59.8%***	***40.2%***	***100.0%***	***58.6%***	***41.4%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,227	-	1,227
Securitization Bonds	(668)	-	(668)	(668)	-	(668)
Spent Nuclear Fuel Trust	(230)	-	(230)	(232)	-	(232)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,361**	**8,605**	**20,966**	**11,897**	**8,719**	**20,616**
% of Adjusted Capitalization	***59.0%***	***41.0%***	***100.0%***	***57.7%***	***42.3%***	***100.0%***

Adjusted debt-to-cap of 57.7% at 6/30/05

QUESTIONS

Quarterly Performance Comparison

American Electric Power

Financial Results for 2nd Quarter 2005 Actual vs 2nd Quarter 2004 Actual

			2004 Actual			2005 Actual	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	24,299 GWh @ $30.9 /MWhr =	750		24,794 GWh @ $ 28.5 /MWhr =	706	
2	Ohio Cos.	11,113 GWh @ $42.2 /MWhr =	469		11,338 GWh @ $ 45.1 /MWhr =	511	
3	Texas Wires	6,250 GWh @ $17.0 /MWhr =	106		6,736 GWh @ $ 16.8 /MWhr =	113	
4	Texas Supply / REP	5,915 GWh @ $14.2 /MWhr =	84		2,199 GWh @ $ 21.8 /MWhr =	48	
5	Off-System Sales	7,813 GWh @ $14.3 /MWhr =	112		7,871 GWh @ $ 19.1 /MWhr =	150	
6	Other Wholesale Transactions		9			5	
7	Transmission Revenue - 3rd Party		119			98	
8	Other Operating Revenue		76			81	
9	Total Gross Margin		1,725			1,712	
10	Operations & Maintenance		(818)			(750)	
11	Depreciation & Amortization		(308)			(317)	
12	Taxes Other than Income Taxes		(176)			(170)	
13	Interest Exp & Preferred Dividend		(161)			(156)	
14	Other Income & Deductions		16			56	
15	Income Taxes		(94)			(113)	
16	Net Earnings Utility Operations		184	0.46		262	0.68
	INVESTMENTS:						
17	AEPES		(3)			(1)	
18	MEMCO		2			5	
19	AEP Coal		(2)			1	
20	UK Business		-			(2)	
21	IPPs and Wind Farms		2			2	
22	AEP Resources - Other		(4)			(7)	
23	AEP Communications		(3)			2	
24	CSW International		-			(1)	
25	Other		(1)			(1)	
26	Total Investments		(9)	(0.02)		(2)	(0.00
27	Parent Company		(25)	(0.06)		(26)	(0.07
28	ON-GOING EARNINGS		150	0.38		234	0.61

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

6 Months YTD Performance Comparison

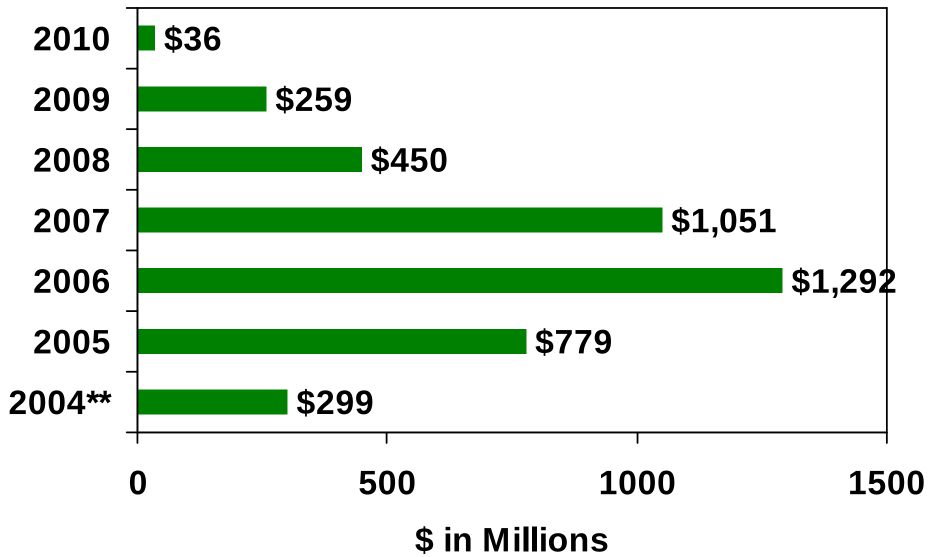
American Electric Power
Financial Results for YTD June 2005 Actual vs YTD June 2004 Actual

			2004 Actual			2005 Actual	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	50,041 GWh @ $ 30.0 /MWhr =	1,500		50,849 GWh @ $ 27.8 /MWhr =	1,412	
2	Ohio Cos.	23,569 GWh @ $ 41.6 /MWhr =	981		23,687 GWh @ $ 42.2 /MWhr =	1,000	
3	Texas Wires	11,740 GWh @ $ 17.5 /MWhr =	206		12,254 GWh @ $ 17.5 /MWhr =	214	
4	Texas Supply / REP	11,139 GWh @ $ 16.4 /MWhr =	183		4,520 GWh @ $ 28.1 /MWhr =	127	
5	Off-System Sales	15,061 GWh @ $ 18.7 /MWhr =	281		15,508 GWh @ $ 20.3 /MWhr =	315	
6	Other Wholesale Transactions		13			8	
7	Transmission Revenue - 3rd Party		243			192	
8	Other Operating Revenue		141			153	
9	Total Gross Margin		3,548			3,421	
10	Operations & Maintenance		(1,524)			(1,435)	
11	Depreciation & Amortization		(618)			(635)	
12	Taxes Other than Income Taxes		(358)			(356)	
13	Interest Exp & Preferred Dividend		(326)			(300)	
14	Other Income & Deductions		25			189	
15	Income Taxes		(259)			(279)	
16	Net Earnings Utility Operations		488	1.23		605	1.56
	INVESTMENTS:						
17	AEPES		(13)			9	
18	MEMCO		4			6	
19	AEP Coal		-			5	
20	UK Business		-			(2)	
21	IPPs and Wind Farms		6			5	
22	AEP Resources - Other		(1)			(18)	
23	AEP Communications		(6)			2	
24	CSW International		-			1	
25	Other		(5)			5	
26	Total Investments		(15)	(0.04)		13	0.03
27	Parent Company		(34)	(0.08)		(40)	(0.10)
28	ON-GOING EARNINGS		439	1.11		578	1.49

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

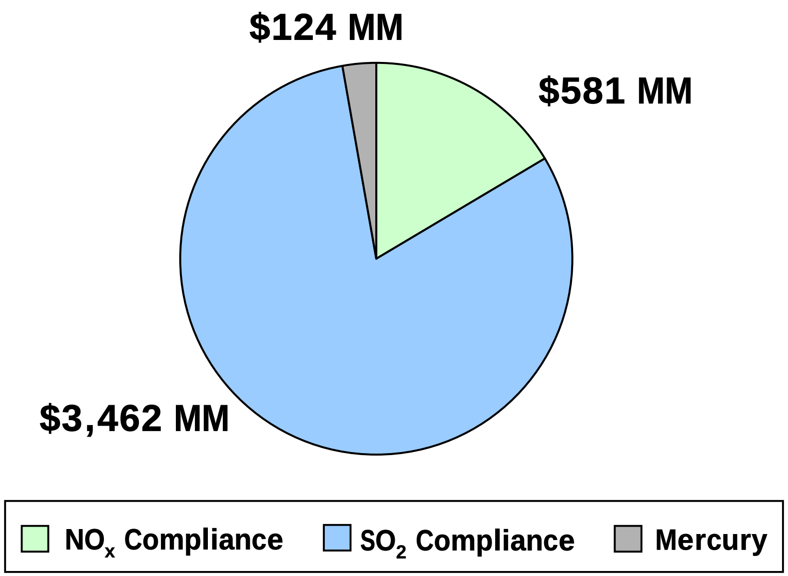
Environmental Investment: $4.1 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



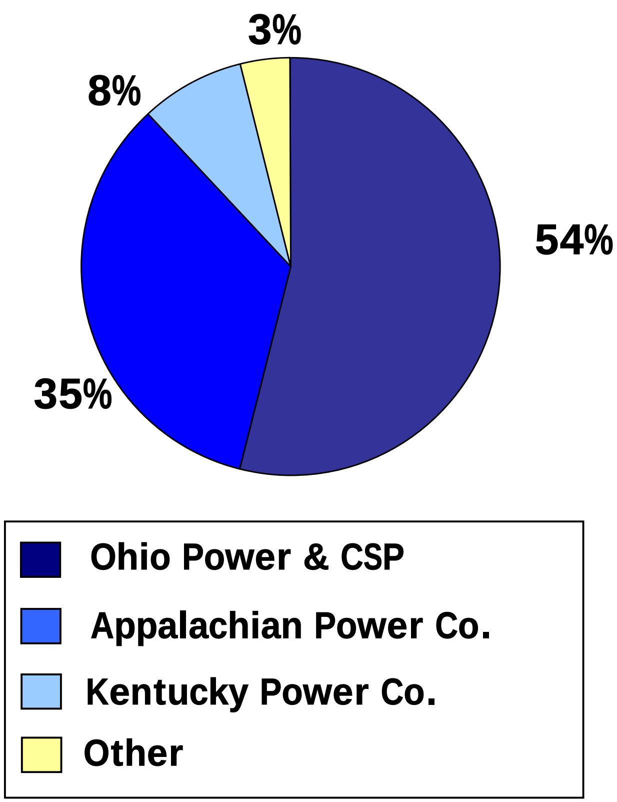
Current Programs
$2.0 Billion:
$0.5 billion for NOx
$1.5 billion for SO_2

Future Programs
$2.1 Billion:
$1.9 billion for SO_2
$0.2 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

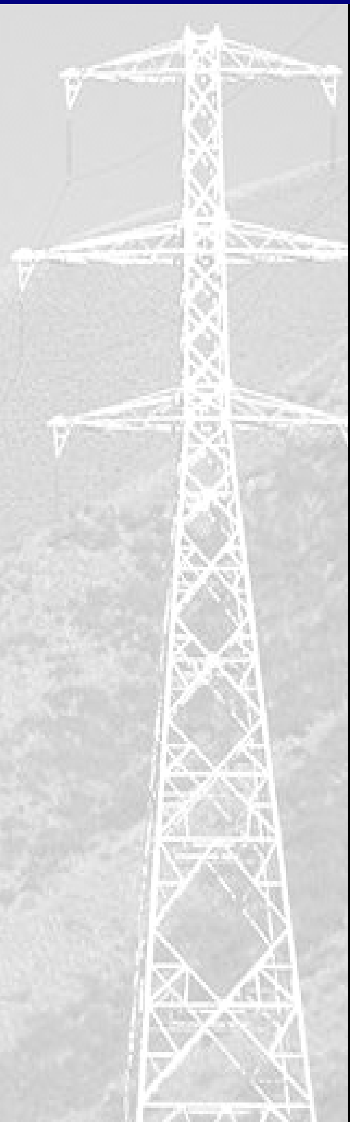
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 54% ($2.2 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 35% ($1.4 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 8% ($319 million)
  - Surcharge mechanism



2Q06 Earnings Release Presentation

July 27, 2006

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Highlights

- Increased 2006 Ongoing Earnings Guidance to $2.65-$2.80 per share
- 2006 Capital Investment projection reduced to $3,663MM
- 2Q06 GAAP Earnings $0.44 per share, Ongoing $0.44 per share
- Wyoming-Jacksons Ferry 765-kV line placed in service June 20
- 2Q06 Regulatory Activity
    - Regulatory assurances provide $415MM of rate relief YTD 2006
    - Ohio transmission rate increase approved May 26
    - TCC $1.72 billion Stranded Cost Securitization financing order obtained June 20 – bonds to be issued Aug/Sept 2006; CTC filing submitted to PUCT June 19
    - IGCC – Compliance tariffs filed at PUCO April 20 to implement Phase 1 charges to collect IGCC plant pre-construction costs incurred during 2006
    - Indiana Depreciation filing, VA E&R case, and VA General Rate case underway

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2Q06 Earnings Performance

	$ millions			Earnings Per Share		
	2nd Qtr 2005	2nd Qtr 2006	Change	2nd Qtr 2005	2nd Qtr 2006	Change
Utility Operations	262	160	(102)	0.68	0.41	(0.27)
Investments	1	15	14	0.01	0.04	0.03
Parent Company	(26)	(3)	23	(0.07)	(0.01)	0.06
AEP On-Going Earnings	237	172	(65)	0.62	0.44	(0.18)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

A Century of Firsts

2Q06 Utility Operations Performance

		2005 Actual		2006 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	465		471	
2	Ohio Companies	485		487	
3	West Regulated Integrated Utilities	232		272	
4	Texas Wires	113		121	
5	Off-System Sales	201		152	
6	Transmission Revenue - 3rd Party	104		49	
7	Other Operating Revenue	114		121	
8	Utility Gross Margin	1,714		1,673	
9	Operations & Maintenance	(745)		(801)	
10	Depreciation & Amortization	(317)		(339)	
11	Taxes Other than Income Taxes	(170)		(186)	
12	Interest Exp & Preferred Dividend	(156)		(160)	
13	Other Income & Deductions	49		43	
14	Income Taxes	(113)		(70)	
15	Utility Operations On-Going Earnings	262	0.68	160	0.41

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q 2006 Performance Drivers

Weather Impact: Negative $0.01 vs. normal
Negative $0.02 vs. prior yr.

- *Rate relief in OH, KY, and PSO was largely offset by rise in fuel costs; increased muni & co-op sales reflect strategy to remarket power supply contracts*
- *Lower OSS due to lower volumes, West margins (sale of STP), and lower trading revenues.*
- *3rd Party Transmission revenues down due to absence of SECA revenues and provision for SECA refund ($18MM)*
- *O&M expense drivers: (1) increased plant outages; (2) higher tree-trimming expenses; (3) higher A&G expenses*
- *Increased D&A due to increased amortization expense at the Ohio Companies*
- *Increase in Taxes Other than Income Taxes driven by higher property taxes*
- *Income tax decrease driven by lower pretax income*

6 Months YTD Earnings Performance

	$ millions			Earnings Per Share		
	YTD June 2005	YTD June 2006	Change	YTD June 2005	YTD June 2006	Change
Utility Operations	605	525	(80)	1.56	1.33	(0.23)
Investments	13	30	17	0.03	0.08	0.05
Parent Company	(40)	(5)	35	(0.10)	(0.01)	0.09
AEP On-Going Earnings	578	550	(28)	1.49	1.40	(0.09)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

6 Months YTD Utility Operations Performance

		2005 Actual ($ millions)	2005 Actual EPS	2006 Actual ($ millions)	2006 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	989		1,035	
2	Ohio Companies	953		1,004	
3	West Regulated Integrated Utilities	410		467	
4	Texas Wires	213		227	
5	Off-System Sales	448		375	
6	Transmission Revenue - 3rd Party	205		151	
7	Other Operating Revenue	257		256	
8	Utility Gross Margin	3,475		3,515	
9	Operations & Maintenance	(1,478)		(1,528)	
10	Depreciation & Amortization	(635)		(672)	
11	Taxes Other than Income Taxes	(356)		(373)	
12	Interest Exp & Preferred Dividend	(300)		(314)	
13	Other Income & Deductions	178		153	
14	Income Taxes	(279)		(256)	
15	Utility Operations On-Going Earnings	605	1.56	525	1.33

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance Drivers

Weather Impact: Negative $0.07 vs. normal
Negative $0.06 vs. prior yr.

- *Rate Relief ($121MM), mostly Ohio RSP; Increased margins reflecting customer growth, usage and price ($71MM); New muni & coop power supply contracts ($35MM); Offset by weather ($37MM) and lower fuel margins mainly in the East ($109MM).*
- *Lower off system sales due to lower volumes and margins (sale of STP) and trading contribution*
- *Lower ECAR, SECA & ERCOT Transmission revenue and provision for SECA Refund ($18MM)*
- *O&M increase related to higher plant outages, base plant operations & increased maintenance; higher tree-trimming; Offset by lower storm restoration costs*
- *D&A increase primarily associated with higher amortization at the Ohio Companies and TCC*
- *Income taxes increase driven by higher property taxes at Ohio companies*
- *Interest expense increased due to higher LTD interest expense*
- *Other Income & Deductions declined due to lower carrying costs for the Ohio Companies*

2Q06 Cash Flow

A Century of Firsts

($ millions)	Year-to-Date 2005	Year-to-Date 2006
Operating Activities		
Net Income -- Reported	**$ 576**	**$ 556**
Discontinued Operations	(4)	(6)
Continuing Earnings	**572**	**550**
Depreciation, Amortization & Deferred Taxes	599	722
Pension Contributions	(204)	-
Changes in Mark-to-Market	43	(43)
Changes in Components of Working Capital	295	(183)
Other Assets & Liabilities	(323)	91
Cash Flow from Operations	**982**	**1,137**
Investing Activities		
Capital Expenditures	(1,020)	(1,625)
Proceeds on Sale of Assets	1,500	123
Change in Other Cash Deposits (net)	-	(20)
Other Investing (net)	(22)	(64)
Cash (Used) by Investing Activities	**458**	**(1,586)**
Financing Activities		
Common Shares Issued/(Retired), net	(399)	6
Long-term Debt Issuances/(Retirements)	(380)	405
Short-term Debt Increase/(Decrease), net	(9)	147
Other Financing	(26)	30
Dividends Paid	(273)	(291)
Preferred Stock Retirement	(66)	-
Cash (Used for) Financing	**(1,153)**	**297**
Cash From Continuing Operations	**$ 287**	**$ (152)**
Beginning Cash & Cash Equivalent Balances	320	401
Ending Cash & Cash Equivalent Balances	607	249

2Q 2006 Cash Flow Drivers

- *Changes in working capital had a negative cash effect of $183MM primarily as a result of an increase in fuel inventories and decreased customer deposits.*
- *$91MM positive cash effect partly due to deferred fuel recovery at PSO and SWEPCo.*
- *Cash outlay of $1.625 billion in first half 06 for capital investment. FY 2006 guidance assumes $3.663 billion in capital investment.*
- *YTD 06 primary asset sale proceeds: Centrica sharing ($70MM) and Bajio ($29MM); YTD 05 primary asset sale proceeds: HPL ($1B) & Centrica sharing ($70MM);*
- *Portion of HPL sale proceeds used to repurchase shares in 1H05.*
- *Capex in '06 was funded with short-term debt ahead of long-term debt financing.*
- *Ending cash balance for 2Q06 of $249MM. 2006 guidance assumes year-end cash balance of $260MM.*

Capitalization

Capital Structure	Actual 3/31/2006			Actual 6/30/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,142	-	12,142	12,645	-	12,645
Short-term Debt	226	-	226	159	-	159
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,384	9,384	-	9,426	9,426
Total Capitalization per Balance Sheet	**12,368**	**9,445**	**21,813**	**12,804**	**9,487**	**22,291**
% of Capitalization per Balance Sheet	***56.7%***	***43.3%***	***100.0%***	***57.4%***	***42.6%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,199	-	1,199
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(238)	-	(238)	(241)	-	(241)
Total Adjusted Capitalization	**12,726**	**9,415**	**22,141**	**13,144**	**9,457**	**22,601**
% of Adjusted Capitalization	***57.5%***	***42.5%***	***100.0%***	***58.2%***	***41.8%***	***100.0%***

Adjusted debt-to-cap of 58.2% at 6/30/06

QUESTIONS

Quarterly Performance Comparison

American Electric Power

Financial Results for 2nd Quarter 2005 Actual vs 2nd Quarter 2006 Actual

		2005 Actual			2006 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	14,992 GWh @ $31.0 /MWhr =	465		15,782 GWh @ $29.9 /MWhr =	471	
2	Ohio Companies	11,338 GWh @ $42.8 /MWhr =	485		10,860 GWh @ $44.9 /MWhr =	487	
3	West Regulated Integrated Utilities	9,802 GWh @ $23.7 /MWhr =	232		10,016 GWh @ $27.2 /MWhr =	272	
4	Texas Wires	6,736 GWh @ $16.8 /MWhr =	113		6,915 GWh @ $17.5 /MWhr =	121	
5	Off-System Sales	9,918 GWh @ $20.3 /MWhr =	201		8,075 GWh @ $18.9 /MWhr =	152	
6	Transmission Revenue - 3rd Party		104			49	
7	Other Operating Revenue		114			121	
8	Utility Gross Margin		1,714			1,673	
9	Operations & Maintenance		(745)			(801)	
10	Depreciation & Amortization		(317)			(339)	
11	Taxes Other than Income Taxes		(170)			(186)	
12	Interest Exp & Preferred Dividend		(156)			(160)	
13	Other Income & Deductions		49			43	
14	Income Taxes		(113)			(70)	
15	Utility Operations On-Going Earnings		262	0.68		160	0.41
	INVESTMENTS:						
16	Investments On-Going Earnings		1	0.01		15	0.04
17	Parent Company On-Going Earnings		(26)	(0.07)		(3)	(0.01)
18	ON-GOING EARNINGS		237	0.62		172	0.44
	Shares Outstanding (in millions)			384			394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

6 Months YTD Performance Comparison

A Century of Firsts

American Electric Power
Financial Results for YTD June 2005 Actual vs YTD June 2006 Actual

		2005 Performance Driver	2005 Actual ($ millions)	2005 EPS	2006 Performance Driver	2006 Actual ($ millions)	2006 EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	32,176 GWh @ $30.7 /MWhr =	989		33,874 GWh @ $30.6 /MWhr =	1,035	
2	Ohio Companies	23,687 GWh @ $40.2 /MWhr =	953		22,389 GWh @ $44.8 /MWhr =	1,004	
3	West Regulated Integrated Utilities	18,673 GWh @ $22.0 /MWhr =	410		18,939 GWh @ $24.7 /MWhr =	467	
4	Texas Wires	12,254 GWh @ $17.4 /MWhr =	213		12,461 GWh @ $18.2 /MWhr =	227	
5	Off-System Sales	20,030 GWh @ $22.4 /MWhr =	448		16,589 GWh @ $22.6 /MWhr =	375	
6	Transmission Revenue - 3rd Party		205			151	
7	Other Operating Revenue		257			256	
8	Utility Gross Margin		3,475			3,515	
9	Operations & Maintenance		(1,478)			(1,528)	
10	Depreciation & Amortization		(635)			(672)	
11	Taxes Other than Income Taxes		(356)			(373)	
12	Interest Exp & Preferred Dividend		(300)			(314)	
13	Other Income & Deductions		178			153	
14	Income Taxes		(279)			(256)	
15	Utility Operations On-Going Earnings		605	1.56		525	1.33
	INVESTMENTS:						
16	Investments On-Going Earnings		13	0.03		30	0.08
17	Parent Company On-Going Earnings		(40)	(0.10)		(5)	(0.01)
18	ON-GOING EARNINGS		578	1.49		550	1.40
	Shares Outstanding (in millions)			389			394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Guidance: $2.65 to $2.80 Per Share

A Century of Firsts

American Electric Power
Financial Results for 2005 Actual vs. 2006 Forecast

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	65,656 GWh @ $31.5 /MWhr =	2,069		69,550 GWh @ $31.2 /MWhr =	2,173	
2	Ohio Companies	48,877 GWh @ $39.6 /MWhr =	1,937		46,185 GWh @ $47.3 /MWhr =	2,185	
3	West Regulated Integrated Utilities	40,213 GWh @ $22.3 /MWhr =	895		39,649 GWh @ $25.0 /MWhr =	990	
4	Texas Wires	26,525 GWh @ $17.4 /MWhr =	462		26,506 GWh @ $13.8 /MWhr =	366	
5	Off-System Sales	38,493 GWh @ $22.2 /MWhr =	853		37,280 GWh @ $17.7 /MWhr =	661	
6	Transmission Revenue - 3rd Party		411			262	
7	Other Operating Revenue		479			571	
8	Utility Gross Margin		7,106			7,208	
9	Operations & Maintenance		(3,142)			(3,139)	
10	Depreciation & Amortization		(1,285)			(1,280)	
11	Taxes Other than Income Taxes		(743)			(747)	
12	Interest Exp & Preferred Dividend		(595)			(666)	
13	Other Income & Deductions		264			199	
14	Income Taxes		(514)			(525)	
15	Utility Operations On-Going Earnings		1,091	2.80		1,050	2.66
	INVESTMENTS:						
16	Investments On-Going Earnings		24	0.06		26	0.07
17	Parent Company On-Going Earnings		(52)	(0.13)		(10)	(0.03)
18	ON-GOING EARNINGS		1,063	2.73		1,066	2.70
	Shares Outstanding (in millions)			390			394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Cash Flow

	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,066
Depreciation and Amortization	1,318	1,311 *
Pension Funding in Excess of Expense	(626)	-
Extraordinary Items	225	-
Other	173	(641)
Total from Operations	**$ 1,877**	**$ 1,736**
Cash from Investing:		
Capital Expenditures ***	(2,404)	(3,663) **
Asset Sales	1,246	111
Other	153	(114)
Total from Investing	**$ (1,005)**	**$ (3,666)**
Cash from Financing:		
Common Equity	(25)	6
Net Long Term Debt Issued/(Retired)	(12)	2,235 ***
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	133
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,789**
Net Change in Cash	**$ 81**	**$ (141)**
Ending Cash Balance	**$ 401**	**$ 260**

* Assumes point EPS estimate $2.70 per share.

** 2006 guidance excludes AFUDC; 2005 figure excludes equity portion of AFUDC

*** Assumes $1.7 billion of securitization bonds issued in September 2006

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

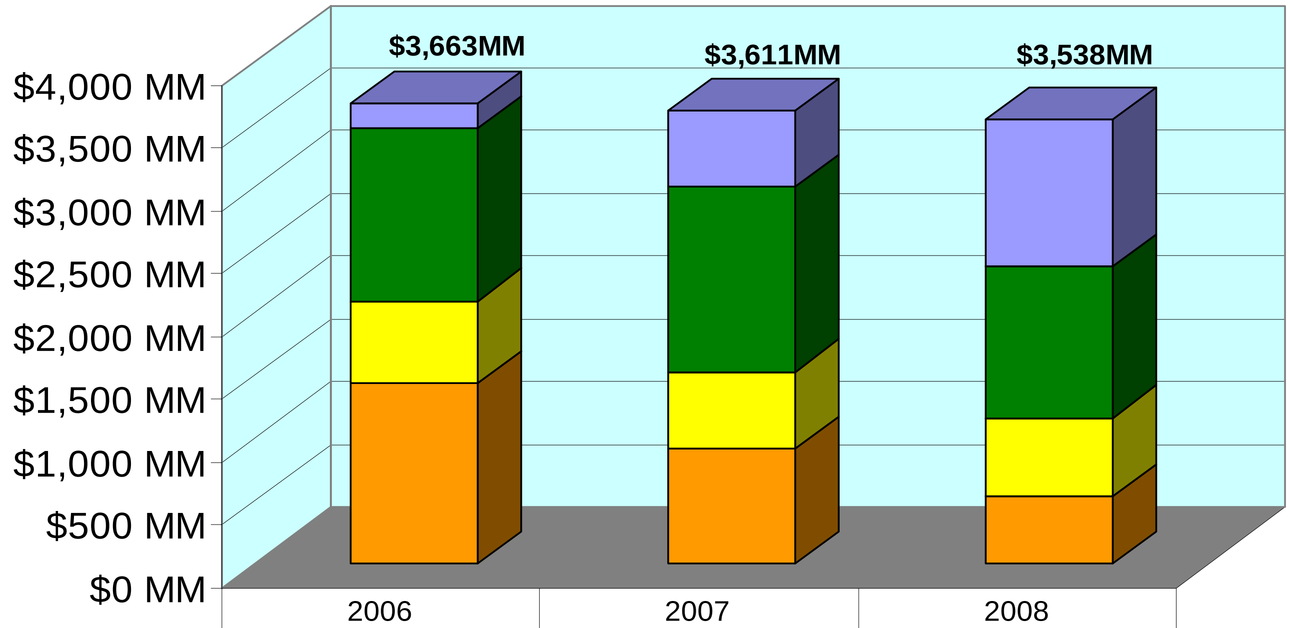
CASH ON HAND EXPECTED TO BE $260 MILLION AT YEAR END 2006

2006 Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC

New Build Generation & Ongoing Infrastructure Replacement investment can be throttled



	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,381	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

2006 Capital Investment Funding Revised

A Century of Firsts

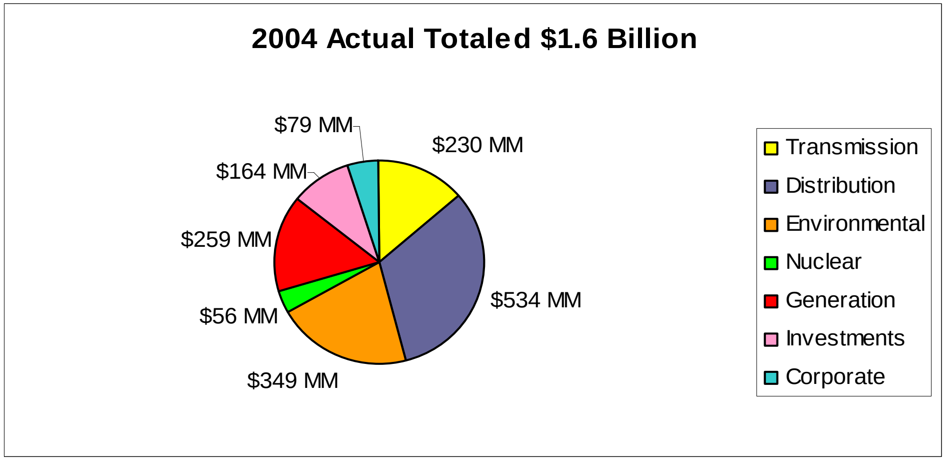
	Actual		Projection		
	2004	**2005**	**2006**	**2007**	**2008**
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,499)	$ (2,091)	$ (1,261)	$ (950)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,572)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,499)	$ (3,663)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,632	$ 1,877	$ 1,736	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 111	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ 6	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 663	$ 1,758	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,705		
Other	$ -	$ 126	$ (117)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (141)	$ (60)	$ -
Ending Cash Balance	$ 320	$ 401	$ 260	$ 200	$ 200

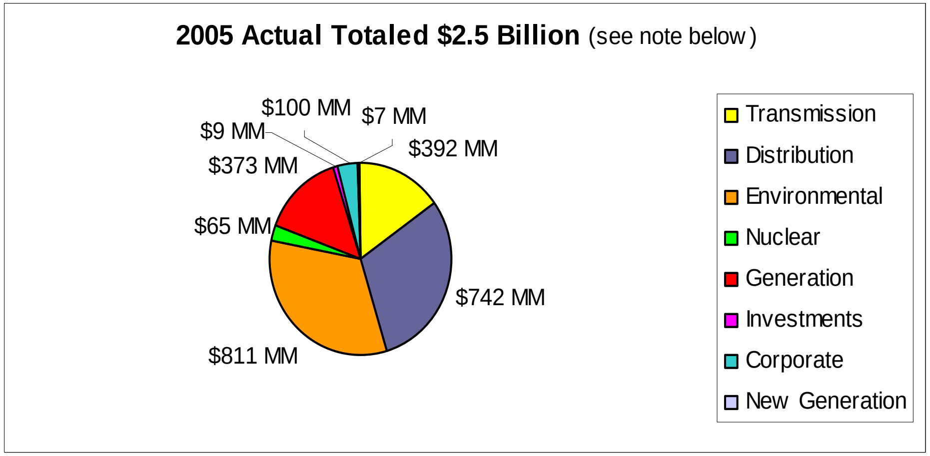
* Cash Flow from Operations assumes full rate recovery on capital expenditures.

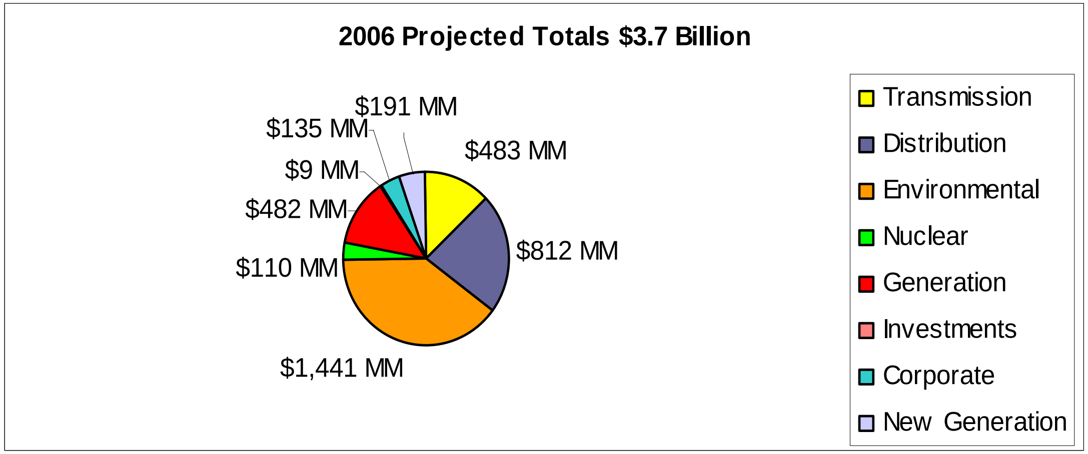
2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Investment 2004 - 2006







Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.

Figures exclude AFUDC.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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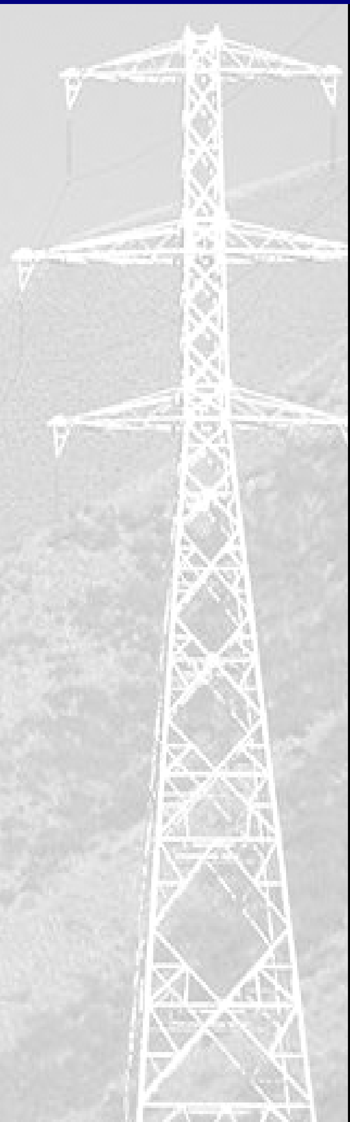
AEP AMERICAN ELECTRIC POWER



3Q05 Earnings Release Presentation

October 27, 2005

“Safe Harbor” Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Highlights

- **3Q05 GAAP Earnings $0.99 Per Share, Ongoing $0.95 Per Share**
- **Increasing 2005 Earnings Guidance to $2.55 - $2.65 Per Share**
- **Quarterly dividend increased to $0.37 per share from $0.35**
- **2006 Guidance Range of $2.50 to $2.70 Per Share**
- **PJM Activity Update**
- **Asset acquisition activity**
    - Completion of Waterford Plant Acquisition
    - Ceredo Plant Acquisition
- **Regulatory Update**
    - TCC Stranded Cost Recovery True-up Filing Submitted
    - FERC Transmission Case
    - APCo Filed for Recovery of E&R Costs in Virginia & Fuel Clause Increase
    - West Virginia Base Rate Filing
    - Kentucky Base Rate Filing

KPSC Case No. 2011-00401
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3Q05 Earnings Performance

	$ millions			Earnings Per Share		
	3rd Qtr 2004	3rd Qtr 2005	Change	3rd Qtr 2004	3rd Qtr 2005	Change
Utility Operations	359	378	19	0.91	0.97	0.06
Investments	(32)	(3)	29	(0.09)	(0.01)	0.08
Parent Company	(9)	(5)	4	(0.02)	(0.01)	0.01
AEP On-Going Earnings	318	370	52	0.80	0.95	0.15

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

3Q05 Utility Operations Performance

		2004 Actual ($ millions)	2004 Actual EPS	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	815		899	
2	Ohio Cos.	513		540	
3	Texas Wires	128		137	
4	Texas Supply / REP	89		28	
5	Off-System Sales	134		203	
6	Other Wholesale Transactions	-		10	
7	Transmission Revenue - 3rd Party	125		105	
8	Other Operating Revenue	114		95	
9	Total Gross Margin	1,918		2,017	
10	Operations & Maintenance	(745)		(812)	
11	Depreciation & Amortization	(322)		(328)	
12	Taxes Other than Income Taxes	(177)		(202)	
13	Interest Exp & Preferred Dividend	(152)		(145)	
14	Other Income & Deductions	9		50	
15	Income Taxes	(172)		(202)	
16	Net Earnings Utility Operations	359	0.91	378	0.97

3Q 2005 Performance Drivers

Weather Impact: Positive $0.06 vs. normal
Positive $0.12 vs. prior yr

- *Increase at Reg Integ Utilities, Ohio Cos & Texas Wires driven by growth in no. of retail customers and load and warmer weather*
- *Decrease in gross margin due to July 2004 plant divestitures, STP sale in May 2005 & expiration of Centrica supply contract*
- *Increased OSS margin as a result of higher power prices*
- *Lower transmission revenues due to elimination of O&T rates*
- *Higher O&M expenses due to timing of maintenance projects, higher demand, tree trimming, etc.*
- *Property tax increases, higher revenue/kwh tax, payroll taxes and higher pretax income drove the increase in tax expense*
- *Other Income & Deductions line includes: (1) carrying costs on OH environmental additions ($10MM) and (2) carrying costs on TX stranded costs ($22MM)*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

9 Months YTD Earnings Performance

	$ millions			Earnings Per Share		
	Sept YTD 2004	Sept YTD 2005	Change	Sept YTD 2004	Sept YTD 2005	Change
Utility Operations	847	982	135	2.14	2.53	0.39
Investments	(47)	10	57	(0.12)	0.02	0.14
Parent Company	(43)	(44)	(1)	(0.11)	(0.11)	0.00
AEP On-Going Earnings	757	948	191	1.91	2.44	0.53

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

9 Months YTD Utility Operations Performance

		2004 Actual ($ millions)	2004 Actual EPS	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	2,315		2,311	
2	Ohio Cos.	1,495		1,540	
3	Texas Wires	333		351	
4	Texas Supply / REP	272		155	
5	Off-System Sales	415		518	
6	Other Wholesale Transactions	13		18	
7	Transmission Revenue - 3rd Party	368		297	
8	Other Operating Revenue	255		248	
9	Total Gross Margin	5,466		5,438	
10	Operations & Maintenance	(2,269)		(2,247)	
11	Depreciation & Amortization	(940)		(963)	
12	Taxes Other than Income Taxes	(535)		(558)	
13	Interest Exp & Preferred Dividend	(479)		(445)	
14	Other Income & Deductions	35		238	
15	Income Taxes	(431)		(481)	
16	Net Earnings Utility Operations	847	2.14	982	2.53

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2005 Performance Drivers

Weather Impact: Positive $0.05 vs. normal
Positive $0.11 vs. prior yr

- *Decline at Reg Integ Utilities attributable to higher fuel costs partially offset by growth in retail customers; Fuel pressure at Ohio Cos. offset by cust. growth & Buckeye Power emissions allowances*
- *Decrease in gross margin due to July 2004 plant divestitures and expiration of Centrica supply agreement*
- *Increased OSS margin due to higher power prices and slightly higher volumes*
- *Lower transmission revenues due to elimination of O&T rates*
- *O&M decrease primarily attributable to sale of TCC generation, lower operating company fringes/employee benefits, lower outside services, etc.*
- *Decreased interest expense reflecting refinancings and lower debt balance*
- *Other Income & Deductions line includes: (1) $70MM Centrica sharing mechanism; (2) carrying costs on OH environmental additions ($47MM) and (3) carrying costs on TX stranded costs ($64MM)*

3Q05 YTD Cash Flow

($ millions)	Year-to-Date 2005	2004
Operating Activities		
Net Income -- Reported	**$ 963**	**$ 912**
Discontinued Operations	(26)	(60)
Continuing Earnings	**937**	**852**
Depreciation, Amortization & Deferred Taxes	1,026	1,131
Impairments	46	2
Pension Contributions	(306)	(27)
Changes in Mark-to-Market	-	89
Changes in Components of Working Capital	392	338
Other Assets & Liabilities	(508)	(114)
Cash Flow from Operations	**1,587**	**2,271**
Investing Activities		
Capital Expenditures	(1,610)	(1,040)
Investment in Discontinued Ops (net)	-	(59)
Change in Other Cash Deposits (net)	202	(79)
Assets Sales Proceeds & Other Inv (net)	1,420	1,196
Cash (Used) by Investing Activities	**12**	**18**
Financing Activities		
Common Shares Issued/(Retired), net	(34)	13
Long-term Debt Issuances/(Retirements)	(554)	(1,482)
Short-term Debt Increase/(Decrease), net	(8)	(201)
Other Financing	-	-
Dividends Paid	(408)	(415)
Preferred Stock Retirement	(66)	(4)
Cash (Used for) Financing	**(1,070)**	**(2,089)**
Cash From Continuing Operations	**$ 529**	**$ 200**
Beginning Cash & Cash Equivalent Balances	320	778
Ending Cash & Cash Equivalent Balances	849	978

Capitalization

Capital Structure	Actual 6/30/05			Actual 9/30/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	11,916	-	11,916	11,742	-	11,742
Short-term Debt	14	-	14	15	-	15
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,382	8,382	-	8,985	8,985
Total Capitalization per Balance Sheet	**11,930**	**8,443**	**20,373**	**11,757**	**9,046**	**20,803**
% of Capitalization per Balance Sheet	***58.6%***	***41.4%***	***100.0%***	***56.5%***	***43.5%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(19)	-	(19)
Off-balance Sheet Leases	1,227	-	1,227	1,227	-	1,227
Securitization Bonds	(668)	-	(668)	(648)	-	(648)
Spent Nuclear Fuel Trust	(232)	-	(232)	(234)	-	(234)
Equity Credit for Equity Units	(276)	276	-	-	-	-
Total Adjusted Capitalization	**11,897**	**8,719**	**20,616**	**12,085**	**9,046**	**21,130**
% of Adjusted Capitalization	***57.7%***	***42.3%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***

Adjusted debt-to-cap of 57.2% at 9/30/05

KPSC Case No. 2011-00401
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QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 3rd Quarter 2005 Actual vs 3rd Quarter 2004 Actual

		2004 Actual			2005 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	27,127 GWh @ $ 30.0 /MWhr =	815		29,252 GWh @ $ 30.7 /MWhr =	899	
2	Ohio Cos.	11,631 GWh @ $ 44.1 /MWhr =	513		12,960 GWh @ $ 41.7 /MWhr =	540	
3	Texas Wires	7,691 GWh @ $ 16.6 /MWhr =	128		8,093 GWh @ $ 16.9 /MWhr =	137	
4	Texas Supply / REP	6,279 GWh @ $ 14.2 /MWhr =	89		1,070 GWh @ $ 26.2 /MWhr =	28	
5	Off-System Sales	9,384 GWh @ $ 14.3 /MWhr =	134		9,535 GWh @ $ 21.3 /MWhr =	203	
6	Other Wholesale Transactions		-			10	
7	Transmission Revenue - 3rd Party		125			105	
8	Other Operating Revenue		114			95	
9	Total Gross Margin		1,918			2,017	
10	Operations & Maintenance		(745)			(812)	
11	Depreciation & Amortization		(322)			(328)	
12	Taxes Other than Income Taxes		(177)			(202)	
13	Interest Exp & Preferred Dividend		(152)			(145)	
14	Other Income & Deductions		9			50	
15	Income Taxes		(172)			(202)	
16	Net Earnings Utility Operations		359	0.91		378	0.97
	INVESTMENTS:						
17	Total Investments		(32)	(0.09)		(3)	(0.01)
18	Parent Company		(9)	(0.02)		(5)	(0.01)
19	ON-GOING EARNINGS		318	0.80		370	0.95

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

9 Months YTD Performance Comparison

American Electric Power

Financial Results for YTD September 2005 Actual vs YTD September 2004 Actual

		2004 Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Performance Driver	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	77,168 GWh @ $ 30.0 /MWhr =	2,315		80,101 GWh @ $ 28.9 /MWhr =	2,311	
2	Ohio Cos.	35,199 GWh @ $ 42.5 /MWhr =	1,495		36,647 GWh @ $ 42.0 /MWhr =	1,540	
3	Texas Wires	19,431 GWh @ $ 17.1 /MWhr =	333		20,348 GWh @ $ 17.2 /MWhr =	351	
4	Texas Supply / REP	17,418 GWh @ $ 15.6 /MWhr =	272		5,590 GWh @ $ 27.7 /MWhr =	155	
5	Off-System Sales	24,445 GWh @ $ 17.0 /MWhr =	415		25,043 GWh @ $ 20.7 /MWhr =	518	
6	Other Wholesale Transactions		13			18	
7	Transmission Revenue - 3rd Party		368			297	
8	Other Operating Revenue		255			248	
9	Total Gross Margin		5,466			5,438	
10	Operations & Maintenance		(2,269)			(2,247)	
11	Depreciation & Amortization		(940)			(963)	
12	Taxes Other than Income Taxes		(535)			(558)	
13	Interest Exp & Preferred Dividend		(479)			(445)	
14	Other Income & Deductions		35			238	
15	Income Taxes		(431)			(481)	
16	Net Earnings Utility Operations		847	2.14		982	2.53
	INVESTMENTS:						
17	Total Investments		(47)	(0.12)		10	0.02
18	Parent Company		(43)	(0.11)		(44)	(0.11)
19	ON-GOING EARNINGS		757	1.91		948	2.44

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

3Q06 Earnings Release Presentation

October 31, 2006

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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A Century of Firsts

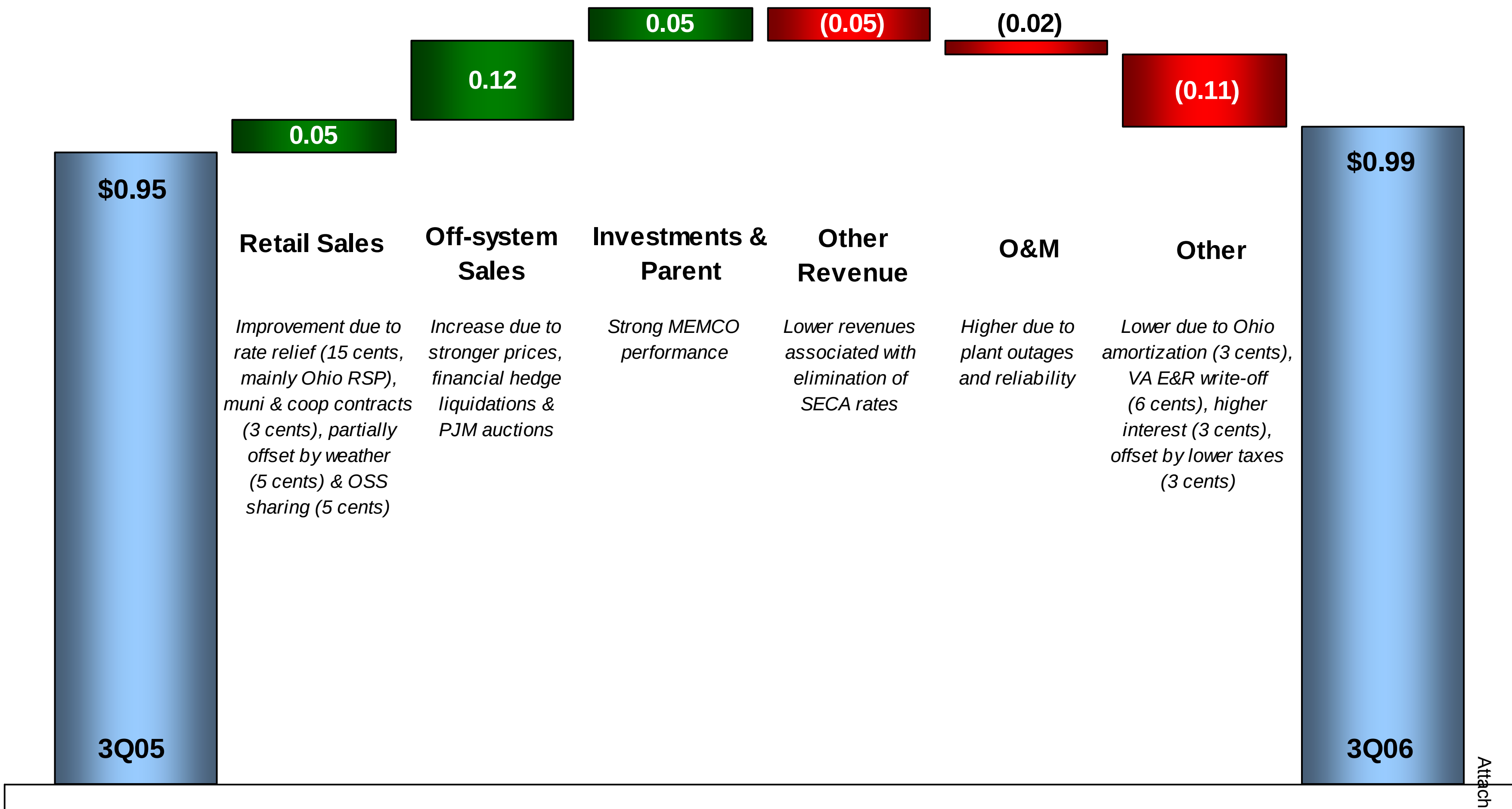
Highlights

- **3Q06 GAAP Earnings $0.67 per share, Ongoing $0.99 per share**
- **Ongoing Earnings Guidance Ranges**

2006 Range $2.65 to $2.80	**2007 Range $2.85 to $3.05**
2008 Range $3.00 to $3.30	**2009 Range $3.15 to $3.45**

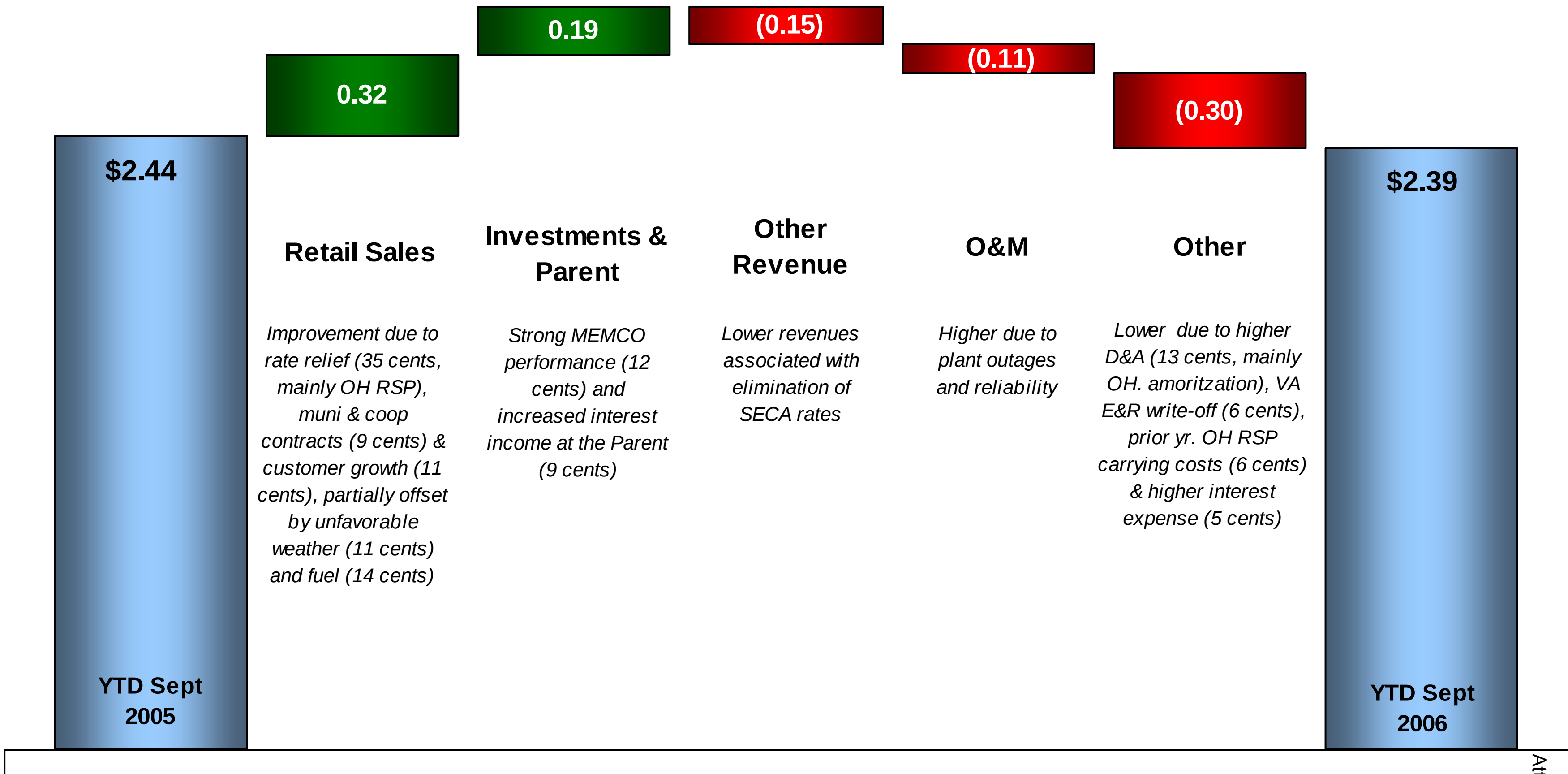
- **Increased EPS Growth Range: 5-7% (CAGR, 2006-2009)**
- **Commitment to recommend an 8-cent/share increase in annual Dividend**
  - **Board declared quarterly 2-cent increase on October 24, 2006, bringing annual dividend level to $1.56/share**
- **Regulatory Activity**
  - **Ohio: submitted RSP Competitive Bid Mechanism; Storm Damage recovery approved ($24MM);**
  - **Texas: $1.7B Securitization complete; PUCT issued ruling on $475MM CTC;**
  - **Indiana Depreciation change denied (requested $75MM);**
  - **Virginia: E&R status; Received base rate case staff testimony**

3Q06 Ongoing Earnings Performance Drivers



4-cent Improvement Driven by Rate Relief, Off-System Sales and Memco

3Q06YTD Ongoing Earnings Performance Drivers



YTD Improvement from Rate Relief, Load Growth & Memco Offset by Weather, Loss of SECA, and VA E&R Write-off

3Q06 Cash Flow

A Century of Firsts

($ millions)	Year-to-Date 2005	Year-to-Date 2006
Operating Activities		
Net Income -- Reported	**$ 963**	**$ 821**
Discontinued Operations	(26)	(6)
Continuing Earnings	**937**	**815**
Depreciation, Amortization & Deferred Taxes	1,068	1,100
Impairments	46	209
Pension Contributions	(306)	-
Changes in Components of Working Capital	392	(9)
Other Assets & Liabilities	(438)	98
Cash Flow from Operations	**1,699**	**2,213**
Investing Activities		
Capital Expenditures	(1,610)	(2,445)
Proceeds on Sale of Assets	1,599	137
Change in Other Cash Deposits (net)	202	(51)
Other Investing (net)	(251)	(115)
Cash (Used) by Investing Activities	**(60)**	**(2,474)**
Financing Activities		
Common Shares Issued/(Retired), net	(34)	24
Long-term Debt Issuances/(Retirements)	(554)	518
Short-term Debt Increase/(Decrease), net	(8)	11
Other Financing	(40)	3
Dividends Paid	(408)	(437)
Preferred Stock Retirement	(66)	-
Cash (Used for) Financing	**(1,110)**	**119**
Cash From Continuing Operations	**$ 529**	**$ (142)**
Beginning Cash & Cash Equivalent Balances	320	401
Ending Cash & Cash Equivalent Balances	849	259

3Q 2006 Cash Flow Drivers

- *2006 Impairment relates to Dow ($136MM)*
- *$98MM positive cash effect partly due to deferred fuel recovery at PSO and SWEPCo.*
- *Cash outlay of $2.445 billion year-to-date 06 for capital investment. FY 2006 guidance assumes $3.663 billion in capital investment.*
- *YTD 06 primary asset sale proceeds: Centrica sharing ($70MM) and Bajio ($29MM); YTD 05 primary asset sale proceeds: HPL ($1B), Texas generation ($314MM) & Centrica sharing ($70MM);*
- *Ending cash balance for 3Q06 of $259MM. 2006 guidance assumes year-end cash balance of $390MM.*

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Capitalization

Capital Structure	Actual 12/31/2005			Actual 9/30/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,763	-	12,763
Short-term Debt	10	-	10	23	-	23
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,524	9,524
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,786**	**9,585**	**22,371**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(21)	-	(21)
Off-balance Sheet Leases	1,213	-	1,213	1,199	-	1,199
Securitization Bonds	(648)	-	(648)	(596)	-	(596)
Spent Nuclear Fuel Trust	(228)	-	(228)	(244)	-	(244)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,694**	**13,154**	**9,555**	**22,709**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.9%***	***42.1%***	***100.0%***

Adjusted debt-to-cap of 57.9% at 9/30/06

A Century of Firsts

QUESTIONS

3Q06 Utility Operations Performance

A Century of Firsts

		2005 Actual		2006 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	557		511	
2	Ohio Companies	498		580	
3	West Regulated Integrated Utilities	327		321	
4	Texas Wires	137		136	
5	Off-System Sales	240		315	
6	Transmission Revenue - 3rd Party	107		69	
7	Other Operating Revenue	119		125	
8	Utility Gross Margin	1,985		2,057	
9	Operations & Maintenance	(775)		(788)	
10	Depreciation & Amortization	(328)		(369)	
11	Taxes Other than Income Taxes	(202)		(185)	
12	Interest Exp & Preferred Dividend	(145)		(161)	
13	Other Income & Deductions	44		20	
14	Income Taxes	(202)		(195)	
15	Utility Operations On-Going Earnings	377	0.97	379	0.96

3Q 2006 Performance Drivers

Weather Impact: Positive $0.01 vs. normal
Negative $0.05 vs. prior yr.

- *Rate relief primarily in OH and KY ($90MM), load growth($9MM) & addition of new muni & coop contracts ($19MM), largely offset by weather ($30MM) and OSS sharing ($33MM)*
- *Higher OSS due to strong generation unit performance in East & favorable results in PJM auction and financial hedge liquidations*
- *3rd Party Transmission revenues down due to absence of SECA revenues in 06.*
- *O&M expense drivers include increased plant outages and higher tree-trimming expenses*
- *Increased D&A due to increased amortization expense at the Ohio Companies & VA E&R write-off*
- *Lower Other Income & Deductions primarily due to write-off of Va. E&R ($27MM)*

Quarterly Performance Comparison

American Electric Power

Financial Results for 3rd Quarter 2005 Actual vs 3rd Quarter 2006 Actual

		2005 Actual			2006 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	16,931 GWh @ $ 32.9 /MWhr =	557		17,720 GWh @ $ 28.8 /MWhr =	511	
2	Ohio Companies	12,960 GWh @ $ 38.4 /MWhr =	498		12,374 GWh @ $ 46.9 /MWhr =	580	
3	West Regulated Integrated Utilities	12,321 GWh @ $ 26.5 /MWhr =	327		12,288 GWh @ $ 26.1 /MWhr =	321	
4	Texas Wires	8,093 GWh @ $ 16.9 /MWhr =	137		7,877 GWh @ $ 17.3 /MWhr =	136	
5	Off-System Sales	10,600 GWh @ $ 22.6 /MWhr =	240		9,974 GWh @ $ 31.6 /MWhr =	315	
6	Transmission Revenue - 3rd Party		107			69	
7	Other Operating Revenue		119			125	
8	Utility Gross Margin		1,985			2,057	
9	Operations & Maintenance		(775)			(788)	
10	Depreciation & Amortization		(328)			(369)	
11	Taxes Other than Income Taxes		(202)			(185)	
12	Interest Exp & Preferred Dividend		(145)			(161)	
13	Other Income & Deductions		44			20	
14	Income Taxes		(202)			(195)	
15	Utility Operations On-Going Earnings		377	0.97		379	0.96
16	Investments On-Going Earnings		(3)	(0.01)		15	0.04
17	Parent Company On-Going Earnings		(4)	(0.01)		(2)	(0.01
18	ON-GOING EARNINGS		370	0.95		392	0.9[illegible]
	Shares Outstanding (in millions)			389			[illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

9 Months YTD Utility Operations Performance

A Century of Firsts

		2005 Actual ($ millions)	2005 Actual EPS	2006 Actual ($ millions)	2006 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	1,545		1,546	
2	Ohio Companies	1,451		1,585	
3	West Regulated Integrated Utilities	737		789	
4	Texas Wires	351		362	
5	Off-System Sales	688		690	
6	Transmission Revenue - 3rd Party	313		220	
7	Other Operating Revenue	375		380	
8	Utility Gross Margin	5,460		5,572	
9	Operations & Maintenance	(2,253)		(2,316)	
10	Depreciation & Amortization	(963)		(1,041)	
11	Taxes Other than Income Taxes	(558)		(558)	
12	Interest Exp & Preferred Dividend	(445)		(475)	
13	Other Income & Deductions	222		173	
14	Income Taxes	(481)		(451)	
15	Utility Operations On-Going Earnings	982	2.53	904	2.29

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance Drivers

Weather Impact: Negative $0.06 vs. normal
Negative $0.11 vs. prior yr.

- *Rate Relief ($210MM), mostly Ohio RSP; Increased margins reflecting customer growth, usage and price ($68MM); New muni & coop power supply contracts ($54MM); Offset by weather ($66MM) and lower fuel margins mainly in the East ($84MM).*
- *Lower ECAR (primarily due to elimination of SECA) and ERCOT Transmission revenue*
- *O&M increase related to higher plant outages, base plant operations & increased maintenance ($40MM); higher tree-trimming ($35MM); Offset by lower storm restoration costs ($23MM) & deferral of Ohio approved storm recovery costs ($24MM)*
- *D&A increase primarily associated with higher amortization at the Ohio Companies and TCC & higher depreciation expense due to E&R write-off ($12MM) & increase cap-ex*
- *Interest expense increased due to higher LTD interest expense ($55MM), offset by AFUDC*
- *Other Income & Deductions declined due to lower carrying costs for the Ohio Companies ($34MM) & write-off of VA E&R ($19MM)*

9 Months YTD Performance Comparison

A Century of Firsts

American Electric Power
Financial Results for YTD September 2005 Actual vs YTD September 2006 Actual

		2005 Actual			2006 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	49,107 GWh @ $ 31.5 /MWhr =	1,545		51,594 GWh @ $ 30.0 /MWhr =	1,546	
2	Ohio Companies	36,647 GWh @ $ 39.6 /MWhr =	1,451		34,763 GWh @ $ 45.6 /MWhr =	1,585	
3	West Regulated Integrated Utilities	30,993 GWh @ $ 23.8 /MWhr =	737		31,227 GWh @ $ 25.3 /MWhr =	789	
4	Texas Wires	20,348 GWh @ $ 17.2 /MWhr =	351		20,338 GWh @ $ 17.8 /MWhr =	362	
5	Off-System Sales	30,630 GWh @ $ 22.5 /MWhr =	688		26,564 GWh @ $ 26.0 /MWhr =	690	
6	Transmission Revenue - 3rd Party		313			220	
7	Other Operating Revenue		375			380	
8	Utility Gross Margin		5,460			5,572	
9	Operations & Maintenance		(2,253)			(2,316)	
10	Depreciation & Amortization		(963)			(1,041)	
11	Taxes Other than Income Taxes		(558)			(558)	
12	Interest Exp & Preferred Dividend		(445)			(475)	
13	Other Income & Deductions		222			173	
14	Income Taxes		(481)			(451)	
15	Utility Operations On-Going Earnings		982	2.53		904	2.29
16	Investments On-Going Earnings		10	0.02		45	0.12
17	Parent Company On-Going Earnings		(44)	(0.11)		(7)	(0.02)
18	ON-GOING EARNINGS		948	2.44		942	2.39
	Shares Outstanding (in millions)			389			39[illegible]

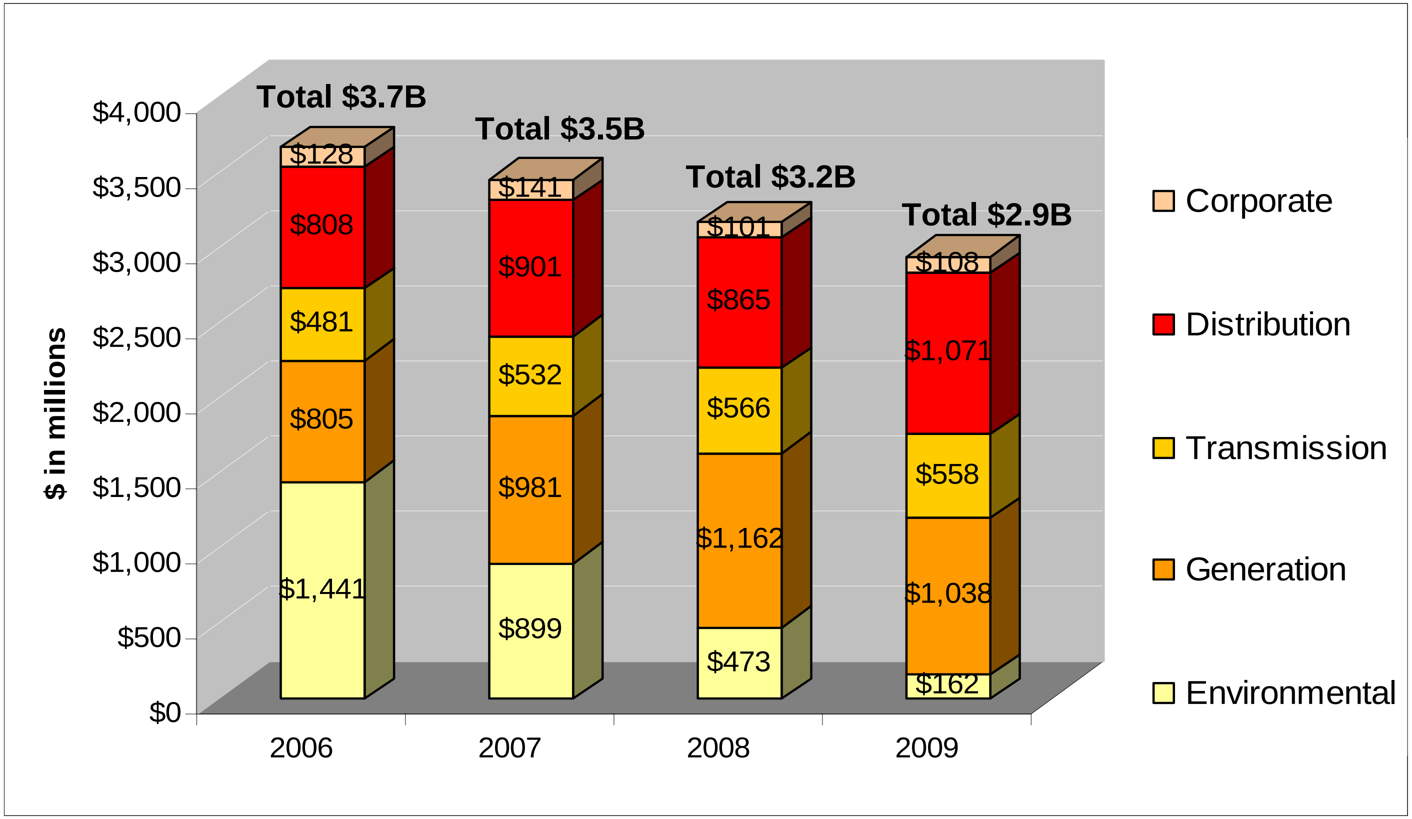
2006 Ongoing Guidance: $2.65 to $2.80 Per Share
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Estimate vs. 2007 Estimate

		Performance Driver	2006 Estimate ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,321 GWh @ $ 30.9 /MWhr =	2,141	71,033 GWh @ $ 33.7 /MWhr =	2,392
2	Ohio Companies	46,083 GWh @ $ 46.6 /MWhr =	2,147	47,902 GWh @ $ 49.5 /MWhr =	2,371
3	West Regulated Integrated Utilities	41,264 GWh @ $ 24.9 /MWhr =	1,026	40,795 GWh @ $ 25.9 /MWhr =	1,058
4	Texas Wires	26,506 GWh @ $ 14.4 /MWhr =	383	26,834 GWh @ $ 16.4 /MWhr =	441
5	Off-System Sales	35,100 GWh @ $ 23.1 /MWhr =	811	30,742 GWh @ $ 21.9 /MWhr =	672
6	Transmission Revenue - 3rd Party		282		255
7	Other Operating Revenue		579		715
8	Utility Gross Margin		7,369		7,904
9	Operations & Maintenance		(3,241)		(3,292)
10	Depreciation & Amortization		(1,316)		(1,413)
11	Taxes Other than Income Taxes		(747)		(785)
12	Interest Exp & Preferred Dividend		(664)		(813)
13	Other Income & Deductions		199		91
14	Income Taxes		(551)		(567)
15	Utility Operations On-Going Earnings		1,049		1,125
16	Investments On-Going Earnings		45		48
17	Parent Company On-Going Earnings		(1)		(6)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Multi-Year Capital Investment Forecast



Note: Excludes AFUDC

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A Century of Firsts

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2005	2006	2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (2,499)	$ (3,663)	$ (3,454)	$ (3,167)	$ (2,937)
Dividend on Common	$ (553)	$ (591)	$ (618)	$ (621)	$ (624)
Cash Sources					
Cash from Operations *	$ 1,877	$ 1,890	$ 2,232	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 1,246	$ 175	$ -	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ (25)	$ 45	$ 80	$ 80	$ 80
Change in Debt, Net	$ (91)	$ 661	$ 1,738	$ 1,176	$ 967
TCC securitization bond issuance	$ -	$ 1,740			
Other	$ 126	$ (268)	$ (95)	$ (67)	$ (69)
Cash Sources Less Capital Expenditures, Dividends & Other	$ 81	$ (11)	$ (117)	$ 43	$ 88
Ending Cash Balance	$ 401	$ 390	$ 273	$ 316	$ 404

Projected 2006-2009 Credit Metric Ranges

Debt to book capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

American Electric Power

3Q07 Earnings Release

October 24, 2007

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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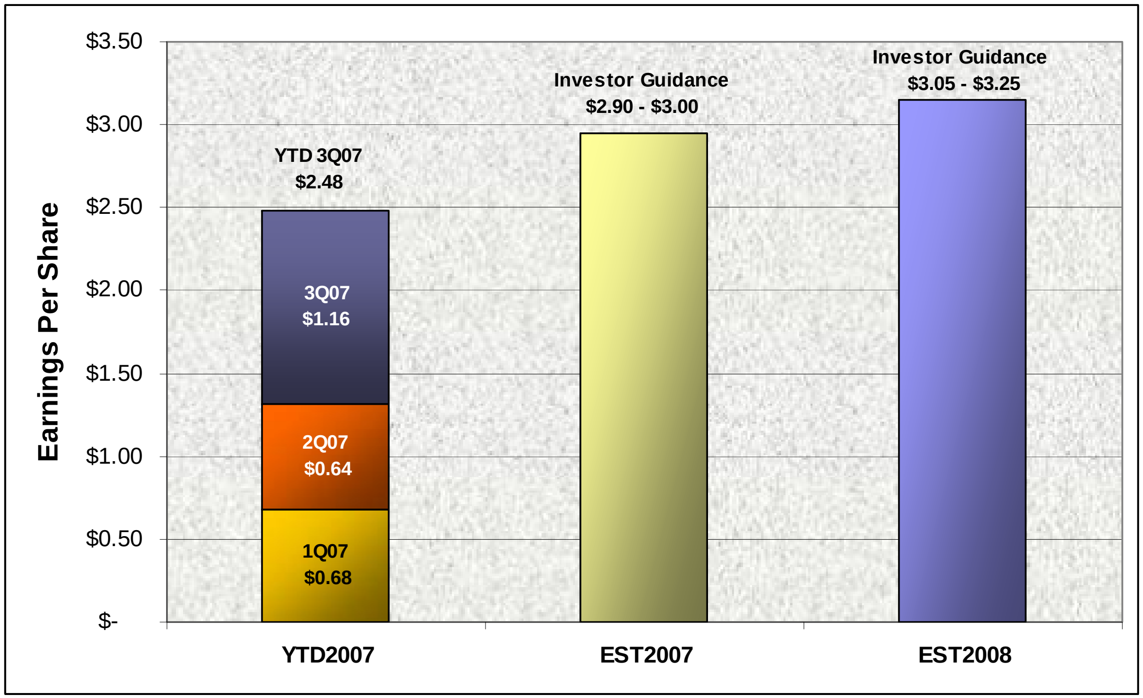
Earnings Highlights

- **3Q 2007 GAAP Earnings of $1.02 per share; Ongoing Earnings of $1.16 per share**
- **YTD 2007 GAAP Earnings of $2.15 per share; Ongoing Earnings of $2.48 per share**



Reaffirming 2007 Ongoing Earnings Guidance Range of $2.90 to $3.00 per share

Reaffirming 2008 Ongoing Earnings Guidance Range of $3.05 to $3.25 per share

Regulatory Update

Key Activities:

- Ohio RSP 4%
- Michigan Depreciation
- PSO Rate Case
- TCC Rate Case
- Electric Transmission Texas
- SWEPCO - Turk

Other Events

Key Activities:

- Ohio Post 2008
- New Source Review Settlement
- PATH JV Formation
- PJM Activities

3Q07 Performance

American Electric Power
Financial Results for 3rd Quarter 2007 Actual vs 3rd Quarter 2006 Actual

		2006 Actual ($ millions)	2006 Actual EPS	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	511		565	
2	Ohio Companies	580		650	
3	West Regulated Integrated Utilities	321		336	
4	Texas Wires	136		152	
5	Off-System Sales	313		349	
6	Net Transmission Revenue	69		11	
7	Other Operating Revenue	123		124	
8	**Utility Gross Margin**	2,053		2,187	
9	Operations & Maintenance	(779)		(771)	
10	Depreciation & Amortization	(374)		(374)	
11	Taxes Other than Income Taxes	(183)		(189)	
12	Interest Exp & Preferred Dividend	(160)		(213)	
13	Other Income & Deductions	18		27	
14	Income Taxes	(197)		(224)	
15	**Utility Operations On-Going Earnings**	378	0.95	443	1.11
	NON-UTILITY OPERATIONS:				
16	MEMCO	19	0.05	18	0.05
17	Generation & Marketing	4	0.01	3	0.01
18	**Non Utility Operations On-Going Earnings**	23		21	
19	Parent & Other On-Going Earnings	(9)	(0.02)	(2)	(0.01)
20	**ON-GOING EARNINGS**	392	0.99	462	1.16

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

3Q07 Performance Drivers:

- *Weather Impact of $16MM:*
  - *Positive $0.03 vs. normal; Positive $0.03 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Rate Relief $66MM; (APCo, Ohio RSP, Texas & PSO)*
  - *Positive retail load growth including new customers; $47MM*
- *Off-System Sales (line 5):*
  - *Favorable OSS combined with favorable trading margins*
- *Net Transmission Revenue (line 6):*
  - *Primarily increased PJM marginal losses ($71MM) offset by increased OSS (line 5) and lower fuel expense (lines 1&2) for a net loss of approximately $20MM*
- *Operations & Maintenance (line 9):*
  - *Lower generation expenses, including absence of 2006 Cook Plant write off and Dow Plant*
- *Interest Expense (line 12):*
  - *Higher interest expense primarily attributed to increased LTD; ($31MM)*
- *Other Income & Deductions (line 13):*
  - *Higher due to prior year write off of VA E&R carrying costs income $33MM; partially offset by lower TCC carrying costs income ($25MM)*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 33.6% in 2007 and 34.3% in 2006*

YTD 2007 Performance

American Electric Power
Financial Results for YTD September 2007 Actual vs YTD September 2006 Actual

		2006 Actual		2007 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	1,546		1,633	
2	Ohio Companies	1,585		1,871	
3	West Regulated Integrated Utilities	789		765	
4	Texas Wires	362		396	
5	Off-System Sales	686		735	
6	Net Transmission Revenue	220		133	
7	Other Operating Revenue	378		413	
8	**Utility Gross Margin**	5,566		5,946	
9	Operations & Maintenance	(2,292)		(2,369)	
10	Depreciation & Amortization	(1,060)		(1,122)	
11	Taxes Other than Income Taxes	(557)		(560)	
12	Interest Exp & Preferred Dividend	(475)		(599)	
13	Other Income & Deductions	171		93	
14	Income Taxes	(451)		(455)	
15	Utility Operations On-Going Earnings	902	2.29	934	2.35
	NON-UTILITY OPERATIONS:				
16	MEMCO	54	0.14	40	0.09
17	Generation & Marketing	10	0.02	17	0.04
18	**Non-Utility Operations On-Going Earnings**	64		57	
19	Parent & Other On-Going Earnings	(24)	(0.06)	(1)	0.00
20	**ON-GOING EARNINGS**	942	2.39	990	2.48

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2007 Performance Drivers:

- *Weather impact of $83MM:*
  - *Positive $0.08 vs. normal; Positive $0.14 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Rate relief; $167MM (AP, KP, Ohio RSP, PSO & TX Wires)*
  - *Positive retail load growth including new customers $168MM*
- *Off-System Sales (line 5):*
  - *Favorable trading margins & West Physical OSS, offset by unfavorable East Physical*
- *Net Transmission Revenue (line 6):*
  - *Increased PJM marginal losses ($91MM) offset by increased OSS (line 5) and lower fuel expense (lines 1&2) for a net loss of approximately $25MM*
- *Other Operating Revenue (line 7):*
  - *Increased securitization revenue*
- *Operations & Maintenance (line 9):*
  - *Increase due to plant outages, storm costs & increased vegetation management*
- *Depreciation & Amortization (line 10):*
  - *Increased amortization related to Texas securitization*
- *Interest Expense (line 12):*
  - *Higher due to TCC securitization bonds and more LTD*
- *Other Income & Deductions (line 13):*
  - *Decreased Centrica sharing contribution ($50MM) in 2007 vs. 2006 and lower TCC carrying costs income ($28MM)*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.8% in 2007 and 33.3% in 2006*

September YTD 2007 Cash Flow

($ millions)	2006	2007
Operating Activities		
Net Income -- Reported	**$ 821**	**$ 858**
Discontinued Operations	(6)	(2)
Continuing Earnings	**815**	**856**
Depreciation, Amortization & Deferred Taxes	1,119	1,336
Extraordinary Loss, net of Taxes	209	79
Changes in Components of Working Capital	(9)	(493)
Other Assets & Liabilities	62	(148)
Cash Flows From Operating Activities	**2,196**	**1,630**
Investing Activities		
Capital Expenditures	(2,428)	(2,595)
Proceeds on Sale of Assets	120	78
Acquisitions of Assets	-	(512)
Change in Other Temporary Cash Investments (net)	(51)	207
Other Investing (net)	(98)	(113)
Cash Flows Used for Investing Activities	**(2,457)**	**(2,935)**
Financing Activities		
Common Shares Issued, net	24	116
Long-term Debt Issuances, net	518	1,054
Short-term Debt Increase, net	11	569
Other Financing	3	(73)
Dividends Paid	(437)	(466)
Cash Flows From Financing Activities	**119**	**1,200**
Cash From Continuing Operations	**$ (142)**	**$ (105)**
Beginning Cash & Cash Equivalent Balances	401	301
Ending Cash & Cash Equivalent Balances	**$ 259**	**$ 196**

YTD 2007 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by changes in accrued taxes, accounts receivable and other current liabilities.

Investing Activities

- Cash outlay of $2.6 billion for YTD capital investment.
- 2007 primary asset sale proceeds: Centrica sharing $20MM and TCC's share of Oklaunion $46MM; 2006 primary asset sale proceeds: Centrica sharing $70MM and Bajio $29MM.
- 2007 acquisitions consist of the Darby Plant for $102MM, Lawrenceburg for $325MM and Dresden for $85MM.

Investing Activities

- Common stock issuance of $116MM primarily related to the exercise of stock options during 2007.
- Changes in long and short term debt driven by capital funding requirements.

Capitalization

Capital Structure	Actual 12/31/2006			Actual 9/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,776	-	14,776
Short-term Debt	18	-	18	587	-	587
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,909	9,909
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,363**	**9,970**	**25,333**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.6%***	***39.4%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(26)	-	(26)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,257)	-	(2,257)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(257)	-	(257)
Total Adjusted Capitalization	**12,291**	**9,473**	**21,764**	**13,993**	**9,970**	**23,963**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.4%***	***41.6%***	***100.0%***

Adjusted debt-to-cap of 58.4% at 9/30/07

Questions

3Q07 Earnings

	$ millions			Earnings Per Share		
	3rd Qtr 2006	3rd Qtr 2007	Change	3rd Qtr 2006	3rd Qtr 2007	Change
Utility Operations	378	443	65	0.95	1.11	0.16
Non-Utility Operations	23	21	(2)	0.06	0.06	0.00
Parent & Other	(9)	(2)	7	(0.02)	(0.01)	0.01
AEP On-Going Earnings	392	462	70	0.99	1.16	0.17
Special Items	(127)	(55)	72	(0.32)	(0.14)	0.18
Reported Earnings (GAAP)	265	407	142	0.67	1.02	0.35

Quarterly Performance Comparison

American Electric Power
Financial Results for 3rd Quarter 2007 Actual vs 3rd Quarter 2006 Actual

		2006 Actual			2007 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	17,720 GWh @ $ 28.8 /MWhr =	511		18,677 GWh @ $ 30.3 /MWhr =	565	
2	Ohio Companies	12,374 GWh @ $ 46.9 /MWhr =	580		13,464 GWh @ $ 48.3 /MWhr =	650	
3	West Regulated Integrated Utilities	12,288 GWh @ $ 26.1 /MWhr =	321		12,469 GWh @ $ 26.9 /MWhr =	336	
4	Texas Wires	7,877 GWh @ $ 17.3 /MWhr =	136		7,721 GWh @ $ 19.7 /MWhr =	152	
5	Off-System Sales	9,974 GWh @ $ 31.4 /MWhr =	313		10,164 GWh @ $ 34.3 /MWhr =	349	
6	Net Transmission Revenue		69			11	
7	Other Operating Revenue		123			124	
8	**Utility Gross Margin**		2,053			2,187	
9	Operations & Maintenance		(779)			(771)	
10	Depreciation & Amortization		(374)			(374)	
11	Taxes Other than Income Taxes		(183)			(189)	
12	Interest Exp & Preferred Dividend		(160)			(213)	
13	Other Income & Deductions		18			27	
14	Income Taxes		(197)			(224)	
15	**Utility Operations On-Going Earnings**		378	0.95		443	1.11
	NON-UTILITY OPERATIONS:						
16	MEMCO		19	0.05		18	0.05
17	Generation & Marketing		4	0.01		3	0.01
18	**Non Utility Operations On-Going Earnings**		23			21	
19	Parent & Other On-Going Earnings		(9)	(0.02)		(2)	(0.01)
20	**ON-GOING EARNINGS**		392	0.99		462	1.16

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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YTD Earnings

	$ millions			$ Earnings Per Share		
	YTD 2006	YTD 2007	Change	YTD 2006	YTD 2007	Change
Utility Operations	902	934	32	2.29	2.35	0.06
Non-Utility Operations	64	57	(7)	0.16	0.13	(0.03)
Parent & Other	(24)	(1)	23	(0.06)	0.00	0.06
AEP On-Going Earnings	942	990	48	2.39	2.48	0.09
Special Items	(121)	(132)	(11)	(0.31)	(0.33)	(0.02)
Reported Earnings (GAAP)	821	858	37	2.08	2.15	0.07

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YTD Performance Comparison

American Electric Power
Financial Results for YTD September 2007 Actual vs YTD September 2006 Actual

		Performance Driver	2006 Actual ($ millions)	2006 Actual EPS	Performance Driver	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	51,594 GWh @ $ 30.0 /MWhr =	1,546		54,734 GWh @ $ 29.8 /MWhr =	1,633	
2	Ohio Companies	34,763 GWh @ $ 45.6 /MWhr =	1,585		38,079 GWh @ $ 49.1 /MWhr =	1,871	
3	West Regulated Integrated Utilities	31,227 GWh @ $ 25.3 /MWhr =	789		32,294 GWh @ $ 23.7 /MWhr =	765	
4	Texas Wires	20,338 GWh @ $ 17.8 /MWhr =	362		20,297 GWh @ $ 19.5 /MWhr =	396	
5	Off-System Sales	26,564 GWh @ $ 25.8 /MWhr =	686		22,996 GWh @ $ 32.0 /MWhr =	735	
6	Net Transmission Revenue		220			133	
7	Other Operating Revenue		378			413	
8	**Utility Gross Margin**		5,566			5,946	
9	Operations & Maintenance		(2,292)			(2,369)	
10	Depreciation & Amortization		(1,060)			(1,122)	
11	Taxes Other than Income Taxes		(557)			(560)	
12	Interest Exp & Preferred Dividend		(475)			(599)	
13	Other Income & Deductions		171			93	
14	Income Taxes		(451)			(455)	
15	Utility Operations On-Going Earnings		902	2.29		934	2.35
	NON-UTILITY OPERATIONS:						
16	MEMCO		54	0.14		40	0.09
17	Generation & Marketing		10	0.02		17	0.04
18	**Non-Utility Operations On-Going Earnings**		64			57	
19	Parent & Other On-Going Earnings		(24)	(0.06)		(1)	0.00
20	**ON-GOING EARNINGS**		942	2.39		990	2.48

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

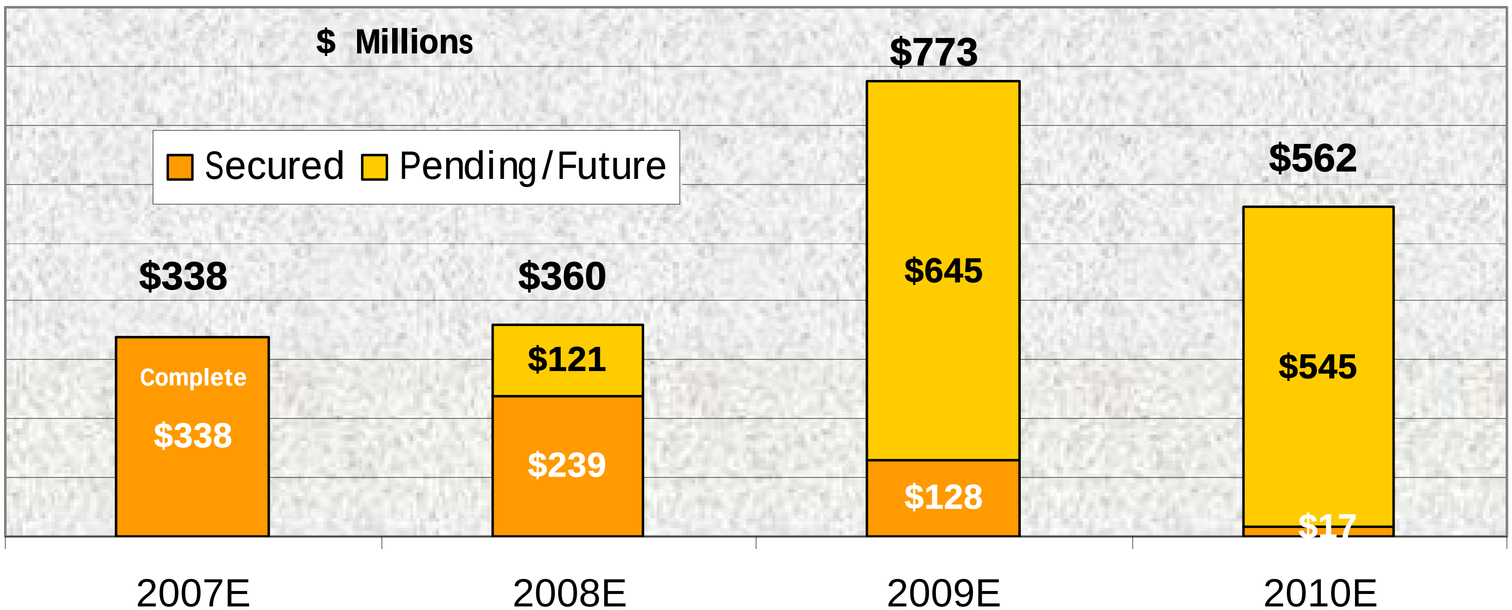
2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Net Transmission Revenue		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

Incremental Rate Relief



2008 Secured:

Ohio 3% & 7%

I&M Depreciation

APCo-WV Construction Surcharge

PSO Peaking Generation & Base Rate Case

Rate Relief Is A Critical Element To AEP's Financial Success

3Q07 Retail Performance

	Load Growth (weather normalized) 3Q07 vs. 3Q06
East Regulated Integrated Utilities	3.7%
Ohio Companies	8.6%
West Regulated Integrated Utilities	0.7%
Texas Wires	1.0%
Impact on EPS	$0.06

	Degree Days 3Q07 vs. 3Q06
East Cooling	123
West Cooling *	(62)
East Heating	(8)
West Heating *	-
Impact on EPS	$0.03

* West statistics represent PSO/SWEPCo customer base only

YTD Retail Performance

	Load Growth (weather normalized) YTD 2007 vs. YTD 2006
East Regulated Integrated Utilities	4.0%
Ohio Companies	8.2%
West Regulated Integrated Utilities	2.3%
Texas Wires	2.3%
Impact on EPS	$0.30

	Degree Days YTD 2007 vs. YTD 2006
East Cooling	275
West Cooling *	(241)
East Heating	468
West Heating *	330
Impact on EPS	$0.14

* West statistics represent PSO/SWEPCo customer base only

Retail Performance

	Rate Relief (in millions)
	3Q07 vs. 3Q06
East Regulated Integrated Utilities	$31
Ohio Companies	$15
West Regulated Integrated Utilities	$5
Texas Wires	$15
AEP System Total	$66
Impact on EPS	$0.11

	Rate Relief (in millions)
	YTD 3Q07 vs. YTD 3Q06
East Regulated Integrated Utilities	$51
Ohio Companies	$84
West Regulated Integrated Utilities	$9
Texas Wires	$23
AEP System Total	$167
Impact on EPS	$0.28

3Q07 Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	3Q 2007	3Q 2006	3Q 2007	3Q 2006	3Q 2007	3Q 2006
East:	**68.03%**	**69.49%**	**86.43%**	**86.18%**	**8.91%**	**8.00%**
Coal:	77.72%	76.06%	85.70%	85.99%	9.51%	8.59%
Super-Critical*	80.27%	79.28%	86.30%	86.37%	9.51%	8.59%
Sub-Critical*	68.84%	66.10%	83.85%	84.82%	9.53%	8.60%
Gas**	14.51%	7.59%	90.20%	89.54%	N/A	N/A
Hydro	2.57%	7.03%	95.31%	88.89%	4.85%	4.55%
Nuclear	85.15%	83.62%	84.05%	83.94%	3.34%	2.42%
SPP:	**48.93%**	**55.09%**	**90.32%**	**91.00%**	**8.09%**	**8.01%**
Coal:	82.45%	88.50%	87.76%	95.33%	10.34%	3.62%
Super-Critical*	89.53%	93.49%	91.75%	95.36%	6.83%	4.39%
Sub-Critical*	79.77%	86.87%	86.25%	95.13%	11.67%	3.51%
Gas	27.23%	32.34%	91.97%	88.05%	6.02%	11.84%
Texas:						
Coal	**82.49%**	**76.29%**	**83.86%**	**76.03%**	**14.47%**	**14.77%**
AEP System	**63.86%**	**66.24%**	**87.28%**	**87.15%**	**8. 81%**	**8.12%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

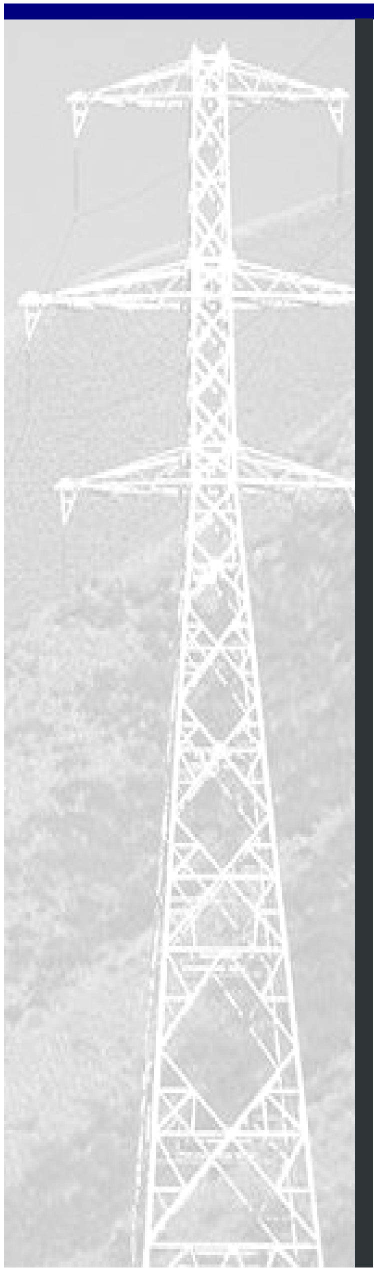
** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours. (3Q2007 = .85% / 3Q2006 =.01%)

YTD Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	YTD 2007	YTD 2006	YTD 2007	YTD 2006	YTD 2007	YTD 2006
East:	**65.22%**	**65.83%**	**82.00%**	**83.00%**	**8.75%**	**8.55%**
Coal:	72.08%	71.65%	79.42%	81.54%	9.50%	9.39%
Super-Critical*	73.02%	75.08%	78.43%	82.31%	9.50%	7.92%
Sub-Critical*	69.19%	61.06%	82.48%	79.16%	9.51%	13.95%
Gas	8.33%	3.08%	89.65%	91.91%	N/A	N/A
Hydro	8.59%	10.15%	91.90%	93.90%	11.64%	4.55%
Nuclear	95.02%	85.75%	93.70%	85.43%	1.40%	0.84%
SPP:	**43.87%**	**46.54%**	**85.65%**	**85.96%**	**7.22%**	**6.74%**
Coal:	76.87%	76.70%	82.06%	82.79%	6.67%	3.46%
Super-Critical*	75.10%	82.19%	77.54%	84.43%	7.66%	5.30%
Sub-Critical*	77.56%	74.85%	83.76%	82.04%	6.33%	2.86%
Gas	22.01%	25.82%	88.04%	88.14%	7.75%	9.76%
Texas:						
Coal	**70.00%**	**61.02%**	**70.78%**	**63.88%**	**20.47%**	**27.16%**
AEP System	**60.69%**	**61.28%**	**82.69%**	**83.40%**	**8.61%**	**8.51%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours. (YTD2007 = .79% / YTD2006 =.08%)



3Q08 Earnings Release Presentation

October 31, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Third Quarter 2008 Highlights

- **Economic Conditions/Outlook**
- **Current State of Credit Markets/AEP Liquidity**
- **DC Cook Plant Unit 1 Update**
- **Regulatory Updates – all $518MM of 2008 rate relief secured**
  - **Ohio ESP**
  - **Virginia Rate Case Settlement**
  - **Pending Rate Cases in Indiana and Oklahoma**
  - **Generation and Transmission**
- **Earnings:**
  - **3Q08 GAAP/Ongoing Earnings $0.93 per share**
  - **2008 YTD GAAP Earnings $3.06 per share**
  - **2008 YTD Ongoing $2.65 per share**
- **Tightening 2008 Ongoing Earnings Guidance Range to $3.15 to $3.25**

3Q08 Performance

American Electric Power

Financial Results for 3rd Quarter 2008 Actual vs 3rd Quarter 2007 Actual

		2007 Actual		2008 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	534		499	
2	Ohio Companies	629		577	
3	West Regulated Integrated Utilities	336		341	
4	Texas Wires	152		153	
5	Off-System Sales	329		322	
6	Transmission Revenue - 3rd Party	81		85	
7	Other Operating Revenue	126		150	
8	Utility Gross Margin	2,187		2,127	
9	Operations & Maintenance	(771)		(846)	
10	Depreciation & Amortization	(374)		(379)	
11	Taxes Other than Income Taxes	(189)		(187)	
12	Interest Exp & Preferred Dividend	(213)		(225)	
13	Other Income & Deductions	27		45	
14	Income Taxes	(224)		(179)	
15	**Utility Operations On-Going Earnings**	443	1.11	356	0.89
16	**Transmission Operations On-Going Earnings**	0	0.00	1	0.00
	NON-UTILITY OPERATIONS:				
17	AEP River Operations	18	0.05	11	0.03
18	Generation & Marketing	3	0.01	16	0.04
19	**Parent & Other On-Going Earnings**	(2)	(0.01)	(10)	(0.03)
20	ON-GOING EARNINGS	462	1.16	374	0.93

Note: For analysis purposes, certain amounts have been reclassified for this effect on earnings presentation.

3Q08 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *$78MM higher fuel costs in Ohio, including consumables*
  - *Unfavorable weather impact of $42MM ($0.07) versus prior year and a $0.03 unfavorable impact versus normal; additionally, Hurricane Ike caused outages in SWEPCo and the Ohio Companies, resulting in $10MM in lost revenues*
  - *Offset by rate relief $90MM (APCo, I&M, KPCo, Ohio RSPs, PSO, SWEPCo & TCC)*
- *Off-System Sales (line 5):*
  - *Lower margins in the west due to a favorable fuel reconciliation recorded in the prior year quarter, somewhat offset by higher power prices & lower internal load in the east*
- *Other Operating Revenue (line 7):*
  - *Higher miscellaneous operating revenues including rents and pole attachments and 2007 TCC provision for bonded rates*
- *Operations & Maintenance (line 9):*
  - *Higher expenditures in all categories due to maintenance outages, reliability and storm restoration, some of which have revenue offsets*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Other Income & Deductions (line 13):*
  - *Higher due to increased interest income and carrying charges*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 33.5% in 2008 and 33.6% in 2007*
- *River Operations decreased due primarily to weather related issues including hurricanes and flooding and an oil spill in New Orleans harbor, which limited ship arrivals and departures.*
- *Generation & Marketing increased due to higher gross margins from the marketing business and from the optimization of Oklaunion*
- *Parent decreased due to higher interest expense and lower interest income*

YTD Performance

American Electric Power

Financial Results for YTD September 2008 Actual vs YTD September 2007 Actual

		2007 Actual		2008 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	1,592		1,621	
2	Ohio Companies	1,842		1,823	
3	West Regulated Integrated Utilities	765		820	
4	Texas Wires	396		410	
5	Off-System Sales	713		786	
6	Transmission Revenue - 3rd Party	225		247	
7	Other Operating Revenue	413		440	
8	Utility Gross Margin	5,946		6,147	
9	Operations & Maintenance	(2,369)		(2,433)	
10	Depreciation & Amortization	(1,122)		(1,099)	
11	Taxes Other than Income Taxes	(560)		(569)	
12	Interest Exp & Preferred Dividend	(599)		(653)	
13	Other Income & Deductions	93		135	
14	Income Taxes	(455)		(500)	
15	**Utility Operations On-Going Earnings**	934	2.35	1,028	2.56
16	**Transmission Operations On-Going Earnings**	0	0.00	2	0.00
	NON-UTILITY OPERATIONS:				
17	AEP River Operations	40	0.09	21	0.05
18	Generation & Marketing	17	0.04	43	0.11
19	**Parent & Other On-Going Earnings**	(1)	0.00	(30)	(0.07)
20	**ON-GOING EARNINGS**	990	2.48	1,064	2.65

Note: For analysis purposes, certain amounts have been reclassified for this effect on earnings presentation.

YTD Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief $247MM (APCo, Ohio RSPs, I&M, KPCo, Texas, SWEPCo & PSO)*
  - *Positive load growth including new customers; $74MM*
  - *Positive impact due to 2007 unfavorable true-up of VA order; $37MM*
  - *Offset by $135MM higher fuel costs in Ohio, including consumables, and $29MM increased OSS sharing*
  - *Unfavorable weather impact of $65MM ($0.10) versus prior year and unfavorable $0.03 ($18MM) versus normal; additionally, Hurricane Ike caused outages in SWEPCo and the Ohio Companies, resulting in $10MM in lost revenues*
- *Off-System Sales (line 5):*
  - *Favorable due to higher prices and volumes, higher plant availability & lower internal load*
- *Operations & Maintenance (line 9):*
  - *Increase primarily due to storm restoration, maintenance, reliability, Red Rock write off & employee benefits, partially offset by a deferral of 2007 PSO ice storms in 1Q2008*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Other Income & Deductions (line 13):*
  - *Higher due to increased interest income and carrying charges*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.7% in 2008 and 32.8% in 2007*
- *River Operations decreased due primarily to weather related issues including hurricanes and flooding and an oil spill in New Orleans harbor, which limited ship arrivals and departures.*
- *Generation & Marketing increased due to higher gross margins from the marketing business and from the optimization of Oklaunion*
- *Parent decreased due to higher interest expense and lower interest income*

YTD 2008 Cash Flow

($ millions)	9 months YTD 2007	9 months YTD 2008
Operating Activities		
Net Income -- Reported	**$ 858**	**$ 1,228**
Discontinued Operations	(2)	(1)
Continuing Earnings	**856**	**1,227**
Depreciation, Amortization & Deferred Taxes	1,336	1,714
Changes in Components of Working Capital	(462)	(288)
Extraordinary Loss	79	-
Over/(Under) Fuel Recovery, Net	(133)	(284)
Other Assets & Liabilities	(45)	(316)
Cash Flows From Operating Activities	**1,631**	**2,053**
Investing Activities		
Capital Expenditures	(2,595)	(2,576)
Proceeds on Sale of Assets	78	83
Change in Other Temporary Cash Investments, net	151	(368)
Acquisition of Assets	(512)	(97)
Other Investing, net	(57)	(103)
Cash Flows Used for Investing Activities	**(2,935)**	**(3,061)**
Financing Activities		
Common Shares Issued, net	116	106
Long-term Debt Issuances, net	1,054	979
Short-term Debt Increase, net	569	642
Other Financing	(74)	(65)
Dividends Paid	(466)	(494)
Cash Flows From Financing Activities	**1,199**	**1,168**
Cash From Continuing Operations	**$ (105)**	**$ 160**
Beginning Cash & Cash Equivalent Balances	301	178
Ending Cash & Cash Equivalent Balances	$ 196	$ 338

2008 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by G & A type items
- Changes in other assets and liabilities largely driven by changes in securitized transition assets, regulatory assets related to the PSO storm and Red Rock cancellation and other employee-related non-current assets.

Investing Activities

- Cash outlay of $2.6B for 2008 YTD capital investment.
- 2008 asset sale proceeds relate to miscellaneous utility property sales; 2007 asset sale proceeds primarily relate to Centrica sharing $20MM and TCC's sale of its share of Oklaunion $46MM.
- Change in Other Temporary Cash Investments, net in 2008 relates to the purchase of variable rate securities, primarily with funds received from our draw down on our credit facilities
- Change in 2008 Other Investing primarily relates to the purchase of nuclear fuel of $99MM.

Financing Activities

- 2008 common share issuances of $106MM primarily due to issuances through the dividend reinvestment program.
- Changes in long and short term debt driven by capital funding requirements.

AEP Liquidity

as of October 28, 2008

Liquidity Summary (unaudited)	Actual 10/28/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	1,366	
Less		
Draw on Credit Facilities	(1,969)	
Commercial Paper Outstanding	(178)	
Letters of Credit Issued	(439)	
Net Available Liquidity	**$2,699**	

Accessing the credit lines provides AEP with added flexibility to bridge our cash needs over the next several months while maintaining a strong liquidity position.

Capitalization

Capital Structure	Actual 12/31/2007			Actual 9/30/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,994	-	14,994	16,007	-	16,007
Short-term Debt	660	-	660	1,302	-	1,302
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	10,079	10,079	-	10,917	10,917
Total Capitalization per Balance Sheet	**15,654**	**10,140**	**25,794**	**17,309**	**10,978**	**28,287**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***61.2%***	***38.8%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
Cash and Marketable Securities	(178)	-	(178)	(781)	-	(781)
Capital and Operating Leases	1,522	-	1,522	1,470	-	1,470
Securitization Bonds	(2,257)	-	(2,257)	(2,132)	-	(2,132)
Receivables Securitization	507	-	507	555	-	555
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(263)	-	(263)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	-
Total Adjusted Capitalization	**14,970**	**10,140**	**25,110**	**16,000**	**11,136**	**27,136**
% of Adjusted Capitalization	***59.6%***	***40.4%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***

Adjusted debt-to-cap of 59.0% at 9/30/08

Questions

3Q08 Earnings

	$ millions			Earnings Per Share		
	3rd Qtr 2007	3rd Qtr 2008	Change	3rd Qtr 2007	3rd Qtr 2008	Change
Utility Operations	443	356	(87)	1.11	0.89	(0.22)
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	21	27	6	0.06	0.07	0.01
Parent & Other	(2)	(10)	(8)	(0.01)	(0.03)	(0.02)
AEP On-Going Earnings	462	374	(88)	1.16	0.93	(0.23)
Special Items	(55)	0	55	(0.14)	0.00	0.14
Reported Earnings (GAAP)	407	374	(33)	1.02	0.93	(0.09)

Quarterly Performance Comparison

American Electric Power

Financial Results for 3rd Quarter 2008 Actual vs 3rd Quarter 2007 Actual

		2007 Actual Performance Driver	2007 Actual ($ millions)	2007 Actual EPS	2008 Actual Performance Driver	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	18,677 GWh @ $ 28.6 /MWhr =	534		18,060 GWh @ $ 27.6 /MWhr =	499	
2	Ohio Companies	13,464 GWh @ $ 46.8 /MWhr =	629		13,127 GWh @ $ 43.9 /MWhr =	577	
3	West Regulated Integrated Utilities	12,469 GWh @ $ 26.9 /MWhr =	336		12,070 GWh @ $ 28.2 /MWhr =	341	
4	Texas Wires	7,721 GWh @ $ 19.6 /MWhr =	152		7,961 GWh @ $ 19.3 /MWhr =	153	
5	Off-System Sales	10,164 GWh @ $ 32.4 /MWhr =	329		9,777 GWh @ $ 33.0 /MWhr =	322	
6	Transmission Revenue - 3rd Party		81			85	
7	Other Operating Revenue		126			150	
8	Utility Gross Margin		2,187			2,127	
9	Operations & Maintenance		(771)			(846)	
10	Depreciation & Amortization		(374)			(379)	
11	Taxes Other than Income Taxes		(189)			(187)	
12	Interest Exp & Preferred Dividend		(213)			(225)	
13	Other Income & Deductions		27			45	
14	Income Taxes		(224)			(179)	
15	**Utility Operations On-Going Earnings**		443	1.11		356	0.89
16	**Transmission Operations On-Going Earnings**		0	0.00		1	0.00
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		18	0.05		11	0.03
18	Generation & Marketing		3	0.01		16	0.04
19	**Parent & Other On-Going Earnings**		(2)	(0.01)		(10)	(0.03)
20	ON-GOING EARNINGS		462	1.16		374	0.93

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

September YTD Earnings

	Sept YTD 2007	Sept YTD 2008	Change	Sept YTD 2007	Sept YTD 2008	Change
Utility Operations	934	1,028	94	2.35	2.56	0.21
Transmission Operations	0	2	2	0.00	0.00	0.00
Non-Utility Operations	57	64	7	0.13	0.16	0.03
Parent & Other	(1)	(30)	(29)	0.00	(0.07)	(0.07)
AEP On-Going Earnings	990	1,064	74	2.48	2.65	0.17
Special Items	(132)	164	296	(0.33)	0.41	0.74
Reported Earnings (GAAP)	858	1,228	370	2.15	3.06	0.91

3Q08 Earnings Release

September YTD Performance Comparison

American Electric Power
Financial Results for YTD September 2008 Actual vs YTD September 2007 Actual

		Performance Driver	2007 Actual ($ millions)	2007 EPS	Performance Driver	2008 Actual ($ millions)	2008 EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	54,734 GWh @ $ 29.1 /MWhr =	1,592		54,483 GWh @ $ 29.8 /MWhr =	1,621	
2	Ohio Companies	38,079 GWh @ $ 48.4 /MWhr =	1,842		39,634 GWh @ $ 46.0 /MWhr =	1,823	
3	West Regulated Integrated Utilities	32,294 GWh @ $ 23.7 /MWhr =	765		32,278 GWh @ $ 25.4 /MWhr =	820	
4	Texas Wires	20,297 GWh @ $ 19.5 /MWhr =	396		20,916 GWh @ $ 19.6 /MWhr =	410	
5	Off-System Sales	22,996 GWh @ $ 31.0 /MWhr =	713		25,436 GWh @ $ 30.9 /MWhr =	786	
6	Transmission Revenue - 3rd Party		225			247	
7	Other Operating Revenue		413			440	
8	Utility Gross Margin		5,946			6,147	
9	Operations & Maintenance		(2,369)			(2,433)	
10	Depreciation & Amortization		(1,122)			(1,099)	
11	Taxes Other than Income Taxes		(560)			(569)	
12	Interest Exp & Preferred Dividend		(599)			(653)	
13	Other Income & Deductions		93			135	
14	Income Taxes		(455)			(500)	
15	**Utility Operations On-Going Earnings**		934	2.35		1,028	2.56
16	**Transmission Operations On-Going Earnings**		0	0.00		2	0.00
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		40	0.09		21	0.05
18	Generation & Marketing		17	0.04		43	0.11
19	**Parent & Other On-Going Earnings**		(1)	0.00		(30)	(0.07)
20	**ON-GOING EARNINGS**		990	2.48		1,064	2.65

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Detailed Ongoing Earnings Guidance

2007 Actual: $3.00

2008E: $3.15 - $3.25

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

3Q08 Retail Performance

	Load Growth (weather normalized) 3Q08 vs. 3Q07
East Regulated Integrated Utilities	-1.1%
Ohio Companies	0.4%
West Regulated Integrated Utilities	0.1%
Texas Wires	4.7%
Impact on EPS	$0.01

	Weather Impact 3Q08 vs. 3Q07
East Regulated Integrated Utilities	($0.03)
Ohio Companies	($0.02)
West Regulated Integrated Utilities	($0.02)
Texas Wires	$0.00
Impact on EPS	($0.07)

	Major Storms * 3Q08 vs. 3Q07
East Regulated Integrated Utilities	$0.00
Ohio Companies	($0.02)
West Regulated Integrated Utilities	($0.00)
Texas Wires	$0.00
Impact on EPS	($0.02)

* - represents lost revenues related to Hurricane Ike

YTD Retail Performance

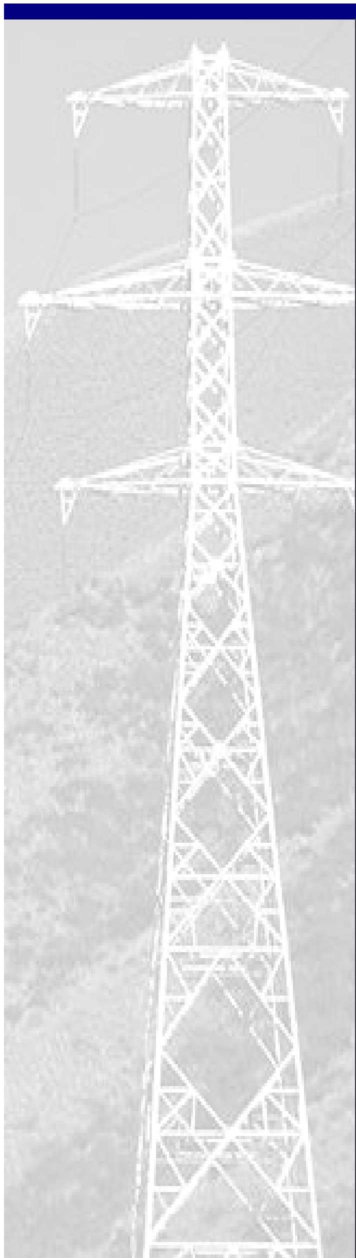
	Load Growth (weather normalized)
	YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	0.8%
Ohio Companies	3.3%
West Regulated Integrated Utilities	0.7%
Texas Wires	2.2%
Impact on EPS	$0.12

	Weather Impact
	YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	($0.06)
Ohio Companies	($0.04)
West Regulated Integrated Utilities	($0.01)
Texas Wires	$0.01
Impact on EPS	($0.10)

Retail Performance

	Rate Relief (in millions)
	3Q08 vs. 2Q07
East Regulated Integrated Utilities	$16
Ohio Companies	$61
West Regulated Integrated Utilities	$8
Texas Wires	$5
AEP System Total	$90
Impact on EPS	$0.15

	Rate Relief (in millions)
	YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	$60
Ohio Companies	$148
West Regulated Integrated Utilities	$22
Texas Wires	$17
AEP System Total	$247
Impact on EPS	$0.40



3Q09 Earnings Release Presentation

October 29, 2009

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Third Quarter 2009 Highlights

- 3Q09 GAAP Earnings $0.93 per share;
  3Q09 Ongoing Earnings $0.93
- 2009 YTD GAAP Earnings $2.47 per share;
  2009 YTD Ongoing Earnings $2.49
- Tightening 2009 Ongoing Earnings Guidance Range to $2.90 to $3.05 per share from $2.75 to $3.05
- Ohio ESP & SEET Update
- Turk Plant Update
- Cook Plant Update
- Thoughts on 2010

3Q09 Performance

	Per Share
3Q08 EPS	$ 0.93
Rate Relief	$ 0.49
Load Contraction	$ (0.08)
Weather	$ (0.07)
Off-System Sales	$ (0.22)
O&M	$ 0.08
Share Count Dilution	$ (0.17)
Other	$ (0.03)
3Q09 EPS	$ 0.93

3Q09 Performance Drivers:

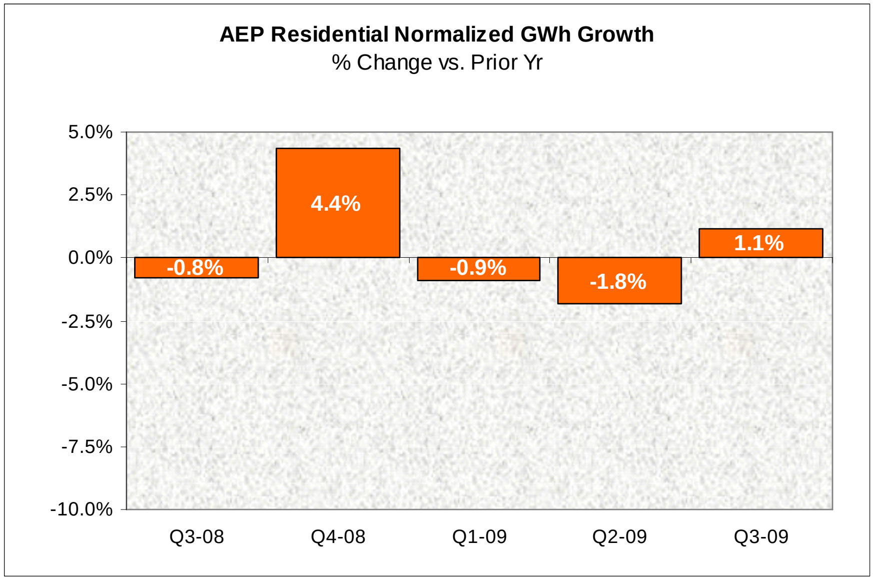
- *Rate relief of $302MM in multiple jurisdictions*
- *Load Contraction of $47MM (weather adjusted)*
- *Weather was unfavorable by $42MM vs. prior year and unfavorable by $65MM vs. normal*
- *Lower Off-System Sales (post sharing) of $136MM*
- *Decreased O&M expense of $50MM due to quarter over quarter positive variance in storm restoration costs and lower non-outage maintenance expense*
- *Share Count Dilution due to increase in weighted average shares outstanding of 75MM (402MM to 477MM)*
- *Other includes higher Depreciation & Amortization, Interest & Taxes, partly offset by higher Other Operating Revenue*

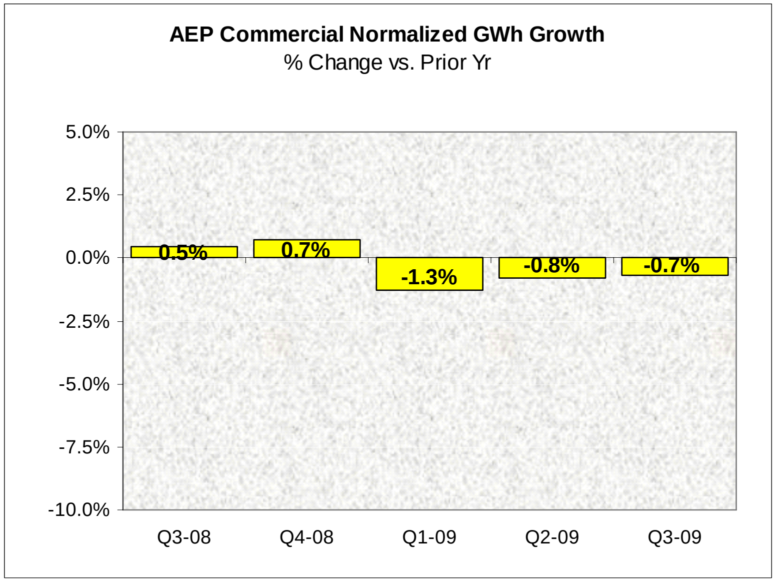
Retail Rate Performance

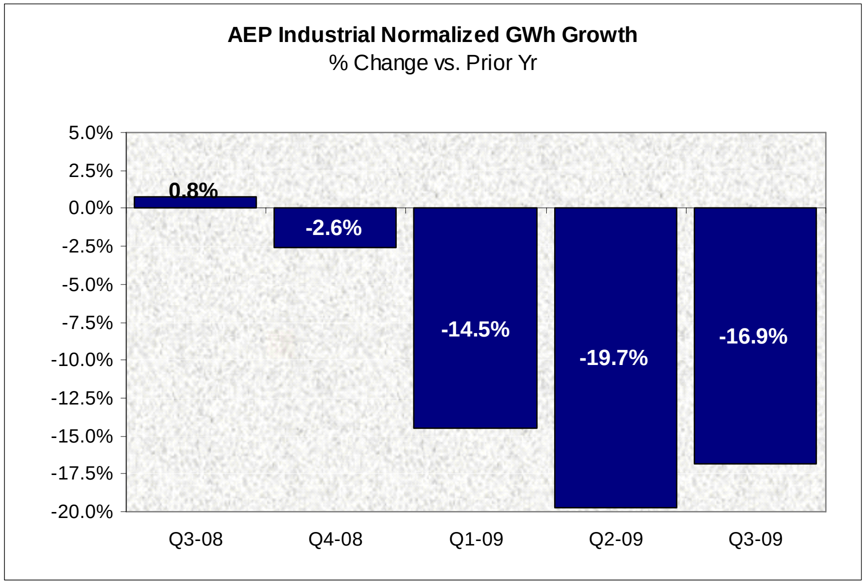
	Rate Relief (in millions)
	3Q09 vs. 3Q08
East Regulated Integrated Utilities	$56
Ohio Companies	$219
West Regulated Integrated Utilities	$24
Texas Wires	$3
AEP System Total	$302
Impact on EPS	$0.49

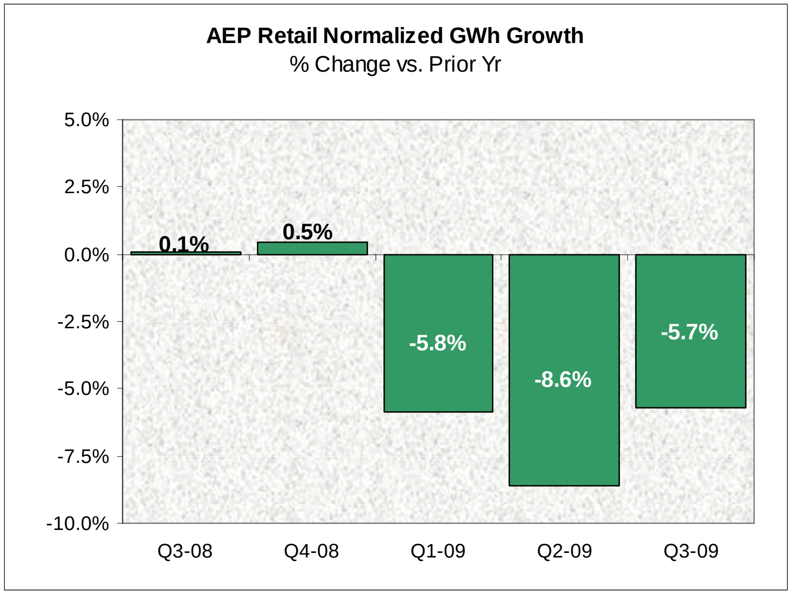
	Rate Relief (in millions)
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	$203
Ohio Companies	$320
West Regulated Integrated Utilities	$71
Texas Wires	$10
AEP System Total	$604
Impact on EPS	$0.98

Normalized Retail Load Trends

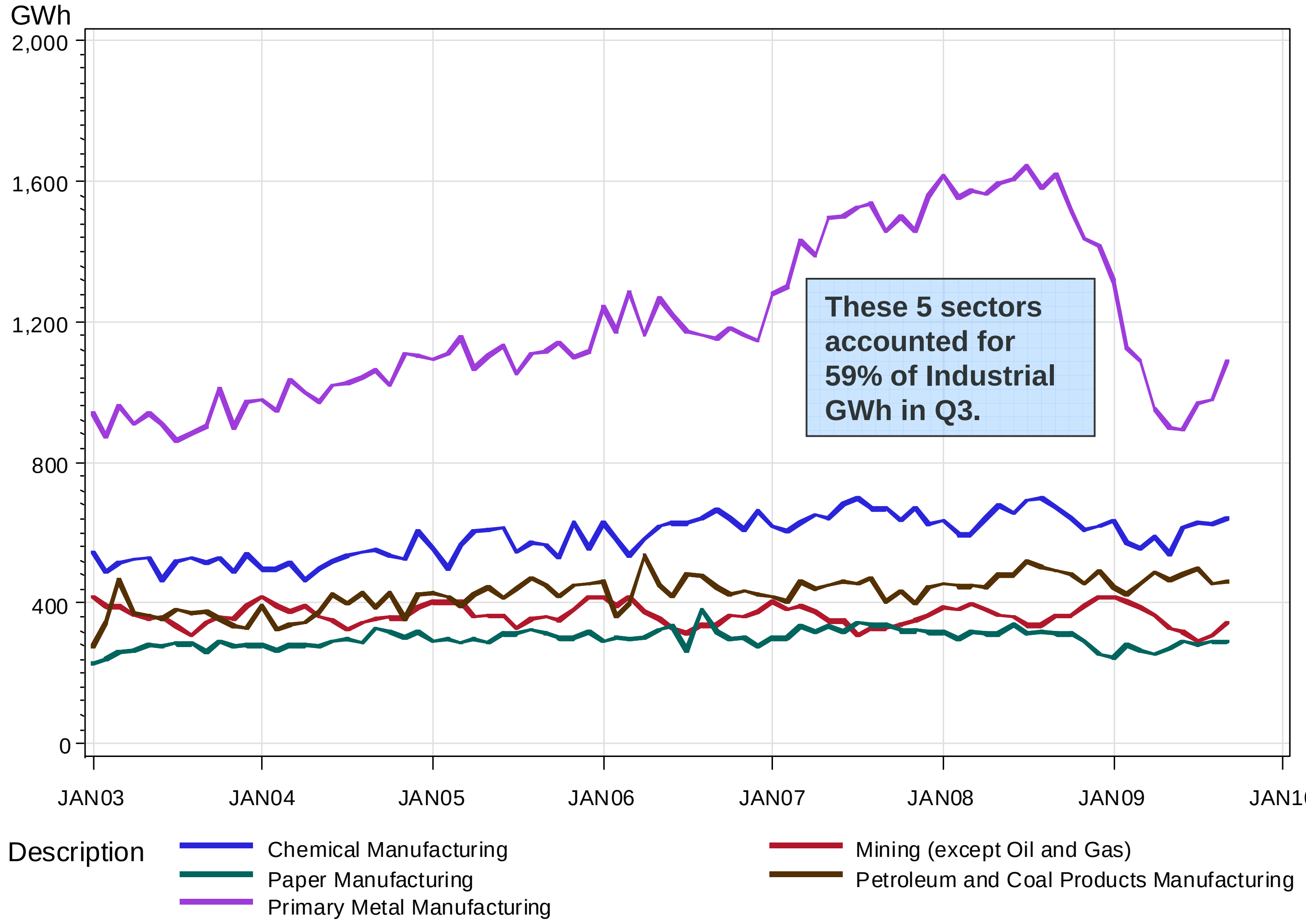




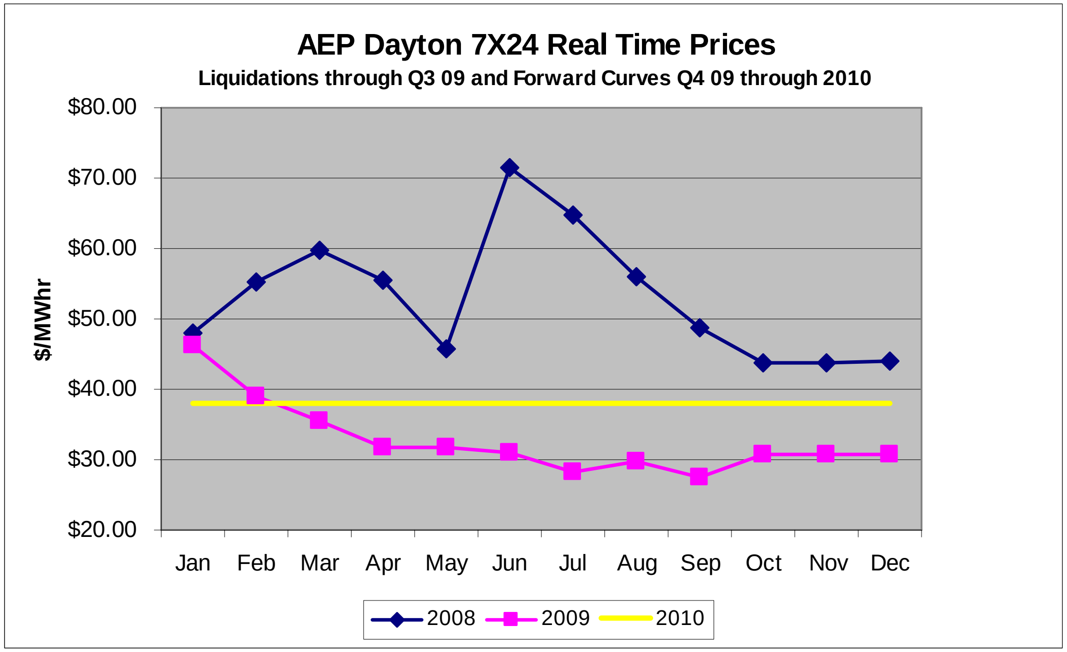




Industrial Sales Analysis



Off-System Sales



- **AEP/Dayton Hub 7X24 prices (liquidations) Q3 2009 were 50% below Q3 2008**
- **AEP Off system sales volumes were off 53%**
- **The calendar year 2010 strip is already above the estimated liquidation for 2009 but still well below 2008 liquidations by about 29%**

Q3 7X24 Price Liquidations				
Hub	2009	2008	$ Change	% Change
AEP Dayton	28.51	56.59	(28.09)	-50%
PJM West	33.20	77.37	(44.17)	-57%
NiHub	25.70	53.29	(27.59)	-52%
CinHub	25.23	52.32	(27.09)	-52%
NG	3.40	10.26	(6.86)	-67%

Questions

3Q09 Earnings Release

3Q09 Earnings

	$ millions			Earnings Per Share		
	3rd Qtr 2008	3rd Qtr 2009	Change	3rd Qtr 2008	3rd Qtr 2009	Change
Utility Operations	$ 356	$ 443	$ 87	$ 0.89	$ 0.93	$ 0.04
Transmission Operations	1	2	1	0.00	0.00	0.00
Non-Utility Operations	27	15	(12)	0.07	0.03	(0.04)
Parent & Other	(10)	(17)	(7)	(0.03)	(0.03)	0.00
AEP On-Going Earnings	374	443	69	0.93	0.93	0.00
Special Items	0	0	0	0.00	0.00	0.00
Reported Earnings (GAAP)	$ 374	$ 443	$ 69	$ 0.93	$ 0.93	$ -

Quarterly Performance Comparison

American Electric Power
Financial Results for 3rd Quarter 2009 Actual vs 3rd Quarter 2008 Actual

		2008 Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	2009 Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	18,060 GWh @ $ 27.6 /MWhr =	499		16,419 GWh @ $ 35.7 /MWhr =	586	
2	Ohio Companies	13,127 GWh @ $ 43.9 /MWhr =	577		11,720 GWh @ $ 63.3 /MWhr =	742	
3	West Regulated Integrated Utilities	12,070 GWh @ $ 28.2 /MWhr =	341		11,766 GWh @ $ 30.2 /MWhr =	356	
4	Texas Wires	7,961 GWh @ $ 19.3 /MWhr =	153		8,467 GWh @ $ 19.8 /MWhr =	167	
5	Off-System Sales	9,812 GWh @ $ 32.8 /MWhr =	322		4,538 GWh @ $ 21.1 /MWhr =	96	
6	Transmission Revenue - 3rd Party		85			95	
7	Other Operating Revenue		150			202	
8	Utility Gross Margin		2,127			2,244	
9	Operations & Maintenance		(846)			(796)	
10	Depreciation & Amortization		(379)			(412)	
11	Taxes Other than Income Taxes		(187)			(191)	
12	Interest Exp & Preferred Dividend		(225)			(233)	
13	Other Income & Deductions		45			37	
14	Income Taxes		(179)			(206)	
15	Utility Operations On-Going Earnings		356	0.89		443	0.93
16	Transmission Operations On-Going Earnings		1	-		2	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		11	0.03		10	0.02
18	Generation & Marketing		16	0.04		5	0.01
19	Parent & Other On-Going Earnings		(10)	(0.03)		(17)	(0.03)
20	ON-GOING EARNINGS		374	0.93		443	0.93

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance

		Per Share
YTD08 EPS	$	2.65
Rate Relief	$	0.98
Load Contraction	$	(0.23)
Weather	$	(0.05)
Off-System Sales	$	(0.50)
O&M	$	0.05
Share Count Dilution	$	(0.31)
Other	$	(0.10)
YTD09 EPS	$	2.49

YTD Performance Drivers:

- *Rate relief of $604MM in multiple jurisdictions*
- *Load Contraction of $143MM (adjusted for weather)*
- *Weather was unfavorable vs. prior year by $34MM and unfavorable $53MM vs. normal*
- *Lower Off-System Sales (post sharing) of $310MM*
- *Decreased O&M expense of $29MM due to reduction in plant outages & related expenses and tree trimming; offset by deferral of PSO ice storms in 2008*
- *Share count dilution due to increased weighted average shares outstanding of 50MM (402MM to 452MM)*
- *Other items including higher Depreciation and Amortization and prior year coal contract settlements somewhat offset by higher Other Operating Income*

September YTD Earnings

	$ millions			Earnings Per Share		
	Sept YTD 2008	Sept YTD 2009	Change	Sept YTD 2008	Sept YTD 2009	Change
Utility Operations	$ 1,028	$ 1,111	$ 83	$ 2.56	$ 2.46	$ (0.10)
Transmission Operations	2	3	1	0.00	0.01	0.01
Non-Utility Operations	64	55	(9)	0.16	0.12	(0.04)
Parent & Other	(30)	(45)	(15)	(0.07)	(0.10)	(0.03)
AEP On-Going Earnings	1,064	1,124	60	2.65	2.49	(0.16)
Special Items	164	(5)	(169)	0.41	(0.02)	(0.43)
Reported Earnings (GAAP)	$ 1,228	$ 1,119	$ (109)	$ 3.06	$ 2.47	$ (0.59)

YTD Performance Comparison

American Electric Power
Financial Results for YTD September 2009 Actual vs YTD September 2008 Actual

		2008 Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	2009 Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	54,483 GWh @ $ 29.8 /MWhr =	1,621		50,223 GWh @ $ 36.8 /MWhr =	1,848	
2	Ohio Companies	39,634 GWh @ $ 46.0 /MWhr =	1,823		35,769 GWh @ $ 57.7 /MWhr =	2,063	
3	West Regulated Integrated Utilities	32,278 GWh @ $ 25.4 /MWhr =	820		30,928 GWh @ $ 29.1 /MWhr =	899	
4	Texas Wires	20,916 GWh @ $ 19.6 /MWhr =	410		21,093 GWh @ $ 20.6 /MWhr =	434	
5	Off-System Sales	25,611 GWh @ $ 30.7 /MWhr =	786		10,752 GWh @ $ 25.0 /MWhr =	269	
6	Transmission Revenue - 3rd Party		247			269	
7	Other Operating Revenue		440			593	
8	Utility Gross Margin		6,147			6,375	
9	Operations & Maintenance		(2,433)			(2,404)	
10	Depreciation & Amortization		(1,099)			(1,173)	
11	Taxes Other than Income Taxes		(569)			(573)	
12	Interest Exp & Preferred Dividend		(652)			(681)	
13	Other Income & Deductions		134			91	
14	Income Taxes		(500)			(524)	
15	Utility Operations On-Going Earnings		1,028	2.56		1,111	2.46
16	Transmission Operations On-Going Earnings		2	-		3	0.01
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		21	0.05		22	0.05
18	Generation & Marketing		43	0.11		33	0.07
19	Parent & Other On-Going Earnings		(30)	(0.07)		(45)	(0.10)
20	ON-GOING EARNINGS		1,064	2.65		1,124	2.49

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2009 Cash Flow

($ millions)	2008	2009
Operating Activities		
Net Income -- Reported	$ 1,228	$ 1,119
Discontinued Operations	(1)	-
Continuing Earnings	1,227	1,119
Depreciation, Amortization & Deferred Taxes	1,714	2,033
Extraordinary Loss, net of Taxes	-	5
Changes in Components of Working Capital	(296)	(917)
Over/(Under) Fuel Recovery, Net	(284)	(377)
Other Assets & Liabilities	(305)	8
Cash Flows From Operating Activities	2,056	1,871
Investing Activities		
Capital Expenditures	(2,576)	(2,123)
Proceeds on Sale of Assets	83	258
Change in Other Temporary Cash Investments, net	(368)	23
Acquisition of Assets	(97)	(70)
Other Investing, net	(103)	(185)
Cash Flows Used for Investing Activities	(3,061)	(2,097)
Financing Activities		
Common Shares Issued, net	106	1,706
Long-term Debt Issuances, net	979	1,253
Short-term Debt Increase/(Decrease), net	642	(1,624)
Other Financing	(65)	(80)
Dividends Paid	(497)	(563)
Cash Flows From Financing Activities	1,165	692
Cash From Continuing Operations	$ 160	$ 466
Beginning Cash & Cash Equivalent Balances	178	411
Ending Cash & Cash Equivalent Balances	$ 338	$ 877

YTD 2009 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by fuel (coal) stock increase.
- Changes in fuel recovery primarily relate to deferrals at APCo, OPCo and CSP.

Investing Activities

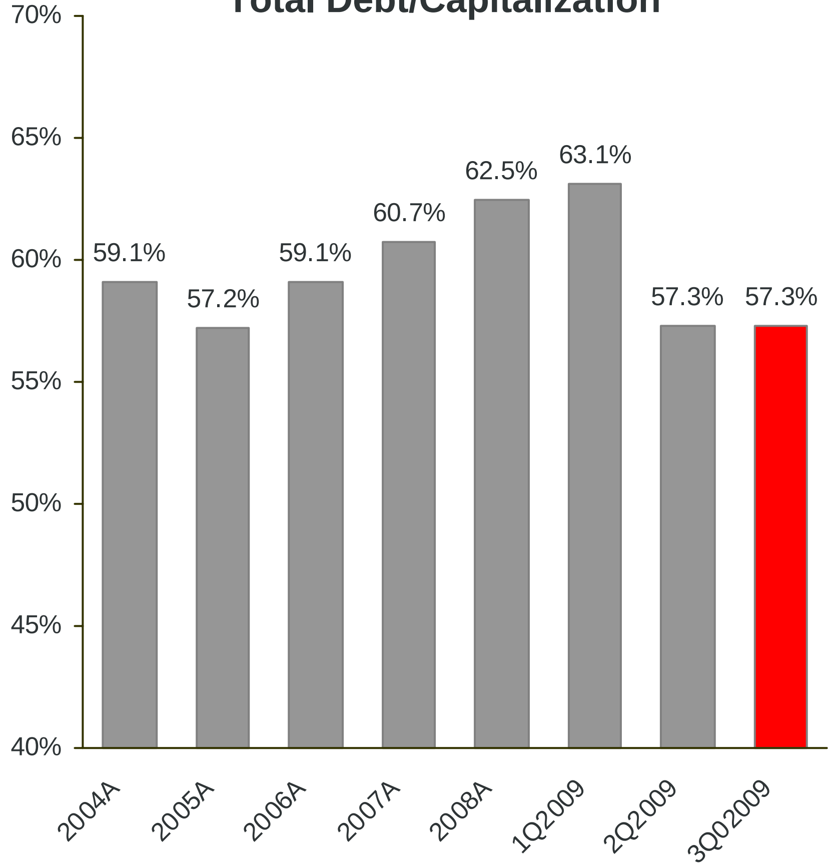
- Cash outlay for 2009 YTD capital investment.
- 2009 asset sale proceeds relate to the transfer of assets from TCC to ETT and the payments from third-party owners of the Turk Plant.
- Change in other investing primarily relates to the purchase of nuclear fuel.

Financing Activities

- 2009 common share issuances of $1,706MM primarily due to equity offering completed in April.
- Changes in short term debt relate to payments made on credit facilities from the proceeds of the equity offering.
- Changes in long-term debt driven by capital funding requirements.

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

Detailed Ongoing Earnings Guidance

2008 Actual: $3.24

2009E: $2.90-$3.05

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	66,754 GWh @ $ 36.9 /MWhr =	2,466
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	47,284 GWh @ $ 57.8 /MWhr =	2,733
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,111 GWh @ $ 28.8 /MWhr =	1,155
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,208 GWh @ $ 21.1 /MWhr =	575
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	13,525 GWh @ $ 24.6 /MWhr =	333
6	Transmission Revenue - 3rd Party		329		356
7	Other Operating Revenue		569		779
8	Utility Gross Margin		**8,046**		**8,397**
9	Operations & Maintenance		(3,366)		(3,309)
10	Depreciation & Amortization		(1,450)		(1,582)
11	Taxes Other than Income Taxes		(749)		(768)
12	Interest Exp & Preferred Dividend		(872)		(924)
13	Other Income & Deductions		168		124
14	Income Taxes		(567)		(597)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,341**
16	**Transmission Operations On-Going Earnings**		**2**		**4**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		47
18	Generation & Marketing		65		36
	Non-Utility Operations On-Going Earnings		**120**		**83**
19	**Parent & Other On-Going Earnings**		**(31)**		**(64)**
20	**ON-GOING EARNINGS**		**1,301**		**1,364**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

3Q09 Retail Performance

	Load Growth (weather normalized) 3Q09 vs. 3Q08
East Regulated Integrated Utilities	-7%
Ohio Companies	-7%
West Regulated Integrated Utilities	-2%
Texas Wires	-2%
Impact on EPS	**($0.08)**

	Weather Impact 3Q09 vs. 3Q08
East Regulated Integrated Utilities	($0.03)
Ohio Companies	($0.05)
West Regulated Integrated Utilities	($0.01)
Texas Wires	$0.02
Impact on EPS	**($0.07)**

YTD Retail Performance

	Load Growth (weather normalized)
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	-7%
Ohio Companies	-9%
West Regulated Integrated Utilities	-4%
Texas Wires	-3%
Impact on EPS	($0.23)

	Weather Impact
	YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	($0.02)
Ohio Companies	($0.04)
West Regulated Integrated Utilities	($0.01)
Texas Wires	$0.02
Impact on EPS	($0.05)

Off System Sales Gross Margin Detail

	3Q08			3Q09		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	9,812	$ 30.27	$ 297	4,538	$ 8.37	$ 38
Oklaunion Margin	-		$ 10	-		$ 10
Marketing/Trading	-		$ 15	-		$ 48
Pre-Sharing Gross Margin	9,812		$ 322	4,538		$ 96

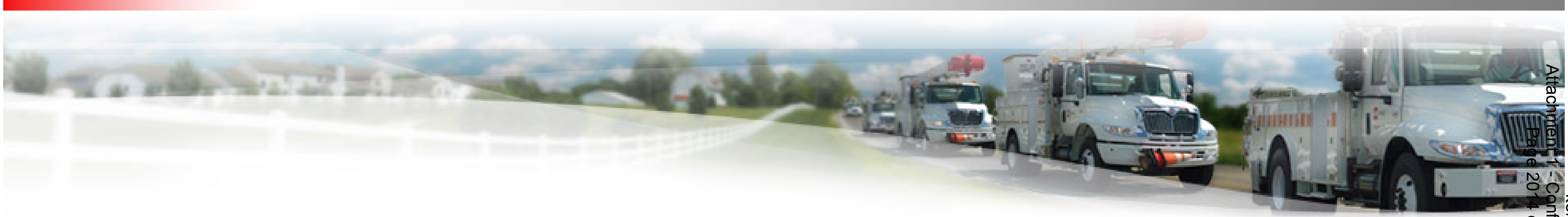
	YTD 2008			YTD 2009		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	25,611	$ 26.51	$ 679	10,752	$ 8.56	$ 92
Oklaunion Margin	-		$ 33	-		$ 36
Marketing/Trading	-		$ 74	-		$ 141
Pre-Sharing Gross Margin	25,611		$ 786	10,752		$ 269

Reduction in Pre-Sharing OSS Physical Sales primarily due to lower demand and significantly lower realized prices as a result of natural gas price contraction.

AEP AMERICAN® ELECTRIC POWER

3Q11 Earnings Release Presentation

October 26, 2011



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Third Quarter 2011 Highlights

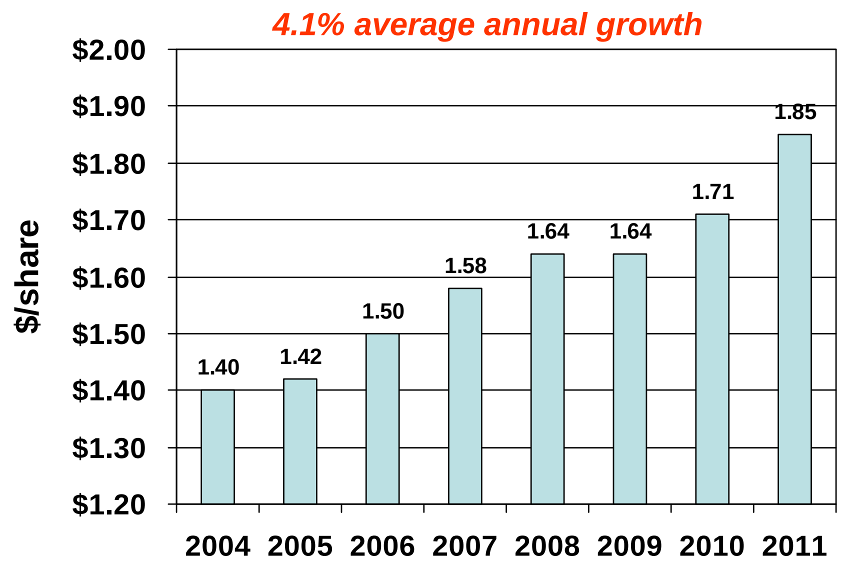
Financial Performance

- Delivered GAAP earnings of $1.93 and on-going earnings of $1.17 per share
- Tightening 2011 earnings guidance to $3.07 to $3.17 per share, from $3.00 to $3.20 per share

Announcements

- Nick Akins elected CEO effective November 12, 2011
- Board declared $0.47/share quarterly dividend; an increase of $0.01/share, or 2.2%
- Redemption of all preferred shares at AEP Subsidiaries

Dividend history since 2004



Dividend remains in-line with payout ratio target and earnings growth

Update on Key Areas of Interest

- **Hearing on Ohio Stipulation Underway**
  - Transition to Market for Ohio
  - Corporate Separation

PUCO decision expected later this year

- **Environmental Rules**
  - CSAPR Allocations
  - MACT Rules

Timing for compliance periods – impact on reliability

- **Transmission**
  - RITELine - FERC Approval in October
  - ETT
  - Transco Update

Gaining traction in regulated business growth

- **TCC Supreme Court Remand**

Keeps credit and balance sheet strong

Regulatory certainty provides clarity to AEP's business plan

3Q11 Performance

Third Quarter Reconciliation

	EPS	Ongoing Earnings ($ in millions)
3Q10	$ 1.15	$552
POLR Remand	$ (0.06)	
Customer Switching	$ (0.04)	
Operations & Maintenance	$ (0.03)	
Retail Margin	$ (0.02)	
Off-System Sales	$ -	
Weather	$ 0.02	
Other	$ 0.04	
TCC True-Up Remand	$ 0.04	
Rate Changes	$ 0.07	
3Q11	$ 1.17	$566

EPS Based on 482MM shares in Q311

3Q11 Performance Drivers

- Refund of POLR charges from Ohio ESP Remand ruling $43M
- Gross Customer Switching up $33M
- O&M expense net of offsets increased $19M primarily due to higher storm expenses and higher generation maintenance
- Retail Margins down $12M
- Weather was favorable by $14M vs. prior year, favorable $79M vs. normal
- Income from carrying costs related to TCC True-up Remand $28M
- Rate Changes net of offsets of $53M from multiple operating jurisdictions

Delivered solid quarter within Company's expectations

September YTD 2011 Performance

September YTD 2011 Reconciliation

		EPS	Ongoing Earnings ($ in millions)
2010	$	2.65	$1,272
POLR Remand	$	(0.06)	
Customer Switching	$	(0.10)	
Operations & Maintenance	$	(0.06)	
Retail Margin	$	(0.02)	
Off-System Sales	$	0.07	
Weather	$	-	
Other	$	(0.02)	
TCC True-Up Remand	$	0.04	
Rate Changes	$	0.22	
2011	$	2.72	$1,310

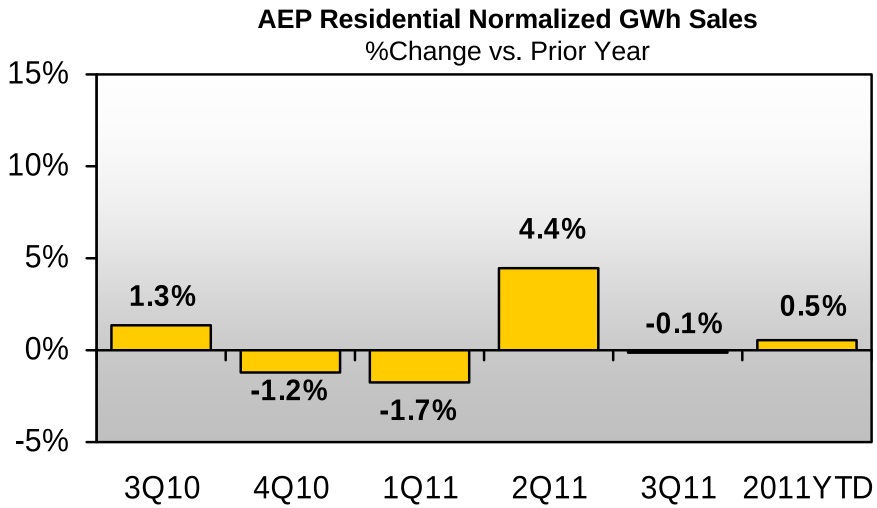
EPS Based on 482MM shares in YTD11

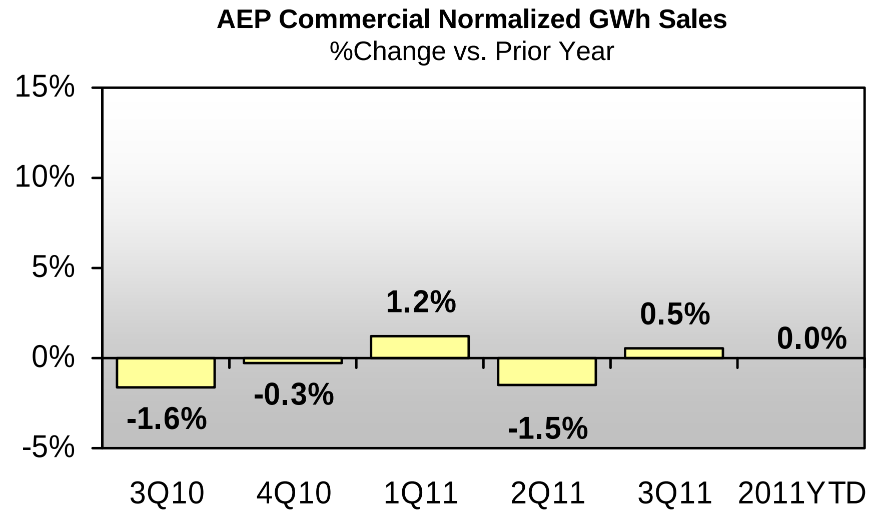
YTD 2011 Performance Drivers

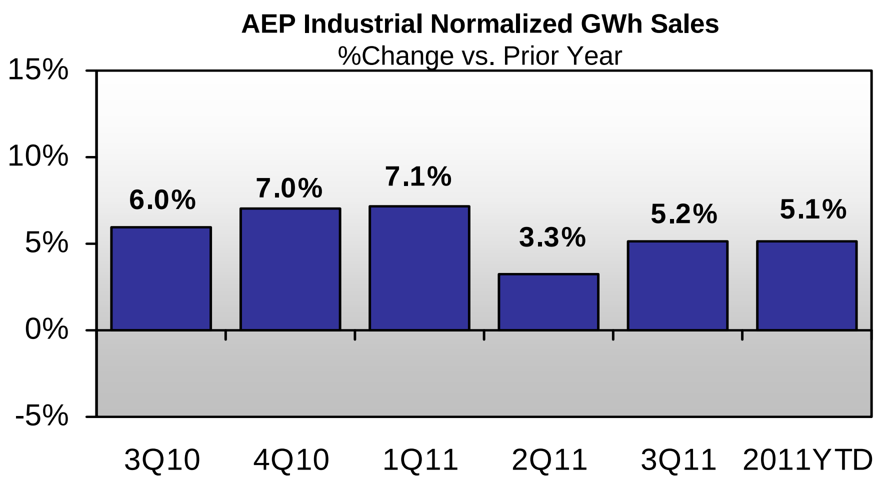
- Refund of POLR charges from Ohio ESP Remand ruling $43M
- Gross Customer Switching up $76M
- O&M expense net of offsets increased $48M primarily due to higher storm expenses
- Retail Margins down $12M
- Off-System Sales, net of sharing, were favorable by $49M due to higher volumes and higher prices
- Weather was unfavorable by $1M vs. prior year, favorable $147M vs. normal
- Income from carrying costs related to TCC True-up Remand $28M
- Rate Changes net of offsets of $163M from multiple operating jurisdictions

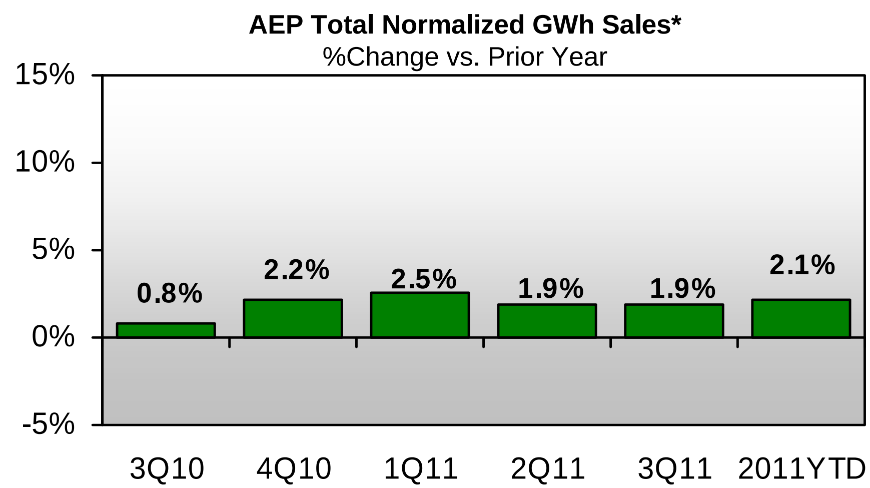
YTD results give Company confidence to raise mid-point of guidance range

Normalized Load Trends









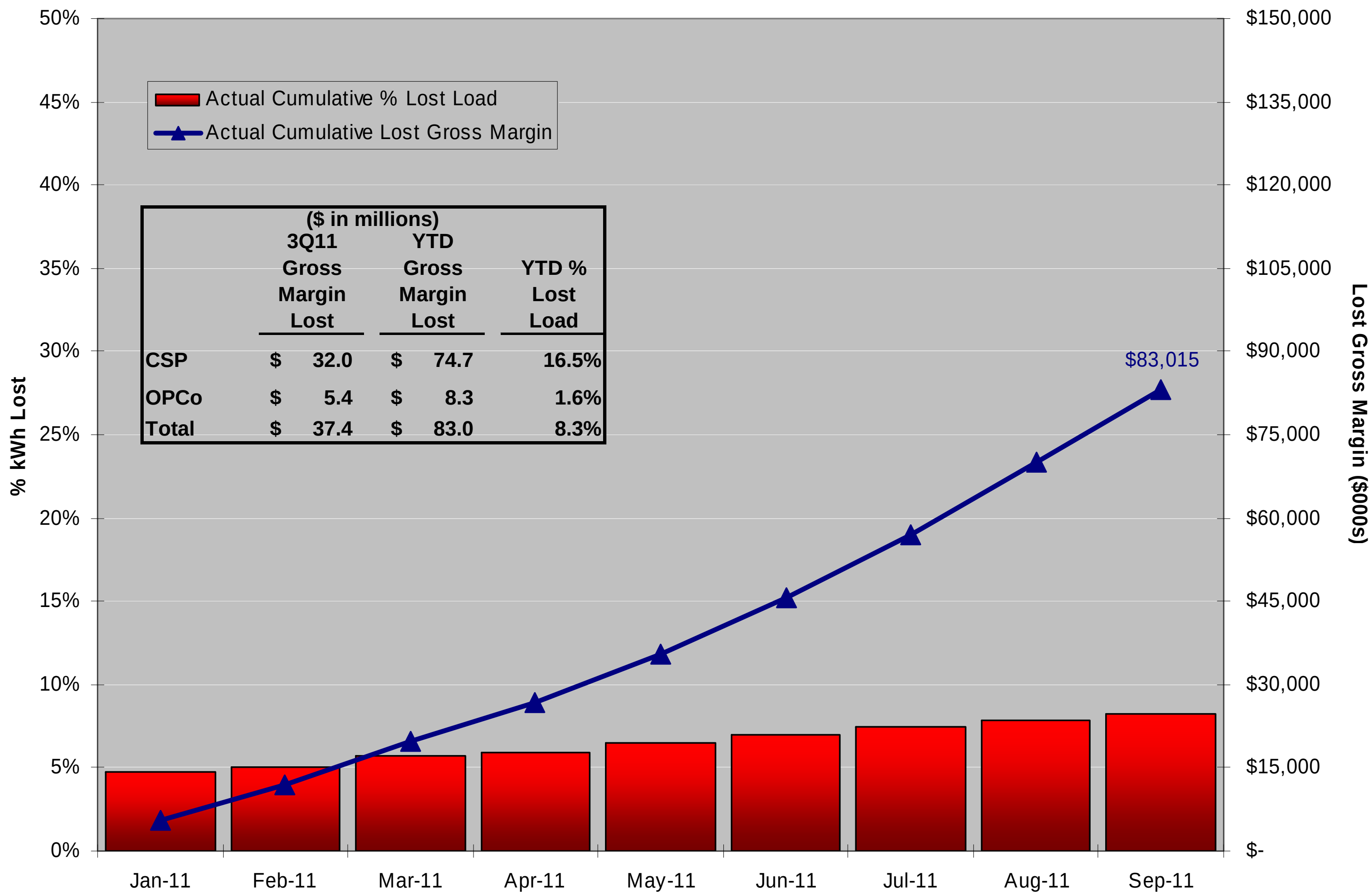
Note: Chart represents connected load

*includes firm wholesale load

Industrial sales leads load growth

Customer Switching

AEP-OH Customers Choosing Other Energy Providers

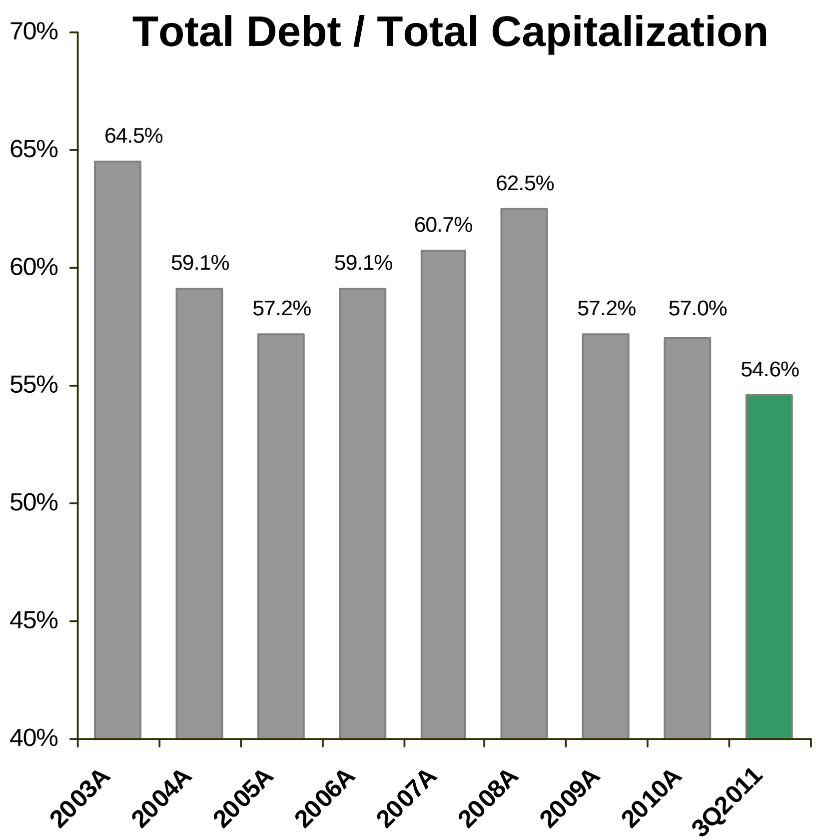


($ in millions)

	3Q11 Gross Margin Lost	YTD Gross Margin Lost	YTD % Lost Load
CSP	$ 32.0	$ 74.7	16.5%
OPCo	$ 5.4	$ 8.3	1.6%
Total	$ 37.4	$ 83.0	8.3%

Customer switching impacts offset by off-system sales and capacity revenues

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Debt to Cap ratio lowest in 8 years

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.5%	15%- 20%

Note: Credit statistics represent the trailing 12 month as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

Liquidity profile renewed this year

Summary

- Solid performance for 2011
- Continued focus on capital and O&M discipline, as well as cash proceeds from securitization bonds in TX, will keep our credit statistics and balance sheet strong
- Certainty from “overhangs” on the company will be resolved soon
- Operating company performance remains a priority

Management committed to earnings and dividend growth

Questions

3Q11 Earnings

	$ millions			Earnings Per Share		
	3rd Qtr 2010	3rd Qtr 2011	Change	3rd Qtr 2010	3rd Qtr 2011	Change
Utility Operations	$ 530	$ 542	$ 12	$ 1.11	$ 1.12	$ 0.01
Transmission Operations	4	9	5	0.01	0.02	0.01
Non-Utility Operations	15	25	10	0.03	0.05	0.02
Parent & Other	3	(10)	(13)	-	(0.02)	(0.02)
AEP On-Going Earnings	552	566	14	1.15	1.17	0.02
Cost Reduction Initiative	3	-	(3)	0.01	-	(0.01)
Carbon Capture and Storage - Ohio	-	(5)	(5)	-	(0.01)	(0.01)
Sporn Unit 5 Retirement	-	(31)	(31)	-	(0.06)	(0.06)
MR5 - Suspended Scrubber	-	(27)	(27)	-	(0.05)	(0.05)
Texas Capacity Auction True-Up	-	425	425	-	0.88	0.88
Special Items Total	3	362	359	0.01	0.76	0.75
Reported Earnings (GAAP)	$ 555	$ 928	$ 373	$ 1.16	$ 1.93	$ 0.77

Quarterly Performance Comparison

American Electric Power
Financial Results for 3rd Quarter 2011 Actual vs 3rd Quarter 2010 Actual

		2010 Actual			2011 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	17,326 GWh @ $ 42.5 /MWhr =	737		17,136 GWh @ $ 42.4 /MWhr =	727	
2	Ohio Companies	12,788 GWh @ $ 60.8 /MWhr =	777		13,089 GWh @ $ 55.5 /MWhr =	727	
3	West Regulated Integrated Utilities	12,657 GWh @ $ 34.3 /MWhr =	435		13,377 GWh @ $ 34.4 /MWhr =	460	
4	Texas Wires	8,141 GWh @ $ 21.0 /MWhr =	171		8,917 GWh @ $ 21.2 /MWhr =	189	
5	Off-System Sales	7,314 GWh @ $ 15.3 /MWhr =	112		9,616 GWh @ $ 11.6 /MWhr =	111	
6	Transmission Revenue - 3rd Party		95			109	
7	Other Operating Revenue		151			142	
8	Utility Gross Margin		2,478			2,465	
9	Operations & Maintenance		(853)			(876)	
10	Depreciation & Amortization		(413)			(435)	
11	Taxes Other than Income Taxes		(210)			(210)	
12	Interest Exp & Preferred Dividend		(239)			(223)	
13	Other Income & Deductions		35			99	
14	Income Taxes		(268)			(278)	
15	Utility Operations On-Going Earnings		530	1.11		542	1.12
16	Transmission Operations On-Going Earnings		4	0.01		9	0.02
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		15	0.03		17	0.03
18	Generation & Marketing		-	-		8	0.02
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(14)			(13)	
20	Other Investments		17			3	
21	Parent & Other On-Going Earnings		3	-		(10)	(0.02)
22	ON-GOING EARNINGS		552	1.15		566	1.17

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

September YTD Earnings

	$ millions			Earnings Per Share		
	Sept YTD 2010	Sept YTD 2011	Change	Sept YTD 2010	Sept YTD 2011	Change
Utility Operations	$ 1,239	$ 1,280	$ 41	$ 2.59	$ 2.66	$ 0.07
Transmission Operations	5	19	14	0.01	0.04	0.03
Non-Utility Operations	36	43	7	0.07	0.09	0.02
Parent & Other	(8)	(32)	(24)	(0.02)	(0.07)	(0.05)
AEP On-Going Earnings	1,272	1,310	38	2.65	2.72	0.07
Medicare D Subsidy	(21)	-	21	(0.04)	-	0.04
Cost Reduction Initiative	(182)	9	191	(0.38)	0.02	0.40
Litigation Settlement Enron Bankruptcy	-	(22)	(22)	-	(0.05)	(0.05)
Carbon Capture and Storage - Ohio	-	(5)	(5)	-	(0.01)	(0.01)
Carbon Capture -- APCo WV	-	(26)	(26)	-	(0.06)	(0.06)
Carbon Capture -- APCo VA	(34)	-	34	(0.07)	-	0.07
Sporn Unit 5 Retirement	-	(31)	(31)	-	(0.06)	(0.06)
MR5 - Suspended Scrubber	-	(27)	(27)	-	(0.05)	(0.05)
Texas Capacity Auction True-Up	-	425	425	-	0.88	0.88
Special Items Total	(237)	323	560	(0.49)	0.67	1.16
Reported Earnings (GAAP)	$ 1,035	$ 1,633	$ 598	$ 2.16	$ 3.39	$ 1.23

YTD 2011 Performance Comparison

American Electric Power
Financial Results for YTD September 2011 Actual vs YTD September 2010 Actual

		2010 Actual			2011 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	51,425 GWh @ $ 42.0 /MWhr =	2,160		50,623 GWh @ $ 42.1 /MWhr =	2,132	
2	Ohio Companies	36,733 GWh @ $ 58.6 /MWhr =	2,153		38,225 GWh @ $ 54.9 /MWhr =	2,099	
3	West Regulated Integrated Utilities	32,722 GWh @ $ 32.0 /MWhr =	1,050		33,910 GWh @ $ 32.7 /MWhr =	1,111	
4	Texas Wires	21,324 GWh @ $ 22.1 /MWhr =	472		22,983 GWh @ $ 21.8 /MWhr =	502	
5	Off-System Sales	16,038 GWh @ $ 15.2 /MWhr =	244		22,232 GWh @ $ 13.2 /MWhr =	293	
6	Transmission Revenue - 3rd Party		277			311	
7	Other Operating Revenue		402			402	
8	Utility Gross Margin		6,758			6,850	
9	Operations & Maintenance		(2,467)			(2,564)	
10	Depreciation & Amortization		(1,205)			(1,226)	
11	Taxes Other than Income Taxes		(603)			(618)	
12	Interest Exp & Preferred Dividend		(712)			(683)	
13	Other Income & Deductions		114			188	
14	Income Taxes		(646)			(667)	
15	Utility Operations On-Going Earnings		1,239	2.59		1,280	2.66
16	Transmission Operations On-Going Earnings		5	0.01		19	0.04
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		19	0.04		23	0.05
18	Generation & Marketing		17	0.03		20	0.04
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(40)			(41)	
20	Other Investments		32			9	
21	Parent & Other On-Going Earnings		(8)	(0.02)		(32)	(0.07)
22	ON-GOING EARNINGS		1,272	2.65		1,310	2.72

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.07 - $3.17

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	3Q11 vs. 3Q10
East Regulated Integrated Utilities	$34
Ohio Companies	$15
West Regulated Integrated Utilities	$4
Texas Wires	$0
AEP System Total	$53
Impact on EPS	$0.07

	Rate Changes, net of trackers (in millions)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	$106
Ohio Companies	$36
West Regulated Integrated Utilities	$22
Texas Wires	$0
AEP System Total	$163
Impact on EPS	$0.22

3Q11 Retail Performance

	Retail Load (weather normalized)
	3Q11 vs. 3Q10
East Regulated Integrated Utilities	(0.8%)
Ohio Companies	3.0%
West Regulated Integrated Utilities	2.4%
Texas Wires	4.9%
Impact on EPS	$0.02

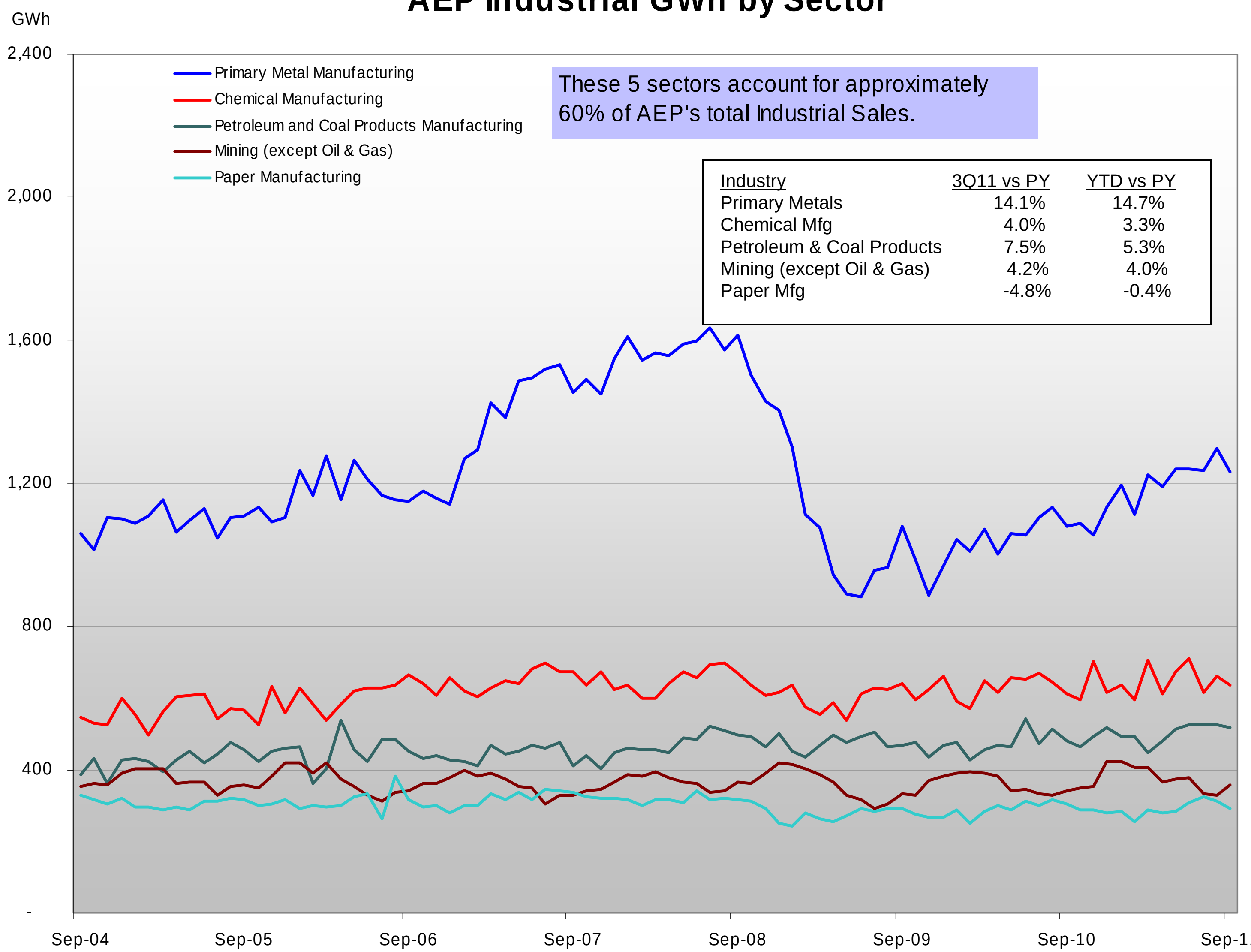
	Weather Impact (in millions)
	3Q11 vs. 3Q10
East Regulated Integrated Utilities	($3)
Ohio Companies	($3)
West Regulated Integrated Utilities	$14
Texas Wires	$5
Impact on EPS	$0.02

YTD 2011 Retail Performance

	Retail Load (weather normalized)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	(0.6%)
Ohio Companies	4.5%
West Regulated Integrated Utilities	2.7%
Texas Wires	3.5%
Impact on EPS	$0.02

	Weather Impact (in millions)
	YTD11 vs. YTD10
East Regulated Integrated Utilities	($24)
Ohio Companies	($8)
West Regulated Integrated Utilities	$15
Texas Wires	$16
Impact on EPS	$0.00

Industrial Sales Volumes



These 5 sectors account for approximately 60% of AEP's total Industrial Sales.

Industry	3Q11 vs PY	YTD vs PY
Primary Metals	14.1%	14.7%
Chemical Mfg	4.0%	3.3%
Petroleum & Coal Products	7.5%	5.3%
Mining (except Oil & Gas)	4.2%	4.0%
Paper Mfg	-4.8%	-0.4%

Off System Sales Gross Margin Detail

3Q11

	3Q10 GWh	3Q10 Realization	3Q10 ($millions)	3Q11 GWh	3Q11 Realization	3Q11 ($millions)
OSS Physical Sales	7,314	$ 18.02	$ 132	9,616	$ 15.18	$ 146
Marketing/Trading	-		$ 36	-		$ 23
Pre-Sharing Gross Margin	7,314		$ 168	9,616		$ 169
Margin Shared			$ (56)			$ (58)
Net OSS			$ 112			$ 111

- Physical off-system sales margins exceeded last year by $14M
- Volumes up 31% versus last year
- Improved AEP/Dayton Hub pricing: 3% increase in liquidation prices
- Lower Trading & Marketing results by $13M

YTD11

	YTD10 GWh	YTD10 Realization	YTD10 ($millions)	YTD11 GWh	YTD11 Realization	YTD11 ($millions)
OSS Physical Sales	16,038	$ 14.86	$ 238	22,232	$ 14.93	$ 332
Marketing/Trading	-		$ 105	-		$ 89
Pre-Sharing Gross Margin	16,038		$ 344	22,232		$ 421
Margin Shared			$ (100)			$ (128)
Net OSS			$ 244			$ 293

- Physical off-system sales margins exceeded last year by $94M
- Volumes up 39% versus last year
- Improved AEP/Dayton Hub pricing: 4% increase in liquidation prices
- Lower Trading & Marketing results by $16M

Off-System Sales

3Q11 vs. 3Q10

Q3 2011 Liquidations vs. Q3 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	40.60	41.80	1.20	3%
PJM West	51.34	46.38	(4.96)	-10%
NiHub	37.48	37.43	(0.05)	0%
CinHub	37.60	37.55	(0.05)	0%
SPP	31.67	34.00	2.33	7%
Natural Gas ($/mmBtu)	4.29	4.13	(0.16)	-4%

YTD11 vs. YTD10

YTD 2011 Liquidations vs. YTD 2010 Liquidations ($/MWh)

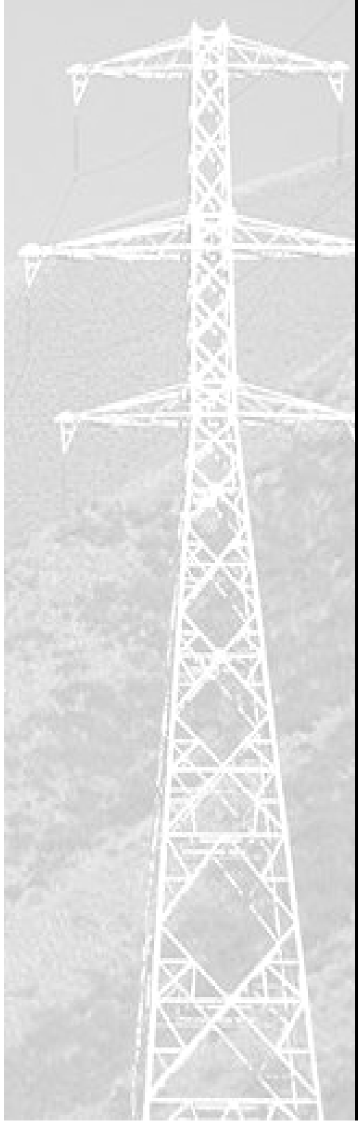
Hub	2010	2011	$ Change	% Change
AEP Dayton	38.36	40.07	1.71	4%
PJM West	47.61	46.18	(1.43)	-3%
NiHub	35.06	35.37	0.31	1%
CinHub	35.74	36.27	0.53	1%
SPP	33.88	30.74	(3.14)	-9%
Natural Gas ($/mmBtu)	4.58	4.21	(0.37)	-8%

Balance of 2011 Forwards vs. Balance of Year 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	35.29	35.30	0.01	0%
PJM West	43.56	40.69	(2.87)	-7%
NiHub	27.41	28.44	1.03	4%
CinHub	32.04	30.82	(1.22)	-4%
SPP	28.22	28.56	0.34	1%
Natural Gas ($/mmBtu)	3.78	3.74	(0.04)	-1%

Power forwards and NG futures as of October 11, 2011

A Century of Firsts



4Q05 Earnings Release Presentation

February 1, 2006

“Safe Harbor” Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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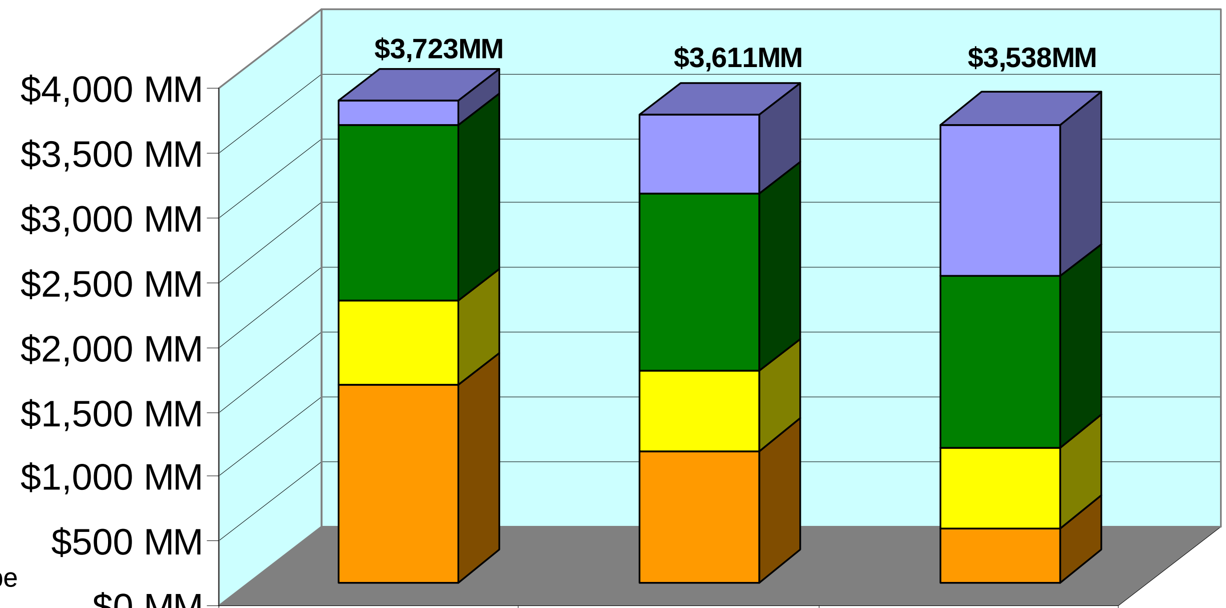
Highlights

- **2005 Full Year GAAP Earnings $2.09 Per Share, Ongoing $2.73 Per Share**
- **4Q05 GAAP Earnings ($0.38) Per Share, Ongoing $0.29 Per Share**
- **Pension Fully Funded in 2005**
- **Quarterly dividend increased to $0.37 per share from $0.35**
- **2005 Asset acquisition activity**
  - Waterford & Ceredo Plants and Monongahela Power's Ohio Operations
- **2006 Guidance Range of $2.50 to $2.70 per share**
- **2006 Regulatory Overview**
  - TCC Stranded Cost True-Up Case
  - West Virginia Rate Filings
  - Kentucky General Base Rate Filing
  - Virginia Environmental & Reliability Filing
  - Indiana Depreciation Filing
  - AEP-Ohio IGCC
- **AEP Interstate Project**

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

4Q05 Earnings Performance

	$ millions			Earnings Per Share		
	4th Qtr 2004	4th Qtr 2005	Change	4th Qtr 2004	4th Qtr 2005	Change
Utility Operations	202	109	(93)	0.51	0.27	(0.24)
Investments	(7)	14	21	(0.02)	0.04	0.06
Parent Company	(28)	(8)	20	(0.07)	(0.02)	0.05
AEP On-Going Earnings	167	115	(52)	0.42	0.29	(0.13)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4Q05 Utility Operations Performance

		2004 Actual		2005 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	688		679	
2	Ohio Cos.	464		514	
3	Texas Wires	108		111	
4	Texas Supply / REP	75		50	
5	Off-System Sales	57		112	
6	Other Wholesale Transactions	1		3	
7	Transmission Revenue - 3rd Party	83		97	
8	Other Operating Revenue	81		86	
9	Total Gross Margin	1,557		1,652	
10	Operations & Maintenance	(790)		(883)	
11	Depreciation & Amortization	(316)		(322)	
12	Taxes Other than Income Taxes	(172)		(185)	
13	Interest Exp & Preferred Dividend	(148)		(150)	
14	Other Income & Deductions	131		30	
15	Income Taxes	(60)		(33)	
16	Net Earnings Utility Operations	202	0.51	109	0.27

4Q 2005 Performance Drivers

Weather Impact: Positive $0.02 vs. normal
Positive $0.03 vs. prior yr

- *Favorable weather and customer growth at Reg Integ Utilities offset by off system sales sharing & capacity settlement*
- *Ohio Co increase driven by favorable weather and capacity settlement*
- *Texas Supply decrease mainly due to sale of STP in May 2005, outages at Oklaunion, and margin sharing; partially offset by fuel refund*
- *Increased OSS margin resulting from higher power prices*
- *Increase due to higher ECAR revenues*
- *Higher O&M expenses due to higher plant maintenance & operation expense, tree trimming, & PJM expense*
- *Other Income & Deductions consists of: (a) decline in TCC carrying costs ($102MM); (b) contribution from OH environmental additions ($12MM)*
- *Income taxes decline due to reduction in pretax income; somewhat offset by property tax increases & higher revenue/kwh taxes*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

12 Months YTD Earnings Performance

	$ millions			Earnings Per Share		
	Dec YTD 2004	Dec YTD 2005	Change	Dec YTD 2004	Dec YTD 2005	Change
Utility Operations	1049	1091	42	2.65	2.80	0.15
Investments	(54)	24	78	(0.14)	0.06	0.20
Parent Company	(71)	(52)	19	(0.18)	(0.13)	0.05
AEP On-Going Earnings	924	1063	139	2.33	2.73	0.40

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

12 Months YTD Utility Operations Performance

		2004 Actual ($ millions)	2004 EPS	2005 Actual ($ millions)	2005 EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		2,990	
2	Ohio Cos.	1,959		2,053	
3	Texas Wires	441		462	
4	Texas Supply / REP	347		206	
5	Off-System Sales	472		630	
6	Other Wholesale Transactions	15		21	
7	Transmission Revenue - 3rd Party	451		394	
8	Other Operating Revenue	335		334	
9	Total Gross Margin	7,023		7,090	
10	Operations & Maintenance	(3,059)		(3,129)	
11	Depreciation & Amortization	(1,256)		(1,285)	
12	Taxes Other than Income Taxes	(707)		(743)	
13	Interest Exp & Preferred Dividend	(627)		(595)	
14	Other Income & Deductions	166		267	
15	Income Taxes	(491)		(514)	
16	Net Earnings Utility Operations	1,049	2.65	1,091	2.80

YTD 2005 Performance Drivers

Weather Impact: Positive $0.07 vs. normal
Positive $0.15 vs. prior yr

- *Favorable weather and customer growth at Reg Integ Utilities offset by lower fuel margin, off system sales sharing & capacity settlement*
- *Ohio Co increase driven by favorable weather, customer count, emissions allowance settlement & capacity settlement; slightly offset by lower fuel margin*
- *Texas Wires increase product of favorable customer count, price/usage variances, and weather*
- *Texas Supply decline due to sale of TCC generation assets/expiration of Centrica supply contract; slightly offset by fuel provision reversal*
- *Increased OSS margin resulting from higher volumes and power prices/margins*
- *Trans Rev. decline due to elimination of through & out rates*
- *Higher O&M expenses due to higher maintenance, tree trimming, environmental expense, & PJM expense*
- *Increase in Dep & Amort offset by reduced interest expense*
- *Other Income & Deductions consists of: (a) Centrica Sharing revenue ($70MM); (b) OH RSP environmental carrying charges ($57MM); (c) AFUDC-Equity income & Other ($19MM) & (d) a decline in TCC carrying costs ($45MM);*
- *2005 taxes increases mainly due to: growth in pretax income, property tax increases & higher revenue/kwh taxes*

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2005 Cash Flow

($ millions)	Year-to-Date 2004	Year-to-Date 2005
Operating Activities		
Net Income -- Reported	**$ 1,089**	**$ 814**
Discontinued Operations	(83)	(27)
Continuing Earnings	**1,006**	**787**
Depreciation, Amortization & Deferred Taxes	1,559	1,334
Cumulative Effect of Accounting Changes	-	17
Impairments	15	46
Extraordinary Loss, net of Taxes	121	225
Pension Contributions	(231)	(626)
Changes in Mark-to-Market	14	84
Changes in Components of Working Capital	430	440
Other Assets & Liabilities	(282)	(512)
Cash Flow from Operations	**2,632**	**1,795**
Investing Activities		
Capital Expenditures	(1,637)	(2,402)
Investment in Discontinued Ops (net)	(59)	-
Change in Other Cash Deposits (net)	129	179
Assets Sales Proceeds & Other Inv (net)	1,314	1,294
Cash (Used) by Investing Activities	**(253)**	**(929)**
Financing Activities		
Common Shares Issued/(Retired), net	17	(24)
Long-term Debt Issuances/(Retirements)	(1,829)	(78)
Short-term Debt Increase/(Decrease), net	(409)	(13)
Other Financing	(51)	(50)
Dividends Paid	(555)	(554)
Preferred Stock Retirement	(10)	(66)
Cash (Used for) Financing	**(2,837)**	**(785)**
Cash From Continuing Operations	**$ (458)**	**$ 81**
Beginning Cash & Cash Equivalent Balances	778	320
Ending Cash & Cash Equivalent Balances	320	401

Capitalization

Capital Structure	Actual 12/31/04			Actual 12/31/2005		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,226	-	12,226
Short-term Debt	23	-	23	10	-	10
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	(66)	66	-	30	(30)	-
Defeased First Mortgage Bonds	(84)	-	(84)	(30)	-	(30)
Off-balance Sheet Leases	1,241	-	1,241	1,213	-	1,213
Securitization Bonds	(698)	-	(698)	(648)	-	(648)
Spent Nuclear Fuel Trust	(229)	-	(229)	(228)	-	(228)
Total Adjusted Capitalization	**12,540**	**8,642**	**21,182**	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***59.2%***	***40.8%***	***100.0%***	***58.0%***	***42.0%***	***100.0%***

Adjusted debt-to-cap of 58.0% at 12/31/05

QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 4th Qtr Quarter 2004 Actual vs 4th Qtr Quarter 2005 Actual

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Actual Performance Driver	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	24,922 GWh @ $27.6 /MWhr =	688		25,769 GWh @ $26.3 /MWhr =	679	
2	Ohio Cos.	11,525 GWh @ $40.3 /MWhr =	464		12,230 GWh @ $42.0 /MWhr =	514	
3	Texas Wires	6,150 GWh @ $17.6 /MWhr =	108		6,177 GWh @ $18.0 /MWhr =	111	
4	Texas Supply / REP	4,788 GWh @ $15.7 /MWhr =	75		1,034 GWh @ $48.4 /MWhr =	50	
5	Off-System Sales	7,016 GWh @ $ 8.1 /MWhr =	57		6,829 GWh @ $16.4 /MWhr =	112	
6	Other Wholesale Transactions		1			3	
7	Transmission Revenue - 3rd Party		83			97	
8	Other Operating Revenue		81			86	
9	Total Gross Margin		1,557			1,652	
10	Operations & Maintenance		(790)			(883)	
11	Depreciation & Amortization		(316)			(322)	
12	Taxes Other than Income Taxes		(172)			(185)	
13	Interest Exp & Preferred Dividend		(148)			(150)	
14	Other Income & Deductions		131			30	
15	Income Taxes		(60)			(33)	
16	Net Earnings Utility Operations		202	0.51		109	0.27
	INVESTMENTS:						
26	Total Investments		(7)	(0.02)		14	0.04
27	Parent Company		(28)	(0.07)		(8)	(0.02)
28	ON-GOING EARNINGS		167	0.42		115	0.29

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

12 Months YTD Performance Comparison

American Electric Power
Financial Results for YTD December 2004 Actual vs YTD December 2005 Actual

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Actual Performance Driver	2005 Actual ($ millions)	2005 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,091 GWh @ $ 29.4 /MWhr =	3,003		105,870 GWh @ $ 28.2 /MWhr =	2,990	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		48,877 GWh @ $ 42.0 /MWhr =	2,053	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		26,525 GWh @ $ 17.4 /MWhr =	462	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		6,619 GWh @ $ 31.1 /MWhr =	206	
5	Off-System Sales	31,460 GWh @ $ 15.0 /MWhr =	472		31,872 GWh @ $ 19.8 /MWhr =	630	
6	Other Wholesale Transactions		15			21	
7	Transmission Revenue - 3rd Party		451			394	
8	Other Operating Revenue		335			334	
9	Total Gross Margin		7,023			7,090	
10	Operations & Maintenance		(3,059)			(3,129)	
11	Depreciation & Amortization		(1,256)			(1,285)	
12	Taxes Other than Income Taxes		(707)			(743)	
13	Interest Exp & Preferred Dividend		(627)			(595)	
14	Other Income & Deductions		166			267	
15	Income Taxes		(491)			(514)	
16	Net Earnings Utility Operations		1,049	2.65		1,091	2.80
	INVESTMENTS:						
26	Total Investments		(54)	(0.14)		24	0.06
27	Parent Company		(71)	(0.18)		(52)	(0.13)
28	ON-GOING EARNINGS		924	2.33		1,063	2.73

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (554)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,795	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,314	$ 1,294	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (24)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 2,434	$ 1,661	$ 1,623
Other	$ 43	$ 160	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.402B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

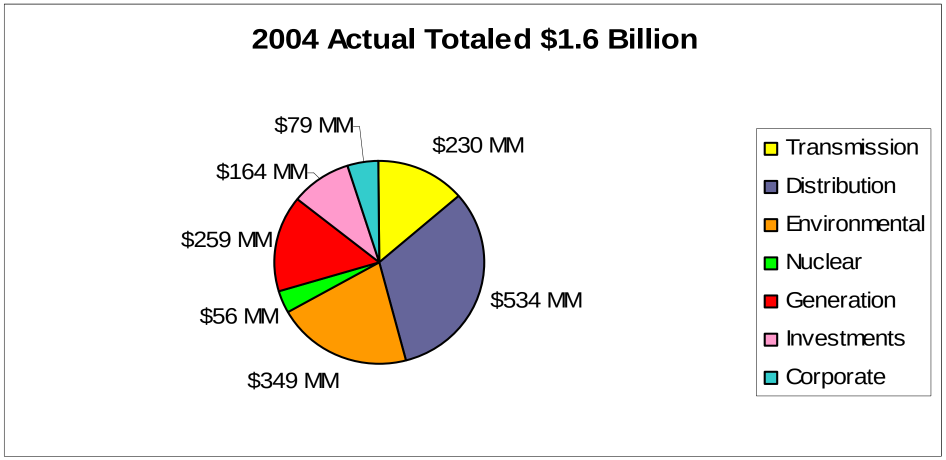
Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

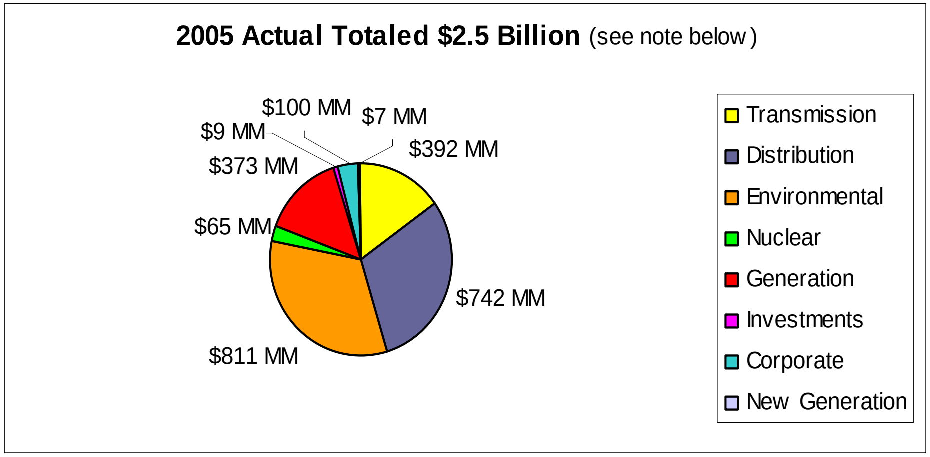
REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

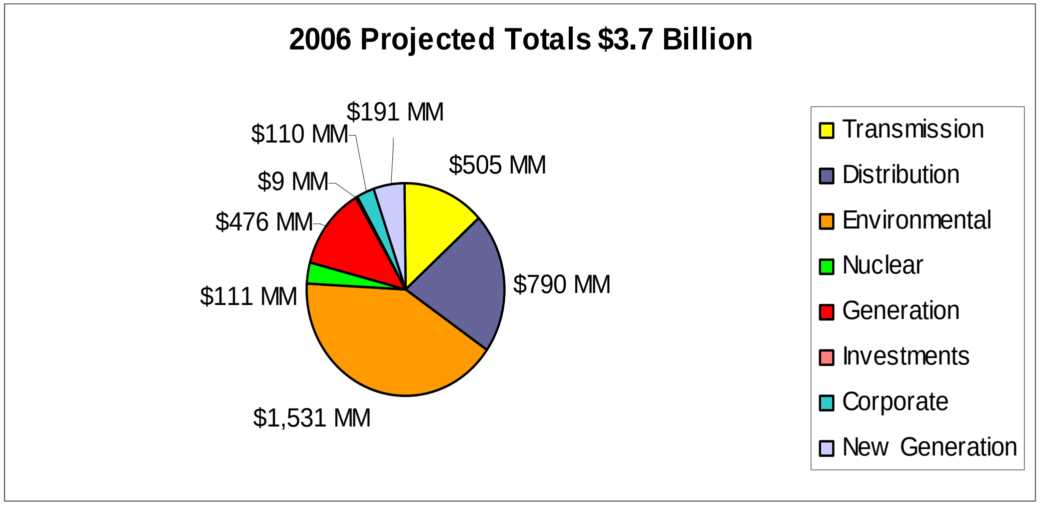
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2049 of 9556

Capital Investment 2004-2006

Figures exclude AFUDC

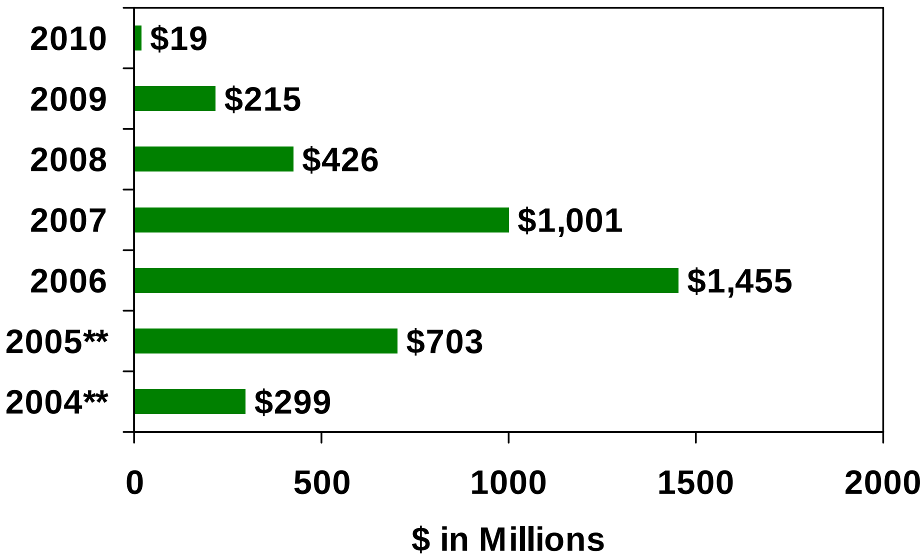






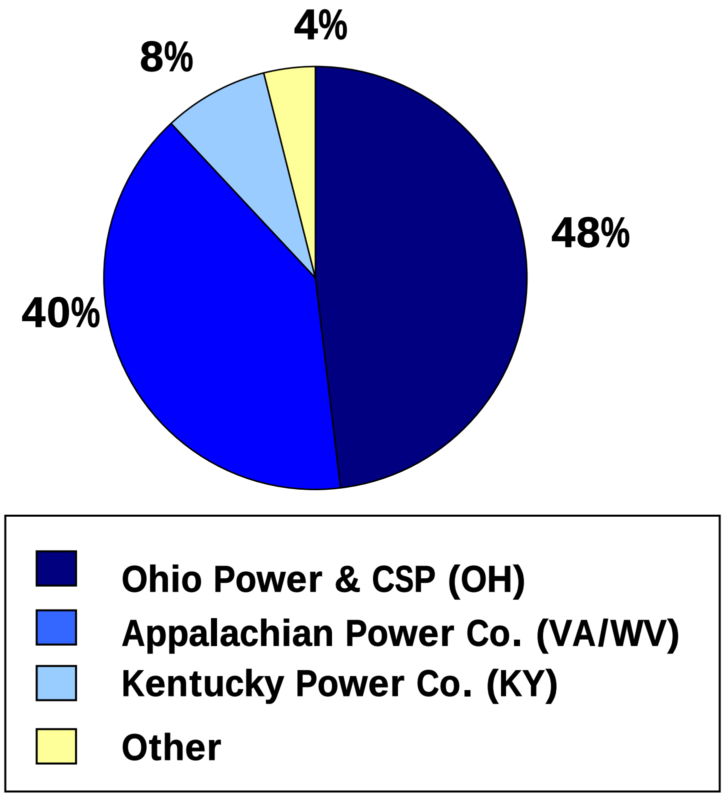
Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

$4.1 Billion Environmental Investment



*Environmental investment for NOx, SO_2, & Hg purposes including AFUDC

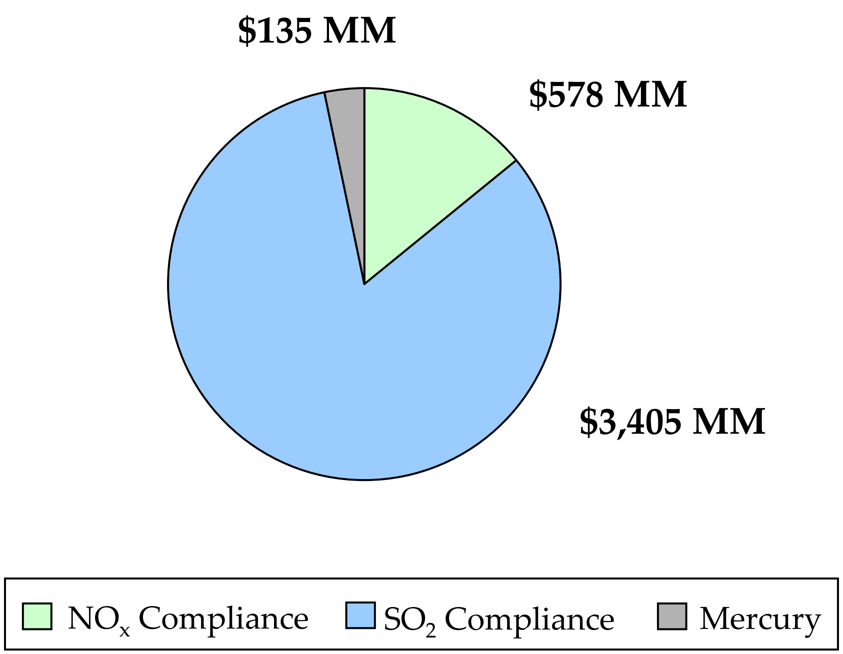
** Actual investment level in 2004 and 2005



MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment

Compliance Allocation



Current Programs

\$2.0 Billion:

\$0.5 Billion for NOx

\$1.5 Billion for SO_2

Future Programs

\$2.1 Billion:

\$1.9 Billion for SO_2

\$0.2 Billion for Other

\$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Figures Include AFUDC

4Q06 Earnings Release Presentation

AMERICAN ELECTRIC POWER

January 30, 2007

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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2006 Accomplishments & 2007 Plans

2006 Accomplishments

- ✓ 2006 GAAP Earnings $2.54 per share; Ongoing $2.77 per share
- ✓ 4Q06 GAAP Earnings $0.46 per share; Ongoing $0.38 per share
- ✓ Total shareholder return 18.8%
- ✓ Quarterly dividend increased 5.4% to $0.39 per share
- ✓ Secured $450M of new rate relief and $1.7B in Texas securitization
- ✓ Increased EPS growth range: 5 – 7% (2006-2009)
- ✓ Announced multiple transmission investment projects
  - ✓ $1B Electric Transmission Texas LLC
  - ✓ $2B 765 kV Study with ITC in Michigan
  - ✓ $3B I-765 Project in PJM
  - ✓ $3B project filed with SPP
- ✓ Completed sale of Plaquemine Facility in November 2006

2007 Plans

- Achieve ongoing earnings within guidance range of $2.85 to $3.05/share
- Continue disciplined investment in utility:
  - Generation
    - New generation @ PSO & SWEPCO
    - Lawrenceburg & Darby Plants
    - IGCC
  - Environmental
    - Substantially complete environmental tie-ins
  - Transmission
    - Establish Electric Transmission Texas LLC
    - Establish AEP Transmission Company, LLC
  - Seek innovative recovery for new investments
    - Reliability
    - Storms
- Control costs
- Maintain credit ratings
- Influence key legislative outcomes
  - Participate in GHG control dialogue
  - Ohio Post-2008 Operating Environment
  - Virginia Operating Environment

2007 Update

- **2007 Guidance Updates**
  - **Reaffirming Ongoing Earnings Guidance Range of $2.85 to $3.05 per share**
    - Revised segment presentation
    - New guidance detail (appendix) incorporates updated assumptions for rate relief, purchase of new generation, Ormet supply contract, TCC securitization and other financing items
- **2007 Regulatory Update**
  - **Indiana Depreciation Case – Request for Reconsideration Denied**
  - **Virginia**
    - General Base Rate Case Filing
  - **Texas**
    - TNC & TCC Wires Base Rate Case Filings
  - **Oklahoma**
    - General Base Rate Case Filing; January 2007 Ice Storm
  - **Ohio**
    - RSP Competitive Bid Mechanism Submitted
    - 4% Generation Increase Filing
    - Distribution Reliability Plan
  - **FERC: Regional Rate Design Proceedings**

4Q06 Ongoing Earnings

	$ millions			Earnings Per Share		
	4th Qtr 2005	4th Qtr 2006	Change	4th Qtr 2005	4th Qtr 2006	Change
Utility Operations	109	127	18	0.27	0.32	0.05
Investments	14	19	5	0.04	0.05	0.01
Parent Company	(8)	5	13	(0.02)	0.01	0.03
AEP On-Going Earnings	115	151	36	0.29	0.38	0.09

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

9-cent Improvement Driven by Rate Relief and Parent

4Q06 Utility Operations Performance

		2005 Actual		2006 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	524		565	
2	Ohio Companies	486		525	
3	West Regulated Integrated Utilities	158		230	
4	Texas Wires	111		114	
5	Off-System Sales	165		144	
6	Transmission Revenue - 3rd Party	98		52	
7	Other Operating Revenue	104		146	
8	Utility Gross Margin	1,646		1,776	
9	Operations & Maintenance	(889)		(886)	
10	Depreciation & Amortization	(322)		(370)	
11	Taxes Other than Income Taxes	(185)		(177)	
12	Interest Exp & Preferred Dividend	(150)		(195)	
13	Other Income & Deductions	42		73	
14	Income Taxes	(33)		(94)	
15	Utility Operations On-Going Earnings	109	0.27	127	0.32

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4Q 2006 Performance Drivers

Weather Impact: Negative $0.03 vs. normal
Negative $0.05 vs. prior yr.

- *Rate relief primarily in OH, WV, VA and KY ($115MM), load growth ($47MM) & addition of new muni & coop contracts ($20MM), largely offset by weather ($29MM)*
- *Lower OSS due to a favorable adjustment in 2005 to reduce a Texas fuel over-recovery regulatory provision, partially offset by higher margins in the East*
- *3rd Party Transmission revenues down due to absence of SECA revenues in 2006*
- *Increased Other Operating Revenue primarily due to securitization revenue related to the October 2006 Texas securitization*
- *Increased D&A due to increased amortization expense related to the Texas securitization and at the Ohio Companies and higher depreciable asset balance*
- *Interest expense up due to increased long term debt outstanding, including Texas securitization bonds issued in October 2006, and higher interest rates; Other Income & Deductions increased due to carrying costs for APCo, primarily related to the VA E&R case*
- *Income Taxes up due to increased income and federal tax reserve increases*

2006 Ongoing Earnings

	$ millions			Earnings Per Share		
	2005	2006	Change	2005	2006	Change
Utility Operations	1,091	1,031	(60)	2.80	2.61	(0.19)
Investments	24	64	40	0.06	0.16	0.10
Parent Company	(52)	(2)	50	(0.13)	0.00	0.13
AEP On-Going Earnings	1,063	1,093	30	2.73	2.77	0.04

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Improvement from Rate Relief, Load Growth & MEMCO Somewhat Offset by Weather, Fuel Costs and Loss of SECA Rates

2006 Utility Operations Performance

		2005 Actual ($ millions)	2005 Actual EPS	2006 Actual ($ millions)	2006 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	2,069		2,111	
2	Ohio Companies	1,937		2,110	
3	West Regulated Integrated Utilities	895		1,018	
4	Texas Wires	462		476	
5	Off-System Sales	853		835	
6	Transmission Revenue - 3rd Party	411		271	
7	Other Operating Revenue	479		527	
8	Utility Gross Margin	7,106		7,348	
9	Operations & Maintenance	(3,142)		(3,202)	
10	Depreciation & Amortization	(1,285)		(1,411)	
11	Taxes Other than Income Taxes	(743)		(735)	
12	Interest Exp & Preferred Dividend	(595)		(670)	
13	Other Income & Deductions	264		246	
14	Income Taxes	(514)		(545)	
15	Utility Operations On-Going Earnings	1,091	2.80	1,031	2.61

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2006 Performance Drivers

Weather Impact: Negative $0.08 vs. normal
Negative $0.16 vs. prior yr.

- *Rate Relief ($325MM), mostly Ohio RSP, KY, APCO; Increased margins reflecting customer growth, usage and price ($60MM); Mon Power customers ($63MM); New muni & coop power supply contracts ($70MM); Offset by weather ($95MM) and higher other variable costs ($93MM)*
- *Lower ECAR (primarily due to elimination of SECA) and ERCOT Transmission revenue*
- *Higher gains on sales of emission allowances*
- *O&M increase related to higher base plant operations & increased maintenance ($50MM); higher reliability costs ($26MM); higher A&G expenses ($19MM) and higher RTO costs ($7MM); Offset by lower storm restoration costs ($28MM)*
- *D&A increase primarily associated with higher amortization related to the Texas securitization and at the Ohio Companies & higher depreciation expense due to increased asset balances from cap-ex*
- *Interest expense increased due to higher LTD interest expense ($118MM), which includes interest on Texas securitization bonds issued in October 2006, somewhat offset by AFUDC ($46MM)*
- *Other Income & Deductions declined due to lower carrying costs for the Ohio Companies ($41MM) slightly offset by carrying costs related to VA E&R ($19MM)*

2006 Cash Flow

($ millions)	2005	2006
Operating Activities		
Net Income -- Reported	**$ 814**	**$ 1,002**
Discontinued Operations	(27)	(10)
Continuing Earnings	**787**	**992**
Depreciation, Amortization & Deferred Taxes	1,390	1,474
Impairments	46	209
Extraordinary Loss	225	-
Fuel Over/Under Recovery, Net	(239)	182
Pension Contributions	(626)	-
Changes in Components of Working Capital	442	58
Other Assets & Liabilities	(148)	(144)
Cash Flows From Operating Activities	**1,877**	**2,771**
Investing Activities		
Capital Expenditures	(2,404)	(3,528)
Proceeds on Sale of Assets	1,606	226
Change in Other Temporary Cash Investments (net)	174	(291)
Other Investing (net)	(381)	(191)
Cash Flows Used for Investing Activities	**(1,005)**	**(3,784)**
Financing Activities		
Common Shares Issued/(Retired), net	(25)	99
Long-term Debt Issuances/(Retirements)	(78)	1,413
Short-term Debt Increase/(Decrease), net	(13)	9
Other Financing	(122)	(16)
Dividends Paid	(553)	(592)
Cash Flows From (Used for) Financing Act.	**(791)**	**913**
Cash From Continuing Operations	**$ 81**	**$ (100)**
Beginning Cash & Cash Equivalent Balances	320	401
Ending Cash & Cash Equivalent Balances	401	301

2006 Cash Flow Drivers

- *2006 Impairment relates to Dow ($136MM)*
- *Positive cash effect partly due to deferred fuel recovery at PSO and SWEPCo*
- *Changes in Working Capital largely driven by Customer Deposits, Accounts Receivable and Fuel Inventory*
- *Cash outlay of $3.5 billion for 2006 capital investment. FY 2006 guidance assumed $3.7 billion in capital investment*
- *2006 primary asset sale proceeds: Centrica sharing ($70MM), Plaquemine Facility ($64MM), ICE shares ($40MM) and Bajio ($29MM); 2005 primary asset sale proceeds: HPL ($1B), Texas generation ($315MM), Centrica sharing ($115MM) and PacHydro ($88MM)*
- *Common stock issuance of $99MM primarily related to the exercise of stock options during 2006*
- *Ending cash balance for 2006 of $301MM. 2006 guidance assumed year-end cash balance of $390MM*

Capitalization

Capital Structure	Actual 12/31/2005			Actual 12/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	13,698	-	13,698
Short-term Debt	10	-	10	21	-	21
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,088	9,088	-	9,412	9,412
Total Capitalization per Balance Sheet	**12,236**	**9,149**	**21,385**	**13,719**	**9,473**	**23,192**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***59.2%***	***40.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(21)	-	(21)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,213	-	1,213	1,183	-	1,183
Securitization Bonds	(648)	-	(648)	(2,335)	-	(2,335)
Spent Nuclear Fuel Trust	(228)	-	(228)	(247)	-	(247)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,693**	**12,328**	**9,443**	**21,771**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***56.6%***	***43.4%***	***100.0%***

Adjusted debt-to-cap of 56.6% at 12/31/06

QUESTIONS

Quarterly Performance Comparison

American Electric Power
Financial Results for 4th Quarter 2006 Actual vs 4th Quarter 2005 Actual

		2005 Actual			2006 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	16,549 GWh @ $ 31.7 /MWhr =	524		17,513 GWh @ $ 32.3 /MWhr =	565	
2	Ohio Companies	12,230 GWh @ $ 39.7 /MWhr =	486		11,117 GWh @ $ 47.2 /MWhr =	525	
3	West Regulated Integrated Utilities	9,220 GWh @ $ 17.1 /MWhr =	158		9,280 GWh @ $ 24.8 /MWhr =	230	
4	Texas Wires	6,177 GWh @ $ 18.0 /MWhr =	111		6,043 GWh @ $ 18.9 /MWhr =	114	
5	Off-System Sales	7,863 GWh @ $ 21.0 /MWhr =	165		6,776 GWh @ $ 21.3 /MWhr =	144	
6	Transmission Revenue - 3rd Party		98			52	
7	Other Operating Revenue		104			146	
8	Utility Gross Margin		1,646			1,776	
9	Operations & Maintenance		(889)			(886)	
10	Depreciation & Amortization		(322)			(370)	
11	Taxes Other than Income Taxes		(185)			(177)	
12	Interest Exp & Preferred Dividend		(150)			(195)	
13	Other Income & Deductions		42			73	
14	Income Taxes		(33)			(94)	
15	Utility Operations On-Going Earnings		109	0.27		127	0.32
21	Investments On-Going Earnings		14	0.04		19	0.05
22	Parent Company On-Going Earnings		(8)	(0.02)		5	0.01
23	ON-GOING EARNINGS		115	0.29		151	0.38
	Shares Outstanding (in millions)			394			39[illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance Comparison

American Electric Power

Financial Results for YTD December 2006 Actual vs YTD December 2005 Actual

		2005 Performance Driver	2005 Actual ($ millions)	2005 Actual EPS	2006 Performance Driver	2006 Actual ($ millions)	2006 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	65,656 GWh @ $ 31.5 /MWhr =	2,069		69,107 GWh @ $ 30.5 /MWhr =	2,111	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		45,880 GWh @ $ 46.0 /MWhr =	2,110	
3	West Regulated Integrated Utilities	40,214 GWh @ $ 22.3 /MWhr =	895		40,506 GWh @ $ 25.1 /MWhr =	1,018	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,382 GWh @ $ 18.0 /MWhr =	476	
5	Off-System Sales	38,493 GWh @ $ 22.2 /MWhr =	853		33,340 GWh @ $ 25.0 /MWhr =	835	
6	Transmission Revenue - 3rd Party		411			271	
7	Other Operating Revenue		479			527	
8	Utility Gross Margin		7,106			7,348	
9	Operations & Maintenance		(3,142)			(3,202)	
10	Depreciation & Amortization		(1,285)			(1,411)	
11	Taxes Other than Income Taxes		(743)			(735)	
12	Interest Exp & Preferred Dividend		(595)			(670)	
13	Other Income & Deductions		264			246	
14	Income Taxes		(514)			(545)	
15	Utility Operations On-Going Earnings		1,091	2.80		1,031	2.61
21	Investments On-Going Earnings		24	0.06		64	0.16
22	Parent Company On-Going Earnings		(52)	(0.13)		(2)	-
23	ON-GOING EARNINGS		1,063	2.73		1,093	2.77
	Shares Outstanding (in millions)			390			39[illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2065 of 9556

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

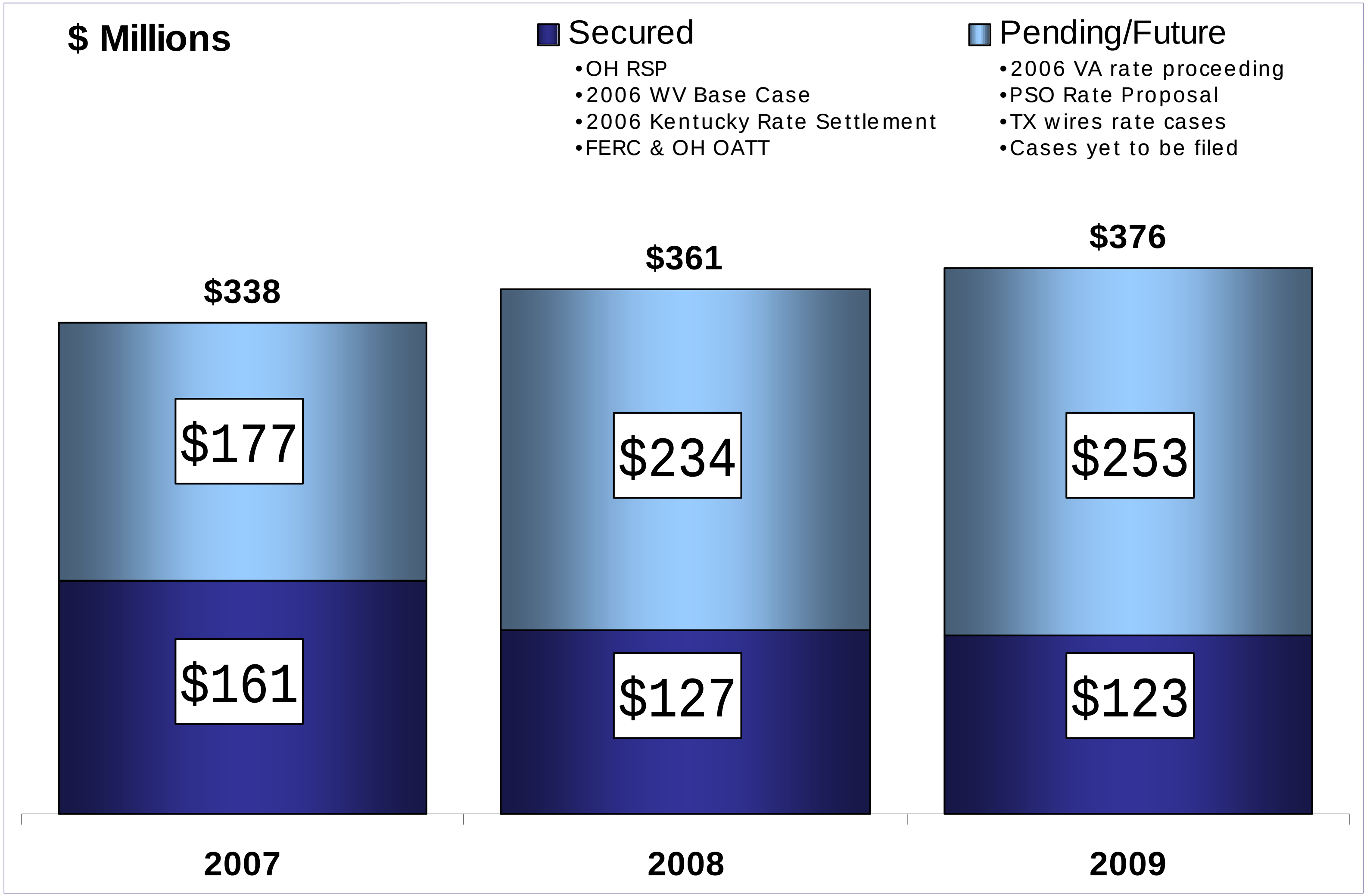
American Electric Power

Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

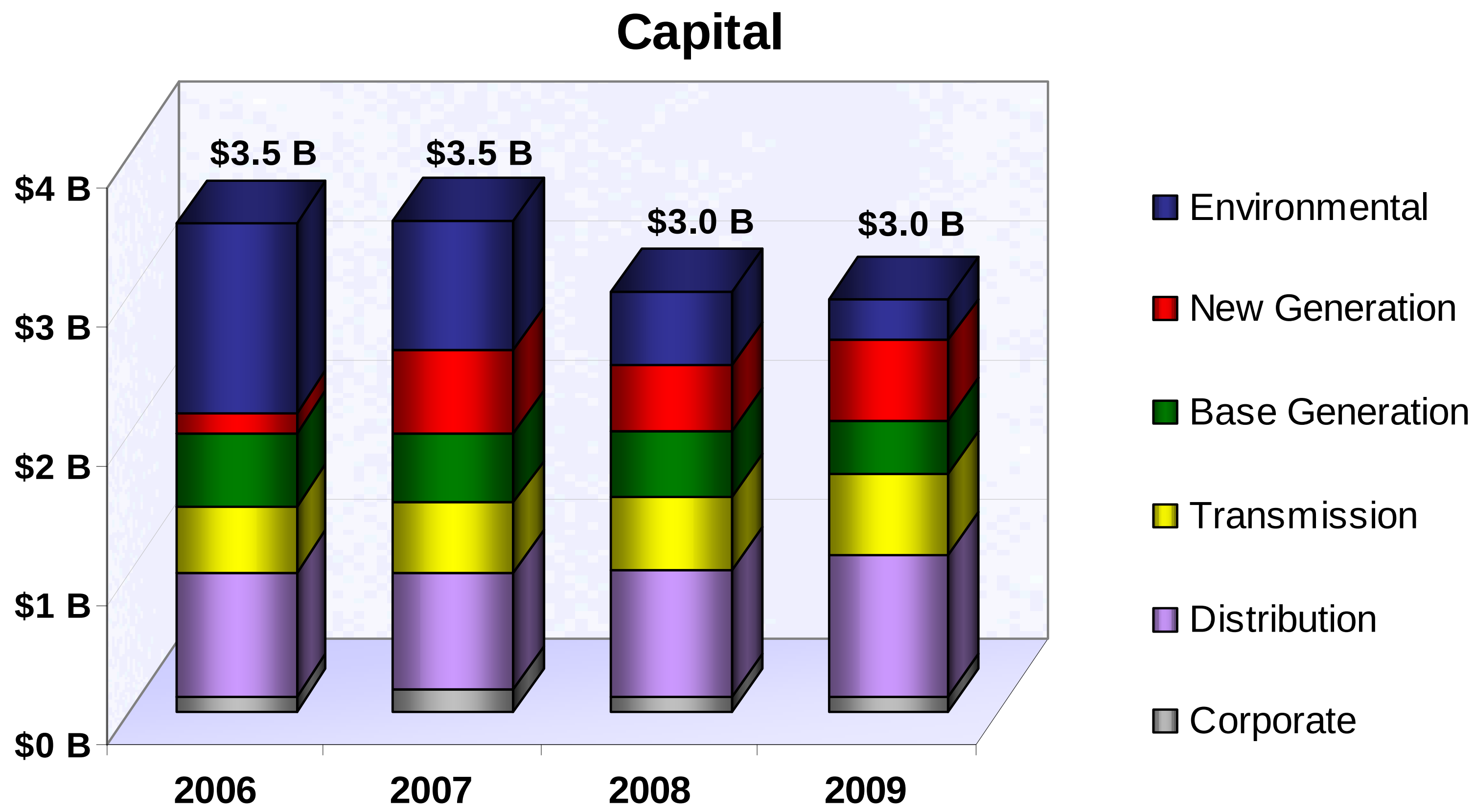
Incremental Rate Relief Composition



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

Rate Relief is a Critical Element to AEP's Financial Success

Multi-Year Capital Investment Forecast



- *Total 2007 Capital Forecast = $3.9B (including Lawrenceburg)*
- *All periods presented exclude AFUDC*

Multi-Year Capital Investment Funding Plan

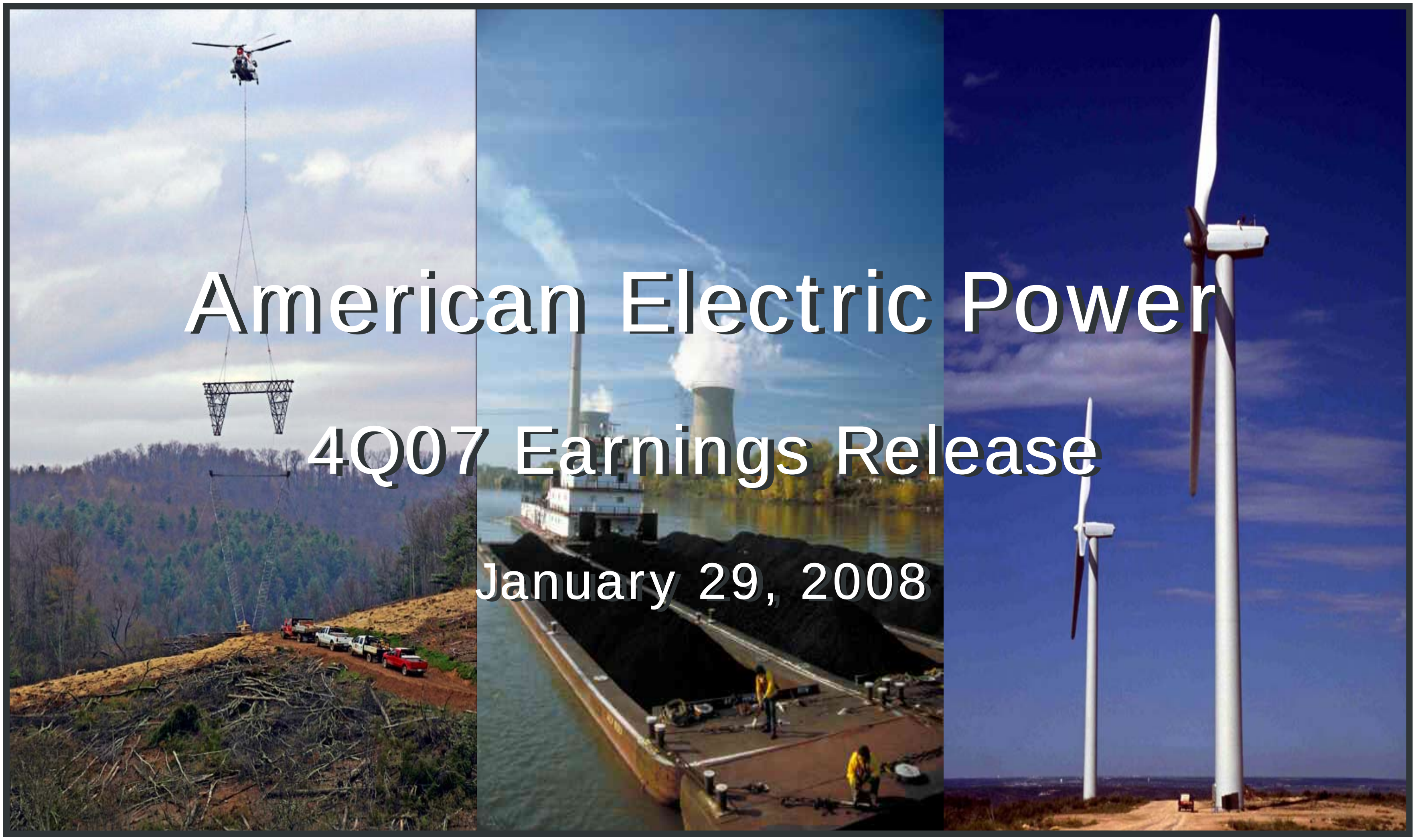
	Actual 2006	Projection 2007	Projection 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,771	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 226	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,422	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other, primarily Working Capital, Items	$ (208)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.



American Electric Power

4Q07 Earnings Release

January 29, 2008

AEP AMERICAN ELECTRIC POWER®

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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2007 Highlights

2007 Financial Highlights

- 2007 GAAP Earnings $2.73 per share; Ongoing $3.00 per share
- 4Q07 GAAP Earnings $0.58 per share; Ongoing $0.52 per share
- Quarterly Dividend increased 4.9% to $0.41 per share
- Increased EPS growth range to 5-9% (2007 – 2010)

2007 Operational Excellence

- Incremental rate relief - $352MM
- Transmission projects on track
- Environmental program nearing completion
- Generation purchases at favorable prices
- PSO storm damage restoration in January & December – cost recovery expected
- Improved safety & health – no fatalities

Continued track record of financial and operational excellence

2008 Update

2008 Plans

- Achieve ongoing earnings within guidance range of $3.10 to $3.30
- Continued disciplined investment in utility operations:
  - New Generation - SWEPCO
  - IGCC
- Environmental Retrofits:
  - Complete required tie-ins
- Transmission Initiatives:
  - PATH
  - ETT/ETA
- Regulatory Strategy – accelerate cash flow and earnings:
  - Increase filing frequency
  - Single issue cost recovery
  - Formula rates

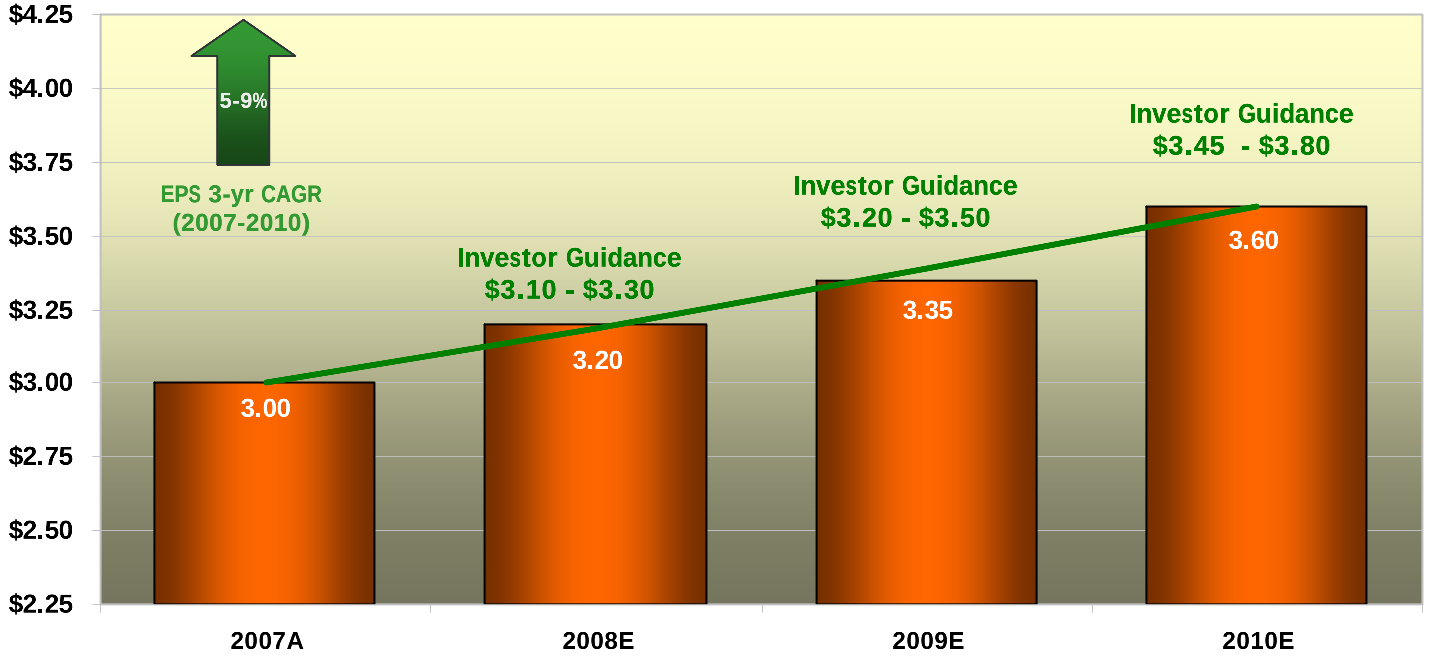
Regulatory Plan Highlights

- Ohio:
  - 2008 RSP 4%
  - Post 2008
- Indiana:
  - Base rate case filing
- Oklahoma:
  - 2007 ice storms
  - Red Rock cost recovery
- SWEPCO:
  - Turk plant
  - Stall plant
- Virginia:
  - Fuel factor
  - IGCC
- West Virginia:
  - IGCC

Secured $235MM of $518MM of rate relief for 2008 with approximately 70% of the pending/future rate relief in the form of settlements in front of the commission or storm damage

Earnings Highlights

- 4Q 2007 GAAP Earnings of $0.58 per share; Ongoing Earnings of $0.52 per share
- YTD 2007 GAAP Earnings of $2.73 per share; Ongoing Earnings of $3.00 per share



Achieved high end of 2007 guidance range at $3.00 per share

Increasing 2008 guidance by $0.05 per share to $3.10 - $3.30 per share

4Q07 Performance

American Electric Power
Financial Results for 4th Quarter 2007 Actual vs 4th Quarter 2006 Actual

		2006 Actual ($ millions)	2006 Actual EPS	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	565		582	
2	Ohio Companies	525		582	
3	West Regulated Integrated Utilities	230		230	
4	Texas Wires	114		133	
5	Off-System Sales	144		204	
6	Net Transmission Revenue	52		19	
7	Other Operating Revenue	146		121	
8	**Utility Gross Margin**	1,776		1,871	
9	Operations & Maintenance	(885)		(957)	
10	Depreciation & Amortization	(375)		(361)	
11	Taxes Other than Income Taxes	(178)		(188)	
12	Interest Exp & Preferred Dividend	(195)		(191)	
13	Other Income & Deductions	75		31	
14	Income Taxes	(92)		(53)	
15	**Utility Operations On-Going Earnings**	126	0.31	152	0.38
	NON-UTILITY OPERATIONS:				
16	MEMCO	26	0.07	21	0.05
17	Generation & Marketing	2	0.01	20	0.05
18	**Non Utility Operations On-Going Earnings**	28		41	
19	Parent & Other On-Going Earnings	(3)	(0.01)	16	0.04
20	**ON-GOING EARNINGS**	151	0.38	209	0.52

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4Q07 Performance Drivers:

- *Weather Impact of $22MM:*
  - *Positive $0.01 vs. normal; Positive $0.04 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Rate Relief $48MM; (APCo, Ohio RSP, PSO & Texas Wires)*
  - *Positive load growth including new customers; $29MM*
- *Off-System Sales (line 5):*
  - *Favorable due to higher volumes and prices*
- *Net Transmission Revenue (line 6):*
  - *Primarily increased PJM marginal losses of $52MM offset by increased OSS (line 5) and lower fuel expense (lines 1&2) for a net loss of approximately $10MM*
- *Other Operating Revenue (line 7):*
  - *Lower third-party and miscellaneous revenues*
- *Operations & Maintenance (line 9):*
  - *Increased expenses $72MM; primarily attributed to PSO storm restoration*
- *Other Income & Deductions (line 13):*
  - *Lower due to reinstatement of VA E&R carrying costs in 4Q06*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 25.9% in 2007 and 42.2% in 2006 due to unfavorable FIT adjustments in 2006 & favorable amended state income tax returns in 2007*

YTD 2007 Performance

American Electric Power
Financial Results for YTD December 2007 Actual vs YTD December 2006 Actual

		2006 Actual ($ millions)	2006 Actual EPS	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	2,111		2,215	
2	Ohio Companies	2,110		2,452	
3	West Regulated Integrated Utilities	1,018		994	
4	Texas Wires	476		529	
5	Off-System Sales	829		939	
6	Net Transmission Revenue	271		152	
7	Other Operating Revenue	527		536	
8	**Utility Gross Margin**	7,342		7,817	
9	Operations & Maintenance	(3,177)		(3,326)	
10	Depreciation & Amortization	(1,435)		(1,483)	
11	Taxes Other than Income Taxes	(735)		(748)	
12	Interest Exp & Preferred Dividend	(670)		(790)	
13	Other Income & Deductions	246		124	
14	Income Taxes	(543)		(508)	
15	Utility Operations On-Going Earnings	1,028	2.61	1,086	2.72
	NON-UTILITY OPERATIONS:				
16	MEMCO	80	0.20	61	0.15
17	Generation & Marketing	12	0.03	37	0.09
18	**Non-Utility Operations On-Going Earnings**	92		98	
	PARENT & OTHER:				
19	Parent & Other On-Going Earnings	(27)	(0.07)	15	0.04
20	**ON-GOING EARNINGS**	1,093	2.77	1,199	3.00

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2007 Performance Drivers:

- *Weather impact of $105MM:*
  - *Positive $0.09 vs. normal; Positive $0.17 vs. prior year*
- *Retail Sales (lines 1-4):*
  - *Rate relief; $214MM (AP, KP, Ohio RSP, PSO & TX Wires)*
  - *Positive load growth including new customers $196MM*
- *Off-System Sales (line 5):*
  - *Favorable trading margins & West physical OSS, offset by unfavorable East physical*
- *Net Transmission Revenue (line 6):*
  - *Increased PJM marginal losses of $144MM offset by increased OSS (line 5) and lower fuel expense (lines 1&2) for a net loss of approximately $34MM*
- *Operations & Maintenance (line 9):*
  - *Increased expenses $149MM attributed to storm restoration, plant outages and other base cost of operations*
- *Depreciation & Amortization (line 10):*
  - *Increased amortization related to Texas securitization offset by lower depreciation expense*
- *Interest Expense (line 12):*
  - *Higher due to Texas securitization bonds and more LTD*
- *Other Income & Deductions (line 13):*
  - *Decreased Centrica sharing contribution of $50MM in 2007 vs. 2006 and lower Texas carrying costs income of $69MM*

4Q07 Earnings Release

2007 Cash Flow

($ millions)	2006	2007
Operating Activities		
Net Income -- Reported	$ 1,002	$ 1,089
Discontinued Operations	(10)	(24)
Continuing Earnings	992	1,065
Depreciation, Amortization & Deferred Taxes	1,498	1,604
Impairments	209	-
Extraordinary Loss, net of Taxes	-	79
Changes in Components of Working Capital	61	(163)
Other Assets & Liabilities	(28)	(197)
Cash Flows From Operating Activities	2,732	2,388
Investing Activities		
Capital Expenditures	(3,528)	(3,556)
Proceeds on Sale of Assets	186	222
Acquisition of Assets	-	(512)
Change in Other Temporary Cash Investments (net)	(291)	78
Other Investing (net)	(110)	(140)
Cash Flows Used for Investing Activities	(3,743)	(3,908)
Financing Activities		
Common Shares Issued, net	99	143
Long-term Debt Issuances, net	1,413	1,260
Short-term Debt Increase, net	7	642
Other Financing	(17)	(18)
Dividends Paid	(591)	(630)
Cash Flows From Financing Activities	911	1,397
Cash From Continuing Operations	$ (100)	$ (123)
Beginning Cash & Cash Equivalent Balances	401	301
Ending Cash & Cash Equivalent Balances	$ 301	$ 178

2007 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by changes in accrued taxes and accounts receivable/payable.

Investing Activities

- Cash outlay of $3.6 billion for 2007 capital investment.
- 2007 primary asset sale proceeds: Centrica sharing $20MM, TCC's share of Oklaunion $46MM, TCC's asset sale to Electric Transmission Texas $70MM and Sweeny Plant $82MM; 2006 primary asset sale proceeds: Centrica sharing $70MM, Bajio $29MM and DOW Plant $64MM.
- 2007 acquisitions consist of the Darby Plant for $102MM, Lawrenceburg for $325MM and Dresden for $85MM.

Investing Activities

- 2007 common share issuances of $143MM: stock options exercised $86MM and issuances for the dividend reinvestment program $57MM.
- Changes in long and short term debt driven by capital funding requirements.

Capitalization

Capital Structure	Actual 12/31/2006			Actual 12/31/2007		
	Debt	**Equity**	**Total**	**Debt**	**Equity**	**Total**
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,994	-	14,994
Short-term Debt	18	-	18	660	-	660
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	10,079	10,079
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,654**	**10,140**	**25,794**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(26)	-	(26)	(19)	-	(19)
Rockport Unit 2 Off-balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,257)	-	(2,257)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(259)	-	(259)
Total Adjusted Capitalization	**12,291**	**9,473**	**21,764**	**14,302**	**10,140**	**24,442**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.5%***	***41.5%***	***100.0%***

Adjusted debt-to-cap of 58.5% at 12/31/07

Questions

4Q07 Earnings

	$ millions			Earnings Per Share		
	4th Qtr 2006	4th Qtr 2007	Change	4th Qtr 2006	4th Qtr 2007	Change
Utility Operations	126	152	26	0.31	0.38	0.07
Non-Utility Operations	28	41	13	0.08	0.10	0.02
Parent & Other	(3)	16	19	(0.01)	0.04	0.05
AEP On-Going Earnings	151	209	58	0.38	0.52	0.14
Special Items	30	22	(8)	0.08	0.06	(0.02)
Reported Earnings (GAAP)	181	231	50	0.46	0.58	0.12

Quarterly Performance Comparison

American Electric Power
Financial Results for 4th Quarter 2007 Actual vs 4th Quarter 2006 Actual

		Performance Driver	2006 Actual ($ millions)	2006 Actual EPS	Performance Driver	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	17,513 GWh @ $ 32.3 /MWhr =	565		17,801 GWh @ $ 32.7 /MWhr =	582	
2	Ohio Companies	11,117 GWh @ $ 47.2 /MWhr =	525		12,962 GWh @ $ 44.9 /MWhr =	582	
3	West Regulated Integrated Utilities	9,280 GWh @ $ 24.8 /MWhr =	230		9,610 GWh @ $ 23.9 /MWhr =	230	
4	Texas Wires	6,043 GWh @ $ 18.8 /MWhr =	114		6,385 GWh @ $ 20.8 /MWhr =	133	
5	Off-System Sales	6,776 GWh @ $ 21.2 /MWhr =	144		7,899 GWh @ $ 25.9 /MWhr =	204	
6	Net Transmission Revenue		52			19	
7	Other Operating Revenue		146			121	
8	**Utility Gross Margin**		1,776			1,871	
9	Operations & Maintenance		(885)			(957)	
10	Depreciation & Amortization		(375)			(361)	
11	Taxes Other than Income Taxes		(178)			(188)	
12	Interest Exp & Preferred Dividend		(195)			(191)	
13	Other Income & Deductions		75			31	
14	Income Taxes		(92)			(53)	
15	**Utility Operations On-Going Earnings**		126	0.31		152	0.38
	NON-UTILITY OPERATIONS:						
16	MEMCO		26	0.07		21	0.05
17	Generation & Marketing		2	0.01		20	0.05
18	**Non Utility Operations On-Going Earnings**		28			41	
19	Parent & Other On-Going Earnings		(3)	(0.01)		16	0.04
20	**ON-GOING EARNINGS**		151	0.38		209	0.52

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Earnings

	$ millions			$ Earnings Per Share		
	YTD 2006	YTD 2007	Change	YTD 2006	YTD 2007	Change
Utility Operations	1,028	1,086	58	2.61	2.72	0.11
Non-Utility Operations	92	98	6	0.23	0.24	0.01
Parent & Other	(27)	15	42	(0.07)	0.04	0.11
AEP On-Going Earnings	1,093	1,199	106	2.77	3.00	0.23
Special Items	(91)	(110)	(19)	(0.23)	(0.27)	(0.04)
Reported Earnings (GAAP)	1,002	1,089	87	2.54	2.73	0.19

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YTD Performance Comparison

American Electric Power
Financial Results for YTD December 2007 Actual vs YTD December 2006 Actual

		Performance Driver (2006)	2006 Actual ($ millions)	2006 Actual EPS	Performance Driver (2007)	2007 Actual ($ millions)	2007 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111		72,535 GWh @ $ 30.5 /MWhr =	2,215	
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110		51,040 GWh @ $ 48.0 /MWhr =	2,452	
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018		41,904 GWh @ $ 23.7 /MWhr =	994	
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476		26,682 GWh @ $ 19.8 /MWhr =	529	
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829		30,895 GWh @ $ 30.4 /MWhr =	939	
6	Net Transmission Revenue		271			152	
7	Other Operating Revenue		527			536	
8	**Utility Gross Margin**		7,342			7,817	
9	Operations & Maintenance		(3,177)			(3,326)	
10	Depreciation & Amortization		(1,435)			(1,483)	
11	Taxes Other than Income Taxes		(735)			(748)	
12	Interest Exp & Preferred Dividend		(670)			(790)	
13	Other Income & Deductions		246			124	
14	Income Taxes		(543)			(508)	
15	Utility Operations On-Going Earnings		1,028	2.61		1,086	2.72
	NON-UTILITY OPERATIONS:						
16	MEMCO		80	0.20		61	0.15
17	Generation & Marketing		12	0.03		37	0.09
18	**Non-Utility Operations On-Going Earnings**		92			98	
	PARENT & OTHER:						
19	Parent & Other On-Going Earnings		(27)	(0.07)		15	0.04
20	**ON-GOING EARNINGS**		1,093	2.77		1,199	3.00

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Detailed Ongoing Earnings Guidance

2007 Actual: $3.00

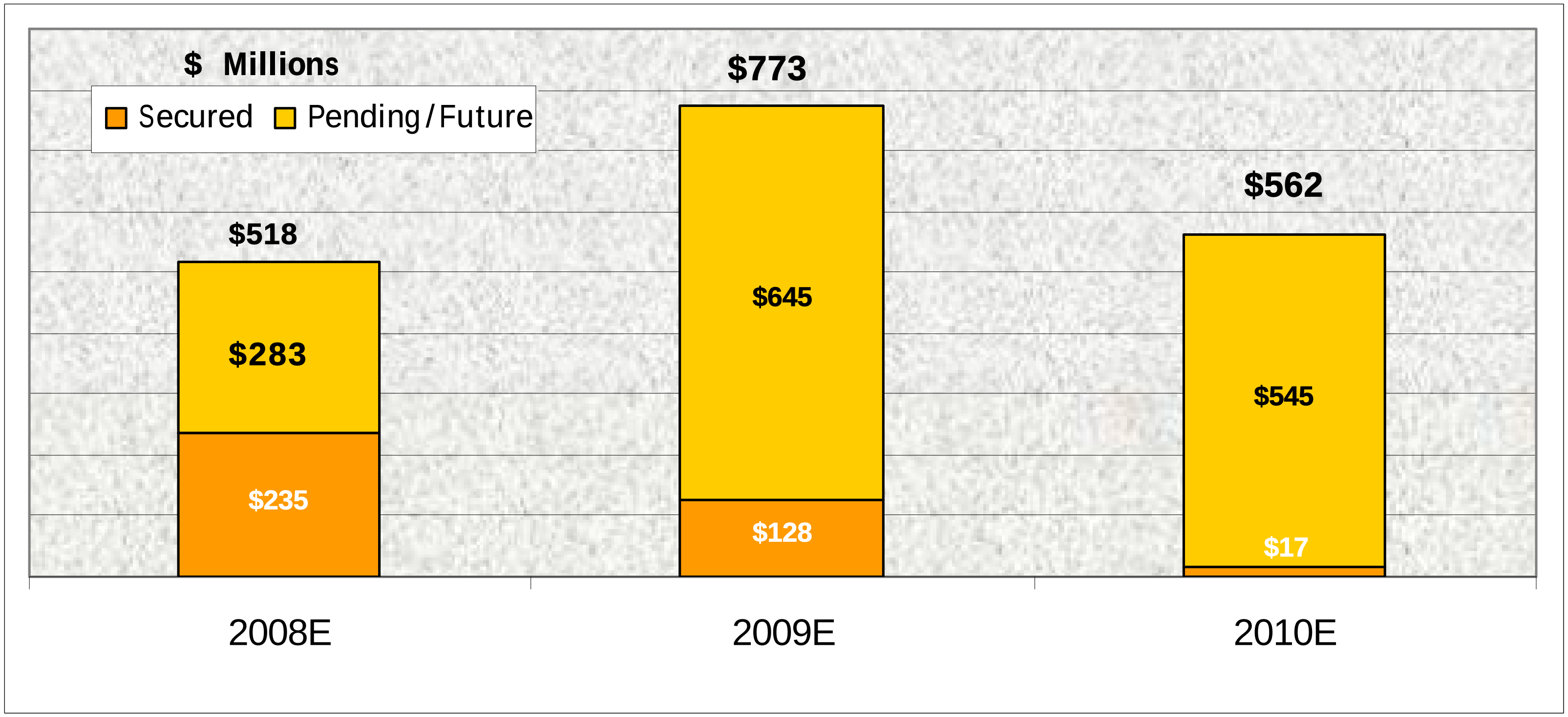
2008E: $3.10 - $3.30 (Revised)

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

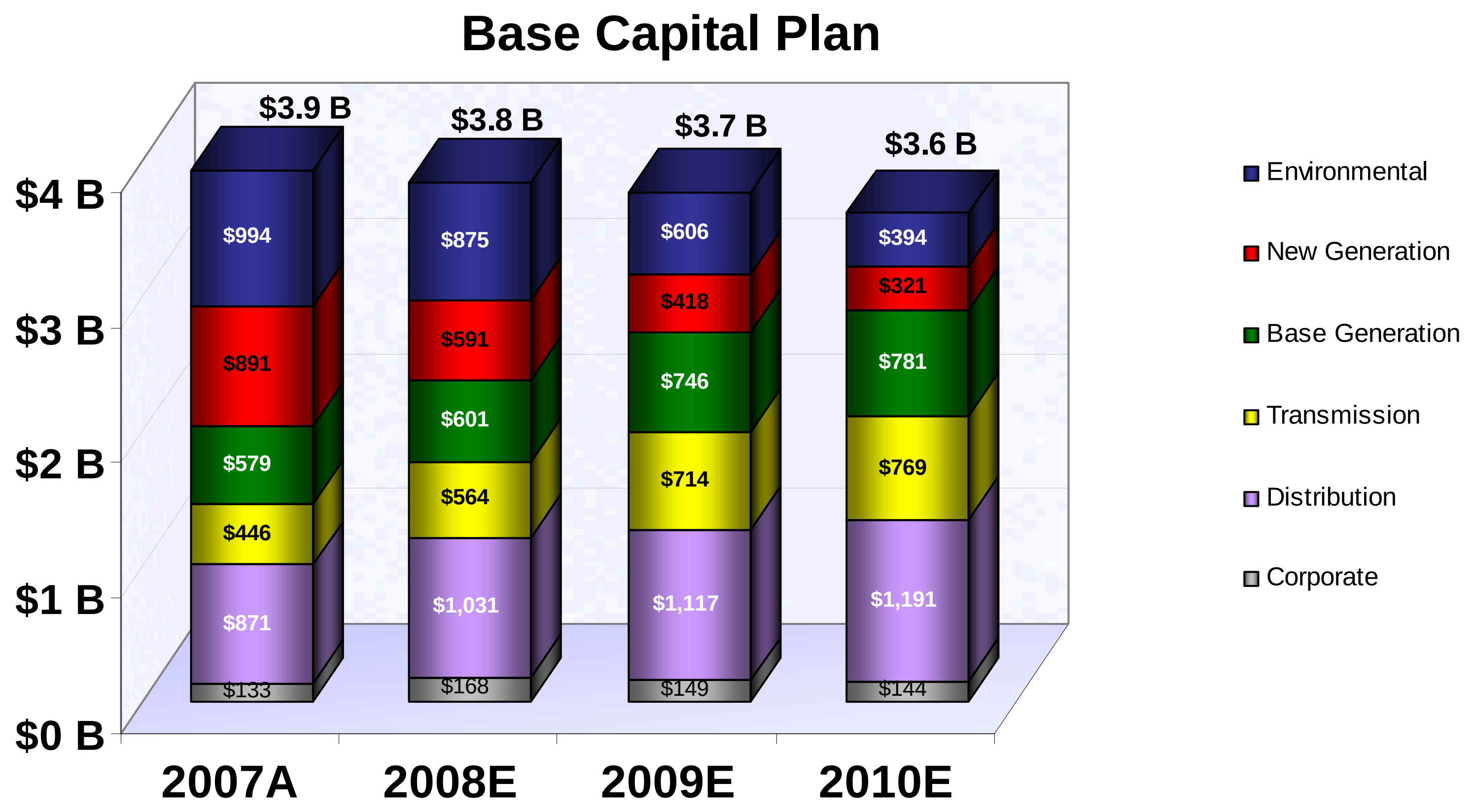
Incremental Rate Relief



- **2008 Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case.**
- **2008 Pending: Ohio 2008 4% RSP & Marginal Loss Recovery, APCo - Virginia Fuel Factor, PSO January 2007 Ice Storm Recovery, SWEPCo - LA Financial Review.**

Secured $235MM of $518MM for 2008

4-Year Capital Investment Forecast



Note: Amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$'s in MM	Actual 2007		Projection 2008		Projection 2009		Projection 2010
Planned Capital Investment (Excluding AFUDC) *	$	(3,914)	$	(3,830)	$	(3,750)	$	(3,600)
Planned Transmission Initiatives	$	-	$	(75)	$	(57)	$	(194)
Dividend on Common Stock		(630)		(659)		(664)		(669)
Cash Sources								
Cash from Operations		2,388		2,572		2,691		3,324
Proceeds from Sale of Assets		222		-		-		-
Common Stock Issued (Dividend Reinvestment Plan)		143		150		150		150
Change in Debt, Net		1,902		1,796		2,119		1,180
Other		(234)		(6)		(458)		(247)
Change in Cash		(123)		(52)		31		(56)
Ending Cash Balance	$	178	$	126	$	157	$	101

* Includes distressed generation purchases of $512MM in 2007.

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital investment is funded from cash from operations and debt issuances

4Q07 Retail Performance

	Load Growth (weather normalized) 4Q07 vs. 4Q06
East Regulated Integrated Utilities	0.5%
Ohio Companies	8.5%
West Regulated Integrated Utilities	(0.6)%
Texas Wires	4.4%
Impact on EPS	$0.04

	Degree Days 4Q07 vs. 4Q06
East Cooling	68
West Cooling *	55
East Heating	69
West Heating *	56
Impact on EPS	$0.04

* West statistics represent PSO/SWEPCo customer base only

YTD Retail Performance

	Load Growth (weather normalized) YTD 2007 vs. YTD 2006
East Regulated Integrated Utilities	3.1%
Ohio Companies	8.3%
West Regulated Integrated Utilities	1.7%
Texas Wires	2.8%
Impact on EPS	$0.35

	Degree Days YTD 2007 vs. YTD 2006
East Cooling	343
West Cooling *	(186)
East Heating	537
West Heating *	387
Impact on EPS	$0.17

* West statistics represent PSO/SWEPCo customer base only

Retail Performance

	Rate Relief (in millions)
	4Q07 vs. 4Q06
East Regulated Integrated Utilities	$12
Ohio Companies	$14
West Regulated Integrated Utilities	$7
Texas Wires	$15
AEP System Total	$48
Impact on EPS	$0.08

	Rate Relief (in millions)
	YTD 2007 vs. YTD 2006
East Regulated Integrated Utilities	$63
Ohio Companies	$98
West Regulated Integrated Utilities	$16
Texas Wires	$37
AEP System Total	$214
Impact on EPS	$0.35

4Q07 Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	4Q 2007	4Q 2006	4Q 2007	4Q 2006	4Q 2007	4Q 2006
East:	**61.47%**	**60.83%**	**78.45%**	**78.23%**	**7.01%**	**8.48%**
Coal:	71.31%	66.46%	76.71%	76.61%	7.56%	9.30%
Super-Critical*	72.96%	68.28%	76.44%	75.35%	6.66%	9.58%
Sub-Critical*	66.21%	60.83%	77.52%	80.48%	10.24%	8.44%
Gas**	4.72%	1.08%	91.50%	95.60%	N/A	N/A
Hydro	5.68%	12.24%	70.17%	87.58%	11.46%	6.23%
Nuclear	78.58%	77.04%	77.81%	75.29%	0.70%	0.00%
SPP:	**41.25%**	**40.86%**	**82.25%**	**87.08%**	**5.15%**	**6.98%**
Coal:	79.18%	77.35%	83.22%	83.10%	1.85%	5.04%
Super-Critical*	87.02%	90.29%	88.88%	93.64%	2.19%	6.04%
Sub-Critical*	76.22%	74.50%	81.09%	78.98%	1.71%	4.67%
Gas	16.71%	16.01%	81.62%	89.80%	9.14%	9.61%
Texas:						
Coal	**77.90%**	**78.19%**	**83.02%**	**79.96%**	**8.82%**	**13.00%**
AEP System	**57.07%**	**56.45%**	**79.38%**	**80.31%**	**6.66%**	**8.27%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours. (4Q2007 = 0.42% / 4Q2006 = 0.34%)

YTD Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	YTD 2007	YTD 2006	YTD 2007	YTD 2006	YTD 2007	YTD 2006
East:	**64.26%**	**64.57%**	**81.09%**	**81.80%**	**8.32%**	**8.54%**
Coal:	71.89%	70.34%	78.73%	80.29%	9.02%	9.37%
Super-Critical*	73.00%	73.36%	77.93%	80.55%	8.81%	8.31%
Sub-Critical*	68.44%	61.00%	81.23%	79.49%	9.62%	12.63%
Gas **	7.27%	2.58%	90.19%	92.84%	N/A	N/A
Hydro	7.85%	10.68%	86.42%	92.30%	11.61%	4.99%
Nuclear	90.86%	83.55%	89.68%	82.87%	1.25%	0.65%
SPP:	**43.20%**	**45.10%**	**84.79%**	**86.25%**	**6.75%**	**6.79%**
Coal:	77.45%	76.87%	82.35%	82.87%	5.49%	3.86%
Super-Critical*	78.10%	83.77%	80.41%	86.76%	6.20%	5.50%
Sub-Critical*	77.21%	75.02%	83.09%	81.27%	5.23%	3.31%
Gas	20.65%	23.33%	86.39%	88.56%	8.04%	9.73%
Texas:						
Coal	**71.95%**	**65.35%**	**73.95%**	**67.78%**	**17.43%**	**23.48%**
AEP System	**59.54%**	**60.06%**	**81.84%**	**82.62%**	**8.13%**	**8.45%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours. (YTD2007 = 1.23% / YTD2006 =0.39%)

AEP AMERICAN ELECTRIC POWER®

4Q10 Earnings Release Presentation

January 28, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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2010 Highlights and 2011 Plan

- **2010 Highlights**
  - 4Q10 and YTD GAAP earnings of $0.37 and $2.53 per share, respectively
  - 4Q10 and YTD on-going earnings of $0.38 and $ 3.03 per share, respectively
  - $329M in rate changes throughout all jurisdictions, $222M net of offsets
  - Overall AEP System on-going ROE of 10.75%
  - Increased quarterly dividend 12%
  - Total shareholder return of 8.7%

- **2011 Plan**
  - **Financial Performance**
    - Earnings guidance of $3.00 to $3.20 per share
    - Maintain fiscal discipline around O&M and capital spending
  - **Regulatory Plan**
    - Rate proceedings – $162M of $235M secured (69%)
    - Ohio Filings – ESP, Distribution Cases, Environmental Cases, 2010 SEET
  - **Policy Update**
    - EPA
    - Transmission

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing

The proposed 2012-2014 AEP Ohio ESP contains a balanced set of customer programs, investment proposals, supply options and associated rate mechanisms. The terms of the proposed ESP offer AEP Ohio customers stable and affordable electricity rates while offering investors reasonable financial stability and returns.

Key Provisions Included in ESP:

- ✓ Generation Rate Realignment
- ✓ Alternative Longer-Term Price Certainty Option
- ✓ Fuel Adjustment Clause Mechanism
- ✓ POLR Provision
- ✓ Recovery of Generation Related Facility Closure Costs
- ✓ Interruptible Power Tariff
- ✓ Plug-in Electric Vehicles Tariff
- ✓ Pool Modification Provision
- ✓ Partnership with Ohio Fund
- ✓ Economic Development Rider
- ✓ Distribution Investment Rider
- ✓ Storm Damage Recovery

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers):
  - Net base $54MM or 1.4% in year 1 (2012)
  - Net base $106MM or 2.7% in year 2 (2013)

4Q10 Performance

Fourth Quarter Reconciliation

	EPS	Ongoing Earnings ($ in millions)
4Q09	$ 0.50	$238
Share Count Effect	$ (0.01)	
Firm Wholesale Margin	$ (0.02)	
SEET Refund	$ (0.06)	
Non-Utility Operations, net	$ (0.07)	
Other Utility Operations, net	$ (0.18)	
Off-System Sales	$ 0.01	
Retail Margin	$ 0.02	
Weather	$ 0.04	
Rate Changes	$ 0.07	
Operations & Maintenance	$ 0.08	
4Q10	$ 0.38	$179

4Q10 Performance Drivers

- Firm Wholesale Margin down $17M due to the loss of two large wholesale customers
- SEET refund of $43M related to PUCO order in the 2009 SEET filing for CSPCo
- Non-Utility Operations/Parent decreased $37M primarily due to a contribution to the AEP Foundation and a fleet lease buyout
- Other Utility Operations, net decreased approximately $88M and primarily includes the absence of accidental outage insurance and higher taxes
- Off-System Sales were favorable by $10M due to higher prices and volume and lower sharing, offset by lower trading
- Retail Margin up $18M due to increased industrial usage
- Weather was favorable by $26M vs. prior year, $15M vs. normal
- Rate Changes net of offsets $51M from multiple operating jurisdictions
- O&M expense net of offsets decreased $63M primarily due to lower storm restoration expenses and cost savings initiatives.

December YTD Performance

Annual Reconciliation

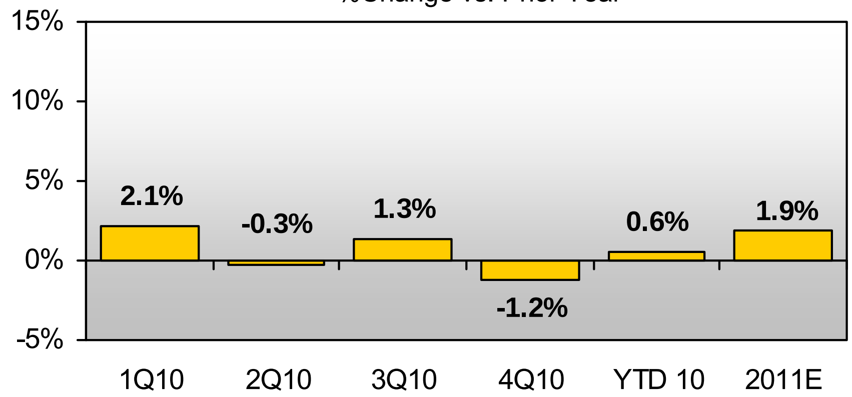
	EPS	Ongoing Earnings ($ in millions)
2009	$ 2.97	$1,362
Non-Utility Operations, net	$ (0.05)	
SEET Refund	$ (0.06)	
Firm Wholesale Margin	$ (0.10)	
Share Count Effect	$ (0.14)	
Other Utility Operations, net	$ (0.52)	
Retail Margin	$ 0.07	
Off-System Sales	$ 0.08	
Operations & Maintenance	$ 0.14	
Weather	$ 0.32	
Rate Changes	$ 0.32	
2010	$ 3.03	$1,451

Annual Performance Drivers

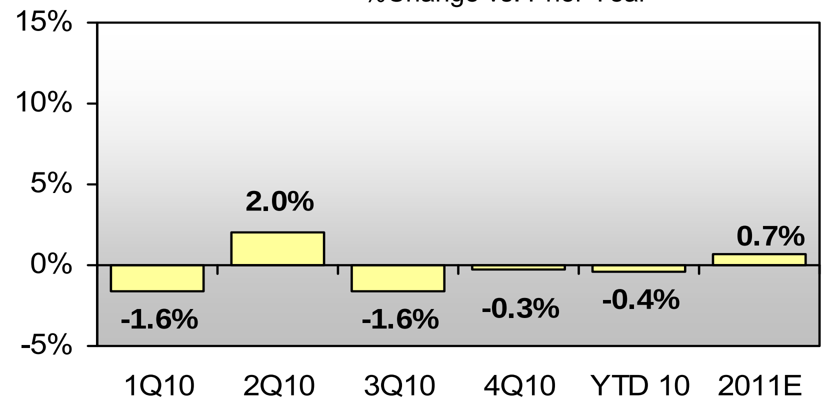
- Non-Utility Operations/Parent decreased $19M primarily due to a contribution to the AEP Foundation and a fleet lease buyout, somewhat offset by favorable tax adjustments
- SEET refund of $43M related to PUCO order in the 2009 SEET filing for CSPCo
- Firm Wholesale Margin down $74M due to the loss of two large wholesale customers
- Share count impact due to 20M weighted average shares outstanding increase (459M to 479M) from equity offering and DRP
- Other Utility Operations, net decreased approximately $238M and primarily includes the absence of accidental outage insurance related to the DC Cook nuclear plant and higher interest expense, depreciation and taxes
- Retail Margin up $48M, due to economic recovery, primarily in the industrial class
- Off-System Sales increase $53M with increased sales in the east offsetting decreased trading/marketing profits
- O&M decrease of $97M net of offsets, primarily due to lower storm restoration expenses and cost savings initiatives
- Weather was favorable by $229M vs. prior year, $164M vs. normal
- Rate Changes net of offsets of $222M from multiple operating jurisdictions

Normalized Load Trends

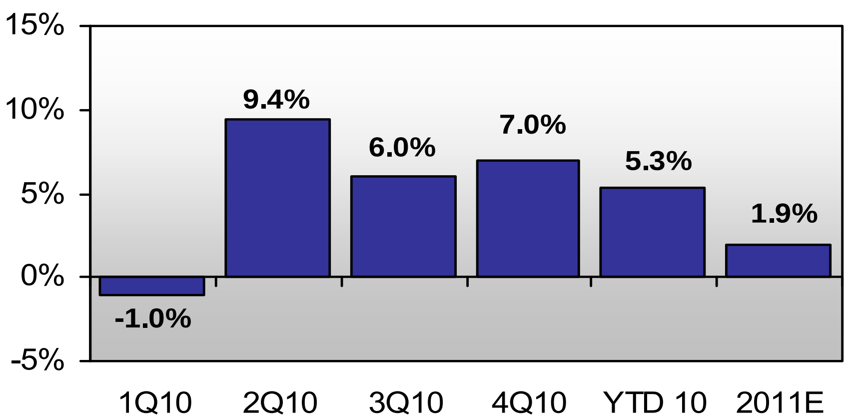
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



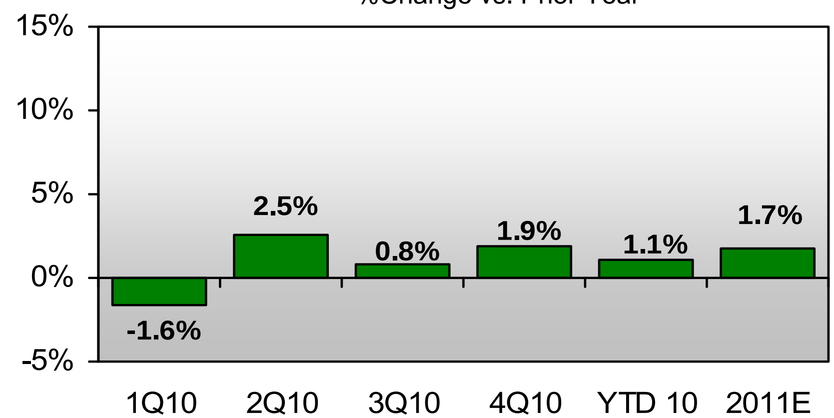
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

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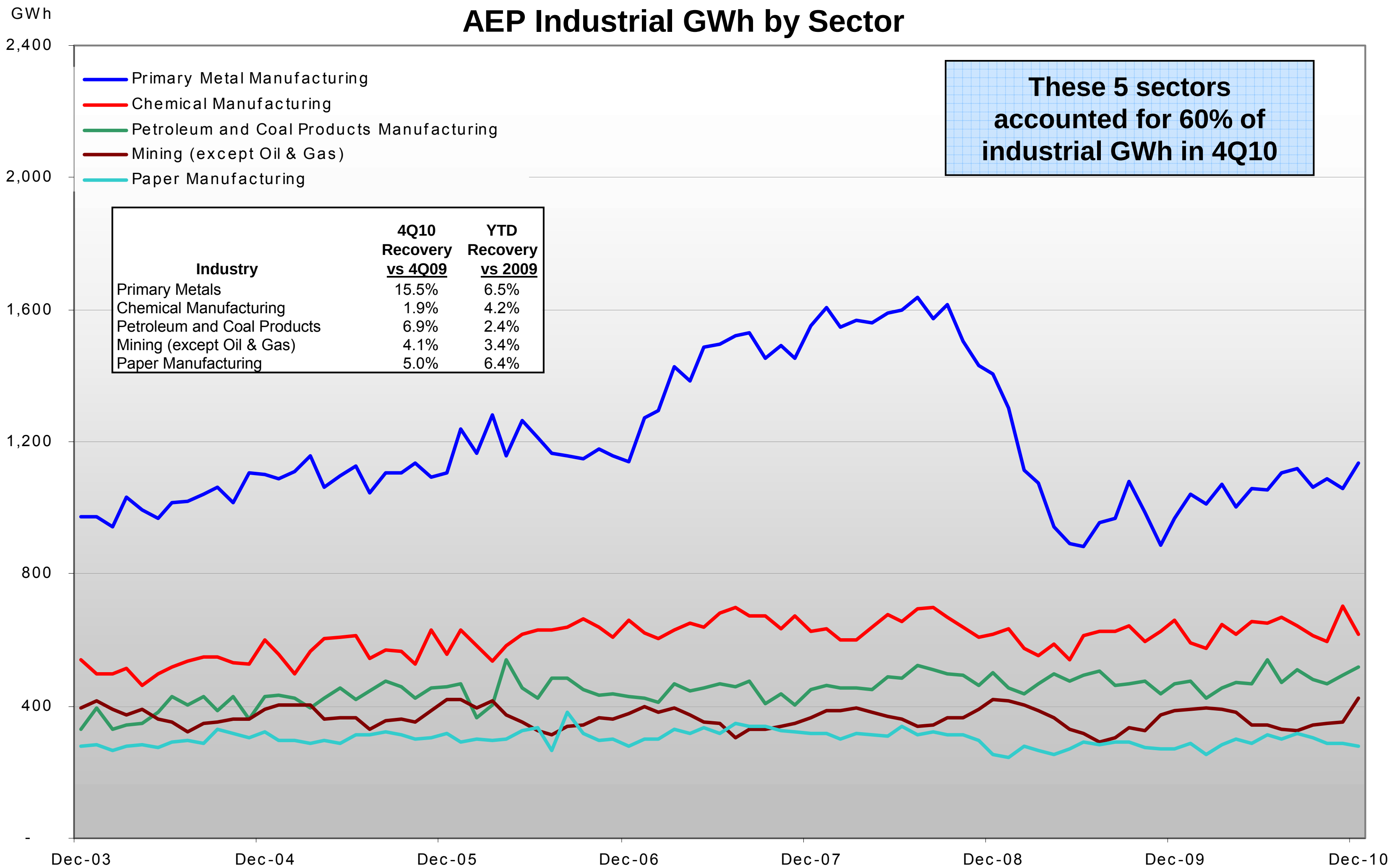
Industrial Sales Volumes



Industry	4Q10 Recovery vs 4Q09	YTD Recovery vs 2009
Primary Metals	15.5%	6.5%
Chemical Manufacturing	1.9%	4.2%
Petroleum and Coal Products	6.9%	2.4%
Mining (except Oil & Gas)	4.1%	3.4%
Paper Manufacturing	5.0%	6.4%

2011 Guidance and Business Initiatives

2011 Guidance: $3.00 - $3.20 per share

2011 Earnings Drivers

- Recovering Economy
- Rate changes (69% secured)
- Continued O&M discipline - $34M decrease net of offsets
- Customer switching – Ohio
- 2010 SEET at Columbus Southern Power
- Off-system sales

Business Initiatives

- Operating Transcos in OH, OK and MI; filings pending in other states
- AEP Eastern System Interconnection Agreement
- Bonus Depreciation
- Capital Allocation

Questions

4Q10 Earnings

	$ millions			Earnings Per Share		
	4th Qtr 2009	4th Qtr 2010	Change	4th Qtr 2009	4th Qtr 2010	Change
Utility Operations	$ 206	$ 180	$ (26)	$ 0.44	$ 0.38	$ (0.06)
Transmission Operations	1	5	4	0.00	0.01	0.01
Non-Utility Operations	33	29	(4)	0.07	0.06	(0.01)
Parent & Other	(2)	(35)	(33)	(0.01)	(0.07)	(0.06)
AEP On-Going Earnings	238	179	(59)	0.50	0.38	(0.12)
Cost Reduction Initiative	0	(3)	(3)	0.00	(0.01)	(0.01)
Special Items Total	0	(3)	(3)	0	(0.01)	(0.01)
Reported Earnings (GAAP)	$ 238	$ 176	$ (62)	$ 0.50	$ 0.37	$ (0.13)

Quarterly Performance Comparison

American Electric Power
Financial Results for 4th Quarter 2010 Actual vs 4th Quarter 2009 Actual

		2009 Actual Performance Driver	2009 Actual ($ millions)	2009 Actual EPS	2010 Actual Performance Driver	2010 Actual ($ millions)	2010 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	16,753 GWh @ $ 37.9 /MWhr =	635		17,337 GWh @ $ 41.7 /MWhr =	723	
2	Ohio Companies	11,699 GWh @ $ 57.3 /MWhr =	670		12,732 GWh @ $ 50.8 /MWhr =	647	
3	West Regulated Integrated Utilities	9,017 GWh @ $ 28.9 /MWhr =	261		9,359 GWh @ $ 29.1 /MWhr =	273	
4	Texas Wires	6,480 GWh @ $ 21.2 /MWhr =	137		6,024 GWh @ $ 23.0 /MWhr =	139	
5	Off-System Sales	4,039 GWh @ $ 11.2 /MWhr =	45		3,133 GWh @ $ 17.7 /MWhr =	55	
6	Transmission Revenue - 3rd Party		85			91	
7	Other Operating Revenue		175			108	
8	Utility Gross Margin		2,008			2,036	
9	Operations & Maintenance		(1,006)			(960)	
10	Depreciation & Amortization		(388)			(393)	
11	Taxes Other than Income Taxes		(178)			(198)	
12	Interest Exp & Preferred Dividend		(238)			(233)	
13	Other Income & Deductions		37			40	
14	Income Taxes		(29)			(112)	
15	Utility Operations On-Going Earnings		206	0.44		180	0.38
16	Transmission Operations On-Going Earnings		1	-		5	0.01
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		25	0.05		21	0.04
18	Generation & Marketing		8	0.02		8	0.02
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(12)			(43)	
20	Other Investments		10			8	
21	Parent & Other On-Going Earnings		(2)	(0.01)		(35)	(0.07)
22	ON-GOING EARNINGS		238	0.50		179	0.38

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

December YTD Earnings

	$ millions			Earnings Per Share		
	Dec YTD 2009	Dec YTD 2010	Change	Dec YTD 2009	Dec YTD 2010	Change
Utility Operations	$ 1,317	$ 1,419	$ 102	$ 2.87	$ 2.97	$ 0.10
Transmission Operations	4	10	6	0.01	0.02	0.01
Non-Utility Operations	88	65	(23)	0.19	0.13	(0.06)
Parent & Other	(47)	(43)	4	(0.10)	(0.09)	0.01
AEP On-Going Earnings	1,362	1,451	89	2.97	3.03	0.06
SWEPCO SFAS 71	(5)	0	5	(0.01)	0.00	0.01
Medicare D Subsidy	0	(21)	(21)	0.00	(0.04)	(0.04)
Cost Reduction Initiative	0	(185)	(185)	0.00	(0.39)	(0.39)
Carbon Capture -- APCo VA	0	(34)	(34)	0.00	(0.07)	(0.07)
Special Items Total	(5)	(240)	(235)	(0.01)	(0.50)	(0.49)
Reported Earnings (GAAP)	$ 1,357	$ 1,211	$ (146)	$ 2.96	$ 2.53	$ (0.43)

YTD 2010 Performance Comparison

American Electric Power
Financial Results for YTD December 2010 Actual vs YTD December 2009 Actual

		2009 Actual			2010 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544		68,761 GWh @ $ 41.9 /MWhr =	2,882	
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733		49,465 GWh @ $ 56.6 /MWhr =	2,800	
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167		42,131 GWh @ $ 31.4 /MWhr =	1,322	
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571		27,348 GWh @ $ 22.3 /MWhr =	611	
5	Off-System Sales	14,786 GWh @ $ 16.7 /MWhr =	246		19,172 GWh @ $ 15.6 /MWhr =	299	
6	Transmission Revenue - 3rd Party		354			369	
7	Other Operating Revenue		768			511	
8	Utility Gross Margin		8,383			8,794	
9	Operations & Maintenance		(3,410)			(3,427)	
10	Depreciation & Amortization		(1,561)			(1,598)	
11	Taxes Other than Income Taxes		(751)			(801)	
12	Interest Exp & Preferred Dividend		(919)			(945)	
13	Other Income & Deductions		128			154	
14	Income Taxes		(553)			(758)	
15	Utility Operations On-Going Earnings		1,317	2.87		1,419	2.97
16	Transmission Operations On-Going Earnings		4	0.01		10	0.02
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		47	0.10		40	0.08
18	Generation & Marketing		41	0.09		25	0.05
	PARENT & OTHER:						
19	Parent Company On-Going Earnings		(58)			(83)	
20	Other Investments		11			40	
21	Parent & Other On-Going Earnings		(47)	(0.10)		(43)	(0.09)
22	ON-GOING EARNINGS		1,362	2.97		1,451	3.03

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2107 of 9556

December YTD 2010 Cash Flow

($ millions)	2009	2010
Operating Activities		
Net Income -- Reported	**$ 1,365**	**$ 1,218**
Depreciation, Amortization & Deferred Taxes	2,868	2,556
Pension Contributions	-	(500)
Application of New Accounting Guidance: Securitized Debt for Receivables	-	(656)
Changes in Components of Working Capital	(1,212)	279
Over/(Under) Fuel Recovery, Net	(474)	(253)
Extraordinary Loss	5	-
Other Assets & Liabilities	(77)	(3)
Cash Flows From Operating Activities	**2,475**	**2,641**
Investing Activities		
Capital Expenditures	(2,792)	(2,318)
Proceeds on Sale of Assets	278	187
Change in Other Temporary Cash Investments, net	(89)	(103)
Acquisition of Assets	(104)	(144)
Other Investing, net	(209)	(124)
Cash Flows Used for Investing Activities	**(2,916)**	**(2,502)**
Financing Activities		
Common Shares Issued, net	1,728	93
Long-term Debt Issuances, net	1,490	(723)
Short-term Debt Increase/(Decrease), net	(1,850)	564
Application of New Accounting Guidance: Securitized Debt for Receivables	-	656
Other Financing	(90)	(101)
Dividends Paid	(758)	(824)
Cash Flows From (Used for) Financing Activities	**520**	**(335)**
Cash From Continuing Operations	**$ 79**	**$ (196)**
Beginning Cash & Cash Equivalent Balances	411	490
Ending Cash & Cash Equivalent Balances	**$ 490**	**$ 294**

YTD 2010 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by coal inventory and accrued taxes.

Investing Activities

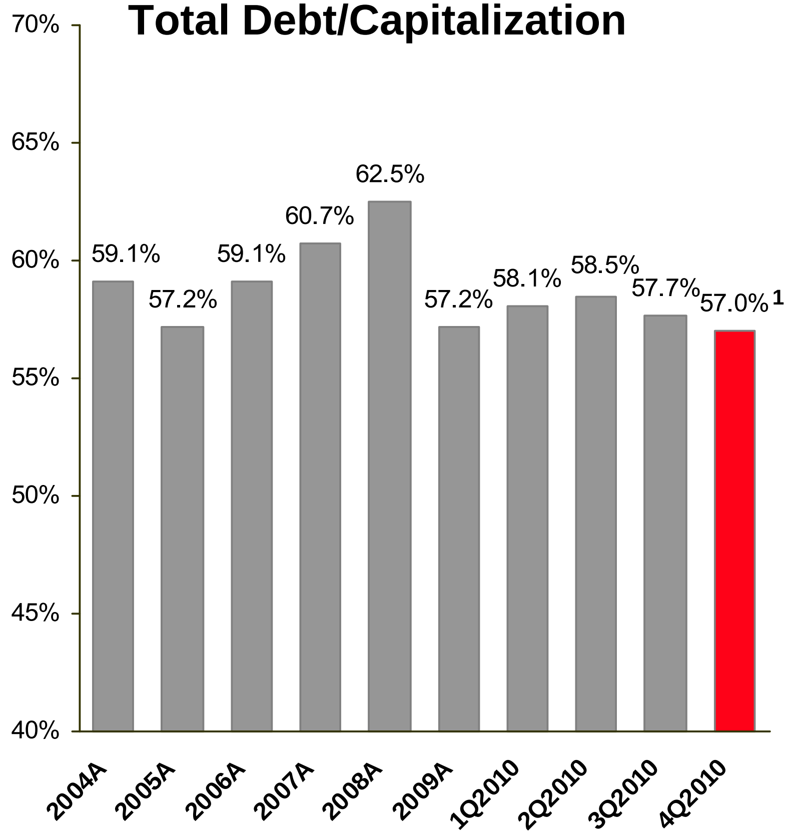
- Cash outlay for 2010 YTD capital investment.
- 2010 asset sale proceeds primarily relate to the transfer of assets to ETT.

Financing Activities

- Changes in long-term debt driven by reduced capital funding requirements.
- Changes in short term debt relate to funding of severance activity and voluntary pension funding.

Capitalization & Liquidity

Total Debt/Capitalization



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Detailed Ongoing Earnings Guidance

AEP®

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Cash Flow Guidance

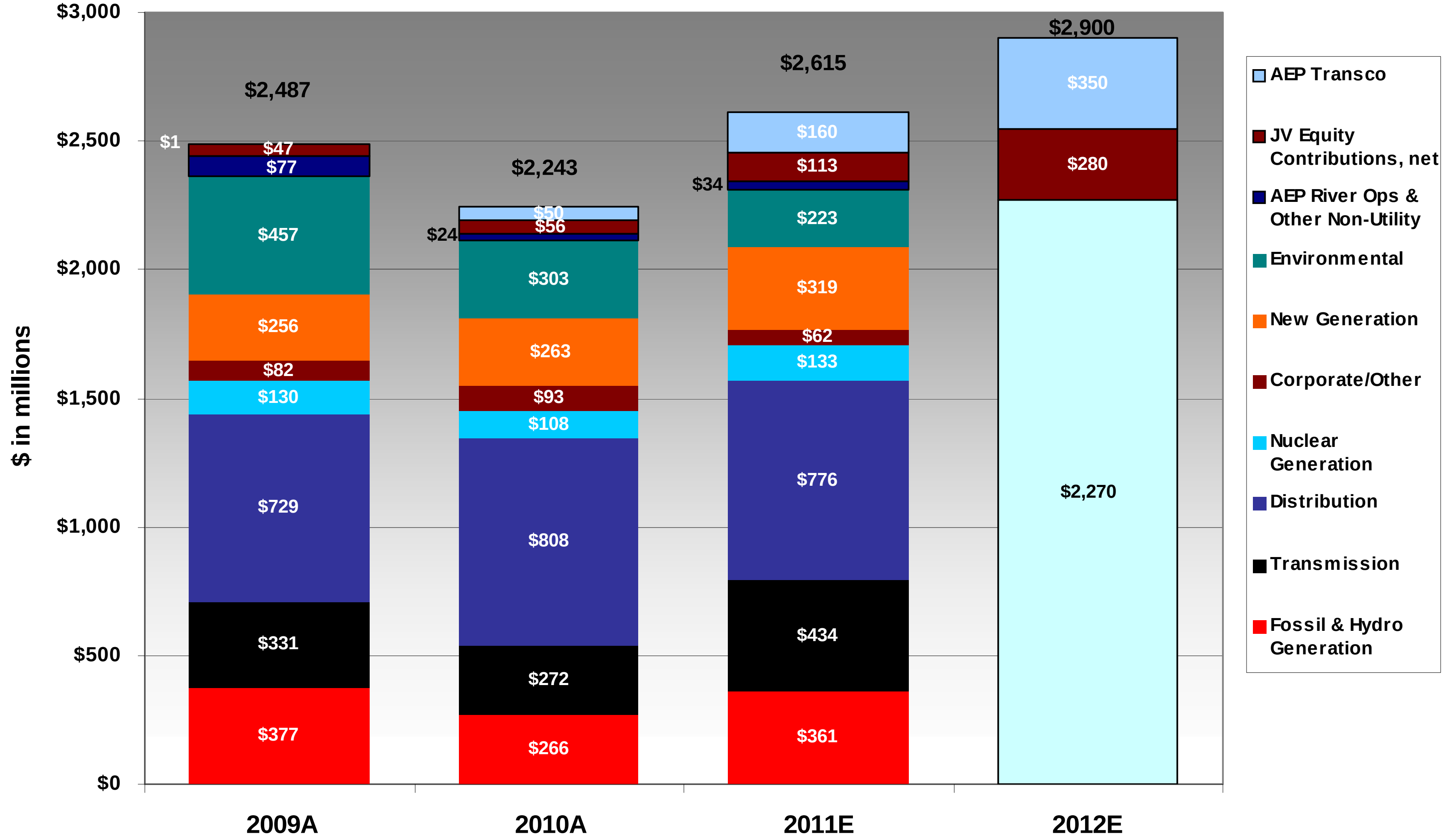
AEP®

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to September 30, 2010 10Q *Enron Bankruptcy* pages 56-57 for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capital Expenditures



Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	4Q10 vs. 4Q09
East Regulated Integrated Utilities	$46
Ohio Companies	-$7
West Regulated Integrated Utilities	$12
Texas Wires	$0
AEP System Total	$51
Impact on EPS	$0.07

	Rate Changes, net of trackers (in millions)
	YTD10 vs. YTD09
East Regulated Integrated Utilities	$141
Ohio Companies	$20
West Regulated Integrated Utilities	$61
Texas Wires	$0
AEP System Total	$222
Impact on EPS	$0.32

4Q10 Retail Performance

	Retail Load* (weather normalized) 4Q10 vs. 4Q09
East Regulated Integrated Utilities	1.8%
Ohio Companies	4.2%
West Regulated Integrated Utilities	4.2%
Texas Wires	-4.8%
Impact on EPS	$0.02

*Excludes Firm Wholesale Load

	Weather Impact (in millions) 4Q10 vs. 4Q09
East Regulated Integrated Utilities	$21
Ohio Companies	$8
West Regulated Integrated Utilities	$1
Texas Wires	($3)
Impact on EPS	$0.04

May not foot due to rounding

YTD 2010 Retail Performance

	Retail Load* (weather normalized) YTD10 vs. YTD09
East Regulated Integrated Utilities	2.1%
Ohio Companies	1.2%
West Regulated Integrated Utilities	3.0%
Texas Wires	1.0%
Impact on EPS	$0.07

*Excludes Firm Wholesale Load

	Weather Impact (in millions) YTD10 vs. YTD09
East Regulated Integrated Utilities	$96
Ohio Companies	$77
West Regulated Integrated Utilities	$61
Texas Wires	($5)
Impact on EPS	$0.32

Off System Sales Gross Margin Detail

AEP®

4Q10

	4Q09			4Q10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	4,039	$ 8.12	$ 33	3,133	$ 16.34	$ 51
Marketing/Trading	-		$ 35	-		$ 21
Pre-Sharing Gross Margin	4,039		$ 68	3,133		$ 73
Margin Shared			$ (23)			$ (17)
Net OSS			$ 45			$ 56

- Physical off-system sales margins exceeded last year by $18M
- Volumes down 22% versus last year
- Improved AEP/Dayton Hub pricing: 9% increase in liquidation prices
- Lower Trading & Marketing results by $14M

YTD10

	YTD09			YTD10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	14,786	$ 10.87	$ 161	19,172	$ 15.12	$ 290
Marketing/Trading	-		$ 176	-		$ 126
Pre-Sharing Gross Margin	14,786		$ 337	19,172		$ 416
Margin Shared			$ (90)			$ (117)
Net OSS			$ 246			$ 299

- Physical off-system sales margins exceeded last year by $129M
- Volumes up 30% versus last year
- Improved AEP/Dayton Hub pricing: 14% increase in liquidation prices
- Lower Trading & Marketing results by $50M

Off-System Sales

4Q10 vs. 4Q09

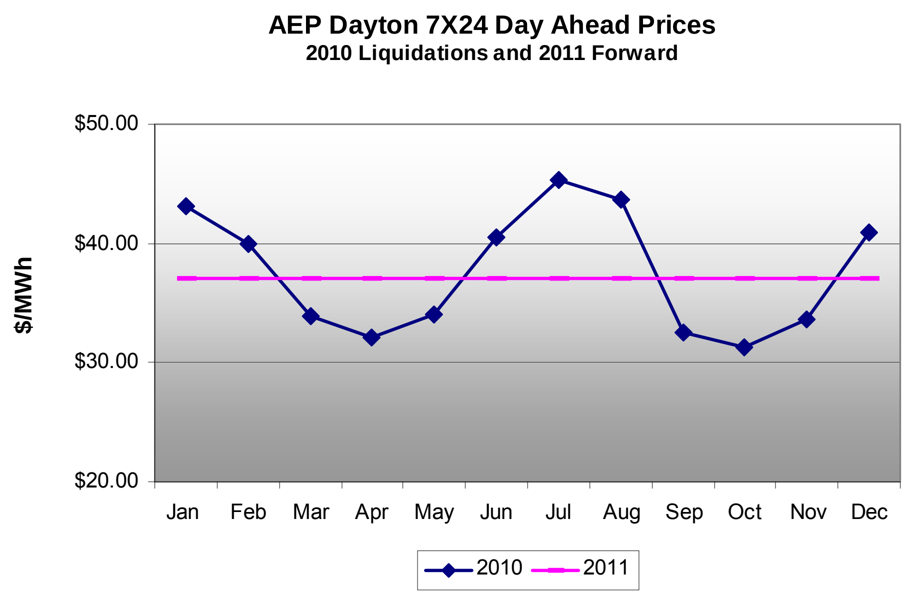
Q4 2010 Liquidations vs. Q4 2009 Liquidations ($/MWh)

Hub	2009	2010	$ Change	% Change
AEP Dayton	32.26	35.29	3.03	9%
PJM West	37.65	43.56	5.91	16%
NiHub	29.1	27.41	-1.69	-6%
CinHub	29.67	32.04	2.37	8%
SPP	35.38	28.21	-7.17	-20%
Natural Gas ($/mmBtu)	4.26	3.78	-0.48	-11%

YTD10 vs. YTD09

YTD 2010 Liquidations vs. YTD 2009 Liquidations ($/MWh)

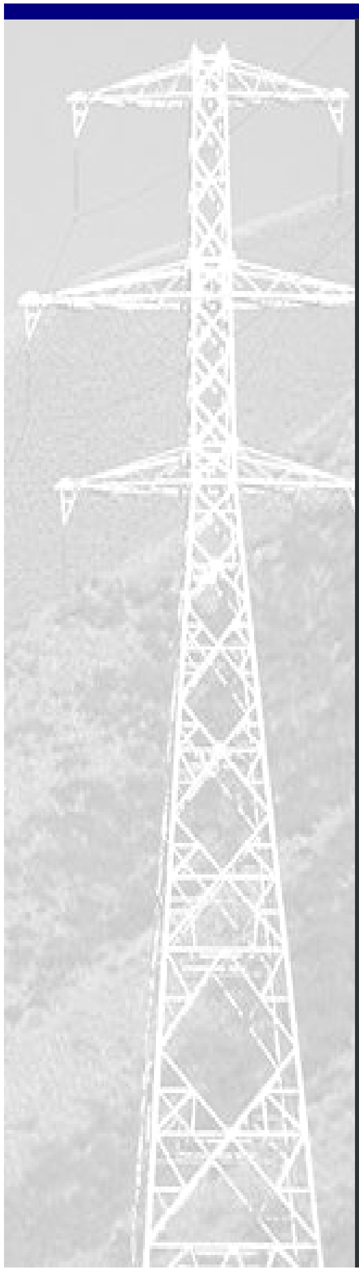
Hub	2009	2010	$ Change	% Change
AEP Dayton	32.98	37.59	4.61	14%
PJM West	38.75	46.59	7.84	20%
NiHub	28.69	33.13	4.44	15%
CinHub	29.46	34.81	5.35	18%
SPP	29.11	32.45	3.34	11%
Natural Gas ($/mmBtu)	3.92	4.37	0.45	11%



2011 Forwards vs. Full Year 2010 Liquidations ($/MWh)

Hub	2010	2011	$ Change	% Change
AEP Dayton	37.59	37.07	(0.52)	-1%
PJM West	46.59	45.4	(1.19)	-3%
NiHub	33.13	30.95	(2.18)	-7%
CinHub	34.81	32.96	(1.85)	-5%
SPP	32.45	30.64	(1.81)	-6%
Natural Gas ($/mmBtu)	4.37	4.63	0.26	6%

Power forwards and NG futures as of January 18, 2011



4Q09 Earnings Release Presentation

January 28, 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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2009 Accomplishments; 2010 Plans

2009 – Successful year

- ✓ **FINANCIAL PERFORMANCE**
  - ✓ **Delivered on-going earnings** $2.97/share, at the upper end of original guidance $2.75 to $3.05
  - ✓ **Raised over $4B in capital**
- ✓ **REGULATORY SUCCESS**
  - ✓ **Rate relief** –$725MM secured
  - ✓ **Fuel recovery** – now active in all jurisdictions
  - ✓ **Trackers**
- ✓ **TECHNOLOGY LEADERSHIP**
  - ✓ **Carbon capture & storage**
  - ✓ **Cook Nuclear Plant Unit 1 restart**
  - ✓ **Ultra supercritical coal - Turk**

2010 – Commitment to perform

- **MANAGE, EXECUTE, DELIVER**
  - **Meet earnings guidance** $2.80 to $3.20
  - **Manage rate cases**
  - **Celebrate 100 years of dividends**
- **POLICY INITIATIVES**
  - **Climate change**
  - **Energy policy**
- **FOCUS ON GROWTH OPPORTUNITES**
  - **Transmission (JVs & Transco)**
  - **Rate base opportunities (G,T & D)**

4Q09 Performance

Fourth Quarter Reconciliation

	EPS	Ongoing Earnings ($ in millions)
4Q08	$ 0.59	$237
Rate Relief	$ 0.28	
Load Contraction	$ (0.11)	
Weather	$ (0.03)	
O&M	$ (0.12)	
Share Count Effect	$ (0.09)	
Other	$ (0.02)	
4Q09	$ 0.50	$238

4Q09 Performance Drivers

- *Rate Relief of $178MM in Ohio, APCo, PSO, I&M*
- *Load Contraction of $70MM, primarily due to industrial customers at APCo (23%), and Ohio (17%)*
- *Weather was unfavorable by $18MM vs. prior year, $13MM vs. normal*
- *O&M expense increased $73MM primarily driven by storm damage and plant outage expenses*
- *Share count impact due to 74MM weighted average shares outstanding increase (404MM to 478MM) from equity offering and DRP*
- *Other includes higher depreciation and interest expense, partly offset by higher other operating revenue*
- *Off-System Sales after sharing is essentially flat quarter over quarter*

December YTD Performance

Annual Reconciliation

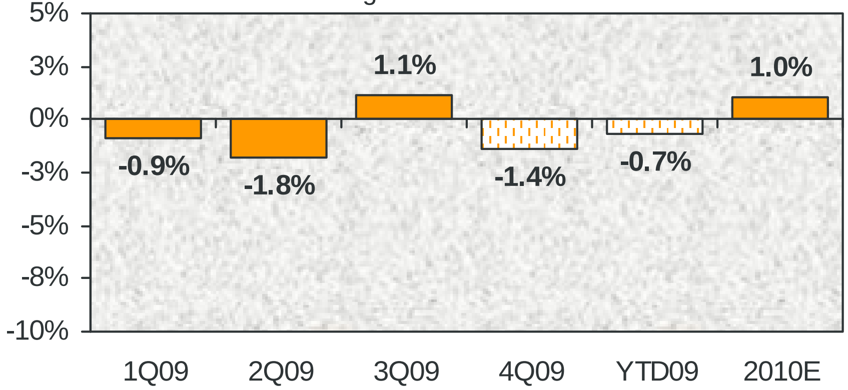
	EPS	Ongoing Earnings ($ in millions)
YTD08	$ 3.24	$1,301
Rate Relief	$ 1.17	
Load Contraction	$ (0.34)	
Weather	$ (0.08)	
Off-System Sales	$ (0.54)	
O&M	$ (0.07)	
Share Count Effect	$ (0.42)	
Other	$ 0.01	
YTD09	$ 2.97	$1,362

Annual Performance Drivers

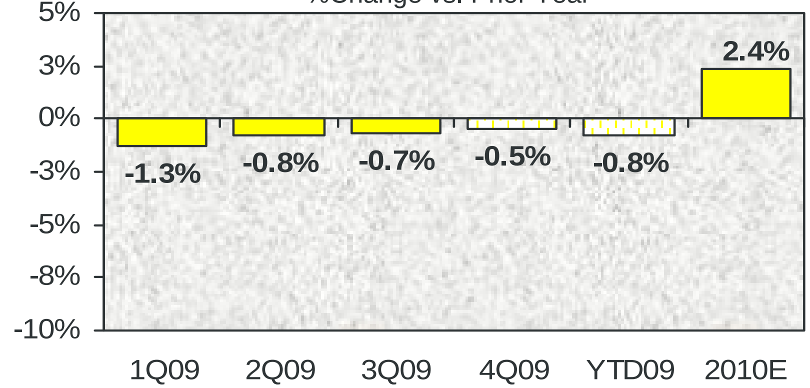
- *Rate Relief of $725MM in Ohio, APCo, PSO, I&M and KGP*
- *Load Contraction of $213MM, primarily Industrial at APCo (25%), Ohio (18%), and I&M (10%)*
- *Weather was unfavorable by $52MM vs. prior year and unfavorable by $66MM vs. normal*
- *Lower Off-System Sales of $333MM after sharing, primarily east physical where volume and price declined*
- *O&M expense increased $44MM primarily due to storm damage*
- *Share count impact due to 57MM weighted average shares outstanding increase (402MM to 459MM) from equity offering and DRP*
- *Other items primarily includes higher other operating income & 3rd party transmission revenue offset by higher depreciation and interest expense*

Normalized Load Trends

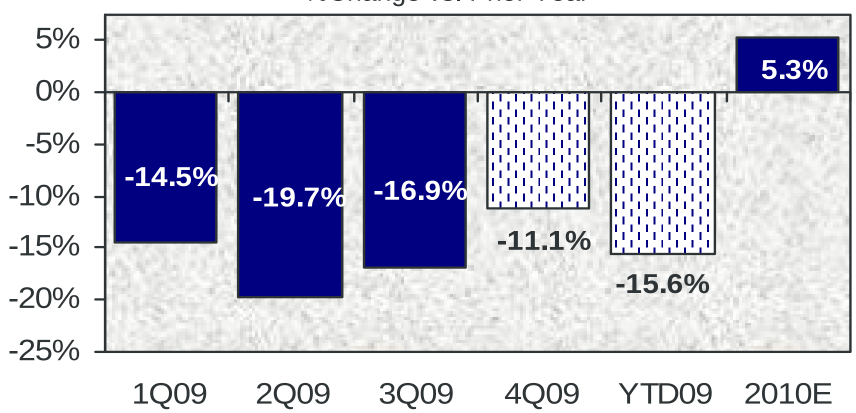
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



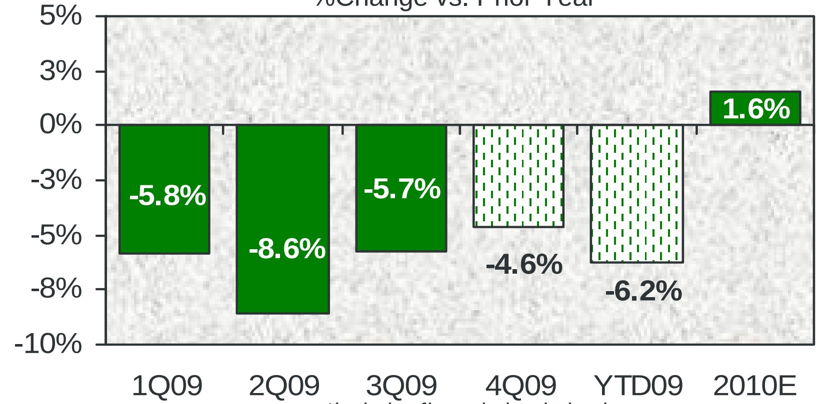
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year

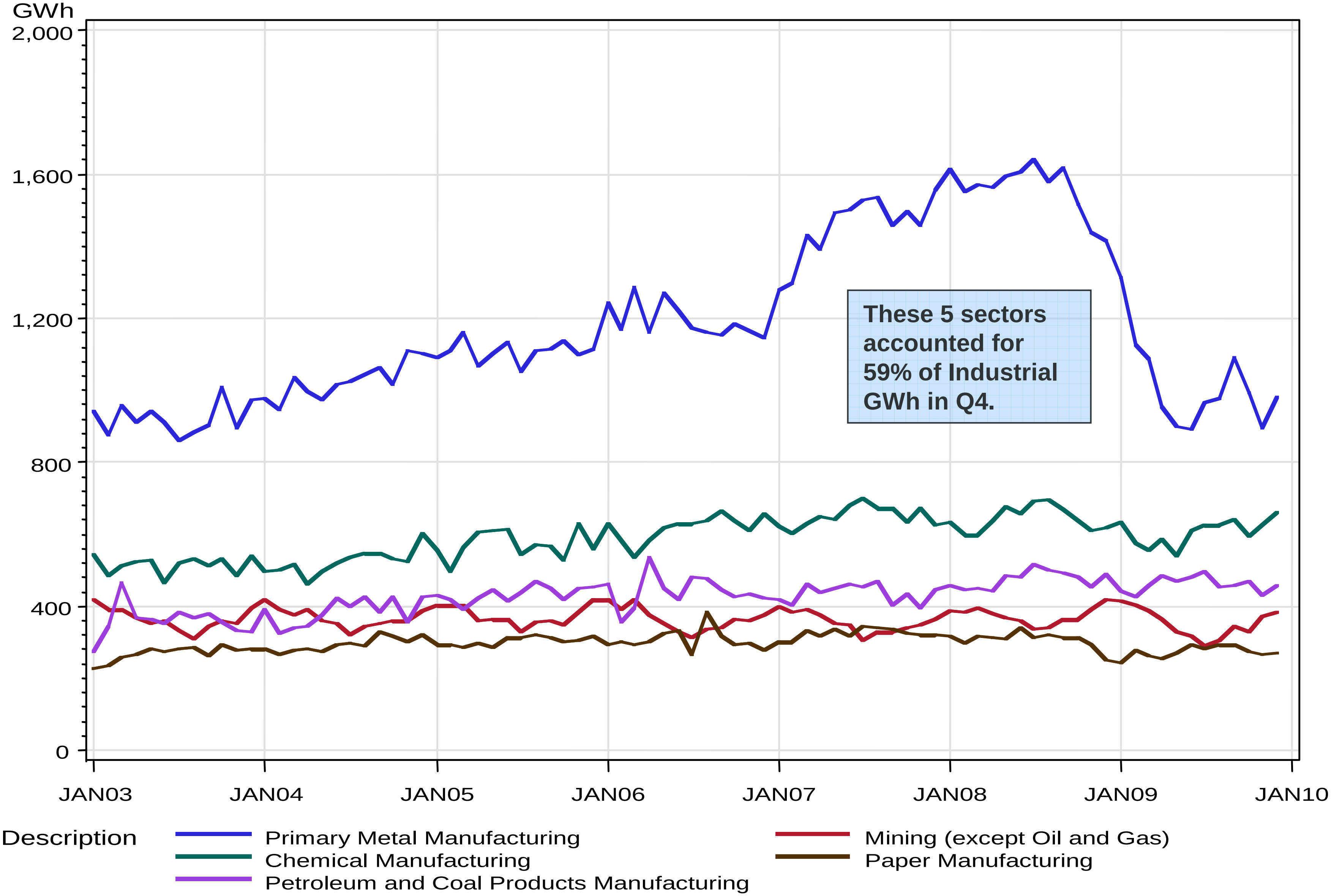


AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

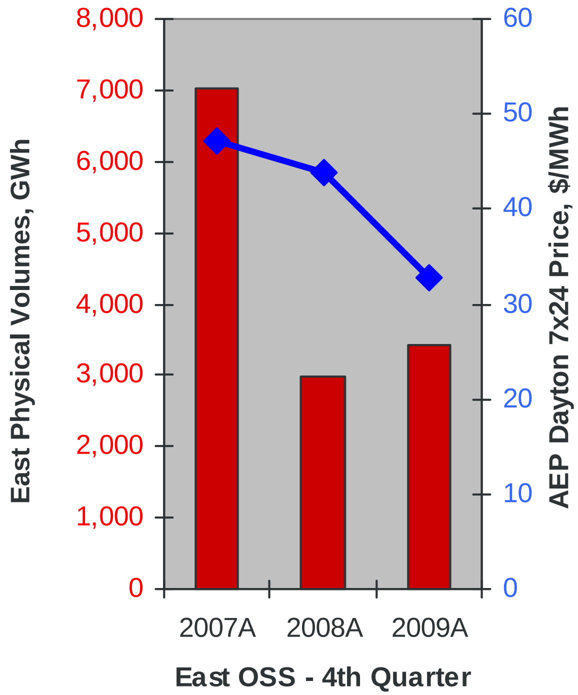
Industrial Sales Volumes



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2124 of 9556

East Off-System Sales

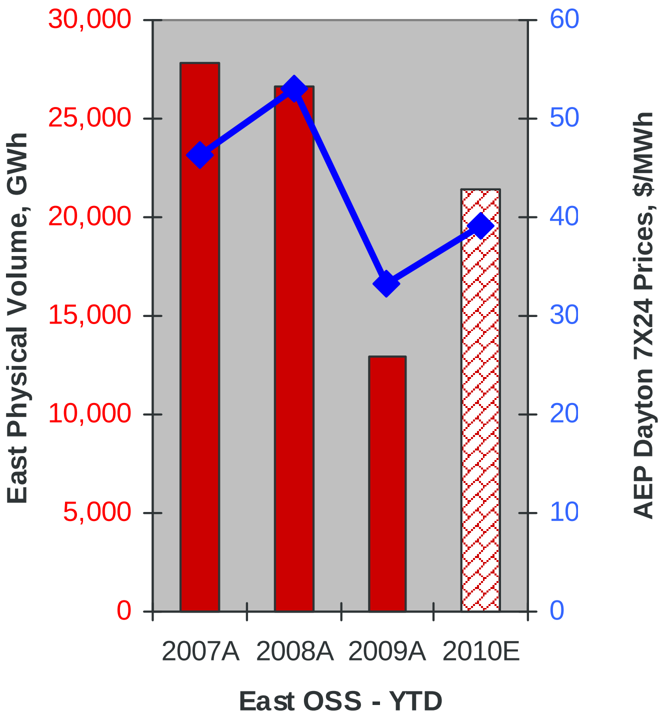
4th Quarter Actual



Volumes – Q4 2009 physical sales showed some improvement vs. Q4 2008, but continue to be off pre-recession levels

Prices – Q4 2009 liquidations reflect lower wholesale electricity pricing due to lower commodity costs and reduced demand

YTD2009 Actual/2010 Est.



Volumes – Annual 2009 physical sales were significantly lower than pre-recession levels

Prices – Annual 2009 liquidations reflect lower wholesale electricity pricing due to lower commodity costs and reduced demand

In 2010, a modest increase in forward electricity prices drives a 65% increase in projected volumes.

Additional 2010 Earnings Drivers

2010 Guidance: $2.80 - $3.20

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

Questions

4Q09 Earnings Release

4Q09 Earnings

	$ millions			Earnings Per Share		
	4th Qtr 2008	4th Qtr 2009	Change	4th Qtr 2008	4th Qtr 2009	Change
Utility Operations	$ 182	$ 206	$ 24	$ 0.45	$ 0.44	$ (0.01)
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	56	33	(23)	0.14	0.07	(0.07)
Parent & Other	(1)	(2)	(1)	0.00	(0.01)	(0.01)
AEP On-Going Earnings	237	238	1	0.59	0.50	(0.09)
Special Items	(85)	0	85	(0.21)	0.00	0.21
Reported Earnings (GAAP)	$ 152	$ 238	$ 86	$ 0.38	$ 0.50	$ 0.12

Quarterly Performance Comparison

American Electric Power
Financial Results for 4th Quarter 2009 Actual vs 4th Quarter 2008 Actual

		Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	18,242 GWh @ $ 36.0 /MWhr =	657		16,753 GWh @ $ 36.6 /MWhr =	613	
2	Ohio Companies	12,547 GWh @ $ 48.4 /MWhr =	607		11,699 GWh @ $ 57.3 /MWhr =	670	
3	West Regulated Integrated Utilities	9,629 GWh @ $ 24.6 /MWhr =	237		9,393 GWh @ $ 27.7 /MWhr =	260	
4	Texas Wires	6,159 GWh @ $ 20.6 /MWhr =	127		6,480 GWh @ $ 21.2 /MWhr =	137	
5	Off-System Sales	3,754 GWh @ $ 15.7 /MWhr =	59		4,044 GWh @ $ 16.8 /MWhr =	68	
6	Transmission Revenue - 3rd Party		82			85	
7	Other Operating Revenue		130			175	
8	Utility Gross Margin		1,899			2,008	
9	Operations & Maintenance		(933)			(1,006)	
10	Depreciation & Amortization		(351)			(388)	
11	Taxes Other than Income Taxes		(180)			(178)	
12	Interest Exp & Preferred Dividend		(219)			(238)	
13	Other Income & Deductions		33			37	
14	Income Taxes		(67)			(29)	
15	Utility Operations On-Going Earnings		182	0.45		206	0.44
16	Transmission Operations On-Going Earnings		-	-		1	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		34	0.09		25	0.05
18	Generation & Marketing		22	0.05		8	0.02
19	Parent & Other On-Going Earnings		(1)	-		(2)	(0.01)
20	ON-GOING EARNINGS		237	0.59		238	0.50

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

December YTD Earnings

	$ millions			Earnings Per Share		
	Dec YTD 2008	Dec YTD 2009	Change	Dec YTD 2008	Dec YTD 2009	Change
Utility Operations	$ 1,210	$ 1,317	$ 107	$ 3.02	$ 2.87	$ (0.15)
Transmission Operations	2	4	2	0.00	0.01	0.01
Non-Utility Operations	120	88	(32)	0.30	0.19	(0.11)
Parent & Other	(31)	(47)	(16)	(0.08)	(0.10)	(0.02)
AEP On-Going Earnings	1,301	1,362	61	3.24	2.97	(0.27)
Special Items	79	(5)	(84)	0.19	(0.01)	(0.20)
Reported Earnings (GAAP)	$ 1,380	$ 1,357	$ (23)	$ 3.43	$ 2.96	$ (0.47)

YTD Performance Comparison

American Electric Power
Financial Results for YTD December 2009 Actual vs YTD December 2008 Actual

		2008 Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	2009 Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278		66,976 GWh @ $ 36.7 /MWhr =	2,461	
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431		47,468 GWh @ $ 57.6 /MWhr =	2,733	
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057		40,321 GWh @ $ 28.8 /MWhr =	1,160	
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537		27,573 GWh @ $ 20.7 /MWhr =	571	
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845		14,795 GWh @ $ 22.7 /MWhr =	337	
6	Transmission Revenue - 3rd Party		329			354	
7	Other Operating Revenue		569			767	
8	Utility Gross Margin		8,046			8,383	
9	Operations & Maintenance		(3,366)			(3,410)	
10	Depreciation & Amortization		(1,450)			(1,561)	
11	Taxes Other than Income Taxes		(749)			(751)	
12	Interest Exp & Preferred Dividend		(871)			(919)	
13	Other Income & Deductions		167			128	
14	Income Taxes		(567)			(553)	
15	Utility Operations On-Going Earnings		1,210	3.02		1,317	2.87
16	Transmission Operations On-Going Earnings		2	-		4	0.01
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		55	0.14		47	0.10
18	Generation & Marketing		65	0.16		41	0.09
21	Parent & Other On-Going Earnings		(31)	(0.08)		(47)	(0.10)
22	ON-GOING EARNINGS		1,301	3.24		1,362	2.97

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD 2009 Cash Flow

($ millions)	2008	2009
Operating Activities		
Net Income -- Reported	$ 1,388	$ 1,365
Discontinued Operations	(12)	-
Continuing Earnings	1,376	1,365
Depreciation, Amortization & Deferred Taxes	2,037	2,868
Extraordinary Loss, net of Taxes	-	5
Changes in Components of Working Capital	(207)	(1,202)
Over/(Under) Fuel Recovery, Net	(272)	(490)
Other Assets & Liabilities	(358)	(60)
Cash Flows From Operating Activities	2,576	2,486
Investing Activities		
Capital Expenditures	(3,800)	(2,792)
Proceeds on Sale of Assets	90	278
Change in Other Temporary Cash Investments, net	39	(89)
Acquisition of Assets	(160)	(104)
Other Investing, net	(196)	(209)
Cash Flows Used for Investing Activities	(4,027)	(2,916)
Financing Activities		
Common Shares Issued, net	159	1,728
Long-term Debt Issuances, net	950	1,490
Short-term Debt Increase/(Decrease), net	1,316	(1,850)
Other Financing	(78)	(100)
Dividends Paid	(663)	(759)
Cash Flows From Financing Activities	1,684	509
Cash From Continuing Operations	$ 233	$ 79
Beginning Cash & Cash Equivalent Balances	178	411
Ending Cash & Cash Equivalent Balances	$ 411	$ 490

YTD 2009 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by coal inventory, taxes payable and employee related expenses.
- Changes in fuel recovery primarily relate to deferrals at APCo, OPCo and CSP.

Investing Activities

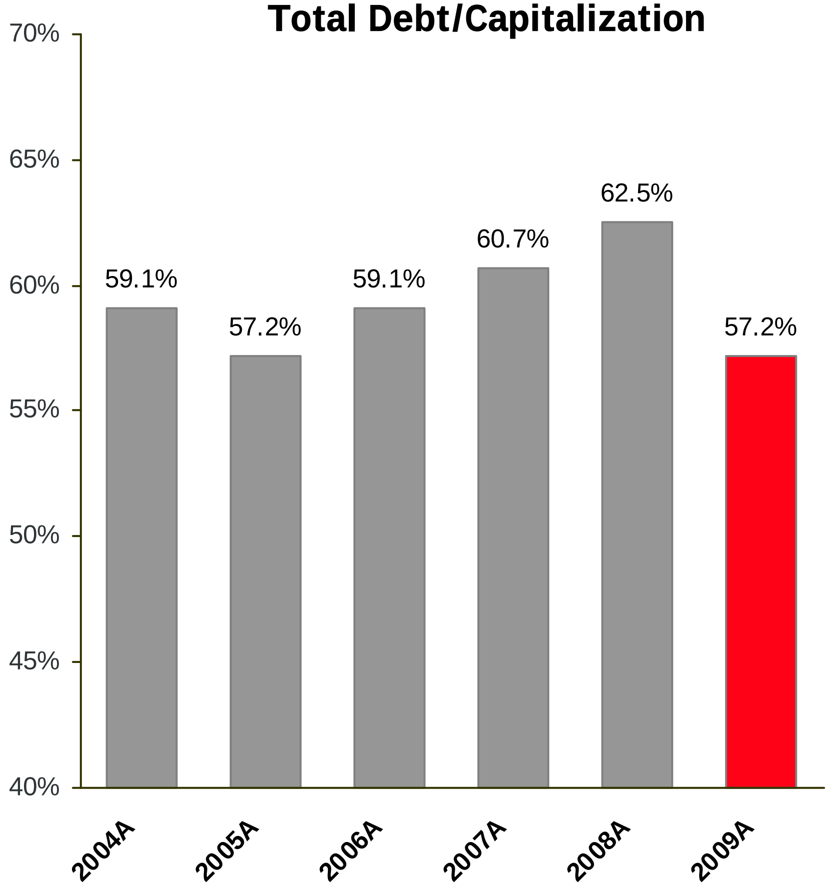
- Cash outlay for 2009 YTD capital investment.
- 2009 asset sale proceeds relate to the transfer of assets from TCC to ETT and the payments from third-party owners of the Turk Plant.
- Change in other investing primarily relates to the purchase of nuclear fuel.

Financing Activities

- 2009 common share issuances of $1,728MM primarily due to equity offering completed in April.
- Changes in short term debt relate to payments made on credit facilities from the proceeds of the equity offering.
- Changes in long-term debt driven by capital funding requirements.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

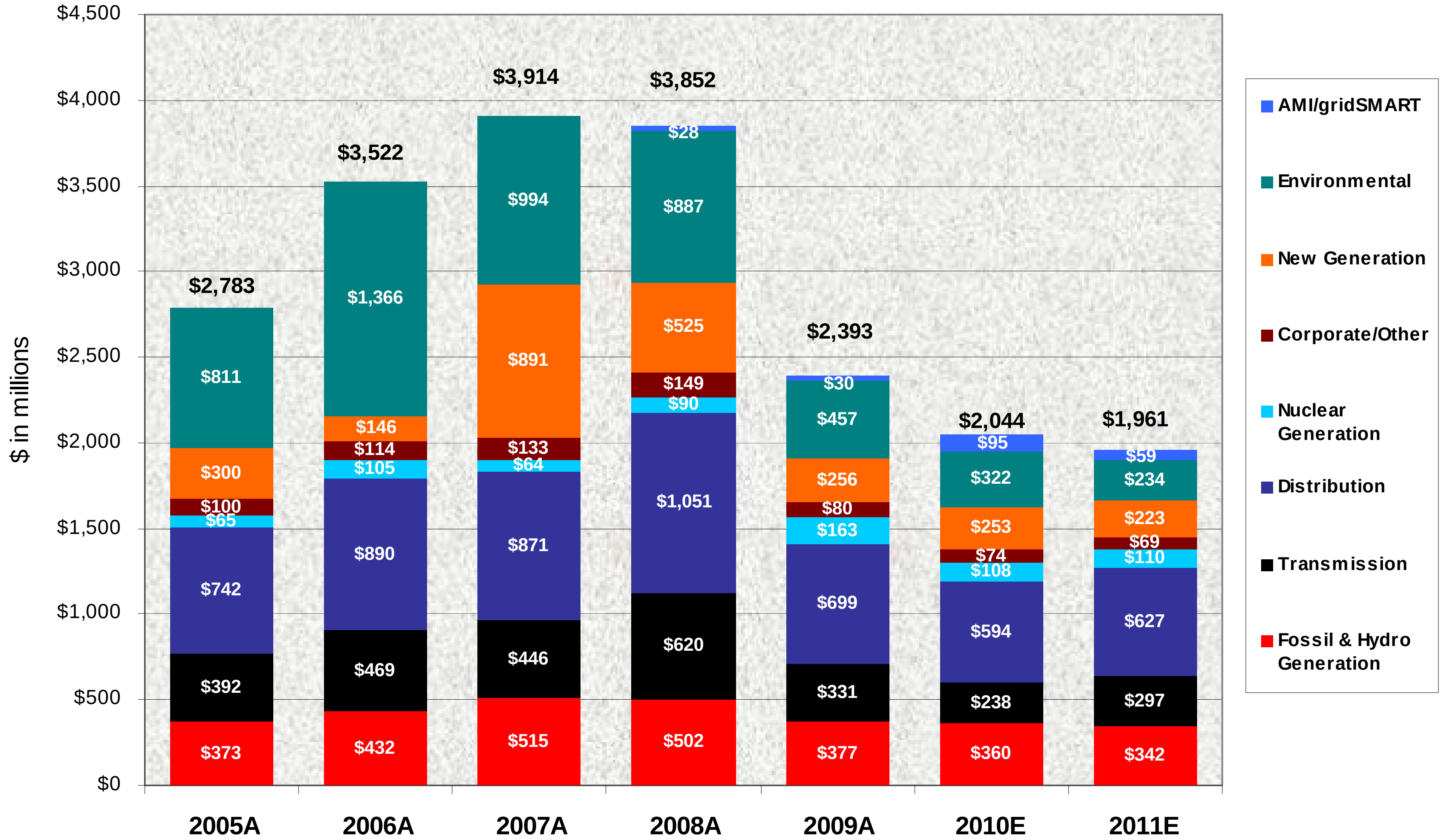
American Electric Power
2009 Actual vs. 2010 Guidance

2010E: $2.80-$3.20

		2009 Performance Driver	2009 Actual ($ millions)	2010 Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Retail Rate Performance

	Rate Relief (in millions) 4Q09 vs. 4Q08
East Regulated Integrated Utilities	$39
Ohio Companies	$125
West Regulated Integrated Utilities	$12
Texas Wires	$2
AEP System Total	$178
Impact on EPS	$0.28

	Rate Relief (in millions) YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	$241
Ohio Companies	$388
West Regulated Integrated Utilities	$83
Texas Wires	$13
AEP System Total	$725
Impact on EPS	$1.17

4Q09 Retail Performance

	Load Contraction (weather normalized) 4Q09 vs. 4Q08
East Regulated Integrated Utilities	-7%
Ohio Companies	-6%
West Regulated Integrated Utilities	-3%
Texas Wires	3%
Impact on EPS	**($0.11)**

	Weather Impact 4Q09 vs. 4Q08
East Regulated Integrated Utilities	($0.02)
Ohio Companies	($0.01)
West Regulated Integrated Utilities	($0.00)
Texas Wires	$0.00
Impact on EPS	**($0.03)**

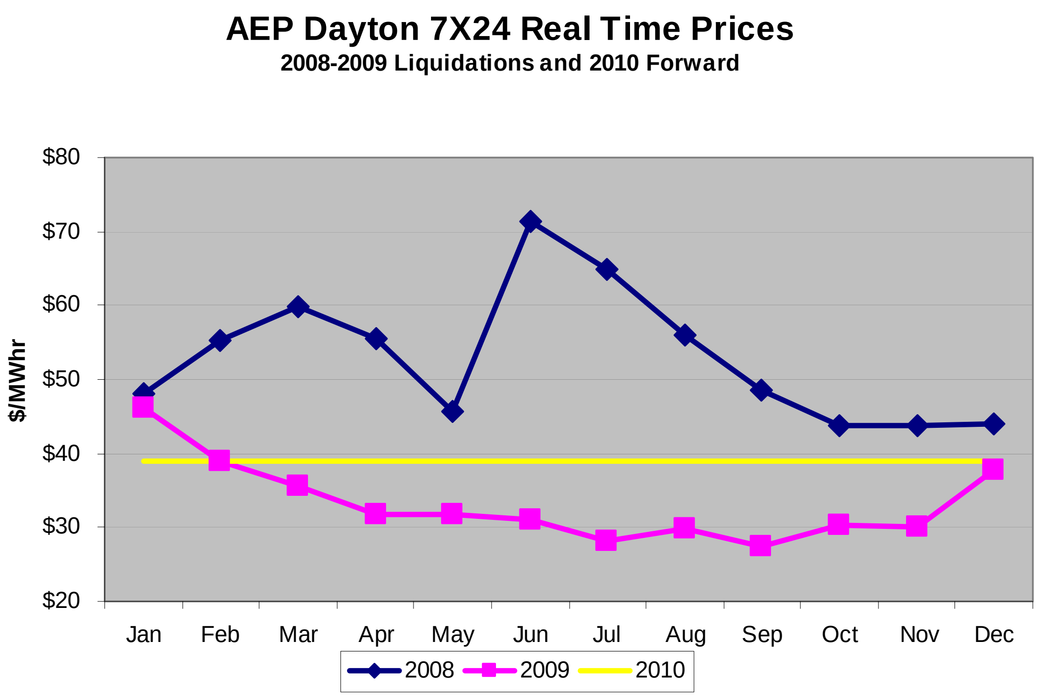
YTD Retail Performance

	Load Contraction (weather normalized) YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	-7%
Ohio Companies	-8%
West Regulated Integrated Utilities	-4%
Texas Wires	-1%
Impact on EPS	($0.34)

	Weather Impact YTD 2009 vs. YTD 2008
East Regulated Integrated Utilities	($0.04)
Ohio Companies	($0.06)
West Regulated Integrated Utilities	($0.02)
Texas Wires	$0.03
Impact on EPS	($0.08)*

*May not foot due to rounding

Off-System Sales



- 4Q09 AEP/Dayton Hub 7X24 prices (liquidations) were 25% below Q4 2008
- 4Q09 AEP Off system sales volumes were up approximately 8% over 4Q08
- The calendar year 2010 strip is currently above actual liquidations for 2009 but remain below 2008 liquidations by approximately 26%

2008 Liquidations vs. 2009 Liquidations*				
Hub	2008	2009	$ Change	% Change
AEP Dayton	53.04	33.23	(19.81)	-37%
PJM West	68.52	38.30	(30.22)	-44%
NiHub	48.99	28.86	(20.14)	-41%
CinHub	49.22	29.05	(20.17)	-41%
SPP	54.89	29.11	(25.77)	-47%
NG ($/mmBtu)	9.04	3.99	(5.05)	-56%

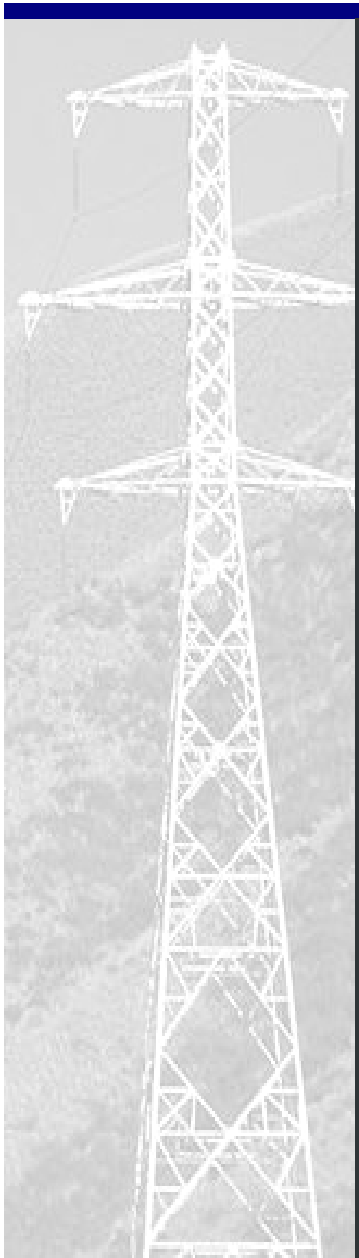
*($/MWh)

2009 Liquidation vs. 2010 Forwards*				
Hub	2009	2010 Fwd	$ Change	% Change
AEP Dayton	33.23	39.22	5.99	18%
PJM West	38.30	48.07	9.77	25%
NiHub	28.86	33.88	5.02	17%
CinHub	29.05	35.10	6.05	21%
SPP	29.11	35.60	6.49	22%
NG ($/mmBtu)	3.99	5.79	1.81	45%

Off System Sales Gross Margin Detail

	4Q08			4Q09		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	3,754	$ 10.39	$ 39	4,044	$ 5.44	$ 22
Oklaunion Margin	-		$ 12	-		$ 11
Marketing/Trading	-		$ 8	-		$ 35
Pre-Sharing Gross Margin	3,754		$ 59	4,044		$ 68

	YTD 2008			YTD 2009		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	29,365	$ 24.45	$ 718	14,795	$ 7.71	$ 114
Oklaunion Margin	-		$ 45	-		$ 47
Marketing/Trading	-		$ 82	-		$ 176
Pre-Sharing Gross Margin	29,365		$ 845	14,795		$ 337



4Q08 Earnings Release Presentation

January 29, 2009

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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2008 Highlights

- **Earnings:**
  - **2008 GAAP Earnings $3.43 per share; ongoing $3.24 per share**
  - **4Q08 GAAP Earnings $0.38 per share; ongoing $0.59 per share**
- **Regulatory Updates – $527MM of rate relief secured in 2008**
  - **Virginia**
  - **Oklahoma**
- **Generation - Turk Plant**
- **Transmission – Joint Ventures**
- **Economic Environment**

2009 Outlook

- Transmission Initiatives
  - PATH
  - ETT/ETA
- Generation
  - Turk plant
  - DC Cook Plant update
- Ohio ESP filing Outcome
- 2009 Earnings guidance of $3.00-$3.40
  - Cash Flow, Capex, Financing

4Q08 Performance

American Electric Power
Financial Results for 4th Quarter 2008 Actual vs 4th Quarter 2007 Actual

		2007 Actual ($ millions)	2007 Actual EPS	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	562		657	
2	Ohio Companies	568		607	
3	West Regulated Integrated Utilities	230		237	
4	Texas Wires	133		127	
5	Off-System Sales	177		59	
6	Transmission Revenue - 3rd Party	71		82	
7	Other Operating Revenue	130		130	
8	Utility Gross Margin	1,871		1,899	
9	Operations & Maintenance	(957)		(933)	
10	Depreciation & Amortization	(361)		(351)	
11	Taxes Other than Income Taxes	(188)		(180)	
12	Interest Exp & Preferred Dividend	(191)		(219)	
13	Other Income & Deductions	31		33	
14	Income Taxes	(53)		(67)	
15	**Utility Operations On-Going Earnings**	152	0.38	182	0.45
	NON-UTILITY OPERATIONS:				
16	AEP River Operations	21	0.05	34	0.09
17	Generation & Marketing	20	0.05	22	0.05
18	**Parent & Other On-Going Earnings**	16	0.04	(1)	-
19	ON-GOING EARNINGS	209	0.52	237	0.59

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4Q08 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief of $114MM (Primarily APCo and Ohio RSPs)*
  - *Positive load growth and new customers of $20MM across the AEP system*
  - *Reduced off-system sales sharing of $47MM, partially offset by $39MM higher fuel costs in Ohio*
  - *Weather had no impact vs. prior year and a $0.01 ($5MM) favorable impact vs. normal*
- *Off-System Sales (line 5):*
  - Off System Sales margins were lower primarily due to reduced generation and higher fuel costs
- *Operations & Maintenance (line 9):*
  - *Lower expenditures in 2008 compared to costs related to PSO storm restoration recorded in 2007 of $68MM partially offset by miscellaneous other costs in G, T&D*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 26.9% in 2008 and 25.9% in 2007*
- *River Operations increased due to strong grain exports and freight rates*
- *Parent and Other decreased primarily due to prior year favorable tax adjustments*

4Q08 Earnings Release

YTD Performance

American Electric Power
Financial Results for YTD December 2008 Actual vs YTD December 2007 Actual

		2007 Actual ($ millions)	2007 Actual EPS	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	2,154		2,278	
2	Ohio Companies	2,410		2,431	
3	West Regulated Integrated Utilities	994		1,057	
4	Texas Wires	529		537	
5	Off-System Sales	890		845	
6	Transmission Revenue - 3rd Party	296		329	
7	Other Operating Revenue	544		569	
8	Utility Gross Margin	7,817		8,046	
9	Operations & Maintenance	(3,326)		(3,366)	
10	Depreciation & Amortization	(1,483)		(1,450)	
11	Taxes Other than Income Taxes	(748)		(749)	
12	Interest Exp & Preferred Dividend	(790)		(872)	
13	Other Income & Deductions	124		168	
14	Income Taxes	(508)		(567)	
15	**Utility Operations On-Going Earnings**	1,086	2.72	1,210	3.02
16	**Transmission Operations On-Going Earnings**	-	-	2	-
	NON-UTILITY OPERATIONS:				
17	AEP River Operations	61	0.15	55	0.14
18	Generation & Marketing	37	0.09	65	0.16
19	**Parent & Other On-Going Earnings**	15	0.04	(31)	(0.08)
20	ON-GOING EARNINGS	1,199	3.00	1,301	3.24

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

YTD Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief $358MM (Primarily APCo, Ohio RSPs, I&M, Texas & PSO)*
  - *Positive load growth including new customers; $74MM*
  - *Positive impact due to 2007 unfavorable true-up of VA order ($37MM)*
  - *Offset by $173MM higher fuel costs in Ohio, including consumables*
  - *Unfavorable weather impact of $65MM ($0.11) versus prior year and unfavorable $0.02 ($13MM) versus normal*
- *Off-System Sales (line 5):*
  - Off System Sales margins were lower primarily due to reduced margin on trading activity
- *Operations & Maintenance (line 9):*
  - *Increase primarily due to various costs in G, T&D offset by 2007 PSO ice storms*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Other Income & Deductions (line 13):*
  - *Higher due to increased interest income on FIT refund and carrying charges*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 31.9% in 2008 and 31.9% in 2007*
- *River Operations decreased due primarily to weather related issues including hurricanes and flooding and an oil spill in New Orleans harbor, which limited ship arrivals and departures*
- *Generation & Marketing increased due to higher gross margins from the marketing business and from the optimization of Oklaunion*
- *Parent and Other decreased due to higher interest expense and lower interest income*

Capitalization

Capital Structure	Actual 12/31/2007			Actual 12/31/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,993	-	14,994	15,983	-	15,983
Short-term Debt	660	-	660	1,976	-	1,976
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	10,079	10,079	-	10,693	10,693
Total Capitalization per Balance Sheet	**15,653**	**10,140**	**25,794**	**17,959**	**10,754**	**28,713**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***62.5%***	***37.5%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
Capital and Operating Leases	1,522	-	1,522	1,439	-	1,439
Securitization Bonds	(2,257)	-	(2,257)	(2,132)	-	(2,132)
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(264)	-	(264)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	-
Total Adjusted Capitalization	**14,640**	**10,139**	**24,779**	**16,845**	**10,912**	**27,756**
% of Adjusted Capitalization	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***

Adjusted debt-to-cap of 60.7% at 12/31/08

Questions

4Q08 Earnings Release

AEP®

4Q08 Earnings

	$ millions			Earnings Per Share		
	4th Qtr 2007	4th Qtr 2008	Change	4th Qtr 2007	4th Qtr 2008	Change
Utility Operations	152	182	30	0.38	0.45	0.07
Transmission Operations	0	0	0	0.00	0.00	0.00
Non-Utility Operations	41	56	15	0.10	0.14	0.04
Parent & Other	16	(1)	(17)	0.04	0.00	(0.04)
AEP On-Going Earnings	209	237	28	0.52	0.59	0.07
Special Items	22	(85)	(107)	0.06	(0.21)	(0.27)
Reported Earnings (GAAP)	231	152	(79)	0.58	0.38	(0.20)

Quarterly Performance Comparison

American Electric Power

Financial Results for 4th Quarter 2008 Actual vs 4th Quarter 2007 Actual

		2007 Actual			2008 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	17,801 GWh @ $ 31.6 /MWhr =	562		18,242 GWh @ $ 36.0 /MWhr =	657	
2	Ohio Companies	12,962 GWh @ $ 43.8 /MWhr =	568		12,547 GWh @ $ 48.4 /MWhr =	607	
3	West Regulated Integrated Utilities	9,610 GWh @ $ 23.9 /MWhr =	230		9,629 GWh @ $ 24.6 /MWhr =	237	
4	Texas Wires	6,385 GWh @ $ 20.8 /MWhr =	133		6,159 GWh @ $ 20.6 /MWhr =	127	
5	Off-System Sales	7,879 GWh @ $ 22.5 /MWhr =	177		3,675 GWh @ $ 16.0 /MWhr =	59	
6	Transmission Revenue - 3rd Party		71			82	
7	Other Operating Revenue		130			130	
8	Utility Gross Margin		1,871			1,899	
9	Operations & Maintenance		(957)			(933)	
10	Depreciation & Amortization		(361)			(351)	
11	Taxes Other than Income Taxes		(188)			(180)	
12	Interest Exp & Preferred Dividend		(191)			(219)	
13	Other Income & Deductions		31			33	
14	Income Taxes		(53)			(67)	
15	**Utility Operations On-Going Earnings**		152	0.38		182	0.45
16	**Transmission Operations On-Going Earnings**		-	-		-	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		21	0.05		34	0.09
18	Generation & Marketing		20	0.05		22	0.05
19	**Parent & Other On-Going Earnings**		16	0.04		(1)	-
20	ON-GOING EARNINGS		209	0.52		237	0.59

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

December YTD Earnings

	$ millions			Earnings Per Share		
	Dec YTD 2007	Dec YTD 2008	Change	Dec YTD 2007	Dec YTD 2008	Change
Utility Operations	1,086	1,210	124	2.72	3.02	0.30
Transmission Operations	0	2	2	0.00	0.00	0.00
Non-Utility Operations	98	120	22	0.24	0.30	0.06
Parent & Other	15	(31)	(46)	0.04	(0.08)	(0.12)
AEP On-Going Earnings	1,199	1,301	102	3.00	3.24	0.24
Special Items	(110)	79	189	(0.27)	0.19	0.46
Reported Earnings (GAAP)	1,089	1,380	291	2.73	3.43	0.70

December YTD Performance Comparison

American Electric Power
Financial Results for YTD December 2008 Actual vs YTD December 2007 Actual

		Performance Driver	2007 Actual ($ millions)	2007 Actual EPS	Performance Driver	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154		72,725 GWh @ $ 31.3 /MWhr =	2,278	
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410		52,181 GWh @ $ 46.6 /MWhr =	2,431	
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994		41,907 GWh @ $ 25.2 /MWhr =	1,057	
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529		27,075 GWh @ $ 19.8 /MWhr =	537	
5	Off-System Sales	30,876 GWh @ $ 28.8 /MWhr =	890		29,111 GWh @ $ 29.0 /MWhr =	845	
6	Transmission Revenue - 3rd Party		296			329	
7	Other Operating Revenue		544			569	
8	Utility Gross Margin		7,817			8,046	
9	Operations & Maintenance		(3,326)			(3,366)	
10	Depreciation & Amortization		(1,483)			(1,450)	
11	Taxes Other than Income Taxes		(748)			(749)	
12	Interest Exp & Preferred Dividend		(790)			(872)	
13	Other Income & Deductions		124			168	
14	Income Taxes		(508)			(567)	
15	**Utility Operations On-Going Earnings**		1,086	2.72		1,210	3.02
16	**Transmission Operations On-Going Earnings**		-	-		2	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		61	0.15		55	0.14
18	Generation & Marketing		37	0.09		65	0.16
19	**Parent & Other On-Going Earnings**		15	0.04		(31)	(0.08)
20	ON-GOING EARNINGS		1,199	3.00		1,301	3.24

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2008 Cash Flow

($ millions)	2007	2008
Operating Activities		
Net Income -- Reported	$ 1,089	$ 1,380
Discontinued Operations	(24)	(12)
Continuing Earnings	1,065	1,368
Depreciation, Amortization & Deferred Taxes	1,604	2,037
Extraordinary Loss, net of Taxes	79	-
Changes in Components of Working Capital	(124)	(207)
Other Assets & Liabilities	(236)	(622)
Cash Flows From Operating Activities	**2,388**	**2,576**
Investing Activities		
Capital Expenditures	(3,556)	(3,800)
Proceeds on Sale of Assets	222	90
Change in Other Temporary Cash Investments, net	(3)	39
Acquisition of Assets	(525)	(160)
Acquisition of Nuclear Fuel	(74)	(192)
Other Investing, net	15	(4)
Cash Flows Used for Investing Activities	**(3,921)**	**(4,027)**
Financing Activities		
Common Shares Issued, net	144	159
Long-term Debt Issuances, net	1,260	950
Short-term Debt Increase, net	642	1,316
Other Financing	(6)	(81)
Dividends Paid	(630)	(660)
Cash Flows From Financing Activities	**1,410**	**1,684**
Cash From Continuing Operations	**$ (123)**	**$ 233**
Beginning Cash & Cash Equivalent Balances	301	178
Ending Cash & Cash Equivalent Balances	$ 178	$ 411

2008 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by fuel (coal) stock increase
- Changes in other assets and liabilities largely driven by changes in mark-to-market and fuel recovery.

Investing Activities

- Cash outlay of $3.8B for 2008 YTD capital investment.
- 2008 asset sale proceeds relate to miscellaneous utility property sales; 2007 asset sale proceeds primarily relate to Centrica sharing and TCC's sale of its share of Oklaunion.
- Acquisition of assets related to purchases by River Operations.

Financing Activities

- 2008 common share issuances of $159MM primarily due to issuances through the dividend reinvestment program.
- Changes in long and short term debt driven by capital funding requirements.

AEP Liquidity

as of December 31, 2008

Liquidity Summary (unaudited)	Actual 12/31/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar. 2011
Revolving Credit Facility	1,454	Apr. 2012
Revolving Credit Facility	627	Apr. 2011
Revolving Credit Facility	338	Apr. 2009
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	411	
Less		
Draw on Credit Facilities	(1,969)	
Letters of Credit Issued	(436)	
Net Available Liquidity	**$1,925**	

Detailed Ongoing Earnings Guidance

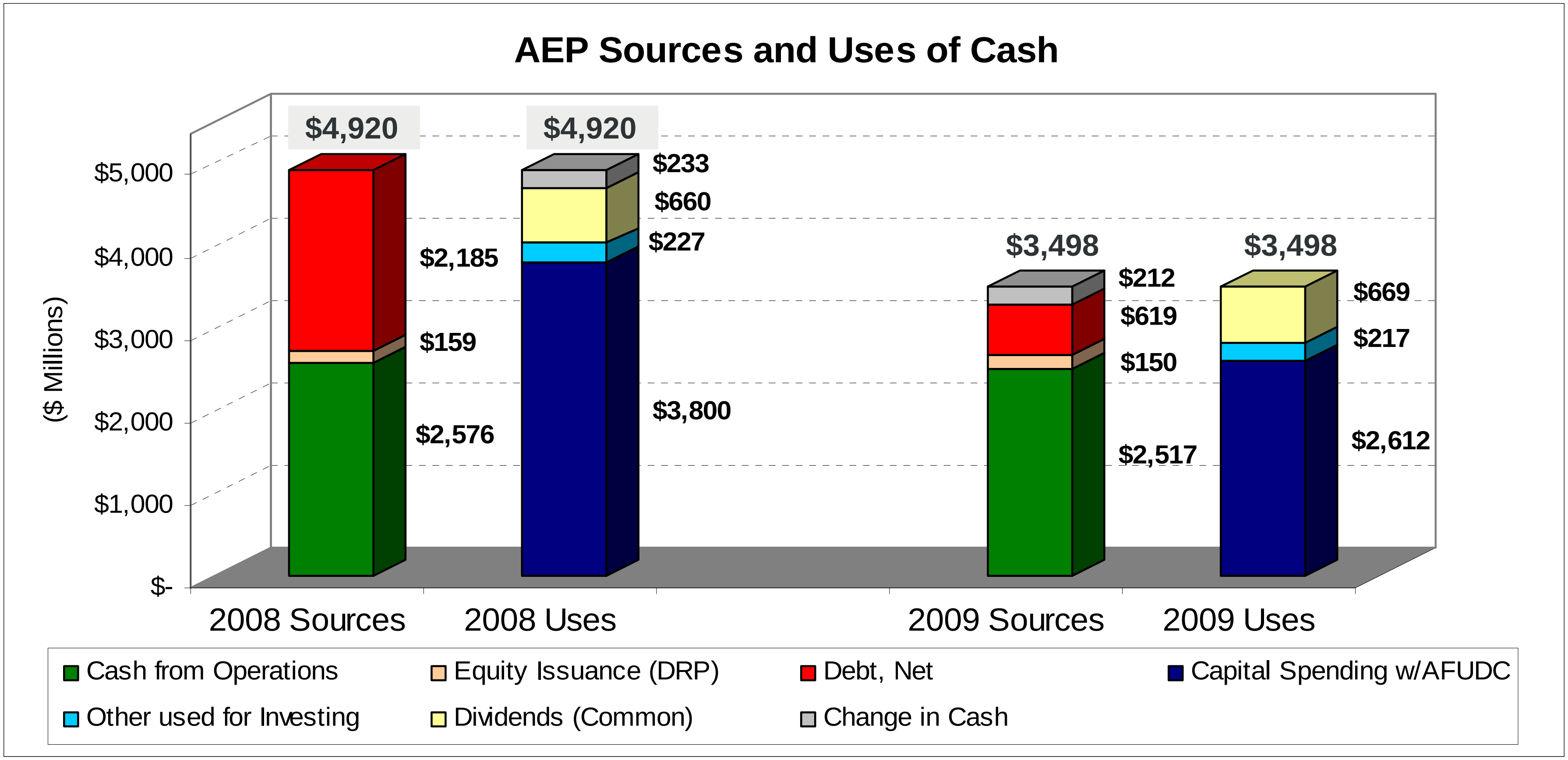
2008 Actual: $3.24

2009E: $3.00-$3.40

American Electric Power
2008 Actual vs 2009 Guidance

	2008 Actual ($ millions)	2009 Guidance ($ millions)
Utility Operations Gross Margin	8,046	8,433
Operations & Maintenance	(3,366)	(3,337)
Depreciation & Amortization	(1,450)	(1,546)
Taxes Other than Income Taxes	(749)	(790)
Interest Exp & Preferred Dividend	(872)	(929)
Other Income & Deductions	168	120
Income Taxes	(567)	(641)
Utility Operations	1,210	1,310
Transmission Operations	2	5
Non-Utility Operations	120	75
Parent & Other	(31)	(91)
ON-GOING EARNINGS	**1,301**	**1,299**

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

4Q08 Earnings Release

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4Q08 Retail Performance

	Load Growth (weather normalized)
	4Q08 vs. 4Q07
East Regulated Integrated Utilities	1.0%
Ohio Companies	0.0%
West Regulated Integrated Utilities	2.2%
Texas Wires	-0.5%
Impact on EPS	$0.03

	Weather Impact
	4Q08 vs. 4Q07
East Regulated Integrated Utilities	$0.01
Ohio Companies	$0.00
West Regulated Integrated Utilities	($0.01)
Texas Wires	($0.01)
Impact on EPS	$0.00*

*May not foot due to rounding

YTD Retail Performance

	Load Growth (weather normalized) YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	0.9%
Ohio Companies	2.8%
West Regulated Integrated Utilities	1.0%
Texas Wires	1.6%
Impact on EPS	$0.12

	Weather Impact YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	($0.04)
Ohio Companies	($0.04)
West Regulated Integrated Utilities	($0.02)
Texas Wires	$0.00
Impact on EPS	($0.11)

*May not foot due to rounding

Retail Performance

	Rate Relief (in millions)
	4Q08 vs. 4Q07
East Regulated Integrated Utilities	**$45**
Ohio Companies	**$58**
West Regulated Integrated Utilities	**$7**
Texas Wires	**$4**
AEP System Total	**$114**
Impact on EPS	**$0.18**

	Rate Relief (in millions)
	YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	**$102**
Ohio Companies	**$206**
West Regulated Integrated Utilities	**$29**
Texas Wires	**$21**
AEP System Total	**$358**
Impact on EPS	**$0.58**

AEP and Climate Change

Bruce H. Braine
Vice President, Strategic Policy Analysis

Sanford Bernstein-CERES Investor Seminar
September 20, 2006

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Key Questions

- **How does “climate” affect business strategy, capital investment, choice of generation?**
- **What does AEP assume re: A cost/price for CO2 in the future? What about allocations?**
- **Will there be credit for early reductions?**
- **Given dramatic increases in CO2 related to new coal plant development, what does AEP believe is the best way to address climate change and what role does the electric sector play?**
- **How should the investment community weigh economic impacts of climate change in valuations given long term time frame?**

AEP Climate and Business Strategy

- **AEP does not support mandatory U.S. GHG requirements unless they are part of a new international agreement that limits GHGs in the long term including developing countries such as China and India.**
- **AEP has had a GHG strategy for a number of years, acknowledging the issue, accepting the science and believing in early proactive action. Our strategy includes**:
  - **Proactive on GHG policy -**IETA, EPRI, Pew, e7, Business Roundtable, etc.
  - **Science/technology R&D-** Future Gen, Sequestration, EPRI, MIT, etc.
  - **Taking voluntary action now** (e.g. CCX, EPA Climate Leaders and SF-6 Program, Asia-Pacific Efficiency, DOE1605B, BRT Climate Resolve) -- **Demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - **Long-term planning (post-2010) to reduce or limit GHGs:**
    - IGCC and FutureGen
    - Retirement of less efficient capacity
    - Emission offsets (e.g., forestry, SF-6)
    - Renewables (e.g. biomass firing, wind PPAs)
- **Capital Allocation and New Generation—**
  - **Coal Builds – IGCC in East; Ultra Supercritical Coal in West**
  - **A Portfolio of New Generation Including Gas and Renewables**

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CCX Overview

- An unprecedented voluntary greenhouse gas emission reduction and trading pilot program administered by 100+ companies and organizations
- Total member emissions= About 240 MM metric tons CO2 equivalent (~ 4% US CO_2 emissions)
- Member commitment to reduce GHG emissions below a “baseline” (average 1998-2001 levels):
    - **1% in 2003**
    - **2% in 2004**
    - **3% in 2005**
    - **4% in 2006**
    - **4.25% in 2007***
    - **4.5% in 2008***
    - **5% in 2009***
    - **6% in 2010***

*Extension Period

AEP Info:
- Current Baseline = 155 MM metric tons (adjusted for divestitures)
- Reduction or offset of about 46 MM metric tons of CO2 during 2003-10
- AEP one of 14 founding members
- AEP first company to commit to extension period

Price of CO2?

- **Fed. law unlikely through 2008. In 2009 and after, prospects for legislation will likely increase, depending on the next President.**
- **Price of CO2--**
  - **If legislation passes -- likely a "cap and trade" program (at a minimum including industrial and electric sectors, like the EU). Thus, CO2 will have a price.**
  - **Today -- price of CO2 in the US voluntary (e.g CCX) markets reflecting a "market" view that future legislation is probable.**
  - **AEP investments (such as IGCC) -- evaluated using a range of values (as shown in the August 31, 2004 Board Report titled "An Assessment of AEP's Actions to Mitigate the Economic Impacts of Emissions Policies", available on AEP.com).**
    - **More recently, we have included Bingaman bill's safety valve prices ($7 per ton CO2 increasing by 5% per year) as a moderate price path assumption.**

Allocation/Auctions and Early Action Credit?

- **Allocation/Auction**
  - Support for large auctions often reflects the incorrect economic assumption that the industry is fully deregulated and co. auction credit purchases are recovered in “market” prices.
  - In fact, about 80% of US coal-fired generation is price regulated today. **Auctions in price-regulated states will increase electricity rates, probably very substantially. (e.g. even a 10% auction will more than double the costs/electricity rate impacts of a 10% reduction program).**
  - **Given this, will major auctions survive politically in any ultimate federal legislation?**
- **Early Action Credits**
  - Some early action credit is probable (in most current legislative proposals), though 100% credit is very unlikely.
  - Probability of credits will increase if they are verified/audited, etc. **(One reason AEP is in CCX and EPA Climate Leaders).**

Best Way to Address Climate Change?

AEP has a GHG strategy, which includes:

1. Taking voluntary proactive action in the short and intermediate term (e.g. Chicago Climate Exchange commitment is from 2003-2010);

2. Being engaged in the development of climate policy so that it is as cost-effective as possible;

3. Evaluating longer term investment decisions such as new generation (e.g. IGCC) in light of the climate issue and the possibility of future mandatory legislation;

4. **Investing in R&D for the technologies which may ultimately substantially reduce CO2 emissions (e.g FutureGen, carbon sequestration).**

How should investment community weigh climate change in valuation?

- Though long-term in nature (even if legislation passes in 2010, it is unlikely to result in impacts prior to 2015), the cost implications and stakes of climate change legislation could be large.
- Companies that have a strategy that considers climate change now in their investment decisions and are taking voluntary actions to reduce their CO2 footprints should be a better value for investors than companies that do not.

AEP AMERICAN ELECTRIC POWER®

Credit Suisse Alternative Energy Conference
Washington, DC
June 2, 2010

AEP®

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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Susan Tomasky

President – AEP Transmission

Building a National Interstate Electric Transmission Company

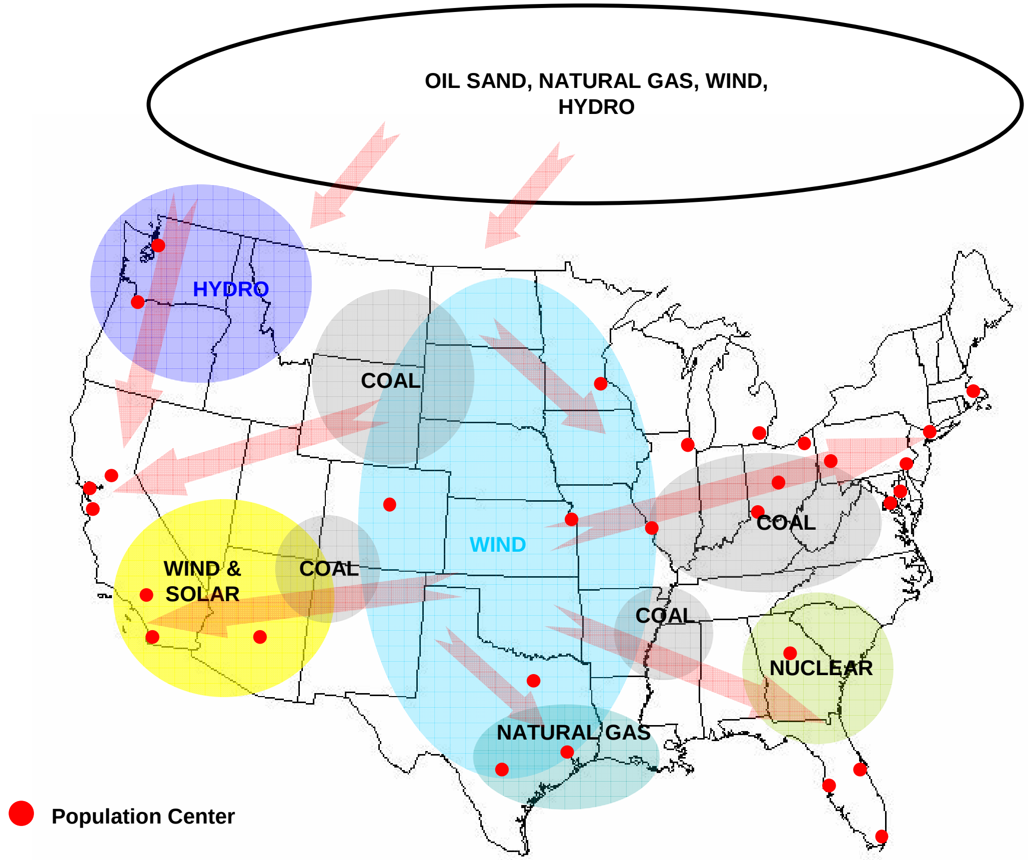
Our Goal: Contribute sustainable shareholder growth by leveraging AEP's position as the nation's leading transmission provider to become the nation's leading developer and owner of interstate transmission investment.

- AEP is recognized as the industry leader in transmission.
  - Recognized technology leader
  - Leader in industry circles - NERC, RTOs, industry groups
  - Recognized as a policy leader
- AEP's asset base provides a strong starting point for new transmission investment within our footprint.
  - 8,139 miles of EHV transmission, including 2,116 miles of 765-kV
  - Operate in three different RTOs in 11 states
  - Existing system requires substantial re-investment
- AEP assets and leadership will open opportunities for significant new regional investments, beyond our traditional retail service territory boundaries.

By leveraging existing assets, expertise and leadership, AEP will grow shareholder value by creating a significant new transmission investment opportunity.

Vision of the Nation's Transmission System

- ❑ A national interstate EHV transmission grid contributes to sustainable energy development:
  - A more sustainable long term national electricity supply portfolio, including tapping extraordinary renewable energy potential.
  - Broader impact of demand-side options and load leveling, lowering the need for new generation.
  - Strengthened national security by enhancing reliability, removing barriers to supply options and enhancing fuel diversity.
  - An alternative path to emission and CO_2 reductions.
- ❑ Economic growth remains closely tied to energy and climate related initiatives, requiring policies which understand these interdependencies.



"Many of our resources, whether it's wind or sun or geothermal, they're out in rural areas…and we just don't have any infrastructure. If we're going to take this whole energy piece on the renewable side seriously … we've got to get the transmission and infrastructure piece right" *Former Utah Gov. Jon Huntsman - AP Western Governors, Utility Heads Seeks Energy Solutions July 1, 2008*

Improved Federal and Regional Policies are Critical to Growing AEP’s Investment Opportunities

- To advance our transmission business strategy, AEP has taken a leadership position in national and regional public policy debates.
- Emerging policies must support and encourage development of new transmission investment to meet our nation’s future energy needs.
- AEP’s goal is to remove barriers to timely transmission investment through improved and clear rules to encourage transmission investment.
- We are vigorously pursuing comprehensive Federal legislation to create federal siting authority, broad cost allocation, and expedited planning.
- Within the current regional framework we are seeking to expedite planning for EHV systems and establish broad cost allocation principles within and across RTOs.
- We continue to strongly support Federal incentives for capital investment in transmission infrastructure.

> “We need a true nationwide transmission version of our interstate highway system; a grid of extra-high voltage backbone transmission lines reaching out to remote resources and overlaying, reinforcing, and tying together the existing grid in each interconnection to an extent never before seen.” *Suedeen Kelly- Former FERC Commissioner*

AEP is Actively Involved in Transmission Related Energy Policy

- Continued state, federal and regional outreach relative to siting, project approval, and cost allocation
  - Help to shape Obama administration energy initiatives to eliminate barriers to transmission investment.
  - Playing a proactive role during development of any future energy legislation (specifically Federal energy bill) to incorporate the needs of transmission development.
  - Aggressively support comprehensive Federal siting legislation.
- Actively participated in RTO proceedings to advocate EHV development, address cost allocation and improve planning.
  - Successful lobby for the SPP Highway/Byway cost allocation methodology that is waiting for FERC's approval.
  - Participating in the MISO changes to cost allocation methodology for projects specific to integrating renewable energy. Cost allocation is expected to be file with FERC by July 15th. Decisions on cost allocation and determining "what lines" get built will be made over the next 12-18months.
  - Working with other PJM TO's on modification to PJM's "bright line" planning process to ensure sufficient focus on western PJM needs. New scenario based planning approach expected to be implemented for the 2010 RTEP process.
  - Working with FERC and PJM to address the significant increase in the activity and interest from independent transmission developers.

Investment Strategy

Provide a pipeline of investment opportunities that will contribute to sustainable earnings growth for AEP shareholders, regardless of the ultimate policy direction at the Federal and regional levels

- AEP is taking a diversified approach to transmission investment, both jurisdictionally and technologically:

  <u>Jurisdictionally</u>

  - **Federal:** Continue pursuit of development of EHV interstate grid.
  - **PJM/East:** Enhance reliability, relieve congestion and enable ultimate access to renewables.
  - **SPP/West & MISO:** Enhance reliability and enable significant nearer-term renewable development.
  - **ERCOT:** Continued development of CREZ transmission build-out.

  <u>Technologically</u>

  - Aggressively seek opportunities to deploy alternative transmission technologies, including 765-kV and HVDC.

- While we will continue to pursue regionally and federally specific strategies to enhance nearer-term investment opportunities, significant on-system investment ($300-600 million potentially up to $1 billion annually) will serve as the anchor to sustainable transmission earnings growth.

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

The Business Potential

- AEP Planned Investments:
  - Capital investment with AEP's service territory will be significant, with approximately $300 to $600 million annually from 2010 – 2014, with the possibility of additional AEP Transco projects up to $450 million.
  - In the Eastern US, AEP is actively pursing development of over 500 miles of 765 kV transmission in PJM and eastern MISO (with 275 miles approved with PATH), at total cost before ownership division of approximately $2.8 billion.
  - In the Southwest so far in 2010, AEP and its joint-venture partners have gained approval of 280 miles of new transmission in SPP (at 345 kV and potentially 765 kV), at a total cost around $515 million.
  - In Texas, AEP continues to pursue EHV transmission expansion throughout the state, with a potential capital spend in excess of $2.5 billion before ownership division.
  - In the Upper Midwest, AEP has a taken a leadership role with the SMARTransmission study, evaluating nearly 8,000 circuit miles of potential 765 kV, 345 kV, and HVDC transmission development in PJM and MISO, at a total cost of over $20 billion.
- Challenges: Making it Happen
  - Capital Requirements – Infrastructure development through JV's requires committed capital to secure timely project development.
  - Regulatory challenges – Federal policies should favor spreading the costs broadly across customers on a regional basis; provide incentives for transmission development and investment and address challenges associated with siting EHV projects.
  - Managing a development business – Pursue standardized deal structures to permit more efficient portfolio management and capital discipline. Pursue alliances to reduce risks associated with commodities and the provision of direct services. Prove to capital markets that the regulatory model provides revenue certainty.

EHV Transmission investments can assist in ensuring a reliable, adequate and affordable energy supply for the nation.

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — COD: 2013-14

- 110 miles of 765 kV
- Partners: Westar (50%) & Electric Transmission America (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14

- 170 miles of 765 kV
- Partners: OG&E (50%) & Electric Transmission America (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

ETT — COD: 2010-2017

- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

PJM

PATH-WV — COD: 2014

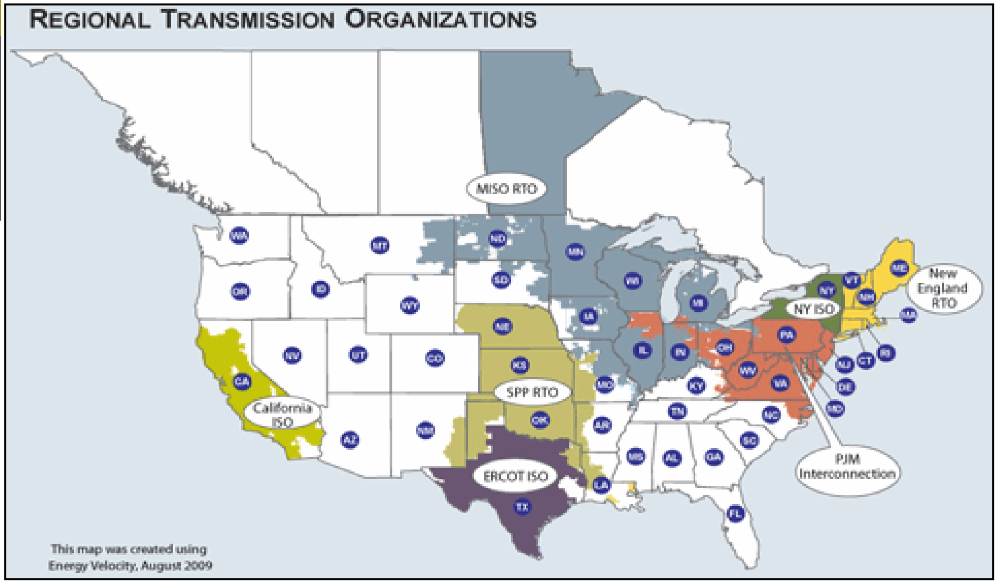
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015

- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

ACTIVE PROJECTS



FUTURE DEVELOPMENT

SMARTransmission Study

- Interregional EHV & Wind Integration Study
- Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay

- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various

- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM

PJM Expansion

- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio

- 700 miles of Proposed 765 kV

Appendix

Transmission Joint Venture Execution

AEP Transmission has made significant strides towards our goal of becoming the nation's leading developer and owner of interstate transmission investments; Major milestones include:

PATH	-FERC approval including cash return on CWIP, 14.3% incentive ROE, and abandonment recovery -Approved by PJM in 2007; CPCN processes on-going dependent upon 2010 PJM RTEP. -Critical siting and right-of-way activities and NEPA permitting process ongoing.
Prairie Wind	-FERC approval including cash return on CWIP, 12.8% incentive ROE, and abandonment recovery -Obtained CCN in Kansas -Successfully promoted regional cost allocation in SPP (filing currently pending FERC approval) -Gained SPP approval (voltage decisions pending)
Tallgrass	-FERC approval including cash return on CWIP, 12.8% incentive ROE, and abandonment recovery -Successfully promoted regional cost allocation in SPP (filing currently pending FERC approval) -Gained SPP approval (voltage decisions pending)
Pioneer	-FERC order received March 2009, including cash return on CWIP, 12.54% incentive ROE, and abandonment recovery -Joint cost allocation discussions with PJM and MISO continuing -Project included in MISO, PJM, and SMARTransmission studies
SMARTransmission	-Initiated a joint-study (including sponsors ETA, MidAmerican Energy, Xcel Energy, Exelon, ATC, Northwestern Energy) to perform a comprehensive evaluation of the transmission needed in the Upper Midwest to support renewable energy development and to transport that energy to consumers -Completed technical study recommending around 8,000 miles of EHV transmission at a cost of over 20 billion. A subsequent economic study is underway, with results to be submitted to PJM and MISO
Other	-Discussions underway with several potential partners in PJM, MISO, SPP, WECC, and elsewhere

Electric Transmission Texas, LLC

Overview:

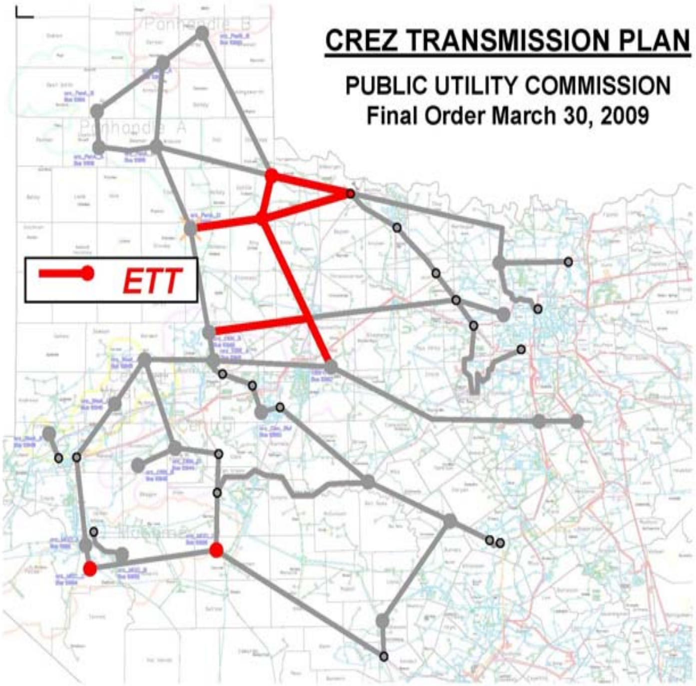
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

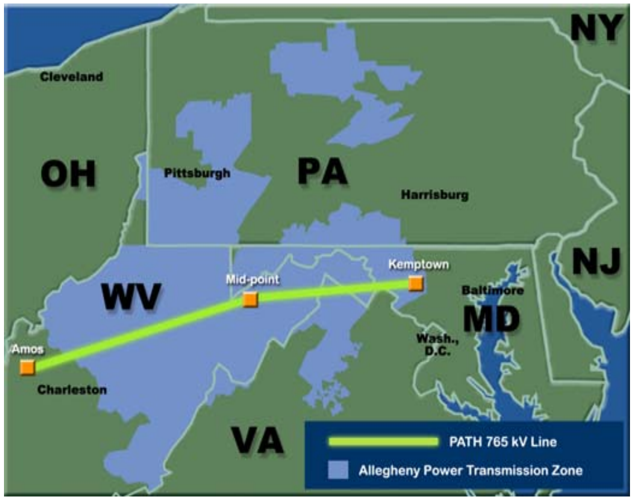
ETT
Electric Transmission Texas

EHV Transmission in PJM: PATH

<u>Project Description</u>: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

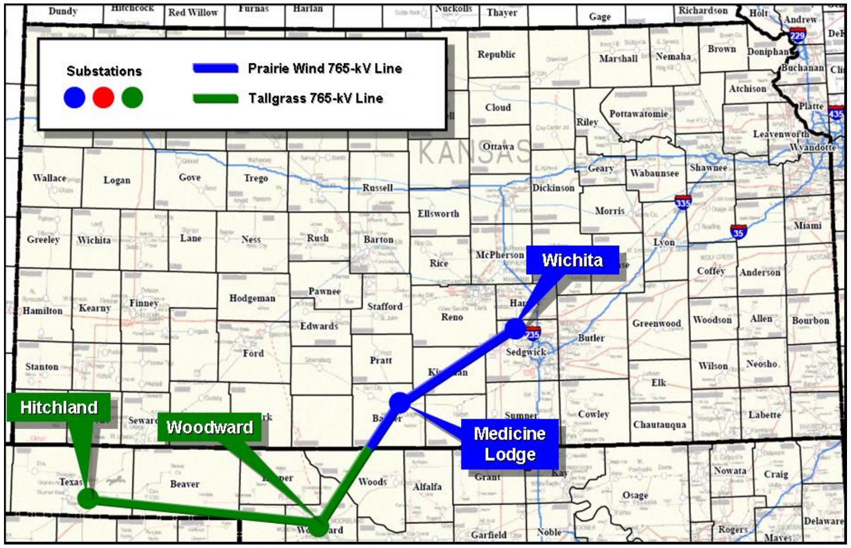
Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP’s ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

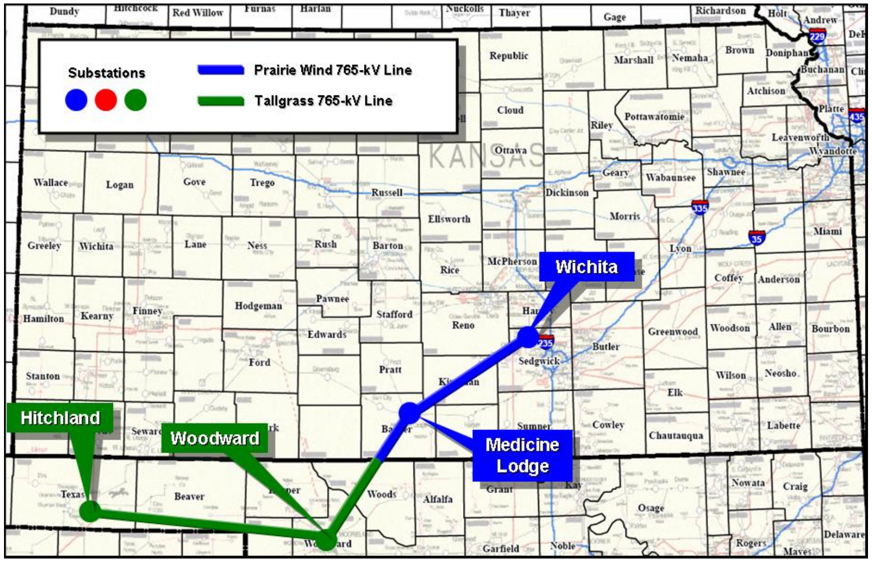
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

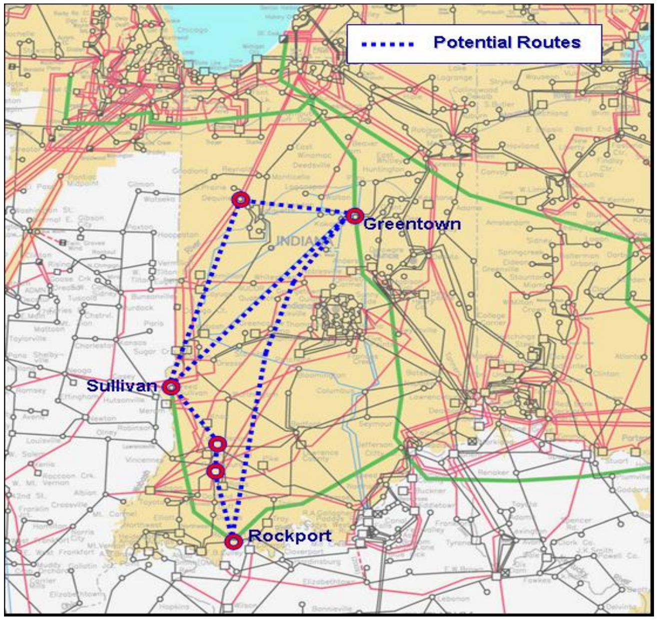
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

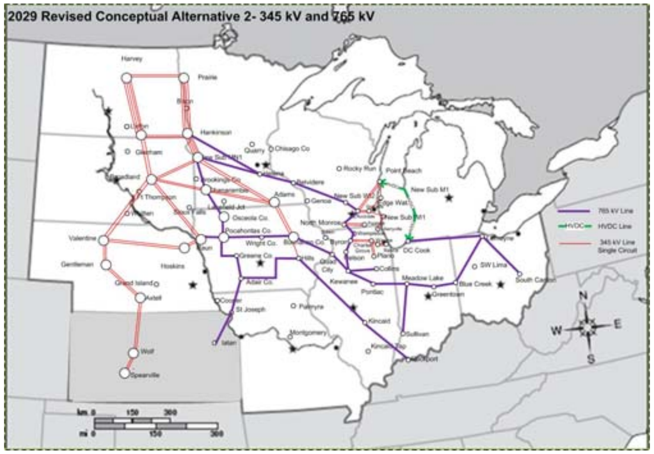
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

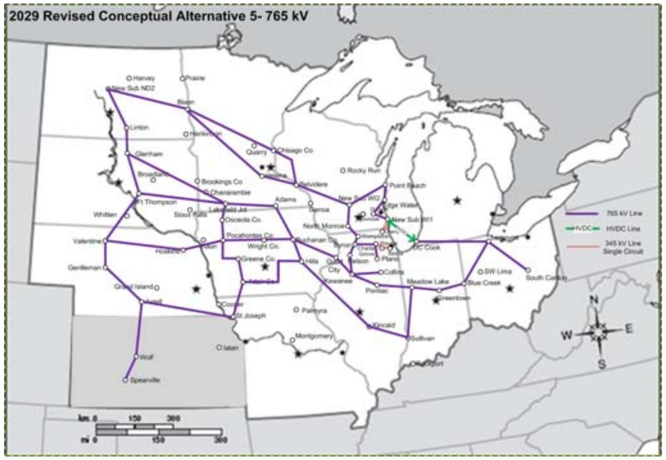
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives





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Environmental Compliance and Impacts

June 9, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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AEP's environmental stewardship

AEP is an environmentally responsible company.

It supports regulations that achieve long-term environmental benefits while considering the impacts on customers, the economy and system reliability.

Environmental regulation must be approached in a coordinated, realistic and cost-effective manner.

AEP does, and will continue to, comply with all environmental regulations.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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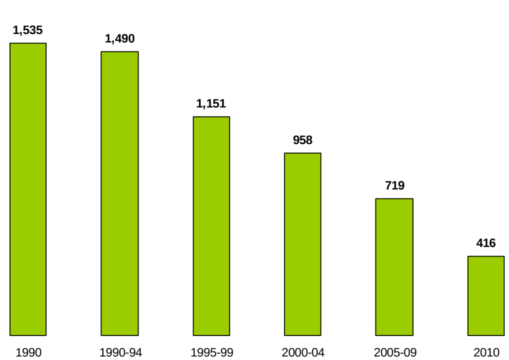
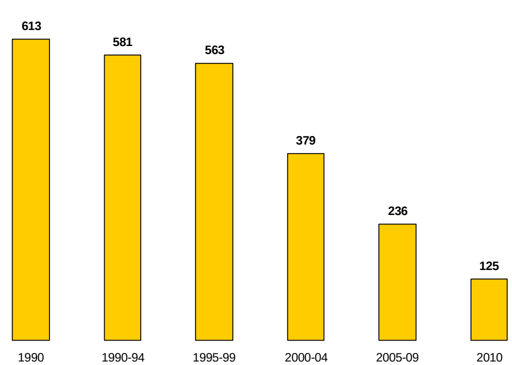
Ongoing air quality improvements

- AEP has improved its environmental performance.
  - Since 1990, AEP has reduced its NOx emissions by 80% and its SO_2 emissions by 73%.
  - AEP has invested more than $7 billion since 1990 to reduce emissions from its coal-fueled generation fleet .
- AEP will continue to improve the environmental performance of its power plants.

TOTAL SYSTEM - AVERAGE ANNUAL SO_2 EMISSIONS (in thousand US tons)



TOTAL SYSTEM - AVERAGE ANNUAL NOx EMISSIONS (in thousand US tons)



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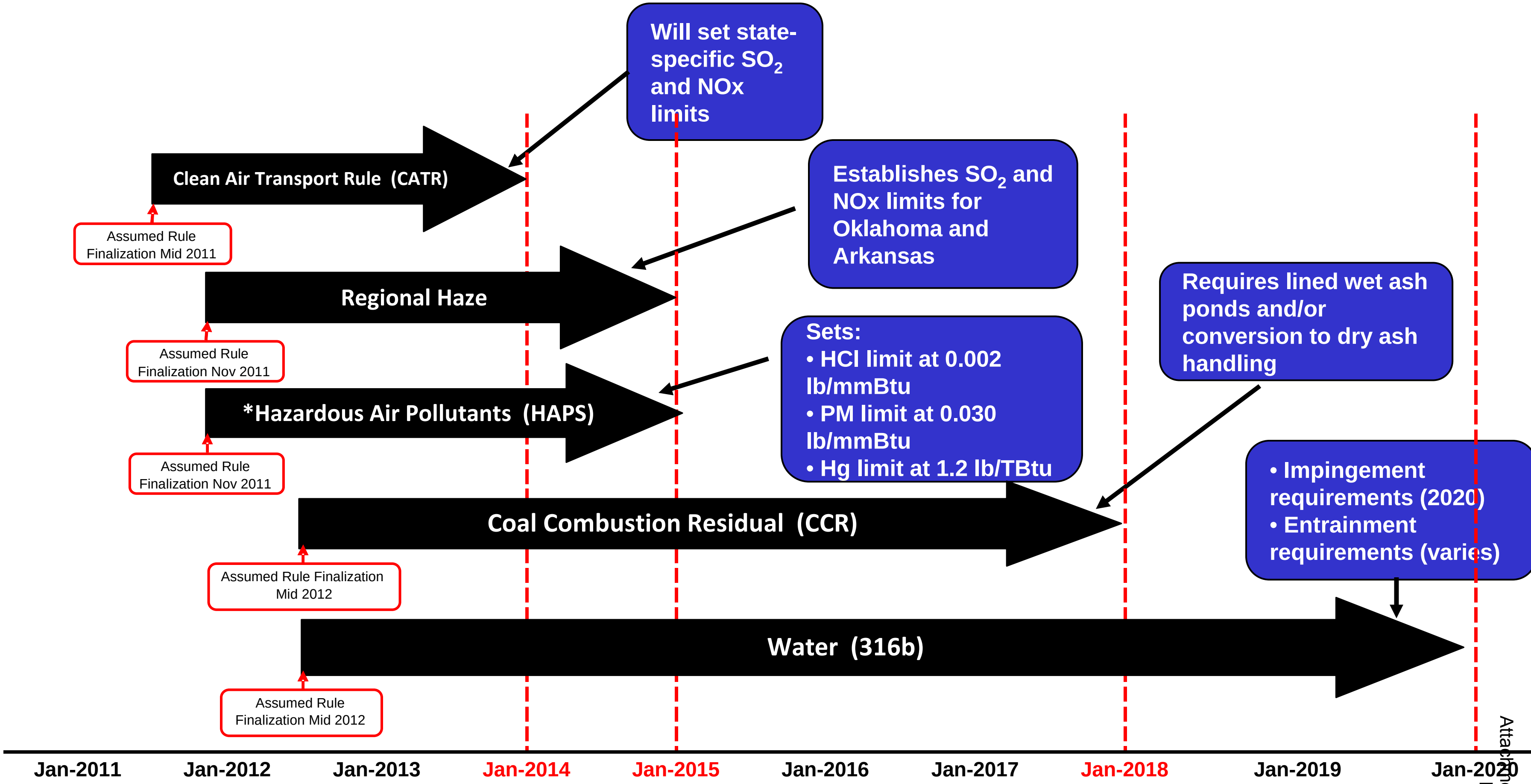
Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

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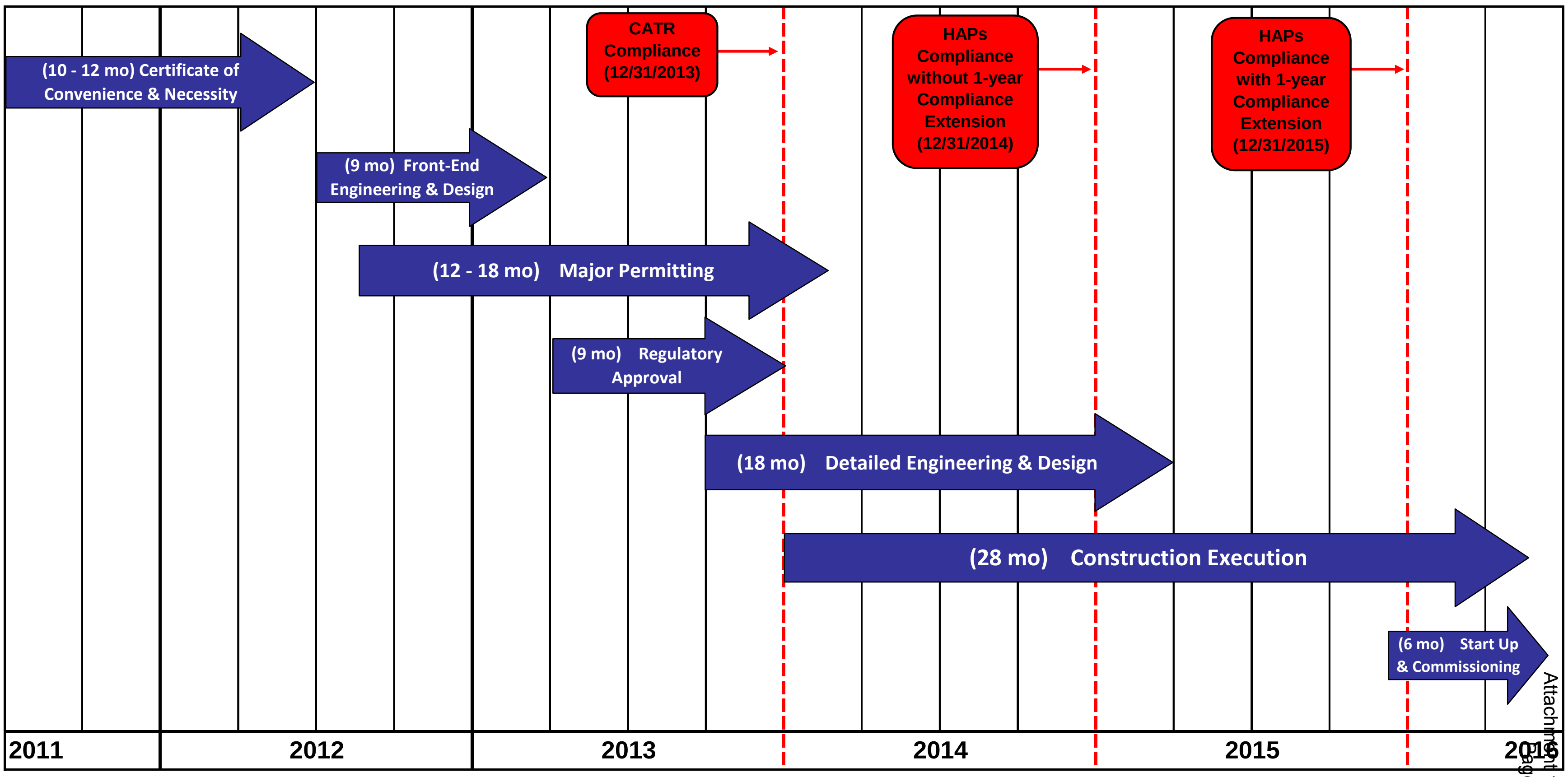
Compliance with time frames is not feasible

Typical FGD system construction timeline.



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Reliability concerns

- Capacity reductions caused by retirements, idled units and curtailments will create grid reliability concerns.
- Generating units provide ancillary services that support grid reliability.
  - These ancillary services -- voltage and reactive load support, frequency response, load following ability, system restoration and black start – will be lost with unit retirements and curtailments.
  - It is not clear how and when these services will be replaced.
- We are meeting with regional reliability organizations to make sure these concerns are being addressed.
- With longer time frames, AEP and the industry can address these concerns.

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A base plan scenario

- The following slides outline what AEP currently expects it will need to do to comply *if all proposed environmental regulations are enacted without change.*
- The scenario is AEP's best estimate at this point in time.
- **This scenario will change.**

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Overall impacts for AEP

To meet compliance deadlines for new environmental regulations, AEP expects it will need to invest $6 billion to $8 billion to:

- Retire more nearly 6,000 MW of existing coal-fired generation Refuel, retrofit with new or upgrade existing environmental controls on another 11,000 MW.
- Build approximately 1,220 MW of new generation.

This will create:

- Abrupt rate increases ranging from 10% to 35%.
- Significant reliability concerns, particularly in the 2014 – 2016 time frame.
- The need to install additional equipment to address impacts on the transmission system due to the reduction in generating capacity.
- Other locally significant economic impacts.

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Overall impacts to employees and communities

- Nearly 750 employees could be displaced through premature unit retirements, while an estimated 170 permanent new jobs could be created by retrofit technologies. **Net impact could be approximately 600 fewer jobs with annual lost wages of approximately $40 million.**
- There will be indirect job losses affecting local vendors, contractors and service providers, as every MW of coal-fueled generation supports an average of three additional indirect jobs.
- In 2015
  - Payroll taxes could decline more than $20 million.
  - Property tax payments could decline approximately $12 million.

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Environmental control technologies

- **FGD** – flue gas desulfurization system (scrubber) – reduces sulfur dioxide emissions
- **SCR** – selective catalytic reduction system – reduces nitrogen oxide emissions
- **ACI** – activated carbon injection – reduces mercury emissions
- **DSI** – dry sorbent injection – neutralizes acid gases
- **Baghouse** – also fabric filter – physically traps and filters particulate matter

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AEP Ohio

Retirements			
Unit(s)	**MW**	**Jobs**	**Date**
Conesville 3	165	20	Dec. 31, 2012
Kammer 1 – 3*	630	60	Dec. 31, 2014
Muskingum River 1 - 4	840	128	Dec. 31, 2014
Picway	100	9	Dec. 31, 2014
Sporn 2, 4*	300	60	Dec. 31, 2014
Sporn 5*	450		Requested
Total	*2,035*	*277*	

^Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharge as proposed
*Units are located in West Virginia

Retrofit-Refuel-Upgrade^		
Units	**Type**	**Notes**
Conesville 5, 6	SCR, DSI	
Gavin 1, 2	FGD upgrade	Curtailment
Muskingum River 5	Refuel to natural gas	Capacity reduced
Zimmer	FGD upgrade	

Other Impacts	
Customer rates	10% - 15%
Lost taxes Payroll (2010) Property (2009 actual)	$9.1 million in Ohio $4.7 million $4.3 million
Lost wages	$10.4 million

Appalachian Power

Retirements			
Unit(s)	**MW**	**Jobs**	**Date**
Clinch River 3	235	43	Dec. 31, 2014
Glen Lyn 5, 6	335	44	Dec. 31, 2014
Kanawha River 1, 2	400	62	Dec. 31, 2014
Sporn 1, 3	300	60	Dec. 31, 2014
Total	*1,270*	*209*	

Premature retirement of AEP Ohio-owned units at Sporn and Kammer plants will have economic impacts in West Virginia.

Retrofit-Refuel-Upgrade		
Unit(s)	**Type**	**Notes**
Clinch River 1, 2	Refuel with natural gas	Capacity reduced

Other Impacts	
Customer rates Virginia West Virginia	 10% - 15% 10% - 15%
Lost taxes Virginia West Virginia	$15.75 million $ 2.9 million $12.89 million
Lost wages Virginia West Virginia	$23.0 million $ 6.1 million $16.9 million

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Indiana Michigan

Retirements			
Unit(s)	**MW**	**Jobs**	**Date**
Tanners Creek 1 - 3	495	-65	Dec. 31, 2014

Retrofit-Refuel-Upgrade		
Unit(s)	**Type**	**Jobs**
Rockport 1	FGD, SCR	+40
Rockport 2	FGD, SCR	+40
Tanners Creek 4	DSI and ACI	

Other Impacts	
Customer rates Indiana Michigan	 25% - 30% 25% - 30%
Taxes (Indiana) Payroll (2010) Property (2009)	($1.0 million) $129,000 ($1.2 million)
Wages (Indiana)	+$1.0 million

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Kentucky Power

Retirements			
Unit(s)	**MW**	**Jobs**	**Date**
Big Sandy 2	800	86	Dec. 31, 2014
Big Sandy 1	278		Dec. 31, 2014
Total	*1,078*		

*A portion of KPC rate impact is from the company's allocation from Rockport.

New Generation		
Unit(s)	**MW**	**Date**
Big Sandy 1	Repower as 640 MW natural gas	Dec. 31, 2015

Other Impacts	
Customer rates	30% - 35%*
Lost taxes Property (2009) Payroll (2010)	$3.7 million $461,000 $3.2 million
Lost wages	$6.0 million

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Public Service Oklahoma

Retrofit-Refuel-Upgrade			
Unit(s)	**Type**	**Notes**	**Jobs**
Northeastern 3, 4	FGD, ACI, Baghouse	Units will be idled 1/1/16 until retrofits are complete	+60
Oklaunion	FGD upgrade, ACI		

Other Impacts	
Customer rates	10% - 15%

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SWEPCO

Retirements			
Unit	**MW**	**Jobs**	**Date**
Welsh 2	528	-44	Dec. 31, 2014

Other Impacts	
Customer rates Arkansas Louisiana Texas	 19% - 23% 16% - 20% 18% - 22%
Lost taxes Payroll (2010) Property (2009)	$1.5 million/year $89,000 $1.4 million
Lost wages	$980,000

Retrofit-Refuel-Upgrade		
Unit(s)	**Type**	**Jobs**
Dolet Hills*	ACI, Baghouse	
Flint Creek	FGD, ACI, Baghouse	+30
Pirkey	ACI, Baghouse	
Welsh 1, 3	ACI, DSI, Baghouse	

*AEP owned MW only

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A better option

AEP supports appropriate environmental regulation or legislation that establish a more coordinated, realistic and cost-effective compliance program.

Regulations must provide appropriate flexibility to achieve the desired emission reductions while managing customer costs.

A thoughtful phased-in approach will achieve similar environmental benefits with significantly less economic and reliability impact.

AEP AMERICAN ELECTRIC POWER

Benefits of a phased-in approach

- Will provide the time utilities need to install environmental retrofits without idling or curtailing generating units.
- Will allow unit retirements to occur over a more reasonable timeframe needed to address grid reliability issues.
- Will support construction jobs over a longer period of time.
- Will provide long-term environmental benefits.
- Will give local communities time to plan for economic losses.

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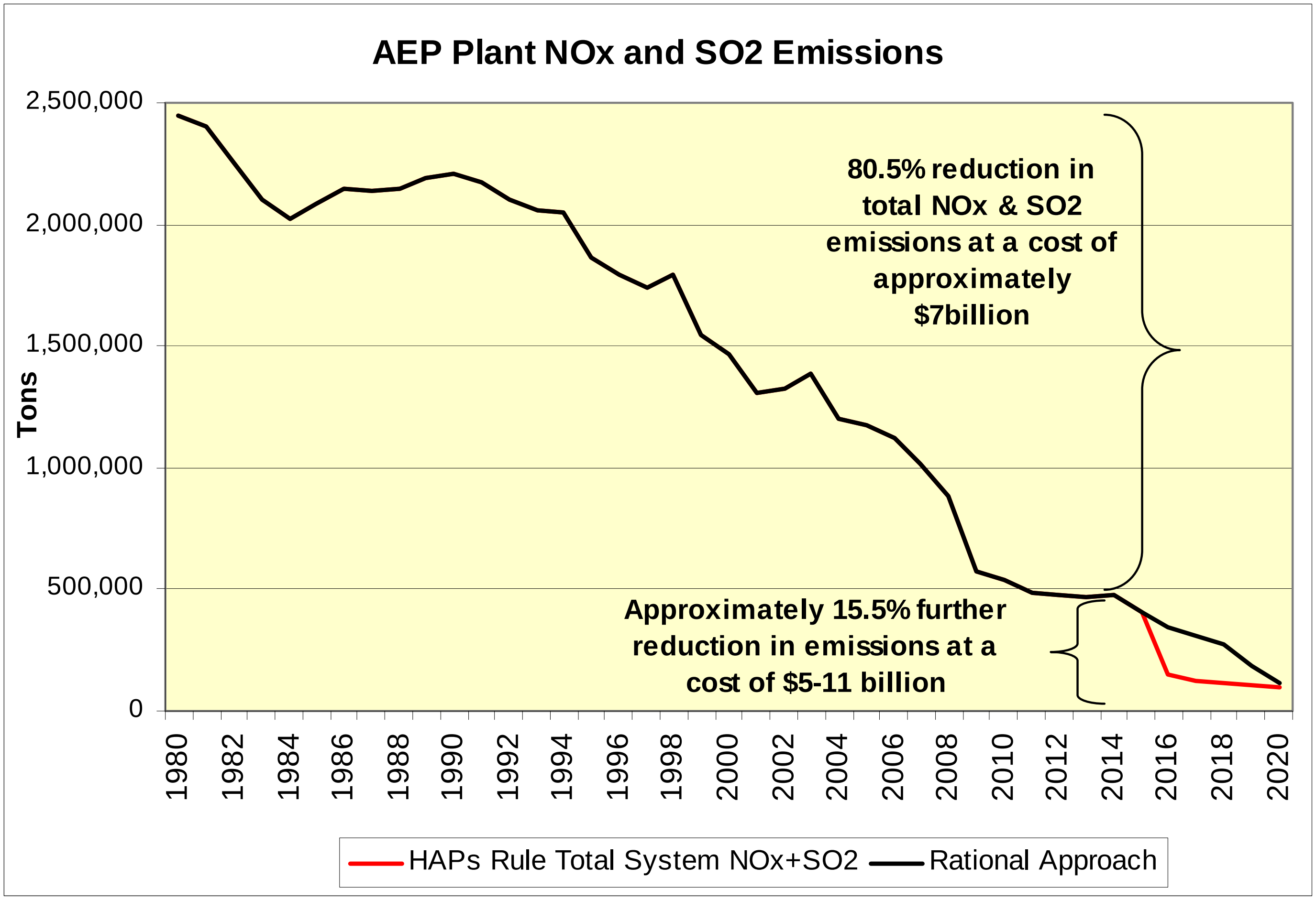
A phased-in approach will arrive at the same destination



AEP AMERICAN® ELECTRIC POWER

46th EEI Financial Conference Presentation

Orlando, FL
November 8, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Nick Akins

President and CEO-elect

American Electric Power

My areas of strategic focus…

1. ***Optimize the earnings stream of the Company***
   - ***ROE optimization***
   - ***Resource transformation***
   - ***Reposition transmission business***
2. ***Achieve regulatory certainty***
   - ***Execute Ohio strategy***
   - ***Energy policy, EPA and environmental investments***
3. ***Earnings and dividend growth***

ROE optimization…

ROE by Jurisdiction		
Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia APCO – West Virginia Wheeling	10.53% 10.00% 10.00%	6.88%
I&M – Indiana I&M – Michigan	10.50% 10.35%	8.24%
SWEPCO – Louisiana SWEPCO – Arkansas SWEPCO – Texas	10.57% 10.25% 10.33%	10.05%
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

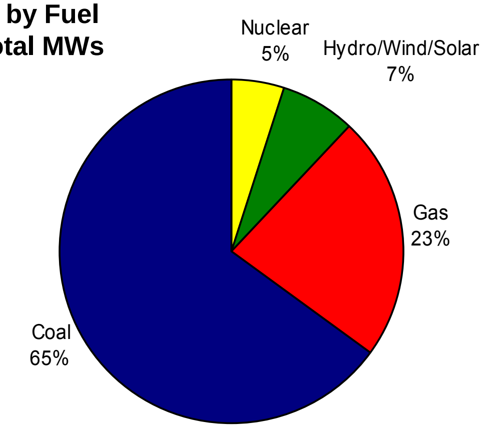
- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Management focused on Operating Company results and rate plans

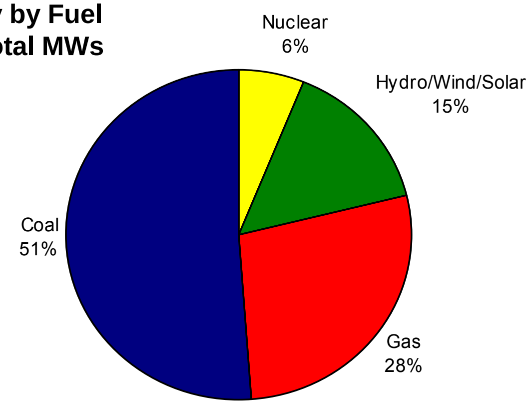
Resource transformation . . .

- Grow rate base and earnings through adding environmental controls
- Retire older, uncontrolled coal units
- Add new capacity (natural gas) to rate base to replace a portion of retirements
- Transformation already occurring due to shale gas

2010 AEP Generating Capacity by Fuel
39,910 total MWs

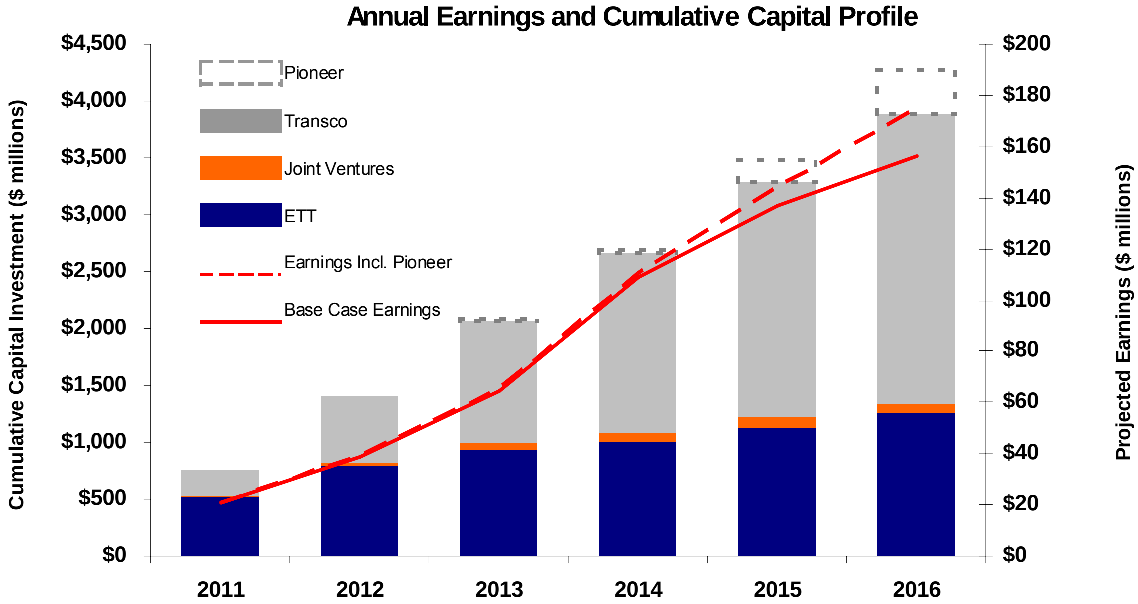


2020 AEP Generating Capacity by Fuel
37,707 total MWs



Need more time to accomplish in order to mitigate customer costs and reliability impacts

Reposition transmission business…

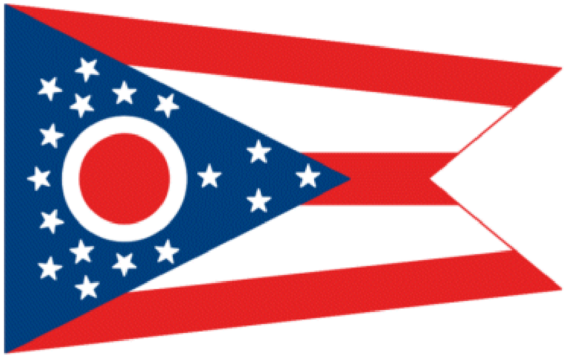


- Electric Transmission Texas
  - 50/50 ownership with MidAm
  - $1B invested to date
  - 9.96% ROE
  - $3B invested by mid-decade
- Transcos
  - 11.20-11.49% ROE
  - Forecasted investment over $500M by end of 2012
- Joint Ventures
  - ETA (50/50 with MidAm)
  - Pioneer

Transmission expected to contribute $40M in net income in 2012

Execute Ohio strategy…

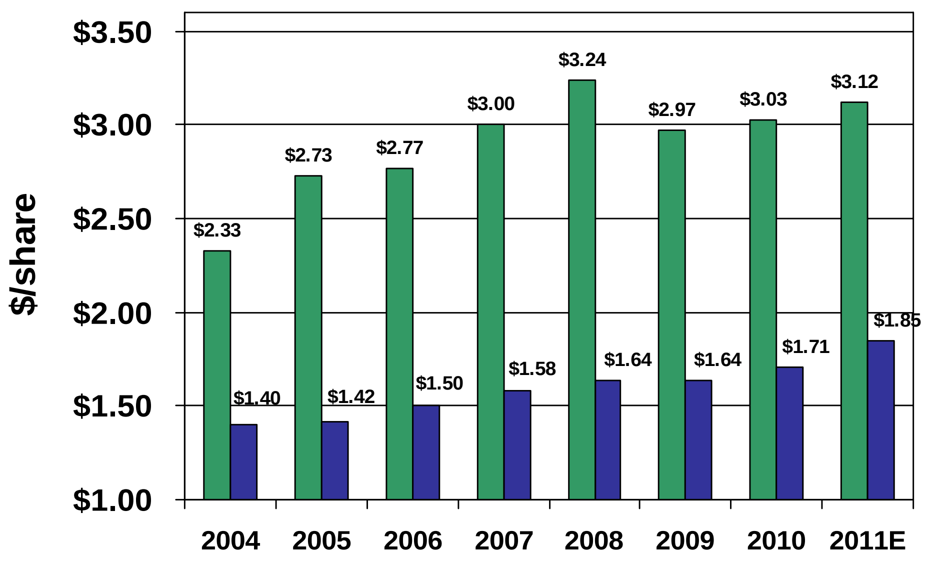
- Stipulation allows for transition to market in Ohio
  - PUCO decision expected before year-end
  - Merge Ohio Power & Columbus Southern
  - 2012-15 transition period to market
- Separate AEP Ohio into two companies
  - WiresCo
    - Regulated T&D company
    - Will auction load fully in 2015
  - GenCo
    - Unregulated generation company
    - Approximately 11,000 MW of capacity
    - Significant hedge profile
    - Allocate capital wisely
    - Targeting an investment grade rating



Transition period will create platform for the Company's future

Earnings and dividend growth …

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

Dividend payout ratio target of 50–60%

2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

Management is committed to earnings and dividend growth

Next Steps…

- Receive Ohio ESP order – December 2011
- EPA regulation clarity – end of 2011
- Analyst & Investor Meeting in early 2012
  - 2012 detailed guidance
  - Long-term earnings growth guidance
  - Financing overview

Analyst & Investor Meeting in early 2012 following receipt of Ohio order and HAPs MACT final rule

Questions

Wellington Shields Berenson Transmission Seminar

January 11, 2011

New York, NY

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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Lisa Barton

Senior Vice President, AEP Transmission

Transmission as a Growth Engine

- Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories
  - Electric Transmission Texas (ETT)
    - Growing Rate Base
    - Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - AEP Transmission Company (AEP Transco)
    - Settlement filed at FERC for wholesale rates. Final order pending.
    - $50MM spend for 2010; $160MM forecasted for 2011
  - Joint Ventures
    - PATH
    - Prairie Wind
    - Pioneer
    - SMART Transmission study
- Two new projects: RITELine and MEC

AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - **Ohio application was approved by PUCO on December 29, 2010**
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

JV Strategy – Nationwide Grid Expansion

AEP®

SPP

Prairie Wind COD: 2013-14

- 75 - 110 miles of 345 kV*
- Partners: Westar (50%) & MidAmerican Energy (25%)
- Estimated Cost: $225 million
- ROE: 12.8%

ERCOT

ETT COD: 2010-2014

- 345 kV and below CREZ & ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Total Estimated Cost: $1.5 billion
- ROE: 9.96%

PJM

PATH-WV COD: 2015

- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 14.3%

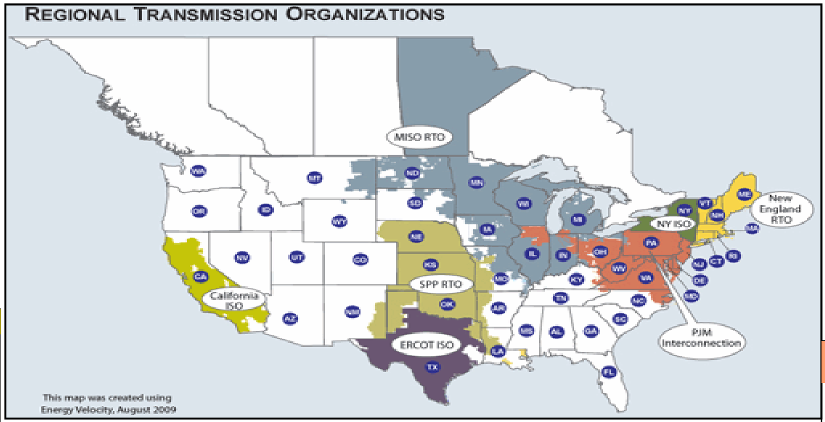
PJM/MISO

Pioneer COD: ~2015-2017

- Up to 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: up to $1 billion
- ROE: 12.54%

* May revert to 765 kV depending on 2010 SPP ITP results

ACTIVE PROJECTS



FUTURE DEVELOPMENT

Tallgrass

- 765kV development in Oklahoma
- Partners: OG&E (50%) & MidAmerican Energy (25%)

SPP EHV Overlay

- Regional Expansion of EHV Backbone

RITELine

- 420 miles of 765kV
- Partners: Exelon & MidAmerican Energy
- Estimated Cost: $1.6 billion

ETT COD: various

- Other Projects
  - Total estimated cost: $1.6 billion (COD 2010-2017)

PJM Expansion

- Regional Expansion of EHV systems

SMARTransmission Study

- Interregional EHV & Wind Integration Study
- Sponsors: ATC, ETA, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

MEC Project

- 180 miles of 765 kV
- Partners: MidAmerican Energy
- Estimated Cost: $650 million

ETT: An Operating Utility

AEP®

Electric Transmission Texas

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	Anticipated 10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

Prairie Wind Transmission, LLC

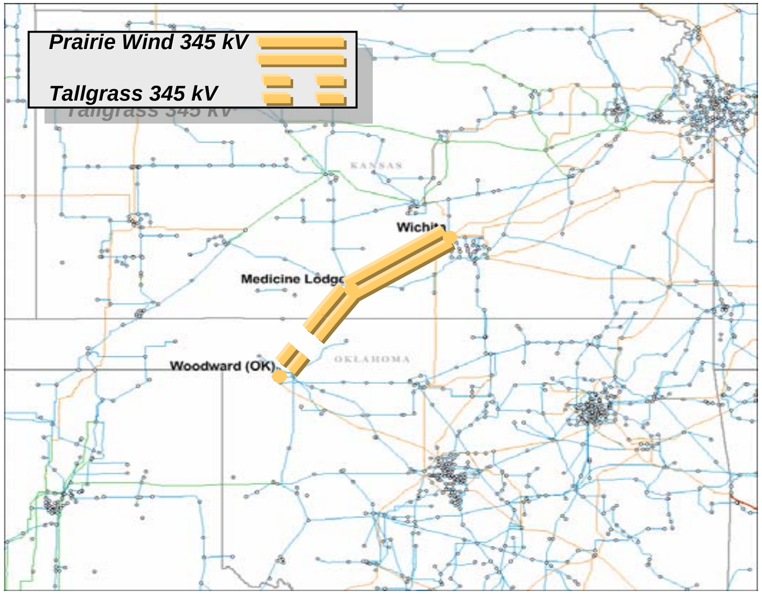
Project Description: 110 miles of EHV transmission lines extending from Wichita, KS to the KS/OK border

Overview:

- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost $225 million and be in-service by 2013-2014
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC was issued to Westar July 2010. Currently working on a novation of the NTC to Prairie Wind. As a Transmission Owner, Prairie Wind will be entitled to collect revenue upon the novation of the Notice to Construct.
  - Currently approved at 345 kV.

Key Challenges:

- Siting and Routing



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

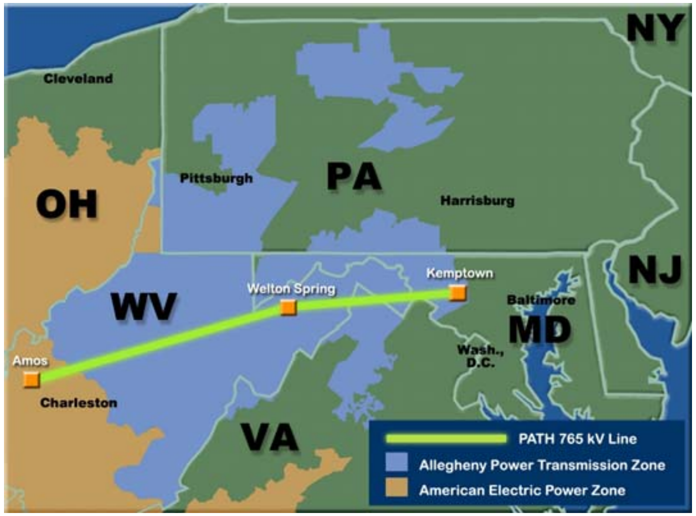
Prairie Wind Transmission
A joint venture between Westar Energy and ETA

Update on PATH, LLC

Project Description: 276 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new Welton Spring substation in Hardy County, WV, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- FERC order issued on November 19, 2010 set the 14.3% ROE for hearing
- Total estimated cost of entire line is $2.1 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.4 billion. AEP share is approximately $700 million
- Estimated completion date: June 1, 2015



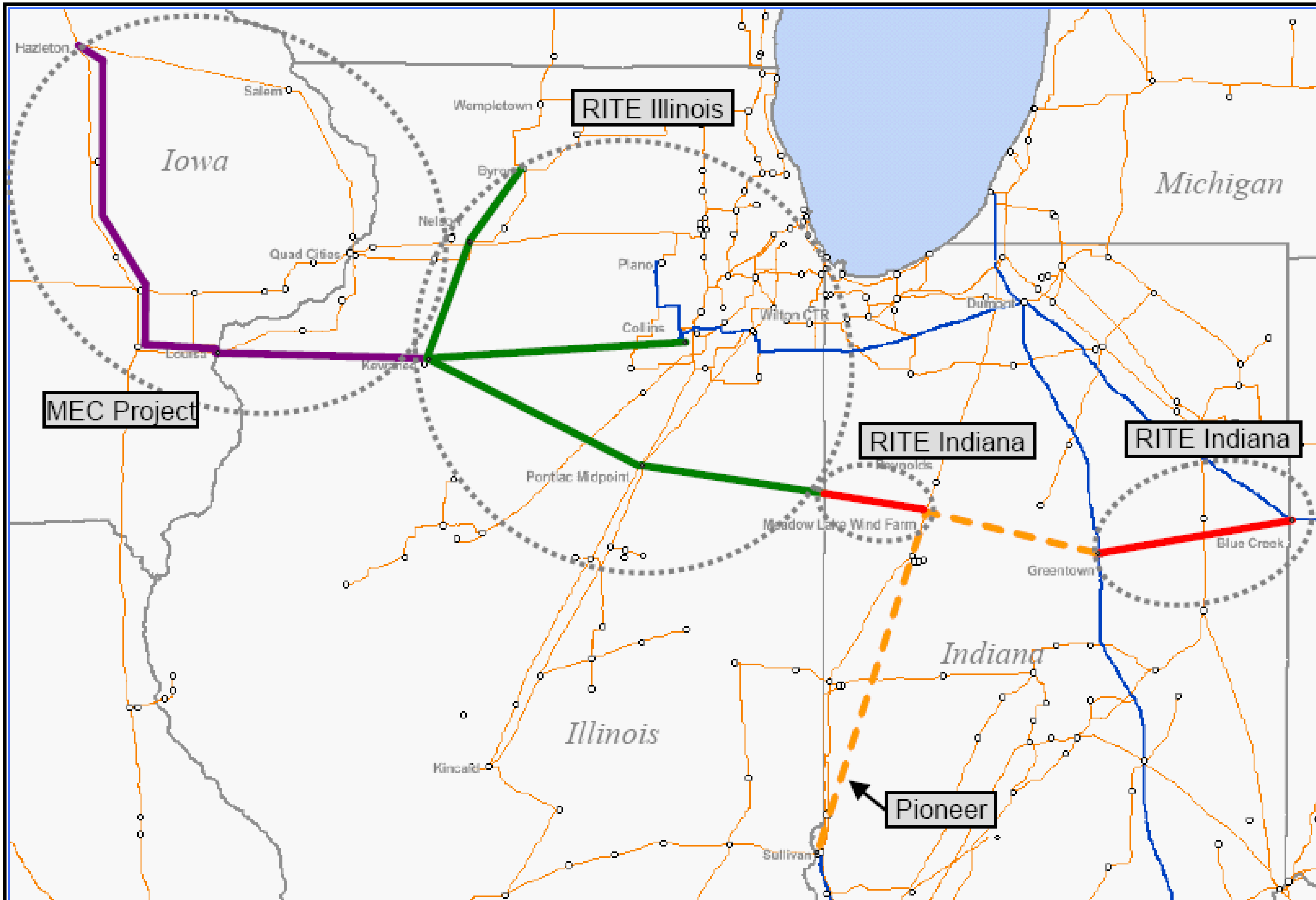
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia, and Maryland
  - CPCN applications are filed and accepted in all three states
  - PJM released a draft 2011 Load Forecast that could affect the required in-service date for PATH
  - PATH filed motions in all three states in December 2010 for a delay in the procedural schedule to allow for the filing of supplemental need testimony to reflect the 2011 PJM Load Forecast

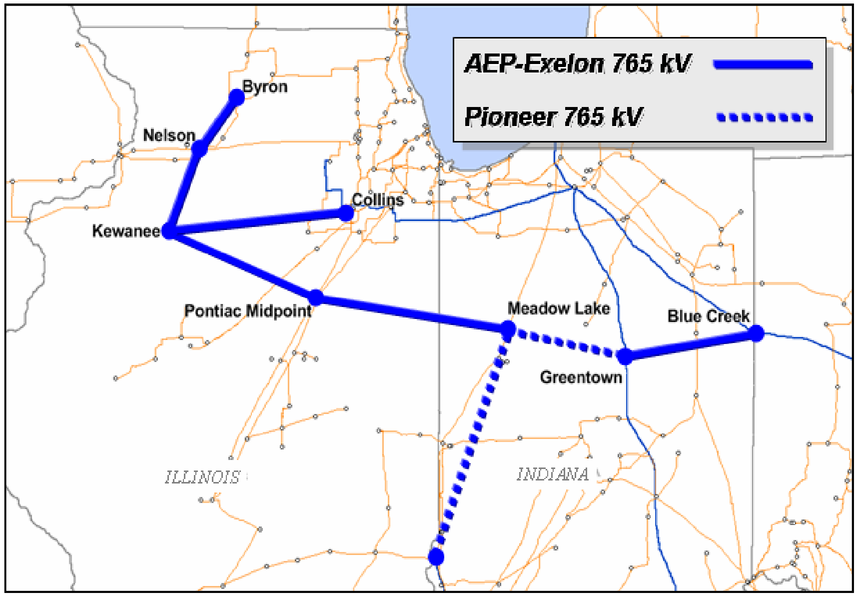
Potomac-Appalachian Transmission Highline

MISO/PJM Interface: Proposed Projects Under Evaluation



RITELine Project

- AEP, ETA and Exelon Corporation executed a Memorandum of Understanding on October 26, 2010 for the development of the Reliability Interregional Transmission Extension Line ("RITELine") project

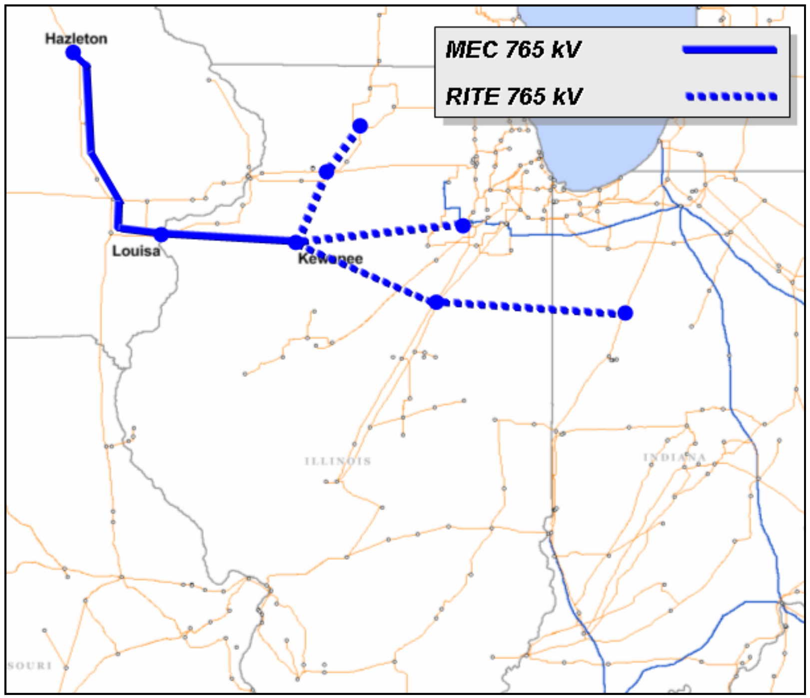


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- Estimated Project Cost: $1.6 billion
- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV line)
- Extends approximately 420 miles from the Byron Substation in Illinois to the Blue Creek substation at the Ohio/Indiana border and from Kewanee to the Collins Substation in Illinois

MEC Project

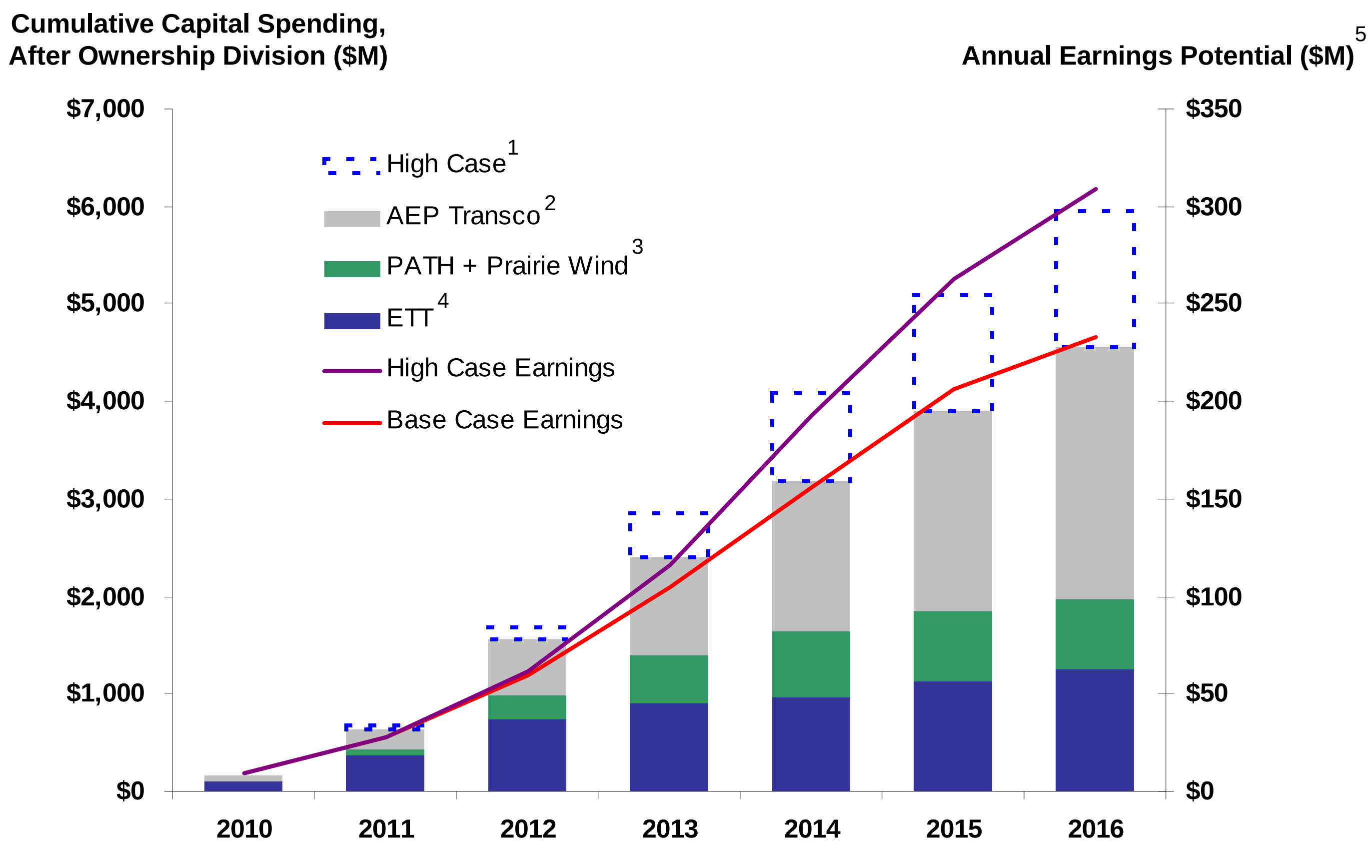
- ETA and MidAmerican Energy Company executed a Memorandum of Understanding on October 28, 2010 for the development of the MEC project



- Estimated Project Cost: $650 million
- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV)
- Extends approximately 180 miles from the Kewanee Substation in Illinois to the Louisa substation in Iowa and northwest to the Hazelton substation

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Transmission – Capital/Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Evolving Regulatory Policy

- 2010 saw a number of steps towards resolving the issues related to planning, cost allocation and siting
  - SPP & FERC approved SPP’s regional cost allocation methodology, and SPP adopted a new, more strategic planning process called the Integrated Transmission Planning process
  - SPP issued notices-to-construct for its “Priority Projects”, including the first segments of an EHV overlay within the region
  - The Midwest ISO, through its Regional Generator Outlet Study (RGOS) and Multi-Value Project (MVP) Process, has moved closer to approving a number of significant transmission projects

- 2011 looks to be a year in which regulatory momentum will support transmission development
  - FERC’s recently issued Notice of Proposed Rulemaking (NOPR), which is still in the comment phase, indicates FERC’s desire to break the logjam and resolve the major issues that stand in the way of strategic development of the nation’s transmission grid

Proposed Reforms in Transmission Planning

- On June 16th FERC issued Notice of Proposed Rulemaking (NOPR) suggesting significant reforms in Transmission Planning and Cost allocation

- Proposals would require Transmission Owners (TO's) in RTO's and ISO's to:
  - Participate in a regional transmission planning process that produces a regional transmission plan that considers and evaluates transmission facilities/non-transmission solutions
  - Amend its OATT such that local and regional transmission planning processes explicitly provide for public policy requirements established by state/federal laws/regulations, (i.e. renewable requirements).
  - Eliminate from transmission provider's OATT or FERC-jurisdictional agreements right of first refusal (ROFR) provisions with respect to facilities included in a regional transmission plan
  - Enter into interregional transmission planning agreement (filed with FERC), to coordinate with transmission providers in neighboring regions

Proposed Reforms in Cost Allocation

- FERC Proposal would also require RTO's and ISO's to establish a method for allocating the costs of:

  - New transmission facilities that are included in the regional transmission planning process in which it participates; and

  - New interregional transmission facility between the two neighboring transmission planning regions "in which the facility is located or among the beneficiaries of the two regions".

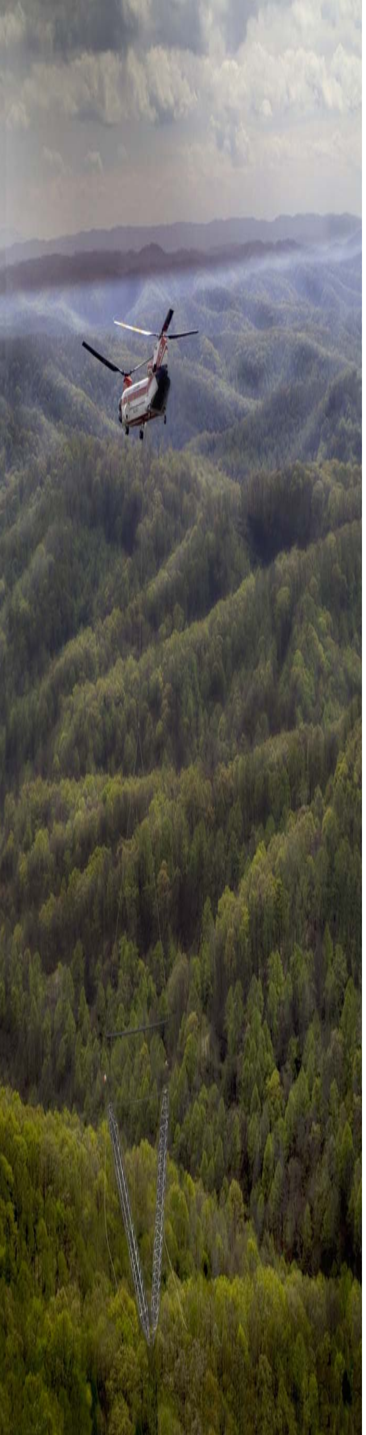
- Inter/cross-regional cost sharing mechanism could significantly improve ability to develop transmission projects across RTO "seams"

41st EEI Financial Conference

November 7, 2006

Caesar's Palace

Las Vegas, Nevada



Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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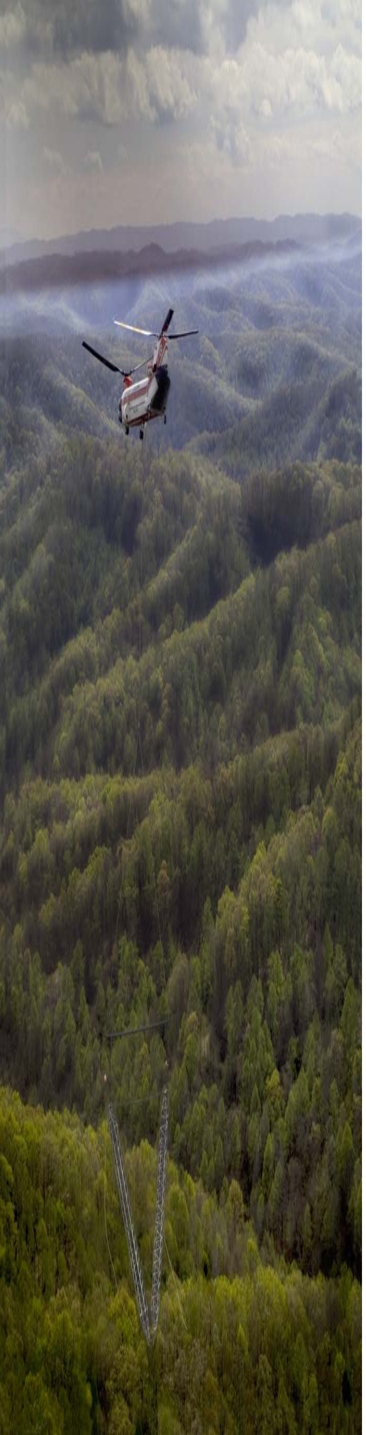
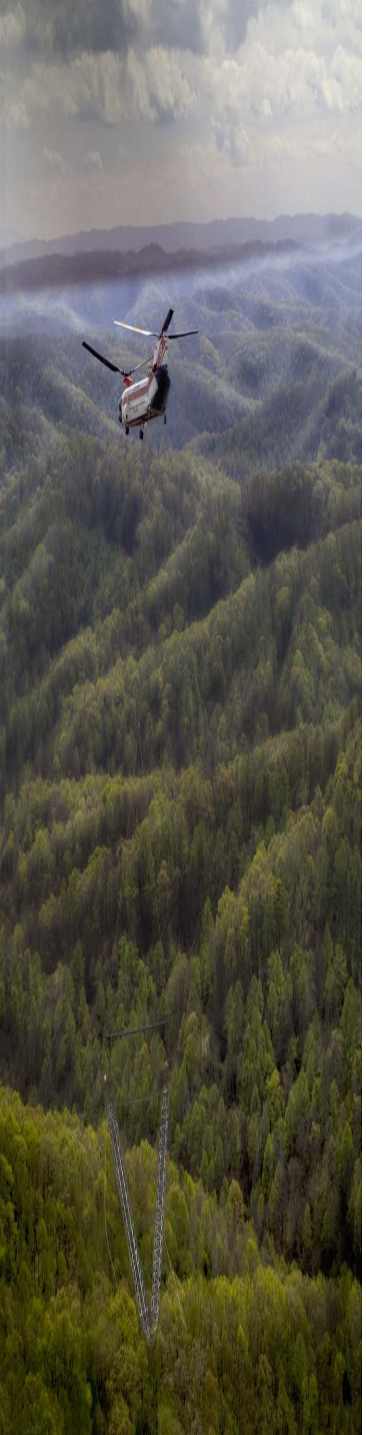


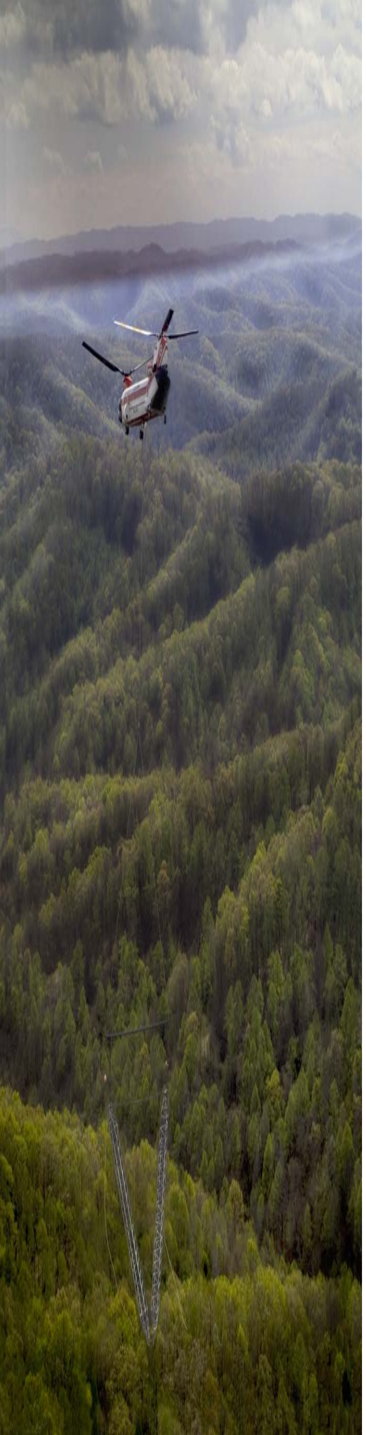
Michael G. Morris
Chairman, President & CEO



Upcoming Investor Communication Activities*

Dec. 5, 2006	**Harris Nesbitt Conference – NYC (One-on-one investor meetings)**
Jan. 30, 2007	**4Q06 Earnings Call**
Mar. 5-6, 2007	**EEI International Conference – London (Generation Panel Discussion)**
Mar. 15, 2007	**Morgan Stanley Conference – NYC (AEP Generation Sustainability Strategy)**

*Note: Events at which Mike Morris is scheduled to speak with investors/analysts.

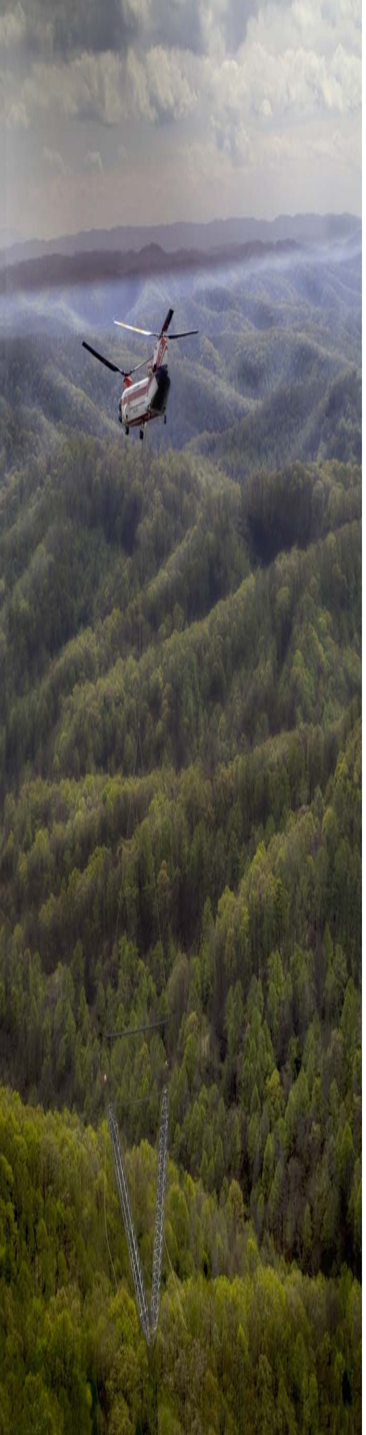


FERC Promotes Transmission Investment with Order 679

- Issued July 20, 2006 to enable EPAct 2005
- Key provisions include:
  - Return on equity at the high end of the zone of reasonableness
  - Return on CWIP
  - Return on premium for acquired assets
  - Full recovery of construction costs and costs of cancelled or abandoned facilities due to factors beyond the utility's control

AEP supports a national interstate grid – our core transmission strength

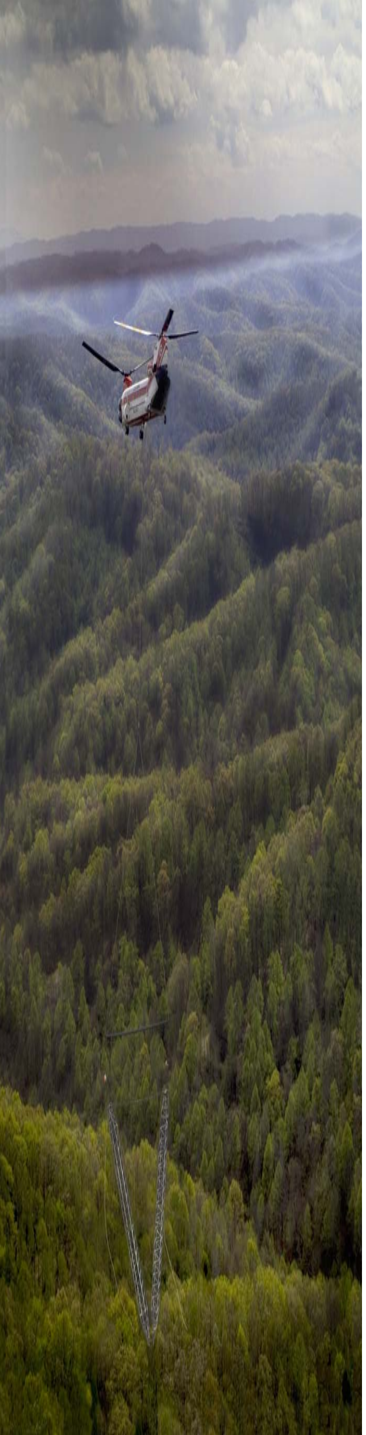
A Century of Firsts



AEP Transmission Vision & Mission

- Maintain our position as the largest transmission company in the United States
- Maintain our leadership in technical innovation of transmission systems
- Set the standards for transmission safety, efficiency, and reliability
- Provide for robust market competition - benefiting customers by de-bottlenecking the U.S. transmission grid
- Reduce the need for new generation by facilitating the optimal economic dispatch of existing generation assets
- Increase earnings for AEP shareholders

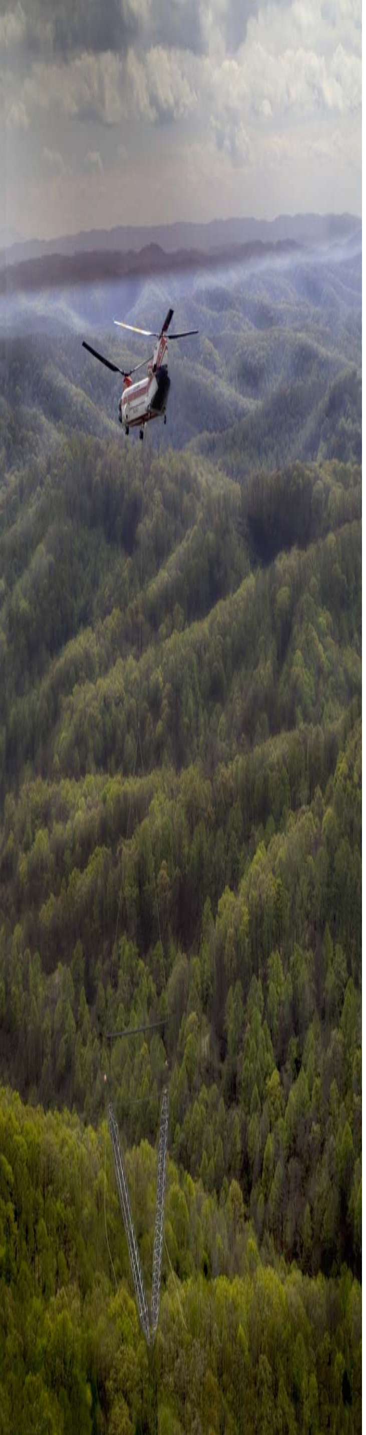
Maintaining our leadership position and setting the standards



AEP Transmission Strategy

- Expand our vibrant transmission business with major new joint venture projects, taking advantage of EPAct 2005
- Aggressively seek recovery through various state and federal mechanisms
- Advocate transmission nationally as an enabler of market efficiency, economic opportunity, environmental optimization, and national security

The AEP Advantage: 100 years of transmission leadership experience in the United States



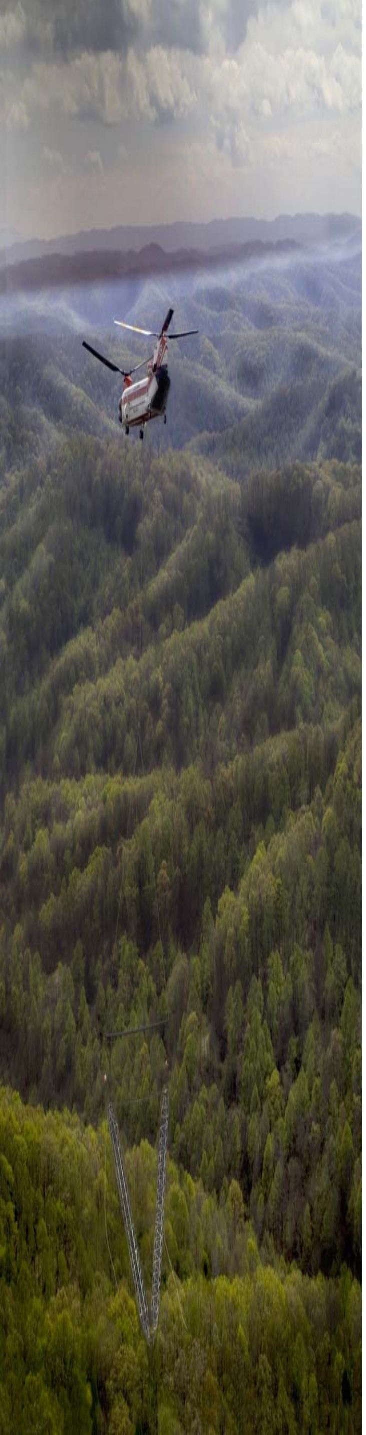
AEP Transmission Network – The Largest in the Country

Operating Company Level

(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP is the leader in transmission expertise



AEP Transmission Investment Is Substantial

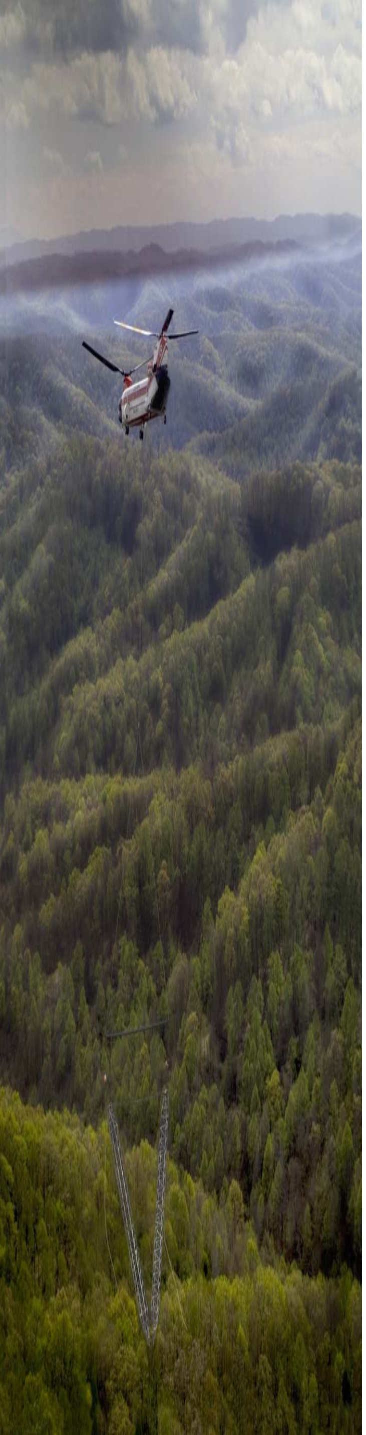
(in millions)

Summary by Operating Co.	**Transmission Plant Original Cost**	**Accum. D&A**	**Net Transmission Plant**
PJM			
AEP Generating Co.	$ -	$ -	$ -
Appalachian Power Co.	1,596	510	1,086
Columbus Southern Power Co.	479	200	279
Indiana Michigan Power Co.	1,042	418	624
Kentucky Power Co.	392	124	268
Ohio Power Co.	1,016	418	598
All other non-registrants	40	26	14
PJM Total	4,565	1,696	2,869
ERCOT			
AEP Texas Central Co.	901	208	693
AEP Texas North Co.	325	139	186
ERCOT Total	1,226	347	879
SPP			
Public Service Co. of Oklahoma	499	158	341
Southwestern Electric Power Co.	662	268	394
SPP Total	1,161	426	735
TOTAL	$ 6,952	$ 2,469	$ 4,483

Balances as of September 30, 2006

Today's net transmission investment totals $4.5 billion

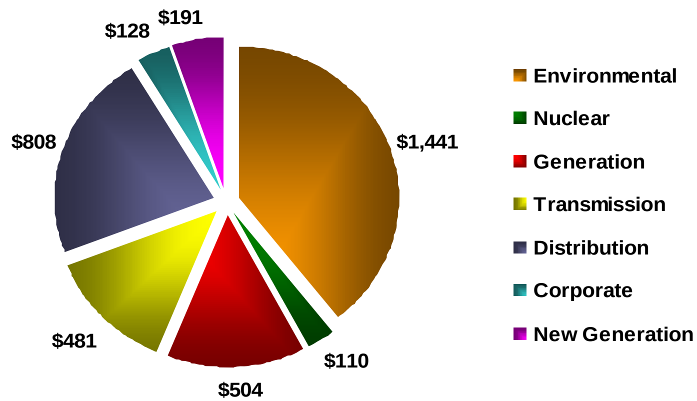
A Century of Firsts



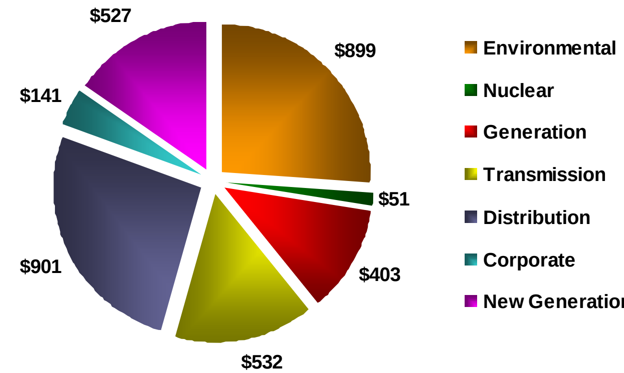
AEP Transmission Investment Forecast

Investing over $2.1 billion 2006-2009

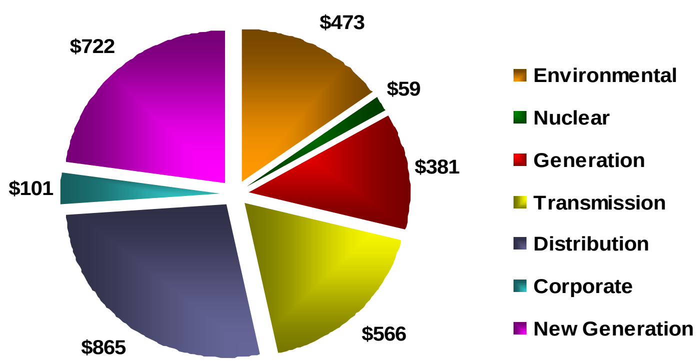
2006 Projected Totals $3.7 Billion



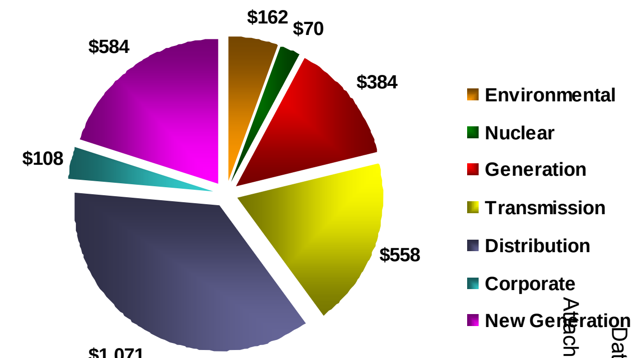
2007 Forecast Totals $3.5 Billion



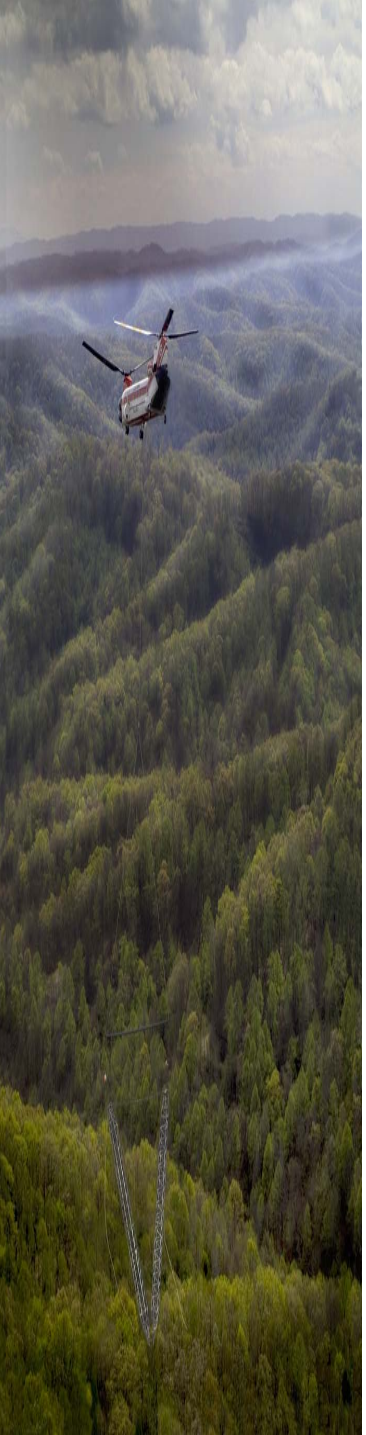
2008 Forecast Totals $3.2 Billion



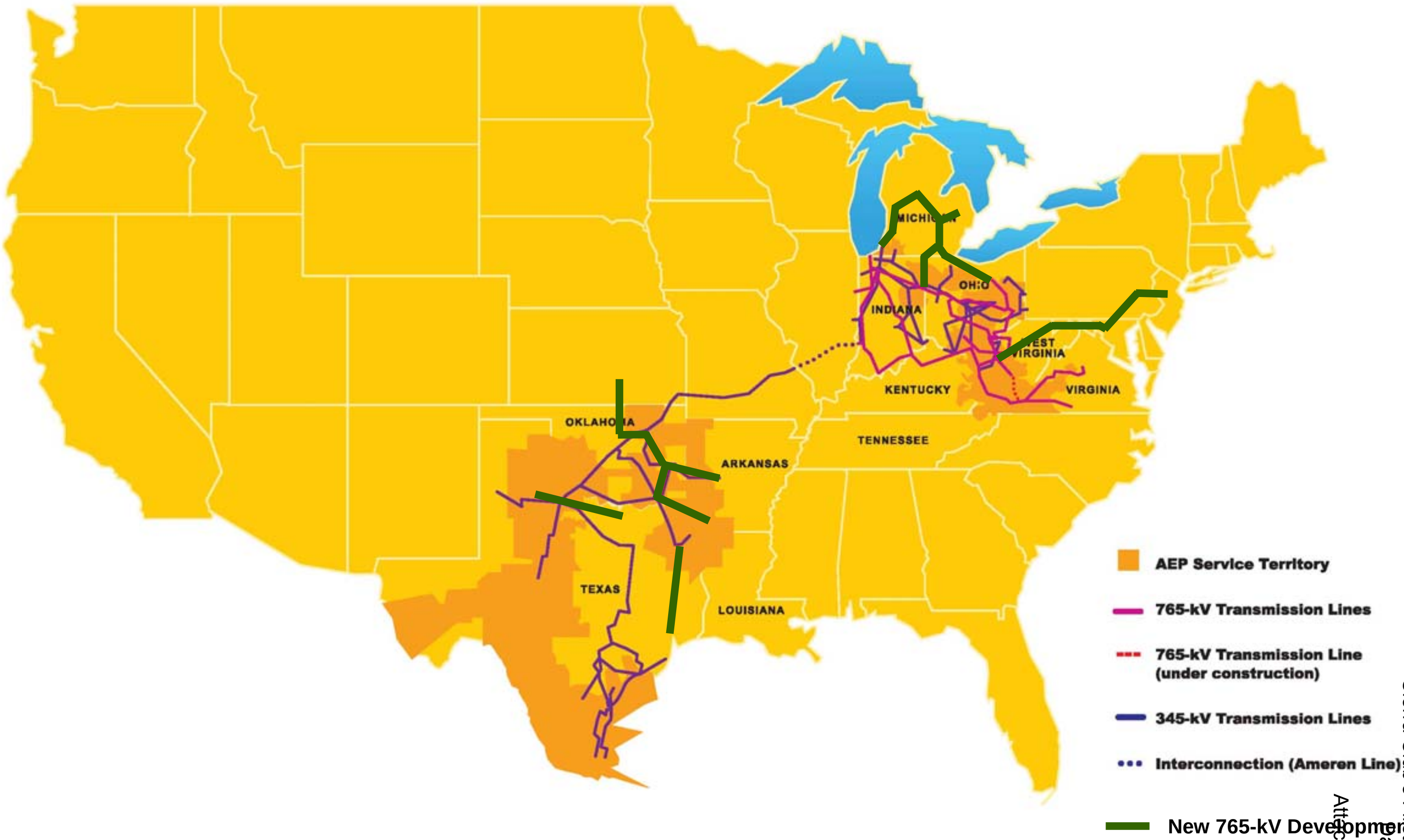
2009 Forecast Totals $2.9 Billion



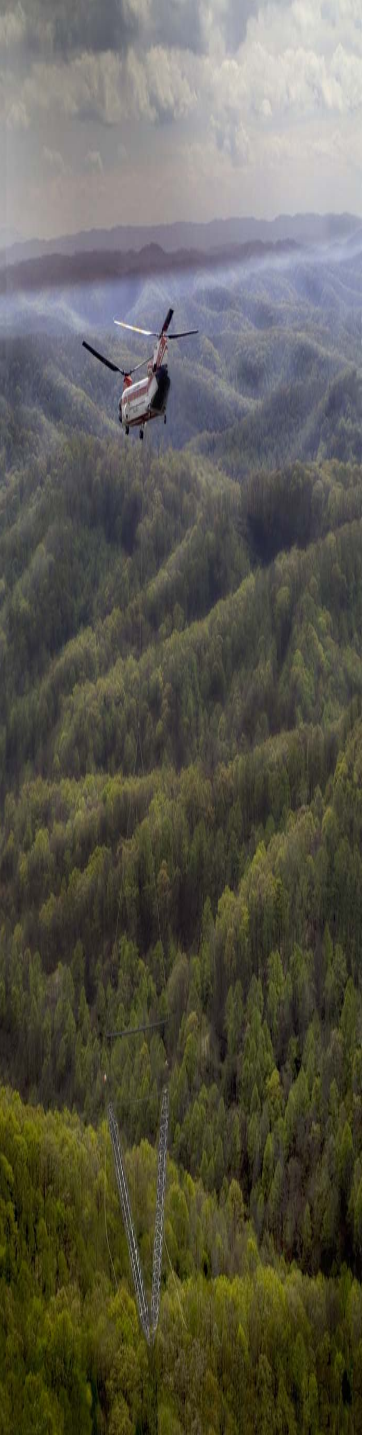
AEP – One of the premier transmission utilities in the United States, if not the world



AEP 765-kV Experience Spans Decades

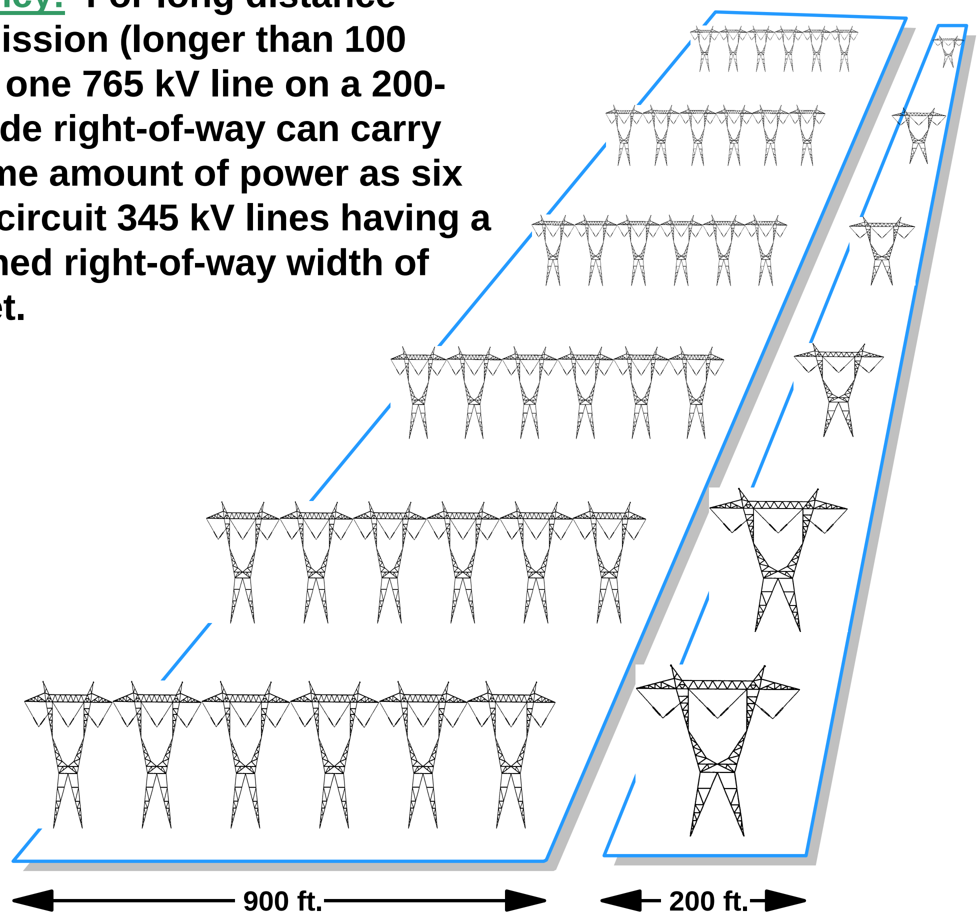


Current AEP 765-kV Mileage: 2,116
Mileage of proposed projects: 1,800 – 2,500



765-kV: The highest capacity, most efficient transmission by far

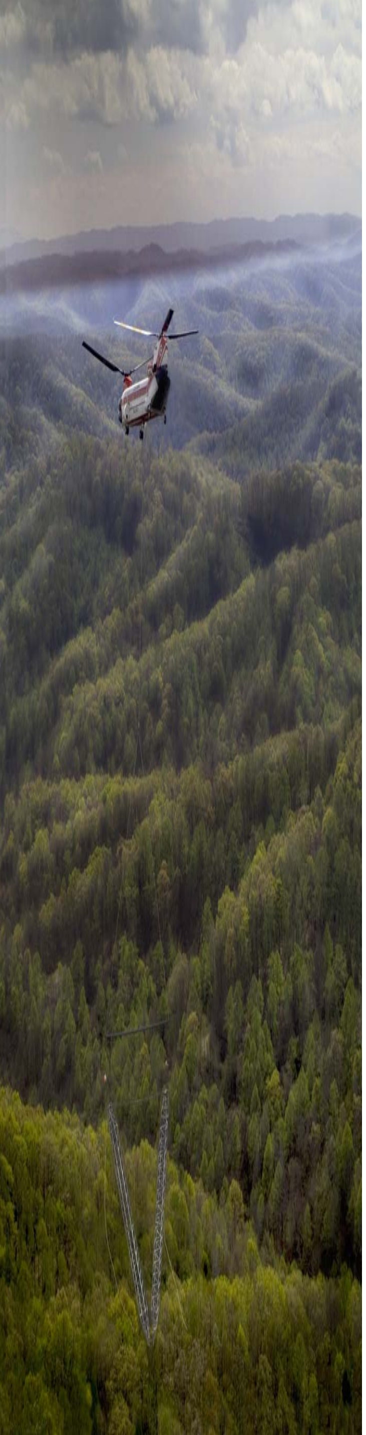
Efficiency: For long distance transmission (longer than 100 miles), one 765 kV line on a 200-foot-wide right-of-way can carry the same amount of power as six single circuit 345 kV lines having a combined right-of-way width of 900 feet.



Cost Advantage: For equivalent capacity, the cost of 765-kV is 48% of the cost of 345-kV

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point), 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.

765-kV maximizes land use, providing greatest capacity increases with least land consumption.



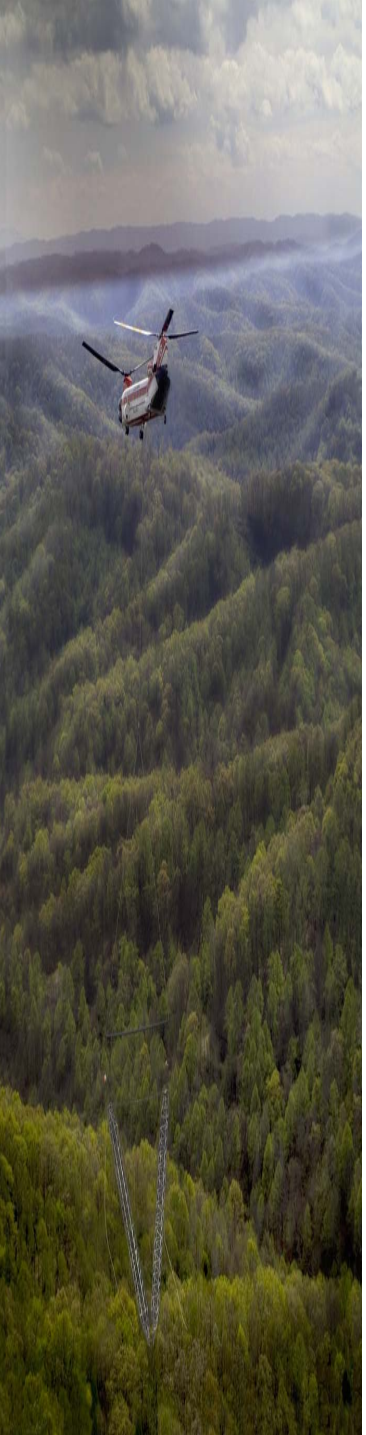
Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~$1 billion in ERCOT
- ~$2 billion 765-kV study in Michigan
- ~$3 billion I-765 Project in PJM
- ~$3 billion project filed with SPP

Building the next US interstate system for enhanced reliability and market efficiency

*Note: ~$9 billion investment opportunity not included in current capital guidance forecasts with exception of ERCOT investment of $60MM in 2007 and $95MM 2008

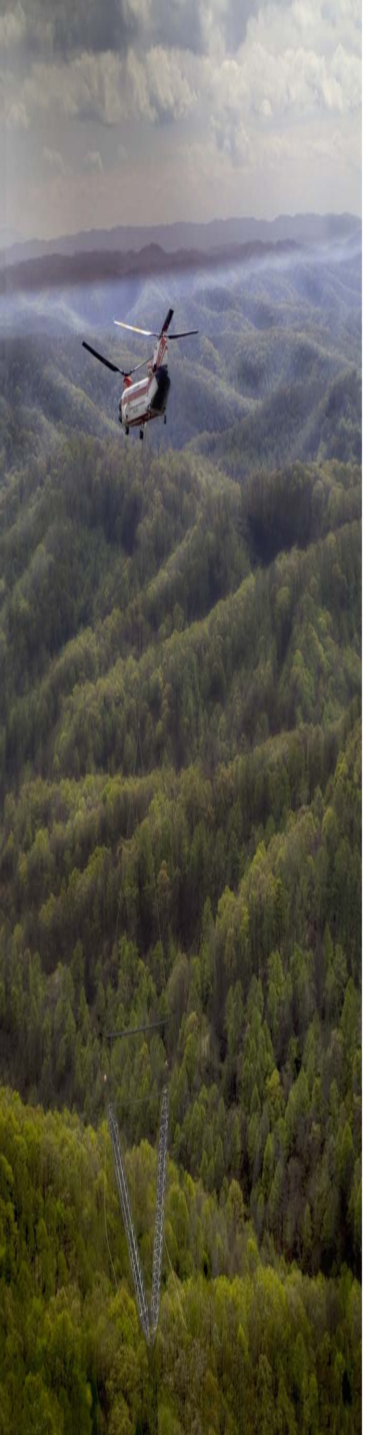


Transmission Investment Earnings Potential

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60*

Earnings accretion over time will be substantial

*Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.



Benefits & Attraction of Texas Transco Joint Venture

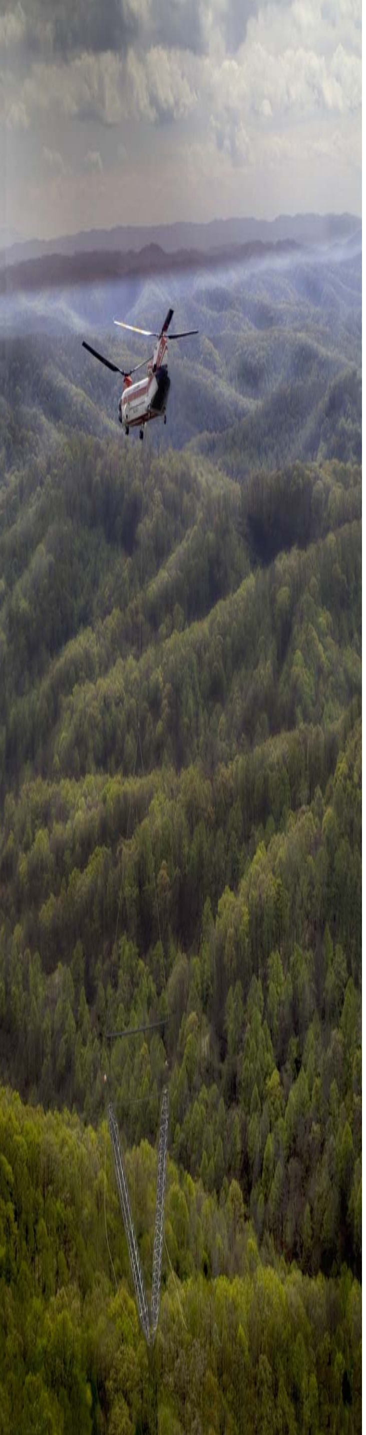
Texas Transco Joint Venture Benefits

- Opportunity to grow ERCOT interest in a timely, resource-efficient manner
- Maximization of asset value
- Formation of strategic relationship that could permit growth beyond current AEP footprint

ERCOT Attraction

- Growing electric demand
- State's commitment to:
  - Wind generation development
  - Promotion of merchant generation
  - Relief of congestion
  - Facilitation of transmission planning in support of the Texas competitive electric market

AEP Texas is uniquely positioned to develop substantial transmission to capture benefits of load growth and traditional & third-party generation



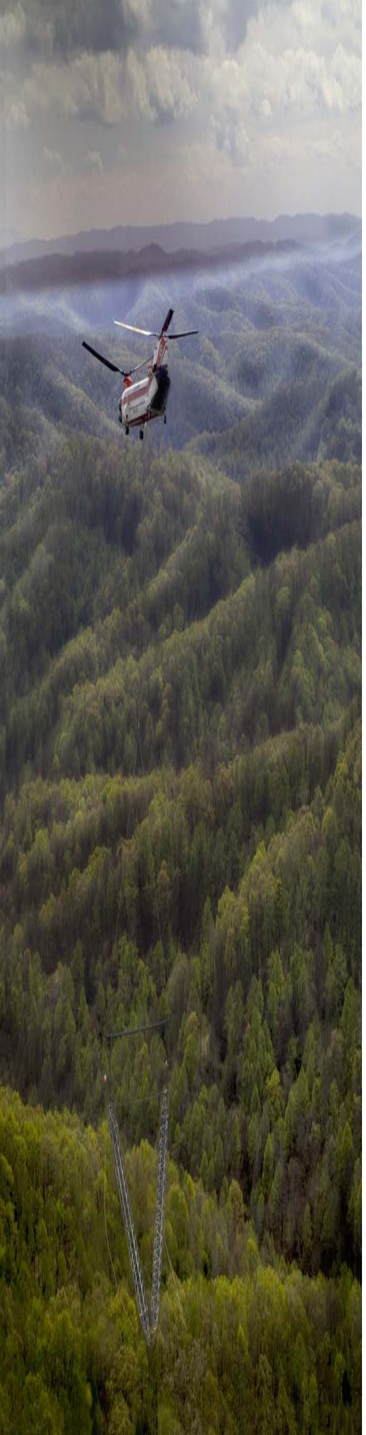
ERCOT Regulatory Certainty

- High degree of regulatory certainty
- Predetermination of need for ERCOT-endorsed projects
- Streamlined annual review process reduces lag
- ROEs commensurate with other state regulatory returns
  - In Texas, current authorized return ranges from 10.125% to 11.25%

ERCOT's predetermination of projects, streamlined annual review process & return opportunity make transmission investment attractive

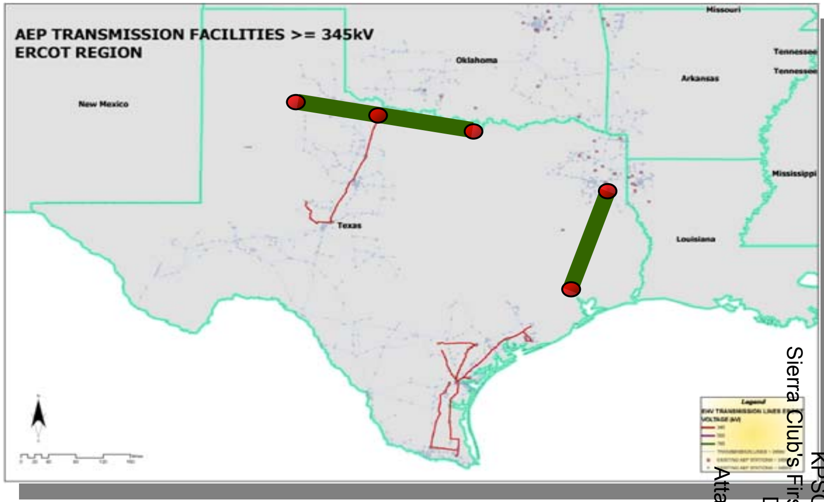
AEP AMERICAN ELECTRIC POWER

MIDAMERICAN ENERGY HOLDINGS COMPANY



- Jointly-owned utility company will design, construct and operate ERCOT transmission assets
- Up to $1B investment potential (before ownership division)
- Equity investment treatment for AEP
- AEP is also exploring 765-kV ERCOT transmission investment opportunity
  - 420 line miles
  - Up to 4000MW improved transfer capability*
  - Anticipated ERCOT rate impact 0.5mils/kWh
- This project may be considered by JV in future

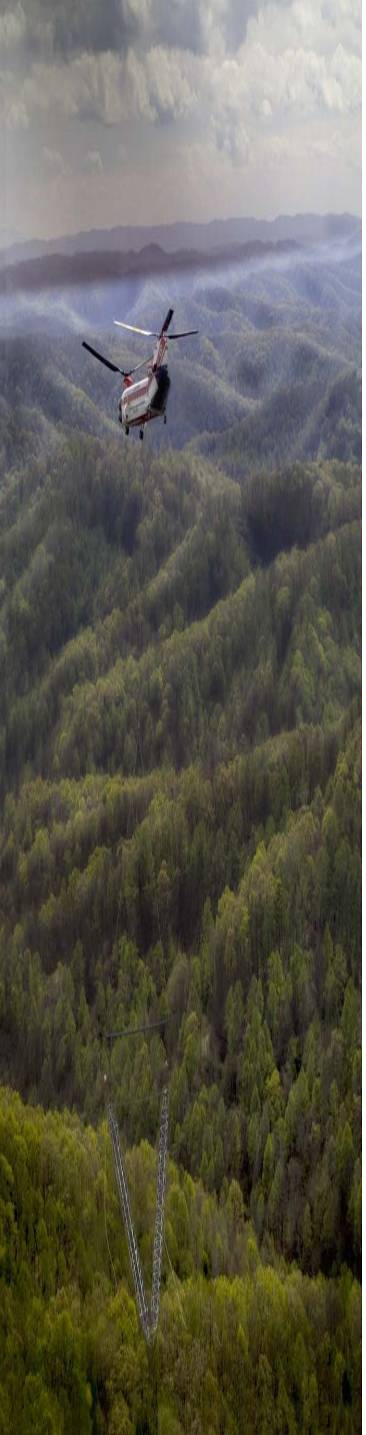
- 2007 commercial operation for first JV projects
- Execution of operating agreement 2006
- Establish JV entity 2007



Conceptual ERCOT transmission project – proposed routes not included in current JV plans

*Line segment capability; ERCOT is a free-flowing network

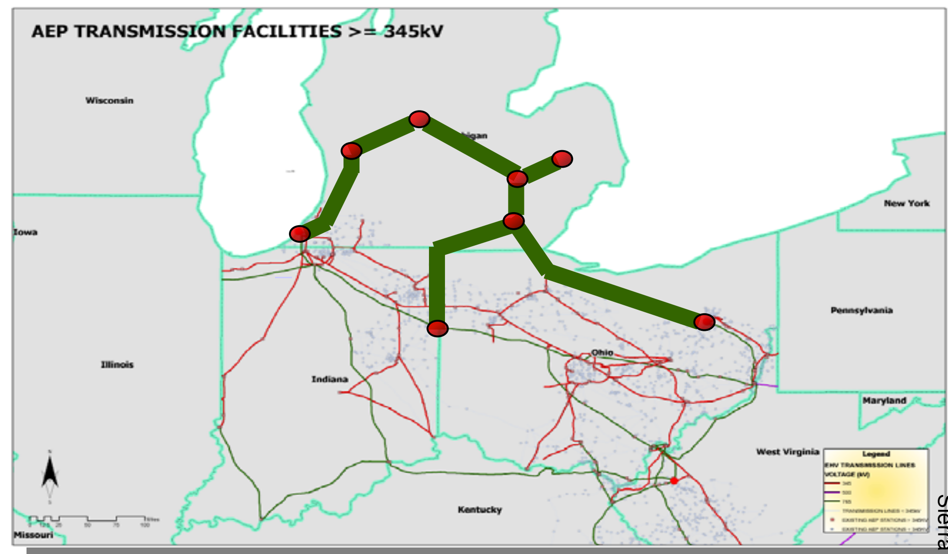
The first large-scale transmission venture in Texas



AEP AMERICAN ELECTRIC POWER

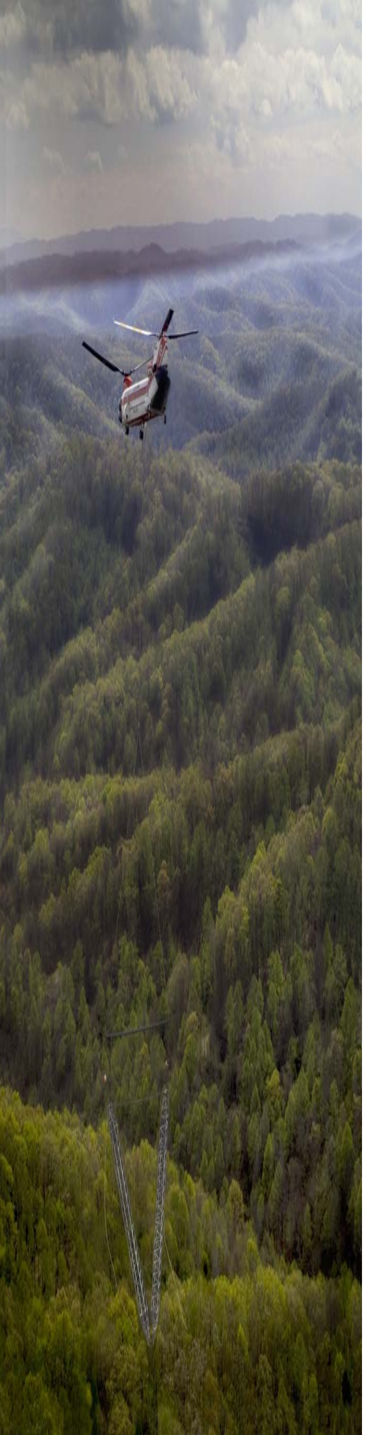
ITC Transmission

- Agreement with ITC *Transmission* for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
  - 630 line miles
  - Over 5000MW improved transfer capability
  - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in late 2006



The ROW routes shown on this diagram are for illustrative purposes only and they may not depict the actual route that could eventually be selected. The substation locations may also be modified.

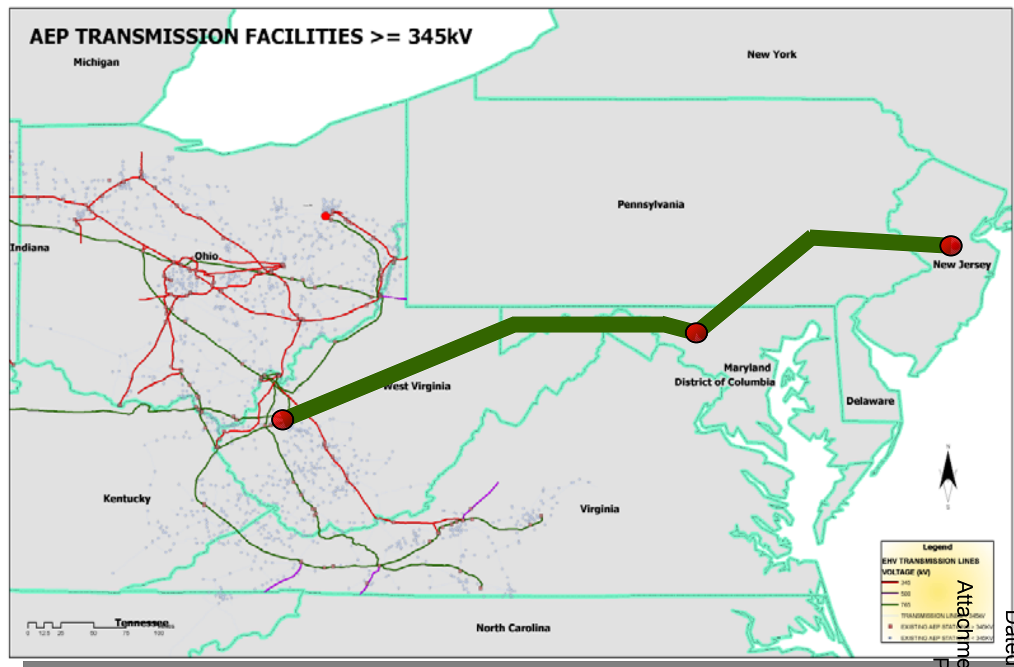
Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints identified in MPSC studies



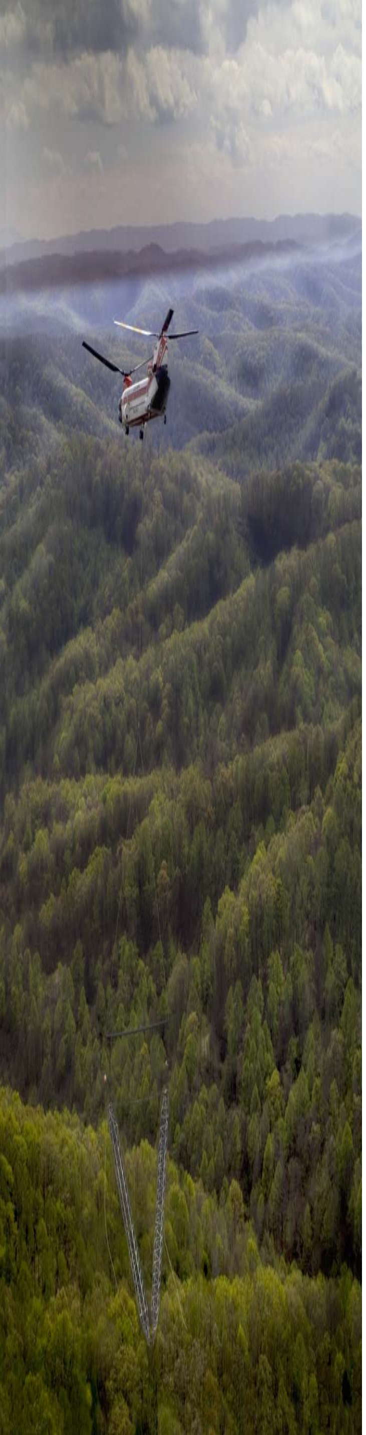
Cruise the I-765

- $3 billion investment
- 550 line miles
- 5000MW improved transfer capability
- Expected PJM rate impact 1mil/kWh
- 2014 estimated in-service date

Original line proposal connects AEP's Amos station to Allegheny Power's Doubs station in Maryland, and terminates at PSEG's Deans station in New Jersey. The final project will undoubtedly vary from the original proposal.



Our I-765 line will be the highest capacity, most reliable line in the United States

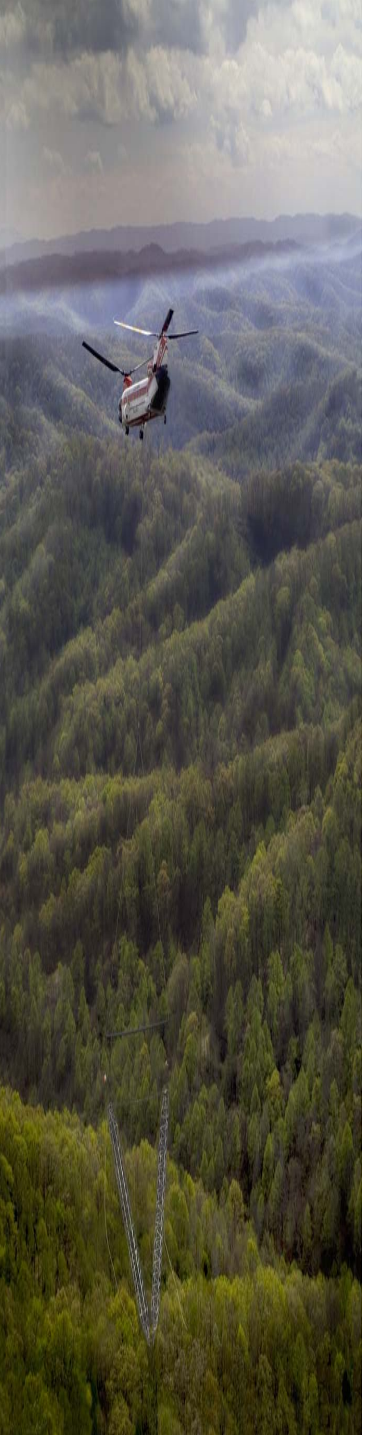


I-765 Benefits

- Improves eastern grid reliability, enhances Midwest – Mid-Atlantic power transfer capability by 5,000 MW
- Improves market efficiency with reduced congestion, lower consumer costs by an estimated $1 billion annually in the east.
- Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.
- Provides AEP with rate base opportunity for transmission investment with ROE upside and other FERC incentives.
- Provides off-system sales and siting opportunity for AEP and other low-cost midwestern generation.

Expect investment to be shared with other transmission owners; incentive ratemaking approved

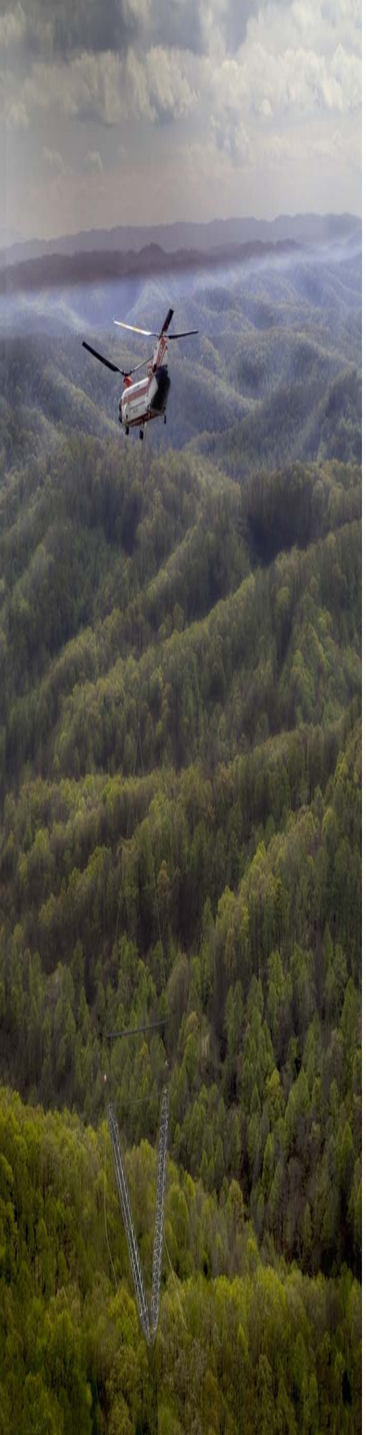
A Century of Firsts



I-765 Regulatory Plan

- Filed plan with PJM (Jan. 31, 2006)
- Filed (Feb. 1, 2006) petition for FERC declaratory order; approved July 20, 2006
- Filed application for DOE early NIETC designation (Jan. 31, 2006); anticipated approval by year-end 2006
- Final regulatory plan depends on PJM tariff
  - Total annual revenue requirement $450-500 million (1 mil/kWh)
  - If AEP's regional rate design proposal for PJM is successful at FERC, revenue requirement would be paid by parties utilizing the system and benefiting customers in PJM East

New technologies including six-conductor bundles and towers designed to blend into the scenery mitigate presence of 765-kV lines in a community



SPP Investment Potential

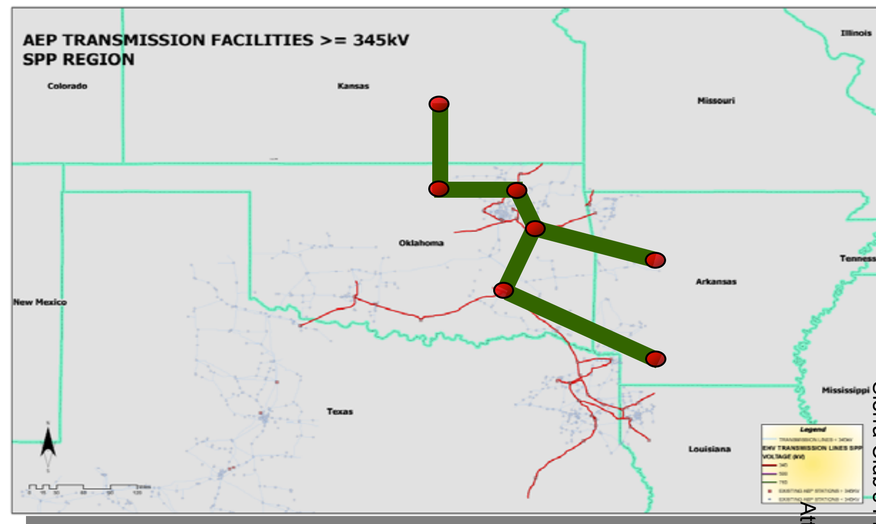
- June 2006 SPP requested proposal to address congestion, reliability & access for new generation

- July 2006 AEP submitted proposal:

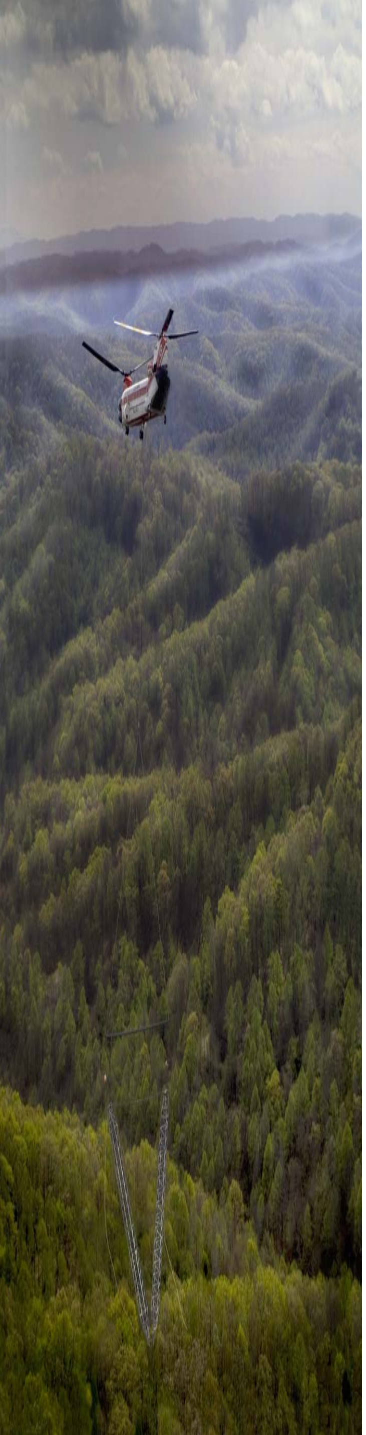
- Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
- Investment ~$3 billion
  - ~4000MW improved transfer capability
  - Anticipated rate impact 2mils/kWh

Next steps:

- SPP conducting studies to evaluate proposals
- AEP providing technical assistance and support



Significant opportunity for 765-kV transmission in SPP



Conclusion

- $2.1 billion traditional transmission investment planned 2006-2009
- Additional $9 billion transmission opportunity being pursued with anticipated partnerships
- Potential earnings contribution of $0.60/share
- The nation's pioneer in EHV technology, AEP has a leadership role in 765-kV development enabling the U.S. transmission grid and improving reliability & market efficiency
- AEP is assessing potential transmission projects and moving forward with care & prudence

A Century of Firsts

Strategic Direction & Financial Outlook

New York, NY

October 10, 2006

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Chairman, President & CEO

Near-Term Investor Communication Activities

October 10, 2006	**Strategic Direction, Financial Outlook & Growth**
October 31, 2006	**3Q06 Earnings Call**
November 7, 2006 (EEI)	**Transmission Opportunity Update & Outlook**

Agenda

- Strategic Direction Overview
- 2006 Earnings Guidance Update
- Commitment to 5-7% Earnings Growth
- Operating Company Strategic Initiatives
- Commitment to recommend a 2-cent increase in quarterly dividend effective 4Q06
- 2007-2009 Capital Investment Projections and Funding
- 2007-2009 Earnings Guidance Details

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

Deliver value to our investors

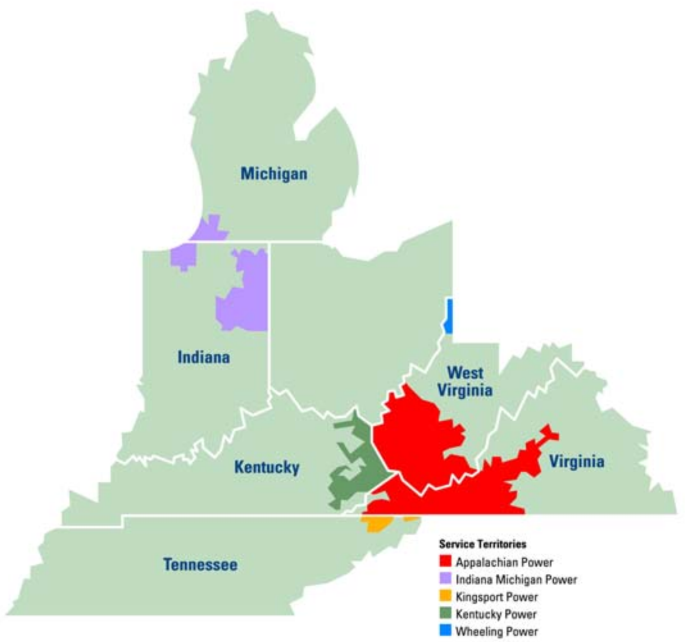
CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Operating Company Structure Benefits

- Re-established operating company model in 2004 – results are being delivered:
  - Increasing growth rate to 5-7%
  - Providing multi-year capital, cash flow and earnings forecasts
- Accountability for performance results
  - Regulatory relationships
    - Capital efficiency
      - Seek high returns
      - Develop innovative rate plans to reduce regulatory lag
  - Operational focus
    - Customer satisfaction

OPERATING COMPANY STRUCTURE DELIVERING IMPROVED PERFORMANCE

East Regulated Utilities

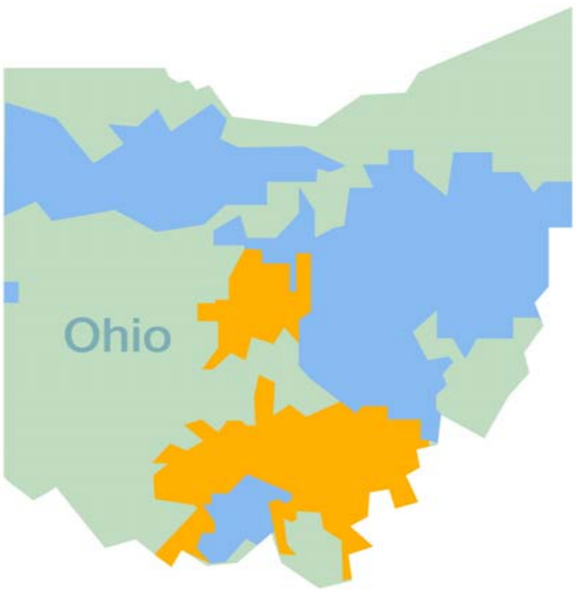


- **Strategic Direction**
  - **Obtain real-time cost recovery**
    - **Kentucky surcharge mechanism**
    - **West Virginia annual rate adjustments through 2009**
    - **Virginia E&R mechanism**
    - **Continue environmental investment program**
  - **Pursue IGCC investment opportunity**
  - **Influence future status of VA deregulation**

MAKING SIGNIFICANT PROGRESS IN REAL-TIME COST RECOVERY

AEP Ohio

Ohio Companies

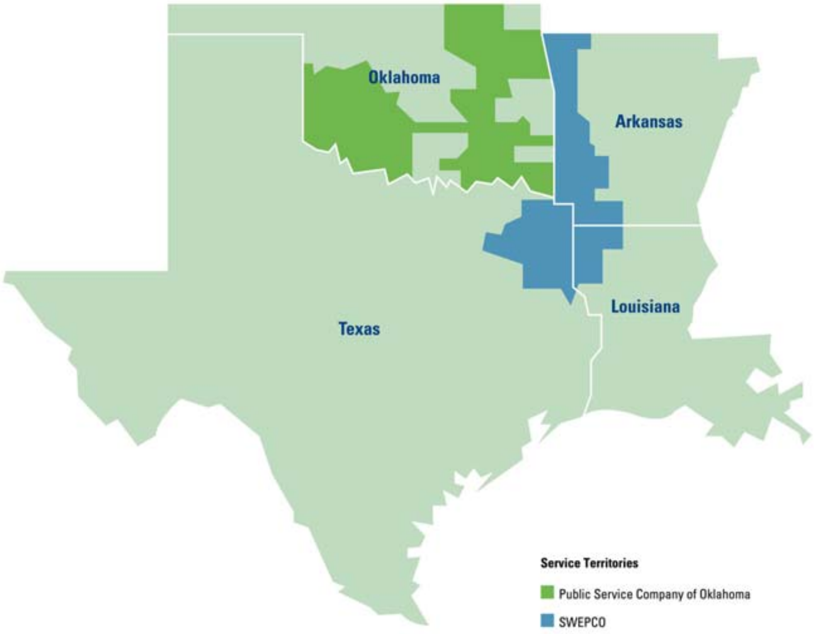


- Ohio Power Service Territory
- Columbus Southern Power Service Territory

- **Strategic Direction**
  - **Reliability enhancement**
  - **Pursue IGCC investment opportunity**
  - **Continue environmental investment program**
  - **Reach post-2008 answer**
    - **Extend RSP**
    - **Go to market**

OHIO POST 2008: SOUND PUBLIC POLICY SHOULD BALANCE ALL STAKEHOLDER EXPECTATIONS

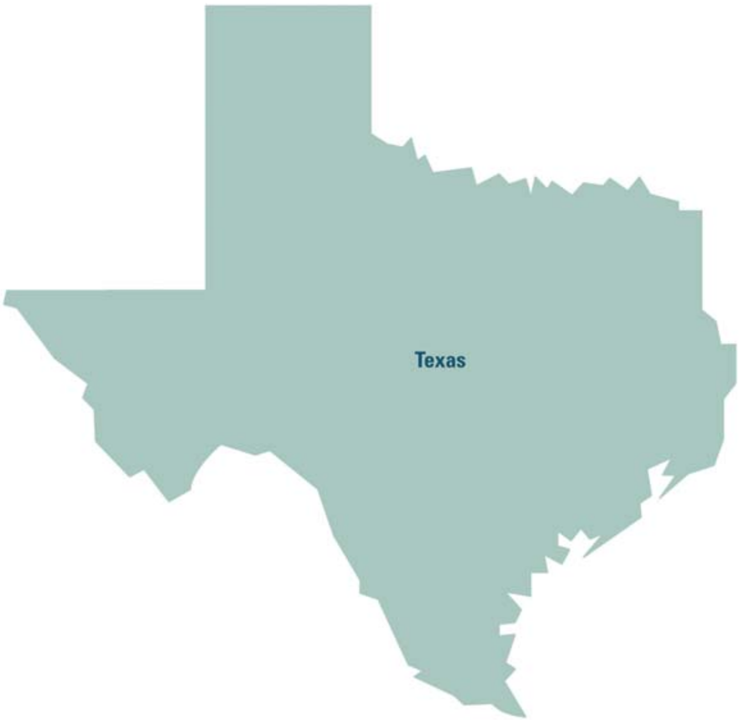
West Regulated Utilities



- **Strategic Direction**
  - **Planned investments to double combined PSO/SWEPCO rate base**
    - **Generation addition at PSO & SWEPCO – nears $3 billion**
  - **Innovative rate plans to reduce lag**
    - **Annual formula based rates**
    - **Return on CWIP**

SUBSTANTIAL GROWTH IN RATE BASE & ASSOCIATED RATE RELIEF TO DRIVE TO EARNINGS

AEP Texas

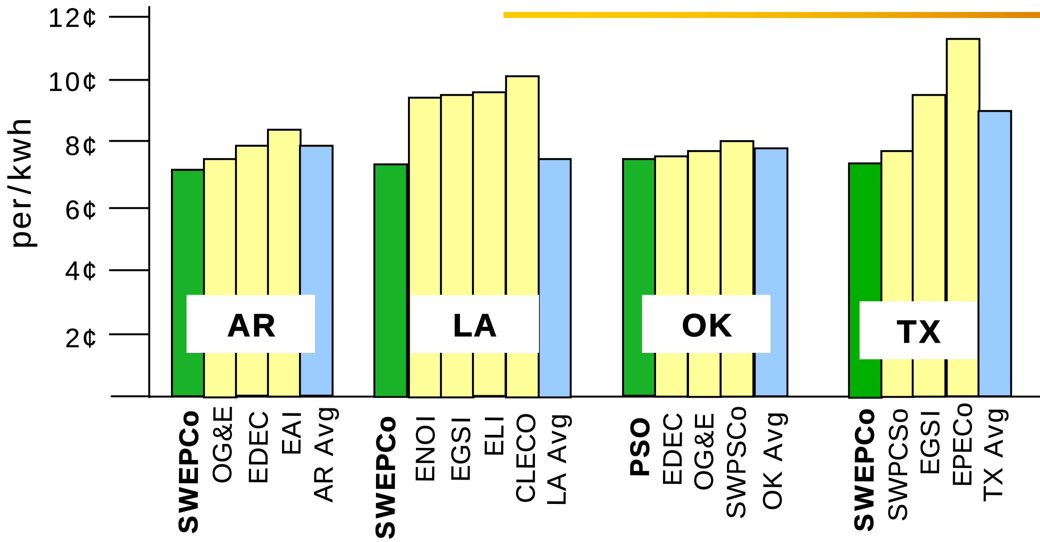


- **Strategic Direction**
- **TNC/TCC Wires Case to be filed late 2006**
- **ERCOT transmission**
  - **Formation of new AEP entity for purposes of transmission investment**
  - **Engage partner for capital investment**
  - **Total investment could double AEP transmission investment in ERCOT**

STRATEGIC DIRECTION AT FOREFRONT – WIRES CASE TO BE FILED; PURSUE TRANSMISSION INVESTMENTS

AEP Is The Low Cost Provider

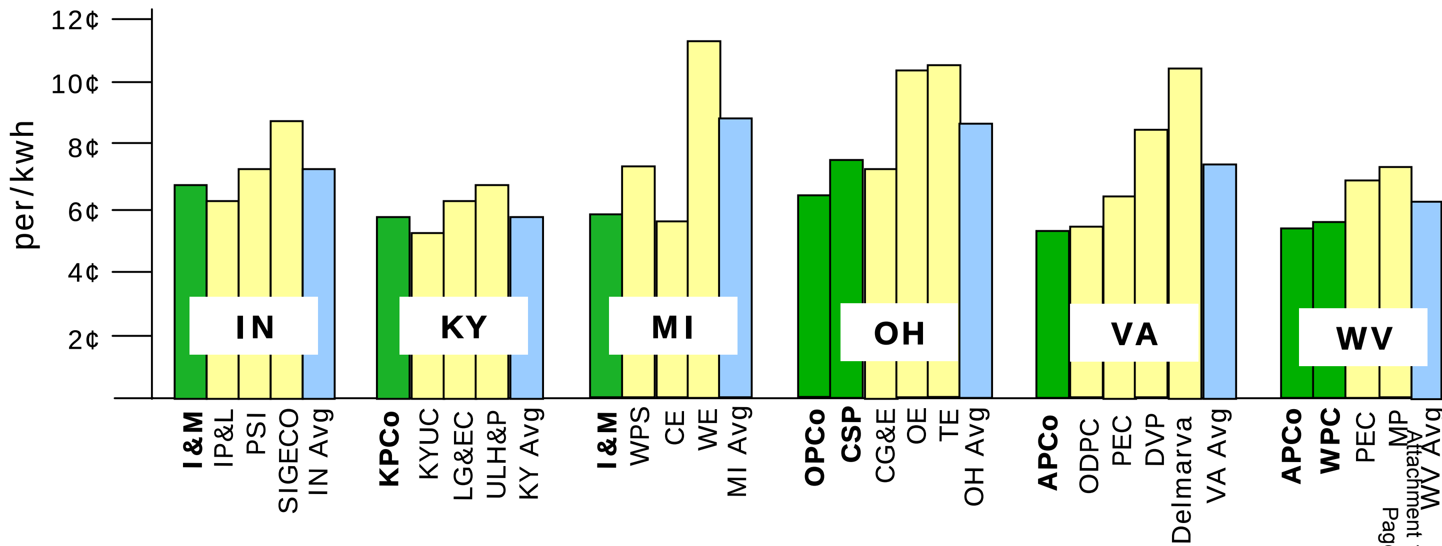
AEP West



Residential Average Realizations as of12/31/2005

Source: Winter 2006 EEI Typical Bills and Average Rates Report

AEP East



2006-2009 PROJECTED ANNUAL RATE INCREASE OF 3.8%

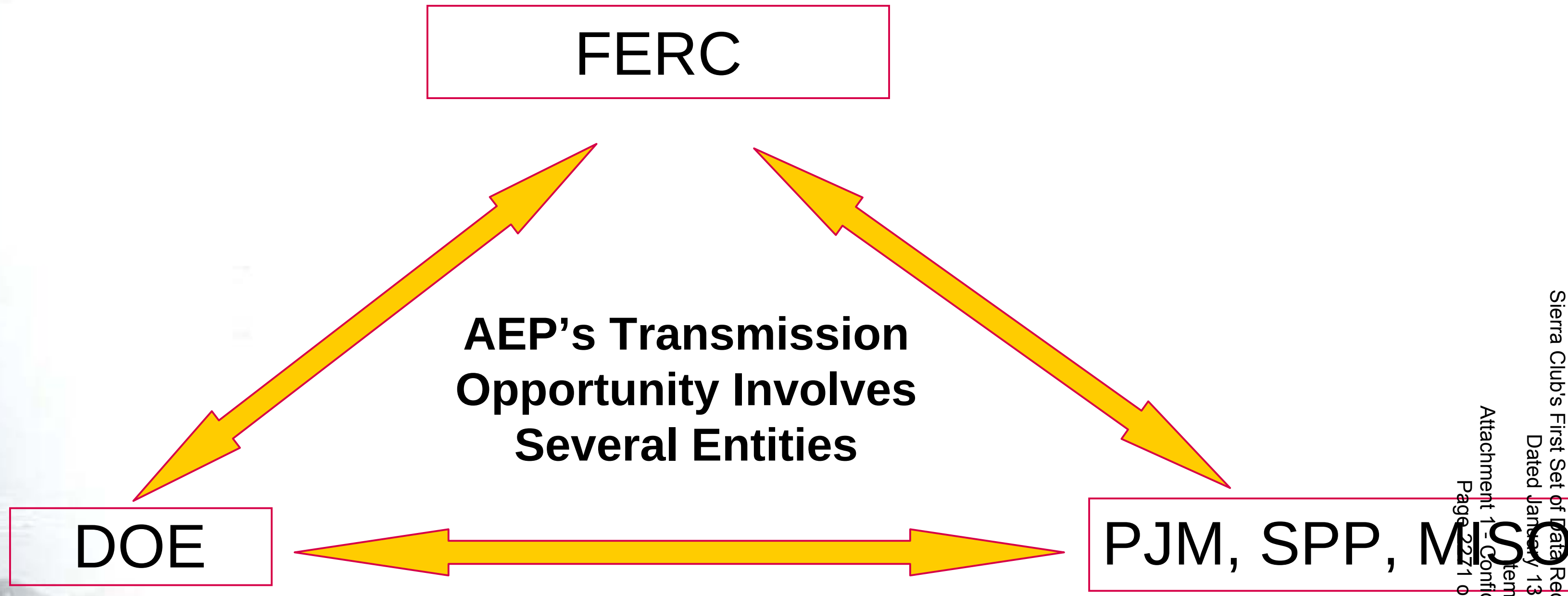
ERCOT Transmission Investment Opportunity

- **ERCOT Provides Unique Investment Opportunity**
  - **Transmission needs are considerable**
    - Competitive market resulting in ERCOT grid expansion
    - Aggressive renewable portfolio requirements for RECs
    - Socialization of grid improvement costs
    - Liberal interconnection of merchant generators
    - Continued Texas economic growth
  - **High degree of regulatory certainty for transmission investment**
    - Predetermination of need for ERCOT endorsed projects
    - Streamlined annual review process reduces lag
    - ROEs commensurate with other state regulatory returns
- **AEP Action Plan**
  - Create affiliated Texas transco company
  - Reduce capital requirements – enter into joint venture

AEP TEXAS IS UNIQUELY POSITIONED TO DEVELOP SUBSTANTIAL TRANSMISSION TO CAPTURE BENEFITS OF LOAD GROWTH AND TRADITIONAL & THIRD PARTY GENERATION

AEP's Interstate Transmission Opportunity

The Energy Policy Act of 2005 provides an unprecedented opportunity for transmission development, and AEP is in an enviable position to build upon its core strength to extend its strong 765 kV system to meet the nation's urgent need for interstate transmission. Lower voltage system opportunities also exist for AEP.



FERC Transmission

Strategic Direction

- **I-765 Project Opportunity ~ $3 billion**
  - **Formed Transco, AEP Transmission Co., LLC, subsidiary to own investment**
  - **Received conditional FERC approval for I-765 Project – cost recovery including incentive ROE rates & return on CWIP**
    - **Revenue accrual with minimal lag**
  - **Filed with DOE for early designation as National Interest Electric Transmission Corridor**
- **SPP Investment Opportunities ~ $2.75 billion**
- **ERCOT Investment Opportunity ~ $1 billion**
- **Other Transmission Investment Opportunities ~ $2 billion**
- **Actively participate in development of FERC regional rate design**

Create joint venture partnership to manage AEP capital requirements

CREATING THE BUSINESS MODEL TO ENHANCE VALUE AND MANAGE AEP CAPITAL OUTLAYS TO MEET THE NATION'S URGENT NEED FOR INTERSTATE TRANSMISSION

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Framework for Long-Range Performance

- Introduction of 2007, 2008 & 2009 Earnings Guidance Ranges:

2007 Range $2.85 to $3.05	2008 Range $3.00 to $3.30	2009 Range $3.15 to $3.45

- Increased EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
    - AEP Transmission Company
  - Seek rate recovery for new investments
  - Control costs
- Combined 2007 & 2008 capital investment amount reduced by $528MM versus previous guidance levels
- Commitment to recommend an 8-cent/share increase in annual dividend effective 4Q06
- Maintain credit ratings
  - BBB/Baa2/BBB

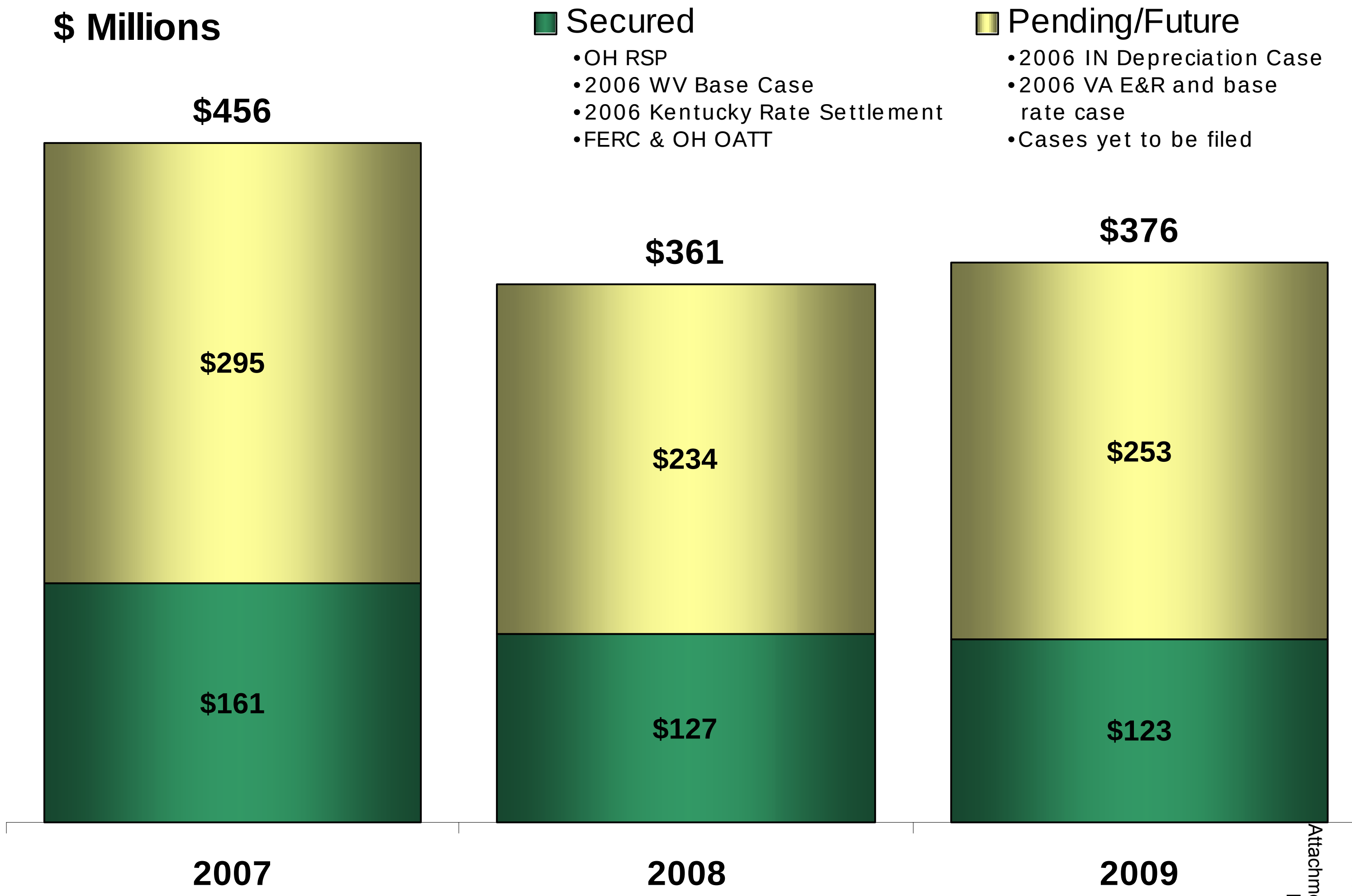
OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Summary of 5-7% Long-Range Growth Components

- **Energy sales growth of 1.5%**
  - Predicated on AEP's ability to economically dispatch at a high load capacity
- **Rate base investment**
  - Generation Plant Purchases & Build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- **Transmission company**
- **Commercial operations**
- **Regulatory strategy**
  - Achieve high returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

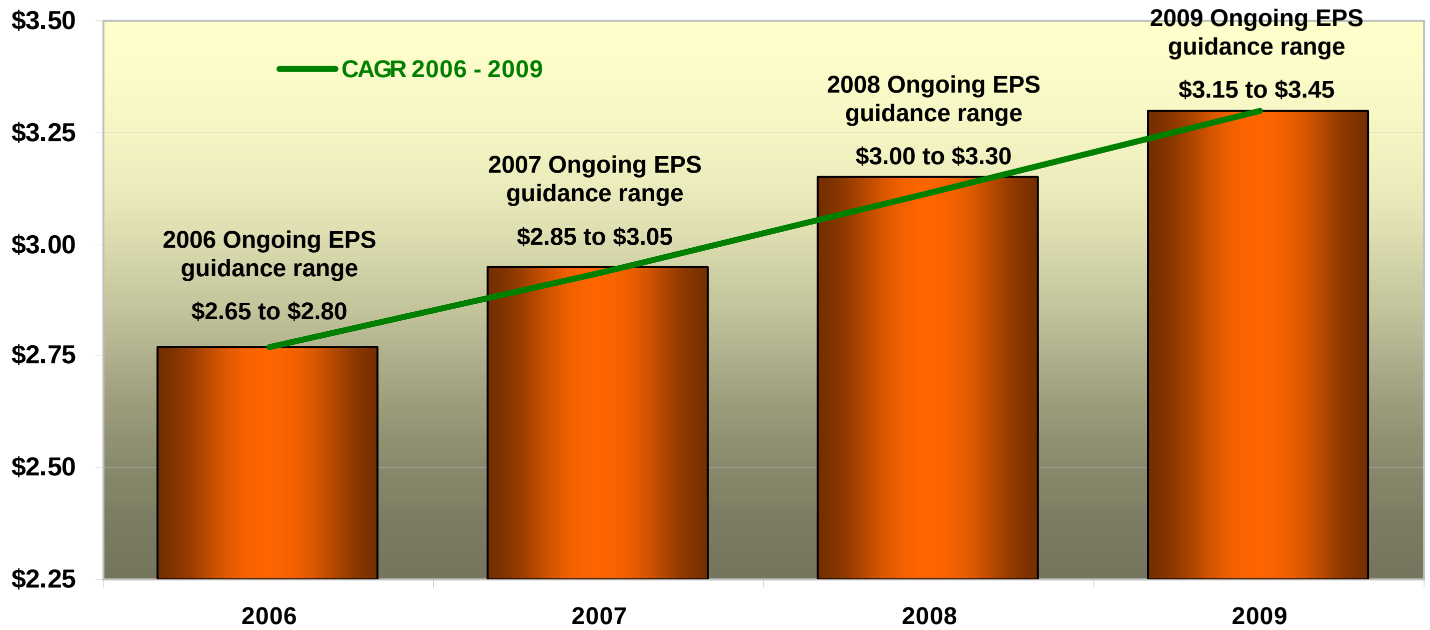
RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Incremental Rate Relief Composition



RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Long-Range EPS Expectations



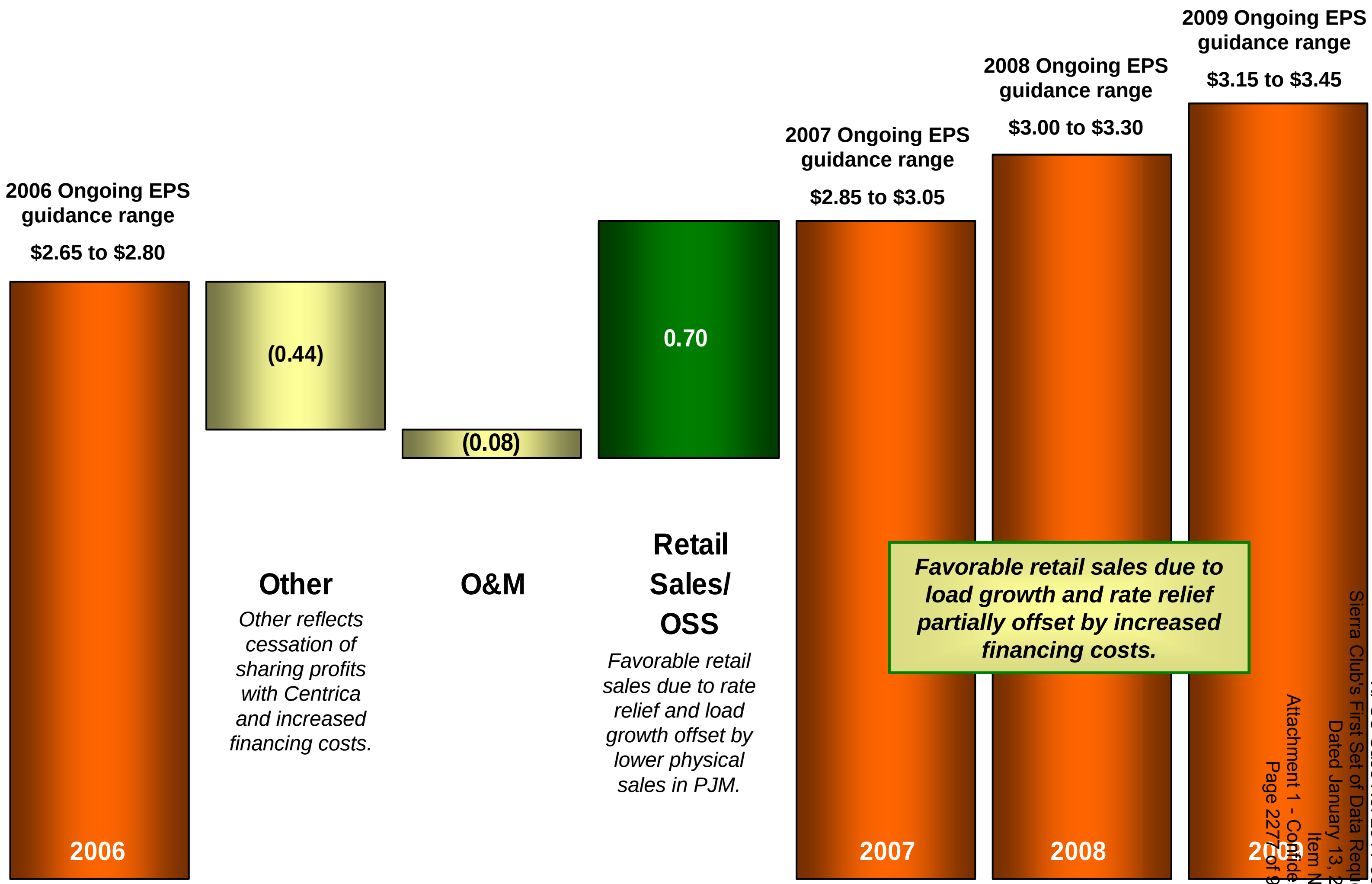
Long-Range Plan Highlights

- Committed to a 5-7% earnings growth range (2006-2009)
- Recommend an 8-cent/share increase in the annual dividend commencing 4Q2006
- Continue capital investment in utility business to support earnings growth
- Fund investment program with new rate relief and debt
  - No common equity issuance (except through Dividend Reinvestment Program)
- Create joint venture to build our transmission company

COMMITTED TO 5-7% EARNINGS GROWTH

Composition of Long-Range EPS Drivers

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS



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Commitment to Credit Quality

Forecast Parameters:

- Maintain minimum $200MM cash balance
- Dividend reinvestment plan activated September 2006
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

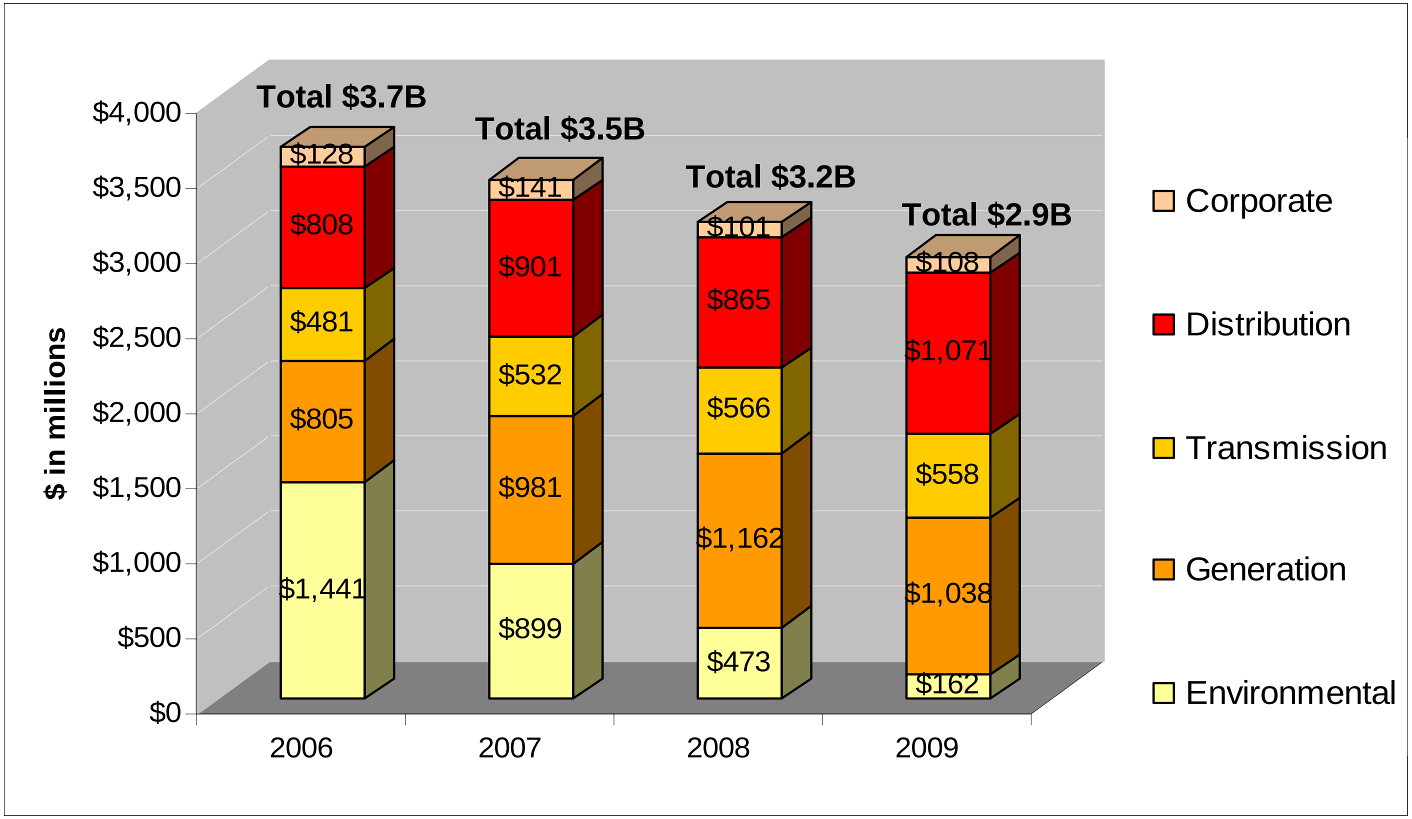
Company	Target Equity Ratio
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	45-48%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS BBB/Baa2/BBB

Holly Koeppel
EVP & Chief Financial Officer

Multi-Year Capital Investment Forecast



Note: Excludes AFUDC

CAPITAL INVESTMENT HAS BEEN REDUCED BY A COMBINED $528M IN 2007 & 2008 VERSUS PREVIOUS GUIDANCE LEVELS

Multi-Year Capital Investment Funding Plan

	Actual 2005	Projection 2006	Projection 2007	Projection 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (2,499)	$ (3,663)	$ (3,454)	$ (3,167)	$ (2,937)
Dividend on Common	$ (553)	$ (591)	$ (618)	$ (621)	$ (624)
Cash Sources					
Cash from Operations *	$ 1,877	$ 1,890	$ 2,232	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 1,246	$ 175	$ -	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ (25)	$ 45	$ 80	$ 80	$ 80
Change in Debt, Net	$ (91)	$ 661	$ 1,738	$ 1,176	$ 967
TCC securitization bond issuance	$ -	$ 1,740			
Other	$ 126	$ (268)	$ (95)	$ (67)	$ (69)
Cash Sources Less Capital Expenditures, Dividends & Other	$ 81	$ (11)	$ (117)	$ 43	$ 88
Ending Cash Balance	$ 401	$ 390	$ 273	$ 316	$ 404

Projected 2006-2009 Credit Metric Ranges
Debt to book capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Ongoing Guidance: $2.65 to $2.80 Per Share
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Estimate vs. 2007 Estimate

		Performance Driver	2006 Estimate ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,321 GWh @ $ 30.9 /MWhr =	2,141	71,033 GWh @ $ 33.7 /MWhr =	2,392
2	Ohio Companies	46,083 GWh @ $ 46.6 /MWhr =	2,147	47,902 GWh @ $ 49.5 /MWhr =	2,371
3	West Regulated Integrated Utilities	41,264 GWh @ $ 24.9 /MWhr =	1,026	40,795 GWh @ $ 25.9 /MWhr =	1,058
4	Texas Wires	26,506 GWh @ $ 14.4 /MWhr =	383	26,834 GWh @ $ 16.4 /MWhr =	441
5	Off-System Sales	35,100 GWh @ $ 23.1 /MWhr =	811	30,742 GWh @ $ 21.9 /MWhr =	672
6	Transmission Revenue - 3rd Party		282		255
7	Other Operating Revenue		579		715
8	Utility Gross Margin		7,369		7,904
9	Operations & Maintenance		(3,241)		(3,292)
10	Depreciation & Amortization		(1,316)		(1,413)
11	Taxes Other than Income Taxes		(747)		(785)
12	Interest Exp & Preferred Dividend		(664)		(813)
13	Other Income & Deductions		199		91
14	Income Taxes		(551)		(567)
15	Utility Operations On-Going Earnings		1,049		1,125
16	Investments On-Going Earnings		45		48
17	Parent Company On-Going Earnings		(1)		(6)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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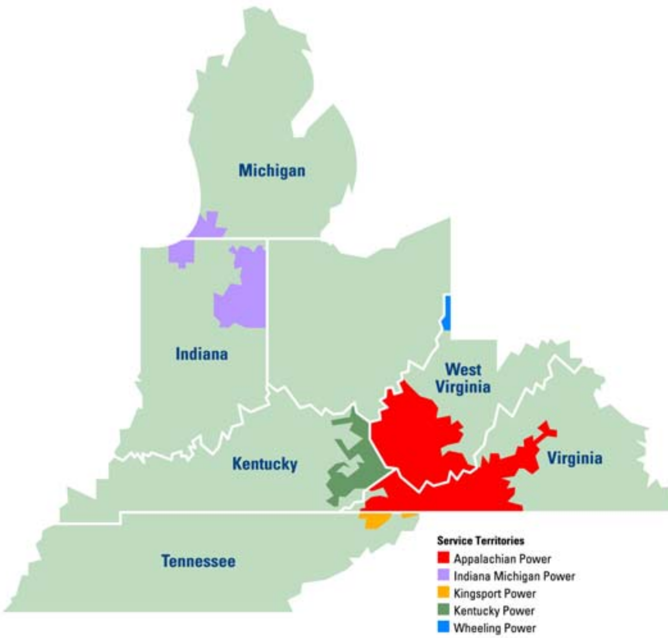
Summary of 2007 Earnings Drivers

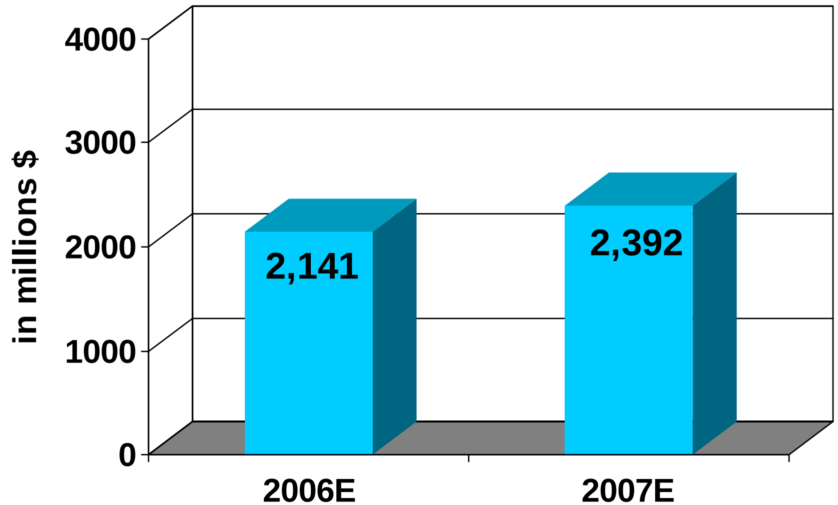
- Load growth of 1.5%
- Rate relief of $456MM ($161MM already secured)
- Improved performance at Investments
- Rising fuel costs of 6-8%
- Increased retail load & higher muni/co-op sales to impact off system sales contribution
- Higher financing costs
- Higher O&M (inflationary pressures)
- Lower contribution from Centrica sharing agreement

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS

Utility Operations

East Regulated Integrated Companies



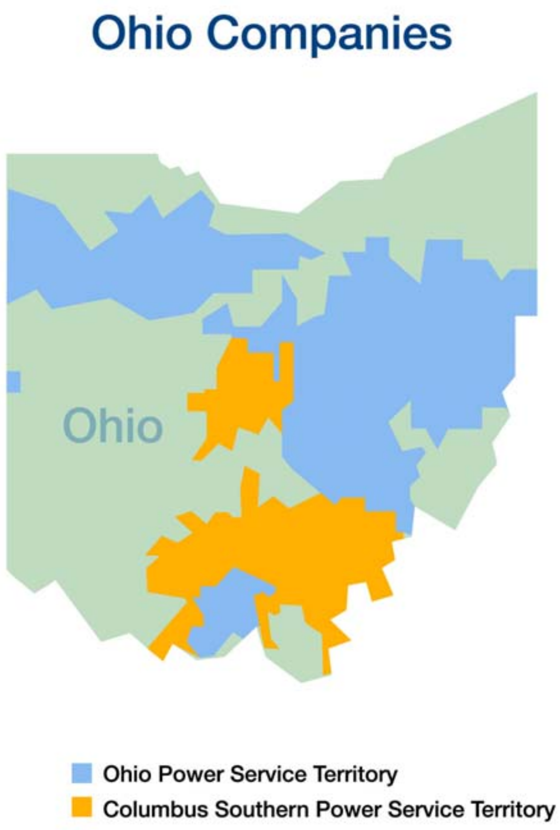


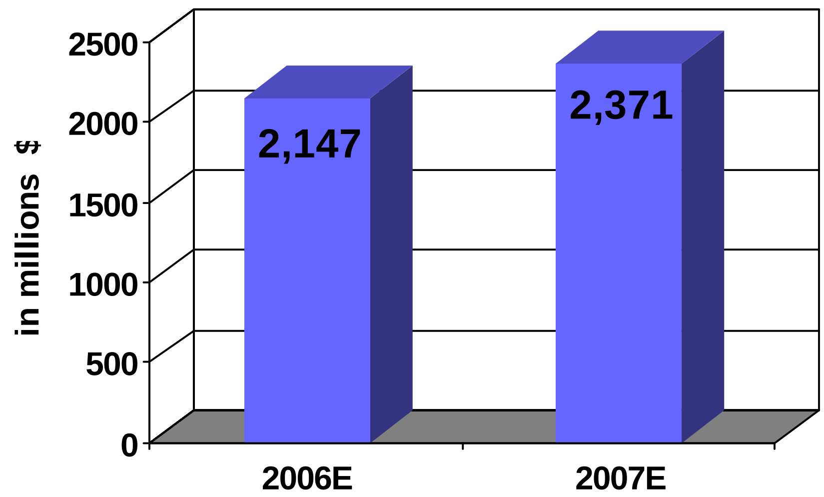
Earnings Drivers (in millions $)

Load Growth & Normal Weather	78
Rate Changes	175
Fuel Clause Activations	36
Capacity Settlement	(24)
Other	(14)
	251

$251 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations



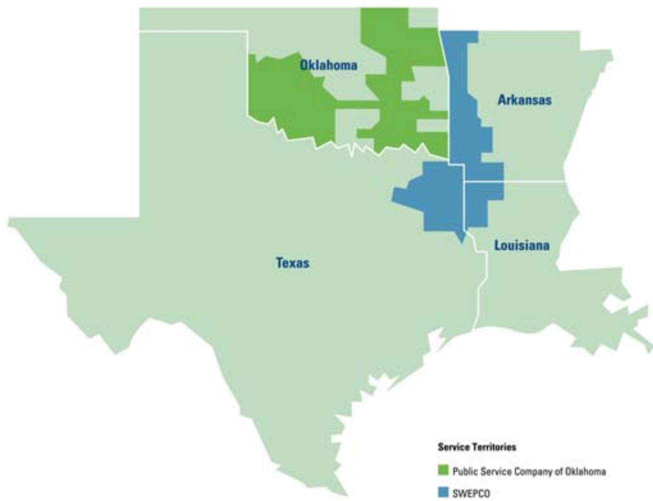


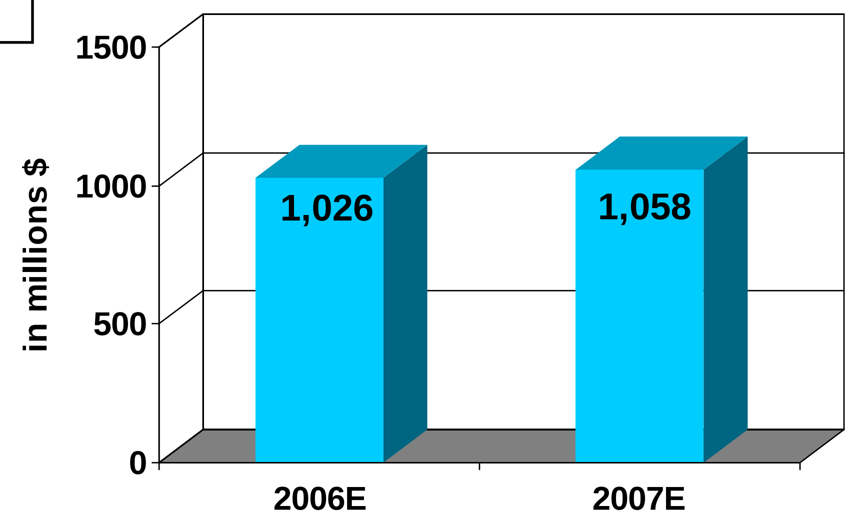
Earnings Drivers (in millions $)	
Load Growth & Normal Weather	94
Rate Relief	120
Fuel Costs	(13)
Capacity Settlement	24
Other	(1)
	224

$224 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations

West Integrated Companies



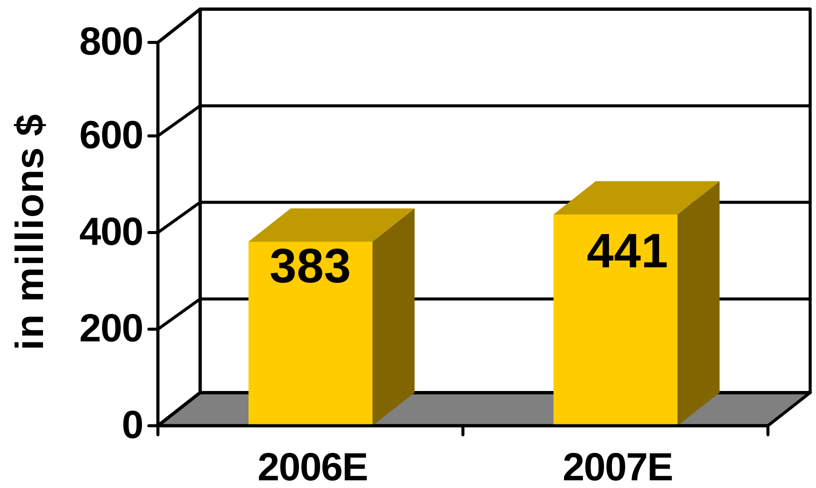


Earnings Drivers (in millions $)	
Load Growth & Normal Weather	(22)
Rate Changes	38
Other	16
	32

$32 MILLION INCREASE IN GROSS MARGIN FOR 2007

Utility Operations

Texas Wires

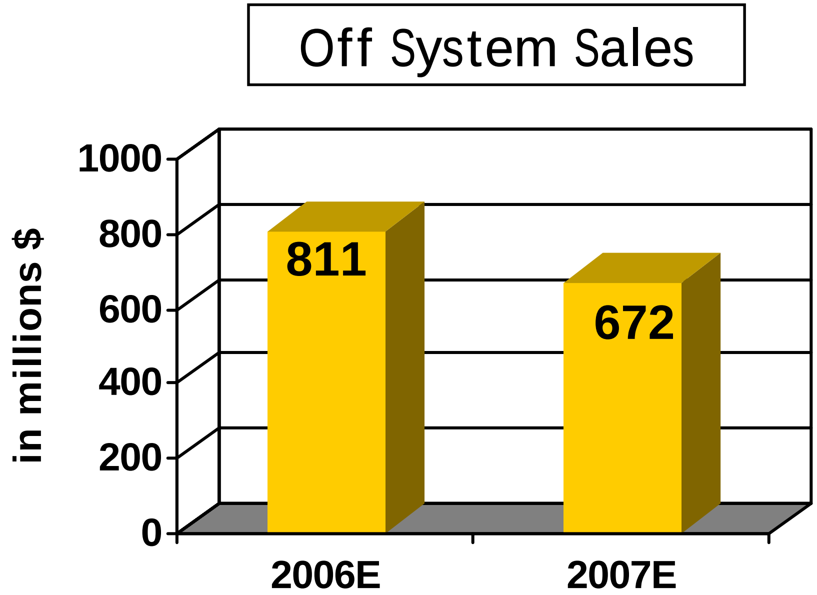


Earnings Drivers (in millions $)

Load Growth & Normal Weather	7
Rate changes	59
Other	(8)
	58

$58MM INCREASE IN GROSS MARGIN FOR 2007

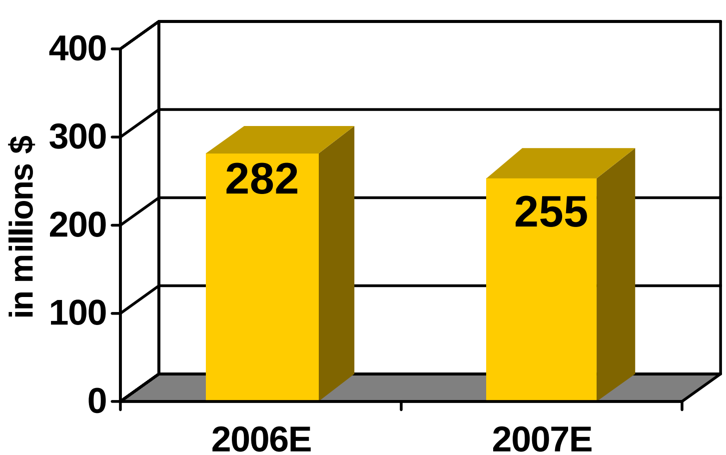
Utility Operations



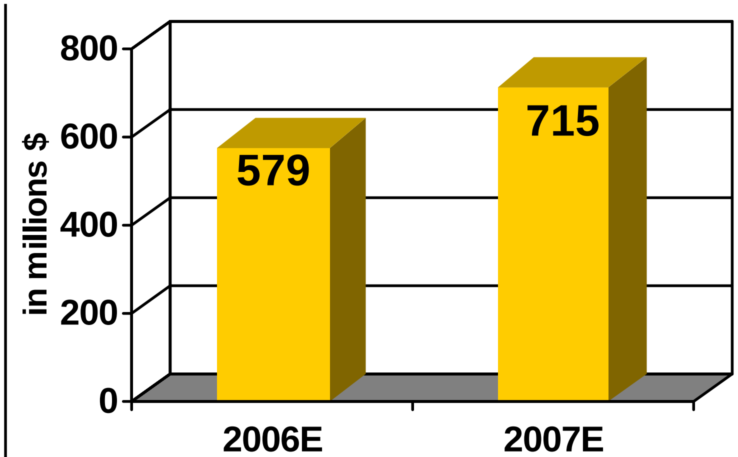
DECLINE IN OFF SYSTEM SALES GROSS MARGIN DRIVEN BY INCREASED RETAIL LOAD AND GROWING MUNI/CO-OP SALES CAPTURED ON LINES 1-3

Utility Operations

Transmission Revenues – 3rd Party



Other Operating Revenue



Earnings Drivers (in millions $)

PJM	(36)
ERCOT	11
SPP	(2)
	(27)

$27MM REDUCTION

Earnings Drivers (in millions $)

TX Securitization Revenue	114
Other	22
	136

$136MM INCREASE

Utility Operations

Expense Drivers

Operations & Maintenance	**(51)**
Depreciation & Amortization	
Plant additions	(103)
Change in depreciation rates	85
Amortizations (primarily TCC Securitization*)	(79)
	(97)
Taxes	
Taxes Other than Income Taxes	(38)
Change in Pre-Tax Income	(16)
	(54)
Interest Expense & Pref. Dividends	
Securitized Debt*	(65)
Debt (net increase)	(84)
	(149)
Total	**(351)**

$51MM increase

$97 MM increase

$54MM increase

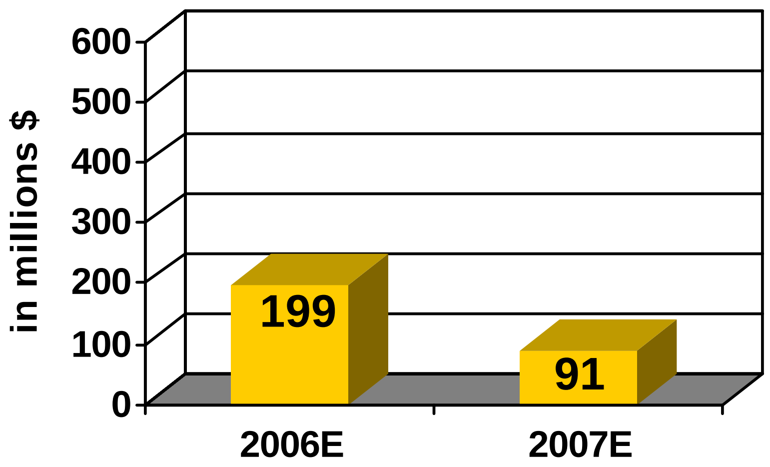
$149MM increase

* TCC amortization and interest expenses associated with $1.7 billion securitization bond issuance in October are fully offset by higher revenues.

UTILITY OPERATIONS EXPENSES TO RISE $351MM IN 2007

Utility Operations

Other Income & Deductions



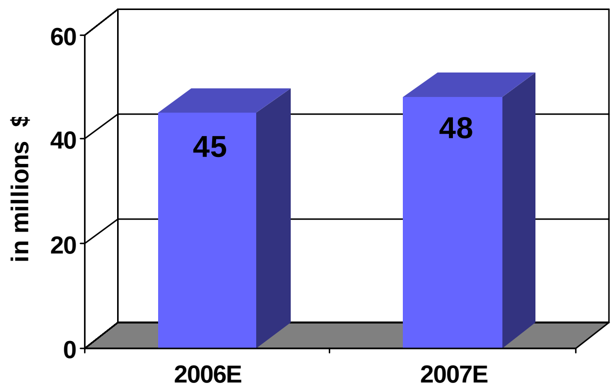
Earnings Drivers (in millions $)

Centrica Sharing	(50)
TX Carrying Charges	(49)
Other	(9)
	(108)

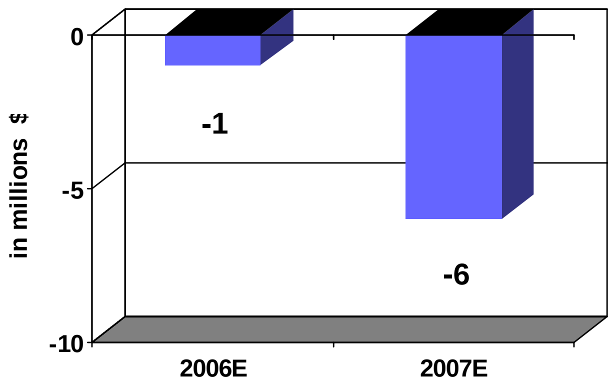
$108MM REDUCTION IN GROSS MARGIN FOR 2007

Investments & Parent Company

Investments



Parent Company



Investment Drivers:

- Slightly lower results from MEMCO
- Elimination of Dow somewhat offset by replacement debt

Parent Company Drivers:

- Increased borrowing at the Parent company

COMBINED PERFORMANCE FLAT YEAR-OVER-YEAR

Risks and Uncertainties within 2007 EPS Guidance Range

2007 EPS Guidance Range is $2.85 to $3.05

2007

- *Outcome of pending regulatory proceedings*
- *Wholesale market volatility*
- *Plant availability*
- *Rising fuel costs*
- *Weather*

Appendix

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

2006 / 2007 Cash Flow

	2006 Guidance	2007 Guidance
Beginning Cash Balance	**$ 401**	**$ 390**
Cash from Operations:		
Income from Continuing Operations	1,093	1,167
Depreciation and Amortization	1,346	1,442
Pension/OPEB Funding & Reserves	2	-
Extraordinary Items	(108)	-
Other	(443)	(377)
Total from Operations	**$ 1,890**	**$ 2,232**
Cash from Investing:		
Capital Expenditures	(3,663)	(3,454)
Asset Sales	175	-
Other	(320)	(91)
Total from Investing	**$ (3,808)**	**$ (3,545)**
Cash from Financing:		
Common Equity	45	80
Net Long Term Debt Issued/(Retired)	2,268 *	1,323
Preferred Stock Redeemed	-	-
Short Term Debt Change, Net	133	415
Common Dividends	(591)	(618)
Other Financing Activities	52	(4)
Total from Financing	**$ 1,907**	**$ 1,196**
Net Change in Cash	**$ (11)**	**$ (117)**
Ending Cash Balance	**$ 390**	**$ 273**

* Includes $1.7 billion of securitization bonds issued in October 2006

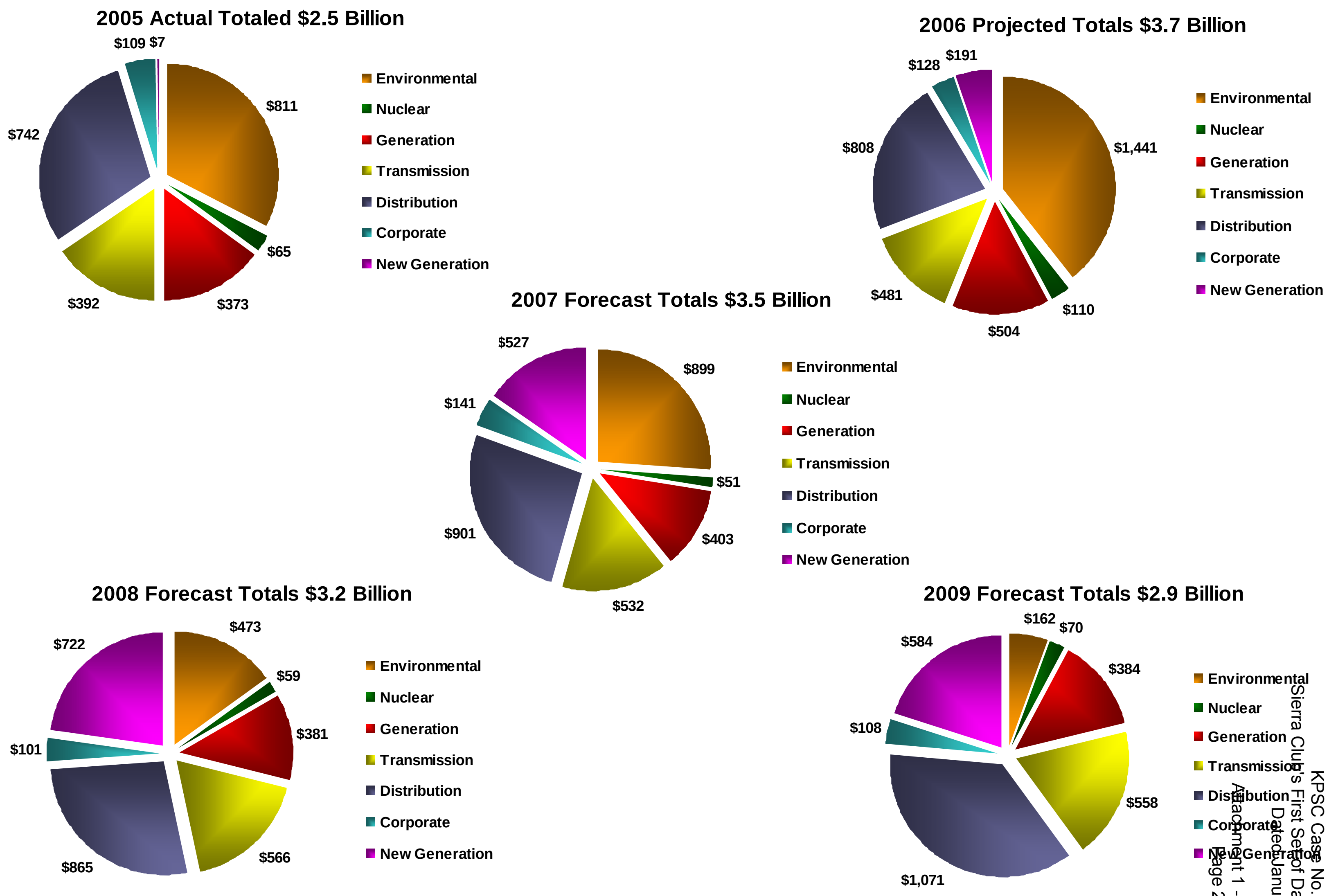
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Structure

Capital Structure	Actual 6/30/2006		
	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	12,645	-	12,645
Short-term Debt	159	-	159
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	9,426	9,426
Total Capitalization per Balance Sheet	**12,804**	**9,487**	**22,291**
% of Capitalization per Balance Sheet	***57.4%***	***42.6%***	***100.0%***
Adjustments			
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)
Off-balance Sheet Leases	1,199	-	1,199
Securitization Bonds	(617)	-	(617)
Spent Nuclear Fuel Trust	(241)	-	(241)
Total Adjusted Capitalization	**13,144**	**9,457**	**22,601**
% of Adjusted Capitalization	***58.2%***	***41.8%***	***100.0%***

Adjusted debt-to-cap of 58.2% at 6/30/06

Capital Investment 2005 - 2009



Notes: Figures exclude AFUDC.

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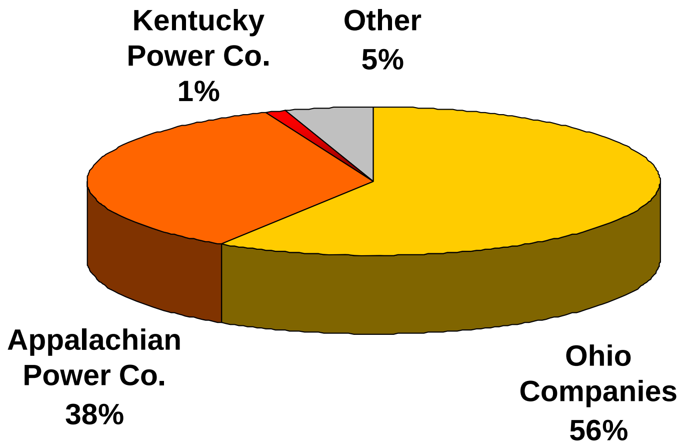
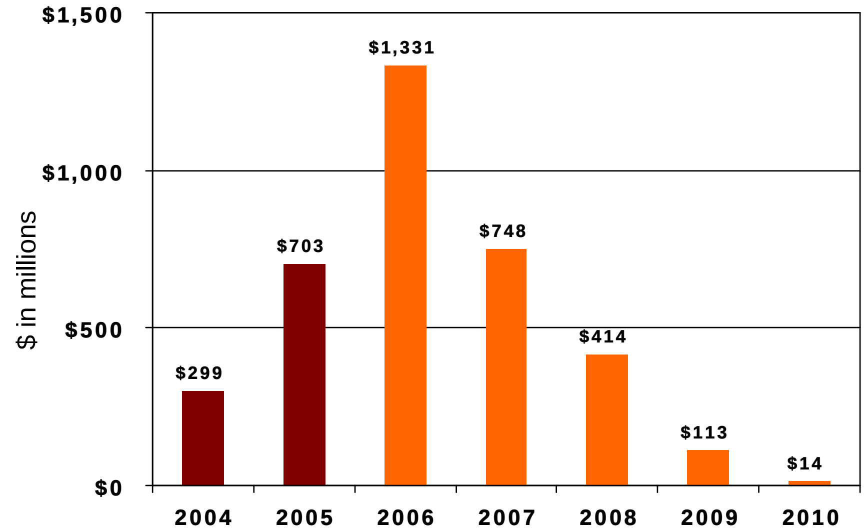
Environmental Investment: SO_2, NOx & Hg

Projected Environmental Investment Allocation



Environmental Investment: NOx, SO_2 & Hg (including AFUDC)



Note: 2004-2005 reflect actual investment level

$3.0 Billion SO_2 Investment	+	$500 Million NOx Investment	+	$100 Million Hg Investment	=	$3.6 Billion Environmental Investment Through 2010

$3.6 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

KPSC Case No. 2011-00401
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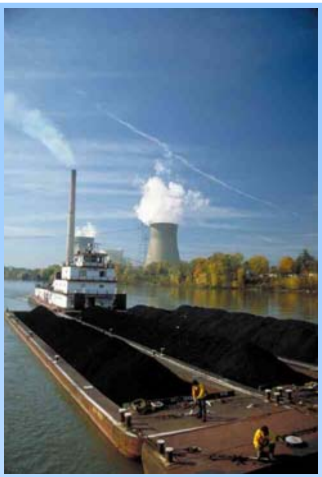
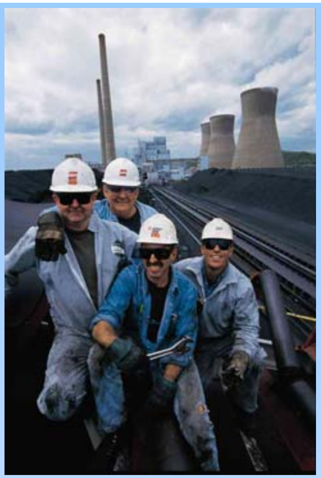
IGCC – Commitment & Expectations

- **We are committed to IGCC technology**
- **Project timing dependent on regulatory recovery assurances**
  - Pursuit of legal and regulatory approvals underway
  - Capital forecast reflects latest expectation for regulatory approvals
  - Interim capacity requirements can be met through distressed generation opportunities, coal fired generation, etc.

AEP BELIEVES IGCC IS THE CLEAN COAL TECHNOLOGY OF THE FUTURE

1906 AEP 2006
AMERICAN ELECTRIC POWER • 100TH ANNIVERSARY
A Century of Firsts





Calyon Utilities & Energy

Merchant Conference

November 30, 2006

New York City

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

Deliver value to our investors

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Framework For Long-Range Performance

- 2006, 2007, 2008 & 2009 Earnings Guidance Ranges:

2006 Range $2.65 to $2.80	**2007 Range $2.85 to $3.05**
2008 Range $3.00 to $3.30	**2009 Range $3.15 to $3.45**

- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
    - AEP Transmission Company
  - Seek rate recovery for new investments
  - Control costs
- Maintain credit ratings
  - BBB/Baa2/BBB

OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

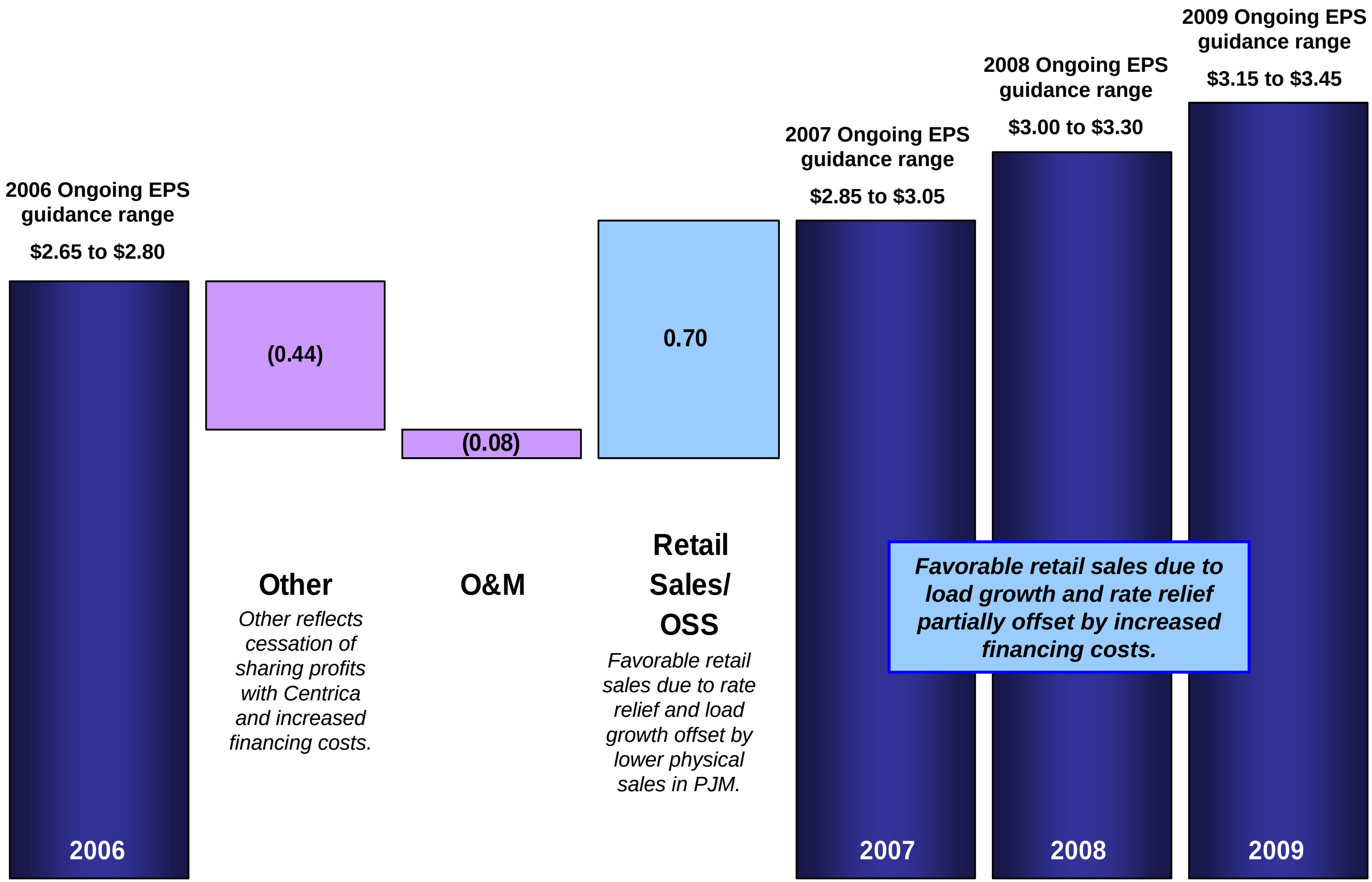
Summary of 5-7% Long-Range Growth Components

- **Energy sales growth of 1.5%**
  - Predicated on AEP's ability to economically dispatch at a high load capacity
- **Rate base investment**
  - Generation Plant Purchases & Build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- **Transmission company**
- **Commercial operations**
- **Regulatory strategy**
  - Achieve high returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Composition of Long-Range EPS Drivers

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS



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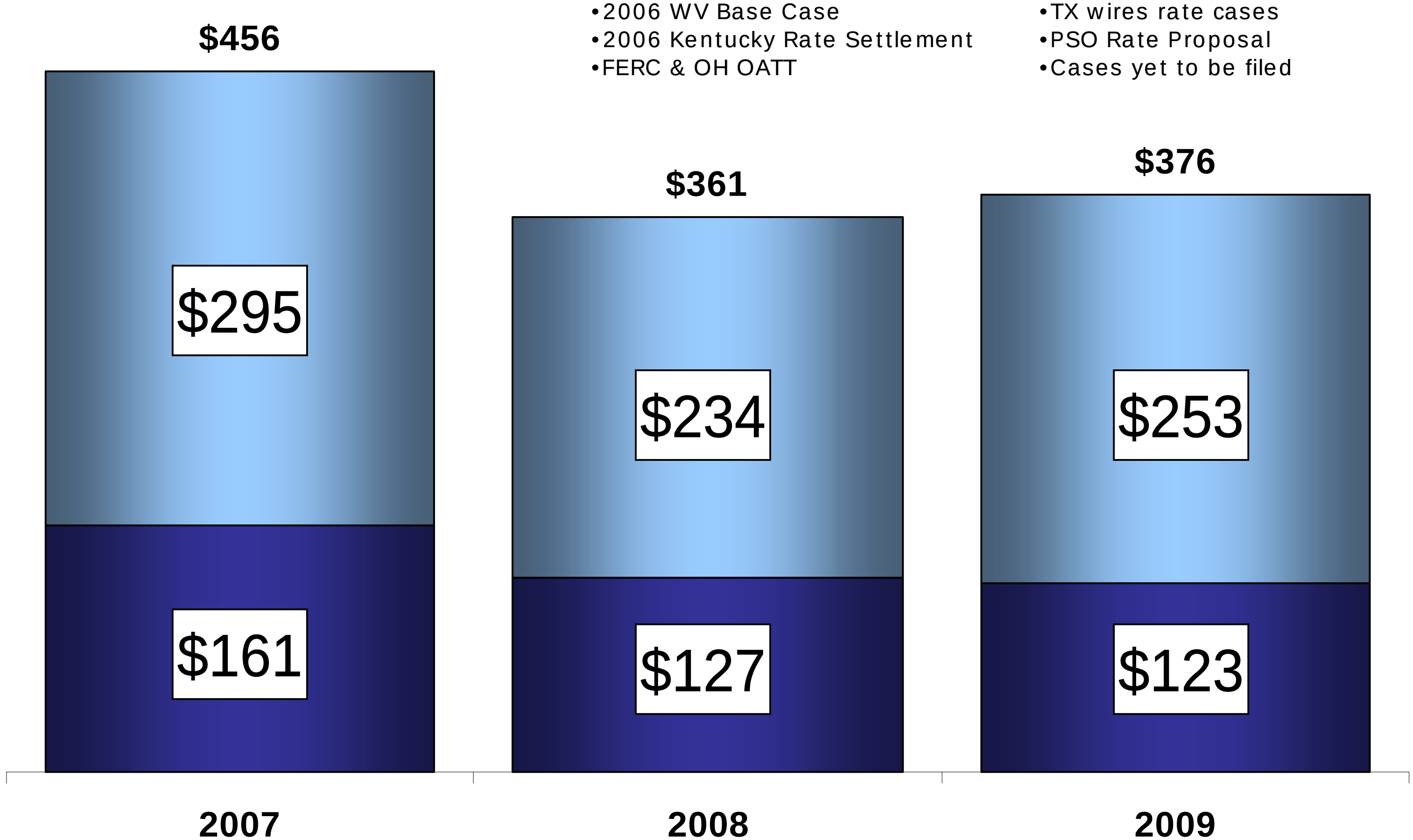
Incremental Rate Relief Composition

$ Millions

Secured
- OH RSP
- 2006 WV Base Case
- 2006 Kentucky Rate Settlement
- FERC & OH OATT

Pending/Future
- VA General Rate Case
- TX wires rate cases
- PSO Rate Proposal
- Cases yet to be filed



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secure, based on the Virginia SCC's Nov. 20th order in our E&R case. Further analysis is required to quantify these amounts.

RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Current State Regulatory Activity

Virginia

VA Environmental & Reliability Order

- On Nov. 20, 2006, the VA SCC issued an order allowing APCo-VA to recover $21.3MM of incremental E&R spending covering the costs incurred July 1, 2004 through Sept. 30, 2005
- The surcharge will be collected Dec. 1, 2006 through Nov.30, 2007
- The order established an ROE of 9.8% (applicable to incremental E&R investment), but allowed for adjustment of ROE in future E&R proceedings
- The next E&R proceeding would seek recovery of costs incurred Oct. 1, 2005 thru Oct. 1, 2006

VA General Rate Case

- Seeking $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM
- SCC ordered implementation of full $198.5MM rate increase to be effective October 2, subject to refund
- SCC staff filed testimony recommending a $12.7MM rate increase, which includes a 9.9% ROE and no off-system sales margin sharing

Texas

TCC & TNC Wires Rate Cases – filed 11/9/06

- TCC & TNC requested rate increases of $82.7MM and $25MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC for the expiration of merger-related billing credits that have been in place since 2000
- Requested ROE of 11.25% using capital structure of 60% debt / 40% equity

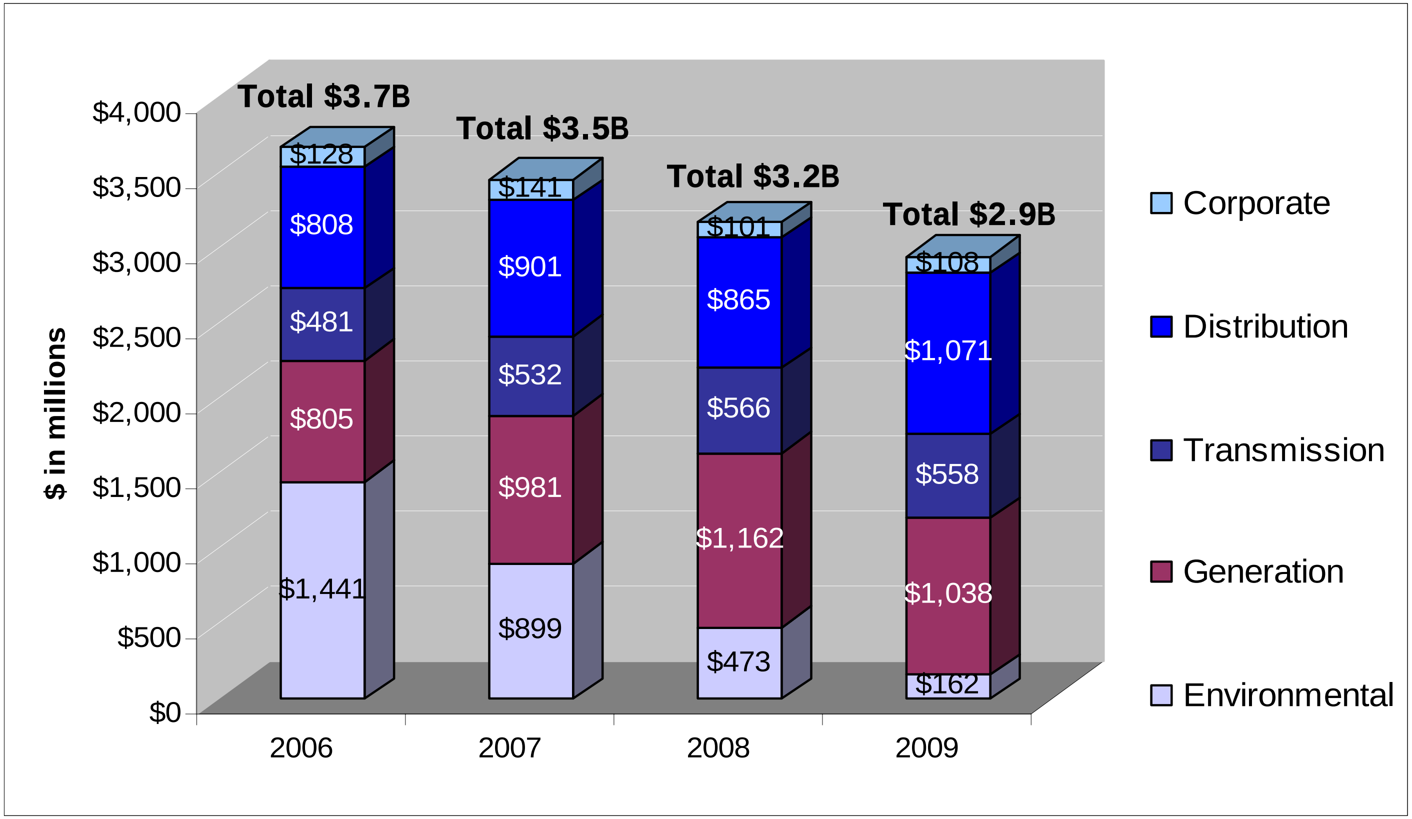
Oklahoma

PSO Rate Proposal – filed 11/21/06

- PSO's rate proposal contains the following major components:
  - $49.6MM overall increase in base rates to recover increased costs and investments already made
  - Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP
  - Requested ROE of 11.75% using capital structure of 54% debt / 46% equity

NEW RATE RELIEF TO CONTRIBUTE TO EARNINGS IN 2007

Multi-year Capital Investment Forecast



Note: Excludes AFUDC

CAPITAL INVESTMENT WILL BE FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Commitment to Credit Quality

Forecast Parameters:

- Maintain minimum $200MM cash balance
- Dividend reinvestment plan activated September 2006
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS BBB/Baa2/BBB

Company	Target Equity Ratio
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	45-48%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

A Century of Firsts

Transmission Opportunities

AEP Transmission Vision & Mission

- Maintain our position as the largest transmission company in the United States
- Maintain our leadership in technical innovation of transmission systems
- Set the standards for transmission safety, efficiency, and reliability
- Provide for robust market competition - benefiting customers by de-bottlenecking the U.S. transmission grid
- Reduce the need for new generation by facilitating the optimal economic dispatch of existing generation assets
- Increase earnings for AEP shareholders

MAINTAINING OUR LEADERSHIP POSITION AND SETTING THE STANDARDS

AEP Transmission Strategy

A Century of Firsts

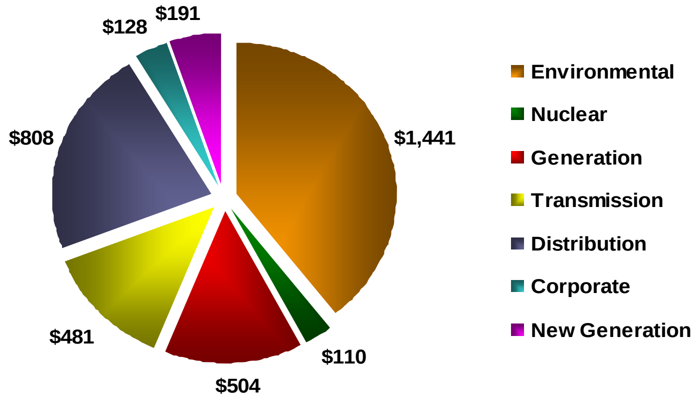
- Expand our vibrant transmission business with major new joint venture projects, taking advantage of EPAct 2005
- Aggressively seek recovery through various state and federal mechanisms
- Advocate transmission nationally as an enabler of market efficiency, economic opportunity, environmental optimization, and national security

THE AEP ADVANTAGE: 100 YEARS OF TRANSMISSION LEADERSHIP EXPERIENCE IN THE UNITED STATES

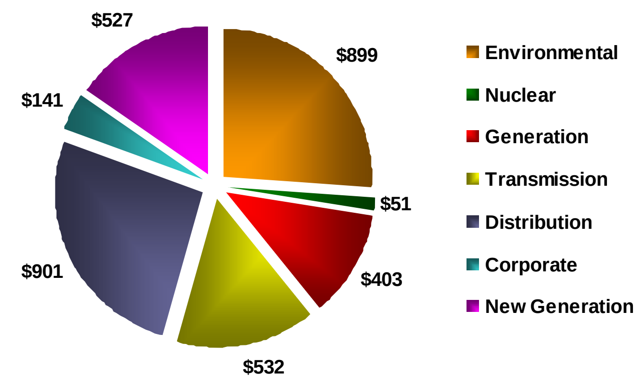
AEP Transmission Investment Forecast

Investing over $2.1 billion 2006-2009

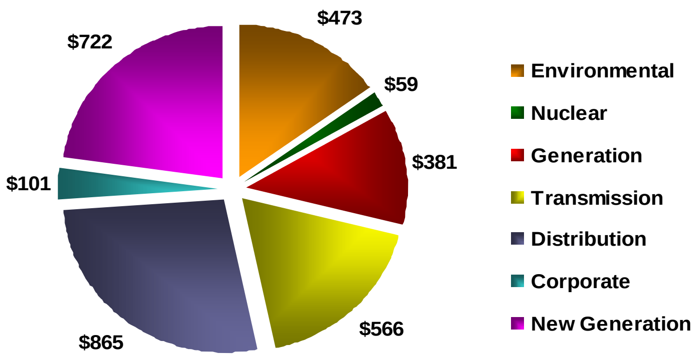
2006 Projected Totals $3.7 Billion



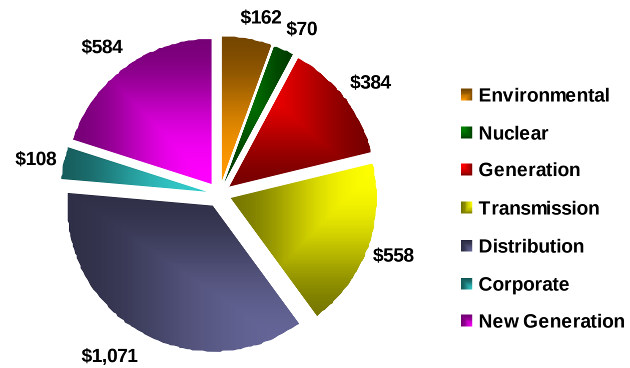
2007 Forecast Totals $3.5 Billion



2008 Forecast Totals $3.2 Billion



2009 Forecast Totals $2.9 Billion



AEP – ONE OF THE PREMIER TRANSMISSION UTILITIES IN THE UNITED STATES, IF NOT THE WORLD

15

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- **~$1 billion in ERCOT via JV with MidAmerican**
- **~$2 billion 765-kV study with ITC in Michigan**
- **~$3 billion I-765 Project in PJM**
- **~$3 billion project filed with SPP**

BUILDING THE NEXT US INTERSTATE SYSTEM FOR ENHANCED RELIABILITY AND MARKET EFFICIENCY

*Note: ~$9 billion investment opportunity not included in current capital guidance forecasts with exception of ERCOT investment of $60MM in 2007 and $95MM 2008

Conclusion

- $2.1 billion traditional transmission investment planned 2006-2009
- Additional $9 billion transmission opportunity being pursued with anticipated partnerships
- Potential earnings contribution of $0.60/share
- The nation's pioneer in EHV technology, AEP has a leadership role in 765-kV development enabling the U.S. transmission grid and improving reliability & market efficiency
- AEP is assessing potential transmission projects and moving forward with care & prudence

Appendix

2006 Ongoing Guidance: $2.65 to $2.80 Per Share
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Estimate vs. 2007 Estimate

		Performance Driver	2006 Estimate ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,321 GWh @ $ 30.9 /MWhr =	2,141	71,033 GWh @ $ 33.7 /MWhr =	2,392
2	Ohio Companies	46,083 GWh @ $ 46.6 /MWhr =	2,147	47,902 GWh @ $ 49.5 /MWhr =	2,371
3	West Regulated Integrated Utilities	41,264 GWh @ $ 24.9 /MWhr =	1,026	40,795 GWh @ $ 25.9 /MWhr =	1,058
4	Texas Wires	26,506 GWh @ $ 14.4 /MWhr =	383	26,834 GWh @ $ 16.4 /MWhr =	441
5	Off-System Sales	35,100 GWh @ $ 23.1 /MWhr =	811	30,742 GWh @ $ 21.9 /MWhr =	672
6	Transmission Revenue - 3rd Party		282		255
7	Other Operating Revenue		579		715
8	Utility Gross Margin		7,369		7,904
9	Operations & Maintenance		(3,241)		(3,292)
10	Depreciation & Amortization		(1,316)		(1,413)
11	Taxes Other than Income Taxes		(747)		(785)
12	Interest Exp & Preferred Dividend		(664)		(813)
13	Other Income & Deductions		199		91
14	Income Taxes		(551)		(567)
15	Utility Operations On-Going Earnings		1,049		1,125
16	Investments On-Going Earnings		45		48
17	Parent Company On-Going Earnings		(1)		(6)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Summary of 2007 Earnings Drivers

- Load growth of 1.5%
- Rate relief of $456MM ($161MM already secured)
- Improved performance at Investments
- Rising fuel costs of 6-8%
- Increased retail load & higher muni/co-op sales to impact off system sales contribution
- Higher financing costs
- Higher O&M (inflationary pressures)
- Lower contribution from Centrica sharing agreement

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS

Risks and Uncertainties within 2007 EPS Guidance Range

2007 EPS Guidance Range is $2.85 to $3.05

2007

- *Outcome of pending regulatory proceedings*
- *Wholesale market volatility*
- *Plant availability*
- *Rising fuel costs*
- *Weather*

Multi-year Capital Investment Funding Plan

	Actual 2005	Projection 2006	2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (2,499)	$ (3,663)	$ (3,454)	$ (3,167)	$ (2,937)
Dividend on Common	$ (553)	$ (591)	$ (618)	$ (621)	$ (624)
Cash Sources					
Cash from Operations *	$ 1,877	$ 1,890	$ 2,232	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 1,246	$ 175	$ -	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ (25)	$ 45	$ 80	$ 80	$ 80
Change in Debt, Net	$ (91)	$ 661	$ 1,738	$ 1,176	$ 967
TCC securitization bond issuance	$ -	$ 1,740			
Other	$ 126	$ (268)	$ (95)	$ (67)	$ (69)
Cash Sources Less Capital Expenditures, Dividends & Other	$ 81	$ (11)	$ (117)	$ 43	$ 88
Ending Cash Balance	$ 401	$ 390	$ 273	$ 316	$ 404

Projected 2006-2009 Credit Metric Ranges

Debt to book capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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New York

December 1, 2005

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Executive Vice President & Chief Financial Officer

Framework for 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
  - New Generation
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

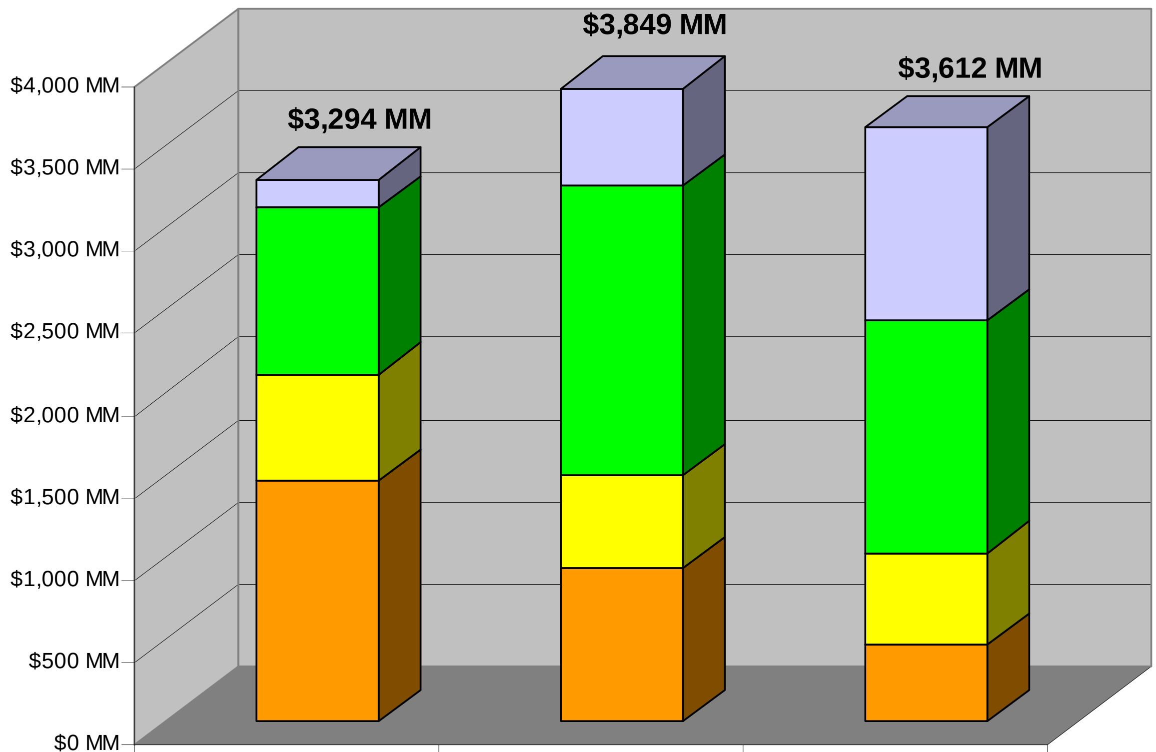
Summary of Major 2006 Earnings Drivers

AEP®

- ✓ Load growth of 2.5%
- ✓ $300MM new rate recovery in progress
- ✓ Rising fuel costs of 10-12%
- ✓ Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- ✓ Decline in utility operations O&M
- ✓ Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Capital Investment Forecast



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$168 MM	$593 MM	$1,176 MM
Ongoing Infrastructure Replacement/ Economically Justified	$1,016 MM	$1,757 MM	$1,412 MM
Mandated T&D	$646 MM	$568 MM	$554 MM
Environmental Compliance	$1,464 MM	$931 MM	$470 MM

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

($ in millions)	Actual 2004	Projection 2005	2006	2007	2008
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,656)	$ (2,110)	$ (1,499)	$ (1,024)
Discretionary Cap Ex Predicated on Rate Recovery &/or Cash Generated	n/a	n/a	$ (1,184)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,656)	$ (3,294)	$ (3,849)	$ (3,612)
Dividend on Common	$ (554)	$ (554)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,597	$ 1,666	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,357	$ 1,628	$ -	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan in 2007 & 2008)	$ 16	$ (33)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,230)	$ (6)	$ 2,129	$ 1,658	$ 1,697
Other	$ (72)	$ (67)	$ (31)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (556)	$ (21)	$ 167	$ (366)	$ 0
Ending Cash Balance	$ 420	$ 399	$ 566	$ 200	$ 200

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing
- ✓ FERC Transmission Case
- ✓ APCo Filing for Recovery of E&R Costs in Virginia & Fuel Clause Increase
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Clause (ENEC) Filing in West Virginia
- ✓ Kentucky Base Rate Filing
- ✓ SWEPCo – Texas Fuel Factor/Surcharge Filing
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

TCC Stranded Cost Recovery Case

- Seeking approval of true-up balances
  - ✓ $2 Billion in stranded costs and associated carrying costs
  - ✓ $400 Million in other true-up amounts including carrying costs
- Dec 2005/Jan 2006 - Final order expected, if not extended
  - ✓ Jan/Feb 2006 - Request for securitization
    - ➢ Sept 2006 - Issuance of securitization bonds if no appeal
  - ✓ Mar/April 2006 – Request approval for CTC to collect other true-up items
    - ➢ Jan 2007 – CTC charge to be implemented

AEP East FERC Transmission Case

Nov 7, 2005 - Announced Settlement agreement – Subject to FERC approval

- Results in $22 Million net revenue in 2006 from wholesale transmission

Regulatory Activity Underway

AEP®

Appalachian Power- Virginia Fuel Factor Increase

Filed Oct 21, 2005 - Annual revenue increase of $57.7 Million

- ✓ Jan 1, 2006 - Interim fuel rate increase effective, subject to refund
- ✓ Jan 12, 2006 - Public hearing

Appalachian Power – Virginia E & R Cost Recovery Factor

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred of $21.1 million
- ✓ Public hearing set for February 7, 2006

Regulatory Activity Underway

Appalachian Power & Wheeling Power - West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $82 Million
- ✓ July 1, 2006 – $9 Million
- ✓ Jan 1, 2007 – $44 Million
- ✓ Jan 1, 2008 – $10 Million
- ✓ Jan 1, 2009 – $38 Million

Procedural Schedule

- ✓ Feb 2, 2006 – Staff & Intervenors testimony
- ✓ Feb 22, 2006 – Rebuttal & Cross-rebuttal
- ✓ Feb 28 – Mar 3, 2006 – Evidentiary Hearing
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ June 23, 2006 – Statutory deadline for an order

Regulatory Activity Underway

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Seek increase of $64.8 Million over existing rates
- ✓ Procedural schedule (subject to change)
  - ✓ Nov 29, 2005 through January 27, 2006 – Data Requests and Responses
  - ✓ Jan 9, 2006 – Intervenor Testimony
  - ✓ Feb 2, 2006 – KPC Rebuttal Testimony
  - ✓ To be Scheduled – Public Hearing and Briefs

SWEPCo Fuel Factor/Surcharge Filing

Filed Nov 7, 2005

- ✓ Annual revenue increase of $48.6 million per year to go into effect the first billing cycle in January, subject to future reconciliation
- ✓ Plus $46.4 million surcharge for a twelve-month period of Feb 2006 through Jan 2007, subject to future reconciliation

IGCC Recovery Application Filed with PUCO

AEP®

Cost Recovery

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007 - mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Next Steps

2005:

- ✓ Secure cost recovery plan
  - ➢ Final PUCO Order expected by end of 2005 for Ohio IGCC filing
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2005—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH

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Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana, Kentucky, FERC*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

Appendix

Earnings Guidance Range
$2.55 to $2.65 for 2005
$2.50 to $2.70 for 2006

AEP®

		2005 Projection Performance Driver	2005 Projection ($ millions)	2005 EPS	2006 Projection Performance Driver	2006 Projection ($ millions)	2006 EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,270 GWh @ $ 31.5 /MWhr =	2,059		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,203 GWh @ $ 39.6 /MWhr =	1,909		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,316 GWh @ $ 22.8 /MWhr =	919		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,387 GWh @ $ 17.3 /MWhr =	455		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off System Sales	41,207 GWh @ $ 20.0 /MWhr =	823		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		400			285	
7	Other Operating Revenue		487			515	
8	Total Gross Margin		7,052			7,283	
9	Operations & Maintenance		(3,140)			(3,045)	
10	Depreciation & Amortization		(1,295)			(1,332)	
11	Taxes Other than Income Taxes		(739)			(761)	
12	Interest Exp & Preferred Dividend		(598)			(688)	
13	Other Income & Deductions		271			153	
14	Income Taxes		(481)			(563)	
15	Net Earnings Utility Operations		1,070	2.75		1,047	2.66
16	Investments		2	0.00		(7)	(0.02)
17	Parent Company		(58)	(0.15)		(17)	(0.04)
18	ON-GOING EARNINGS		1,014	2.60		1,023	2.60
	Shares Outstanding			390MM			393MM

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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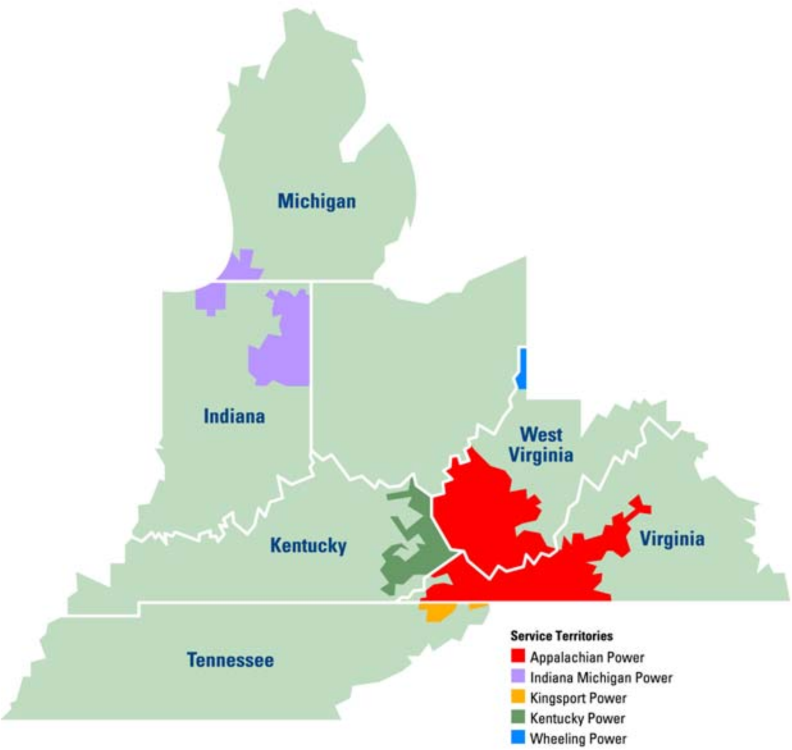
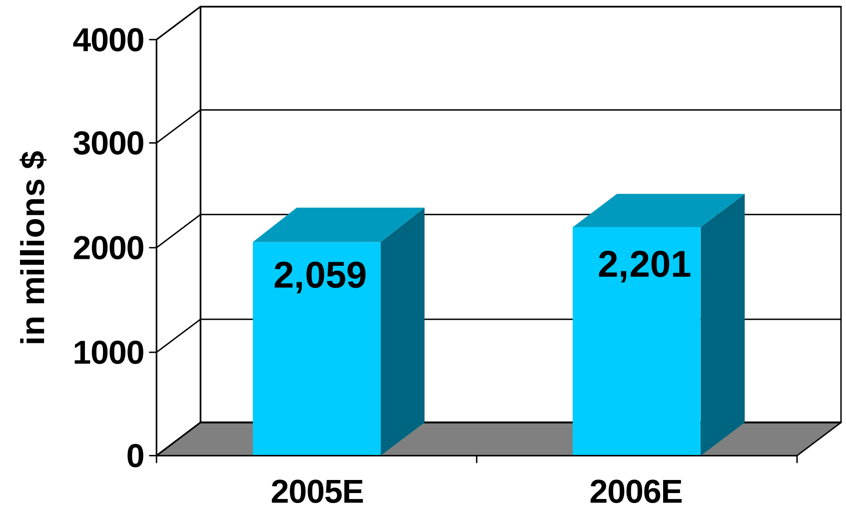
Utility Operations

East Integrated Companies



Gross Margin



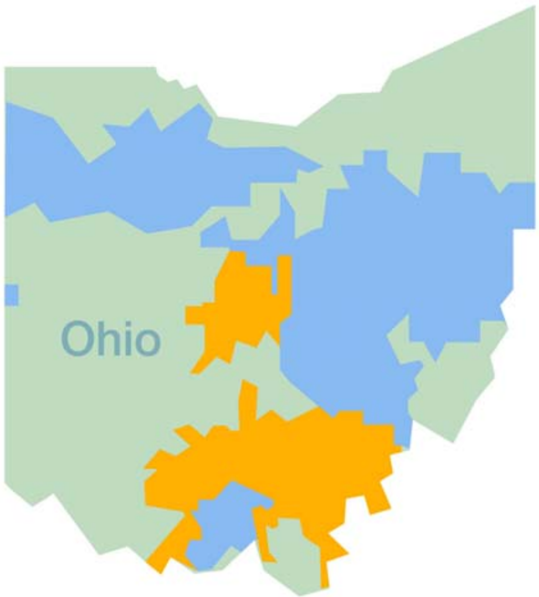
Earnings Drivers

Load Growth	134
Rate Changes	103
Fuel Cost	(53)
Emissions & Consumables	(19)
Other	(23)
	142

$142 MILLION INCREASE IN GROSS MARGIN FOR 2006

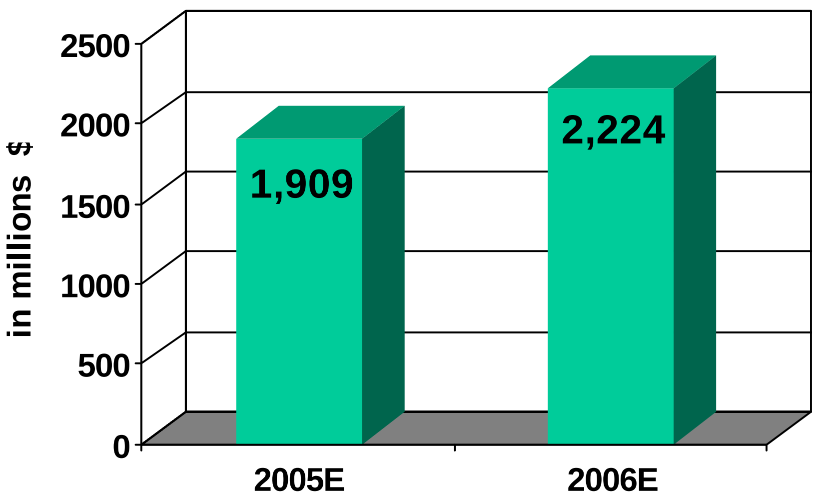
Utility Operations

Ohio Companies



Ohio Power Service Territory
Columbus Southern Power Service Territory

Gross Margin



Earnings Drivers

Load Growth	58
Fuel Cost	(13)
Rate Stabilization Plan	258
Emissions & Consumables	(15)
Other	27
	315

$315 MILLION INCREASE IN GROSS MARGIN FOR 2006

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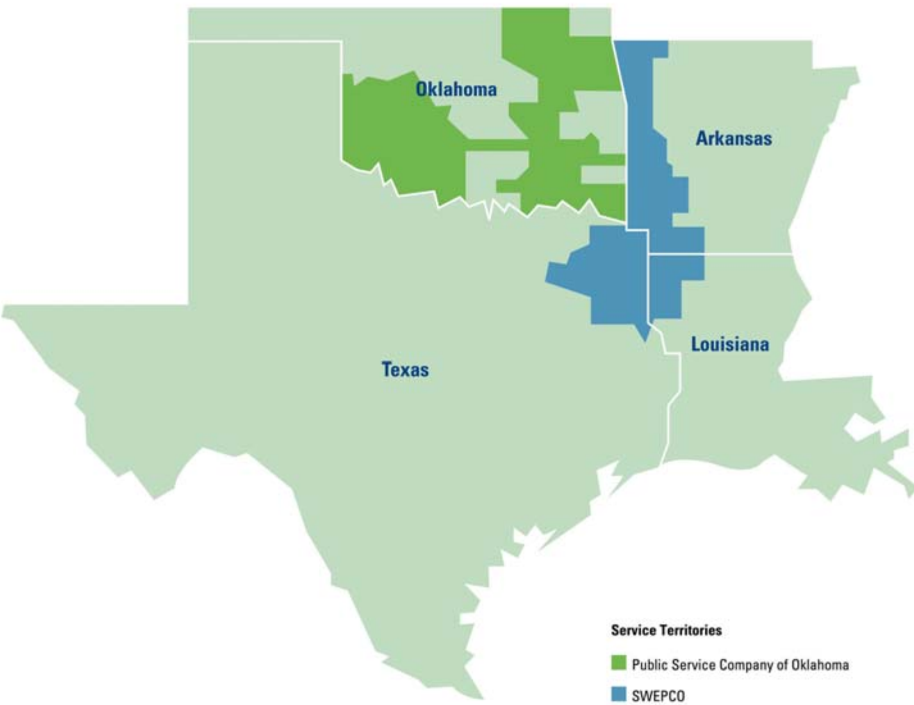
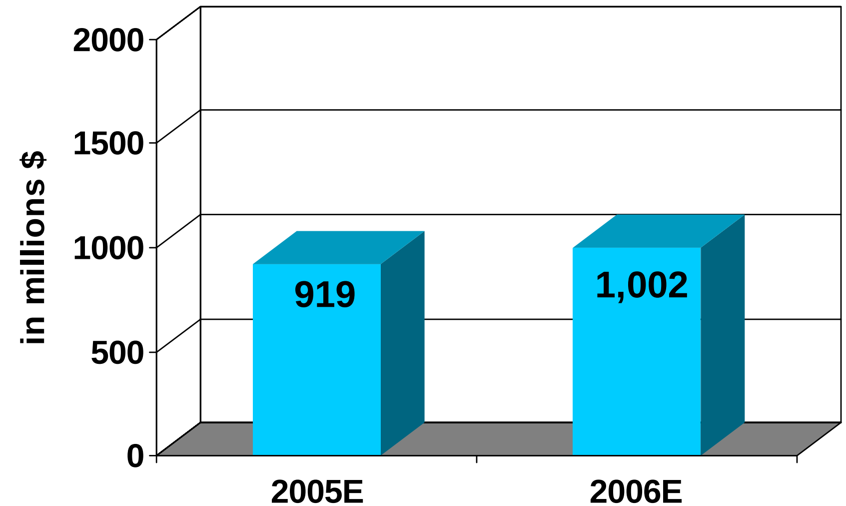
Utility Operations

West Integrated Companies



Gross Margin

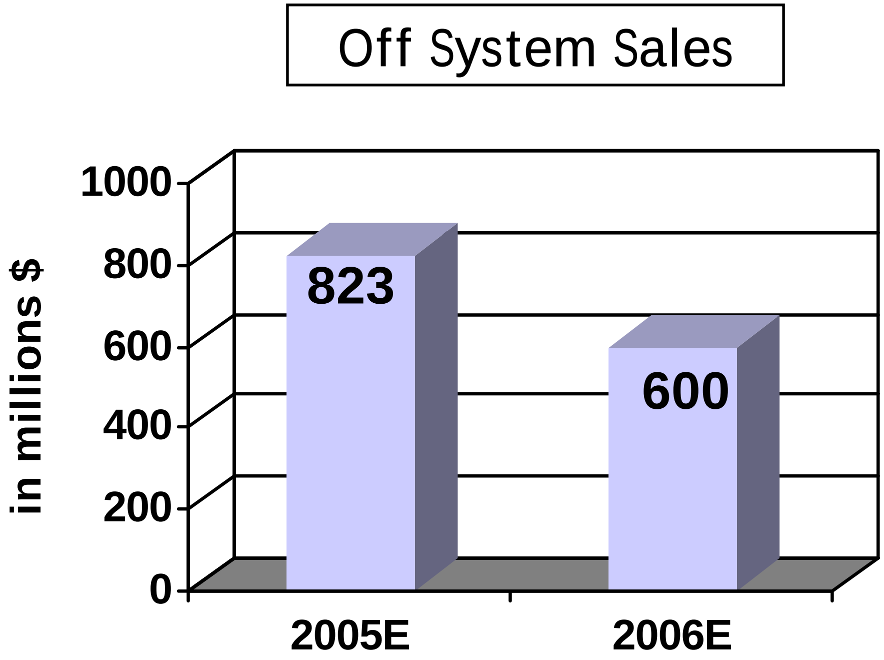


Earnings Drivers

Load Growth	15
Rate Changes	17
Margin Sharing, re: Fuel Clause	51
	83

$83 MILLION INCREASE IN GROSS MARGIN FOR 2006

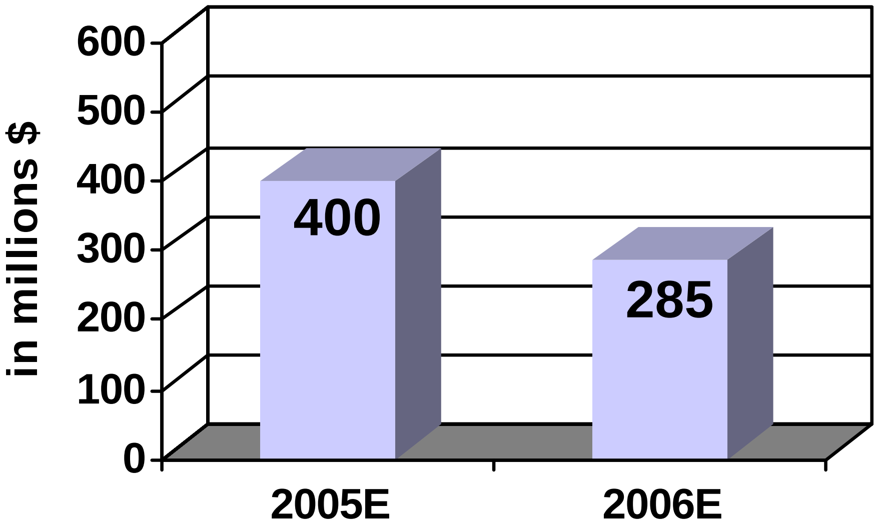
Utility Operations



DECLINE IN OFF SYSTEM SALES GROSS MARGIN DRIVEN BY SALE OF TCC GENERATION, INCREASED PLANNED OUTAGE RATES, & INCREASED RETAIL LOAD

Utility Operations

Transmission Revenues – 3rd Party



Earnings Drivers

Cessation of SECA Rates	(128)
ECAR Zonal Rate Change	22
Other	(9)
	(115)

Offset to Decline in Trans Revenues

(Captured on lines 1 & 2)

Ohio OATT	49
APCO ENEC in WV	9
	58

CESSATION OF SECA RATES WILL BE LARGELY OFFSET BY ECAR ZONAL RATE CHANGE, OHIO OATT ADJUSTMENT, & REACTIVATION OF ENEC IN WEST VIRGINIA

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Utility Operations

AEP®

Expense Drivers

Operations & Maintenance		
Labor, including fringes	48	
Sale of STP	38	$95 million decrease
Other	9	
	95	
Depreciation & Amortization		
Plant additions	(53)	
Change in depreciation rates	90	$37 million increase
Amortizations (TCC Securitization*, Ohio regulatory asset**, Other)	(74)	
	(37)	
Taxes		
Taxes Other than Income Taxes	(22)	
Change in Pre-Tax Income	(21)	$104 million increase
Q4 Accrual True-ups	(15)	
COLI benefit (2005)	(7)	
Flow-through & permanent timing differences	(39)	
	(104)	
Interest Expense & Pref. Dividends		
Securitized Debt	(23) *	
Debt (construction funding)	(67)	$90 million increase
	(90)	
Total	(136)	

•Offset by TCC wires charge to cover securitization bonds issued 9/06

****Offset by cash Ohio POLR charge which begins 1/1/06**

UTILITY OPERATIONS EXPENSES TO RISE $136MM IN 2006

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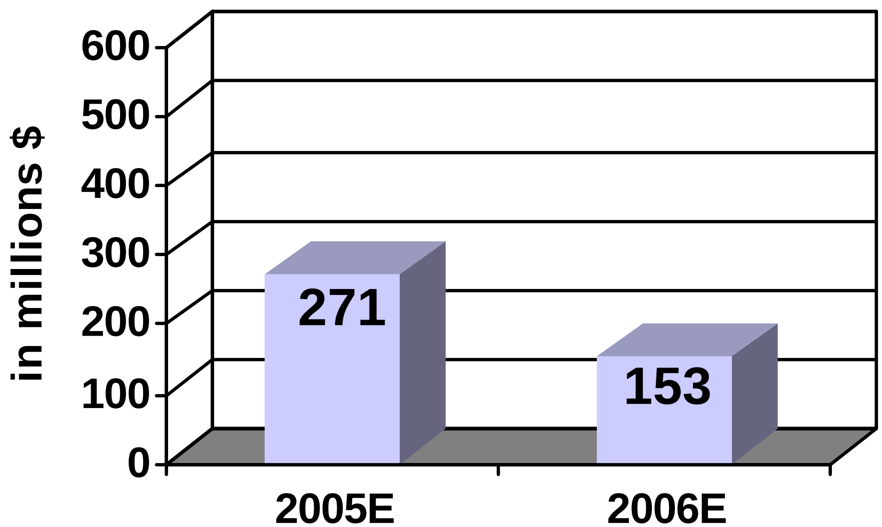
Utility Operations

Other Income & Deductions



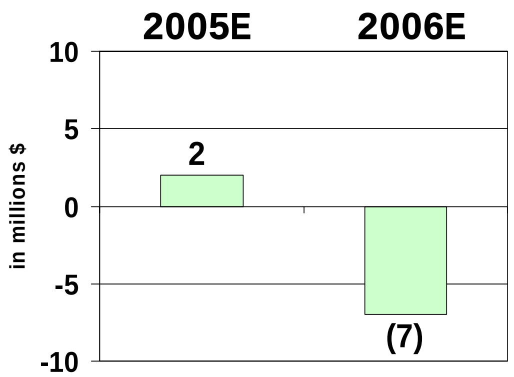
Earnings Drivers	
Reduction in Carrying Charges	
Ohio Companies*	(74)
Texas Central Company**	(12)
Reduction in Centrica Sharing	(20)
Other	(12)
	(118)

*Offset by cash POLR Rider Revenue
**TCC Carrying Charges decline upon issuance of securitization bonds 9/06

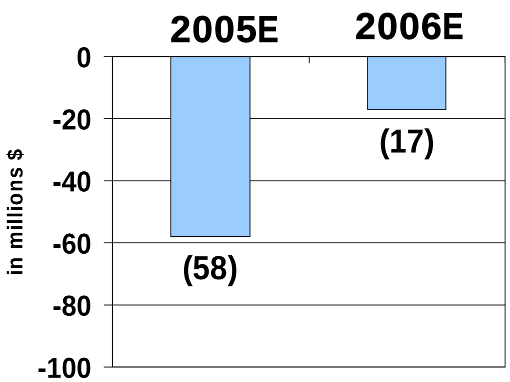
$118MM DECLINE IN OTHER INCOME & DEDUCTIONS DUE TO REDUCTION IN CARRYING CHARGES AND CENTRICA SHARING

Investments & Parent Company

Investments



Parent Company



Investment Drivers:

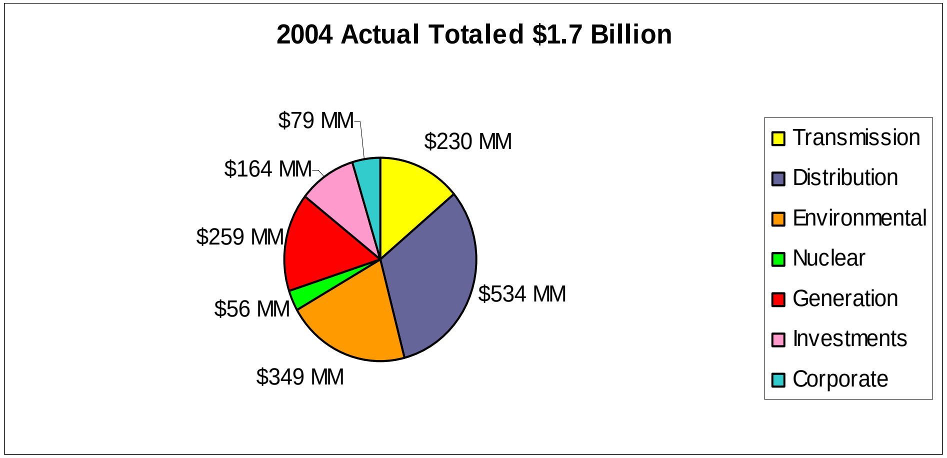
- Misc. true-ups that provided positive impact in 2005 not repeated in 2006
- Ongoing loss from Dow

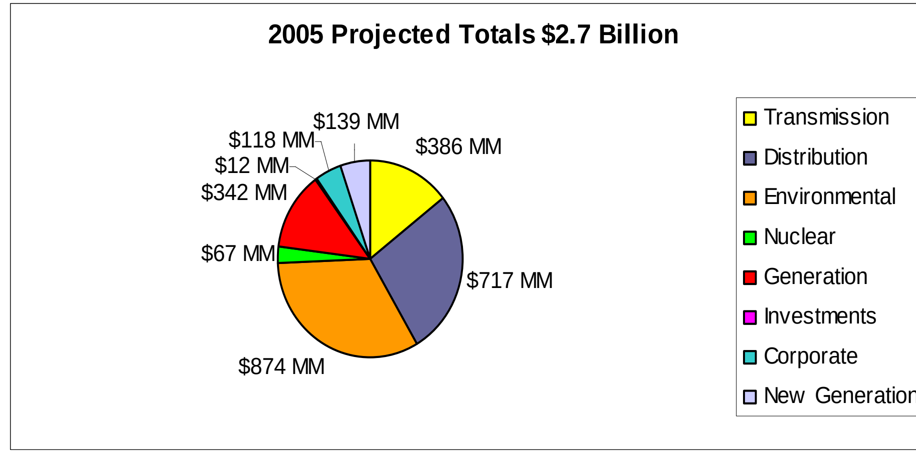
Parent Company Drivers:

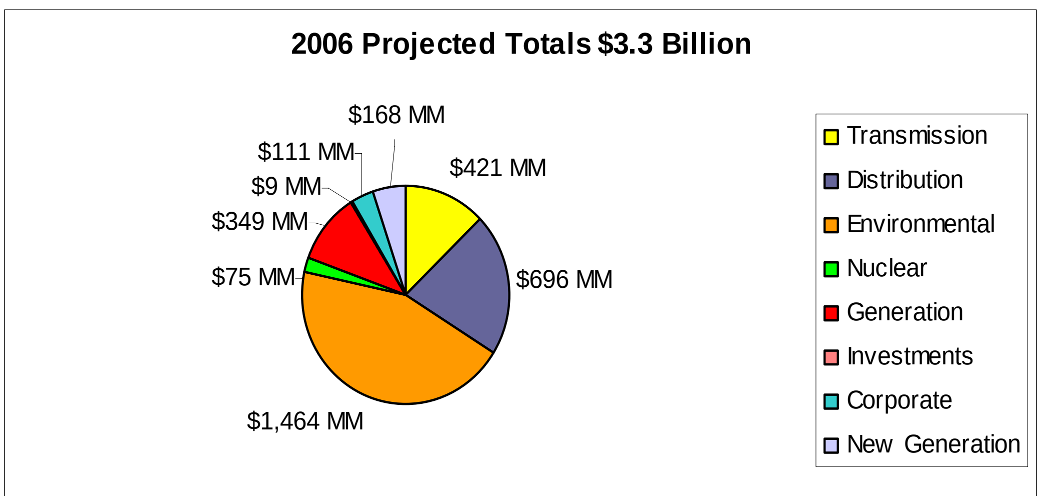
- 2005 included debt call premiums to retire $550MM of LTD
- Reduction in outstanding debt drives decline in interest expense in 2006

$32 MILLION IMPROVEMENT IN CONTRIBUTION FROM INVESTMENTS & PARENT COMPANY

Capital Investment 2004-2006







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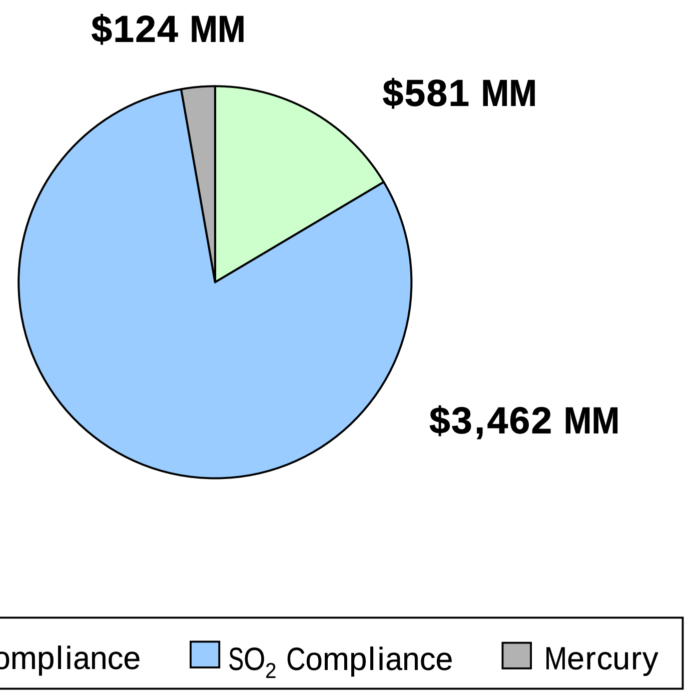
Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT
PROJECTED 2004 THROUGH 2010

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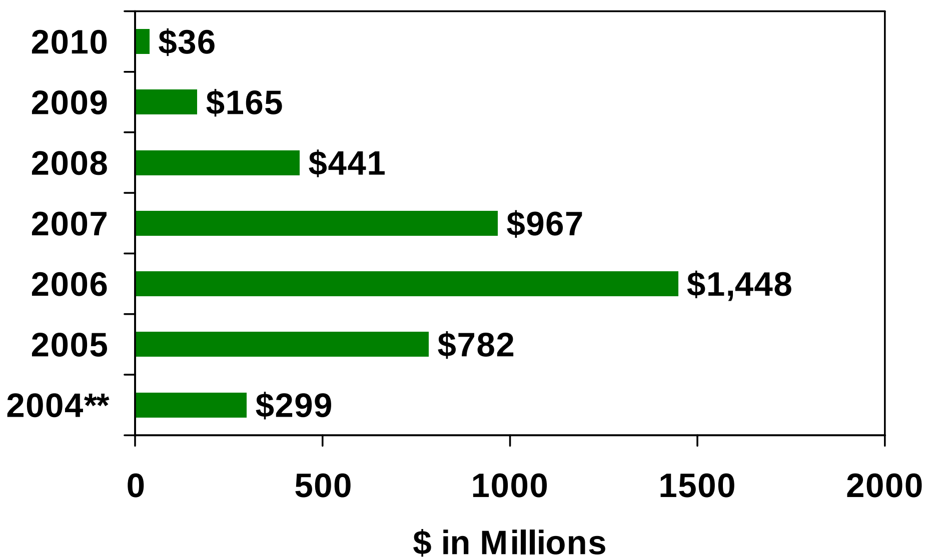
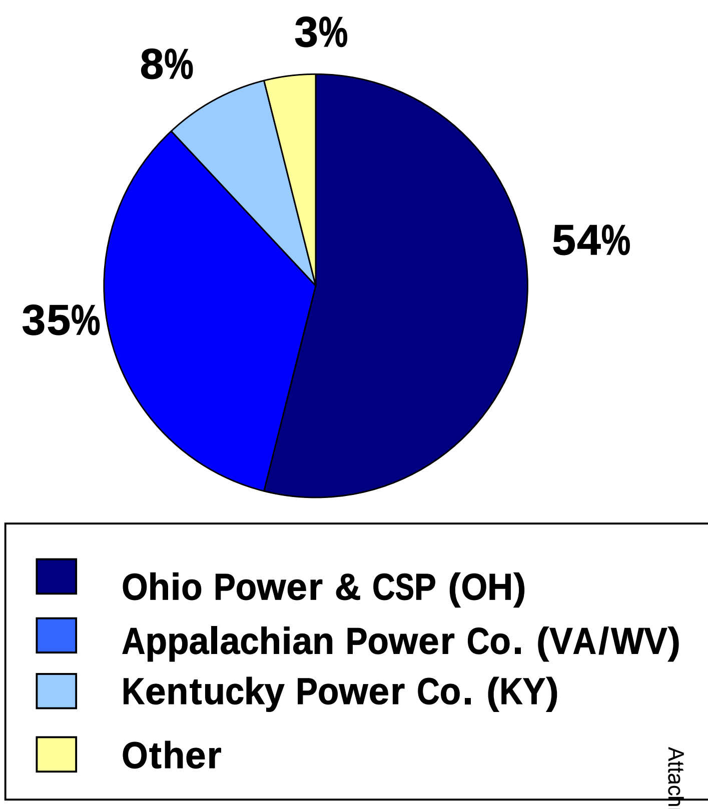
$4.1 Billion Environmental Investment

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Projected Environmental Investment Allocation



MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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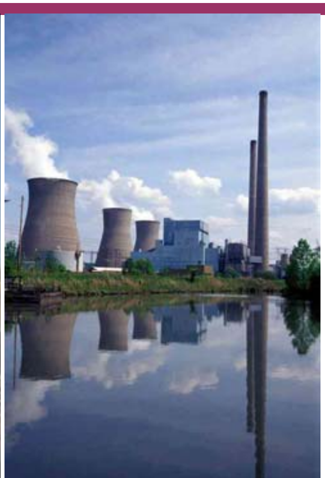
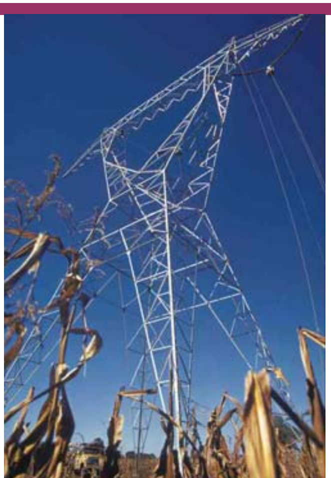
Credit Suisse
2007 Energy Summit Conference

Vail, CO

February 5-6, 2007

AEP AMERICAN® ELECTRIC POWER




"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension and other post retirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP®

Holly Koeppel
EVP & Chief Financial Officer

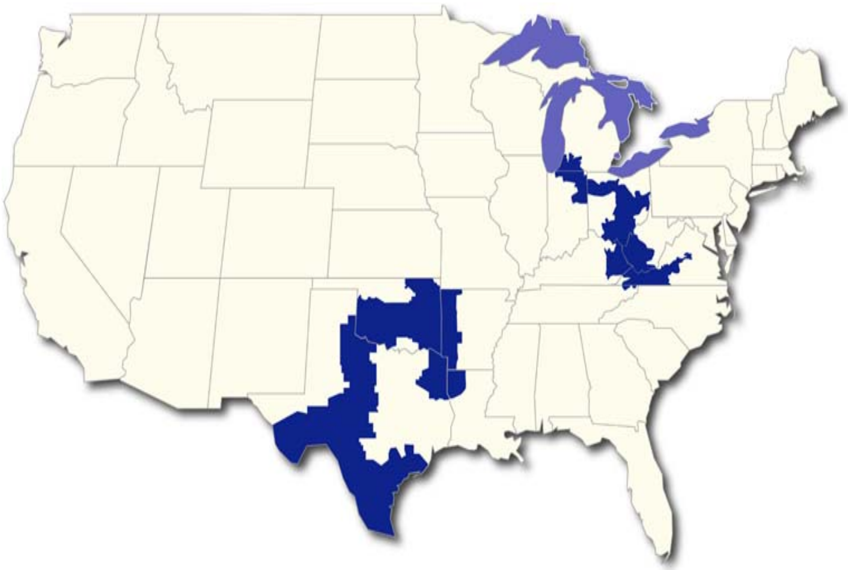
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,000 MW	# 3
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
70%	21%	6%	2%	1%

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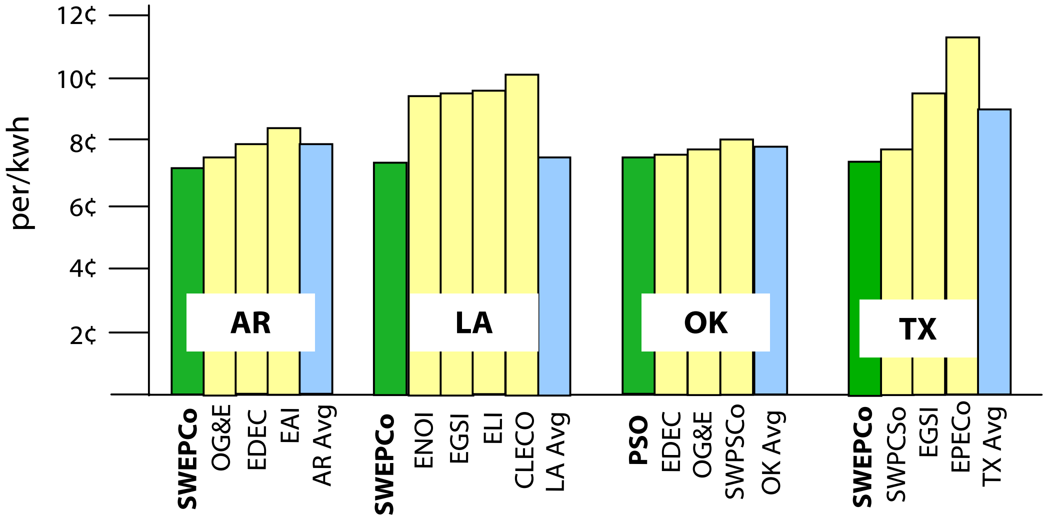
AEP Enjoys Significant Presence Throughout the Energy Value Chain

AEP Provides Low Cost Electric Service

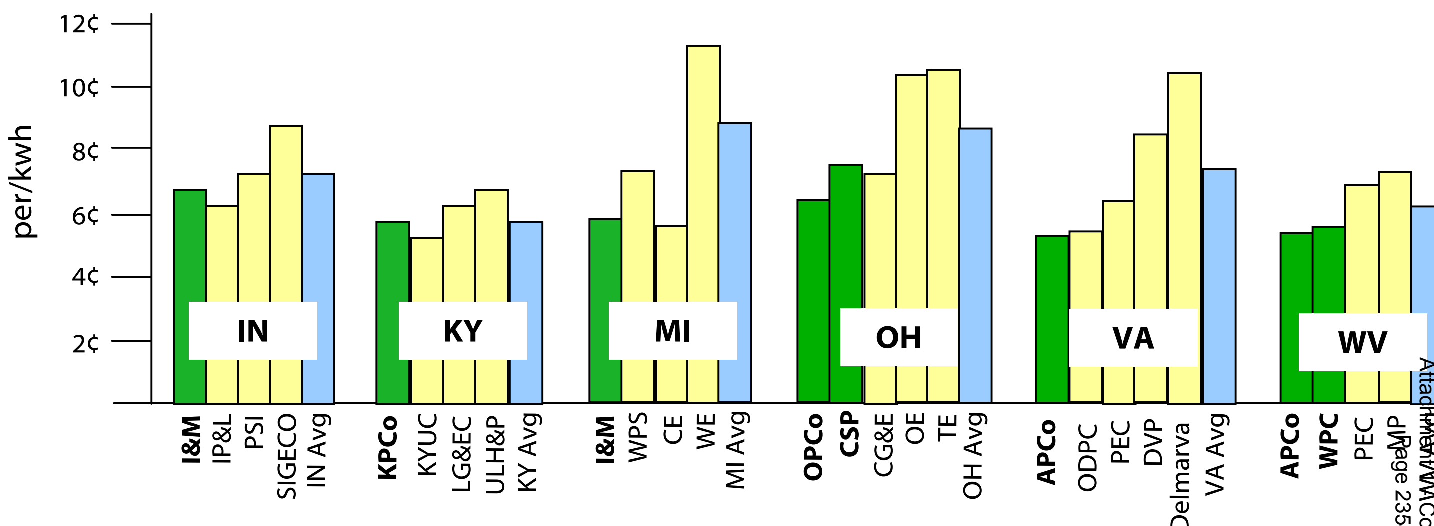
AEP West



Residential Average rates @ 12/31/2005

Source: Winter 2006 EEI Typical Bills and Average Rates Report

AEP East



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2006-2009 Projected Annual Rate Increase Of 3.8%

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

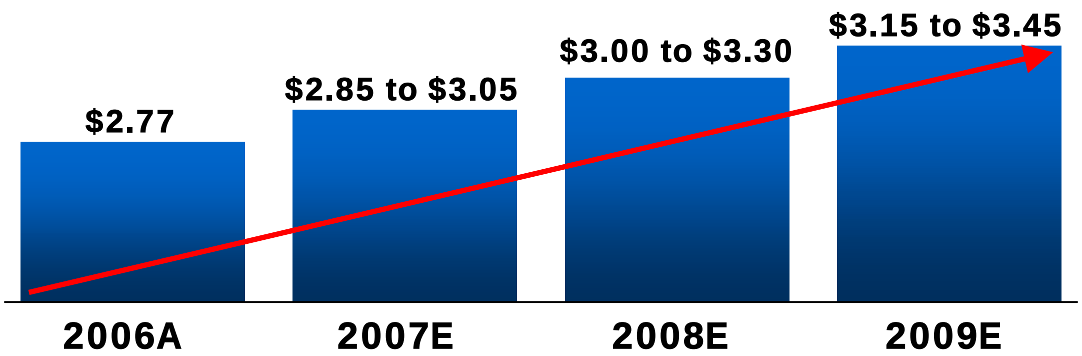
Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

AEP®

Framework For Long-Range Performance

- 2007, 2008 & 2009 Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

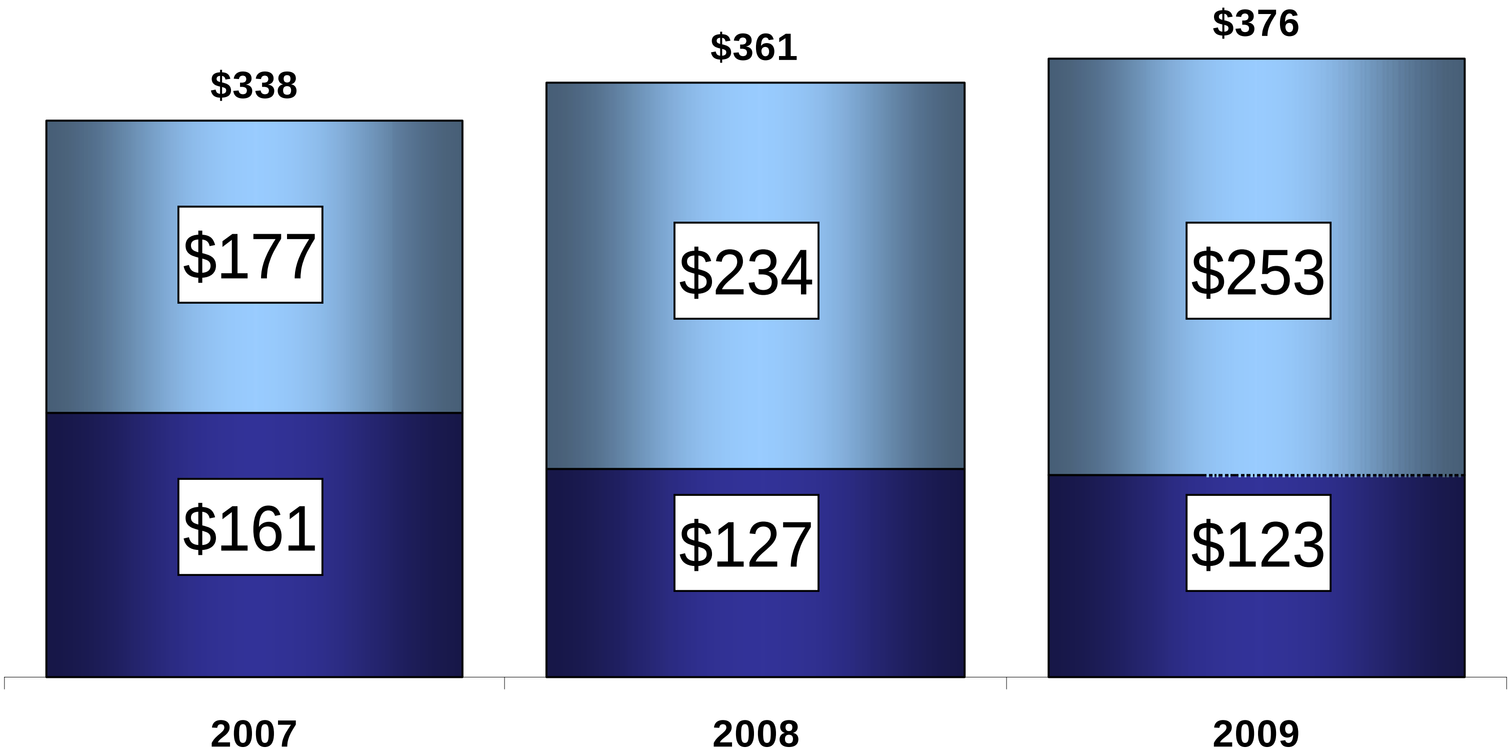
Growth Investment To Be Funded By Cash
From Operations via Rate Relief and Debt Issuances

Incremental Rate Relief Composition

$ Millions

Secured
- OH RSP
- 2006 WV Base Case
- 2006 Kentucky Rate Settlement
- FERC & OH OATT

Pending/Future
- 2006 VA rate proceeding
- PSO Rate Proposal
- TX wires rate cases
- Cases yet to be filed

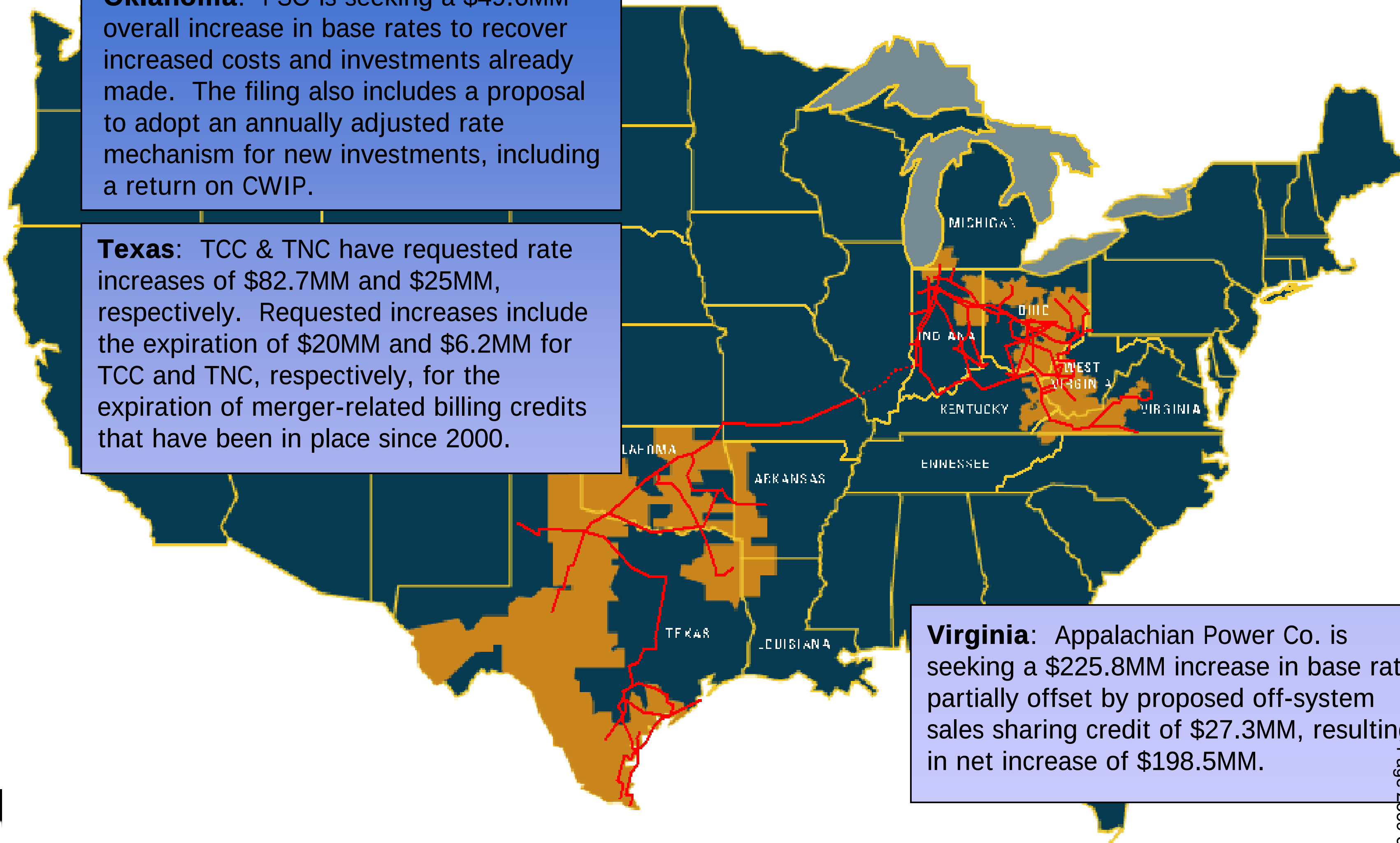


Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

AEP®

Rate Relief Is A Critical Element To AEP's Financial Success

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $82.7MM and $25MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.

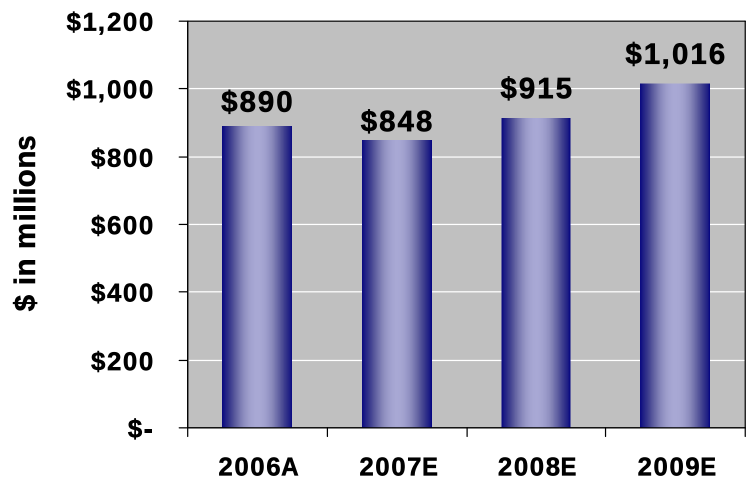
Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an annual average investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $61.7MM and $16MM for TCC & TNC distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



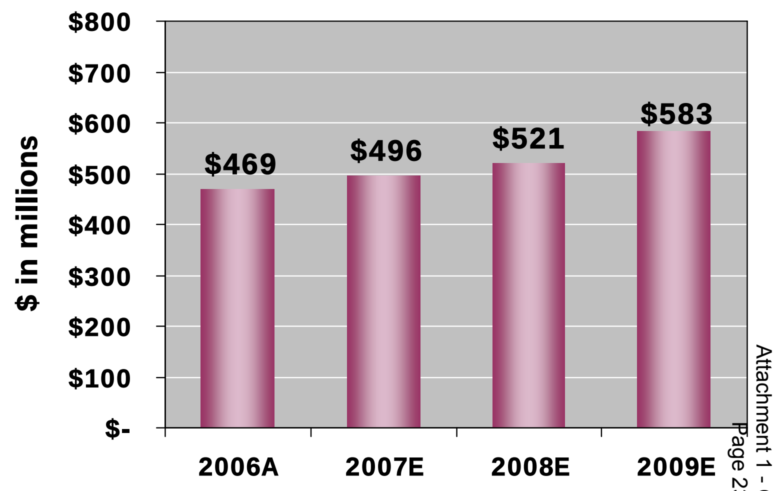
Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

Transmission Investment Forecast

- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of "postage stamp" rate
  - Final order expected in early to mid-2007
- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services
- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity Filed Jan. 22, 2007 to establish ETT as a regulated utility company
  - FERC Filing to transfer transmission assets to ETT submitted Jan. 22, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transcription ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

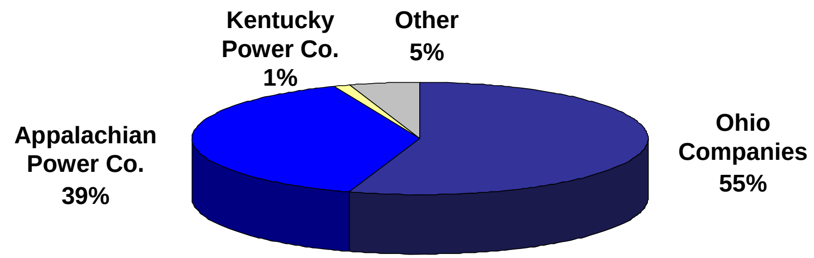
AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

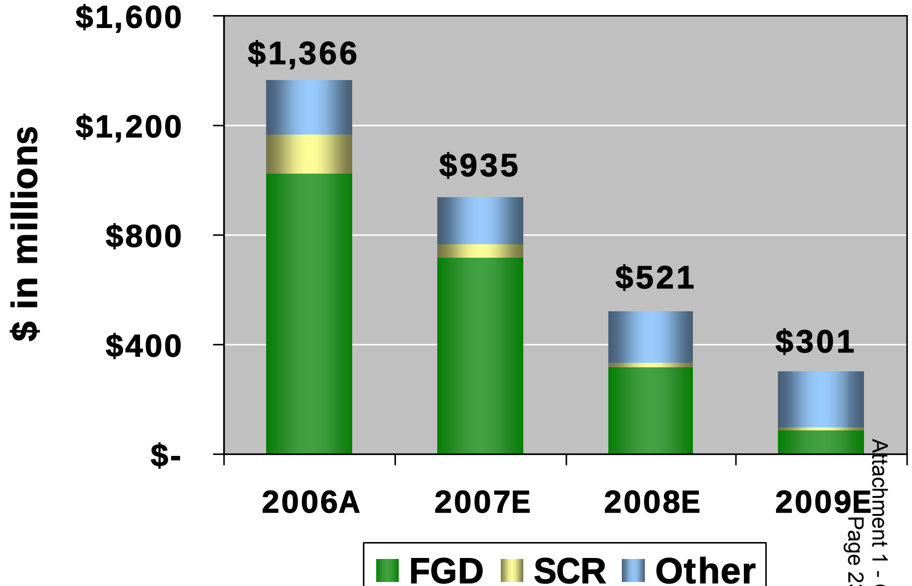
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures – activation of 4% rider
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

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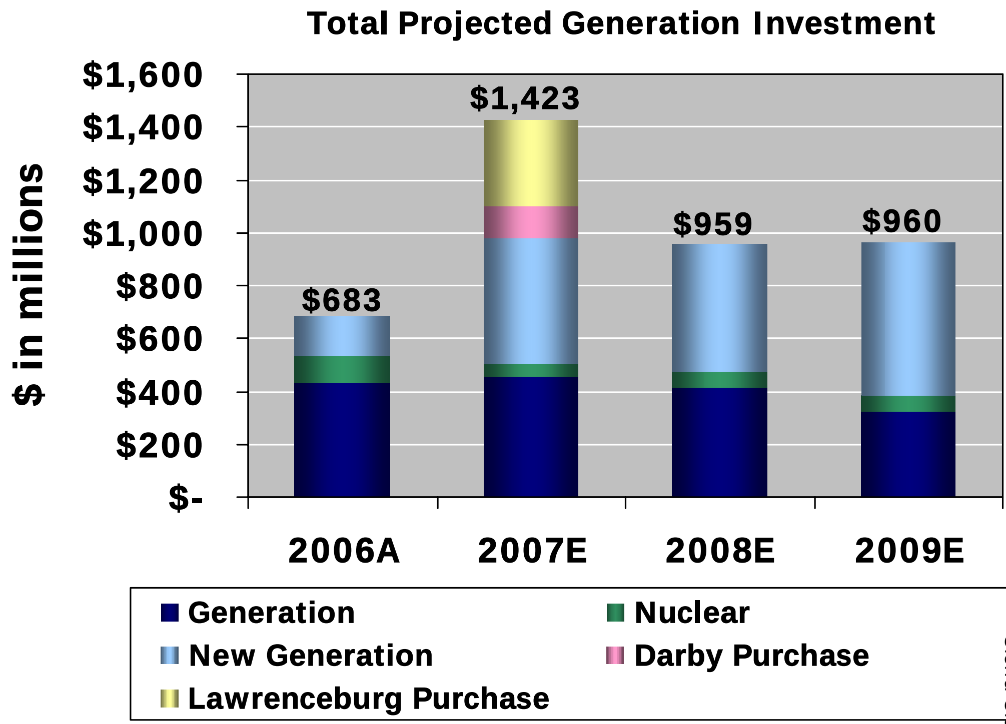
Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP
- Distressed Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	1Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2011
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale expected to close 1Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 75%, or 450 megawatts, totaling about $975 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

AEP®

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.6%
- Positive dividend outlook
- Stable credit profile

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2366 of 9556

Appendix

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 37,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

AEP®

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

AEP®

Rate Base Investment Coupled With Innovative Regulatory Plans Will Reduce Lag And Drive Earnings Growth

AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

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AEP Transmission Network – Largest in the Country

Operating Company Level
(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP®

AEP Is The Leader In Transmission Expertise

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 45% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 48% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 25,746 MEGAWATTS

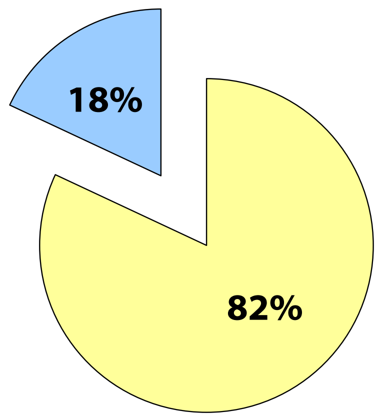
Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	Projected 2007
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	539*	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

* Oklaunion's MW capacity represents combination of PSO, TCC & TNC ownership. TCC's 54 MW ownership of Oklaunion is currently under negotiation for sale.

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

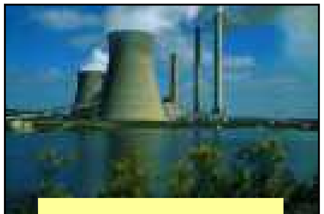
FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP®

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Domestic Generation Fleet

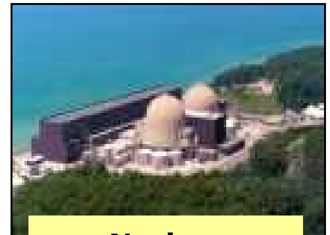


Coal/Lignite

70%

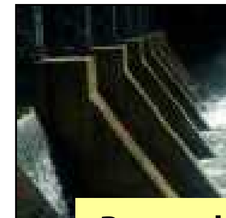
Nat. Gas/Oil

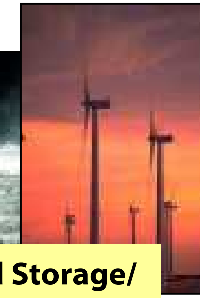
21%



Nuclear

6%





Pumped Storage/
Hydro/Wind

3%

AEP's Generation Fleet
36,672 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	71%
SPP	23%
ERCOT	6%

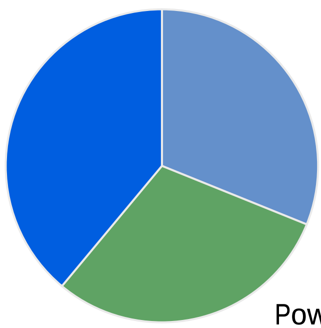
Note: The figures on this slide exclude the Darby and Lawrenceburg plants, as these purchases have not yet closed.

AEP®

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

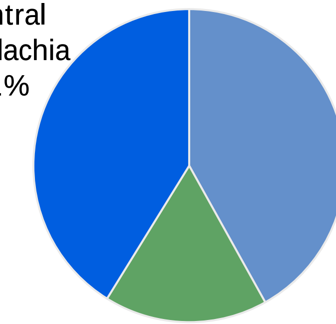
Total AEP System



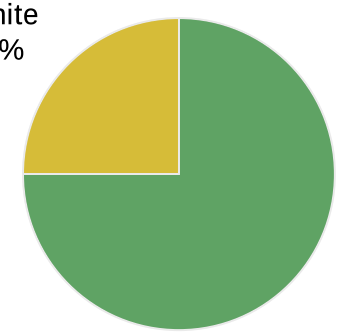
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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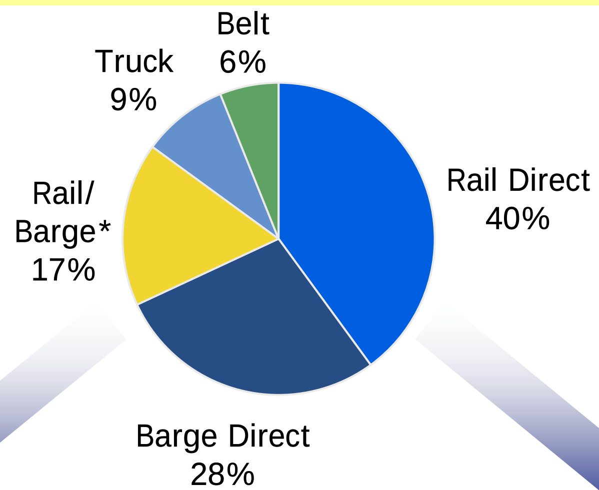
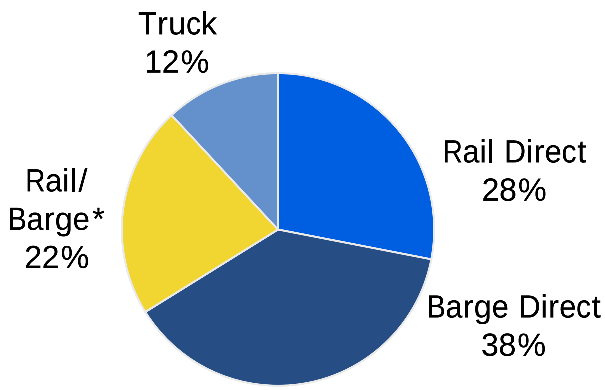
Coal Delivery

2006 Actual

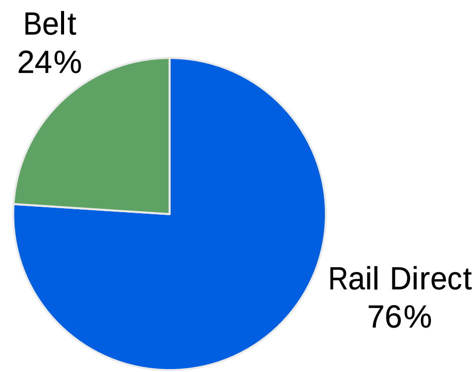
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Regulatory Activity

Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due Feb. 14, 2007; Evidentiary hearing to commence Feb. 27, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the allowed 4% provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval 1) to operate as an electric transmission utility in Texas; 2) to contribute transmission assets currently under construction by AEP subsidiary TCC to the joint venture company; and 3) establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%
  - An order is expected in Fall 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each acquire a 50% interest in the joint venture

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $111MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in early to mid-2007

Regulatory Activity

FERC Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in early to mid-2007.

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power

Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,771	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 226	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,422	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other, primarily Working Capital, Items	$ (208)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP®

Capital Investment Is Funded By Cash From Operations And Debt Issuances

Investor Meeting Hosted by Merrill Lynch

AEP Headquarters
Columbus, Ohio
May 11, 2005

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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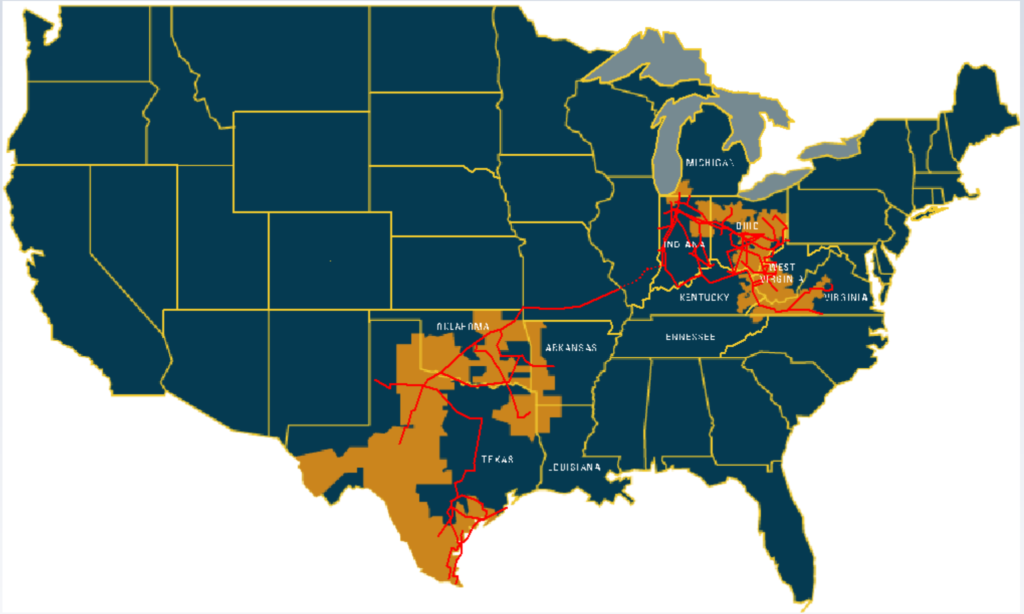
Asset Portfolio

Strength & Scale in Assets & Operations



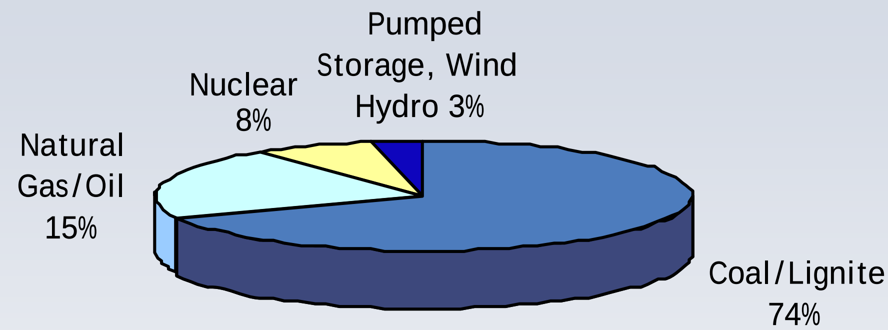
Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

Capacity by Fuel Mix

- 36,000 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,719	0	0
SPP	4,828	3,516	188
Total*	**30,773**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Introduction

The generation assets are co-managed by the Power Generation and the Commercial Operation Groups within AEP – each with a deliberate focus on roles and responsibilities within the organization

Power Generation
Operate 36,000 MW

Commercial Operations
Coal, gas, power and emissions markets

Fossil and Hydro Generation
Bill Sigmon, SVP

Nuclear Generation

Engineering, Environmental & Technical Services
John McManus, VP Environmental Services

Generation Dispatch

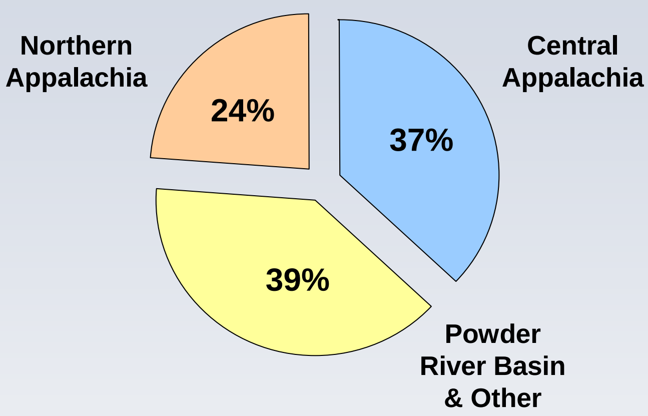
Energy Marketing
Brian Tierney, SVP

Fuel, Emissions & Logistics
Chuck Zebula, SVP

Fuel, Emissions & Logistics

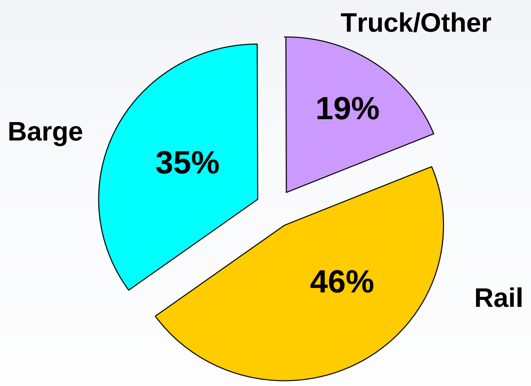
FUEL BASIN DIVERSITY

73 million tons



DELIVERY MODE DIVERSITY

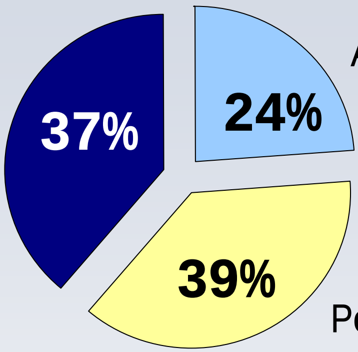
25 GW coal capacity



- All fossil fuel activities including procurement, transportation, inventory, QA/QC, measurement, and coal trading;
- Market-based emission and renewable credit activities;
- Barge transportation, terminal, and railcar maintenance businesses;
- Procures all bulk consumables for use in combustion/emission removal;
- Optimizes all by-products of production including ash and gypsum.

Coal Procurement

AEP SYSTEM

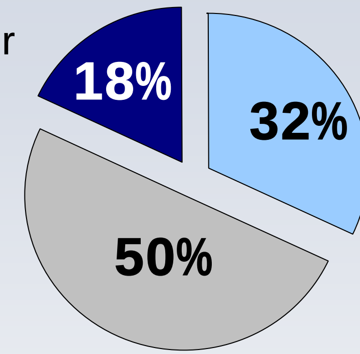


Coal Supply

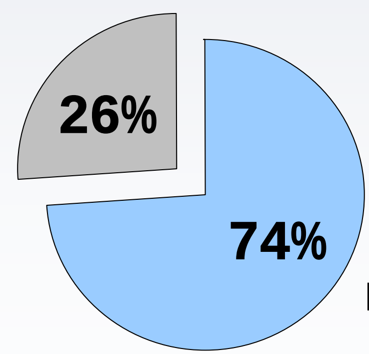
(on average)

- Purchase 75 MM tons per year
- Avg delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

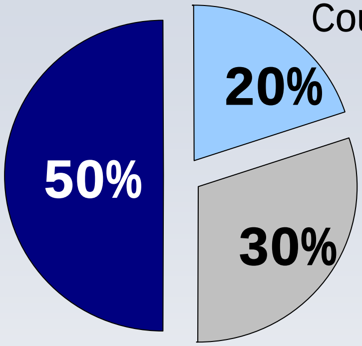


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM

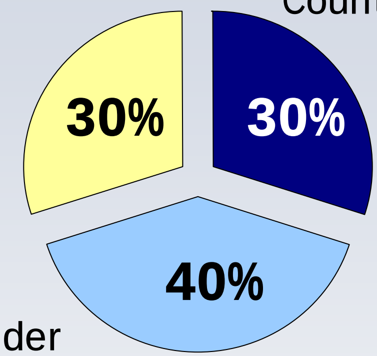


Fuel Cost Recovery
(on average)

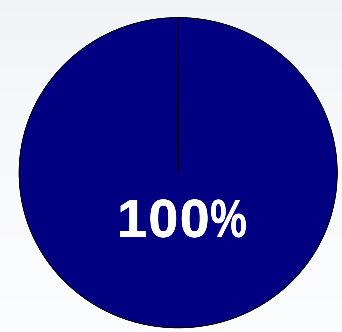
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

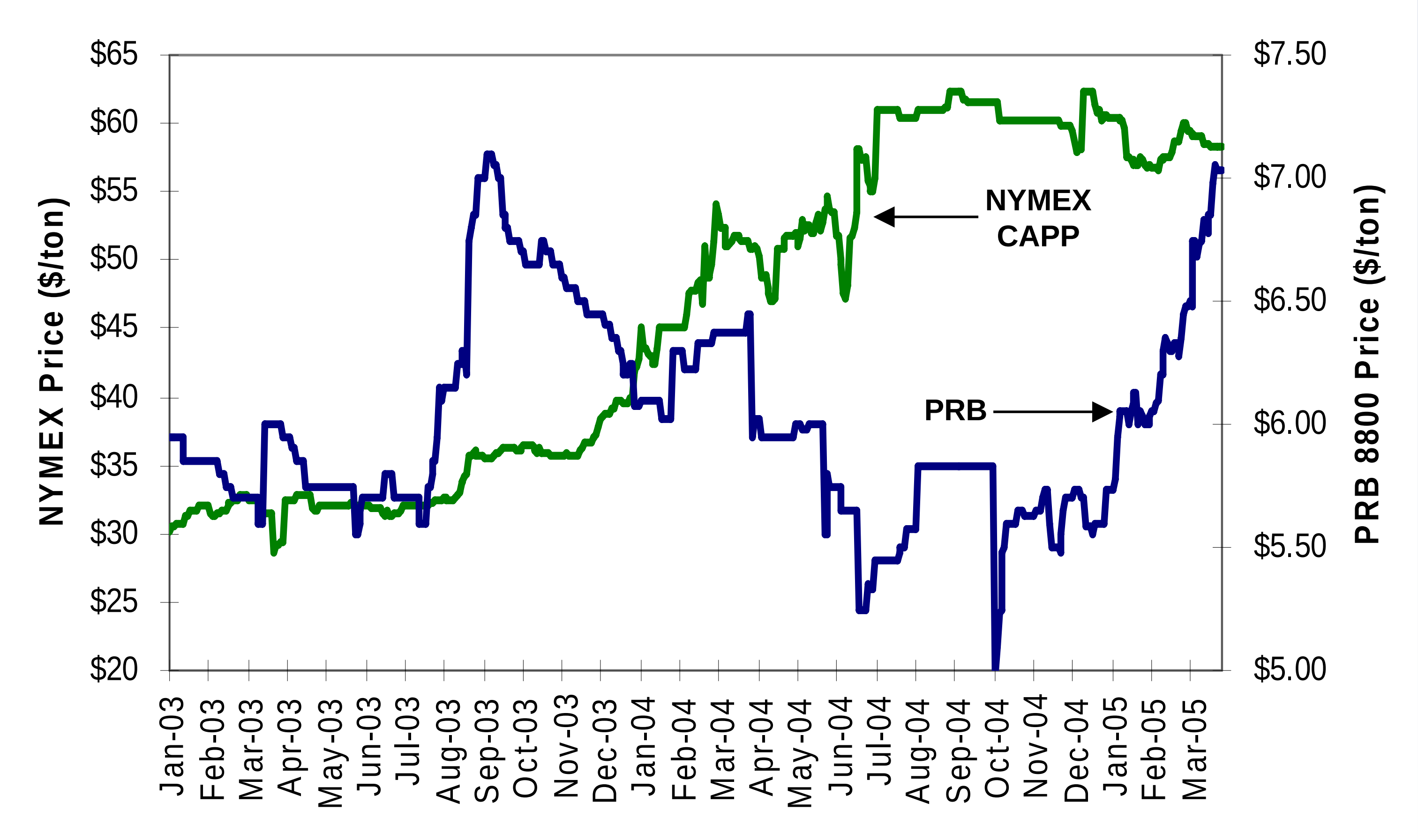


WESTERN SYSTEM



Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



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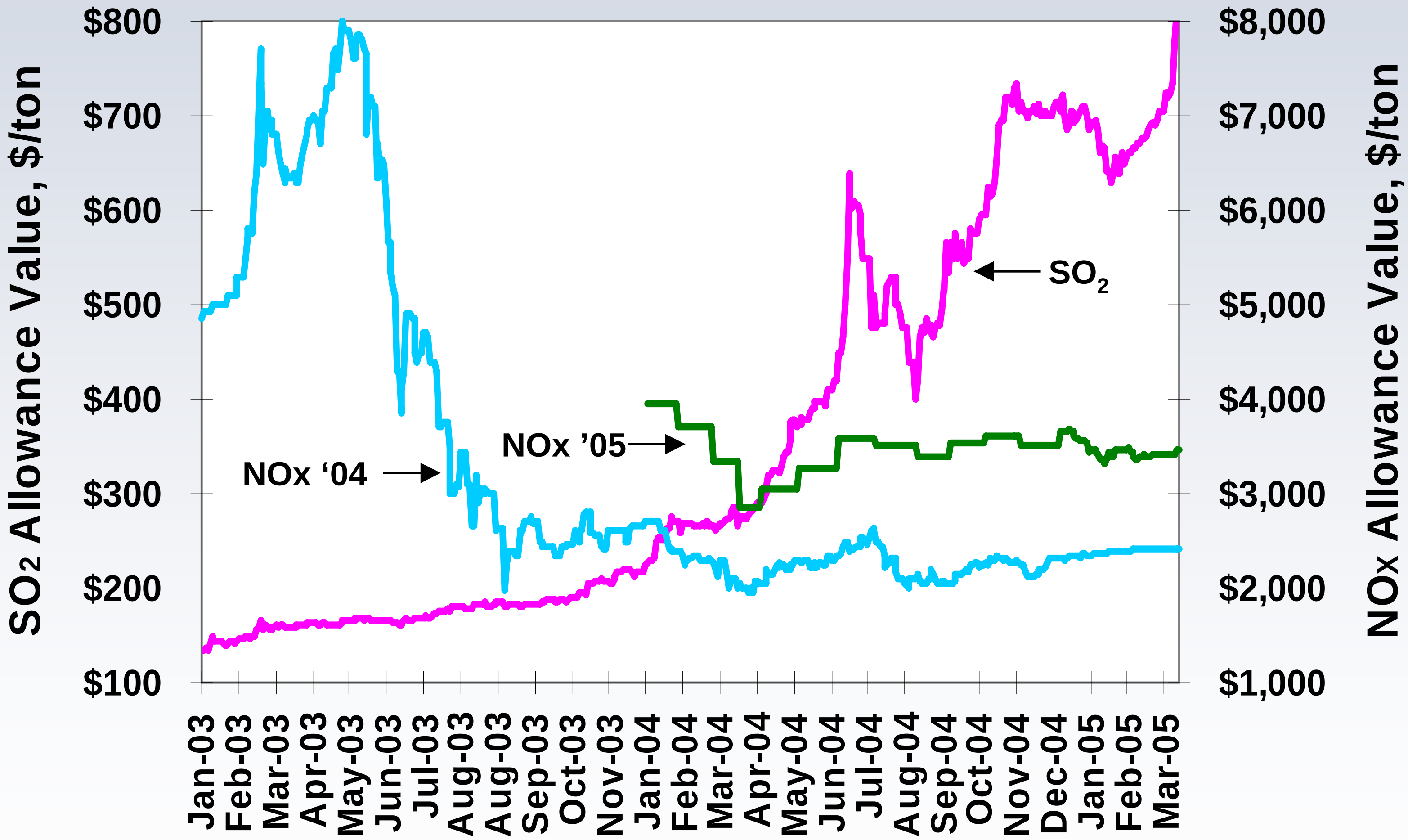
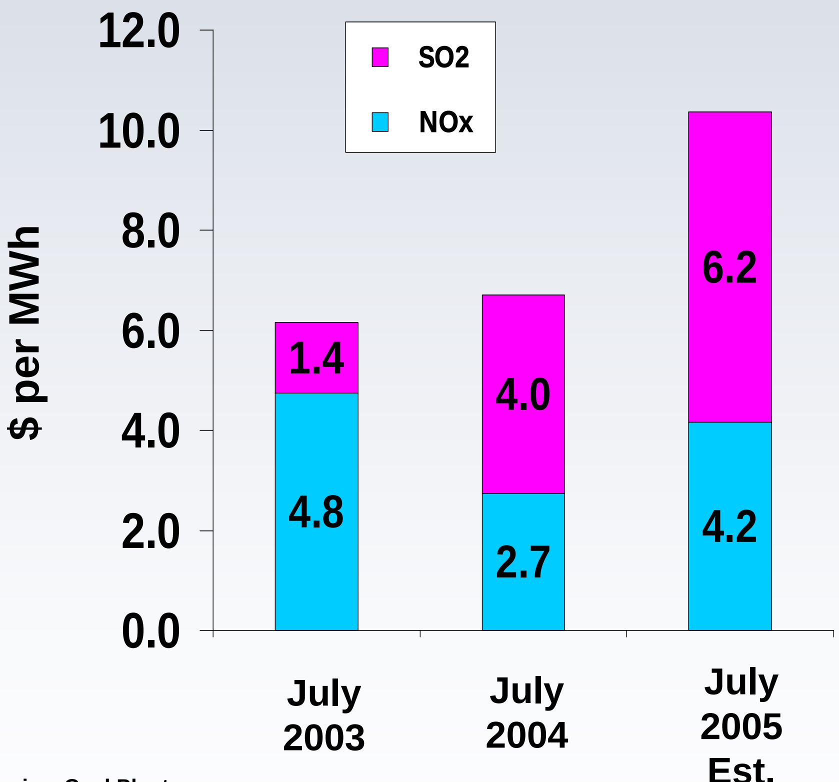
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

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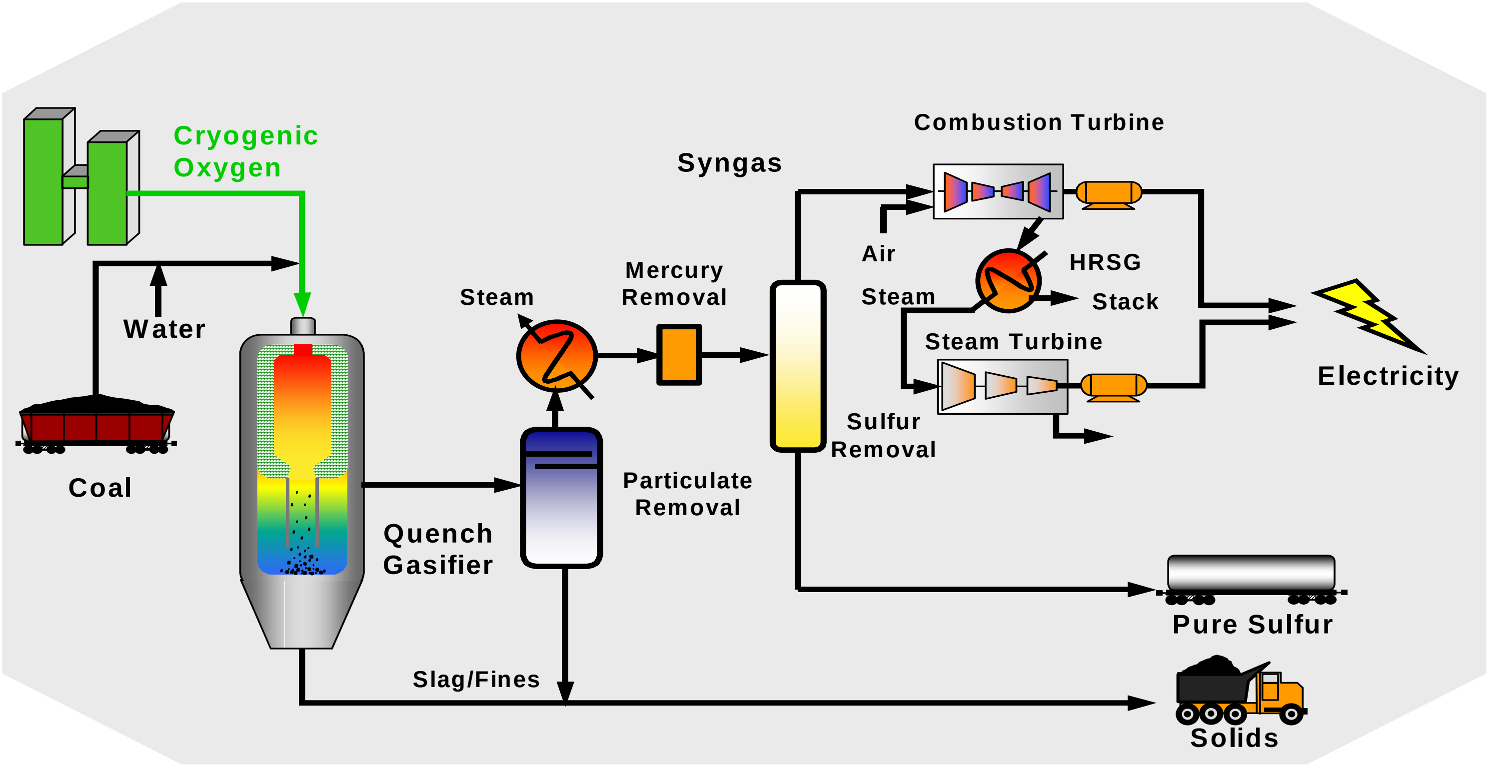
Investing in IGCC

Looking to the Future - IGCC



AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- **Air** – to evaluate best available control technology (BACT)
- **Wastewater** – to understand wastewater streams
- **US COE** (Corp of Engineers) – to obtain permits for construction of river facilities
- **NEPA Process** – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

Next Steps

<u>2005</u>

- ➢ Secure cost recovery plan - June
- ➢ Finalize site selection - August
- ➢ Negotiate with suppliers – Throughout 2005

- ➢ 2005—2007: Obtain permits and finalize engineering and procurement

- ➢ 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March, 2005.
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment.
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

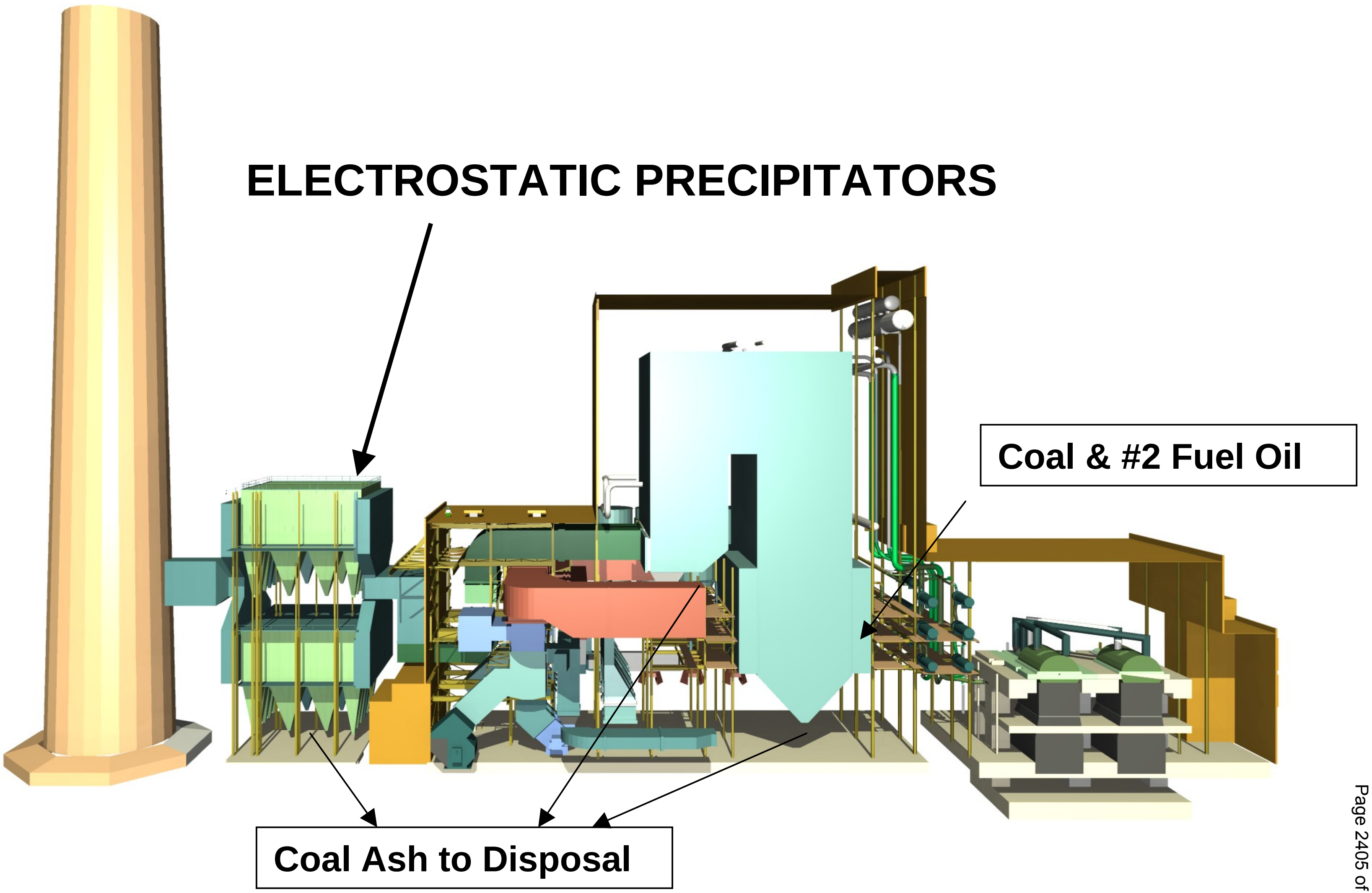
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

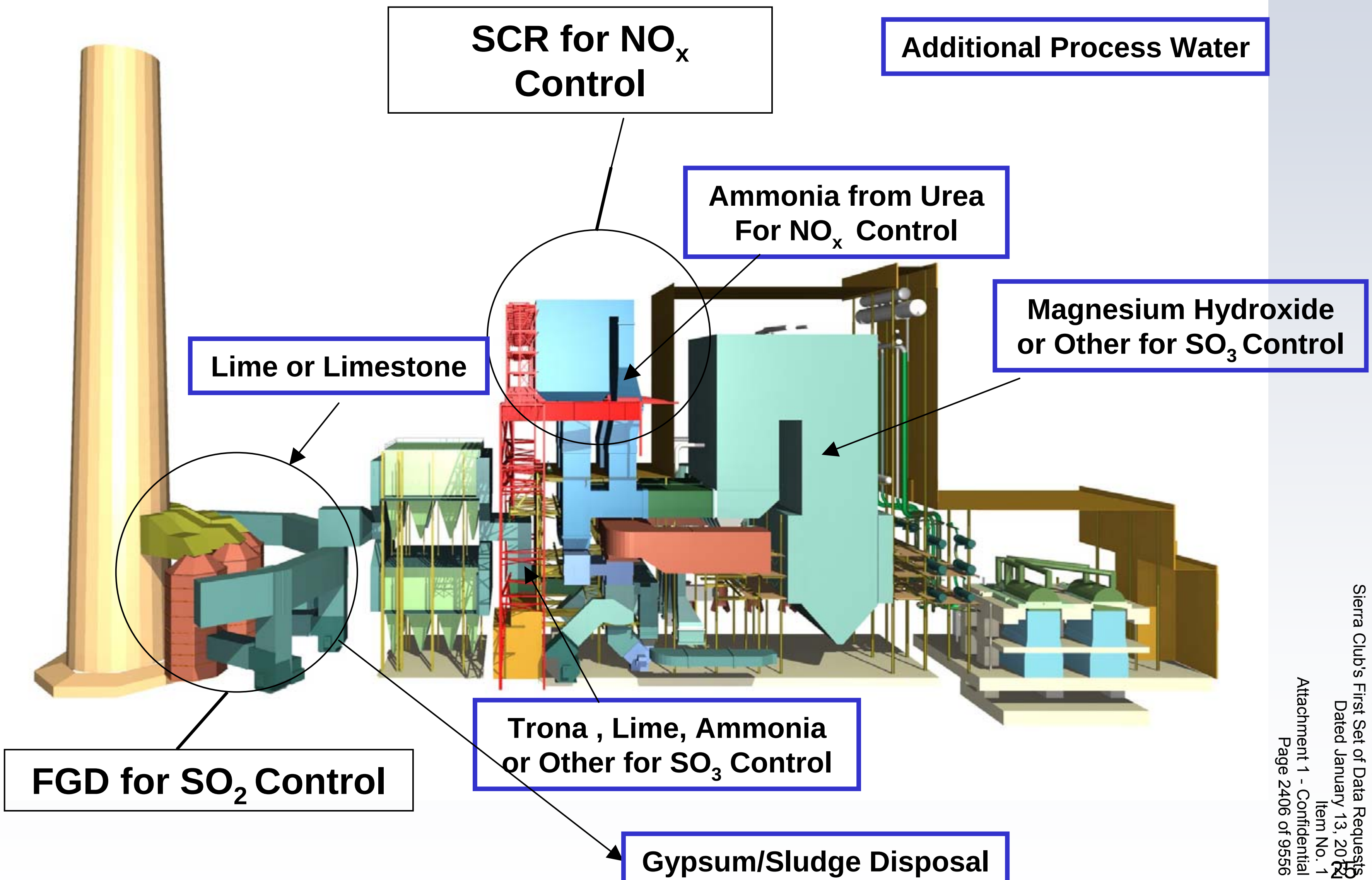
- Rule Finalized March, 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

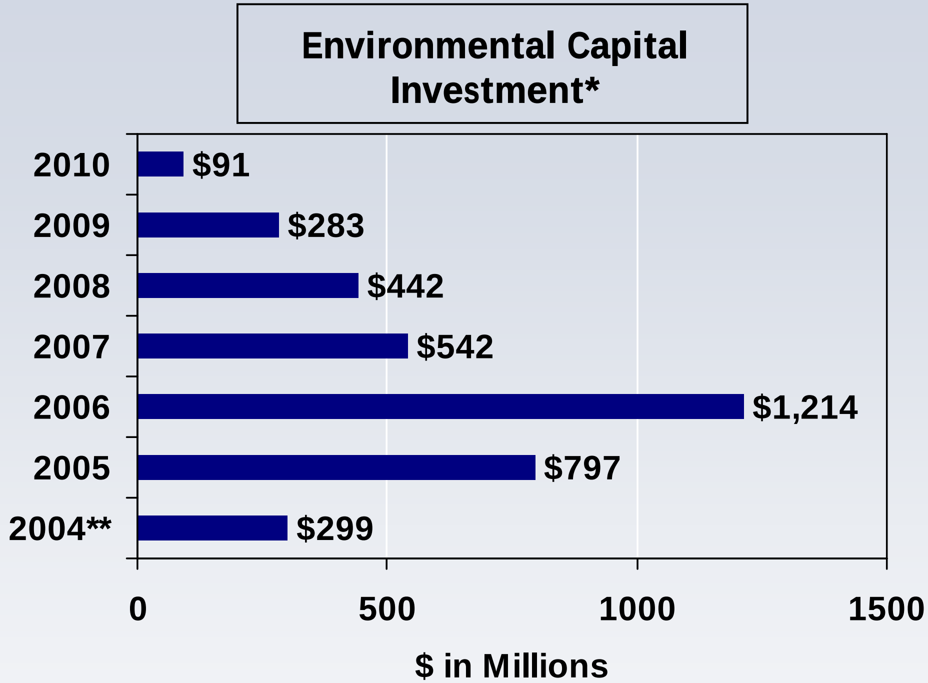
Pulverized Coal Unit As Built in 1970s



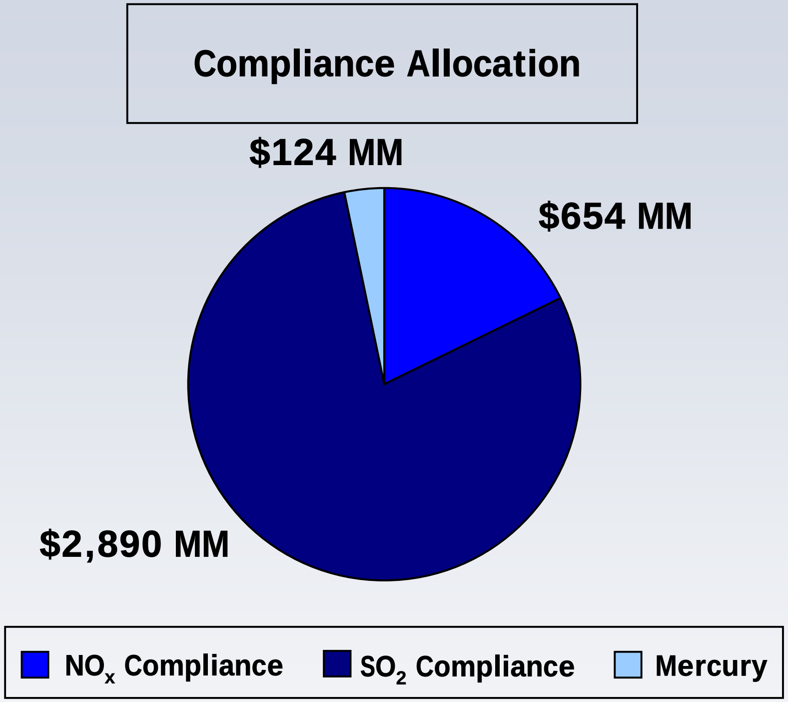
Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



Environmental Investment: $3.7 Billion Through 2010



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

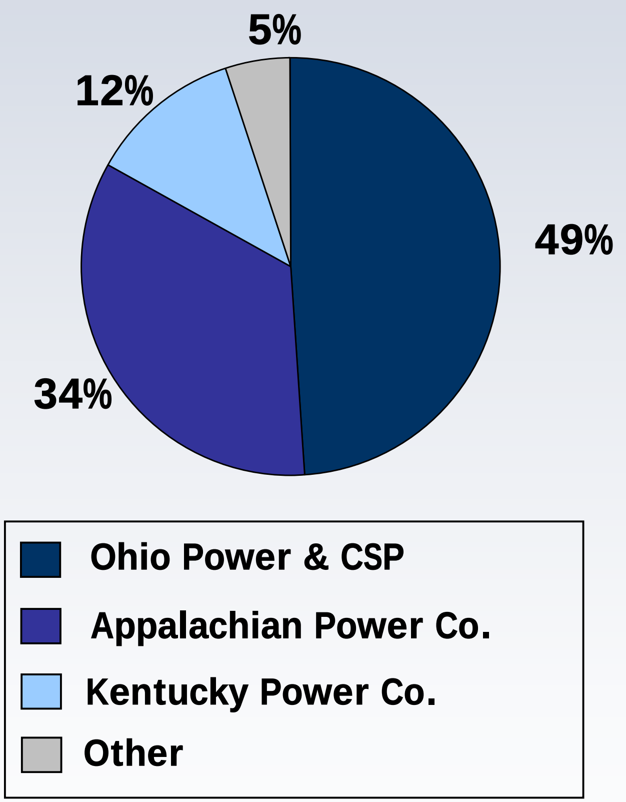
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

	FGD	SCR
Completed	see tables below	see tables below

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Insert Regulatory Matrix

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Revenues				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

Finance

2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual ($ millions)	EPS	2005 Forecast ($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
3	Texas Wires	441		469	
4	Texas Supply / REP	347		198	
5	Off-System Sales	472		547	
6	Other Wholesale Transactions	14		-	
7	Transmission Revenue - 3rd Party	451		410	
8	Other Operating Revenue	331		346	
9	Total Gross Margin	7,018		7,017	
10	Operations & Maintenance	(3,072)		(3,087)	
11	Depreciation & Amortization	(1,256)		(1,275)	
12	Taxes Other than Income Taxes	(700)		(728)	
13	Interest Exp & Preferred Dividend	(616)		(592)	
14	Other Income & Deductions	161		181	
15	Income Taxes	(489)		(529)	
16	Net Earnings Utility Operations	1,046	2.64	988	2.54
	INVESTMENTS:				
17	Gas Operations	(33)		3	
18	Other Investments	(18)		(15)	
19	Total Investments	(51)	(0.13)	(13)	(0.04)
20	Parent Company	(71)	(0.18)	(40)	(0.10)
21	**ON-GOING EARNINGS**	924	2.33	936	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Reflects sale of HPL and paydown of debt*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

2005 Earnings Guidance

			2004 Actual			2005 Forecast	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- Outcome of pending regulatory proceedings
  - Texas, Oklahoma & Louisiana
- Operations within PJM environment
- Plant availability
- Rising fuel costs
- Weather (storm damage and effect on sales)

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

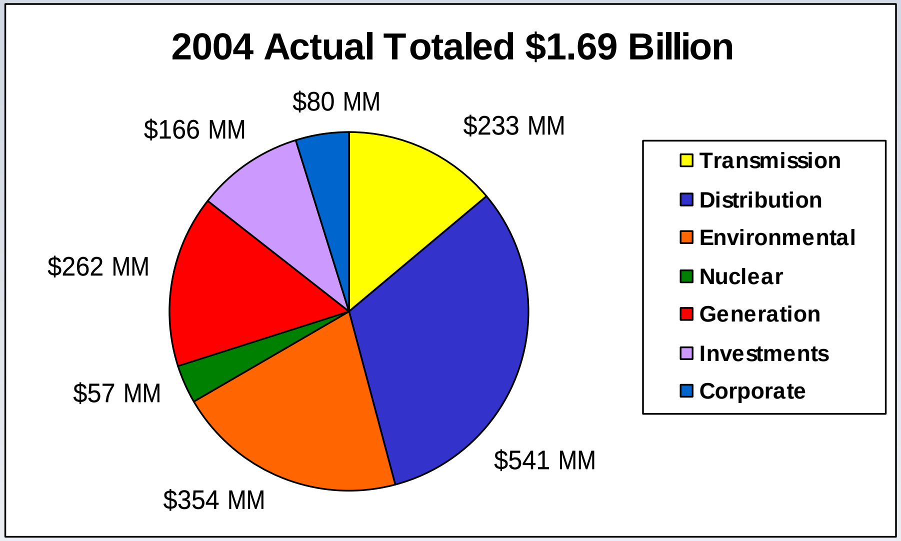
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

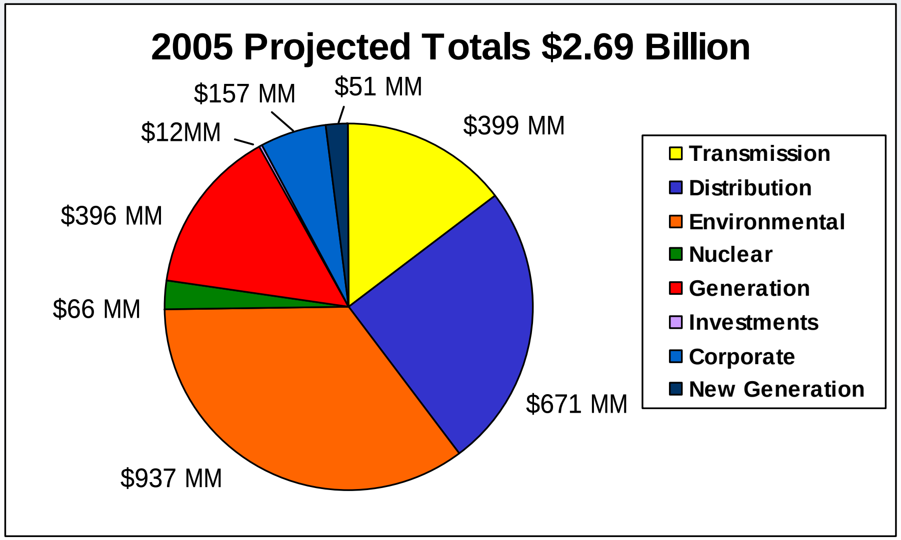
**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex





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Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Insert debt maturity schedule

Insert credit ratings

Operating In PJM Environment

- **Cost of generation to serve retail customers**
  - Retail customers continue to receive the benefits of AEP's lowest generation on an hourly basis
- **Off-system sales margin**
  - October-December was a learning period; results steadily improved each month
  - 4th quarter off-system sales margin was in line with budget

WE CONTINUE TO APPLY LESSONS LEARNED IN PJM TO MAXIMIZE THE VALUE OF OUR GENERATION FLEET

TCC Stranded Cost Carrying Charge

Carrying Cost Details:

Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

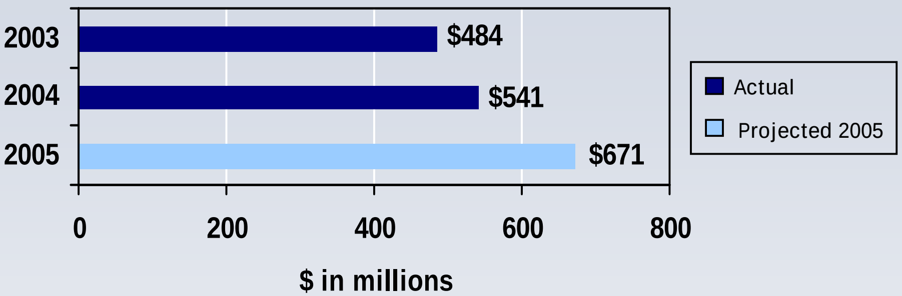
Simplified Calculation:	
Initial Stranded Cost Base (excludes Carrying Charge)	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

Items included in stranded cost base include: Stranded Plant costs ($900 MM), Regulatory Assets ($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly. At 12/31/04 total carrying costs were $302 MM, for a Net True-up Regulatory Asset value of $1.648 Billion.

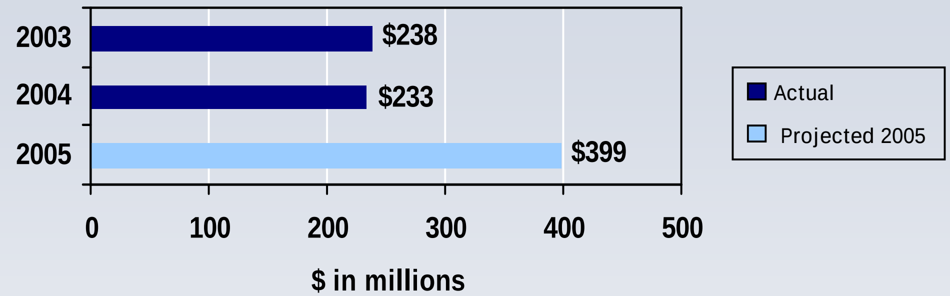
EQUITY COMPONENT RECOVERABLE ONCE AN ORDER IS RECEIVED

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



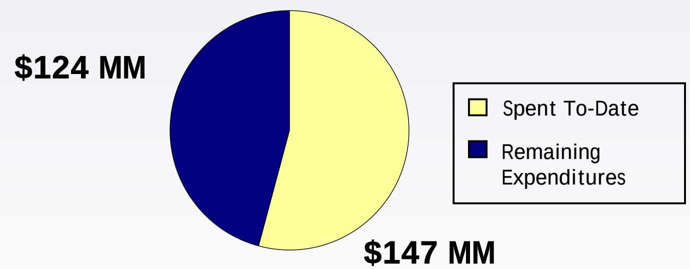
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

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Goldman Sachs Annual Power & Utility Conference

Four Seasons Hotel
Las Vegas, NV
May 11, 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

A Century of Firsts

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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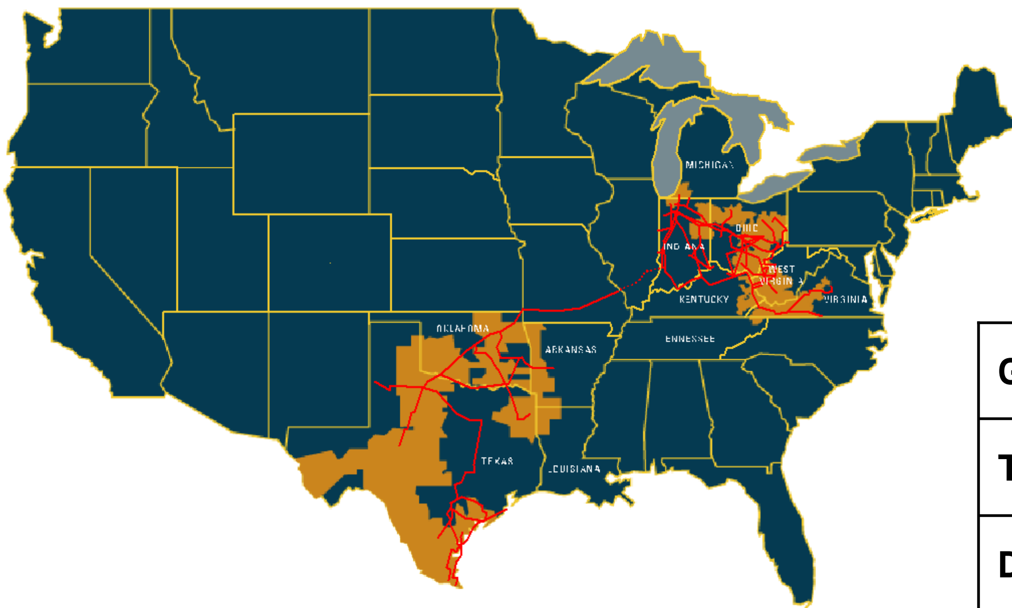
Company Overview

Strength & Scale in Assets & Operations

A Century of Firsts



Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

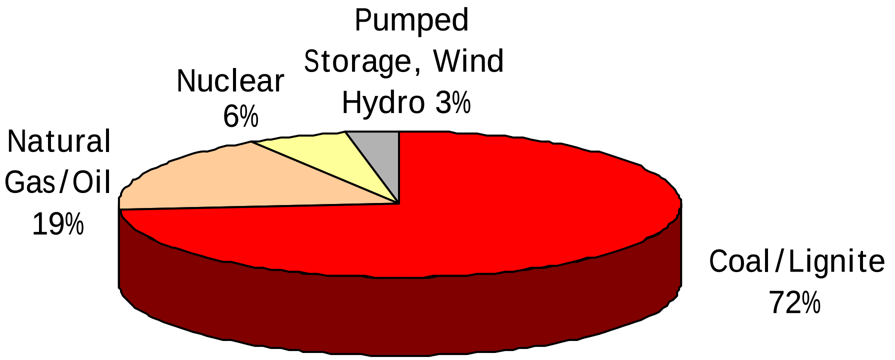
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Asset Portfolio: Generation Fleet Composition

A Century of Firsts

- 35,600 MW Domestic Capacity
- 85% System Availability Factor YE 2005
- 63% System Capacity Factor YE 2005

Capacity by Fuel Mix



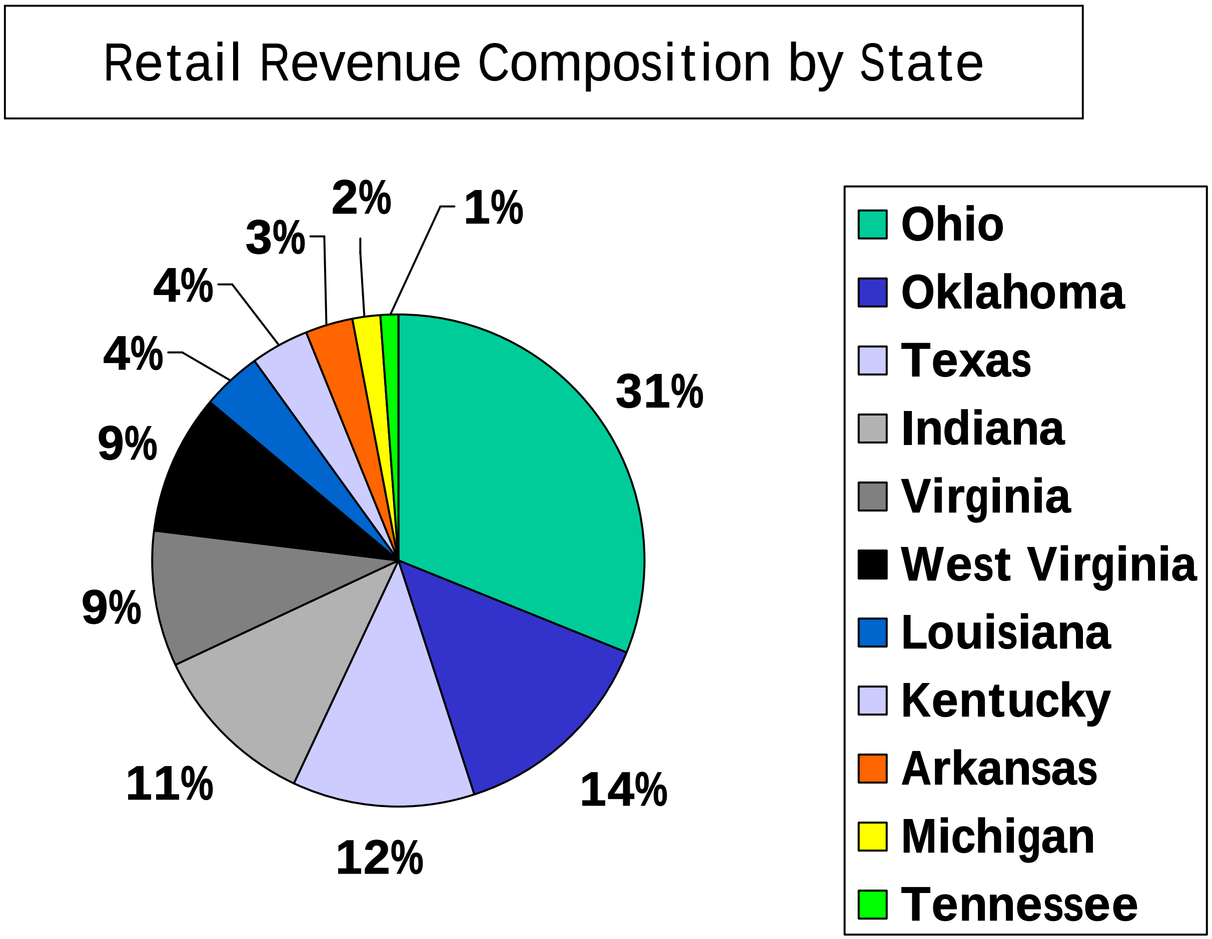
	Baseload	Load-Following	Peaking
PJM	23,985	0	1,954
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**29,902**	**3,516**	**2,142**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

2005 Retail Revenue

A Century of Firsts



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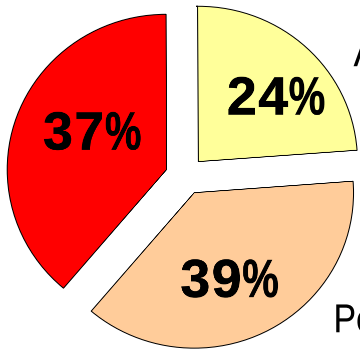
Fuel

Coal Procurement

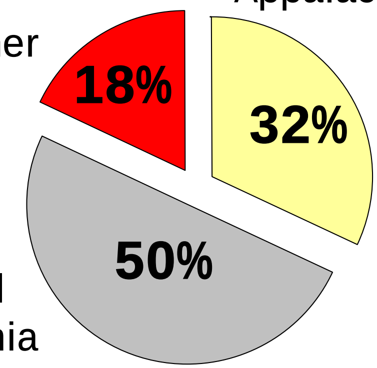
AEP SYSTEM



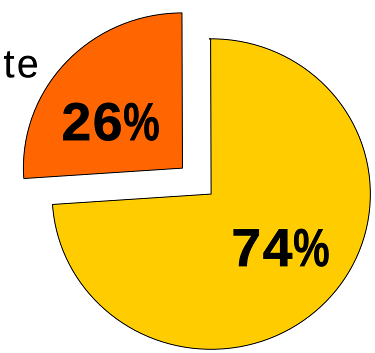
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Essentially >98% purchased for 2006
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM

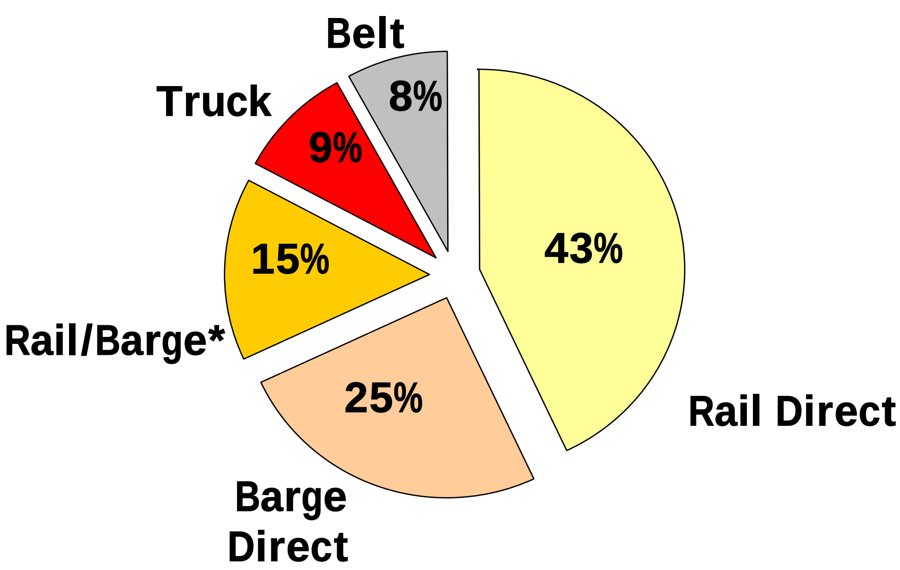


WESTERN SYSTEM

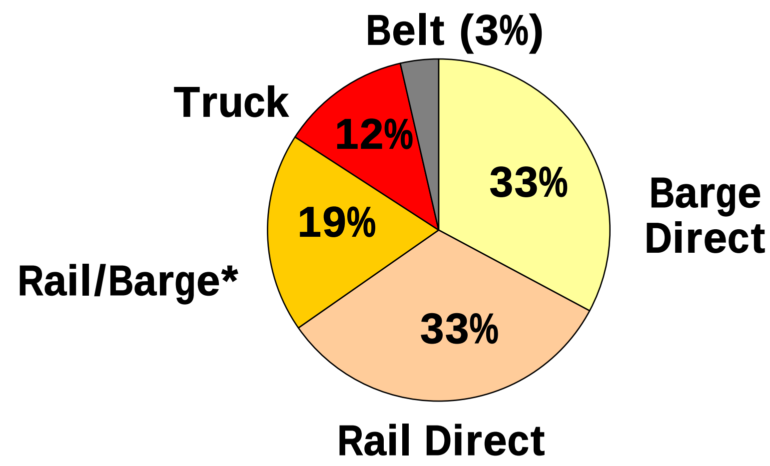


Coal Delivery

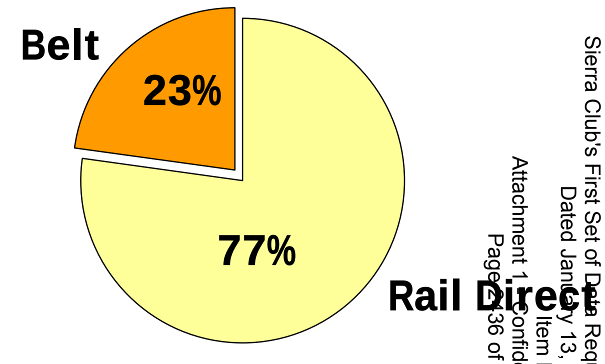
AEP SYSTEM DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



WESTERN SYSTEM
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

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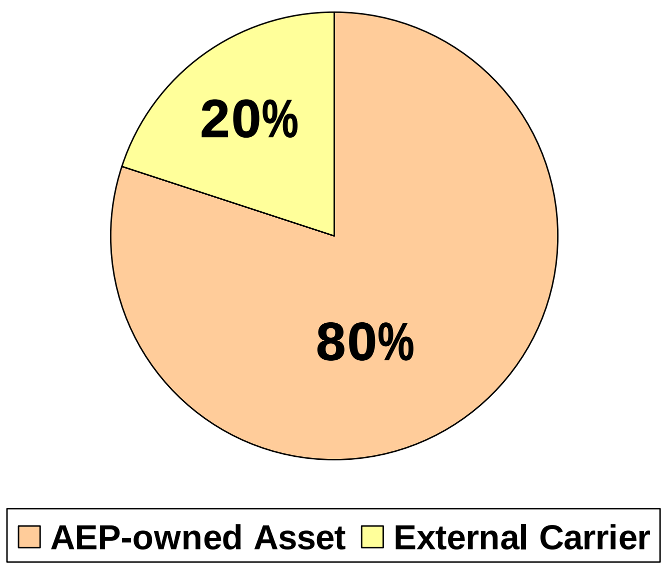
AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

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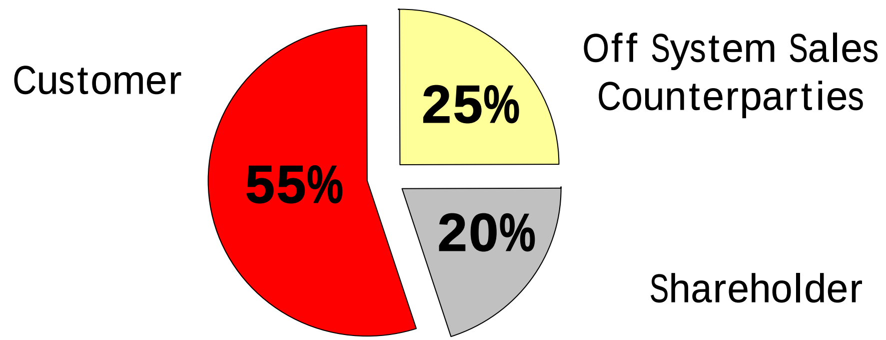
Fuel Recovery

AEP SYSTEM



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KPCo, KGP
  - AEP WEST: PSO, SWEPCO

Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

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Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

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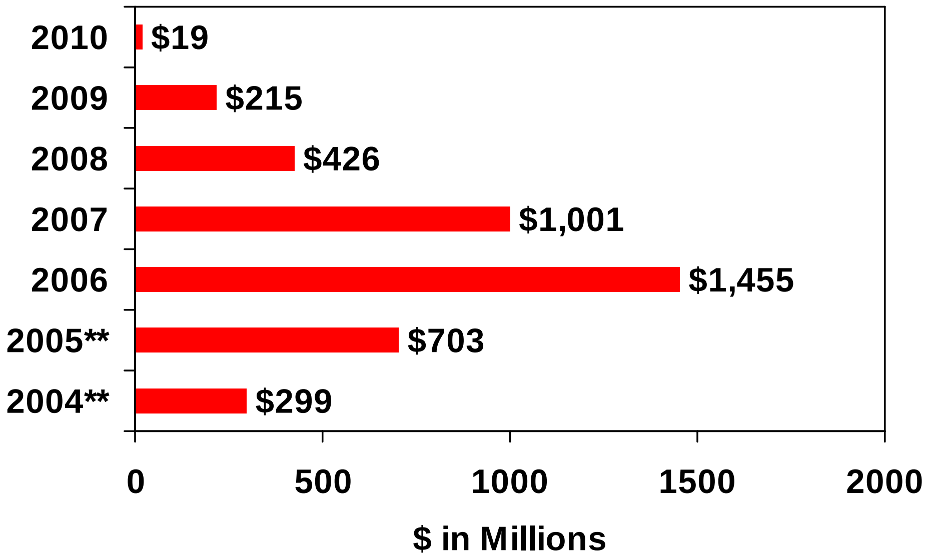
Environmental

$4.1 Billion Environmental Investment

A Century of Firsts

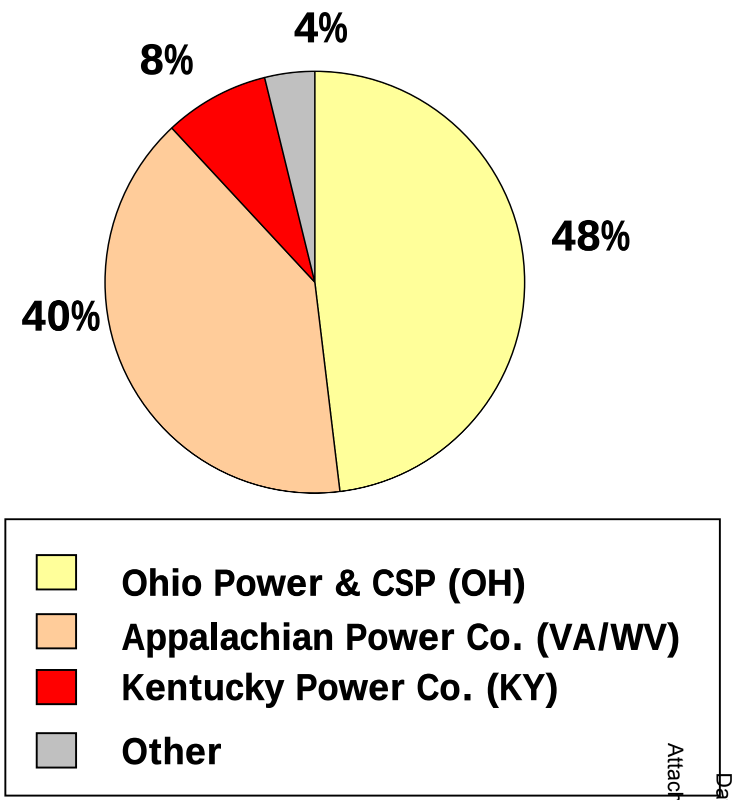
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

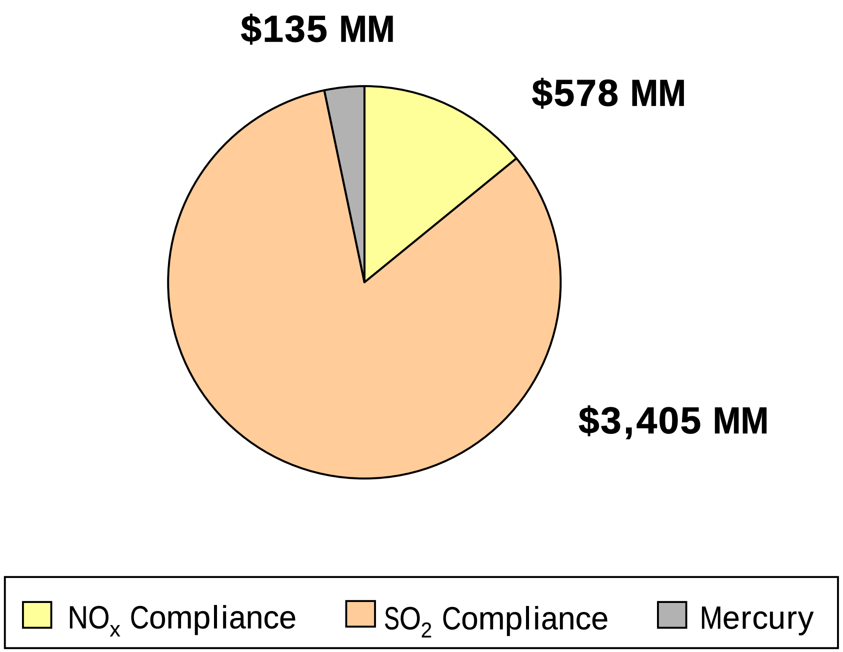
Projected Environmental Investment Allocation



MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT
PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC

Environmental Installations

A Century of Firsts

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD – Reduces SO_2 by 98% (2006 – 2010)

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR - Reduces NOx by 90% (2006 – 2009)

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

2006 – 2010

2006 – 2009

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

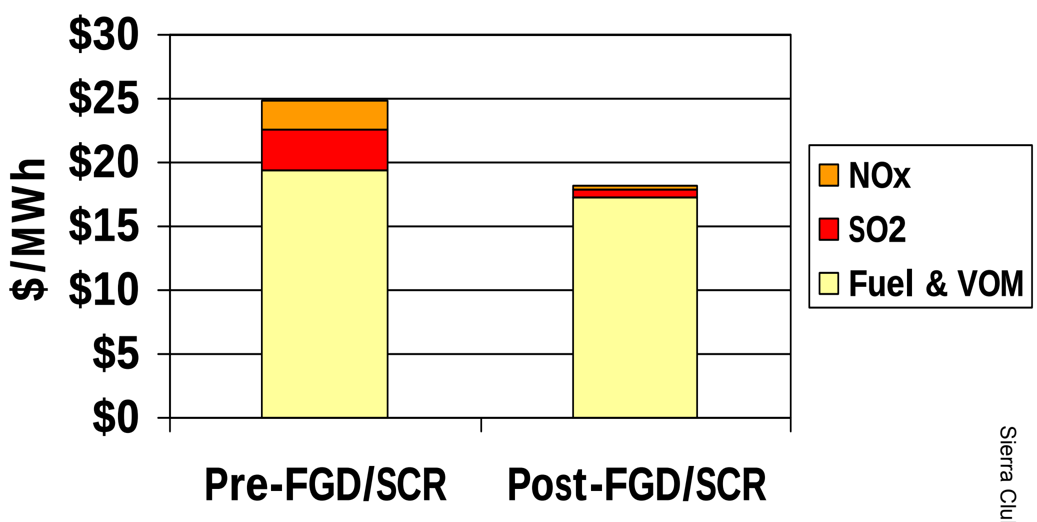
INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

A Century of Firsts

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Investing in IGCC

Integrated Gasification Combined Cycle

A Century of Firsts

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

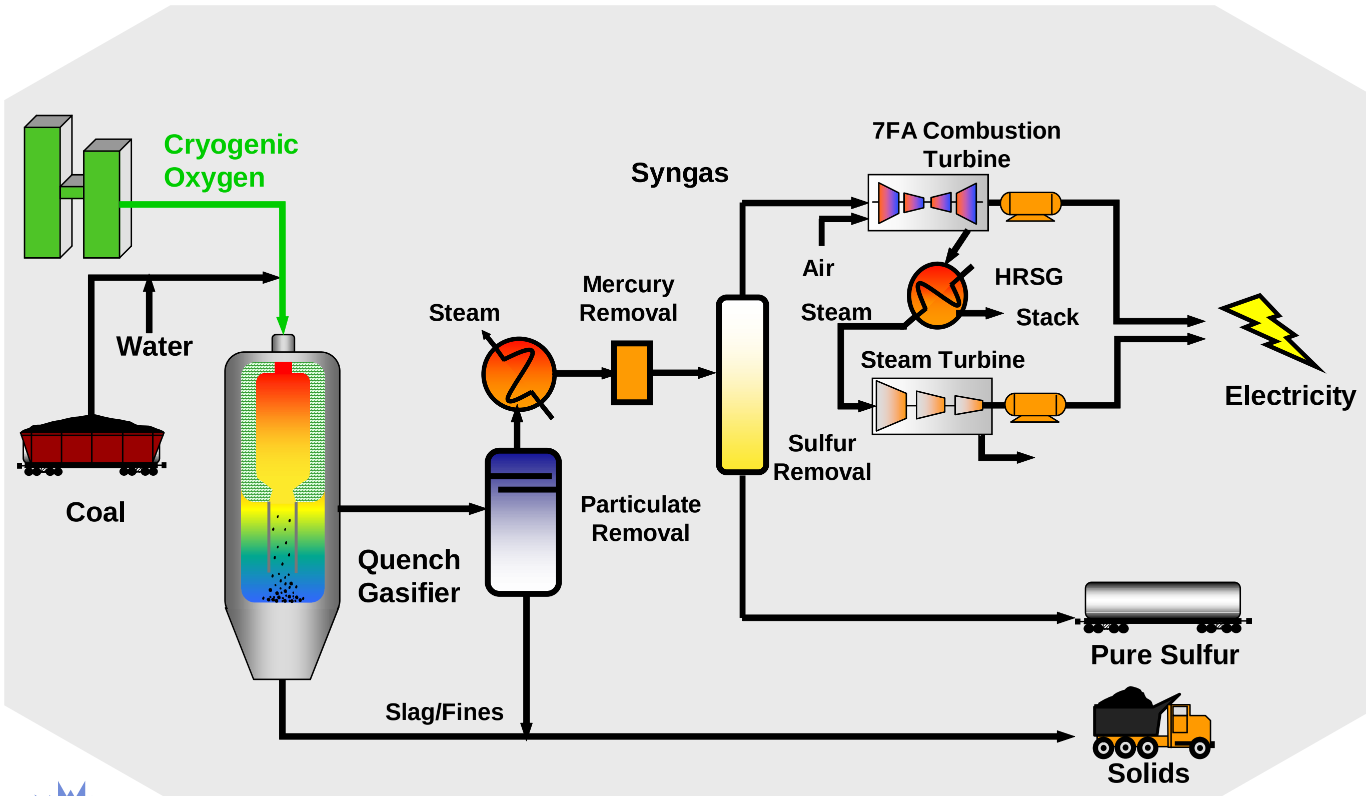
Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC

A Century of Firsts



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

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Investing In IGCC

A Century of Firsts

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Regulatory Overview

Regulatory Activity Underway

A Century of Firsts

- ✓ TCC Stranded Cost Recovery True-up Filing - Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ Indiana Depreciation Petition
- ✓ APCo General Rate Case Filing in Virginia
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia - Settlement Pending
- ✓ IGCC - Received Rate Authorization of Pre - Construction Costs

YTD SECURED $350MM OF THE $500MM RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

A Century of Firsts

TCC Stranded Cost Recovery Case

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - Final order expected in June or July 2006
  - September 2006 - Issuance of securitization bonds if no appeal

Procedural Schedule for TCC Securitization

- ✓ April 17, 2006 – Intervenors Testimony
- ✓ April 24, 2006 – Staff Testimony
- ✓ April 27, 2006 – TCC Rebuttal Testimony
- ✓ May 25-26, 2006 – Hearing On Merits

- May / June 2006 – Request approval for CTC to address other true-up items
  - Expected $475 million credit to customers
  - Sept 2006 – CTC to be implemented

Regulatory Activity Underway

A Century of Firsts

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in third quarter 2006

Appalachian Power – Virginia

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8 million increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3 million in margins from off-system sales (OSS), resulting in a net annual increase of $198.5 million

Regulatory Activity – Settlement Pending

A Century of Firsts

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Filed April 25, 2006 - Joint Settlement Agreement

- ✓ Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- ✓ Provides for timely recovery of Wyoming-Jacksons Ferry 765 kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Settlement Details

- ✓ Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
$23MM	WJF & FGD investment @ 12/31/05
$61MM	Gross revenue increase
($17MM)	ENEC over-recovery negative surcharge
$44MM	Net increase effective 7/28/06

- ✓ Phased-in revenue increases on July 1 in each year 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

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IGCC Regulatory Activity

A Century of Firsts

Ohio - Cost Recovery Filing

Phase 1 - PUCO AUTHORIZED

- ✓ Effective during 2006
- ✓ Provides recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ **Secure cost recovery plan**
  - **April 10, 2006 - PUCO authorized implementation of Phase 1 Rates**
  - **Phase 2 & 3 ruling - Post October 2006 - after completion of FEED study**
- ✓ **Finalize site selection**
- ✓ **Negotiate with suppliers**

2006—2007:

- ✓ **Obtain permits and finalize engineering and procurement**

2007—2010:

- ✓ **Construct and start-up plant**

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

A Century of Firsts

<u>Ohio - Rate Stabilization Plan (2006 - 2008)</u>

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

<u>AEP East FERC Transmission Case</u>

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

<u>SWEPCo Fuel Factor/Surcharge Filing</u>

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

<u>Appalachian Power- Virginia Fuel Factor Increase</u>

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

<u>Kentucky Base Rate Case</u>

Final order approved on March 14, 2006

- ✓ $41 million annual increase in base rates
- ✓ Rates implemented March 30, 2006

Summary Rate Case Information

A Century of Firsts

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Procedural Schedule

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearing
April 24, 2006	Settlement agreement filed
May 4, 2006	Legal briefs filed

- Response briefs due May 15, 2006

Statutory Deadline: July 28, 2006

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Summary Rate Case Information

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Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	**Company Position** (filed 7/1/05)	**Staff Position** (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	**Company Position** (filed 11/14/05)	**Staff Position** (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Capital Investment

Revised Capital Investment Forecast

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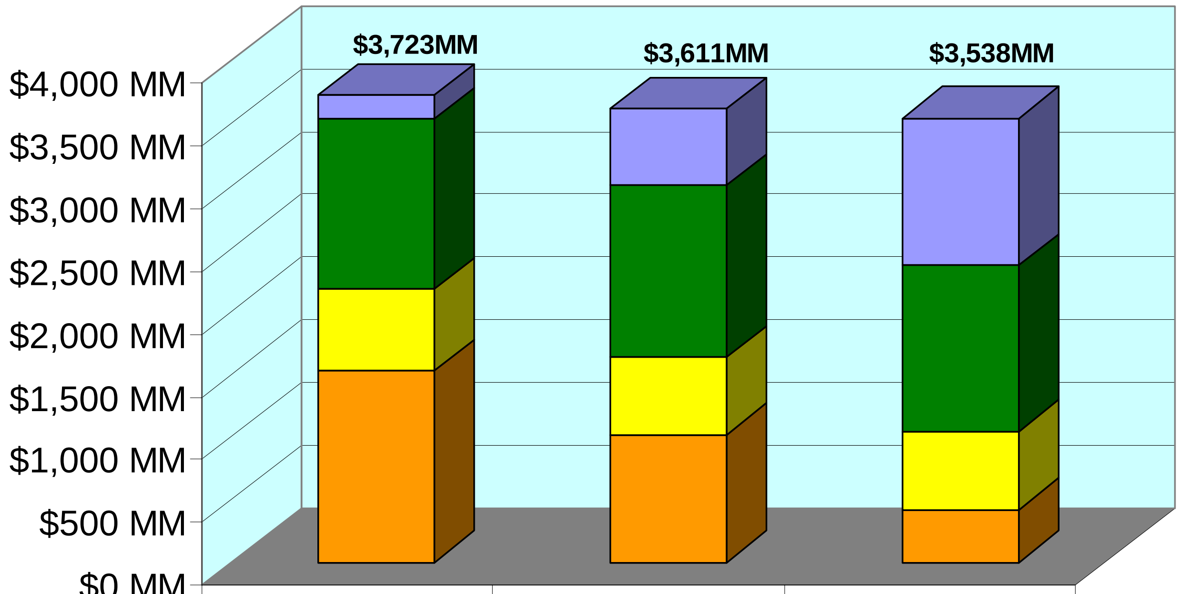
Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE – INVESTMENT LEVEL WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Forecasted Capital Expenditures

A Century of Firsts

Company	2006	2007	2008
		(in thousands)	
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

New Generation

IGCC

- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 megawatt facility to begin in 2007
- Commercial operation date expected in 2010

PSO RFPs

- Submitted RFPs totaling 900 megawatts of baseload and peaking capacity
- Commercial operation dates expected in 2008 and 2011

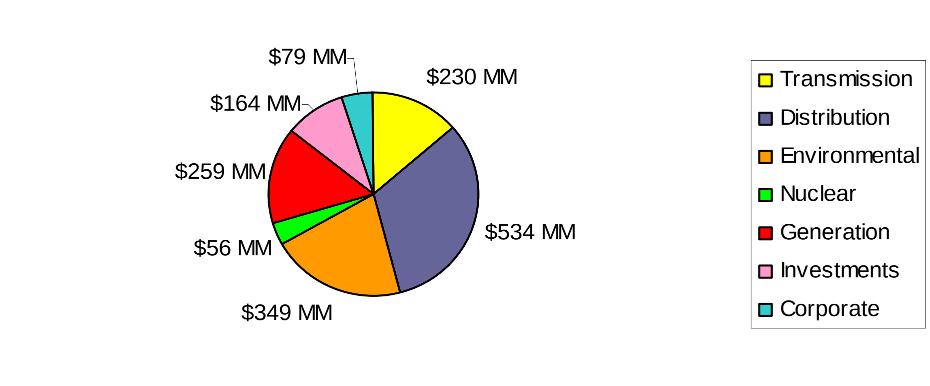
SWEPCO RFPs

- Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity
- PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

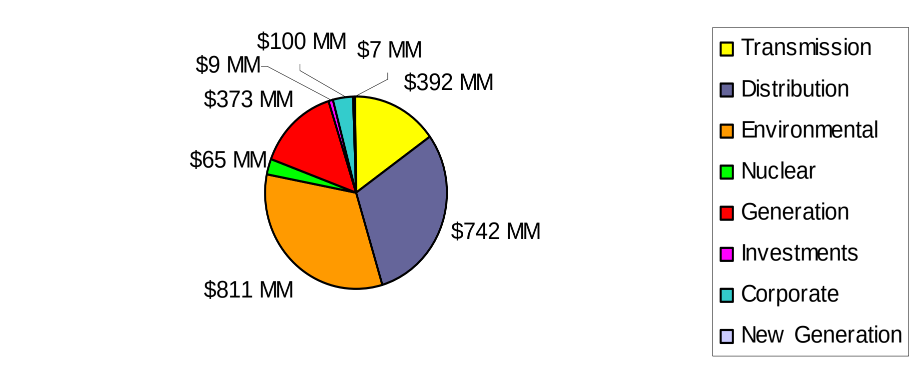
Capital Investment 2004 - 2006

A Century of Firsts

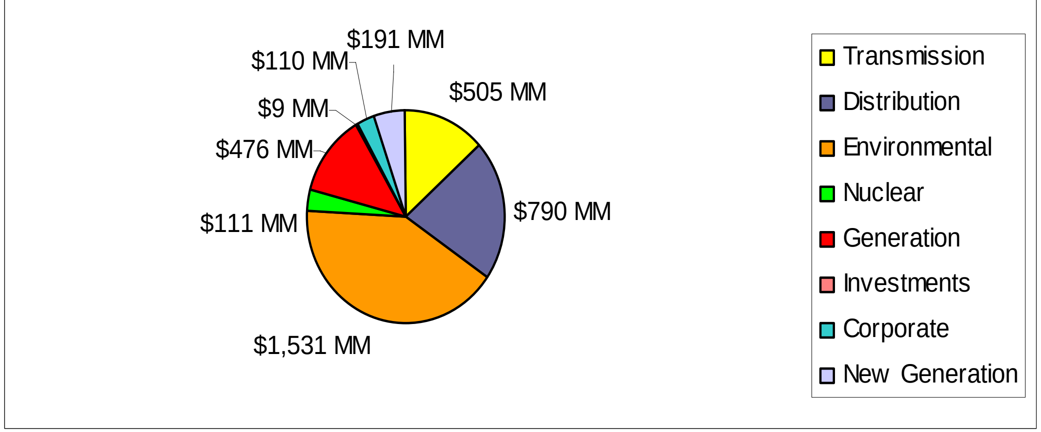
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Finance

2006 Earnings Guidance Range: $2.50 - $2.70

A Century of Firsts

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
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5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
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13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60

Shares Outstanding (in millions) 390 393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

2006 Projected Cash Flow

A Century of Firsts

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capitalization

A Century of Firsts

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.5% at 3/31/06

Appendix

Framework For 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Summary of Major 2006 Earnings Drivers

A Century of Firsts

- ✓ Load growth of 2.5%
- ✓ $500MM rate recovery assured or in progress
- ✓ Rising fuel costs of 11-13%
- ✓ Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- ✓ Decline in utility operations O&M
- ✓ Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

International EEI Conference

February 20-21, 2006

London, United Kingdom
London Hilton on Park Lane

A Century of Firsts

American Electric Power

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

A Century of Firsts

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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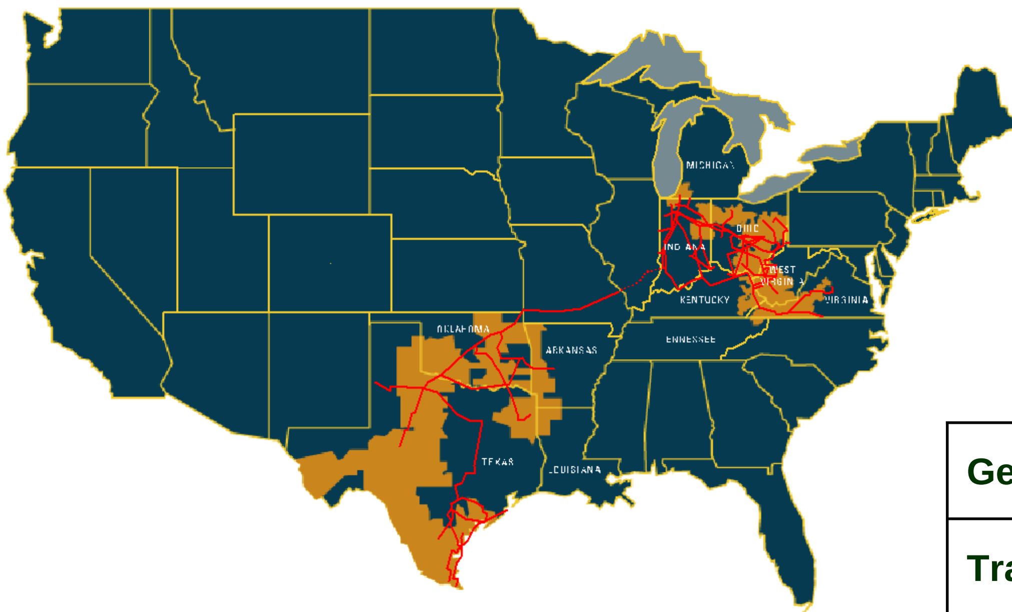
Strength & Scale in Assets & Operations



Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Framework for 2006

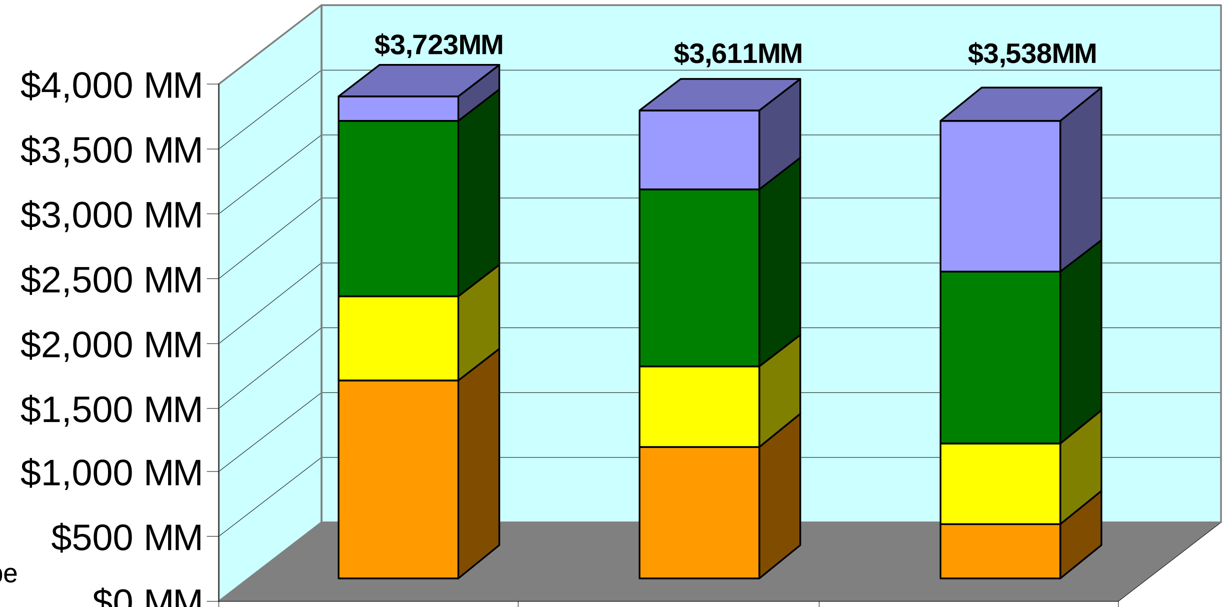
- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

A Century of Firsts

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (554)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,795	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,314	$ 1,294	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (24)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 2,434	$ 1,661	$ 1,623
Other	$ 43	$ 160	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.402B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

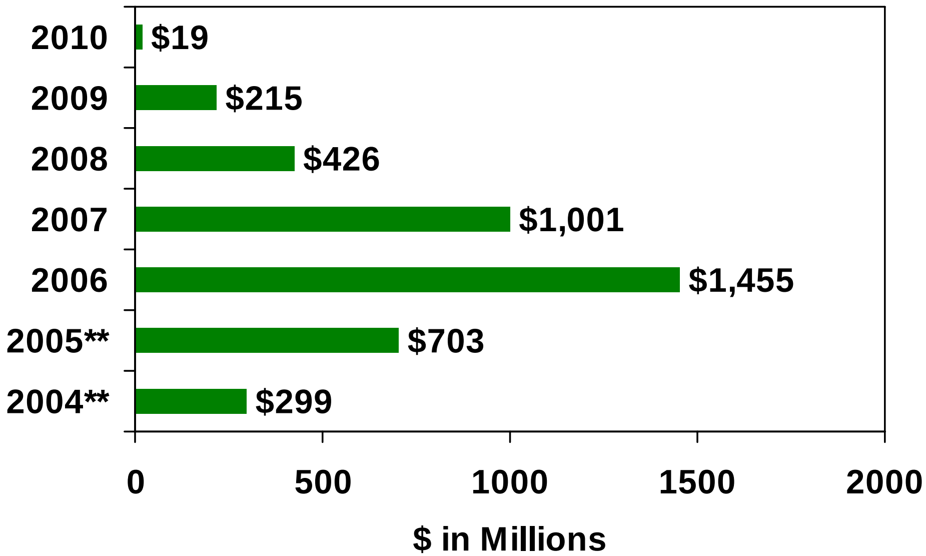
Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

$4.1 Billion Environmental Investment

A Century of Firsts

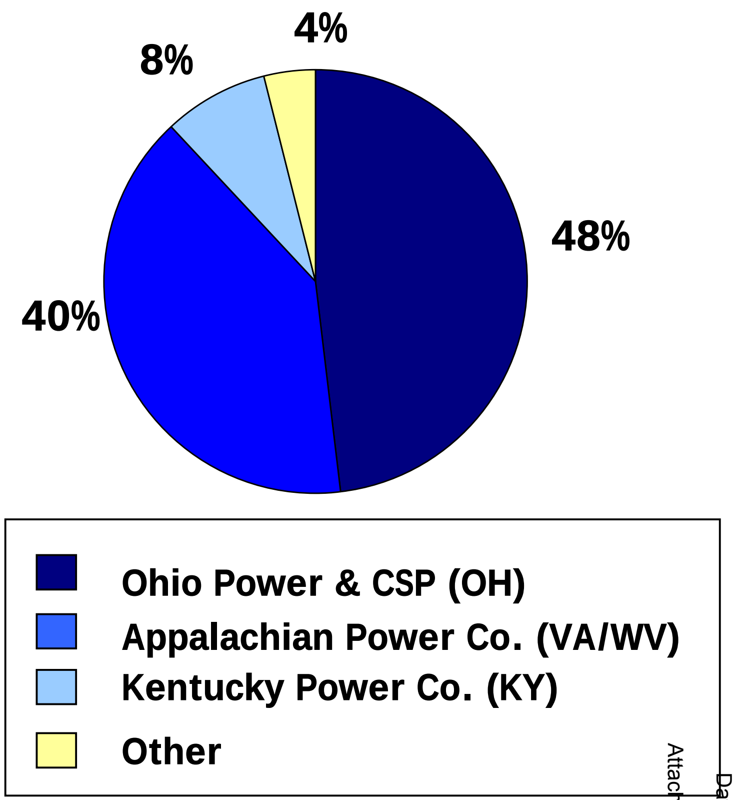
Environmental Capital Investment*



*Environmental investment for NOx, SO_2, & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation

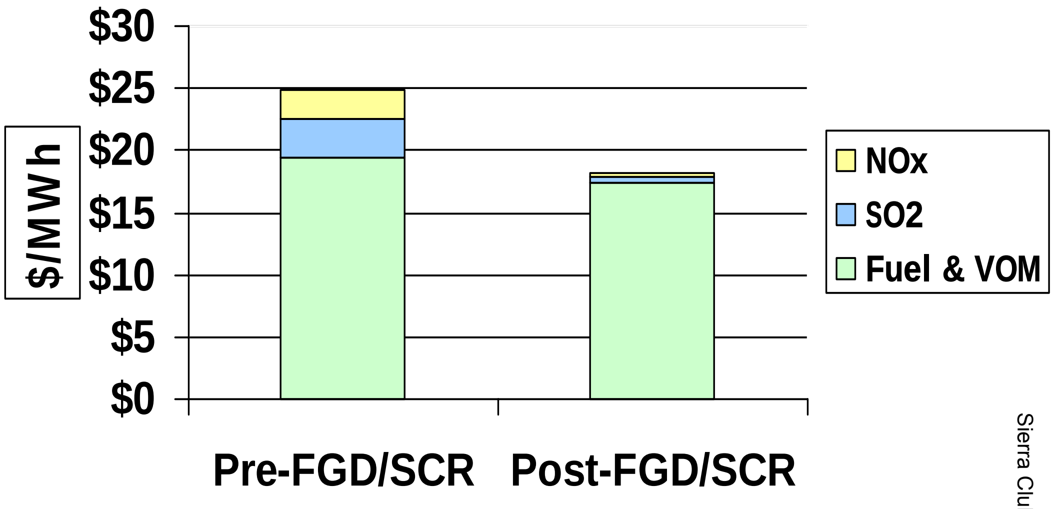


MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ Kentucky Base Rate Filing – Settlement Pending
- ✓ Indiana Depreciation Petition
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

A Century of Firsts

<u>TCC Stranded Cost Recovery Case</u>

- Seeking approval of true-up balances
  - ✓ February 6, 2006 – PUCT draft order provides for net true-up of $1.475 billion
- February 2006 - Final written order expected, if not extended
  - ✓ Feb/Mar 2006 - Request for securitization
    - ➢ 4Q06 - Issuance of securitization bonds if no appeal
  - ✓ Mar/Apr 2006 – Request approval for CTC to collect other true-up items
    - ➢ Jan 2007 – CTC charge to be implemented

<u>Ohio Companies Pass through of FERC OATT Changes</u>

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Regulatory Activity Underway

A Century of Firsts

Appalachian Power – Virginia E & R Cost Recovery Factor

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- ✓ Public hearings are scheduled to begin February 27, 2006

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ March 16, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

Regulatory Activity Underway

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Parties to the case reached a settlement on Feb 6, 2006
  - ✓ $41 million annual increase in base rates
  - ✓ To be effective March 30, 2006
- ✓ Settlement was presented to the Commission at a public hearing on Feb 7, 2006
- ✓ Final order expected in March 2006

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1

- ✓ **Effective during 2006**
- ✓ **Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services**
- ✓ **Approximately $23.7 Million**

Phase 2

- ✓ **Effective 2007- mid 2010 (Construction Phase)**
- ✓ **Seeks recovery of carrying costs associated with plant construction**

Phase 3

- ✓ **Effective mid 2010 (Commercial Operation begins)**
- ✓ **Seeks recovery of projected $1.174 Billion cost of plant over its operating life.**

Ohio Next Steps

2006:

- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan

✓ Generation rate increases implemented January 1, 2006

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

✓ Results in $22 Million net revenue in 2006 from wholesale transmission

Appalachian Power- Virginia Fuel Factor Increase

✓ $57.7 Million increase in fuel factor approved on January 20, 2006

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.

✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

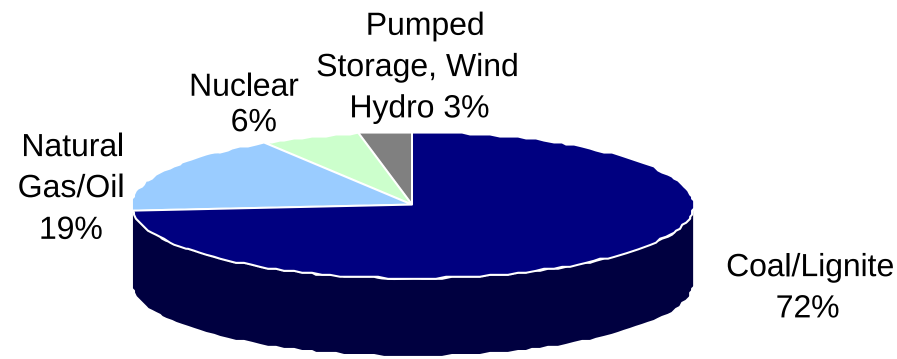
Appendix

Asset Portfolio: Generation Fleet Composition

A Century of Firsts

Capacity by Fuel Mix

- 35,600 MW Domestic Capacity
- 85% System Availability Factor YE 2005
- 63% System Capacity Factor YE 2005



	Baseload	Load-Following	Peaking
PJM	23,985	0	1,954
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**29,902**	**3,516**	**2,142**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

2006 Earnings Guidance Range: $2.50 - $2.70

A Century of Firsts

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	Shares Outstanding (in millions)			390			[illegible]

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A Century of Firsts

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TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

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- ✓ *Rising fuel costs*
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Other	91	(315)
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Capital Expenditures	(2,402)	(3,723)
Asset Sales	1,294	28
Other	179	(163)
Total from Investing	**$ (929)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(24)	-
Net Long Term Debt Issued/(Retired)	(78)	2,434
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(554)	(582)
Other Financing Activities	(50)	(3)
Total from Financing	**$ (785)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

CASH ON HAND OF $326 MILLION AT YEAR END 2006

Capitalization

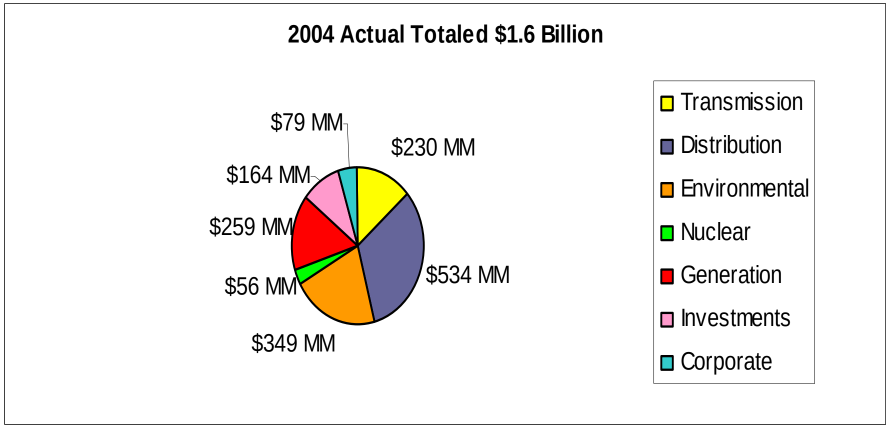
A Century of Firsts

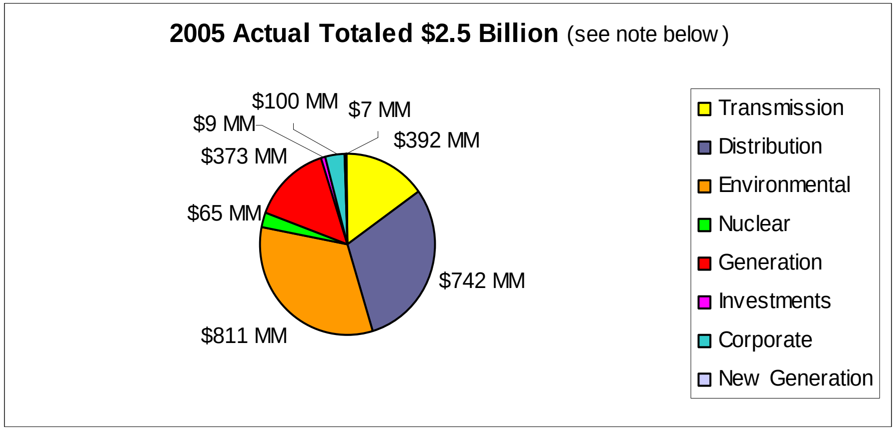
Capital Structure	Actual 12/31/04			Actual 12/31/2005		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,226	-	12,226
Short-term Debt	23	-	23	10	-	10
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	(66)	66	-	30	(30)	-
Defeased First Mortgage Bonds	(84)	-	(84)	(30)	-	(30)
Off-balance Sheet Leases	1,241	-	1,241	1,213	-	1,213
Securitization Bonds	(698)	-	(698)	(648)	-	(648)
Spent Nuclear Fuel Trust	(229)	-	(229)	(228)	-	(228)
Total Adjusted Capitalization	**12,540**	**8,642**	**21,182**	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***59.2%***	***40.8%***	***100.0%***	***58.0%***	***42.0%***	***100.0%***

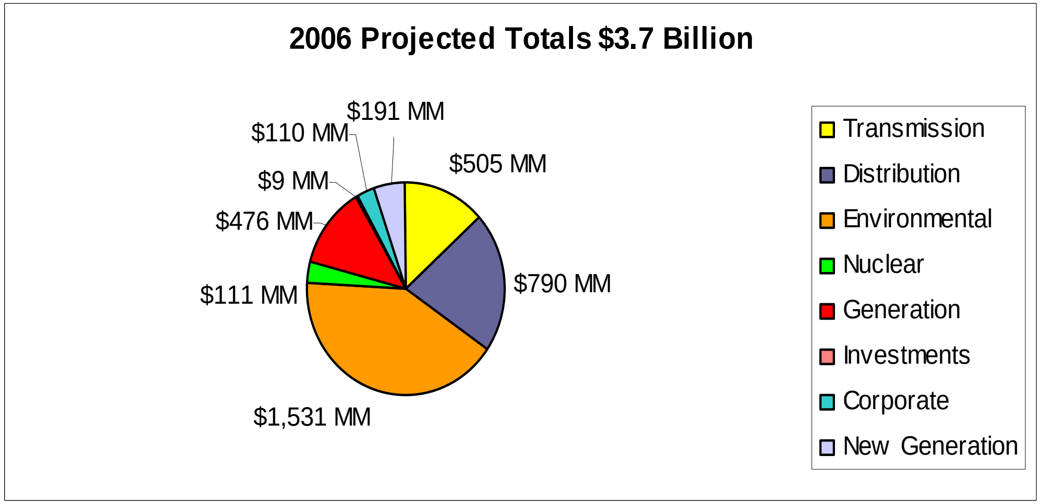
ADJUSTED DEBT-TO-CAP OF 58.0% AT 12/31/05

Capital Investment 2004 - 2006

Figures exclude AFUDC



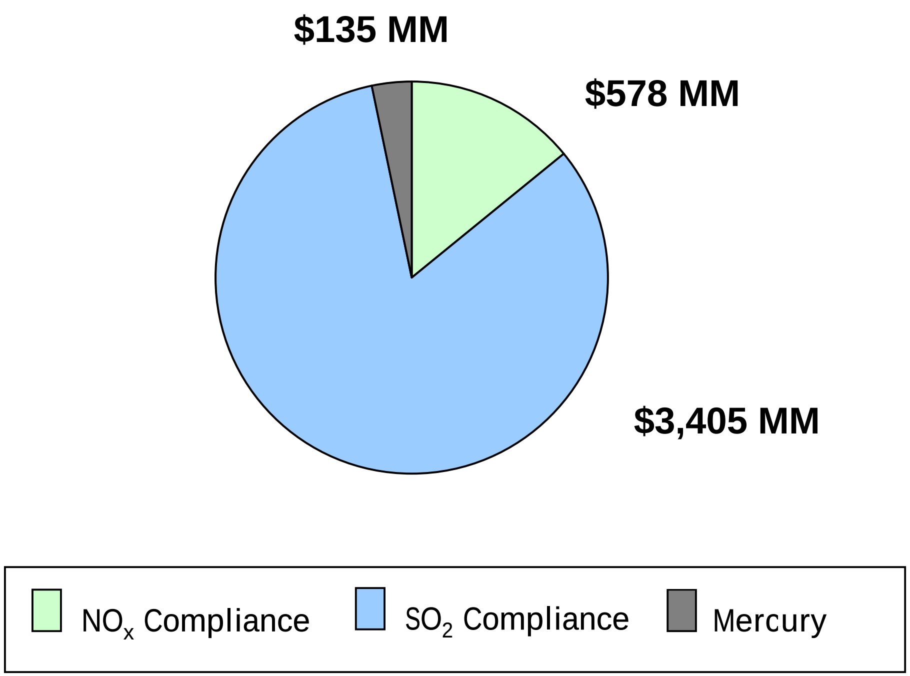




Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Figures Include AFUDC

Environmental Installations

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

2006 – 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Integration Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

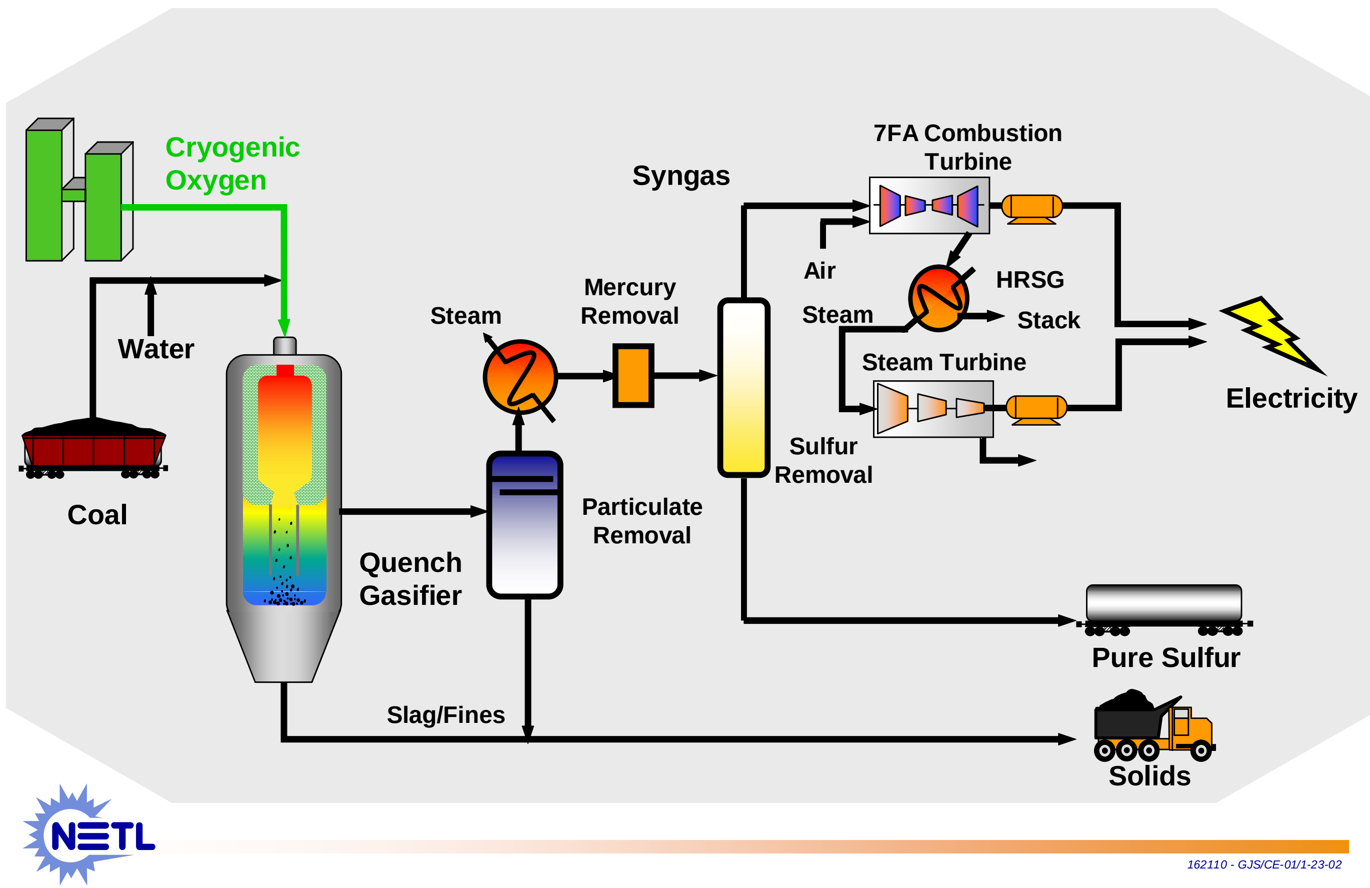
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking to the Future - IGCC



AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing in IGCC

A Century of Firsts

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

•Source: Results of AEP analysis based on EPRI studies.

• Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.

• Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.

• Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.

• Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.

• Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.

• Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure – Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base – Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

March 8, 2006	Staff & Intervenor Testimony
March 29, 2006	Company Rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order is issued.

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

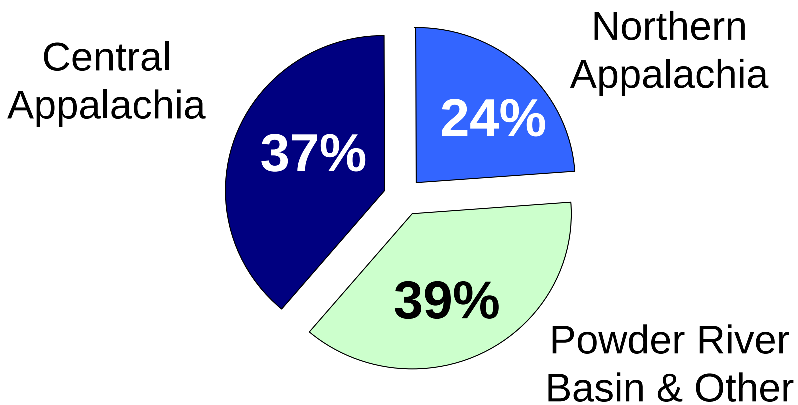
Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Coal Procurement

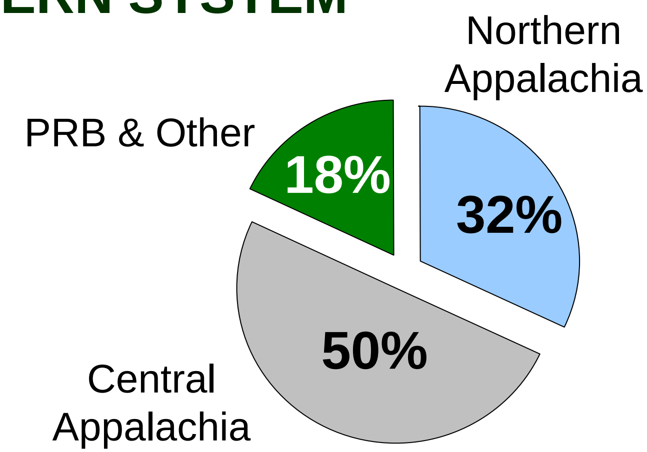
AEP SYSTEM



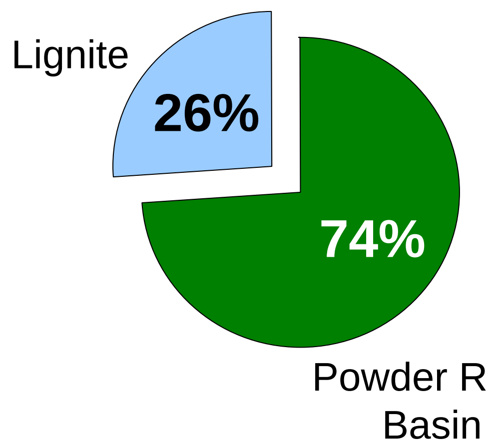
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ \$32.52/ton in 2005
- Essentially 95% purchased for 2006
- Approximately 10%-12% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM



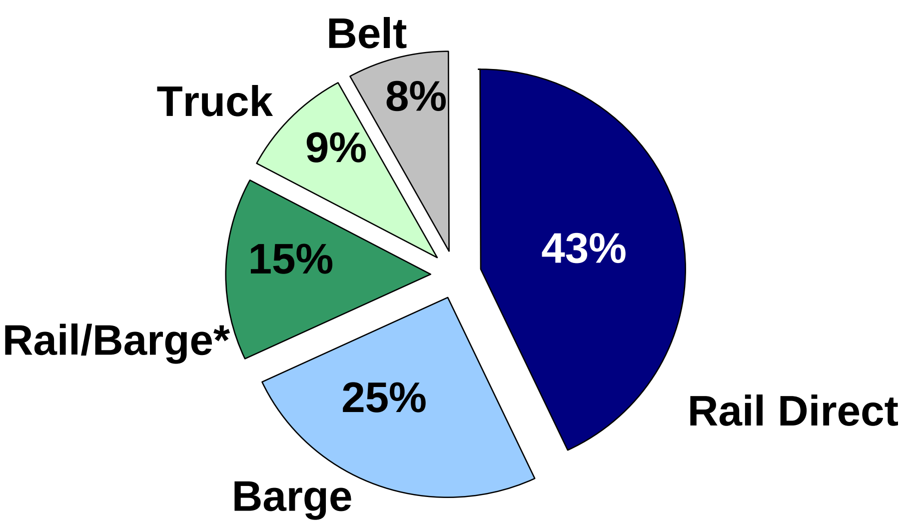
WESTERN SYSTEM



Coal Delivery

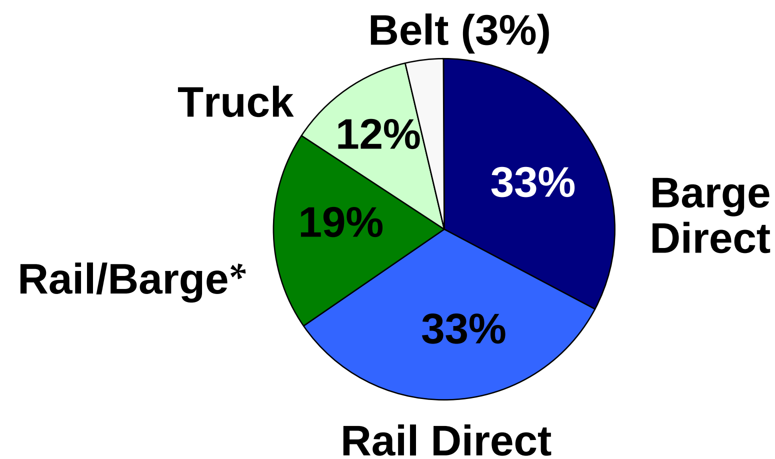
AEP SYSTEM DELIVERY MODE DIVERSITY

2005 Actual



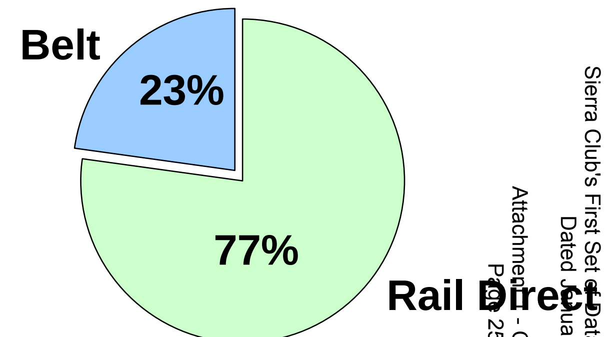
EASTERN SYSTEM

2005 Actual



WESTERN SYSTEM

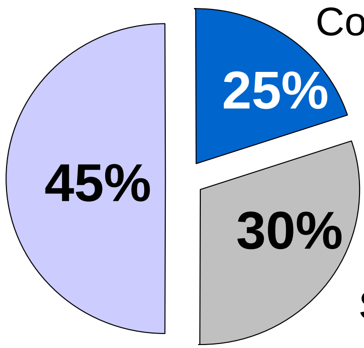
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

Fuel Recovery

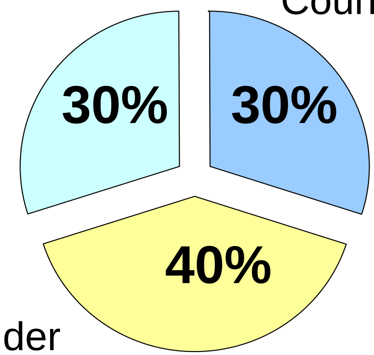
AEP SYSTEM



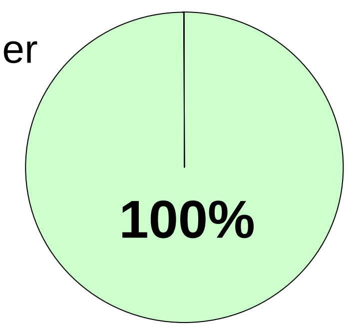
Fuel Cost Recovery
(on average)

- ➢ Fuel recovery varies by jurisdiction
- ➢ 70% of fuel cost is recoverable across the AEP System
- ➢ Active Fuel Clause Jurisdictions:
  - AEP EAST: AP-VA, I&M, KGP, KP
  - AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

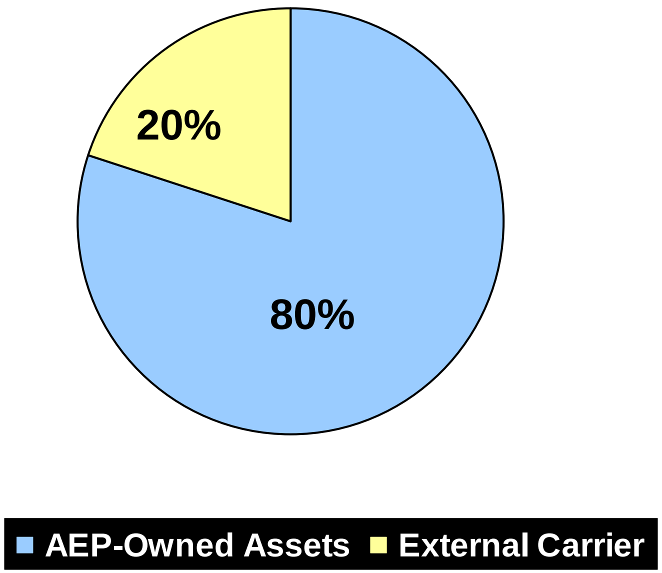


WESTERN SYSTEM



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

International EEI Conference

February 21-22, 2005
London, United Kingdom
London Hilton on Park Lane

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements which are subject to risks and uncertainties. These factors include electric load and customer growth; abnormal weather conditions; available sources and cost of fuel; availability of generating capacity and performance of plants; the speed and degree to which competition is introduced to our service territories; the ability to recover stranded costs in connection with deregulation; new legislation and government regulation; resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to successfully control costs; the success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile; ability to sell assets at attractive prices; international and country-specific developments affecting foreign investments including the disposition of any current foreign investments and potential additional foreign investments; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; electricity and gas market prices; changes in creditworthiness in energy trading market; changes in the financial markets; changes in markets for electricity, natural gas, and other energy-related commodities; actions of rating agencies; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; liquidity in the banking, capital and wholesale power markets; prices for power we generate and sell at wholesale; changes in technology, including the increased use of distributed generation within our transmission and distribution service territory; other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Susan Tomasky

Executive Vice President & Chief Financial Officer

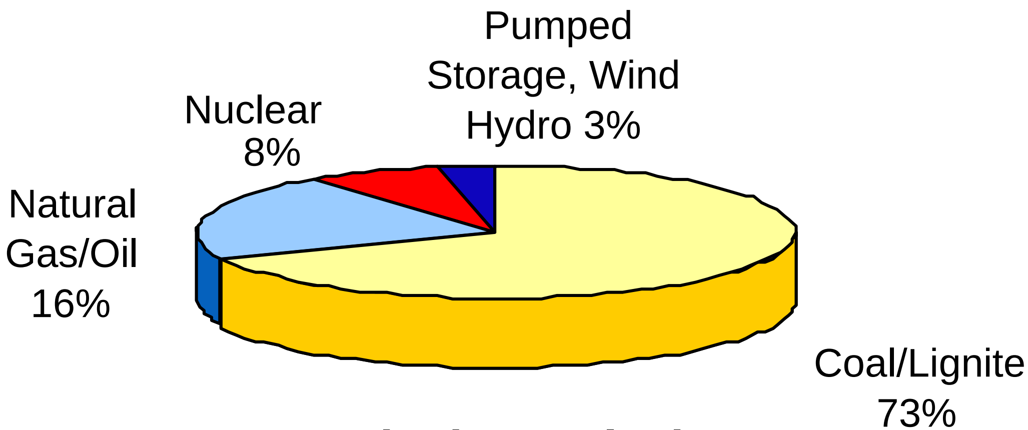
Strength & Scale in Assets & Operations

Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2511 of 9556

Fuel Mix & Operating Statistics



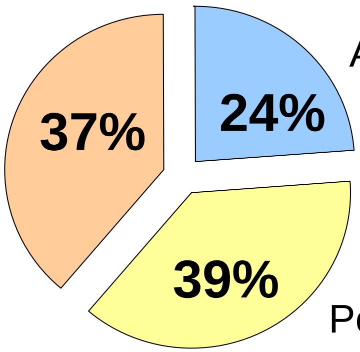
Capacity by Fuel Mix

- 36,000 MW domestic capacity
- 85% system availability factor for YE 2004
- 62% system capacity factor for YE 2004

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Coal Procurement

AEP SYSTEM

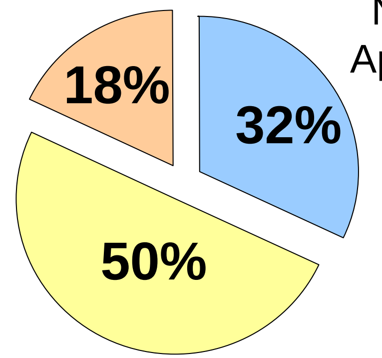


Coal Supply

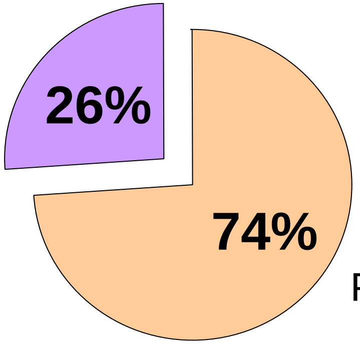
(on average)

- Purchase 75 MM tons per year
- Ave. delivered price ~ $28.50/ton in 2004
- Approximately 96% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

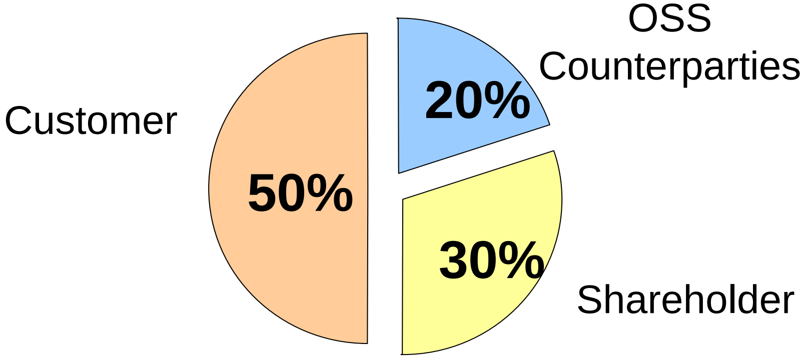


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM



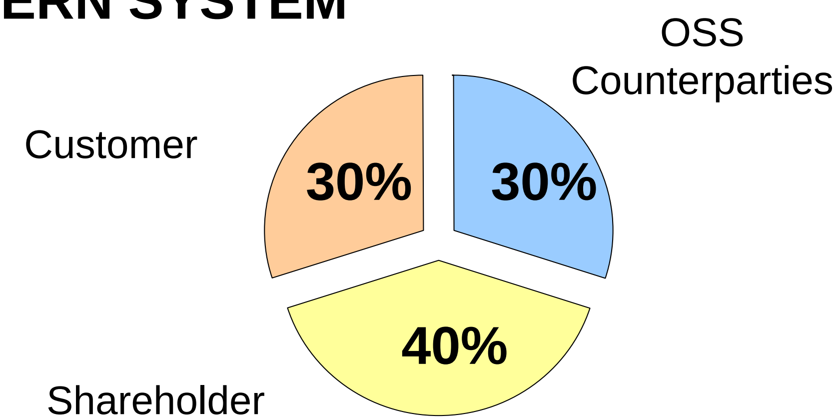
Fuel Cost Recovery

(on average)

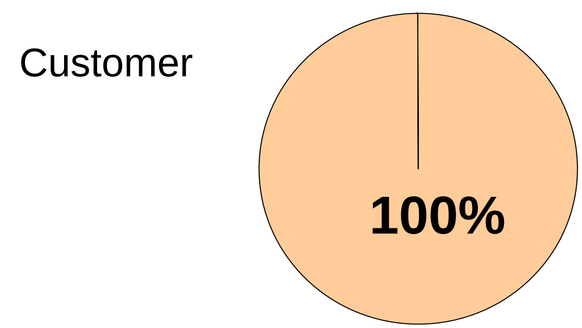
- Fuel recovery varies by jurisdiction
- 70% of fuel costs is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST:
AP-VA, I&M, KGP, KP
AEP WEST:
PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual		2005 Forecast	
		$ in millions	EPS	$ in millions	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
3	Texas Wires	441		469	
4	Texas Supply / REP	347		198	
5	Off-System Sales	472		547	
6	Other Wholesale Transactions	14		-	
7	Transmission Revenue - 3rd Party	451		410	
8	Other Operating Revenue	331		346	
9	Total Gross Margin	7,018		7,017	
10	Operations & Maintenance	(3,072)		(3,073)	
11	Depreciation & Amortization	(1,256)		(1,275)	
12	Taxes Other than Income Taxes	(700)		(728)	
13	Interest Exp & Preferred Dividend	(616)		(598)	
14	Other Income & Deductions	161		182	
15	Income Taxes	(489)		(538)	
16	Net Earnings Utility Operations	1,046	2.64	988	2.48
	INVESTMENTS:				
17	Gas Operations	(33)		11	
18	Other Investments	(18)		(17)	
19	Total Investments	(51)	(0.13)	(6)	(0.02)
20	Parent Company	(71)	(0.18)	(24)	(0.06)
21	**ON-GOING EARNINGS**	924	2.33	958	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Improved performance at HPL*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	960 *
Depreciation & Amortization	1,300	1,317
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	339
Total from Operations	**$ 2,597**	**$ 2,162**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,733)
Asset Sales	1,345	375 **
Other	(28)	43
Total from Investing	**$ (376)**	**$ (2,315)**
Cash from Financing:		
Common Equity	17	345 ***
Net Long Term Debt Issued/(Retired)	(1,829)	800
Preferred Stock Redeemed	(10)	-
Short Term Debt Change, Net	(400)	6
Common Dividends	(555)	(560)
Total from Financing	**$ (2,777)**	**$ 591**
Net Change in Cash	**$ (556)**	**$ 438**
Ending Cash Balance	**$ 420**	**$ 858**

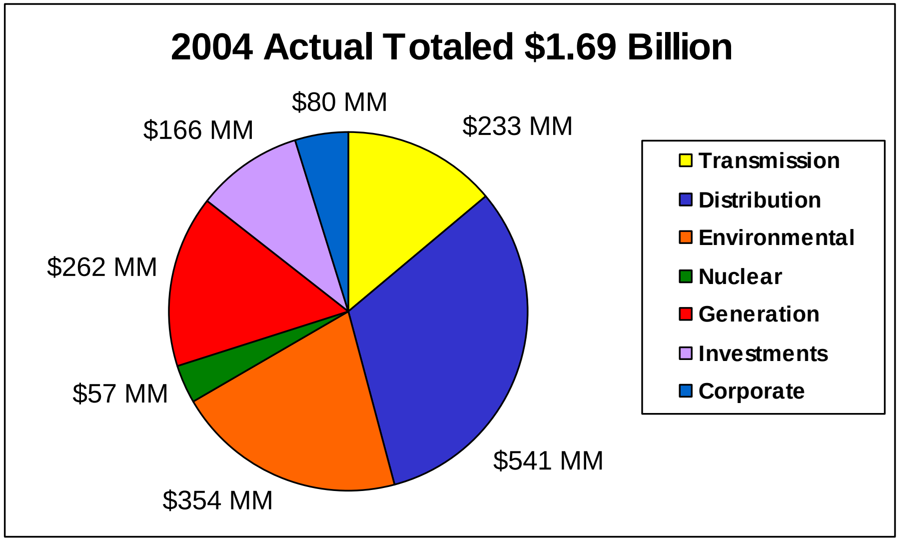
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 399 million shares outstanding**

**** Includes STP & Oklaunion asset sales; receipt of $1 billion relating to HPL sale not reflected in this figure**

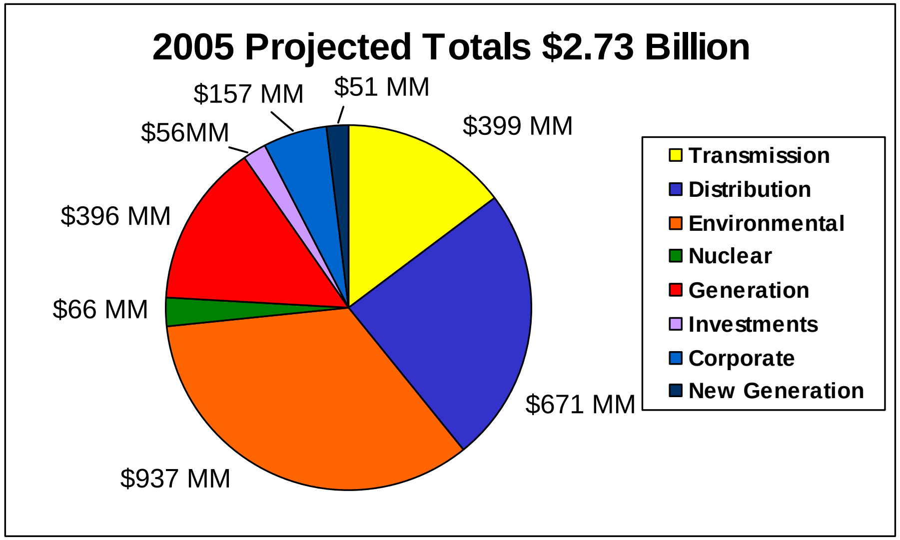
*****Equity units terms require issuance of $345MM common shares in August 2005**

MAINTAIN DEBT-TO-CAP BELOW < 60% IN 2005

2005 Capex



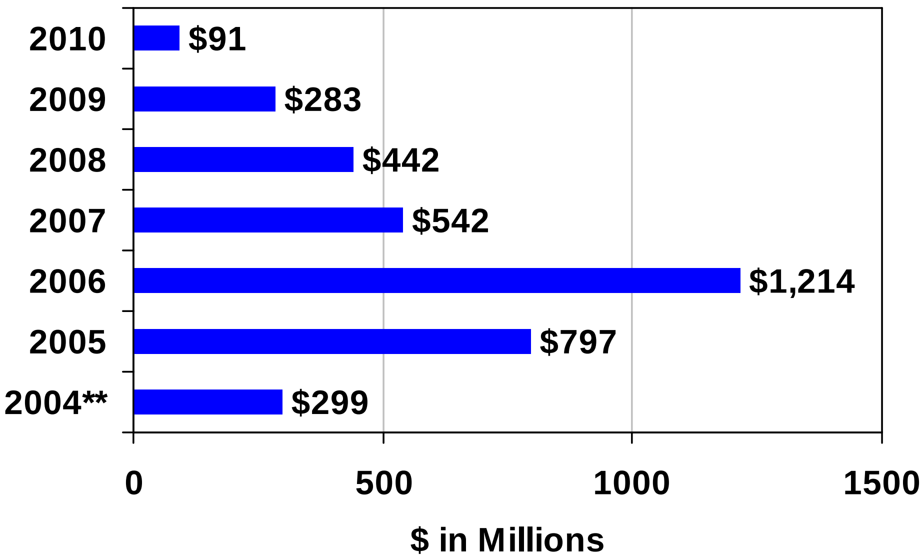
2004 Actual Totaled $1.69 Billion
$80 MM
$233 MM
$166 MM
$262 MM
$57 MM
$354 MM
$541 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate



2005 Projected Totals $2.73 Billion
$157 MM
$51 MM
$399 MM
$56MM
$396 MM
$66 MM
$937 MM
$671 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

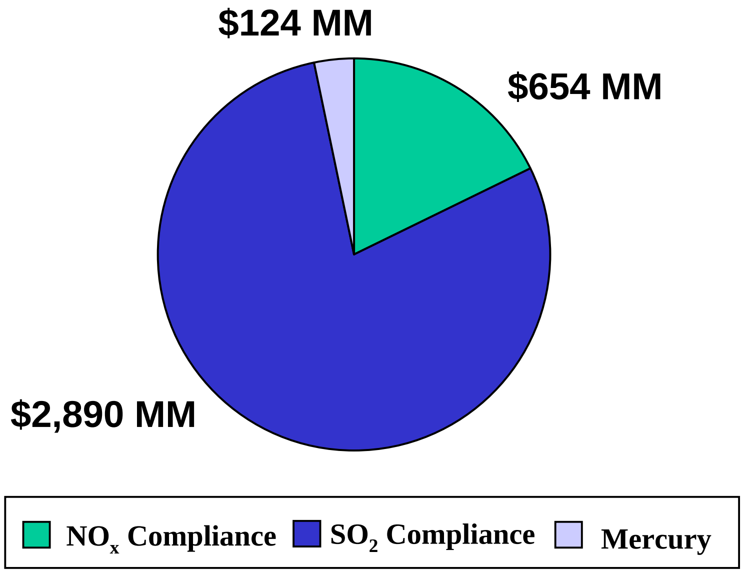
Environmental Investment: $3.7 Billion through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

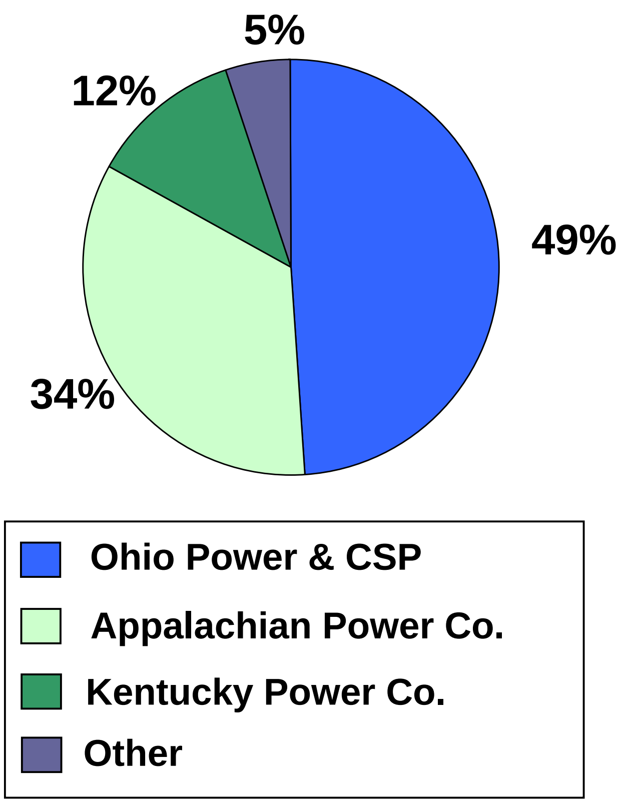
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- Ohio: 49% ($1.8 billion)
  - Rate stabilization plan increases at CSP – 3% and OP – 7%
- Virginia/West Virginia: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- Kentucky: 12% ($433 million)
  - Surcharge mechanism

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
- **Planned Regulatory Activity (2005-2007)**
  - FERC Transmission Rate Case
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

IGCC Investment

2005

- Secure regulatory cost recovery
- Finalize site selection
- Negotiate with suppliers

- **2005—2007:** Obtain permits and finalize engineering and procurement

- **2008—2009**: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

AEP

AEP AMERICAN ELECTRIC POWER

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Appendix

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- ***Outcome of pending regulatory proceedings***
  - ***Texas, Oklahoma & Louisiana***
- ***Operations within PJM environment***
- ***Plant availability***
- ***Rising fuel costs***
- ***Weather (storm damage and effect on sales)***

TCC Stranded Cost Carrying Charge

Carrying Cost Details:

Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

Simplified Calculation:	
Initial Stranded Cost Base	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

Items included in stranded cost base include:
Stranded Plant costs ($900 MM), Regulatory Assets($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly.

EQUITY COMPONENT RECOVERABLE ONCE AN ORDER IS RECEIVED

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Income				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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Replacing Out & Through Transmission Revenues

2003 O&T Revenue Totaled $197MM

Revenue Neutrality due to SECA rates 12/1/04 thru 1Q06

2004	2005	2006	2007

AEP FERC transmission rate case in 2005/Early 2006 to reflect removal of credits from license plate rates;

FERC case establishes rates to replace approximately 53% of O&T Revenue (14% Wholesale, 39% Ohio Retail)

Rate case activity to occur in the AEP East jurisdictions throughout 2006 & 2007 will include establishment of new transmission requirements for AEP's KY,VA, TN, WV, IN, and MI operations

TIMING OF RATE CASE ACTIVITY TO BE A FUNCTION OF ENVIRONMENTAL & OTHER INVESTMENT RECOVERY

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Comparison of Generation Technology Options

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8500	7000
EPC Cost* ($/kW)	1200	1450	400
Total Plant cost** ($/kW)	1450	1750	470
Variable Production Cost*** ($/MWh)	16	14	37

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $37/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

Environmental Investment

Plants under consideration:

Install Scrubbers:	Install SCRs:
2006 - 2010	2005 - 2007
Mitchell	Muskingum
Mountaineer	Amos
Cardinal	Mitchell
Amos	
Big Sandy	
Muskingum	
Conesville	

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh

2005 Guidance

		2004 Actual			2005 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,440 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,073)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(598)	
14	Other Income & Deductions		161			182	
15	Income Taxes		(489)			(538)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.48
	INVESTMENTS:						
17	Gas Operations		(33)			11	
18	Other Investments		(18)			(17)	
19	Total Investments		(51)	(0.13)		(6)	(0.02)
20	Parent Company		(71)	(0.18)		(24)	(0.06)
21	**ON-GOING EARNINGS**		924	2.33		958	2.40
	Shares Outstanding			396			399

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2006 Lehman Brothers CEO Energy/Power Conference

The Waldorf Astoria
New York City

September 7, 2006

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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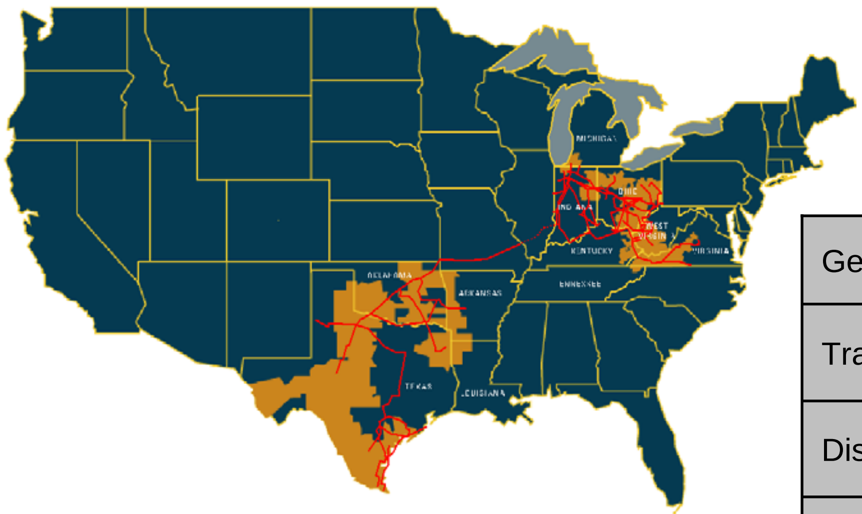
Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

2006 Accomplishments

- Reached settlement on Texas securitization amount. Planning to issue securitization bonds in September 2006 of $1.7 billion.
- Successfully settled rate cases in West Virginia ($129MM over 3 years), Kentucky Power ($41MM), FERC transmission ($22MM) & Ohio OATT ($89MM)
- Began implementation of Ohio RSP & obtained approval to recover storm damage costs
- Received approval from PUCO to proceed with first phase of IGCC construction and recover costs
- Completed & dedicated Wyoming-Jackson Ferry 765-kV line
- Increased 2006 earnings guidance range to $2.65 - $2.80 per share

AEP IS WELL ON ITS WAY TO ESTABLISHING A TRACK RECORD OF REGULATORY SUCCESS

Regulatory Activity Underway

- TCC Securitization of Stranded Costs
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- IGCC – Received Rate Authorization of Pre-Construction Costs
- FERC Regional Rate Design
- FERC SECA Revenues

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Regulatory Activity Underway

TCC Stranded Cost Recovery Case

- April 4, 2006 – Final order, following rehearing, which provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
- May 22, 2006 – Settlement agreement filed with PUCT in securitization proceeding
  - Securitization financing order received June 20
  - Issuance of securitization bonds expected in September

Securitization Order:

- Securitization amount of $1.697 billion plus estimated bond issuance costs ($23 million resulting in $1.72 billion requested to be securitized)
- Securitization order not appealable
- $315 million cost-of-money benefit for ADFIT to be included in CTC
- The treatment of EDFIT and ADITC ($61 million in total) as a reduction to the securitized amount

- June 2006 – Requested approval for CTC to address other true-up items
  - Requested $355 million net credit to customers over 8 years
    - $475 million gross CTC refund proposed, offset by $7 million in rate case expense recovery
    - Requested portion be deferred, pending the outcome of 2 contingent federal matters
      - $16 million of FERC jurisdictional fuel over-recoveries
      - $97 million related to ADITC and EDFIT
  - Hearings set for Sept 2006

Regulatory Activity Underway

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Hearings have been held with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- Hearings held, awaiting Commission Order

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, upon which, the full rate increase requested by APCO-VA will be implemented, subject to refund.

<u>Procedural Schedule</u>

Oct 4, 2006	Intervenor testimony due
Oct 24, 2006	SCC Staff testimony due
Nov 9, 2006	Company to file rebuttal testimony
Dec 6, 2006	Evidentiary Hearings to commence

Regulatory Activity Underway

FERC Regional Rate Design

Regional Rate Design

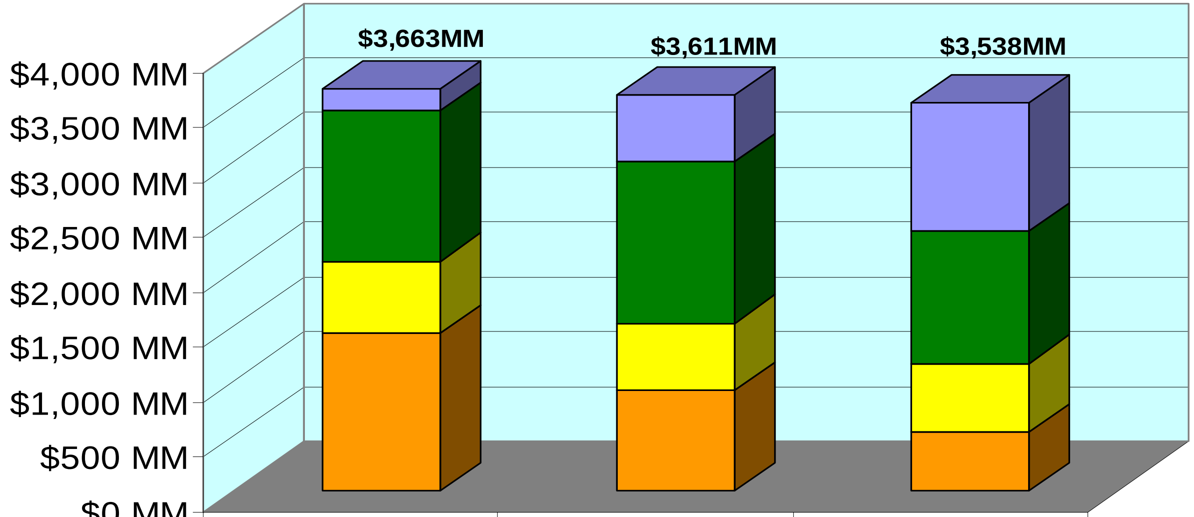
- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service proved by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ rendered initial decision finding:
  - License Plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006 when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
- Exceptions and replies to the exceptions to be filed: Order expected by the Commission late 2006/2007

Seams Elimination Cost Allocations (SECA) Revenues

- August 2006 ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $111 million SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both
- Exceptions due Sept. 11, & Replies due Oct. 2: Order expected by the Commission in early 2007
- We will vigorously appeal the ALJ's decision

2006 Revised Capital Investment Forecast

Capital Investment Forecast
excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,381	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

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AEP's Environmental Compliance Strategy

NOx, SO2, & Hg emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule(CAMR).

Investment will position AEP to accomplish the following:

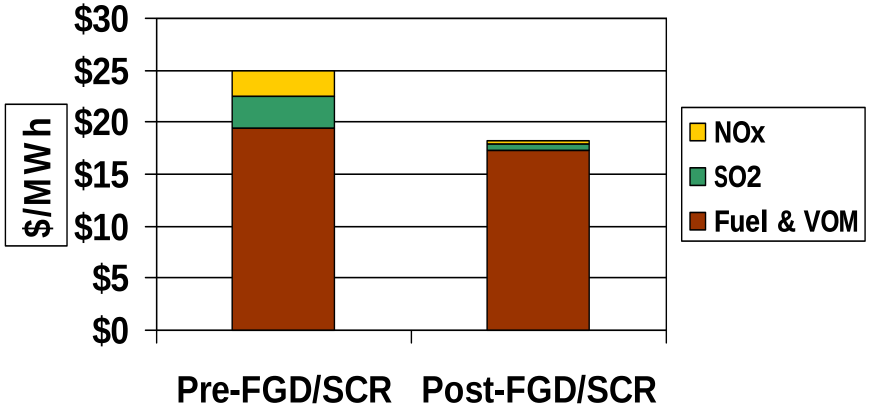
- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

REPRESENTS THE BEST AND LEAST-COST COMPLIANCE PATH TO IMPROVE ENVIRONMENTAL PERFORMANCE ON A FLEET BASIS, WHILE CONTINUING TO PROVIDE A RELIABLE SUPPLY OF POWER TO CUSTOMERS AT A REASONABLE PRICE AND A SOLID RETURN FOR INVESTORS.

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant Comparison of Variable Production Cost Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Cost of Control Technology

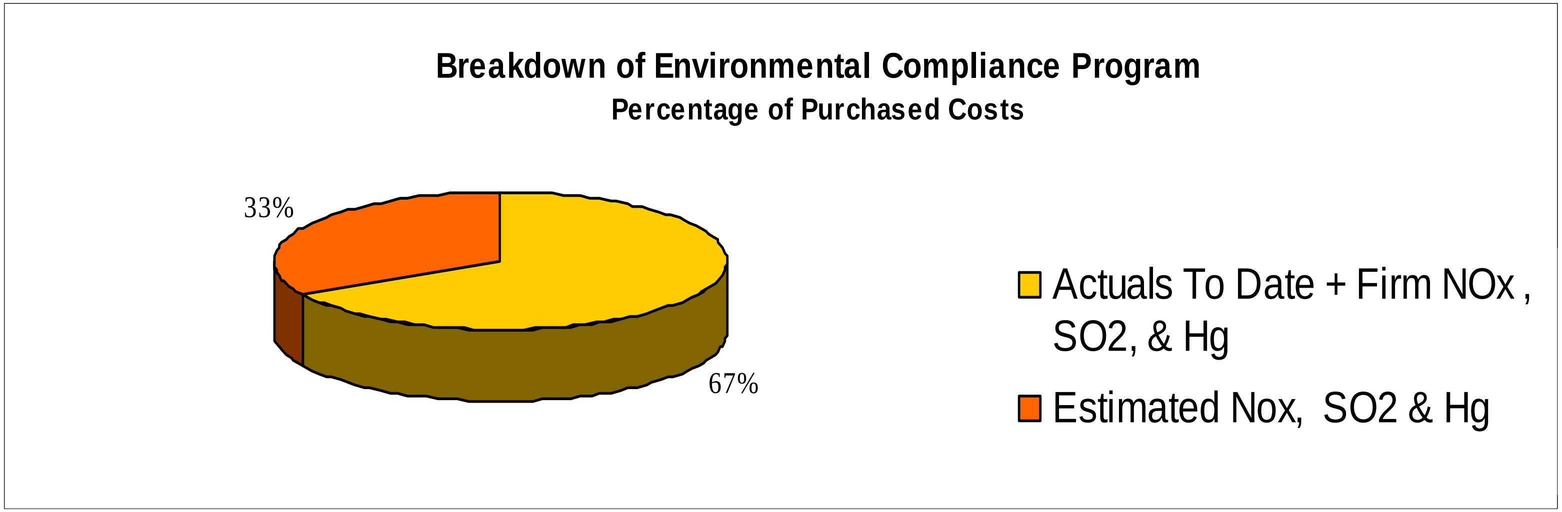
AEP's compliance plan largely relies on SCR & FGD technology to meet the requirements of CAIR and CAMR. AEP also deployed other combustion related controls, such as low NOx burners and optimized boiler controls throughout the system.

Conventional Technology

	SCR	FGD
AEP Capital Cost	~$121/kW avg.	~$250/kW avg.
Pollutant(s)	NO_x	SO_2 (& Hg as co-benefit)
Removal Efficiency	85 to 93%	95%-98% (&~80%)
Aux. Power	Approx. 1%	1.5% to 3.0%

Materials and Vendors

Cost Management of Materials



Typical Vendors

- FGD
  - Spray Tower – B&W/Alstom
  - Jet Bubbling Reactor – B&V Chyioda
- Stack Supplier
  - Pullman Power Inc.
- SCR
  - Babcock Power
- Architect Engineering Firms
  - Black & Veatch
  - Sargent & Lundy
  - Shaw – Stone & Webster
  - Worley Parsons

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in 2007

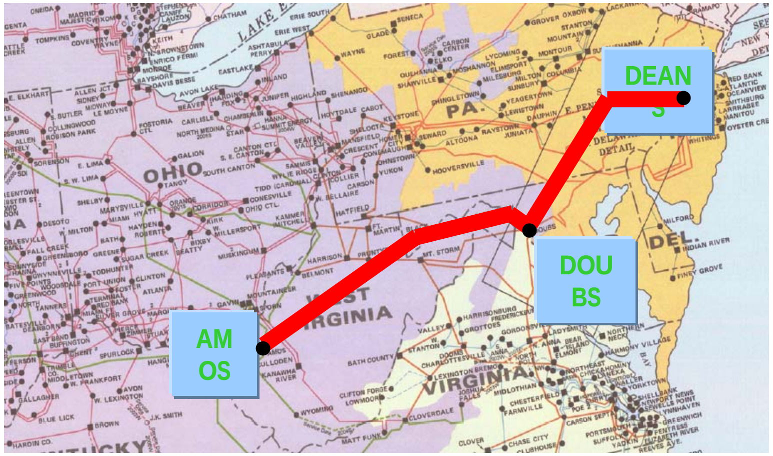
SWEPCO

- May 31, 2006- Announced plans to build $1.4 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling up to 480 MW and combined-cycle gas plant totaling 480 MW
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – of which SWEPCO's investment will be approx. 75%
- Commercial operation dates between 2008 and 2011

PSO RFPs

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

FERC CONDITIONALLY APPROVED REASONABLE COST RECOVERY, INCLUDING INCENTIVE ROE RATES AND CWIP

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What AEP Offers

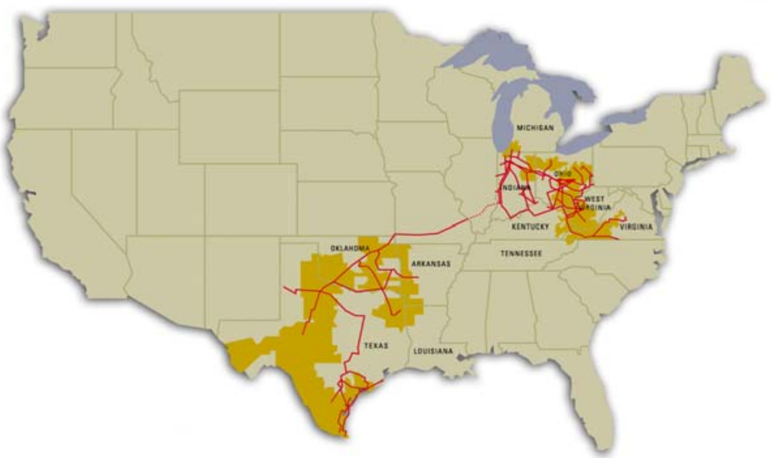
Utility Operations: The Platform for Growth & Financial Strength

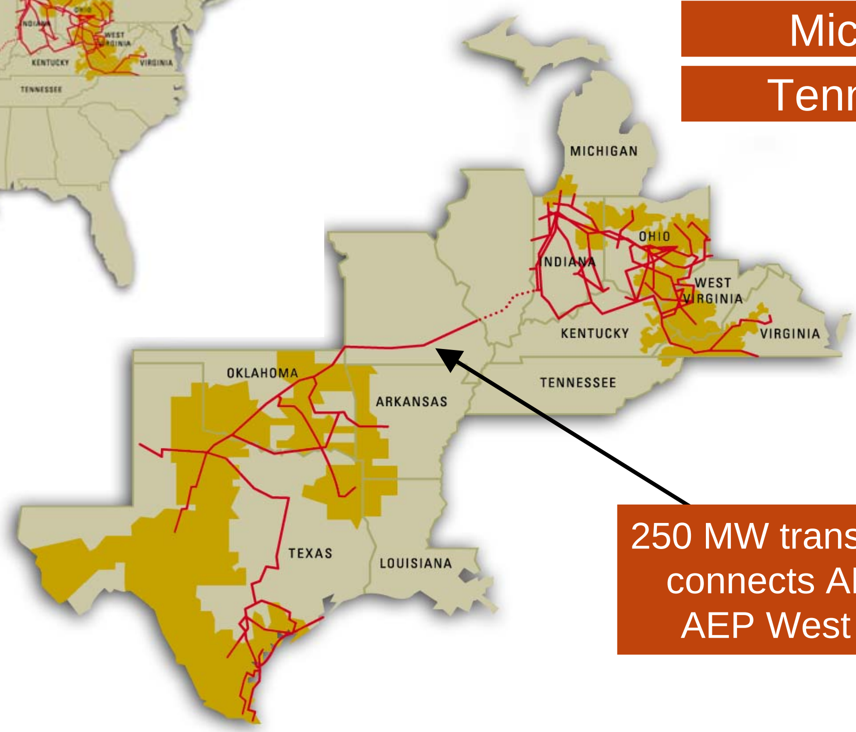
1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Appendix

Where We Operate

Ohio
Indiana
West Virginia
Virginia
Kentucky
Michigan
Tennessee



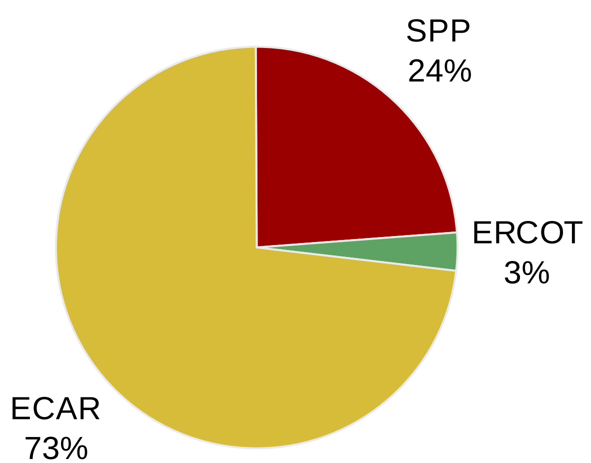


Oklahoma
Texas
Louisiana
Arkansas

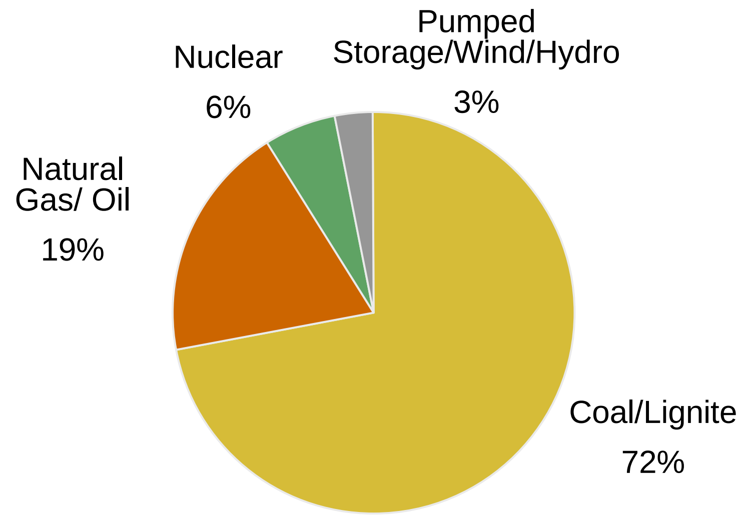
250 MW transmission line connects AEP East & AEP West territories

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

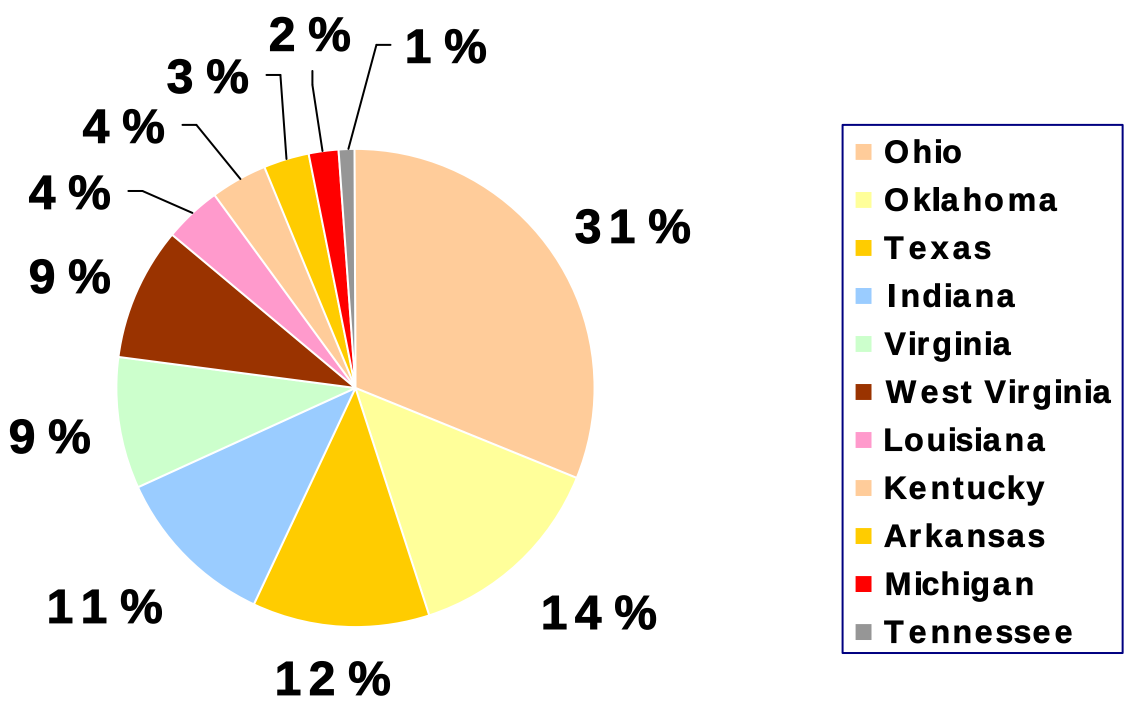
Operating Statistics

Commercial Availability Factor	
2004	85.24%
2005	84.50%

Capacity Factor	
2004	62.06%
2005	62.53%

2005 Retail Revenue

Retail Revenue Composition by State



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Regulatory

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate, for certain specific incremental costs
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- $41 million annual increase in base rates
- Rates effective March 30, 2006

Regulatory Activity Completed

APCo & WPCo West Virginia Rate Case

Settlement approved July 2006

- $44MM initial overall increase in rates effective July 28, 2006 comprised of:
  - $56MM increase in ENEC for fuel & purchased power expenses;
  - $23MM special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry (WJF) 765kV line;
  - $18MM general base rate reduction based on ROE of 10.5%, of which $9MM relates to a reduction in depreciation expense (affects cash flows but not earnings);
  - $17MM credit to refund a portion of deferred prior over-recoveries of ENEC costs of $51MM, currently recorded in regulatory liabilities; therefore, this item impacts cash flows but has no effect on earnings;
- Agreement also provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments and the costs of WJF
- Reinstatement of the ENEC mechanism effective July 1, 2006

CSP & OPCO Storm Related Service Restoration Cost Recovery

August 9, 2006 – PUCO issued ruling allowing CSP and OPCO to recover costs associated with service restoration activities during the back-to-back December 2004 and January 2005 ice storms.

- CSP Recovery - $11.9MM
- OP Recovery - $11.7MM

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

*Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Note: During the course of the hearings, Staff updated their revenue requirement recommendation to $23.6 million.

Summary Rate Case Information

Virginia Base Rate Case

On May 4, 2006, Appalachian Power Co. filed a request with the Virginia SCC to increase base rates $225.8 million partially offset by a proposed credit to reflect sharing of $27.3 million in margins from off-system sales. Docket # PUE-2006-00065

Capital Structure – Company

Capital Structure	Company Proposed in millions	%
Long-Term Debt	2,789	53%
Short-Term Debt	121	2%
Preferred Stock	18	0%
Common Equity	2,286	44%
ITC	13	0%
Total	**5,227**	**100%**

Rate Base and ROE – Company

Rate Base (in millions)	2,345
ROE	11.50%

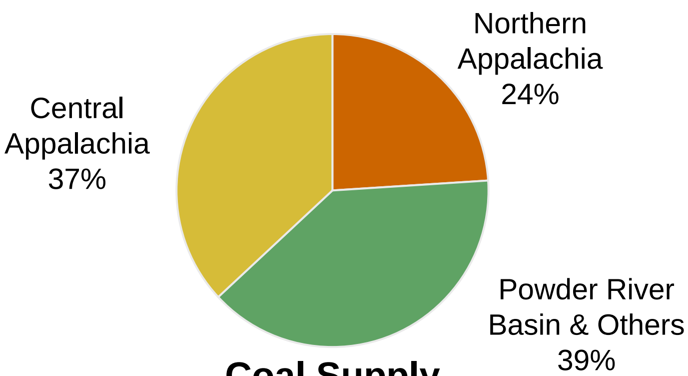
Rate Case Outcome Statistics

Company	Jurisdiction	Date of Final Order	Jurisdictional Rate Base ($ in MM)	ROE	Comments
APCo/WP	WV	7/26/2006	$1,658	10.50%	Settled case. Rate base, ROE and ROR per settlement agreement.
KPCo	KY	3/13/2006	$858 - Rate Base $853 - Capitalization	11.50%	Settled case. Rate base and ROE provided as filed by KPCo. Settlement agreement approved a 10.50% ROE for environmental surcharge filings. KY PSC requires use of total capitalization in rate filings.
PSO	OK	5/2/2005	$1,064	10.75%	Settled case. Rate base and ROE are estimated. A 10.75% ROE was found to be appropriate for AFUDC & affiliate transactions.
TCC	TX	8/15/2005	$862	10.125%	Settled case.

Fuel

Coal Procurement

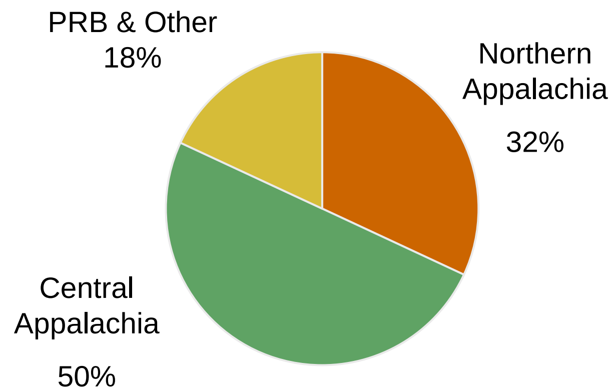
Total AEP System



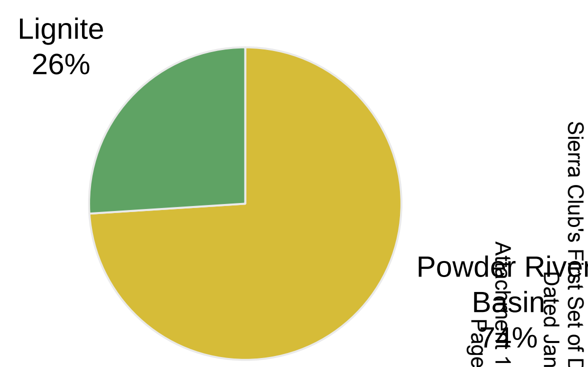
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 95%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System

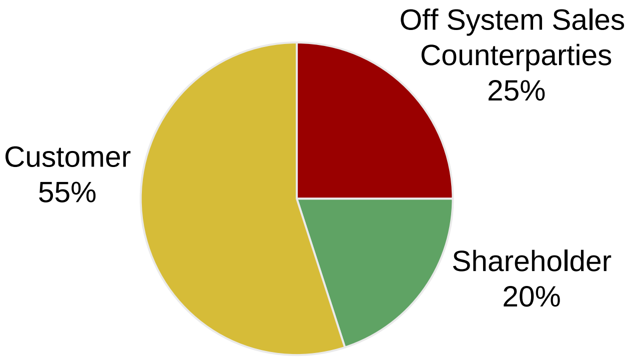


AEP Western System



Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

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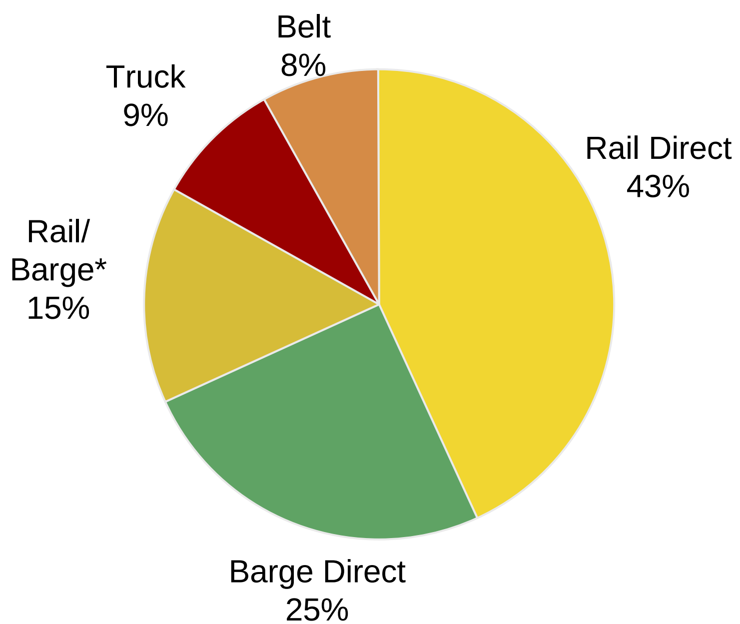
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Annually
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Semi-annually
Virginia	Yes	Annually
West Virginia	Yes	Annually; Deferral accounting for ENEC began July 1, 2006 and new rates became effective July 28, 2006.

Coal Delivery

Total AEP System

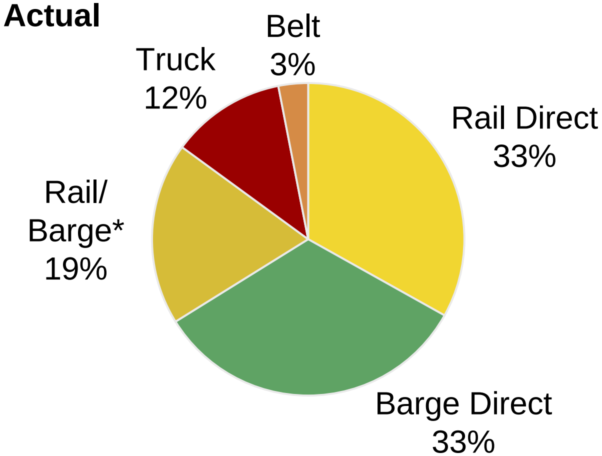
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

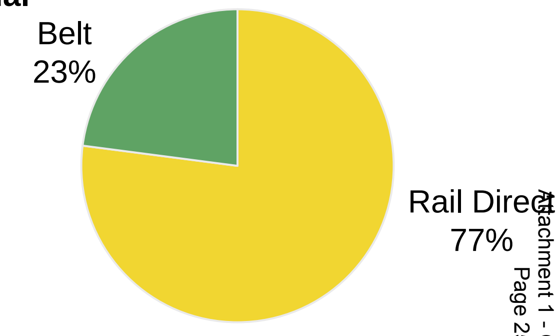
AEP Eastern System

2005 Actual



AEP Western System

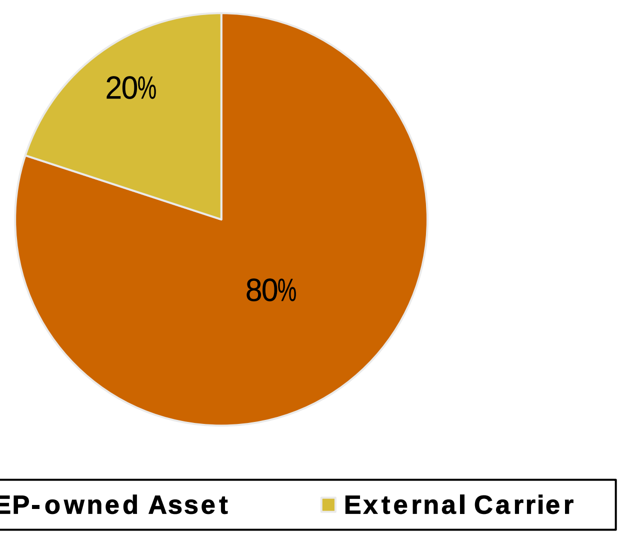
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

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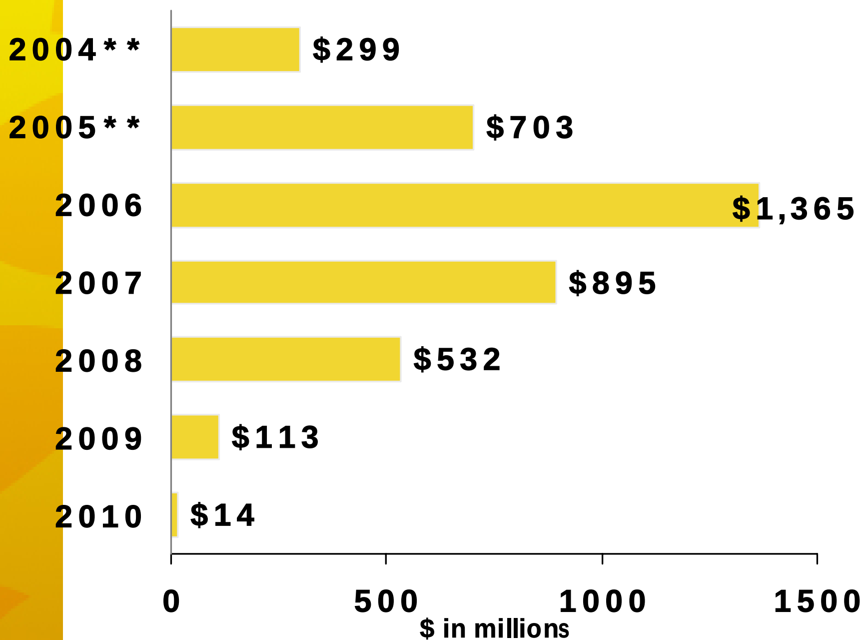
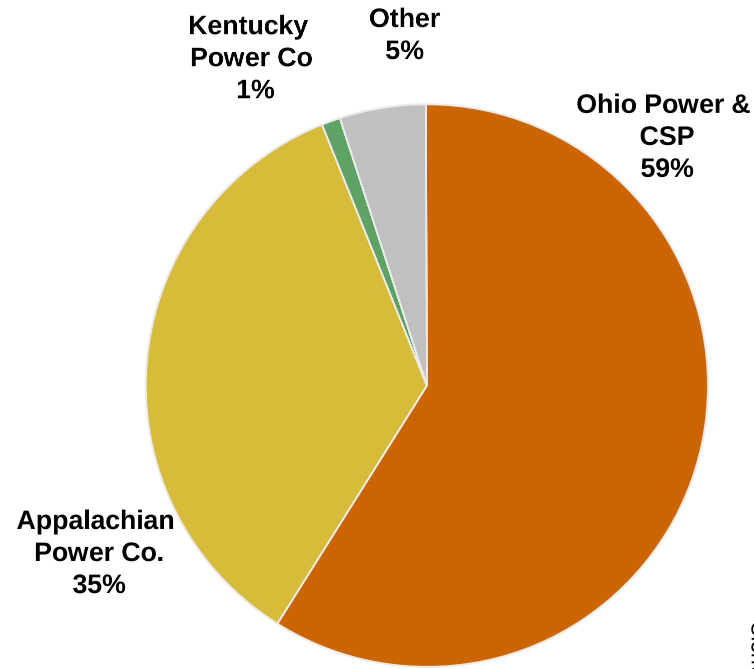
Environmental

Environmental Investment: $3.9 Billion Through 2010

Environmental Capital Investment*



Projected Environmental Investment Allocation



*Environmental investment for NOx, SO_2, & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

($3.9 billion figure reflects delay of Big Sandy 2 investment)

MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

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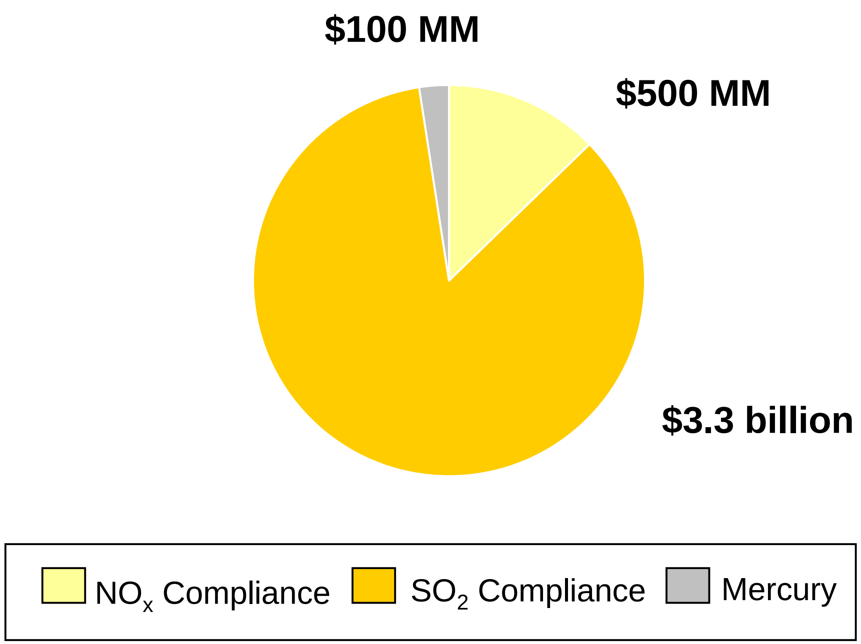
Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$1.9 Billion:

$1.8 Billion for SO_2

$0.1 Billion for Other

$3.9 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC; $3.9 billion figure reflects delay of Big Sandy 2 investment

Environmental Investment

FGD – Reduces SO_2 by 95% to 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD:

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1300	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	627	2009
Muskingum 5	585	2008
Conesville 4	339	2009
Total	**7951**	

SCR:

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

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Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

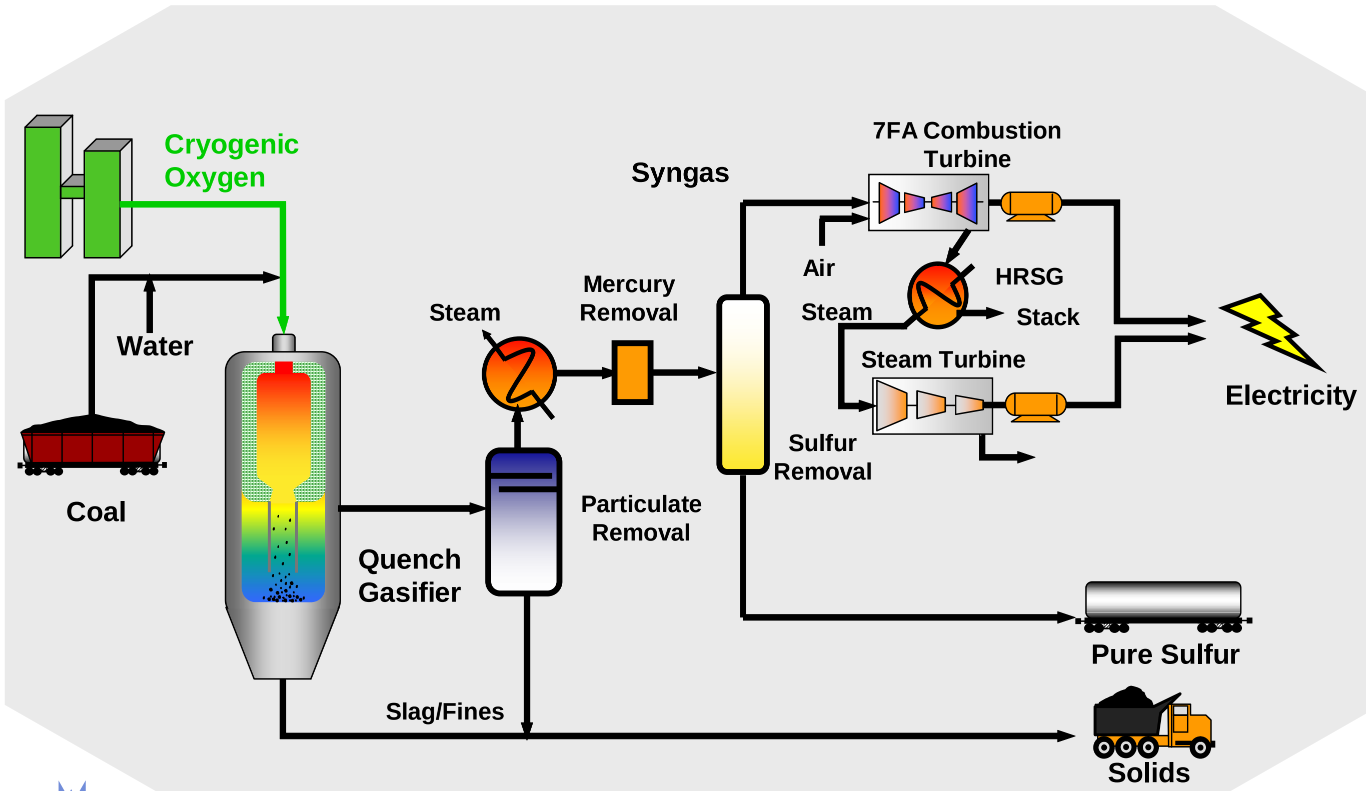
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8700**	**8600**	**7200**
Total Plant Cost (EPC) ($/kW)	**1700**	**1900**	**480**
Production Cost ($/MWh)	**17**	**16**	**57**
Cost of Electricity, without CO2 Capture ($/MWh)	**58**	**63**	**90**
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	**94**	**87**	**137**

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Capital Investment

2006 Capital Investment Funding Revised

	Actual		Projection		
	2004	2005	2006	2007	2008
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,499)	$ (2,091)	$ (1,261)	$ (950)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,572)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,499)	$ (3,663)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,632	$ 1,877	$ 1,736	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 111	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ 6	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 663	$ 1,758	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,705		
Other	$ -	$ 126	$ (117)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (141)	$ (60)	$ -
Ending Cash Balance	$ 320	$ 401	$ 260	$ 200	$ 200

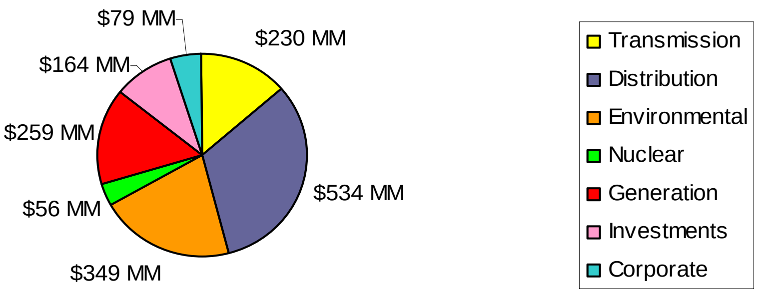
* Cash Flow from Operations assumes full rate recovery on capital expenditures.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

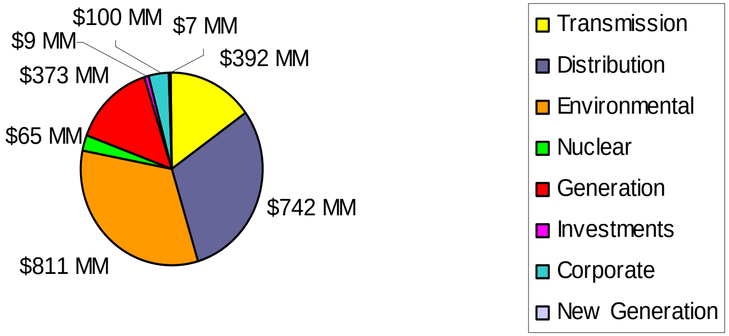
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Investment 2004 - 2006

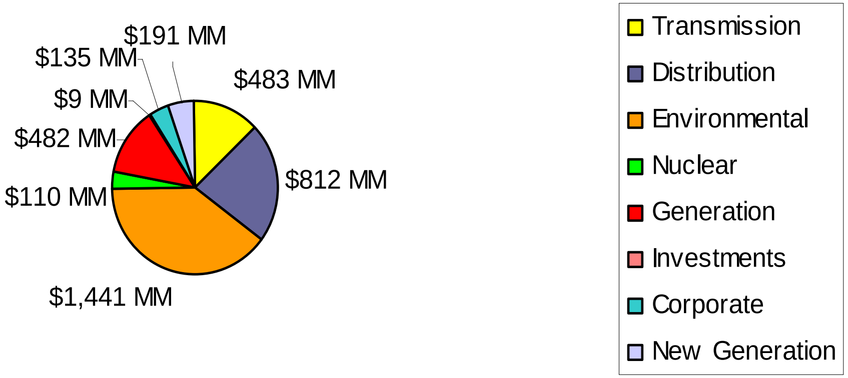
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

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Finance

2006 Guidance: $2.65 to $2.80 Per Share

American Electric Power
Financial Results for 2005 Actual vs. 2006 Forecast

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	65,656 GWh @ $31.5 /MWhr =	2,069		69,550 GWh @ $31.2 /MWhr =	2,173	
2	Ohio Companies	48,877 GWh @ $39.6 /MWhr =	1,937		46,185 GWh @ $47.3 /MWhr =	2,185	
3	West Regulated Integrated Utilities	40,213 GWh @ $22.3 /MWhr =	895		39,649 GWh @ $25.0 /MWhr =	990	
4	Texas Wires	26,525 GWh @ $17.4 /MWhr =	462		26,506 GWh @ $13.8 /MWhr =	366	
5	Off-System Sales	38,493 GWh @ $22.2 /MWhr =	853		37,280 GWh @ $17.7 /MWhr =	661	
6	Transmission Revenue - 3rd Party		411			262	
7	Other Operating Revenue		479			571	
8	Utility Gross Margin		7,106			7,208	
9	Operations & Maintenance		(3,142)			(3,139)	
10	Depreciation & Amortization		(1,285)			(1,280)	
11	Taxes Other than Income Taxes		(743)			(747)	
12	Interest Exp & Preferred Dividend		(595)			(666)	
13	Other Income & Deductions		264			199	
14	Income Taxes		(514)			(525)	
15	Utility Operations On-Going Earnings		1,091	2.80		1,050	2.66
	INVESTMENTS:						
16	Investments On-Going Earnings		24	0.06		26	0.07
17	Parent Company On-Going Earnings		(52)	(0.13)		(10)	(0.03)
18	ON-GOING EARNINGS		1,063	2.73		1,066	2.70
	Shares Outstanding (in millions)			390			39[illegible]

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Cash Flow

	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,066 *
Depreciation and Amortization	1,318	1,311
Pension Funding in Excess of Expense	(626)	-
Extraordinary Items	225	-
Other	173	(641)
Total from Operations	**$ 1,877**	**$ 1,736**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,663) **
Asset Sales	1,246	111
Other	153	(114)
Total from Investing	**$ (1,005)**	**$ (3,666)**
Cash from Financing:		
Common Equity	(25)	6
Net Long Term Debt Issued/(Retired)	(12)	2,235 ***
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	133
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,789**
Net Change in Cash	**$ 81**	**$ (141)**
Ending Cash Balance	**$ 401**	**$ 260**

* Assumes point EPS estimate $2.70 per share.

** 2006 guidance excludes AFUDC; 2005 figure excludes equity portion of AFUDC

*** Assumes $1.7 billion of securitization bonds issued in September 2006

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

CASH ON HAND EXPECTED TO BE $260 MILLION AT YEAR END 2006

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

<u>2005 Ratings Actions</u>

- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Forecasted Capital Expenditures

Company	2006	2007	2008
AEP SYSTEM*	**$3,663,500**	**$3,611,400**	**$3,537,700**
AEGCo	$12,100	$30,000	$39,700
APCo	$928,300	$691,500	$751,700
CSPCo	$318,700	$473,700	$553,400
I&M	$329,800	$278,700	$262,000
KPCo	$53,400	$127,100	$144,000
OPCo	$1,065,400	$954,500	$581,600
PSO	$262,000	$342,800	$408,700
SWEPCo	$314,900	$366,700	$458,700
TCC	$286,100	$247,000	$222,100
TNC	$72,300	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

Long-Term Debt Maturity Profile(1)

Year		2006(3)			2007			2008	
AEP Service Corporation	$	2,000,000	(2)	$	2,000,000	(2)	$	34,000,000	
AEP Inc.	$	-		$	345,000,000		$	-	
AEP Generating Company	$	-		$	-		$	-	
Appalachian Power	$	-		$	342,500,000		$	200,000,000	
Columbus Southern Power	$	-		$	-		$	112,000,000	
Indiana Michigan	$	300,000,000		$	-		$	50,000,000	
Kentucky Power	$	-		$	322,964,000		$	30,000,000	
Ohio Power Company	$	6,177,000	(2)	$	17,854,000		$	55,188,000	(2)
Public Service of Oklahoma	$	-		$	-		$	-	
Southwestern Electric Power	$	9,361,000	(2)	$	95,312,000	(2)	$	5,000,000	(2)
Texas Central Company	$	-		$	-		$	18,581,000	
Texas North Company	$	-		$	8,151,000		$	-	
Total	**$**	**317,538,000**		**$**	**1,133,781,000**		**$**	**504,769,000**	

(1) Excludes tax exempt bond remarketings and securitization bonds.
(2) Includes sinking fund payments, where applicable.
(3) Maturities remaining as of June 30, 2006.

2006 Key Operating Company Highlights

Dependent on Actual Capital Investment

(in millions $)

Company	Projected Capital Expenditures	Projected Issuances	Target Equity Ratio
APCO	$928	$500 - $600 *	42-45%
CSP	$319	$0	44-48%
I&M	$330	$400 - $500	38-42% (a)
KPCo	$53	$0	42-45%
OPCo	$1,065	$350 - $400	44-48%
PSO	$262	$150 - $200	44-48%
SWEPCo	$315	$150 - $200	44-48%
TCC (b)	$286	$0	40%
TNC	$72	$0	40%

*Issuances include potential new money tax-exempt issuances

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Debt Schedules

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.134%		$1,077,775,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

AEP Texas Central*			
Series	**Interest**	**Maturity**	**Amount**
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,339,800
Securitization Bond	5.010%	01/15/2008	$103,272,491
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

* TCC's First Mortgage Bond was defeased in May, 2004

AEP Texas North			
Series	**Interest**	**Maturity**	**Amount**
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Appalachian Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,766,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,041,400

Columbus Southern Power			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Weighted Average or Total	4.702%		$1,220,083,600

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of June 30, 2006

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Debt Schedules

Ohio Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$10,243,904
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,737,500
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	4.638%		$2,230,479,504

Public Service Company of Oklahoma			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$23,288,281
Notes Payable	6.360%	02/22/2007	$7,000,000
Notes Payable	7.030%	02/22/2012	$23,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/10/2008	$113,403,000
Weighted Average or Total	4.135%		$693,795,881

Note: Debt Schedules as of June 30, 2006

Investor & Banker Meeting

March 2, 2005
The Pierre Hotel, NYC

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements which are subject to risks and uncertainties. These factors include electric load and customer growth; abnormal weather conditions; available sources and cost of fuel; availability of generating capacity and performance of plants; the speed and degree to which competition is introduced to our service territories; the ability to recover stranded costs in connection with deregulation; new legislation and government regulation; resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to successfully control costs; the success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile; ability to sell assets at attractive prices; international and country-specific developments affecting foreign investments including the disposition of any current foreign investments and potential additional foreign investments; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; electricity and gas market prices; changes in creditworthiness in energy trading market; changes in the financial markets; changes in markets for electricity, natural gas, and other energy-related commodities; actions of rating agencies; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; liquidity in the banking, capital and wholesale power markets; prices for power we generate and sell at wholesale; changes in technology, including the increased use of distributed generation within our transmission and distribution service territory; other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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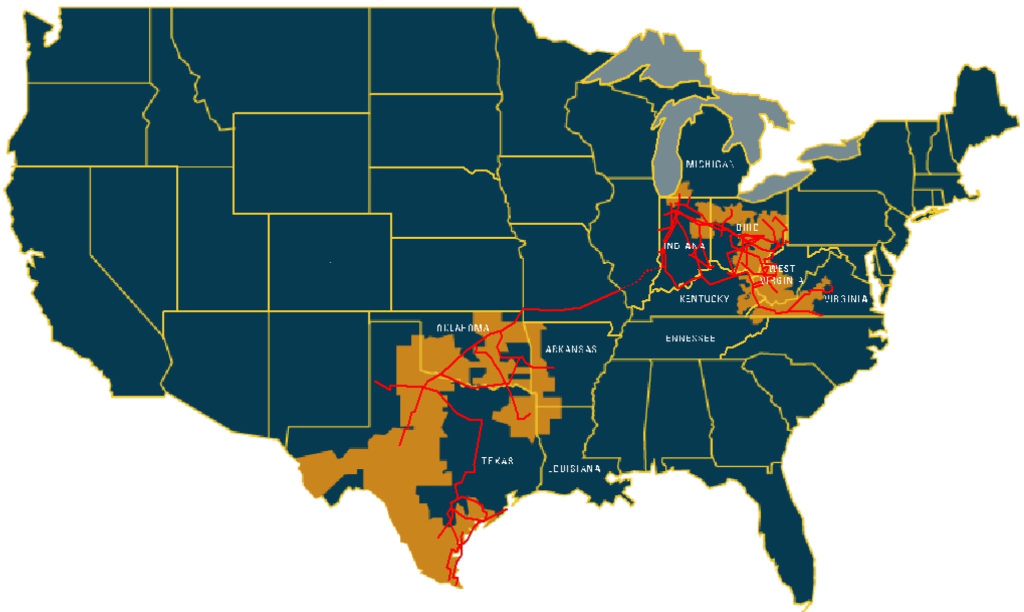
AEP®

Strength & Scale in Assets & Operations



Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

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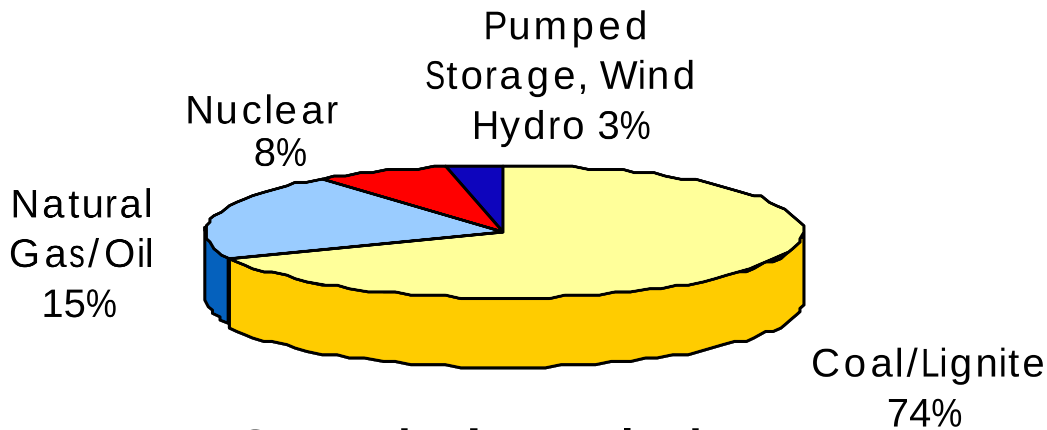
Fuel Mix & Operating Statistics



Capacity by Fuel Mix

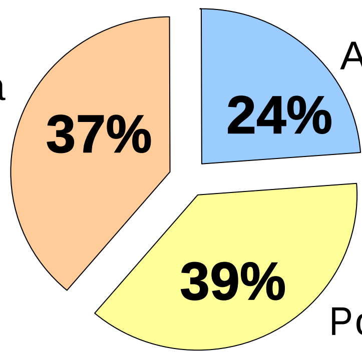
- 36,000 MW domestic capacity
- 85% system availability factor for YE 2004
- 62% system capacity factor for YE 2004

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

AEP®

Coal Procurement

AEP SYSTEM

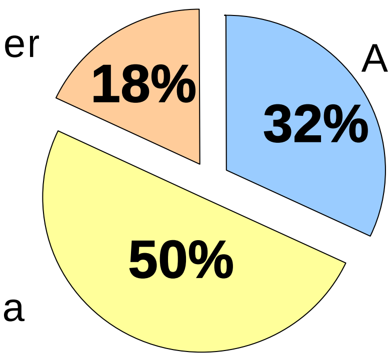


Coal Supply

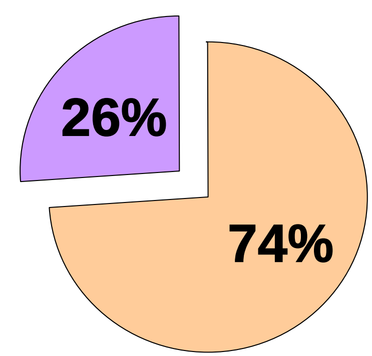
(on average)

- Purchase 75 MM tons per year
- Ave. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM



WESTERN SYSTEM



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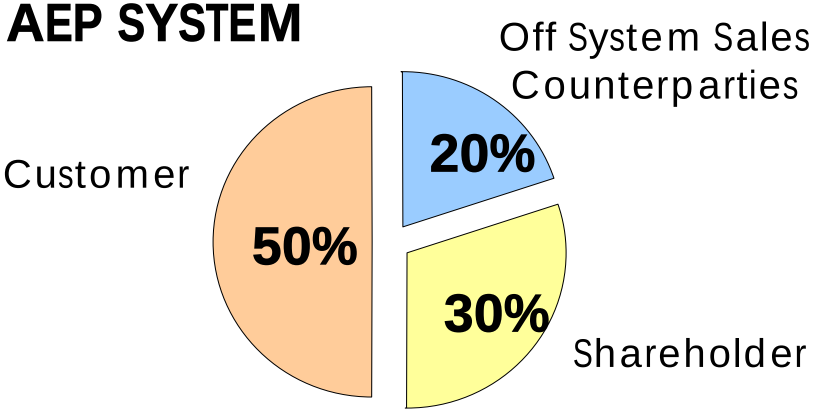
6

Fuel Recovery

AEP SYSTEM

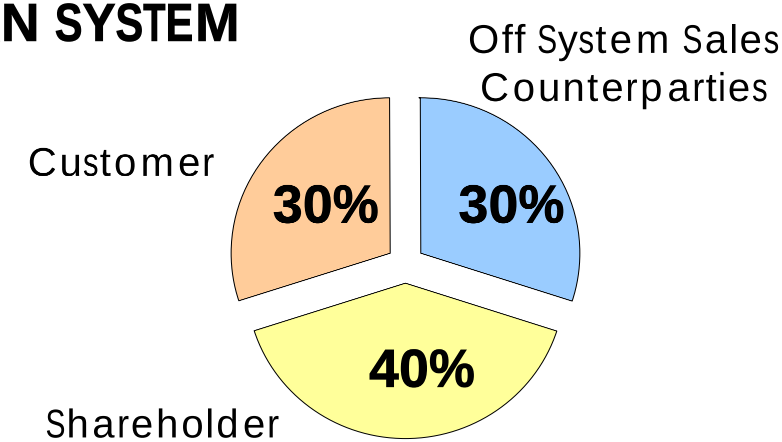


Fuel Cost Recovery
(on average)

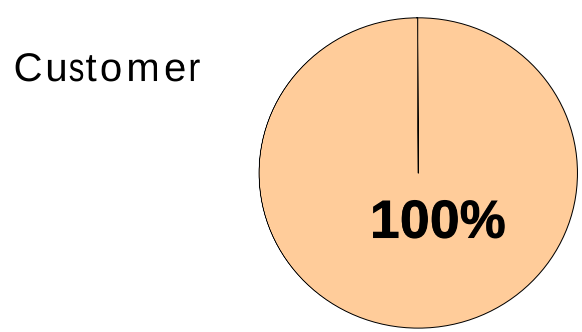
- Fuel recovery varies by jurisdiction
- 70% of fuel costs is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

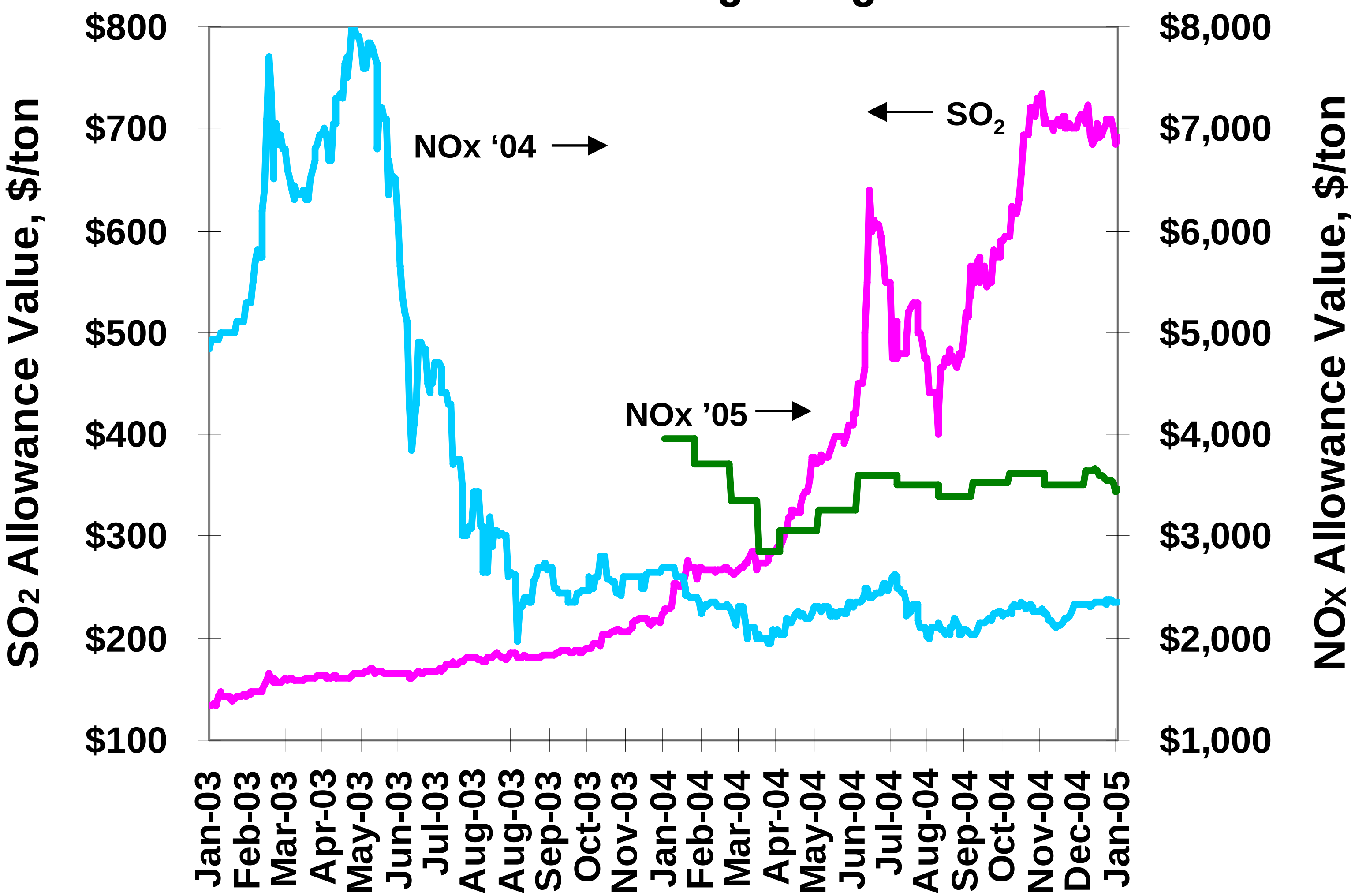


WESTERN SYSTEM



Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



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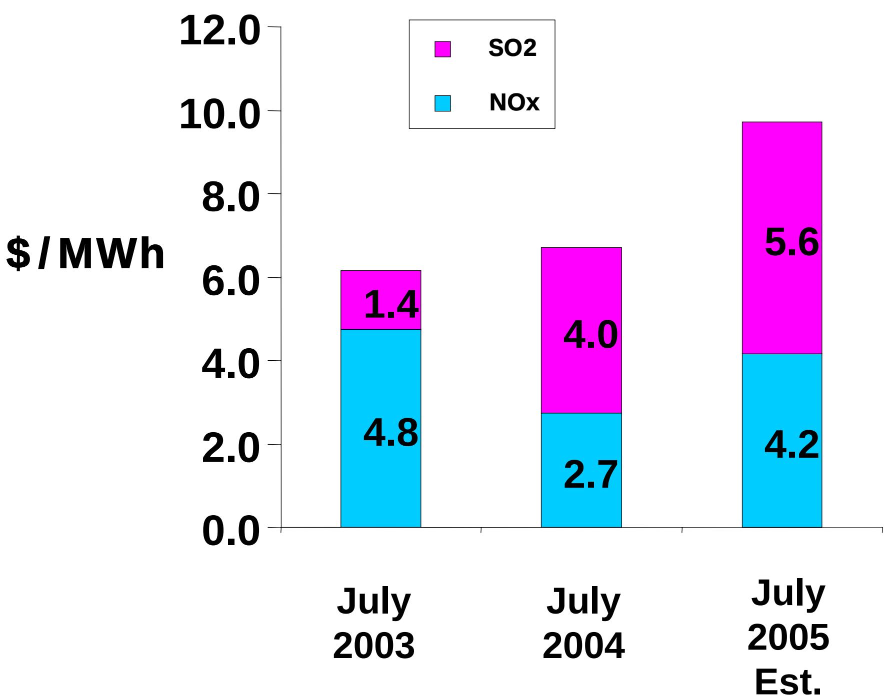
2

Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

AEP®

Operating In PJM Environment

- **Cost of generation to serve retail customers**
  - Retail customers continue to receive the benefits of AEP's lowest generation on an hourly basis

- **Off-system sales margin**
  - October-December was a learning period; results steadily improved each month
  - 4th quarter off-system sales margin was in line with budget

WE CONTINUE TO APPLY LESSONS LEARNED IN PJM TO MAXIMIZE THE VALUE OF OUR GENERATION FLEET

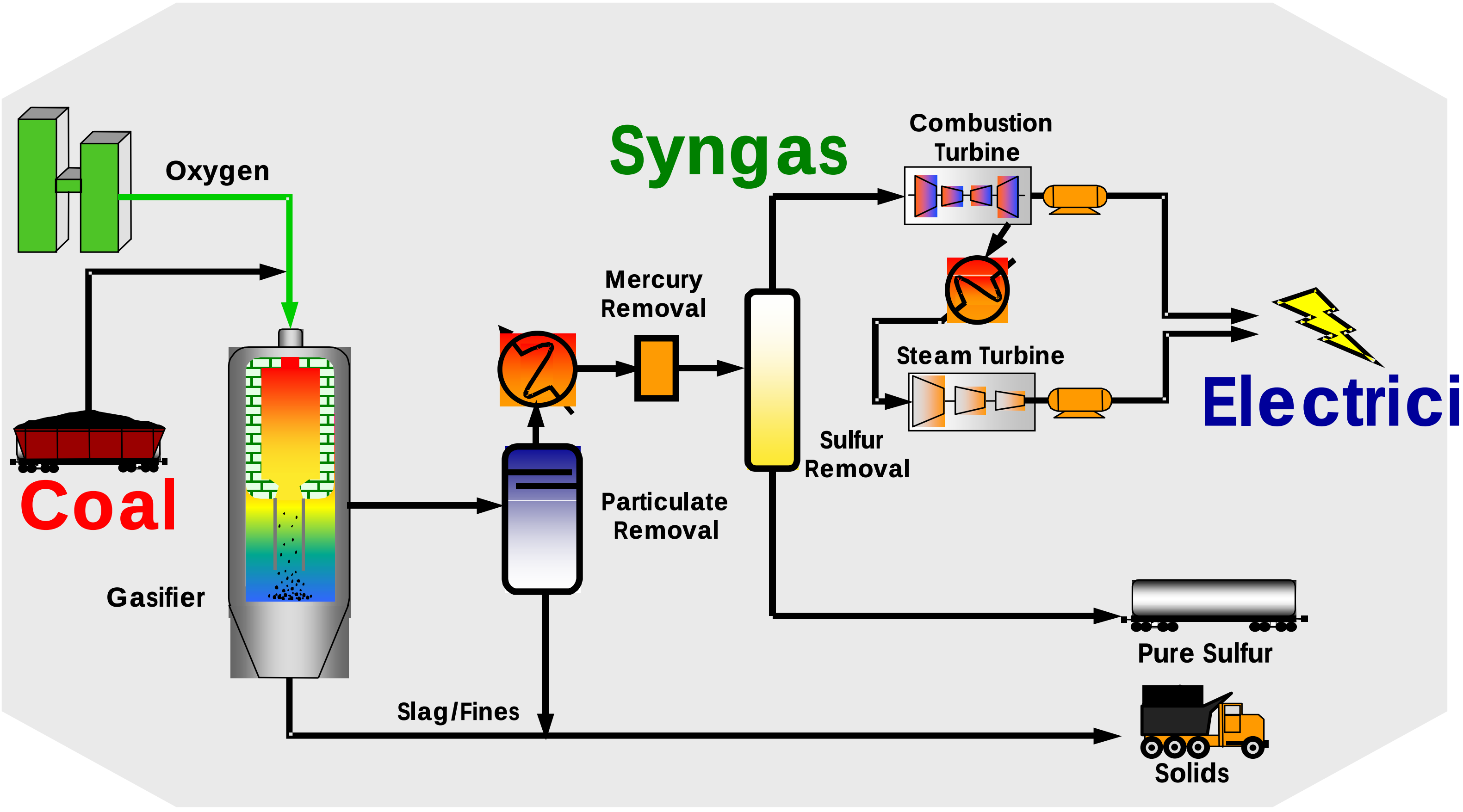
AEP®

Investment To Drive Utility Earnings Growth

- **Investment in new generation: IGCC**
- **Environmental Investment: $3.7 billion 2004- 2010**
- **Energy Delivery Investment**

GROWING EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

IGCC Technology



Source: US Department of Energy

Source: US Department of Energy

Comparison Of Technology Options

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8500	7000
EPC Cost* ($/kW)	1200	1450	400
Total Plant cost** ($/kW)	1450	1750	470
Variable Production Cost*** ($/MWh)	16	14	37

* EPC includes the cost to engineer, procure and construct plant.
** Total plant cost include land, overheads, AFUDC, etc.
*** Assumes Northern App Coal @ $37/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

AEP®

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

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Next Steps

2005

- Secure regulatory cost recovery - June
- Finalize site selection - August
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

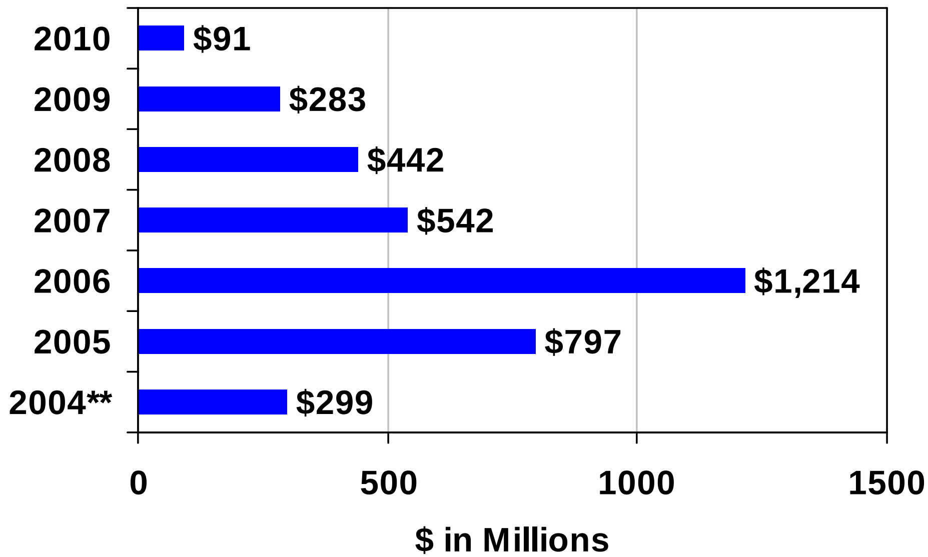
- 2008—2009: Construct and start-up plant

AEP®

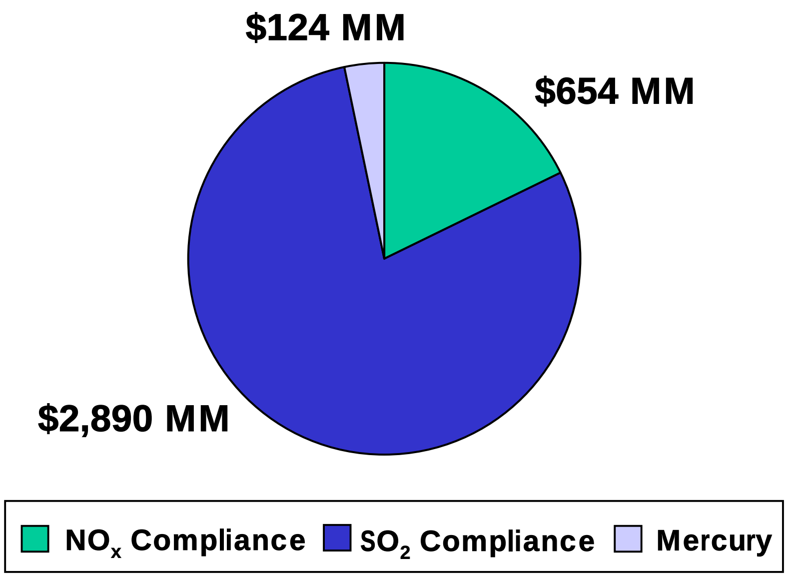
AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



Compliance Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

$1.7 billion for SO_2

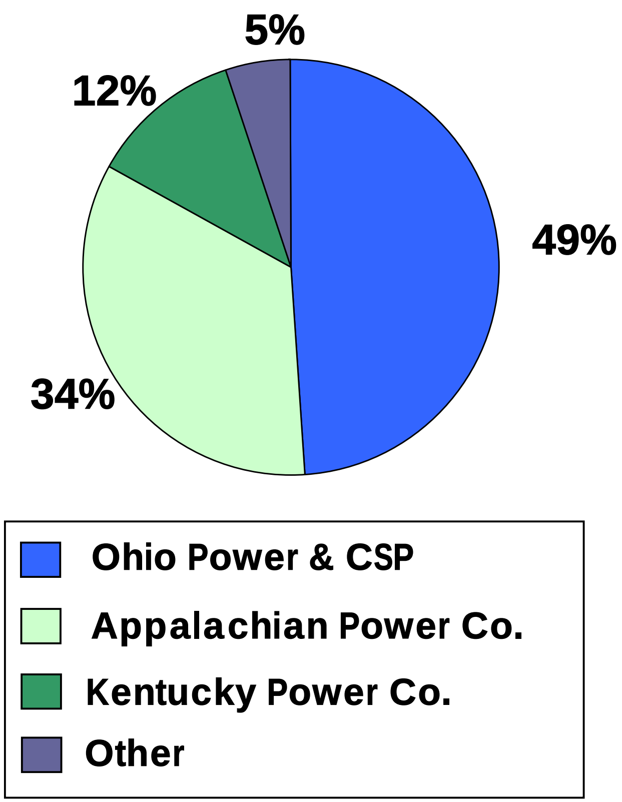
$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

AEP ®

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

AEP®

Environmental Investment

Plants under consideration:

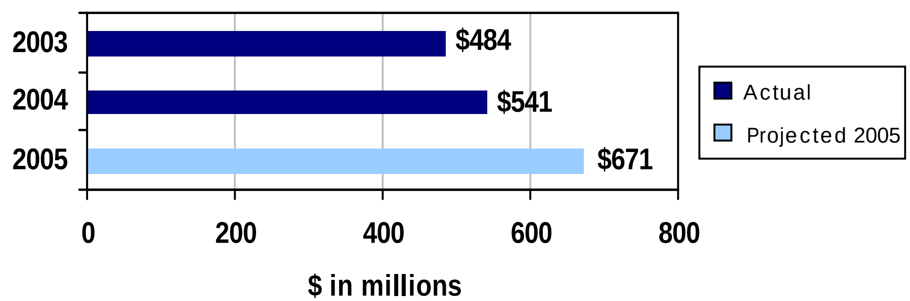
Install Scrubbers:	Install SCRs:
<u>2006 - 2010</u>	<u>2005 - 2007</u>
Mitchell	Muskingum
Mountaineer	Amos
Cardinal	Mitchell
Amos	
Big Sandy	
Muskingum	
Conesville	

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh

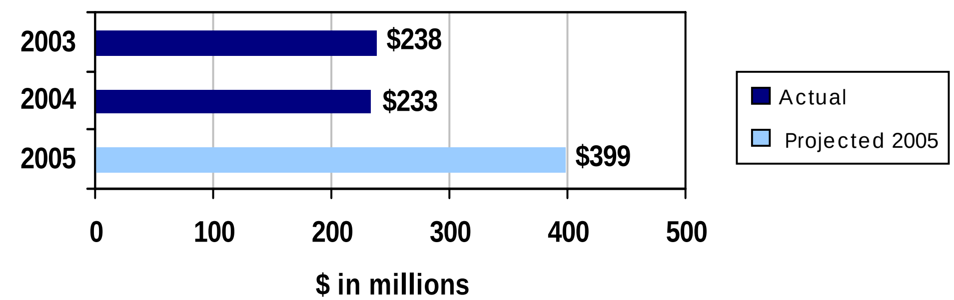
AEP®

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



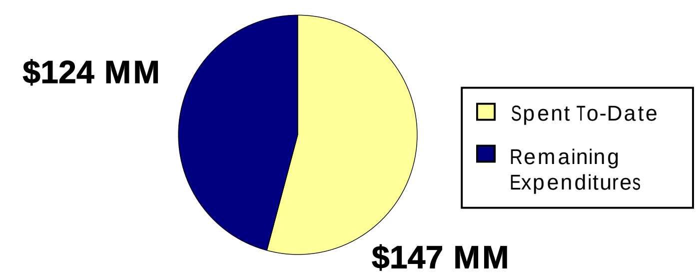
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
- **Planned Regulatory Activity (2005-2007)**
  - FERC Transmission Rate Case
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

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Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Income				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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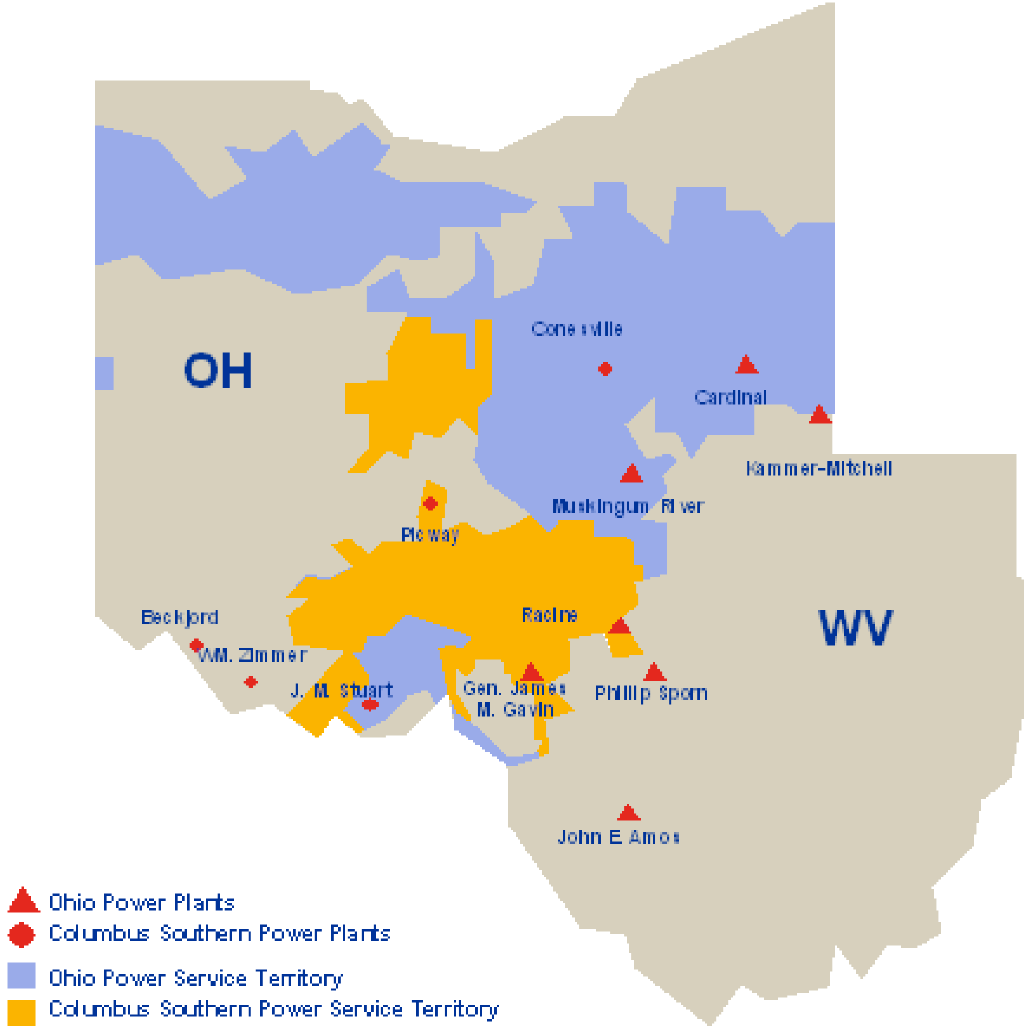
Defining the Ohio Operating Environment Post-2008



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Susan Tomasky
Executive Vice President & Chief Financial Officer

2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
3	Texas Wires	441		469	
4	Texas Supply / REP	347		198	
5	Off-System Sales	472		547	
6	Other Wholesale Transactions	14		-	
7	Transmission Revenue - 3rd Party	451		410	
8	Other Operating Revenue	331		346	
9	Total Gross Margin	7,018		7,017	
10	Operations & Maintenance	(3,072)		(3,087)	
11	Depreciation & Amortization	(1,256)		(1,275)	
12	Taxes Other than Income Taxes	(700)		(728)	
13	Interest Exp & Preferred Dividend	(616)		(592)	
14	Other Income & Deductions	161		181	
15	Income Taxes	(489)		(529)	
16	Net Earnings Utility Operations	1,046	2.64	988	2.54
	INVESTMENTS:				
17	Gas Operations	(33)		3	
18	Other Investments	(18)		(15)	
19	Total Investments	(51)	(0.13)	(13)	(0.04)
20	Parent Company	(71)	(0.18)	(40)	(0.10)
21	**ON-GOING EARNINGS**	924	2.33	936	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Reflects sale of HPL and paydown of debt*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

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TCC Stranded Cost Carrying Charge

Carrying Cost Details:

Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

Simplified Calculation:	
Initial Stranded Cost Base	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

Items included in stranded cost base include:
Stranded Plant costs ($900 MM), Regulatory Assets ($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly.

EQUITY COMPONENT RECOVERABLE ONCE AN ORDER IS RECEIVED

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- ***Outcome of pending regulatory proceedings***
  - ***Texas, Oklahoma & Louisiana***
- ***Operations within PJM environment***
- ***Plant availability***
- ***Rising fuel costs***
- ***Weather (storm damage and effect on sales)***

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2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	936 *
Depreciation & Amortization	1,300	1,305
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	136
Total from Operations	**$ 2,597**	**$ 1,923**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,690)
Asset Sales	1,357	1,456 **
Other	(40)	(487) ***
Total from Investing	**$ (376)**	**$ (1,721)**
Cash from Financing:		
Common Equity	17	(155) ****
Net Long Term Debt Issued/(Retired)	(1,829)	621
Preferred Stock Redeemed	(10)	(66)
Short Term Debt Change, Net	(400)	16
Common Dividends	(555)	(545)
Total from Financing	**$ (2,777)**	**$ (129)**
Net Change in Cash	**$ (556)**	**$ 73**
Ending Cash Balance	**$ 420**	**$ 493**

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

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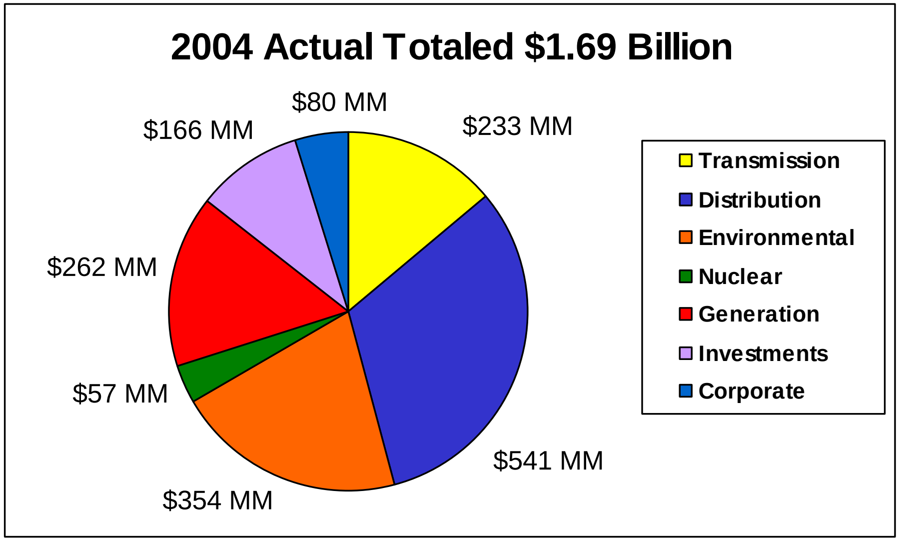
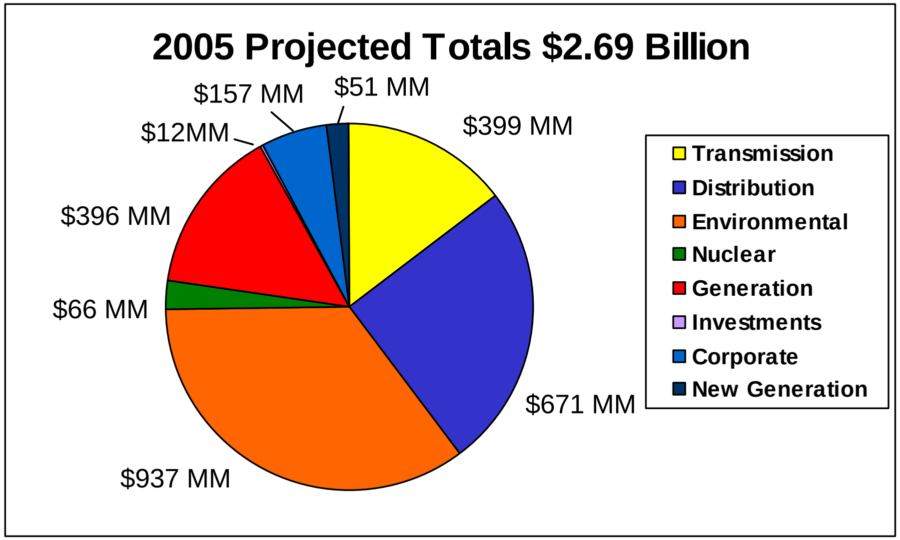
2005 Capex





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Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain capitalization ratio below 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

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Liquidity Summary

Liquidity Summary	Actual Dec-04	
$MM	**Amount**	**Maturity**
5-Year R/C Facility	1,000	May-05
3-Year R/C Facility	750	May-06
3-Year R/C Facility	1,000	May-07
3-Year L/C Facility	200	Sep-06
Total Credit Facilities	**2,950**	
Plus		
Total Cash & Cash Equivalents	**420**	
Less		
Commercial Paper Outstanding	-	
Amount Drawn on Bank Loans	-	
Amount Issued (L/C Facility)	57	
Net Available Liquidity	**3,313**	

R/C=Revolving Credit
L/C=Letter of Credit

Capital Structure

Capital Structure & Ratios	12/31/2004		
	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	12,287	-	12,287
Short-term Debt	23	-	23
Preferred Stock Subject to Mandatory Redemption	66	-	66
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	8,515	8,515
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***
Adjustments			
Preferred Stock Subject to Mandatory Redemption	(66)	66	-
Defeased First Mortgage Bonds	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241
Securitization Bonds	(698)	-	(698)
Spent Nuclear Fuel Trust	(229)	-	(229)
Equity Credit for Equity Units	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***

MAINTAIN DEBT-TO-CAP BELOW 60%

Ratings Summary

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc. Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	S	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	-	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	-	S	3	BBB	NR	S	A-	-	S
Indiana Michigan Power Company	Baa2	-	S	6	BBB	NR	S	BBB	-	S
Kentucky Power Company	Baa2	-	S	5	BBB	NR	S	BBB	-	S
Ohio Power Company	A3	-	S	3	BBB	NR	S	BBB+	-	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

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What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

AEP AMERICAN ELECTRIC POWER

2005 Earnings Guidance

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
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16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.40
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Merrill Lynch

Global Power & Gas Leaders Conference

Millennium Broadway
New York City

September 26, 2006

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Chairman, President & CEO

2006 Accomplishments

- Reached settlement on Texas securitization amount. Planning to issue securitization bonds in October 2006 of $1.7 billion.
- Successfully settled rate cases in West Virginia ($129MM over 3 years), Kentucky Power ($41MM), FERC transmission ($22MM) & Ohio OATT ($89MM)
- Began implementation of Ohio RSP & obtained approval to recover storm damage costs
- Received approval from PUCO to proceed with first phase of IGCC construction and recover costs
- Completed & dedicated Wyoming-Jackson Ferry 765-kV line
- Increased 2006 earnings guidance range to $2.65 - $2.80 per share

AEP IS WELL ON ITS WAY TO ESTABLISHING A TRACK RECORD OF REGULATORY SUCCESS

Regulatory Activity Underway

- TCC Securitization of Stranded Costs
- TCC Request for CTC for other true-up items
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- IGCC – Received Rate Authorization of Pre-Construction Costs
- FERC Regional Rate Design
- FERC SECA Revenues

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Regulatory Activity Underway

TCC Stranded Cost Recovery Case

Securitization Order: Financing Order received June 20

- Securitization amount of $1.697 billion plus estimated bond issuance costs ($23 million resulting in $1.72 billion requested to be securitized)
- Securitization order not appealable
- Issuance of securitization bonds expected in early October

Requested approval for CTC to address other true-up items in June 2006

- Requested $355 million net credit to customers over 8 years
- Additionally requested portion be deferred, pending the outcome of 2 contingent federal matters, including $16 million of FERC jurisdictional fuel over-recoveries and $97 million related to ADITC and EDFIT
- PUCT approved settlement of an interim CTC on September 7, returning $64MM retail clawback to residential customers by year end.
- Hearings re permanent CTC were held September 14, 2006 and decision is expected in November

Regulatory Activity Underway

Indiana Depreciation Filing

- December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service decreasing annual depreciation expense by approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Hearings have been held with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 with a supplemental filing, with updated actual E&R costs incurred through September 30, 2005 of $21.1 million

- Hearings held, awaiting Commission Order

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, upon which, the full rate increase requested by APCO-VA will be implemented, subject to refund.

<u>Procedural Schedule</u>

Oct. 4, 2006	Intervenor testimony due
Oct. 24, 2006	SCC Staff testimony due
Nov. 9, 2006	Company to file rebuttal testimony
Dec. 6, 2006	Evidentiary Hearings to commence

Regulatory Activity Underway

FERC

Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service proved by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ rendered initial decision finding:
  - License Plate rates for existing facilities (effective April 1, 2006 when SECA ended) <u>are not</u> just and reasonable, and must be replaced
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
- Exceptions and replies to the exceptions have been filed; Order expected by the Commission late 2006/2007

Seams Elimination Cost Allocations (SECA) Revenues

- August 2006 ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $111 million SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both
- Exceptions filed Sept. 11, with Replies due Oct. 2: Order expected by the Commission in early 2007
- We will vigorously appeal the ALJ's decision

Post ’08 Environment in Ohio

Potential Outcomes at Conclusion of Current Rate Stabilization Period

Some Form of Regulation

- Requires Legislation

Flashcut to Market

- Could Stifle Economic Development in Ohio

Second Period of Rate Stabilization Plan

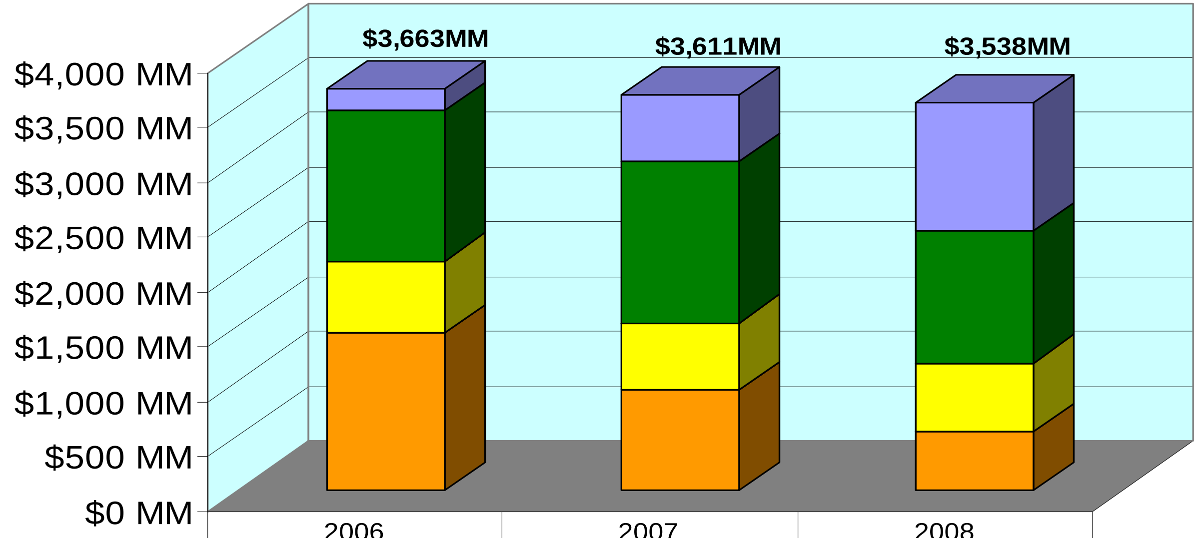
- AEP advocates this approach

SOUND PUBLIC POLICY, WHICH COULD INCLUDE A COMBINATION OF THE ABOVE, SHOULD BALANCE ALL STAKEHOLDER EXPECTATIONS

2006 Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,381	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

Environmental Investment

FGD – Reduces SO_2 by 95% to 98% → **Co-Benefit Hg Capture** ← SCR - Reduces NOx by 90%

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1300	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	627	2009
Conesville 4	339	2009
Total	**7366**	

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Materials and Vendors – AEP's Advantage

Cost Management of Materials

Breakdown of Environmental Compliance Program
Percentage of Purchased Costs

Typical Vendors

- FGD
  - Spray Tower – B&W/Alstom
  - Jet Bubbling Reactor – B&V Chyioda
- Stack Supplier
  - Pullman Power Inc.
- SCR
  - Babcock Power
- Architect Engineering Firms
  - Black & Veatch
  - Sargent & Lundy
  - Shaw – Stone & Webster
  - Worley Parsons

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in OH in 2007, assuming regulatory approval
- Certificates of Convenience and Necessity (CCN) applications filed in OH and WV and currently in process.

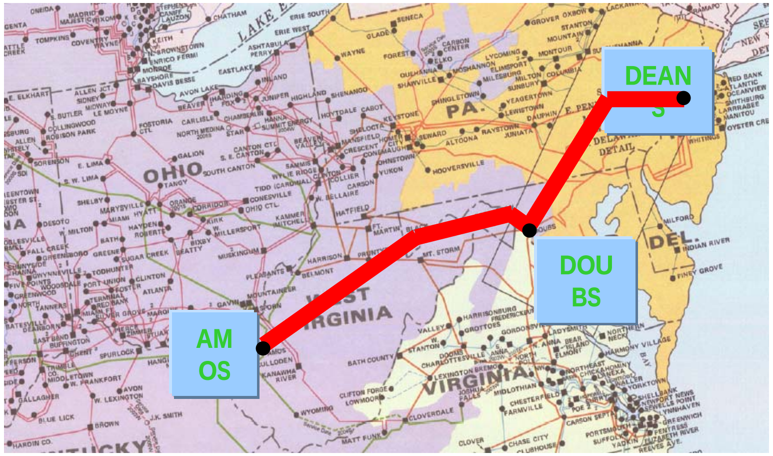
SWEPCO

- May 31, 2006- Announced plans to build $1.7 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling 320 MW at Tontitown, AR and combined-cycle gas plant totaling 480 MW at Arsenal Hill
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – expected SWEPCO investment will be approx. 75%
- Commercial operation dates between 2007 and 2011

PSO RFPs

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

FERC CONDITIONALLY APPROVED REASONABLE COST RECOVERY, INCLUDING INCENTIVE ROE RATES AND CWIP

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1 Strength and scale in assets and operations

2 Focused utility business model

3 Earnings growth driven by native load & capital investment

4 Pioneering advanced technologies in the sector

5 Solid liquidity position and stable credit profile

6 Attractive dividend yield in excess of 4%

Investor Meeting Hosted by Merrill Lynch

AEP Headquarters
Columbus, Ohio
May 11, 2005

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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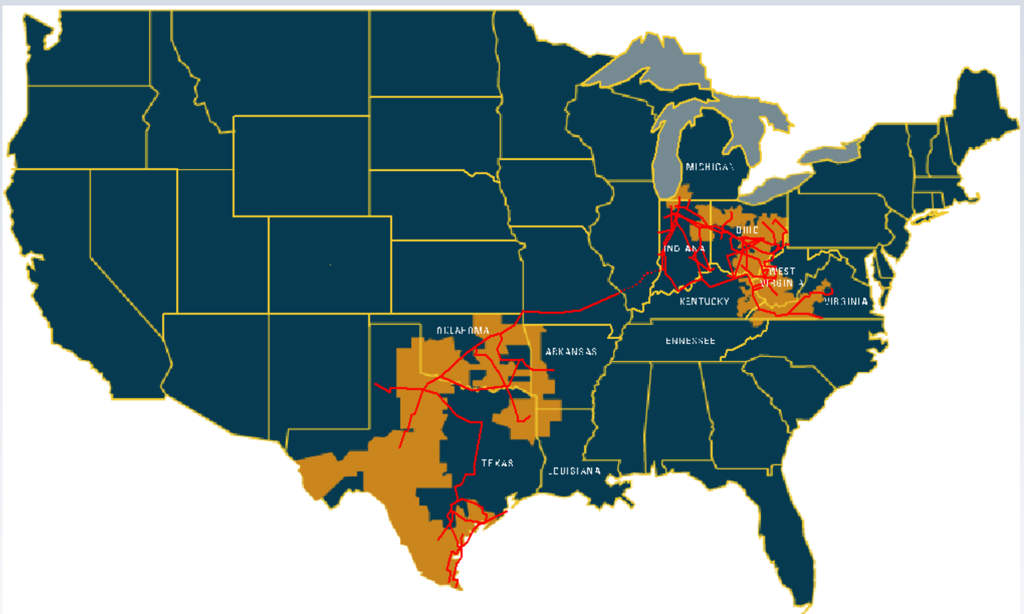
Asset Portfolio

Strength & Scale in Assets & Operations



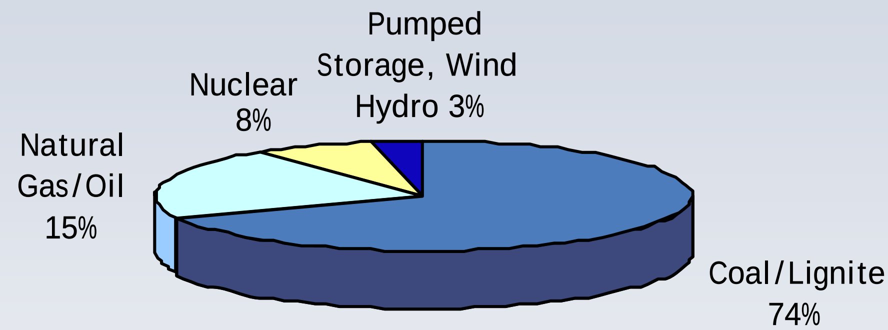
Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 36,000 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,719	0	0
SPP	4,828	3,516	188
Total*	**30,773**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Introduction

The generation assets are co-managed by the Power Generation and the Commercial Operation Groups within AEP – each with a deliberate focus on roles and responsibilities within the organization

Power Generation
Operate 36,000 MW

Commercial Operations
Coal, gas, power and emissions markets

Fossil and Hydro Generation
Bill Sigmon, SVP

Generation Dispatch

Nuclear Generation

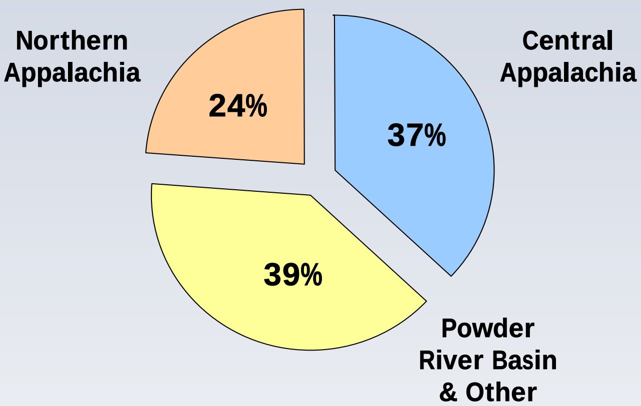
Energy Marketing
Brian Tierney, SVP

Engineering, Environmental & Technical Services
John McManus, VP Environmental Services

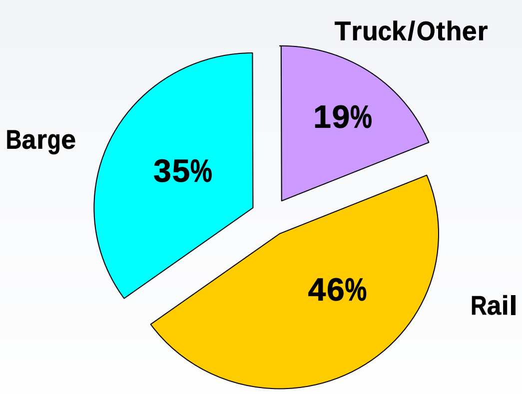
Fuel, Emissions & Logistics
Chuck Zebula, SVP

Fuel, Emissions & Logistics

FUEL BASIN DIVERSITY
73 million tons



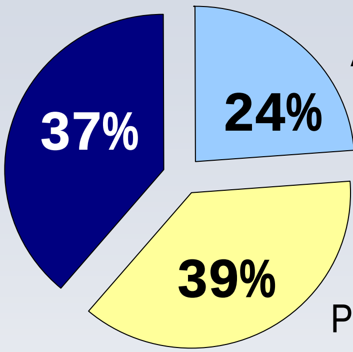
DELIVERY MODE DIVERSITY
25 GW coal capacity



- All fossil fuel activities including procurement, transportation, inventory, QA/QC, measurement, and coal trading;
- Market-based emission and renewable credit activities;
- Barge transportation, terminal, and railcar maintenance businesses;
- Procures all bulk consumables for use in combustion/emission removal;
- Optimizes all by-products of production including ash and gypsum;

Coal Procurement

AEP SYSTEM

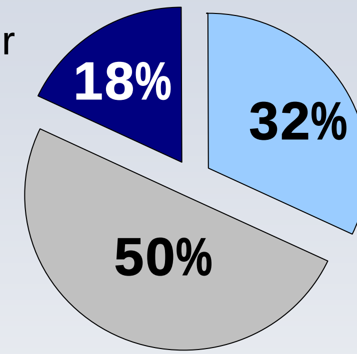


Coal Supply

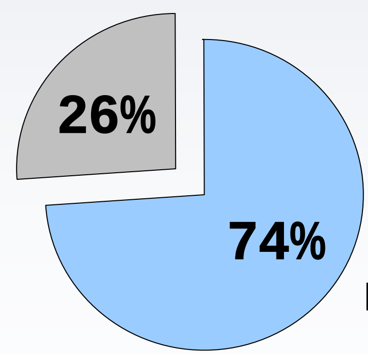
(on average)

- Purchase 75 MM tons per year
- Avg delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

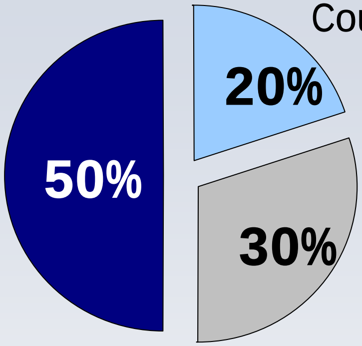


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM



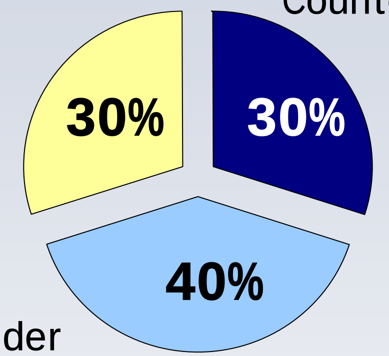
Fuel Cost Recovery

(on average)

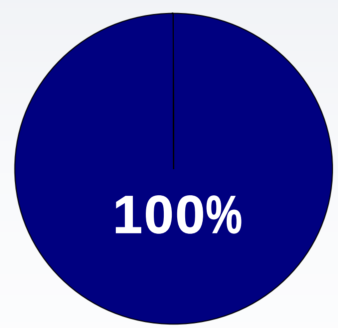
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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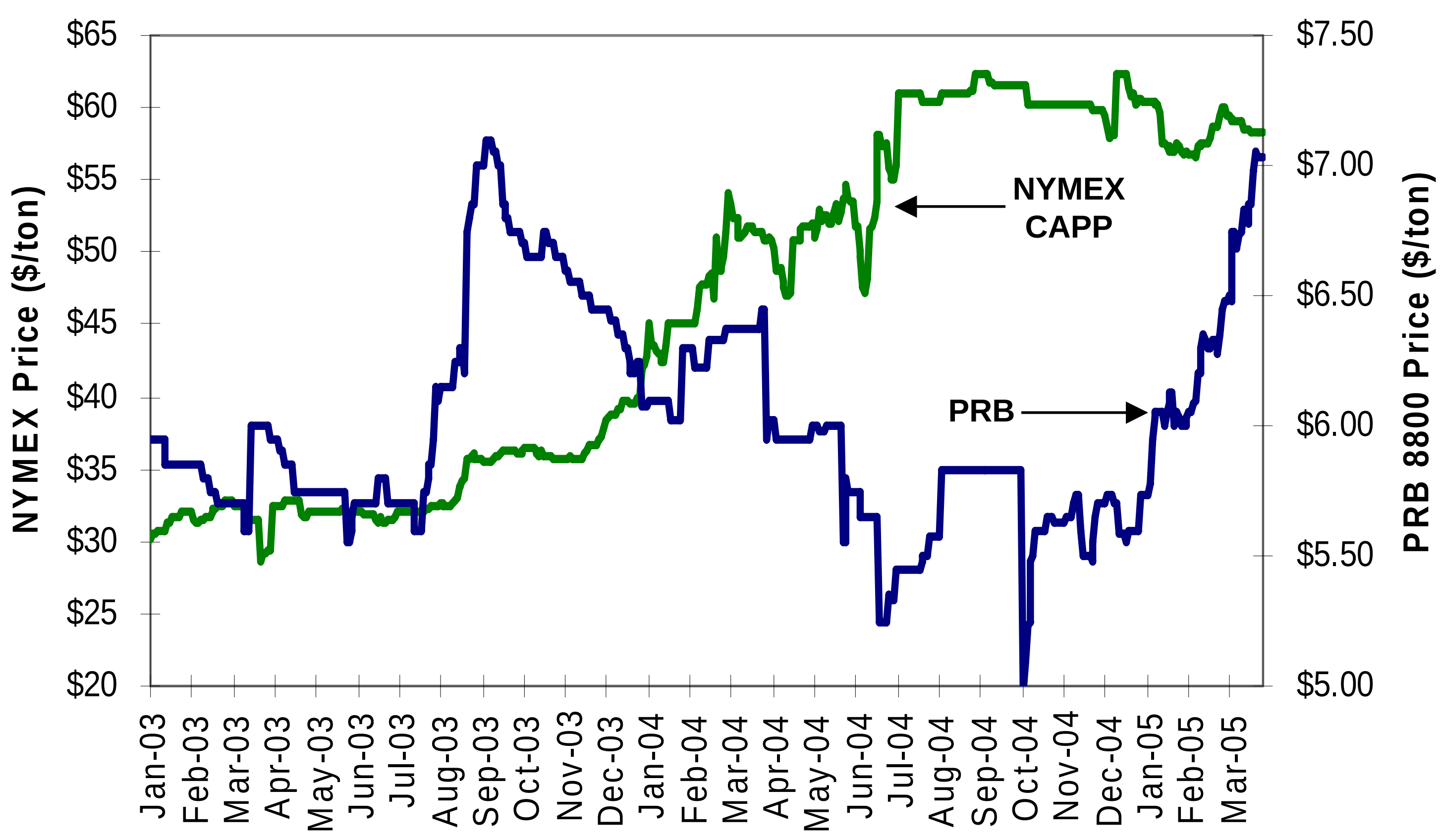
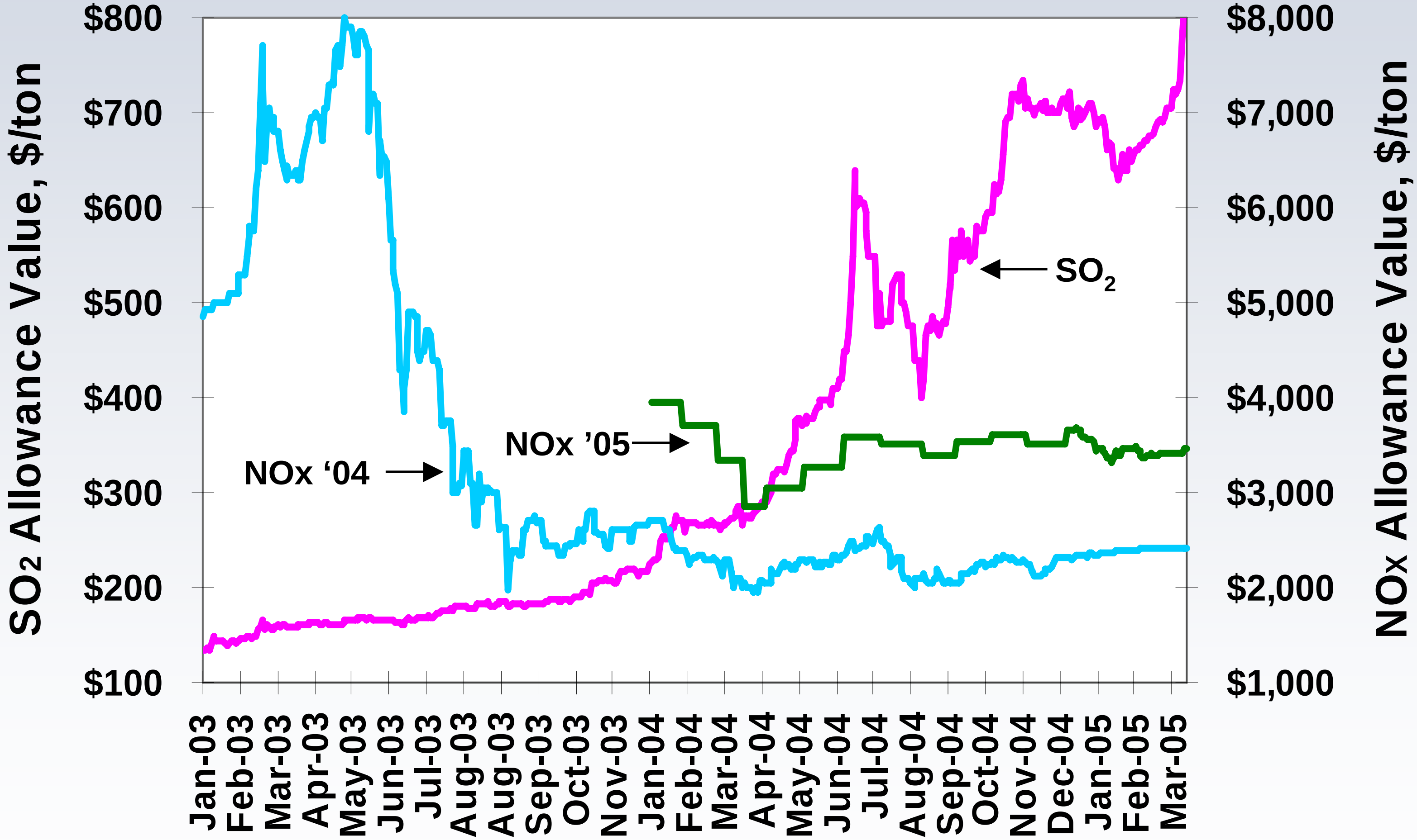
Coal Markets

The tale of two markets - one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



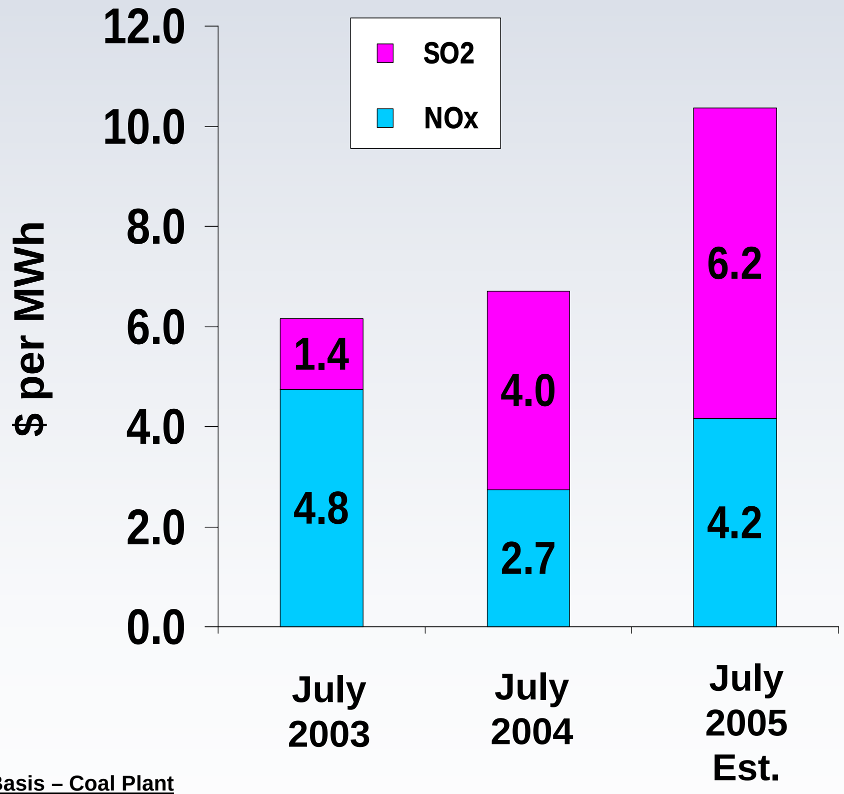
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



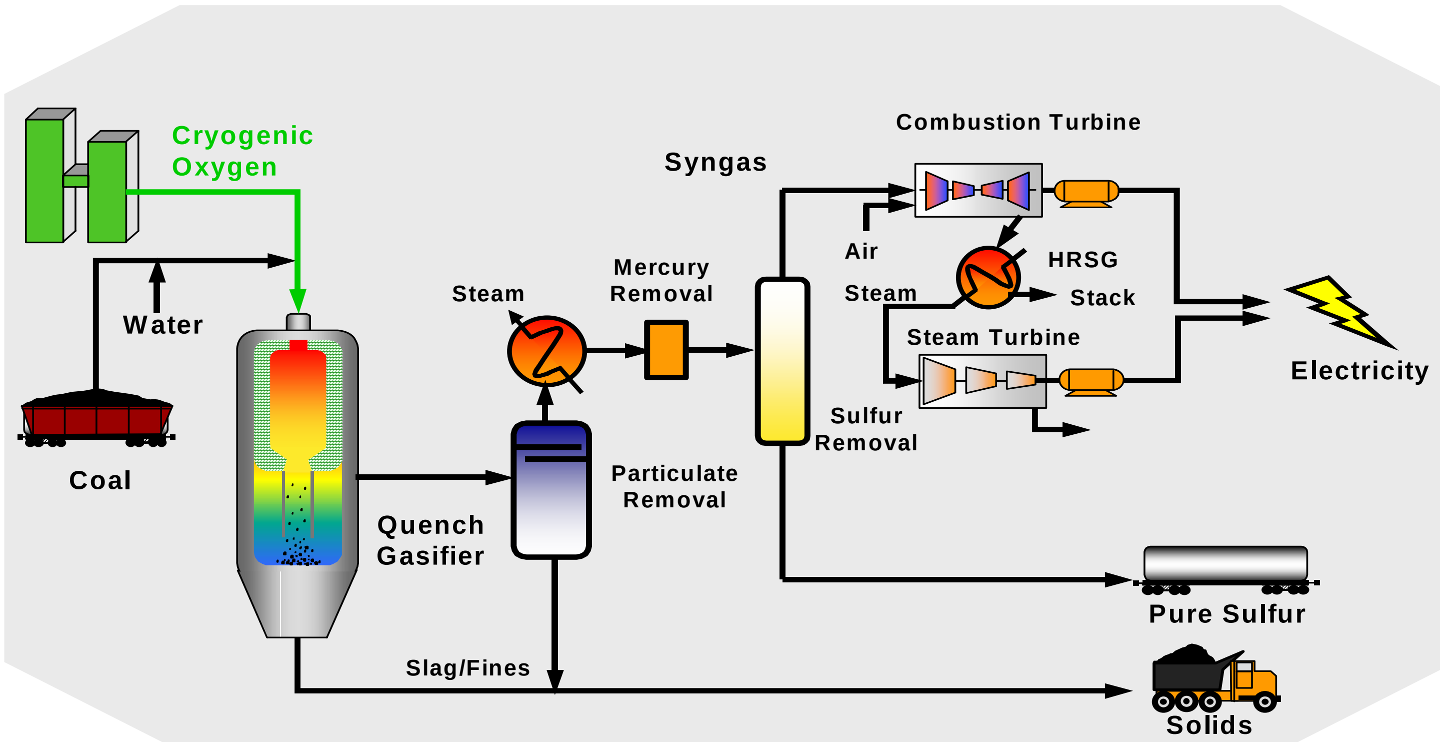
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

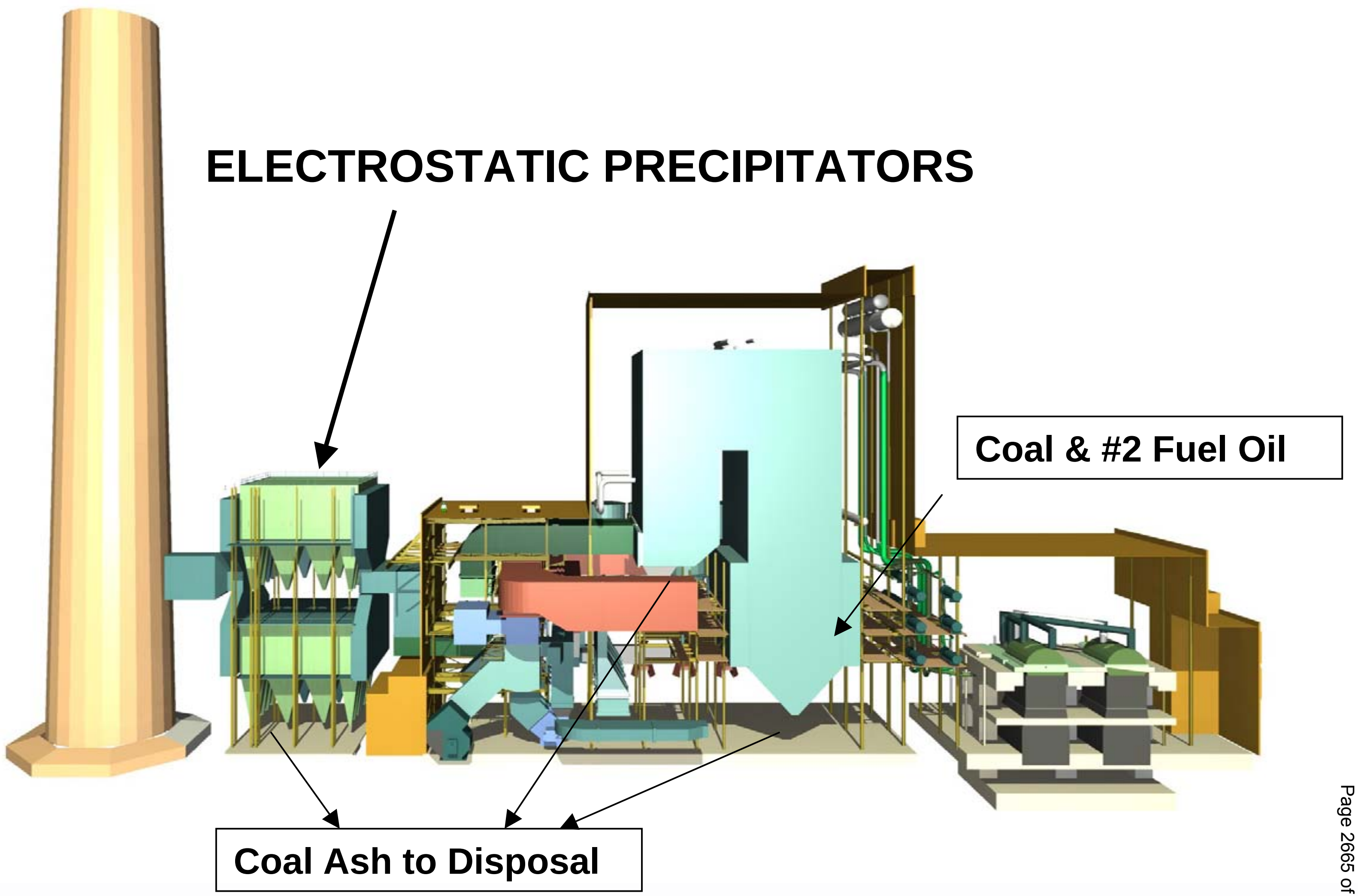
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

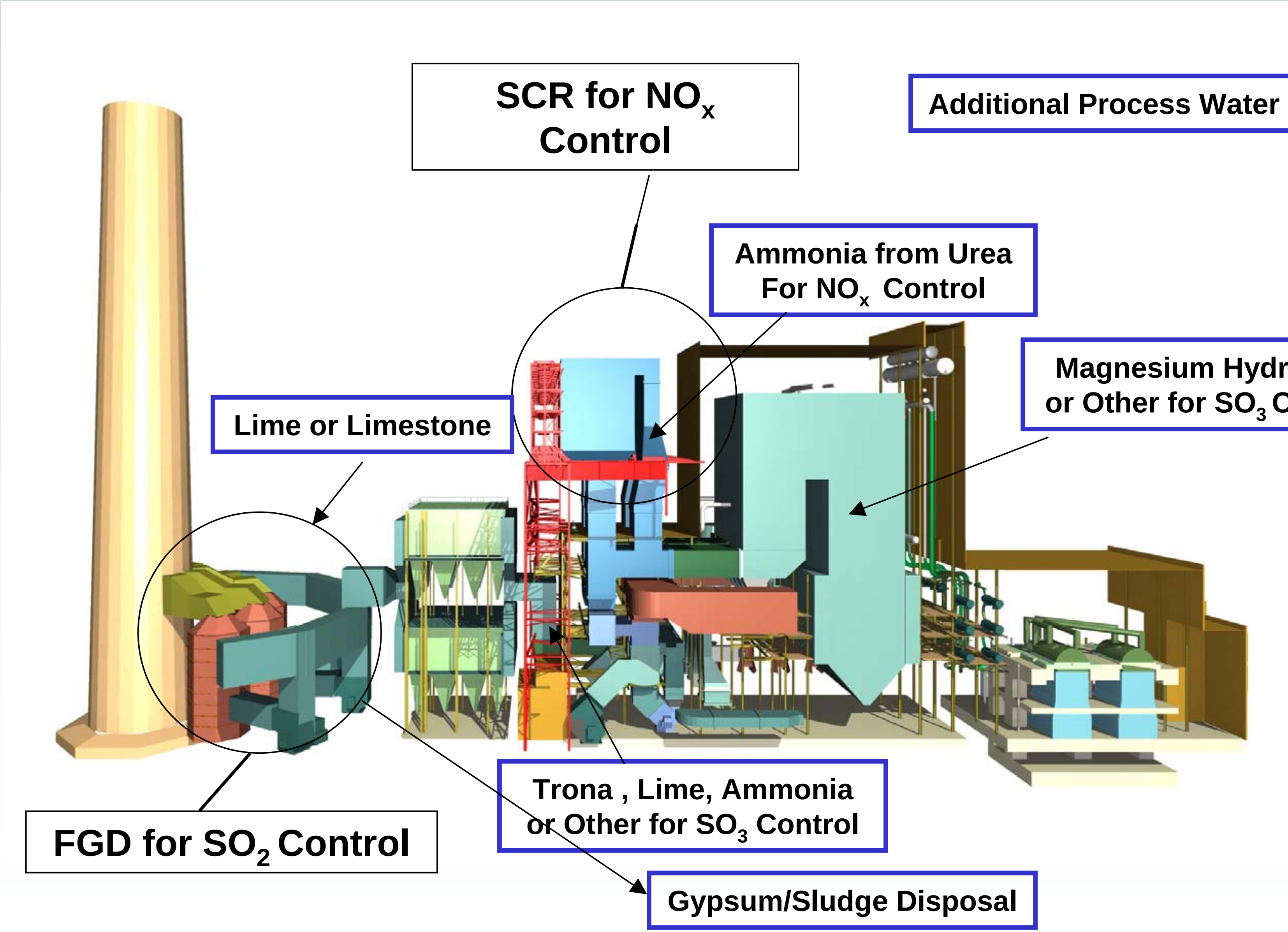
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s

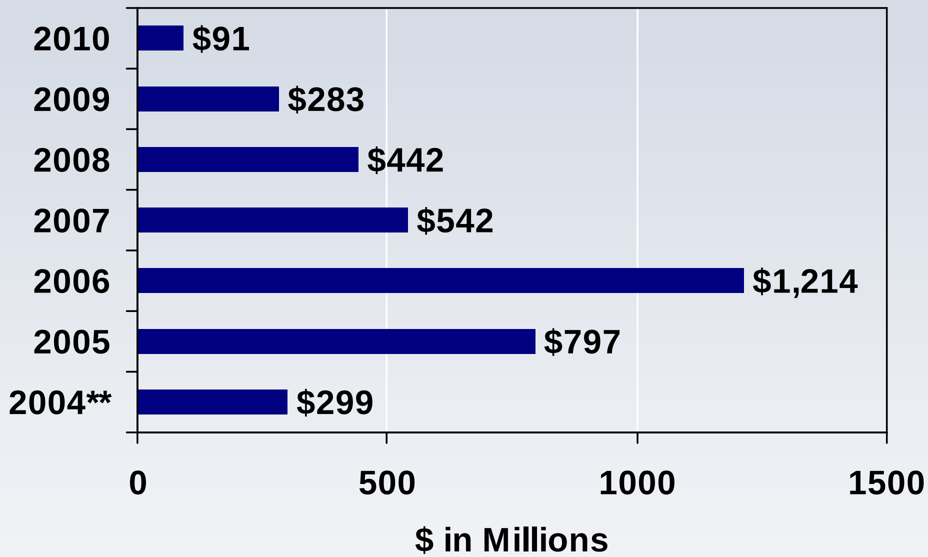


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)

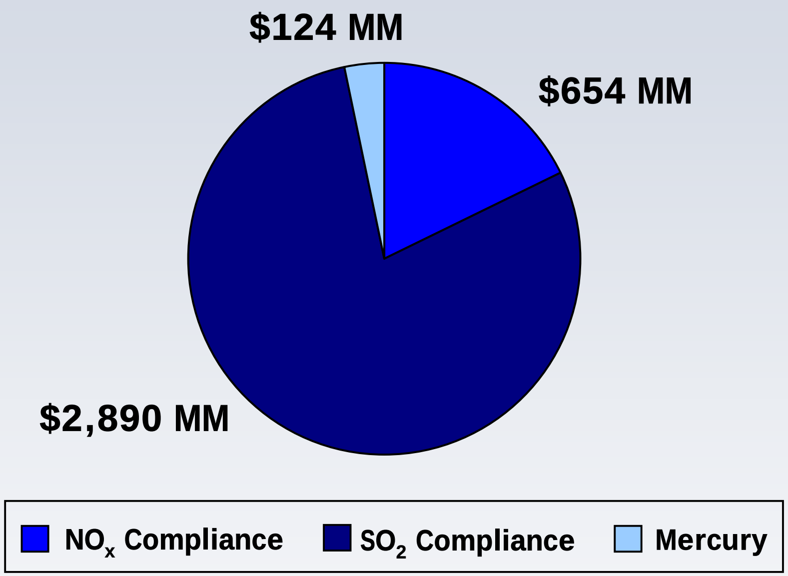


Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



Compliance Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes

** Actual investment level in 2004

Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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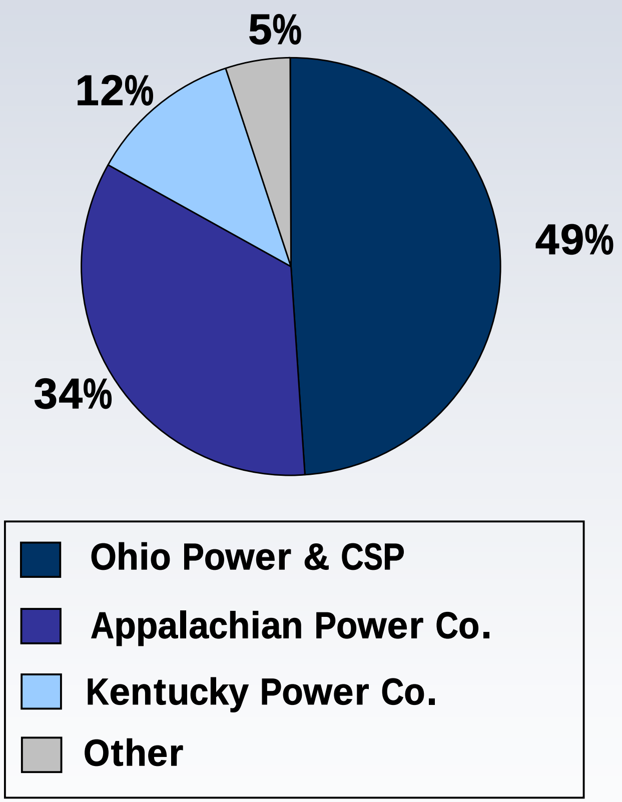
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Planned or Under Construction

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05
  - AEP testimony filed on 5-5-05
  - Technical conference on 5-15-05
  - Hearings start 8-8-05

Indiana (Regulated)
- Base rate freeze expired December 31, 2004.
- Fuel rate cap expired Feb. 29, 2004; interim factors set through September 2005, subject to refund or true-up.
- The status of additional base and fuel clause rate caps, subject to certain conditions, is the subject of a settlement agreement pending before the IURC.

West Virginia (Regulated)
- Base rates not frozen
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- No active fuel clause

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Michigan (Restructured, but Regulated)
- Base rates not frozen
- Active annual fuel clause

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in first half of 2005. TCC wires rate case order expected in June 2005.
- TCC final fuel reconciliation (July 98-Dec. 01) decision approved in February 2005. Additional $2 million disallowance in final decision.
- Proposal for decision received in TNC true-up filing in March 2004 (retail clawback and fuel over-recovery only) recommending adjustment of excess earnings amount in T&D rates. Commission approved order on April 13, 2005.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- General rate case filed Oct. 31, 2003
  - Quality of Service settlement approved by OCC in June 2004
    - Settlement agreement on remaining issues filed with the Commission on March 7, 2005. Order approved on May 2, 2005.
- Fuel clause adjusted quarterly
- 2001 Fuel review case
  - Hearings expected in August 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
  - Likely to include motions to expand scope to include prudence review

Louisiana (Regulated)
- Base rates capped through June 15, 2005
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Revenues				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

Finance

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- *Outcome of pending regulatory proceedings*
  - *Texas & Louisiana*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

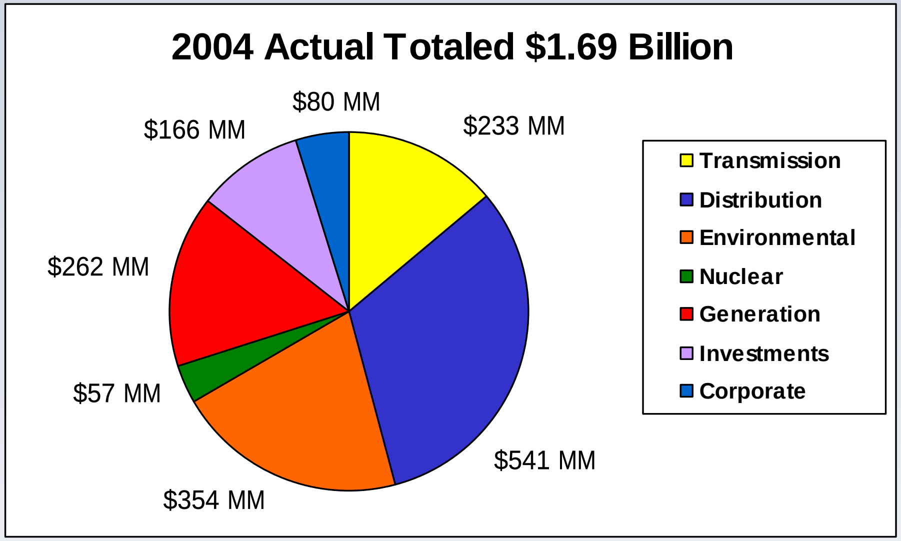
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

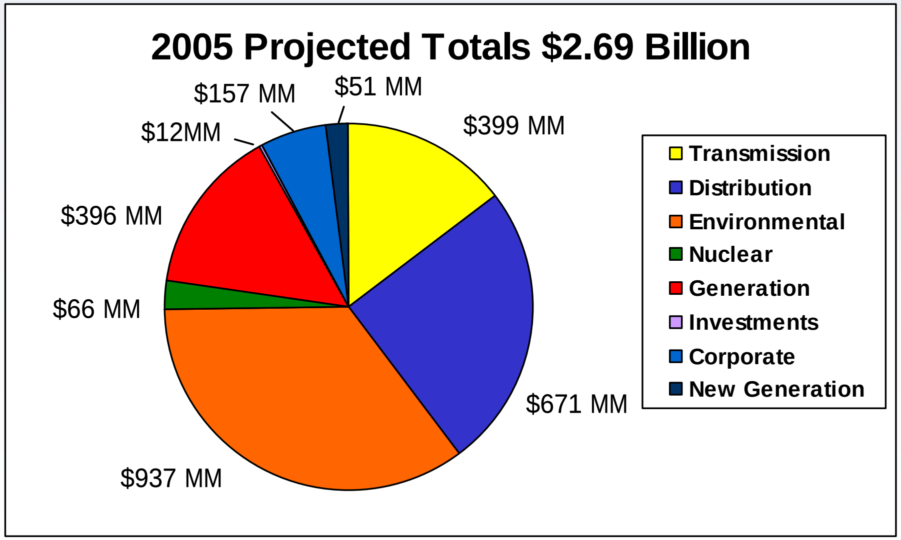
**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex


2004 Actual Totaled $1.69 Billion
$80 MM
$233 MM
$166 MM
$262 MM
$57 MM
$354 MM
$541 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate


2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$399 MM
$12MM
$396 MM
$66 MM
$937 MM
$671 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year		**2005**[1]		**2006**		**2007**
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	65,800,000	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**941,176,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Total includes $65.8 million of defeased mortgage bonds in 2005

(4) Excludes TCC securitization bonds

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Earnings Guidance

			2004 Actual			2005 Forecast	
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.40
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Berenson/Williams Capital Midwest Utilities Conference

April 13, 2005
Chicago, IL

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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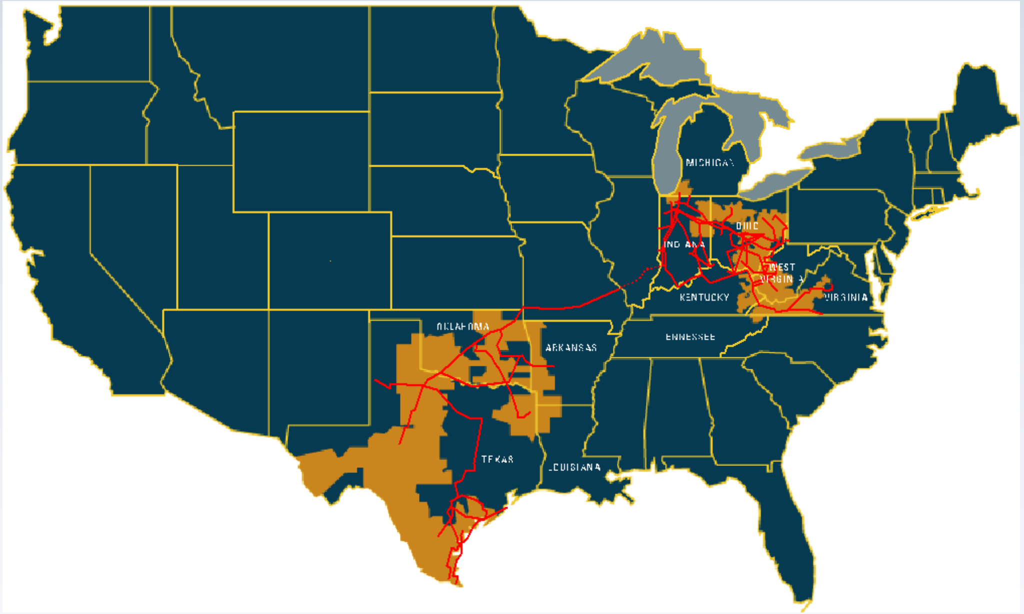
Executive Vice President & Chief Financial Officer

Strength & Scale in Assets & Operations



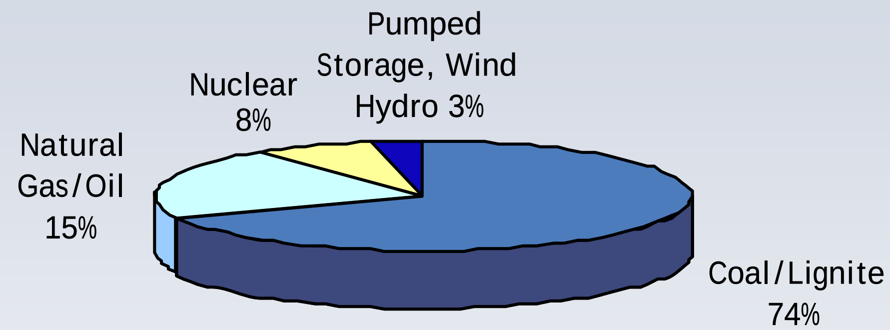
Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 36,000 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



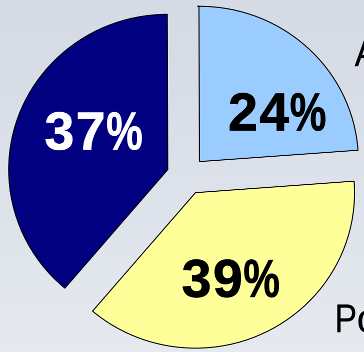
	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,719	0	0
SPP	4,828	3,516	188
Total*	**30,773**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Coal Procurement

AEP SYSTEM

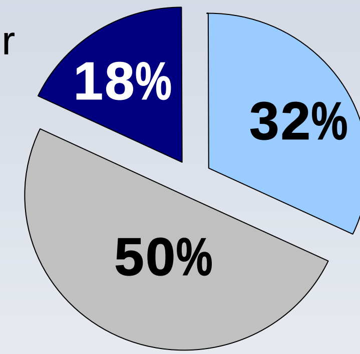


Coal Supply

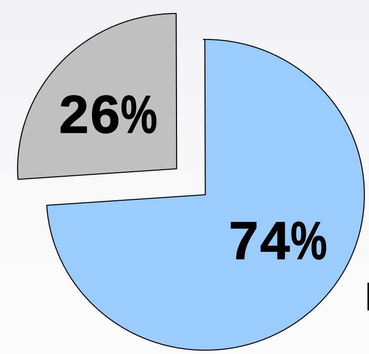
(on average)

- ➢Purchase 75 MM tons per year
- ➢Ave. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM

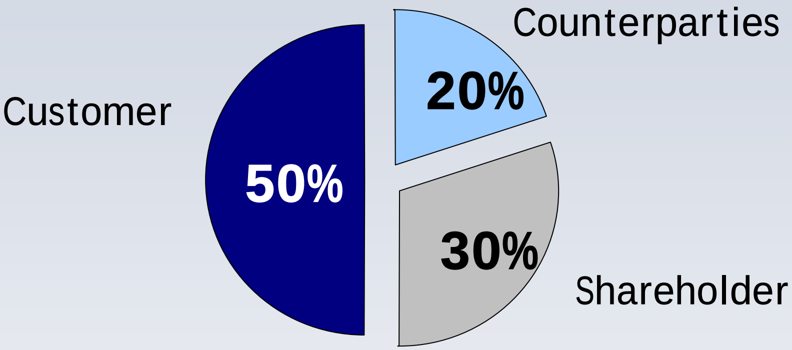


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM



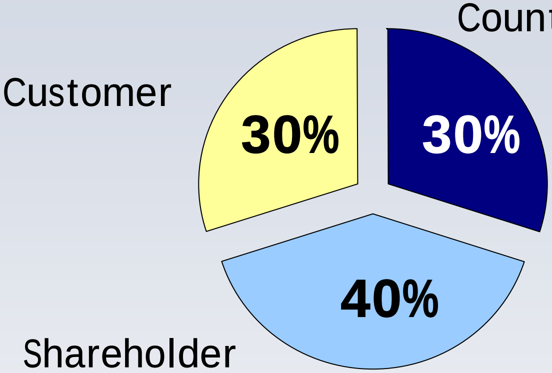
Fuel Cost Recovery

(on average)

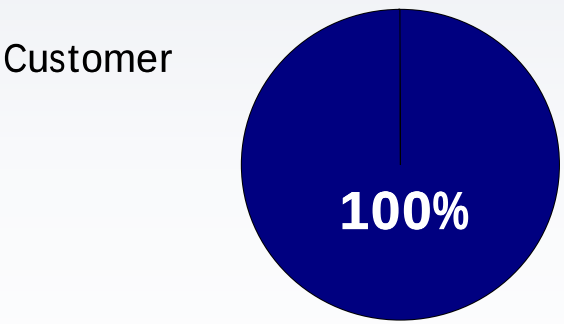
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

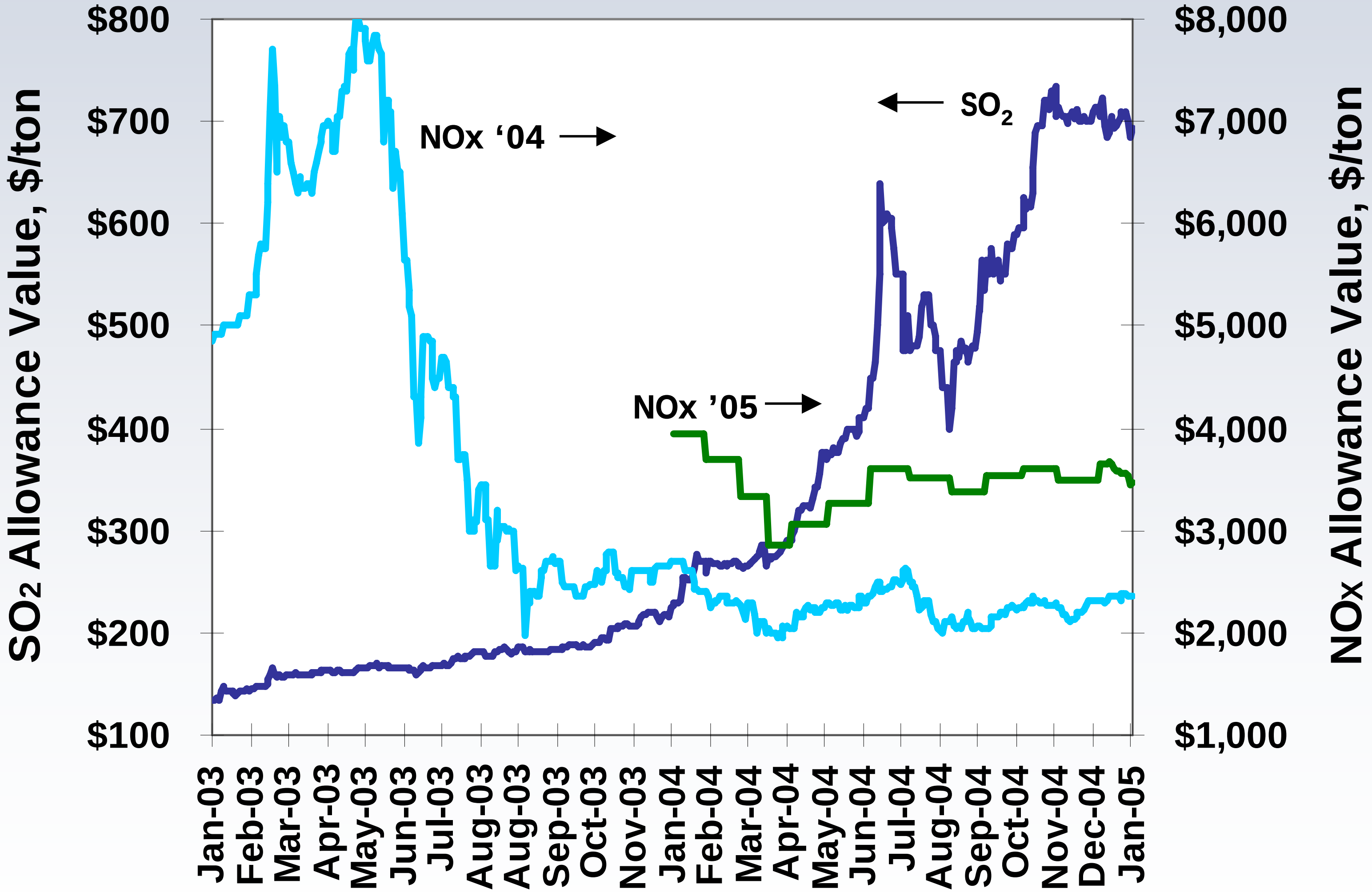


WESTERN SYSTEM



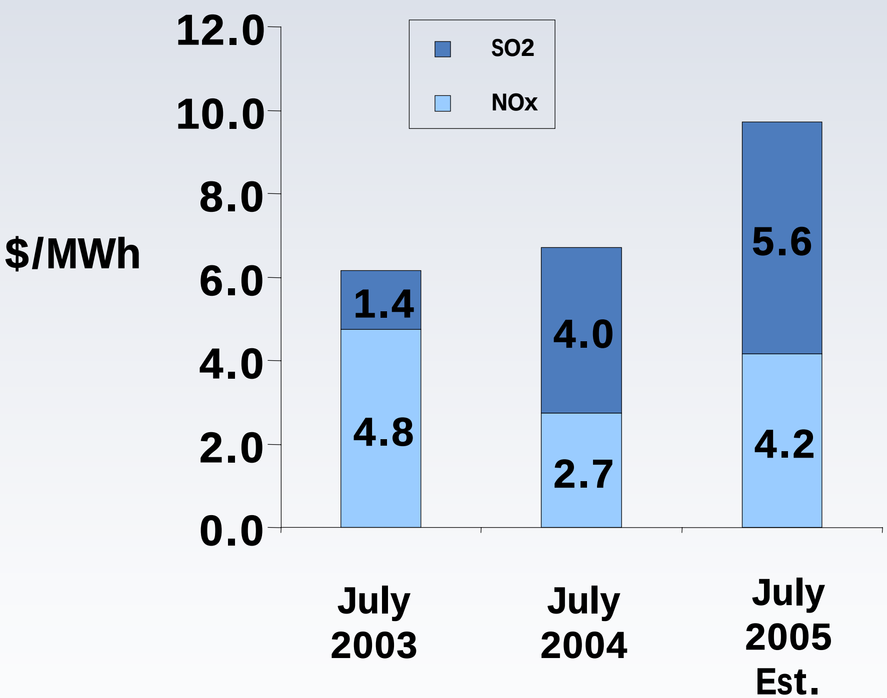
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



<u>Basis - Coal Plant</u>
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investment To Drive Utility Earnings Growth

- Investment in new generation: IGCC
- Environmental Investment: $3.7 billion 2004 - 2010
- Energy Delivery Investment

GROWING EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Investing in IGCC

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

Next Steps

<u>2005</u>

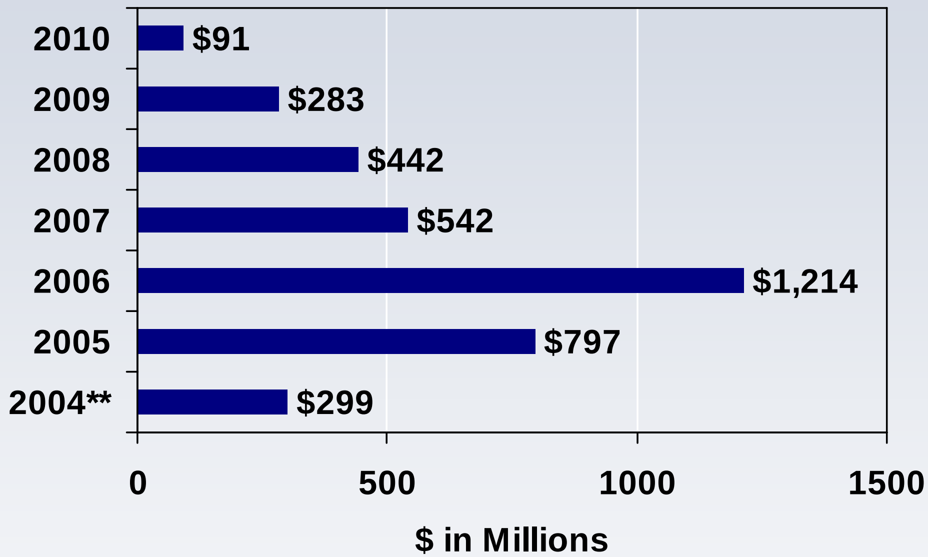
- Secure cost recovery plan - June
- Finalize site selection - August
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

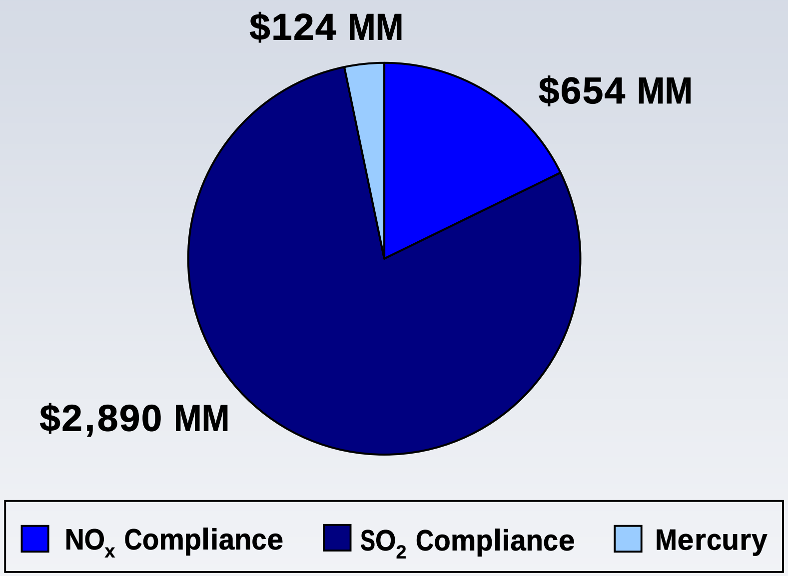
- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental Investment: $3.7 Billion Through 2010



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

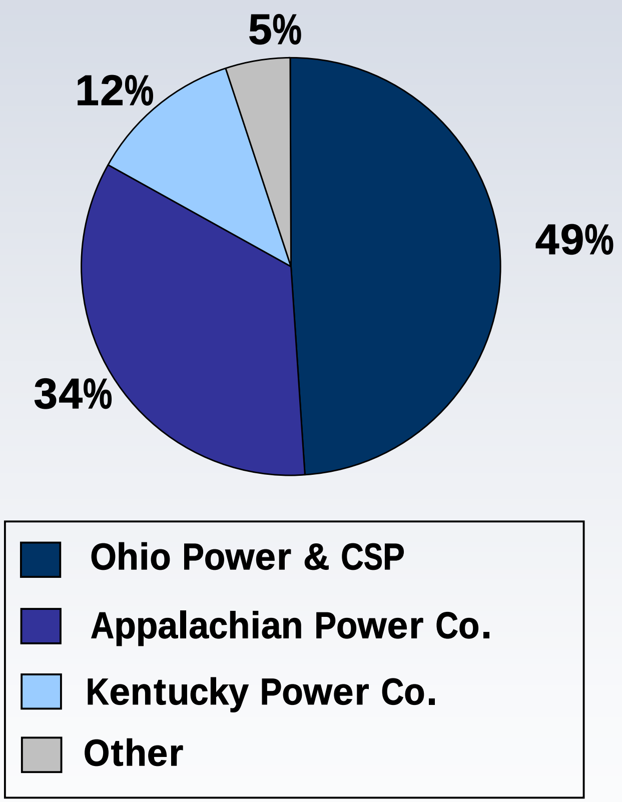
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation

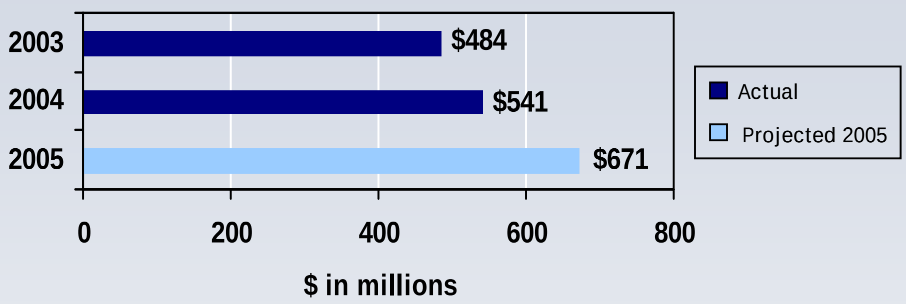


Funding the Environmental Investments

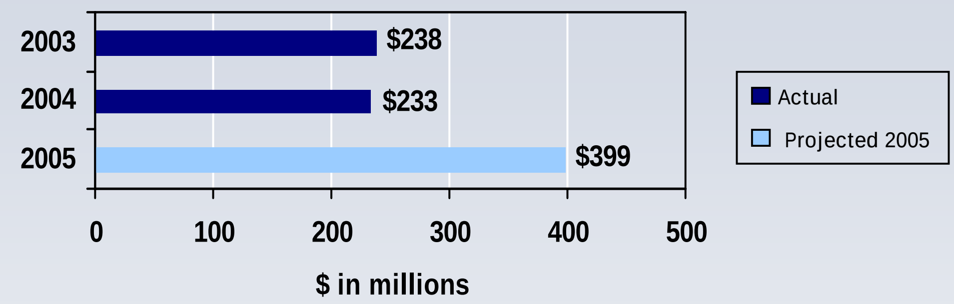
- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



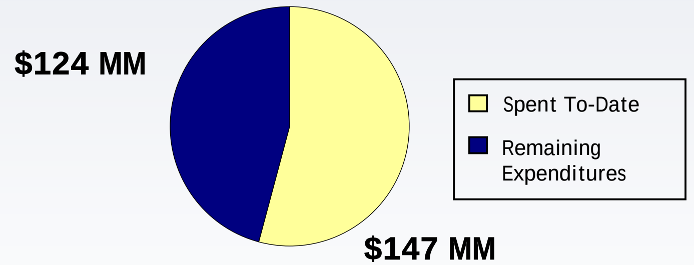
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
3	Texas Wires	441		469	
4	Texas Supply / REP	347		198	
5	Off-System Sales	472		547	
6	Other Wholesale Transactions	14		-	
7	Transmission Revenue - 3rd Party	451		410	
8	Other Operating Revenue	331		346	
9	Total Gross Margin	7,018		7,017	
10	Operations & Maintenance	(3,072)		(3,087)	
11	Depreciation & Amortization	(1,256)		(1,275)	
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13	Interest Exp & Preferred Dividend	(616)		(592)	
14	Other Income & Deductions	161		181	
15	Income Taxes	(489)		(529)	
16	Net Earnings Utility Operations	1,046	2.64	988	2.54
	INVESTMENTS:				
17	Gas Operations	(33)		3	
18	Other Investments	(18)		(15)	
19	Total Investments	(51)	(0.13)	(13)	(0.04)
20	Parent Company	(71)	(0.18)	(40)	(0.10)
21	**ON-GOING EARNINGS**	924	2.33	936	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Reflects sale of HPL and paydown of debt*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

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What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

AEP®

AEP AMERICAN ELECTRIC POWER

Operating In PJM Environment

- **Cost of generation to serve retail customers**
  - Retail customers continue to receive the benefits of AEP's lowest generation on an hourly basis

- **Off-system sales margin**
  - October-December was a learning period; results steadily improved each month
  - 4th quarter off-system sales margin was in line with budget

WE CONTINUE TO APPLY LESSONS LEARNED IN PJM TO MAXIMIZE THE VALUE OF OUR GENERATION FLEET

TCC Stranded Cost Carrying Charge

Carrying Cost Details:

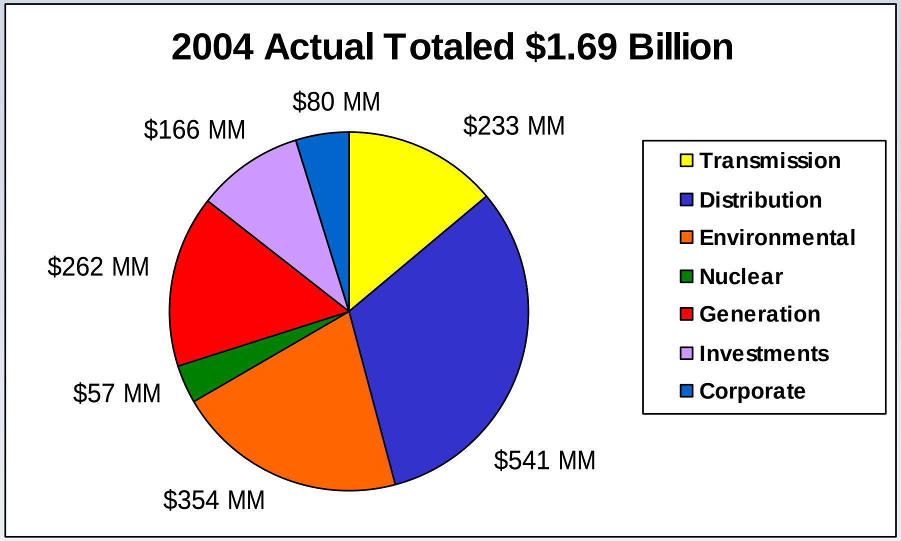
Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

Simplified Calculation:	
Initial Stranded Cost Base (excludes Carrying Charge)	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

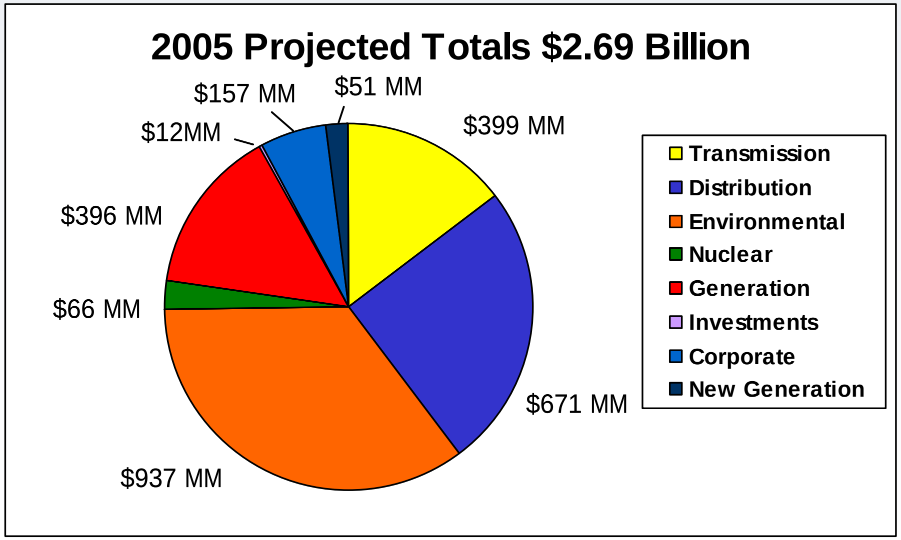
Items included in stranded cost base include: Stranded Plant costs ($900 MM), Regulatory Assets ($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly. At 12/31/04 total carrying costs were $302 MM, for a Net True-up Regulatory Asset value of $1.648 Billion.

EQUITY COMPONENT RECOVERABLE ONCE AN ORDER IS RECEIVED

2005 Capex



2004 Actual Totaled $1.69 Billion
$80 MM
$233 MM
$166 MM
$262 MM
$57 MM
$354 MM
$541 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate



2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$399 MM
$12MM
$396 MM
$66 MM
$937 MM
$671 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Environmental Investment

FGD | SCR

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

Rate Stabilization Plan	Revenues 2005	Revenues 2006	Revenues 2007	Revenues 2008	Incremental Cash 2005	Incremental Cash 2006	Incremental Cash 2007	Incremental Cash 2008
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- Outcome of pending regulatory proceedings
  - Texas, Oklahoma & Louisiana
- Operations within PJM environment
- Plant availability
- Rising fuel costs
- Weather (storm damage and effect on sales)

2005 Earnings Guidance

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
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8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
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15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Morgan Stanley
12th Annual Global Electricity & Energy Conference

March 9, 2005
The Westin Hotel at Times Square

AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements which are subject to risks and uncertainties. These factors include electric load and customer growth; abnormal weather conditions; available sources and cost of fuel; availability of generating capacity and performance of plants; the speed and degree to which competition is introduced to our service territories; the ability to recover stranded costs in connection with deregulation; new legislation and government regulation; resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to successfully control costs; the success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile; ability to sell assets at attractive prices; international and country-specific developments affecting foreign investments including the disposition of any current foreign investments and potential additional foreign investments; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; electricity and gas market prices; changes in creditworthiness in energy trading market; changes in the financial markets; changes in markets for electricity, natural gas, and other energy-related commodities; actions of rating agencies; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; liquidity in the banking, capital and wholesale power markets; prices for power we generate and sell at wholesale; changes in technology, including the increased use of distributed generation within our transmission and distribution service territory; other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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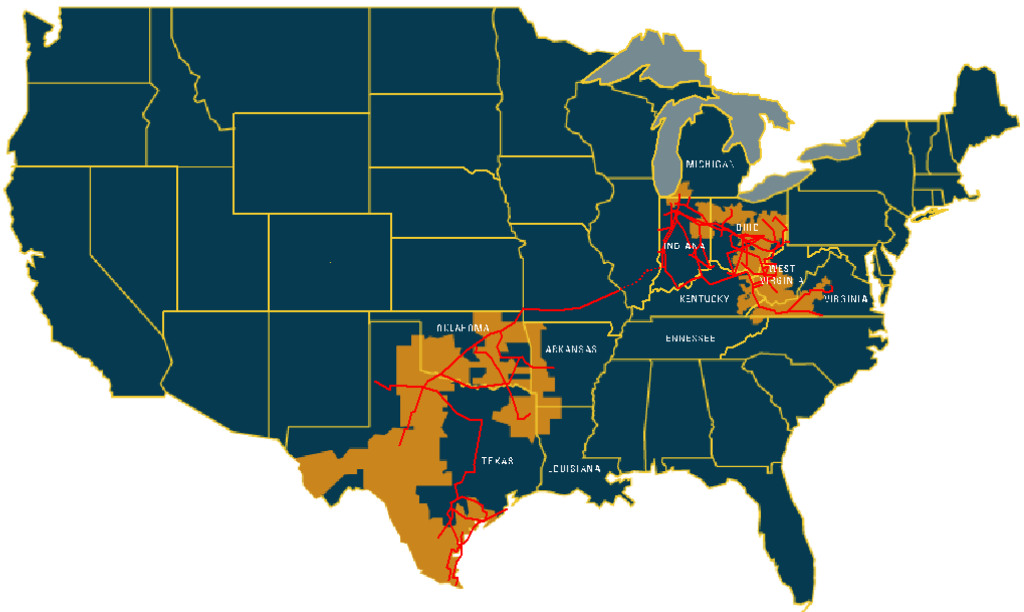
Mike Morris
Chairman, President & Chief Executive Officer

Strength & Scale in Assets & Operations



Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

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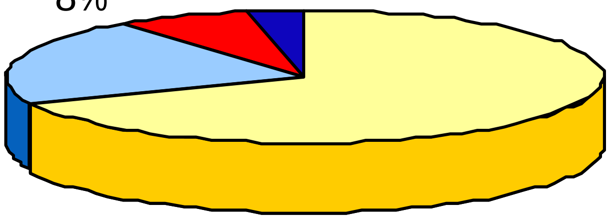
Fuel Mix & Operating Statistics



Capacity by Fuel Mix

- 36,000 MW domestic capacity
- 85% system availability factor for YE 2004
- 62% system capacity factor for YE 2004

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

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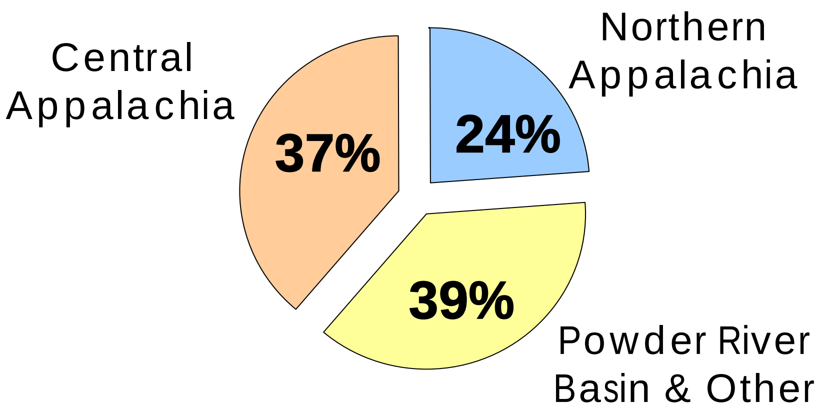
Coal Procurement

AEP SYSTEM

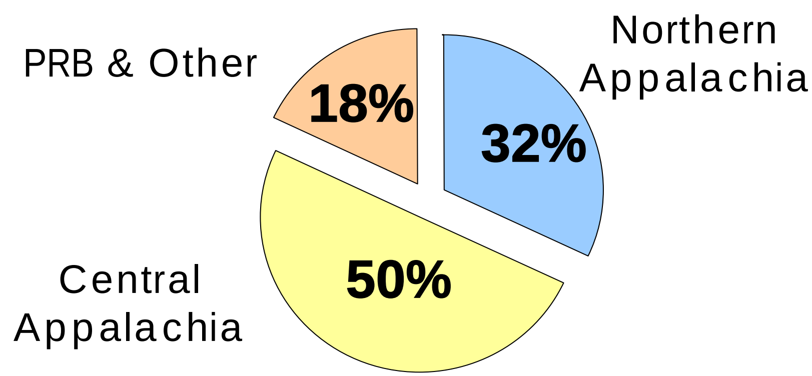


Coal Supply

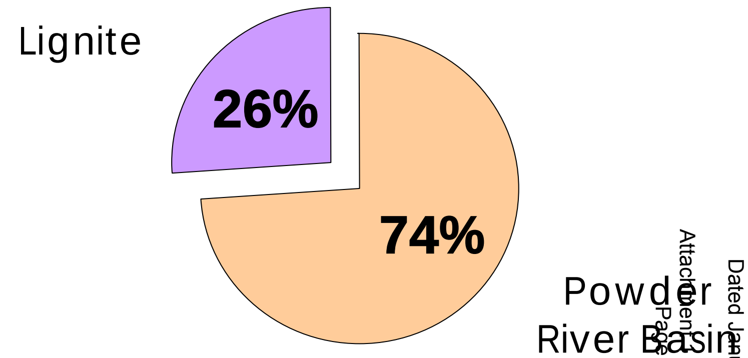
(on average)

- ➢Purchase 75 MM tons per year
- ➢Ave. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM



WESTERN SYSTEM



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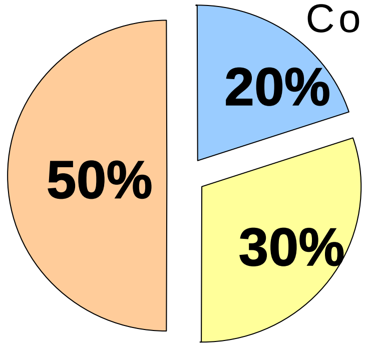
Fuel Recovery

AEP SYSTEM

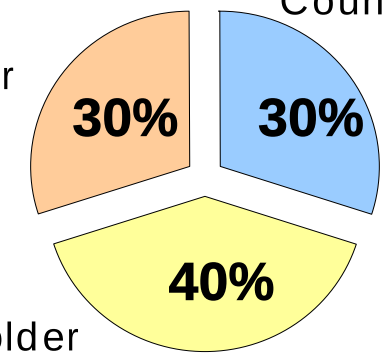


Fuel Cost Recovery
(on average)

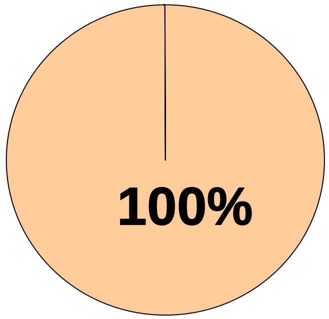
- Fuel recovery varies by jurisdiction
- 70% of fuel costs is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

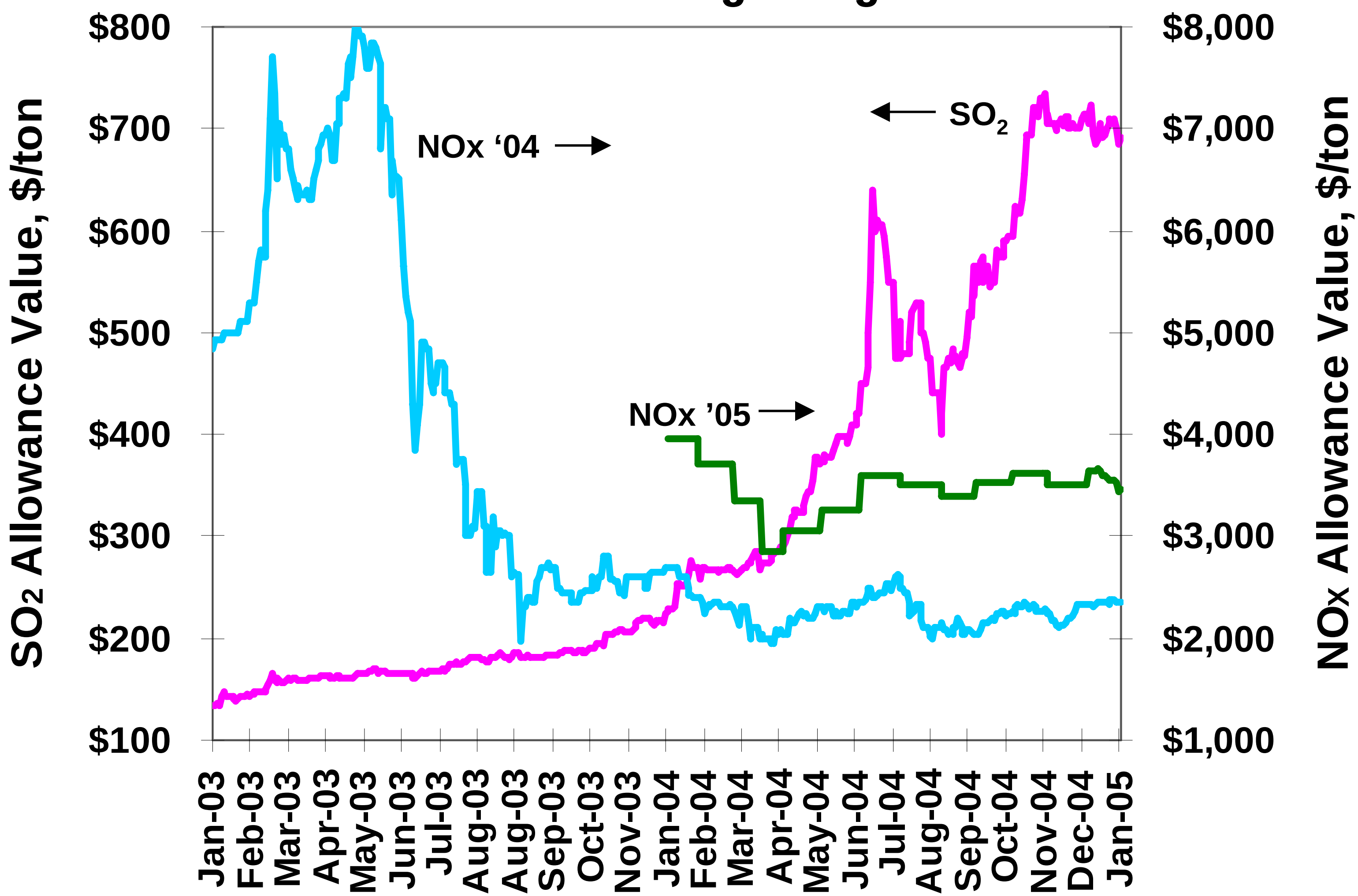


WESTERN SYSTEM



Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



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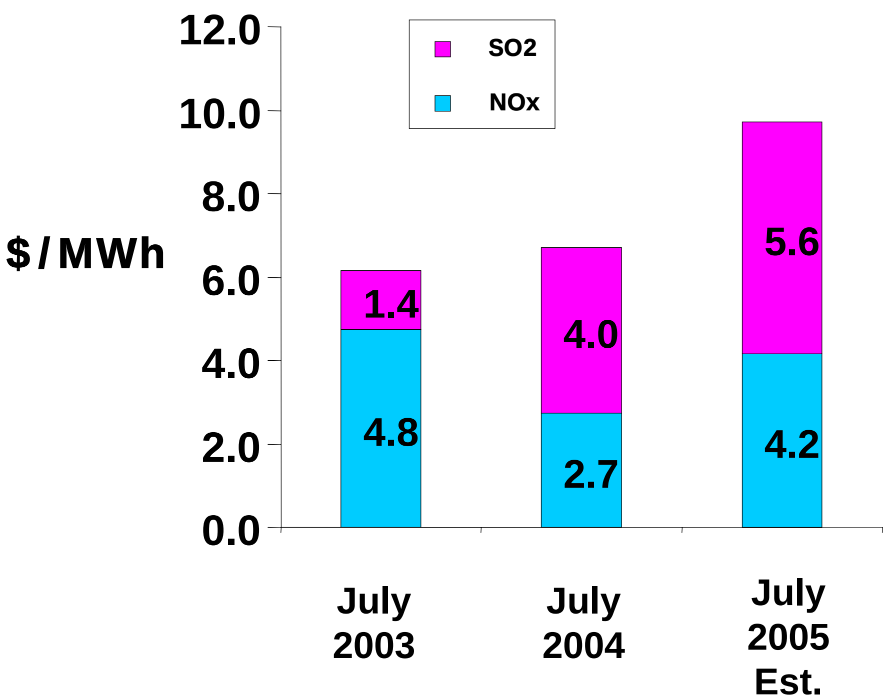
Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Operating In PJM Environment

- **Cost of generation to serve retail customers**
  - Retail customers continue to receive the benefits of AEP's lowest generation on an hourly basis

- **Off-system sales margin**
  - October-December was a learning period; results steadily improved each month
  - 4th quarter off-system sales margin was in line with budget

WE CONTINUE TO APPLY LESSONS LEARNED IN PJM TO MAXIMIZE THE VALUE OF OUR GENERATION FLEET

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Investment To Drive Utility Earnings Growth

- **Investment in new generation: IGCC**
- **Environmental Investment: $3.7 billion 2004- 2010**
- **Energy Delivery Investment**

GROWING EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

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Comparison Of Technology Options

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8500	7000
EPC Cost* ($/kW)	1200	1450	400
Total Plant cost** ($/kW)	1450	1750	470
Variable Production Cost*** ($/MWh)	16	14	37

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $37/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

Next Steps

2005

- Secure regulatory cost recovery - June
- Finalize site selection - August
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

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AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

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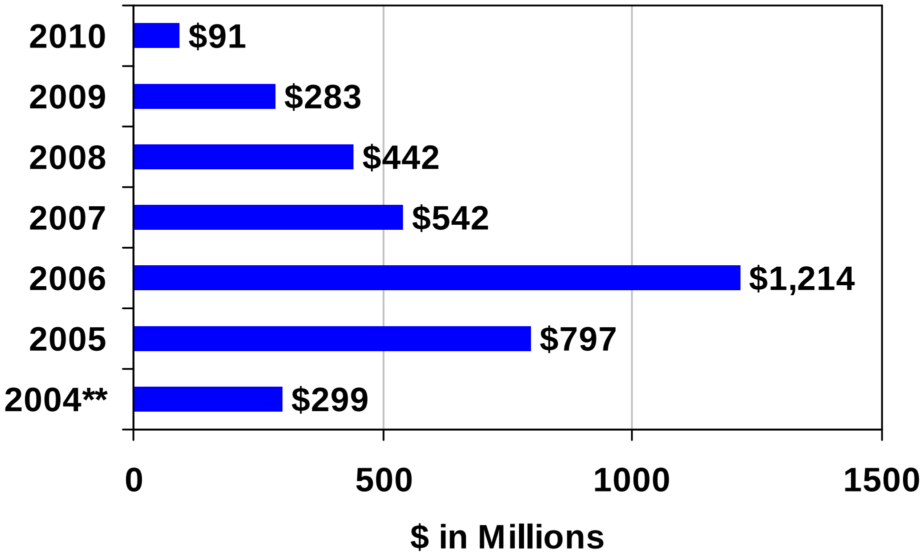
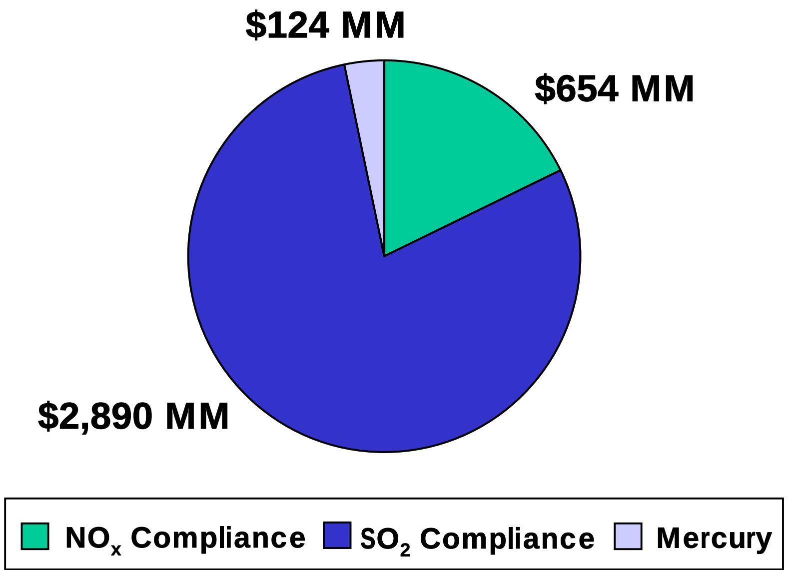
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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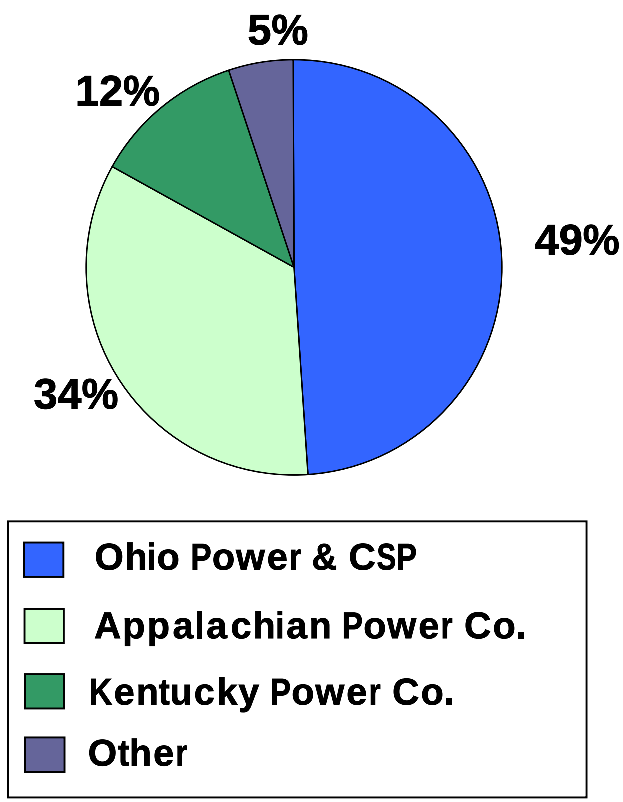
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

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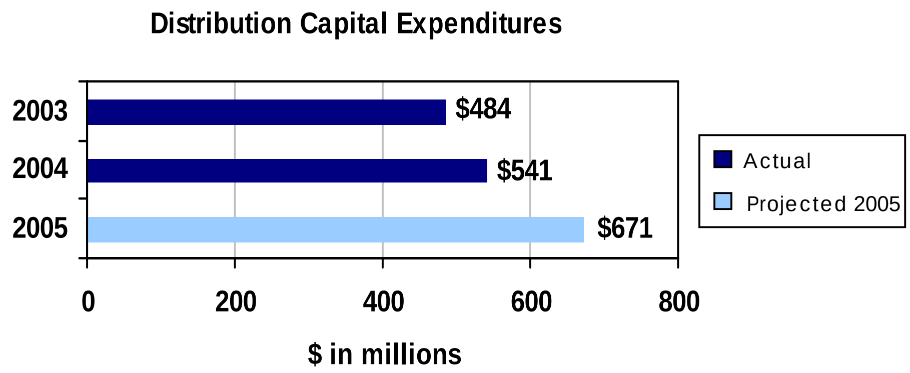
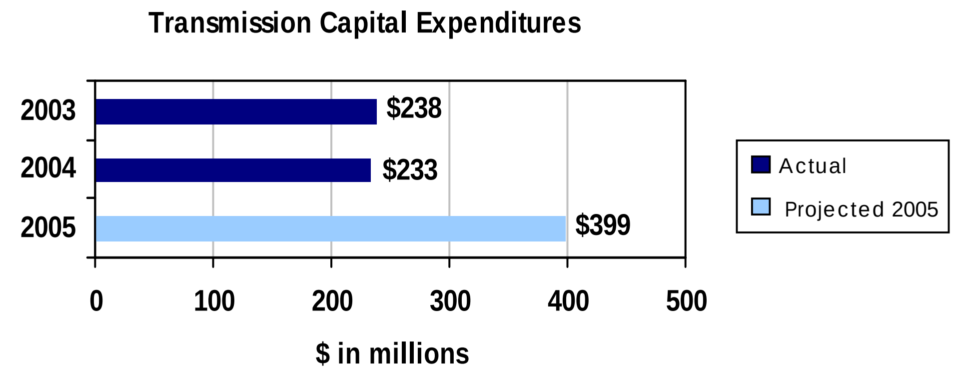
Energy Delivery Investment





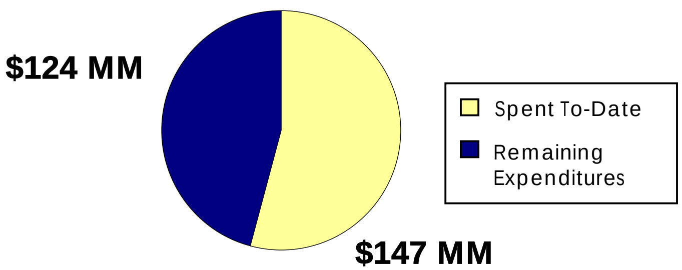
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

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Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
- **Planned Regulatory Activity (2005-2007)**
  - FERC Transmission Rate Case
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

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Ohio Rate Stabilization Plan Recap

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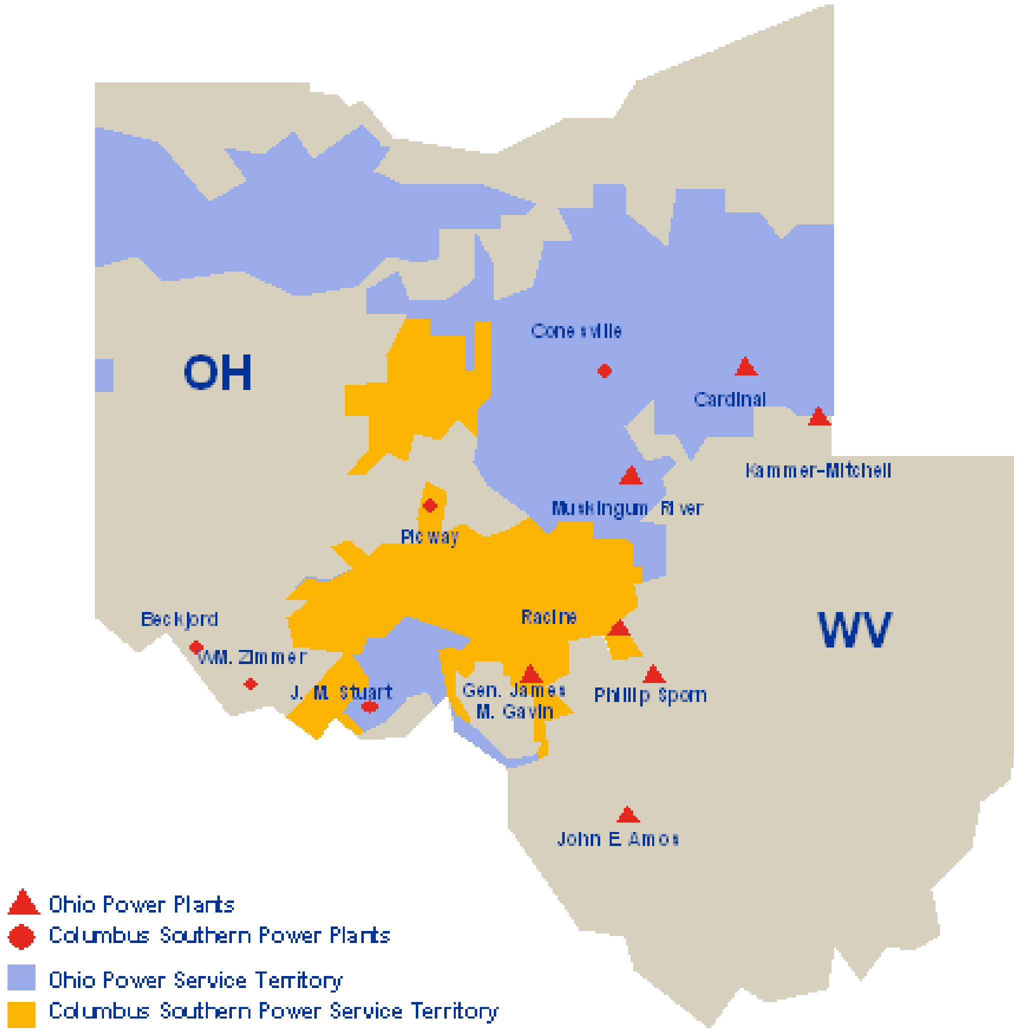
AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

Defining the Ohio Operating Environment Post-2008



2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
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19	Total Investments	(51)	(0.13)	(13)	(0.04)
20	Parent Company	(71)	(0.18)	(40)	(0.10)
21	**ON-GOING EARNINGS**	924	2.33	936	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Reflects sale of HPL and paydown of debt*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

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2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	936 *
Depreciation & Amortization	1,300	1,305
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	136
Total from Operations	**$ 2,597**	**$ 1,923**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,690)
Asset Sales	1,357	1,456 **
Other	(40)	(487) ***
Total from Investing	**$ (376)**	**$ (1,721)**
Cash from Financing:		
Common Equity	17	(155) ****
Net Long Term Debt Issued/(Retired)	(1,829)	621
Preferred Stock Redeemed	(10)	(66)
Short Term Debt Change, Net	(400)	16
Common Dividends	(555)	(545)
Total from Financing	**$ (2,777)**	**$ (129)**
Net Change in Cash	**$ (556)**	**$ 73**
Ending Cash Balance	**$ 420**	**$ 493**

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

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Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain capitalization ratio below 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

AEP AMERICAN ELECTRIC POWER

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- ***Operations within PJM environment***
- ***Plant availability***
- ***Rising fuel costs***
- ***Weather (storm damage and effect on sales)***

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TCC Stranded Cost Carrying Charge

Carrying Cost Details:

Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

Simplified Calculation:	
Initial Stranded Cost Base	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

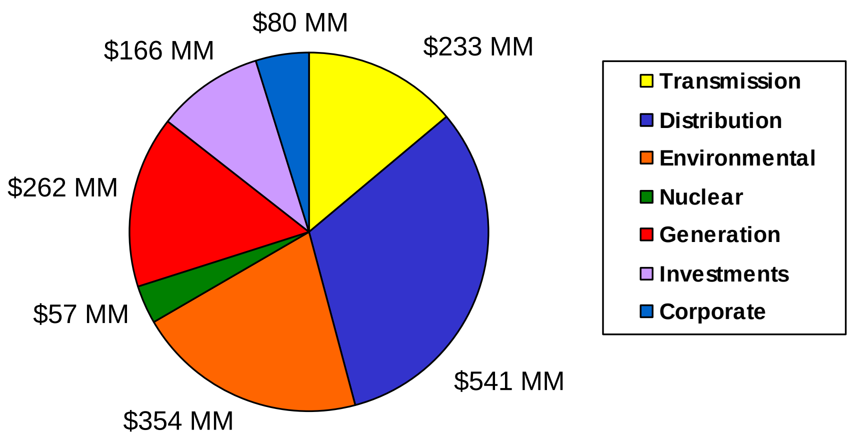
Items included in stranded cost base include:
Stranded Plant costs ($900 MM), Regulatory Assets ($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly.

EQUITY COMPONENT RECOVERABLE ONCE AN ORDER IS RECEIVED

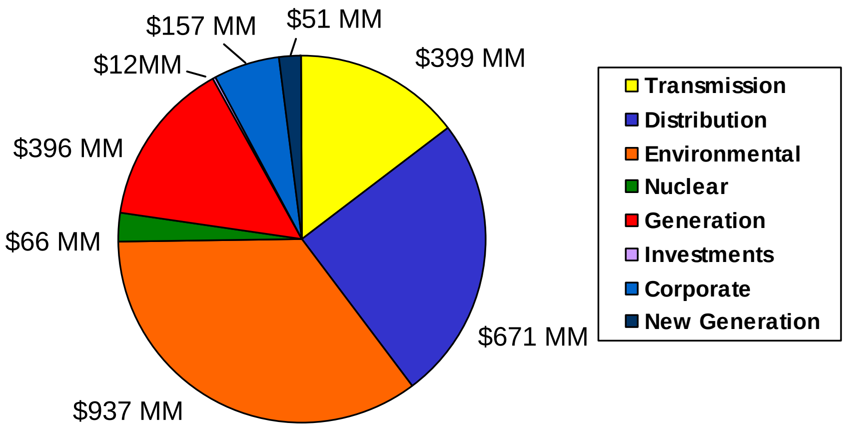
AEP®

2005 Capex

2004 Actual Totaled $1.69 Billion



2005 Projected Totals $2.69 Billion



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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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Capital Structure

Capital Structure & Ratios	12/31/2004		
	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	12,287	-	12,287
Short-term Debt	23	-	23
Preferred Stock Subject to Mandatory Redemption	66	-	66
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	8,515	8,515
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***
Adjustments			
Preferred Stock Subject to Mandatory Redemption	(66)	66	-
Defeased First Mortgage Bonds	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241
Securitization Bonds	(698)	-	(698)
Spent Nuclear Fuel Trust	(229)	-	(229)
Equity Credit for Equity Units	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***

MAINTAIN DEBT-TO-CAP BELOW 60%

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Liquidity Summary

Liquidity Summary	Actual Dec-04	
$MM	**Amount**	**Maturity**
5-Year R/C Facility	1,000	May-05
3-Year R/C Facility	750	May-06
3-Year R/C Facility	1,000	May-07
3-Year L/C Facility	200	Sep-06
Total Credit Facilities	**2,950**	
Plus		
Total Cash & Cash Equivalents	**420**	
Less		
Commercial Paper Outstanding	-	
Amount Drawn on Bank Loans	-	
Amount Issued (L/C Facility)	57	
Net Available Liquidity	**3,313**	

R/C=Revolving Credit
L/C=Letter of Credit

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Environmental Investment

Plants under consideration:

Install Scrubbers:	Install SCRs:
<u>2006 - 2010</u>	<u>2005 - 2007</u>
Mitchell	Muskingum
Mountaineer	Amos
Cardinal	Mitchell
Amos	
Big Sandy	
Muskingum	
Conesville	

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh

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AEP AMERICAN ELECTRIC POWER

UBS 2005 Natural Gas & Electric Utilities Conference

February 17, 2005
The Pierre Hotel, NYC

AEP

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements which are subject to risks and uncertainties. These factors include electric load and customer growth; abnormal weather conditions; available sources and cost of fuel; availability of generating capacity and performance of plants; the speed and degree to which competition is introduced to our service territories; the ability to recover stranded costs in connection with deregulation; new legislation and government regulation; resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to successfully control costs; the success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile; ability to sell assets at attractive prices; international and country-specific developments affecting foreign investments including the disposition of any current foreign investments and potential additional foreign investments; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; electricity and gas market prices; changes in creditworthiness in energy trading market; changes in the financial markets; changes in markets for electricity, natural gas, and other energy-related commodities; actions of rating agencies; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; liquidity in the banking, capital and wholesale power markets; prices for power we generate and sell at wholesale; changes in technology, including the increased use of distributed generation within our transmission and distribution service territory; other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Executive Vice President & Chief Financial Officer

2005 Plans

- ***Earnings Guidance Range: $2.30 to $2.50***
- ***Hold Utility O&M flat & reduce total O&M***
- ***Sustain below 60% debt/cap ratio***
- ***Fully fund pension plan: $100MM contribution per quarter in 2005***
- ***Proceed with remaining non-core asset divestitures, STP & Oklaunion***
- ***Increase utility investment levels to grow business: $2.73 billion in 2005***
- ***Successfully work through regulatory processes***
- ***Finalize IGCC site***
- ***Evaluate dividend level***

2005 Earnings Guidance: $2.30 to $2.50 per share

		2004 Actual $ in millions	2004 Actual EPS	2005 Forecast $ in millions	2005 Forecast EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	Regulated Integrated Utilities	3,003		3,049	
2	Ohio Cos.	1,959		1,998	
3	Texas Wires	441		469	
4	Texas Supply / REP	347		198	
5	Off-System Sales	472		547	
6	Other Wholesale Transactions	14		-	
7	Transmission Revenue - 3rd Party	451		410	
8	Other Operating Revenue	331		346	
9	Total Gross Margin	7,018		7,017	
10	Operations & Maintenance	(3,072)		(3,073)	
11	Depreciation & Amortization	(1,256)		(1,275)	
12	Taxes Other than Income Taxes	(700)		(728)	
13	Interest Exp & Preferred Dividend	(616)		(598)	
14	Other Income & Deductions	161		182	
15	Income Taxes	(489)		(538)	
16	Net Earnings Utility Operations	1,046	2.64	988	2.48
	INVESTMENTS:				
17	Gas Operations	(33)		11	
18	Other Investments	(18)		(17)	
19	Total Investments	(51)	(0.13)	(6)	(0.02)
20	Parent Company	(71)	(0.18)	(24)	(0.06)
21	**ON-GOING EARNINGS**	924	2.33	958	2.40

2005 Earnings Drivers

- *Retail sales increase due to return to normal weather and economic growth*
- *Lower Texas Supply due to sale of TCC assets; lower third-party Transmission margin partially offset by higher off-system sales prices*
- *Higher operating expense partially offset by lower interest expense; 2004 and 2005 Other Income and Deductions include return on Texas Stranded Cost of $109MM and $101MM, respectively*
- *Improved performance at HPL*
- *Lower interest due to debt retirements and assignment of debt to subsidiaries; 2004 includes unfavorable effect of enforcement provisions*

TCC Stranded Cost Carrying Charge

Carrying Cost Details:

Amount Recorded for 2002 & 2003	**$193 Million**
Amount Recorded for 2004	**$109 Million**
Estimated amount for 2005	**$101 Million**

Simplified Calculation:	
Initial Stranded Cost Base	$1.34 billion
@ debt component of the11.79% pre-tax cost of capital	8.12%
Amount (subject to limitation of actual TCC interest expense)	$109MM

Items included in stranded cost base include: Stranded Plant costs ($900 MM), Regulatory Assets($249 MM), ECOM ($483 MM), less Over-recovered fuel ($212 MM) and retail clawback ($61 MM) and Unrefunded excess earnings ($10 MM). Carrying costs are also included and compounded monthly.

Equity component recoverable once an order is received

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- ***Outcome of pending regulatory proceedings***
  - ***Texas, Oklahoma & Louisiana***
- ***Operations within PJM environment***
- ***Plant availability***
- ***Rising fuel costs***
- ***Weather (storm damage and effect on sales)***

Operating in a PJM Environment

- **Cost of generation to serve retail customers**
  - Retail customers continue to receive the benefits of AEP's lowest generation on an hourly basis

- **Off-system sales margin**
  - October-December was a learning period; results steadily improved each month
  - 4th quarter off-system sales margin was in line with budget

WE CONTINUE TO APPLY LESSONS LEARNED IN PJM TO MAXIMIZE THE VALUE OF OUR GENERATION FLEET

2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	960 *
Depreciation & Amortization	1,300	1,317
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	339
Total from Operations	**$ 2,597**	**$ 2,162**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,733)
Asset Sales	1,345	375 **
Other	(28)	43
Total from Investing	**$ (376)**	**$ (2,315)**
Cash from Financing:		
Common Equity	17	345 ***
Net Long Term Debt Issued/(Retired)	(1,829)	800
Preferred Stock Redeemed	(10)	-
Short Term Debt Change, Net	(400)	6
Common Dividends	(555)	(560)
Total from Financing	**$ (2,777)**	**$ 591**
Net Change in Cash	**$ (556)**	**$ 438**
Ending Cash Balance	**$ 420**	**$ 858**

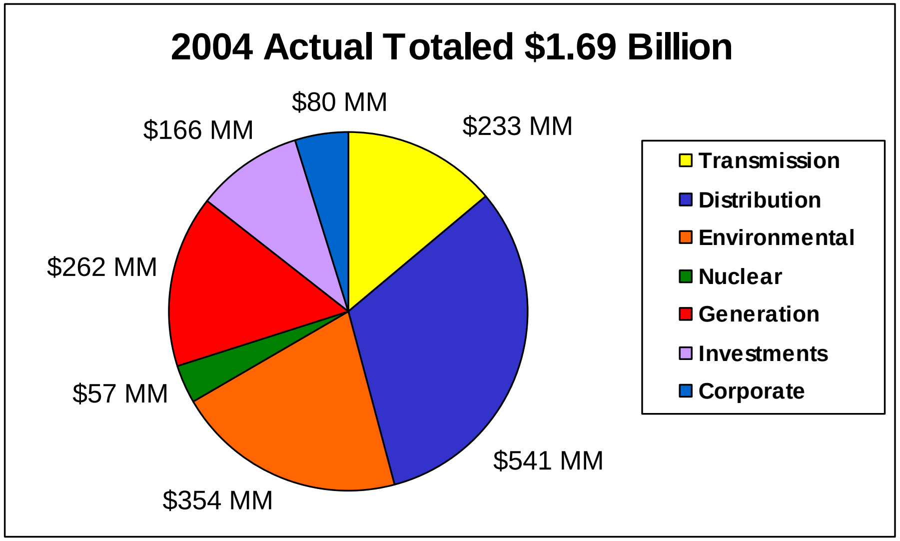
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 399 million shares outstanding**

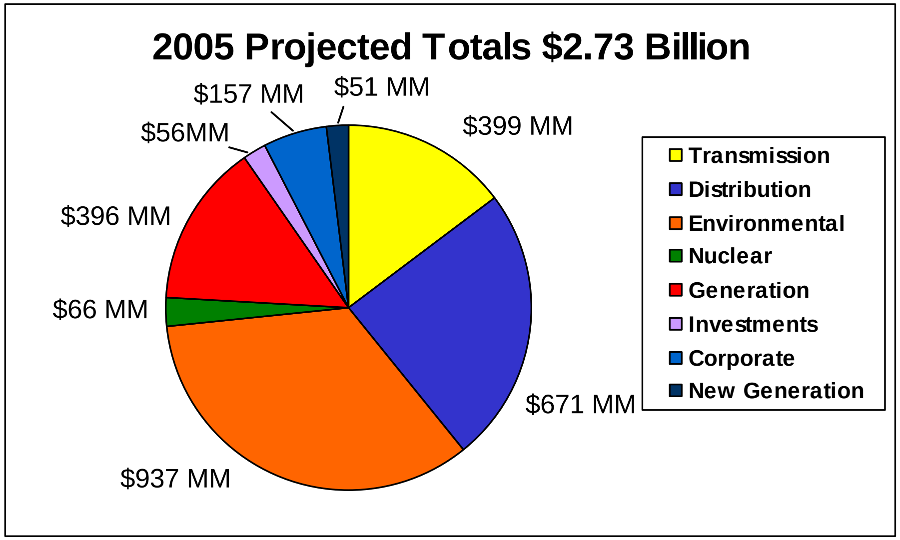
**** Includes STP & Oklaunion asset sales; receipt of $1 billion relating to HPL sale not reflected in this figure**

*****Equity units terms require issuance of $345MM common shares in August 2005**

MAINTAIN DEBT-TO-CAP BELOW < 60% IN 2005

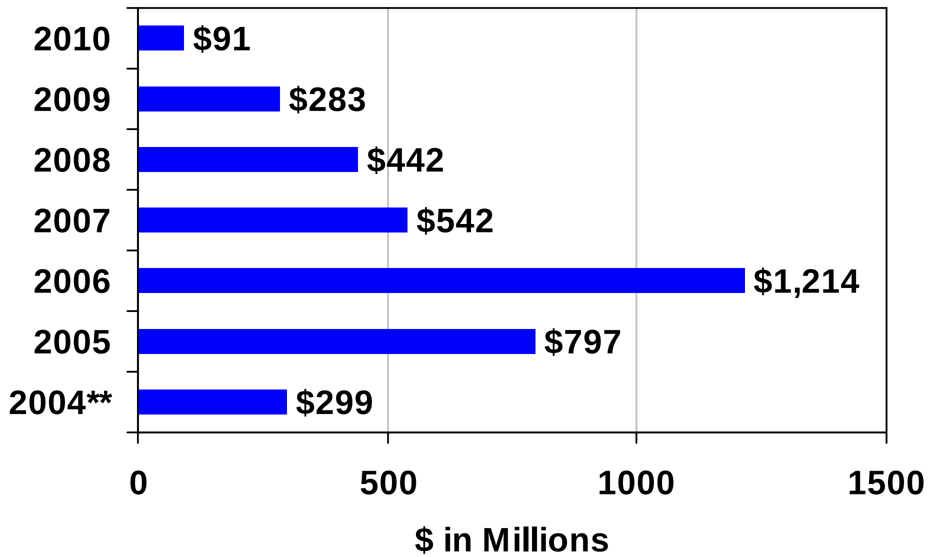
2005 Capex


2004 Actual Totaled $1.69 Billion
$80 MM
$166 MM
$233 MM
$262 MM
$57 MM
$541 MM
$354 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate


2005 Projected Totals $2.73 Billion
$157 MM
$51 MM
$56MM
$399 MM
$396 MM
$66 MM
$671 MM
$937 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

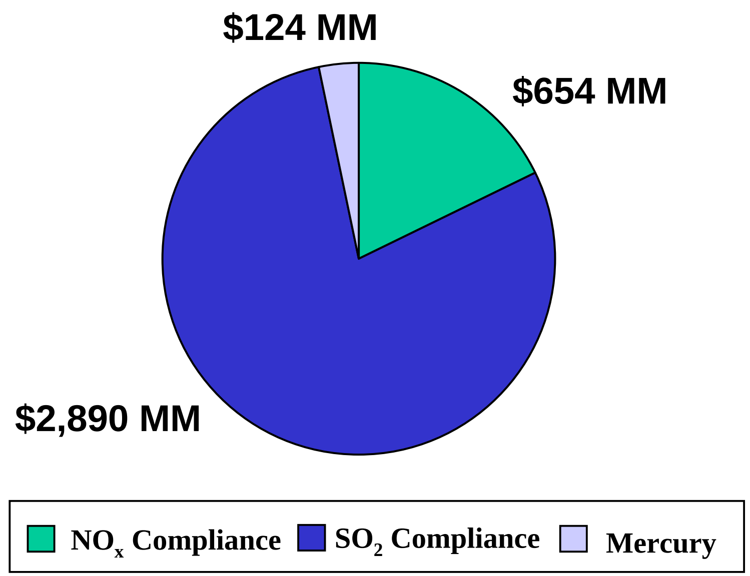
Environmental Investment: $3.7 Billion through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

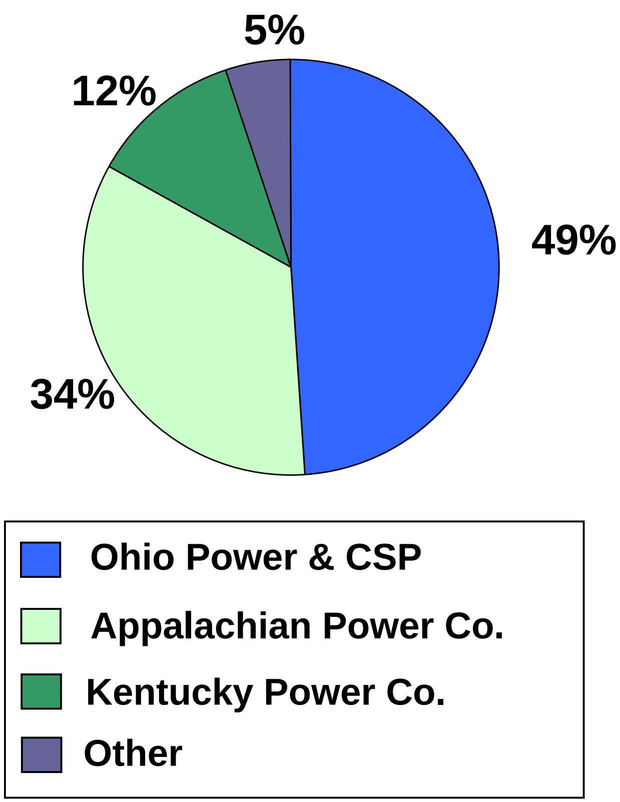
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- Ohio: 49% ($1.8 billion)
  - Rate stabilization plan increases at CSP – 3% and OP – 7%
- Virginia/West Virginia: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- Kentucky: 12% ($433 million)
  - Surcharge mechanism

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Income				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

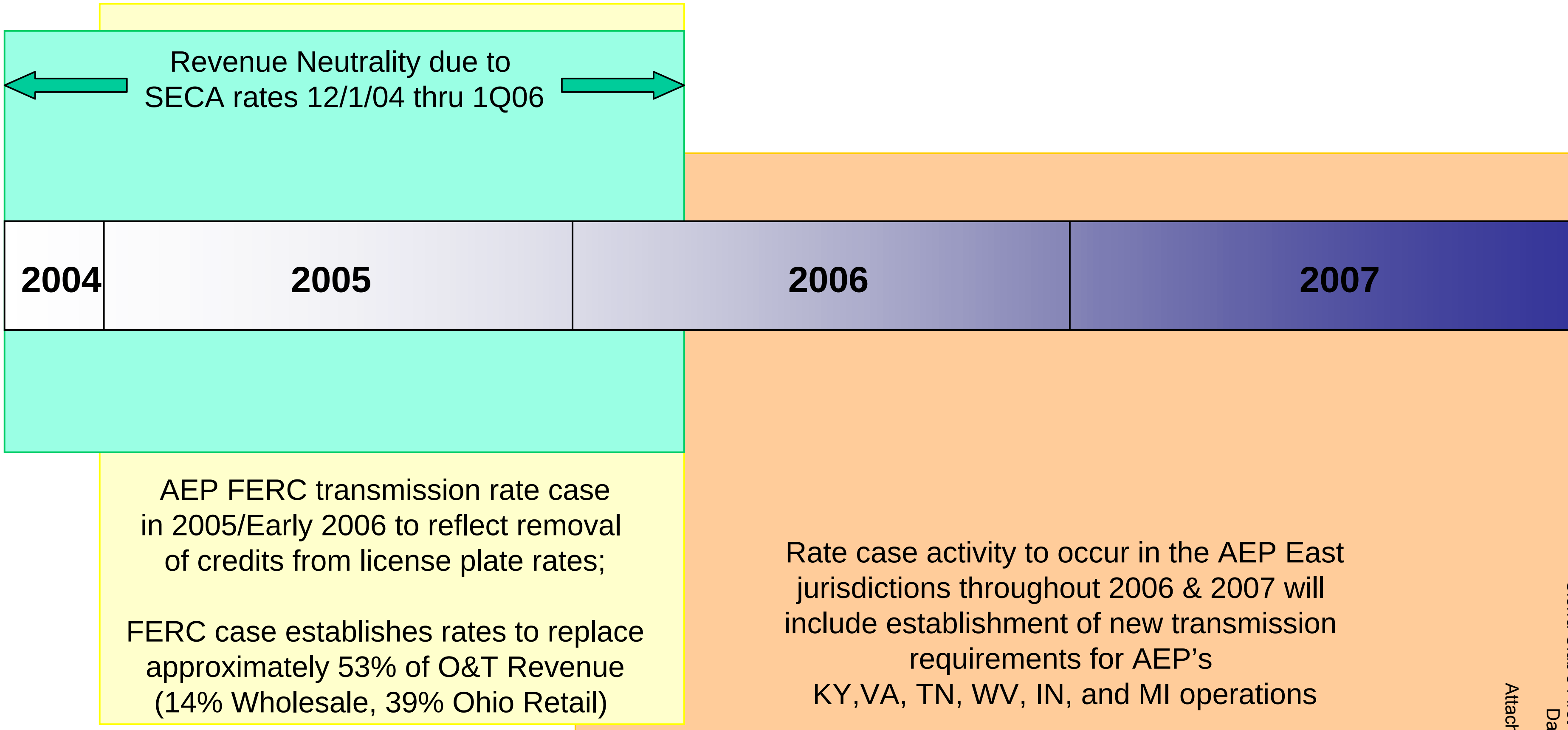
* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

Replacing Out & Through Transmission Revenues

2003 O&T Revenue Totaled $197MM



TIMING OF RATE CASE ACTIVITY TO BE A FUNCTION OF ENVIRONMENTAL & OTHER INVESTMENT RECOVERY

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
  - Louisiana Rate Review
- **Planned Regulatory Activity (2005-2007)**
  - FERC Transmission Rate Case
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

IGCC Investment

2005

- Secure regulatory cost recovery
- Finalize site selection
- Negotiate with suppliers

- **2005—2007:** Obtain permits and finalize engineering and procurement

- **2008—2009**: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

AEP

AMERICAN ELECTRIC POWER

2005 Guidance

		2004 Actual			2005 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,440 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,073)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(598)	
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15	Income Taxes		(489)			(538)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.48
	INVESTMENTS:						
17	Gas Operations		(33)			11	
18	Other Investments		(18)			(17)	
19	Total Investments		(51)	(0.13)		(6)	(0.02)
20	Parent Company		(71)	(0.18)		(24)	(0.06)
21	**ON-GOING EARNINGS**		924	2.33		958	2.40
	Shares Outstanding			396			399

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Transmission/Regulatory Conference

W New York—The Court
January 11, 2007

Hosts: Wall Street Access and
Berenson & Company

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

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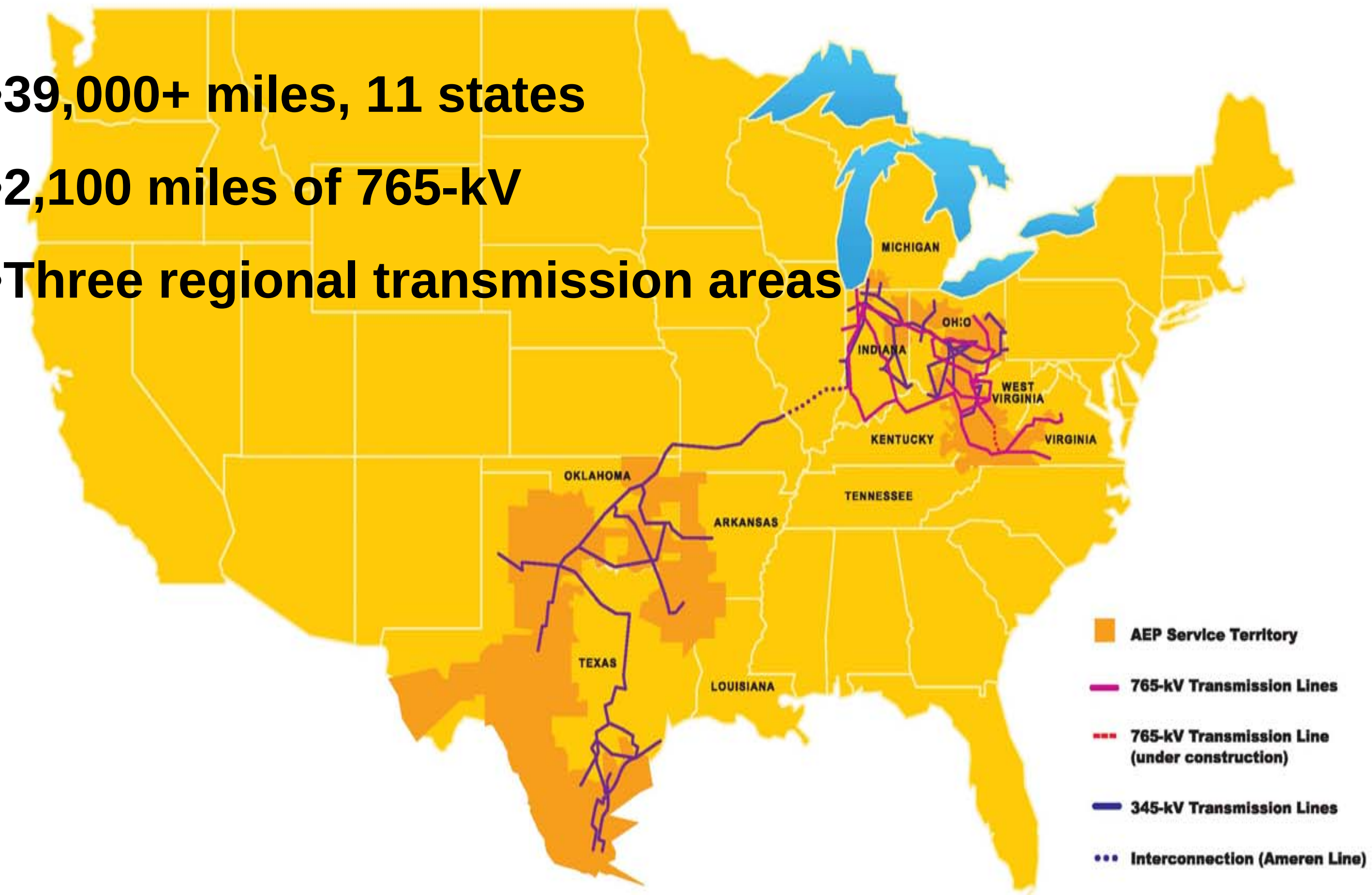
Calvin Crowder
Executive Director – Electric Transmission Texas

AEP's Transmission Grid Today

- 39,000+ miles, 11 states
- 2,100 miles of 765-kV
- Three regional transmission areas



100 Years of 'Firsts'

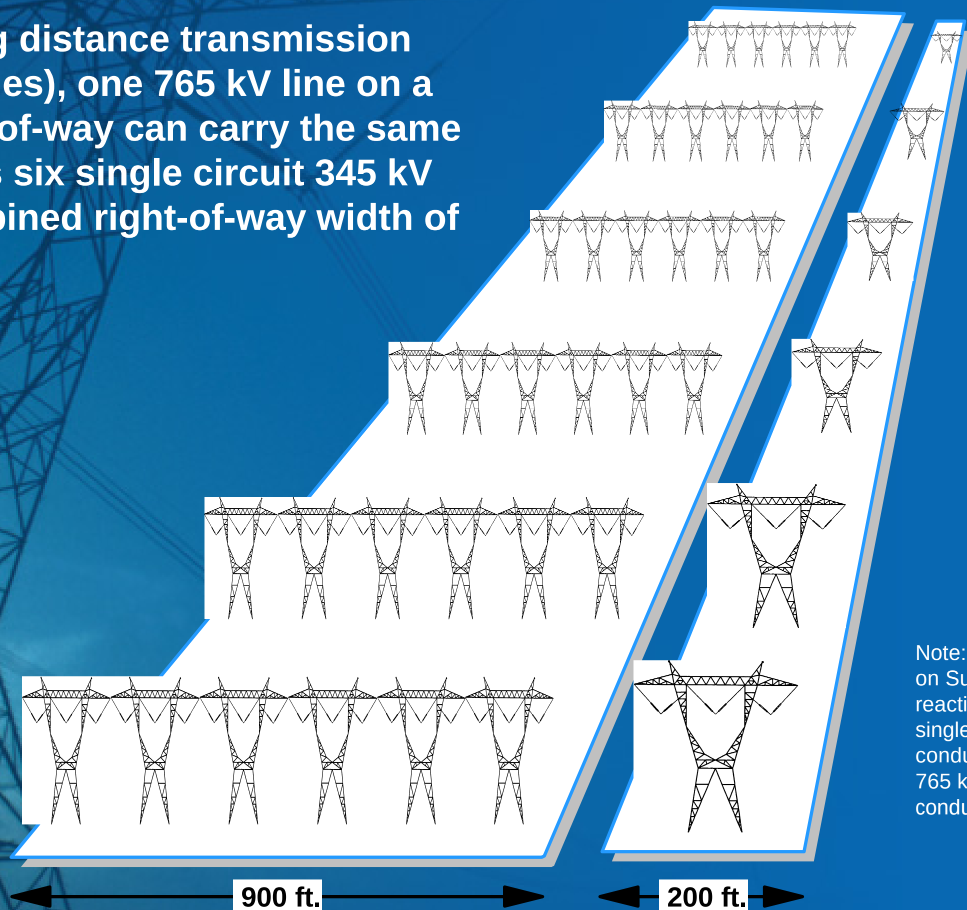
- 1917 – Developed the nation's first long-distance 138-kV transmission line, creating the idea of "coal by wire."
- 1953 – First 345-kV transmission line placed into commercial service.
- 1969 –1st 765-kV line in operation.
- 2006 – AEP's 765-kV Wyoming-Jacksons Ferry line is energized.

More “Firsts” for AEP

- I-765 – First major transmission proposal under EPAct 2005
- First Texas transco
- First 765-kV proposals to address Michigan constraints; Southwest Power Pool

765-kV: Highest Capacity, Most Efficient

Efficiency: For long distance transmission (longer than 100 miles), one 765 kV line on a 200-foot-wide right-of-way can carry the same amount of power as six single circuit 345 kV lines having a combined right-of-way width of 900 feet.



Cost Advantage: For equivalent capacity, the cost of 765-kV is 29% of the cost of 345-kV

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point), 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.

765-kV maximizes land use, providing greatest capacity increases with least land consumption.

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

~$1 billion in ERCOT

~$2 billion 765-kV study in Michigan

~$3 billion I-765 Project in PJM

~$3 billion project filed with SPP

*Note: ~$9 billion investment opportunity not included in current capital guidance forecasts with exception of ERCOT investment of $60MM in 2007 and $95MM 2008

Building the next US interstate system for enhanced reliability and market efficiency

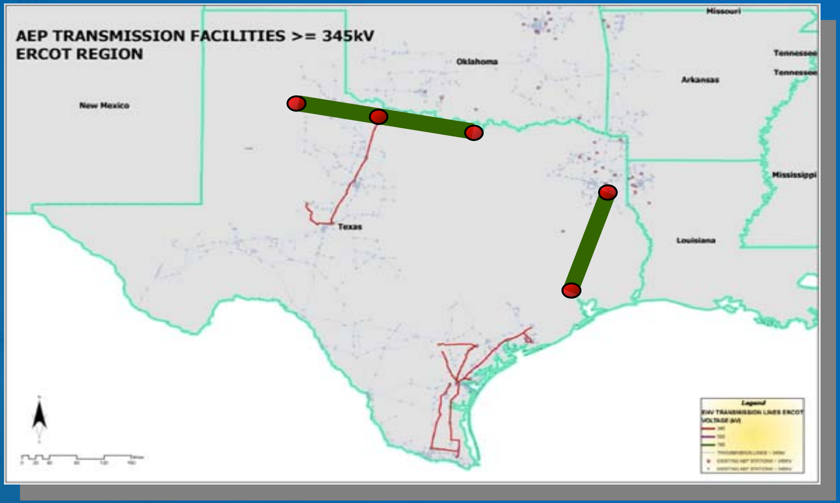
AEP AMERICAN ELECTRIC POWER

MIDAMERICAN ENERGY HOLDINGS COMPANY

- Jointly-owned utility company will design, construct and operate ERCOT transmission assets
- Up to $1B investment potential (before ownership division)
- Equity investment treatment for AEP
- AEP is also exploring 765-kV ERCOT transmission investment opportunity
  - 420 line miles
  - Up to 4000MW improved transfer capability*
  - Anticipated ERCOT rate impact 0.5mils/kWh
- This project may be considered by JV in future

*Line segment capability; ERCOT is a free-flowing network

- Execution of operating agreement 2007
- Establish JV entity second half 2007
- 2007 commercial operation for first JV projects



Conceptual ERCOT transmission project – proposed routes; not included in current JV plans

The first large-scale transmission venture in Texas

Benefits & Attraction of Texas Transco Joint Venture

Texas Transco Joint Venture Benefits

- Opportunity to grow ERCOT interest in a timely, resource-efficient manner
- Maximization of asset value
- Formation of strategic relationship that could permit growth beyond current AEP footprint

ERCOT Attraction

- Growing electric demand
- State's commitment to:
  - Wind generation development
  - Promotion of merchant generation
  - Relief of congestion
  - Facilitation of transmission planning in support of the Texas competitive electric market

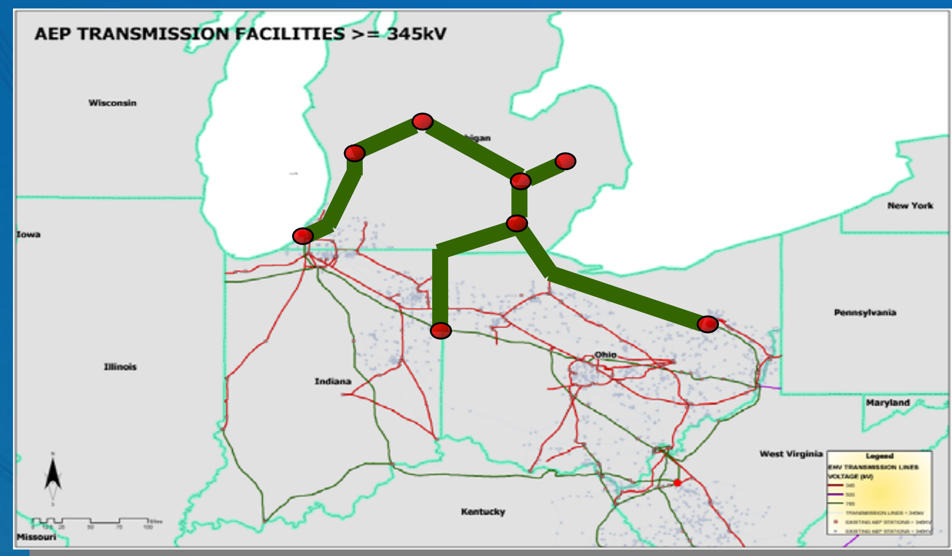
AEP Texas is uniquely positioned to develop substantial transmission to capture benefits of load growth and traditional & third-party generation

ERCOT Regulatory Certainty

- **High degree of regulatory certainty**
- **Predetermination of need for ERCOT-endorsed projects**
- **Streamlined annual review process reduces lag**
- **ROEs commensurate with other state regulatory returns**
  - **In Texas, current authorized return ranges from 10.125% to 11.25%**

ERCOT's predetermination of projects, streamlined annual review process & return opportunity make transmission investment attractive

- Agreement with ITC *Transmission* for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
  - 630 line miles
  - Over 5000MW improved transfer capability
  - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in early 2007



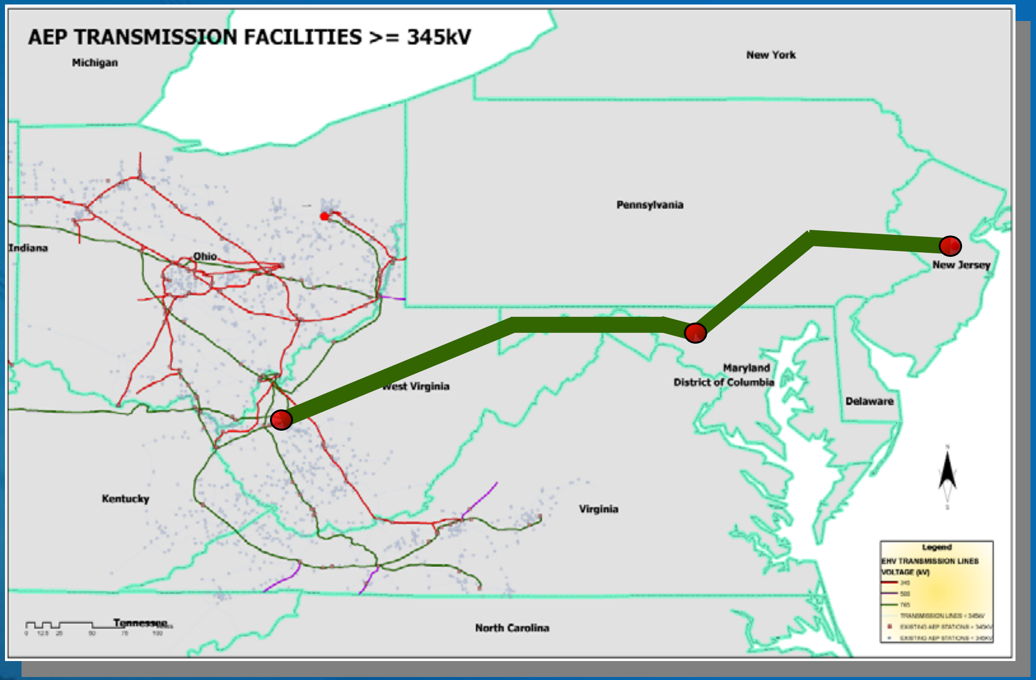
The ROW routes shown on this diagram are for illustrative purposes only and they may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints identified in MPSC studies

Cruise the I-765

- $3 billion investment
- 550 line miles
- 5000MW improved transfer capability
- Expected PJM rate impact 1mil/kWh
- 2014 estimated in-service date

Original line proposal connects AEP's Amos station to Allegheny Power's Doubs station in Maryland, and terminates at PSEG's Deans station in New Jersey. The final project will undoubtedly vary from the original proposal.



Our I-765 line will be the highest capacity, most reliable line in the United States

I-765 Benefits

- Improves eastern grid reliability, enhances Midwest – Mid-Atlantic power transfer capability by 5,000 MW
- Improves market efficiency with reduced congestion and lowers consumer costs by an estimated $1 billion annually in the east.
- Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.
- Provides AEP with rate base opportunity for transmission investment with ROE upside and other FERC incentives.
- Provides off-system sales and siting opportunity for AEP and other low-cost midwestern generation.

Expect investment to be shared with other transmission owners; incentive ratemaking approved

I-765 Regulatory Plan

- Filed plan with PJM (Jan. 31, 2006)
- Filed (Feb. 1, 2006) petition for FERC declaratory order; approved July 20, 2006
- Filed application for DOE early NIETC designation (Jan. 31, 2006); Final regulatory plan depends on PJM tariff
  - Total annual revenue requirement $450-500 million (1 mil/kWh)
  - If AEP's regional rate design proposal for PJM is successful at FERC, revenue requirement would be paid by parties utilizing the system and benefiting customers in PJM East

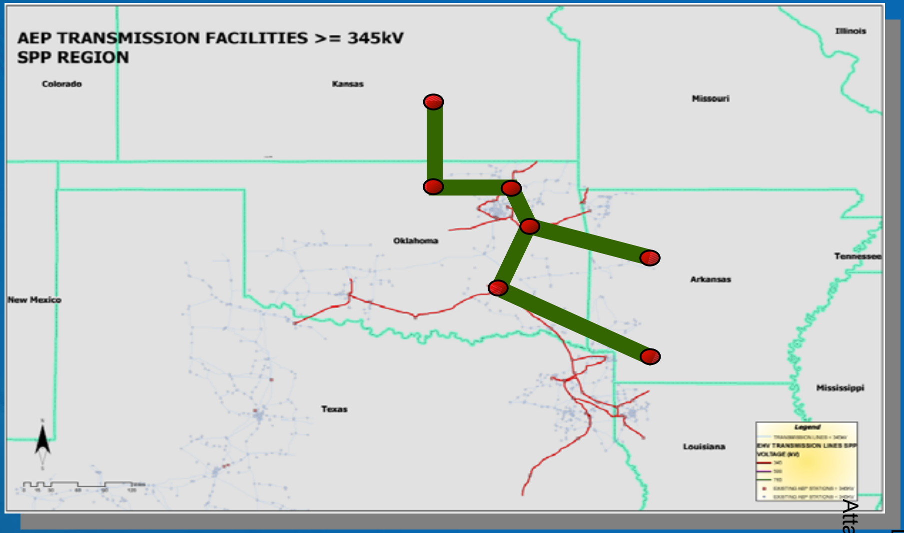
New technologies including six-conductor bundles and towers designed to blend into the scenery mitigate presence of 765-kV lines in a community

SPP Investment Potential

- June 2006 SPP requested proposal to address congestion, reliability & access for new generation
- July 2006 AEP submitted proposal:
  - Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
  - Investment ~$3 billion
    - ~4000MW improved transfer capability
    - Anticipated rate impact 2mils/kWh

Next steps:

- SPP conducting studies to evaluate proposals
- AEP providing technical assistance and support



Significant opportunity for 765-kV transmission in SPP

FERC Promotes Transmission Investment with Order 679

- **Issued July 20, 2006 to enable EPAct 2005**
- **Key provisions include:**
  - **Return on equity at the high end of the zone of reasonableness**
  - **Return on CWIP**
  - **Return on premium for acquired assets**
  - **Full recovery of construction costs and costs of cancelled or abandoned facilities due to factors beyond the utility's control**

AEP supports a national interstate grid – our core transmission strength

State Actions to Support Transmission Development

- **Regional planning-supporting role in RTO area**
- **Siting-first course of action**
- **Wholesale transmission pricing-provides regional benefits**
- **Retail cost recovery**

AEP Transmission Vision & Mission

- Maintain our position as the largest transmission company in the United States
- Maintain our leadership in technical innovation of transmission systems
- Set the standards for transmission safety, efficiency, and reliability
- Provide for robust market competition - benefiting customers by de-bottlenecking the U.S. transmission grid
- Reduce the need for new generation by facilitating the optimal economic dispatch of existing generation assets
- Increase earnings for AEP shareholders

Maintaining our leadership position and setting the standards

Wall Street Utility Group Meeting

New York City

September 21, 2006

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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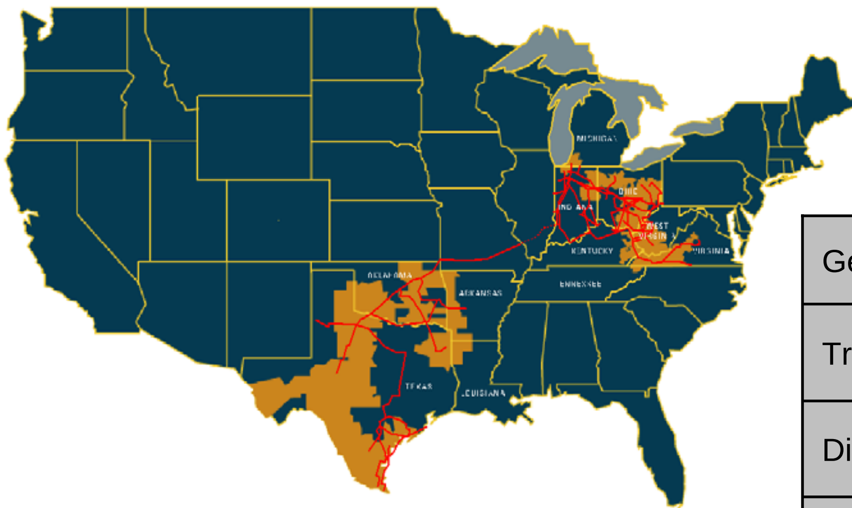
Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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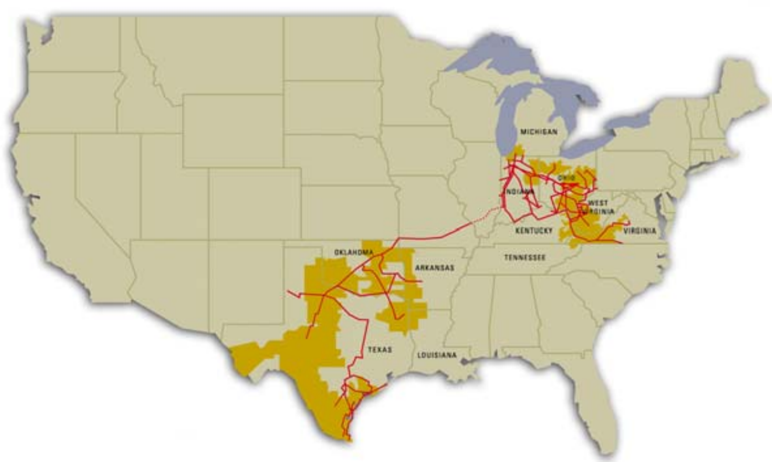
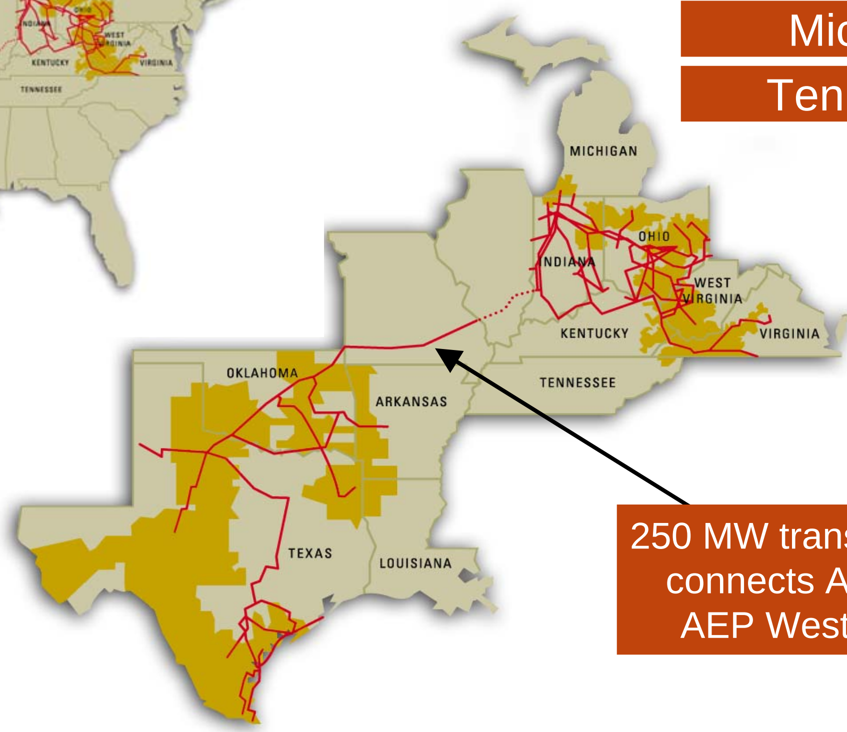
Where We Operate





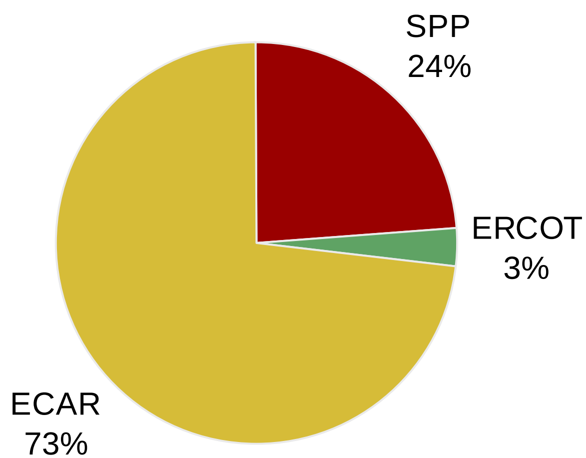
Ohio
Indiana
West Virginia
Virginia
Kentucky
Michigan
Tennessee

Oklahoma
Texas
Louisiana
Arkansas

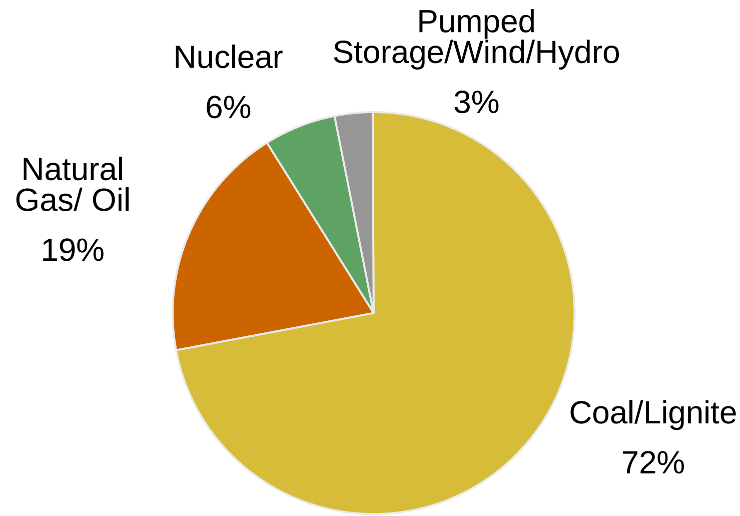
250 MW transmission line connects AEP East & AEP West territories

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

Operating Statistics

Commercial Availability Factor

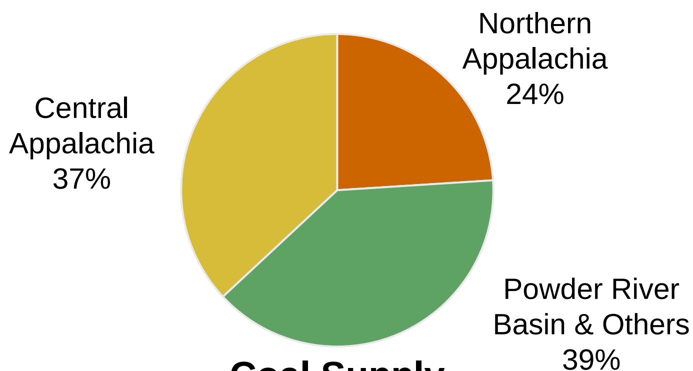
2004	85.24%
2005	84.50%

Capacity Factor

2004	62.06%
2005	62.53%

Coal Procurement

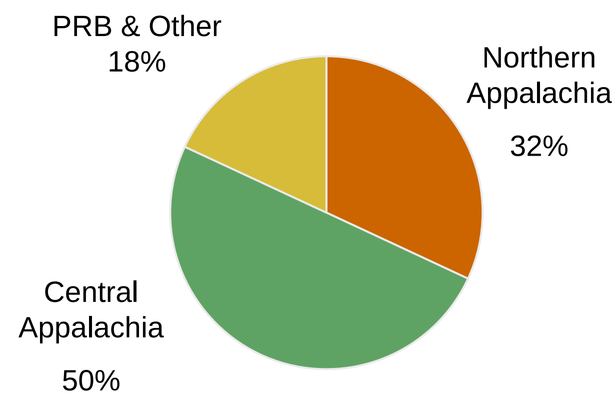
Total AEP System



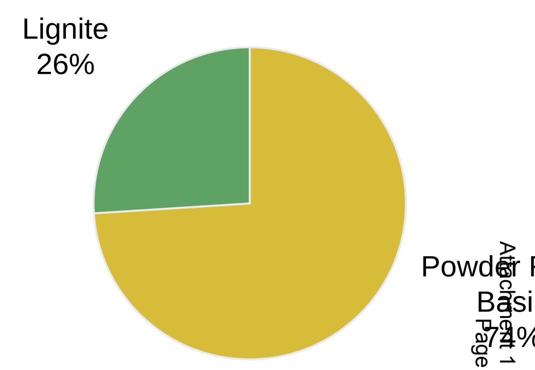
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 95%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

AEP Eastern System



AEP Western System



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IGCC – Significant Role in New Generation Plan

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in 2007

SWEPCO

- May 31, 2006- Announced plans to build $1.7 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling 320 MW at Tontitown, AR and combined-cycle gas plant totaling 480 MW at Arsenal Hill
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – expected SWEPCO investment will be approx. 75%
- Commercial operation dates between 2007 and 2011

PSO RFPs

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

IGCC IS NOT A SILVER BULLET; HAVING OTHER TECHNOLOGY OPTIONS AVAILABLE IS STRATEGICALLY IMPORTANT.

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

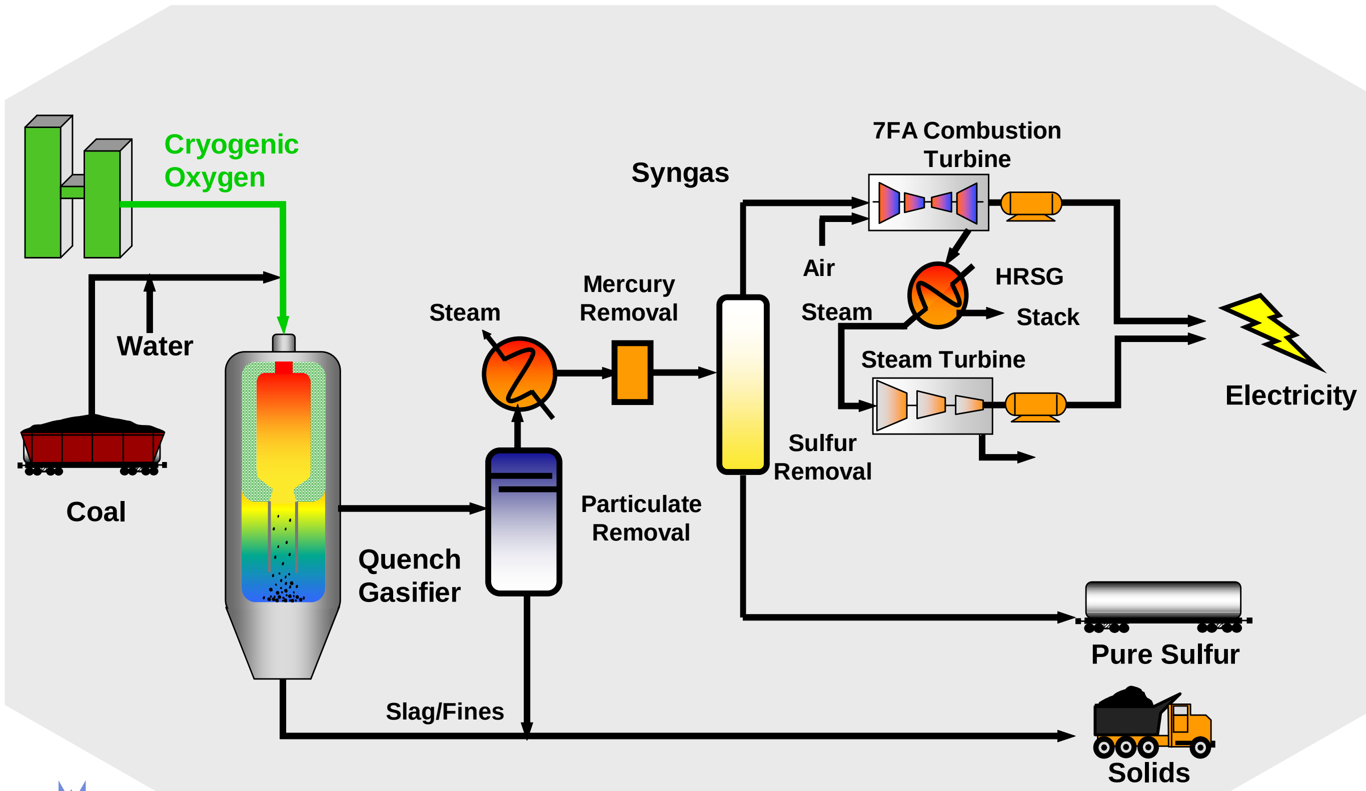
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8700**	**8600**	**7200**
Total Plant Cost (EPC) ($/kW)	**1700**	**1900**	**480**
Production Cost ($/MWh)	**17**	**16**	**57**
Cost of Electricity, without CO_2 Capture ($/MWh)	**58**	**63**	**90**
Estimated Cost of Electricity, with CO_2 Capture ($/MWh)	**94**	**87**	**137**

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO_2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Regulatory Activity

Ohio IGCC Activity

March 18, 2005: CSP and OPCO filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant if built in Ohio.

West Virginia IGCC Activity

January 11, 2006: Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

IGCC Regulatory Activity in Ohio

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 filing – following completion of FEED study
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2010:

- Construct and start-up plant

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Appendix

IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMITTING PROCESS WILL TAKE 1 – 2 YEARS

The Wall Street Utility Group

New York City

January 13, 2005

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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Mike Morris

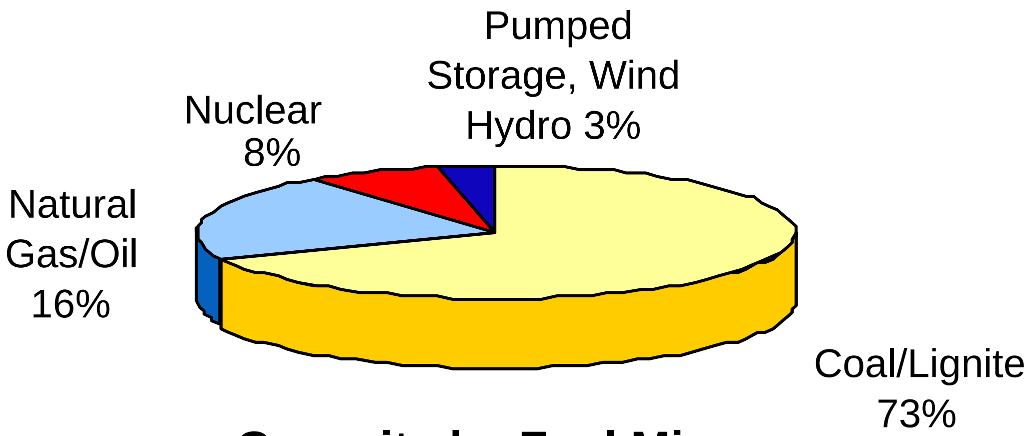
Chairman, President & Chief Executive Officer

Strength & Scale in Assets & Operations

Generation	36,000 MW capacity
Transmission	39,039 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL INVESTMENT OPPORTUNITY

Fuel Mix & Operating Statistics



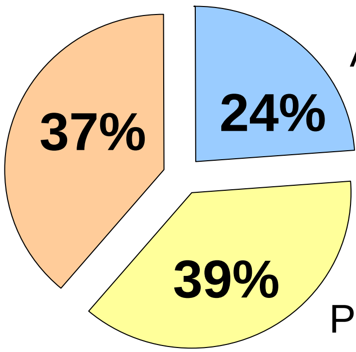
Capacity by Fuel Mix

- 36,000 MW domestic capacity
- 85% system availability factor 9 months YTD 2004
- 63% system capacity factor 9 months YTD 2004

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Coal Procurement

AEP SYSTEM

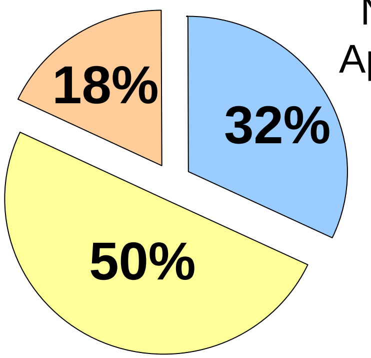


Coal Supply

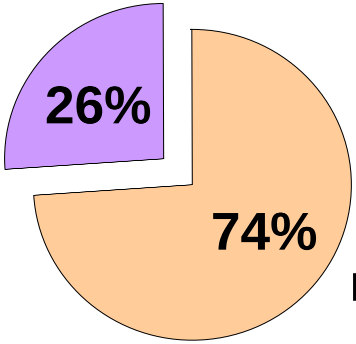
(on average)

- Purchase 75 MM tons per year
- Ave. delivered price ~ $28.50/ton in 2004
- Approximately 96% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

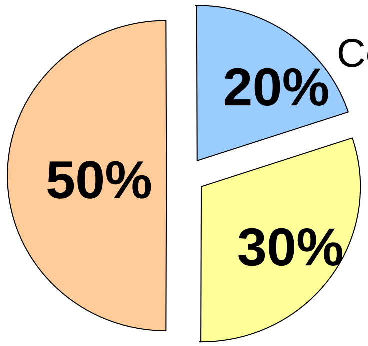


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM

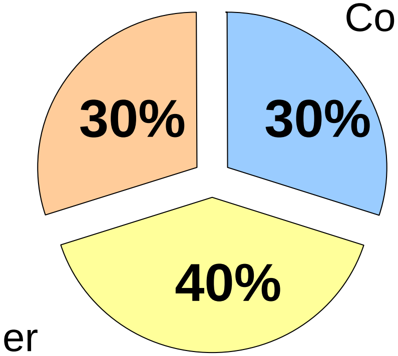


Fuel Cost Recovery
(on average)

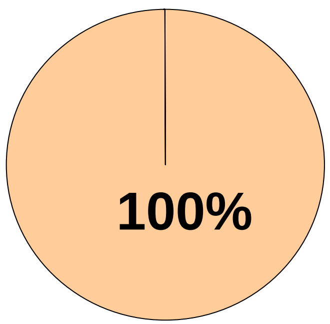
- Fuel recovery varies by jurisdiction
- 70% of fuel costs is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST:
AP-VA, I&M, KGP, KP
AEP WEST:
PSO, SWEPCO

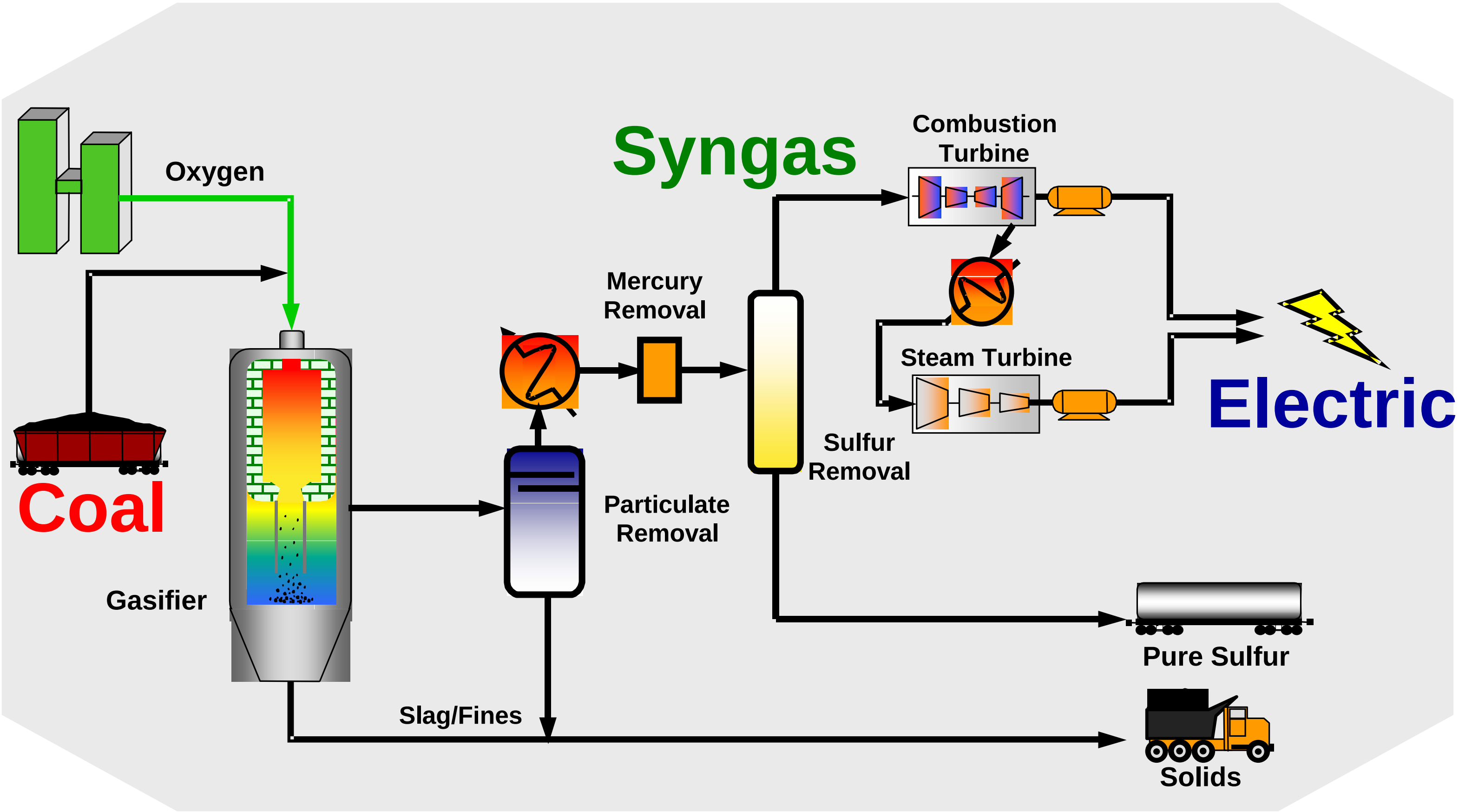
EASTERN SYSTEM



WESTERN SYSTEM



IGCC Technology



Source: US Department of Energy

Source: US Department of Energy

Comparison of Technology Options

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8500	7000
EPC Cost* ($/kW)	1200	1450	400
Total Plant cost** ($/kW)	1450	1750	470
Variable Production Cost*** ($/MWh)	16	14	37

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $37/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

IDENTIFIED AND RANKED THE TOP 10 SITES IN OUR EASTERN STATES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

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Next Steps

<u>2005</u>

- Secure regulatory cost recovery
- Finalize site selection
- Negotiate with suppliers

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental Investment

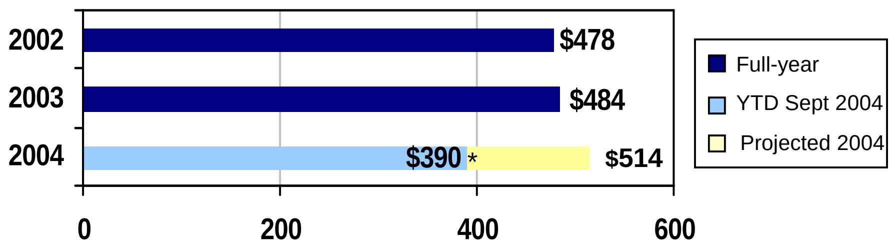
Plants under consideration:

Install Scrubbers:	Install SCRs:
<u>2006 - 2010</u>	<u>2005 - 2007</u>
Mitchell	Muskingum
Mountaineer	Amos
Cardinal	Mitchell
Amos	
Big Sandy	
Muskingum	
Conesville	

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh

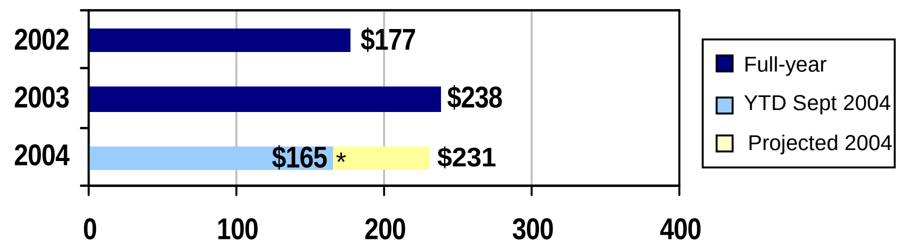
Energy Delivery Investment

Distribution Capital Expenditures



$ in millions

Transmission Capital Expenditures



$ in millions

Operating Company	Transmission & Distribution 2002	2003	2004 **
AEP Ohio	$ 212	$ 181	$ 148
Appalachian Power	130	147	142
Indiana Michigan Power	85	69	50
Kentucky Power	29	27	19
AEP Texas	92	140	93
Public Service Co. of Oklahoma	52	70	53
Southwestern Electric Power	55	88	50
	$ 655	$ 722	$ 555

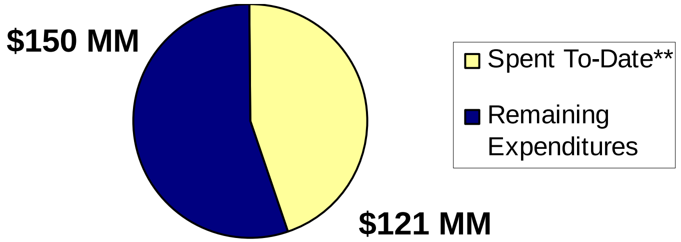
Notes:

* Represents capital expenditures for 9 months ended September 2004; FY 2004 Projected expenditures: $231 for transmission & $514MM for distribution.

** Represents capital expenditures through September 30, 2004

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Managing the Regulatory Process

- **Current Regulatory Activity**
  - Ohio Rate Stabilization Plan
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - PSO Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - FERC Transmission Rate Case
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Ohio: Rate Stabilization Plan

- **RSP Summary**
  - 7% annual increase for OP, max 11% with rate case
  - 3% annual increase for CSP, max 7% with rate case
  - Option to remove 5% generation discount
  - Recover carrying costs on environmental capex and RTO charges

PUCO order to be issued January 2005

AEP'S RATES WILL REMAIN AMONG THE LOWEST IN THE STATE

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Texas: Wires Rate Case & Stranded Cost Recovery

- **TCC Wires Rate Case**
  - Show cause filing made 11/03 seeking $66.5MM increase
  - Settlement with staff filed on 4/30/04 for 10.125% ROE which adjusts increase amount to $41MM
  - On 11/16/04 ALJ recommended $51MM rate reduction following remand of 7/1/04 $31MM rate reduction recommendation
  - Final order expected January 2005

- **Texas Stranded Cost Recovery**
  - Assets sold & ROFR exercised on Oklaunion & STP
  - Closing expected 1H05
  - True-up to begin following asset sale closure
    - Generation & Carrying Cost recovered via Securitization
    - ECOM less Fuel & Retail Clawback recovered via CTC

CASH PROCEEDS FROM SECURITIZATION TO BE USED TO PAY DOWN DEBT & FUND CAP EX

Oklahoma: General Rate Case

- **PSO Rate Case**
  - $41MM rate increase requested based on 12% ROE
  - Intervenor testimony filed January 4:

	Revenue Recommendation	
Party	**$ in MM (reduction)**	**ROE**
OCC Staff	(14.9)	10.11%
Attorney General *	(24)	9.63%
Industrial Customers	(35.6)	9.3%

*Net reduction of $8.7MM (24MM less $15.3 allowed for incremental tree-trimming)

HEARINGS SCHEDULED TO BEGIN MARCH 1, 2005

Replacing Out & Through Transmission Revenues

2003 O&T Revenue Totaled $197MM

Revenue Neutrality due to SECA rates 12/1/04 thru 1Q06

2004	2005	2006	2007

AEP FERC transmission rate case in 2005/Early 2006 to reflect removal of credits from license plate rates;

FERC case establishes rates to replace approximately 53% of O&T Revenue (14% Wholesale, 39% Ohio Retail)

Rate case activity to occur in the AEP East jurisdictions throughout 2006 & 2007 will include establishment of new transmission requirements for AEP's KY,VA, TN, WV, IN, and MI operations

TIMING OF RATE CASE ACTIVITY TO BE A FUNCTION OF ENVIRONMENTAL & OTHER INVESTMENT RECOVERY

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Positive dividend outlook
- Stable credit profile

American Electric Power

Transmission Initiatives Update/Overview

Wall Street Access / Berenson & Company
Westin Times Square - New York
January 10, 2008

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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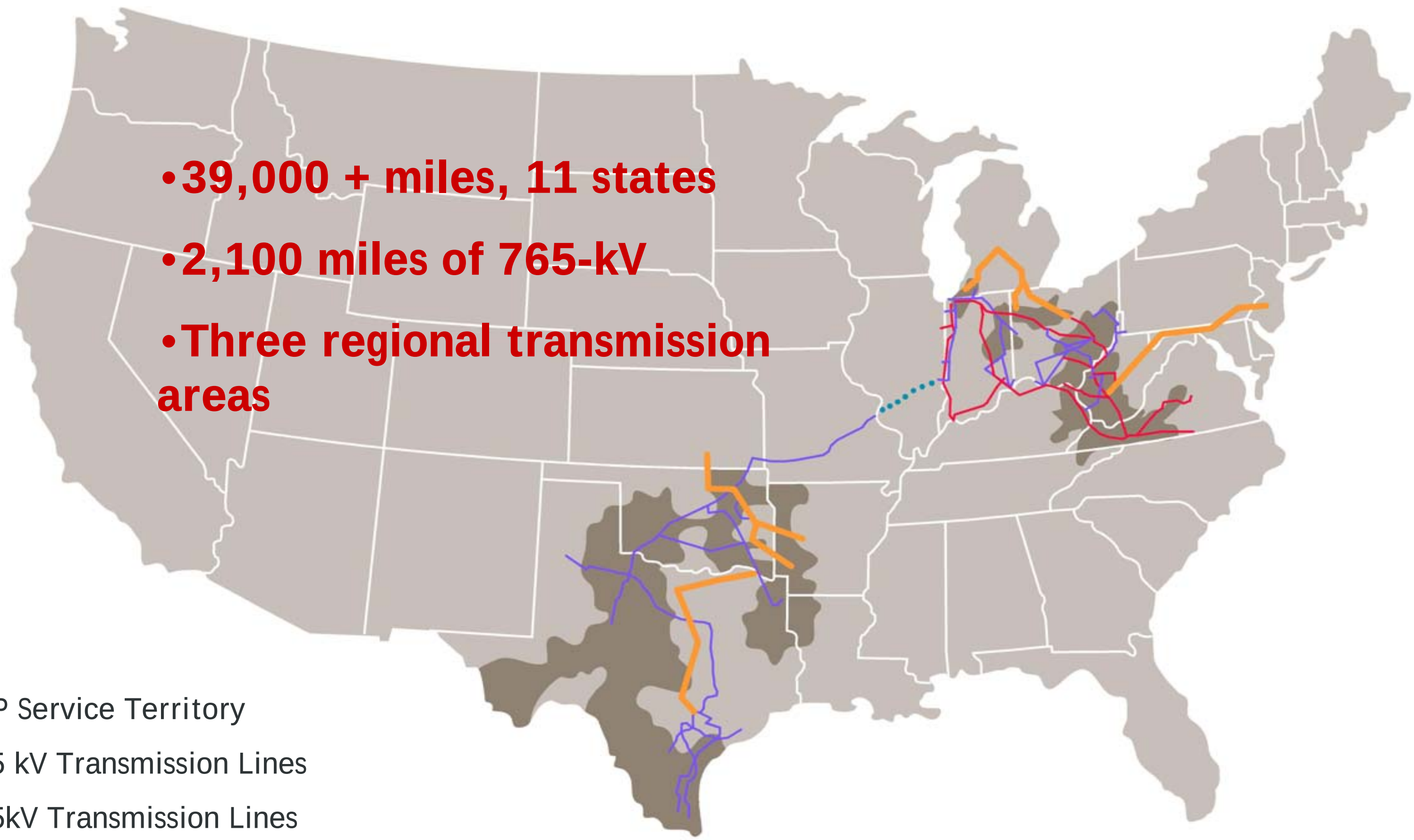
Transmission Conference

Calvin Crowder

President – Electric Transmission Texas, LLC

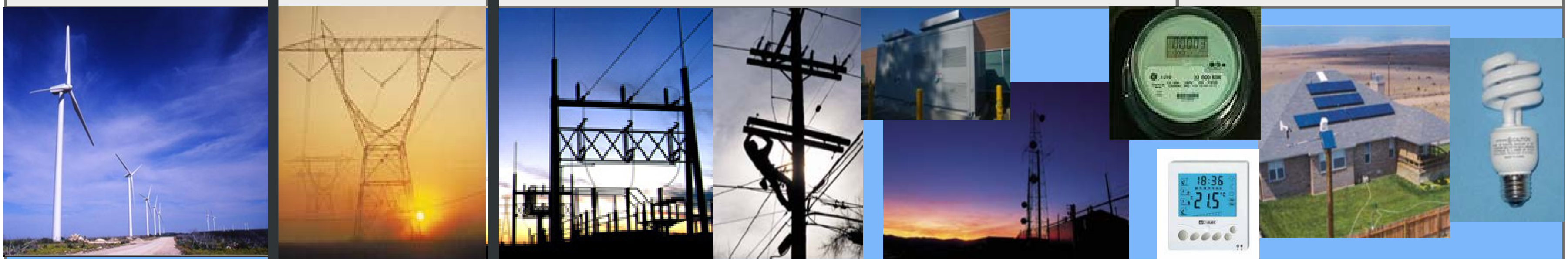
The AEP Footprint

- **39,000 + miles, 11 states**
- **2,100 miles of 765-kV**
- **Three regional transmission areas**



AEP Service Territory
765 kV Transmission Lines
345kV Transmission Lines
Interconnection (Ameren Line)
New 765kV Development

Vision for Sustainability



Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

Existing generation and transmission control systems	**GridSMART**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Goals for U.S. Transmission Development

- AEP advocates high-efficiency 'EHV" transmission systems should serve as the foundation for new transmission investment to provide the electrical equivalent of the interstate highway system.
- EHV systems provide benefits not provided by lower voltage solutions including:
  - Enabling a more sustainable supply portfolio through renewable energy and technological advancements
  - Advancing national security by enhancing reliability, removing barriers to supply options and allowing greater flexibility in fuel diversity
  - Extending benefits to large geographic regions, transcending state and regional borders
  - Providing for longer term solutions and postponing new lower voltage fixes
  - Enhancing operational performance and providing flexibility by off loading the overburdened underlying system

A national interstate transmission system is within our reach in a reasonable period of time.

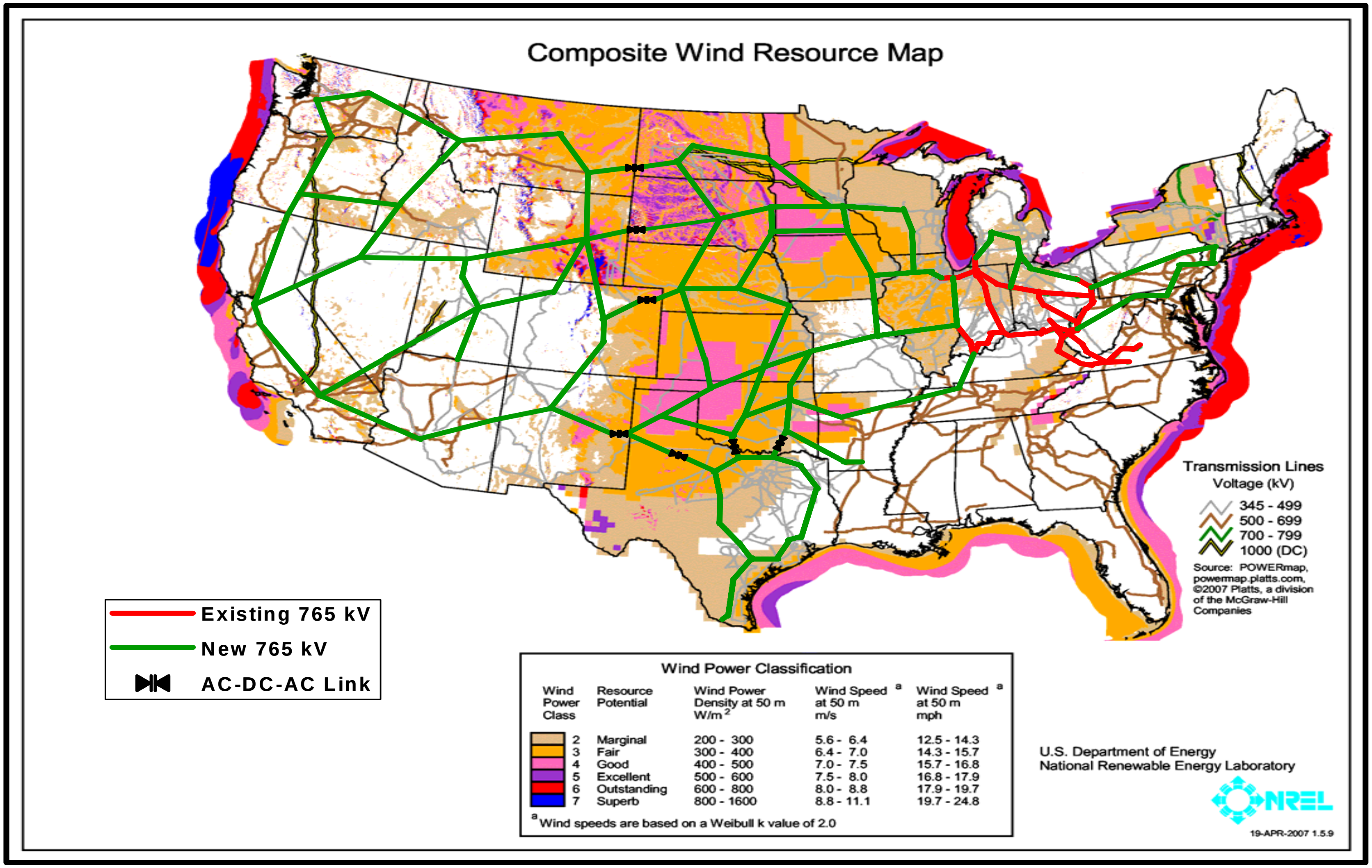
AEP Transmission Key Investment Strategies

- Cultivate a climate that encourages and promotes the development of an interstate transmission system
- Collaborate with likeminded, qualified investment partners to build needed "interstate projects" in a timely manner
- Create sustainable investment opportunities for AEP shareholders
- Leverage AEP's extra-high voltage (EHV) expertise and existing infrastructure
- Continue our present top-tier performance in safety & health, operations and reliability

AEP is well positioned to be a key player in the development of tomorrow's interstate transmission system.

Building an Interstate Transmission System

AEP/AWEA: Cultivating a Vision for the Future



Building an Interstate Transmission System

Federal Focus Needed

- **Federal action/incentives to build:**
  - Return on equity at the high end of the zone of reasonableness
  - Return on CWIP
  - Return on premium for acquired assets
  - Full recovery of construction costs and costs of cancelled or abandoned facilities due to factors beyond the utility's control
- **Advancement of federal policies to encourage EHV investments:**
  - NIETC designations and backstop siting
  - Targeted policies to advance EHV solutions to promote "National Solutions" and a sustainable national energy policy
  - Cost allocation mechanisms which promote the identification and development of "National Solutions"

As the electric grid evolves, so must our policies for planning, allocating and recovering the cost of transmission investments.

Building an Interstate Transmission System

Regional and State Focus Needed

- **Regional actions needed:**
  - Adoption of long term planning horizons for EHV upgrades
  - Recognition of the value of inter-regional EHV assets
  - Cost allocation mechanisms which promote EHV transmission growth
  - Timely inter-regional planning processes
- **State actions needed:**
  - Support for RTO findings and determinations of need
  - Expedited siting processes
  - Pass through of transmission rates
  - Recognition of the value of regional and inter-regional assets

A true interstate transmission system requires a national vision and policies that promote those investments.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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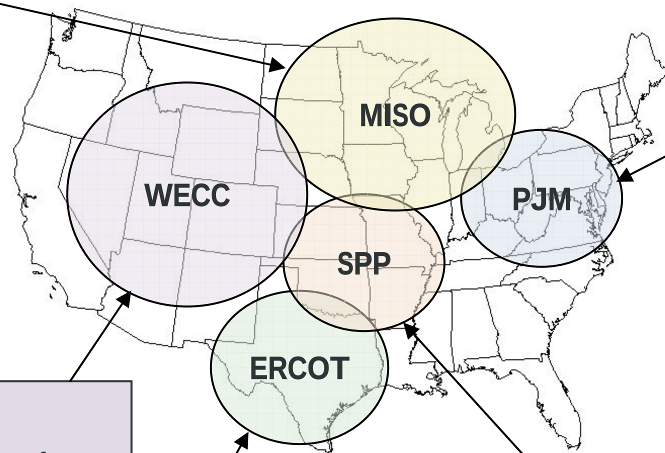
Transmission Investment Opportunities

The investigation of opportunities needs to be mindful of regional drivers

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues



PJM

Congestion will be reduced and reliability will be increased

WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

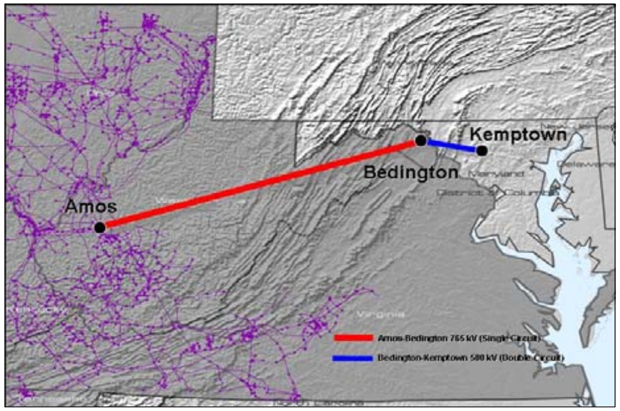
ERCOT

Load growth and access to wind resources driving transmission investment

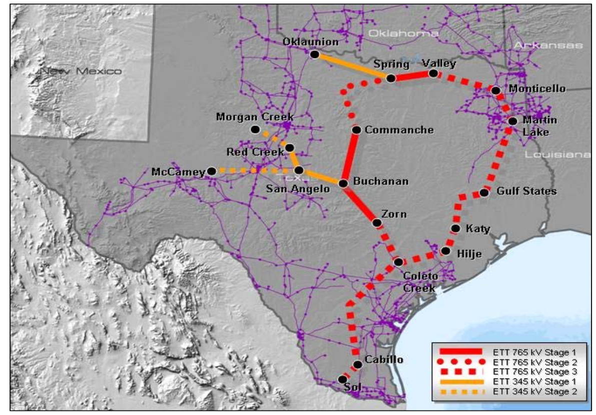
I-765™ Transmission: Investment Opportunities

Transmission Conference

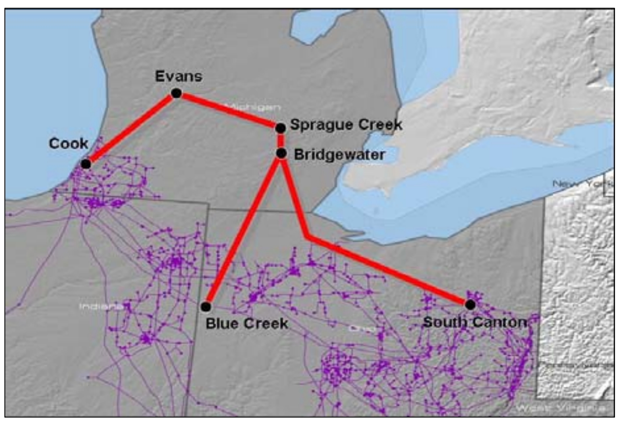
AEP is Advancing the Development of a National Interstate Today



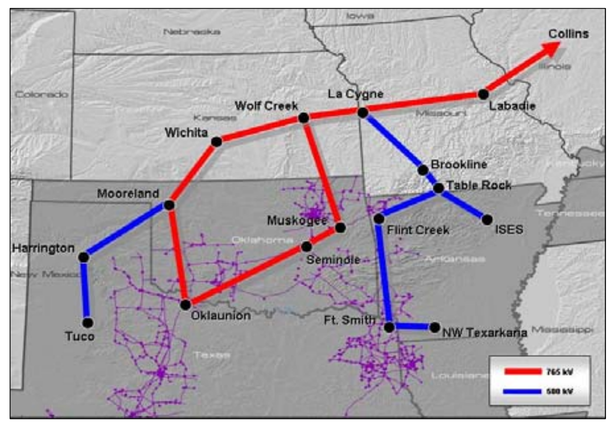
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

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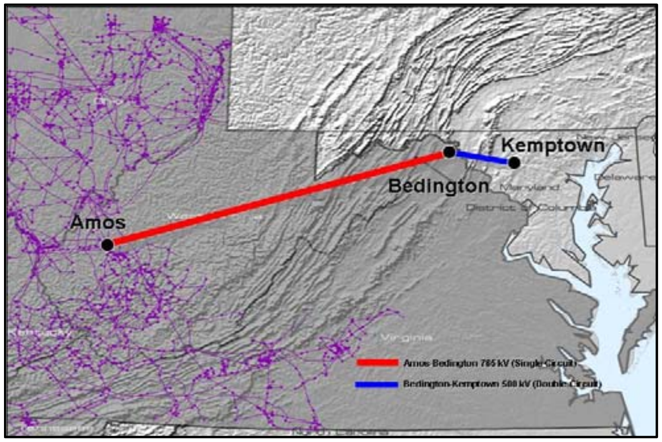
I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, 14.3% ROE, recovery of all costs incurred prior to the time rates go into effect, and recovery of all prudently incurred development and construction costs if the project is abandoned.*
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012

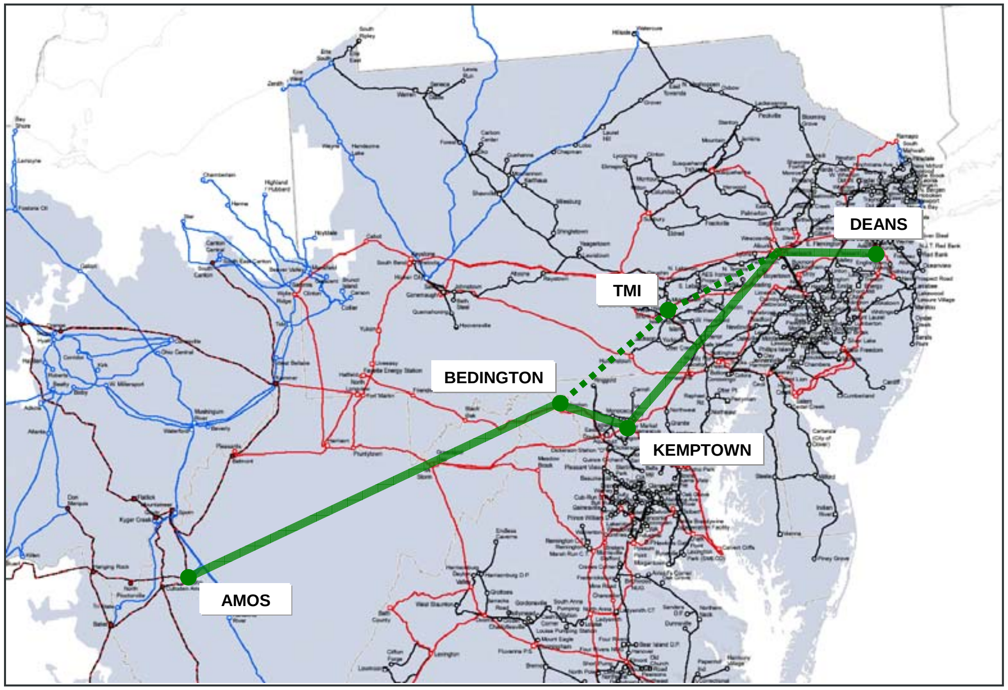


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in PJM East

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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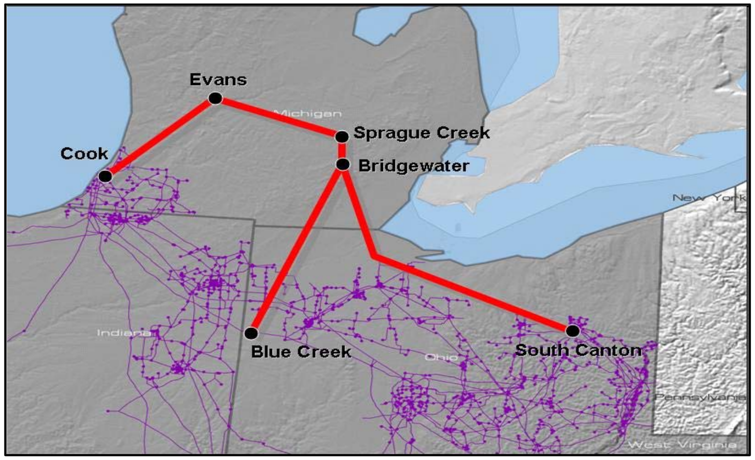
I-765^{TM} Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - \$2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015



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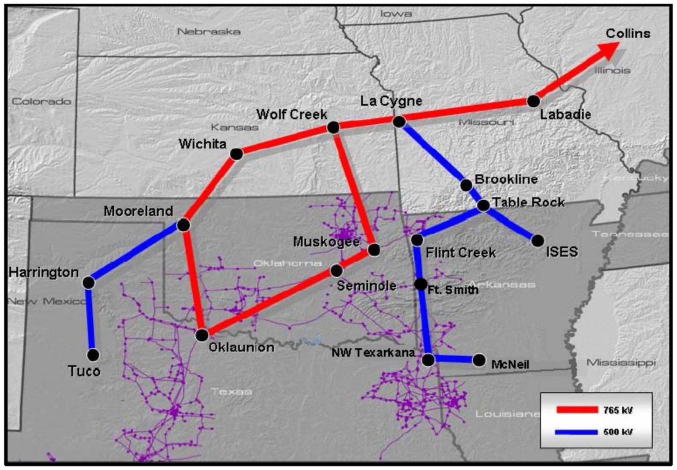
I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation – Completed 3Q 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



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Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by the Joint Venture would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity
  - Services provided by AEP
  - Investment opportunities can be offered by either partner
- *Transaction Status*
  - Participation Agreement signed Jan. 9, 2007
  - PUCT Recently Approved:
    - ROE of 9.96%
    - Establishment of Transmission Utility Status
    - Transfer of $70 million assets from AEP Texas to ETT
  - FERC approval for asset transfer received April 20, 2007
  - Closed JV with Mid-American Energy Holdings Company on December 21, 2007
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects to ETT Q2 2008

Benefits & Attraction of ETT Investments

JV Benefits

- Opportunity to grow ERCOT interest in a timely, resource-efficient manner
- Maximization of asset value
- Formation of strategic relationship that could permit growth beyond current footprint

ERCOT Attraction

- Growing electric demand
- State's commitment to:
  - Wind generation
  - Promotion of merchant generation
  - Relief of congestion
  - Facilitation of transmission planning in support of the Texas competitive market

ETT is uniquely positioned to develop substantial transmission to capture the benefits of load growth.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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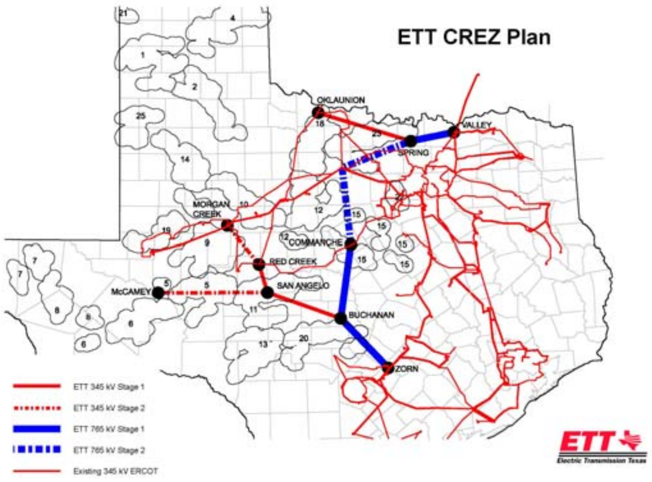
Texas CREZ Update

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **CREZ Approval Stages (*current expectation*)**
  - Stage 1 – Interim order designating power regions – Q3 2007
  - Stage 2 – CREZ Transmission Optimization Study – Q1/Q2 2008
  - Stage 3 – PUCT selection of transmission construction designees – Q2 2009*
  - Stage 4 – CCN development and submission – Q2 2010*
  - Stage 5 – CCN approval – Q4 2010 (if 6 months)*
  - Stage 6 – Construction (TBD)

*If PUC adopts TSP Rule



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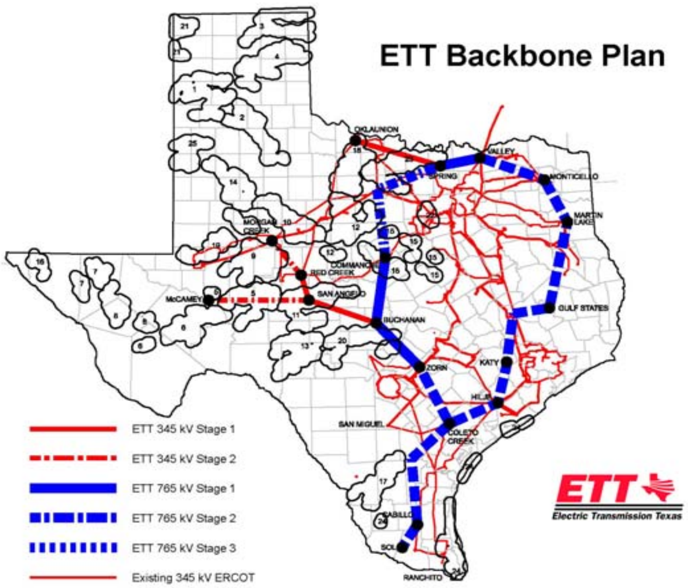
CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to harvest up to 10GW wind generation
  - Build a robust transmission system for ERCOT Texas
  - $1.5 billion investment Phase 1 – 2012*
  - $1.5 billion investment Phase 2 – 2015*

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



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* Before ownership division.

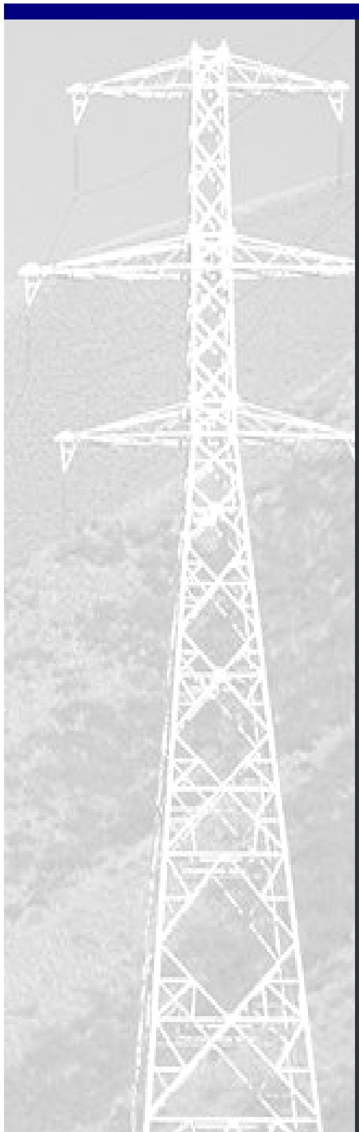
Summary

AEP will continue to take a leadership position by:

- Creating a vision of the future for transmission investment on a national level.
- Cultivating a climate for growth in transmission investment at the regional and national level.
- Pursuing a two pronged investment strategy focused on:
  - Significant "base plan" investment in traditional service territory
  - Pursuit of strategic alliances for off system investments which provide significant financial growth for AEP shareholders

"If your actions inspire others to dream more, learn more, do more and become more, you are a leader." – John Quincy Adams

AEP AMERICAN® ELECTRIC POWER



2Q08 Earnings Release Presentation

July 31, 2008

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Second Quarter 2008 Highlights

- 2Q08 GAAP/Ongoing Earnings $0.70 per share; 2008 YTD GAAP Earnings $2.13 per share; 2008 YTD Ongoing $1.72 per share
- Reaffirming 2008 Ongoing Earnings Guidance Range of $3.10 to $3.30 per share
- Ohio ESP Filing Highlights
- New Generation-Turk Plant
- Transmission Update

Anticipated Outcome of Ohio Filing Keeps Us in Our Targeted Earnings Range

2Q08 Performance

American Electric Power
Financial Results for 2nd Quarter 2008 Actual vs 2nd Quarter 2007 Actual

		2007 Actual		2008 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	453		528	
2	Ohio Companies	610		551	
3	West Regulated Integrated Utilities	229		257	
4	Texas Wires	131		134	
5	Off-System Sales	203		243	
6	Transmission Revenue - 3rd Party	71		82	
7	Other Operating Revenue	148		144	
8	**Utility Gross Margin**	1,845		1,939	
9	Operations & Maintenance	(770)		(840)	
10	Depreciation & Amortization	(365)		(365)	
11	Taxes Other than Income Taxes	(187)		(188)	
12	Interest Exp & Preferred Dividend	(207)		(218)	
13	Other Income & Deductions	27		49	
14	Income Taxes	(105)		(114)	
15	**Utility Operations On-Going Earnings**	238	0.60	263	0.66
16	**Transmission Operations On-Going Earnings**	-	0.00	-	0.00
	NON-UTILITY OPERATIONS:				
17	MEMCO	7	0.02	3	0.01
18	Generation & Marketing	15	0.03	26	0.06
19	**Parent & Other On-Going Earnings**	(3)	(0.01)	(12)	(0.03)
20	**ON-GOING EARNINGS**	257	0.64	280	0.70

For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q08 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief $77MM; (APCo, I&M, Ohio RSPs, PSO & Texas)*
  - *Positive load growth including new customers, $23MM*
  - *Positive impact due to $37MM true-up to VA order booked in 2Q07*
  - *Offset by $42MM lower fuel margins & $16MM increased OSS sharing*
  - *Unfavorable weather impact of $0.03 ($20MM) versus prior year and no impact versus normal*
- *Off-System Sales (line 5):*
  - *Favorable due to higher prices and lower internal load*
- *Operations & Maintenance (line 9):*
  - *Higher expenditures in all categories due to maintenance outages, reliability and employee benefits*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 30.2% in 2008 and 30.6% in 2007*
- *MEMCO decreased due to increased diesel expense and flooding on rivers*
- *Generation & Marketing increased due to plant optimization & favorable contracts*
- *Parent decreased due to higher interest expense*

2Q08 YTD Performance

American Electric Power

Financial Results for YTD June 2008 Actual vs YTD June 2007 Actual

		2007 Actual		2008 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	1,057		1,122	
2	Ohio Companies	1,213		1,247	
3	West Regulated Integrated Utilities	429		480	
4	Texas Wires	244		256	
5	Off-System Sales	384		464	
6	Transmission Revenue - 3rd Party	143		162	
7	Other Operating Revenue	289		289	
8	**Utility Gross Margin**	3,759		4,020	
9	Operations & Maintenance	(1,598)		(1,587)	
10	Depreciation & Amortization	(748)		(720)	
11	Taxes Other than Income Taxes	(371)		(382)	
12	Interest Exp & Preferred Dividend	(386)		(428)	
13	Other Income & Deductions	66		90	
14	Income Taxes	(231)		(321)	
15	**Utility Operations On-Going Earnings**	491	1.24	672	1.67
16	**Transmission Operations On-Going Earnings**	-	0.00	1	0.00
	NON-UTILITY OPERATIONS:				
17	MEMCO	22	0.06	10	0.03
18	Generation & Marketing	14	0.03	27	0.07
19	Parent & Other On-Going Earnings	1	-	(20)	(0.05)
20	**ON-GOING EARNINGS**	528	1.33	690	1.72

For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2Q08 YTD Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief $152MM; (APCo, Ohio RSPs, PSO & Texas Wires)*
  - *Positive load growth including new customers; $77MM*
  - *Positive impact due to 2007 unfavorable true-up of VA order; $37MM*
  - *Offset by $42MM higher fuel costs and $32MM increased OSS sharing*
  - *Unfavorable weather impact of $0.04 ($23MM) versus prior year and favorable $0.01 ($3MM) versus normal;*
- *Off-System Sales (line 5):*
  - *Favorable due to higher prices and volumes (higher plant availability & lower internal load)*
- *Operations & Maintenance (line 9):*
  - *Decrease primarily due to deferral of 2007 PSO ice storms in 1Q2008, offset by increases for maintenance, reliability & employee benefits*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates on variable-rate debt*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.3% in 2008 and 32.0% in 2007*
- *MEMCO unfavorable due to river flooding & diesel costs*
- *Generation & Marketing favorable due to plant optimization & favorable contract*
- *Parent unfavorable due to higher interest expense*

2008 Cash Flow

($ millions)	2007	2008
Operating Activities		
Net Income -- Reported	**$ 451**	**$ 854**
Discontinued Operations	(2)	(1)
Continuing Earnings	**449**	**853**
Depreciation, Amortization & Deferred Taxes	783	1,123
Changes in Components of Working Capital	(288)	(253)
Extraordinary Loss	79	-
Other Assets & Liabilities	(54)	(526)
Cash Flows From Operating Activities	**969**	**1,197**
Investing Activities		
Capital Expenditures	(1,823)	(1,608)
Proceeds on Sale of Assets	74	69
Change in Other Temporary Cash Investments, net	101	114
Other Investing, net	(479)	(220)
Cash Flows Used for Investing Activities	**(2,127)**	**(1,645)**
Financing Activities		
Common Shares Issued, net	90	71
Long-term Debt Issuances, net	874	732
Short-term Debt Increase/(Decrease), net	420	45
Other Financing	(44)	(31)
Dividends Paid	(311)	(329)
Cash Flows From Financing Activities	**1,029**	**488**
Cash From Continuing Operations	**$ (129)**	**$ 40**
Beginning Cash & Cash Equivalent Balances	301	178
Ending Cash & Cash Equivalent Balances	**$ 172**	**$ 218**

2008 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by G & A type items
- Changes in other assets and liabilities largely driven by changes in unrecovered fuel.

Investing Activities

- Cash outlay of $1.6B for 2008 YTD capital investment.
- 2008 asset sale proceeds relate to miscellaneous utility property sales; 2007 asset sale proceeds primarily relate to Centrica sharing $20MM and TCC's sale of its share of Oklaunion $46MM.
- Change in 2008 Other Investing primarily relates to the purchase of nuclear fuel of $100MM and $35MM contributions to nuclear trust & the purchase of MEMCO barges.

Financing Activities

- 2008 common share issuances of $71MM primarily due to issuances through the dividend reinvestment program.
- Changes in long and short term debt driven by capital funding requirements.

Capitalization

Capital Structure	Actual 12/31/2007			Actual 6/30/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,994	-	14,994	15,753	-	15,753
Short-term Debt	660	-	660	705	-	705
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	10,079	10,079	-	10,630	10,630
Total Capitalization per Balance Sheet	**15,654**	**10,140**	**25,794**	**16,458**	**10,691**	**27,149**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***60.6%***	***39.4%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
Capital and Operating Leases	1,522	-	1,522	1,484	-	1,484
Securitization Bonds	(2,257)	-	(2,257)	(2,183)	-	(2,183)
Receivables Securitization	507	-	507	765	-	765
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(262)	-	(262)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	-
Total Adjusted Capitalization	**15,148**	**10,140**	**25,288**	**16,104**	**10,849**	**26,953**
% of Adjusted Capitalization	***59.9%***	***40.1%***	***100.0%***	***59.7%***	***40.3%***	***100.0%***

Adjusted debt-to-cap of 59.7% at 6/30/08

Questions

2Q08 Earnings

	$ millions			Earnings Per Share		
	2nd Qtr 2007	2nd Qtr 2008	Change	2nd Qtr 2007	2nd Qtr 2008	Change
Utility Operations	238	263	25	0.60	0.66	0.06
Transmission Operations	0	0	0	0.00	0.00	0.00
Non-Utility Operations	22	29	7	0.05	0.07	0.02
Parent & Other	(3)	(12)	(9)	(0.01)	(0.03)	(0.02)
AEP On-Going Earnings	257	280	23	0.64	0.70	0.06
Special Items	(77)	1	78	(0.19)	0.00	0.19
Reported Earnings (GAAP)	180	281	101	0.45	0.70	0.25

Quarterly Performance Comparison

American Electric Power

Financial Results for 2nd Quarter 2008 Actual vs 2nd Quarter 2007 Actual

		2007 Performance Driver	2007 Actual ($ millions)	2007 Actual EPS	2008 Performance Driver	2008 Actual ($ millions)	2008 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	16,845 GWh @ $ 26.9 /MWhr =	453		16,881 GWh @ $ 31.3 /MWhr =	528	
2	Ohio Companies	12,030 GWh @ $ 50.7 /MWhr =	610		12,606 GWh @ $ 43.7 /MWhr =	551	
3	West Regulated Integrated Utilities	10,150 GWh @ $ 22.5 /MWhr =	229		10,339 GWh @ $ 24.9 /MWhr =	257	
4	Texas Wires	6,746 GWh @ $ 19.3 /MWhr =	131		7,132 GWh @ $ 18.8 /MWhr =	134	
5	Off-System Sales	7,168 GWh @ $ 28.3 /MWhr =	203		7,499 GWh @ $ 32.4 /MWhr =	243	
6	Transmission Revenue - 3rd Party		71			82	
7	Other Operating Revenue		148			144	
8	Utility Gross Margin		1,845			1,939	
9	Operations & Maintenance		(770)			(840)	
10	Depreciation & Amortization		(365)			(365)	
11	Taxes Other than Income Taxes		(187)			(188)	
12	Interest Exp & Preferred Dividend		(207)			(218)	
13	Other Income & Deductions		27			49	
14	Income Taxes		(105)			(114)	
15	**Utility Operations On-Going Earnings**		238	0.60		263	0.66
	NON-UTILITY OPERATIONS:						
16	MEMCO		7	0.02		3	0.01
17	Generation & Marketing		15	0.03		26	0.06
18	Parent & Other On-Going Earnings		(3)	(0.01)		(12)	(0.03)
19	**ON-GOING EARNINGS**		257	0.64		280	0.70

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

June YTD Earnings

	June YTD 2007	June YTD 2008	Change	June YTD 2007	June YTD 2008	Change
Utility Operations	491	672	181	1.24	1.67	0.43
Transmission Operations	0	1	1	0.00	0.00	0.00
Non-Utility Operations	36	37	1	0.09	0.10	0.01
Parent & Other	1	(20)	(21)	0.00	(0.05)	(0.05)
AEP On-Going Earnings	528	690	162	1.33	1.72	0.39
Special Items	(77)	164	241	(0.20)	0.41	0.61
Reported Earnings (GAAP)	451	854	403	1.13	2.13	1.00

June YTD Performance Comparison

American Electric Power

Financial Results for YTD June 2008 Actual vs YTD June 2007 Actual

		2007 Actual			2008 Actual		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	36,057 GWh @ $ 29.3 /MWhr =	1,057		36,423 GWh @ $ 30.8 /MWhr =	1,122	
2	Ohio Companies	24,615 GWh @ $ 49.3 /MWhr =	1,213		26,507 GWh @ $ 47.0 /MWhr =	1,247	
3	West Regulated Integrated Utilities	19,825 GWh @ $ 21.6 /MWhr =	429		20,208 GWh @ $ 23.7 /MWhr =	480	
4	Texas Wires	12,577 GWh @ $ 19.4 /MWhr =	244		12,955 GWh @ $ 19.8 /MWhr =	256	
5	Off-System Sales	12,832 GWh @ $ 29.9 /MWhr =	384		15,658 GWh @ $ 29.6 /MWhr =	464	
6	Transmission Revenue - 3rd Party		143			162	
7	Other Operating Revenue		289			289	
8	**Utility Gross Margin**		3,759			4,020	
9	Operations & Maintenance		(1,598)			(1,587)	
10	Depreciation & Amortization		(748)			(720)	
11	Taxes Other than Income Taxes		(371)			(382)	
12	Interest Exp & Preferred Dividend		(386)			(428)	
13	Other Income & Deductions		66			90	
14	Income Taxes		(231)			(321)	
15	**Utility Operations On-Going Earnings**		491	1.24		672	1.67
16	**Transmission Operations On-Going Earnings**		-	0.00		1	0.00
	NON-UTILITY OPERATIONS:						
17	MEMCO		22	0.06		10	0.03
18	Generation & Marketing		14	0.03		27	0.07
21	Parent & Other On-Going Earnings		1	-		(20)	(0.05)
22	**ON-GOING EARNINGS**		528	1.33		690	1.72

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Detailed Ongoing Earnings Guidance

2007 Actual: $3.00

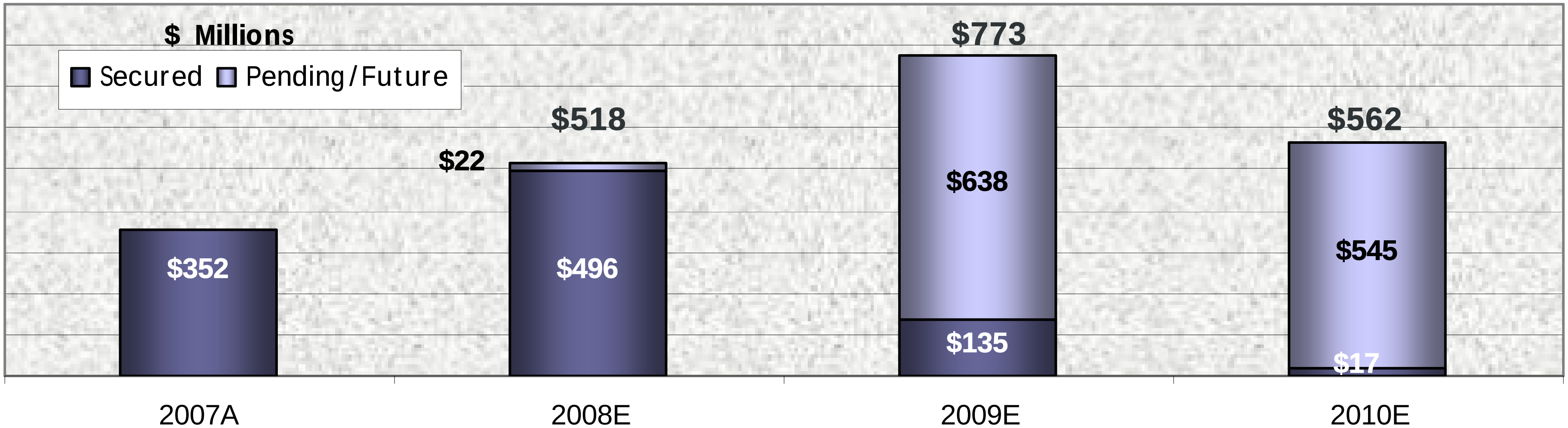
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

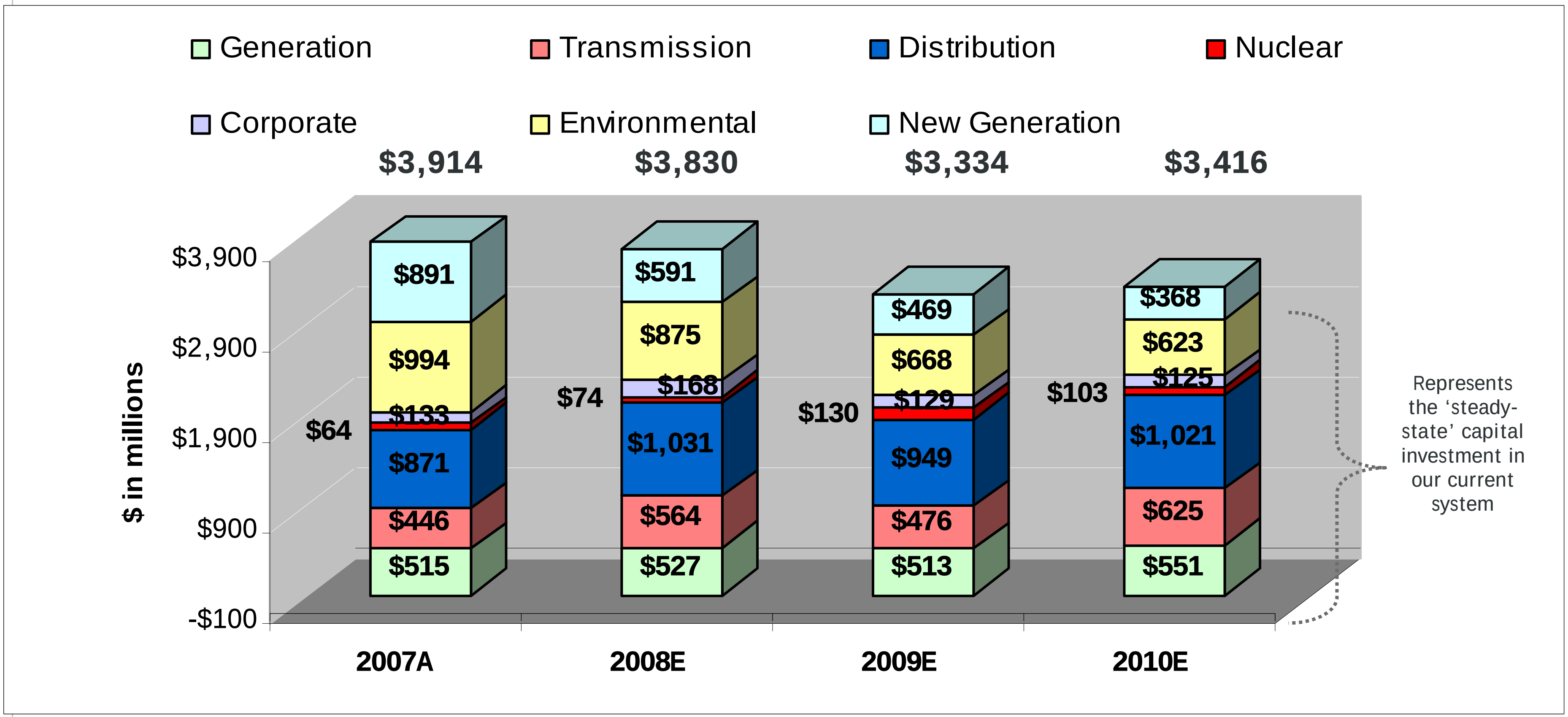
Incremental Rate Relief



- 96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.
- 2008 Pending: 2008 TCC/TNC TCRF filings, and Virginia base case rates subject to refund ($208MM requested).
- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM, Ohio ESP, other cases yet to be filed.

Secured $496MM of $518MM for 2008

4-Year Capital Investment Forecast



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2Q08 Retail Performance

	Load Growth (weather normalized)
	2Q08 vs. 2Q07
East Regulated Integrated Utilities	.9%
Ohio Companies	1.5%
West Regulated Integrated Utilities	.9%
Texas Wires	-1%
Impact on EPS	$0.03

	Weather Impact
	2Q08 vs. 2Q07
East Regulated Integrated Utilities	($0.02)
Ohio Companies	($0.02)
West Regulated Integrated Utilities	$0.00
Texas Wires	$0.01
Impact on EPS	($0.03)

YTD Retail Performance

	Load Growth (weather normalized) YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	1.7%
Ohio Companies	4.8%
West Regulated Integrated Utilities	1.0%
Texas Wires	0.7%
Impact on EPS	$0.12

	Weather Impact YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	($0.03)
Ohio Companies	($0.02)
West Regulated Integrated Utilities	($0.00)
Texas Wires	$0.01
Impact on EPS	($0.04)

Retail Performance

	Rate Relief (in millions)
	2Q08 vs. 2Q07
East Regulated Integrated Utilities	**$29**
Ohio Companies	**$39**
West Regulated Integrated Utilities	**$6**
Texas Wires	**$3**
AEP System Total	**$77**
Impact on EPS	**$0.12**

	Rate Relief (in millions)
	YTD 2008 vs. YTD 2007
East Regulated Integrated Utilities	**$43**
Ohio Companies	**$83**
West Regulated Integrated Utilities	**$14**
Texas Wires	**$12**
AEP System Total	**$152**
Impact on EPS	**$0.25**

2Q08 Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	2Q 2008	2Q 2007	2Q 2008	2Q 2007	2Q 2008	2Q 2007
East:	**59.03%**	**60.13%**	**77.34%**	**77.75%**	**9.58%**	**9.32%**
Coal:	67.93%	66.34%	76.34%	73.94%	10.56%	10.30%
Super-Critical*	71.58%	66.34%	77.48%	72.29%	10.71%	11.18%
Sub-Critical*	56.65%	66.35%	72.84%	79.06%	10.06%	7.75%
Gas**	2.78%	5.32%	78.93%	86.43%	N/A	N/A
Hydro	8.91%	10.00%	87.12%	91.85%	6.85%	10.96%
Nuclear	81.51%	98.17%	80.77%	97.33%	0.14%	0.98%
SPP:	**37.79%**	**40.61%**	**78.19%**	**80.22%**	**11.08%**	**8.84%**
Coal:	65.74%	71.56%	72.40%	76.68%	13.49%	6.02%
Super-Critical	54.16%	53.68%	58.59%	56.17%	9.62%	15.12%
Sub-Critical	70.19%	78.32%	77.69%	84.43%	14.54%	3.44%
Gas	20.73%	19.89%	81.72%	82.59%	9.03%	11.34%
Texas:						
Coal	**67.06%**	**84.67%**	**81.20%**	**86.13%**	**11.14%**	**11.48%**
AEP System	**54.14%**	**56.03%**	**77.59%**	**78.41%**	**9.94%**	**9.25%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run less frequently, this factor gauges performance based on period hours instead of service hours. (2Q08 = 1.11% /2Q07 = 0.74%)

June YTD Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	YTD 2008	YTD 2007	YTD 2008	YTD 2007	YTD 2008	YTD 2007
East:	**63.29%**	**63.75%**	**81.32%**	**79.66%**	**9.48%**	**8.66%**
Coal:	72.96%	69.22%	79.52%	76.22%	10.28%	9.50%
Super-Critical*	75.03%	69.34%	79.48%	74.43%	10.56%	9.49%
Sub-Critical*	66.55%	68.86%	79.65%	81.78%	9.42%	9.50%
Gas**	2.44%	3.93%	87.97%	89.26%	N/A	N/A
Hydro	8.32%	11.65%	84.81%	90.17%	11.59%	14.62%
Nuclear	87.75%	100.08%	87.09%	98.64%	1.28%	0.50%
SPP:	**38.28%**	**41.25%**	**80.76%**	**83.23%**	**8.21%**	**6.67%**
Coal:	70.41%	74.04%	76.04%	79.16%	8.15%	4.48%
Super-Critical	68.80%	67.75%	72.30%	70.33%	6.09%	8.20%
Sub-Critical	70.91%	76.42%	77.50%	82.50%	8.85%	3.22%
Gas	18.56%	19.26%	83.66%	85.97%	8.27%	8.91%
Texas:						
Coal	**62.23%**	**63.56%**	**73.49%**	**64.29%**	**8.14%**	**23.77%**
AEP System	**57.42%**	**58.57%**	**81.09%**	**80.28%**	**9.20%**	**8.48%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run less frequently, this factor gauges performance based on period hours instead of service hours. (YTD 08 = 0.96% / YTD 07 = 2.07%)

Morgan Stanley Global Electricity & Energy Conference

New York, NY
March 16, 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Framework for 2006

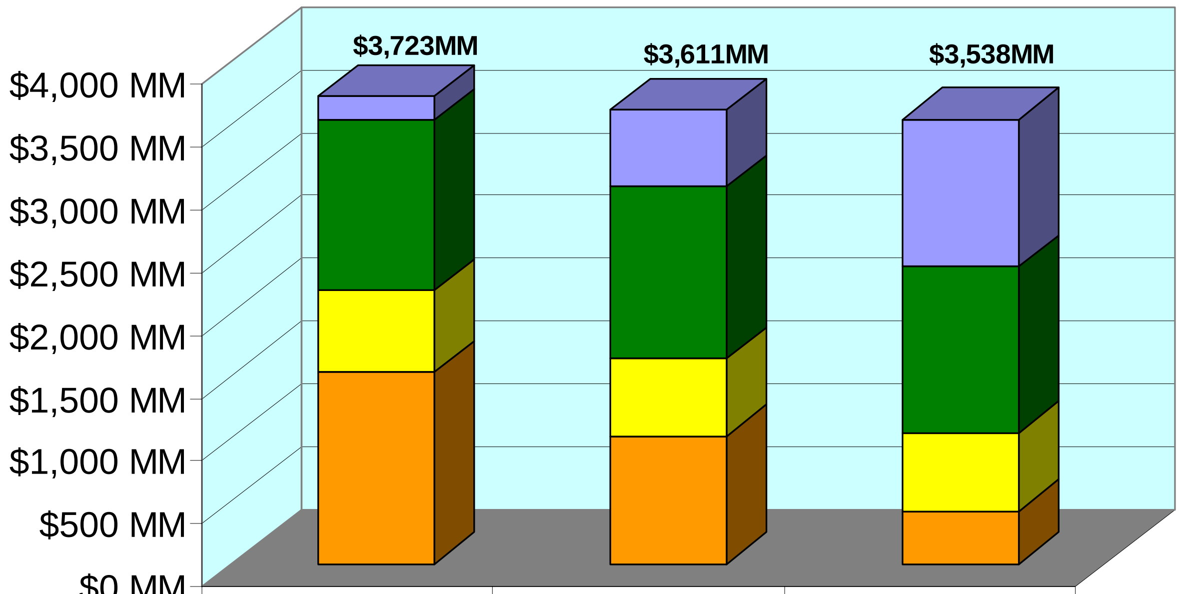
- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

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Capital Investment Funding

AEP®

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

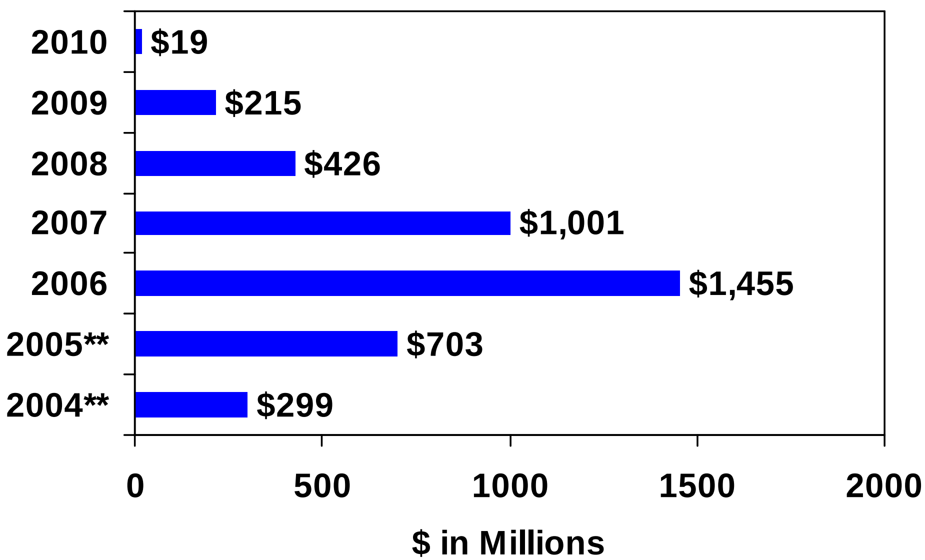
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

$4.1 Billion Environmental Investment

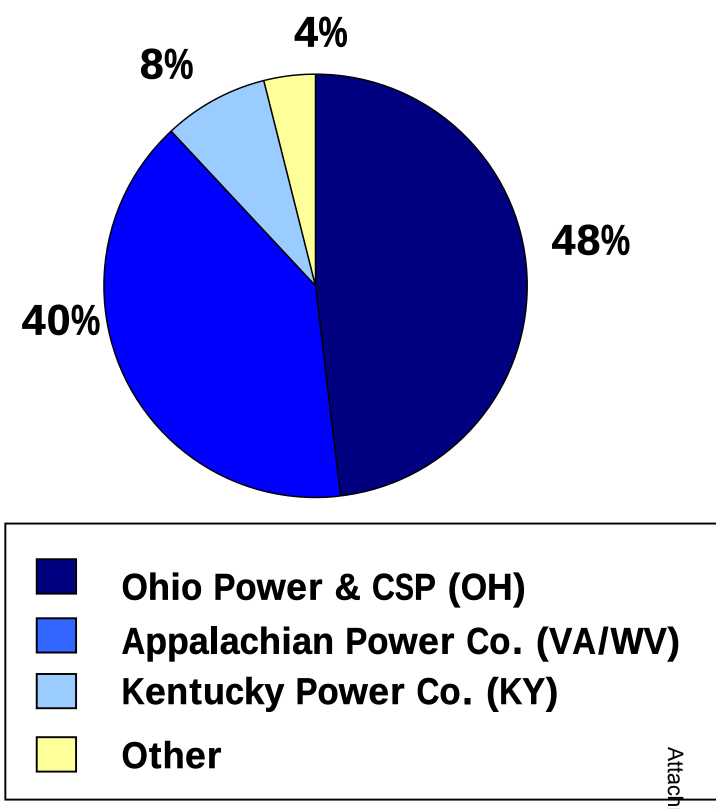
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation

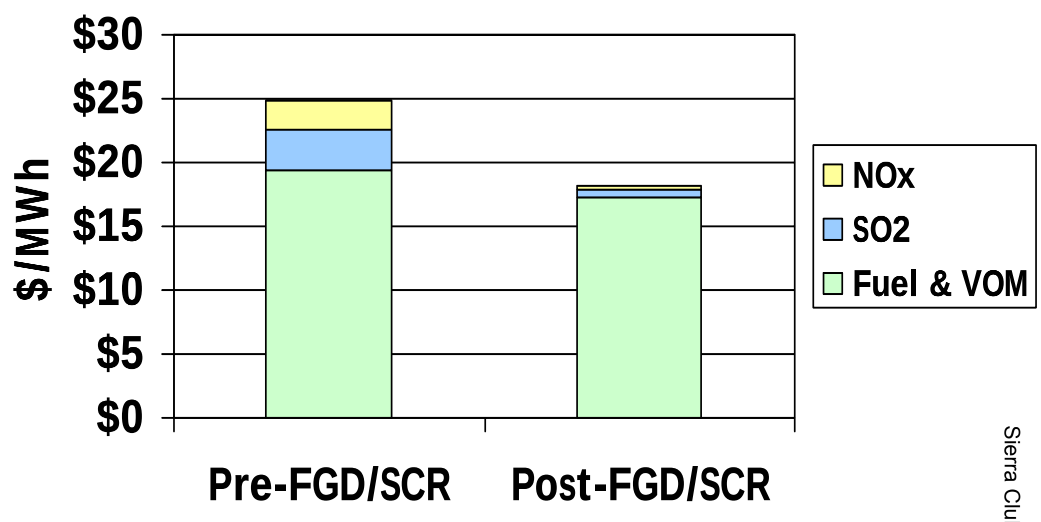


MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Activity Underway

- ✓ **TCC Securitization Process**
- ✓ **Ohio Companies filing for pass through of FERC OATT changes**
- ✓ **APCo Filing for Recovery of E&R Costs in Virginia**
- ✓ **APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia**
- ✓ **Kentucky Base Rate Filing - Settlement Pending**
- ✓ **Indiana Depreciation Petition**
- ✓ **IGCC**
- ✓ **APCo notified the Virginia SCC of plans to file a base rate case no sooner than May 1, 2006**

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

TCC Stranded Cost Recovery Case

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - ➢ Final order expected in May 2006
  - ➢ September 1, 2006 - Issuance of securitization bonds if no appeal
- April 2006 – Request approval for CTC to address other true-up items
  - ➢ Expected $475 million credit to customers
  - ➢ Jan 2007 – CTC to be implemented

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Regulatory Activity Underway

Appalachian Power – Virginia E & R Cost Recovery Factor

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- ✓ Hearings completed March 1, 2006

➢ APCo gave notice to the VA SCC on March 1, 2006 of its plan to file a general rate case no sooner than May 1, 2006.

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million*
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

* Base rate increase of $16MM, ENEC of $56MM & miscellaneous of $2MM

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ March 16, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

Regulatory Activity Underway

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Parties to the case reached a settlement on Feb 6, 2006
  - ✓ $41 million annual increase in base rates
  - ✓ To be effective March 30, 2006
- ✓ Settlement was presented to the Commission at a public hearing on Feb 7, 2006
- ✓ Final order expected in March 2006

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

Regulatory Activity Underway

Ohio - Cost Recovery Filing

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

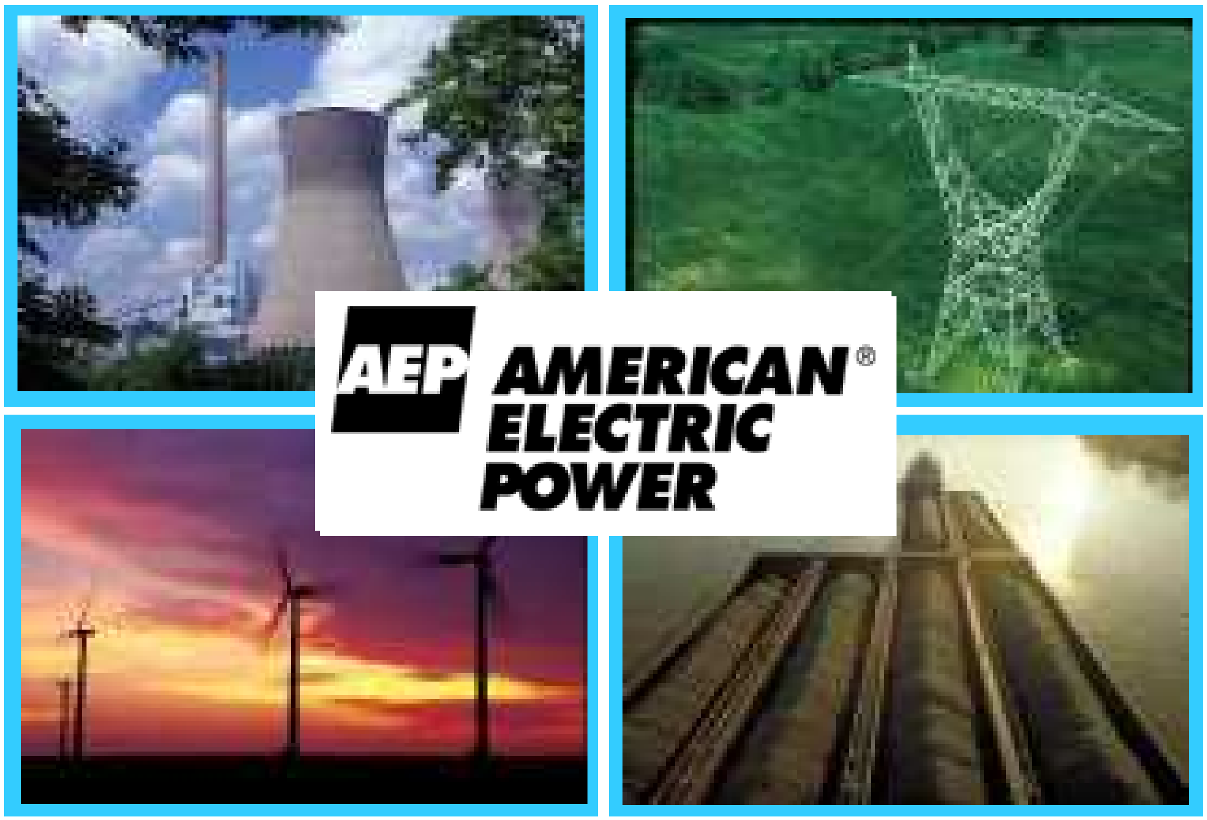
What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

AEP

AEP AMERICAN ELECTRIC POWER

Alliance Bernstein & Clients Office Visit



Columbus, OH

June 11, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Table of Contents

AEP Participants

11:00—12:00 PM	
Craig Baker	***SVP Regulatory Services***
12:00—1:15 PM	
Mike Morris	***Chairman, President & CEO***
Holly Koeppel	***EVP & CFO***
1:30—2:15PM	
Mike Rencheck	***SVP Engineering, Project & Field Services***
Bill Sigmon	***SVP Fossil & Hydro Generation***
2:15—2:45PM	
Max Chau	***Director, Transmission Line Projects Engineering***
John Stough	***Director, Transmission Business Development***
2:45—3:15PM	
Dennis Welch	***SVP Environment, Safety and Health***
Bruce Braine	***VP Strategic Policy Analysis***

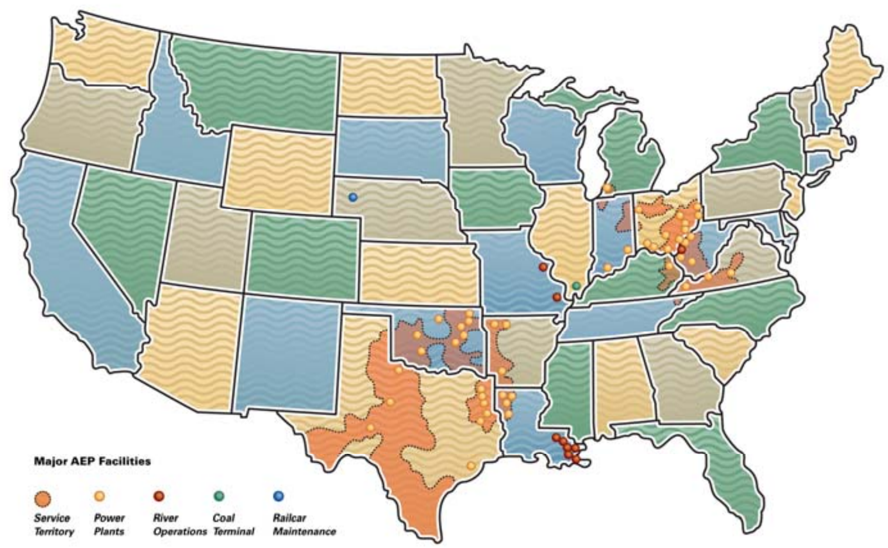
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2878 of 9556

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

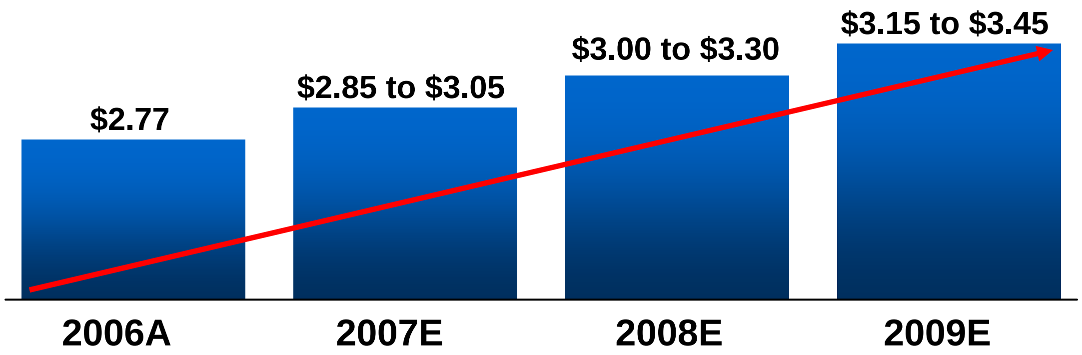
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

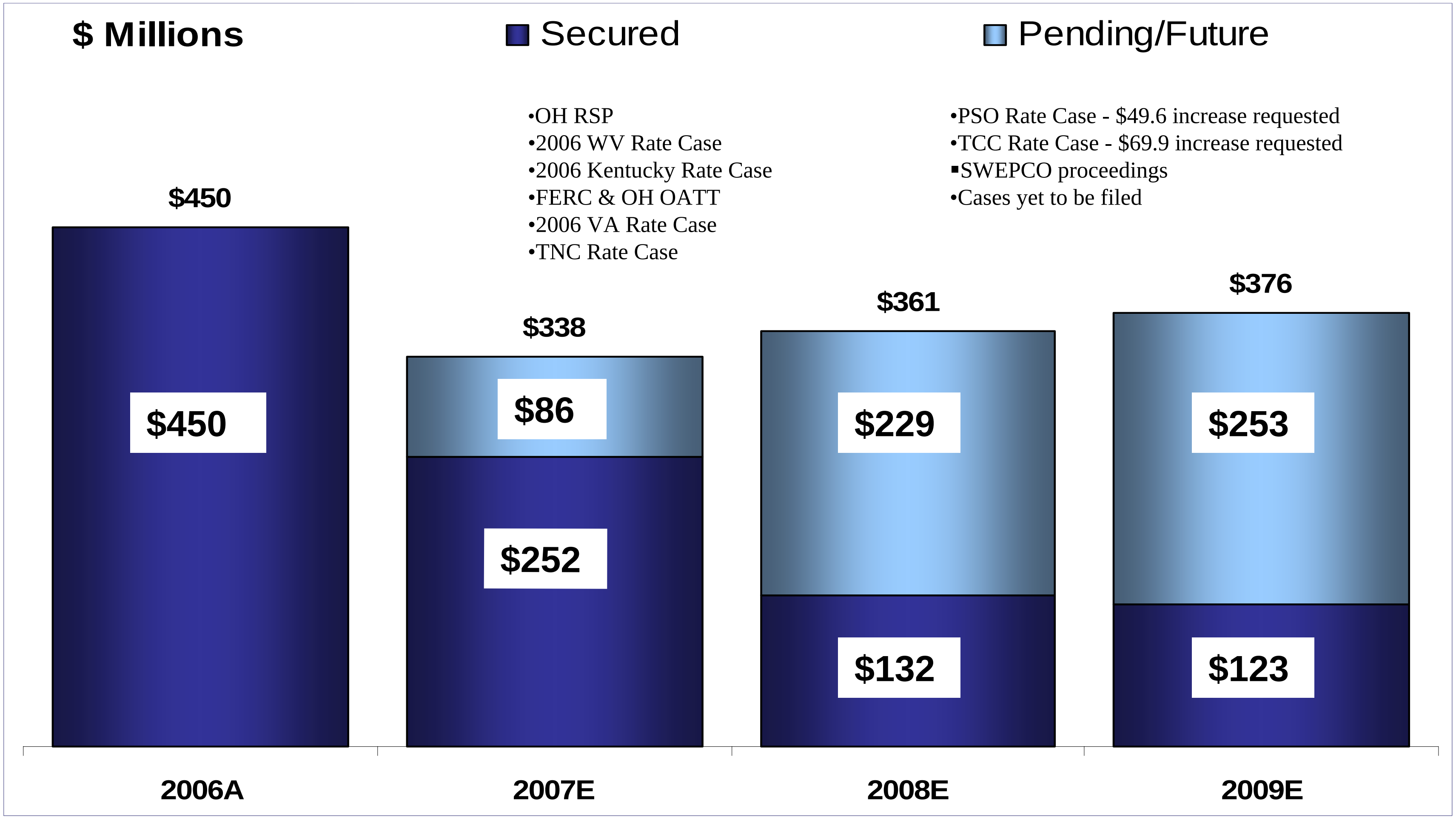
Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

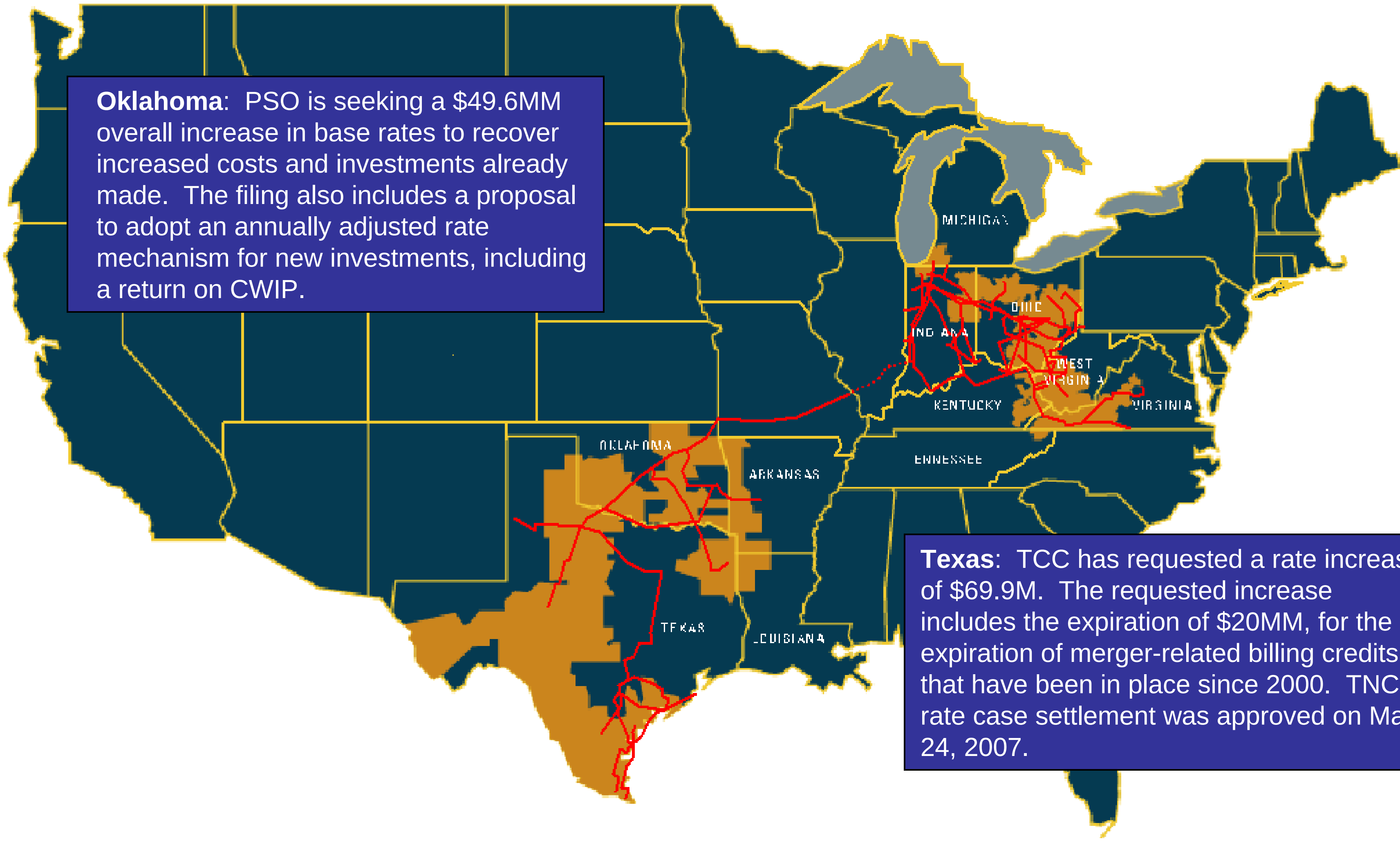
Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC has requested a rate increase of $69.9M. The requested increase includes the expiration of $20MM, for the expiration of merger-related billing credits that have been in place since 2000. TNC's rate case settlement was approved on May 24, 2007.

Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065). An order was issued on May 15, 2007, authorizing a $24MM rate increase and an ROE of 10.0%,with E&R to be addressed in a separate filing.

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

May 4, 2006	Case filed
Oct. 2, 2006	Rates went into effect, subject to refund
Oct. 24, 2006	Staff testimony filed
Dec. 7, 2006	Hearings commenced
Feb. 5, 2007	Briefs filed
Mar. 28, 2007	Hearing Examiner Recommendation filed
Apr. 18, 2007	APCo filed comments to HE report
May 15, 2007	Commission order issued

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base $2.3 billion

Summary Rate Case Information

Texas Central Company Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
June 19, 2007	Final order expected

Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Evidentiary hearing commenced May 22, 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

Regulatory Activity

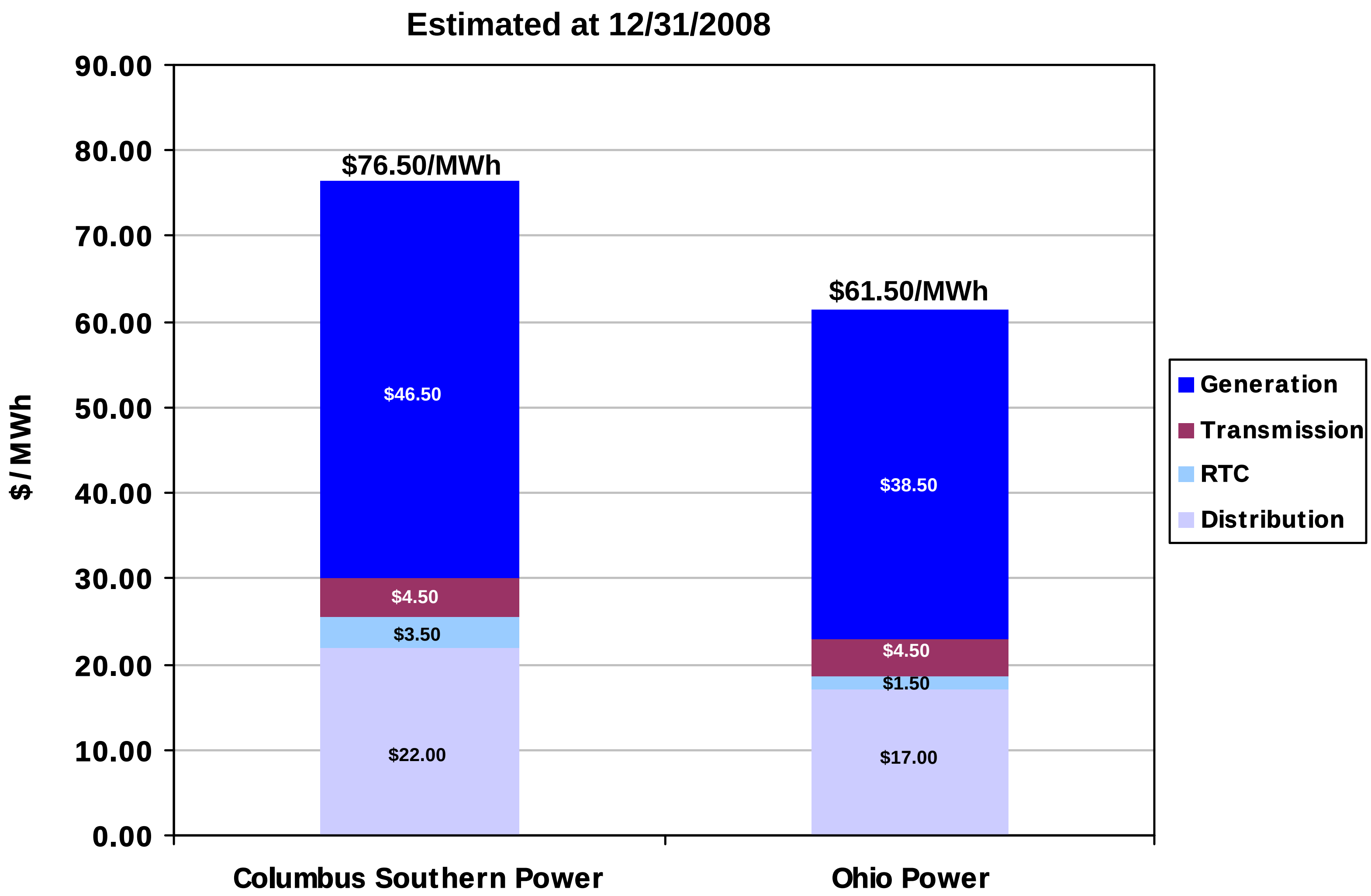
Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
    - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
    - Intervenor testimony is due June 8, 2007. Staff testimony is due June 18, 2007. Hearings are scheduled for July 16-19, 2007.
        - An order is expected mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
    - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

Average Unbundled AEP Ohio Rates



Purchased Generation

Waterford

– 821 MW combined-cycle gas plant
– $220MM purchase price
– Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

– 505 MW simple-cycle gas plant
– $100MM purchase price
– APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

– 480 MW simple-cycle gas plant
– $102MM purchase price
– Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

– 1140 MW combined-cycle gas plant
– $325MM purchase price
– AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison (Tontitown)	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall (Arsenal Hill)	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk (Hempstead)	Arkansas	$1.3 B(1)	Coal	Ultra-supercritical	600(1)	2011
PSO	Red Rock	Oklahoma	$1.8 B(2)	Coal	Ultra-supercritical	950(2)	2012
CSP/OP	Great Bend	Ohio	Under Review(3)	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review(3)	Coal	IGCC	600	TBD

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) PSO will own 50%, or 475 megawatts, totaling approximately $900MM in capital investment.
(3) FEED (front-end engineering and design) study is completed. Final results will be available in June.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit filed and approved in Feb 2007
  - Units 3 and 4 online by summer peaking-season 2007; Units 1 and 2 online by Jan 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by Mar 2008

PSO

- Southwestern & Riverside Additions
  - Air permit received March 22, 2007
  - Commercial operation date of Dec 2007
  - Projects to be completed by Q1 2008
  - Regulatory Recovery
    - Settlement and final order in the Lawton Cogen case authorizes costs for Southwestern and Riverside peakers to be recovered through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

- Turk Plant (Fulton, AR)
  - Certificate of Need approvals (LA, AR, TX) expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for Sept 2007
    - AR and TX rate recovery will be addressed in separate filings
  - Approximately 85-90% of costs are firm
    - EPC contract for balance of plant work awarded in May 2007
    - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

- Red Rock Plant (Red Rock, OK)
  - Used and useful determination filed in Feb 2006 – approval expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Order expected in PSO rate filing by June 19, 2007 – filing includes request for CWIP treatment for new projects
  - Original cost estimate of $1.8 billion – revised cost estimate expected in July 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results to be filed in June 2007. Cost estimates expected to be in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony due June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – pre-draft report is expected in June 2007
- Regulatory Recovery Filing
  - Filing expected in June 2007 – will include request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP Is Committed To IGCC Technology

IGCC Permitting Process

<u>IGCC Permitting Issues</u>

- ➢ **<u>Air</u>**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- ➢ **<u>Wastewater</u>**
  - ✓ Understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- ➢ **<u>US ACE (US Army Corp of Engineers</u>**)
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

Permitting process takes 1 – 2 years and is well under way

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

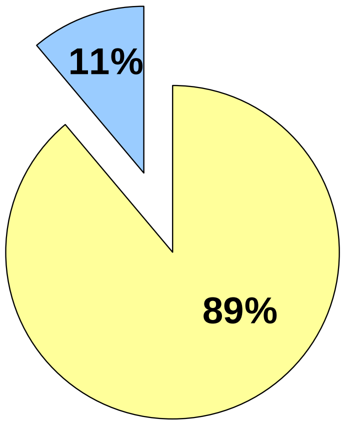
Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-10
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	In-service	☑	In-service
Mitchell 2	800	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	Upgrade In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2008
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	Upgrade In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

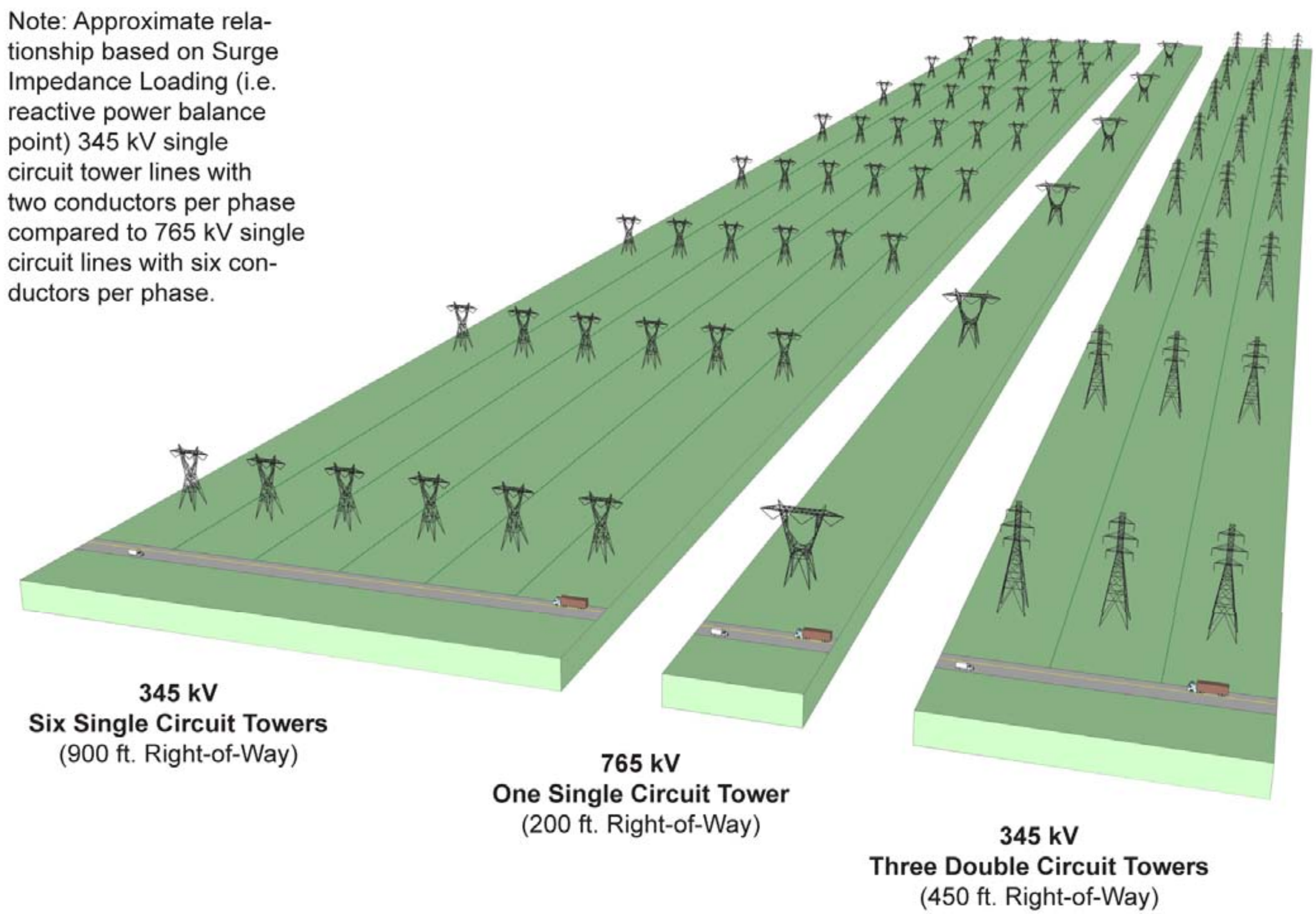
Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765 Right-of-Way Comparison



From a siting standpoint, 765 kV is much more efficient in terms of economies of scale and right-of-way than lower capacity lines

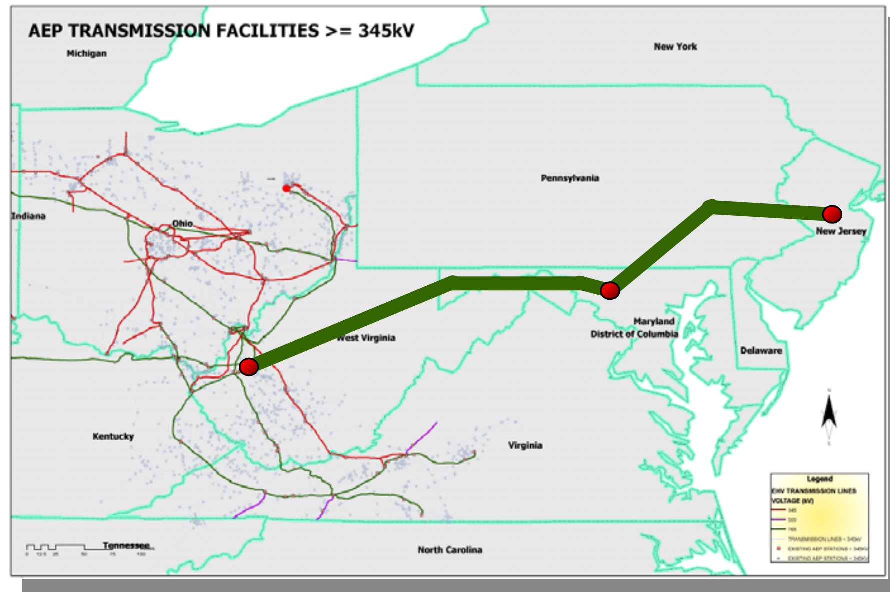
I-765™ PJM Transmission Project

Joint Venture with AYE

- 290 miles of the proposed 550 mile project
- Line will link AEP's Amos station in WV to AYE's proposed Kemptown station in MD with an intermediate station at AYE's Bedington station in WV
- JV project costs will encompass $1.1 billion, with each company owning 50%
- AEP's investment will total approximately $700 million, including ancillary projects
- Entire I-765™ project included in DOE's draft National Interest Electric Transmission Corridor
- FERC incentive rate treatment applies
- Operations to commence in the 2H07

Remaining I-765™ Project

- PJM is evaluating the Kemptown (MD) - Deans (NJ) line as a separate alternative



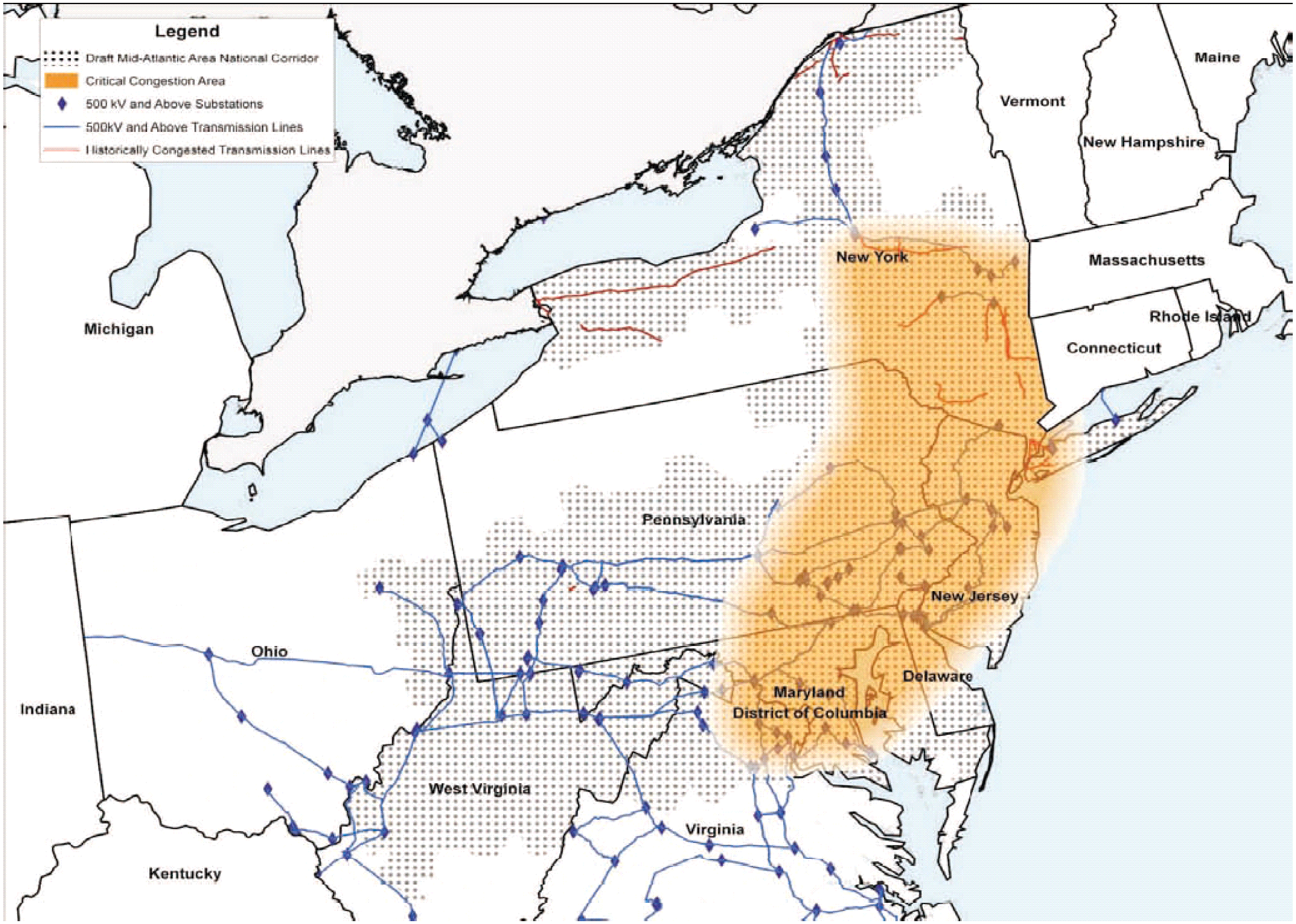
➢Jointly owned with Allegheny, will improve eastern grid reliability

➢Enhance Midwest-Mid-Atlantic power transfer capability by 5000 MW

➢Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.

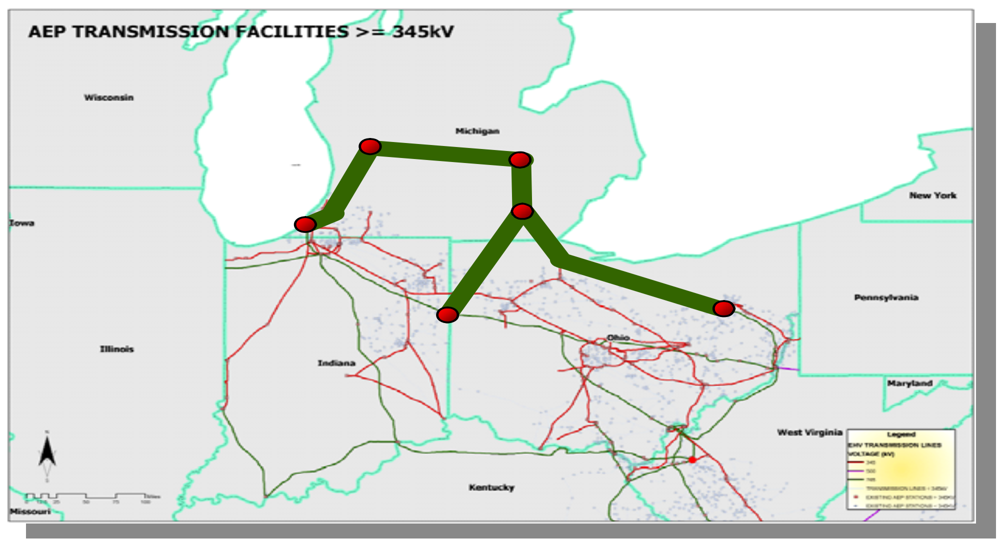
PJM's Targeted In-Service Date For the 290-Mile Project Is 2012

DOE Draft Mid-Atlantic National Interest Electric Transmission Corridor



Michigan 765kV Study

- Agreement with ITC Transmission for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
  - 630 line miles
  - Over 5000MW improved transfer capability
  - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in 2Q07
- We anticipate signing an MOU with ITC on joint ownership in mid-2007

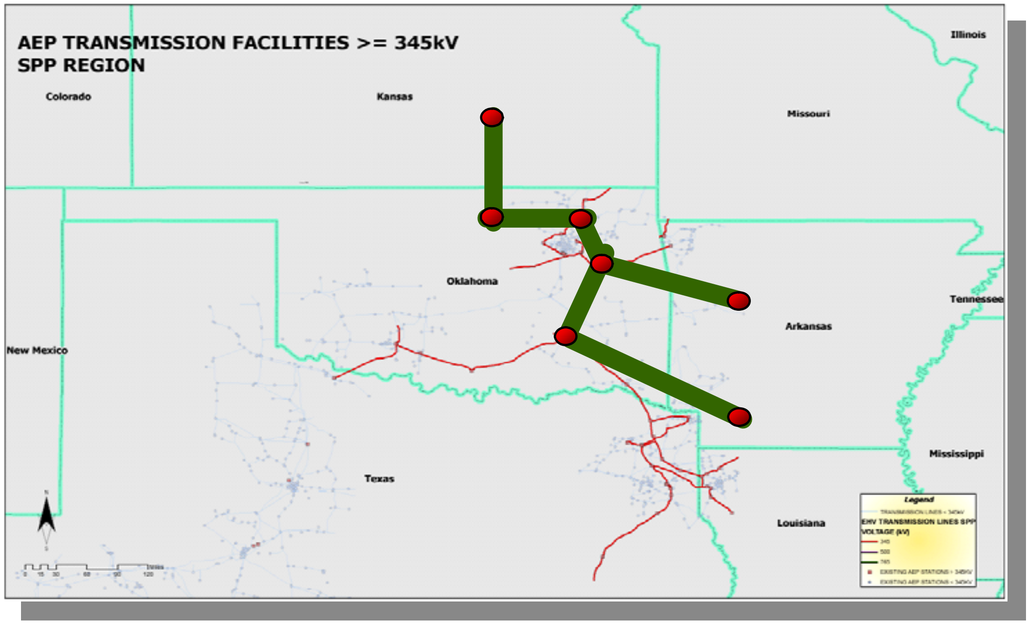


Project Construction Would Not Proceed Until Proper Regulatory Approvals Are Received And Cost Allocation Is Clarified

SPP Transmission Potential

- **June 2006 SPP requested proposal to address congestion, reliability & access for new generation**
- **July 2006 AEP submitted proposal:**
  - Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
  - Investment ~$3 billion
    - ~4000MW improved transfer capability
    - Anticipated rate impact 2mils/kWh

Next steps:
SPP issued EHV Overlay Study RFP to review 345 kV, 500 kV, and 765 kV potential projects in SPP with results expected in mid-2007



Long-term Opportunity For Large Transmission Investments to Reduce Congestion, Enhance Reliability and Access New Generation

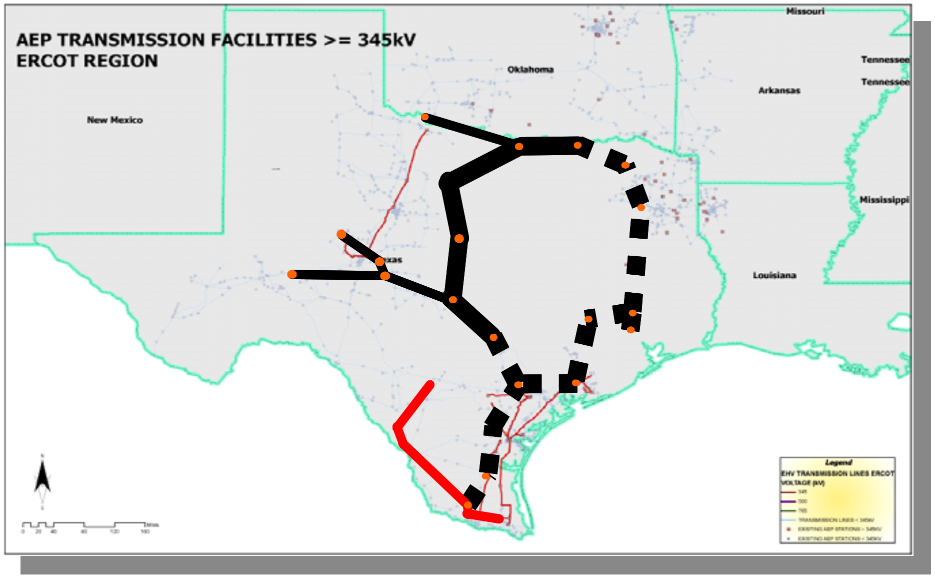
Electric Transmission Texas, LLC

Joint Venture with MidAmerican Energy

- Ownership – 50% AEP / 50% MidAmerican Energy
- 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
- AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
- Hearings with PUCT to be held July 16-19, 2007
- Initial funding in 3Q07 after regulatory approvals
- Debt – Initially bank financing

Competitive Renewable Energy Zone (CREZ) docket

- In February 2007, ETT proposed the development of a long-term transmission plan for ERCOT to address the Texas legislature's CREZ initiative. The plan includes:
  - $1.5 billion for Stage I of CREZ development by 2012
  - $1.5 billion for Stage II of CREZ development by 2015
  - $4.2 billion for Stage III for completion of ERCOT transmission backbone needed for long-term



Operations of JV Could Begin As Soon As 3Q07 Upon Receipt of Regulatory Approvals

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

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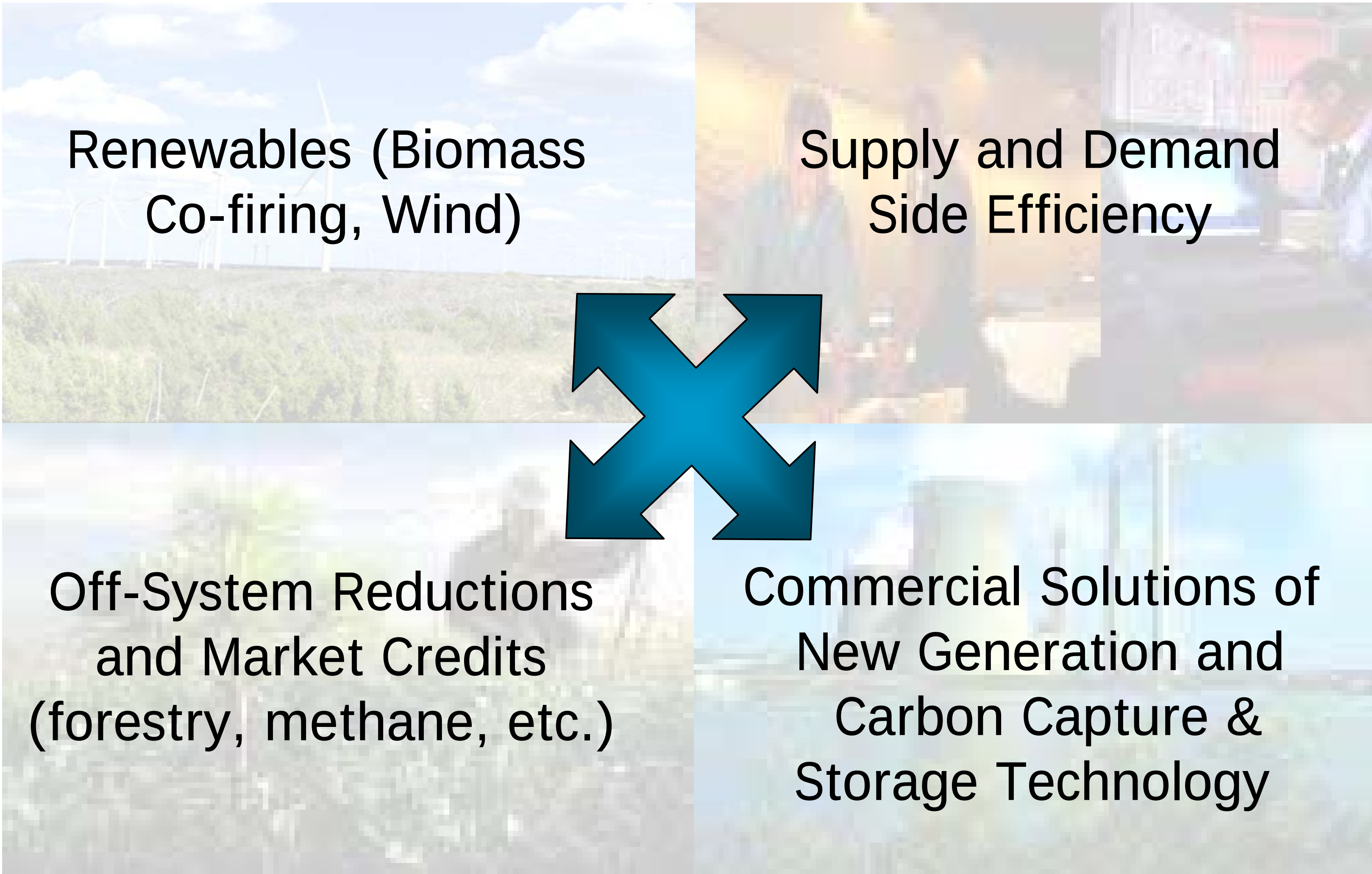
AEP's Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Process Plant Footprint

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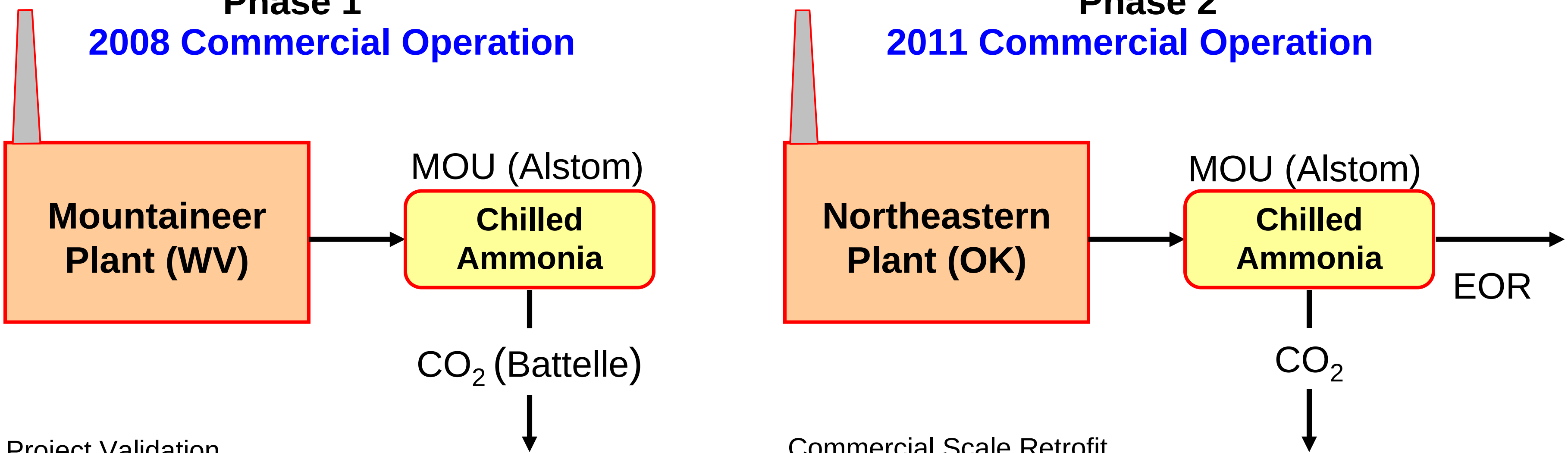
Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



Project Validation

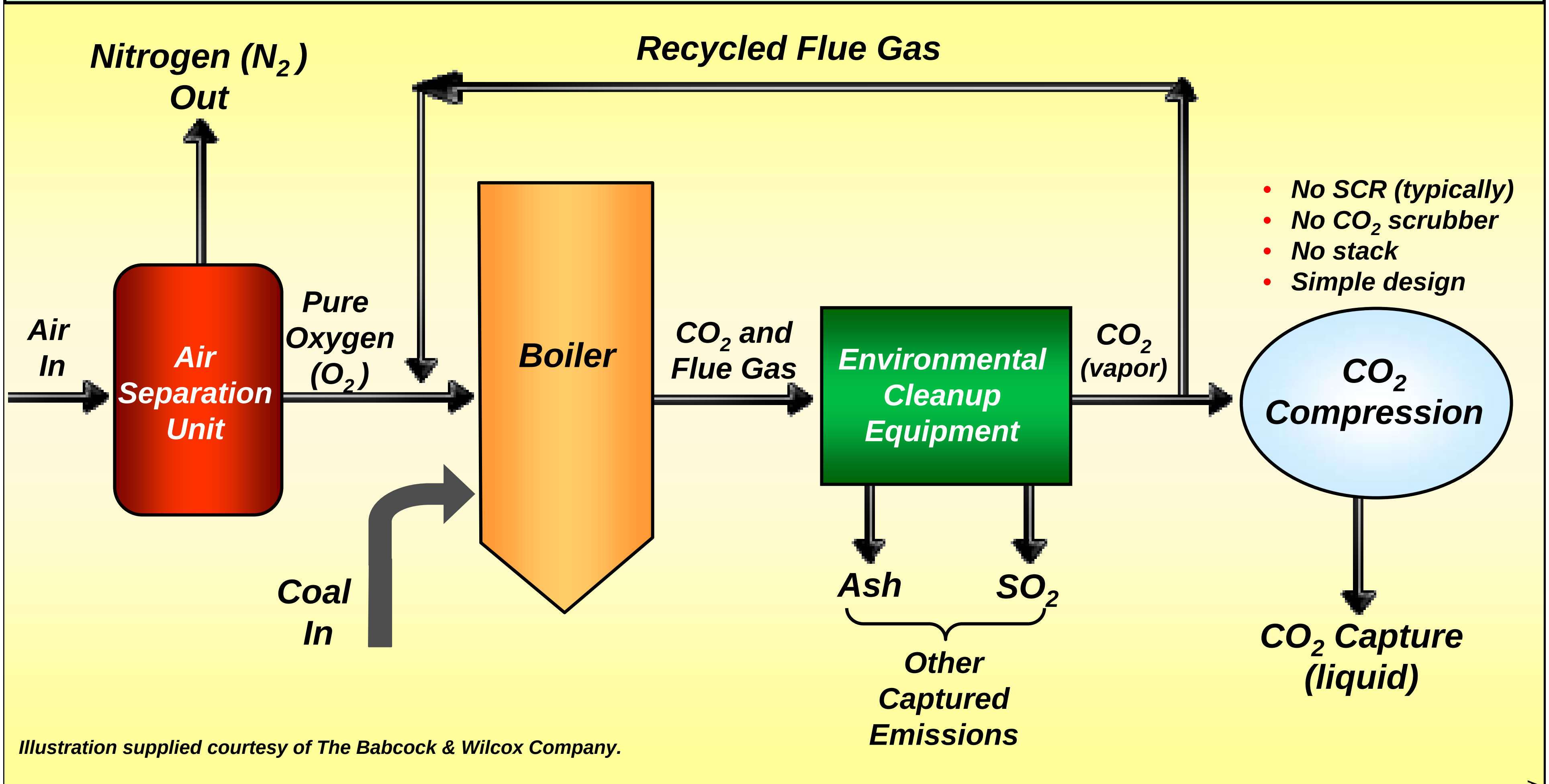
- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

Post-combustion Carbon Solution Provides Pure Co_2 Stream For Capture

Oxy-Fuel Technology Initiative



Near-zero Emissions Using Oxy-fuel Combustion Technology

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Appendix

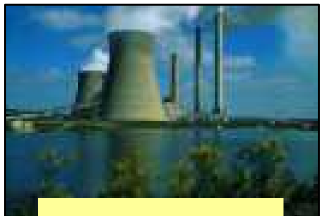
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

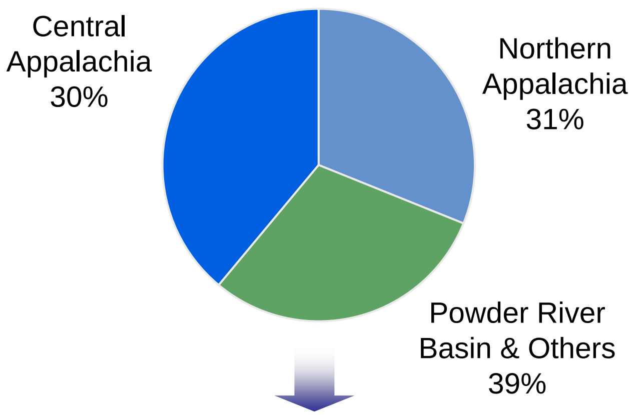
* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

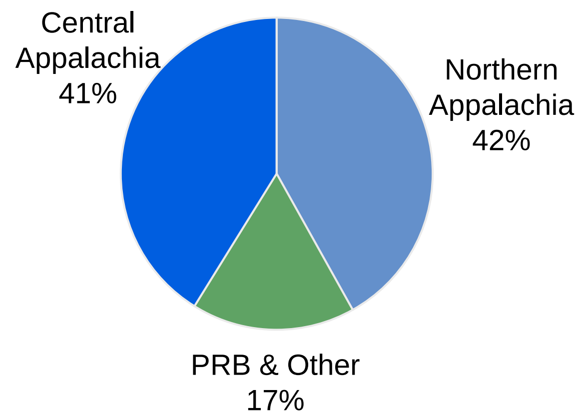
Total AEP System



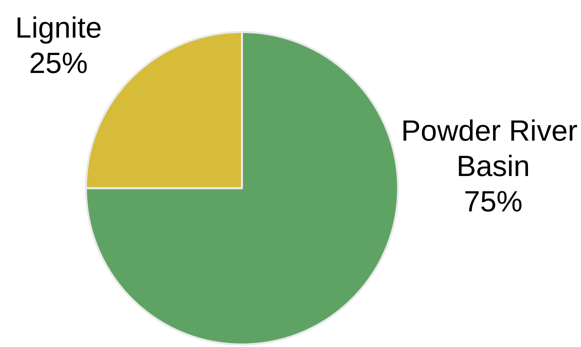
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

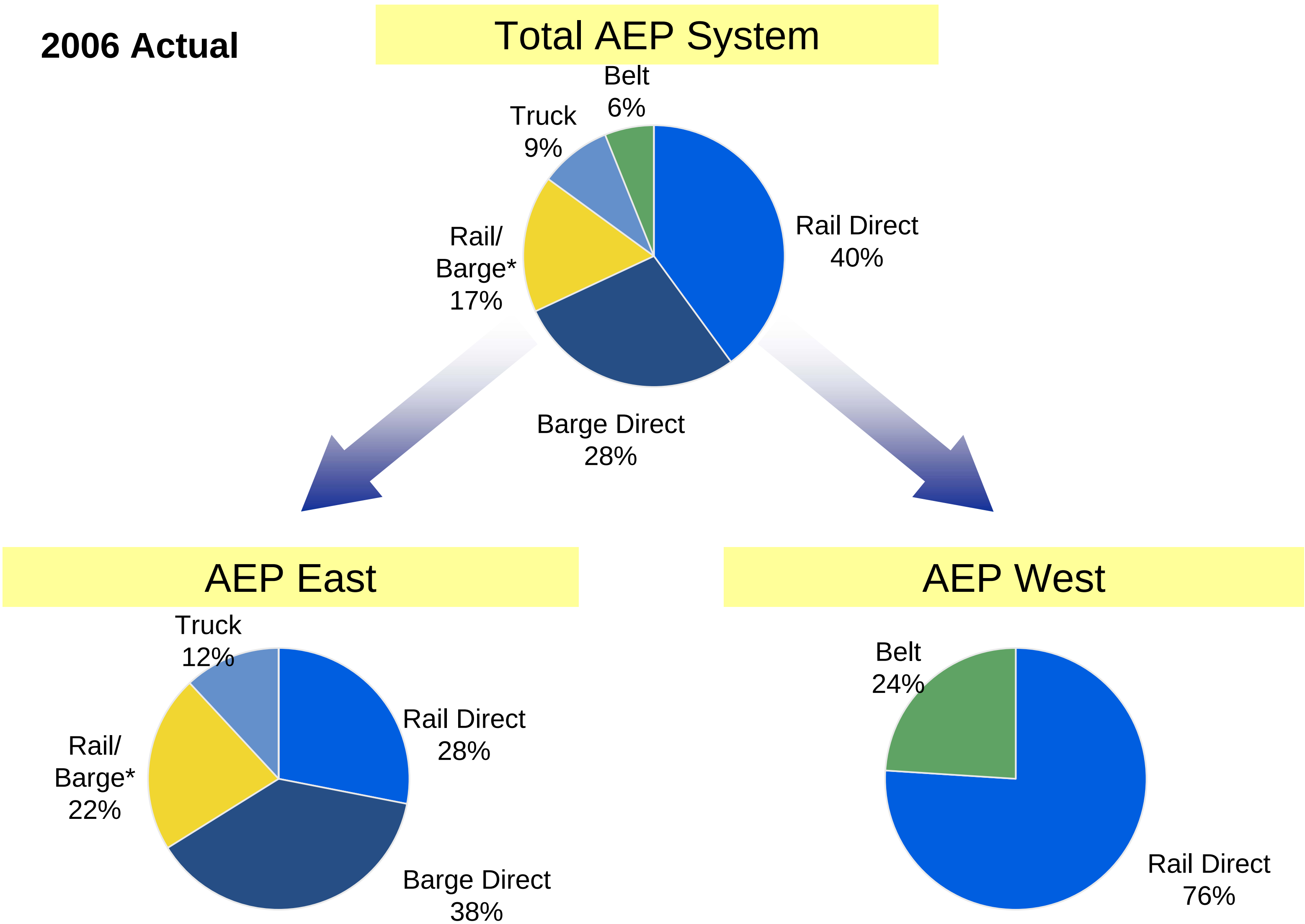


AEP West



Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

New Transmission Investment Funding Plans

- **Electric Transmission Texas LLC**
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% MidAmerican Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- **AEP I-765$_{TM}$ Interstate Project**
  - Forming a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- **Other Transmission Projects**
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

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Procedural Schedules and Details

- Red Rock Facility - Oklahoma
  - PSO and OG&E Cases were consolidated by the OCC
  - PSO Docket Nos. 200500516 and 200600030
  - OG&E Docket No. 200700012
  - Staff/Intervenor Testimony - received May 21
  - Rebuttal Testimony – June 18
  - Hearings re. Used and Useful Determination – July 2
  - Hearings re. OG&E Cost Recovery – July 19
  - ALJ Report – August 6
  - Order – August 21

- Mountaineer IGCC CPCN
  - Docket No. 06-0033-E-CN
  - APCo Testimony – June 18
  - Staff and Intervenor Testimony – August 17
  - Rebuttal Testimony – August 31
  - Hearings – September 10-14
  - Order – December 2

- Turk Plant - Arkansas
  - Docket No. 06-154-U
  - Staff/Intervenor Testimony – June 29
  - Rebuttal Testimony – July 13
  - Public Hearings – July 19 or August 9

- Turk Plant - Louisiana
  - Docket No. U-29702
  - Staff/Intervenor Testimony – June 15
  - Rebuttal Testimony – July 16
  - Public Hearings – September 11-14

- ETT LLC - Texas
  - Docket No. 33734
  - Intervenor Testimony – June 8
  - Staff Testimony – June 18
  - Rebuttal Testimony – June 26
  - Hearings – July 16-19

Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - ▪ Generation plant purchases & build
  - ▪ Transmission – interstate & intrastate
  - ▪ Distribution
  - ▪ Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - ▪ Achieve timely returns
  - ▪ Seek cash returns on investment during construction
  - ▪ Create & secure innovative rate plans
    - – Pursue post-2008 solution in Ohio
    - – Expand use of trackers
    - – Formula rates

New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

AEP AMERICAN ELECTRIC POWER®

Analyst & Investor Meeting

October 19, 2010
New York, NY

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Update on 2010 Priorities

2010 +

- Navigate through ongoing economic conditions
- Maintain capital spending and balance sheet discipline
- Continue delivering successful regulatory outcomes

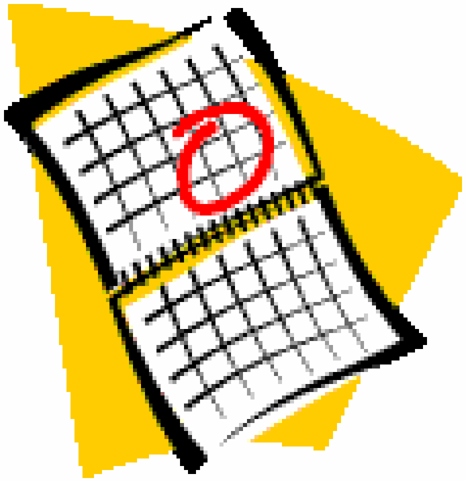
✓ Capital spending plan on target for $2.2B in 2010
✓ Stable credit outlook
✓ Labor and non-labor O&M cuts of $150M
✓ Reasonable rate case outcomes in VA, KY, MI, TX
✓ Exceeded rate relief goal of $320M for 2010
✓ Filed SEET in Ohio
✓ Implemented enhanced operating company model
✓ Narrowing 2010 guidance to $2.95 to $3.05/share

- Participate in policy making at both the state and federal levels, particularly related to environmental/climate and transmission issues
- Invest in the next generation of energy infrastructure: high voltage transmission, CCS, gridSMART®

✓ Active in legislative efforts for cap & trade bills
✓ Vocal in transmission policy efforts
✓ ETT and Transco efforts moving forward
✓ Success with Mountaineer CCS project
✓ 4 gridSMART® pilots underway

5 Focus Areas before 11/11/11

- Ohio SEET resolution and new ESP beginning in 2012
- FERC NOPR on transmission
- Environmental policy and EPA regulations on coal
- Succession planning/transition
- Long-term growth plan and capital allocation



A quick preview …….

- Economic outlook is difficult but improving
- Focus on Capital Allocation
  - <u>Capital for Growth</u>
    - Approximate $150M increase in capital budget to $2.6B for 2011
    - 2012 capital budget announced at $2.9B
  - <u>Return of Capital to Shareholders</u> - management will recommend 9.5% increase in dividend
  - <u>Capital to Reduce Risk</u> – voluntarily funded $500M into pension in 2010; additional $150M allocated for 2011
- Balance sheet remains strong
  - Stable credit outlook for AEP and subsidiaries
  - Capital spending plan supported by cash flows
- Earnings Guidance and Outlook
  - 2011 earnings guidance of $3.00 to $3.20/share
  - Average annual EPS growth rate defined over two periods:
    - 2012 – 2014 4-6%
    - post-2014 5-7%

Today's Program

- Operating Company Panel – led by Bob Powers
  - Opening Comments
  - Panel Discussion
- Generation – Nick Akins
  - Capacity Overview
  - Environmental Policy and EPA Regulations
  - Impact on AEP
- Transmission – Susan Tomasky
  - ETT, Transco and JV Overview/Update
  - Capital Spending Profile
  - Policy Update
- Financial – Brian Tierney
  - 3Q10 Earnings
  - 2011 Earnings Guidance
  - Capital Spending Plan
  - Liquidity & Financing Plan
  - Dividend Policy & EPS Growth Rate

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Bob Powers

President, AEP Utilities

Managing Operations and Investment

AEP®

Challenges:

Required refinement of the operating company model and improved line-of-sight management due to decreased load growth, regulatory lag, reduced rate headroom, and environmental challenges

Actions:

- ❑ Empower operating company employees to drive results
- ❑ Efficiently allocate capital
- ❑ Demonstrate O&M and capital expenditure discipline
- ❑ Identify asset renewal strategy for investing in traditional distribution and transmission assets that enhance reliability and customer satisfaction
- ❑ Enable long-term planning discussions with regulators and legislators

Expected Outcomes:
Optimize spending for more efficient return on investment
Improve dialogue with customers and regulators
Minimize lag in rate recovery

Operating Company Panel

AEP

Charles Patton

AEP APPALACHIAN POWER
A unit of American Electric Power

Joe Hamrock

AEP OHIO
A unit of American Electric Power

Paul Chodak

AEP INDIANA MICHIGAN POWER
A unit of American Electric Power

Stuart Solomon

AEP PUBLIC SERVICE COMPANY OF OKLAHOMA
A unit of American Electric Power

Venita McCellon-Allen

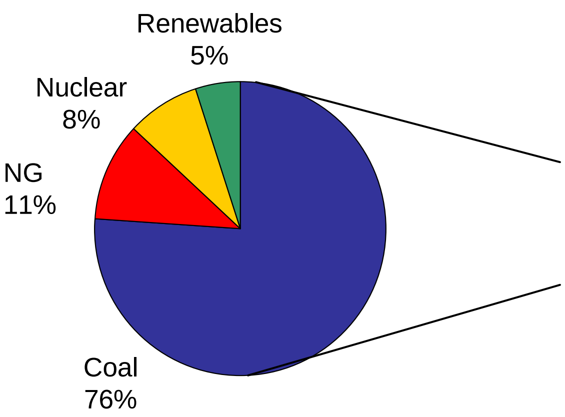
AEP SOUTHWESTERN ELECTRIC POWER COMPANY
A unit of American Electric Power

Nick Akins

Executive Vice President, Generation

AEP Generation Capacity

East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

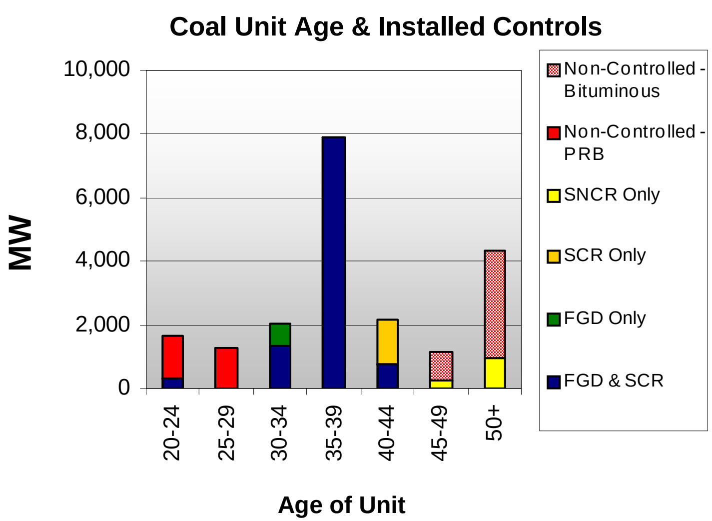


Coal Source

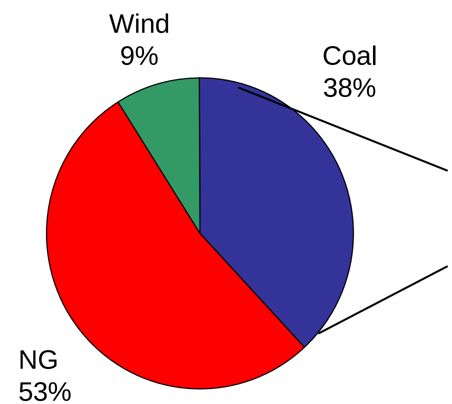
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind

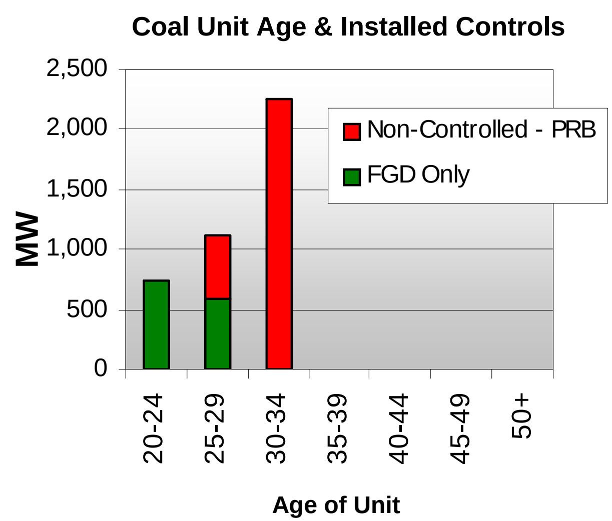


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

[1] Represents cost of committed position (90%)



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The Pressure on Coal Generation

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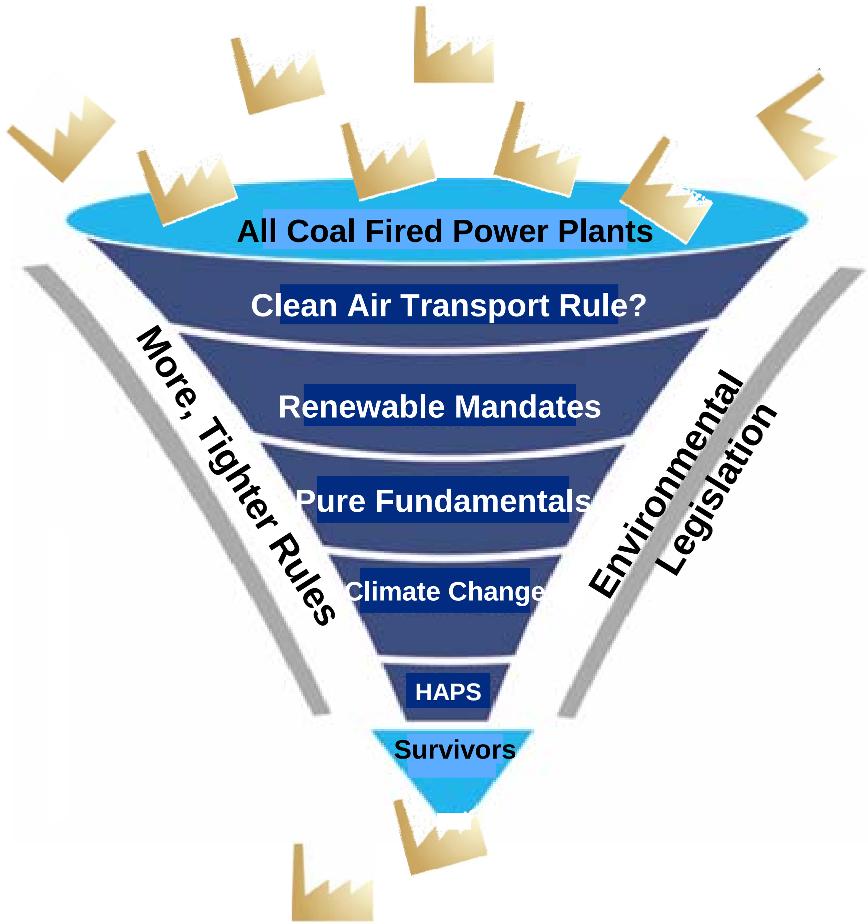
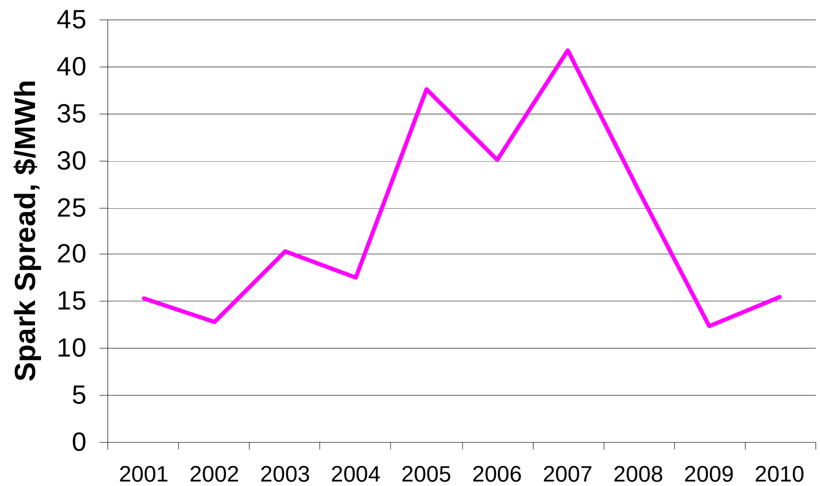


Dark Spread Compression

NYMEX coal



<u>Key EPA Actions Pending</u>

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in Spring 2011

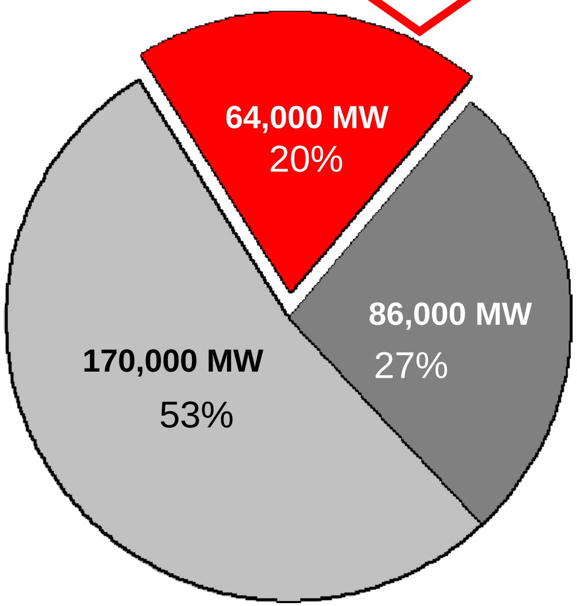
The threshold level for coal is being defined

Continual Evaluation is Required

“Fully-Exposed”	“Partially-Exposed”	“Least-Exposed”
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

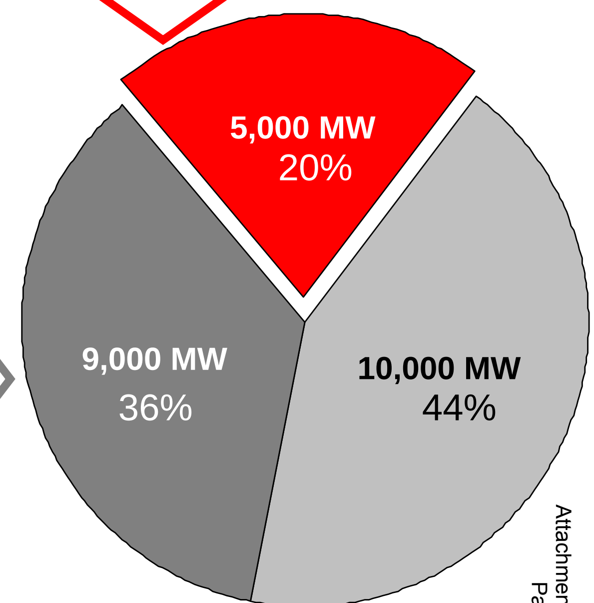
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements



AEP Coal

Nearly 50% of U.S. coal plants are exposed

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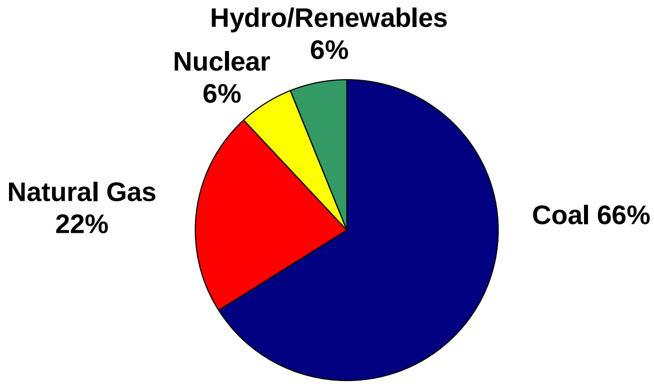
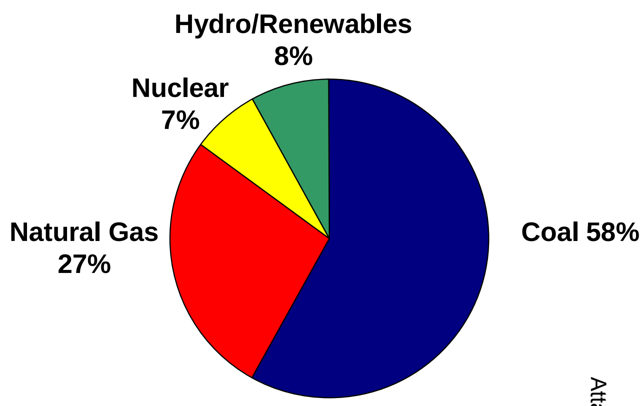
Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

Susan Tomasky

President, AEP Transmission

Transmission as a Growth Engine

- Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories
  - Electric Transmission Texas (ETT)
    - Growing Rate Base
    - Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - AEP Transmission Company (AEP Transco)
    - Settlement filed at FERC for wholesale rates
    - $50MM spend for 2010; $160MM forecasted for 2011
  - Joint Ventures
    - PATH
    - Prairie Wind
    - Pioneer
    - SMART Transmission study
- Two potential new projects – Watch this Space!

ETT: An Operating Utility

AEP®

ETT
Electric Transmission Texas

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	Anticipated 10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

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AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - Ohio application for public utility status pending; approval expected in 2010
  - Oklahoma and Michigan did not require filings
- "Baseline" capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

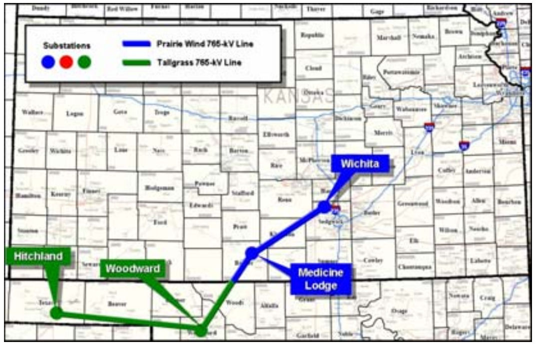
Progress on Joint Ventures in 2010

PATH:

- Re-filed for certification in VA
- Letter from PJM confirmed the 2015 in-service date
- PJM Testimony "RTEP final with respect to PATH"
- FERC approved formula rate (14.3% ROE)

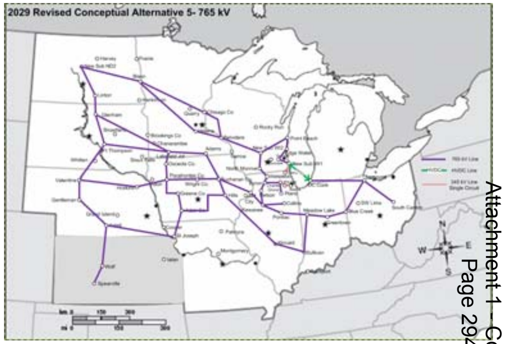
Prairie Wind:

- Approved by SPP as a Priority Project (Notice To Construct rcv'd)
- Cost allocation approved by SPP and FERC
- FERC approved formula rate (12.8% ROE)
- In-service date is 2013-2014



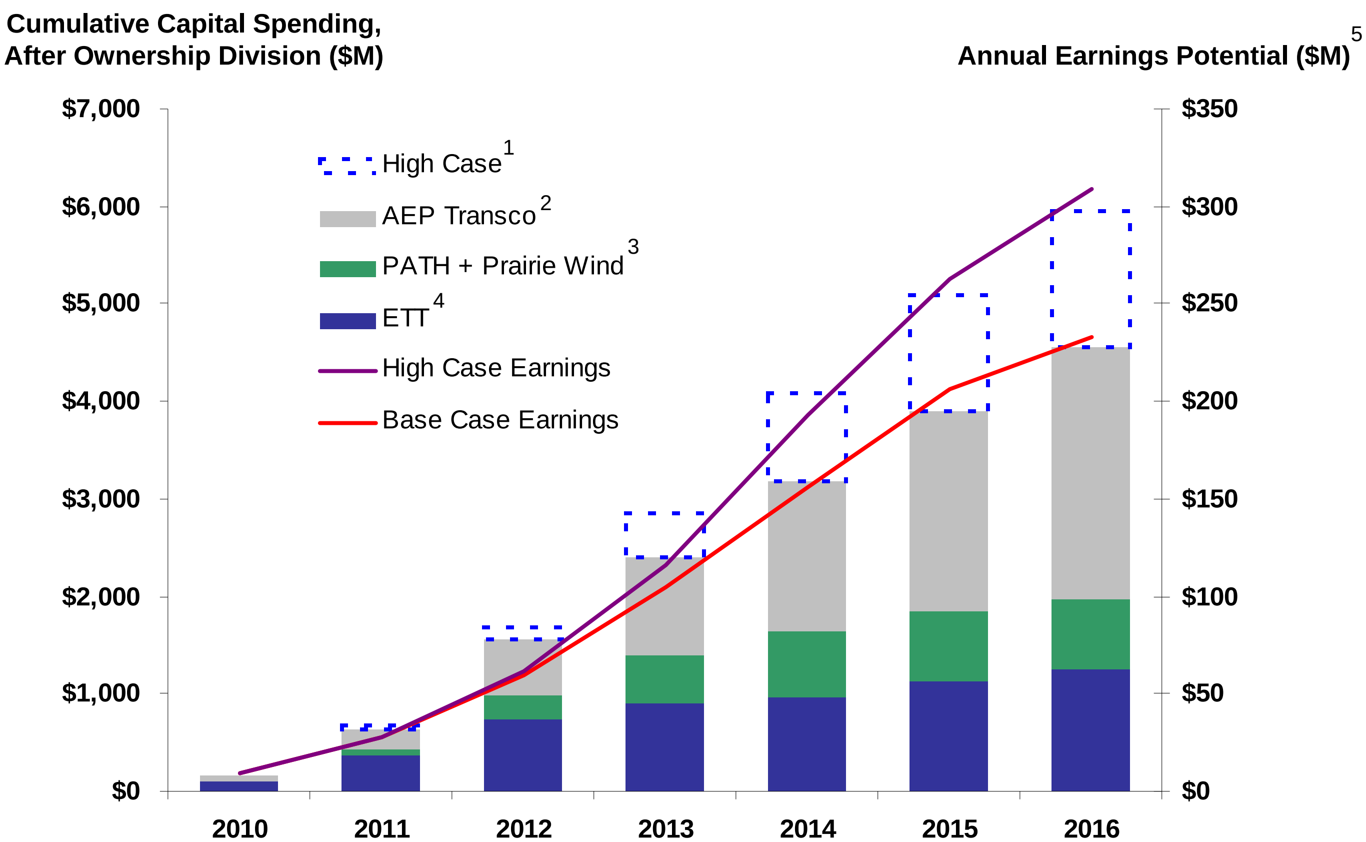
Pipeline of Future Projects:

- Pioneer
  - FERC approved formula rate (12.54% ROE)
  - Awaiting RTO project approval; MISO included Pioneer in its proposed EHV plan
- Tallgrass
  - Will move forward if approved at 765 kV
- Smart Transmission Study
  - Comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Capital Investment and Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Evolving Regulatory Policy

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- 2010 saw a number of steps towards resolving the issues related to planning, cost allocation and siting
  - SPP & FERC approved SPP's regional cost allocation methodology, and SPP adopted a new, more strategic planning process called the Integrated Transmission Planning process
  - SPP issued notices-to-construct for its "Priority Projects", including the first segments of an EHV overlay within the region
  - The Midwest ISO, through its Regional Generator Outlet Study (RGOS) and Multi-Value Project (MVP) Process, has moved closer to approving a number of significant transmission projects

- 2011 looks to be a year in which regulatory momentum will support transmission development
  - FERC's recently issued Notice of Proposed Rulemaking (NOPR), which is still in the comment phase, indicates FERC's desire to break the logjam and resolve the major issues that stand in the way of strategic development of the nation's transmission grid

Brian Tierney

Chief Financial Officer &
Executive Vice President

3Q10 Performance

AEP®

Third Quarter Reconciliation

		EPS	Ongoing Earnings ($ in millions)
3Q09	$	0.93	$443
Share Count Effect	$	(0.01)	
Rate Changes	$	0.10	
Retail Margin	$	-	
Firm Wholesale Margin	$	(0.03)	
Weather	$	0.18	
OSS	$	0.06	
Operations & Maintenance	$	(0.02)	
Other Utility Operations, net	$	(0.09)	
Non-Utility Operations/Parent	$	0.03	
3Q10	$	1.15	$552

3Q10 Performance Drivers

- Rate Changes net of offsets $74M from multiple operating jurisdictions
- Retail Margin flat for the quarter
- Firm Wholesale Margin down $21M due to the loss of two large wholesale customers
- Weather was favorable by $131M vs. prior year, $65M vs. normal
- OSS was favorable by $42M due to higher prices and volume, offset by lower trading
- O&M expense net of offsets increase of $12M primarily due to employee related expenses
- Other Utility Operations, net decreased approximately $66M and primarily includes the absence of accidental outage insurance and higher interest expense, D&A and taxes
- Non-Utility Operations/Parent increased $20M primarily due to tax adjustments

September YTD 2010 Performance

AEP®

September YTD 2010 Reconciliation

		EPS	Ongoing Earnings ($ in millions)
YTD09	$	2.49	$1,124
Share Count Effect	$	(0.16)	
Rate Changes	$	0.25	
Retail Margin	$	0.04	
Firm Wholesale Margin	$	(0.08)	
Weather	$	0.29	
OSS	$	0.06	
Operations & Maintenance	$	0.05	
Other Utility Operations, net	$	(0.32)	
Non-Utility Operations/Parent	$	0.03	
YTD10	$	2.65	$1,272

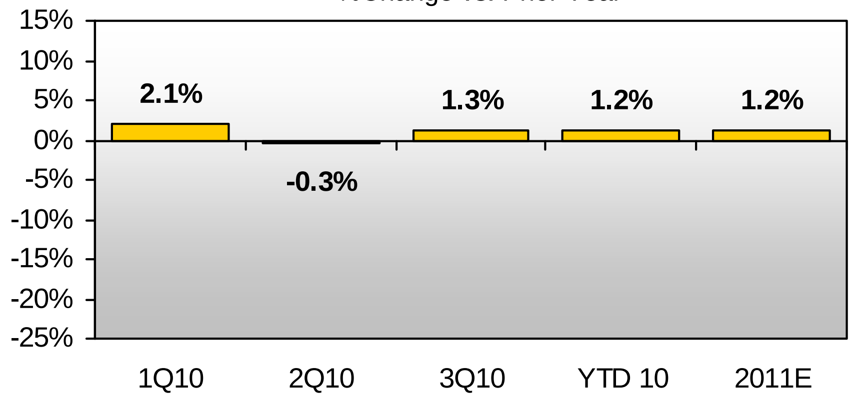
YTD 2010 Performance Drivers

- Share count impact due to 27M weighted average shares outstanding increase (452M to 479M) from equity offering and DRP
- Rate Changes net of offsets of $175M from multiple operating jurisdictions
- Retail Margin up $30M, due to recovery across all customer classes, primarily industrial
- Firm Wholesale Margin down $58M due to the loss of two large wholesale customers
- Weather was favorable by $202M vs. prior year, $148M vs. normal
- OSS increase $43M with increased sales in the east offsetting decreased trading/marketing profits
- O&M decrease of $38M net of offsets, primarily due to lower storm costs including the deferral of 2009 storm costs at APCo, and other G&A items
- Other Utility Operations, net decreased approximately $225M and primarily includes the absence of accidental outage insurance related to the DC Cook nuclear plant and higher interest expense, D&A and taxes

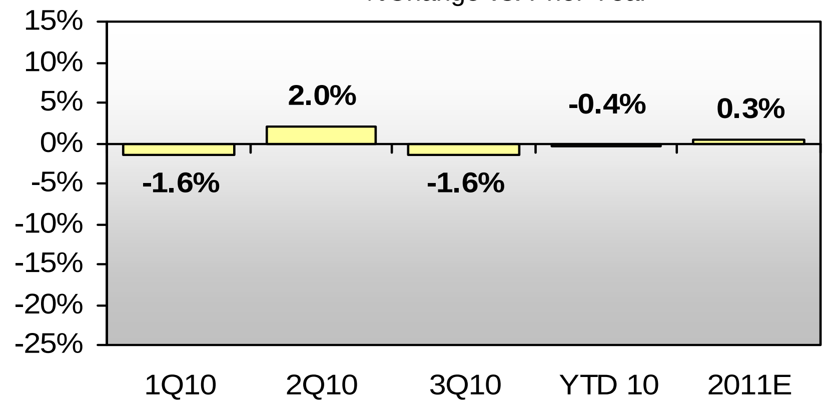
Updated 2010 Guidance Range: $2.95 - $3.05

Normalized Load Trends

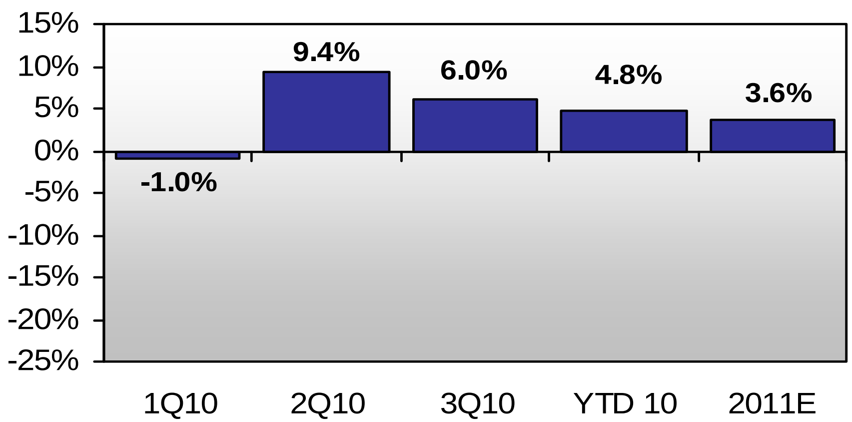
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



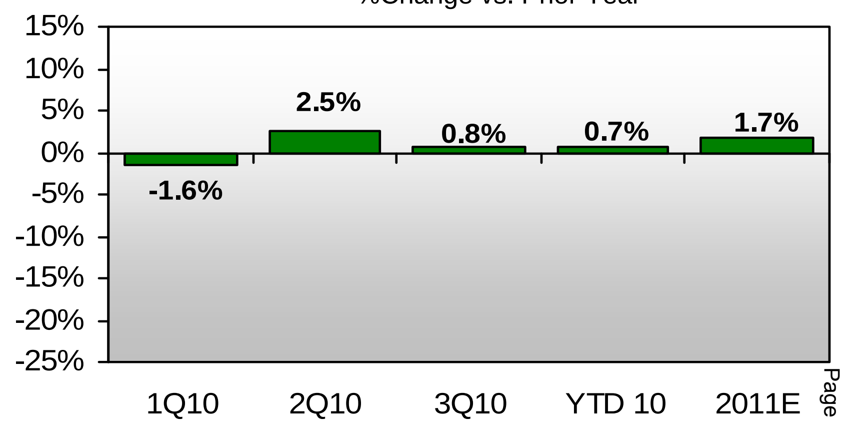
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year

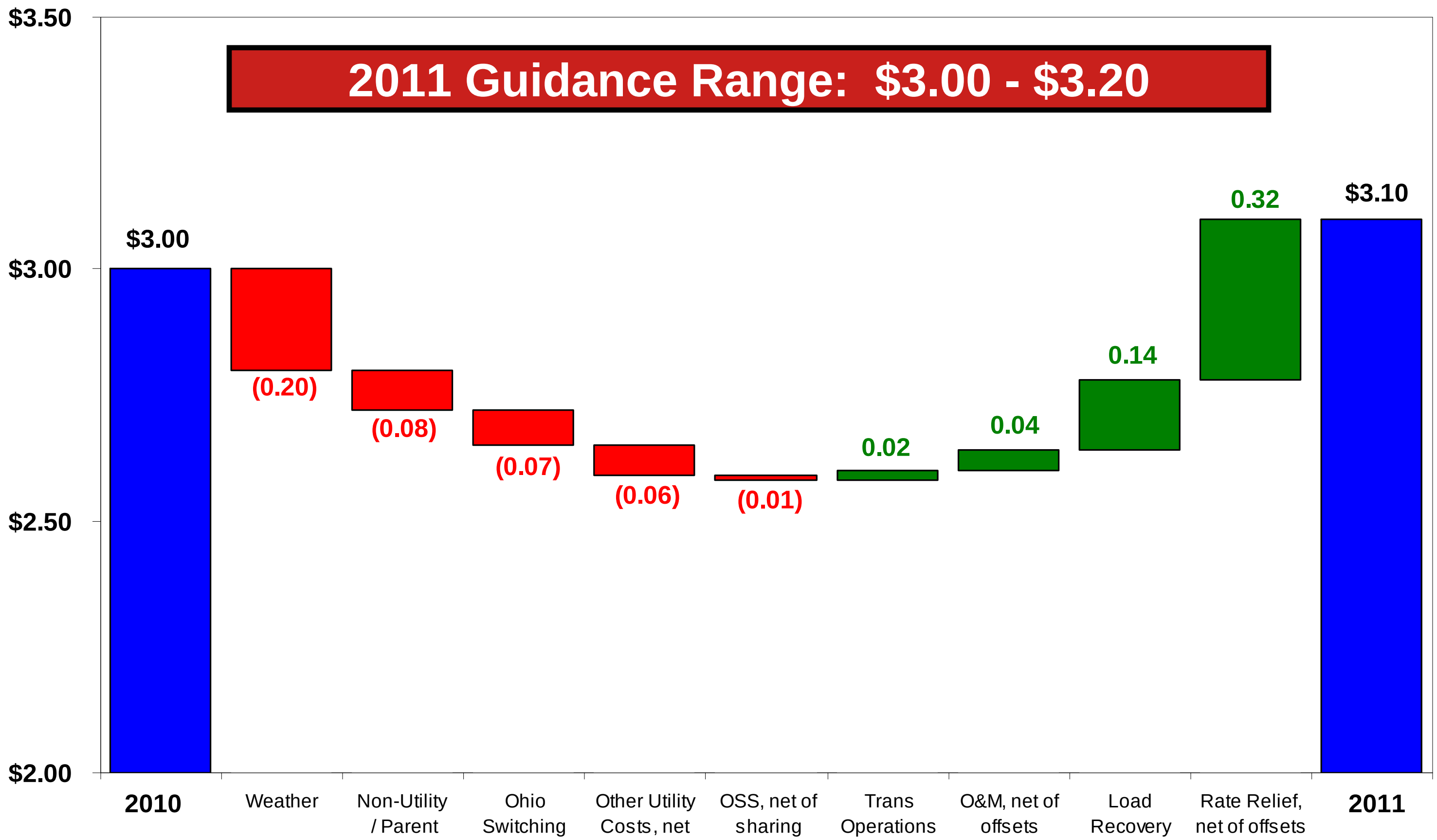


*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

2011 Earnings Drivers

AEP®



- $235M in rate relief (67% already secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $23M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

Capital for Growth

- Increase in capital budget of $150M for 2011 to $2.6B
- Announce capital budget plan of $2.9B for 2012

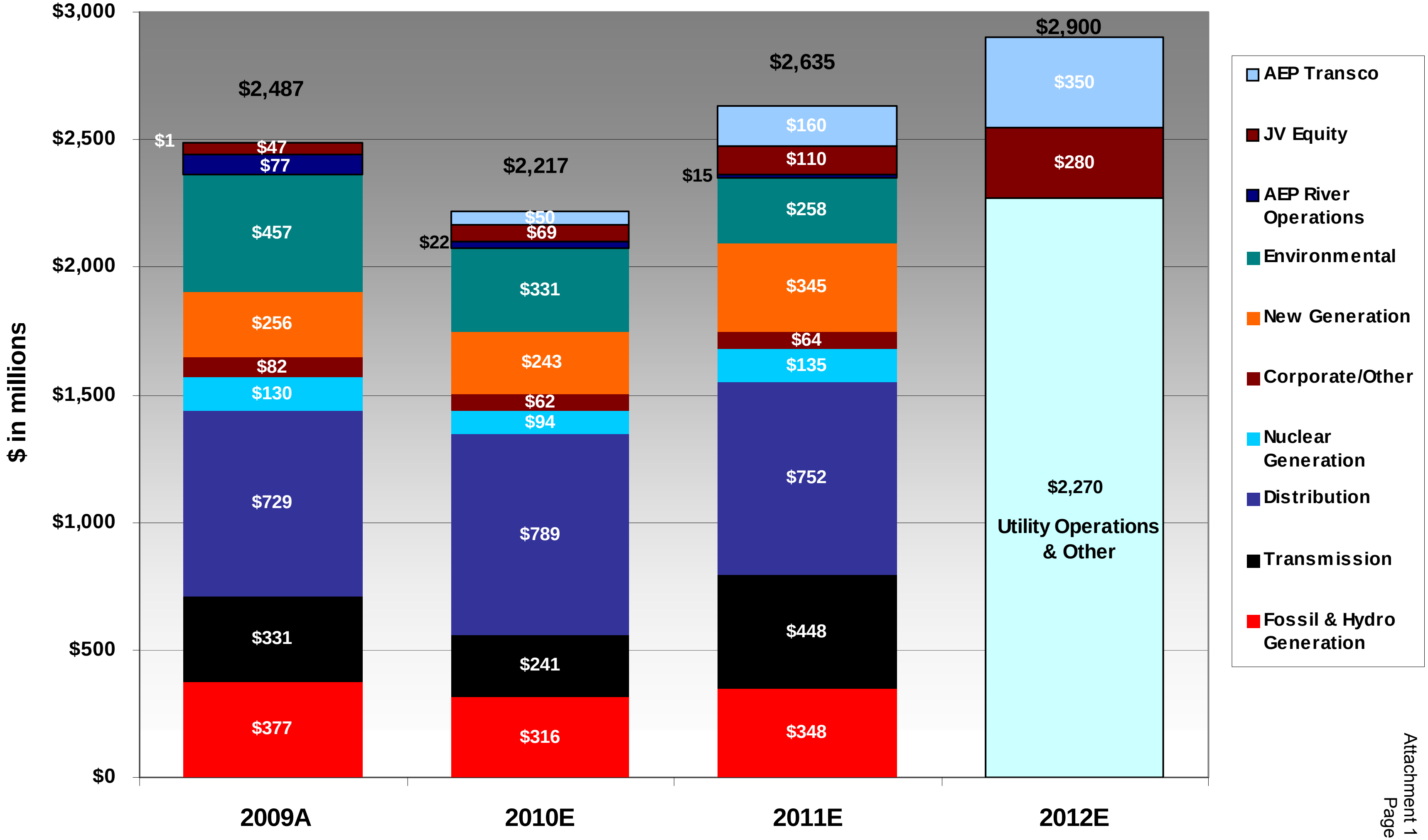
Return of Capital to Shareholders

- 9.5% increase in quarterly dividend beginning in the fourth quarter, subject to board of directors approval
- Future dividend increases will grow with earnings

Capital to Reduce Risk

- Voluntarily funding pension $500M in 2010
- Allocating an additional $150M of funding for pension in 2011

Capital Expenditures



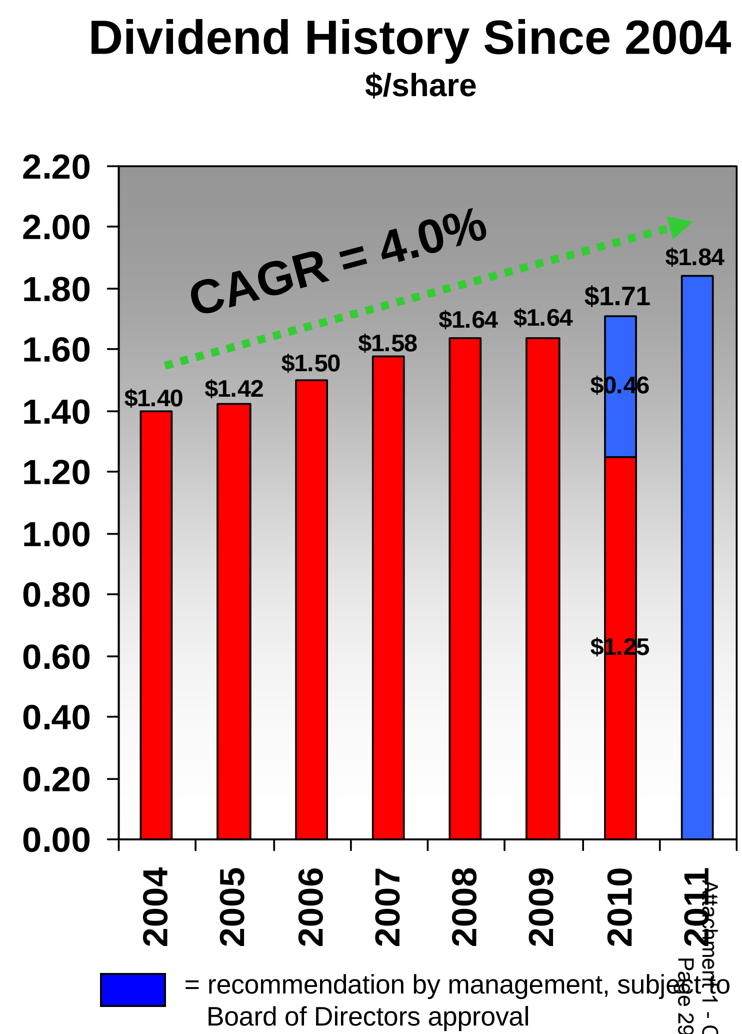
Liquidity and Financing

- Strong liquidity position supported by core Credit Facilities
  - Two $1.5B credit lines underpin liquidity position
    - Renewed 3-year $1.5B credit line in June 2010
    - Other $1.5B facility expires in April 2012, expect to address this renewal in 2011
  - Both facilities are undrawn

- Financing highlights
  - Cash flow and capital spending plan keep balance sheet stable
  - Committed to solid-investment grade credit metrics (BBB/Baa2)
    - Debt-to-Capital of 55-59%
    - FFO/Debt in the mid- to high teens
  - Debt Financing
    - Maturities total $620M in 2011
    - Net debt increases about $50M

Dividend Policy and Recommendation

- Long history of dividend payments
  - Paid 401st consecutive quarterly dividend in September
  - Record of dividend growth
- Management will recommend increasing quarterly dividend by 9.5% in fourth quarter, subject to Board of Directors approval
  - Quarterly payout increases from $0.42/share to $0.46/share
  - Annual payout increases to $1.84/share
- Dividend Policy
  - 50-60% payout ratio
  - For 2011, the payout ratio would be at the high end of the range (59.4% at the mid-point of guidance)
  - Expect future dividend growth consistent with earnings growth

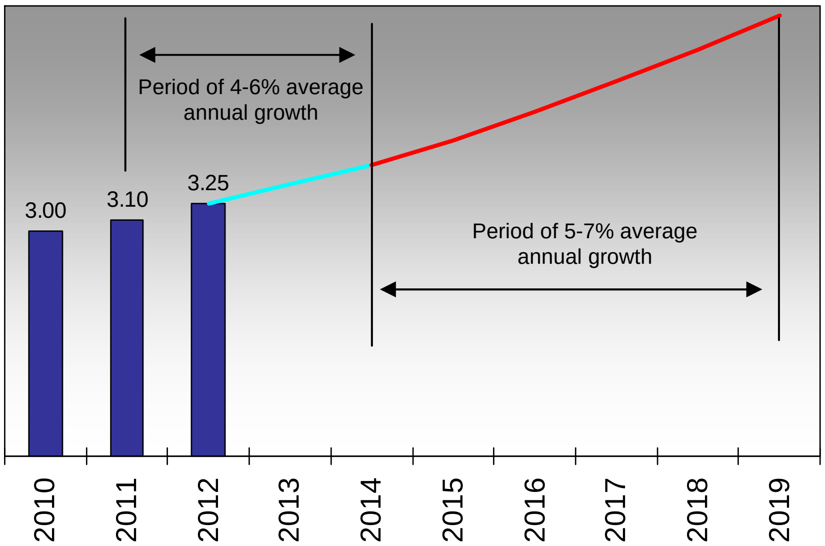


Dividend growth consistent with earnings growth since 2004

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Recap

What you heard today

- Operating company model provides additional capital efficiency and discipline
- Environmental compliance will continue to provide rate base growth opportunities
- Transmission is moving forward with ETT, Transco and PATH, all near-term opportunities

Total Return Proposition

- >5% dividend yield at $36/share
- 4-6% EPS growth over the 2012-2014 timeframe
- Higher growth of 5-7% post 2014

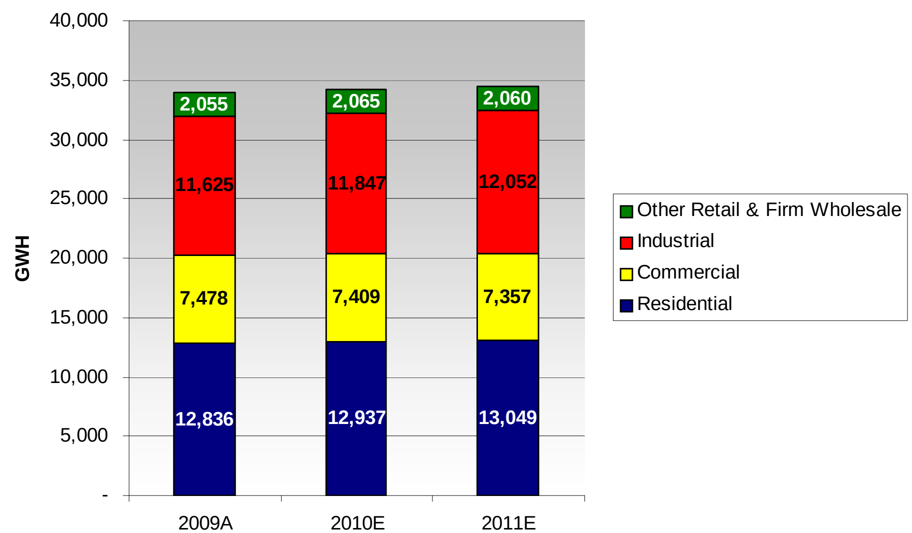
Setting EPS target of $3.25/share for 2012

APPENDIX

Overview of Appalachian Power

Total Customers at 12/31/09:		
Residential	817,600	85%
Commercial	129,800	14%
Industrial	4,300	<1%
Other	7,100	1%
Total	958,800	
Generating Capacity	6,287 MW	

Normalized Retail Load



Load represents Appalachian Power and Wheeling Power

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Coal Mining – 27%

Primary Metals – 14%

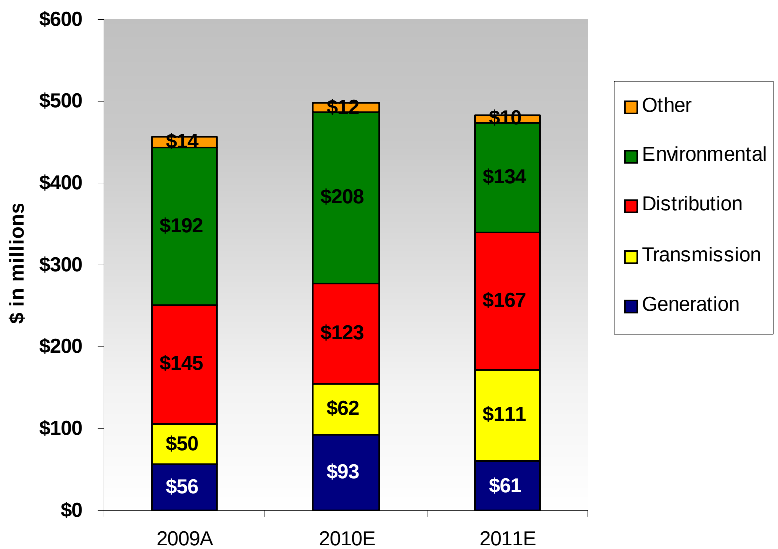
Electric/Gas/Sanitary Services – 9%

Chemical Products – 8%

Paper Products – 7%

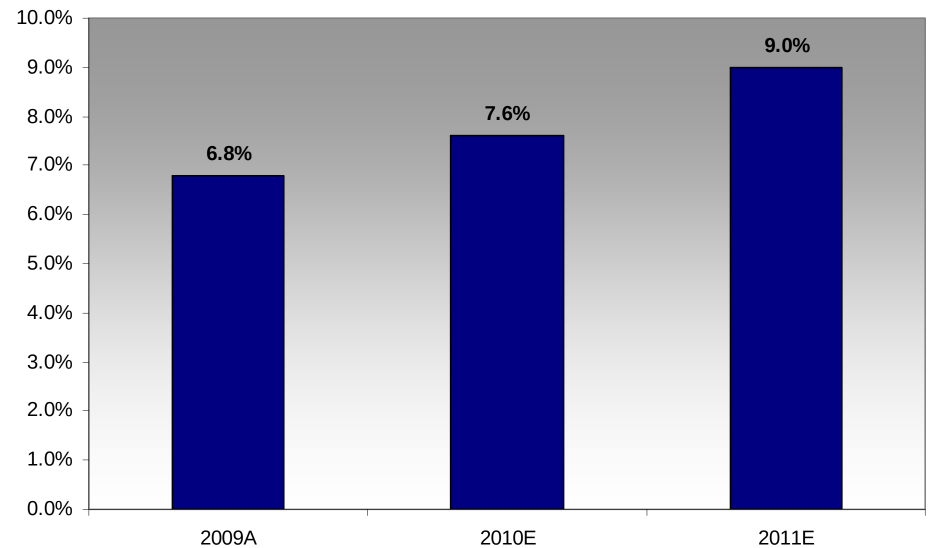
Overview of Appalachian Power

Capital Forecast



Capital represents Appalachian Power and Wheeling Power

Forecasted ROEs



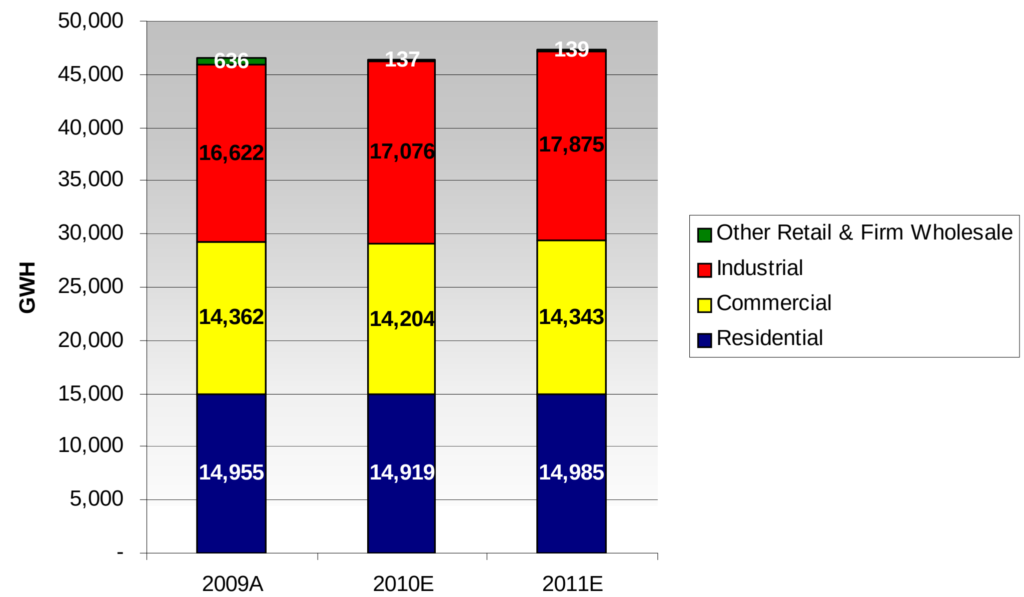
ROEs represent Appalachian Power and Wheeling Power

Major Capital Project:
Amos Plant Unit 1 Scrubber

Current and Future Regulatory Activity:
WV Base Rate Case
VA Biennial Base Rate Case – March 31, 2011

Overview of AEP Ohio

Normalized Retail Load



2010E and 2011E represent connected load

Total Customers at 12/31/09:

Residential	1,274,800	87%
Commercial	170,900	12%
Industrial	10,500	1%
Other	2,800	<1%
Total	1,459,000	

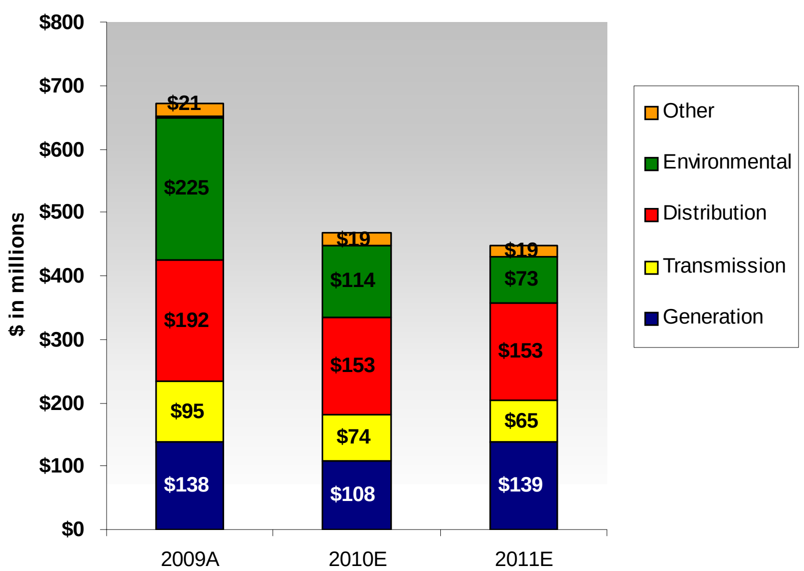
Generating Capacity 12,246 MW

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

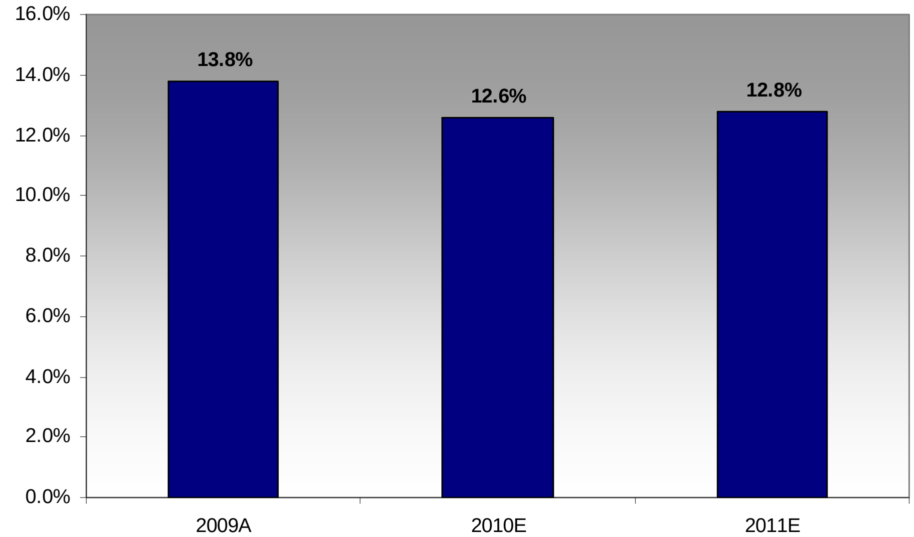
Primary Metals – 42%
Chemical Products – 9%
Petroleum Refining – 8%
Rubber/Plastic Products – 6%
Stone/Clay/Glass Products – 4%

Overview of AEP Ohio

Capital Forecast



Forecasted ROEs



Major Capital Projects:
Conesville Plant Unit 4 Scrubber
Conesville Plant Mercury Mitigation

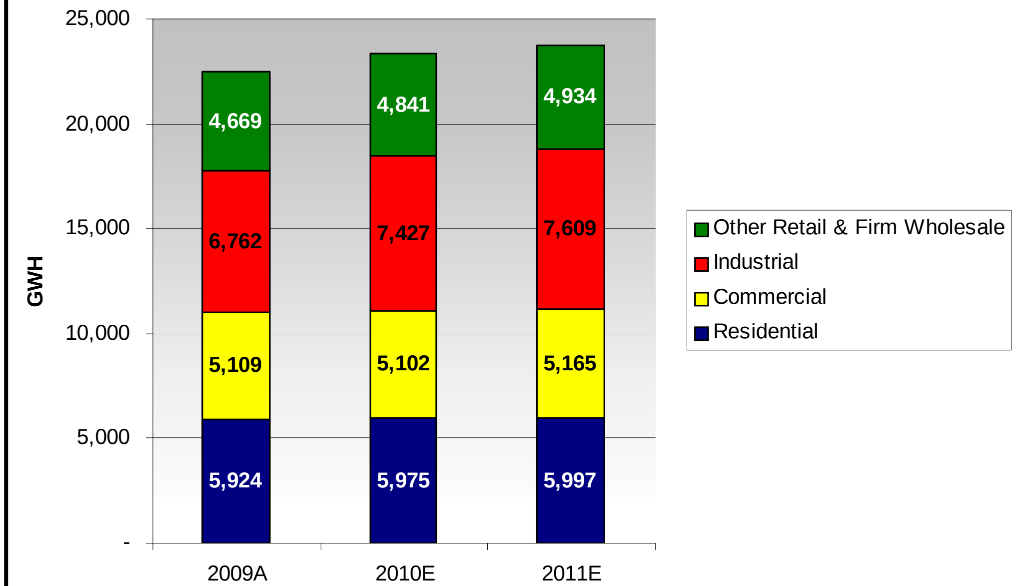
Current and Future Regulatory Activity:
2009 SEET
CSPCo/OPCo Merger
2010 SEET
2010 Environmental Rider
Electric Security Plan
Distribution Base Rate Case

Overview of Indiana Michigan Power

Total Customers at 12/31/09:

Residential	507,200	87%
Commercial	68,400	12%
Industrial	5,100	1%
Other	2,000	<1%
Total	582,700	
Generating Capacity	4,511 MW	

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Primary Metals – 38%

Chemical Products – 11%

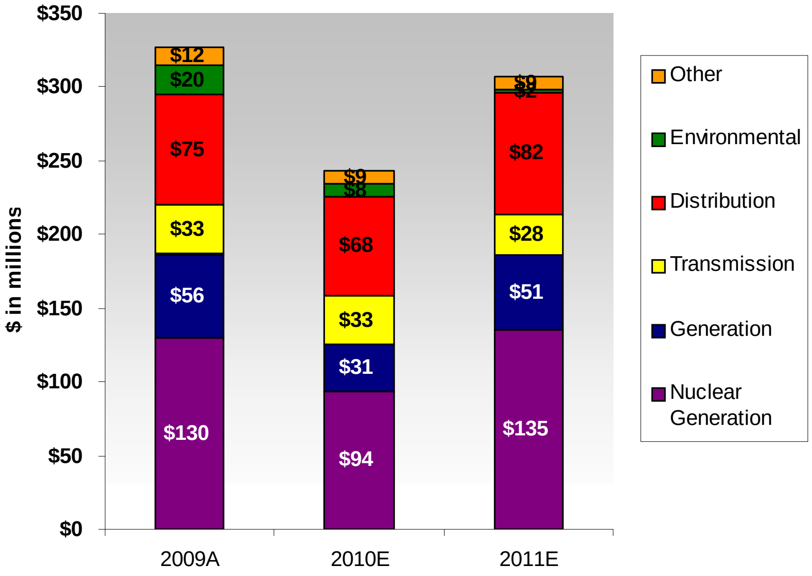
Transportation Equipment – 7%

Rubber/Plastic Products – 9%

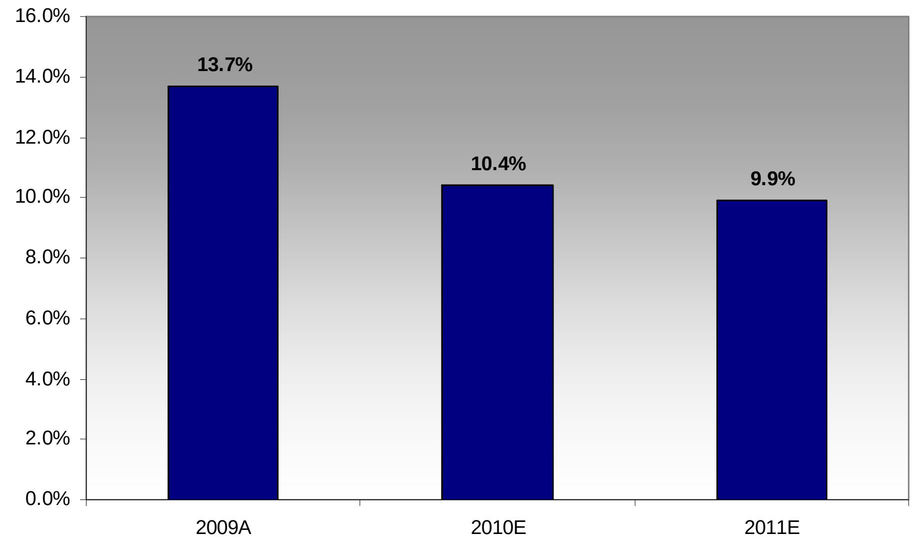
Fabricated Metal Products – 6%

Overview of Indiana Michigan Power

Capital Forecast



Forecasted ROEs



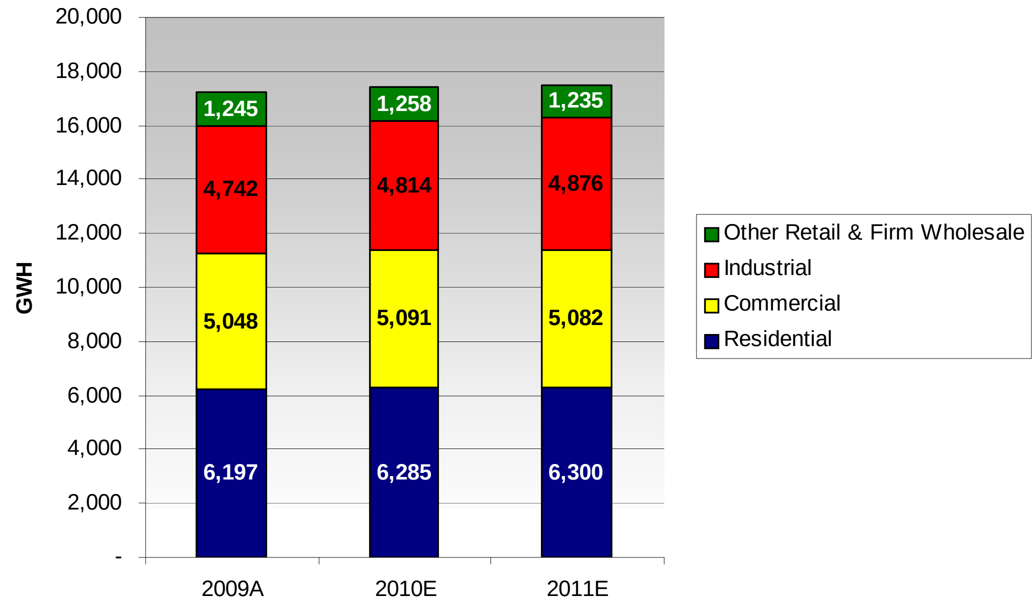
Major Capital Projects:
Cook Plant Life Cycle Management and Dry Cask Fuel Storage

Current and Future Regulatory Activity:
No major filings announced

Overview of PSO

Total Customers at 12/31/09:		
Residential	457,000	87%
Commercial	59,900	11%
Industrial	6,600	1%
Other	7,200	1%
Total	530,700	
Generating Capacity	4,408 MW	

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Paper Products – 17%
Oil & Gas Extraction – 13%
Transportation Equipment – 8%
Stone/Clay/Glass Products – 8%
Petroleum Refining – 8%

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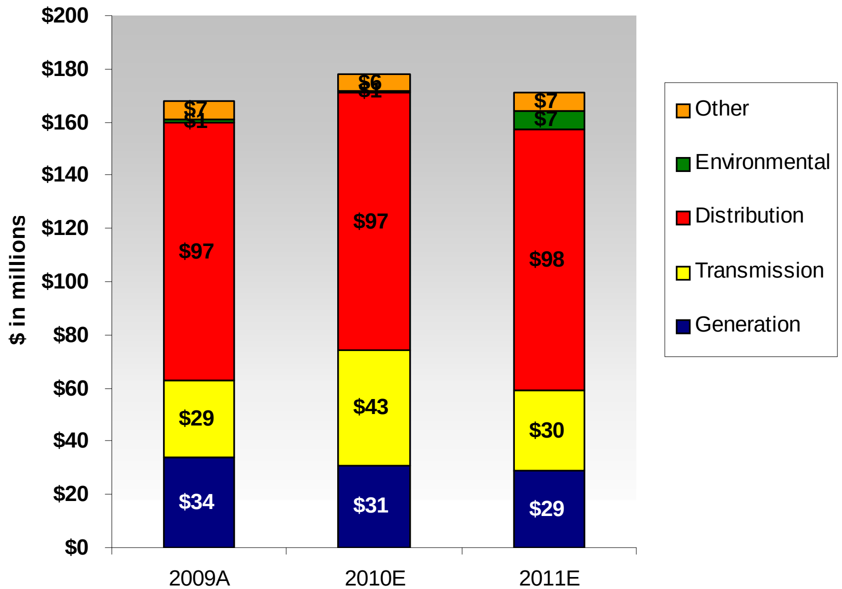
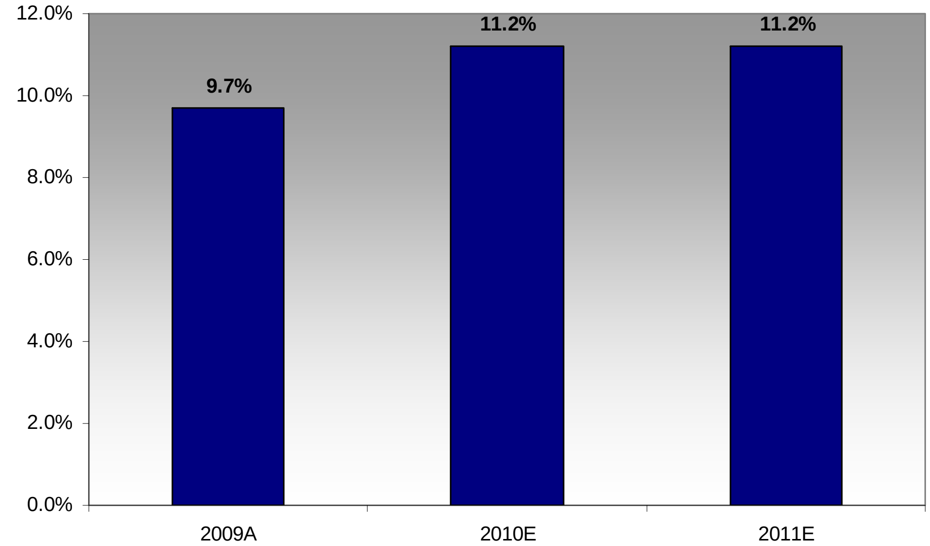
Overview of PSO

Capital Forecast



Forecasted ROEs



Major Capital Projects:
No major projects

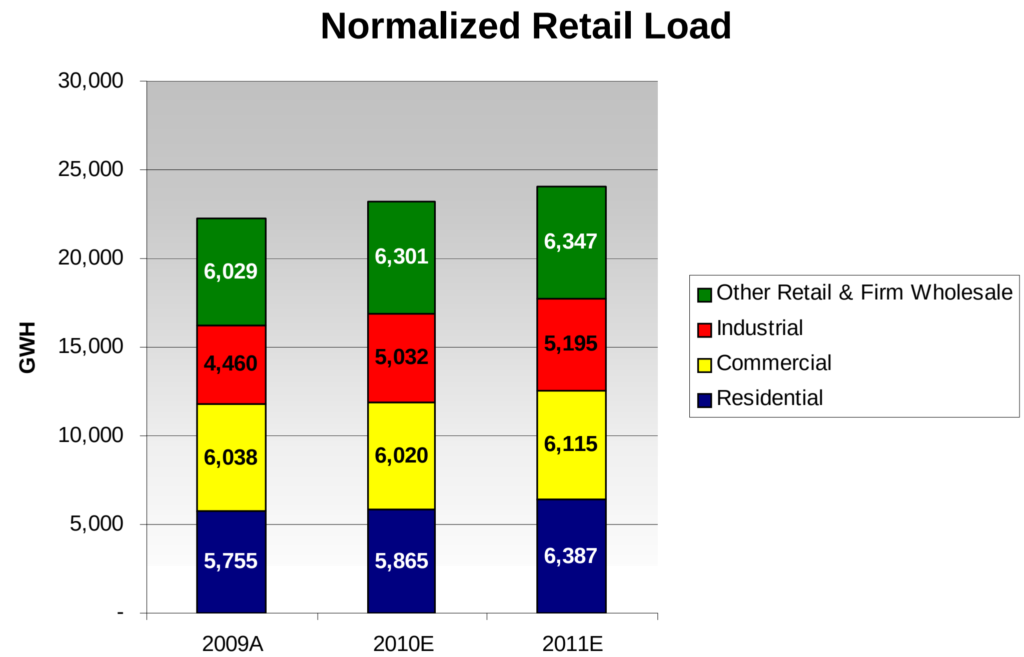
Current and Future Regulatory Activity:
OK Base Rate Case

Overview of SWEPCO

Total Customers at 12/31/09:		
Residential	400,000	84%
Commercial	66,300	14%
Industrial	7,200	2%
Other	500	<1%
Total	474,000	

Generating Capacity 5,307 MW *

* - includes Stall Plant capacity (509MW) that came on line in June 2010



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Food Products – 16%

Oil & Gas Extraction – 15%

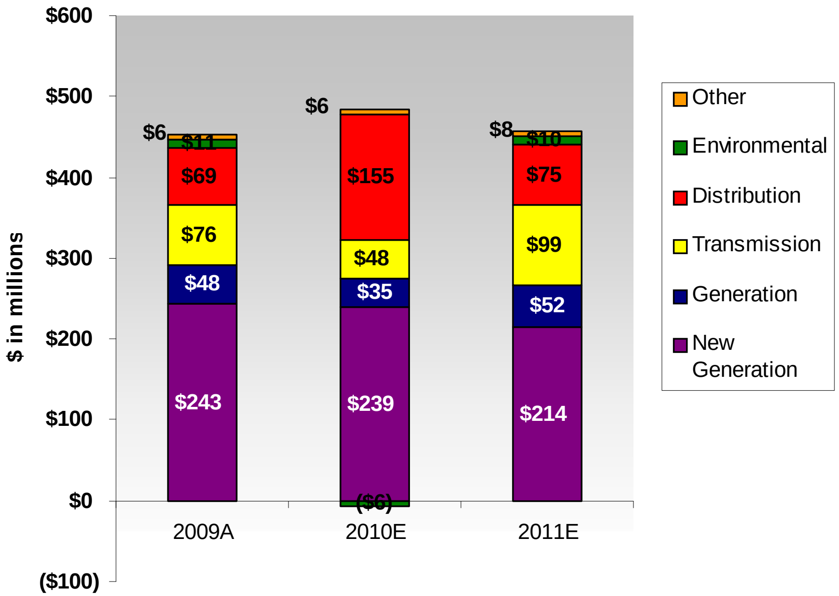
Paper Products – 14%

Petroleum Refining – 6%

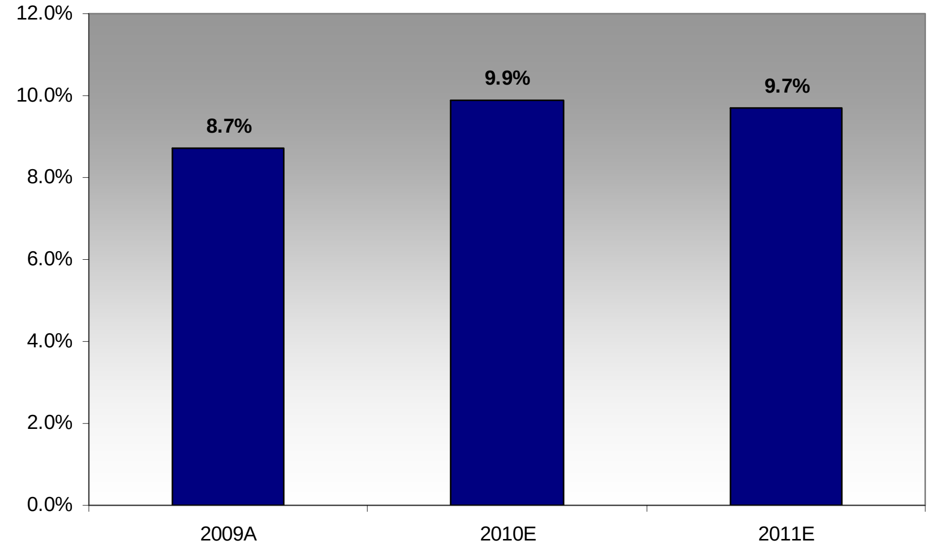
Chemical Products – 6%

Overview of SWEPCO

Capital Forecast



Forecasted ROEs

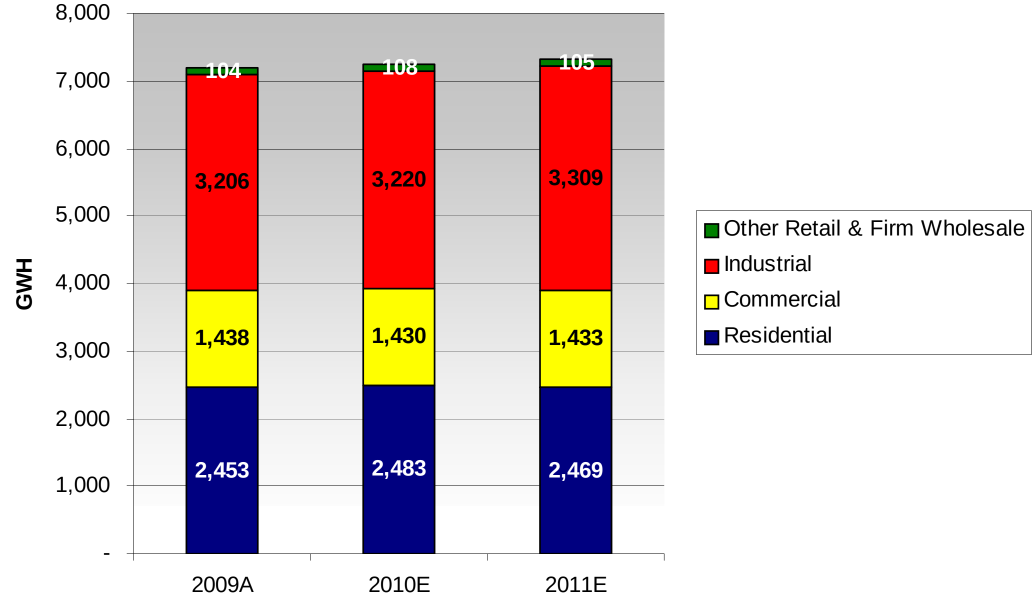


Major Capital Project: John W. Turk Plant

Current and Future Regulatory Activity: Turk Plant Recovery – LA and TX

Overview of Kentucky Power

Normalized Retail Load



Total Customers at 12/31/09:

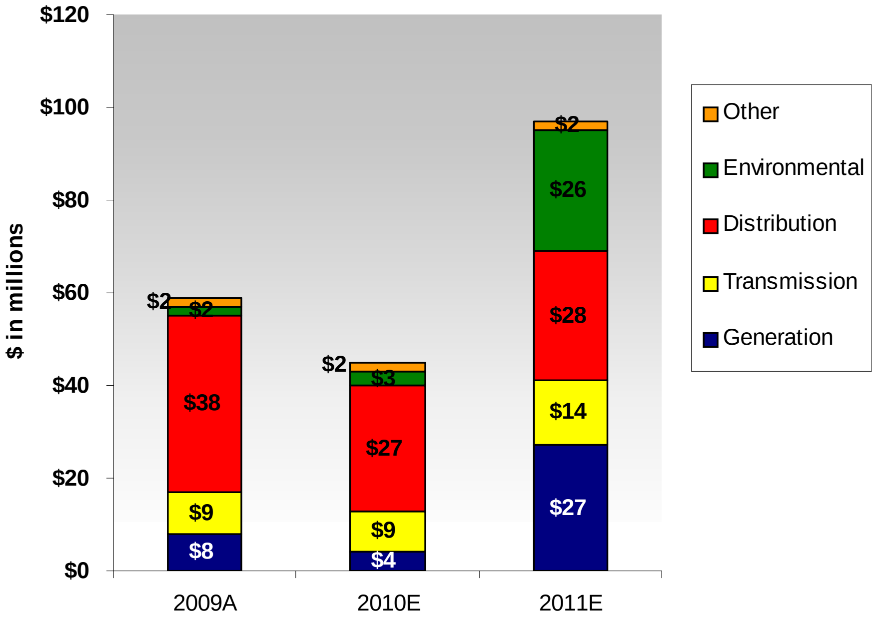
Residential	143,600	82%
Commercial	29,600	17%
Industrial	1,400	1%
Other	400	<1%
Total	175,000	
Generating Capacity	1,078 MW	

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

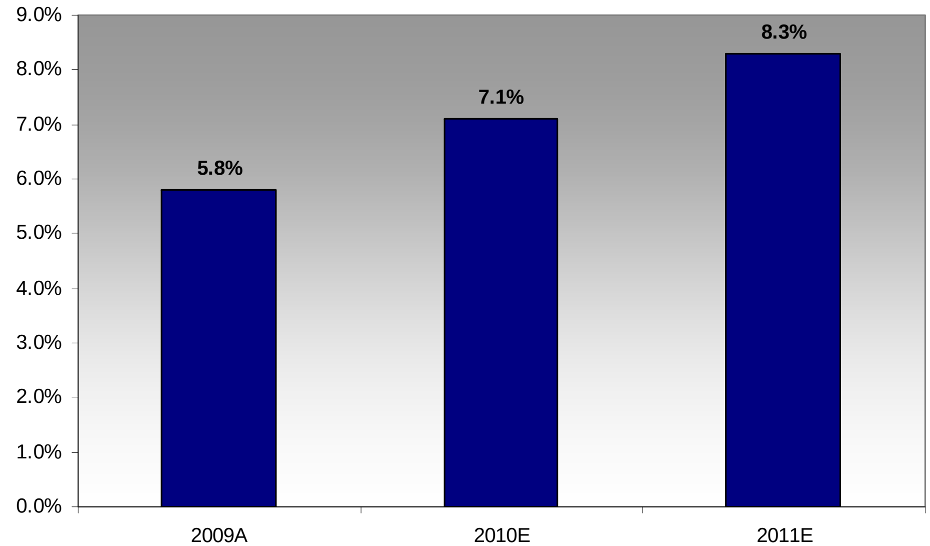
Petroleum Refining – 36%
Coal Mining – 32%
Primary Metals – 11%
Chemical Products – 10%
Electric/Gas/Sanitary Services – 5%

Overview of Kentucky Power

Capital Forecast



Forecasted ROEs



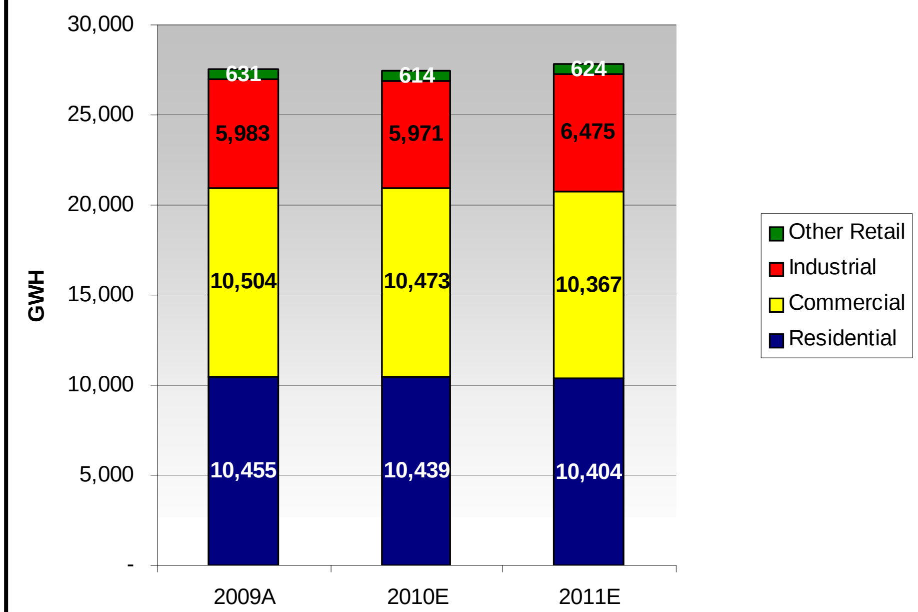
Major Capital Project:
No Major Projects

Future Regulatory Activity:
No major filings announced

Overview of AEP Texas

Total Customers at 12/31/09:		
Residential	799,400	84%
Commercial	135,100	14%
Industrial	9,700	1%
Other	7,000	1%
Total	951,200	
Generating Capacity	377 MW	

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Petroleum Refining – 39%

Chemical Products – 29%

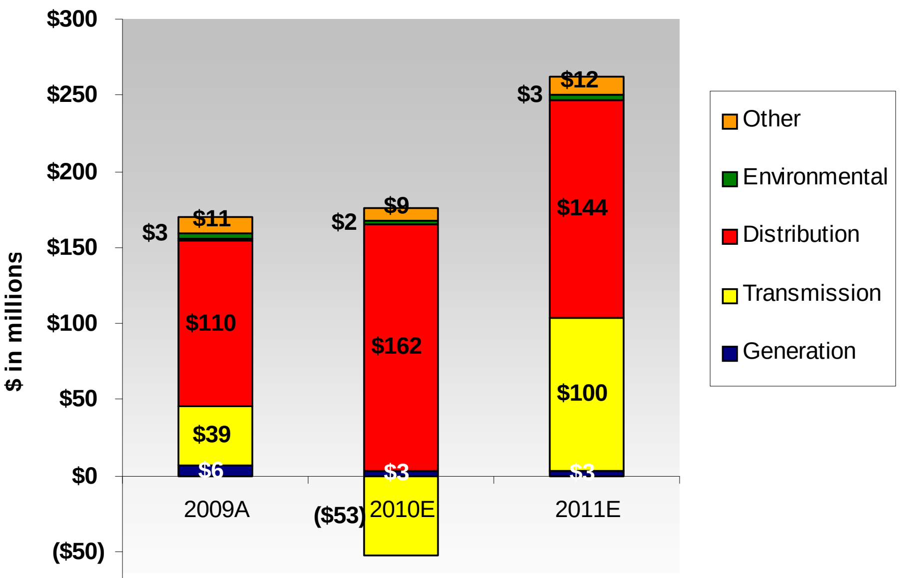
Oil & Gas Extraction – 12%

Food Products – 4%

Pipelines (excluding Nat Gas) – 1%

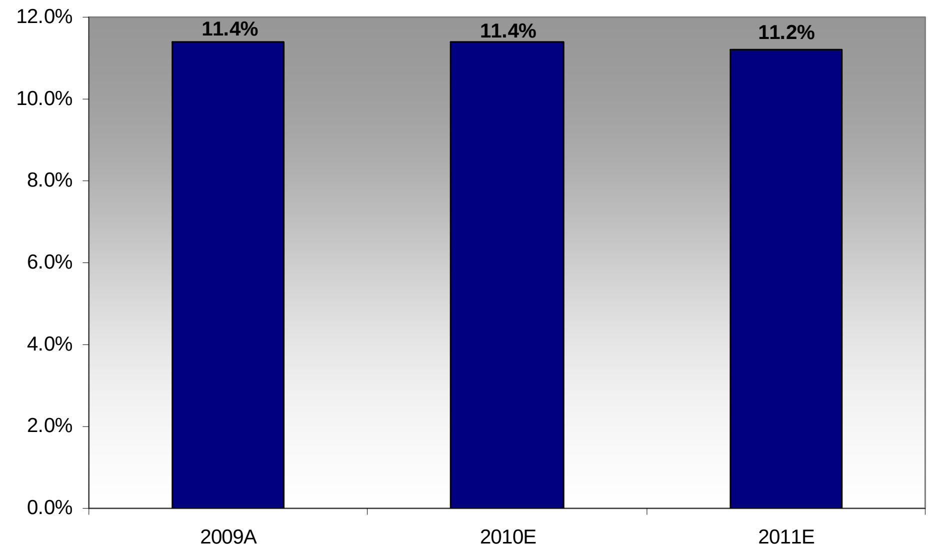
Overview of AEP Texas

Capital Forecast



Note: ($53) million in 2010E capital represents transfer of assets to Electric Transmission Texas

Forecasted ROEs



Major Capital Projects: AMI Deployment

Future Regulatory Activity: TCOS Filings

Detailed Ongoing Earnings Guidance

AEP®

2010E: $2.95 - $3.05

2011E: $3.00 - $3.20

American Electric Power

Financial Results for 2011 Guidance vs 2010 Projection

		Performance Driver	2010 Projection ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		[illegible]1
18	Generation & Marketing		20		[illegible]2
19	Parent & Other On-Going Earnings		(22)		([illegible]3)
20	ON-GOING EARNINGS		1,439		1,[illegible]06

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Cash Flow Guidance

	$ in millions	
	2010E	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,205	$ 1,499
Depreciation & Amortization	1,654	1,588
Pension Funding	(500)	(150)
Other Cash Flow Items	653	234
Working Capital[1]	(218)	424
Cash From Operations	$ 2,794	$ 3,595
Investing Activities		
Construction Expenditures	(2,217)	(2,635)
Other Investing Activity	(352)	(265)
Total Investing Activities	$ (2,569)	$ (2,900)
Financing Activities		
Dividends	(826)	(893)
Net Debt Issued/(Retired)[1]	190	48
Common Equity	121	150
Total from Financing Activities	$ (515)	$ (695)
Beginning Cash Balance	$ 490	$ 200
Ending Cash Balance	$ 200	$ 200

[1] 2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Pension and OPEB Estimate

- Investment returns for our pension plan and OPEB funds are solid so far this year. Year-to-date, the pension fund is up about 8% through September, with similar gains in the OPEB funds.
- After making a discretionary contribution of $350 million in September, cash contributions to the pension will total $500 million for 2010.
- We currently would have no required cash contributions to the pension for 2011 but are allocating a voluntary contribution up to $150 million.
- We expect combined pension and OPEB expense to decrease $34M from 2010 to 2011 (pre-tax and pre-capitalization).
- Discount rates are assumed to be 5.6% for pension and 5.85% for OPEB for 2010, and 4.75% and 5.0% for 2011 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

AMERICAN ELECTRIC POWER

Strategic Direction & Financial Outlook

& 1Q09 Earnings Presentation

April 24, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

Mike Morris, Chairman, President & CEO

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER

Equity Offering – Successful Execution

Landmark Offering

- Largest US regulated electric utility equity offering in history:
  - 69MM shares (upsized 20%)
  - Gross proceeds of $1.69B
  - Largest equity offering to-date in 2009
  - Lowest file / offer discount of any non-financial follow-on offering since June 2007 at (2.3%)

Focus on Fundamentals

- Achieved key objectives:
  - Strengthened balance sheet and enhanced liquidity
  - Supports stable investment grade ratings and financial flexibility
  - No further equity proceeds needed in medium term (excluding the DRP)
  - Focused investors on operational and financial strength and unique transmission investment growth prospects, which provide diversified earnings growth and an attractive dividend yield

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AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 1,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

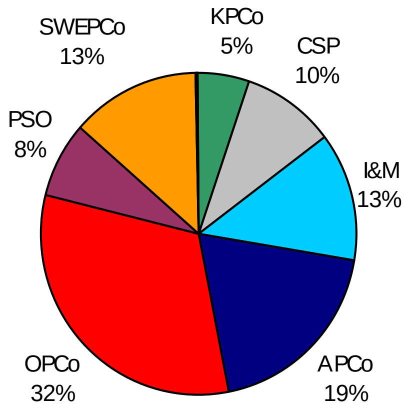
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

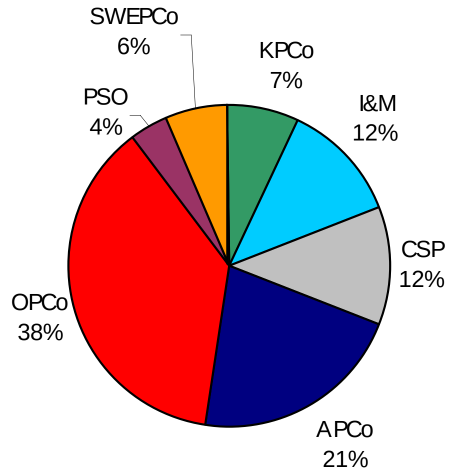
AEP AMERICAN ELECTRIC POWER

CO_2 Cost Recovery – Should Follow SO_2 & NOx

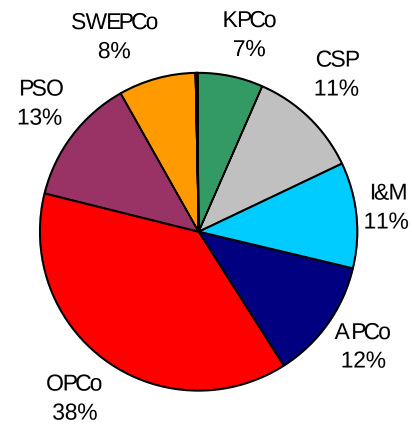
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



2008 AEP System NOx Emissions
248k tons

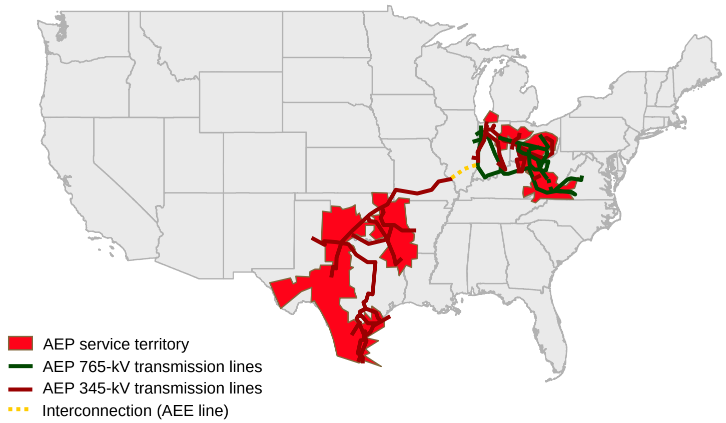


- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview



AEP's Leadership Position

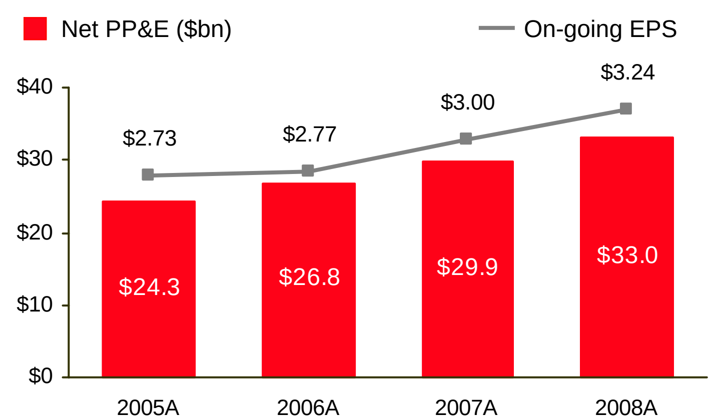
Transmission miles[1] ('000s)	
AEP	39.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0
AEE	7.4

Generation owned[1] (GW)	
SO	42.6
AEP	40.6 *
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

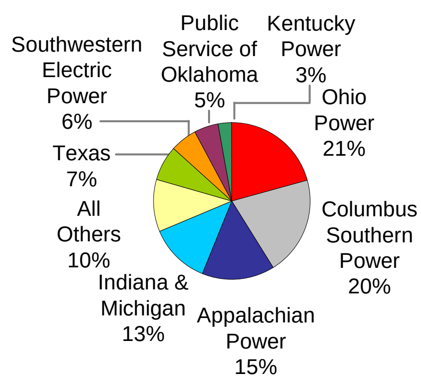
Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

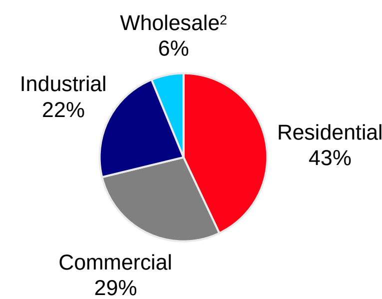
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

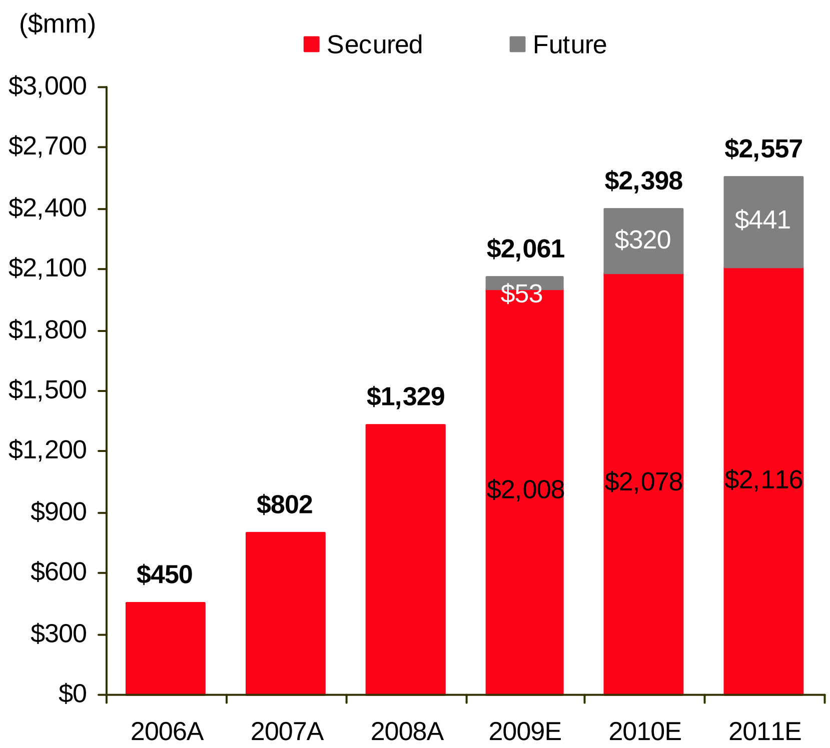
- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

AEP AMERICAN ELECTRIC POWER

Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



	2006A	2007A	2008A	2009E	2010E	2011E
Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] *$70mm and $38mm was secured for 2010 and 2011, respectively, as of March 31, 2009*

AEP AMERICAN ELECTRIC POWER

Our Regulatory Approach:

Maximize utility company returns:

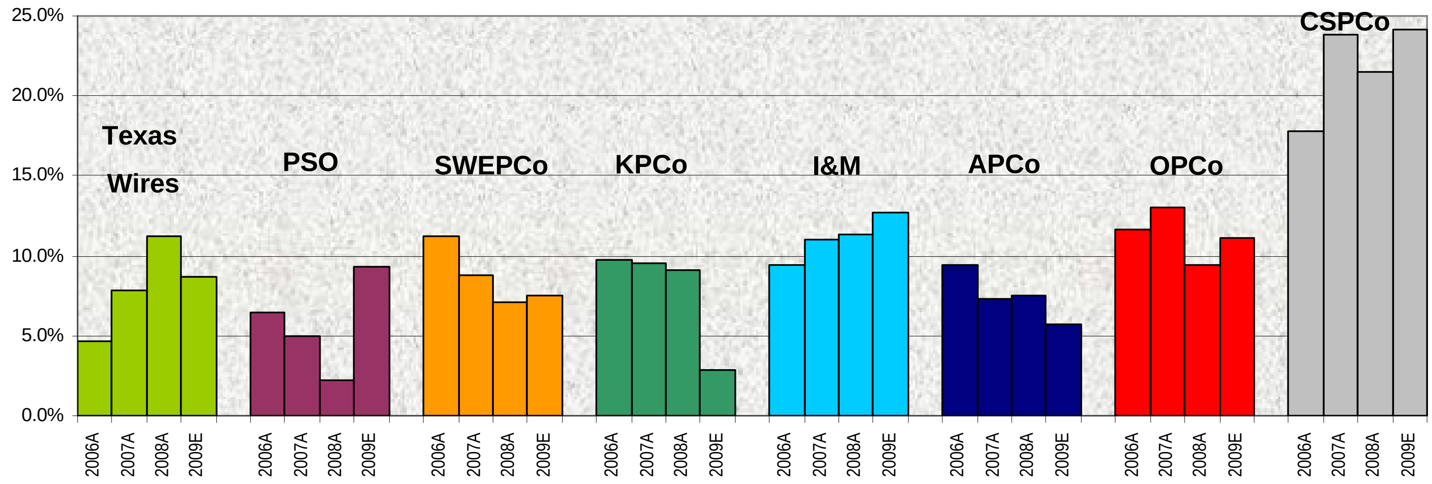
- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
  - ✓ Texas ($7MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

Net Income & Pro-Forma Earned ROE by Operating Company

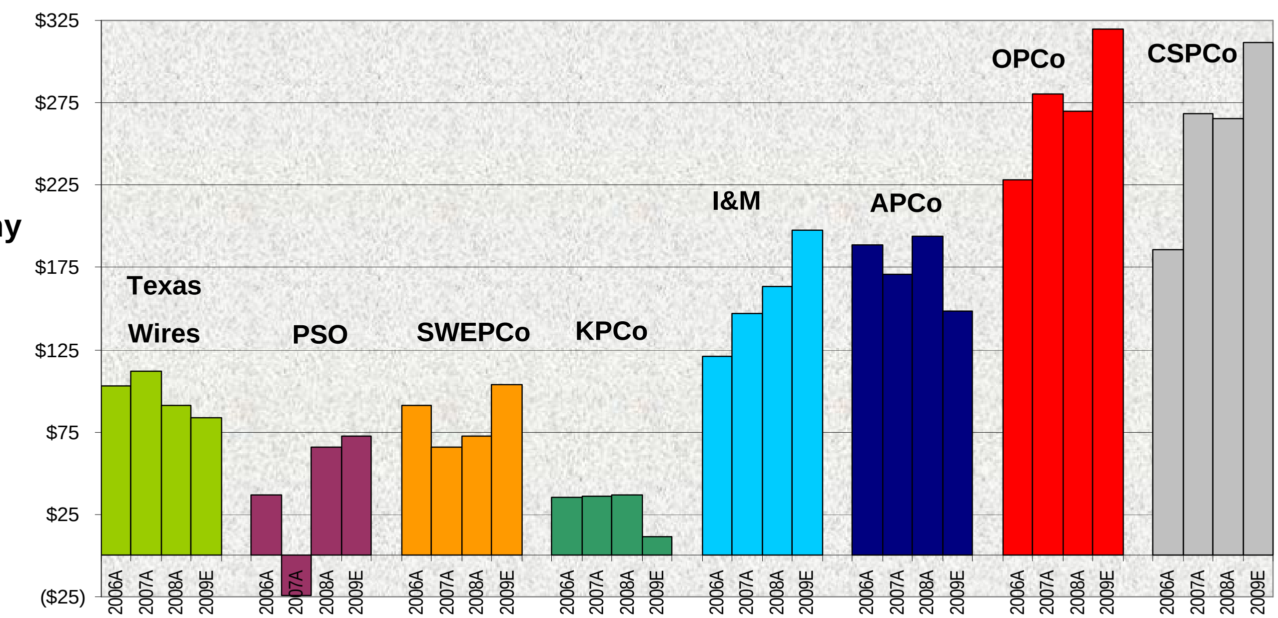


Pro-Forma Earned ROEs

Earned ROEs represent 12 months ended December 31. Regulatory Lag ranges from 3-15 months by jurisdiction.

Net Income by Operating Company

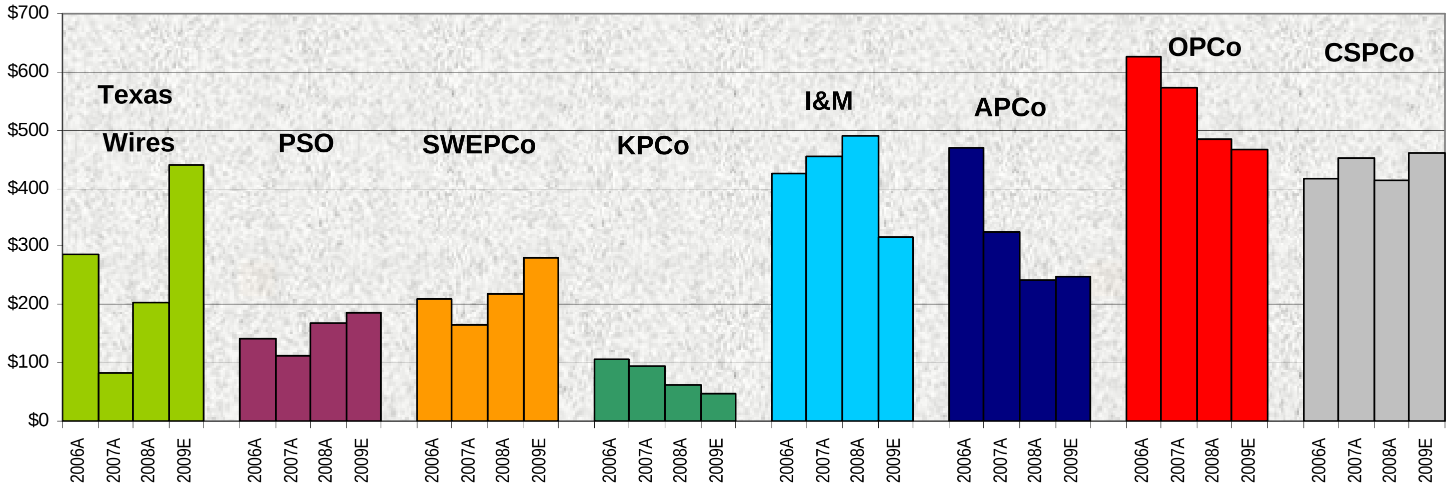
($ in millions)



AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 2984 of 9556

Cash Flow and Capex by Operating Company

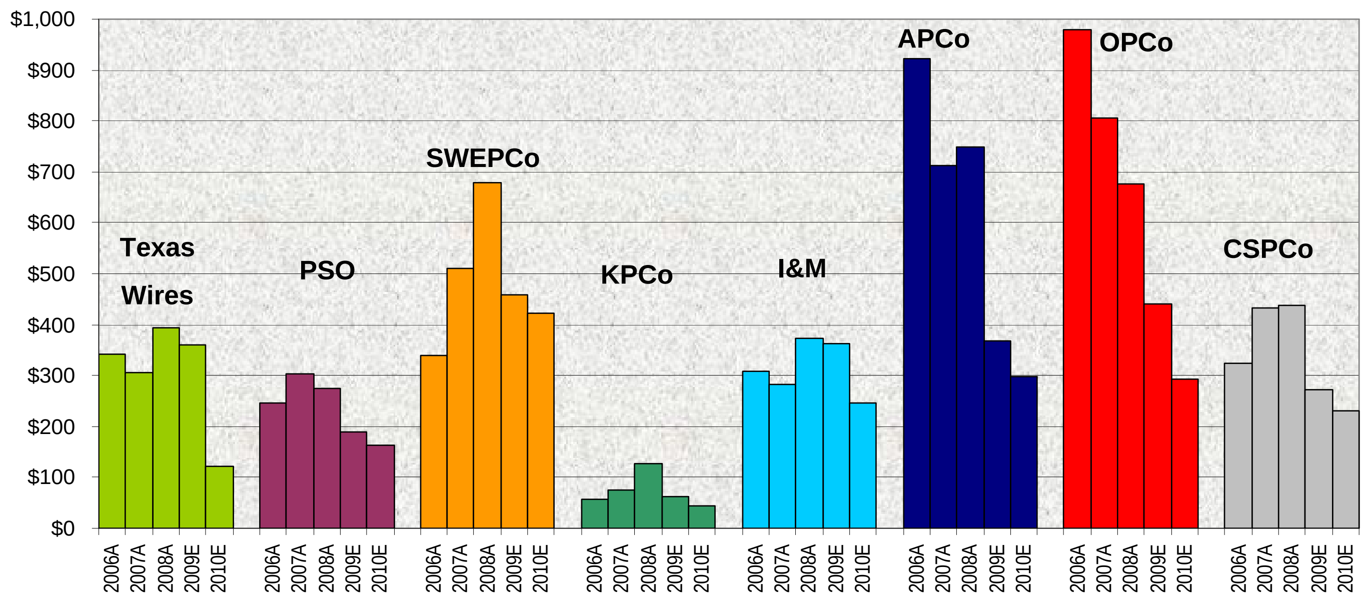


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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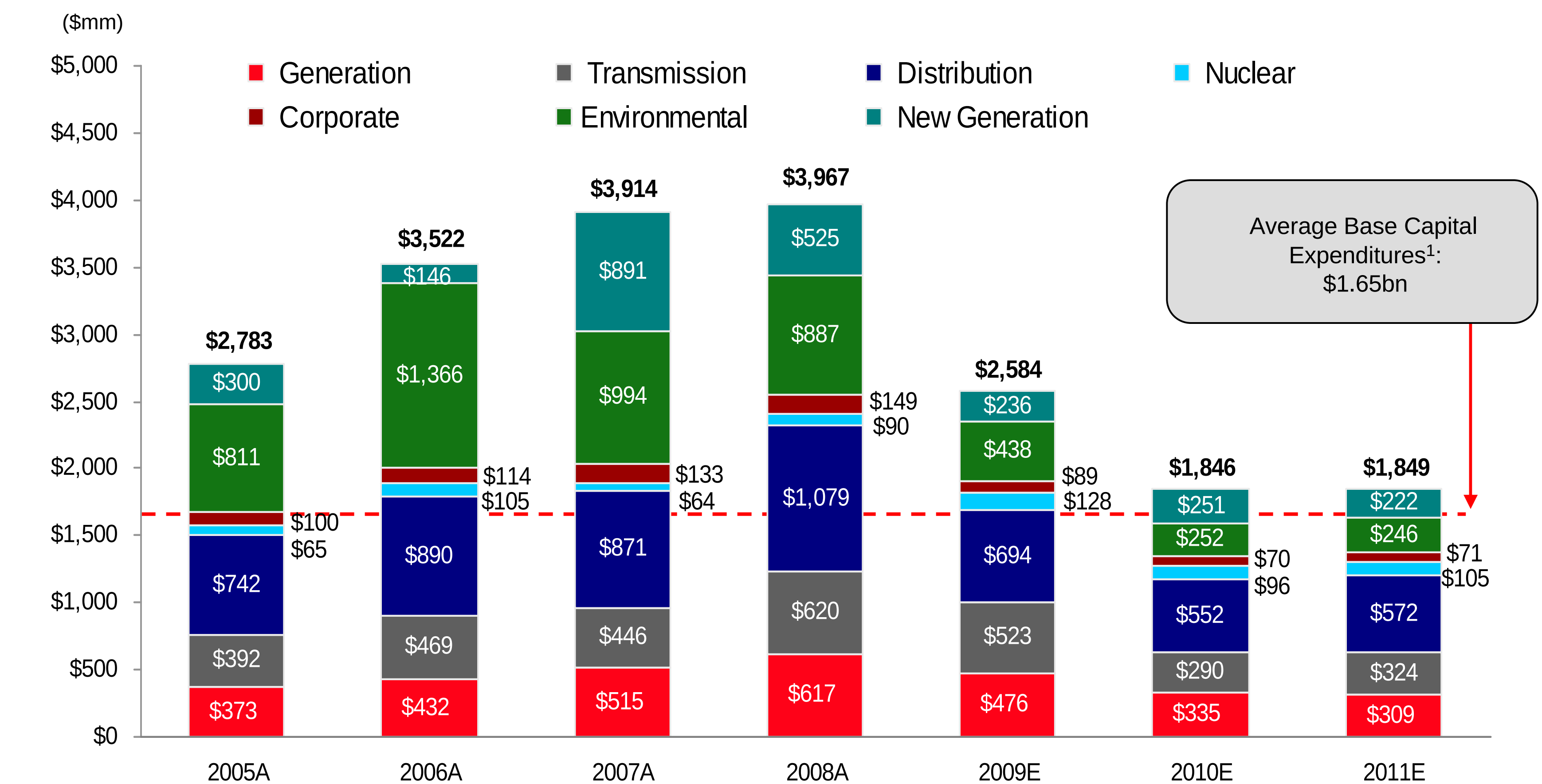
Utility Capital Expenditures Support Growth of 2 - 4%



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion

AEP AMERICAN ELECTRIC POWER

Transmission Opportunities

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

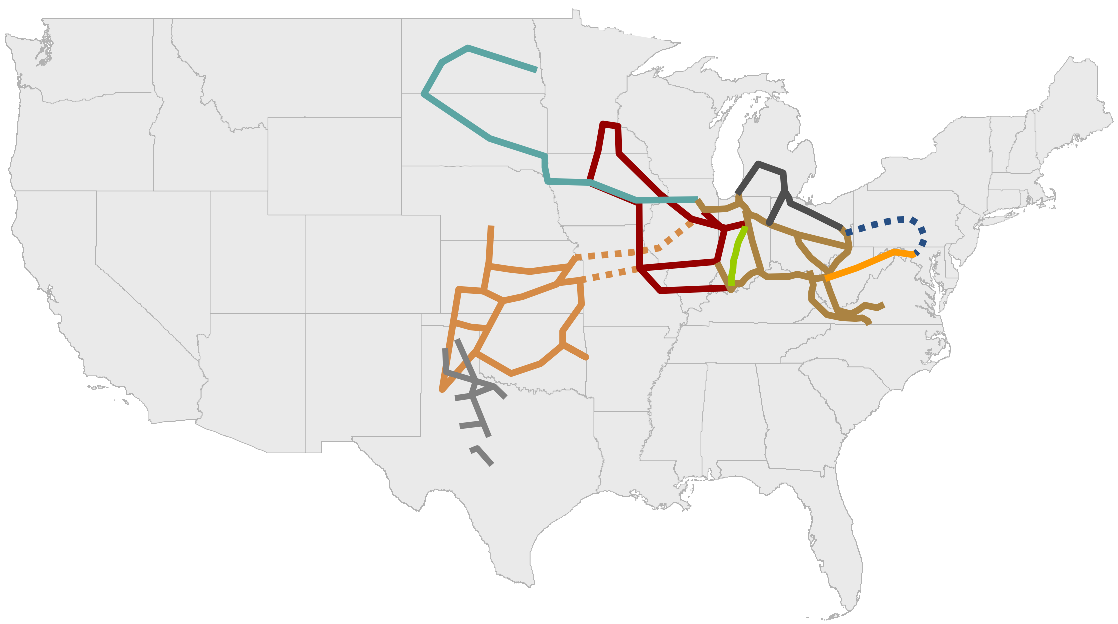
Pioneer	COD: 2015
■ 240 miles of 765 kV	
■ Partner: Duke Energy (50%)	
■ Estimated Cost: $1 billion	
■ ROE: 12.54%	

PATH-WV	COD: 2014
■ 244 miles of 765 kV	
■ Partner: Allegheny Energy (50%)	
■ Estimated Cost: $1.2 billion	
■ ROE: 14.3%	

Tallgrass	COD: 2013-14
■ 170 miles of 765 kV	
■ Partners: OG&E (50%) & MidAmerican Energy (25%)	
■ Estimated Cost: $500 million	
■ ROE: 12.8%	

Prairie Wind	COD: 2013-14
■ 230 miles of 765 kV	
■ Partners: Westar Energy (50%) & MidAmerican Energy (25%)	
■ Estimated Cost: $600 million	
■ ROE: 12.8%	

ETT	COD: 2013
■ 345 kV in ERCOT	
■ Partner: MidAmerican Energy (50%)	
■ Estimated Cost: $400 million	
■ ROE: 9.96%	



Future Projects:

EHV Michigan	COD: ~2020
■ 700 miles of 765 kV	
■ Partner: ITC	

PJM Projects	
■ Enhance existing 765/345 kV	

Hartland	COD: ~2020
■ 1000+ miles of 765 kV	
■ Partner: Hartland Wind LLC	

MISO Vision Plan	
■ 765 kV Backbone	

SPP Overlay	COD: 2013-14
■ 765 kV Backbone	

ETT	COD: ~2018
■ 345 kV in ERCOT	

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

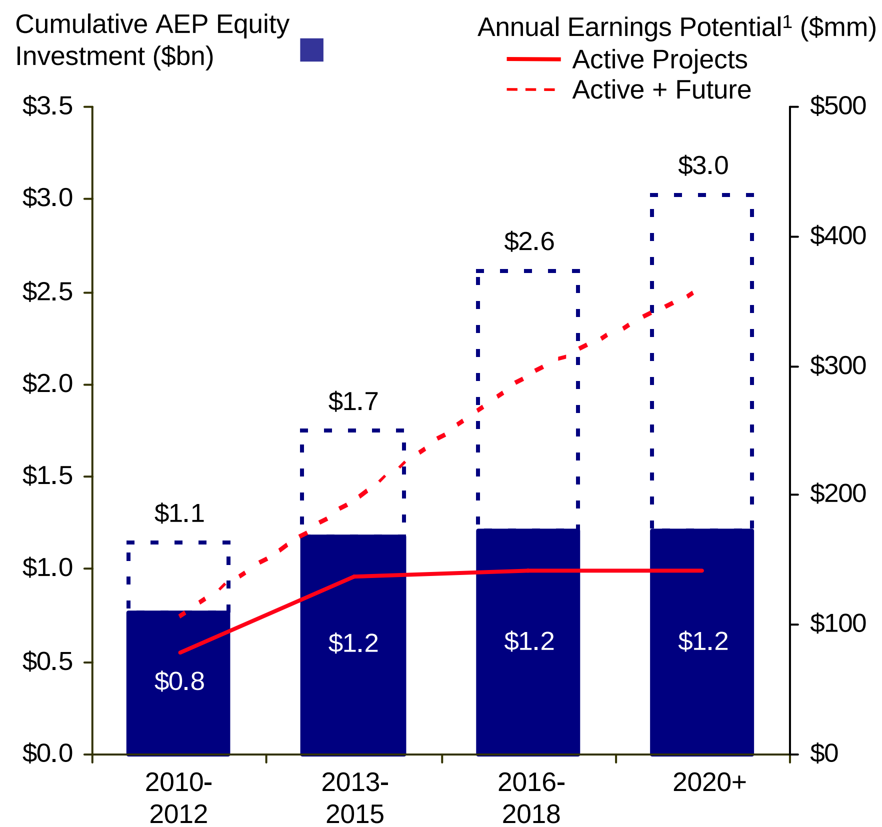
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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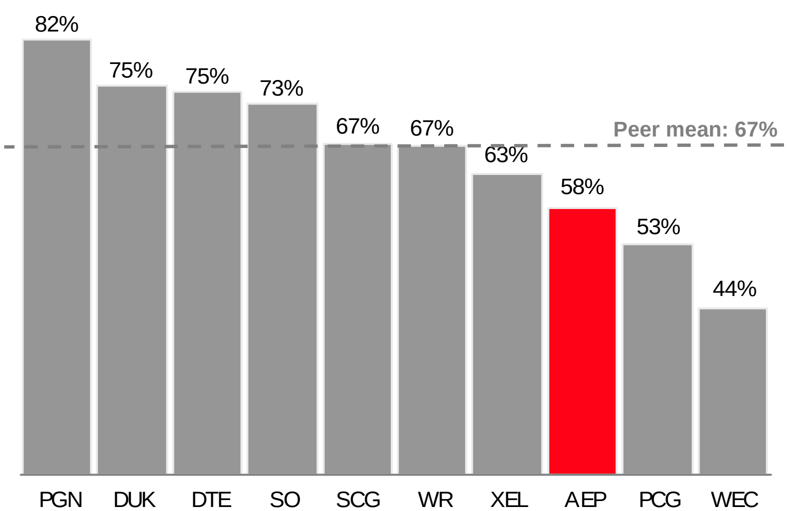
Dividend Overview

- We have paid 395 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

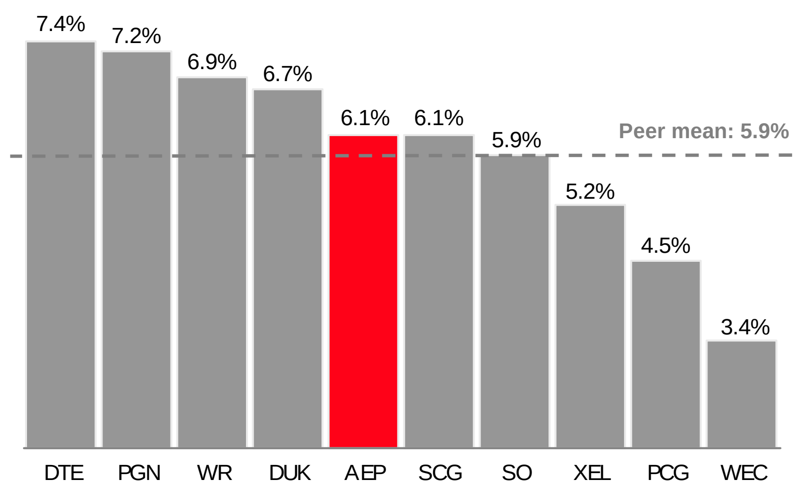
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 4/20/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 4/20/09

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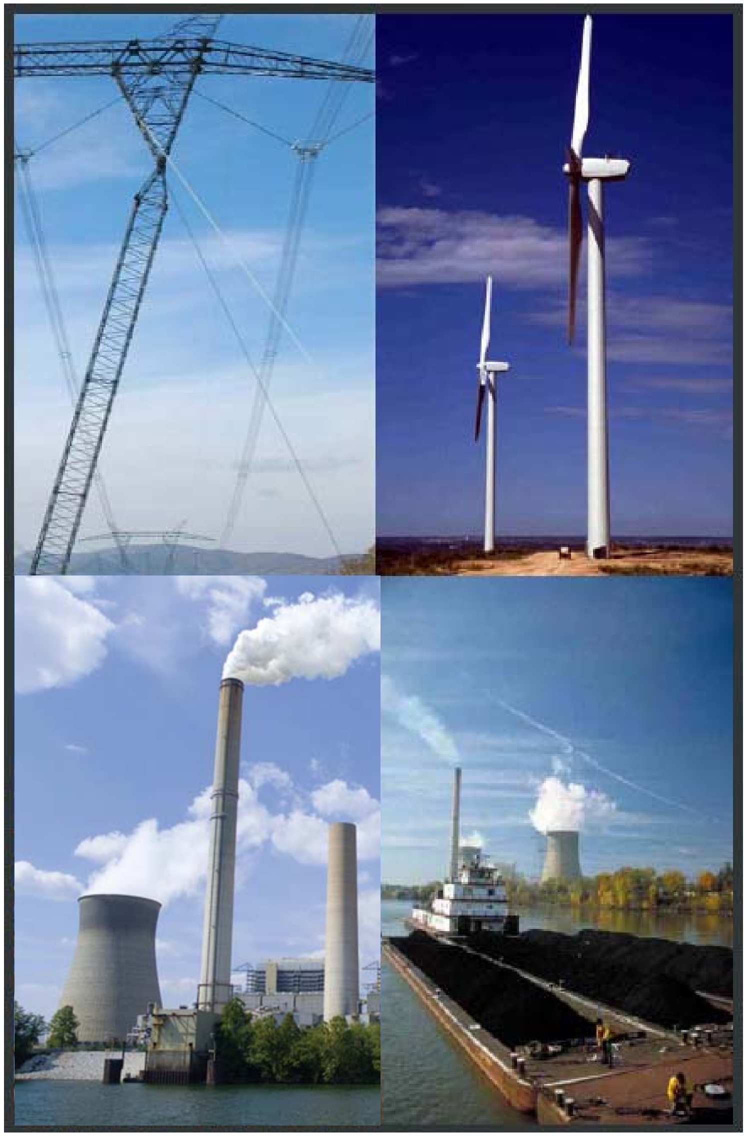
AEP is a Compelling Investment

- Market leading assets and operations
- Attractive pipeline of growth capital opportunities
- Successful regulatory management supports earnings continuity
- Strengthened balance sheet, liquidity and credit profile
- Diversified earnings growth and attractive dividend



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2009 Financial Outlook and 1st Quarter 2009 Results

Holly Koeppel, EVP & CFO

Overview of 2009 Guidance

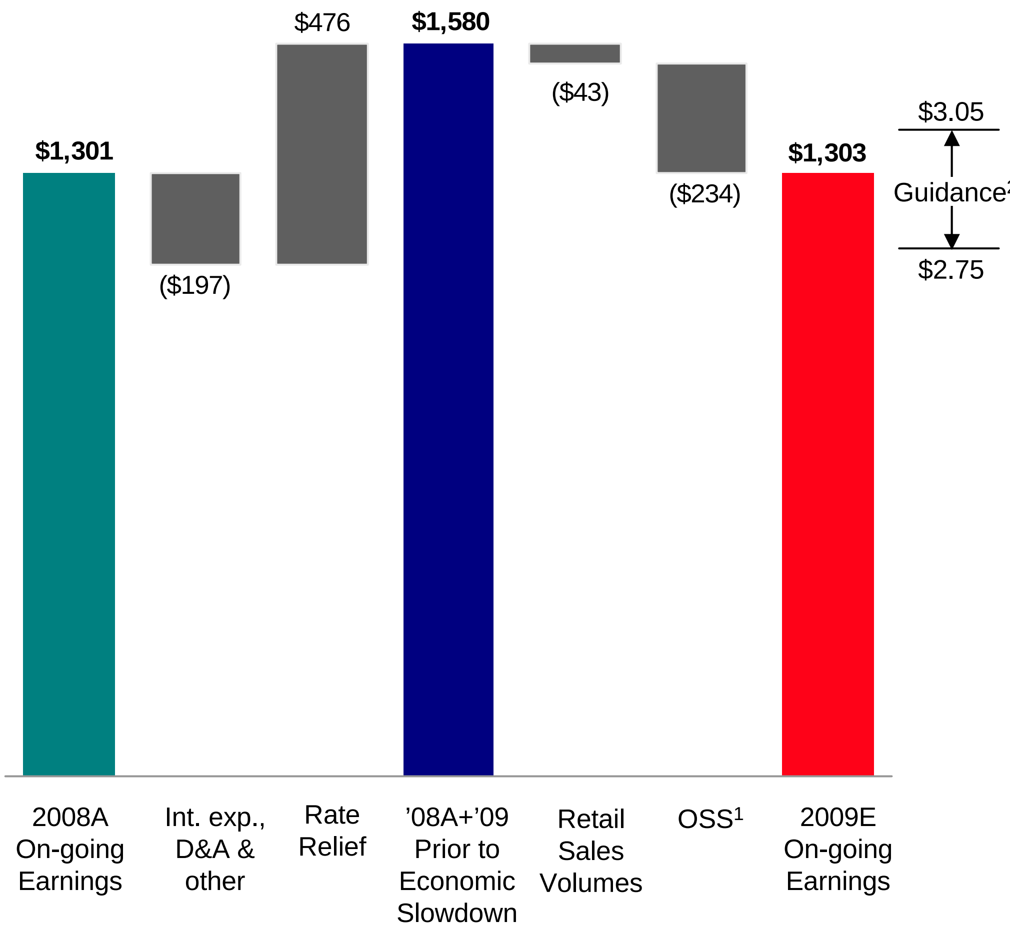
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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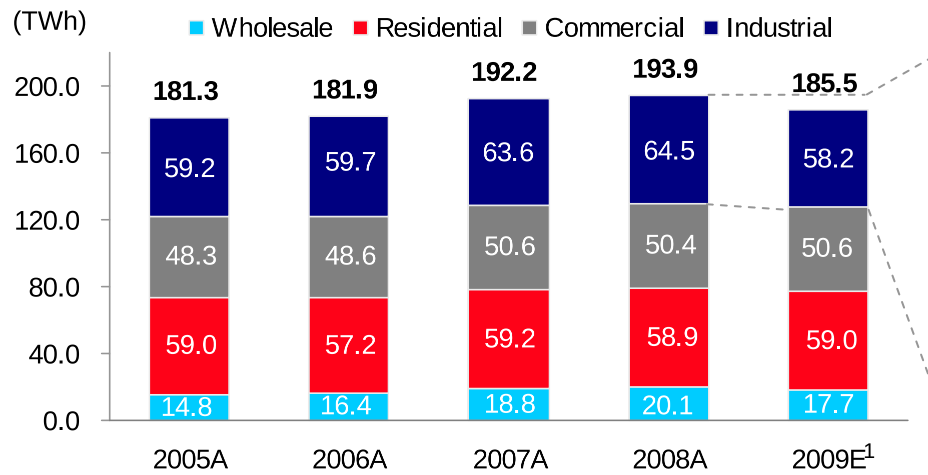
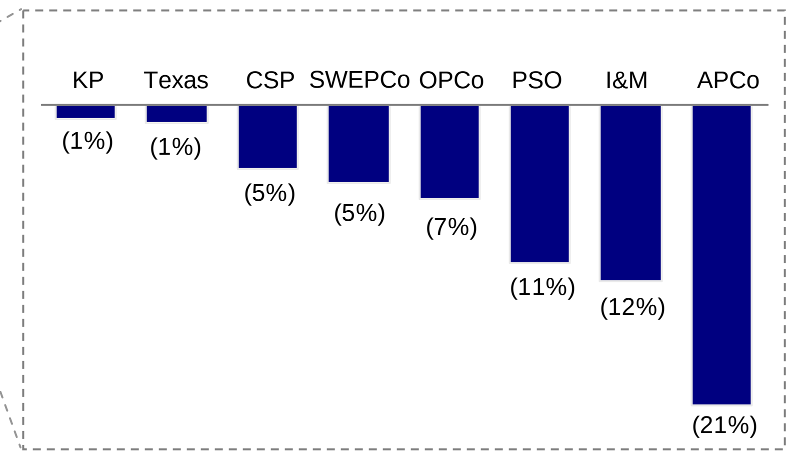
Key Drivers of Revised 2009 Guidance: Retail Sales

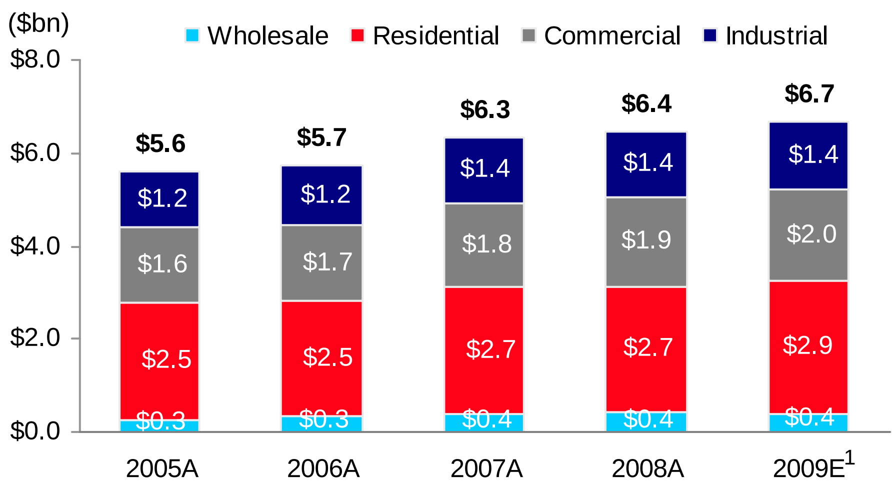
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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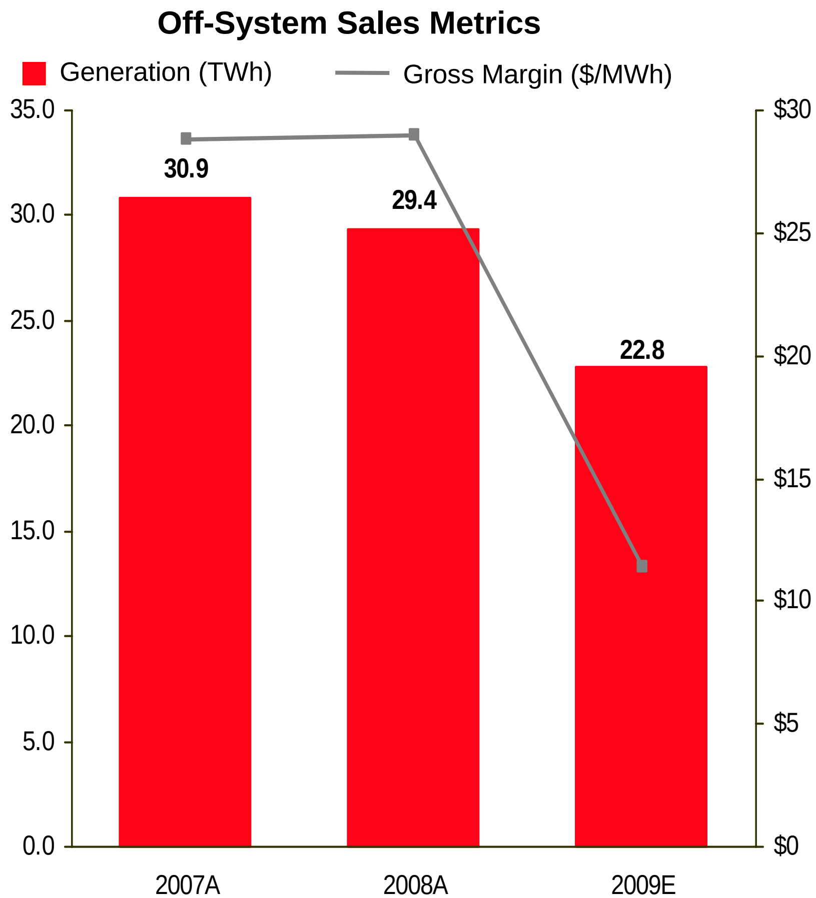
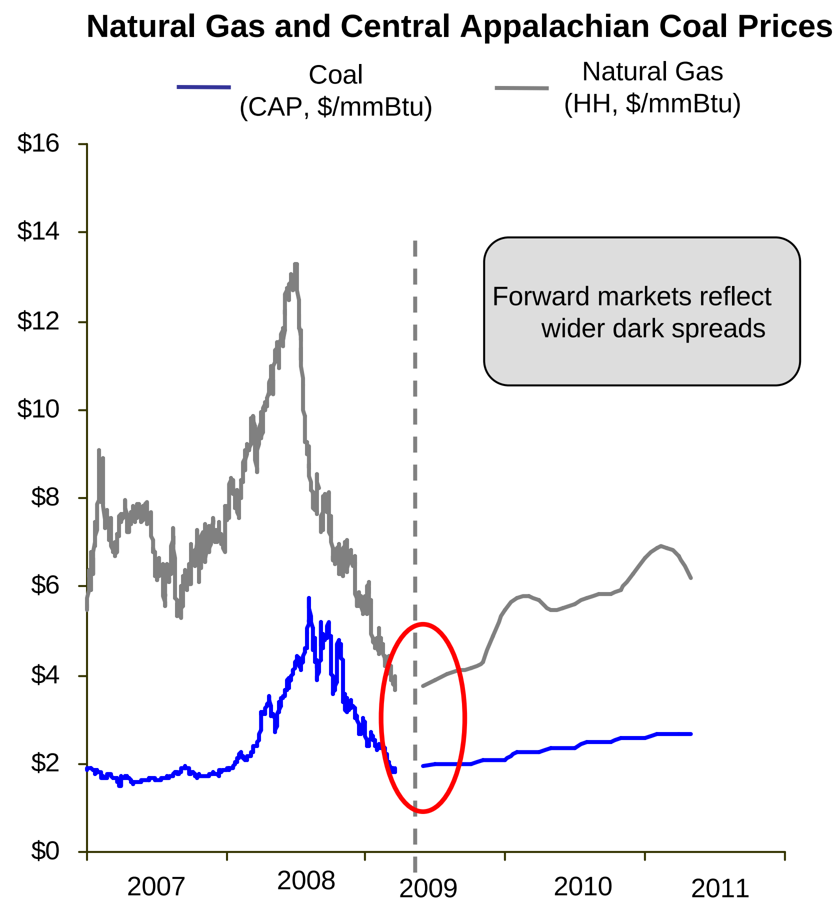
[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

Key Drivers of Revised 2009 Guidance: Off-System Sales



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- 1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip
- Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip

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Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

1Q09 Performance

American Electric Power
Financial Results for 1st Quarter 2009 Actual vs 1st Quarter 2008 Actual

		2008 Actual		2009 Actual	
		($ millions)	EPS	($ millions)	EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	594		691	
2	Ohio Companies	696		639	
3	West Regulated Integrated Utilities	223		239	
4	Texas Wires	122		127	
5	Off-System Sales	221		85	
6	Transmission Revenue - 3rd Party	80		84	
7	Other Operating Revenue	145		206	
8	Utility Gross Margin	2,081		2,071	
9	Operations & Maintenance	(747)		(803)	
10	Depreciation & Amortization	(355)		(373)	
11	Taxes Other than Income Taxes	(194)		(194)	
12	Interest Exp & Preferred Dividend	(210)		(221)	
13	Other Income & Deductions	41		31	
14	Income Taxes	(207)		(168)	
15	**Utility Operations On-Going Earnings**	409	1.02	343	0.84
16	**Transmission Operations On-Going Earnings**	1	-	-	-
17	AEP River Operations	7	0.02	11	0.03
18	Generation & Marketing	1	-	24	0.06
19	**Parent & Other On-Going Earnings**	(8)	(0.02)	(18)	(0.04)
20	ON-GOING EARNINGS	410	1.02	360	0.89

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER

1Q09 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief of $101MM (Primarily APCo and PSO)*
  - *Lower OSS sharing of $54MM*
  - *Offset by:*
    - *$58MM favorable variance in the prior year related to a coal contract amendment*
    - *$20MM credit for fuel to I&M customers from a portion of Cook Unit 1 accidental outage policy proceeds*
    - *Load contraction of $6MM, primarily from industrial customers in I&M and the Ohio companies*
  - *Weather had no EPS impact vs. prior year or normal*
- *Off-System Sales (line 5):*
  - *Off System Sales were lower primarily due to lower volumes and market prices which reflect weak market demand and a significant drop in natural gas prices*
- *Other Operating Revenue (line 7):*
  - *Increase due to accidental outage insurance payments related to the DC Cook Unit 1 outage ($54MM)*
- *Operations & Maintenance (line 9):*
  - *Higher O&M costs related to the 1Q08 PSO storm deferral of $72MM, 2009 storms ($38MM) and an accrual of$15MM for the Partnership with Ohio Fund, offset by the Red Rock write-off in 1Q08($10MM) and a decrease in employee-related expenses ($34MM)*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.9% in 2009 and 33.6% in 2008*
- *River Operations increased due to gains on the sale of two older towboats.*
- *Generation & Marketing increased as a result of higher gross margin from marketing activities in ERCOT.*
- *Parent and Other decreased primarily due to higher interest expense at the Parent.*

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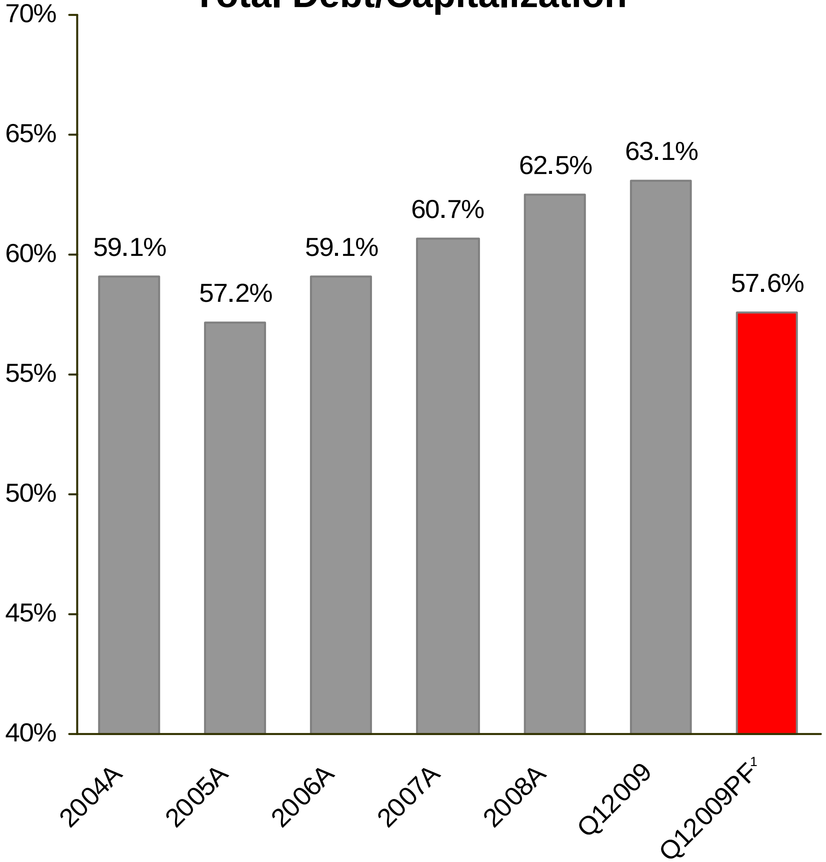
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	**04/20/2009**	**Maturity**
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

AEP AMERICAN ELECTRIC POWER

Appendix

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

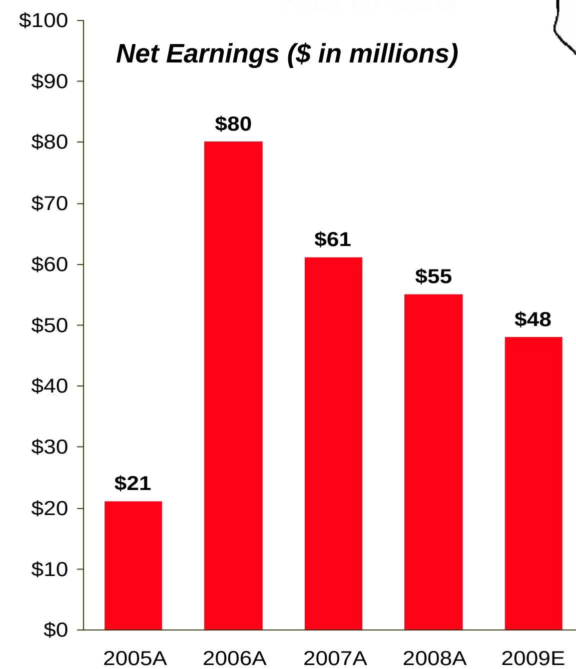
		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP River Operations

- Full-service inland waterways carrier
  - 2,978 hopper barges
  - 58 towboats/25 harbor boats
- Tonnage & Commodity
  - Captive: 37MM tons of coal
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA
- 2009 earnings forecast lower than 2008 due to economic downturn

Inland Waterway Routes For AEP River Operations



AMERICAN ELECTRIC POWER

Generation and Marketing

- Business Purpose: To own and operate or contract for electric generation assets and provide innovative power supply products to municipals, electric cooperatives and other market participants
- Owns and Operates 2 Texas Wind Farms – 310MW
- Marketing and Risk Management Activities in ERCOT
- FERC-approved, 20-year PPA with AEP Texas North for TNC's capacity and energy of the Oklaunion plant (54.69%)
- 2009 earnings forecast lower than 2008 due to lower optimization activities around the Oklaunion output and lower revenues from the wind farms

Trent Wind Farm

Oklaunion Plant

AEP AMERICAN ELECTRIC POWER

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

AEP AMERICAN ELECTRIC POWER

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN
FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
(Incl. OVEC of $68.8M)								
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9	*
Required Rate of Return		7.00%	
Required Operating Income	$	42.6	
Adjusted Operating Income	$	27.3	
Difference	$	15.3	
Revenue Conversion Factor		1.65	
Revenue Deficiency	$	25.2	
Generation Recovery Rider	$	28.7	
Total Required Rate Relief	$	53.9	

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

AEP AMERICAN ELECTRIC POWER

Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

AEP AMERICAN ELECTRIC POWER

Use of Equity Proceeds – Reduce Leverage

69 million shares issued at $24.50 / share

Net Proceeds: $1.64 billion

External Settlements

$1.44 billion Facility Pay-down

Intercompany transfers

Approximate Equity Contributions
$1.14 billion *

Money Pool borrowing reduction

- **OPCo: $550 million**
- **APCo: $250 million**
- **I&M: $120 million**
- **KPCo: $30 million**
- **PSO: $20 million**
- **SWEPCO: $125 million**
- **TCC: $35 million**
- **TNC: $10 million**

* - subject to AEP board of director approval

AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	R	BBB	S	BBB+	S
AEP Texas North Company	Baa1	R	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	R	BBB	S	BBB+	S

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

AEP AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)
(as of March 31, 2009)

Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ 150	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ 70	$ 679	$ -
Public Service of Oklahoma	$ 50	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 270	$ 1,791	$ 625

AEP AMERICAN ELECTRIC POWER

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

AEP AMERICAN ELECTRIC POWER

DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2009 Actual vs 1st Quarter 2008 Actual

		Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	19,542 GWh @ $ 30.4 /MWhr =	594		18,661 GWh @ $ 37.0 /MWhr =	691	
2	Ohio Companies	13,901 GWh @ $ 50.0 /MWhr =	696		13,134 GWh @ $ 48.7 /MWhr =	639	
3	West Regulated Integrated Utilities	9,869 GWh @ $ 22.6 /MWhr =	223		9,063 GWh @ $ 26.4 /MWhr =	239	
4	Texas Wires	5,823 GWh @ $ 21.0 /MWhr =	122		5,738 GWh @ $ 22.1 /MWhr =	127	
5	Off-System Sales	8,236 GWh @ $ 26.8 /MWhr =	221		2,595 GWh @ $ 32.7 /MWhr =	85	
6	Transmission Revenue - 3rd Party		80			84	
7	Other Operating Revenue		145			206	
8	Utility Gross Margin		2,081			2,071	
9	Operations & Maintenance		(747)			(803)	
10	Depreciation & Amortization		(355)			(373)	
11	Taxes Other than Income Taxes		(194)			(194)	
12	Interest Exp & Preferred Dividend		(210)			(221)	
13	Other Income & Deductions		41			31	
14	Income Taxes		(207)			(168)	
15	**Utility Operations On-Going Earnings**		409	1.02		343	0.84
16	**Transmission Operations On-Going Earnings**		1	-		-	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		7	0.02		11	0.03
18	Generation & Marketing		1	-		24	0.06
19	**Parent & Other On-Going Earnings**		(8)	(0.02)		(18)	(0.04)
20	ON-GOING EARNINGS		410	1.02		360	0.89

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER

1Q2009 Cash Flow

($ millions)	2008	2009
Operating Activities		
Net Income -- Reported	$ 573	$ 360
Discontinued Operations	-	-
Continuing Earnings	573	360
Depreciation, Amortization & Deferred Taxes	427	543
Changes in Components of Working Capital	(74)	(468)
Other Assets & Liabilities	(298)	(117)
Cash Flows From Operating Activities	628	318
Investing Activities		
Capital Expenditures	(778)	(897)
Proceeds on Sale of Assets	18	172
Change in Other Temporary Cash Investments, net	(17)	90
Acquisition of Nuclear Fuel	(98)	(76)
Other Investing, net	(19)	(16)
Cash Flows Used for Investing Activities	(894)	(727)
Financing Activities		
Common Shares Issued, net	45	47
Long-term Debt Issuances, net	627	854
Short-term Debt Decrease, net	(251)	(1)
Other Financing	(14)	(25)
Dividends Paid	(164)	(167)
Cash Flows From Financing Activities	243	708
Cash From Continuing Operations	$ (23)	$ 299
Beginning Cash & Cash Equivalent Balances	178	411
Ending Cash & Cash Equivalent Balances	$ 155	$ 710

1Q2009 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by fuel (coal) stock increase and G&A type items
- Changes in other assets and liabilities largely driven by changes in un-recovered fuel

Investing Activities

- Cash outlay of $897MM for 2009 YTD capital investment.
- 2009 asset sale proceeds primarily relate to the transfer of assets from TCC to ETT ($60MM) and payments from the third-party owners of the Turk Plant ($104MM)

Financing Activities

- Long-term debt issuances of $854MM primarily related to I&M and APCo senior notes.

AEP AMERICAN ELECTRIC POWER

AEP Environmental Roadshow

Hosted by Sanford Bernstein

April 14, 2005

New York City

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to control operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness and number of participants in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Senior Vice President – Fuel, Emissions & Logistics

John McManus

Vice President – Environmental Services

Introduction

AEP®

The generation assets are co-managed by the Power Generation and the Commercial Operation Groups within AEP – each with a deliberate focus on roles and responsibilities within the organization

Power Generation
Operate 36,000 MW

Commercial Operations
Coal, gas, power and emissions markets

Fossil and Hydro Generation
Bill Sigmon, SVP

Generation Dispatch

Nuclear Generation

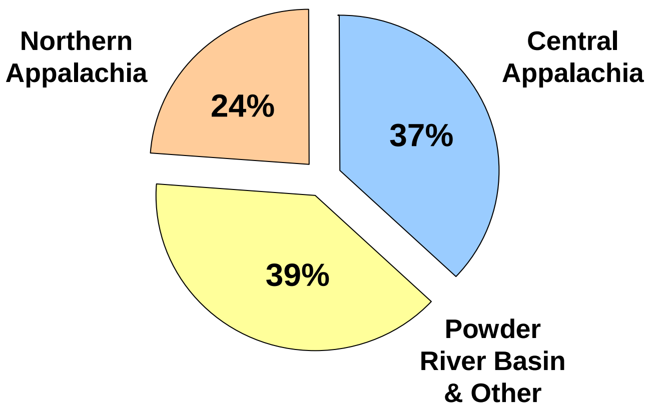
Energy Marketing
Brian Tierney, SVP

Engineering, Environmental & Technical Services
John McManus, VP Environmental Services

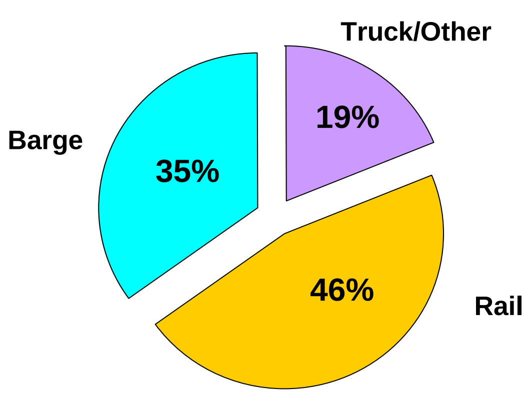
Fuel, Emissions & Logistics
Chuck Zebula, SVP

Fuel, Emissions & Logistics

FUEL BASIN DIVERSITY
73 million tons



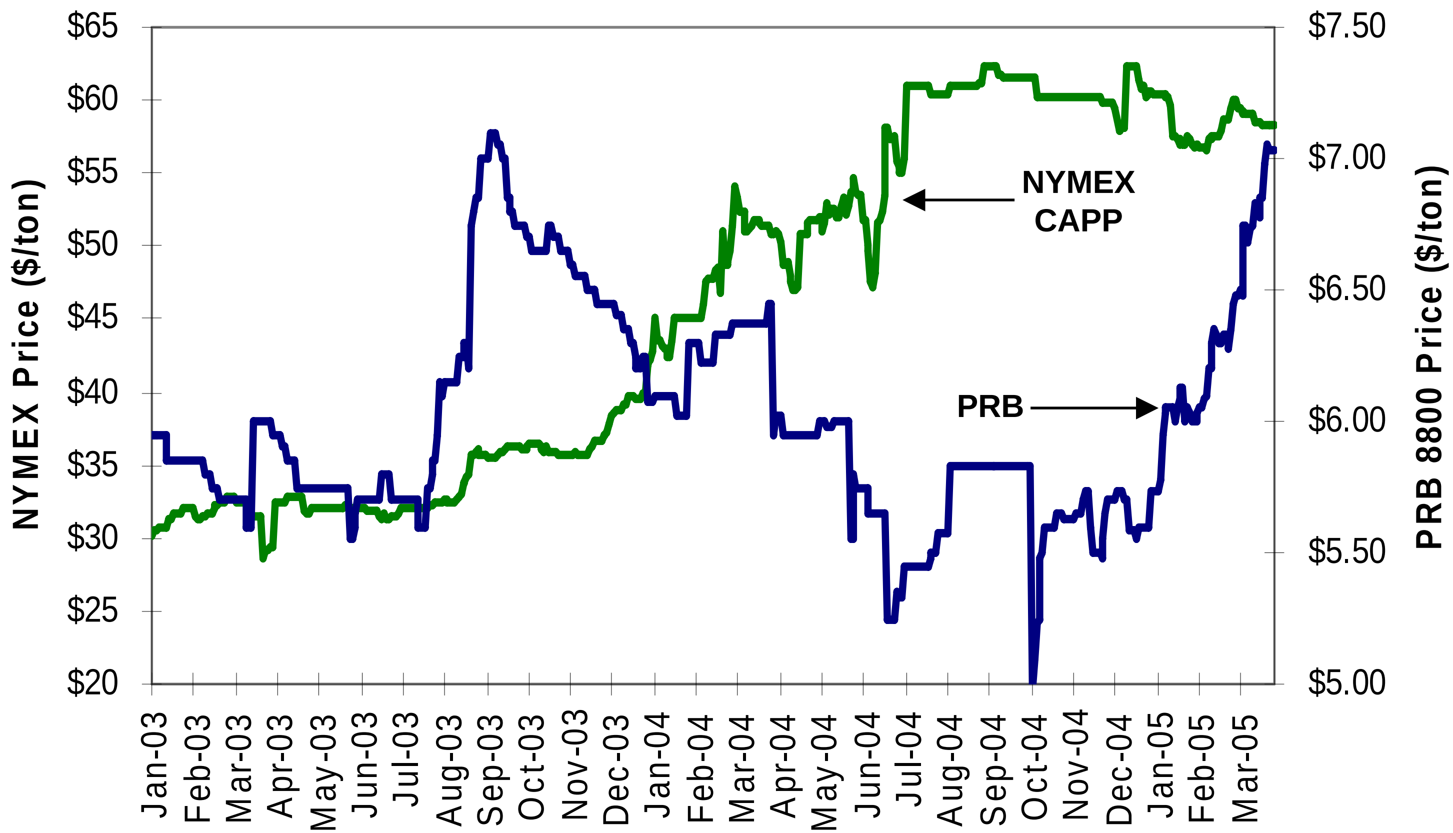
DELIVERY MODE DIVERSITY
25 GW coal capacity



- All fossil fuel activities including procurement, transportation, inventory, QA/QC, measurement, and coal trading;
- Market-based emission and renewable credit activities;
- Barge transportation, terminal, and railcar maintenance businesses;
- Procures all bulk consumables for use in combustion/emission removal;
- Optimizes all by-products of production including ash and gypsum.

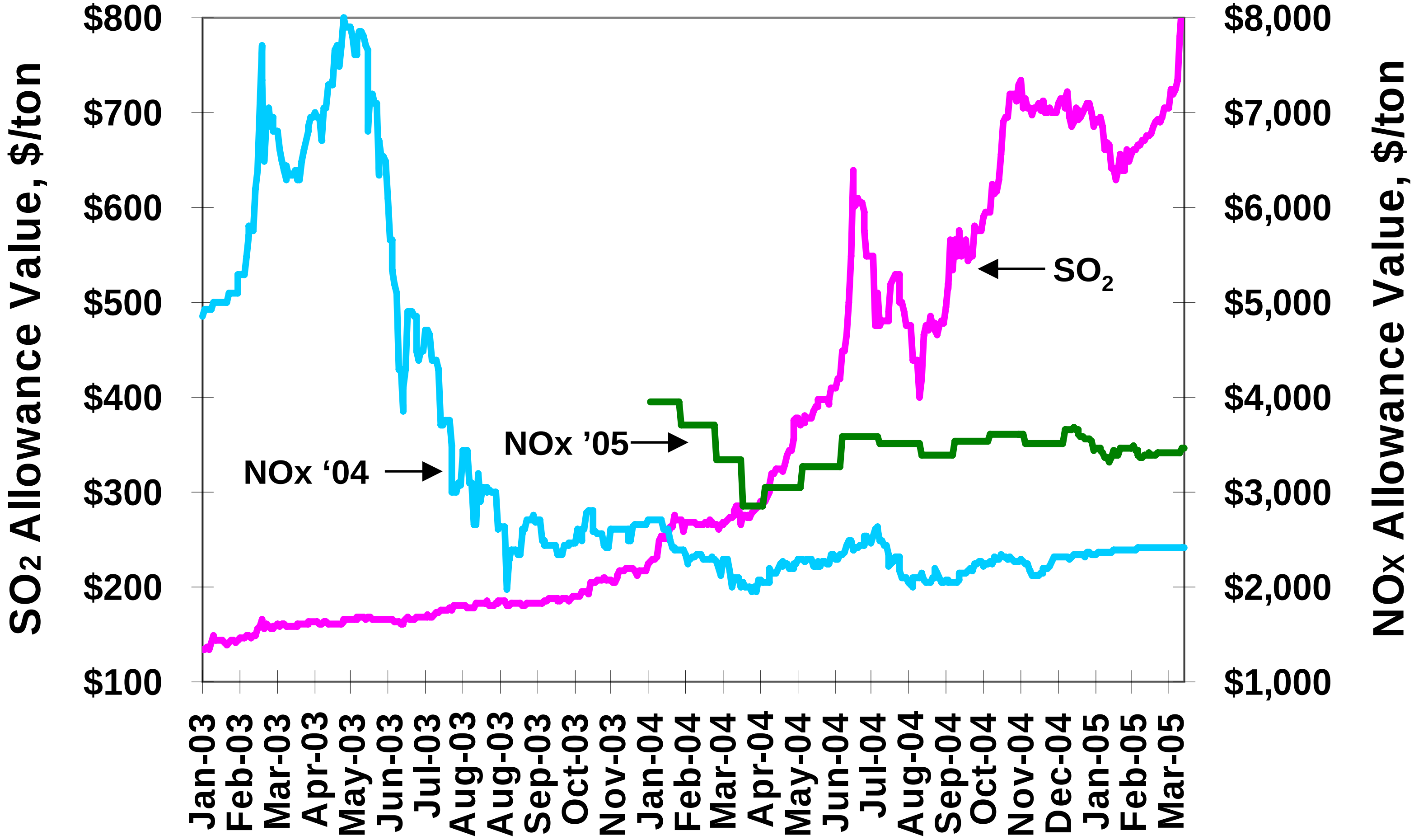
Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited “immediate” substitution capability (PRB) but gaining strength



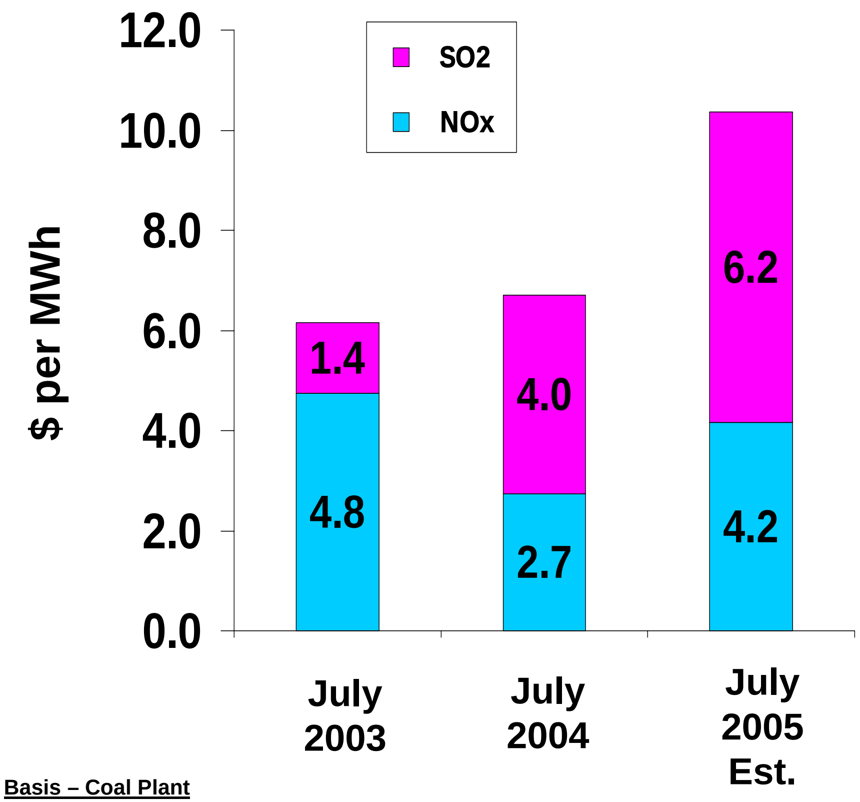
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



__Basis – Coal Plant__
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Clean Air Interstate Rule

- Rule Finalized March, 2005.
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment.
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

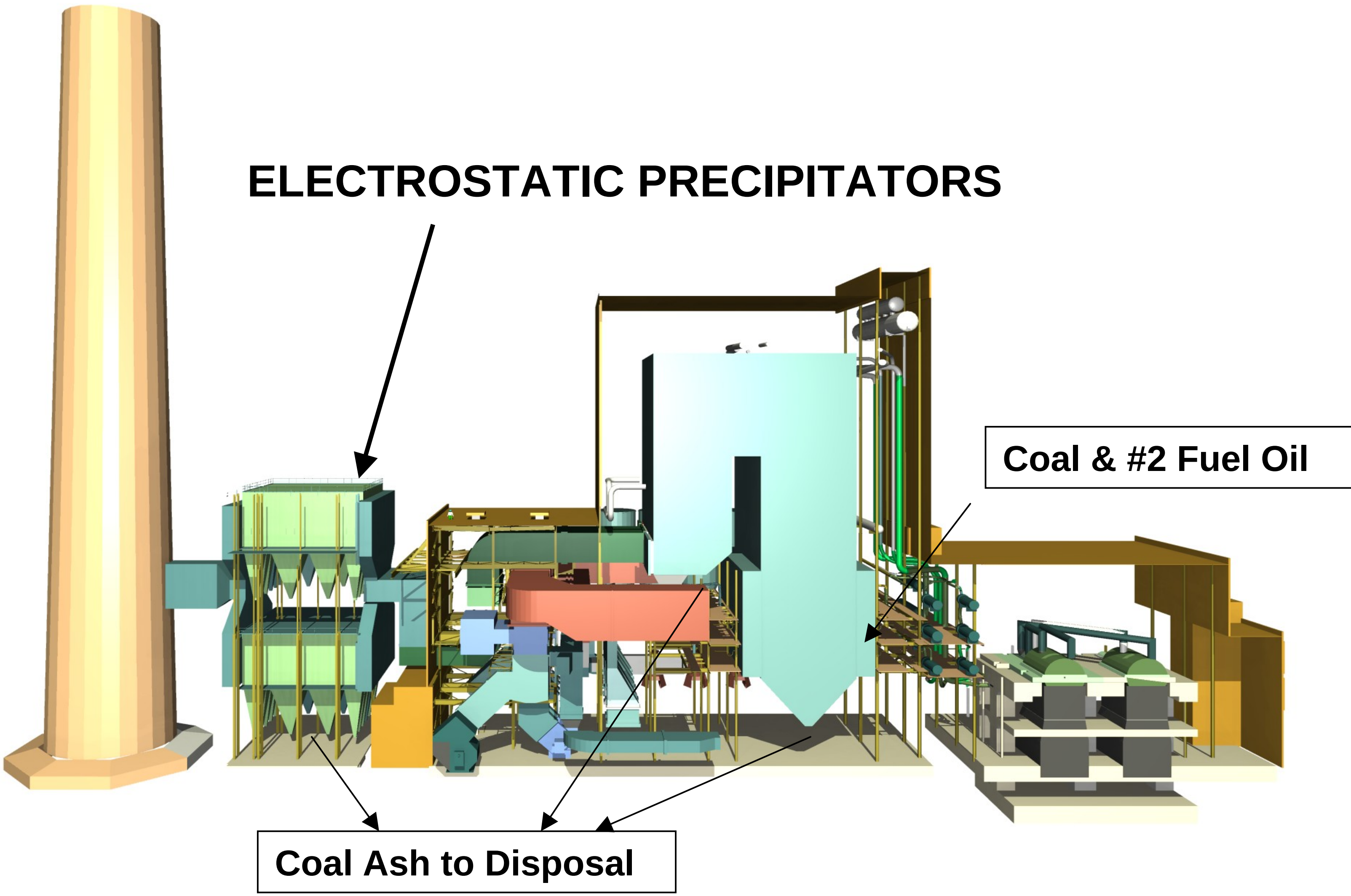
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

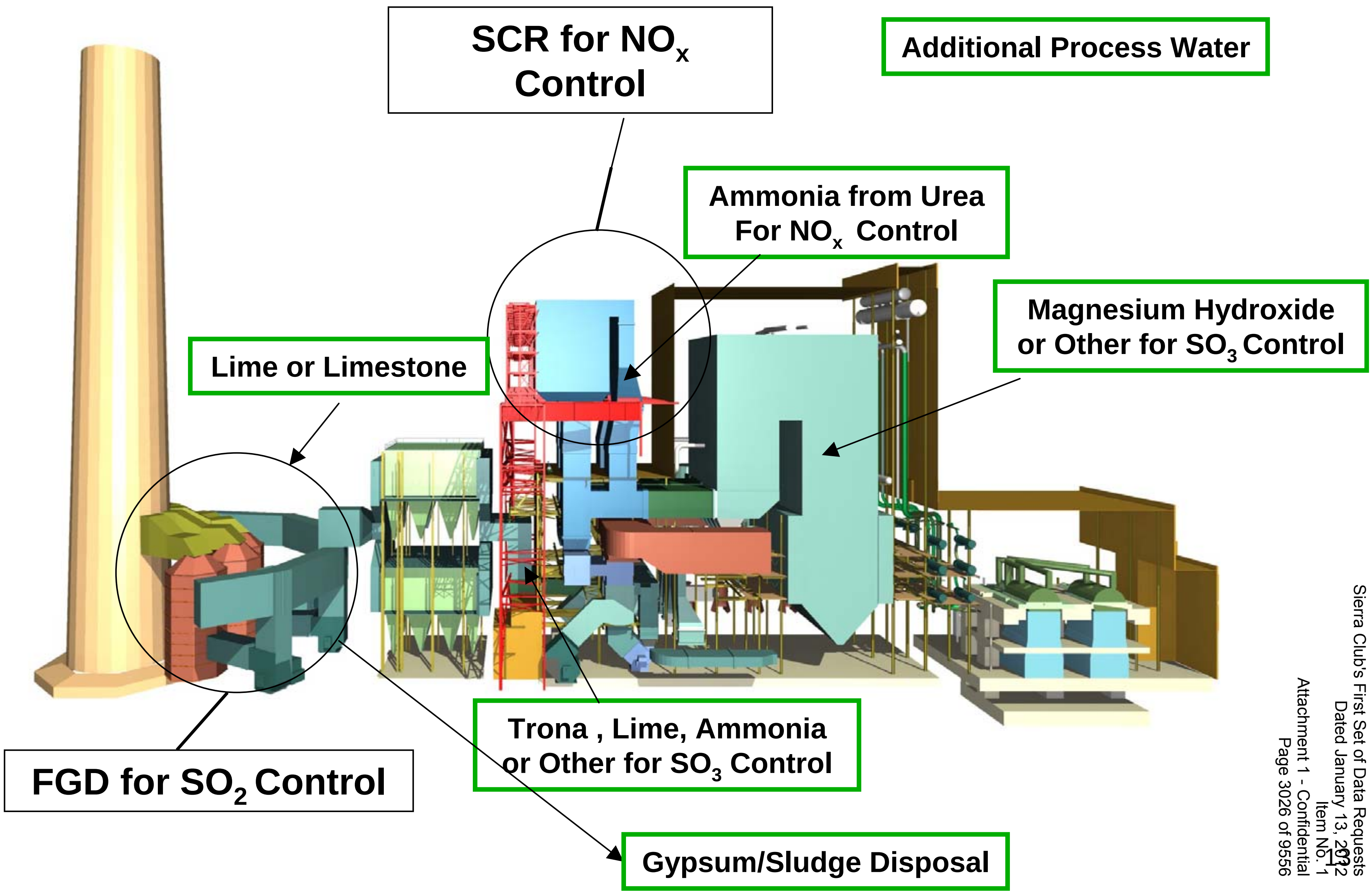
- Rule Finalized March, 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit As Built in 1970s

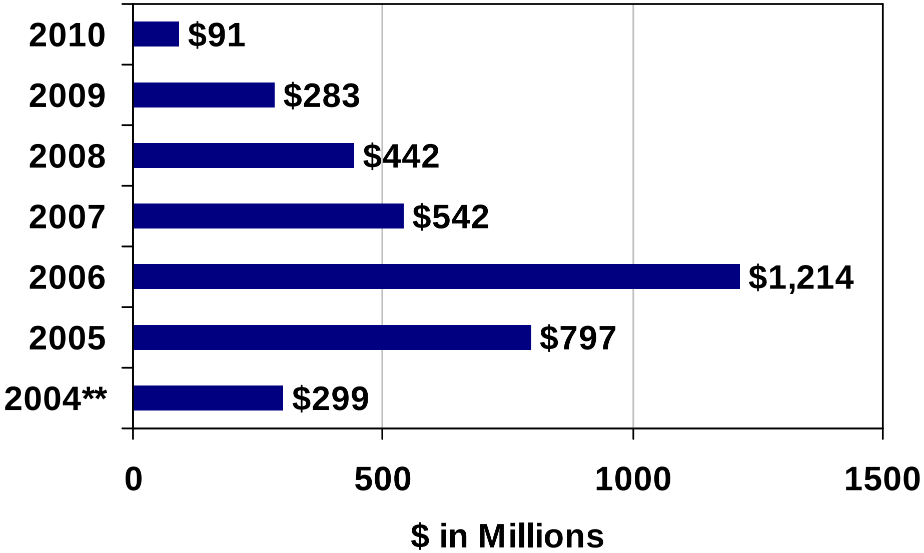


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



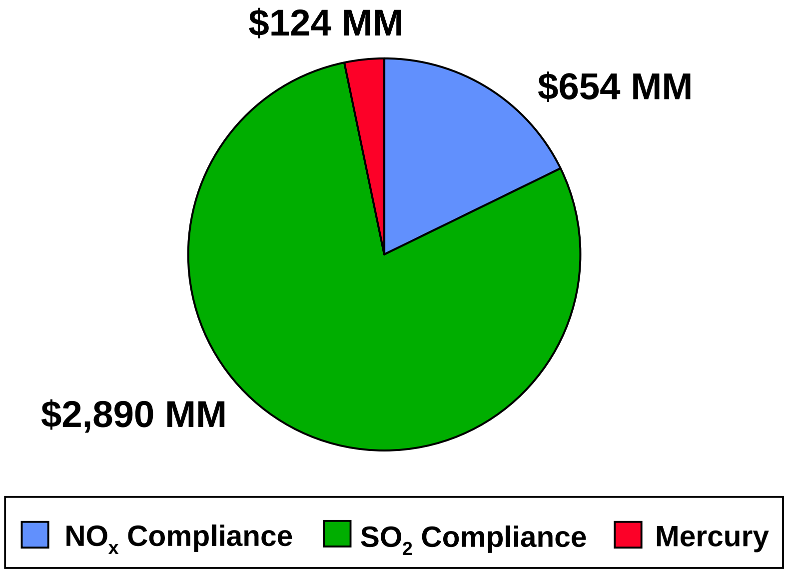
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

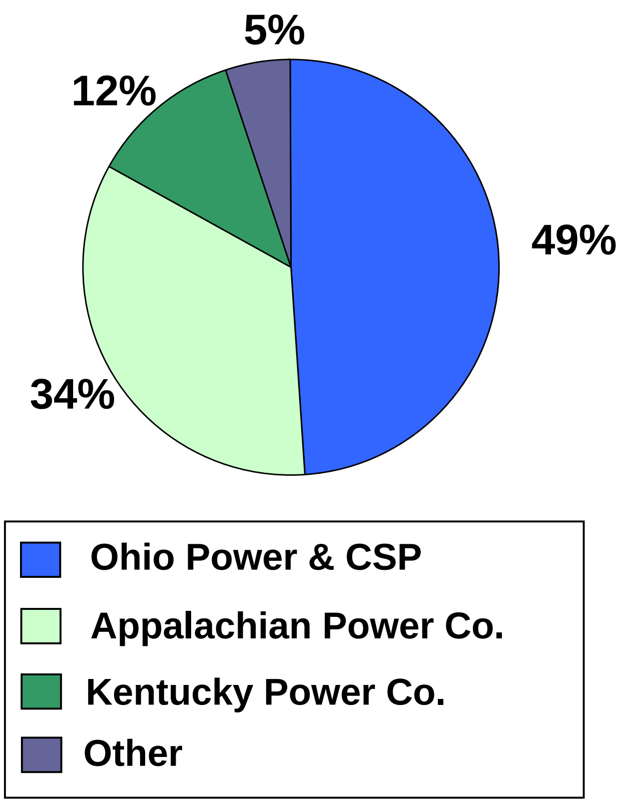
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

AEP®

	FGD	SCR

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 – 2010

SCR

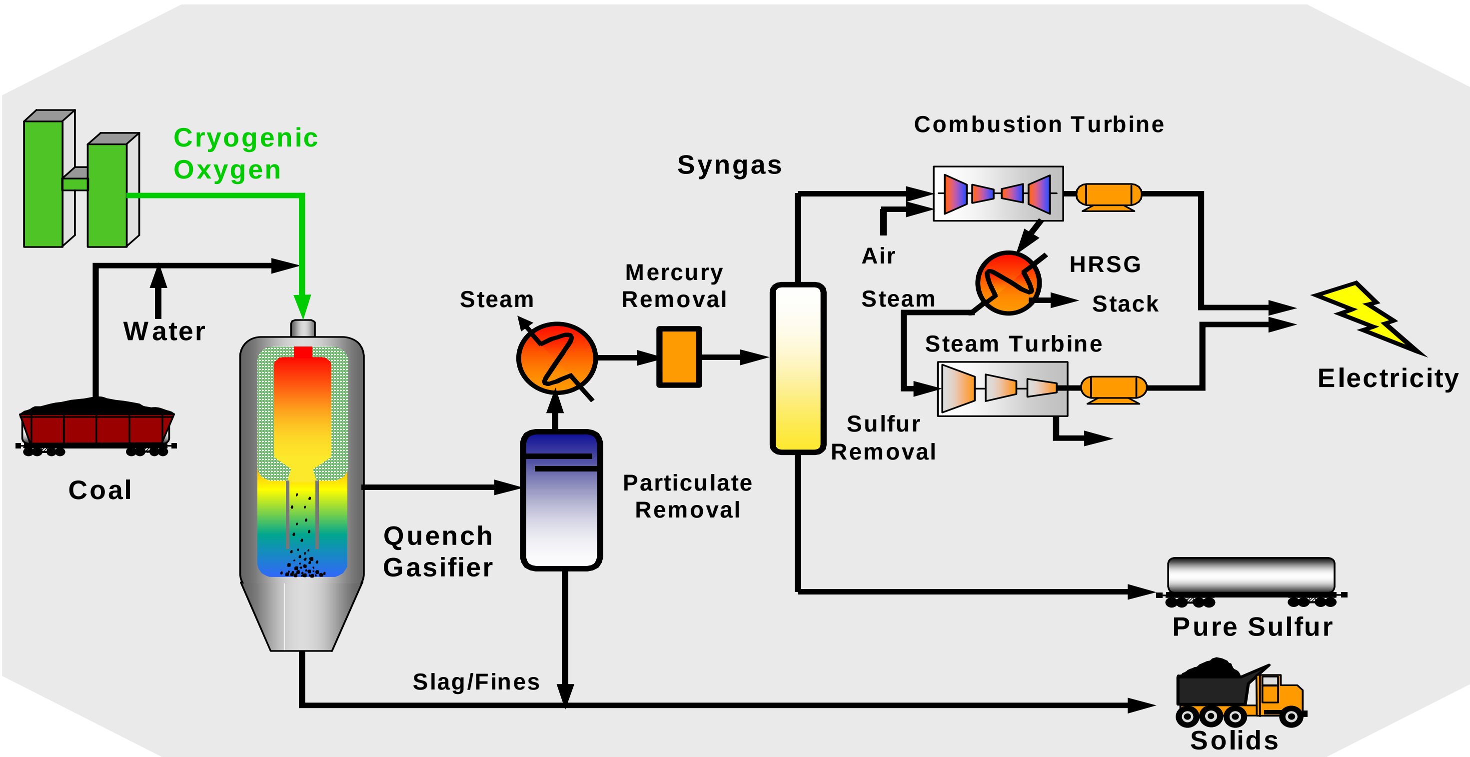
Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 – 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Looking to the Future - IGCC



AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

IGCC vs. Pulverized Coal and Natural Gas Combined Cycle

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**530**
Heat Rate (BTU/kWh)	**8700**	**8600**	**7200**
EPC cost* ($/kW)	**1290**	**1350**	**440**
Total Plant cost ($/kW)**	**1490**	**1610**	**475**
Variable Production cost* ($/MWh)**	**15**	**14**	**38**

Source: Electric Power Research Institute

*   EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

STRATEGIC ADVANTAGE OF IGCC OUTWEIGHS LEAST COST CONSIDERATION

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

Next Steps

2005

- Secure regulatory cost recovery - June
- Finalize site selection - August
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

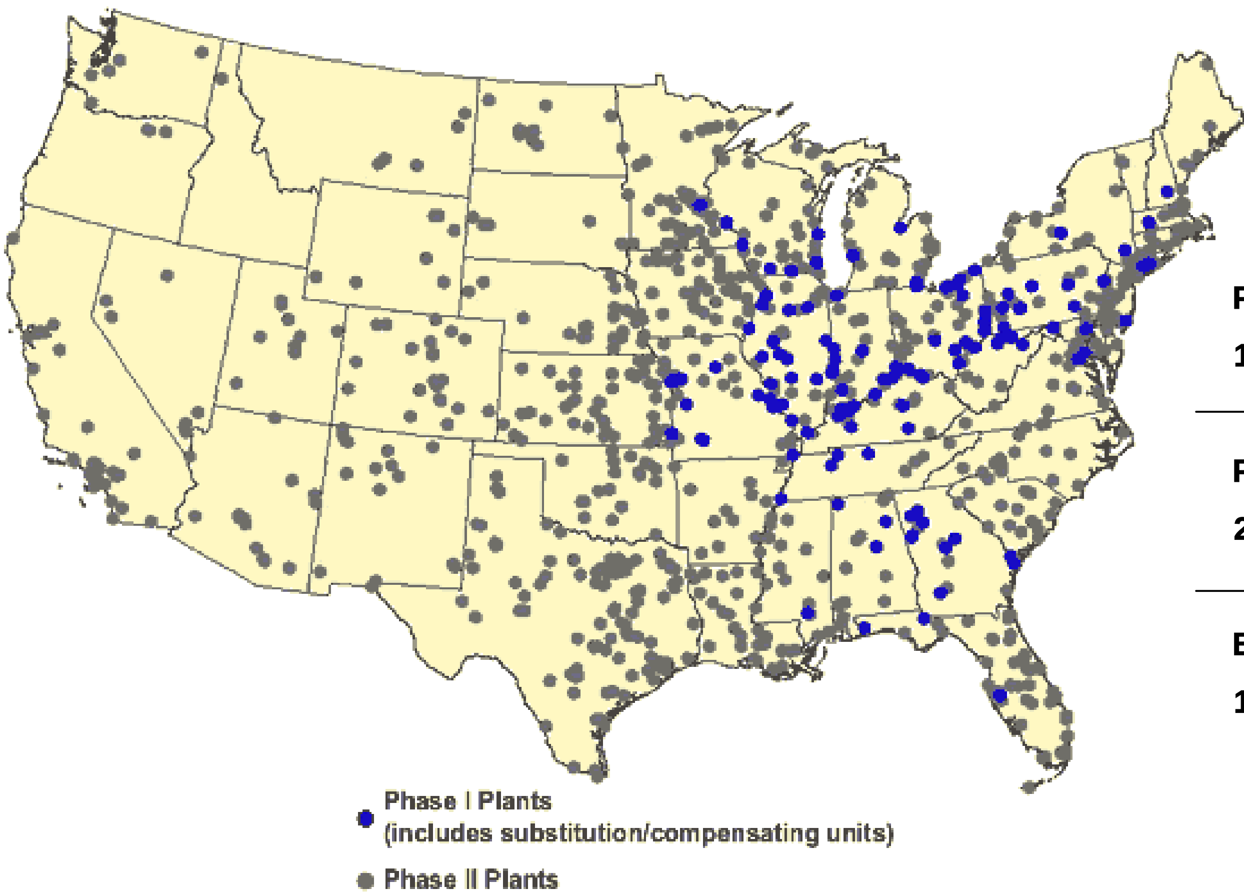
- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Appendix

Power Plants – Title IV SO_2

Fossil fired power plants affected by Title IV of the CAAA of 1990



PHASE I

1995 – 2.5 lbs/mmBtu standard

PHASE II

2000 – 1.2 lbs/mmBtu standard

BASIS

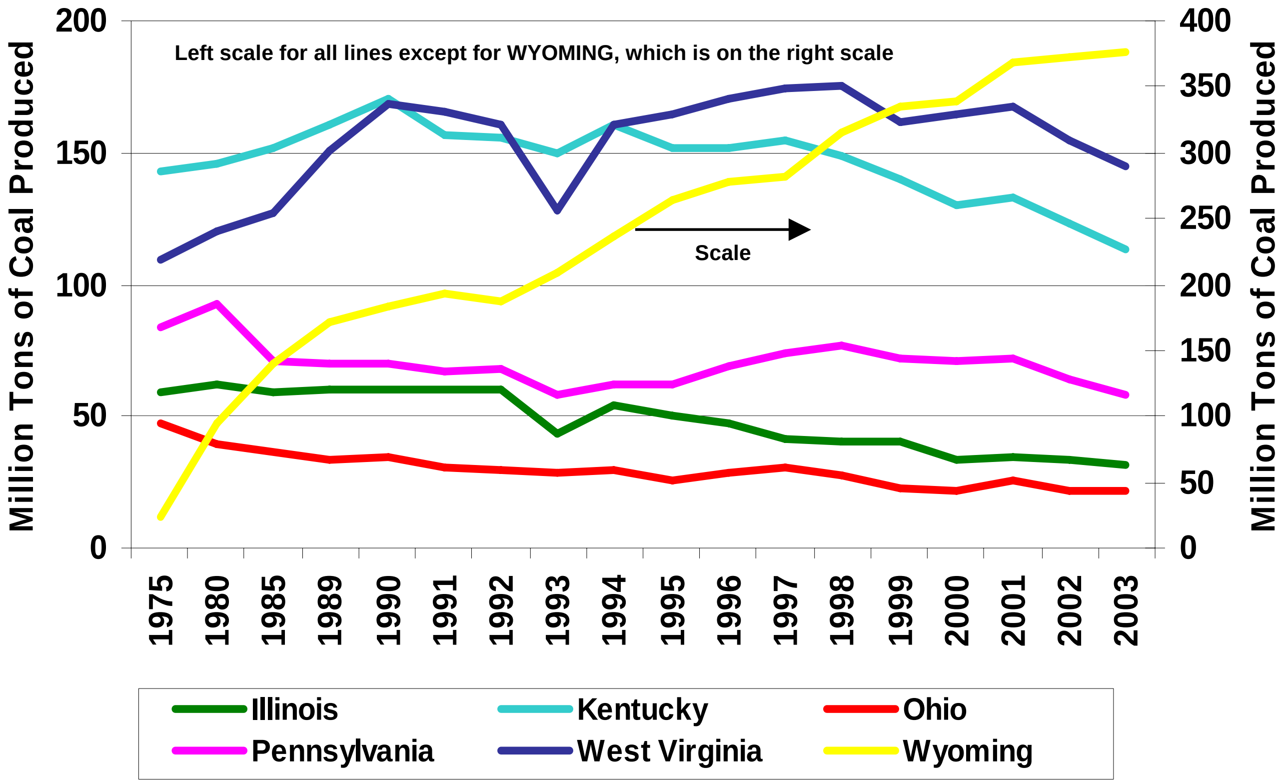
1985-87 Heat Input

Compliance Options for SO_2

- Fuel Switching
  - – Coal type – low-sulfur vs. high-sulfur coal
  - – Natural gas
- Install Scrubber for SO_2 control
- Buy Allowances from others
- Reduce operating hours/Shut-down
- New Sources must obtain Allowances

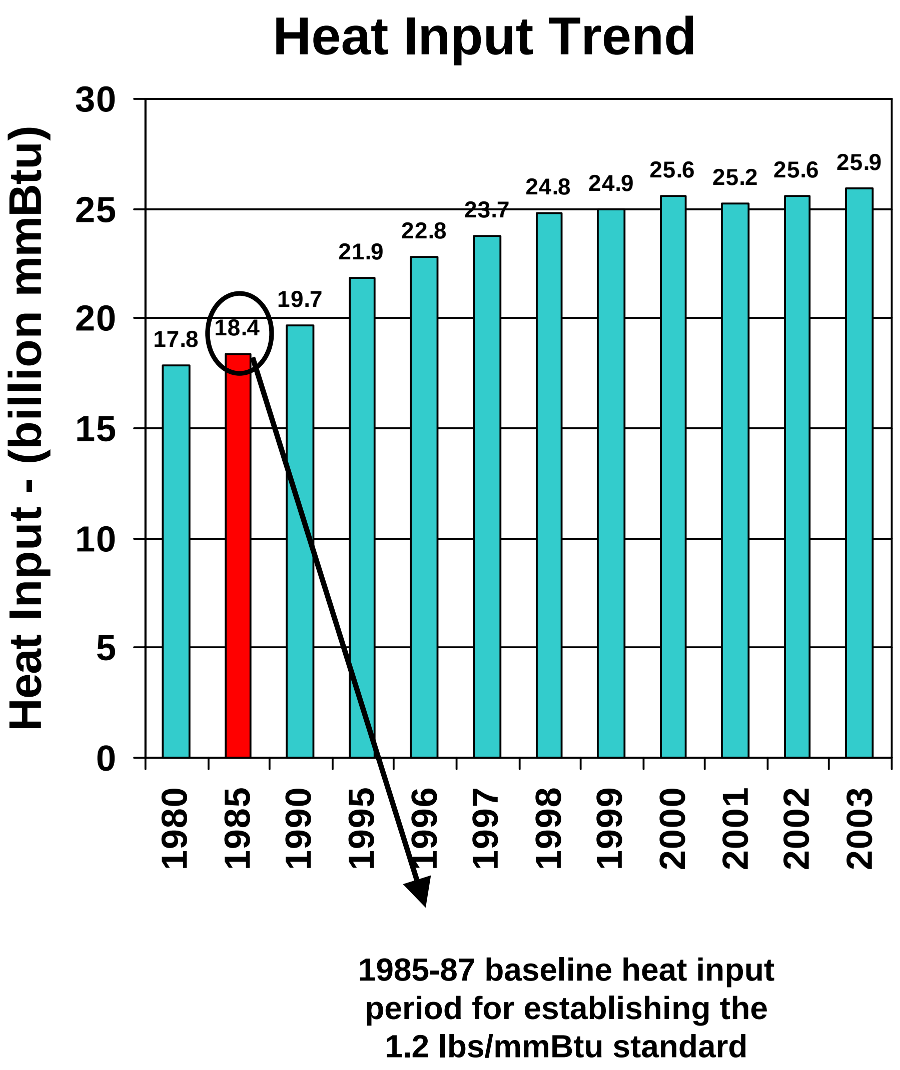
Key State Coal Production Trends

Production of coal from Ohio and Illinois and other high sulfur coal-producing states decreased in production as a result of the CAAA. Production of coal from Wyoming, Eastern Kentucky and Southern West Virginia saw the largest increases, due to the marketability (SO_2 content) and price of the coals.



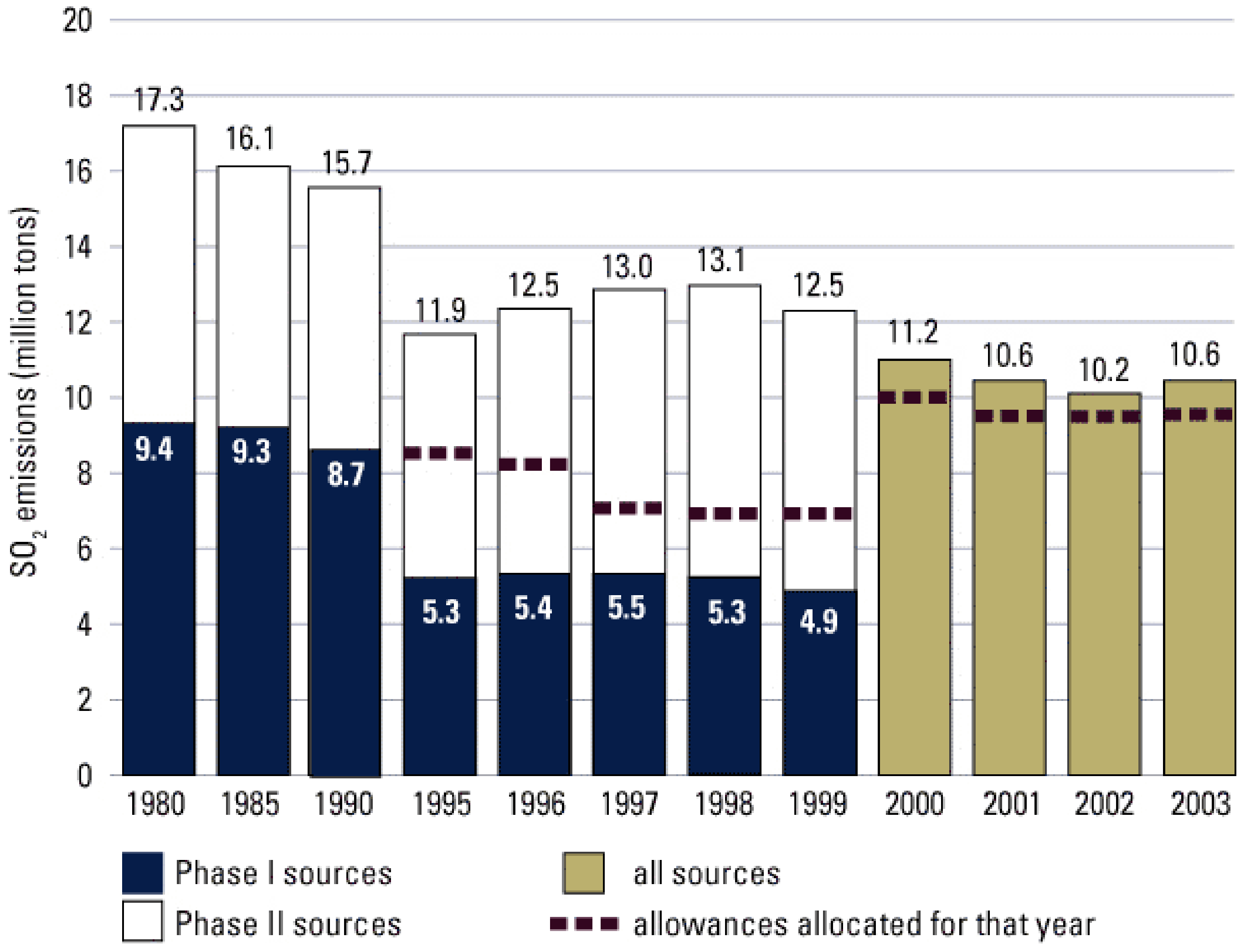
Production from Wyoming increased at a rate of 10.4% per year from 1975 to 2003

Growth in Heat Input



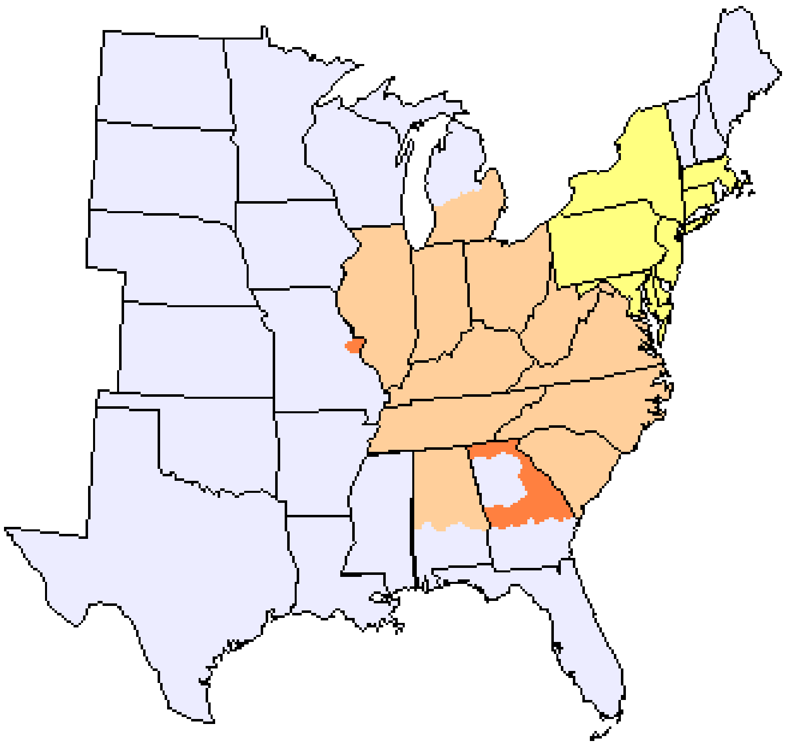
HEAT input has grown near 40% since the baseline period in 1985-1987 – therefore making the effective standard about 0.8 lbs SO_2/mmBtu

Title IV SO_2 Program Results



NOx SIP Call

Northeast States – May 1, 2003
Midwest/Southeast – May 31, 2004
Missouri/Georgia – ??



- Cap and Trade Program
- Program Basis
  - 0.15 lbs/mmBtu NOx
  - 85% reduction
  - 1995-97 heat input
- Seasonal Program
  - May 1 – Sept 30
  - Other months program is business as usual
- State (19) Implemented

Compliance Options for NOx

- Install Controls
  - Selective Catalytic Reduction
    - 90% removal, $120/kW capital cost
  - SNCR
    - 30% removal, $25-30/kW capital cost
  - Combustion Controls
- Fuel has some influence
- Buy Allowances from others
- Reduce operating hours/Shut-down
- New Sources must obtain Allowances

Information

USEPA website - www.epa.gov/airmarkets

AMERICAN ELECTRIC POWER

Artio Global Investors
Office Visit
August 10, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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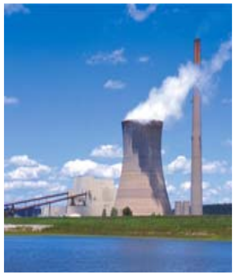
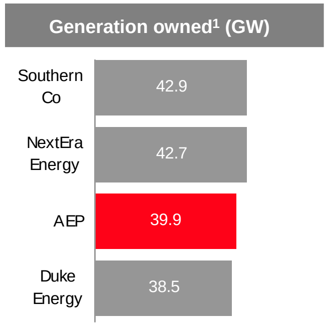
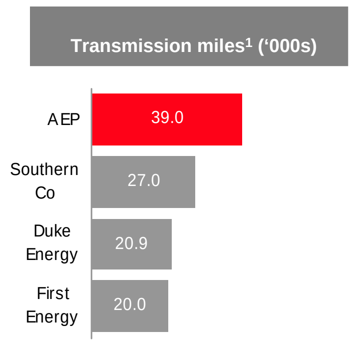
American Electric Power



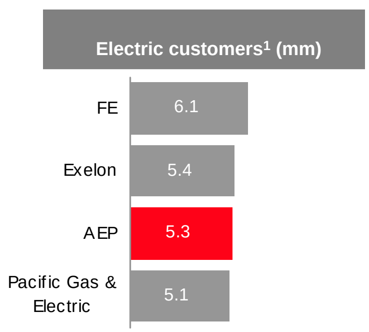
One of the largest
U.S. electricity generators



The largest U.S. electricity
transmitter

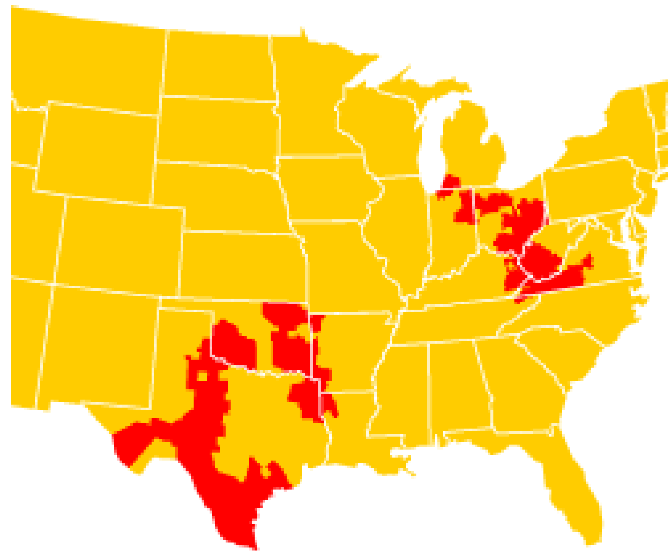


One of the largest U.S.
electricity distributors



¹ : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

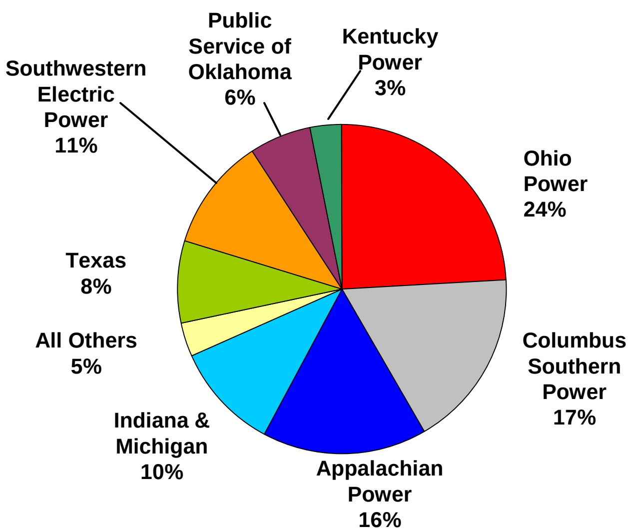
$17.0B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

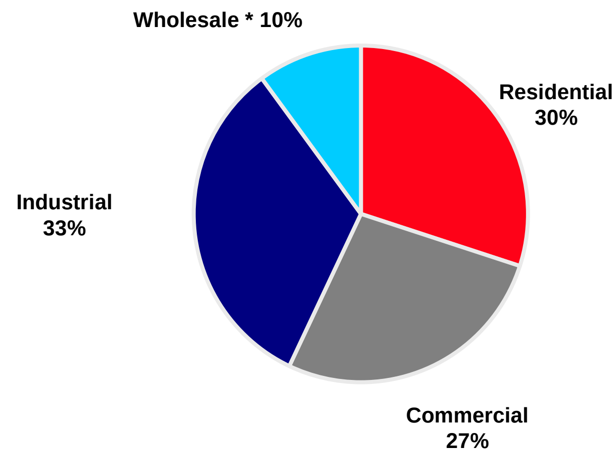
4

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



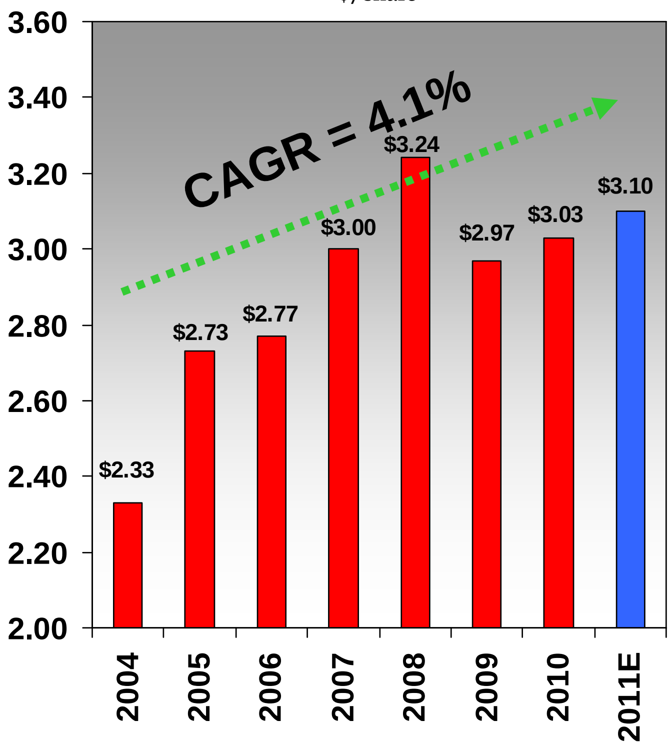
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

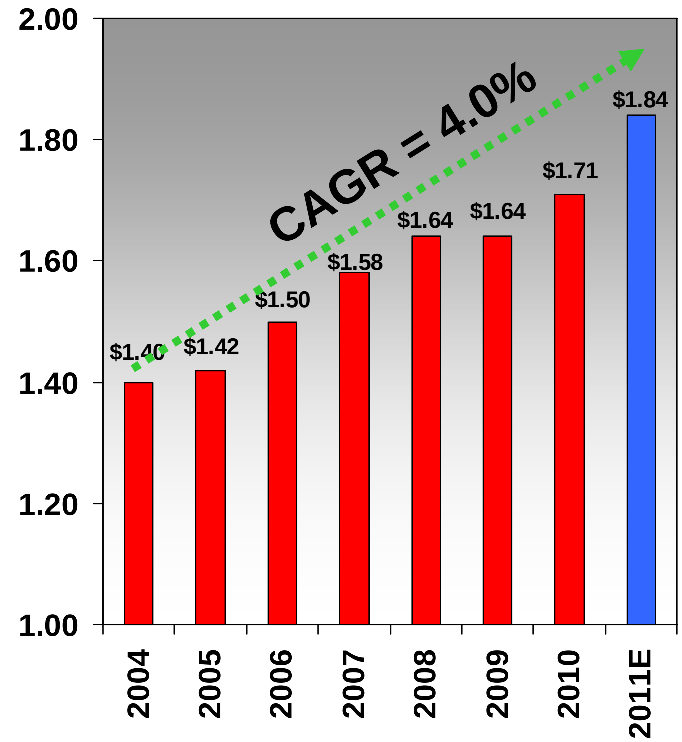
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield over 5.0%

Detailed Ongoing Earnings Guidance

2010A: $3.03

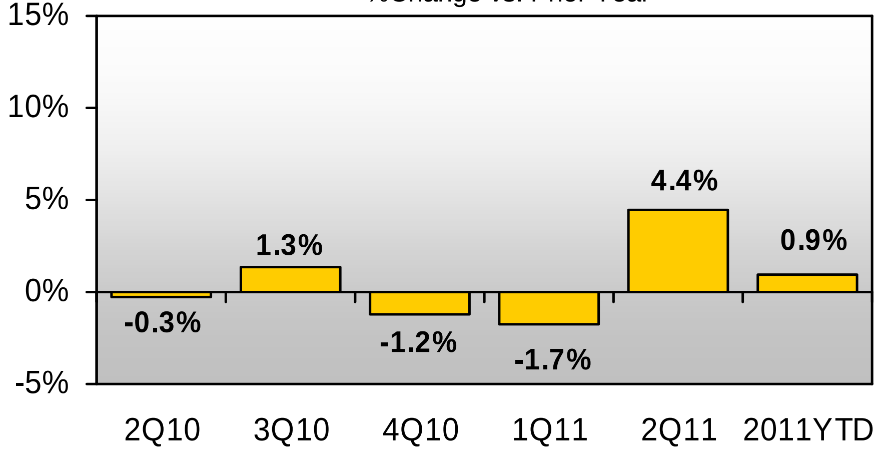
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

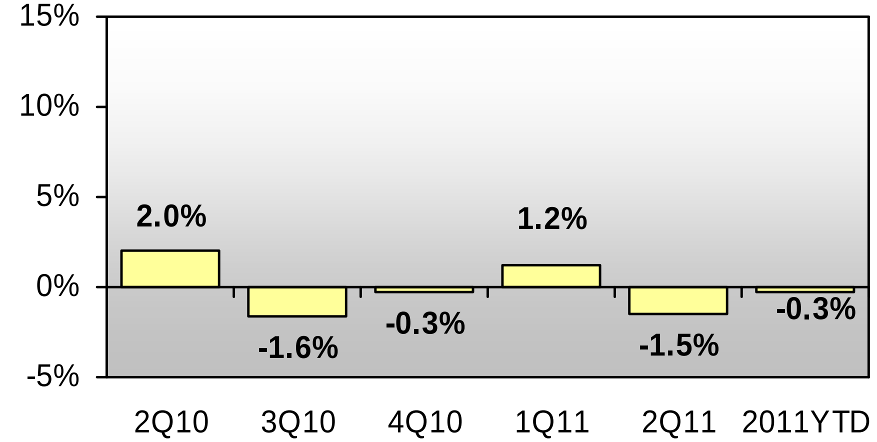
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

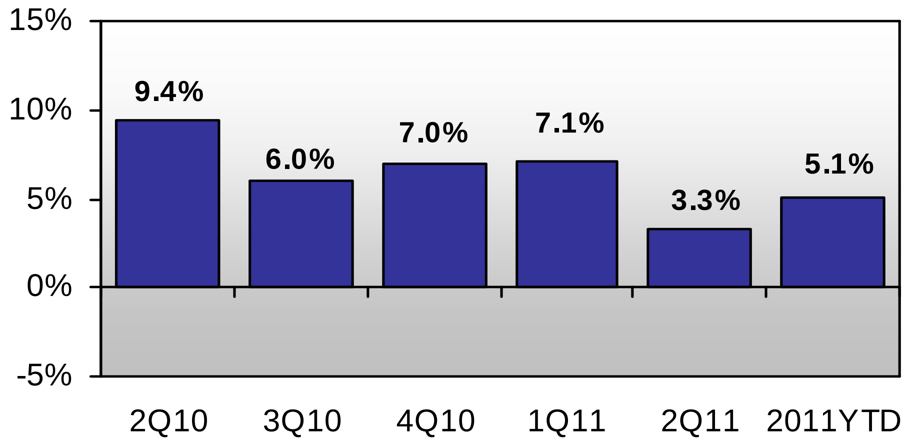
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



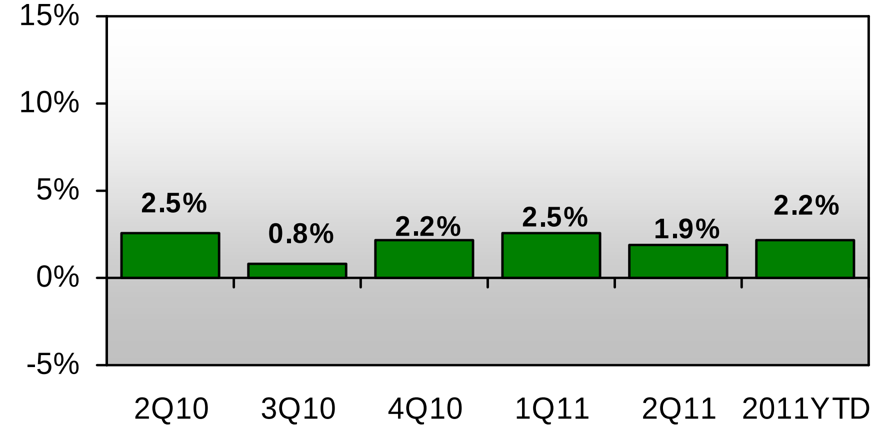
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



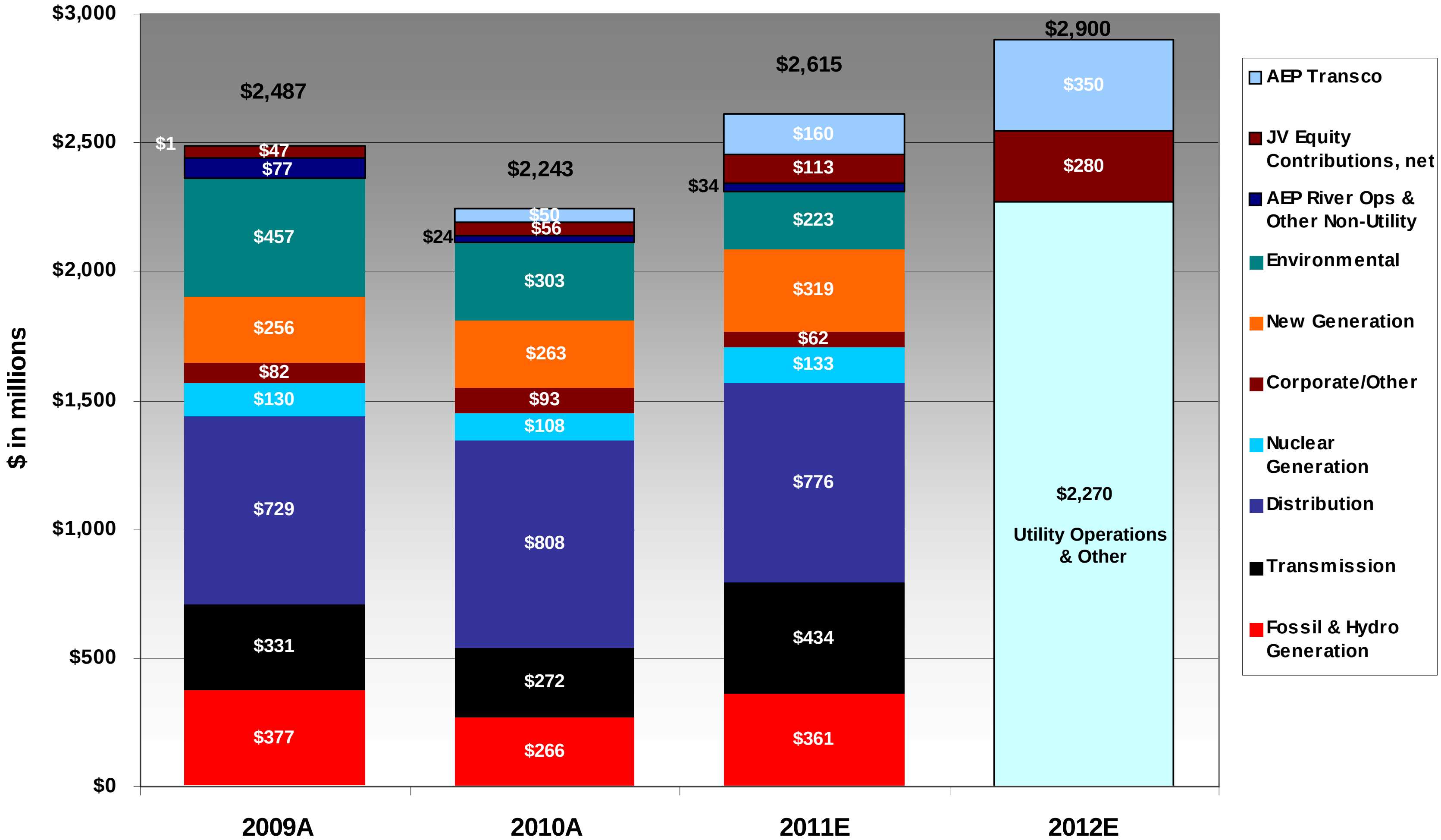
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

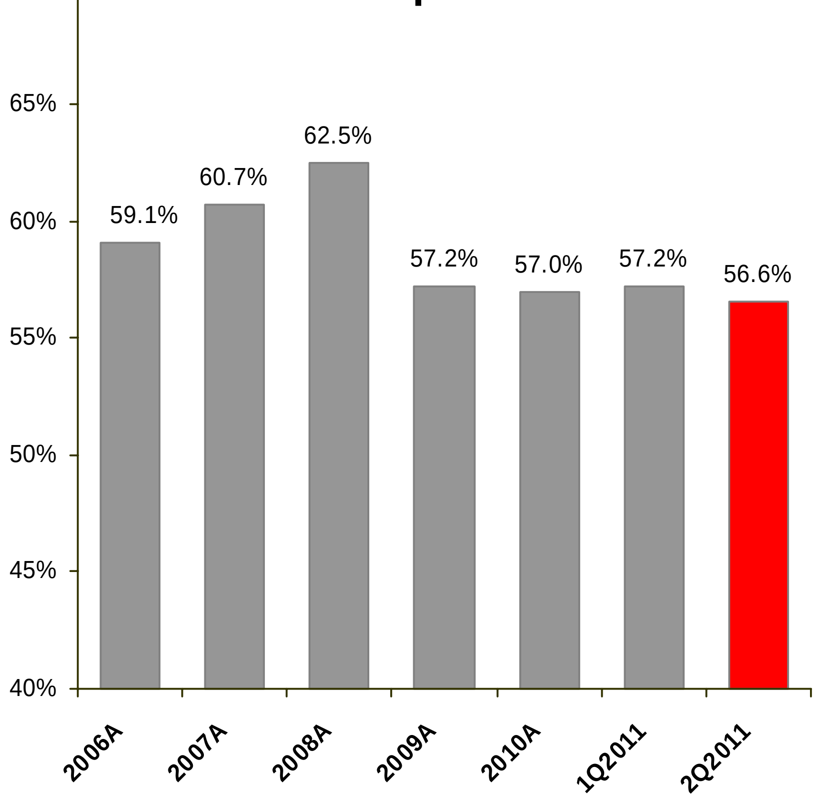
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

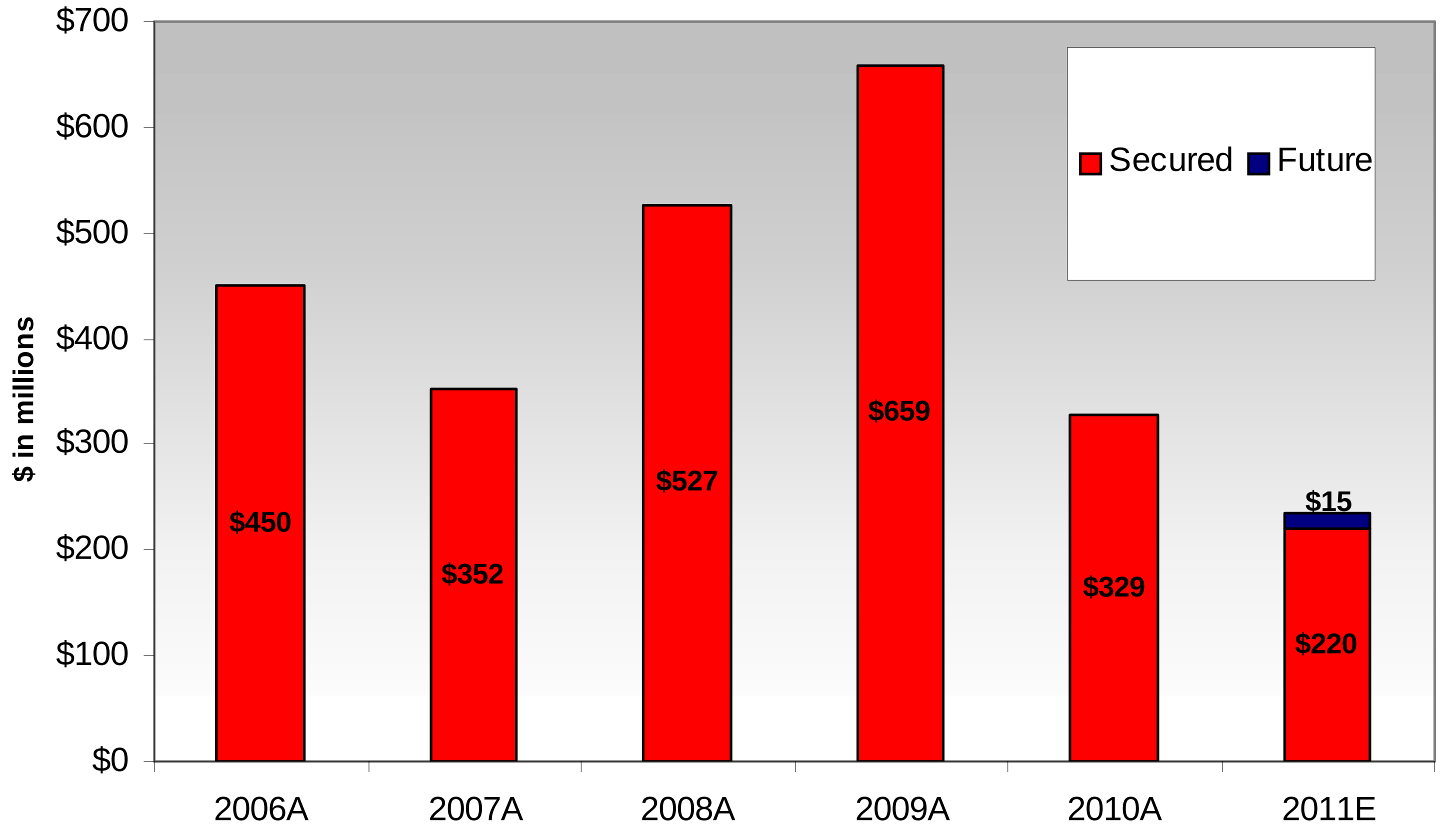
Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case - Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase). (Docket #:) A procedural schedule is pending from the VSCC.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed . APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure - Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief - Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

I&M Michigan Base Rate Case (Docket# U-16801)

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure - Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief - Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

AEP®

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3060 of 9556

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – August 4; Hearing August 15**

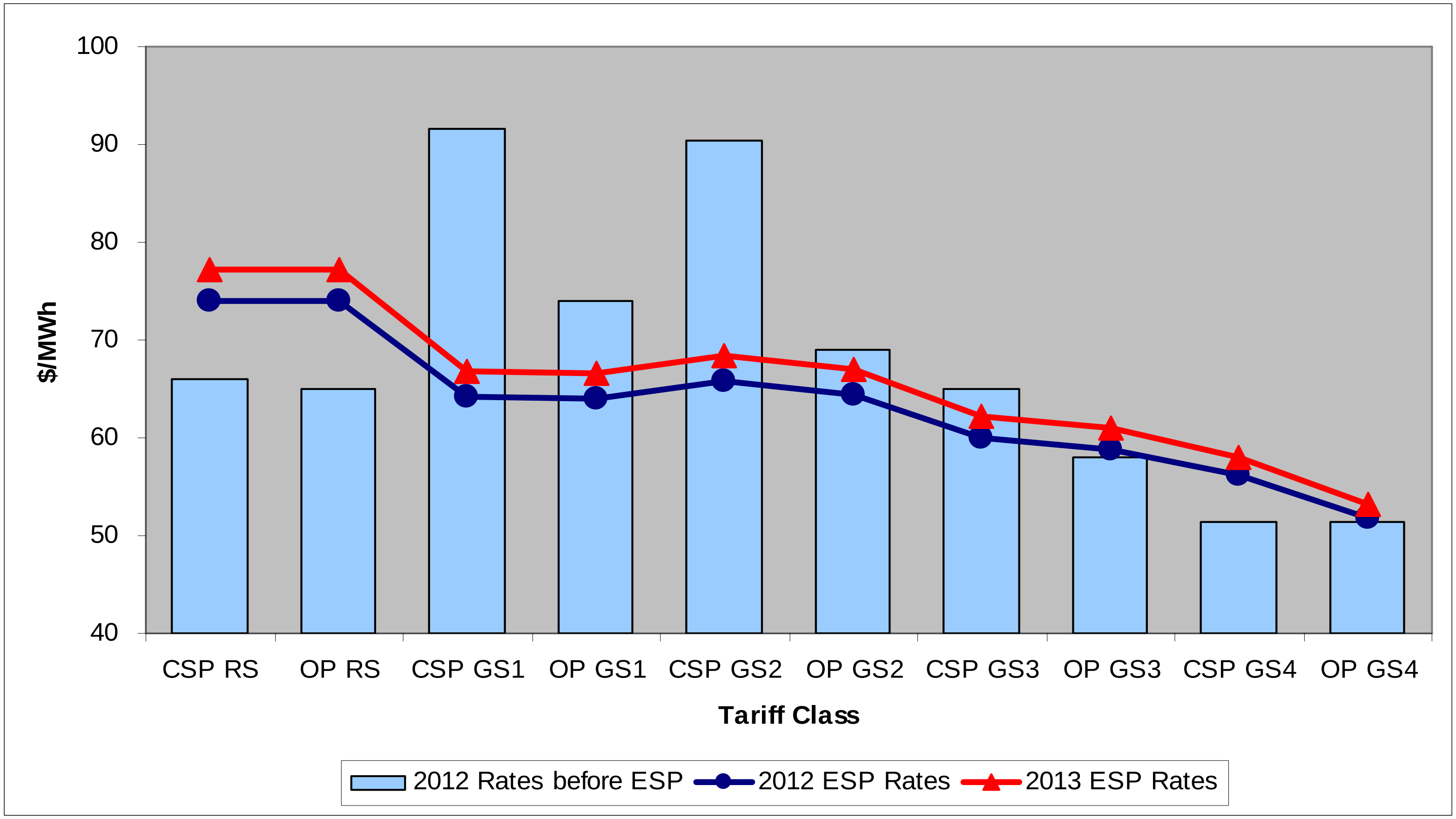
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

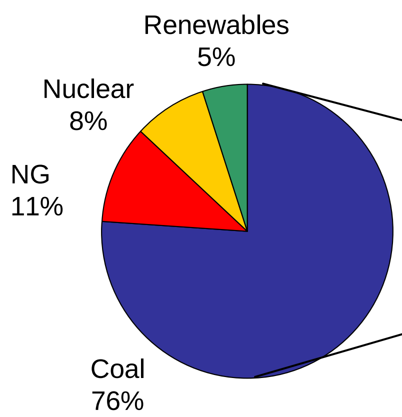
List of ESP Riders – Existing and Proposed

AEP®

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

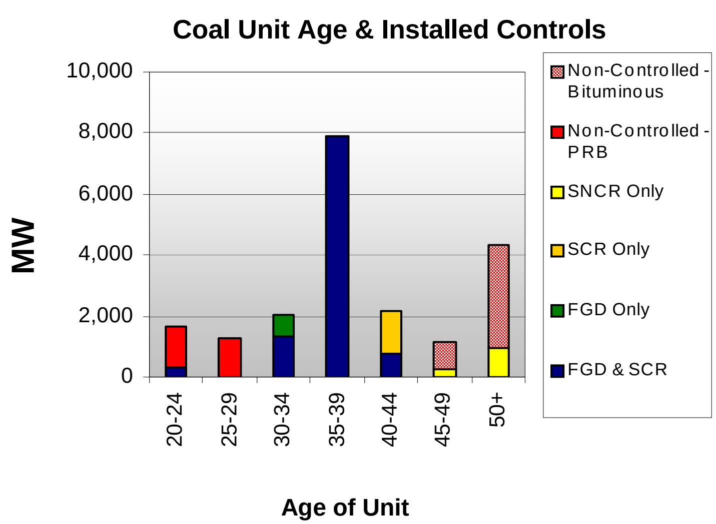
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



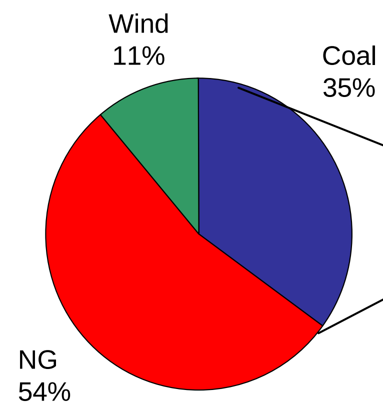
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



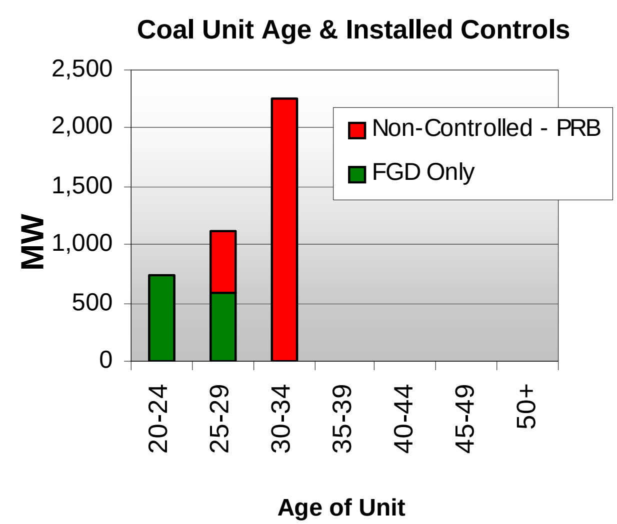
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



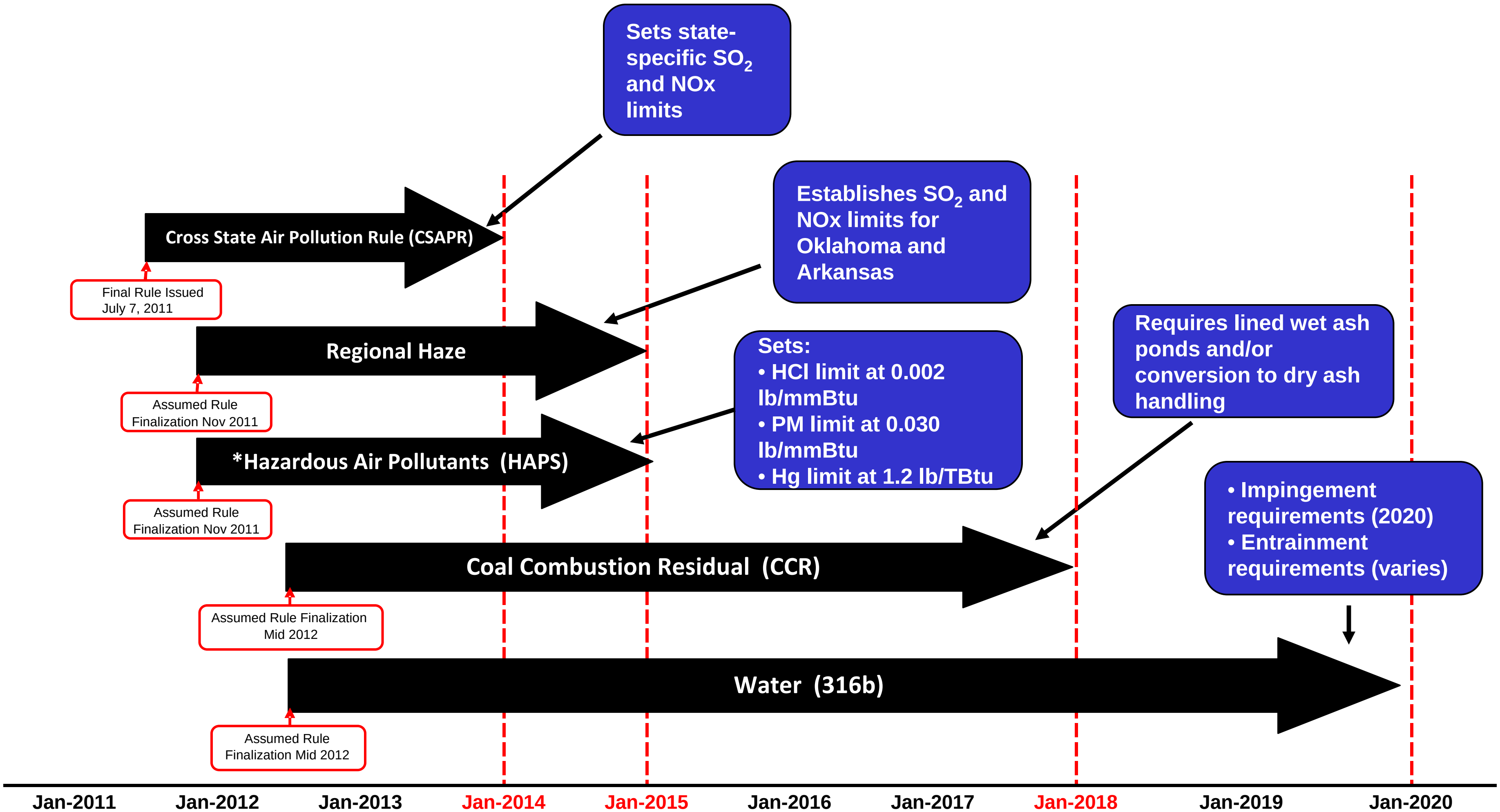
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5	510	Refuel with Natural Gas			
	Gavin 1	1320	FGD upgrade			
	Gavin 2	1320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	*
APCO	Clinch River 1	211	Refuel with Natural Gas			
	Clinch River 2	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	**
I&M	Rockport 1	1320	FGD, SCR			
	Rockport 2	1320	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670**	***
KPCO	Big Sandy 1	640	New Natural Gas			
	Total MW	**640**	**Total Expected Cost**		**525**	

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

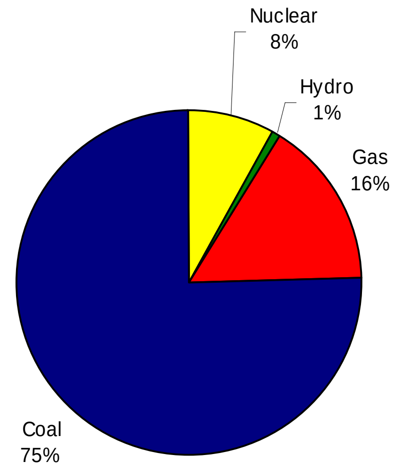
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

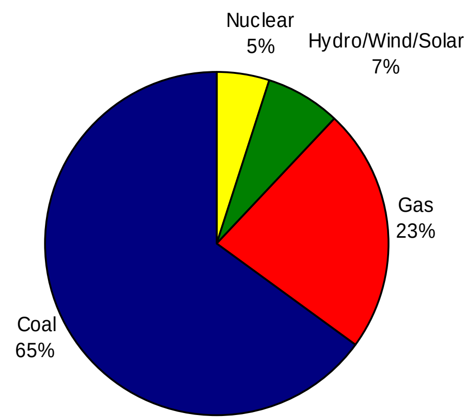
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

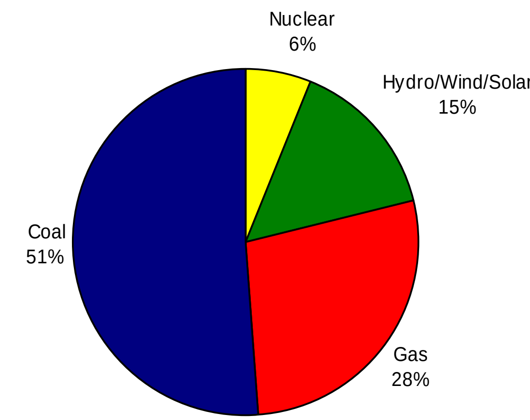
1990 AEP Generating Capacity by Fuel
37,428 total MW's



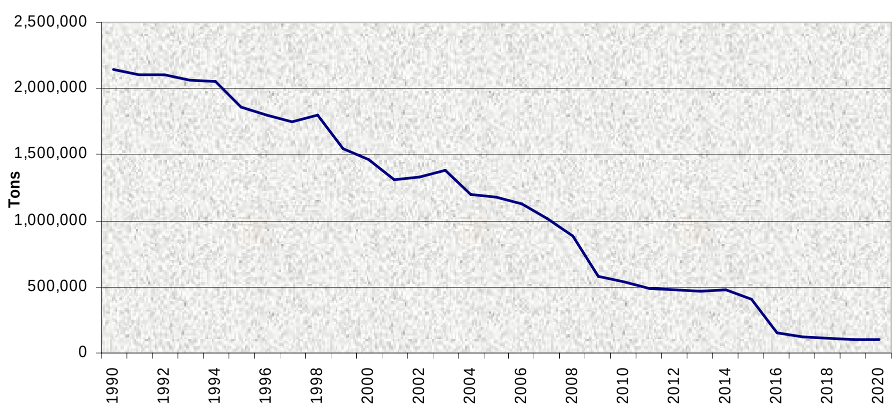
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons

- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

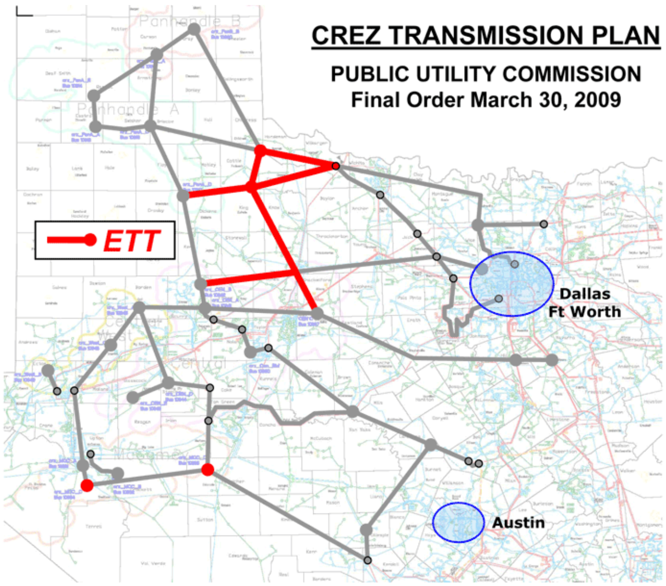
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

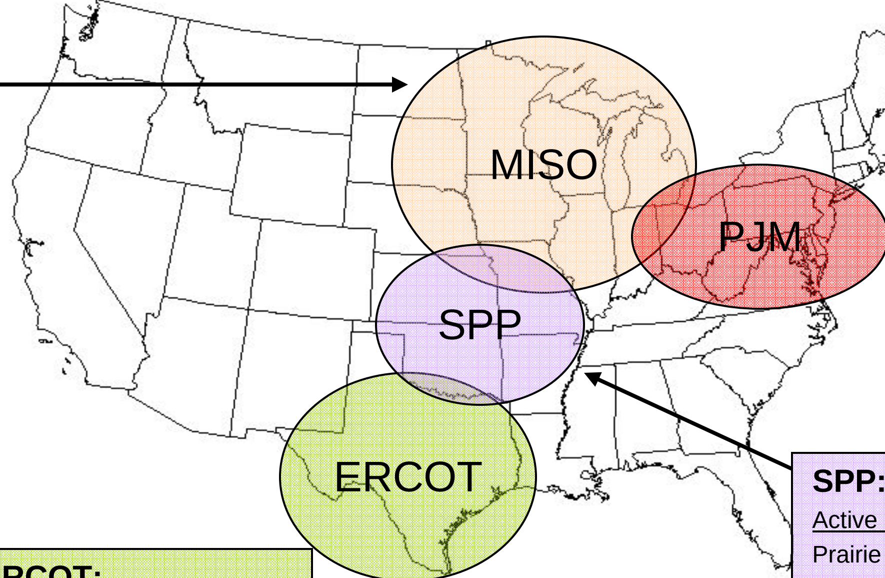
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Atlantic Equities & Clients Office Visit

Columbus, OH
April 7, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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Ohio

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

AEP®

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

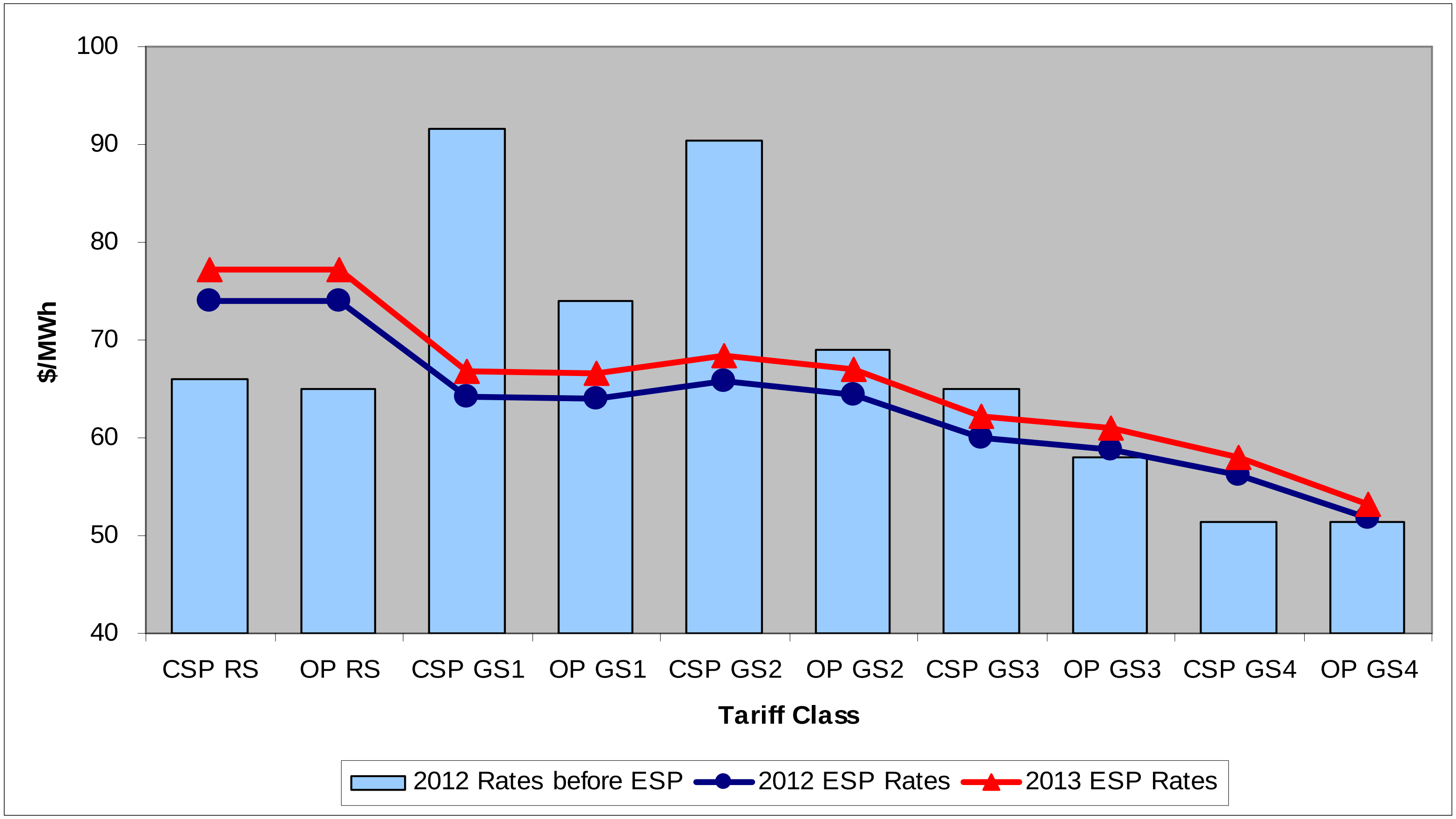
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

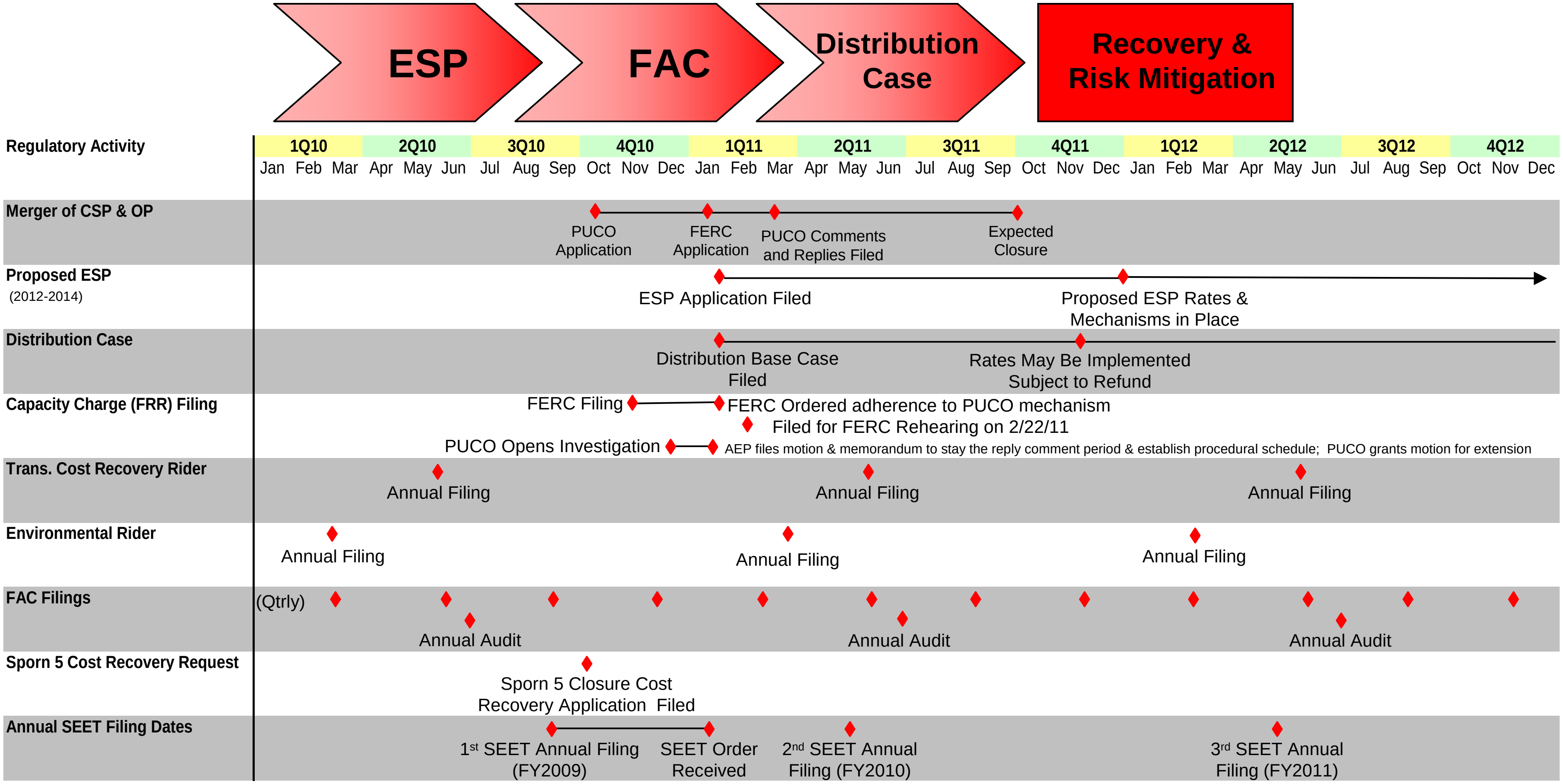
Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Ohio Timeline



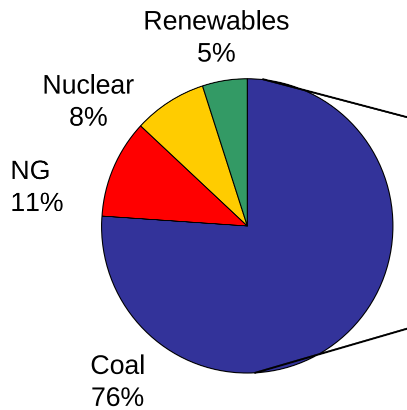
AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Generation/Environmental & EPA Matters

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



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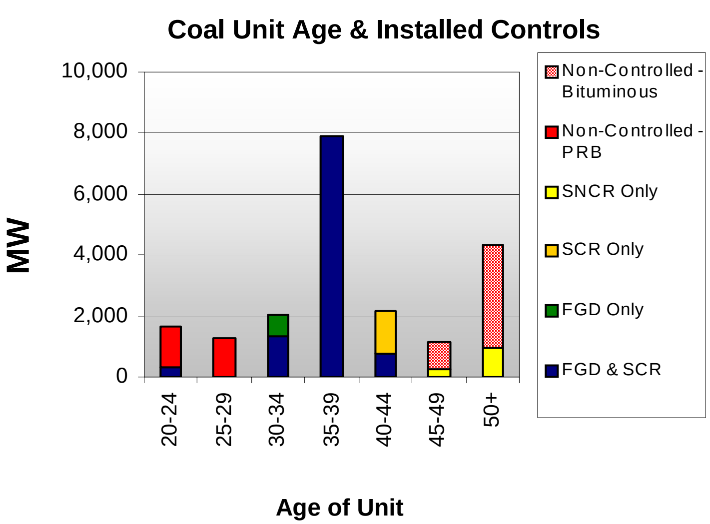

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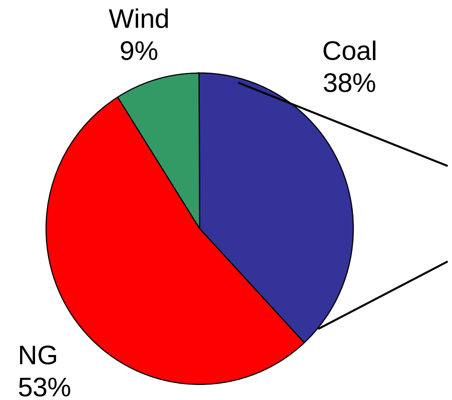
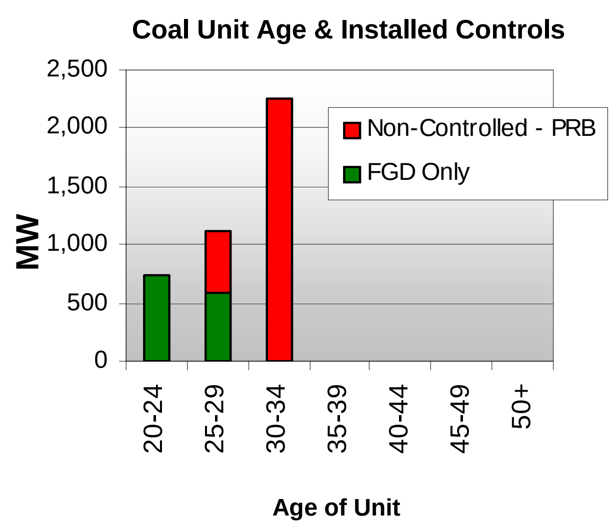


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

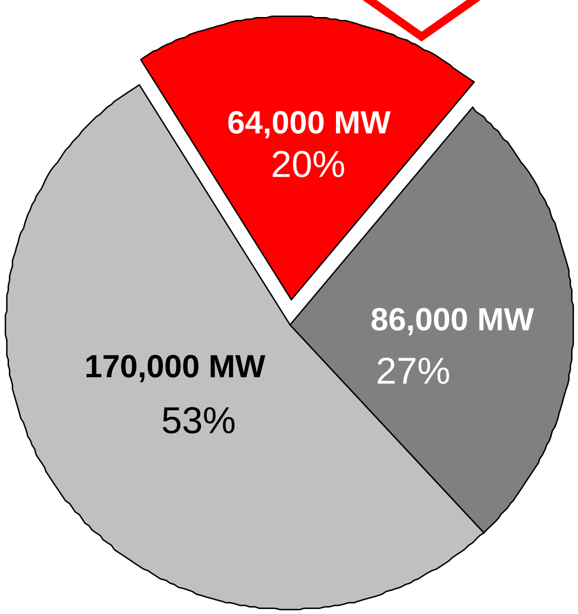


Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

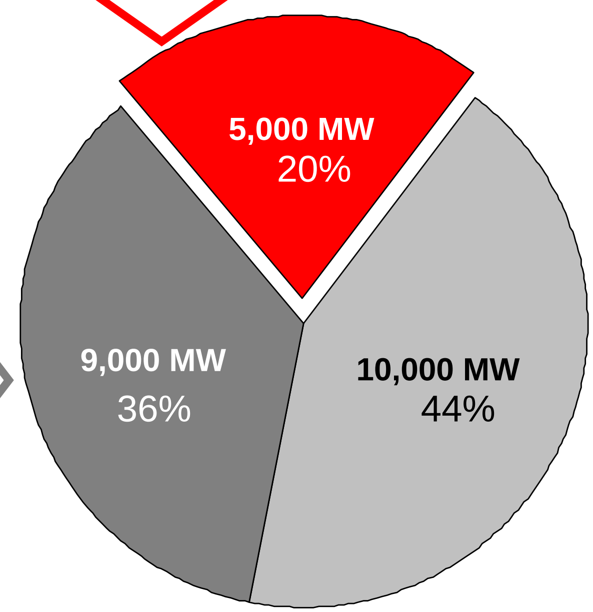
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements



AEP Coal

Nearly 50% of U.S. coal plants are exposed

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3086 of 9556

Pending EPA Regulations

AEP®

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- “Hazardous” option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

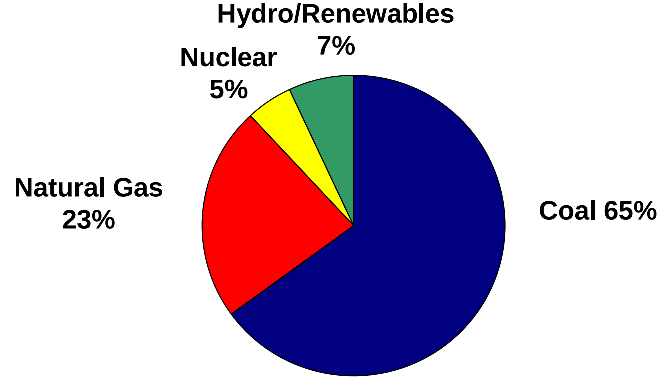
The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

Environmental Project Status Report

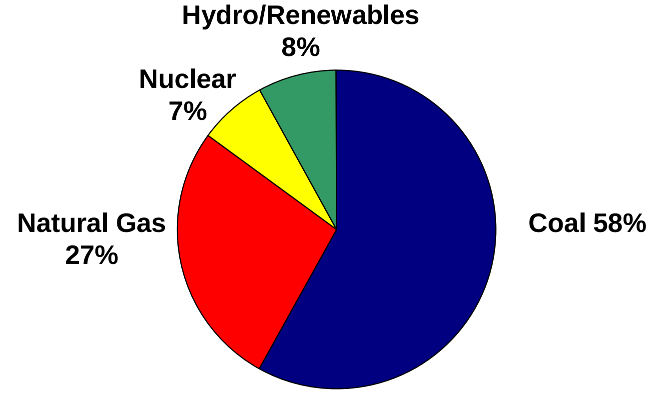
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (under construction)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2010



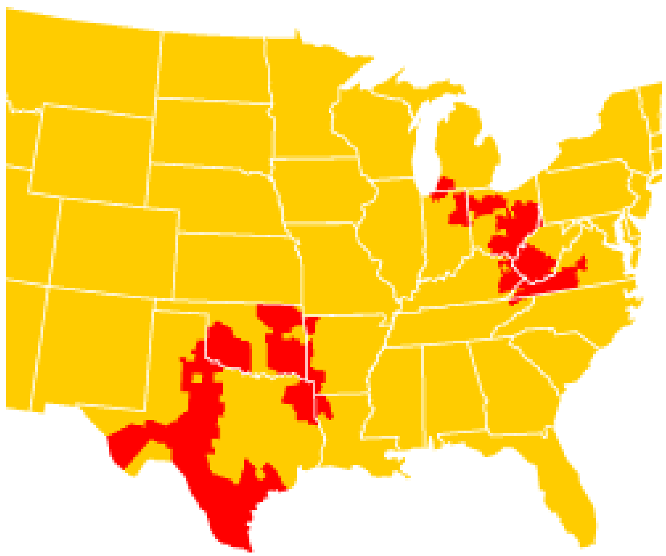
Projected Capacity - 2017

Appendix

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



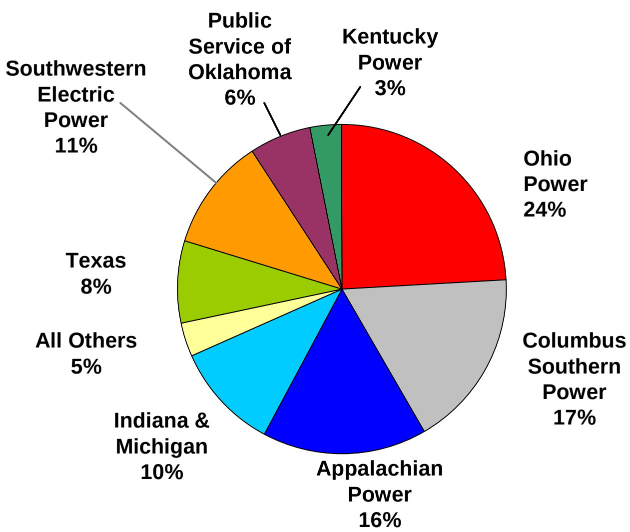
AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

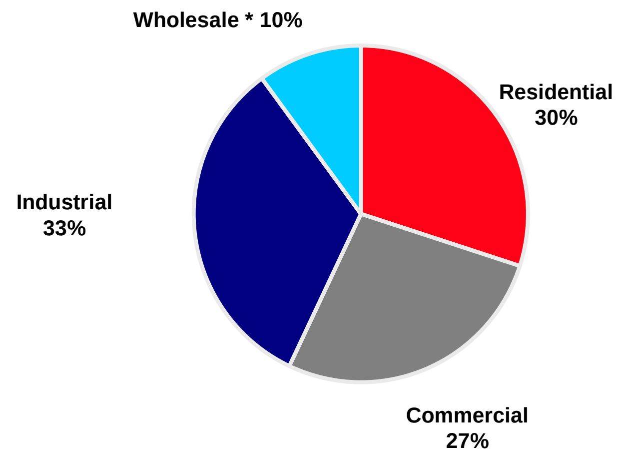
$16.7B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



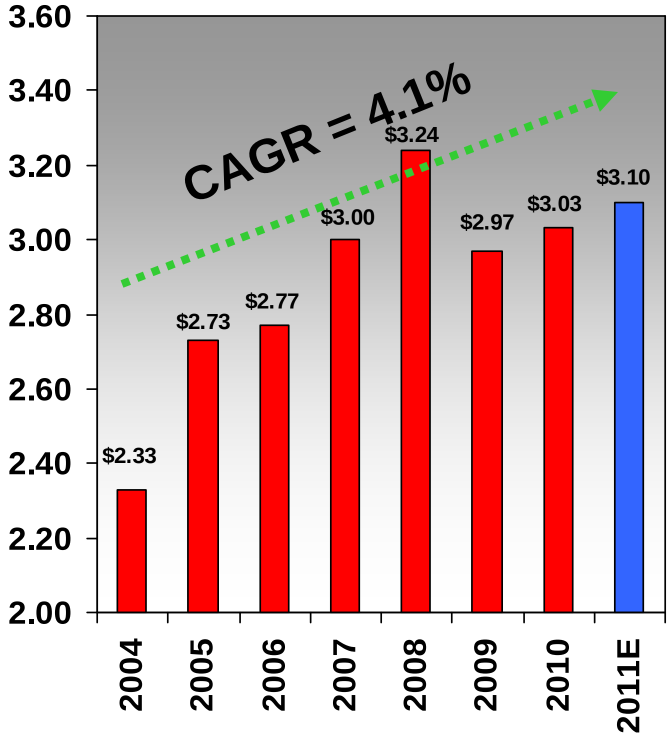
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

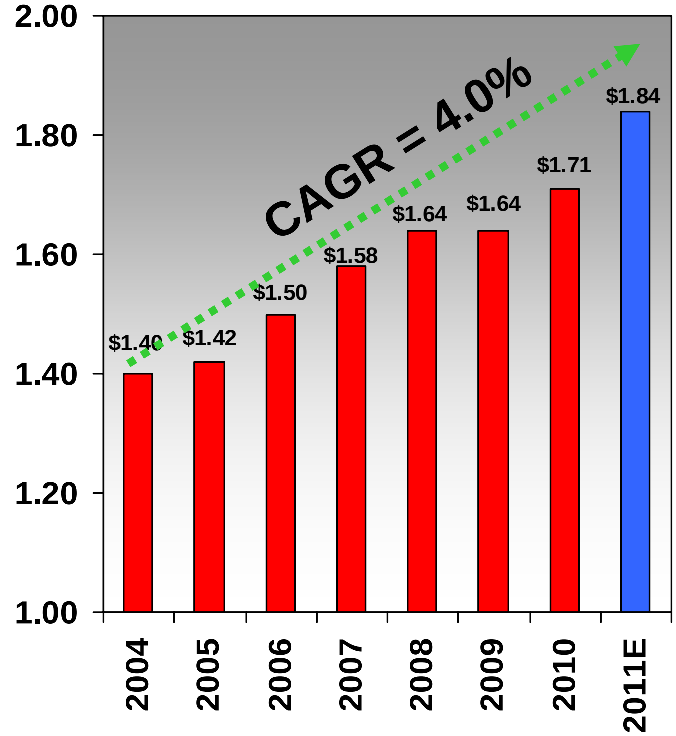
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

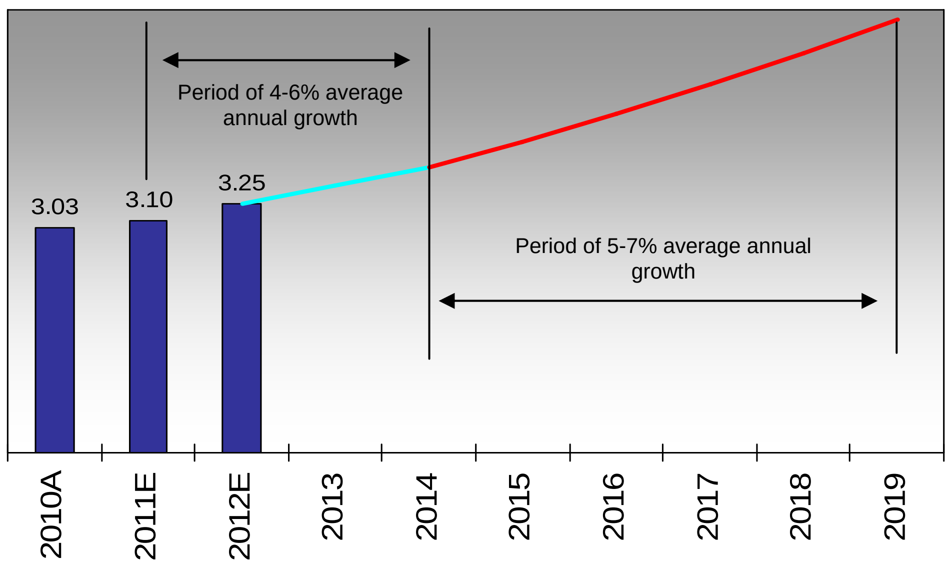
- Quarterly dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy

- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Detailed Ongoing Earnings Guidance

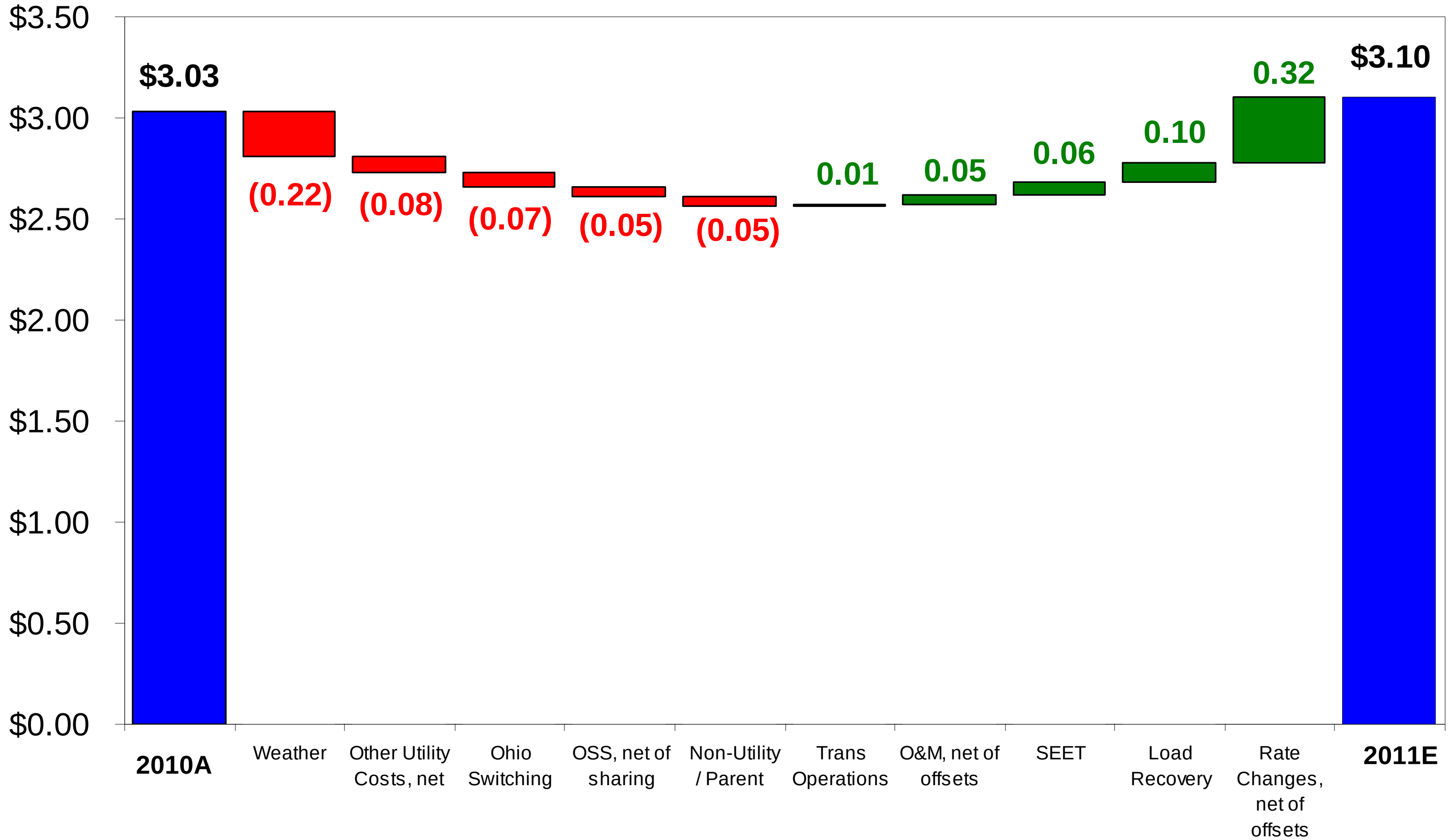
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

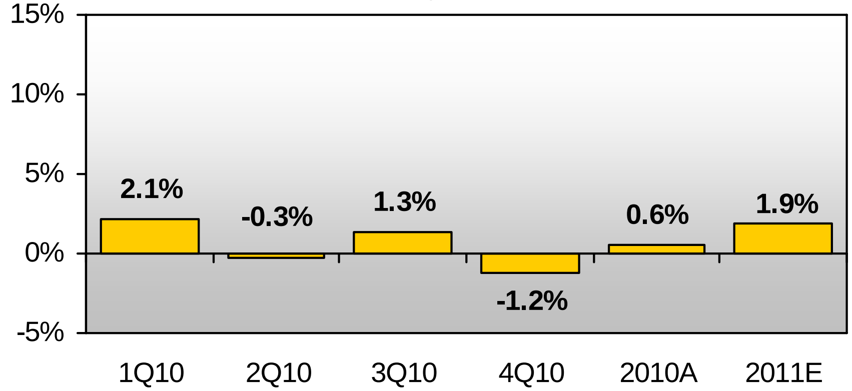


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

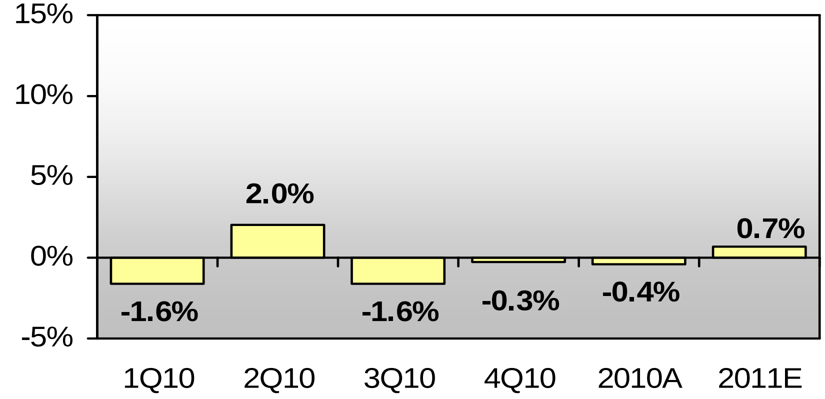
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

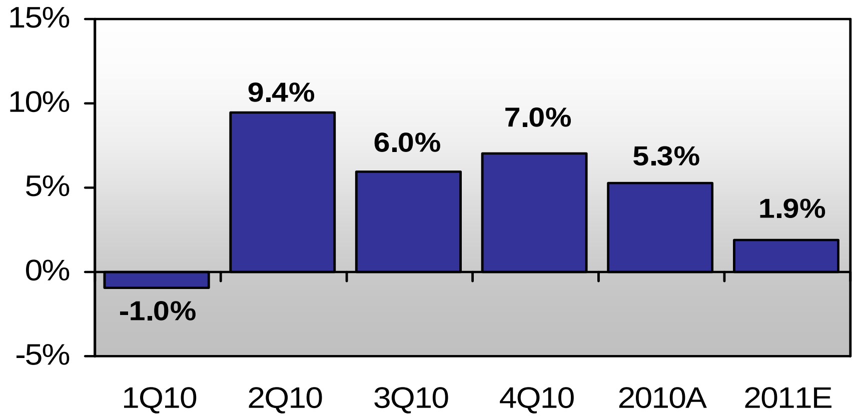
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



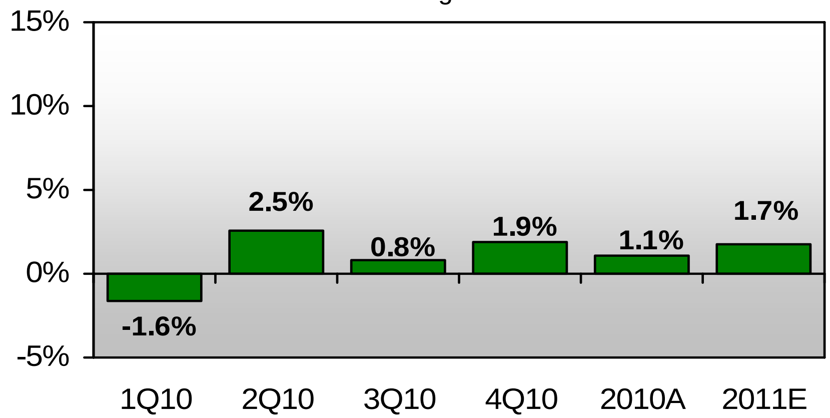
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

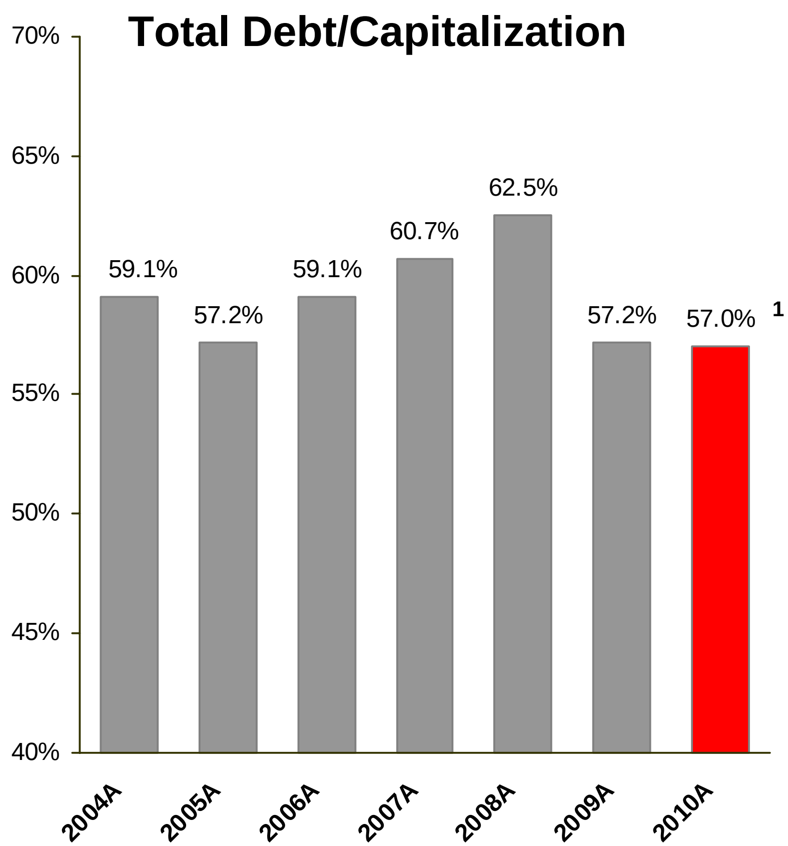
$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



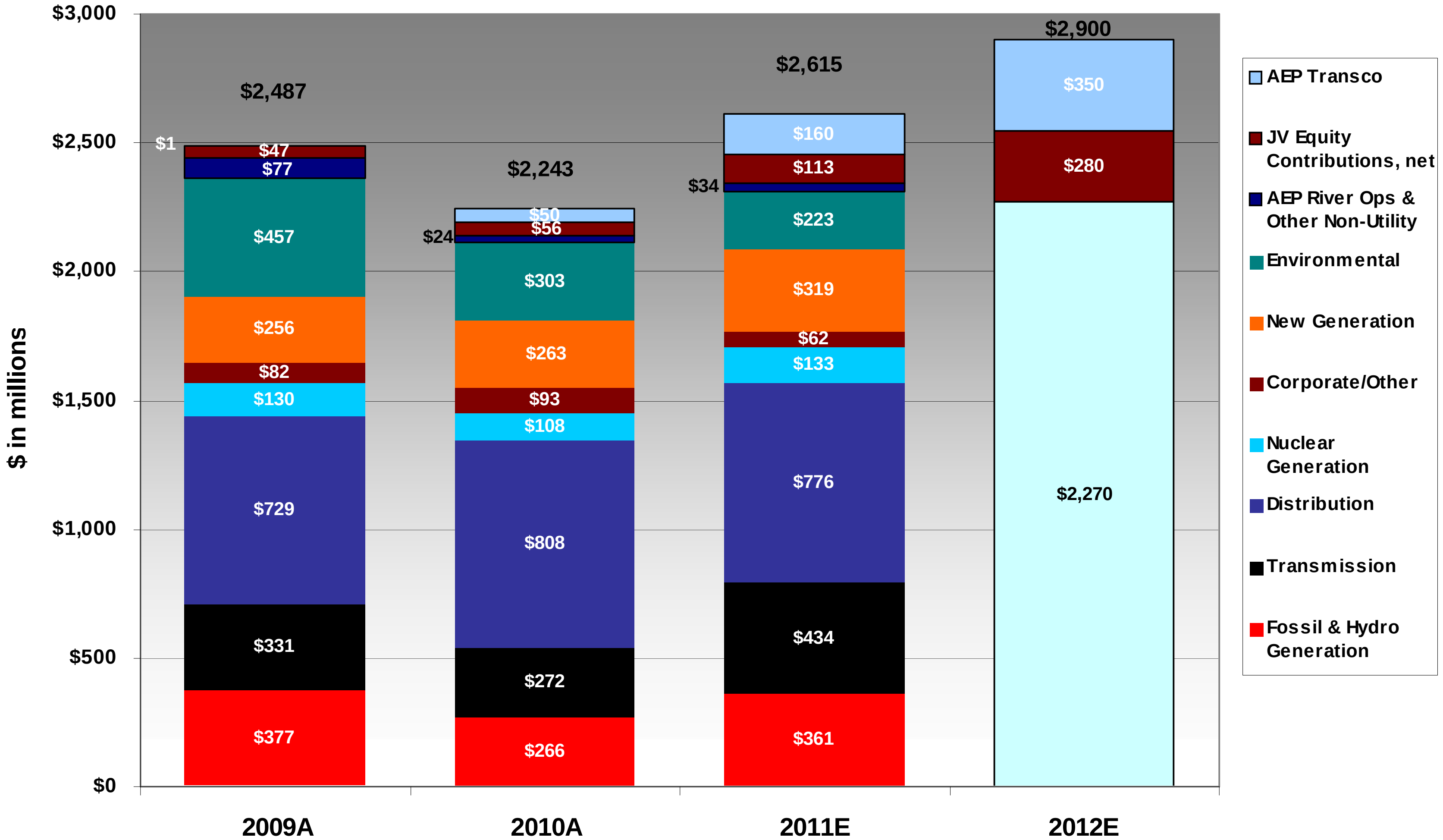
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

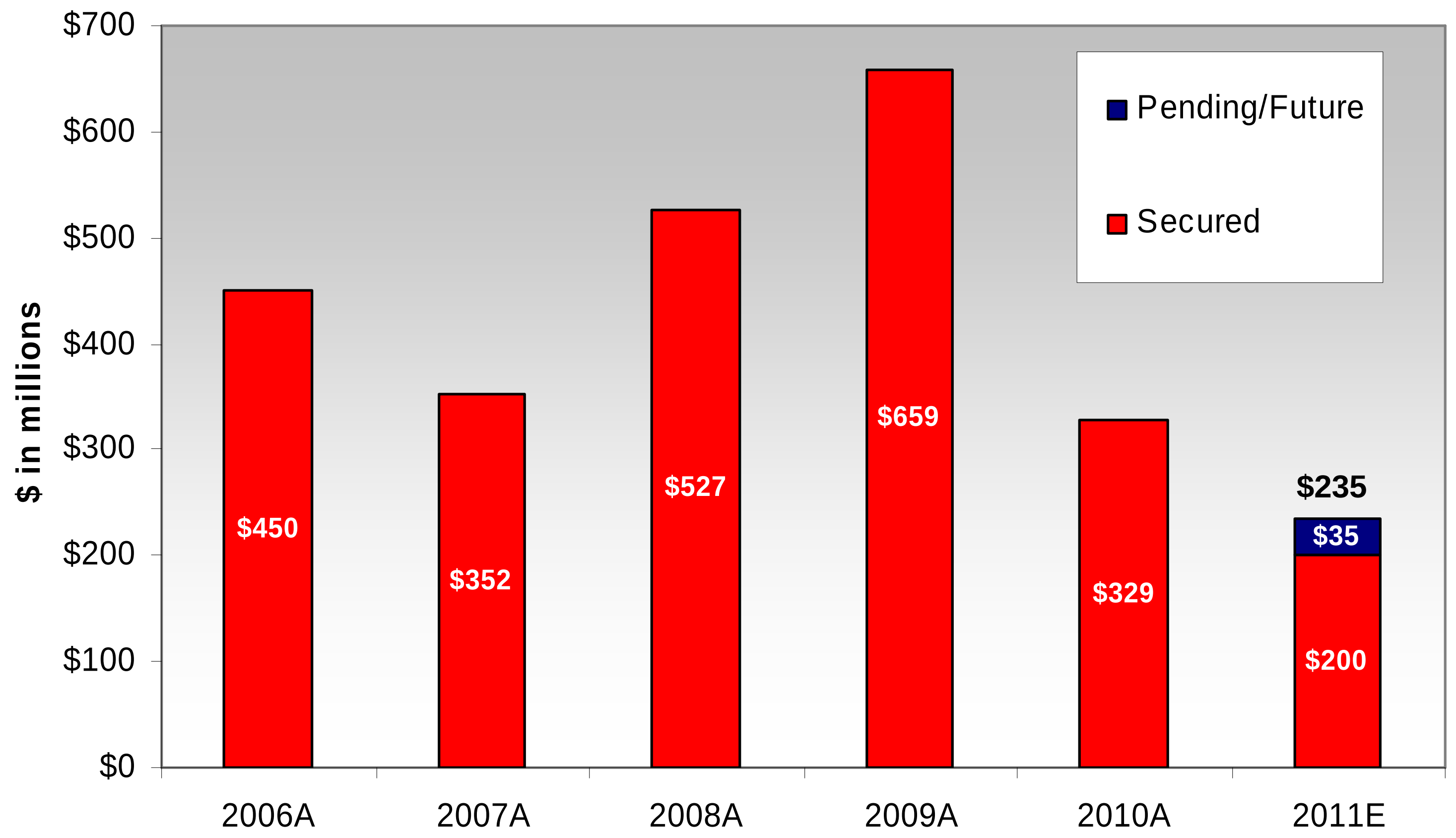
[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). A procedural schedule is pending from the VSCC.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule - TBD

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

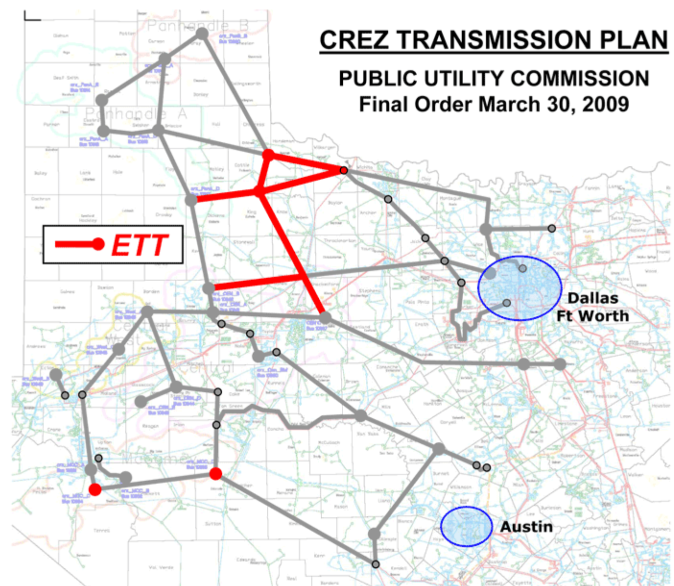
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  – Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  – Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  – PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

Filing Status Update:

- ***Ohio*** *(filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia*** *(filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia*** *(withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

$160M capital spend forecasted for 2011

Joint Venture Strategy: Long-term

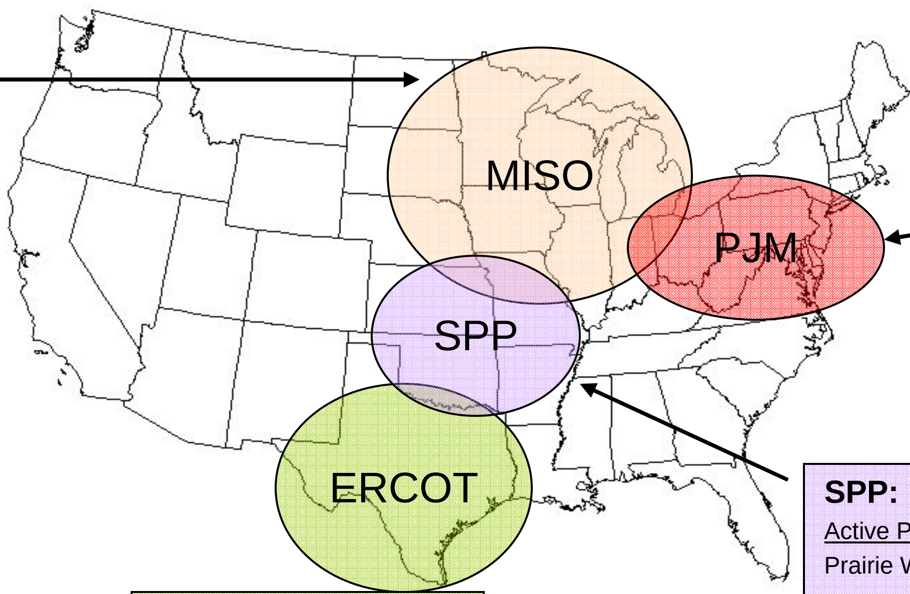
- **Strategy:** JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

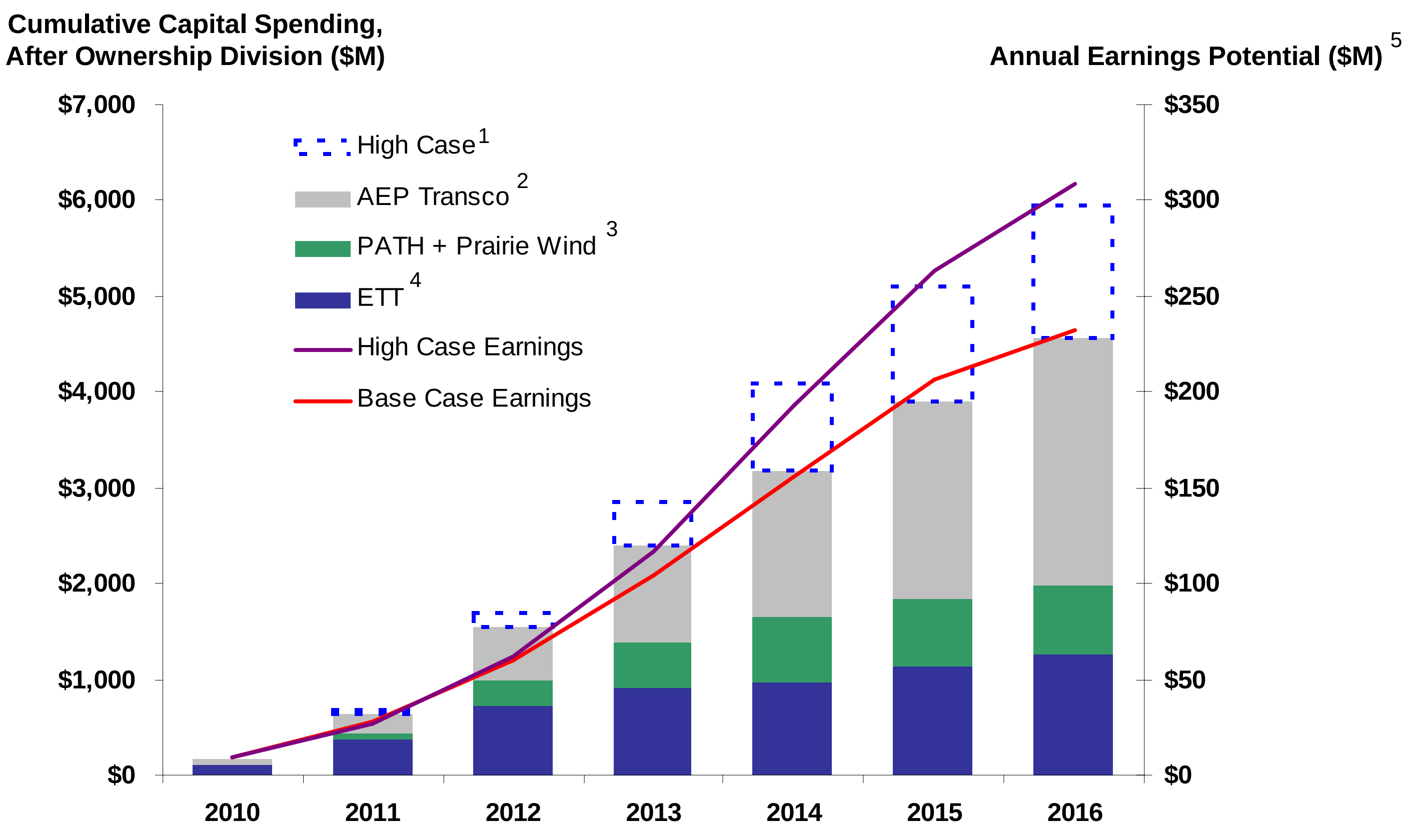
Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

AMERICAN ELECTRIC POWER

Barclays Capital 2009 CEO Energy/Power Conference

New York, NY

September 10, 2009

STRONG
FLEXIBLE
ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

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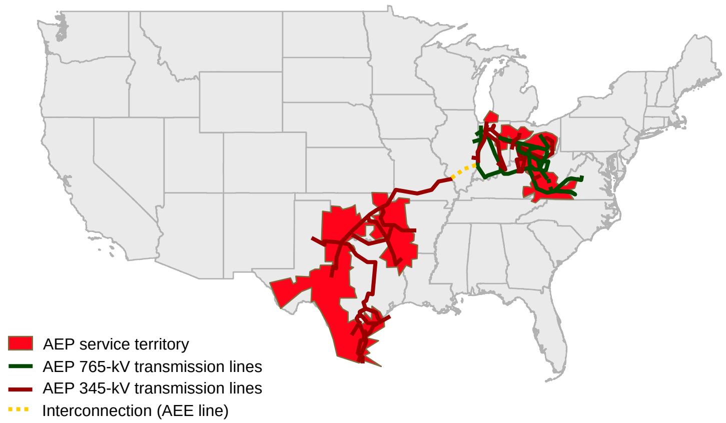
Premier Regulated Utility Platform

Overview

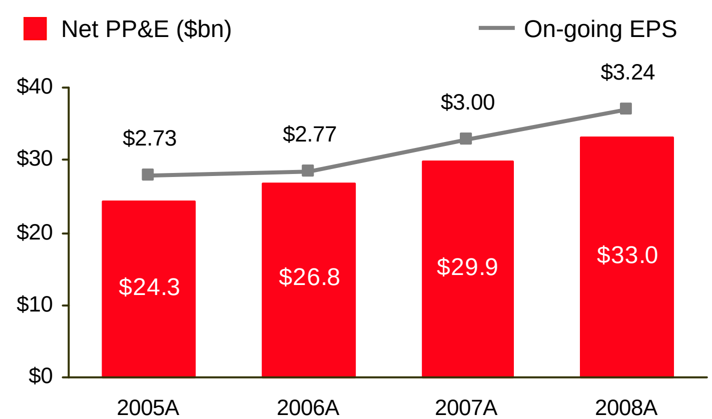


AEP's Leadership Position

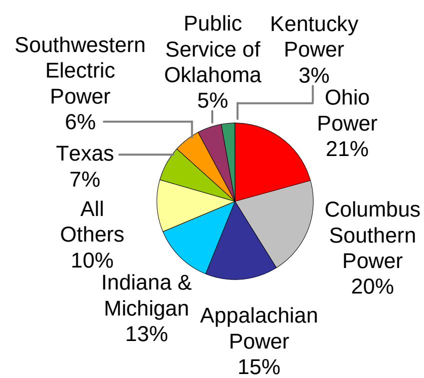
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn

- Highly diversified regulated utility earnings contribution

[1] Source: Company filings

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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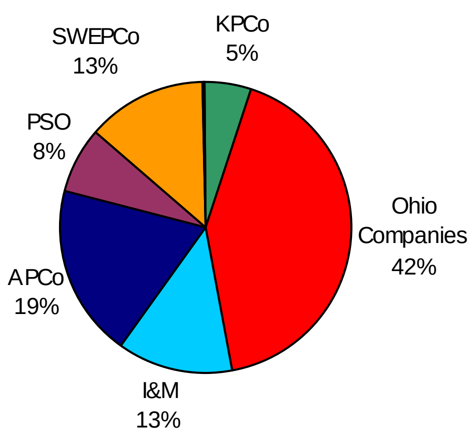
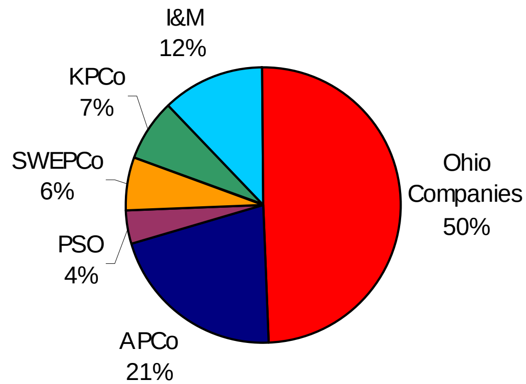
CO_2 Cost Recovery – Should Follow SO_2 & NOx

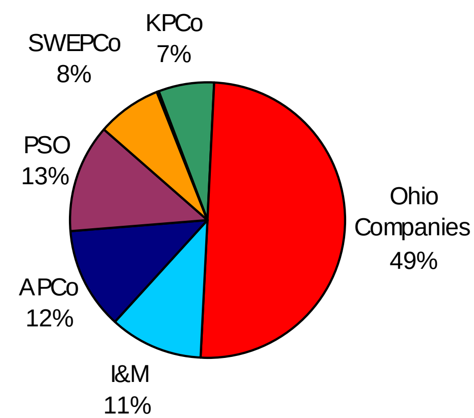
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



2008 AEP System NOx Emissions
248k tons



- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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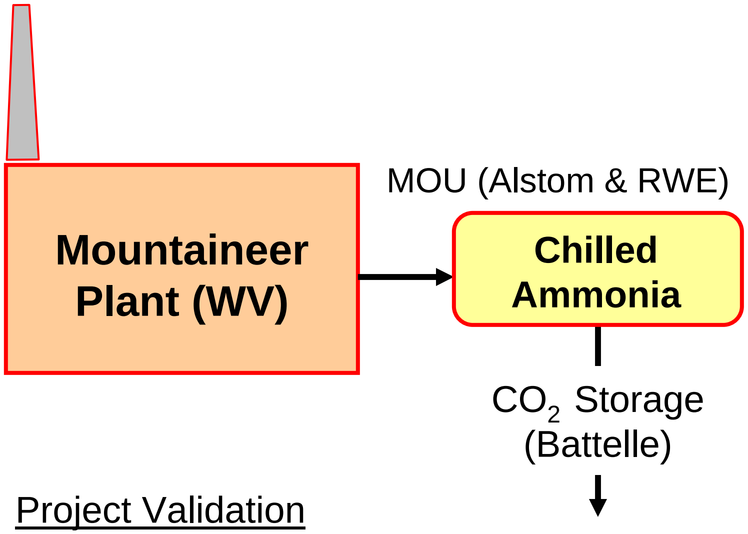
Carbon Capture & Storage



Project Validation

- **Alstom “Chilled Ammonia” Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies’ Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **Operations commenced September 2009**
- **Geologic storage for CO_2**
- **Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the ‘economic’ hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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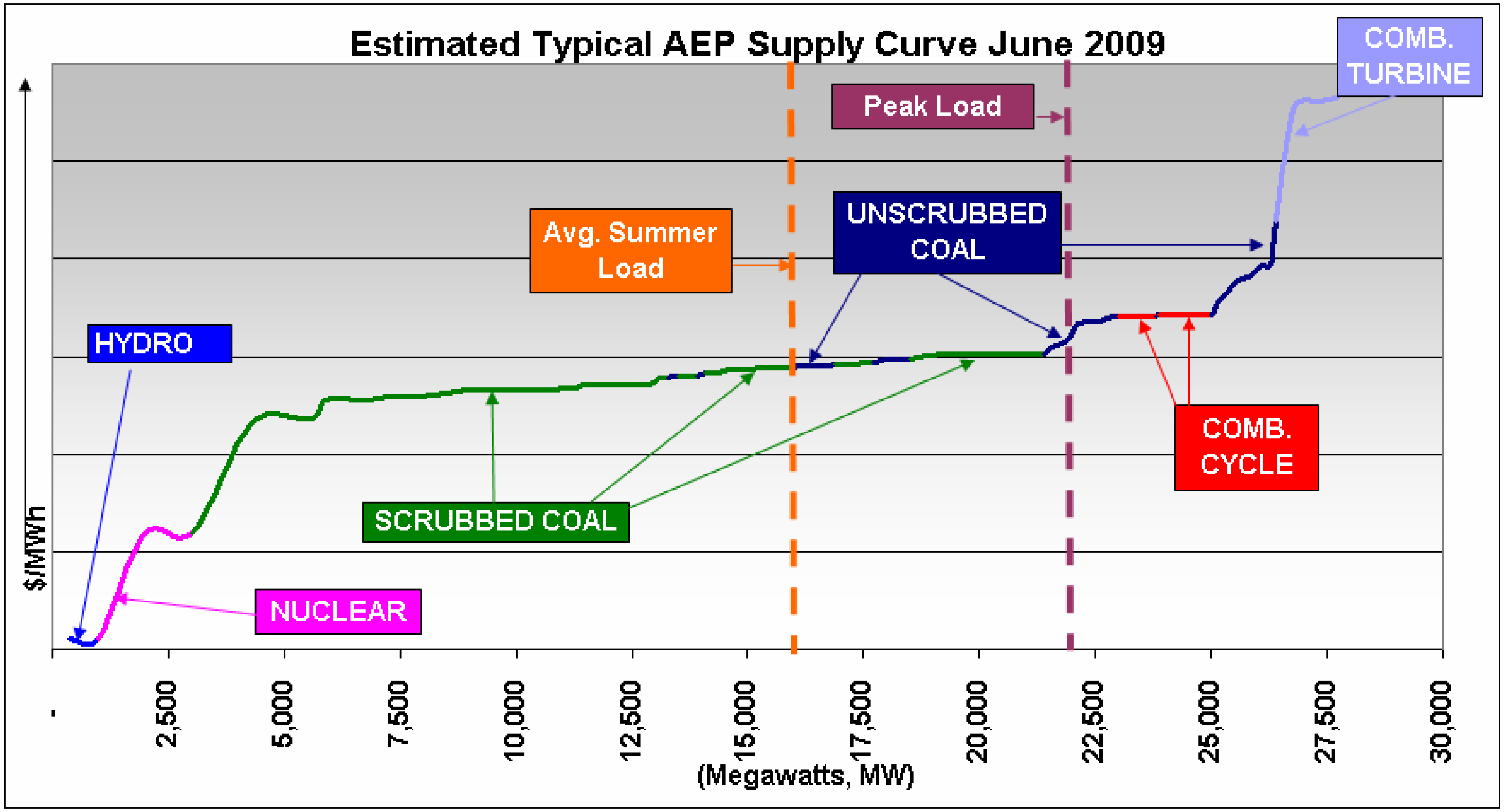
AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



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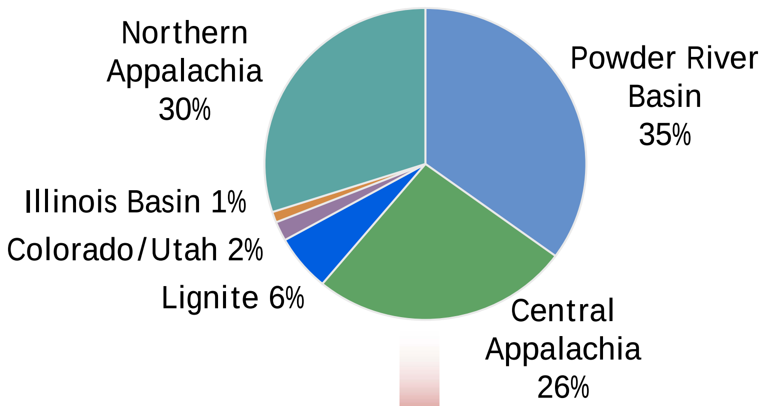
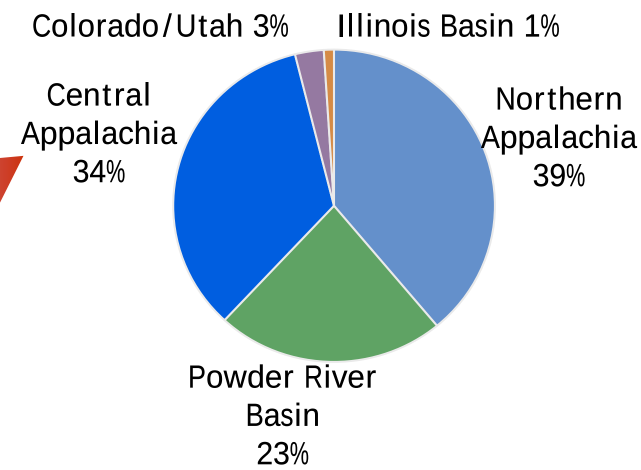
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

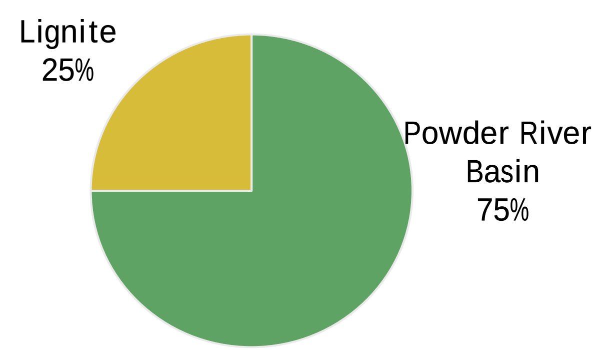
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

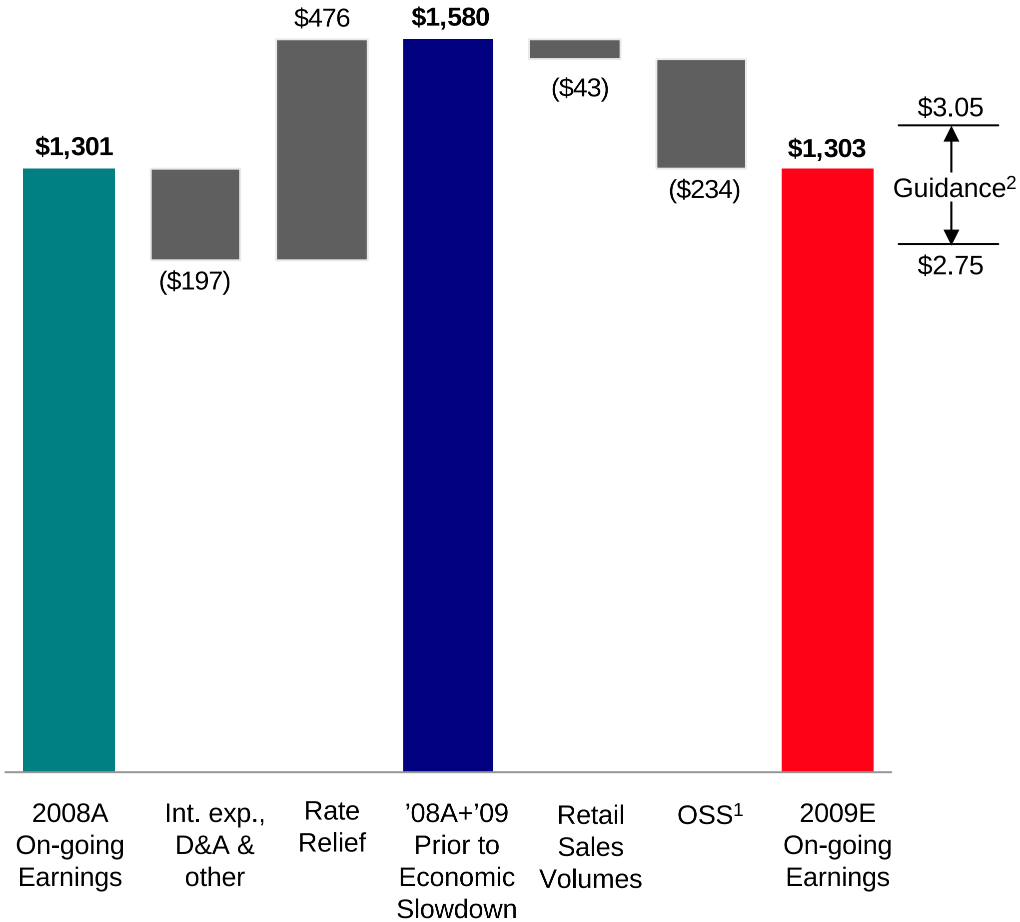
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax

[1] Net of sharing

[2] Assumes 2009 average shares outstanding ~ 450 million

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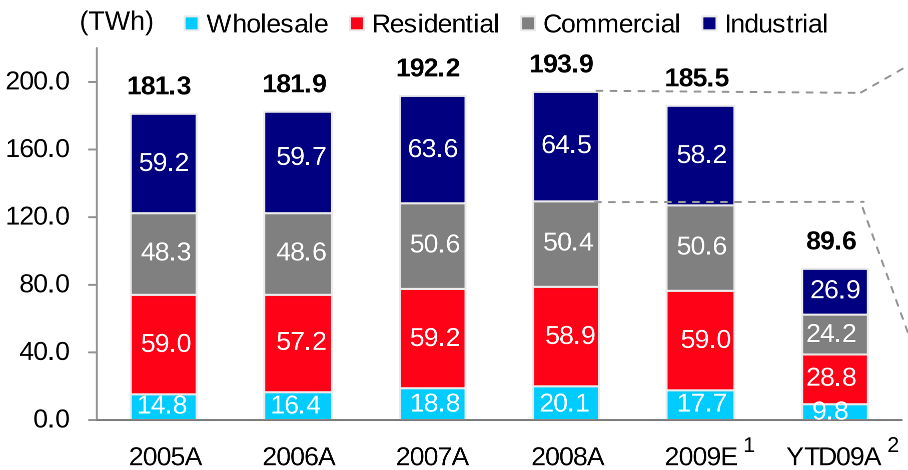
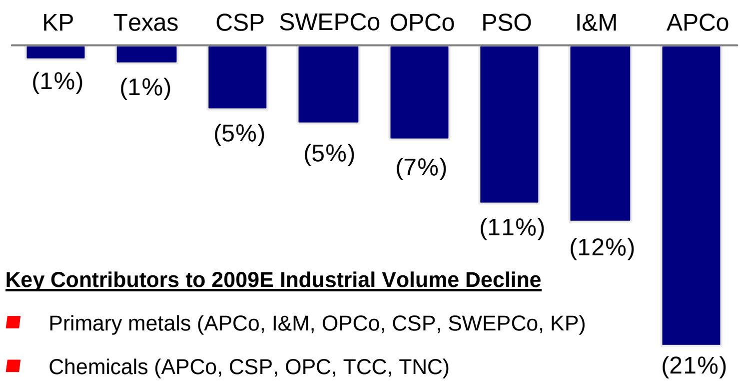
Key Drivers of 2009 Guidance: Retail Sales

Retail Load by Customer Class



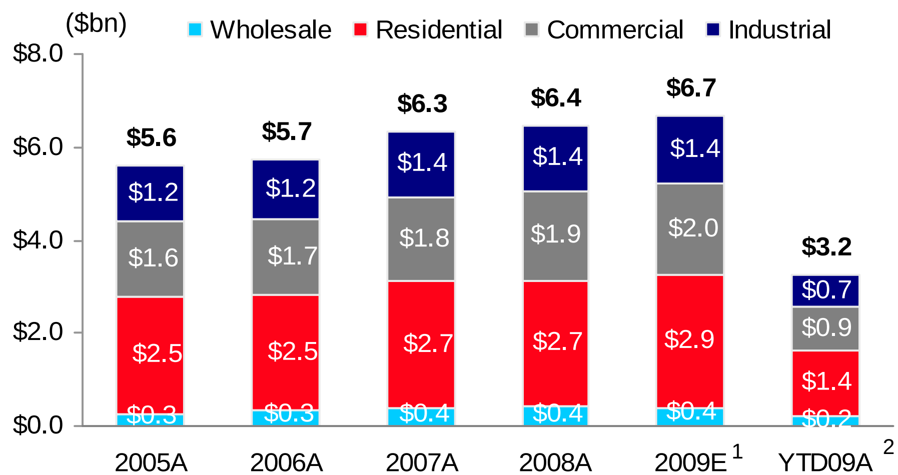
Forecast Drop in 2009 Industrial Sales

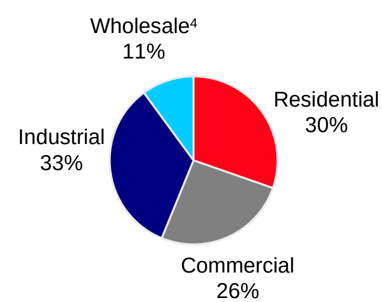


Key Contributors to 2009E Industrial Volume Decline

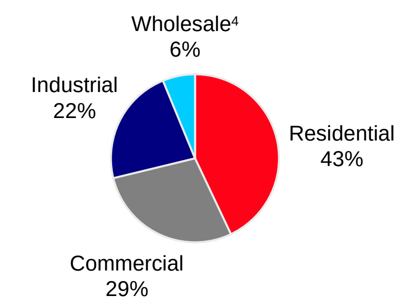
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Chemicals (APCo, CSP, OPC, TCC, TNC)
- Paper (APCo, PSO, SWEPCo)
- Plastics & Rubber (APCo, CSP, OPCo, I&M)

Retail Base Revenue[3] by Customer Class





2008 Retail Load = 193.9 TWh



2008 Retail Base Revenue [3] = $6.4bn

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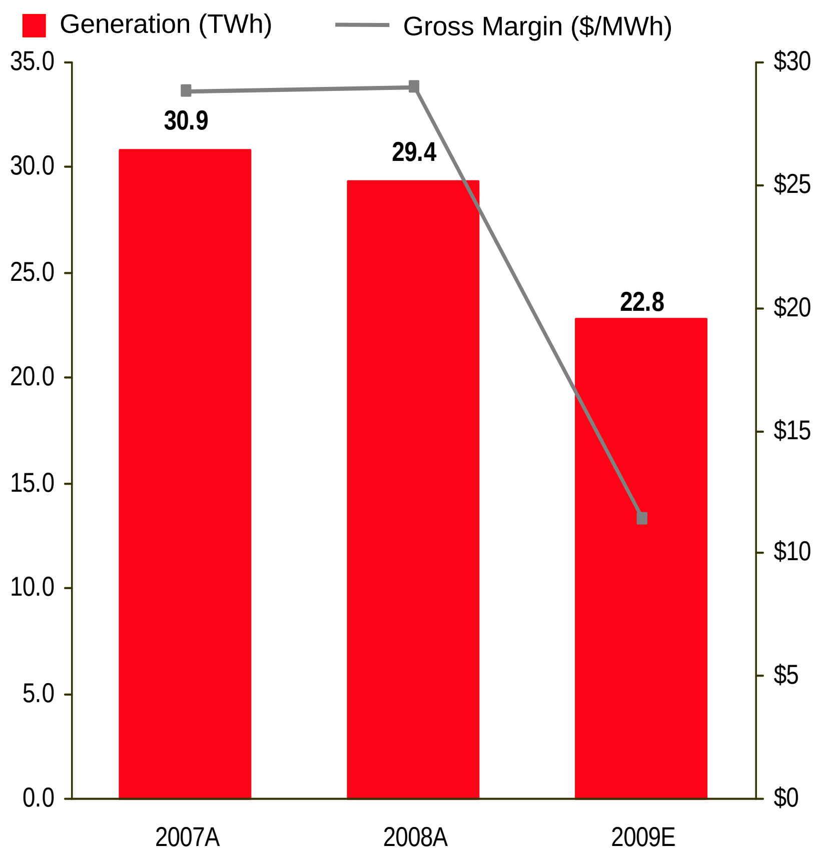
[1] 2009E assumes normalized weather
[2] YTD09A represents actual results through June 30, 2009

[3] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables
[4] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

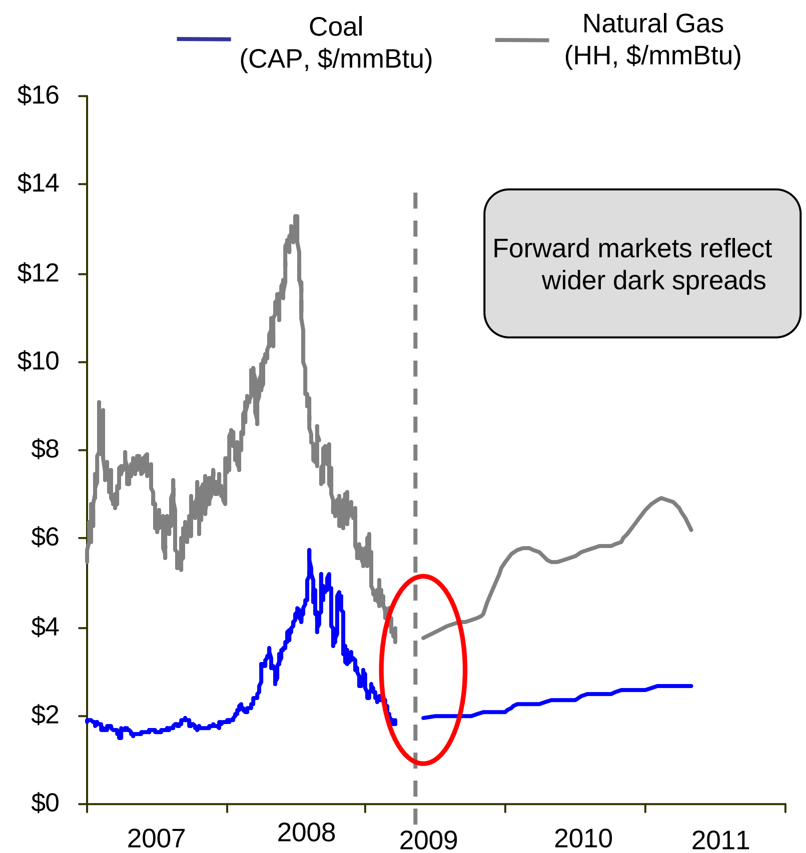
Key Drivers of 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions	2007A	2008A	2009E
OSS Physical Sales	$ 674	$ 718	$ 106
Oklaunion Payment	46	45	49
Marketing/Trading	170	82	105
Pre-sharing Gross Margin	$ 890	$ 845	$ 260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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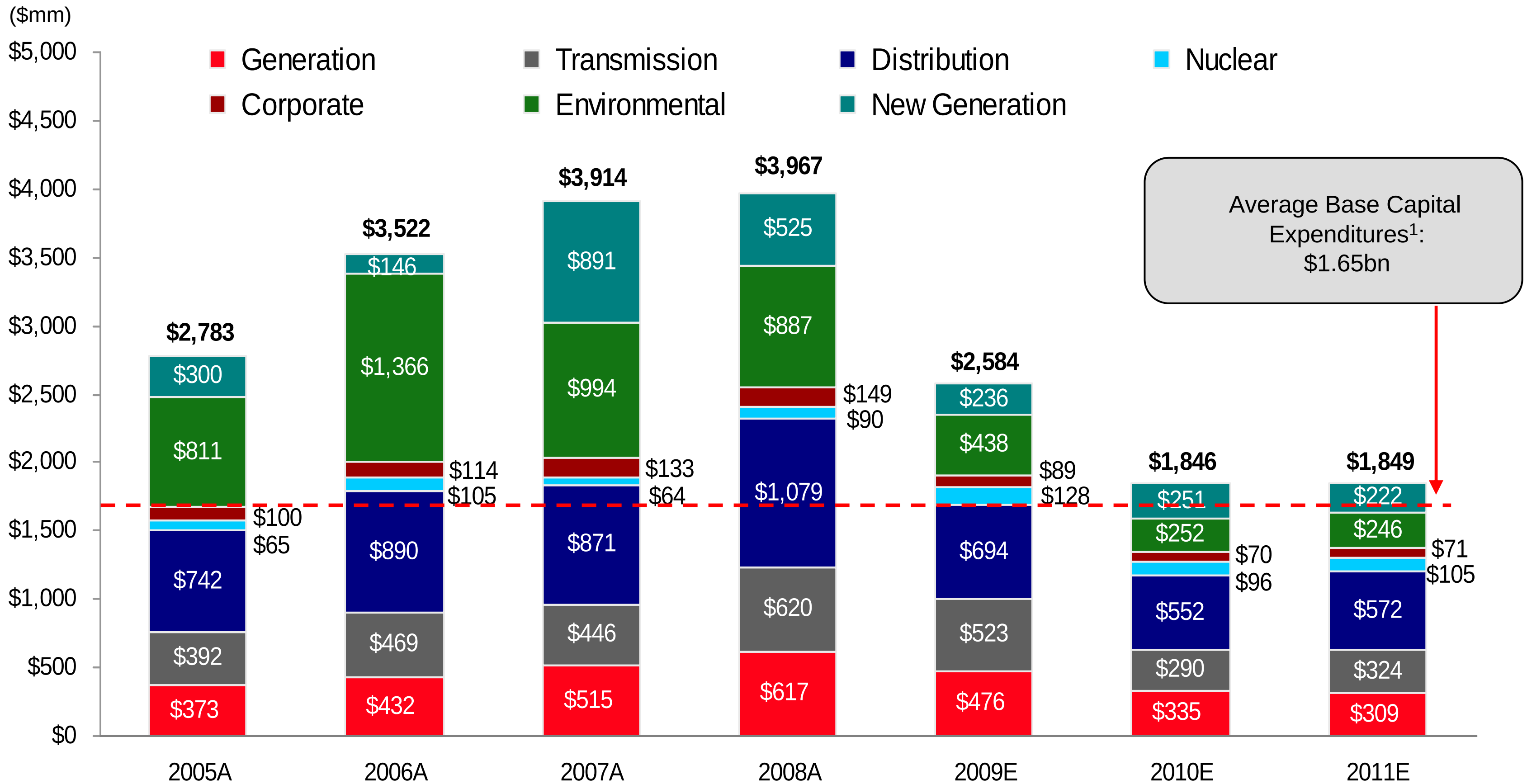
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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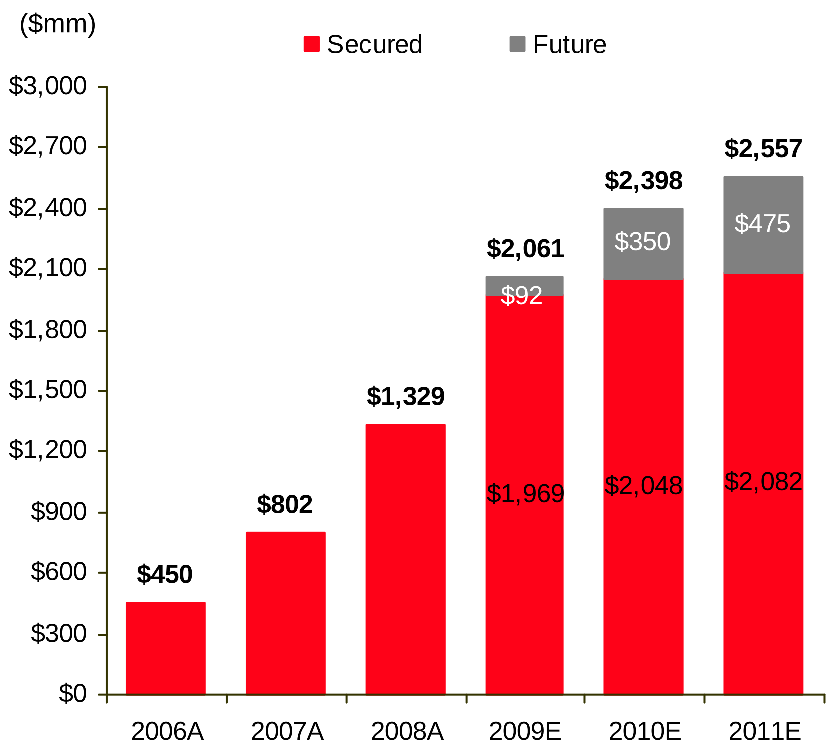
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] *$79mm and $38mm was secured for 2010 and 2011, respectively, as of August 31, 2009*

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Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ APCo VA ($178MM)
  - ✓ PSO ($30MM)
  - ✓ SWEPCo AR ($54MM) TX ($75MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Rehearing Order	2010 ESP Appl.	2010 PUCO Rehearing Order	2011 ESP Appl.	2011 PUCO Rehearing Order	Cumulative ESP Appl.	Cumulative PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030) A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

December 12, 2009	Rates Effective, Subject to Refund
December 28, 2009	Intervenor Testimony due
January 27, 2010	Staff Testimony due
February 17, 2010	APCo Rebuttal Testimony due
March 16, 2010	Hearing Commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

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Summary Rate Case Information

SWEPCo Texas General Rate Case

On August 28, 2009 SWEPCo filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to recover concurrent financing costs related to the construction of the Stall and Turk plants as well as increased operating costs and enhanced distribution reliability spending. (Docket# 37364) An order is expected in 2010.

Projected Capital Structure - Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule TBD

Required Rate Relief - Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recovery Riders	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

($ in millions)
(as of June 30, 2009)

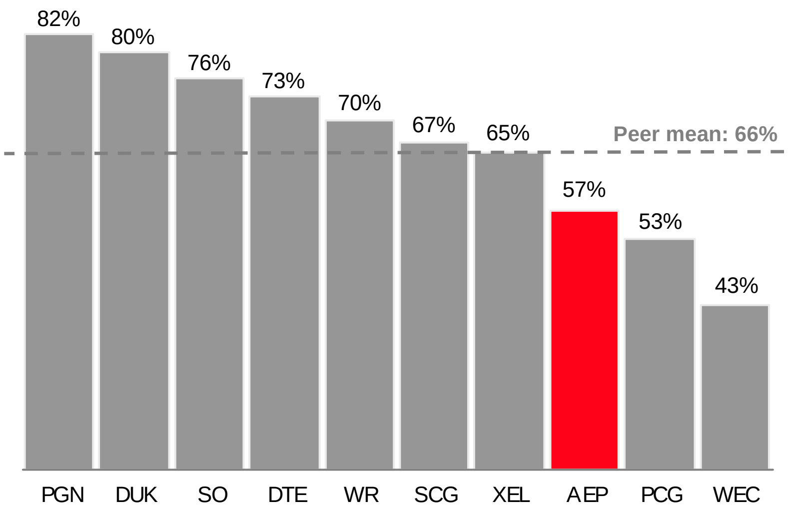
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

AMERICAN ELECTRIC POWER

Dividend Overview

- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

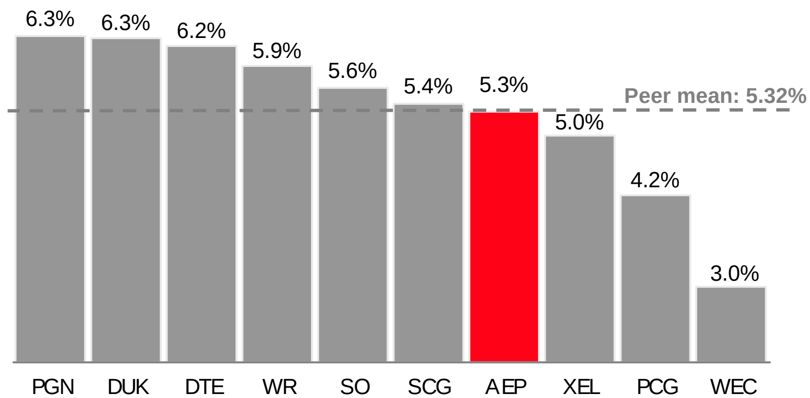
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 9/1/09

Dividend Yield vs. Integrated Electric Peers



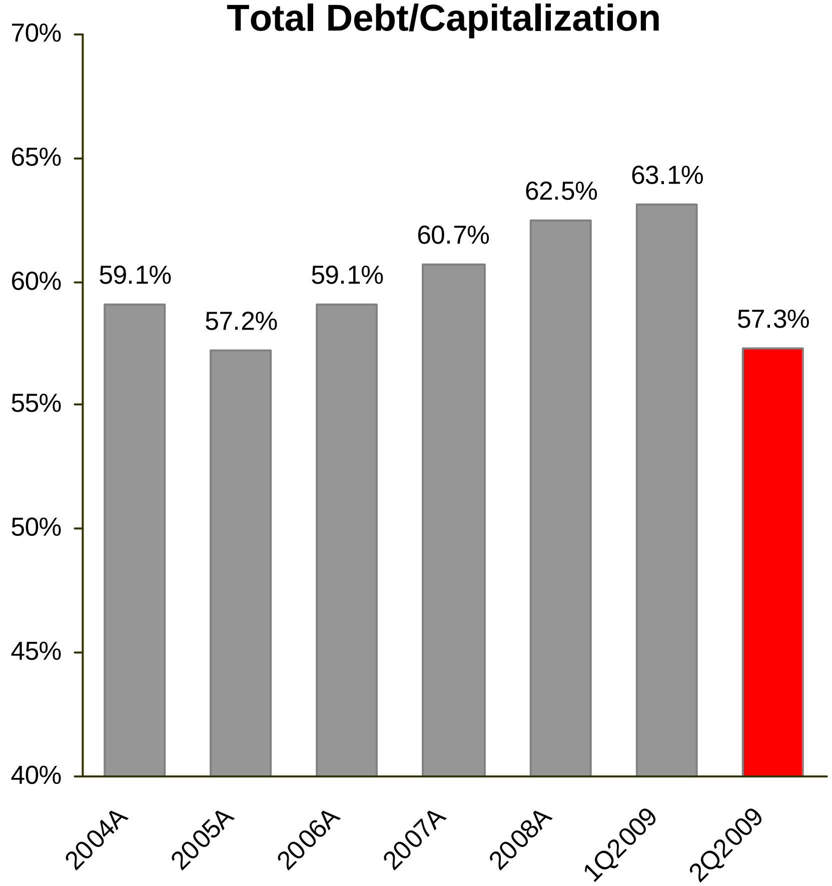
Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 9/1/09

AMERICAN ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 6/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

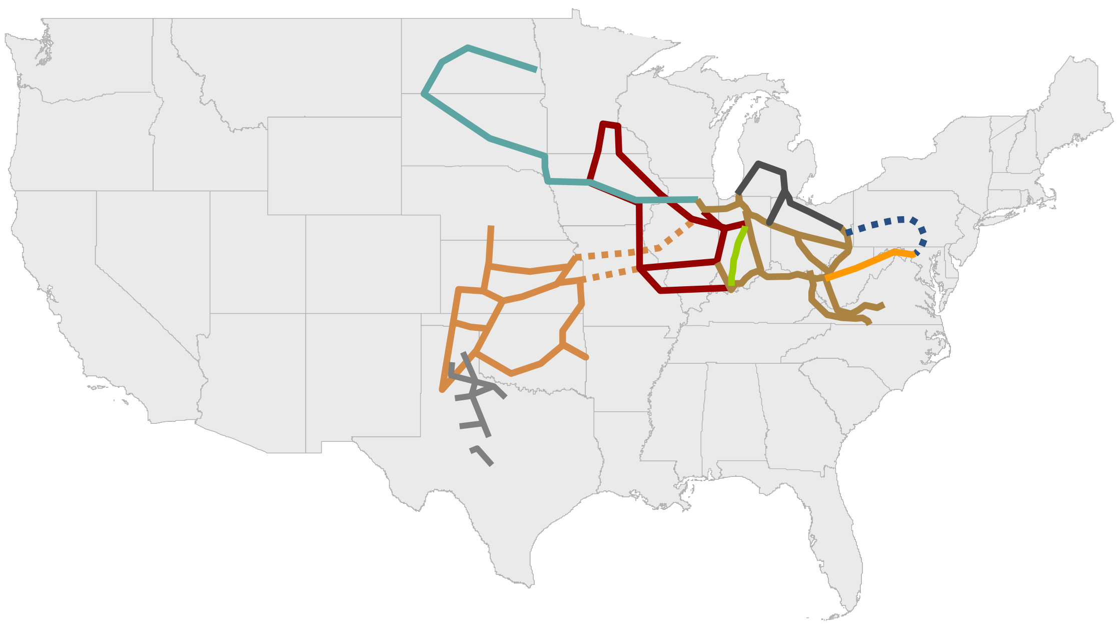
Pioneer — **COD: 2015**
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV — **COD: 2014**
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass — **COD: 2013-14**
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind — **COD: 2013**
- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT — **COD: 2013**
- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan — **COD: ~2020**
- 700 miles of 765 kV

PJM Projects
- Enhance existing 765/345 kV

Hartland — **COD: ~2020**
- 1000+ miles of 765 kV

MISO Vision Plan
- 765 kV Backbone

SPP Overlay — **COD: 2013-14**
- 765 kV Backbone

ETT — **COD: ~2018**
- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

AMERICAN ELECTRIC POWER

Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

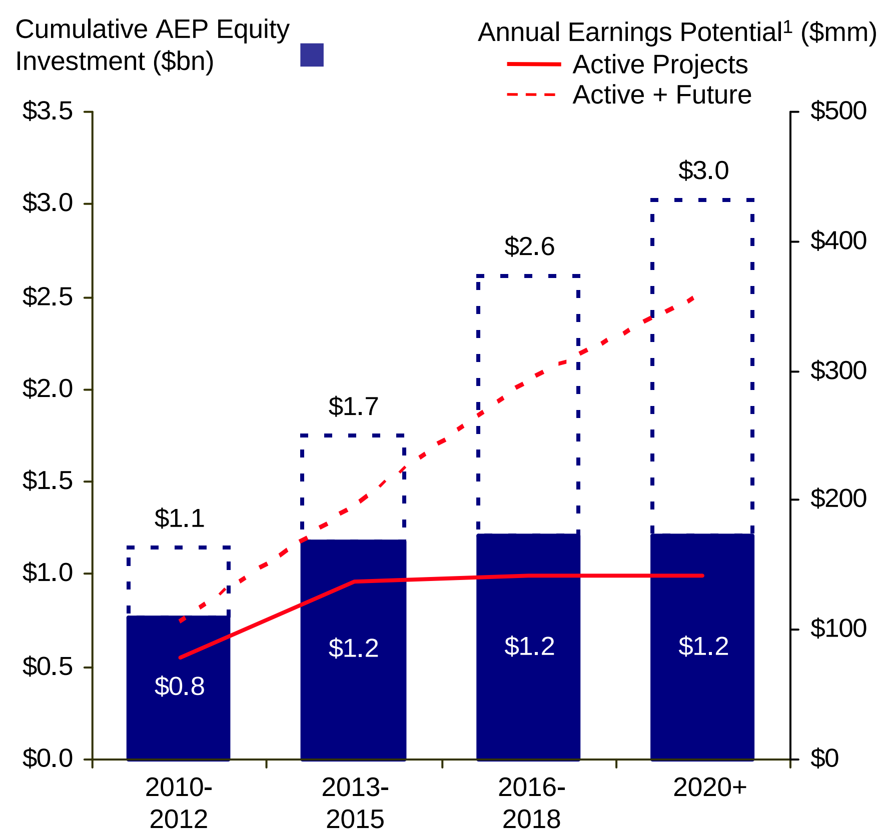
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives

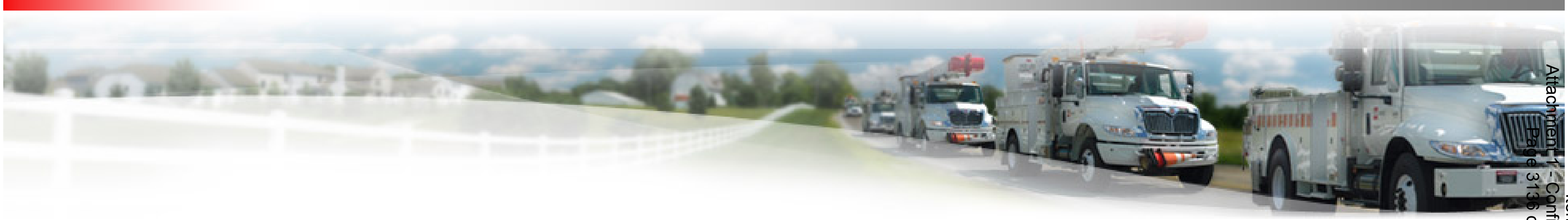


[1] Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects

AEP AMERICAN ELECTRIC POWER

Barclays Capital CEO Energy-Power Conference

New York, NY
September 8, 2011



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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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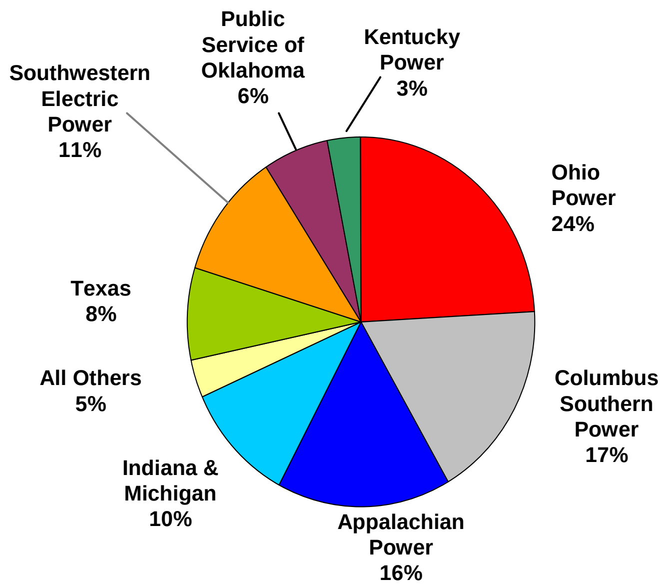
Brian Tierney, EVP and CFO

3

Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



Items to Watch

- Economic Recovery
- Ohio ESP and Other Filings
- EPA Regulations
- ETT and Transcos
- On-going Rate Cases and ROEs
  - Virginia
  - Michigan
  - Ohio

June YTD 2011 Performance

June YTD 2011 Reconciliation

		EPS	Ongoing Earnings ($ in millions)
2010	$	1.50	$720
Operations & Maintenance	$	(0.04)	
Other Costs, net	$	(0.05)	
Customer Switching	$	(0.06)	
Rate Changes	$	0.15	
Off-System Sales	$	0.07	
Weather	$	(0.02)	
2011	$	1.55	$744

EPS Based on 482MM shares in YTD11

YTD 2011 Performance Drivers

- O&M increase of $30M, net of offsets, primarily due to higher storm expenses
- Other Costs, Net increased $35M primarily due to gain on sale of ICE shares in 2Q10 and increased taxes
- Customer Switching in Ohio up $43M from last year
- Rate Changes, net of offsets, of $110M from multiple operating jurisdictions
- Off-System Sales, net of sharing, were favorable by $49M due to higher volumes and higher power prices
- Weather was unfavorable by $15M vs. prior year, favorable $67M vs. normal

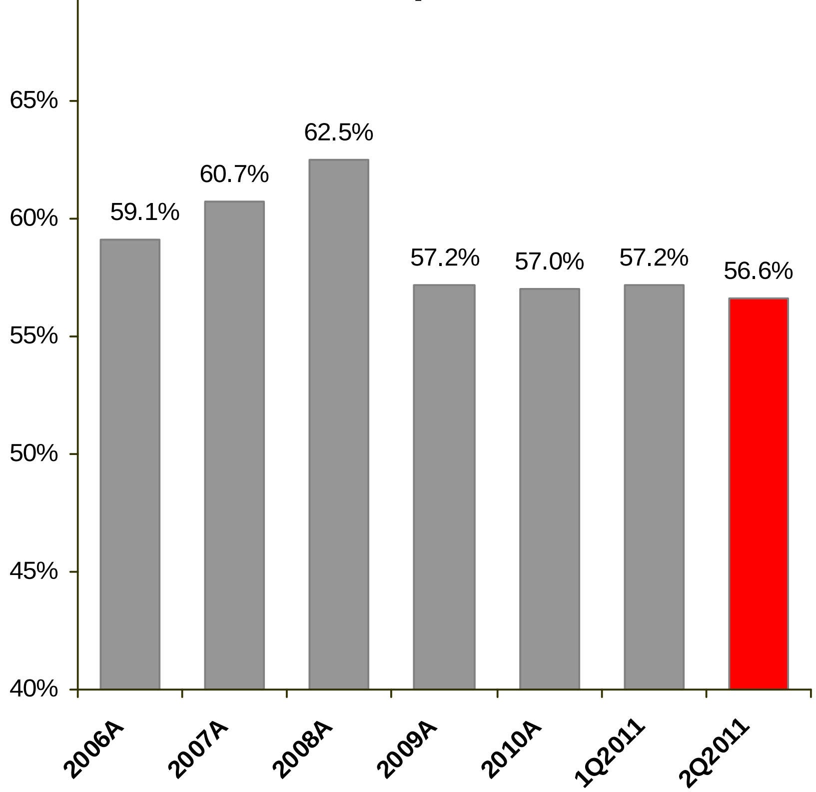
2011 On-going Earnings Guidance of $3.00 - $3.20 per share

AEP Texas Central Supreme Court Remand

- In early 2006, TCC received an order in the stranded cost proceeding enabling it to securitize $1.7 billion in stranded assets in October 2006, but denied recovery for other items.
  - TCC's inability to sell all of the capacity it was required to auction resulted in the PUCT rejecting the auction prices for purposes of calculating a legislatively-prescribed market-based true-up.
  - This led to a disallowance of $421 million and an after-tax impairment of $274 million being booked in 2005.
- In July 2011, the Texas Supreme Court reversed the PUCT's decision to reject use of auction prices, and the issue has been remanded to the PUCT.
- TCC is entitled to recovery of the $421 million plus carrying costs back to 2002. The carrying costs are expected to be $527 million.
- There will be regulatory proceedings and likely settlement discussions before the final amount is approved. TCC can securitize the recovery.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modifications costs greater than $50 million
- **Transition to market** - company will make a specific percentage of generation resources open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available,
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

AEP Highlights

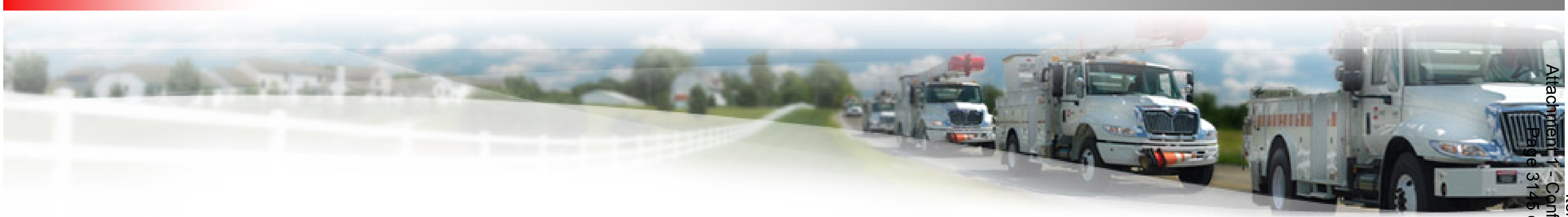
- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Significant Investment Opportunities in Environmental Retrofits and Transmission
- Strong Value and Total Return Proposition
  - Near 5% dividend yield
  - P/E discount to peers

Mountaineer Plant (WV)

AEP AMERICAN® ELECTRIC POWER

Barclays Capital Clean Solutions Conference

New York, NY
May 18, 2011



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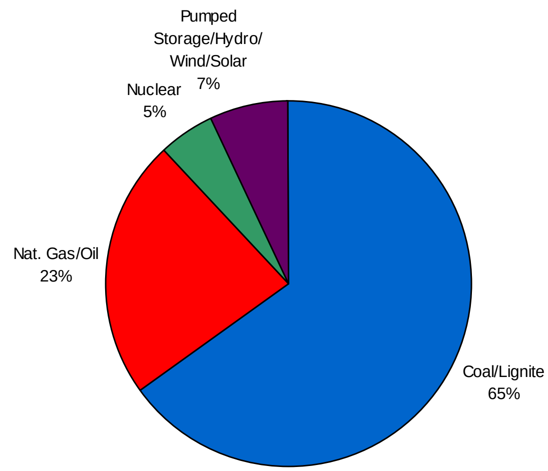
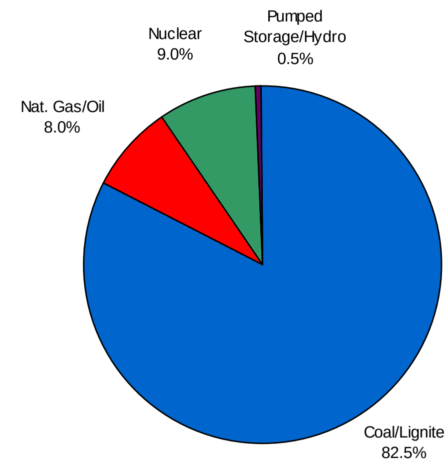
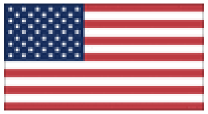
Domestic Generation Fleet

Generation Capacity by Fuel Type
Based on 39,910 MW

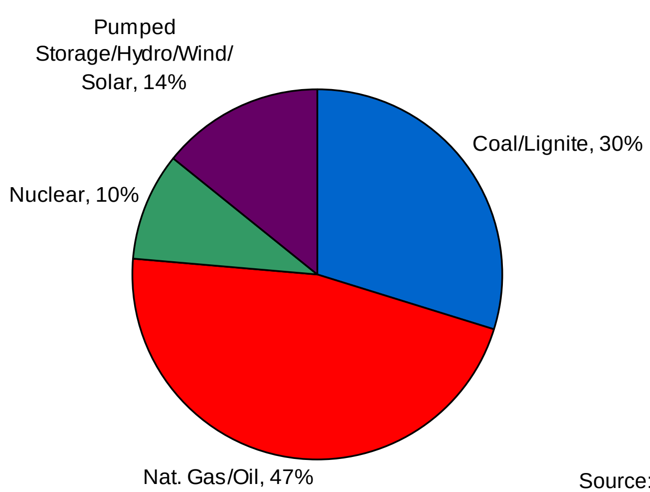


2010 Generation Production by Fuel Type
Based on 173.2 TWh

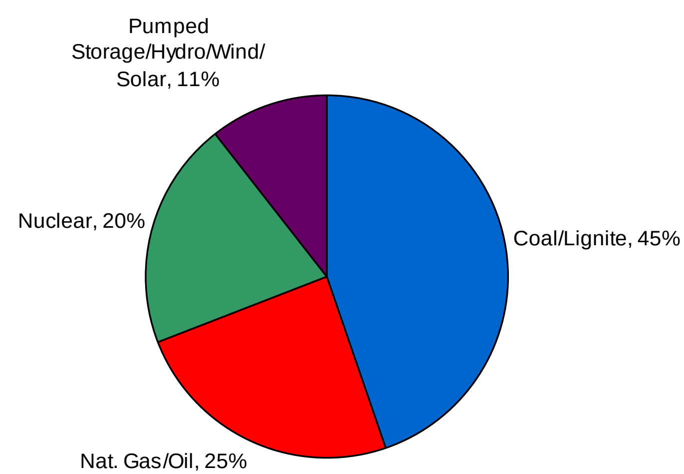




Generation Capacity by Fuel Type
Based on 1,063,848 MW



2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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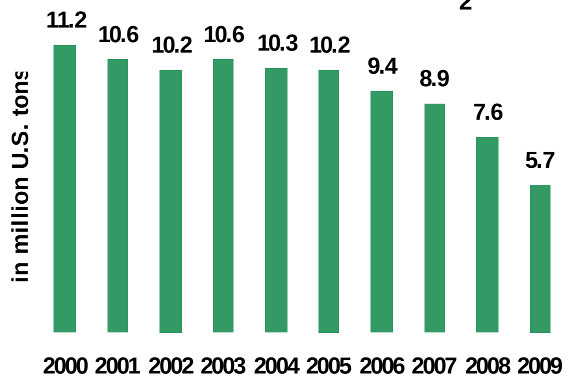
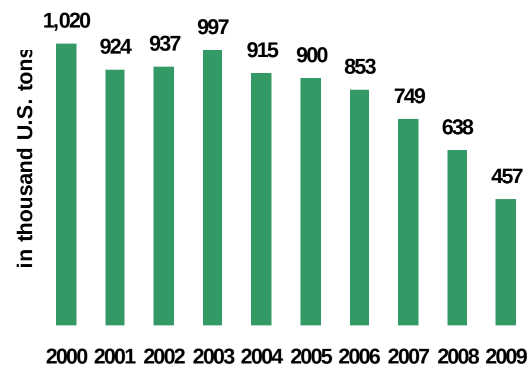
Emissions Reductions since 2000

U.S. Power Plant SO_2 Emissions



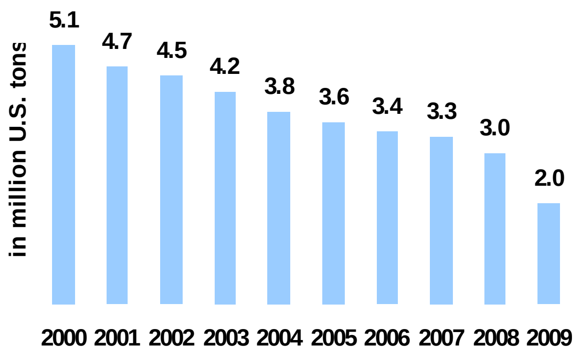
49% reduction since 2000

AEP SO_2 Emissions



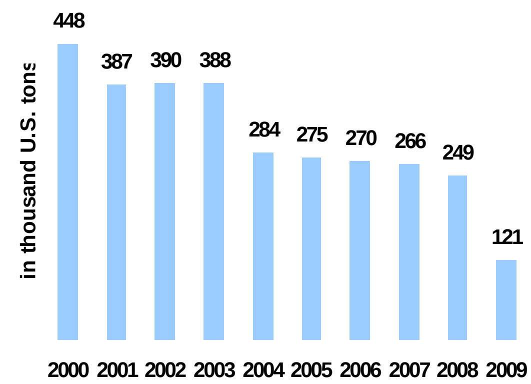
55% reduction since 2000

U.S. Power Plant NOx Emissions



61% reduction since 2000

AEP NOx Emissions



73% reduction since 2000

Source: EPA, 2010; Acid Rain Program

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

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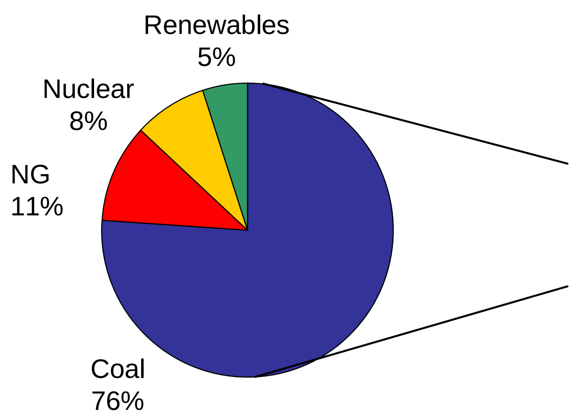
Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

AEP Generation Capacity

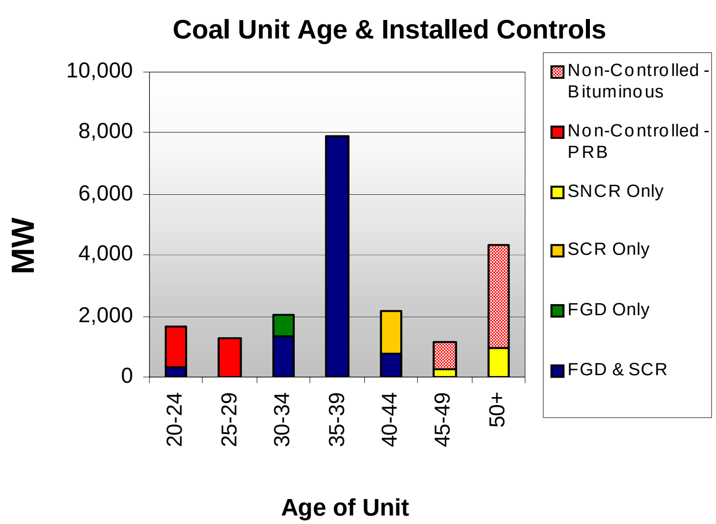
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



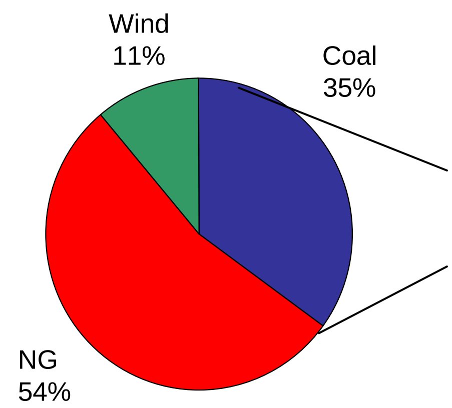
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



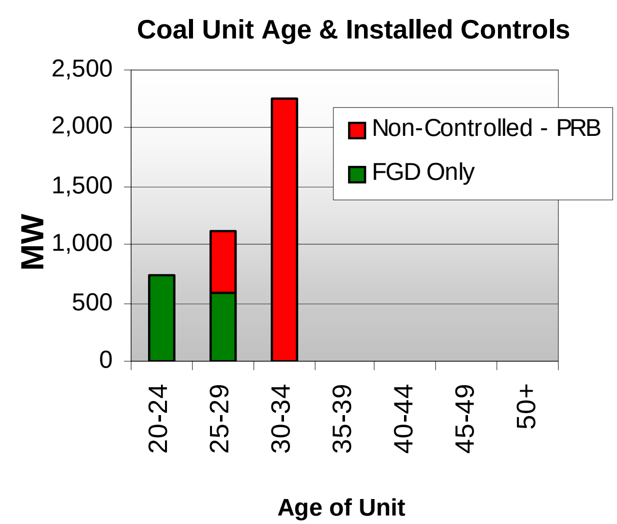
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Pending EPA Regulations

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

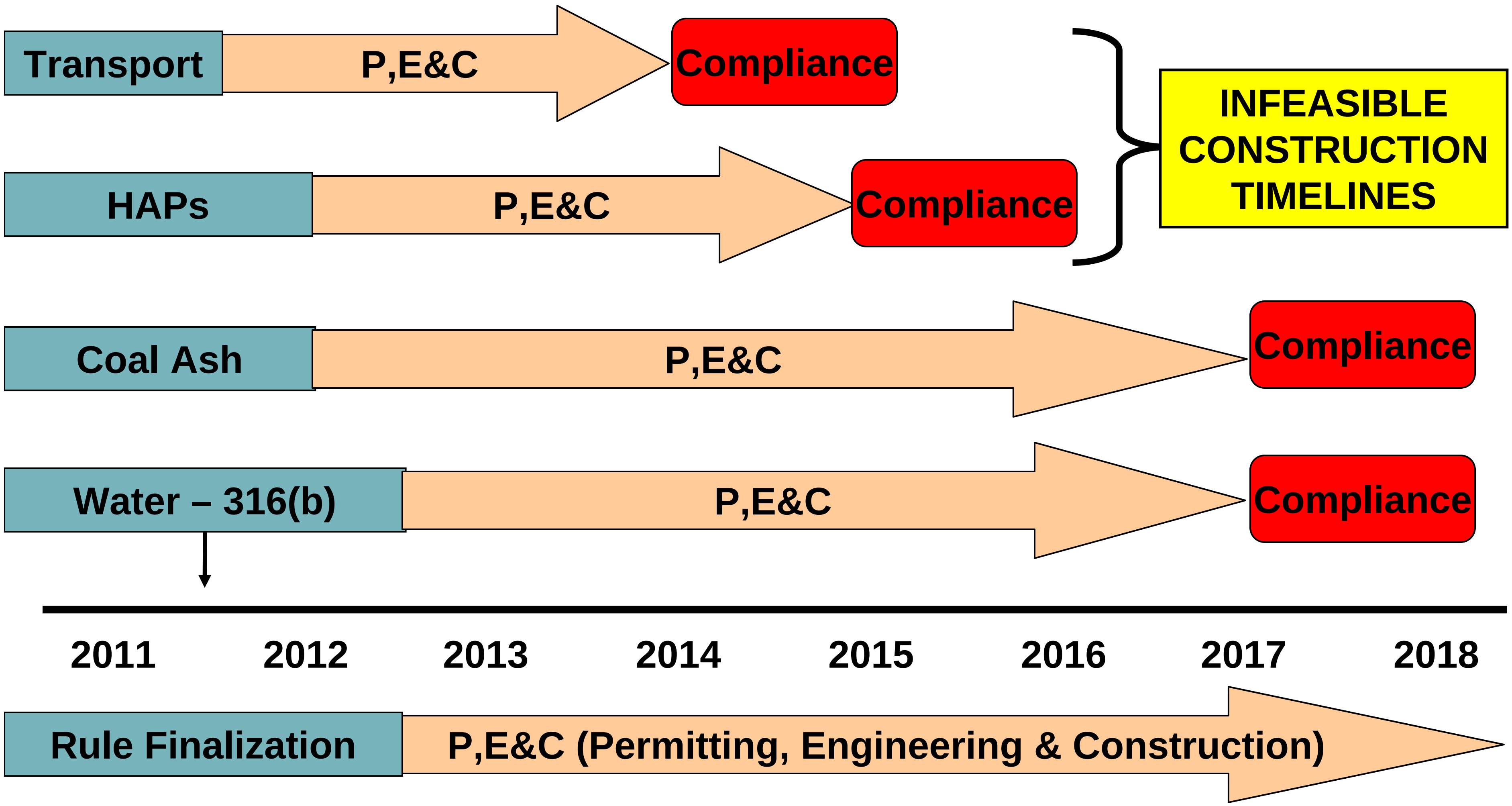
- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- “Hazardous” option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

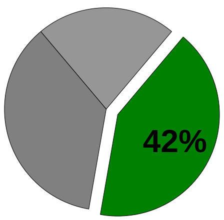
Anticipated EPA Timeline for Retrofits or Replacement



AEP Coal Fleet Assessment

AEP®

Least Exposed



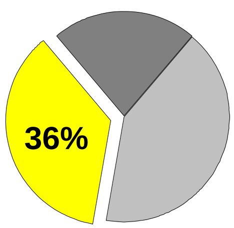
Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

2012 – 2020

Range of Capital ($Millions) (1)

Proposed Rules		Low		High
Water Rules (2)	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules (3)	$	766	$	1,046

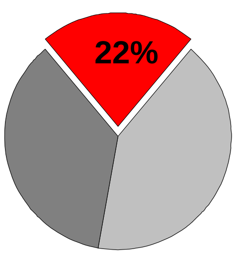
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High (4)
Water Rules (2)	$	26	$	46
CCR Rules	$	357	$	726
Air Rules (3) (5)	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

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Key Takeaways

- Established track record of constructing state of the art pollution control equipment
  - 9 scrubbers on 7,900 MW's between 2003-2011(12,000+ scrubbed in total)
  - 12 SCR's on 11,000+ MW's between 2001-2011
- We are supportive of Clean Air Act, but it must be under a feasible timetable
  - Grid reliability concerns
  - Resource availability concerns
- We are analyzing all the rules together to determine most efficient compliance with the rules
  - Nearly 11,000 MW's will comply without major additions

AEP AMERICAN ELECTRIC POWER

Barclays Capital 2010
CEO Energy-Power Conference
New York, NY
September 15, 2010

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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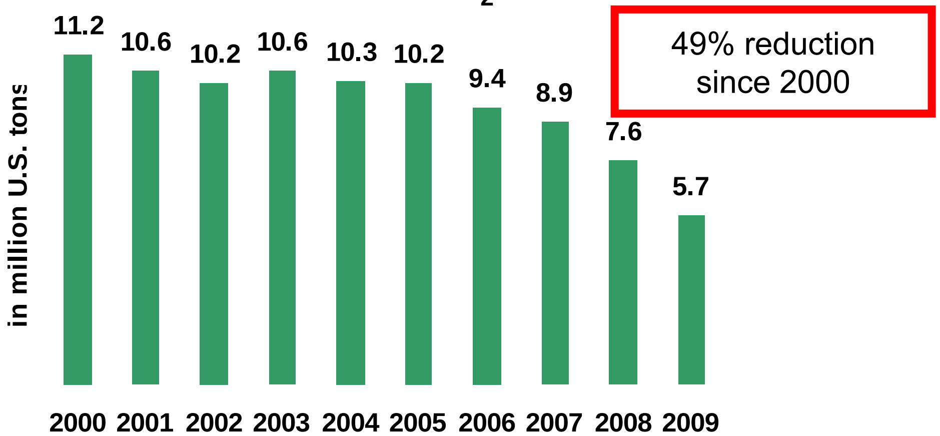
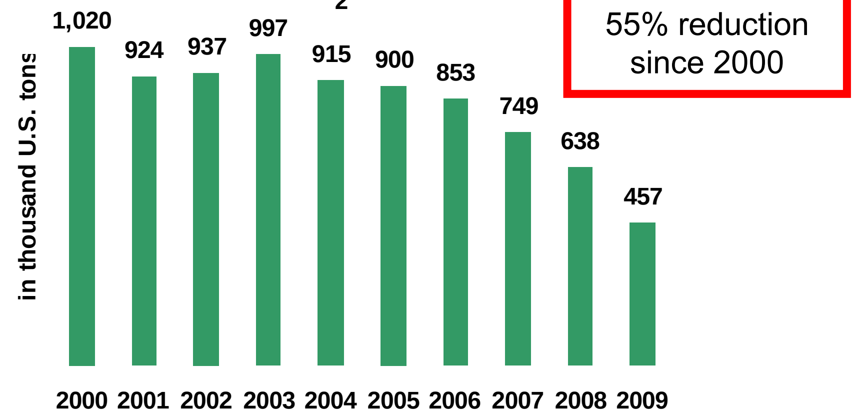
Significant Progress Has Been Made But . . .

U.S. Power Plant SO_2 Emissions

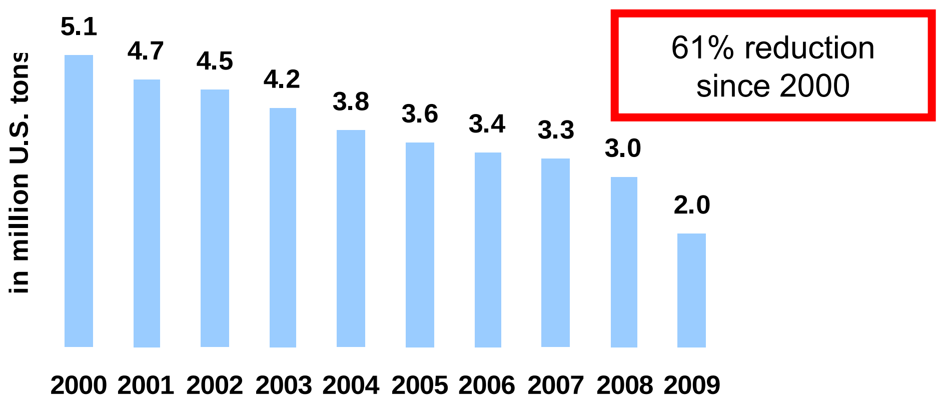


Source: EPA, 2010; Acid Rain Program

AEP SO_2 Emissions

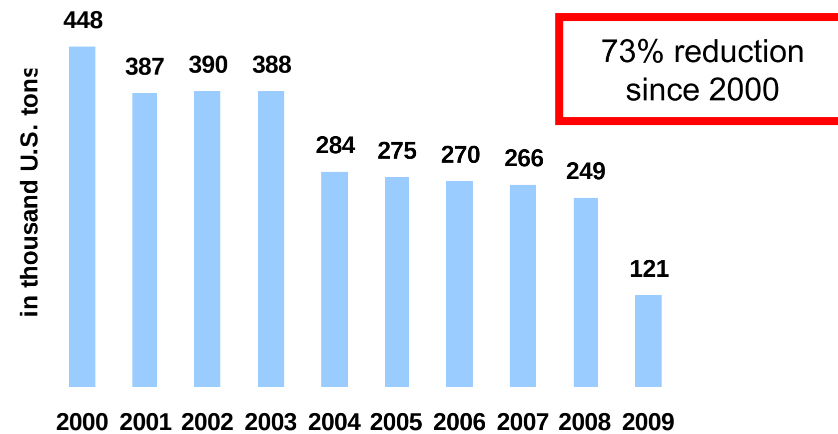


U.S. Power Plant NOx Emissions



Source: EPA, 2010; Acid Rain Program

AEP NOx Emissions



Over $5B capital invested by AEP from 2004-2010 to reduce emissions

Recent and Major Upcoming EPA Actions

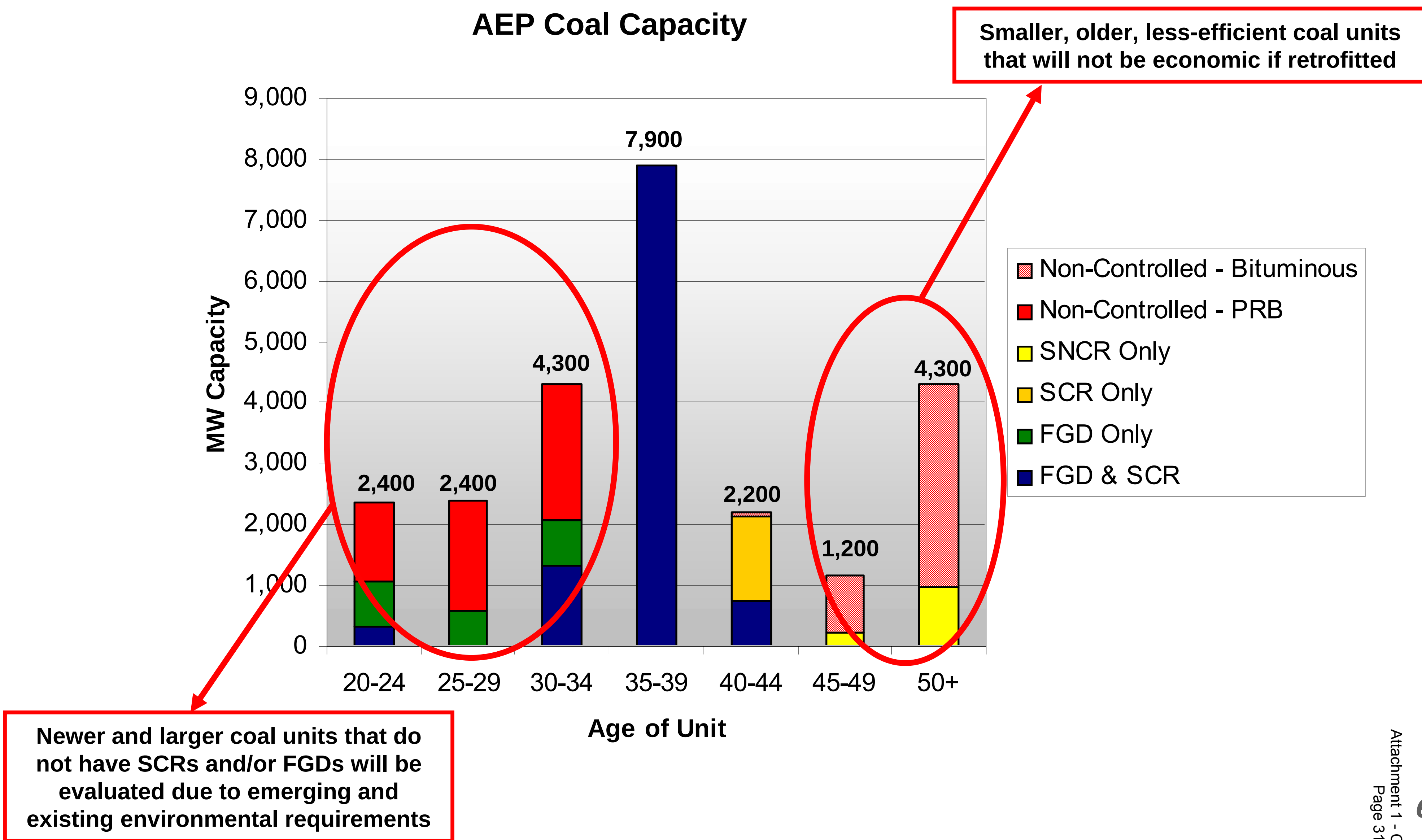
- **Transport Rule – Proposed July 2010**
  - Governs power plant emissions of SO_2 and NOx that affect downwind fine particle and ozone concentrations
  - 2012 program start date with stringent second phase beginning in 2014
  - Limited interstate trading and no use of previously banked SO_2 allowances from CAIR program
  - 2014 SO_2 limits in AEP-East states will require almost all coal units to be scrubbed or retired/use gas
  - AEP believes an extension of the compliance deadlines is essential to allow states to develop implementation plans and give companies time to install the retrofits needed to comply

- **“Coal Ash” Rule – Proposed May 2010**
  - EPA proposed two different regulatory designations:
    - Solid waste – action required by ~2017
    - “Special” hazardous waste - action required by ~2018-2020
  - AEP supports regulation of coal ash under the Subtitle ‘D Prime’ option of the RCRA
  - Cost to AEP customers estimated at $3.9 billion by 2020 to comply with Subtitle D option

- **Mercury and other Hazardous Air Pollutants (HAPs) Rule**
  - Expect proposed rule in spring 2011, finalized in late 2011; likely compliance year - 2015
  - Could require major pollution control retrofits at most U.S. coal plants (FGD, baghouses, etc.)

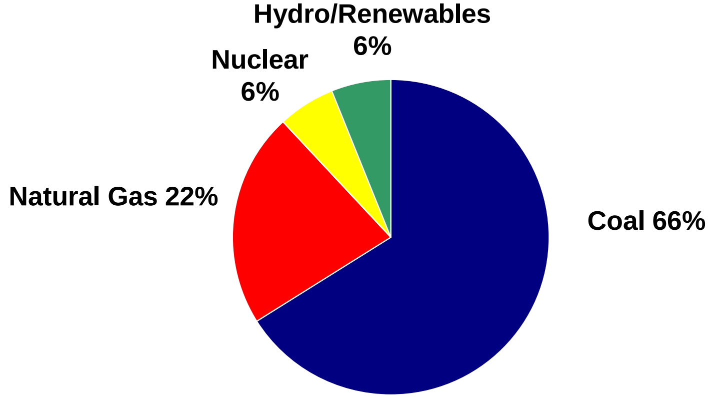
Cumulative effects of EPA proposed rules and carbon legislation/regulation are a major concern for utility resource planning

Plant Retirements are Inevitable

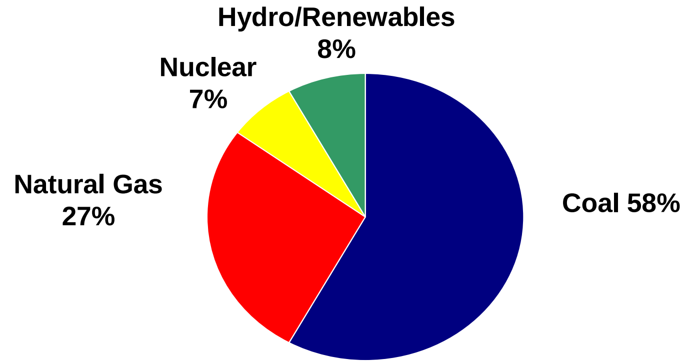


AEP's Actions

- Operate uncontrolled, older and smaller units on a seasonal basis – minimizes capital and O&M spending
- Continue pursuit of CCS to take advantage of first-mover advantages such as DOE clean coal grants
- Complete the Dresden NGCC Plant and add renewables where regulatory recovery is provided
- Complete Cook Nuclear Plant uprate
- Transition toward retirement of approximately 5,000MW of coal units
- Influence federal and state policy to benefit our customers and shareholders
- Transformation plan that includes new technologies such as gridSMART and storage



Fuel Mix - 2009



Projected Fuel Mix - 2017

Carbon Legislation Update

- **Climate Cap and Trade Legislation (American Power Act of 2010) is dead in 2010**
  - Prospects for cap-and-trade legislation after 2010 will require truly bipartisan legislation given the expected changes in Congress

- **Cap and Trade Legislation that advanced in 2010 did include some improved provisions:**
  - Significantly higher electric utility allowance allocation
  - More generous CCS bonus allowances
  - Sound domestic offset provisions
  - Price collar that should help eliminate high price spikes

- **However, there were still some problem areas:**
  - Inadequate EPA preemption language on CO_2 would lead to duplicative CO_2 regulatory measures
  - More restrictive international offsets provisions could drive up compliance costs
  - Early action credit is very limited
  - Market trading provisions are overly restrictive

- **EPA is expected to move forward on CO_2 regulation in 2011**

AEP advocates delay in EPA regulatory action on CO_2 or legislation to enable significant multi-faceted study to determine overall economic and system reliability effects

Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process

Carbon Capture and Storage project Mountaineer Plant - New Haven, WV

Thoughts about the Energy Policy Debate

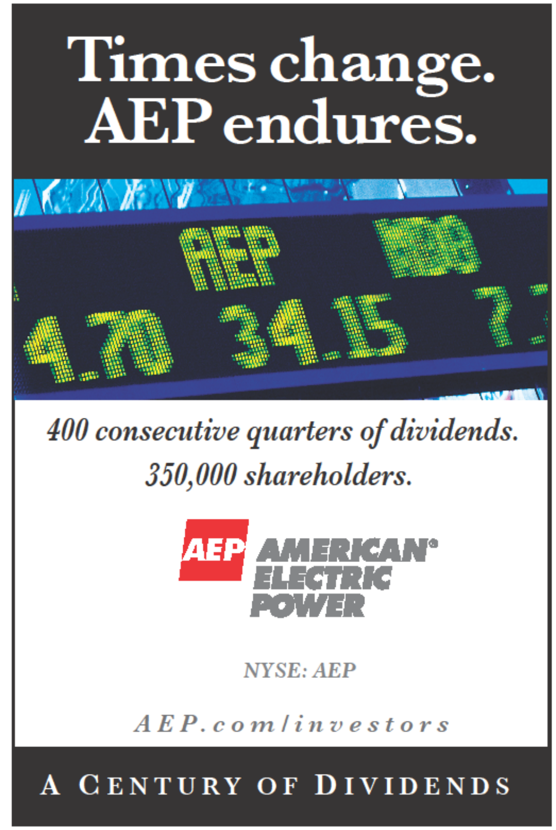
To make significant advancement in developing clean, domestic energy and reducing emissions, our nation needs a national energy policy with specific goals and guidelines, particularly as it relates to renewables, transmission and environmental regulations.

- Cap and trade
- Incentives to develop and deploy new technologies
- Timelines for emission reductions that provide a rational glide path for transitioning the existing generating fleet to a smaller environmental footprint
- Mandates to develop reasonable cost allocation methodologies to support EHV transmission
- Support for the siting of national-interest transmission lines

Trent Mesa Wind turbines in west Texas

Value Proposition

- **Current Yield Opportunity of 4.6%[1]**
  - June 10th – 400th consecutive quarterly dividend paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



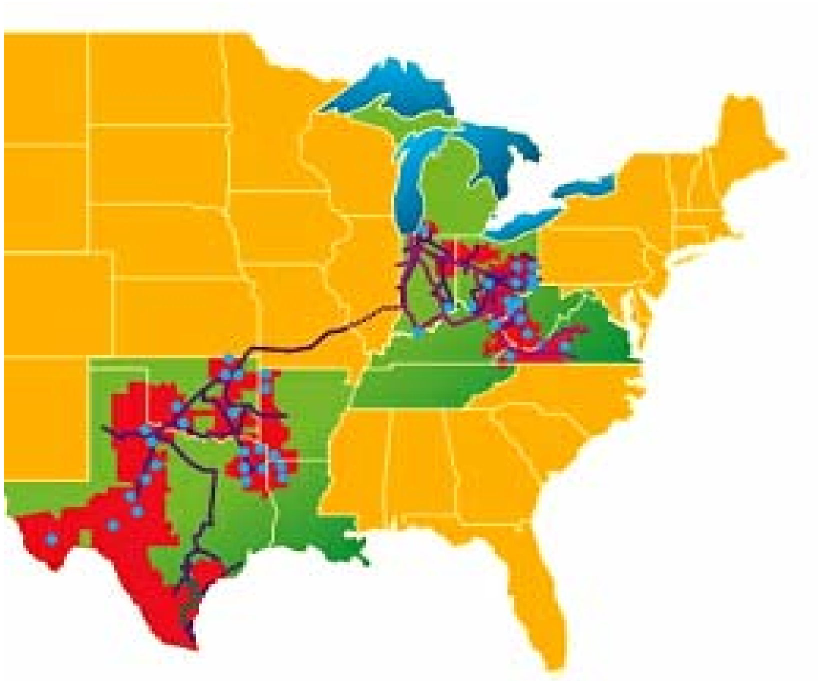
Attractive total return potential

[1] yield percentage based on AEP closing price of $36.40 on 09/09/2010

Appendix

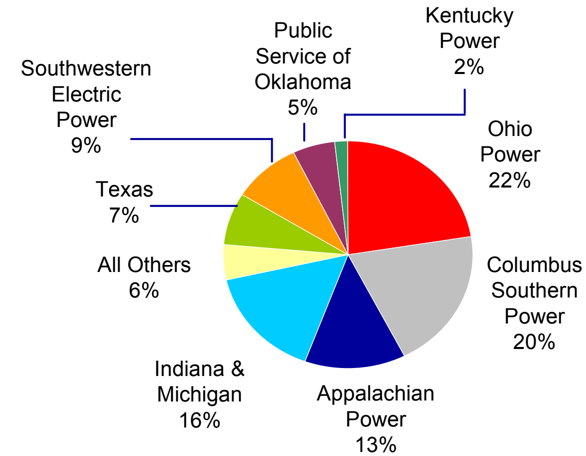
Highly Diversified Regulated Utility Platform

5.2 million customers in 11 states

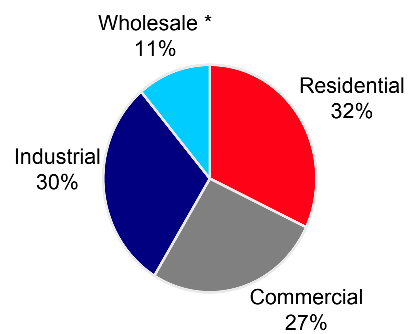


Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

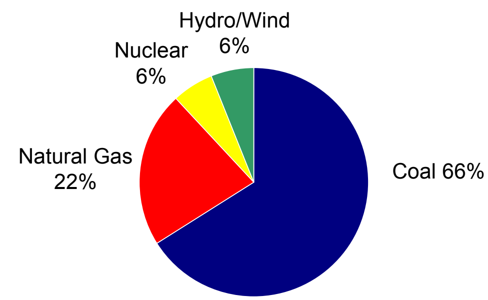


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



Transmission Opportunities

- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - In service assets $0.4 billion
  - CREZ opportunity $1.1 billion est. in service 2010 - 2013
  - Other ETT projects $1.6 billion est. in service 2010-2017
  - Framework in Texas allows for more expeditious siting and recovery
- **AEP Transmission Company (Transco): Within our existing footprint**
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually
- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
  - Robust pipeline of projects up to $15B

Electric Transmission Texas

ELECTRIC TRANSMISSION AMERICA, LLC

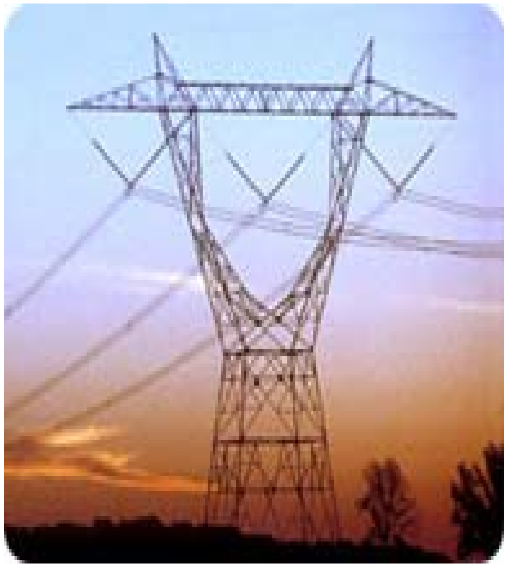
Prairie Wind Transmission
A joint venture between Westar Energy and ETA

PATH
Potomac-Appalachian Transmission Highline

Tallgrass Transmission
A joint venture between OGE Energy Corp. and ETA

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filings made in OH and WV
- FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
- Seek retail tracking mechanisms at the state level (OH, AR, VA, TX-ERCOT already secured)



765-kV Tower

JV Strategy - Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 345 kV*
- Partners: Westar (50%) & MidAmerican Energy (50%)
- Estimated Cost: $165 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 345 kV*
- Partners: OG&E (50%) & MidAmerican Energy (50%)
- Estimated Cost: $350 million
- ROE: 12.8%

* May revert to 765 kV depending on 2010 SPP ITP results

ERCOT

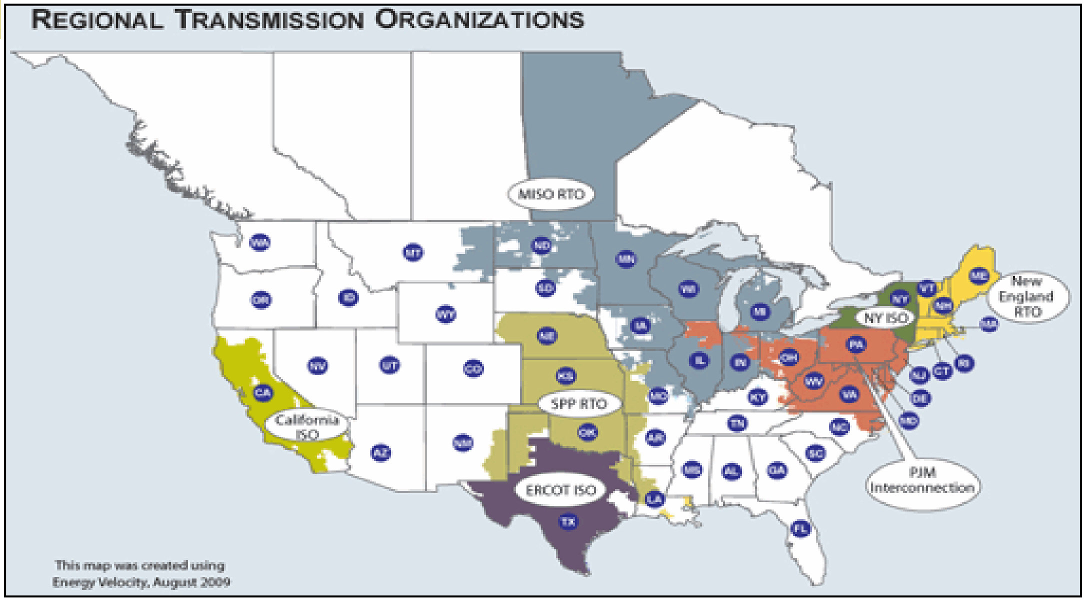
ETT — COD: 2010-2014
- 345 kV and below CREZ & ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.5 billion
- ROE: 9.96%

PJM

PATH-WV — COD: 2015
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2016
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Sponsors: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP EHV Overlay	ETT — COD: various	PJM Expansion	EHV Michigan/Ohio
Regional Expansion of 765 kV Backbone	Other Projects - $1.6 billion (COD 2010-2017)	Regional Expansion of 765 kV, 500 kV and 345 kV systems	700 miles of Proposed 765 kV
SPP	**ERCOT**	**PJM**	**PJM/MISO**

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

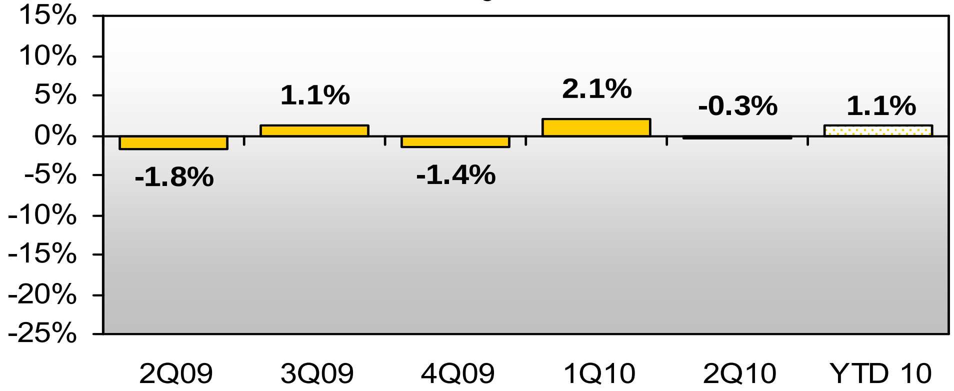
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

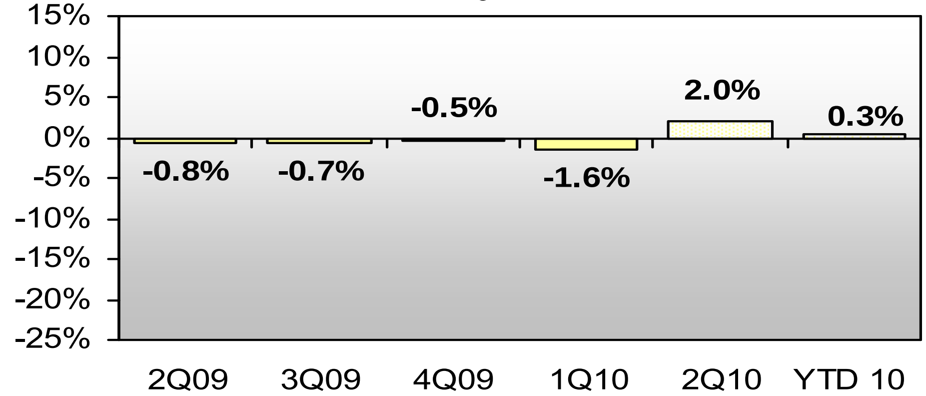
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends

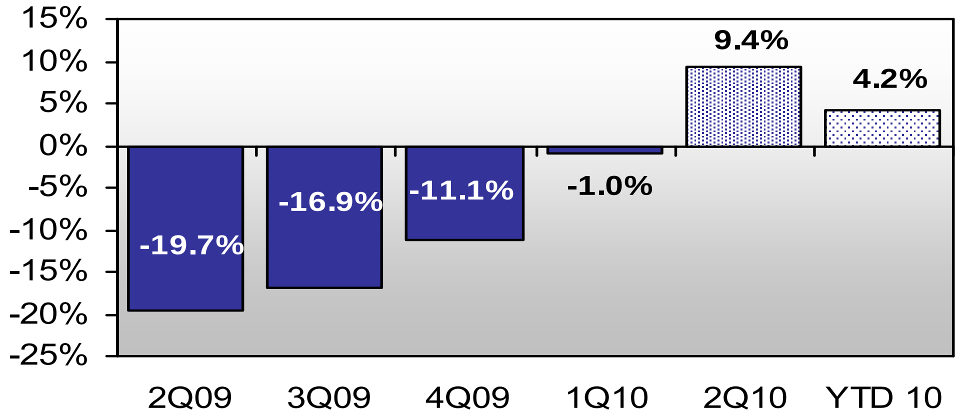
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



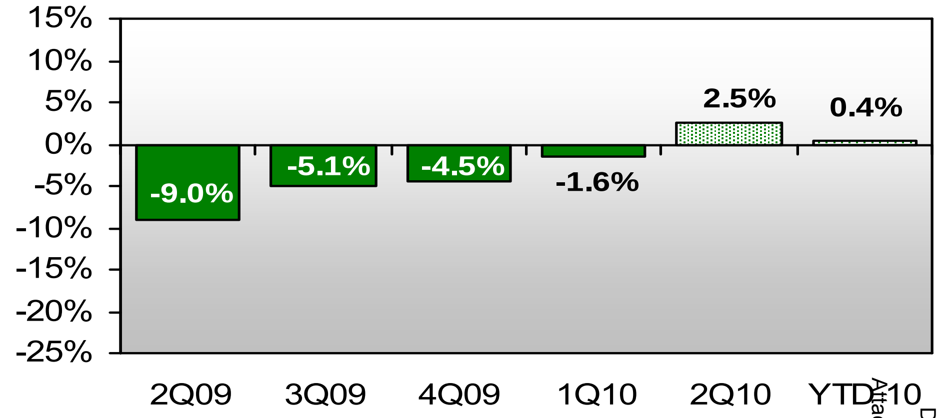
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



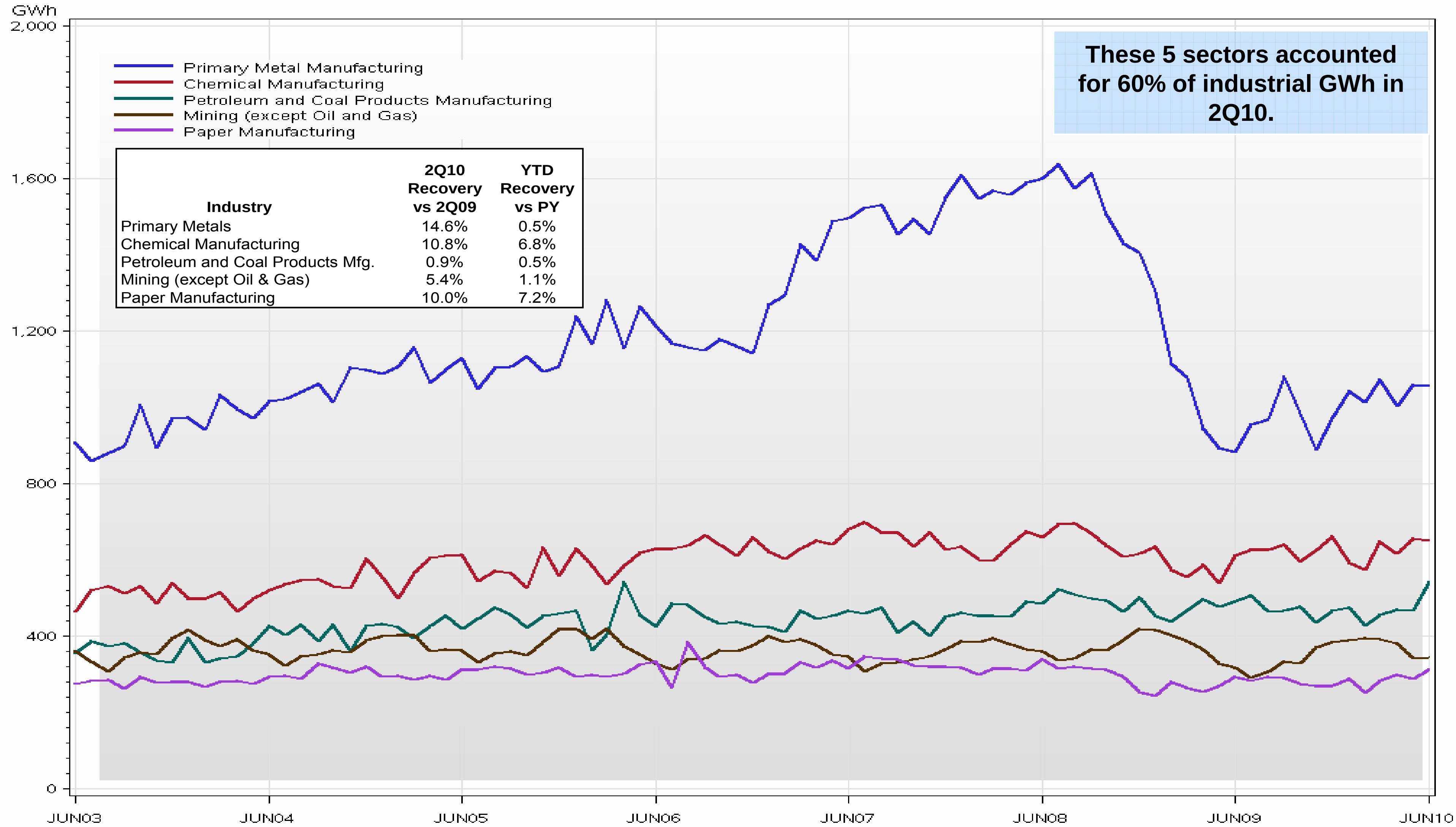
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Industrial Sales

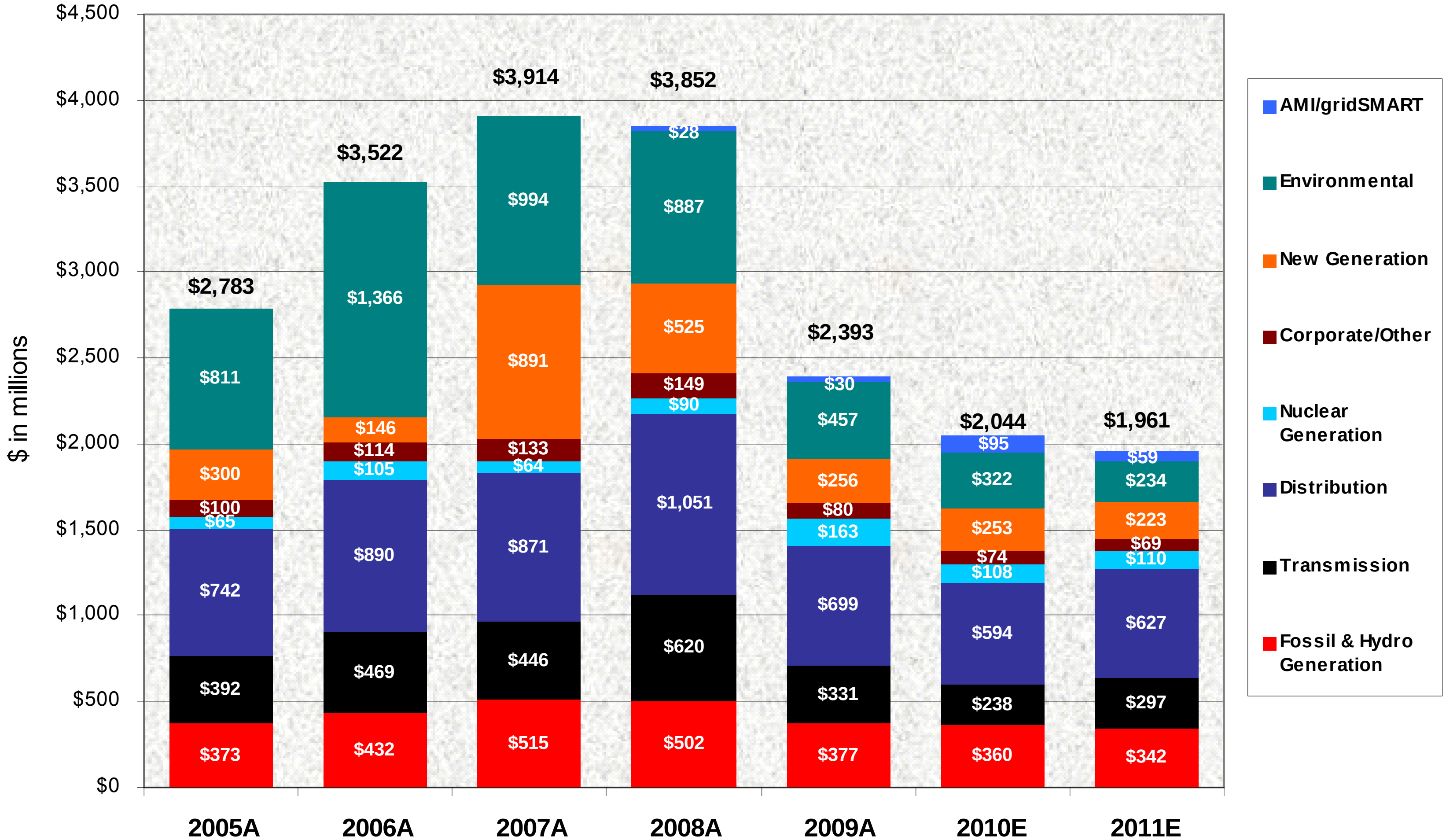
AEP Industrial GWh by Sector



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

These 5 sectors accounted for 60% of industrial GWh in 2Q10.

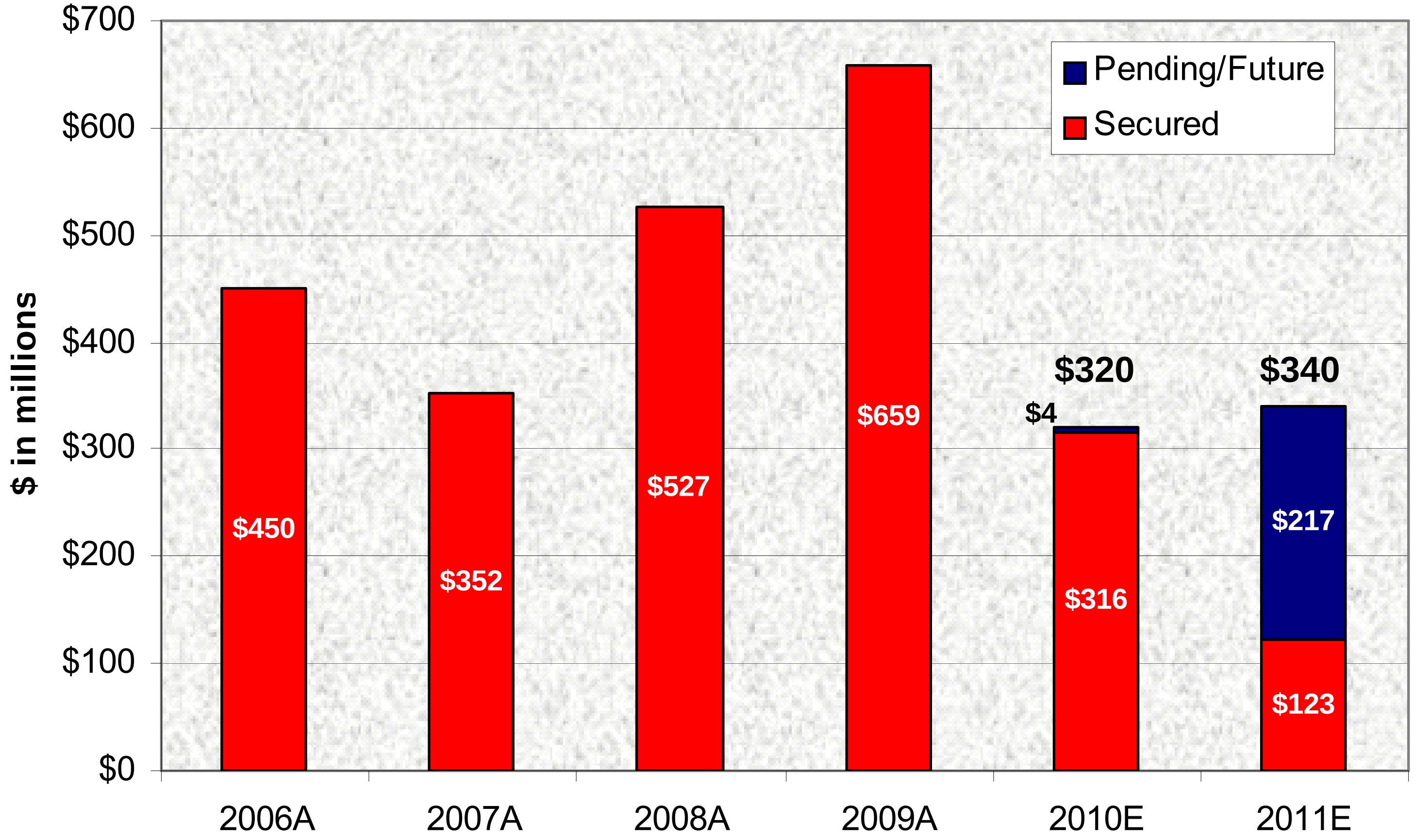
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Oklahoma, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Current Base Rate Cases

$ in millions

I&M - Michigan

	Company Filing	Staff Testimony
Rate increase	**$63**	$34
Rate base/investment	$601	$585
Return on equity	11.75%	10.35%
Equity component	44.19%	44.14%
Riders requested	Numerous	Denied except Net Lost Revenues

Status: Case filed on January 27, 2010. Hearing held August 9-10, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Order due January 25, 2011.

$370 million total base rate increase requests on file ($258 million net of existing riders)

APCo - West Virginia

	Company Filing	Staff Testimony
Rate increase	**$224** *	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

* - net increase is $143 million after changes in Construction Surcharge

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

PSO - Oklahoma

	Company Filing	Staff Testimony
Rate increase	**$82** *	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

* - net increase is $52 million after elimination of existing Capital Investment Rider

Status: Case filed on July 9, 2010. Staff & Intervenor testimony due October 26, 2010.

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

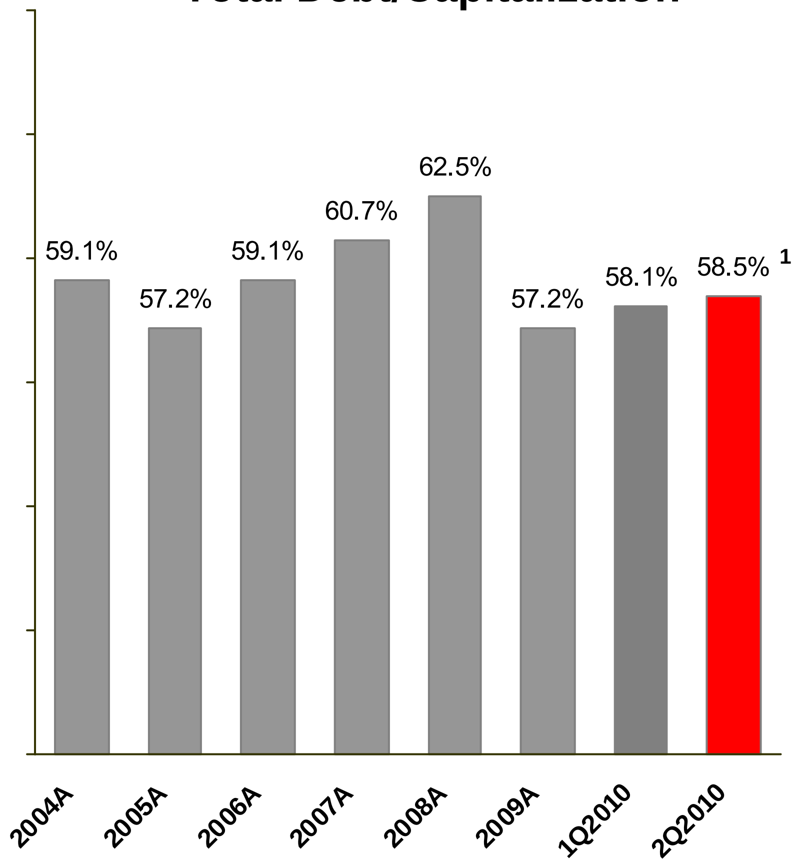
(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.

Current Liquidity Summary
As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable

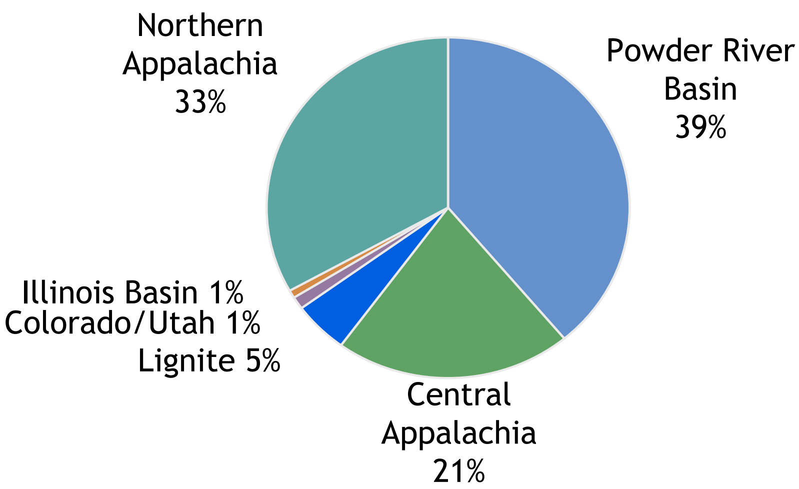
2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

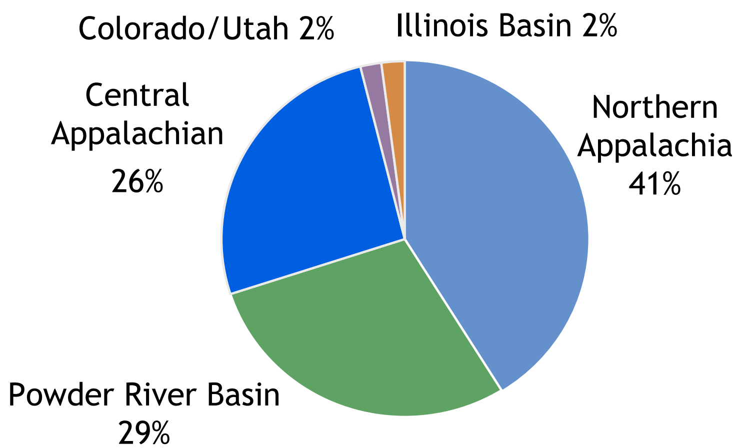
(1) Debt to Capitalization excludes securitization bonds

Coal Procurement - 2010 Projected

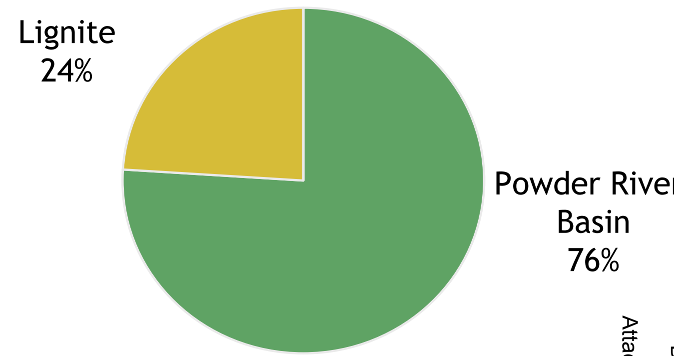
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 80% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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Barclays Capital Global Warming Solutions and Clean Technology Conference
New York, NY
May 19, 2010

General James M. Gavin Plant (Ohio)

Carbon Capture & Storage Facility (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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John M. McManus
VP - Environmental Services

AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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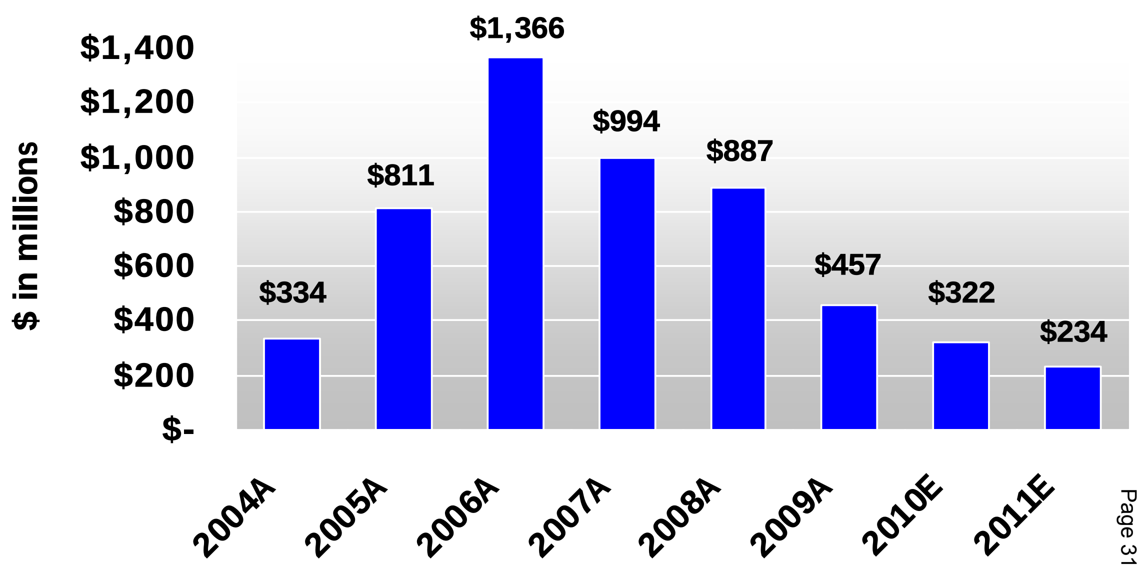
Our Fleet is Well Positioned for the Future

	2009 Capacity (MW)	2009 Fleet %	2010-2011 [1] Capacity (MW)	2010-2011 [1] Fleet %
Coal Controlled:				
FGD and SCR	8,729	23%	10,329 [2]	27%
FGD only	2,077	5%	2,077	5%
SCR only	2,985	8%	1,385 [2]	4%
SNCR only	1,200	3%	1,200	3%
Natural Gas	8,691	23%	9,191 [3]	24%
Non-Emitting [4]	4,650	12%	4,650	12%
Non-Controlled	9,670	25%	9,670	25%
Total [5]	38,002	100%	38,502	100%

(1) Assumes no fleet retirements during this two-year period
(2) Change result of completion of Amos Units 1&2 FGDs
(3) Increase result of completion of NGCC Stall Plant in Louisiana
(4) Includes Nuclear, Hydro and Wind (owned and PPAs)
(5) Total capacity excludes 43.5% ownership of Ohio Valley Electric Corporation

Environmental Capex



AMERICAN ELECTRIC POWER

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

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Coal Combustion By-Products Facts

- AEP currently owns and operates 44 earthen ash dam impoundments
  - 11 are large, high hazard potential Class I dams
  - Annual engineering inspection program of those dams
  - EPA consultants ranked all 11 as satisfactory or fair in 2009
- Two-thirds of AEP's CCBs currently use dry disposal; one-third utilizes wet disposal
- 40% of AEP's CCBs have beneficial uses
- AEP supports federal regulation of the disposal of CCBs but is strongly opposed to regulation of these materials as hazardous wastes

AEP AMERICAN® ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Other Pending Environmental Matters

- Clean Air Interstate Rule Replacement
- Hazardous Air Pollutants
- Cooling Water Intakes
- Greenhouse Gases – Legislation vs. Regulation

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Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation
Captured CO_2 – September 2009
Injected CO_2 – October 2009

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CO_2 Capture:

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage:

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

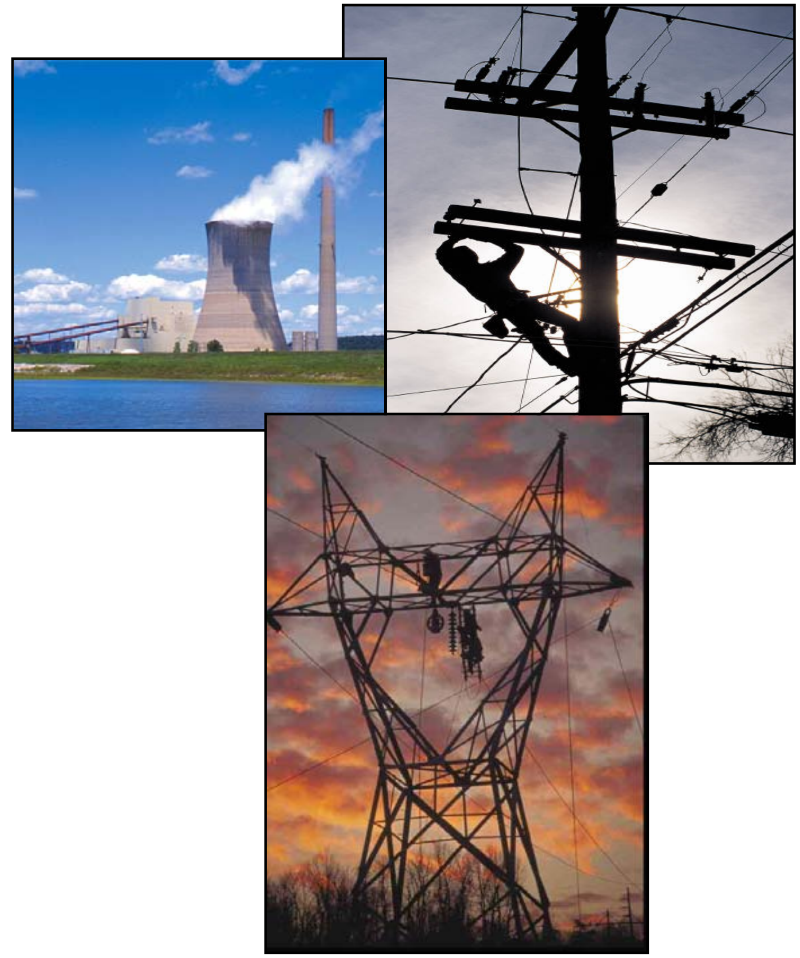
PHASE I – Validation:

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II – Commercialization:

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% DOE funding. Commercial operation in 2015.

AEP Value Proposition



Regulated Utility Platform

- Diversified service territory
- Successful regulatory track record
- Value compared to regulated peer group

Earnings Growth Prospects

- Investment in utility platform greater than depreciation level (2 - 4%)
- With transmission opportunities (4 - 8%)

Yield Opportunity of 5.1%[1]

- 50-60% payout ratio targeted
- Nearly a century of dividend payments to shareholders

AEP AMERICAN® ELECTRIC POWER

[1] yield percentage based on AEP closing price of $33.14 on 05/10/2010

Barclays Capital CEO Energy-Power Conference Handout

New York, NY
September 8, 2011

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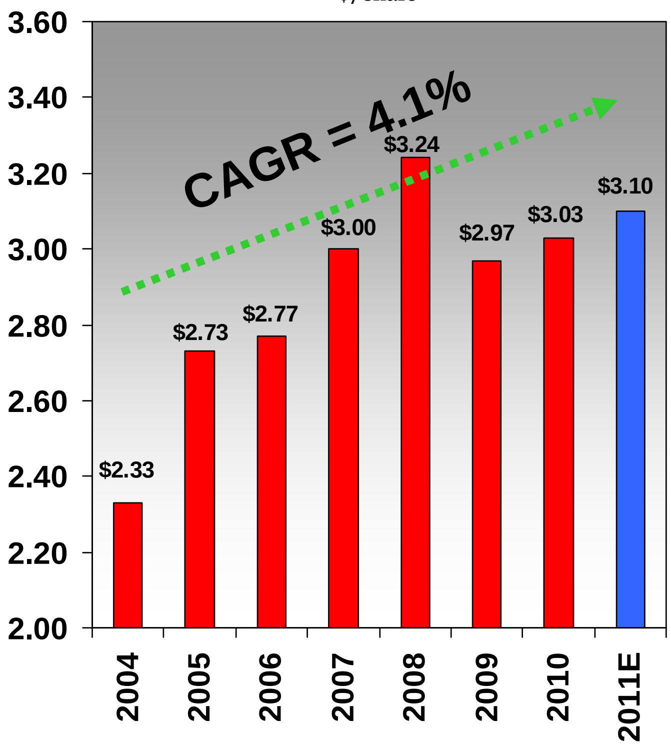
Table of Contents

Earnings and Dividends

On-Going EPS History Since 2004

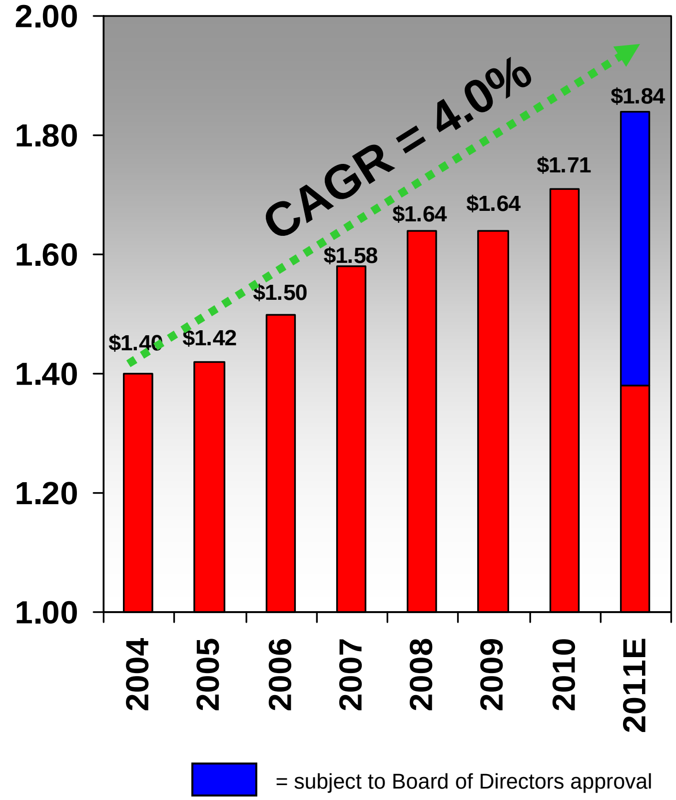
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield near 5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

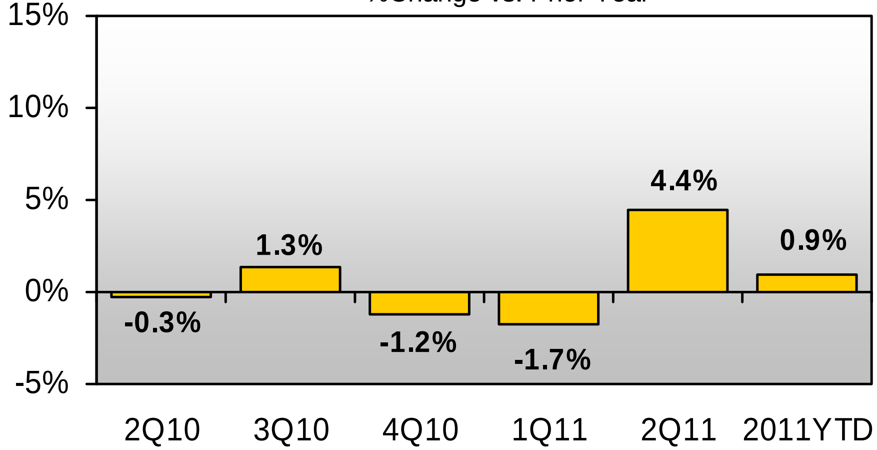
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

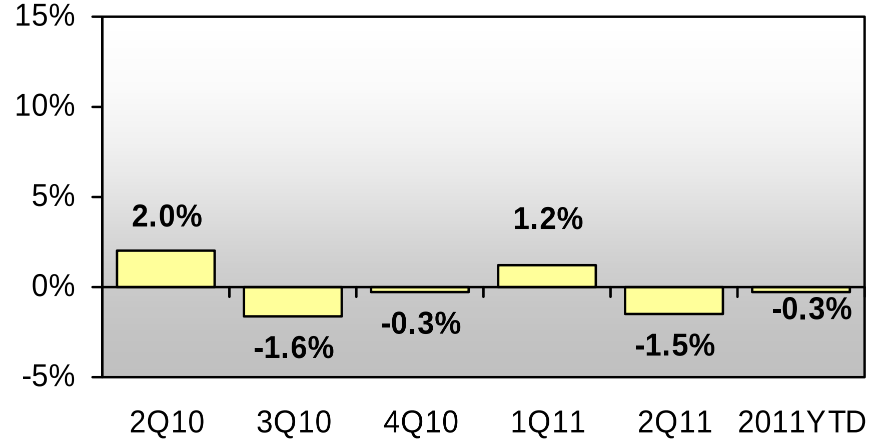
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

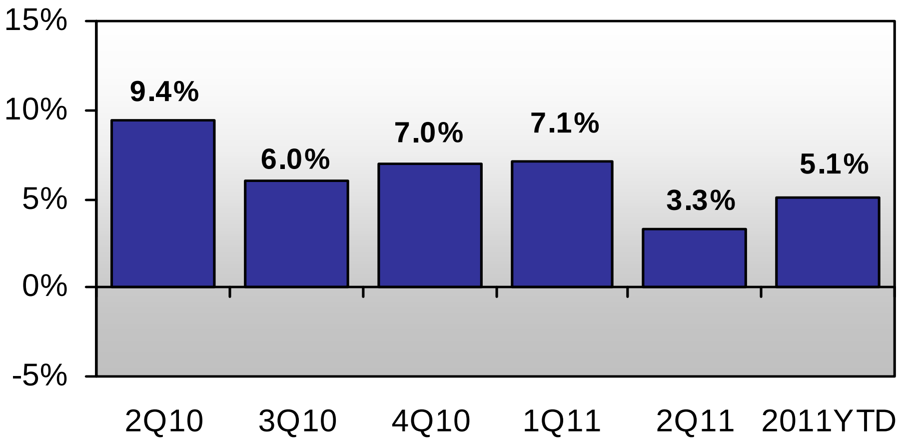
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



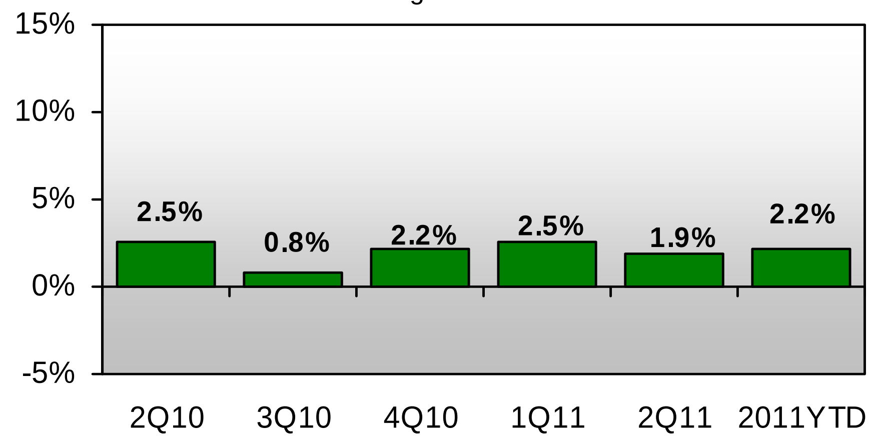
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



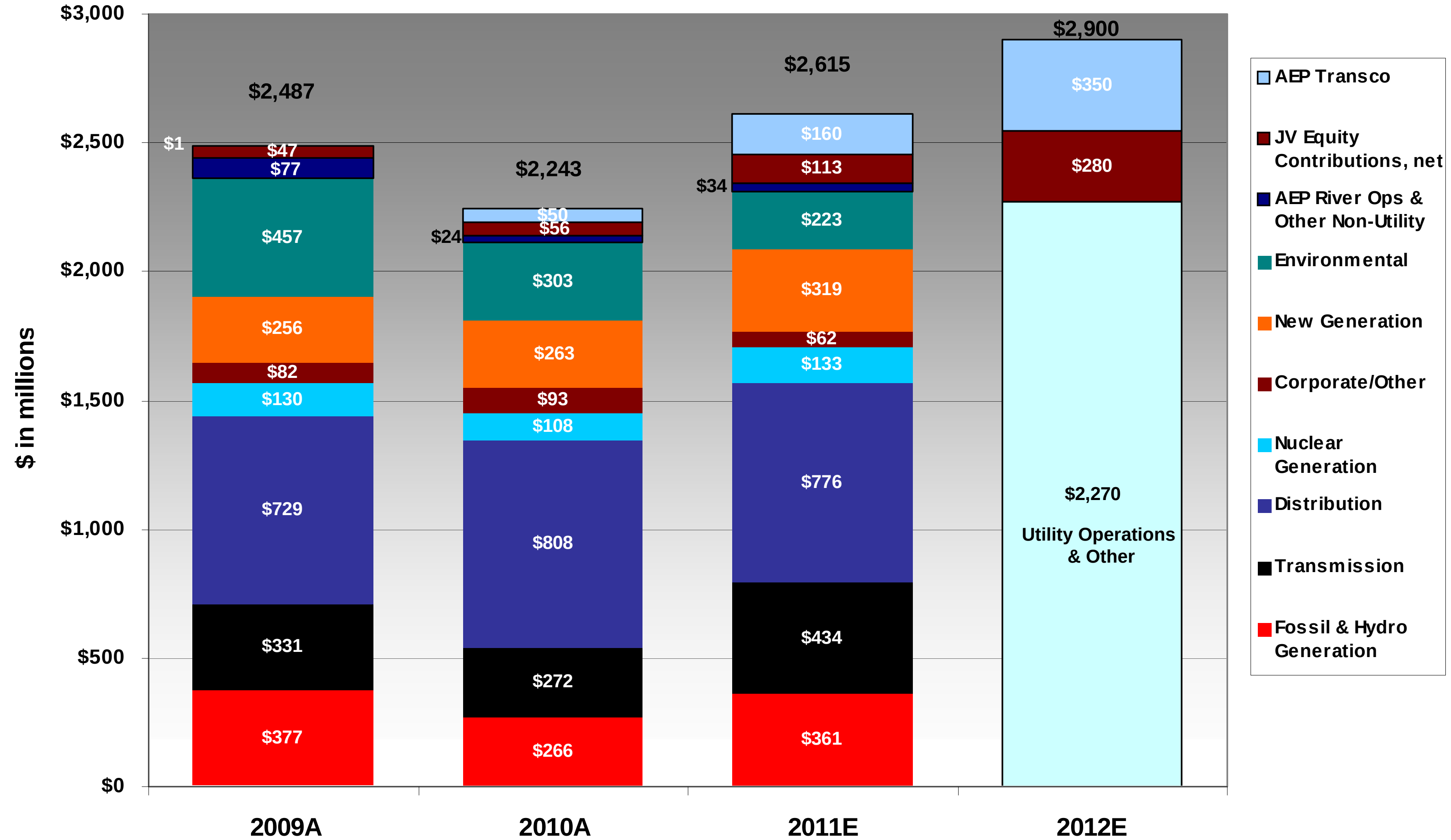
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

7

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Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[(1)]	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

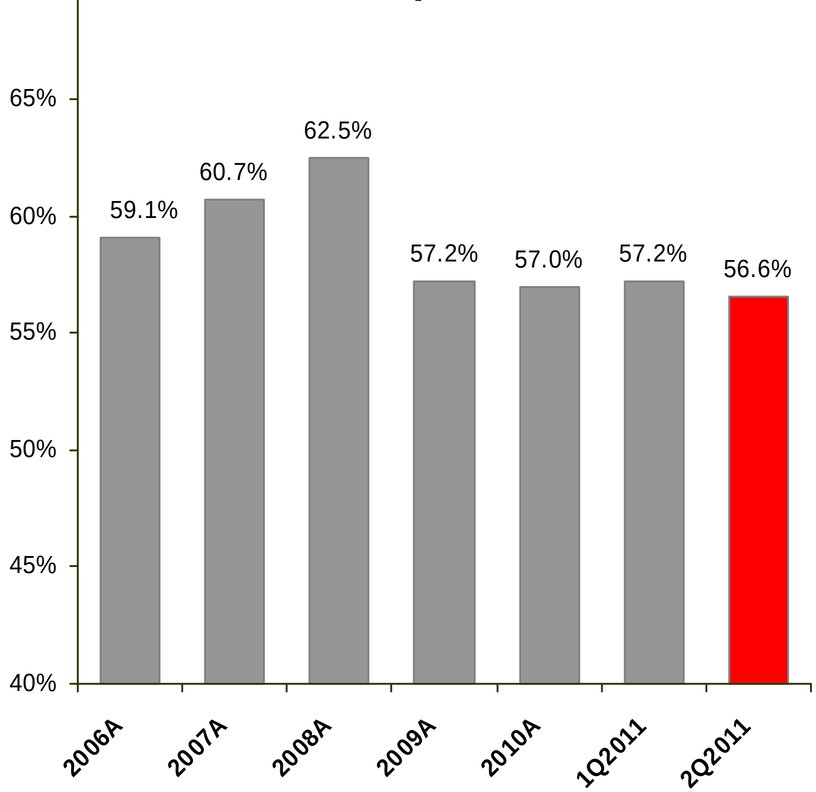
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

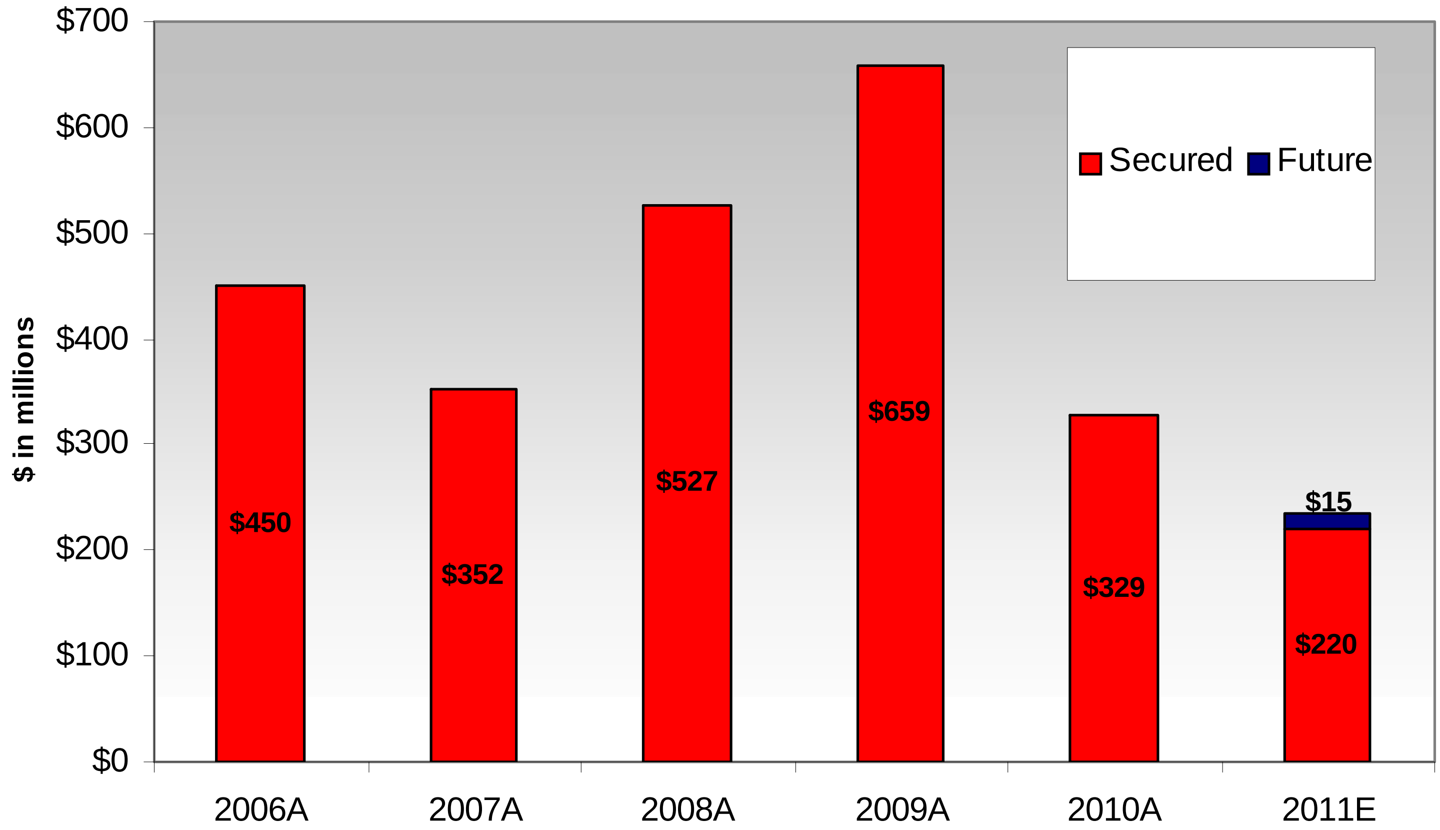
Liquidity Summary (unaudited)		Actual	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

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Summary Rate Case Information

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Rates Implemented, subject to refund	January 1, 2012
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

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Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 25; Staff testimony – August 4; Hearing – September 7**

	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

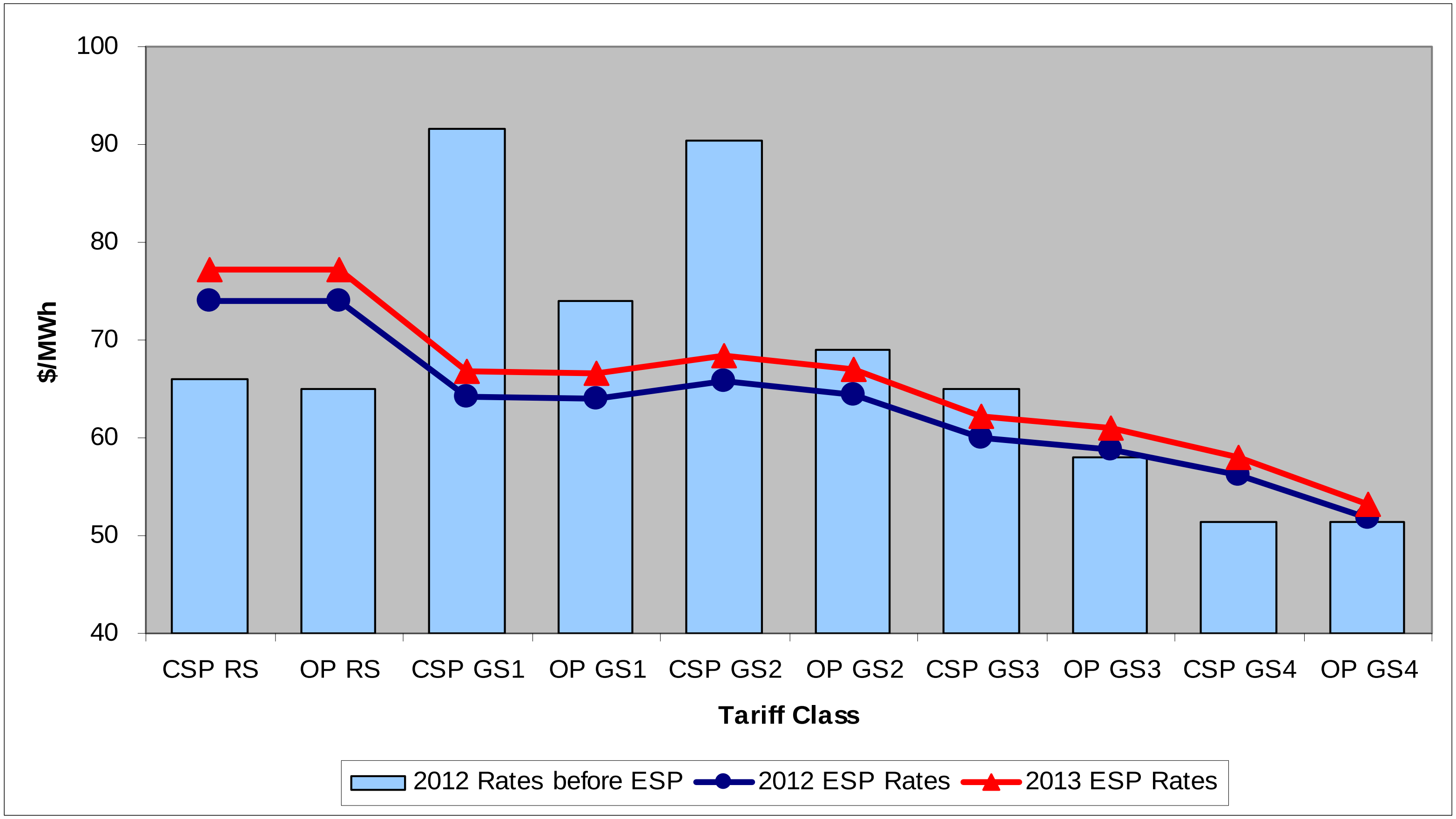
N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

AEP®

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

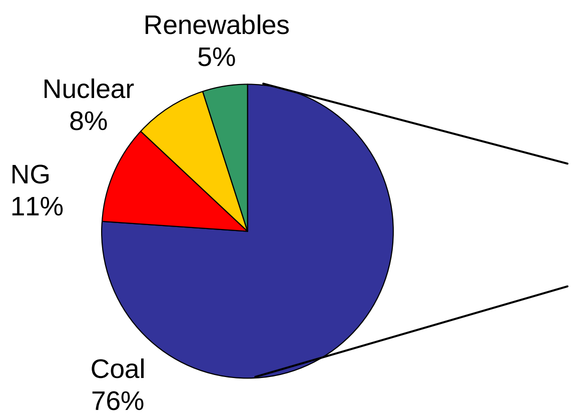
The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

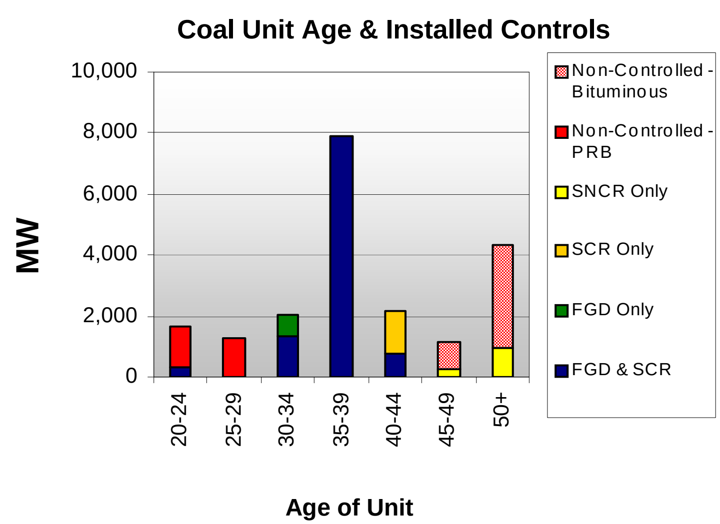
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



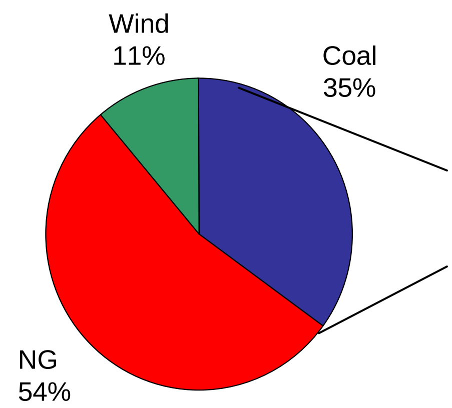
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



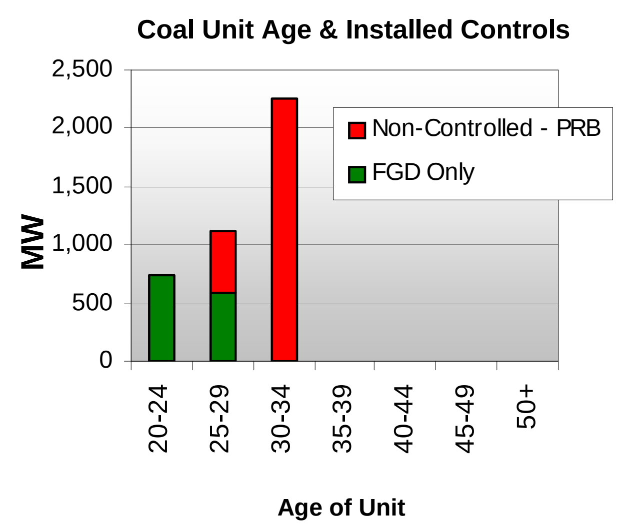
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



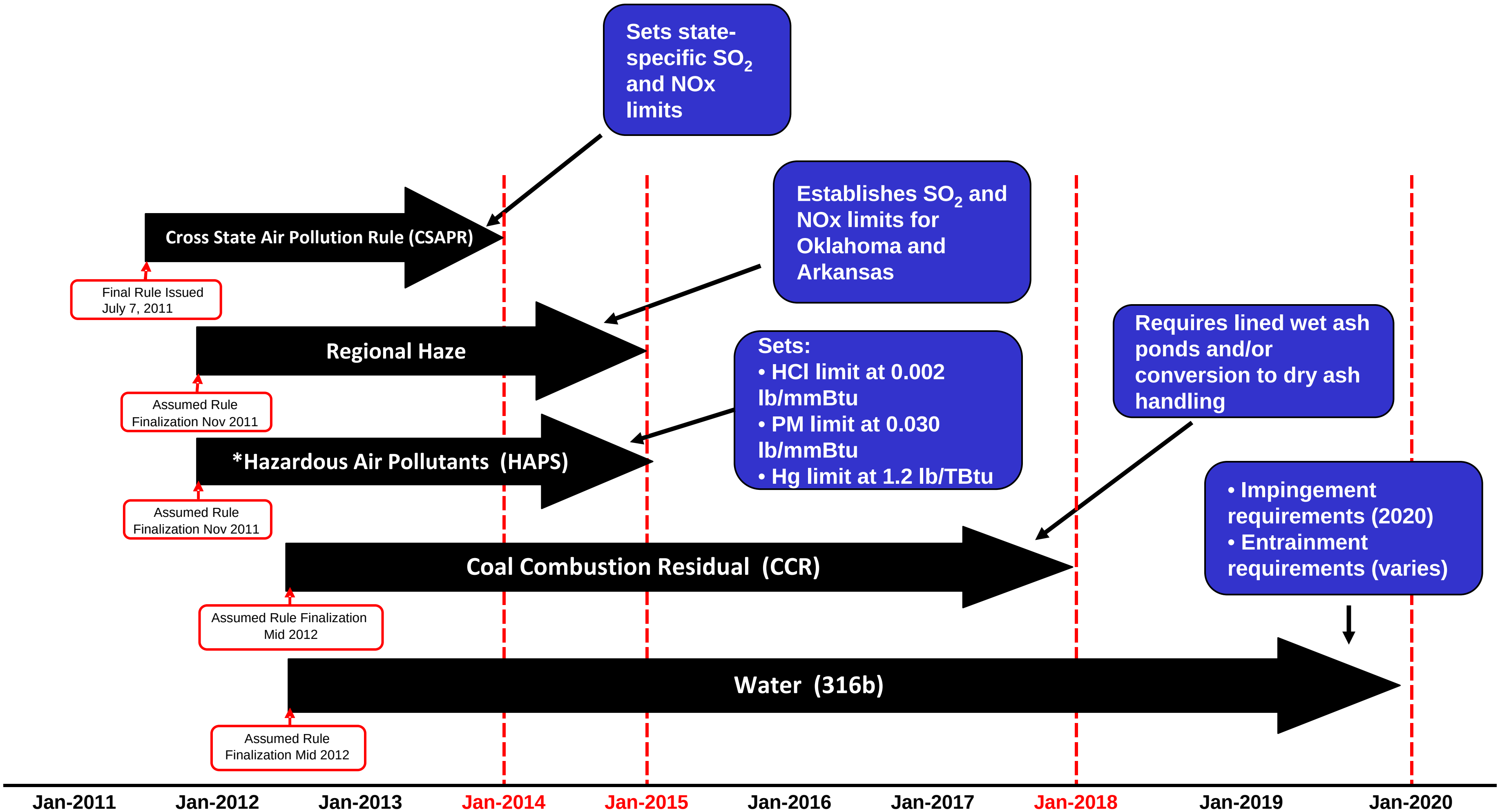
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Anticipated environmental regulations and compliance deadlines



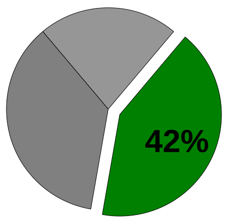
* **Units that will be retrofit are eligible for a one year compliance extension from the EPA**

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) [1]

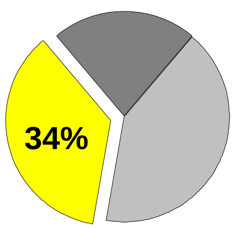
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules [2]	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules [3]	$	1,425	$	1,900

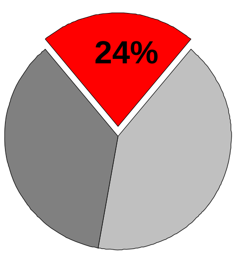
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules [2]	$	55	$	85
CCR Rules	$	385	$	520
Air Rules [3] [4]	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules [2]	$	-	$	5
CCR Rules	$	30	$	45
Air Rules [3]	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5	510	Refuel with Natural Gas		
	Gavin 1	1320	FGD upgrade		
	Gavin 2	1320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800** *
APCO	Clinch River 1	211	Refuel with Natural Gas		
	Clinch River 2	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765** **
I&M	Rockport 1	1320	FGD, SCR		
	Rockport 2	1320	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670** ***
KPCO	Big Sandy 1	640	New Natural Gas		
	Total MW	**640**	**Total Expected Cost**		**525**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

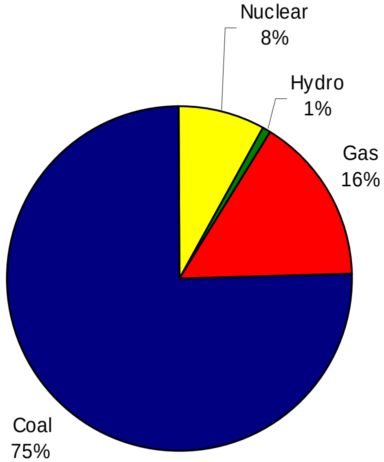
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

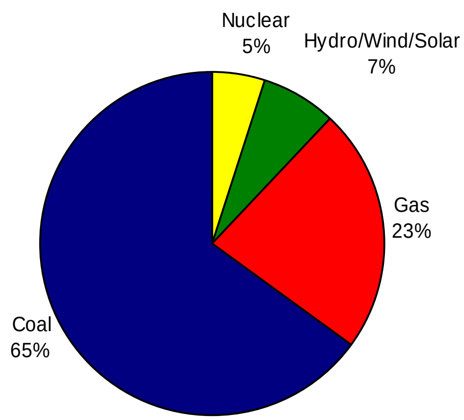
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

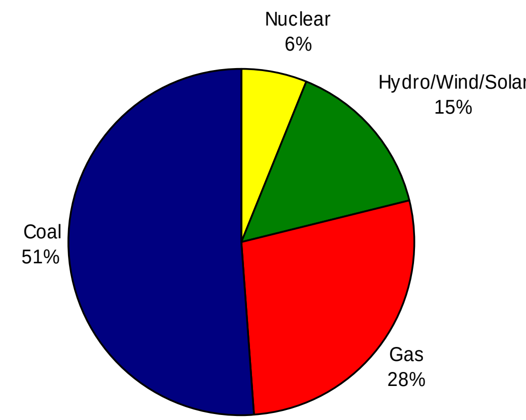
1990 AEP Generating Capacity by Fuel
37,428 total MW's



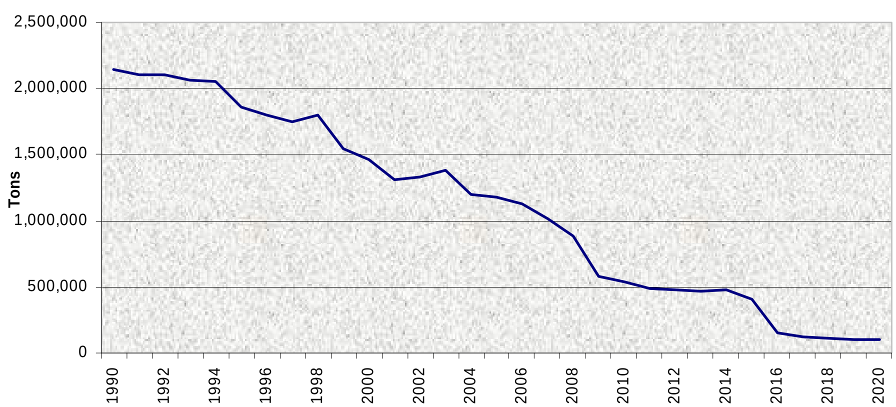
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $210 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

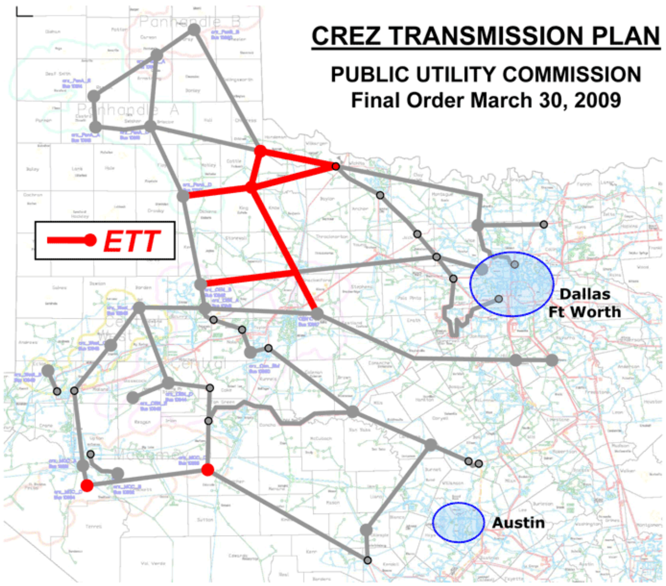
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $490 million
2012: $750 million
2013: $1,200 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.5 B:**
  – Approximately 500 miles of lines and 29 substations with in-service dates through 2020

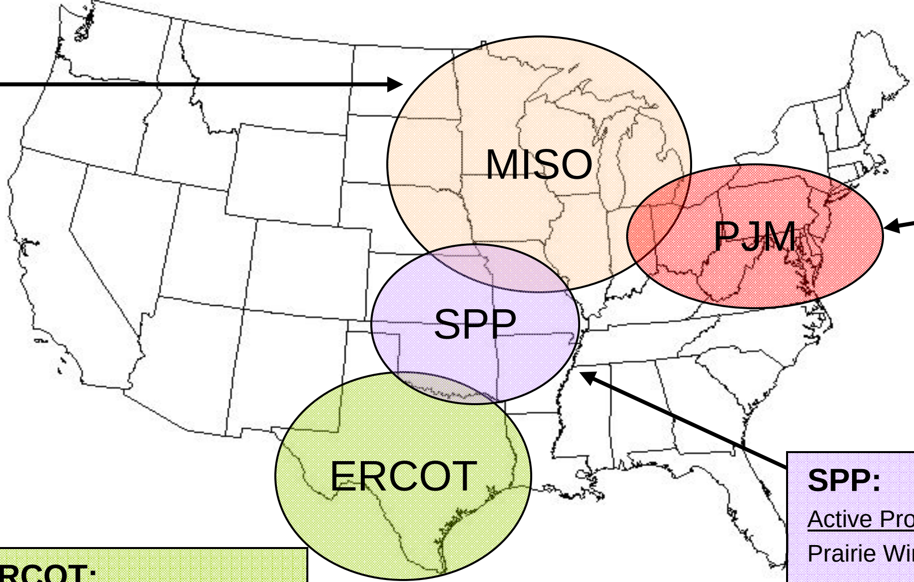
- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.4 B:**
  – Nine new transmission lines totaling approximately 600 miles and 16 substations
  – PUCT Certificate of Convenience and Necessity (CCN) proceedings underway; 5 lines already approved

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3217 of 9556

BEAR STEARNS GLOBAL CREDIT CONFERENCE

AEP AMERICAN® ELECTRIC POWER

May 15, 2007
New York, NY

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

AEP®

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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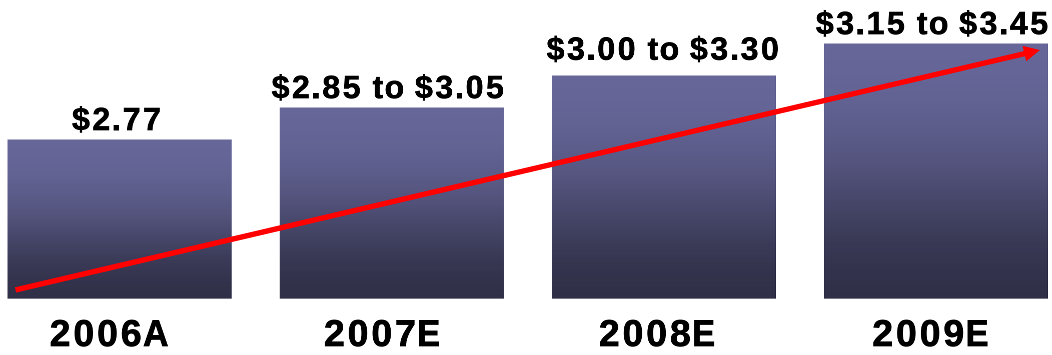
Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:

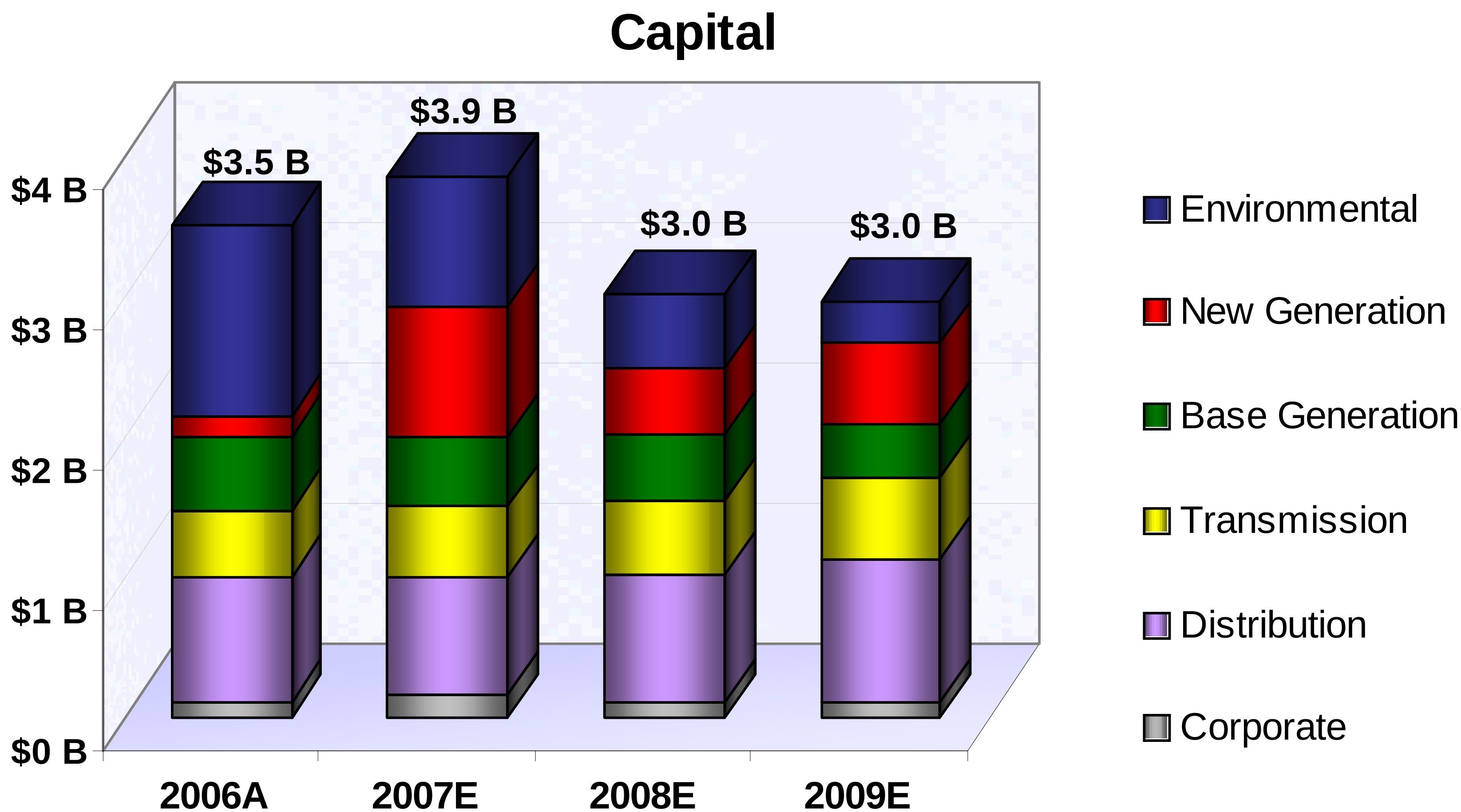


- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief

- Maintain credit ratings
  - BBB/Baa2/BBB

OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Capital Investment Forecast



- *Total 2007 Capital Forecast of $3.9B includes purchase of Darby and Lawrenceburg Generation Stations*
- *All periods presented exclude AFUDC*

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

New Transmission Investment Funding Plans

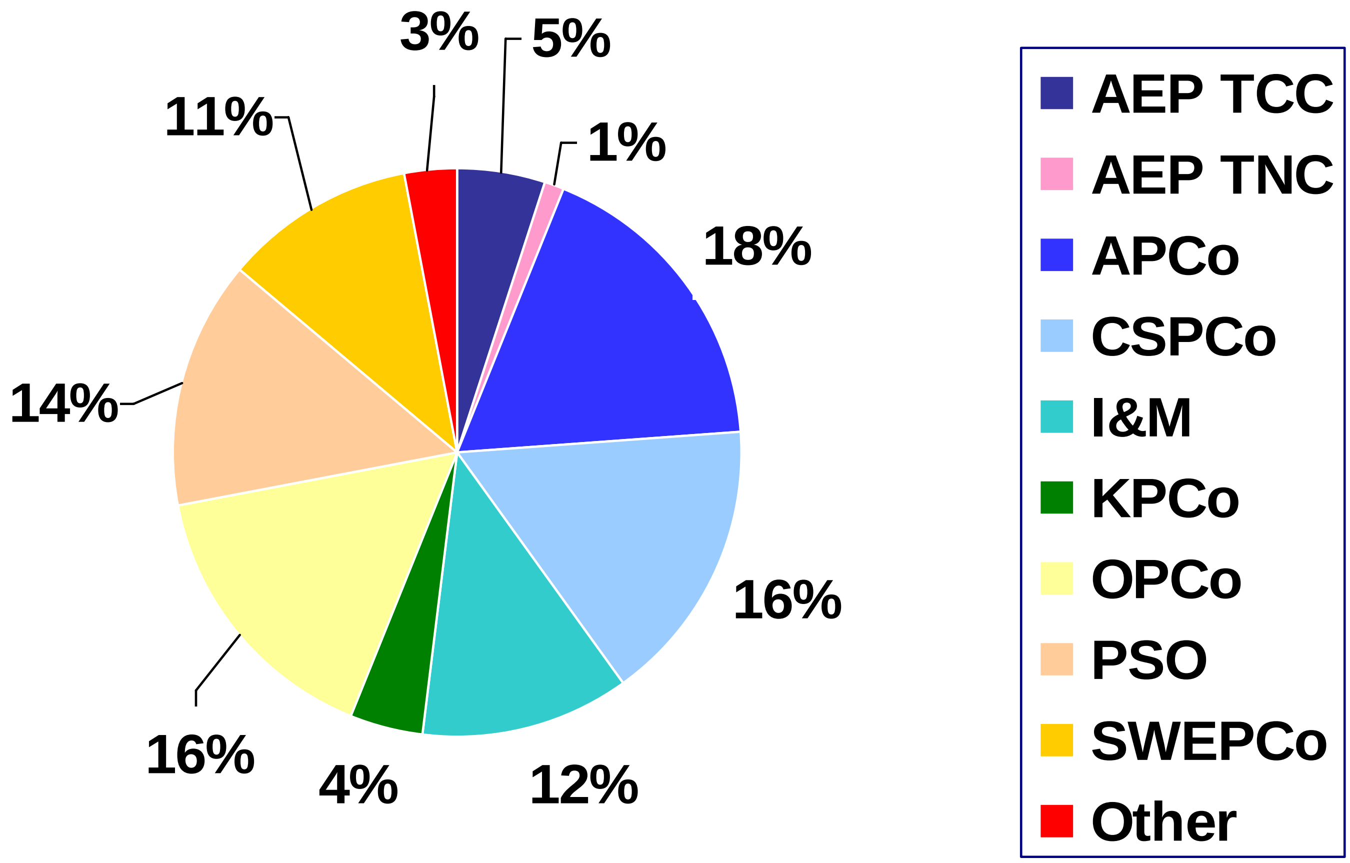
- **Electric Transmission Texas LLC**
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% MidAmerican Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- **AEP I-765 Interstate Project**
  - Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- **Other Transmission Projects**
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

2006 Retail Revenue

Retail Revenue Composition by Operating Company



2007 Key Operating Company Highlights

AEP®

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$400-$500	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

MAINTAIN FINANCIAL STRENGTH OF UTILITY COMPANIES BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Figures exclude AFUDC.

Long-Term Debt Maturity Profile

($ in millions)

Year	2007	2008	2009
AEP Service Corp.	$ -	$ 36	$ -
AEP, Inc.	$ 345	$ -	$ -
AEG	$ -	$ -	$ -
APCo	$ 325	$ 200	$ 150
CSPCo	$ -	$ 112	$ -
KPCo	$ 323	$ 30	$ -
I&M	$ -	$ 50	$ 45
OPCo	$ -	$ 45	$ 106
PSO	$ -	$ -	$ 50
SWEPCo	$ 90	$ 118	$ -
TCC	$ -	$ 68	$ -
TNC *	$ 8	$ -	$ -
Total	$ 1,091	$ 659	$ 351

Note: Maturities remaining as of March 31, 2007

* - represents TNC first mortgage bonds that were defeased in December 2005

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's	S&P		Fitch
	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS

Managing Subsidiary Cash Flows

- **We monitor:**
  - AEP consolidated cash requirements
  - Utility expected rates of return and potential regulatory lags
  - Amount of capital spending and internal cash needs
  - Free cash flow – cash available after construction
  - Credit ratios

- **Dividends and equity:**
  - We pay dividends based on free cash flow and credit metrics
  - When additional equity/cash is needed, the first option is dividend reductions, then capital infusions

OUR OBJECTIVE IS TO MAINTAIN THE FINANCIAL STRENGTH AND CAPITAL MARKETS ACCESS OF THE AEP OPERATING COMPANIES

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

Regulatory Activity

FERC Regional Rate Design

- ➢ The FERC instituted an investigation of PJM's zonal rate regime
  - ➢ Present regime may need to be replaced
  - ➢ Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- ➢ July 2006 ALJ-rendered initial decision:
  - ➢ License plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - ➢ Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - ➢ Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
- ➢ April 2007 Commission decision:
  - ➢ Reaffirmed PJM's current "license plate" rate design, reversing the finding of the ALJ; each utility pays for transmission service based on the costs of transmission facilities located in the same, sub-regional zone that the utility is located in
  - ➢ Directed PJM to develop a detailed methodology to be included in PJM's tariff for determining who benefits from and therefore, who pays for new facilities below 500 kV.
  - ➢ Determined that the costs of all new PJM-planned facilities that operate at or above 500 kV should be shared on a region-wide basis.

Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 11, 2007; Evidentiary hearing to commence May 22, 2007.

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

APPENDIX

2007 On-going Earnings Guidance Range: $2.85 - $3.05

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

AEP®

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

CASH ON HAND EXPECTED TO BE $205 MILLION AT YEAR END 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 3/31/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	13,902	-	13,902
Short-term Debt	18	-	18	175	-	175
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,540	9,540
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**14,077**	**9,601**	**23,678**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.5%***	***40.5%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(27)	-	(27)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(251)	-	(251)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**12,679**	**9,601**	**22,280**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***56.9%***	***43.1%***	***100.0%***

ADJUSTED DEBT/CAPITALIZATION: 56.90%

Debt Schedules – as of 3/31/07

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.102%		$1,077,775,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Weighted Average or Total	4.150%		$45,000,000

Debt Schedules – as of 3/31/07

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Preferred Stock	4.000%	N/A	$4,191,200
Preferred Stock	4.200%	N/A	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.895%		$688,687,300
Securitization Bond	5.010%	1/15/2008 **	$49,523,804
Securitization Bond	5.560%	1/15/2010 **	$107,094,258
Securitization Bond	5.960%	7/15/2013 **	$214,926,738
Securitization Bond	6.250%	1/15/2016 **	$191,856,858
Securitization Bond	4.980%	1/1/2010 **	$217,000,000
Securitization Bond	4.980%	7/1/2013 **	$341,000,000
Securitization Bond	5.090%	7/1/2015 **	$250,000,000
Securitization Bond	5.170%	1/1/2018 **	$437,000,000
Securitization Bond	5.306%	7/1/2020 **	$494,700,000
Weighted Average or Total	5.323%		$2,303,101,658

* TCC's First Mortgage Bond was defeased in May 2004

** represents scheduled final payment date, no ultimate maturity date

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond *	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	N/A	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

* TNC's First Mortgage Bond was defeased in December 2005

Debt Schedules – as of 3/31/07

AEP

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	N/A	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	06/29/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.294%		$2,530,038,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Debt Schedules – as of 3/31/07

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	N/A	$5,535,700
Preferred Stock	4.120%	N/A	$1,105,500
Preferred Stock	4.560%	N/A	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.811%		$1,320,082,400

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Debt Schedules – as of 3/31/07

AEP®

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$5,853,659
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	N/A	$1,459,500
Preferred Stock	4.200%	N/A	$2,282,400
Preferred Stock	4.400%	N/A	$3,148,200
Preferred Stock	4.500%	N/A	$9,737,300
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	5.863%		$2,216,836,059

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.000%	N/A	$4,454,800
Preferred Stock	4.240%	N/A	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Weighted Average or Total	5.498%		$676,621,700

Debt Schedules – as of 3/31/07

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$18,352,372
Notes Payable	Floating	06/30/2008	$3,750,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	N/A	$3,767,300
Preferred Stock	4.650%	N/A	$190,700
Preferred Stock	4.280%	N/A	$738,600
Senior Notes	5.380%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.535%		$926,536,972

Earned ROEs

Company	Earned ROE as of March 31, 2007
AEP Texas Central Company	**5.81%**
AEP Texas North Company	**5.24%**
Appalachian Power Company	**8.97%**
Columbus Southern Power Company	**17.14%**
Indiana Michigan Power Company	**7.12%**
Kentucky Power Company	**11.06%**
Ohio Power Company	**10.57%**
Public Service Company of Oklahoma	**3.75%**
Southwestern Electric Power Company	**10.11%**

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

Summary Rate Case Information

AEP®

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 7, 2006	Hearings commenced
February 5, 2007	Briefs filed
March 28, 2007	Hearing Examiner Recommendation filed

APCo filed its comments on the Hearing Examiner's report on April 18, 2007 and now awaits an order from the SCC. No statutory deadline.

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

Summary Rate Case Information

AEP®

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

AEP Texas Central Company

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

President and Chief Operating Officer: Charles Patton

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**630,000**
• **Commercial**	**102,000**
• **Industrial**	**5,000**
• **Other**	**1,000**
Total	**738,000**
Transmission Miles	**5,000**
Distribution Miles	**28,000**

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AEP Texas Central Company

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CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data (in thousands)

Revenue	$	665,000
% of AEP Retail		5%
Net Income (Loss)	$	42,000
Capital Expenditure	$	270,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,324,000
Net Plant Assets	$	2,240,000

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 241,000	$ 247,000	$ 222,100

AEP Texas North Company

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

President and Chief Operating Officer: Charles Patton

MAJOR CUSTOMERS:

Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

PRINCIPAL INDUSTRIES SERVED:

Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**6,000**
Total	**189,000**

Generating Capacity **377 MW**

Oklaunion Plant – Vernon, TX
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**4,500**
Distribution Miles	**14,000**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data (in thousands)

Revenue	$	329,000
% of AEP Retail		1%
Net Income	$	15,000
Capital Expenditure	$	70,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	968,000
Net Plant Assets	$	842,000
Cash	$	84

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$143,000	$188,000	$149,000

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3256 of 9556

Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers:

• **Residential**	**810,000**
• **Commercial**	**128,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**949,000**

Generating Capacity **6,282 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **80.8%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas** **8.4%**

Transmission Miles	**6,750**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 7,016,000
Net Plant Assets	$ 5,524,000
Cash	$ 2,318

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 664,000	$ 531,000	$ 461,000

Appalachian Power

AEP®

APCo Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants

Name	Location	Megawatt Capacity	Fuel
Buck #1, 2, 3	Ivanhoe, Virginia	5	Hydro
Byllesby #1, 2, 3, 4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	528	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	28	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lyn #1, 2	Glen Lyn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	9	Hydro
Niagara #1, 2	Roanoke, Virginia	1	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2 *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	12	Hydro
Marmet #1, 2, 3	Marmet, West Virginia	11	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

AEP®

APPALACHIAN AREA UTILITIES *

West Virginia	**Customers**
APCo	**434,504**
Allegheny	492,354

Virginia	**Customers**
APCo	**503,525**
Dominion Virginia	2,171,253
Allegheny	95,665
Kentucky Utilities	29,900
Conectiv	21,930

Tennessee	**Customers**
APCo	**45,960**

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- **Top 10 Customers = 49% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

TYPICAL BILL COMPARISON **

West Virginia	
APCo	**55.28**
AEP – Wheeling	**55.28**
Allegheny	70.46

Virginia	
APCo	**61.39**
ODPCo	64.69
Dominion Virginia	90.98
Conectiv	132.23

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:

Century Aluminum of WV, Inc. (WV)
CONSOL Energy (VA)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Dickenson-Russell Coal Co, LLC (VA)
Steel of WV, Inc. (WV)
Toyota Motor Manufacturing (WV)

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

- Food processing
- Chemicals
- Primary metals
- Fabricated metals
- Rubber and plastic products

Total Customers:

• Residential	662,000
• Commercial	76,000
• Industrial	4,000
Total	742,000

Generating Cap	3,708 MW

Generating Capacity by Fuel Mix:

• Coal:	63.2%
• Natural Gas	36.1%
• Hydro:	0.7%

Transmission Miles	2,400
Distribution Miles	17,200

Columbus Southern Power

AEP

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data (in thousands)

Revenue	$ 1,807,000
% of AEP Retail	16%
Net Income	$ 185,000
Capital Expenditure	$ 307,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,521,000
Net Plant Assets	$ 2,725,000
Cash	$ 1,319

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 439,000	$ 354,000	$ 233,000

Columbus Southern Power

AEP®

Columbus Southern Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,254	Coal
J. M. Stuart #*1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer #*1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	26	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	857	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	480	Nat Gas

Columbus Southern Power

AEP®

OHIO UTILITIES *

Ohio	**Customers**
**AEP Ohio ** **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**72.87**
AEP (CSP)	**92.05**
DP&L	97.79
Duke Ohio (CG&E)	98.10
FE (Ohio Edison)	121.67
FE (Toledo Edison)	124.38
FE (CEI)	129.86

**** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers:	
• **Residential**	**508,000**
• **Commercial**	**67,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**582,000**
Generating Capacity	**5,753 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.2%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana Michigan Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004 Debt	2004 Equity	2004 Total	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data (in thousands)

Revenue	$	1,977,000
% of AEP Retail		12%
Net Income	$	121,000
Capital Expenditure	$	325,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,546,000
Net Plant Assets	$	3,313,000
Cash	$	1,369

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 252,000	$ 264,000	$ 294,000

Indiana Michigan Power

I&M Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	5	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	2	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	2	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	1	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

AEP®

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I&M	**453,788**
IP & L	462,837
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECO	144,632

Michigan	Customers
I&M	**125,588**
Consumers Energy	1,779,184
Detroit Edison	2,156,214

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	
I & M	**69.27**
IP & L	78.91
Duke Indiana (PSI)	89.99
SIGECo	88.67

Michigan	
I & M	**65.02**
Consumers Energy	102.36
Detroit Edison	112.19

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**

Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,200**
Distribution Miles	**9,700**

Kentucky Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data (in thousands)

Revenue	$	586,000
% of AEP Retail		4%
Net Income	$	35,000
Capital Expenditure	$	78,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	1,311,000
Net Plant Assets	$	1,002,000
Cash	$	702

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 70,000	$ 114,000	$ 100,000

Kentucky Power

AEP®

Kentucky Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

AEP®

KENTUCKY UTILITIES *

Kentucky	**Customers**
KPCo	**175,255**
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	59.91
LG&E	65.43
Duke Kentucky	65.89
KPCo	**75.63**

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Total Customers:

• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**

Generating Capacity **8,498 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.9%**
- **Hydro:** **0.1%**

Transmission Miles **6,500**

Distribution Miles **26,200**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data (in thousands)

Revenue	$ 2,725,000
% of AEP Retail	16%
Net Income	$ 229,000
Capital Expenditure	$ 1,000,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 6,819,000
Net Plant Assets	$ 5,569,000
Cash	$ 1,625

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 832,000	$ 368,000	$ 389,000

Ohio Power

Ohio Power Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak – August 2nd	5,260 MW

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	26	Hydro

Ohio Power

AEP®

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**72.87**
AEP (CSP)	**92.05**
DP&L	97.79
Duke Ohio (CG&E)	98.10
FE (Ohio Edison)	121.67
FE (Toledo Edison)	124.38
FE (CEI)	129.86

**** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers:

• Residential	447,000
• Commercial	58,000
• Industrial	7,000
• Other	8,000
Total	520,000

Generating Capacity	4,219 MW

Generating Capacity by Fuel Mix:

- **Coal:** 25%
- **Natural Gas:** 75%

Transmission Miles	3,600
Distribution Miles	21,200

Public Service Company of Oklahoma

AEP®

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data (in thousands)

Revenue	$ 1,442,000
% of AEP Retail	14%
Net Income	$ 37,000
Capital Expenditure	$ 240,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 2,579,000
Net Plant Assets	$ 1,999,000
Cash	$ 1,651

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 319,000	$ 330,000	$ 466,000

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

AEP®

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	511,924
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	79.04
SPSCo	82.19
PSO	83.24
OG&E	89.96

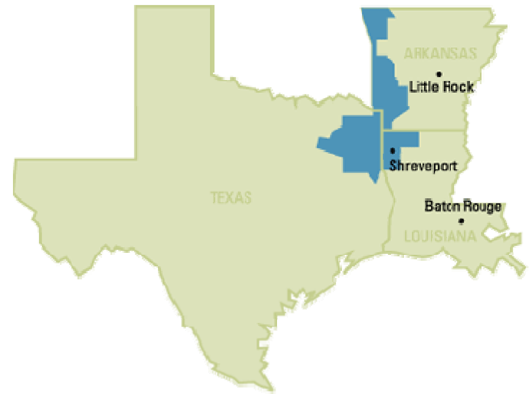
** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.

- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

Total Customers:

• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**456,000**

Generating Capacity	**4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite: 60%**
- **Natural Gas: 40%**

Transmission Miles	**3,500**
Distribution Miles	**19,300**

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data (in thousands)

Revenue	$ 1,432,000
% of AEP Retail	11%
Net Income	$ 92,000
Capital Expenditure	$ 323,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,191,000
Net Plant Assets	$ 2,494,000
Cash	$ 2,618

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 537,000	$ 605,000	$ 540,000

Southwestern Electric Power

AEP®

Southwestern Electric Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

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SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	109,760
Entergy AR	672,890

Louisiana	Customers
SWEPCo	171,564
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	166,906
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	80.14
Empire District	91.66
OG&E	92.72
ETR	102.77

Louisiana	
SWEPCo	79.11
Entergy LA	92.17
Entergy Gulf St	104.81
Entergy NO	117.92
CLECO	121.25

Texas	
SPSCo	88.55
SWEPCo	93.56
ETR	120.27
EP	133.32
TXU	153.73

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

Building Tomorrow's Transmission Infrastructure

Lisa Barton

Vice President – Transmission Strategy

American Electric Power

January 7, 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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A Changing Landscape

- National energy policy will inevitably drive significant changes in the nation's supply portfolio
- A national Renewable Portfolio Standard and CO_2 legislation will impact all states, and the ability to effectively comply with these policies is reliant on a transmission system built to adapt to changes.
- Renewable resources pose significant operational challenges. A robust and flexible transmission system is critical to making sure those challenges do not jeopardize reliability to customers.
- Large scale "backbone" transmission takes several years to permit and construct – without transmission being built **<u>first</u>**, much of the planned renewable generation will not be developed.
- AEP believes that development of an interstate backbone transmission grid – analogous to the interstate highway system – is necessary to meet our nation's energy goals.


Today's Challenge

- **Why Change Now?**
  - Dramatic shifts in generation profile.
  - Electrically isolated large scale renewables need to be interconnected and efficiently delivered.
  - Environmental requirements are likely to force retirement of large fossil units, potentially at a magnitude never before faced in this country.
  - The search for a "bright line" between reliability and economic transmission projects is increasingly artificial.
- **What Needs to Change?**
  - Planning for a new energy supply paradigm.
  - Cost allocation principles to encompass a strategic expansion of transmission.
  - Siting processes which are aligned with state, regional and national energy policy objectives.
- **"What got us here won't get us there."**

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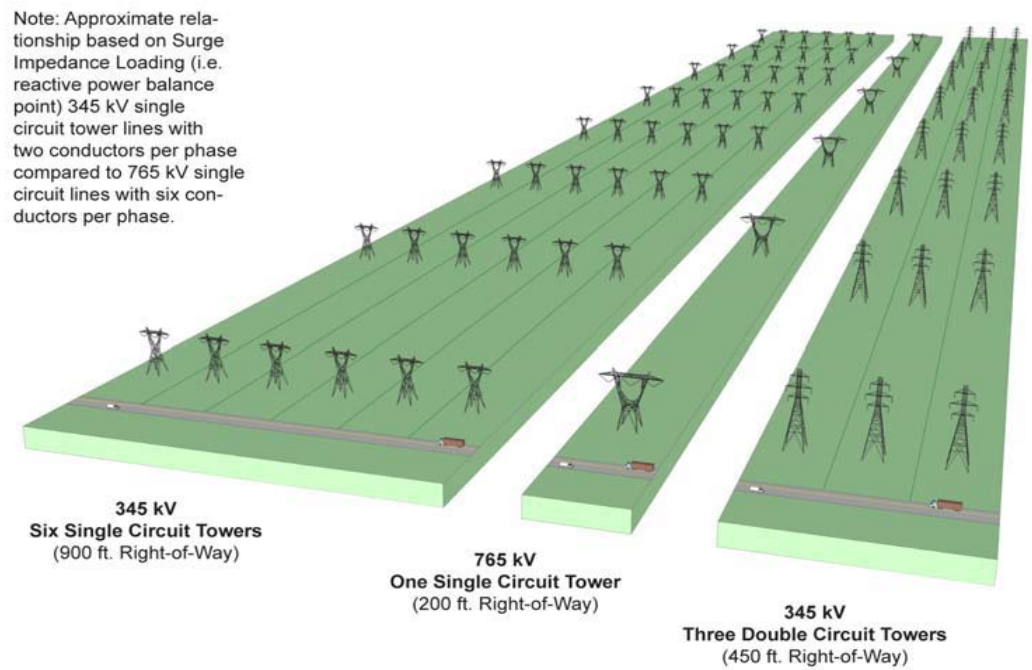
Planning & Building Smarter

- Advance a long-term, strategic "system-based" approach to transmission planning.
- Transmission grid should be adaptable to address:
  - Policy driven goals to interconnect and ensure efficient deliverability of renewables.
  - Facilitate the retirement of aging and expensive resources.
  - Regional availability of resources and operational requirements of the grid.
- Extra-high voltage (EHV) planning is needed both "within and between" traditional planning regions, with:
  - Consistent planning criteria applied to EHV transmission.
  - Regional and inter-regional planning efforts and consensus on transmission development goals.
  - Longer time horizons to ensure development of strategic as opposed to "band-aid" solutions.

A strategically planned EHV grid can provide the required transmission capacity and operating flexibility while drawing on diverse resources that will insulate consumers from resource shortages and catastrophic events.

Planning & Building Smarter

- Use higher voltage and higher capacity lines to make best use of new rights-of-way.
- Use higher voltage lines and more efficient equipment to reduce energy losses.
- Apply “Smart Grid” technologies to the transmission system.



Siting transmission projects will become increasingly difficult into the future. We need to minimize our footprint while maximizing the benefits to the system.

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Fair Allocation of Costs & Benefits

- RTOs and planning authorities need to ensure cost allocation structures support systems that are robust, efficient and capable of meeting their long term energy needs.

- "Beneficiary based" models which consider a line by line cost benefit analysis for EHV are not consistent with the need to build a robust backbone grid to meet national energy policy goals.

  - These fail to capture the full system benefits afforded by such facilities.
  - Determination of "who benefits" is complex, can change over time, and is often met with objection and debate.

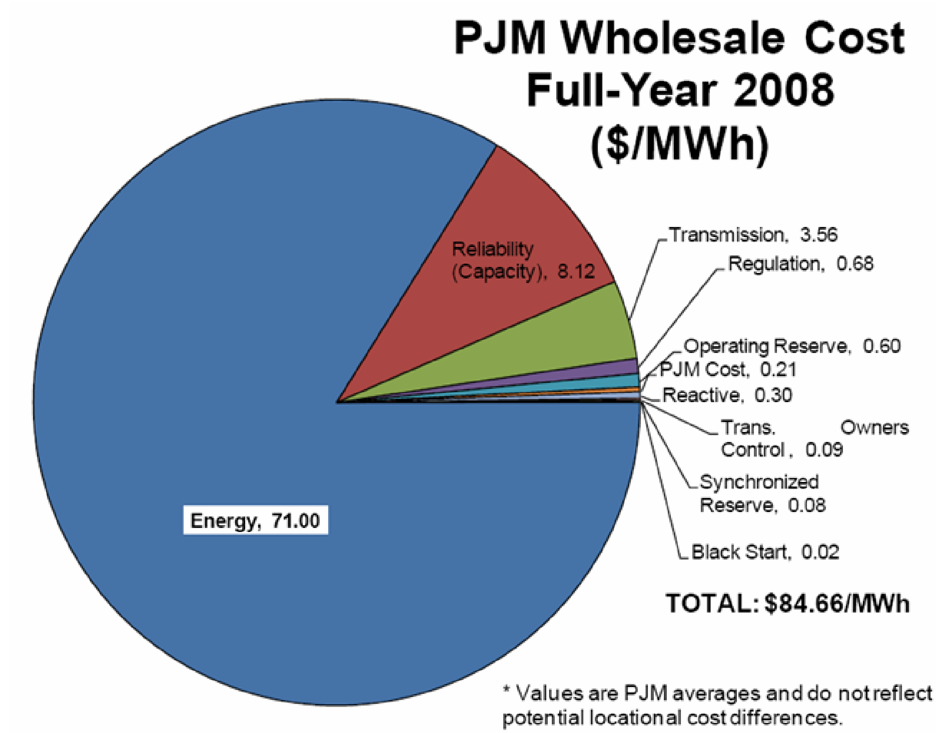
- We have seen that broad based regional cost allocation methodologies have resulted in projects that provide regional benefits. Similarly, interconnection-wide cost allocation can result in a system that provides inter-regional benefits.

- Consider all benefits – electrical and economic - of large-scale transmission development:

  - Lowered emissions.
  - Generation diversity and reserve sharing.
  - Loss savings.
  - Reduction of congestion and production cost savings.
  - Avoidance or deferment of incremental upgrades.
  - Enhanced reliability and national security.

Fair Allocation of Costs & Benefits

- Transmission represents a very small part of the customer bill.
- Substantial investments in transmission have a small impact.
- Transmission expansion facilitates lower delivered energy costs due to:
  - Increased competition and less constrained markets.
  - Reduced energy losses.
- Studies often show transmission can pay for itself, provided costs are broadly allocated.



"Least Cost" is rarely "Best Value"

Development Needs

To make significant strides in developing clean, domestic energy and reducing emissions, we as a nation need:

- National energy policy with specific goals and guidelines, particularly as it relates to renewables and CO_2.
- Federal planning authorities that can mandate RTOs, utilities, or other planning entities to develop long-term, interconnection-wide transmission plans that will facilitate national energy goals.
- Mandates to develop reasonable regional and interregional cost allocation methodologies to support EHV transmission that is in the national interest.
- Support for the siting of national-interest transmission lines where necessary.
- Benchmarks to check progress of plans and ensure timely construction.

AEP's Transmission Investment Opportunities

- <u>AEP Transmission Company (Transco)</u>: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM
- <u>Electric Transmission Texas (ETT)</u>: Projects in Texas ERCOT jurisdiction
  - Framework in Texas allows for more expeditious siting and recovery
  - $840MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B within the next decade
- <u>Joint Ventures (JVs)</u>: Outside of our footprint, with Electric Transmission America (ETA) or others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
  - Robust pipeline of projects up to $15B

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AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades

- Next steps:
  - Obtain state utility status where required, and join PJM and SPP as transmission owners
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

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JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 765 kV
- Partners: Westar (50%) & MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

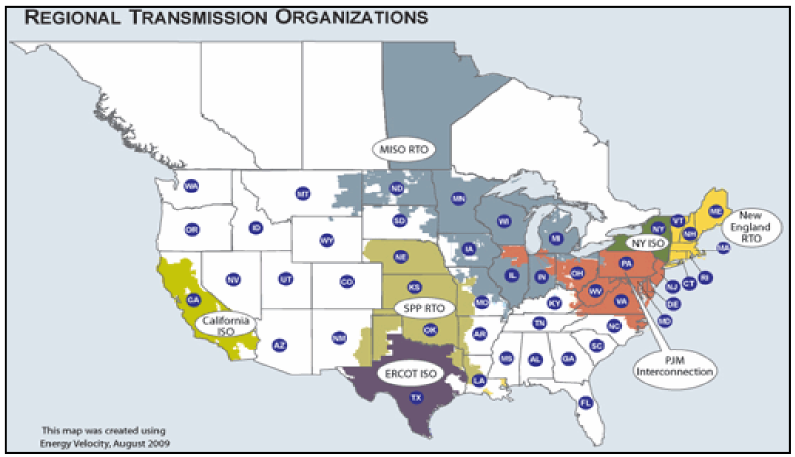
ETT — COD: 2010-2013
- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $600 million+
- ROE: 9.96%

PJM

PATH-WV — COD: TBD
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%



FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Sponsors: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay
- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various
- Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)

PJM

PJM Expansion
- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio
- 700 miles of Proposed 765 kV

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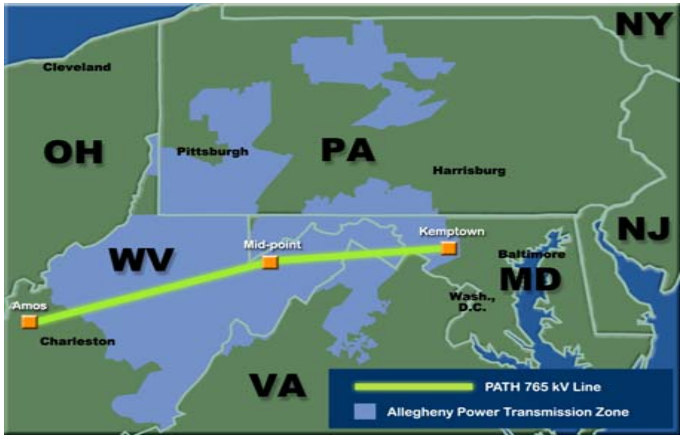
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Overview

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008

Key Challenges

- Estimated completion date: 2014 +, pending the outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).
- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million

Potomac-Appalachian Transmission Highline

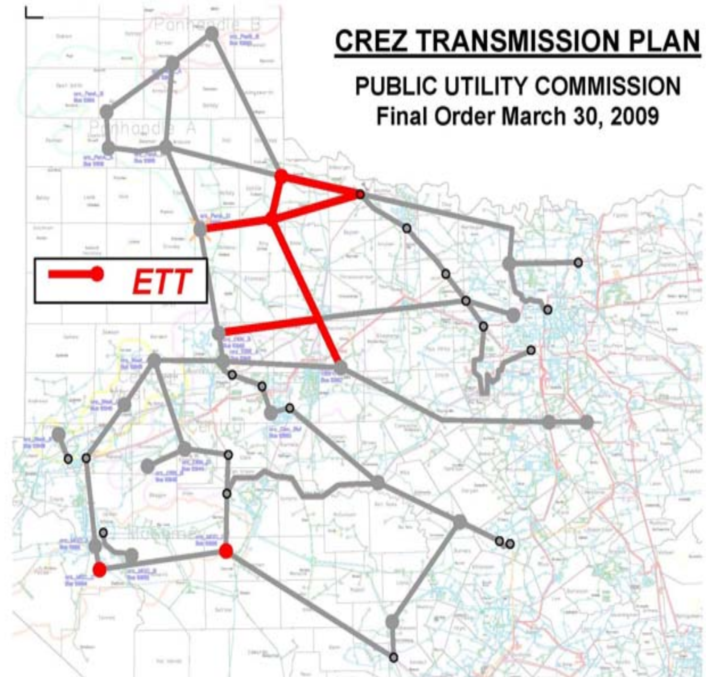
Texas CREZ Project

Overview

- On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
- Staging to occur in separate docket and consider timing of wind projects and congestion.
- PUCT established 2 categories based on priorities. ETT has no first priority lines.
- PUCT issued a final order assigning transmission service providers on March 30, 2009.
- ETT's share of CREZ investment is approx. $840MM of $4.9B total of which AEP's ownership is 50%.
- The filing calls for completion of the plan by 2013.

Next Steps

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

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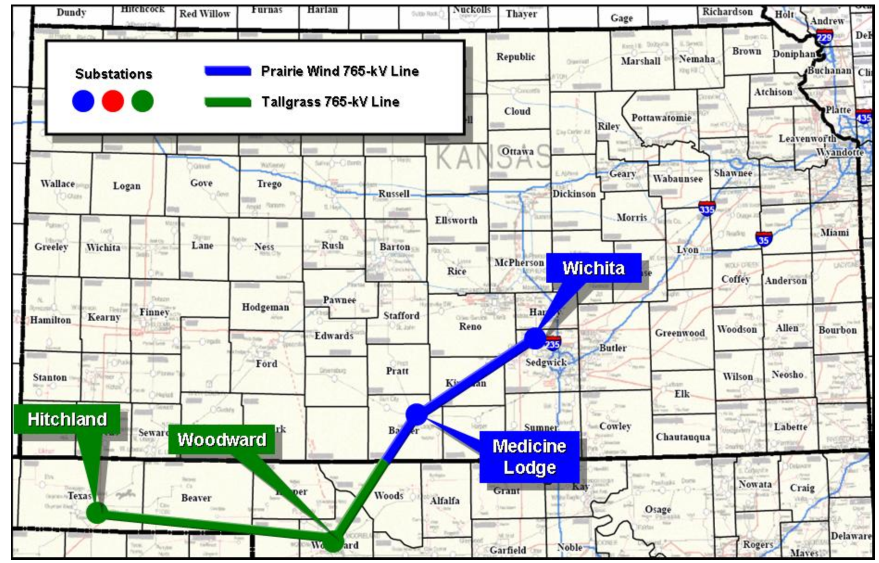
Prairie Wind Transmission, LLC

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- The project is expected to cost approximately $400 million and be in-service by 2013 and was approved by the KCC on July 24, 2009.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

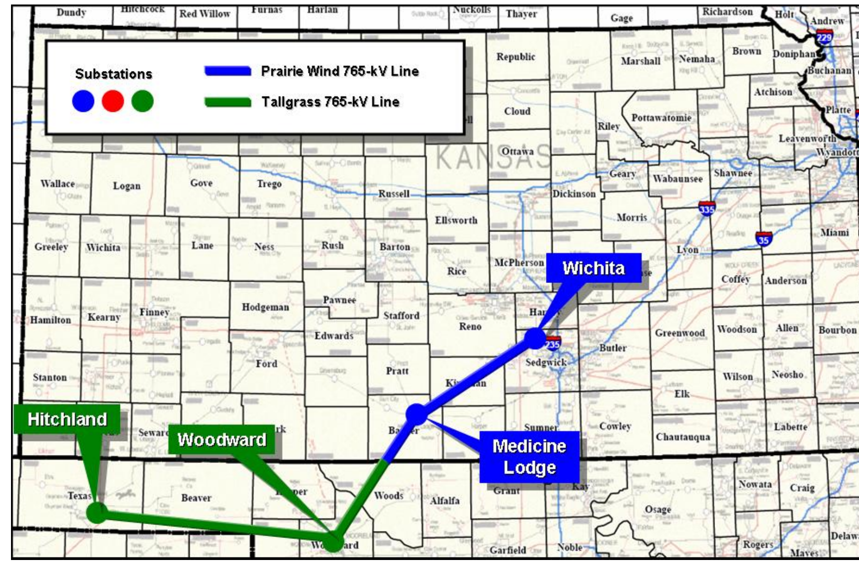
Key Challenges

- RTO Approval
- Siting

Tallgrass Transmission, LLC

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

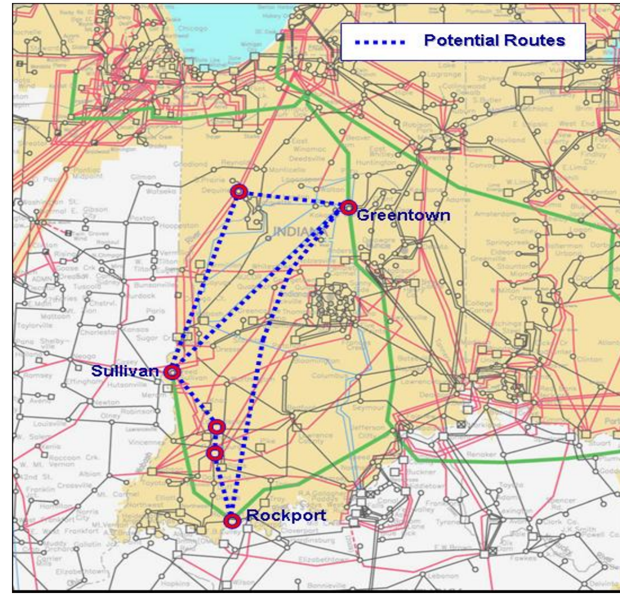
Key Challenges

- RTO Approval
- Siting

Pioneer Transmission, LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

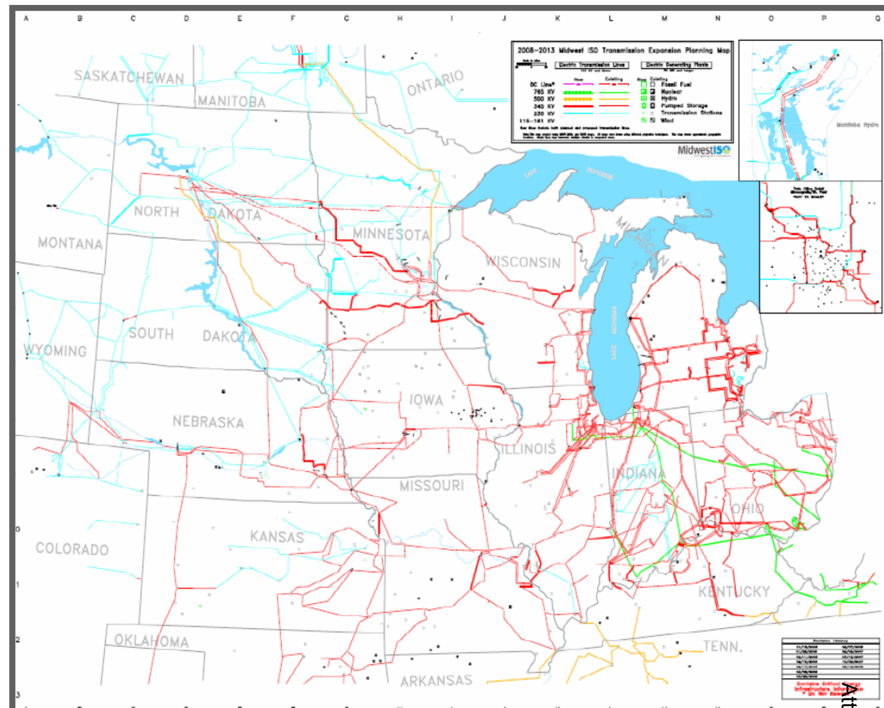
Key Challenges

- RTO Approval (PJM & MISO) and Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

- Announced SMARTransmission Study in August 2009.
  - Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
  - Study due to be completed end of 1st Qtr 2010 and will include "overlay" options and quantification of economic benefits.
- Next Steps
  - Investment Structure
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including incentives
- Mitigation
  - Collaborative approach involving impacted utilities, RTOs, commissions and others



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

AEP AMERICAN ELECTRIC POWER

Key Investment Attributes

AEP is the Leader

- Largest US transmission footprint
- Interstate EHV transmission highway vision
- National renewables transmission strategy

Quality Investments

- 4 FERC-approved ($3.0 billion)
- AEP Transco (2010 Investment: $118 million)
- Independent ERCOT transmission JV company (up to $3.0 billion)
- Robust pipeline of future high-voltage transmission projects (up to $15 billion)

Attractive Returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Robust long-term annual earnings growth potential

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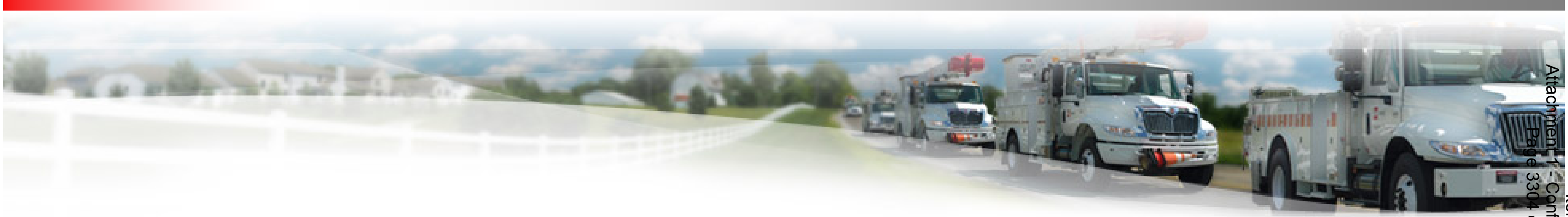
Sanford Bernstein Conference Call

December 8, 2010



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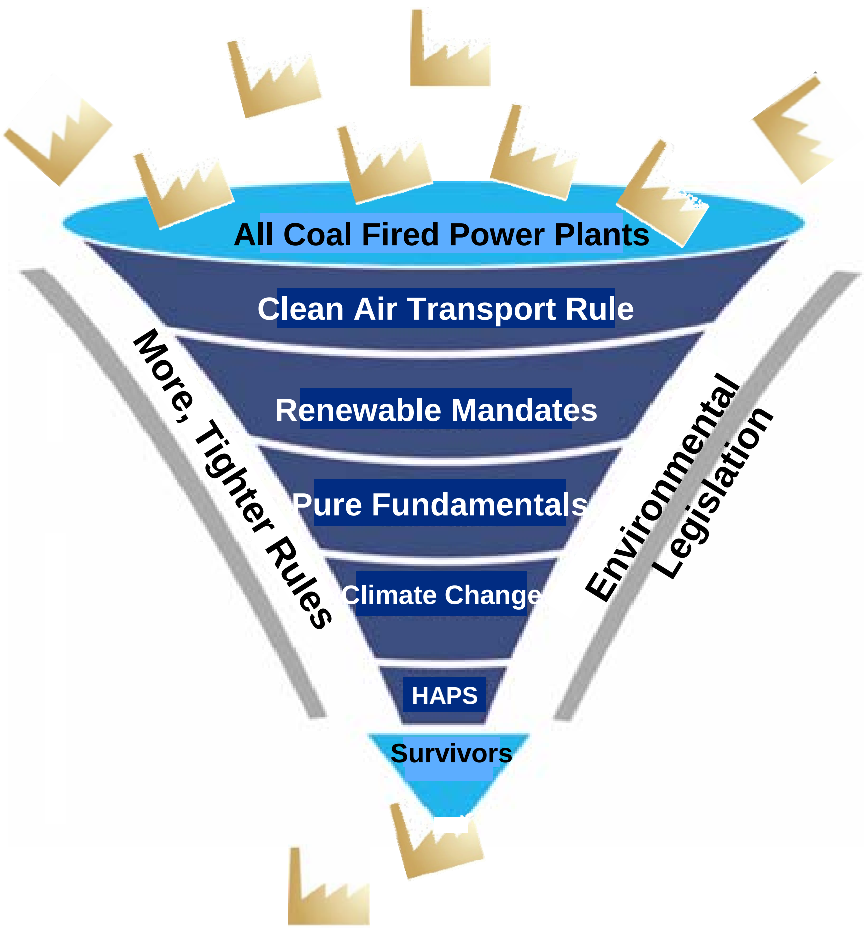
John McManus

VP, Environmental Services

The Pressure on Coal Generation

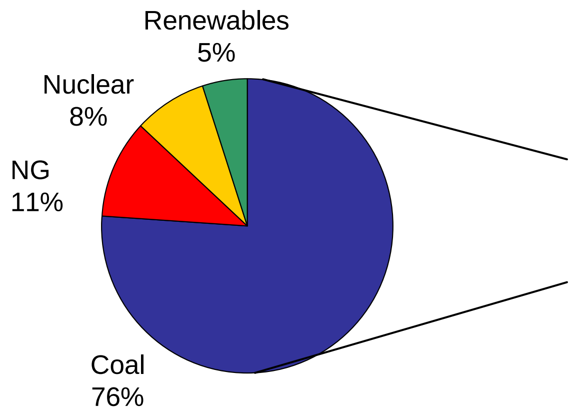


Key EPA Actions Pending

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in March 2011
- Cooling Water Intakes – Expect Proposed Rule in Spring 2011
- Greenhouse Gas Tailoring Rule – January 2011

AEP Generation Capacity

East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

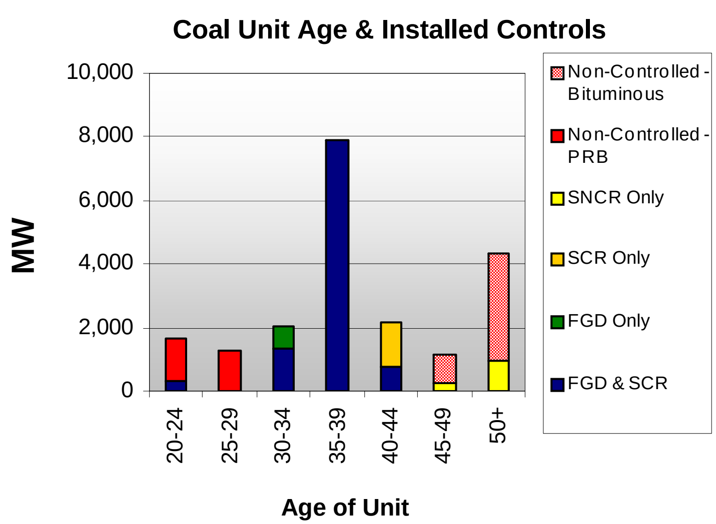


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



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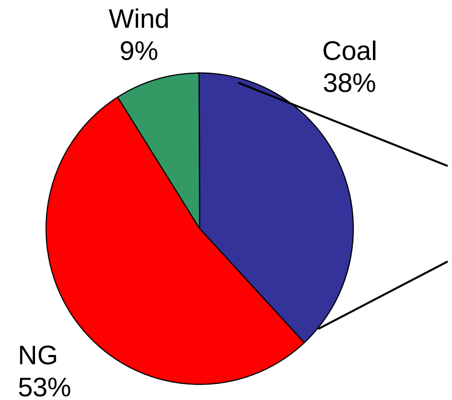
PSO, SWEPCO, TNC, Wind

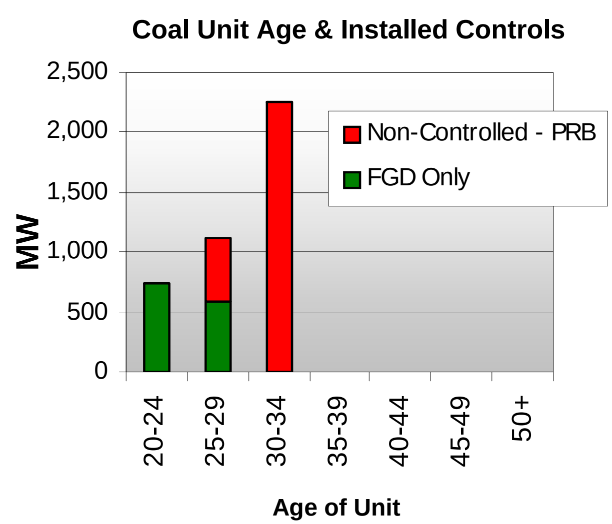


Coal Source

PRB	75%
Lignite	25%

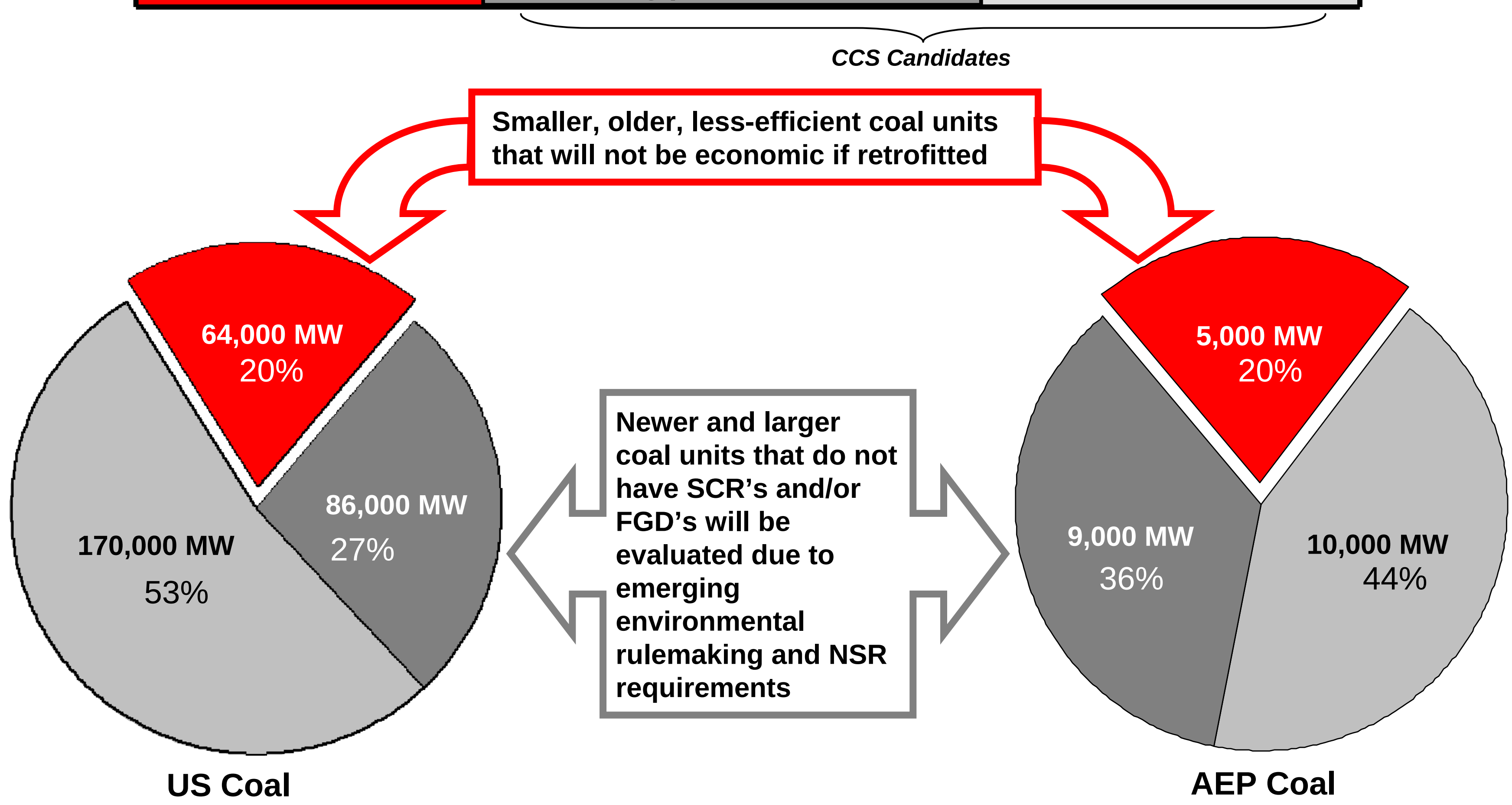
Avg. Delivered Cost
2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

[1] Represents cost of committed position (90%)



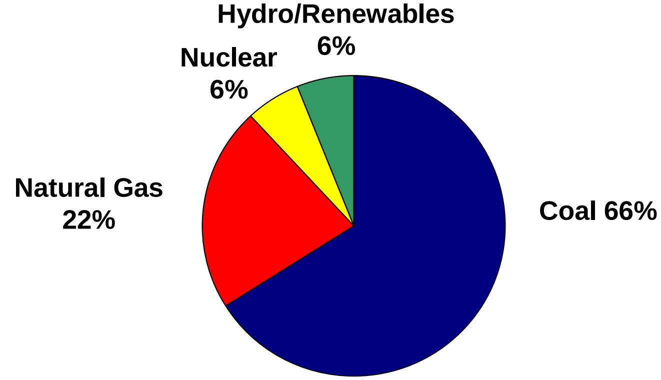
Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

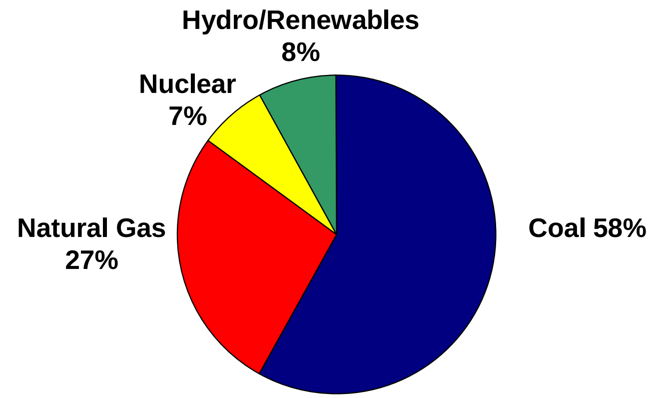


Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

AEP and Environmental Investments

Mountaineer Plant - New Haven, WV

AEP AMERICAN ELECTRIC POWER®

Northeastern Plant - Oologah, OK

Bernstein Energy and Utilities Conference

December 2, 2008

Bruce Braine

VP, Strategic Policy Analysis

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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Jana Croom
Analyst
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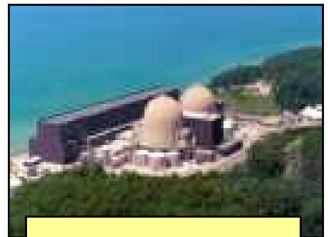
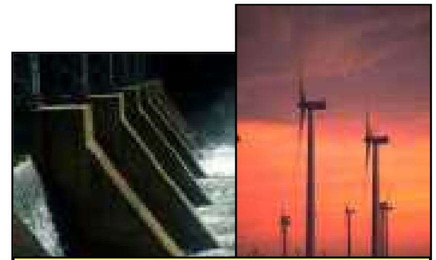
Company Overview

Natural Gas/ Oil
23%



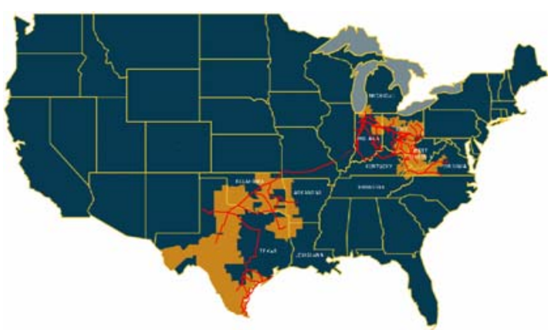
Nuclear
6%

Coal/Lignite
66%



Pumped Storage/ Hydro/Wind
5%

AEP's Generation Fleet
38,721 MW Capacity



5.1 million customers in 11 states
Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Generation	~38,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

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The Next Administration—Energy and the Environment

- **Energy Legislation -- A First Priority**
  - For Electric Utilities: Federal RPS Likely
- **Climate Legislation -- Also a Priority**
  - Passage Complex
- **Further Air Emissions Requirements --SO_2, NOx, and Mercury???**

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AEP's GHG Reduction Portfolio

Renewables

(e.g. 1100 MW of Existing Wind;
600 MW New Wind PPAs by 2011;
Biomass Co-firing)

Efficiency

(e.g. Coal Plant Heat Rate Improvements
DSM and Energy Efficiency)

Offsets & GHG Markets

(e.g. Chicago Climate Exchange,
Forest Preservation and Tree Planting,
Methane Capture from Livestock,
2.5 MM CO2eTons/yr by 2011 Goal)

New Technology: Advanced Coal & CCS

(e.g., Chilled Ammonia Retrofits;
Ultra-super Critical Coal Generation)

AEP

AEP is investing in a portfolio of GHG reduction alternatives

AEP Position: A "Reasonable" Approach to Climate Legislation

- **Reductions and Timing -** Moderate with Adequate Lead Times
- **Scope of Program -** Economy Wide
- **Flexibility of the Program -** Trading, Banking, Unrestricted Offsets, Early Action Credits
- **Allowance Allocation And Other Cost Issues -** Emissions Based and "Low" auctions
- **Technology Development/Deployment -** Bonus allowances for carbon capture and storage
- **International Linkage -** e.g., AEP-IBEW Proposal

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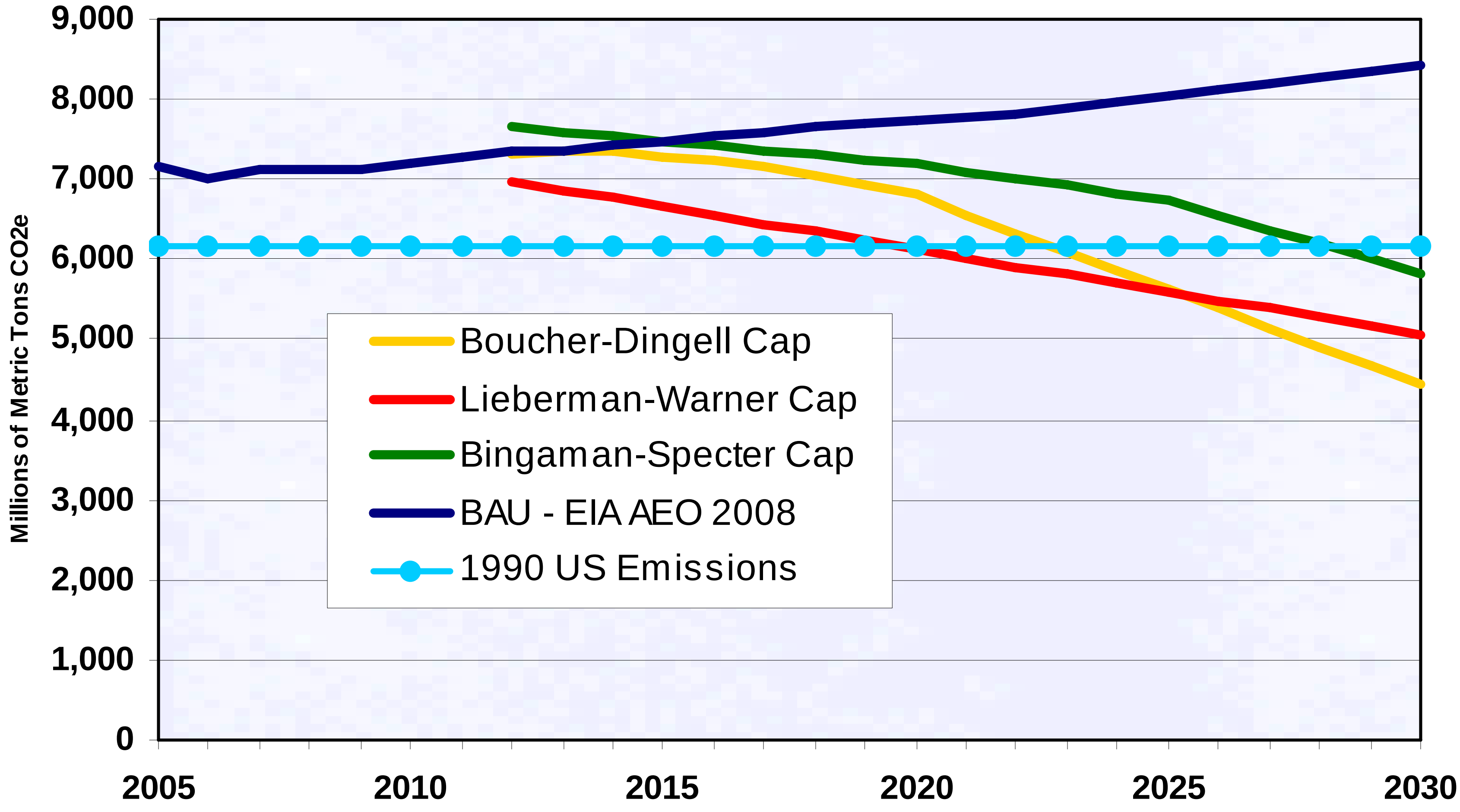
Emission Reductions Under Selected Bills



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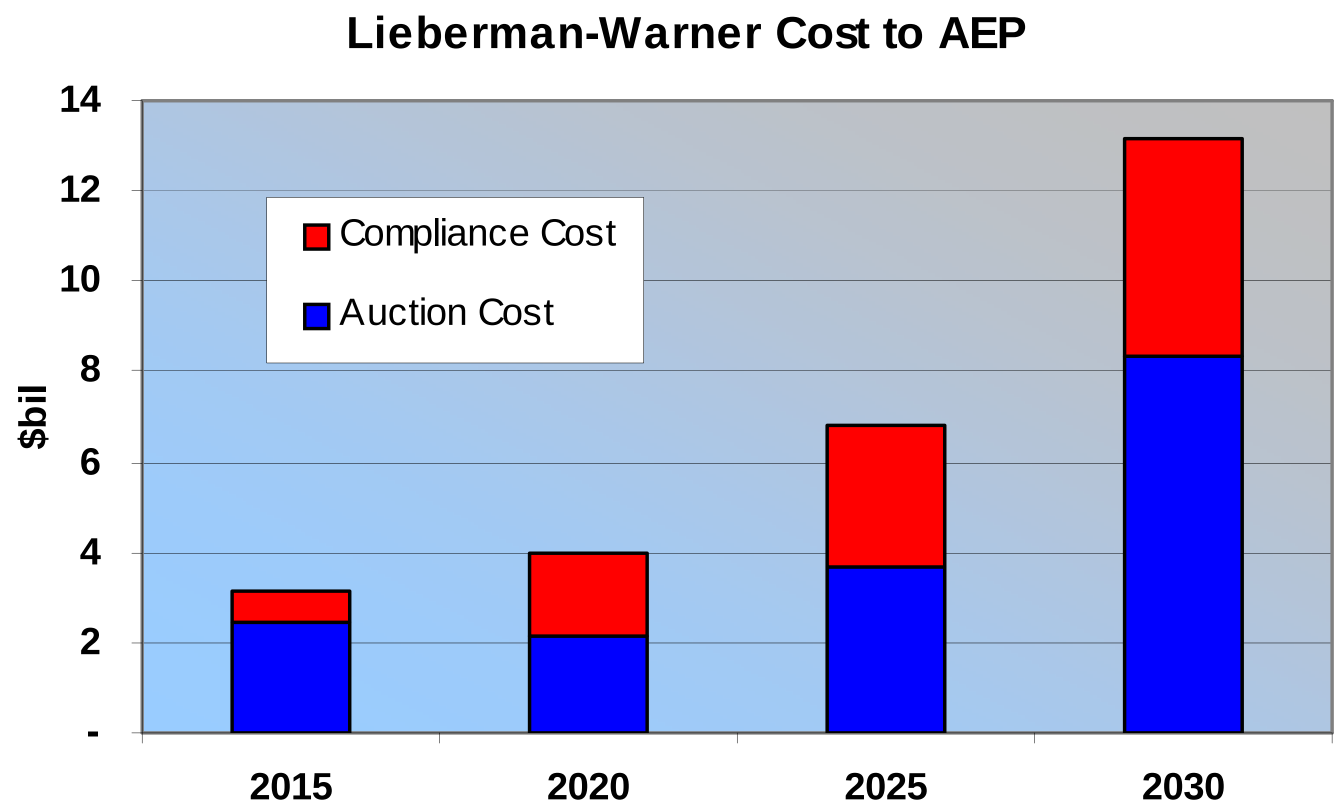
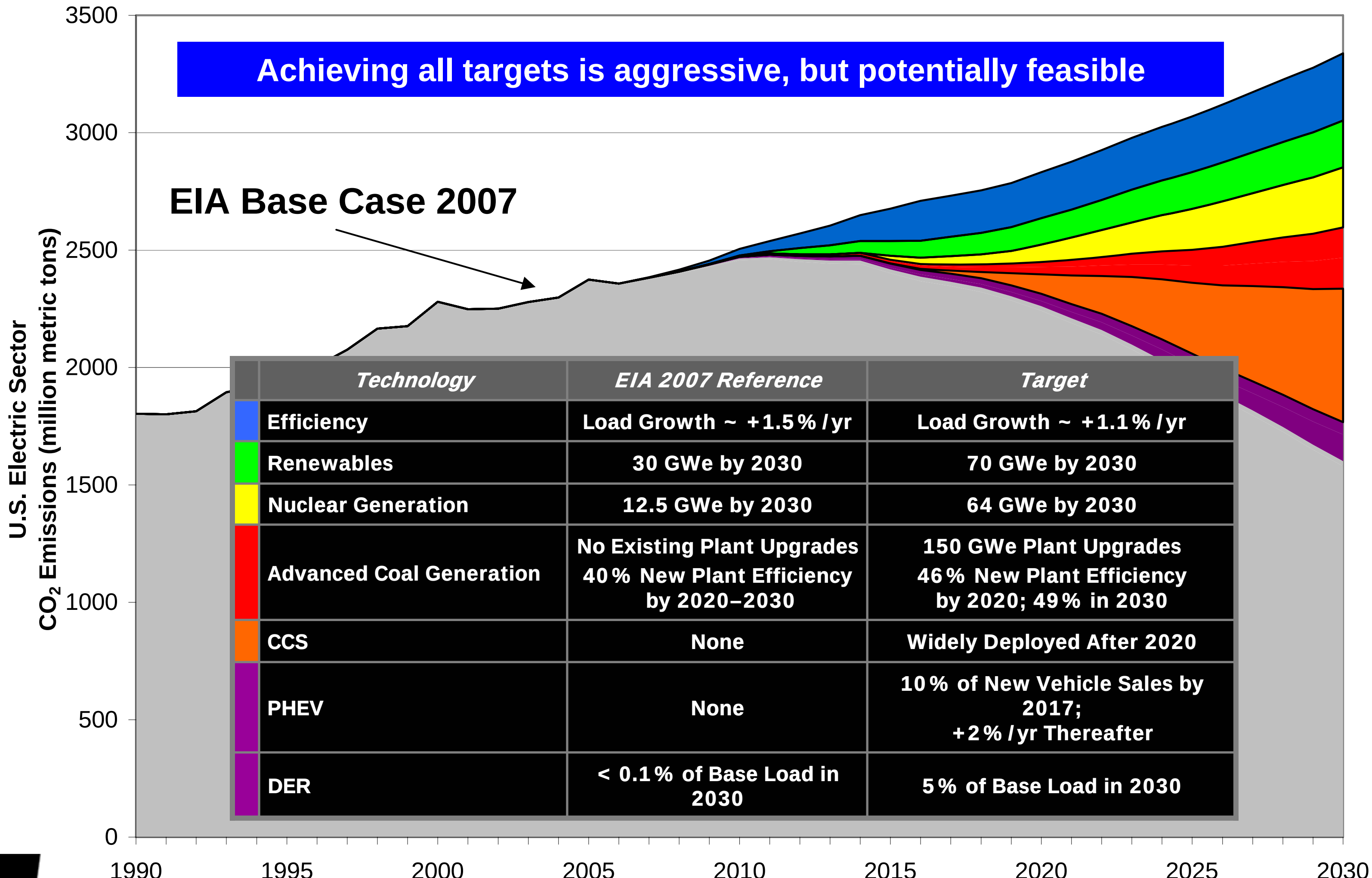
Annual AEP Cost Increases



The cost and rate impacts of Lieberman-Warner are very large, particularly due to increasing levels of auctions over time. <u>Auction purchases account for more than two-thirds of total costs.</u>

A Portfolio is Needed and CCS is Key



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

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EPRI ELECTRIC POWER RESEARCH INSTITUTE

AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

2009 Initial Operation

1300 MW Mountaineer Plant (WV) → MOU (Alstom & RWE) **Chilled Ammonia 20MWe scale**

CO_2 Storage (Battelle)

Captures and Stores ~100,000 metric tons of CO_2 /yr.

Phase 2

300 MW Slipstream → MOU (Alstom) **Chilled Ammonia ~300MWe scale**

CO_2 Storage

Captures and Stores 1.5 Million metric tons of CO_2/yr.

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The Challenge: CCS is Expensive

$50+

$/ton CO_2e

$0

- CCS w/ Geologic Sequestration
- Other renewable, advanced geothermal and/or solar
- Carbon Capture for Enhanced Oil Recovery
- New Biomass Generation
- Dispatch of additional gas vs. inefficient coal
- Biomass Co-firing
- Forestry
- New Wind
- Nuclear
- Energy Efficiency
- Methane Offsets

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AEP AMERICAN ELECTRIC POWER®

Bernstein Environmental Utilities Conference

New York, NY
April 5, 2011

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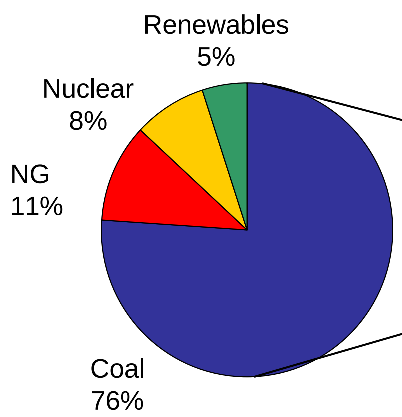

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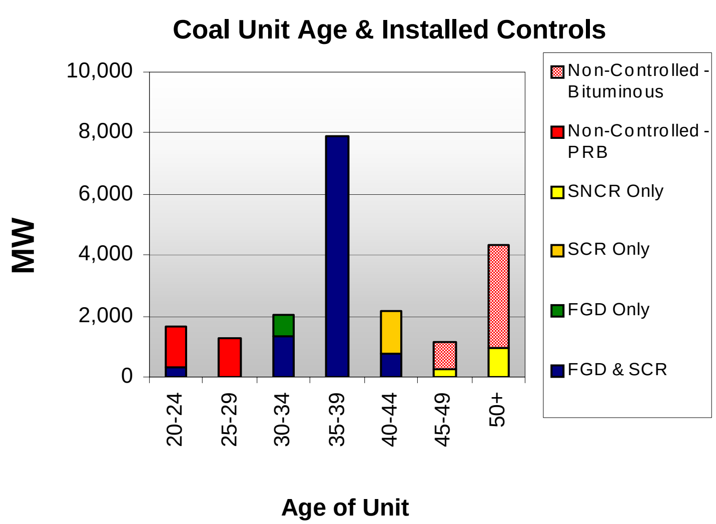
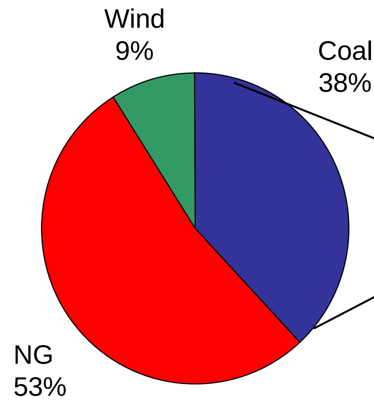


West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind



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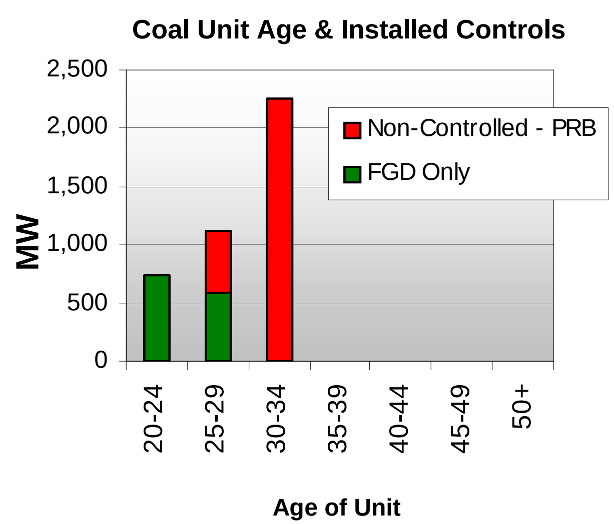
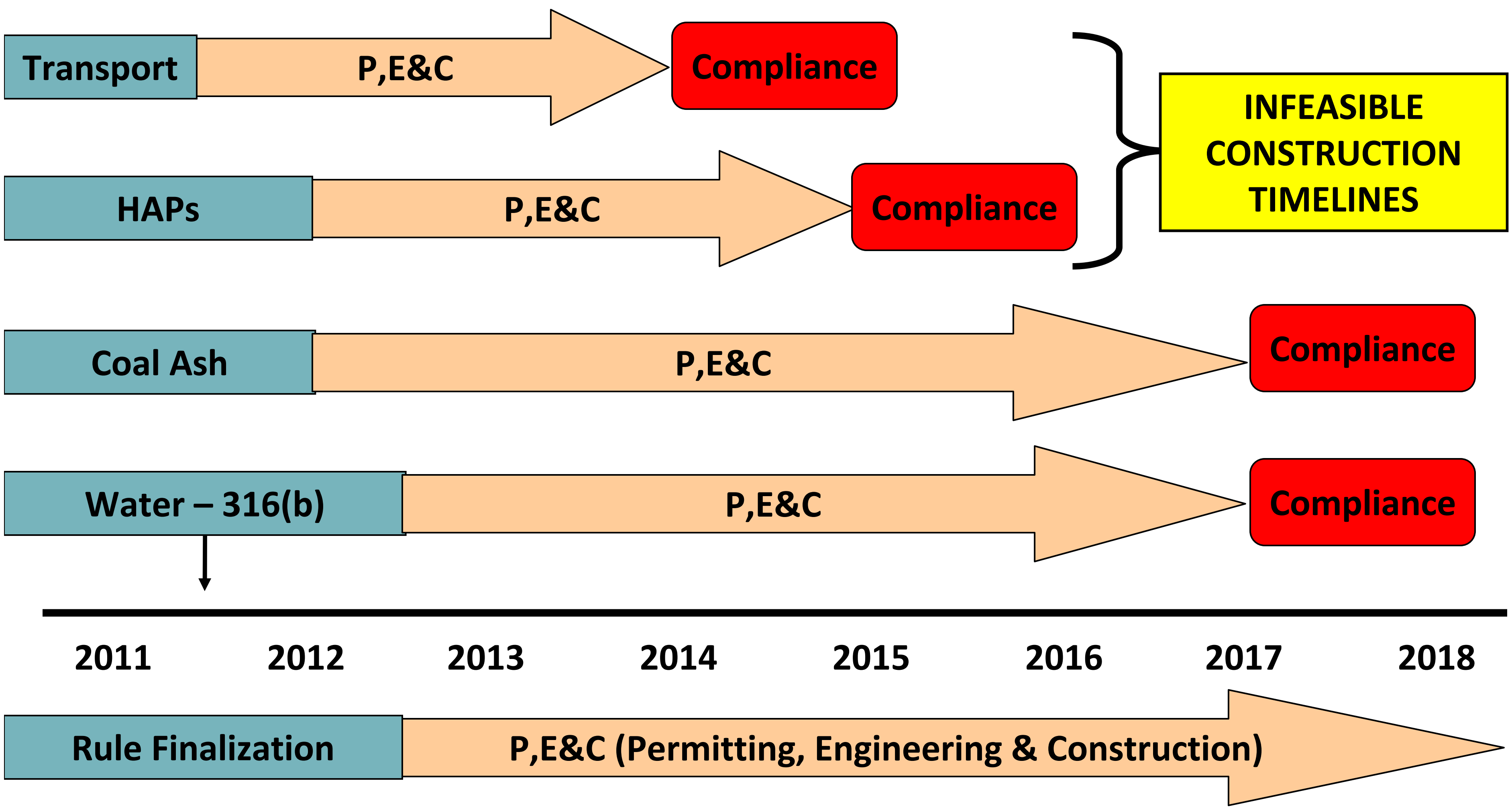


Anticipated EPA Timeline for Retrofits or Replacement



Transport Rule (SO_2 and NOx)

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

Mercury and HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub-categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

Coal Ash (CCR) Rules

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - "Non-hazardous", solid waste - action required by ~2017
  - "Special" hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- "Hazardous" option could cost DOUBLE this amount

316(b) Proposal

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until a site-specific study is conducted
- Cost impact very uncertain at this time

Implications

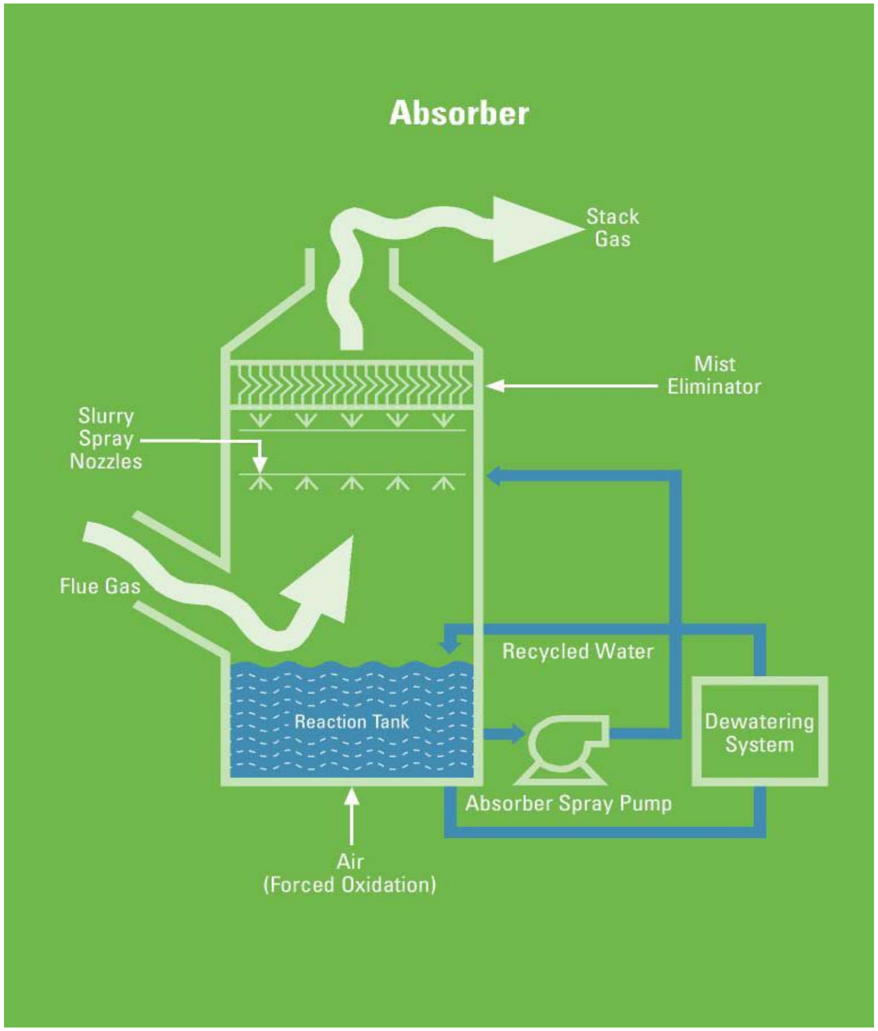
- Implementation Schedule
- Costs
- Labor Availability
- Retirement Decisions
- Electric System Reliability
- Others?

Questions?

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3333 of 9556

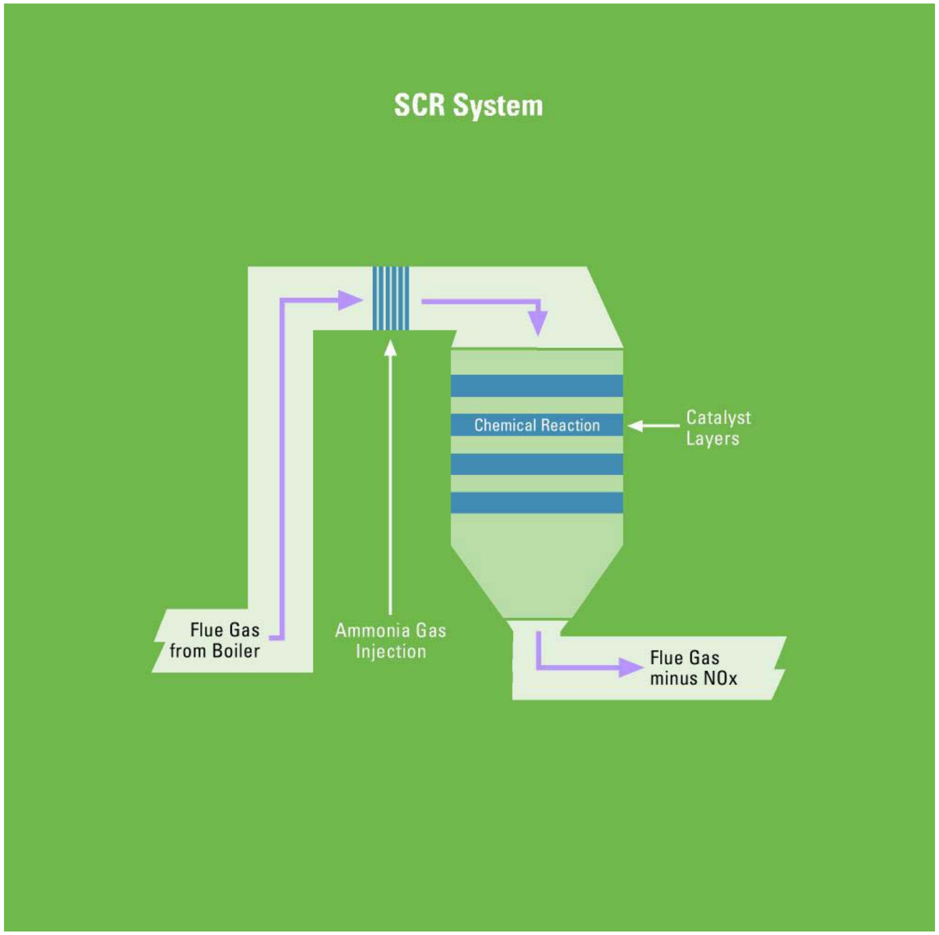
APPENDIX

How an FGD Works



- Limestone is fed from the silo and crushed in the ball mill
- Crushed limestone is mixed with water to form a slurry
- Exhaust gas is routed through absorber vessels where it is sprayed with the slurry
- SO_2 reacts with the slurry and forms calcium sulfate or gypsum
- The calcium sulfate falls to the lower part of the vessel
- Blowers inject air to force oxidation of the product
- Hydroclones wring out much of the water to produce gypsum: the water is re-circulated

How an SCR Works



- Urea, a harmless compound often used as fertilizer, is mixed with water
- Steam is used to drive the ammonia gas from the urea mixture
- The ammonia gas is piped into the flue gas ahead of the SCR
- The ammonia reacts with the flue gas as it passes over the catalyst, forming nitrogen gas and water vapor
- The harmless nitrogen and water vapor are released into the atmosphere

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

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Sanford Bernstein & Clients Office Visit
Columbus, OH
March 7, 2011

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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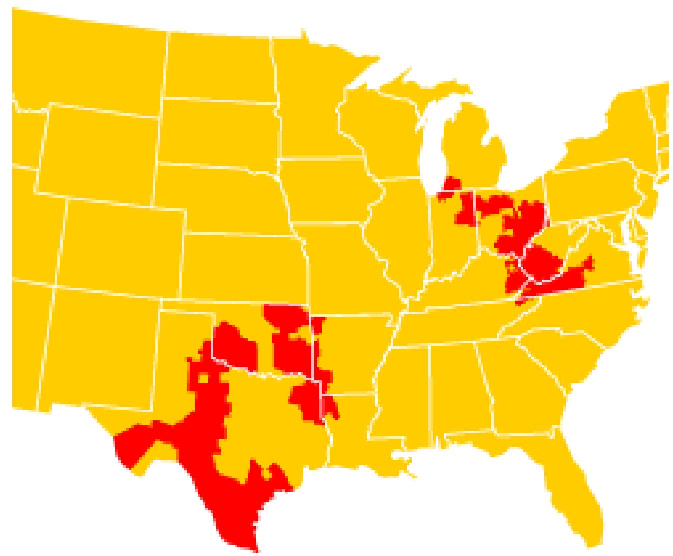
American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



AEP Fast Facts

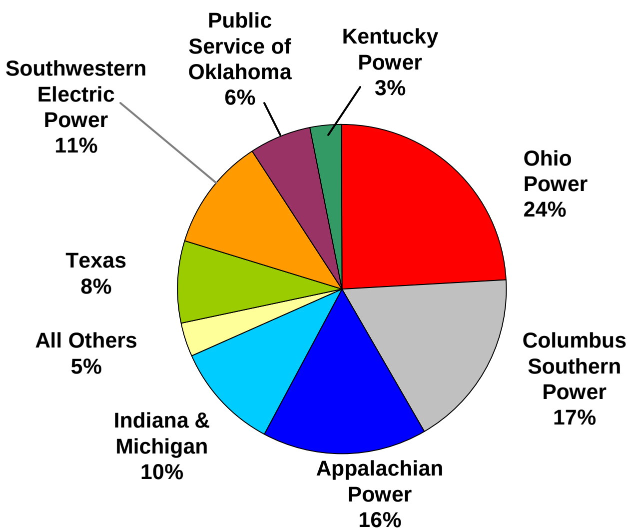
5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$17B Market Capitalization
BBB/Baa2/BBB credit rating

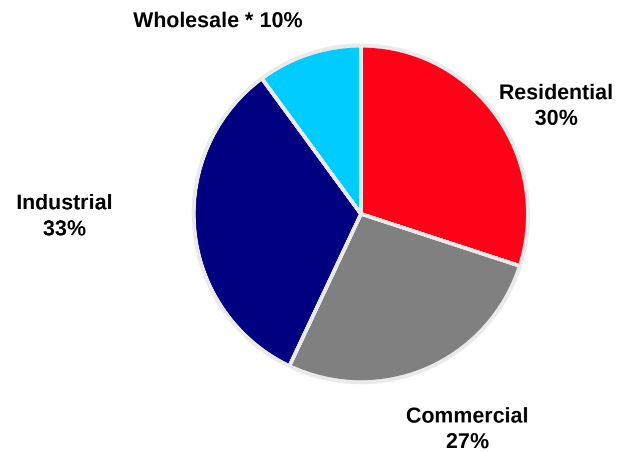
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



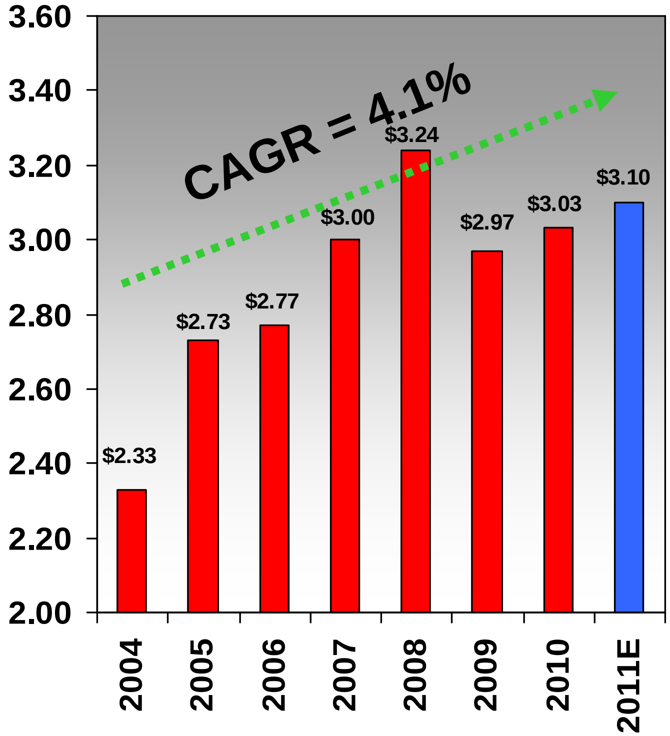
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

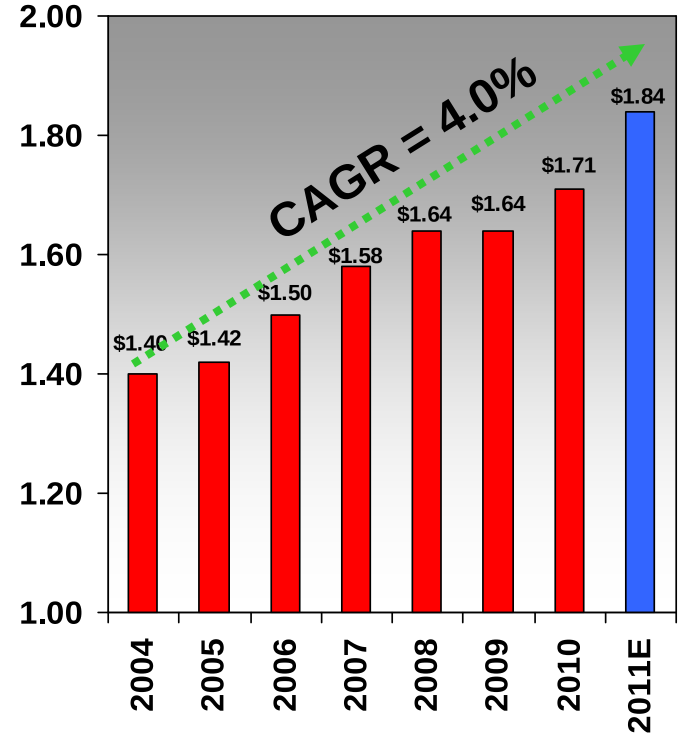
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



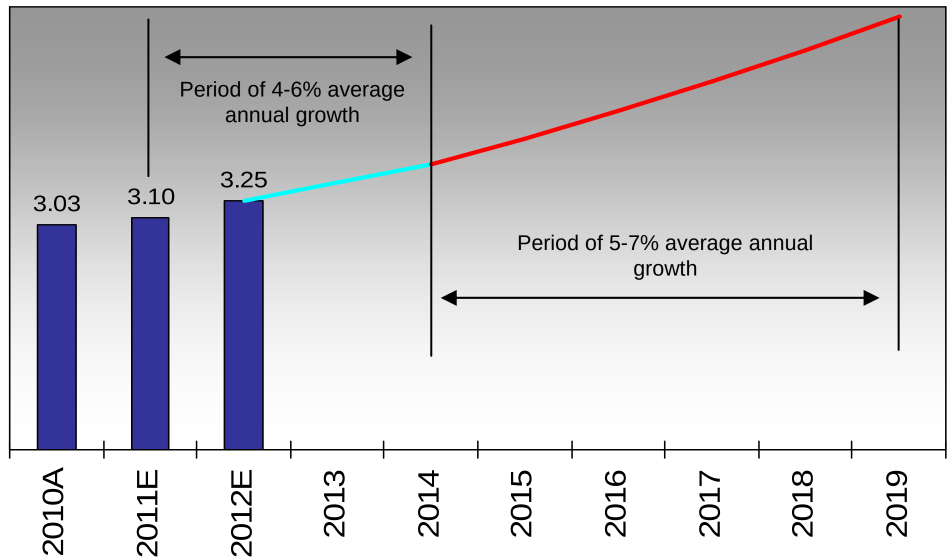
= subject to Board of Directors approval

- Dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend declared in January 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Detailed Ongoing Earnings Guidance

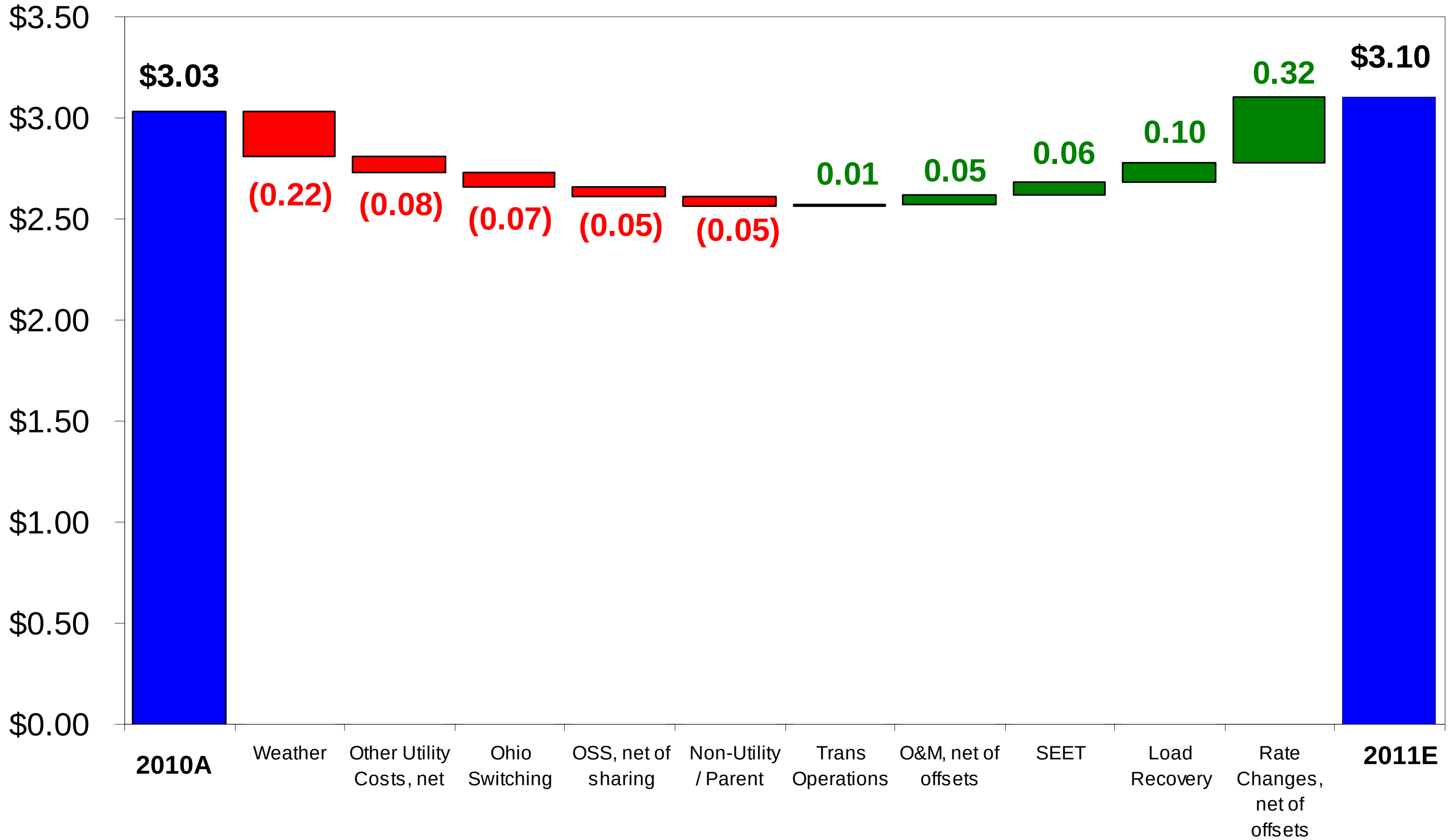
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

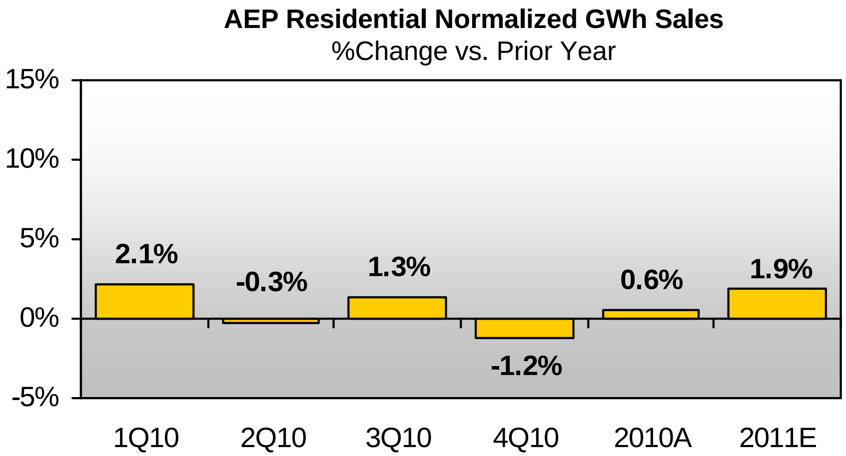
2011 Earnings Drivers

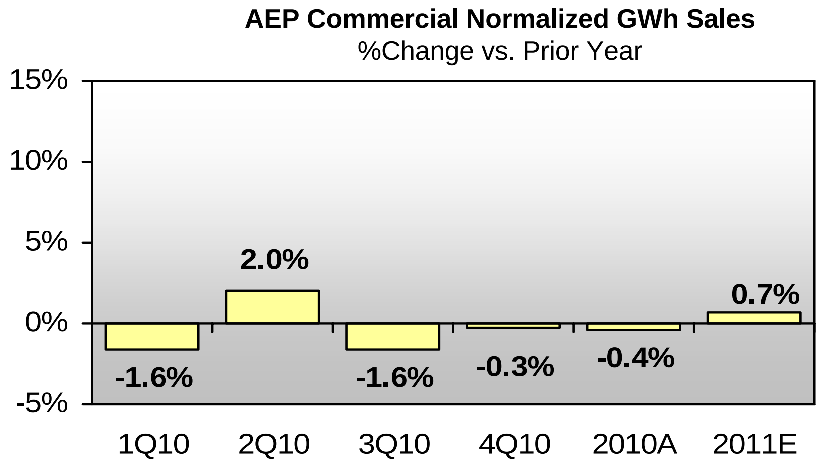


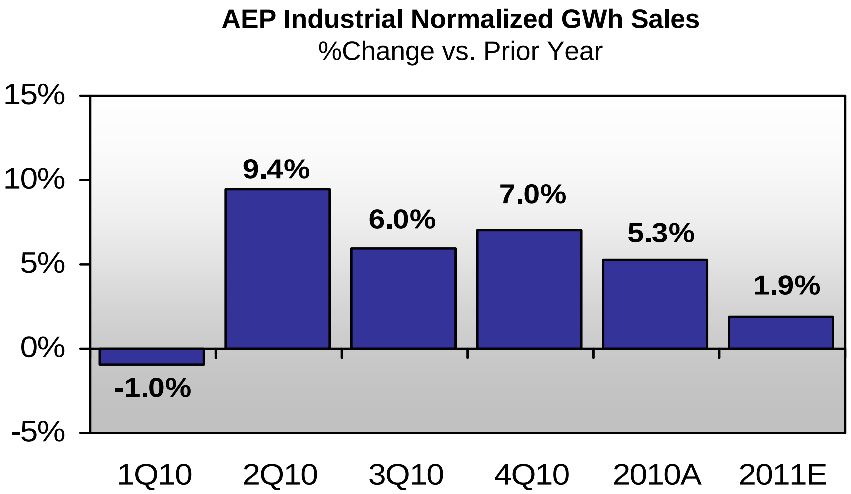
- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

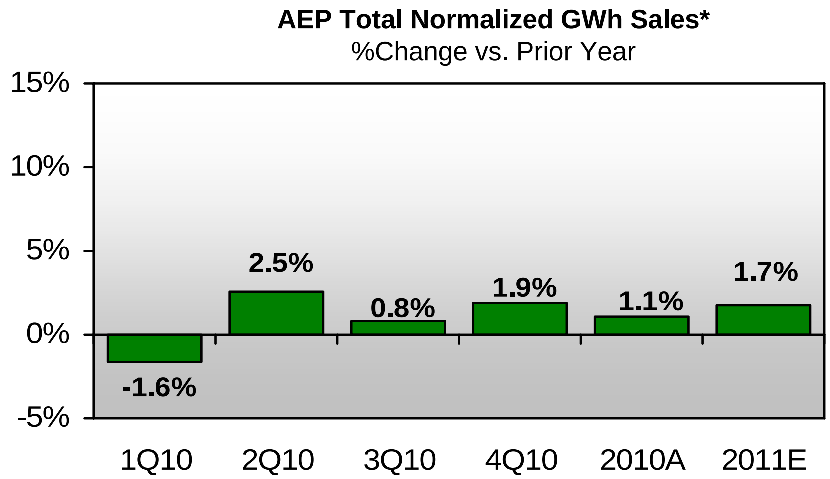
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends









*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

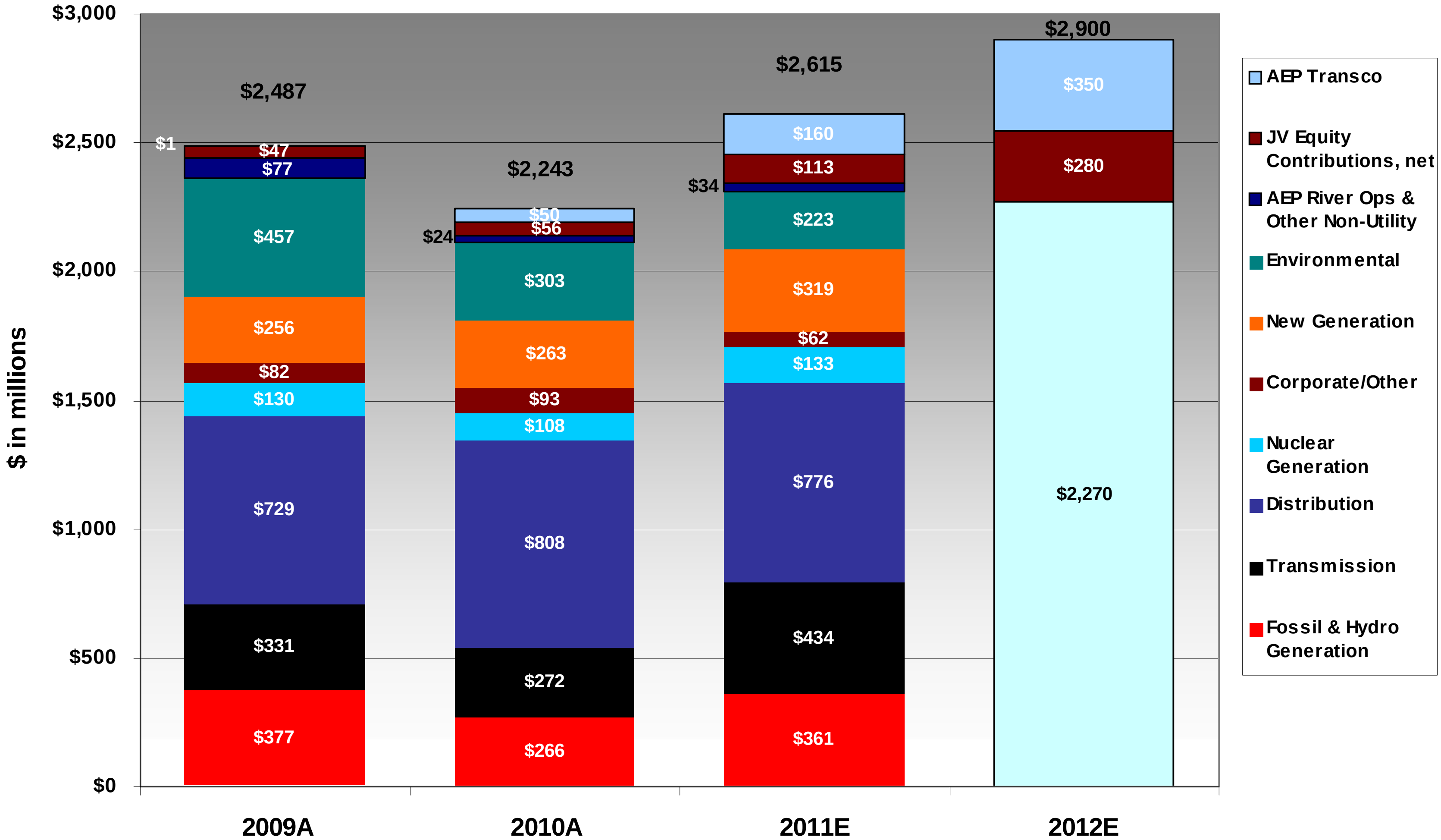
$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

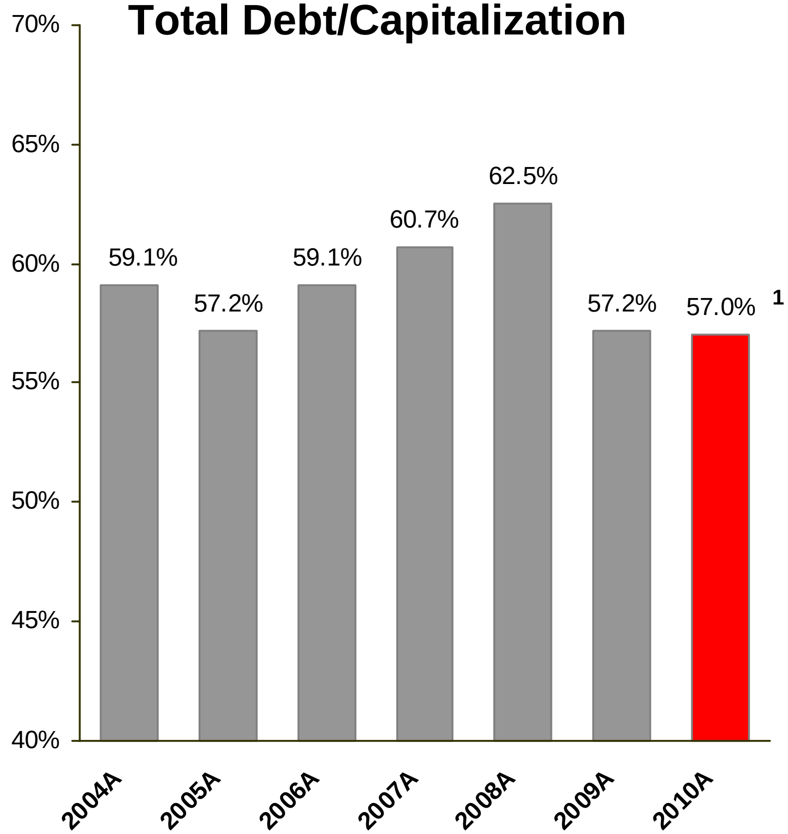
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Capitalization & Liquidity

Total Debt/Capitalization



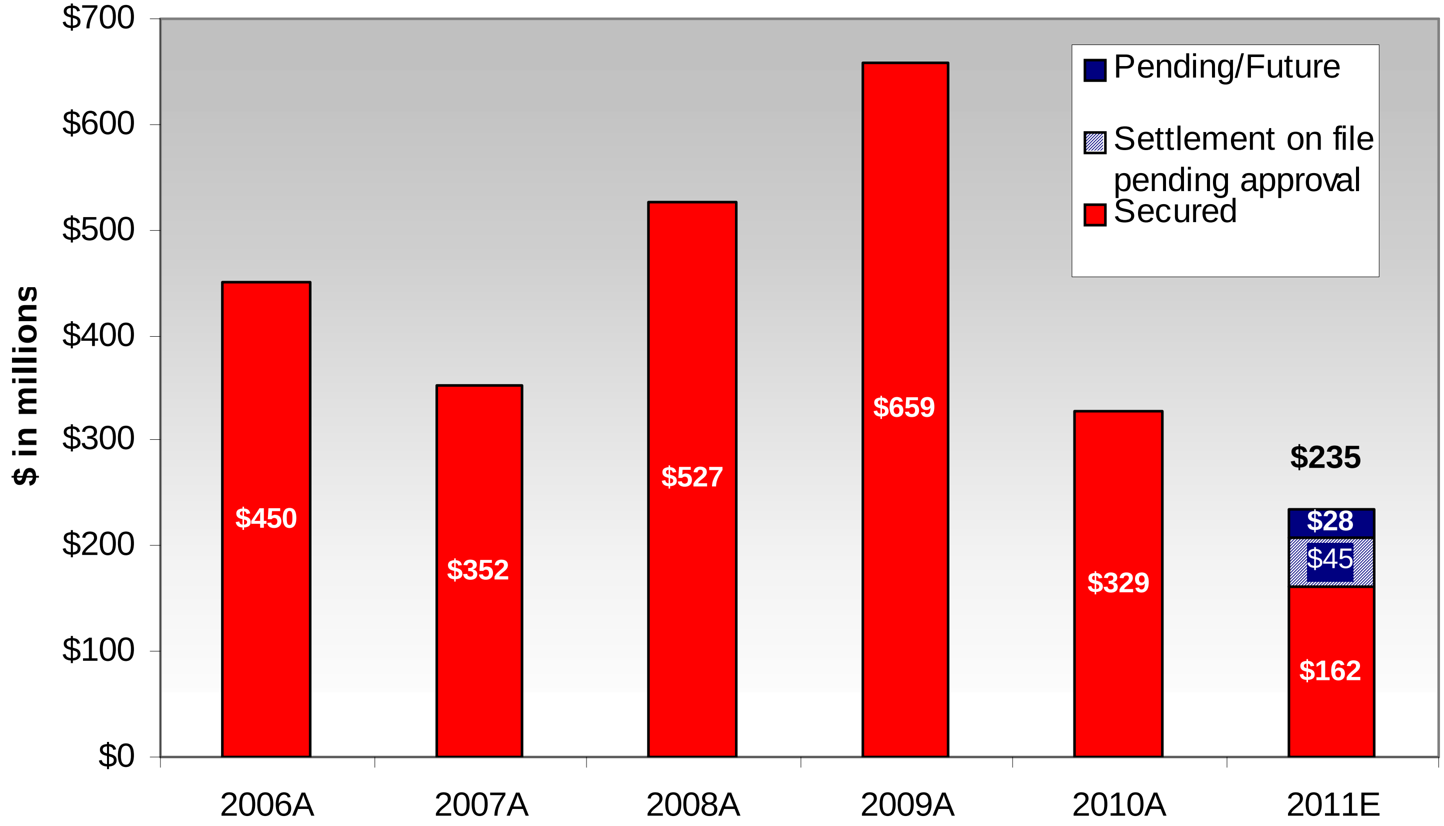
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

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AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

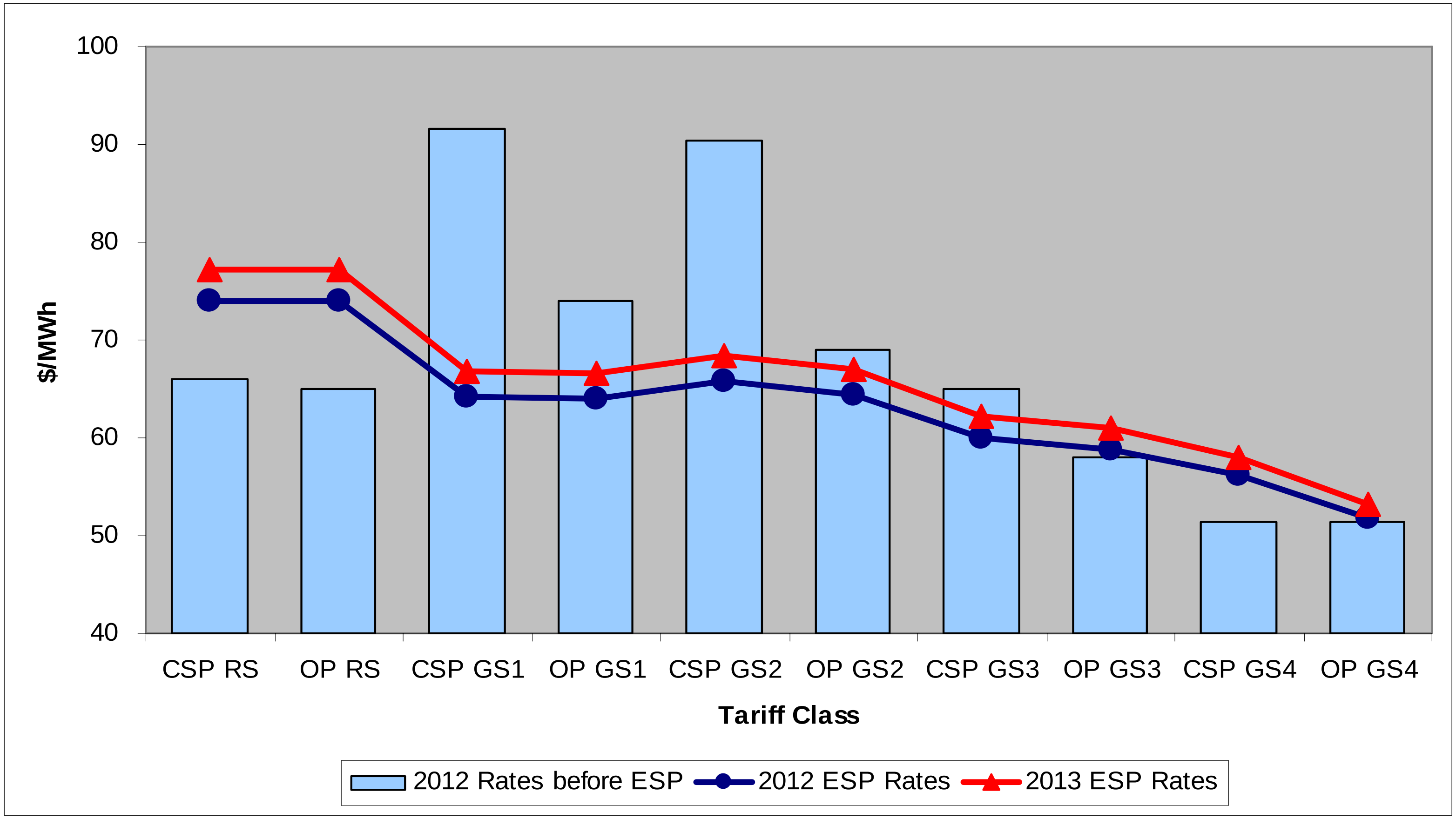
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

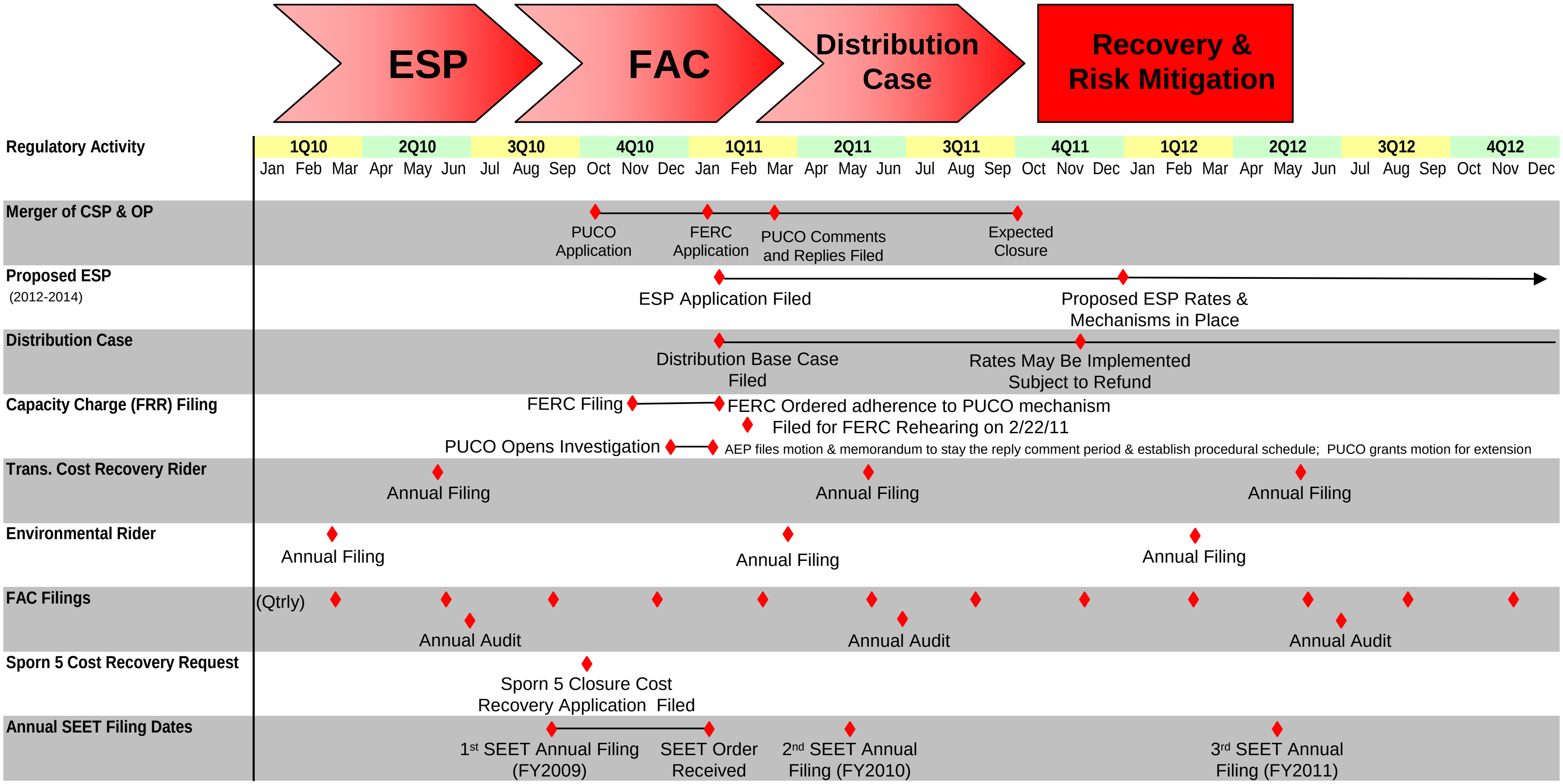
List of ESP Riders – Existing and Proposed

AEP®

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline

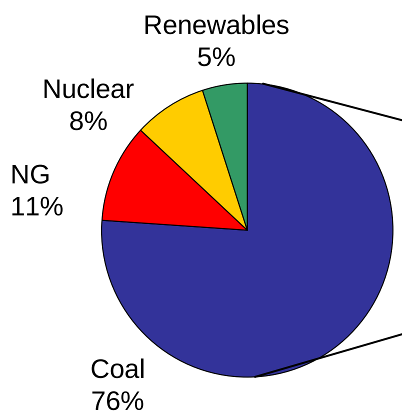
AEP®



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

AEP Generation Capacity

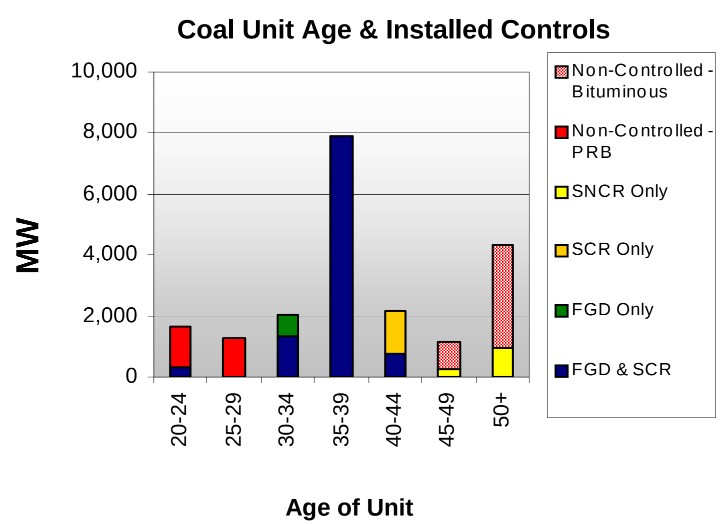
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



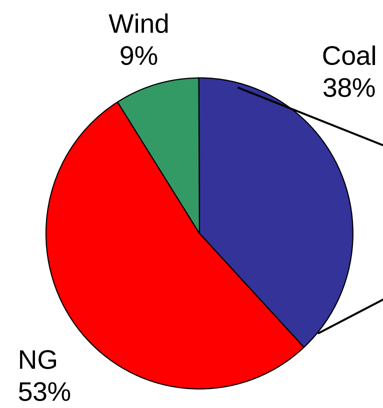
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



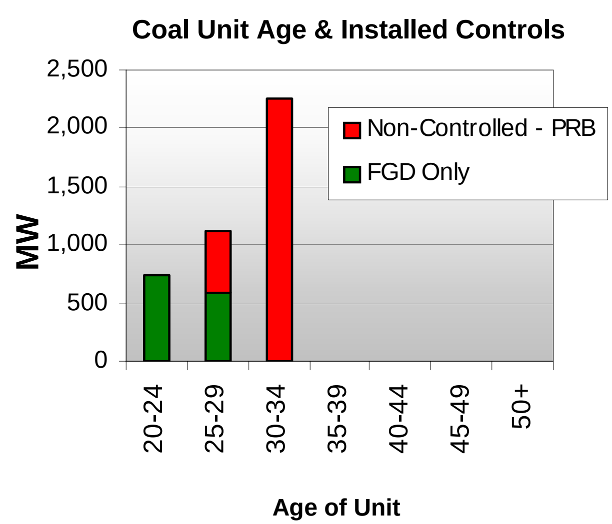
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

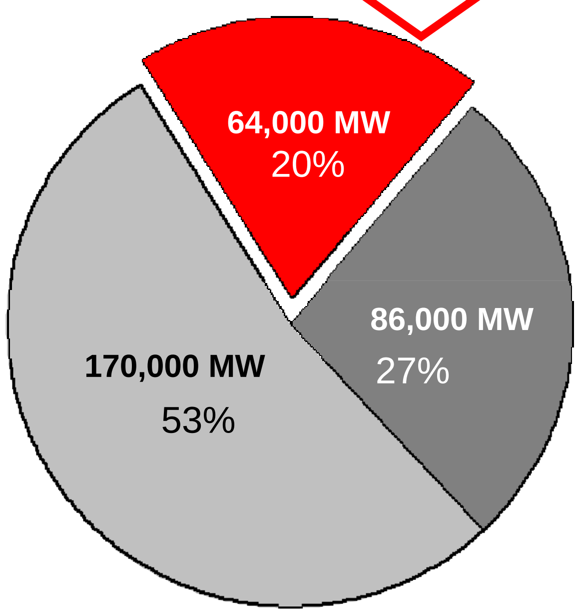


Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

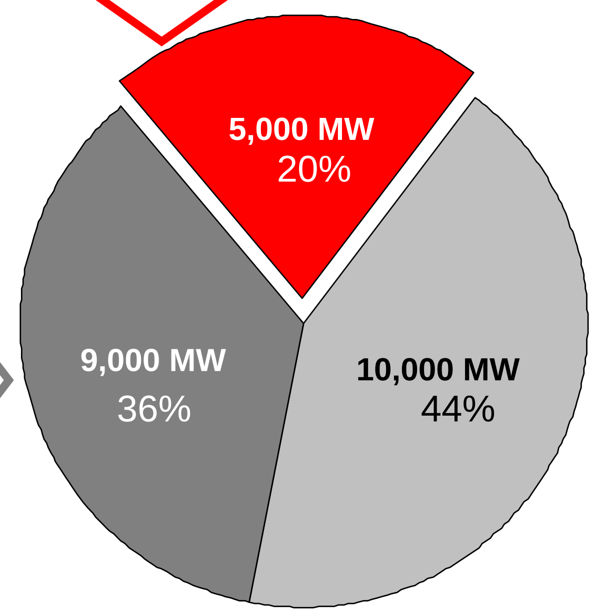
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements

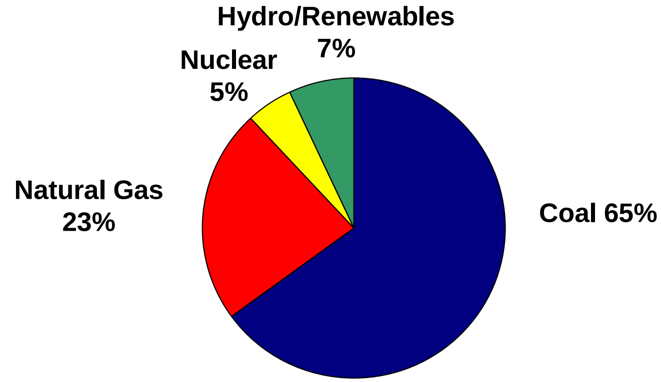


AEP Coal

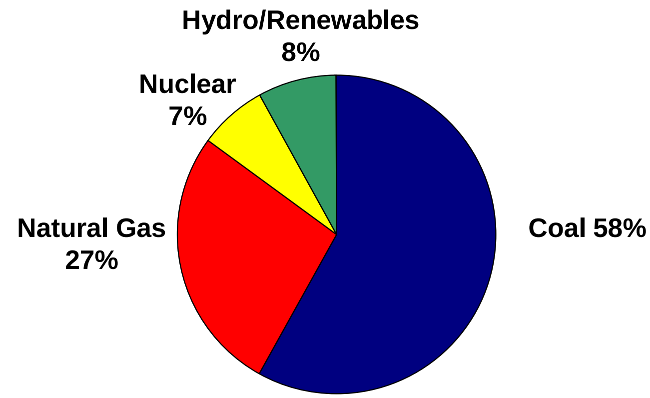
Nearly 50% of U.S. coal plants are exposed

Continued Investment in Utility Platform

- ❑ Plan for old, small coal units
  - – Initially operate seasonally
  - – Transition towards retirement
  - – Regulatory plan for recovery
- ❑ Continue evaluation of “partially exposed” units for additional controls
- ❑ Add non-coal capacity when needed
  - – Dresden NGCC (partially complete)
  - – New NGCC at existing site
  - – Cook plant uprate (under study)
  - – Renewables
- ❑ Deploy technology as appropriate
  - – Continue pursuit of CCS technology
  - – Energy storage technologies
  - – gridSMART®



Capacity - 2010



Projected Capacity - 2017

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions us as one of the key AEP growth businesses.

Texas Transmission Growth Strategy :Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

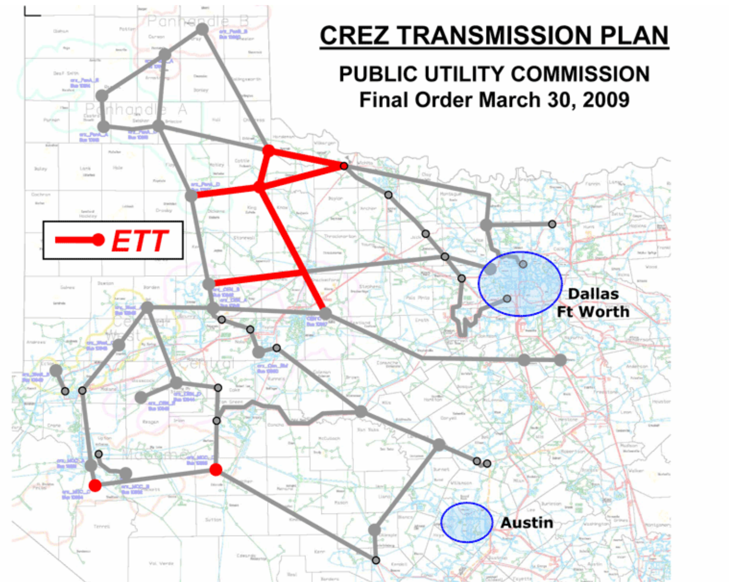
Current rate base is $385 million; expected to grow as follows:

2010: $405 million
2011: $465 million
2012: $765 million
2013: $1,415 million

Interim TCOS filings twice per calendar year

Line Miles: 110

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Transco Update

- $160 million capital spend forecasted for 2011

Filing Status Update

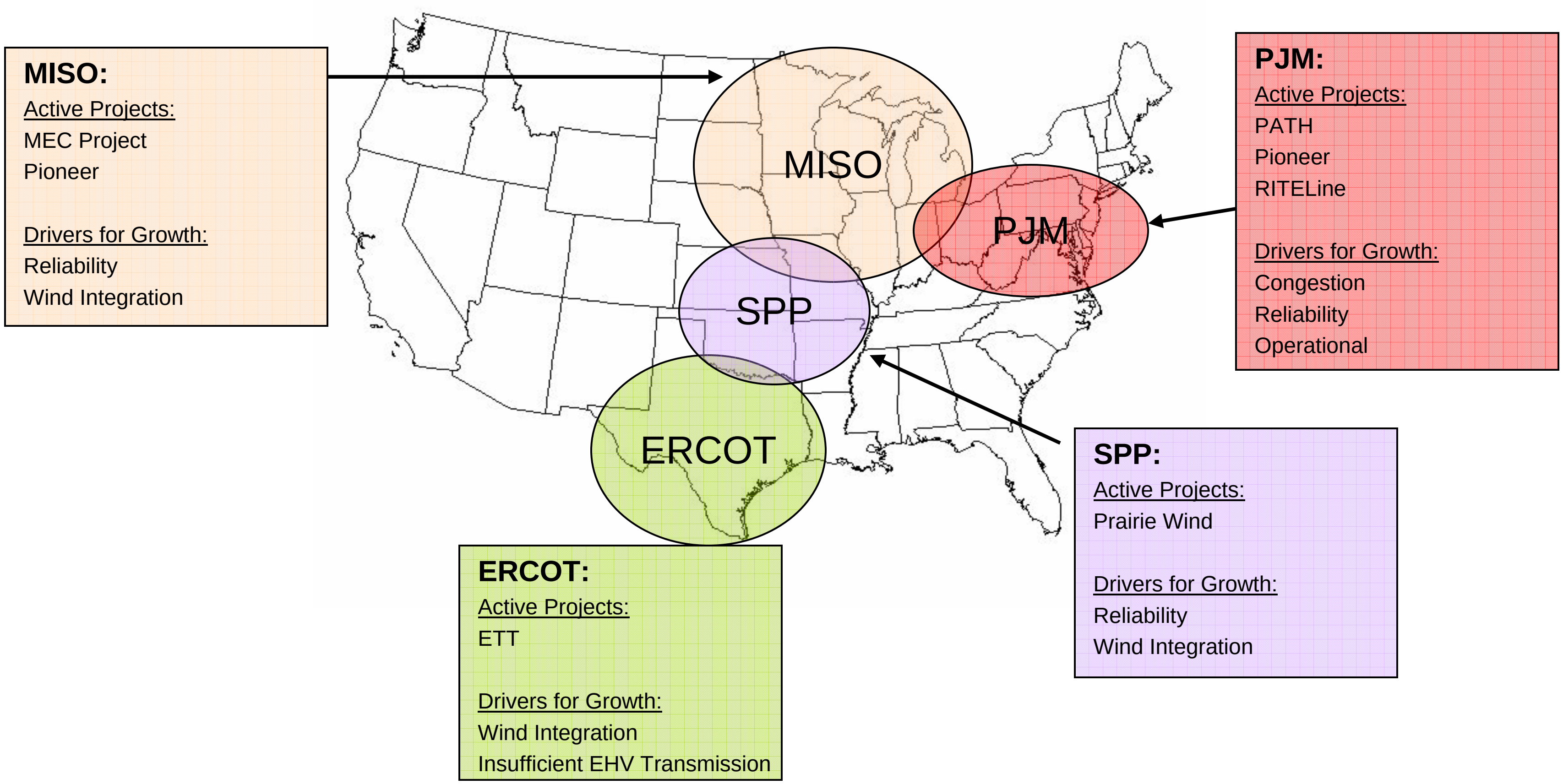
- *Ohio (filed)* – PUCO approved the Ohio Transco December 29, 2010
- *West Virginia (filed)* – Procedural schedule is set, with company testimony filed January 6, 2011; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June 2011
- *Arkansas and Louisiana* - Filing date in Arkansas likely early 2011
- *Texas-SPP* - Expecting TX filing in mid 2011
- *Kentucky* – Informal Conference with staff held March 2, 2011
- *Indiana* – Met with IURC January 10, 2011 on Transmission matters, plan to file in March 2011
- *Virginia (withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- *Michigan and Oklahoma* - Do not require state filing

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT



AMERICAN ELECTRIC POWER

Sanford Bernstein

Strategic Decisions Conference

New York, NY

May 27, 2009

STRONG

FLEXIBLE

ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

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AMERICAN ELECTRIC POWER

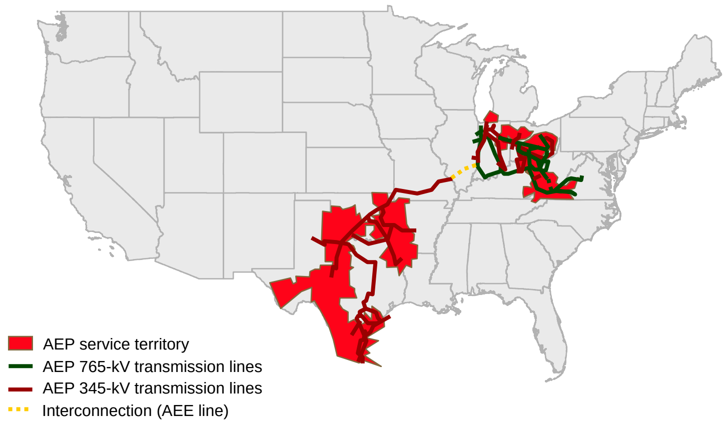
AEP Highlights

Premier utility platform	■ Leadership position in electric generation, transmission and distribution operations ■ Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states ■ $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth
Effective regulatory relationships	■ Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow ■ Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability) ■ Constructive local relationships deliver successful regulatory outcomes
High-growth transmission business	■ The leading US transmission owner, operator, and developer ■ Exceptional portfolio of high-quality development projects and project partners ■ Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint
Stable financial position	■ Maximization of shareholder value through regulated utility and transmission investments ■ Balanced approach to cost containment and capital allocation ■ Commitment to investment grade profile, prudent balance sheet, and liquidity management ■ Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

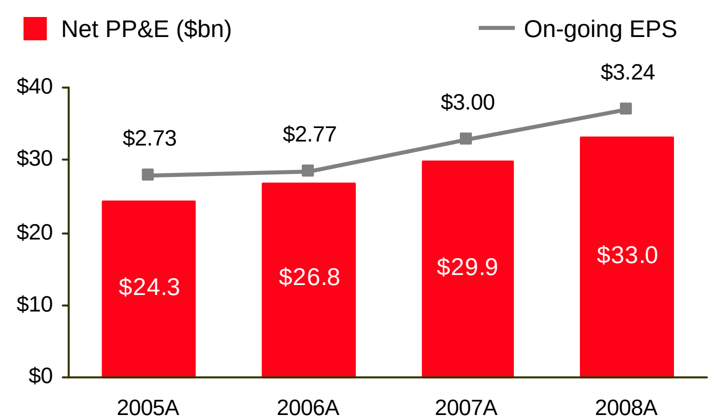


AEP's Leadership Position

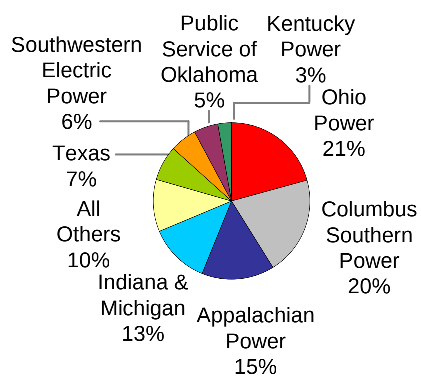
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

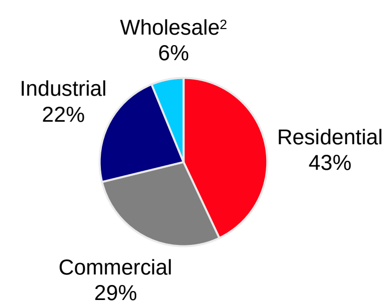
Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- Highly diversified regulated utility earnings contribution
- Balanced customer mix

[1] Source: Company filings
[2] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

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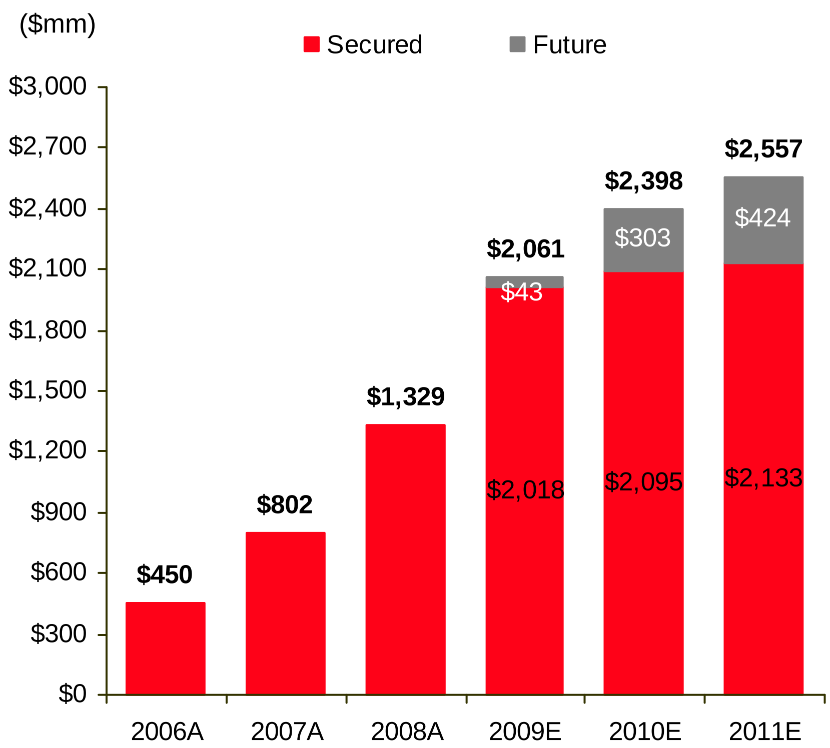
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] *$77mm and $38mm was secured for 2010 and 2011, respectively, as of May 15, 2009*

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

AMERICAN ELECTRIC POWER

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN
FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Regulatory Activity Underway

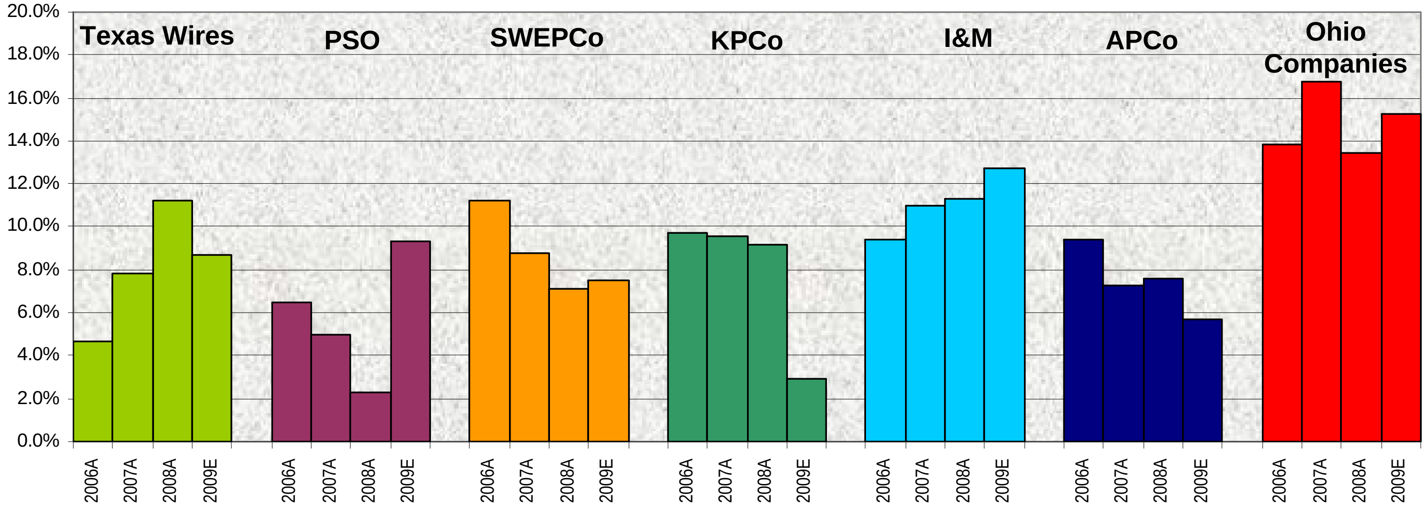
APCo-Virginia E&R Filing

On May 15, 2009, Appalachian Power filed the fourth and final tranche of E&R surcharge filings with the SCC, requesting a $41.6 MM increase for environmental and reliability costs incurred during the period January 1, 2008 through December 31, 2008, with a proposed one year recovery period commencing January 1, 2010. No procedural schedule has been set by the SCC.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	07/01/2004 thru 09/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/01/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008- 00045	10/01/2006 thru 12/31/2007	01/01/2009 thru 12/31/2009	$60.6 million
IV	PUE-2009-00039	01/01/2008 thru 12/31/2008	Proposed 01/01/2010 thru 12/31/2010	$41.6 million

Pro-Forma Earned ROE & Net Income by Operating Company

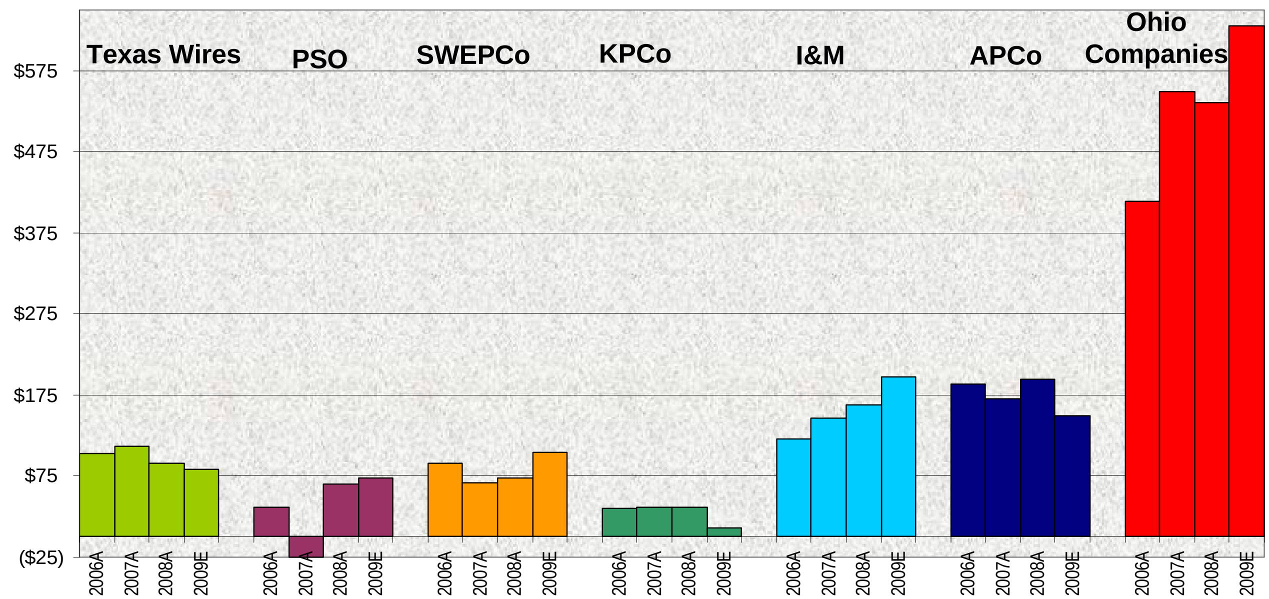


Pro-Forma Earned ROEs

Earned ROEs represent 12 months ended December 31. Regulatory Lag ranges from 3-15 months by jurisdiction.

Net Income by Operating Company

($ in millions)



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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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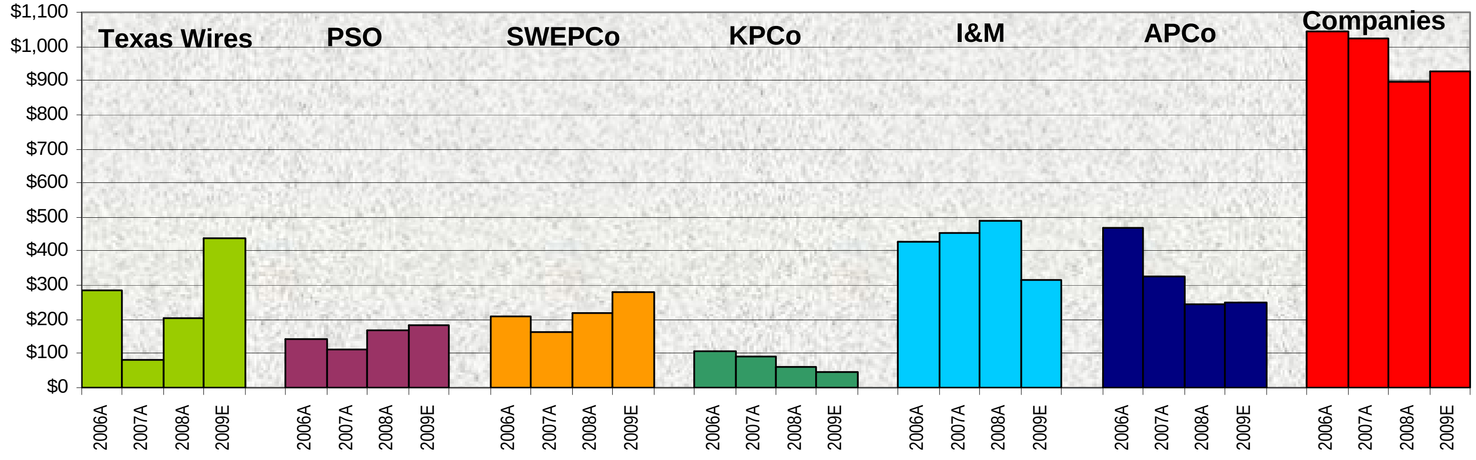
Cash Flow and Capex by Operating Company

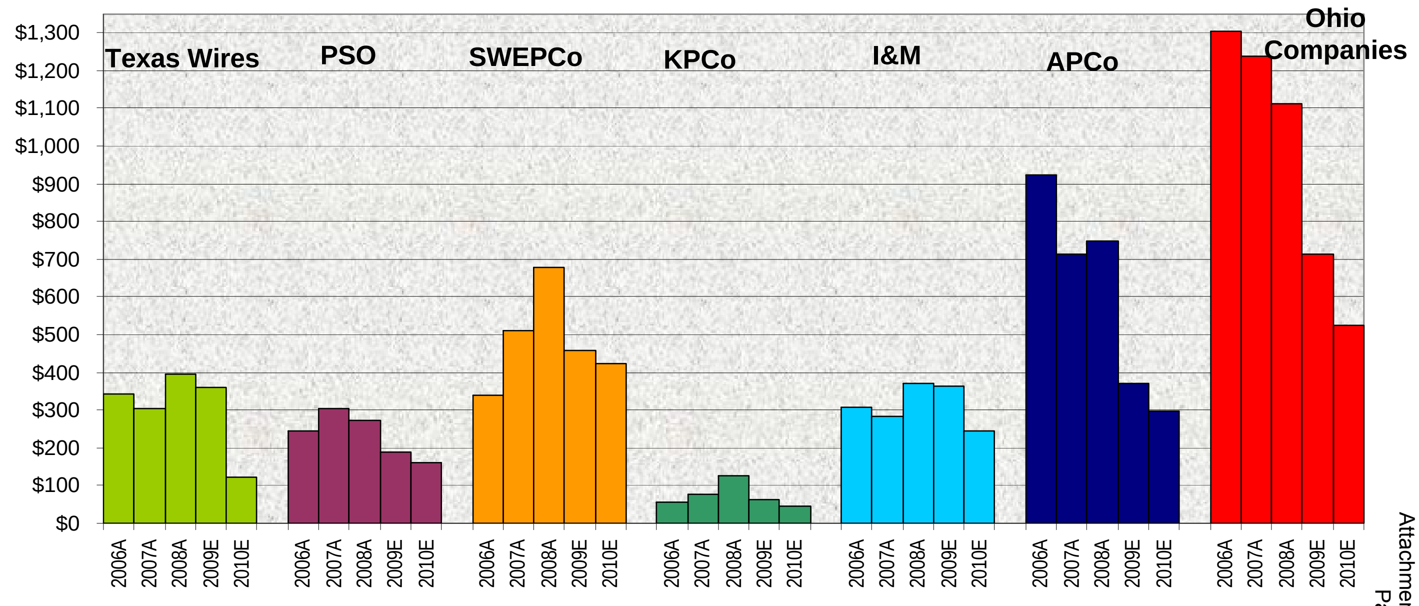


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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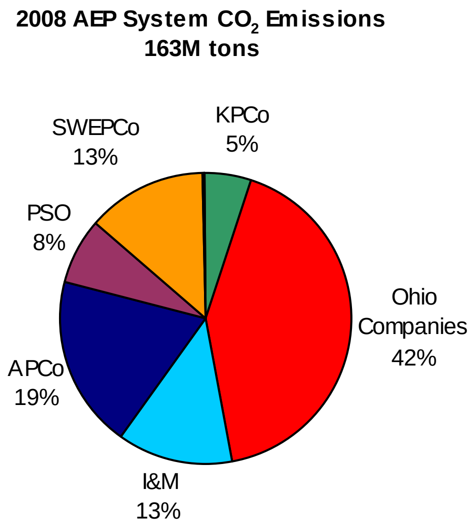
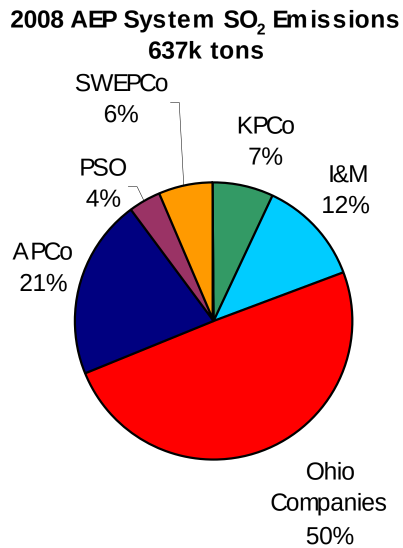
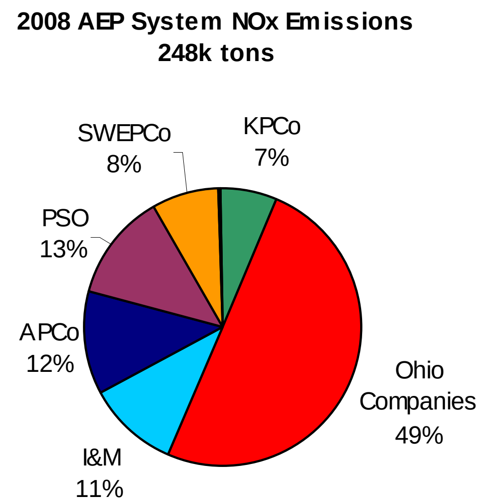
CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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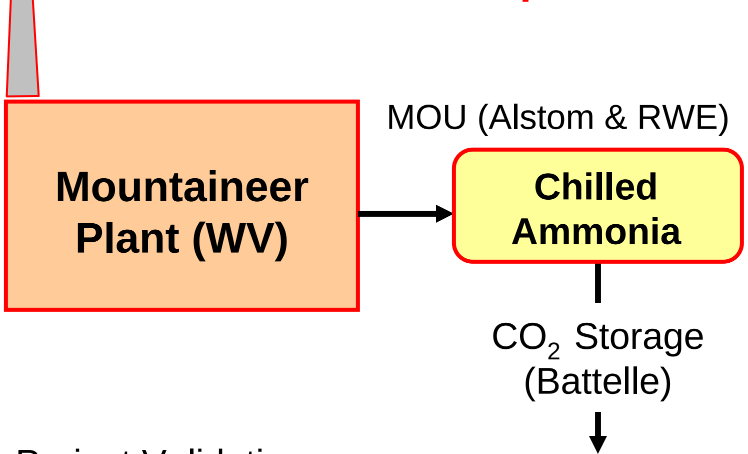
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- **Alstom “Chilled Ammonia” Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies’ Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the ‘economic’ hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – AEP self-reported impacts to jurisdictional wetlands in March 2009. Work continues outside the jurisdictional areas. Hearing on the air permit appeal is scheduled for June 2009.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

DC Cook Unit 1 Update

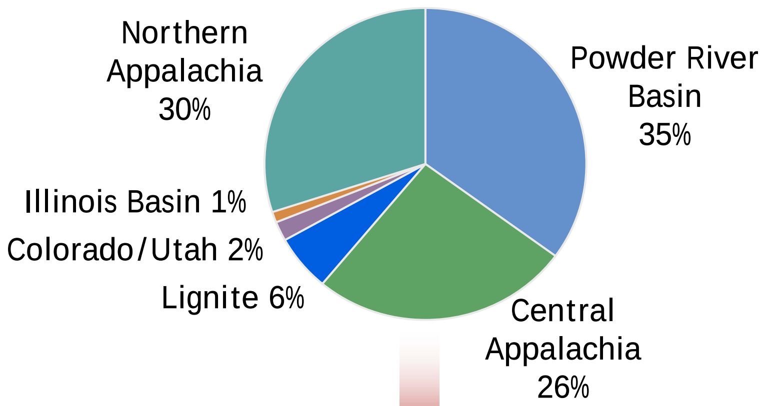
- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

AEP AMERICAN ELECTRIC POWER

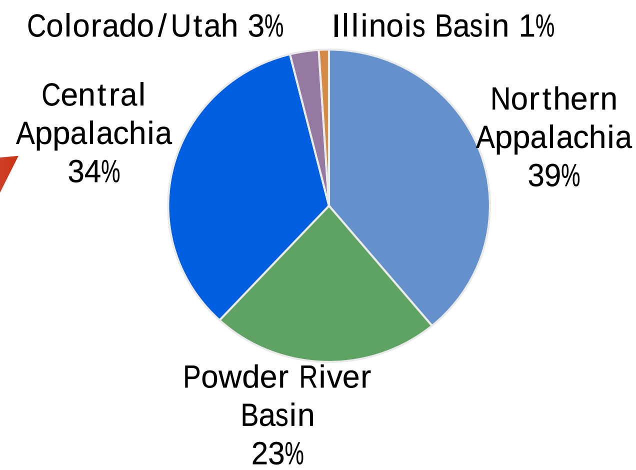
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

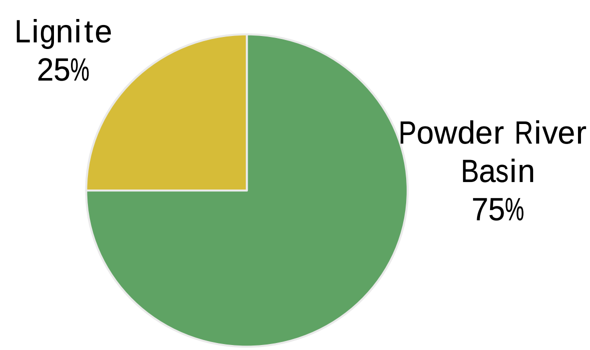
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

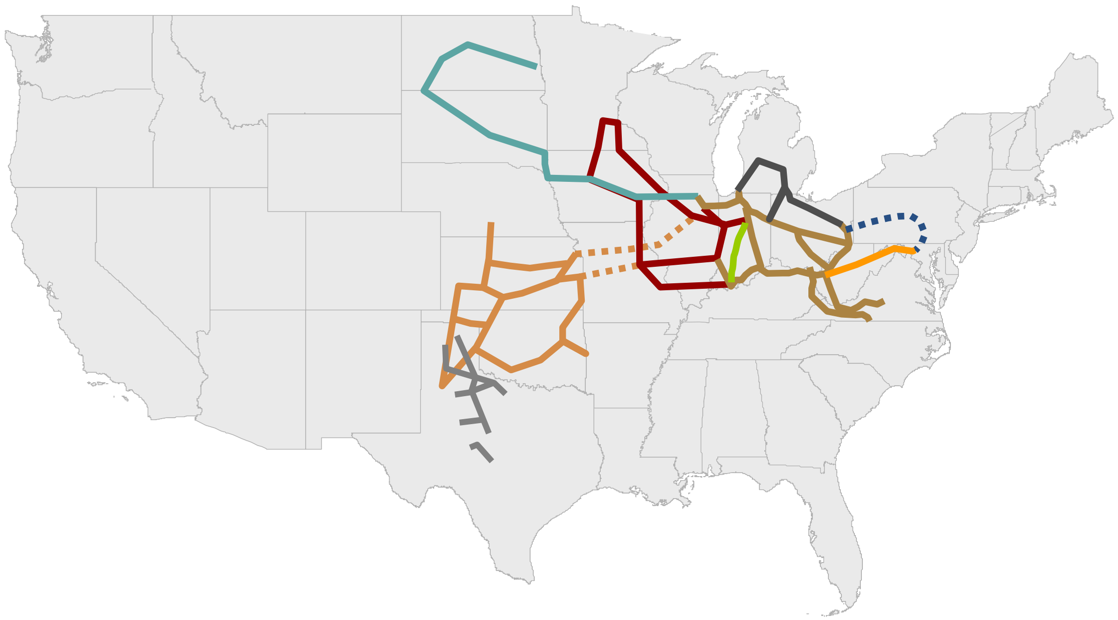
Pioneer	COD: 2015
240 miles of 765 kV	
Partner: Duke Energy (50%)	
Estimated Cost: $1 billion	
ROE: 12.54%	

PATH-WV	COD: 2014
275 miles of 765 kV	
Partner: Allegheny Energy (50%)	
Estimated Cost: $1.2 billion	
ROE: 14.3%	

Tallgrass	COD: 2013-14
170 miles of 765 kV	
Partners: OG&E (50%) & MidAmerican Energy (25%)	
Estimated Cost: $500 million	
ROE: 12.8%	

Prairie Wind	COD: 2013-14
230 miles of 765 kV	
Partners: Westar Energy (50%) & MidAmerican Energy (25%)	
Estimated Cost: $600 million	
ROE: 12.8%	

ETT	COD: 2013
345 kV in ERCOT	
Partner: MidAmerican Energy (50%)	
Estimated Cost: $400 million	
ROE: 9.96%	



Future Projects:

EHV Michigan	COD: ~2020
700 miles of 765 kV	
Partner: ITC	

PJM Projects	
Enhance existing 765/345 kV	

Hartland	COD: ~2020
1000+ miles of 765 kV	
Partner: Hartland Wind LLC	

MISO Vision Plan	
765 kV Backbone	

SPP Overlay	COD: 2013-14
765 kV Backbone	

ETT	COD: ~2018
345 kV in ERCOT	
Additional CREZ spend of $750-$850 million	

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

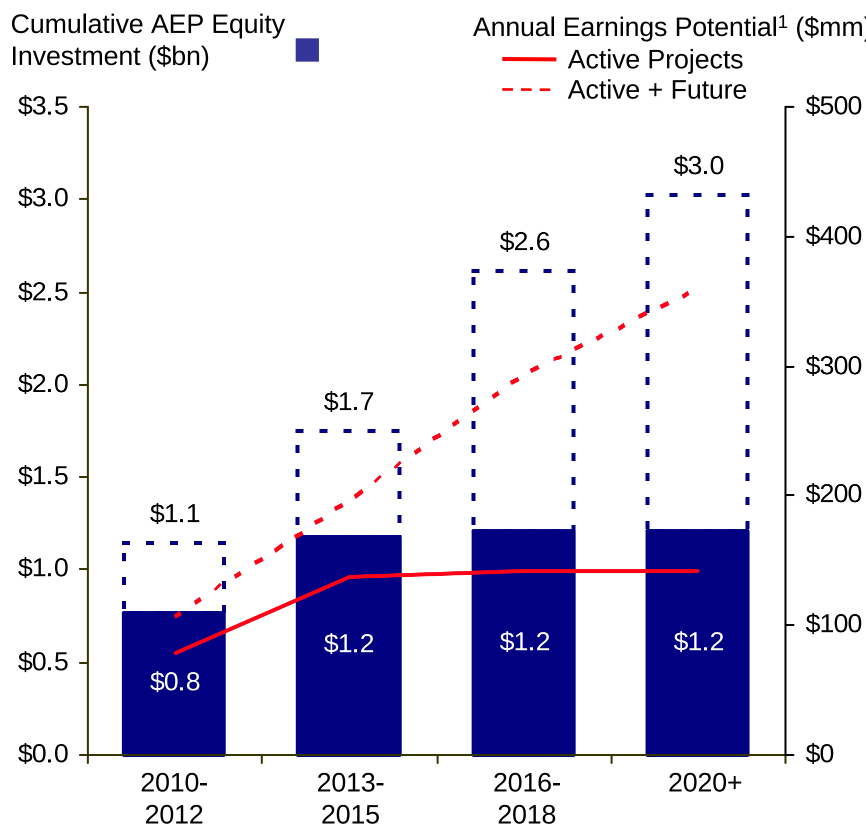
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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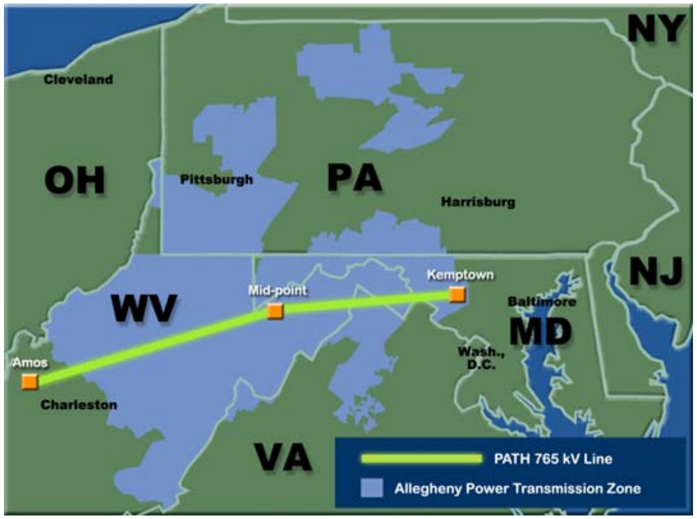
EHV Transmission in PJM: PATH

<u>Project Description:</u> 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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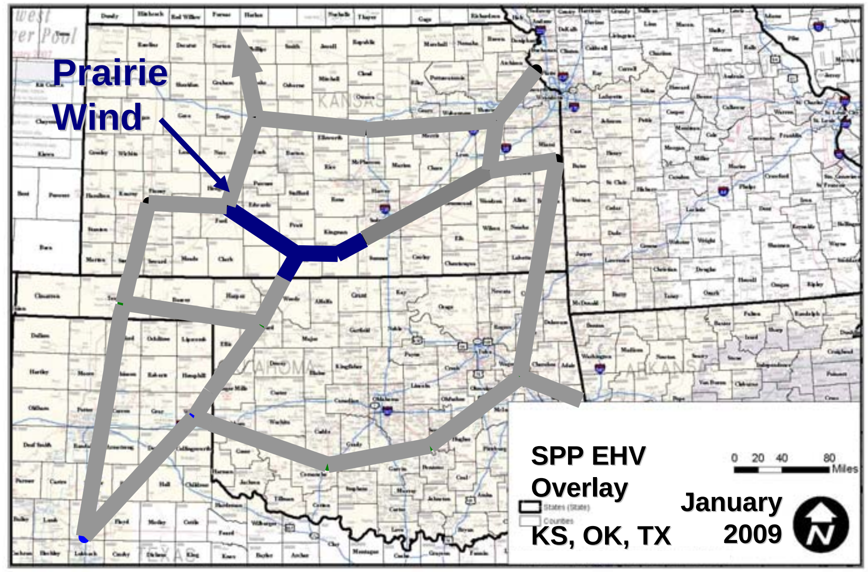
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3387 of 9556

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Competing ITC Great Plains project

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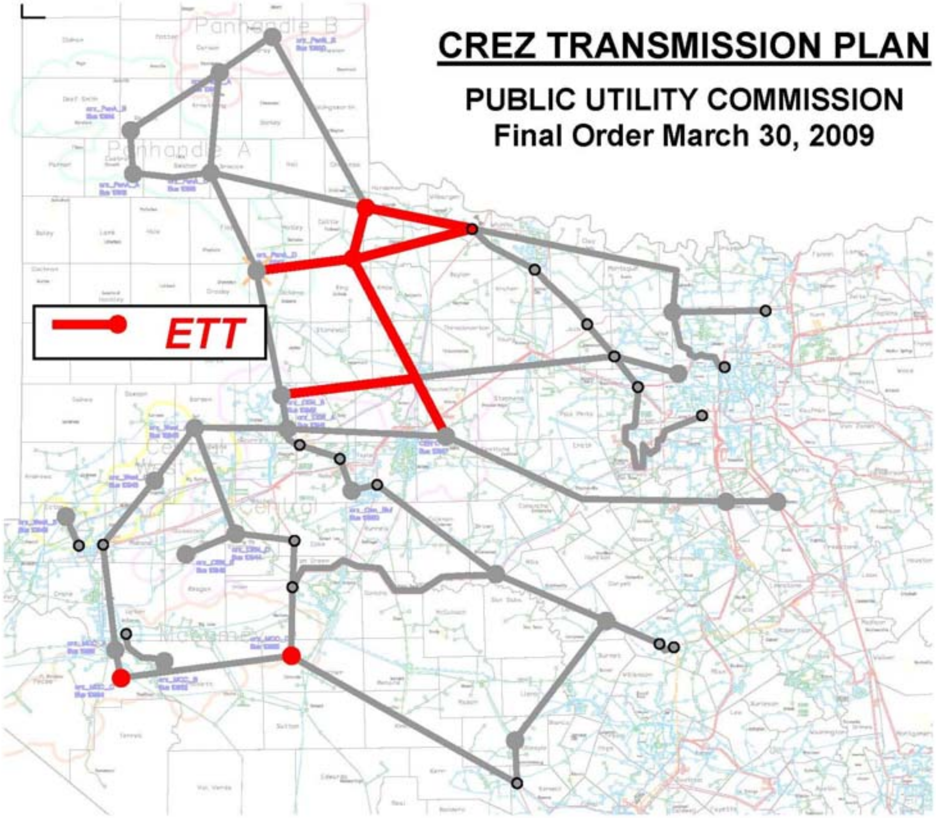
Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT Electric Transmission Texas

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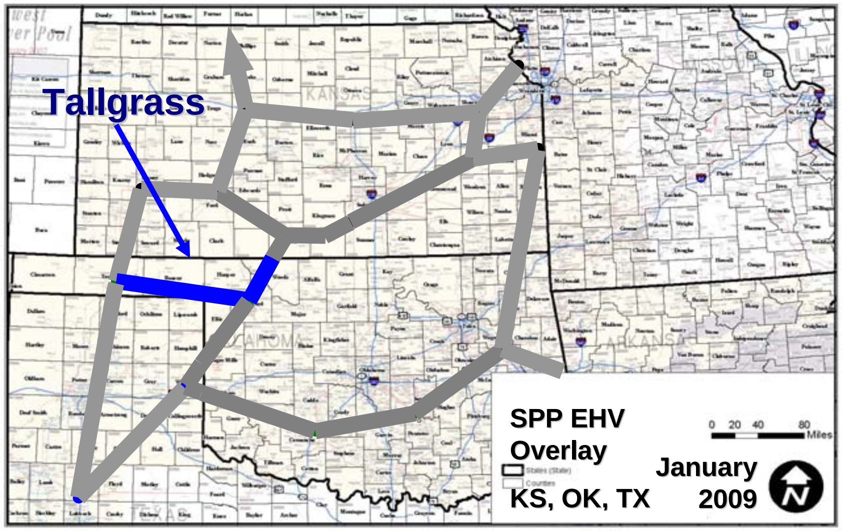
Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

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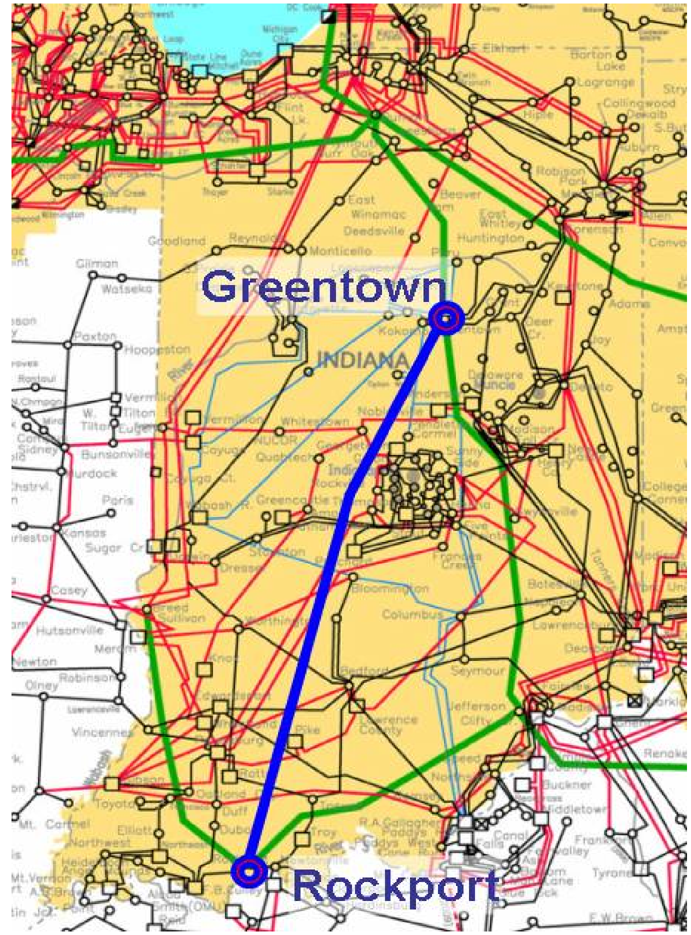
Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AMERICAN ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER

Overview of 2009 Guidance

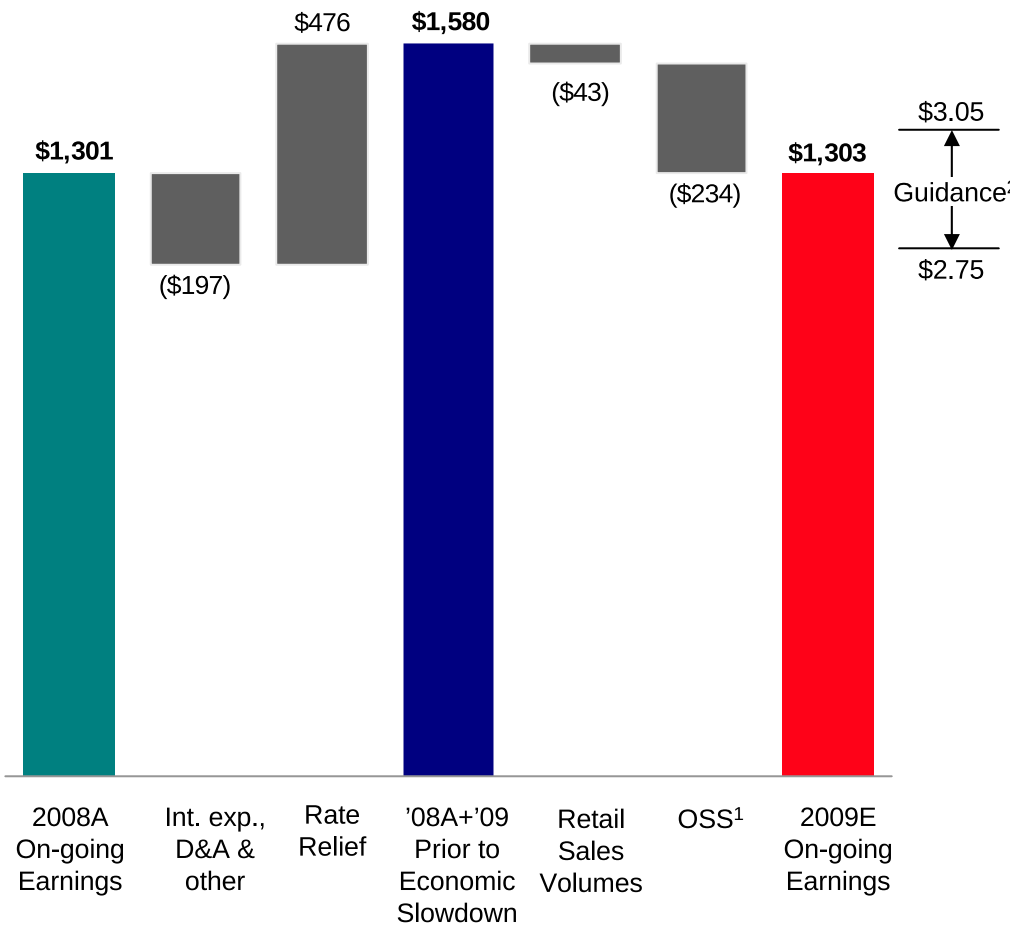
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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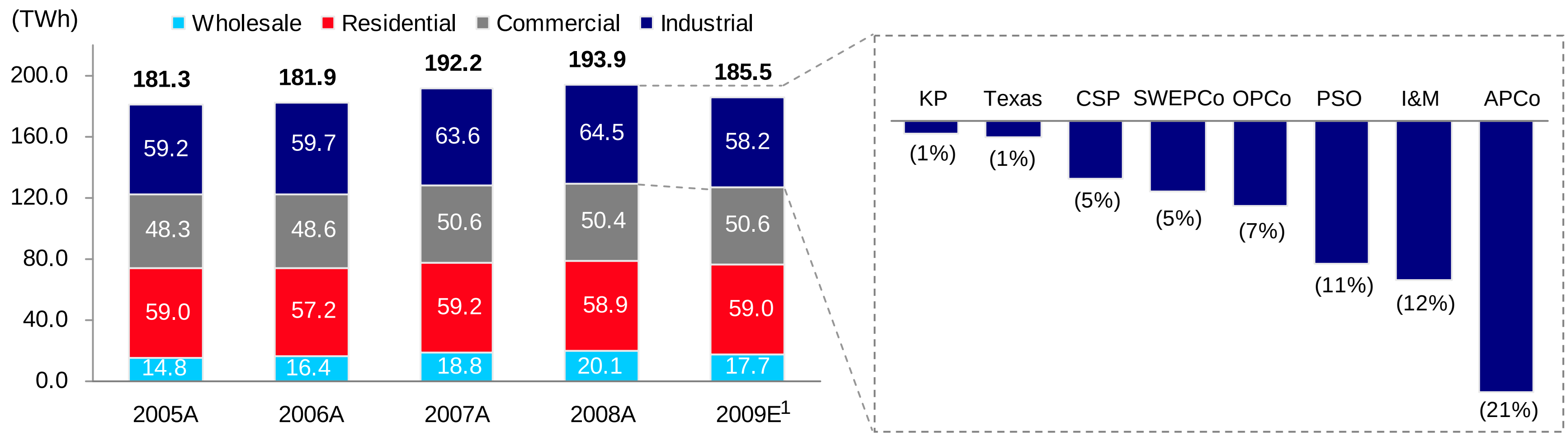
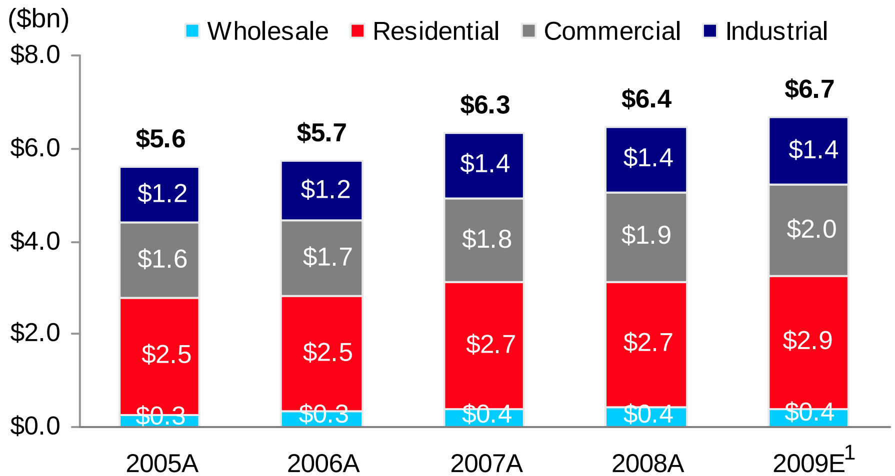
Key Drivers of Revised 2009 Guidance: Retail Sales

Retail Load by Customer Class

Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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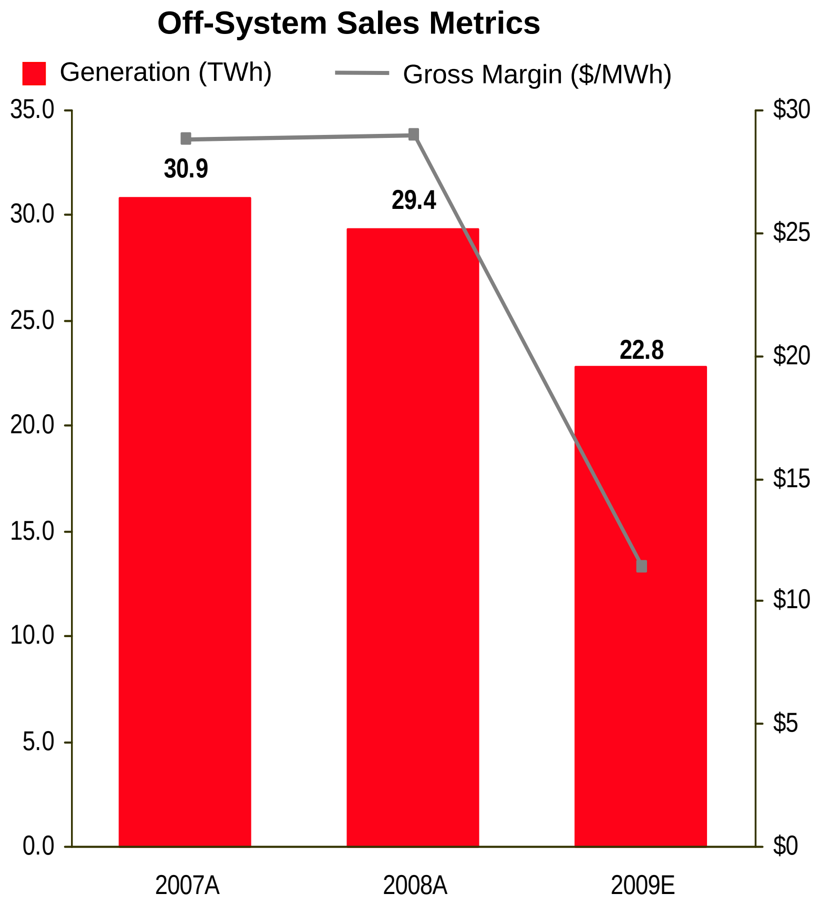
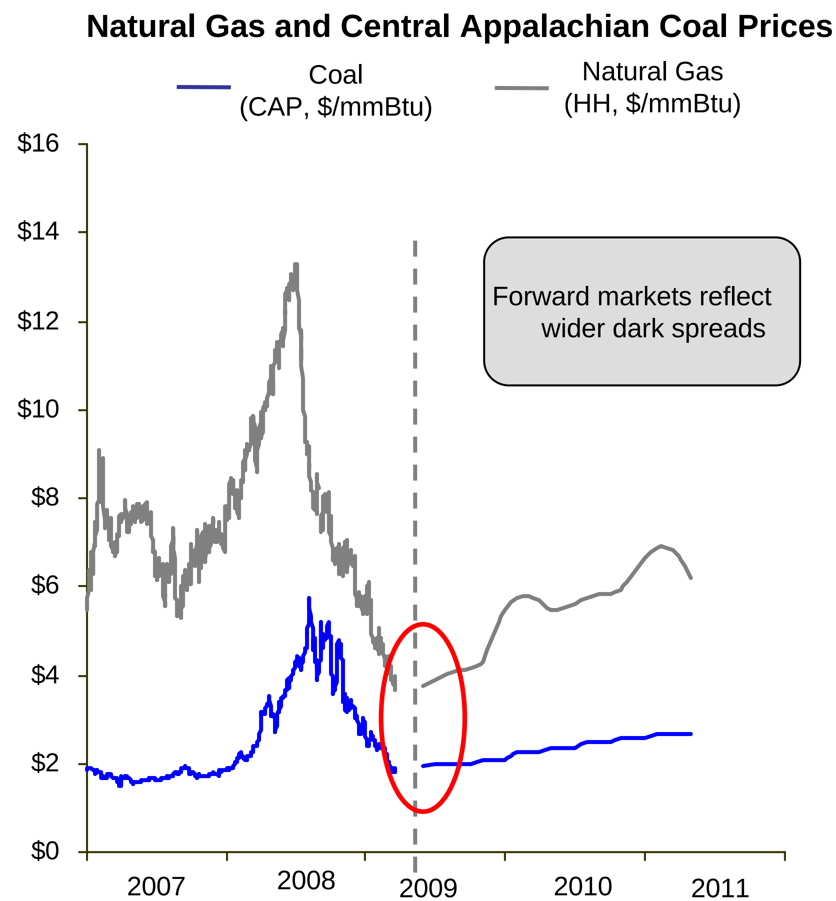
[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

Key Drivers of Revised 2009 Guidance: Off-System Sales



$ in millions	2007A	2008A	2009E
OSS Physical Sales	$ 674	$ 718	$ 106
Oklaunion Payment	46	45	49
Marketing/Trading	170	82	105
Pre-sharing Gross Margin	$ 890	$ 845	$ 260



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- 1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip
- Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip

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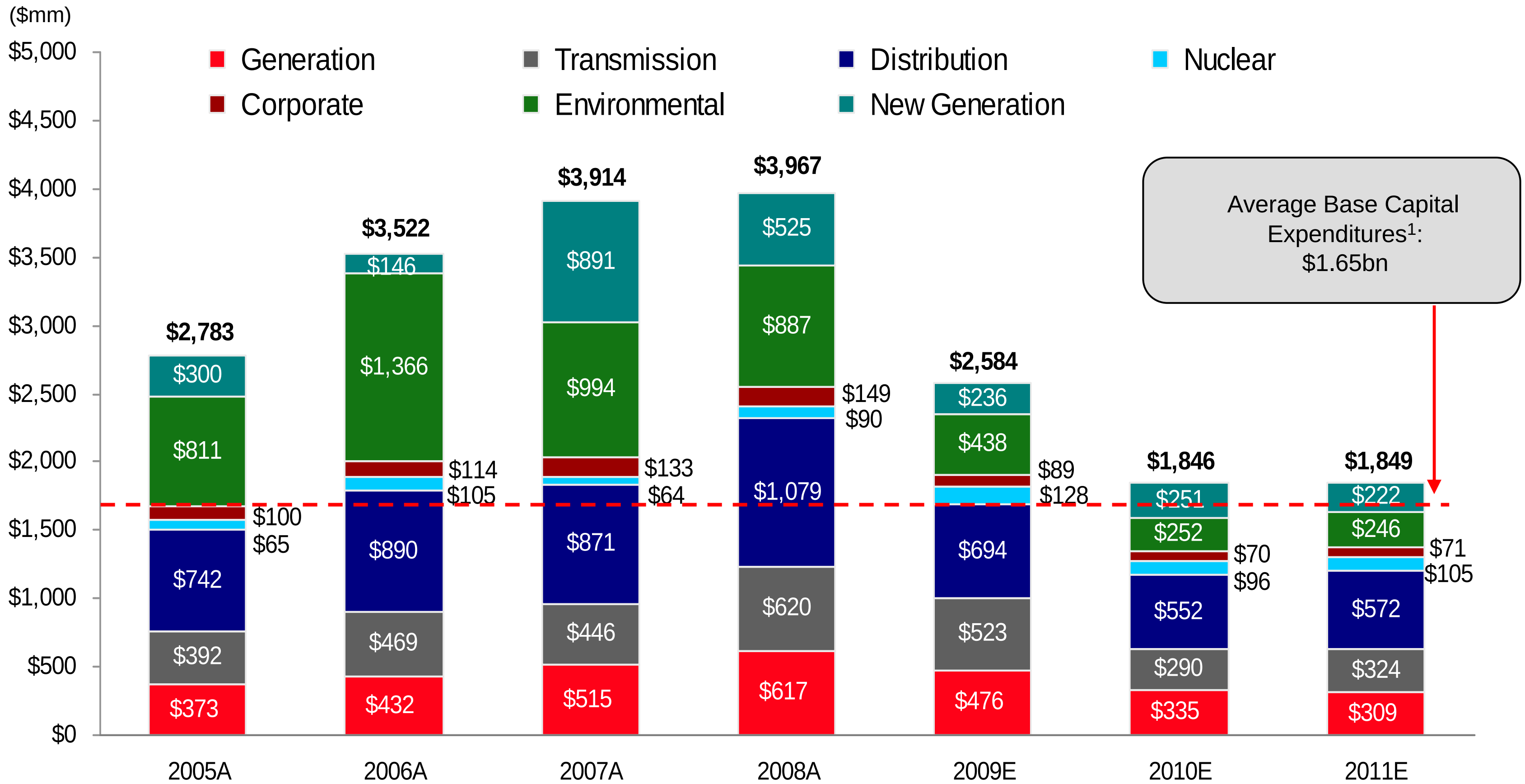
Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

AEP AMERICAN ELECTRIC POWER

Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
¹ Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

AEP AMERICAN ELECTRIC POWER

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

AEP AMERICAN ELECTRIC POWER

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AMERICAN ELECTRIC POWER

Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	R	BBB	S	BBB+	S
AEP Texas North Company	Baa1	R	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	R	BBB	S	BBB+	S

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

AEP AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)
(as of March 31, 2009)

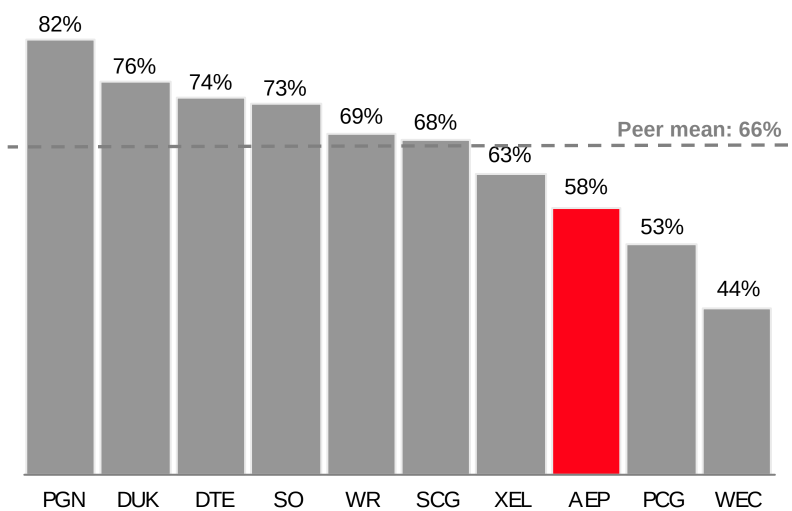
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ 150	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ 70	$ 679	$ -
Public Service of Oklahoma	$ 50	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 270	$ 1,791	$ 625

AEP AMERICAN ELECTRIC POWER

Dividend Overview

- We have paid 395 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

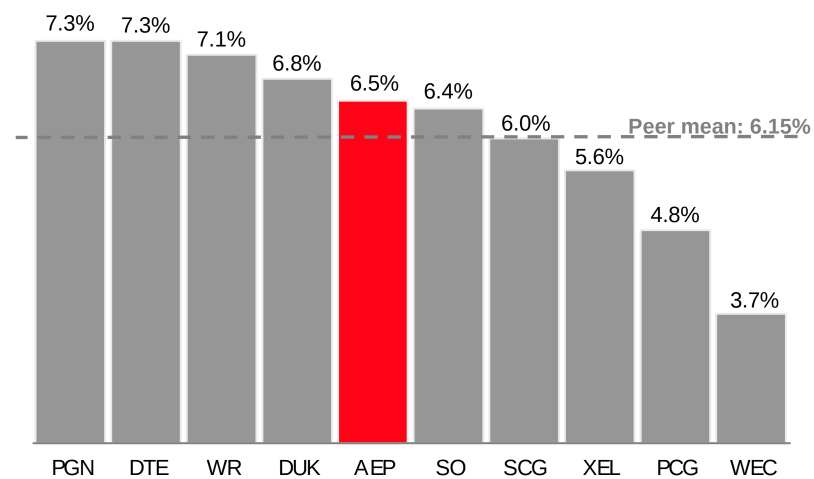
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 5/21/09

Dividend Yield vs. Integrated Electric Peers



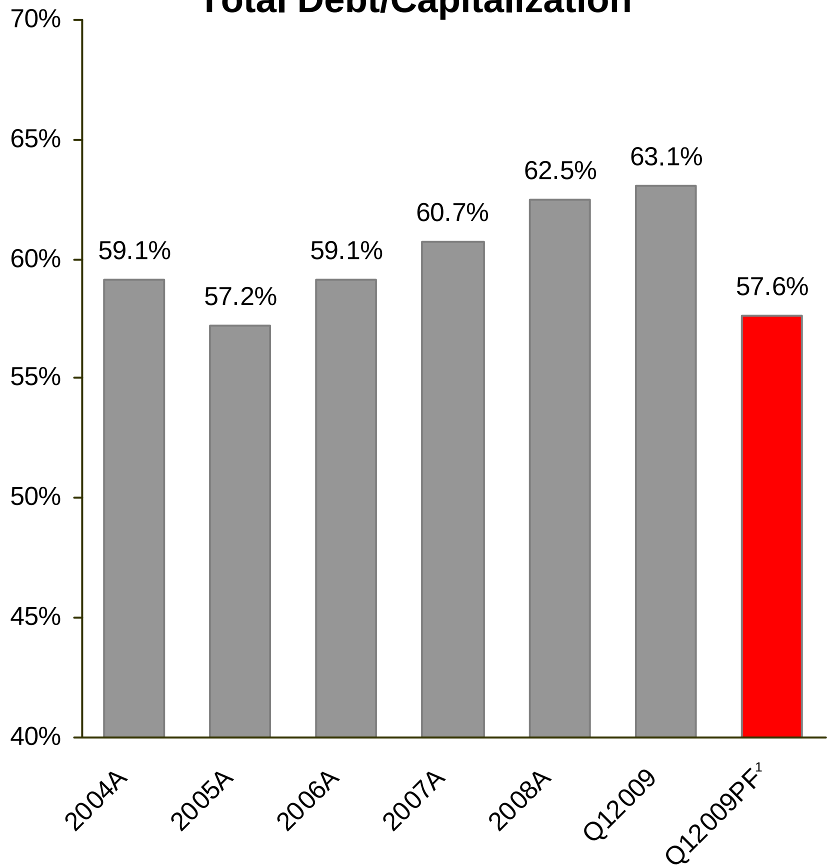
Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 5/21/09

AEP AMERICAN ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	**04/20/2009**	**Maturity**
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)[1]	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

1- An additional $500MM has been repaid subsequent to 4/20/09.

AEP AMERICAN ELECTRIC POWER

AEP AMERICAN ELECTRIC POWER®

Better Investing National Conference
St. Louis, MO
June 12, 2010

AEP® A CENTURY OF DIVIDENDS • 1910 - 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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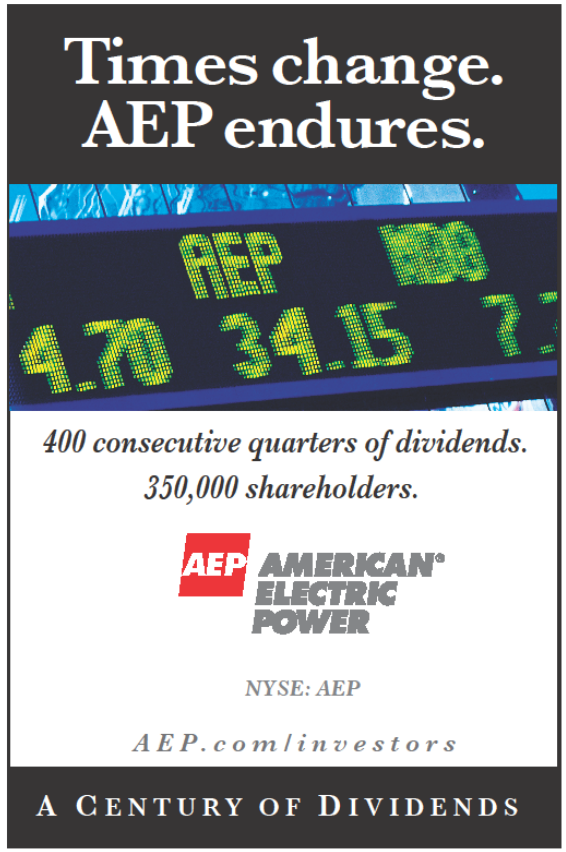
We are Proud of our Record….



Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 5.1%[1]**
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 21 analysts
- 15 Buy Ratings
- 6 Hold Ratings

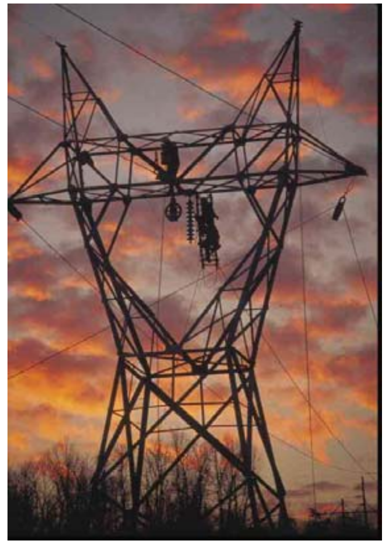
Attractive total return potential

[1] yield percentage based on AEP closing price of $32.45 on 06/11/2010

Industry Leadership

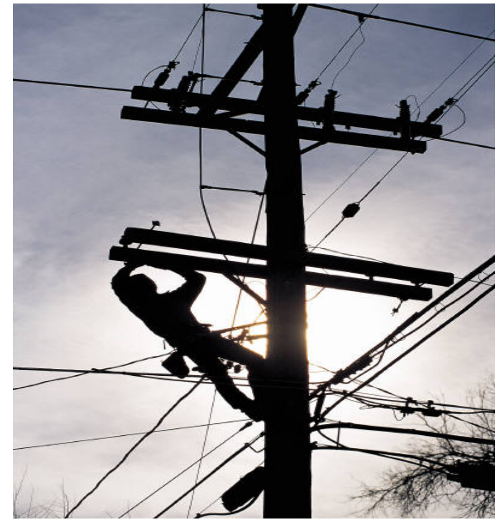
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

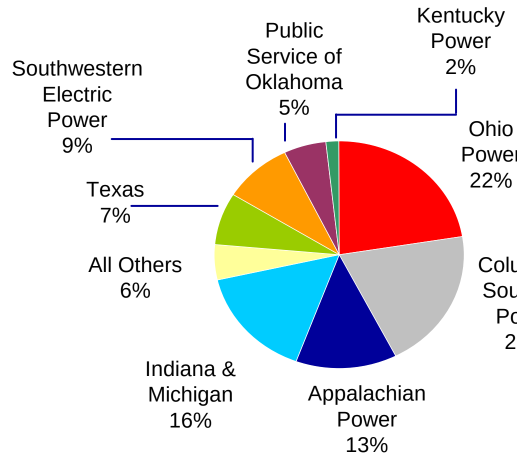
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

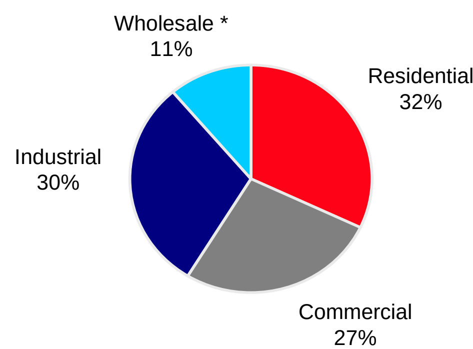
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

2010 Ongoing Earnings Guidance

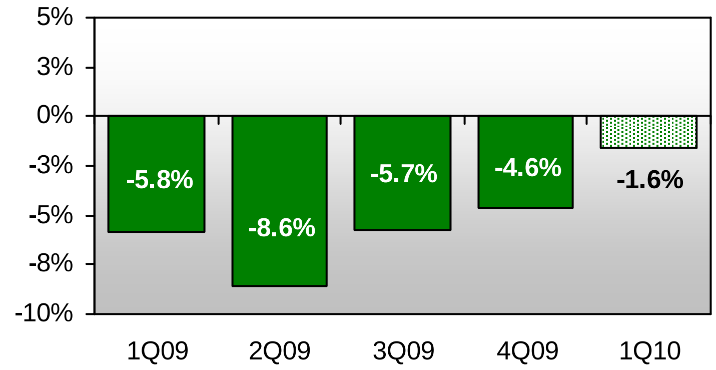
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost cutting initiatives**

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART[SM] Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

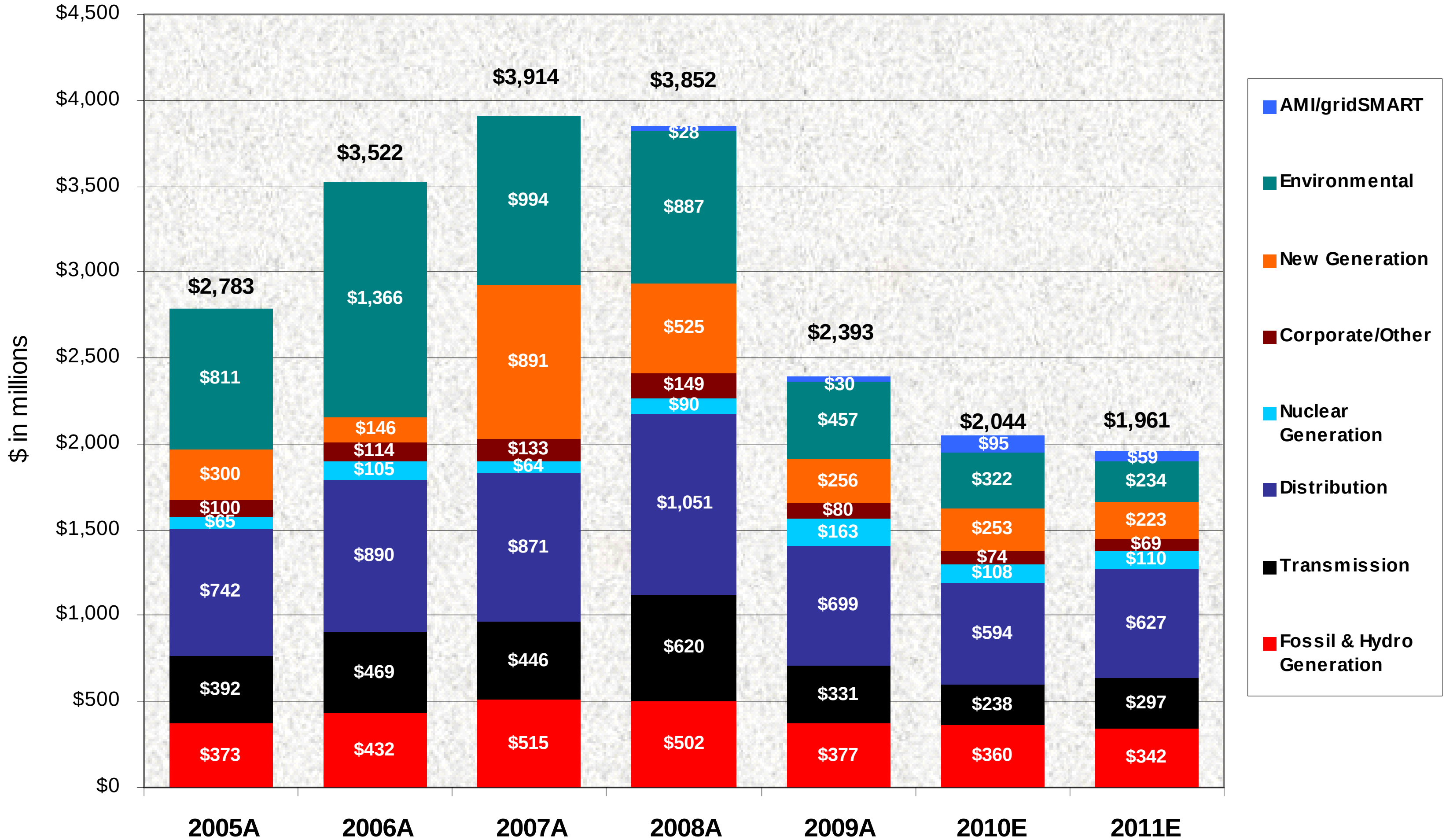
765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

- <u>AEP Transmission Company (Transco)</u>: Within our existing footprint
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually
- <u>Electric Transmission Texas (ETT)</u>: Projects in Texas ERCOT jurisdiction
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B within this decade
- <u>Joint Ventures (JVs)</u>: Outside of our footprint, with Electric Transmission America (ETA) or others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

10

Dividend Overview

- We paid our 400th consecutive quarterly dividend to shareholders on June 10, 2010 to shareholders of record on May 10th

- Annual Dividend - $1.68/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December

- Attractive yield of 5.1% as of June 11, 2010

- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value and Total Return Proposition**

Mountaineer Plant (WV)

AEP AMERICAN ELECTRIC POWER®

BetterInvesting Presentation

Cincinnati, OH
September 16, 2011

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Value Proposition to Retail Investors

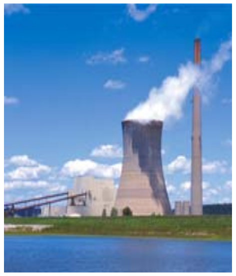
- **Attractive Yield Opportunity near 5.0%**
  - 50-60% payout ratio targeted
  - Quarterly dividend increased 12% in 2010
  - 405 consecutive quarters of dividend payments to our shareholders
- **Earnings Growth Prospects**
  - 4 – 6% in the 2012 to 2014 time frame
  - 5 – 7% beyond 2014

Current Wall Street Analyst Coverage:

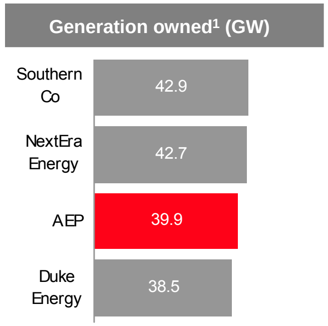
- **24 analysts**
- **11 Buy Ratings**
- **12 Hold Ratings**
- **1 Sell Rating**

Attractive total return potential

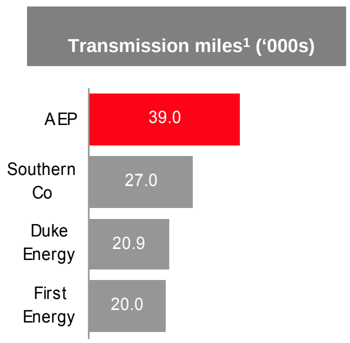
American Electric Power



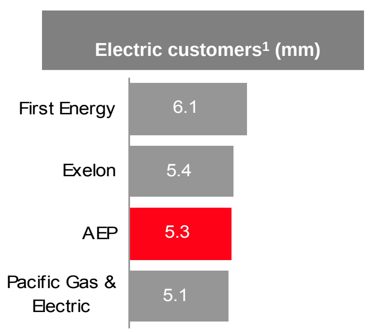
One of the largest
U.S. electricity generators



The largest U.S. electricity
transmitter

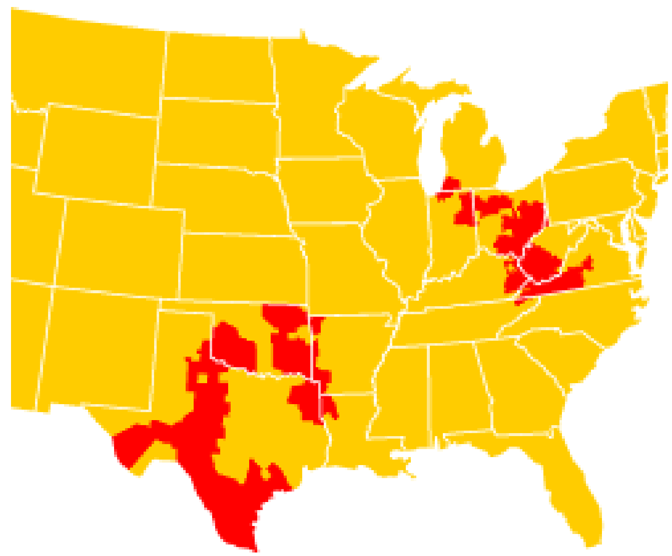


One of the largest U.S.
electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

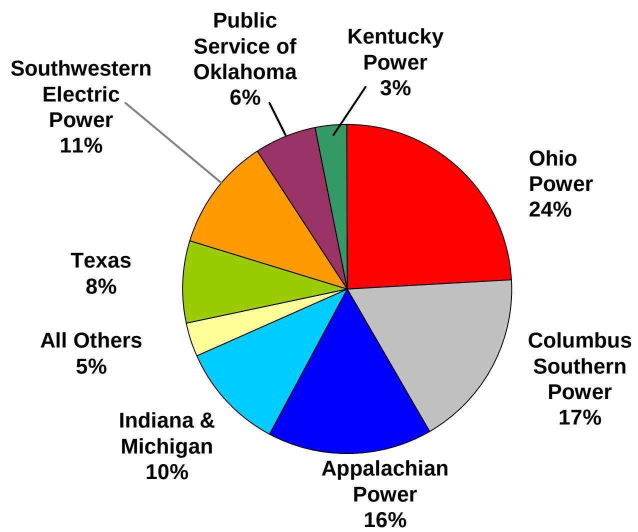
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$18.1B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

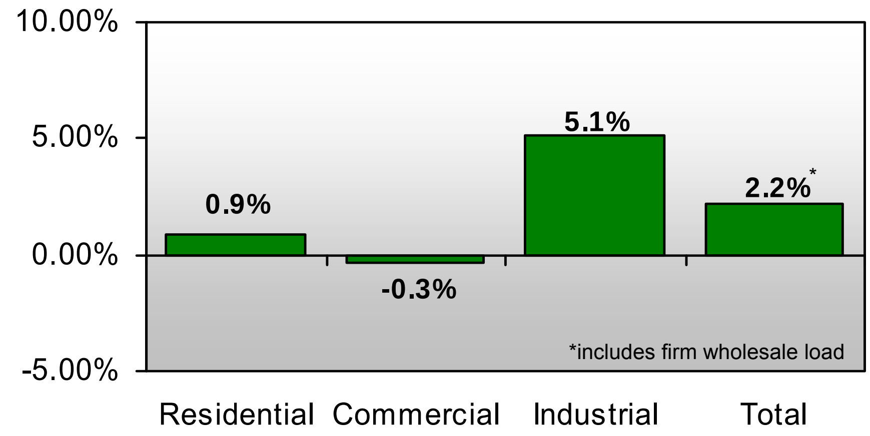
Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



AEP Total Normalized GWh Sales

2011 YTD % Change vs. Prior Year

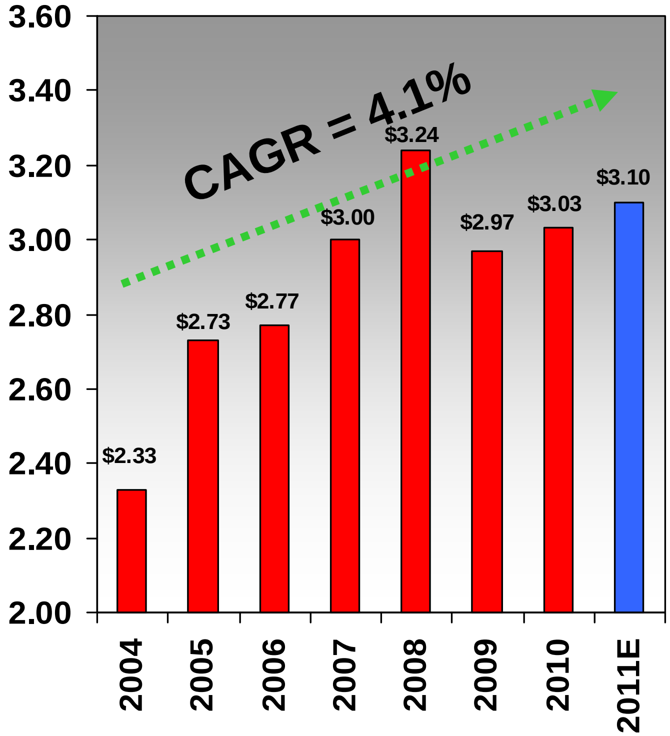


Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

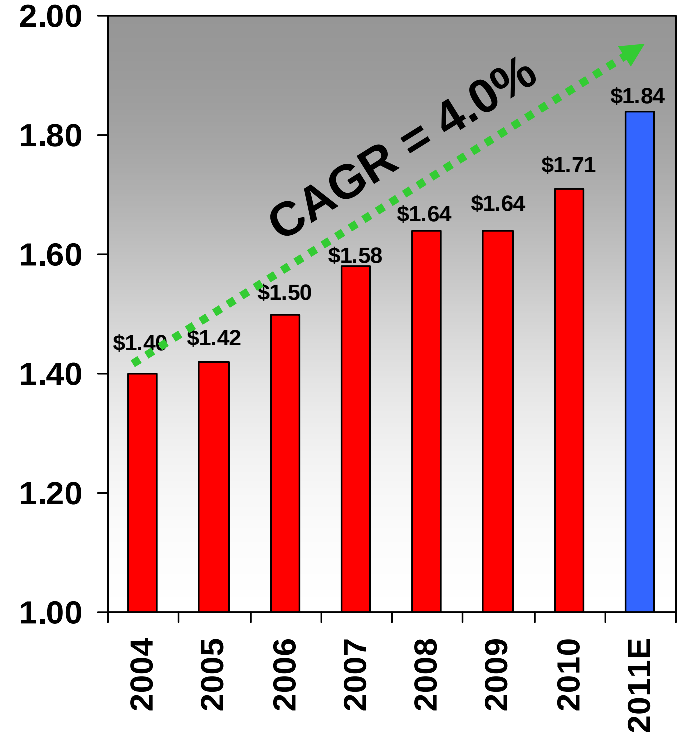
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



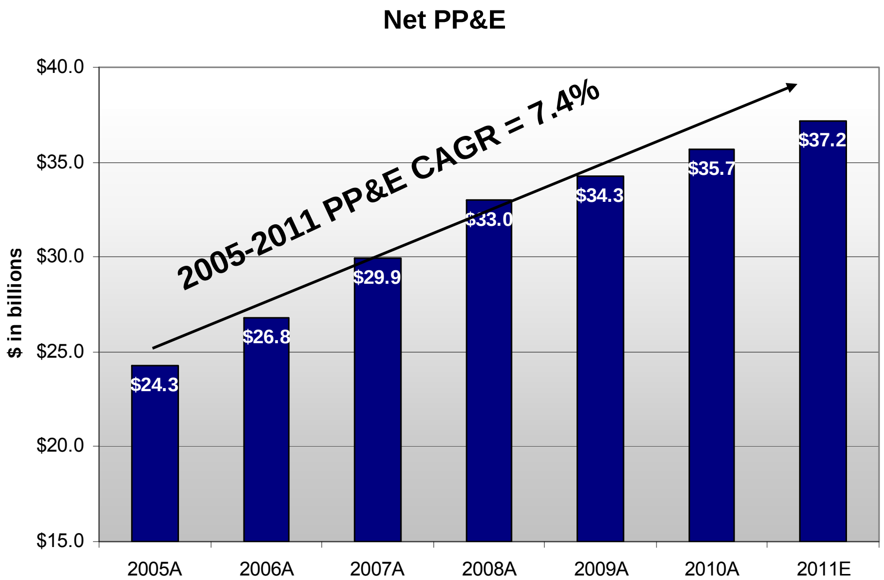
= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend paid in September 2011
- 50-60% payout ratio target
- Current yield near 5%

Ratemaking Environment

AEP®

Growth in Net PP&E

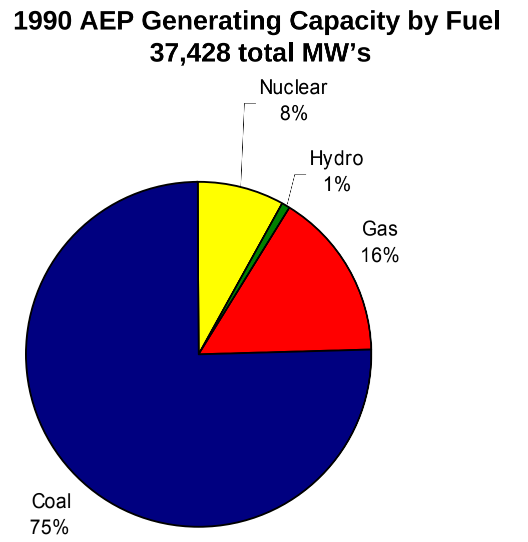


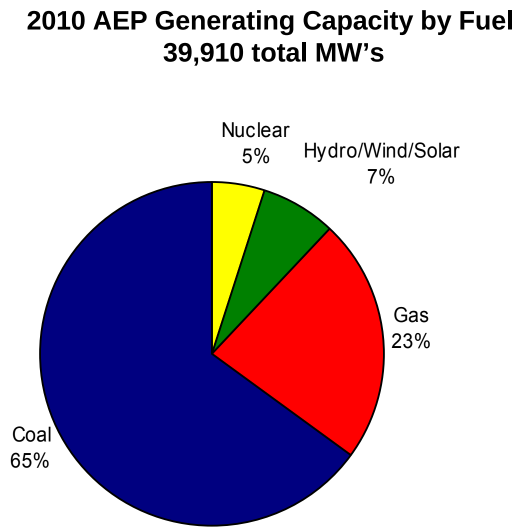
Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

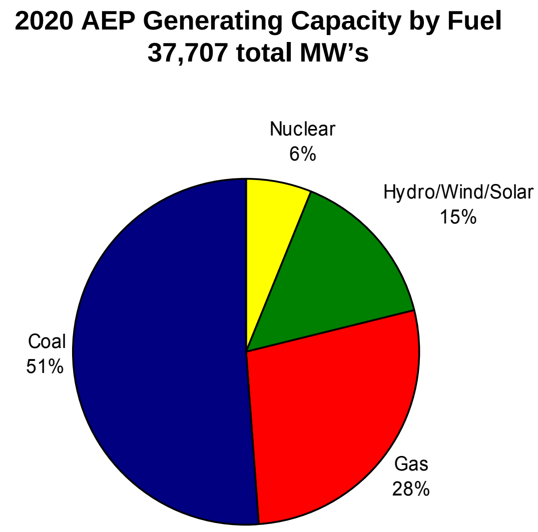
Regulatory Framework

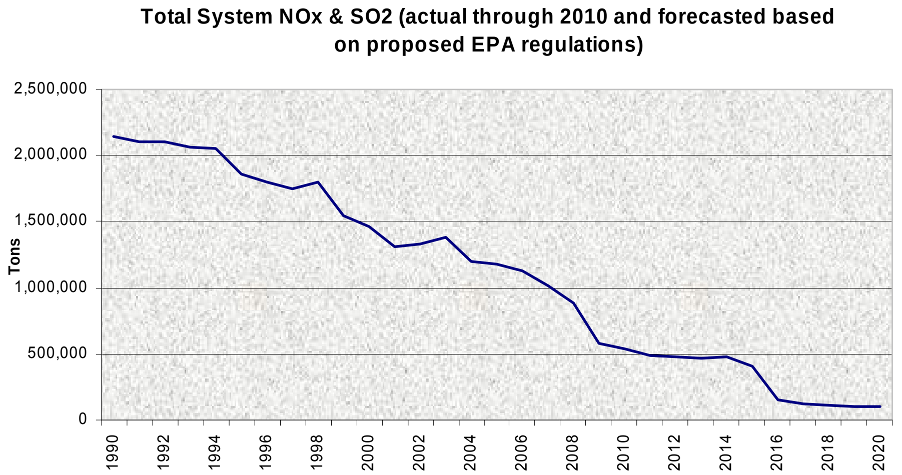
- Base Rates
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- Recovery of Fuel Costs in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)
  - Customers have choice for generation service; 6.9% customer switching through 2Q11
  - Current generation rates set for 2009 – 2011
  - Upcoming hearing October 4th on 2012-2015 rate plan settlement
  - Settlement requires separation of transmission and distribution from generation. Generation moves to market pricing on June 1, 2015.

Generation Transformation









- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Additional Investment Opportunities

AEP®

ETT Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:** Current rate base is $412 million; expected to grow as follows:
  - 2011: $482 million
  - 2012: $778 million
  - 2013: $1,352 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $160 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

Additional joint ventures diversify AEP's investment outside the traditional footprint while providing longer-term incremental earnings.

AEP Highlights

- Large, Diverse Electric Utility
- Focus on Capital Allocation
- Strong Balance Sheet
- Growth Opportunities
- Dividend yield near 5%

Mountaineer Plant (WV)

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3427 of 9556

2011 BetterInvesting Great Lakes Regional Conference
Ann Arbor, MI

March 26, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 5.4%[1]**
  - 50-60% payout ratio targeted
  - Quarterly dividend increased 12% in 2010
  - 403 consecutive quarters of dividend payments to our shareholders
- **Earnings Growth Prospects**
  - 4 – 6% in the 2012 to 2014 time frame
  - 5 – 7% beyond 2014

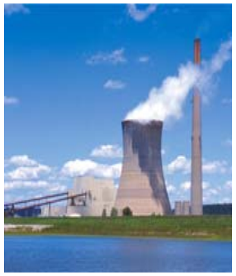
Current Wall Street Analyst Coverage:

- **20 analysts**
- **9 Buy Ratings**
- **11 Hold Ratings**

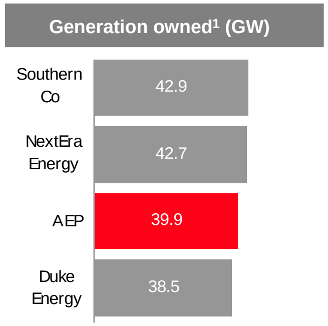
Attractive total return potential

[1] yield percentage based on AEP closing price of $34.06 on 03/21/2011

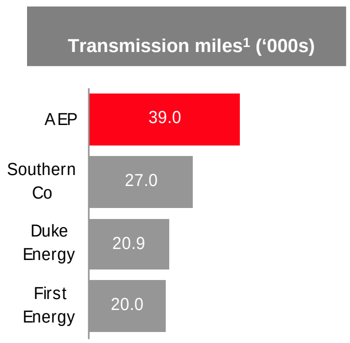
American Electric Power



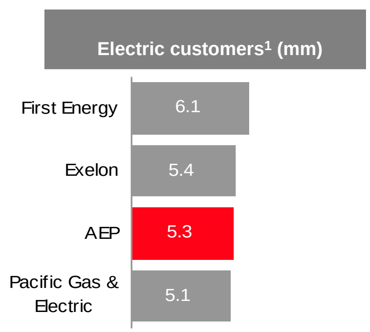
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

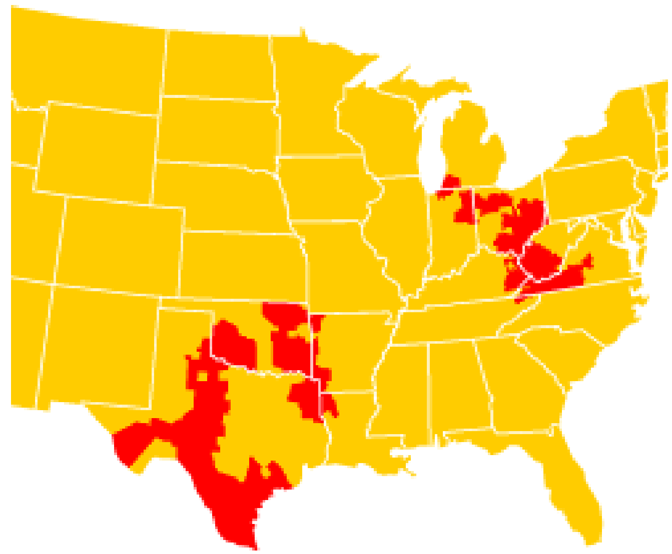


One of the largest U.S. electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

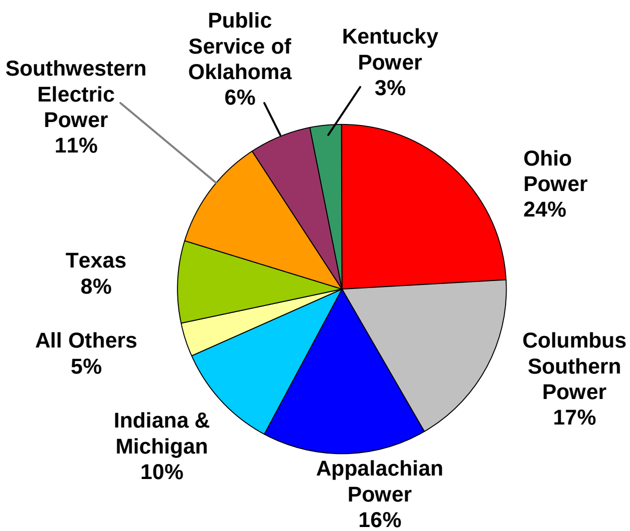
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$16.5B Market Capitalization
BBB/Baa2/BBB credit rating

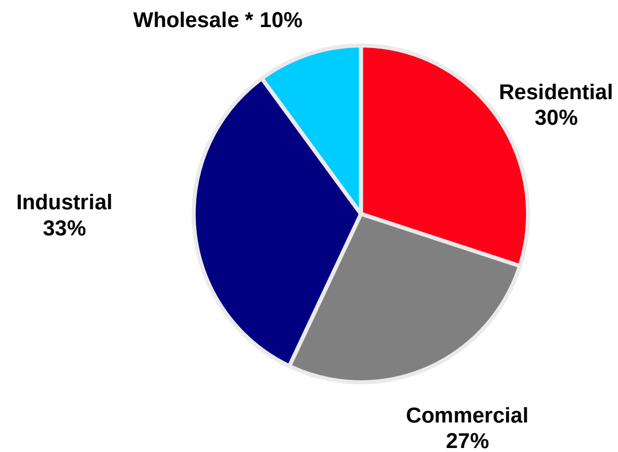
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



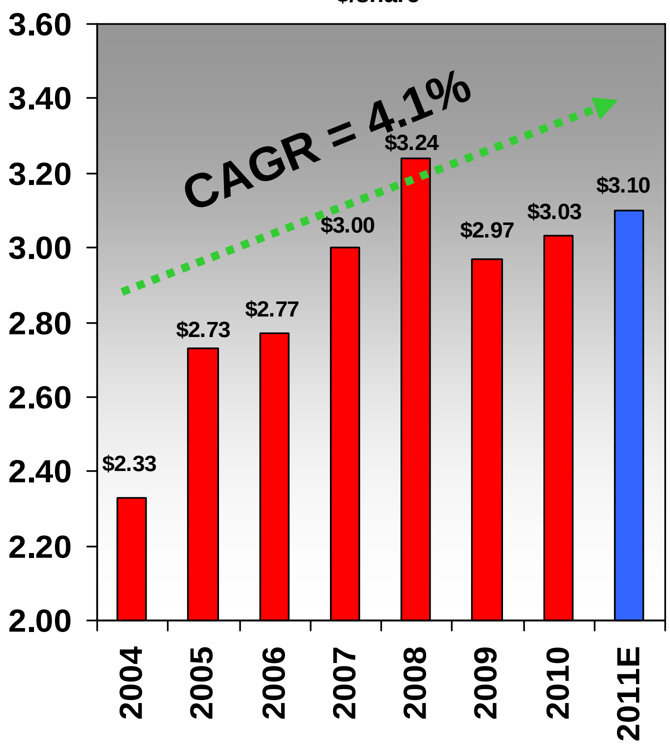
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

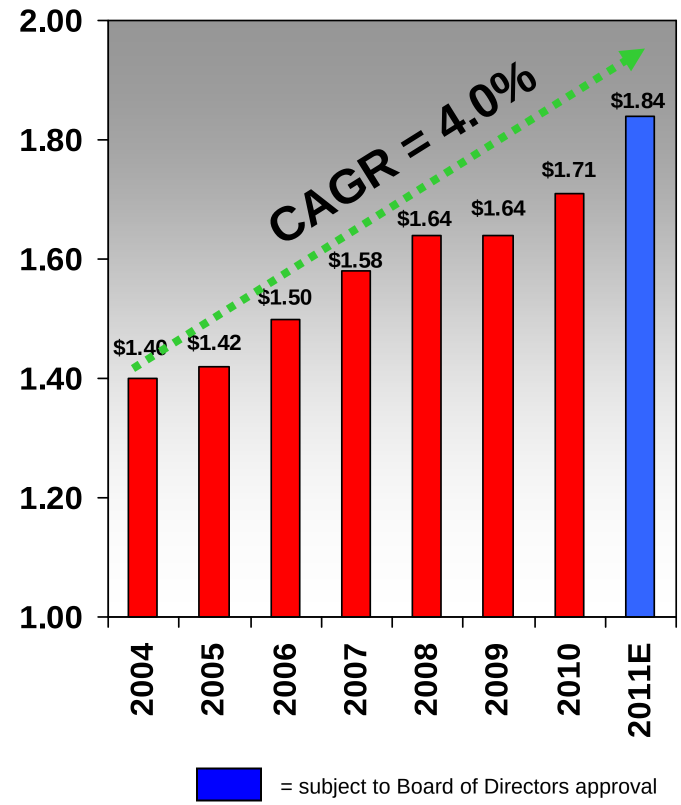
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend increased 12% in 2010
- 403rd consecutive quarterly dividend paid in March 2011
- 50-60% payout ratio target
- Current yield over 5%

2011 Ongoing Earnings Guidance

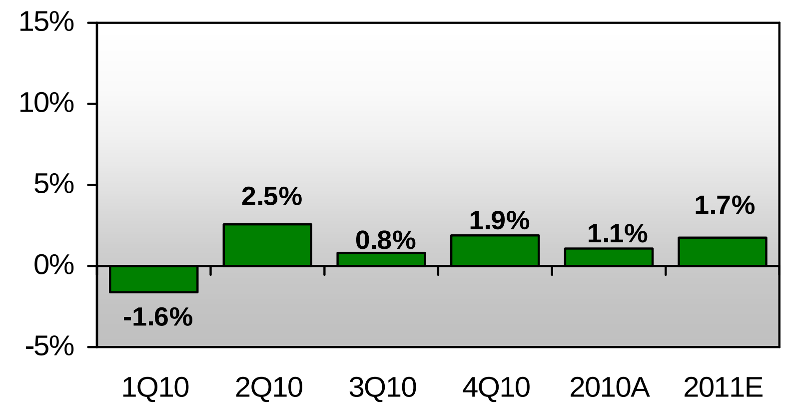
2010A: $3.03/share

2011E: $3.00-$3.20/share

Near-Term Earnings Drivers

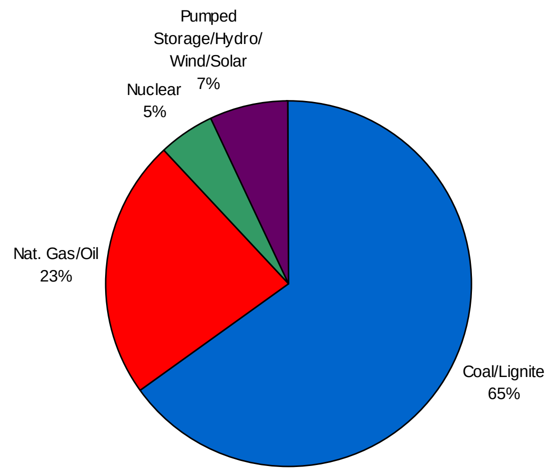
- Recovering economy
- Rate recovery from returns on capital investment
- Continued O&M discipline

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year

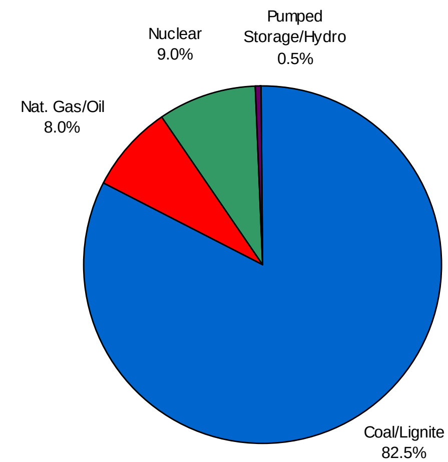


Domestic Generation Fleet

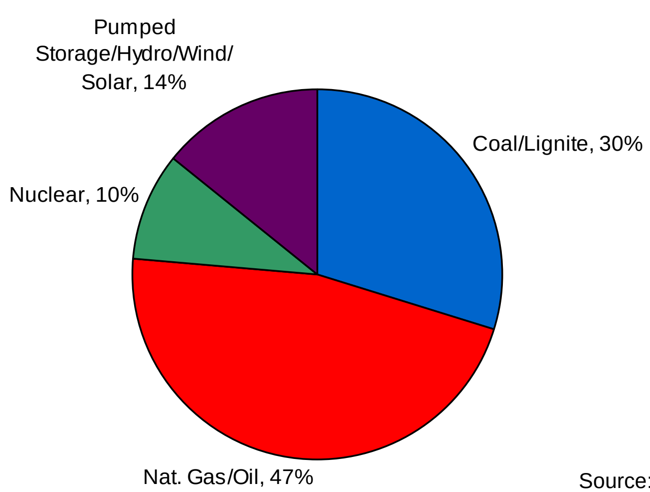
Generation Capacity by Fuel Type
Based on 39,910 MW



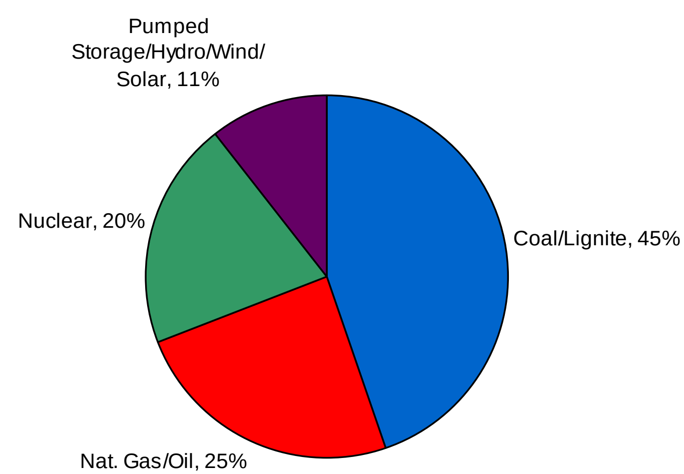
2010 Generation Production by Fuel Type
Based on 173.2 TWh



Generation Capacity by Fuel Type
Based on 1,063,848 MW

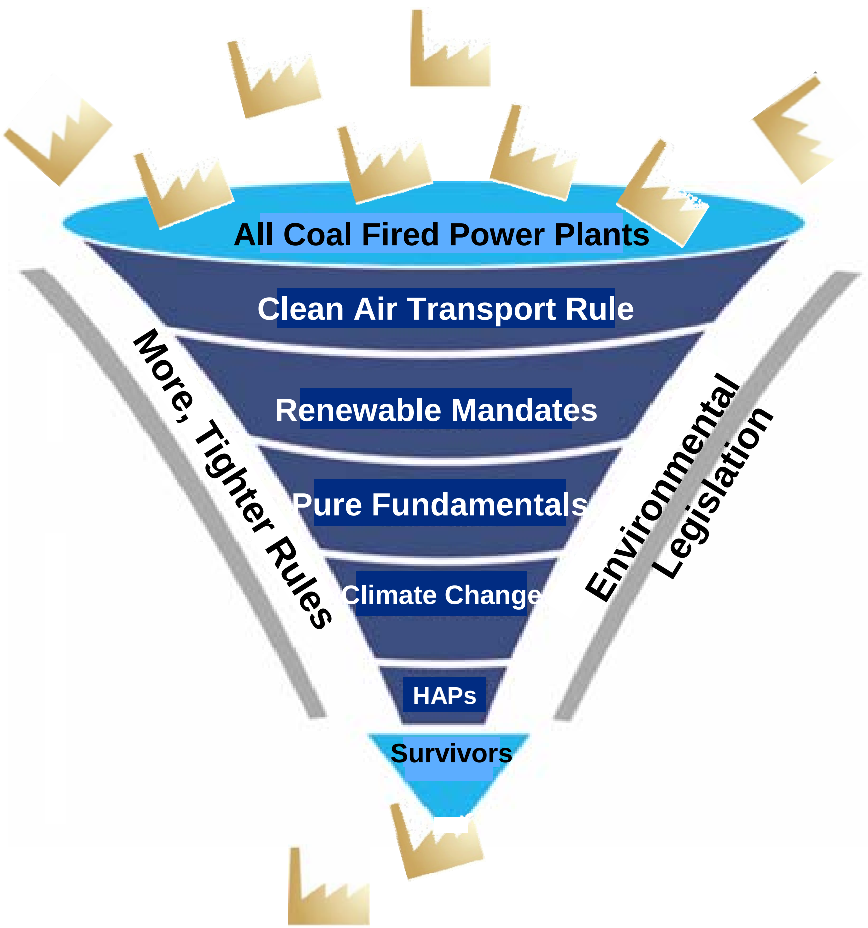


2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

The Pressure on Coal Generation



Key EPA Actions Pending

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Proposed March 2011
- Cooling Water Intakes – Expect Proposed Rule in Spring 2011
- Greenhouse Gas Tailoring Rule – January 2011

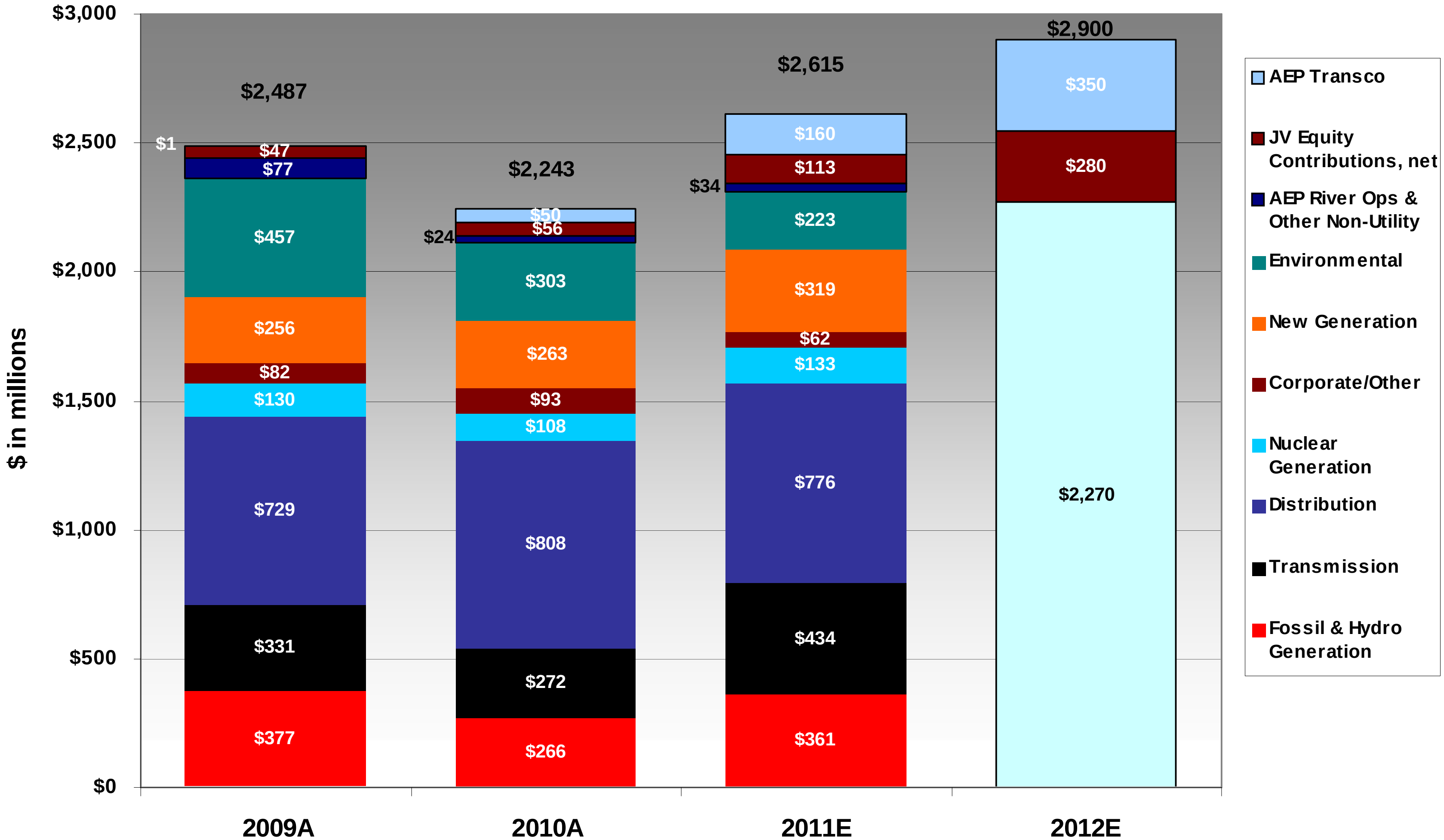
Transmission Investment Strategy

- **<u>Near-Term Investment</u>** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.
- **<u>Mid-Term Investment</u>** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012; Expected ROE will be in the 11.20%-11.49% range
- **<u>Long-Term Investment</u>** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

765-kV Tower

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Capital Expenditures



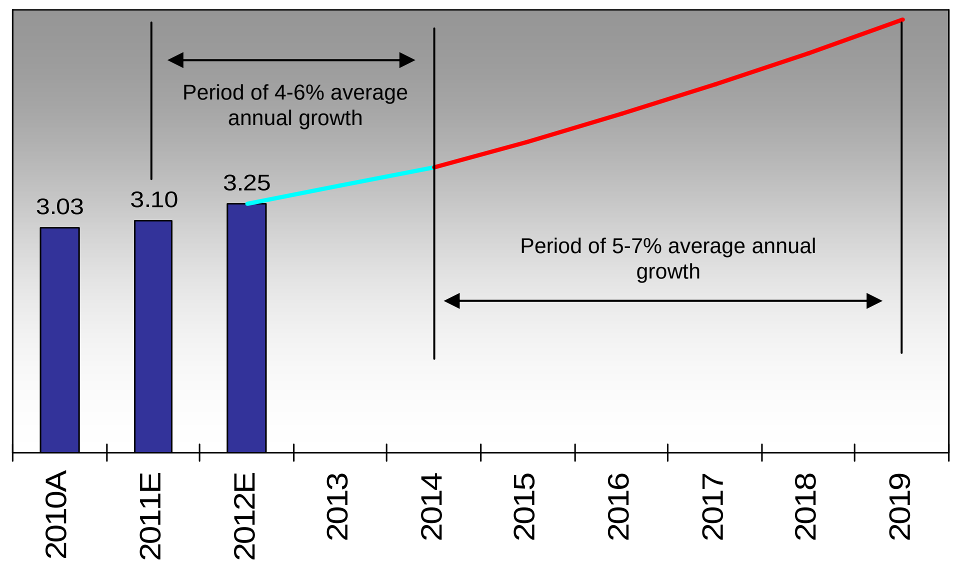
Investment levels greater than depreciation of $1.3B per year cause rate base growth in 2011 and 2012

Long-term EPS Growth Rate

AEP®

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3439 of 9556

AEP Highlights

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Mountaineer Plant (WV)

Black River Asset Management Office Visit

Columbus, OH

September 17, 2008

AEP AMERICAN ELECTRIC POWER®

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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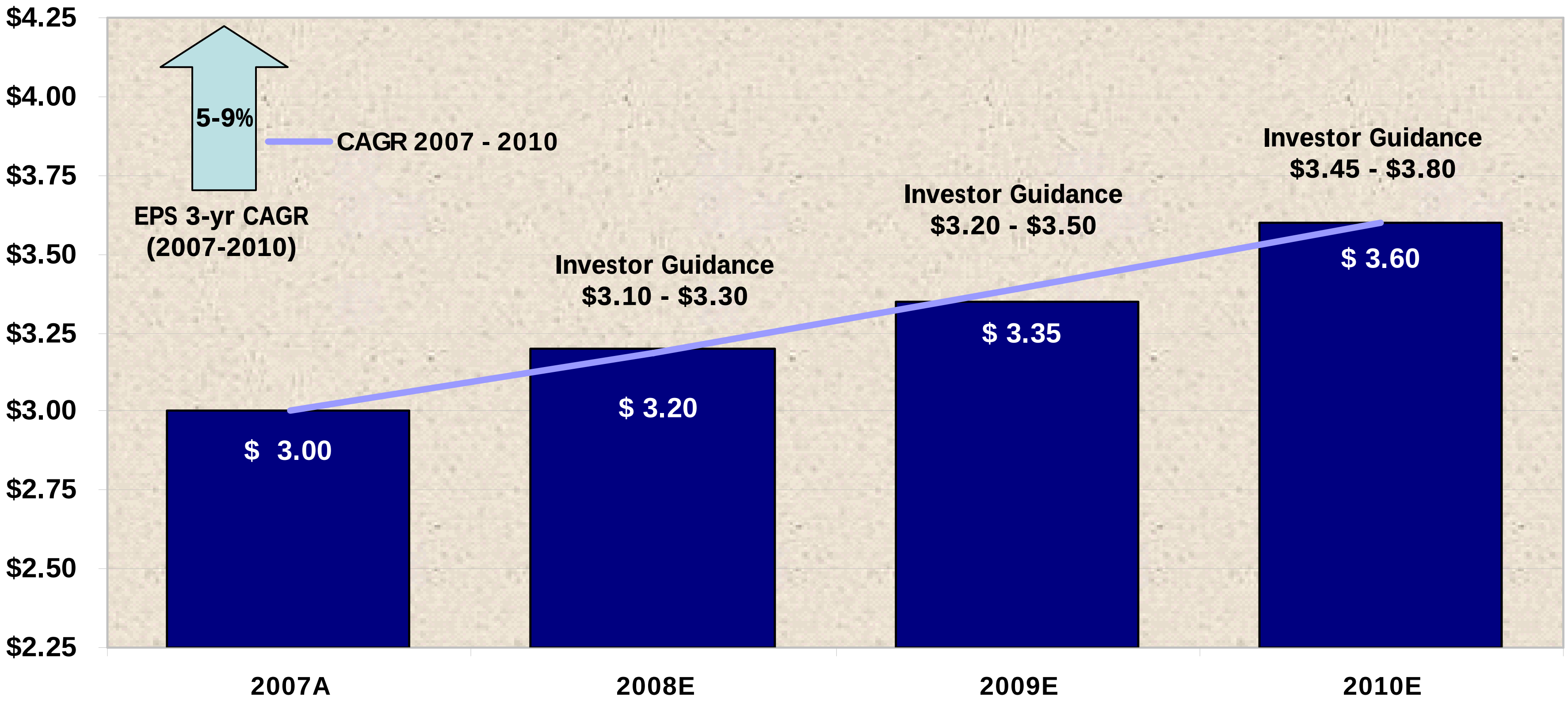
The AEP Value Proposition

Leveraging our vast energy platform with low-risk investments in infrastructure to enable sustainable growth.



AEP's ability to ensure a disciplined approach to capital investment allows us to sustainably grow earnings and shareholder value.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Detailed Ongoing Earnings Guidance

2007A: $3.00

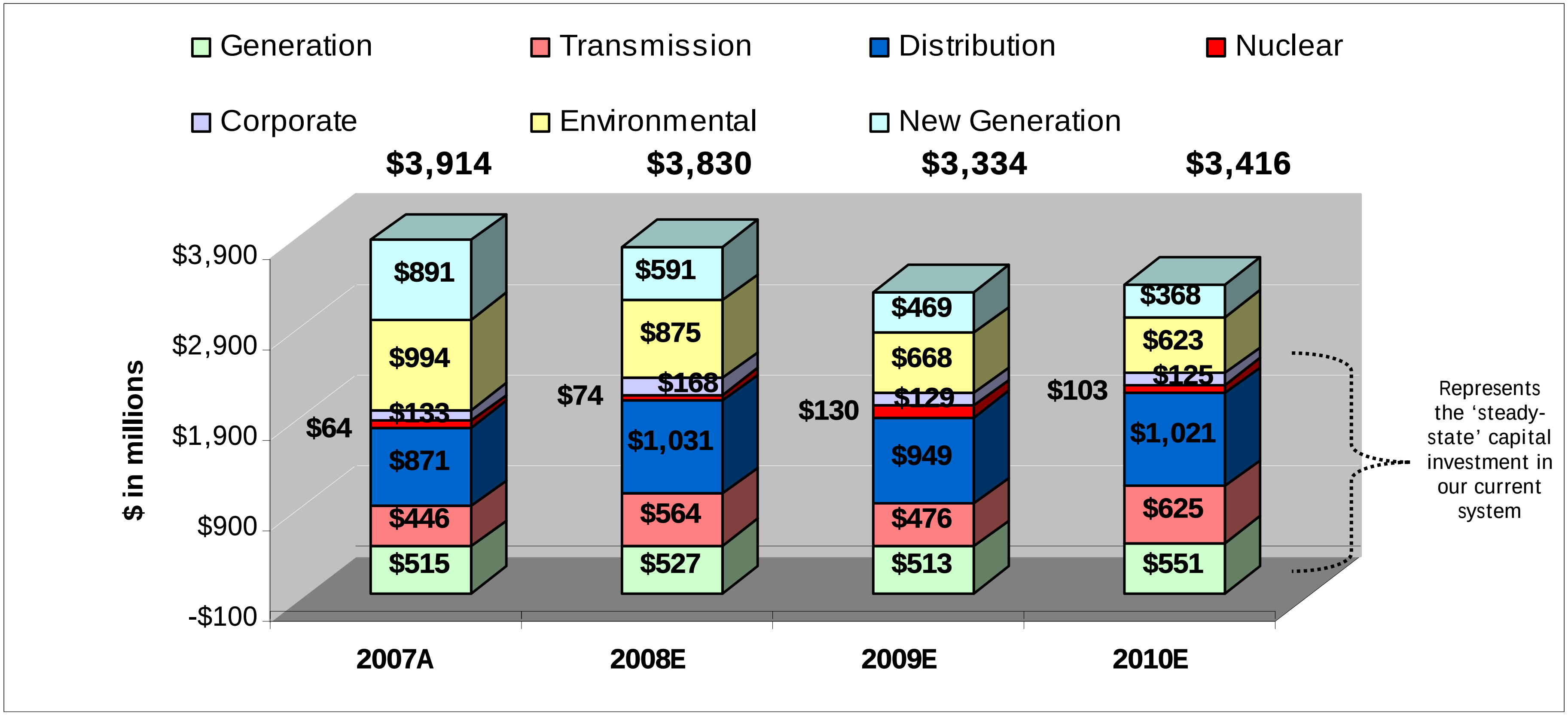
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4-Year Capital Investment Forecast



Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$583	$474	**$2,495**
I&M	$282	$386	$458	$497	**$1,623**
KPCo	$76	$127	$89	$106	**$398**
TCC	$212	$208	$186	$282	**$888**
TNC	$93	$120	$87	$91	**$391**
PSO	$303	$277	$257	$419	**$1,256**
SWEPCo	$511	$741	$710	$681	**$2,643**
CSP	$432	$404	$312	$308	**$1,456**
OPCo	$805	$635	$441	$411	**$2,292**
Other Companies	$488	$206	$211	$147	**$1,052**
Total Capex	**$3,914**	**$3,830**	**$3,334**	**$3,416**	**$14,494**

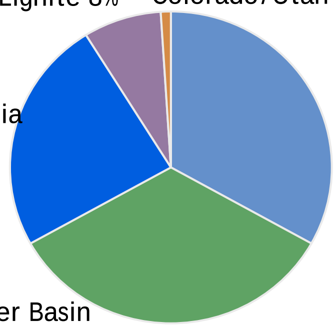
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

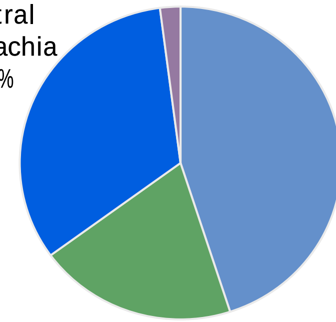
Total AEP System



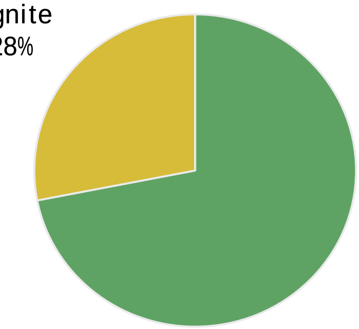
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East

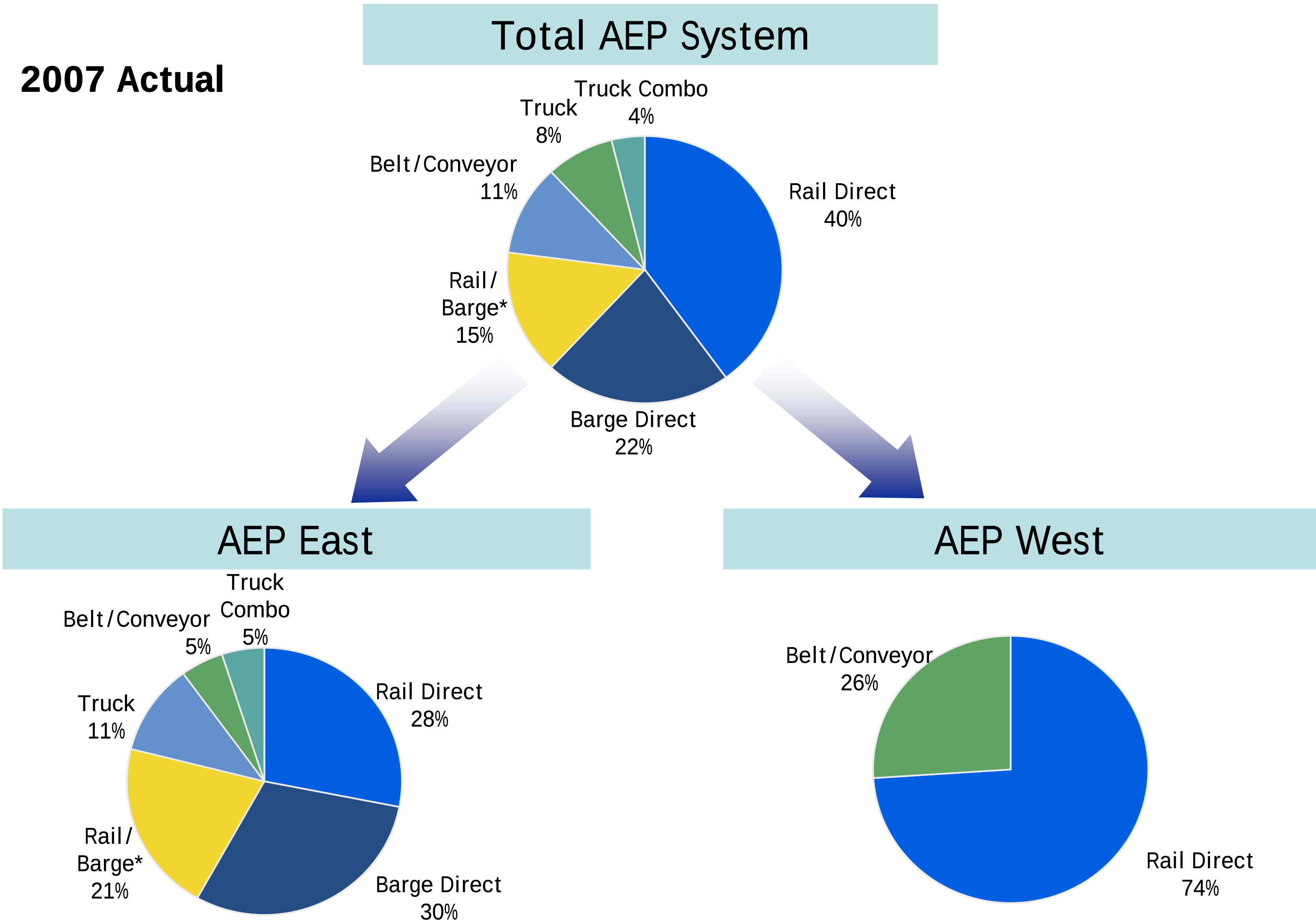


AEP West



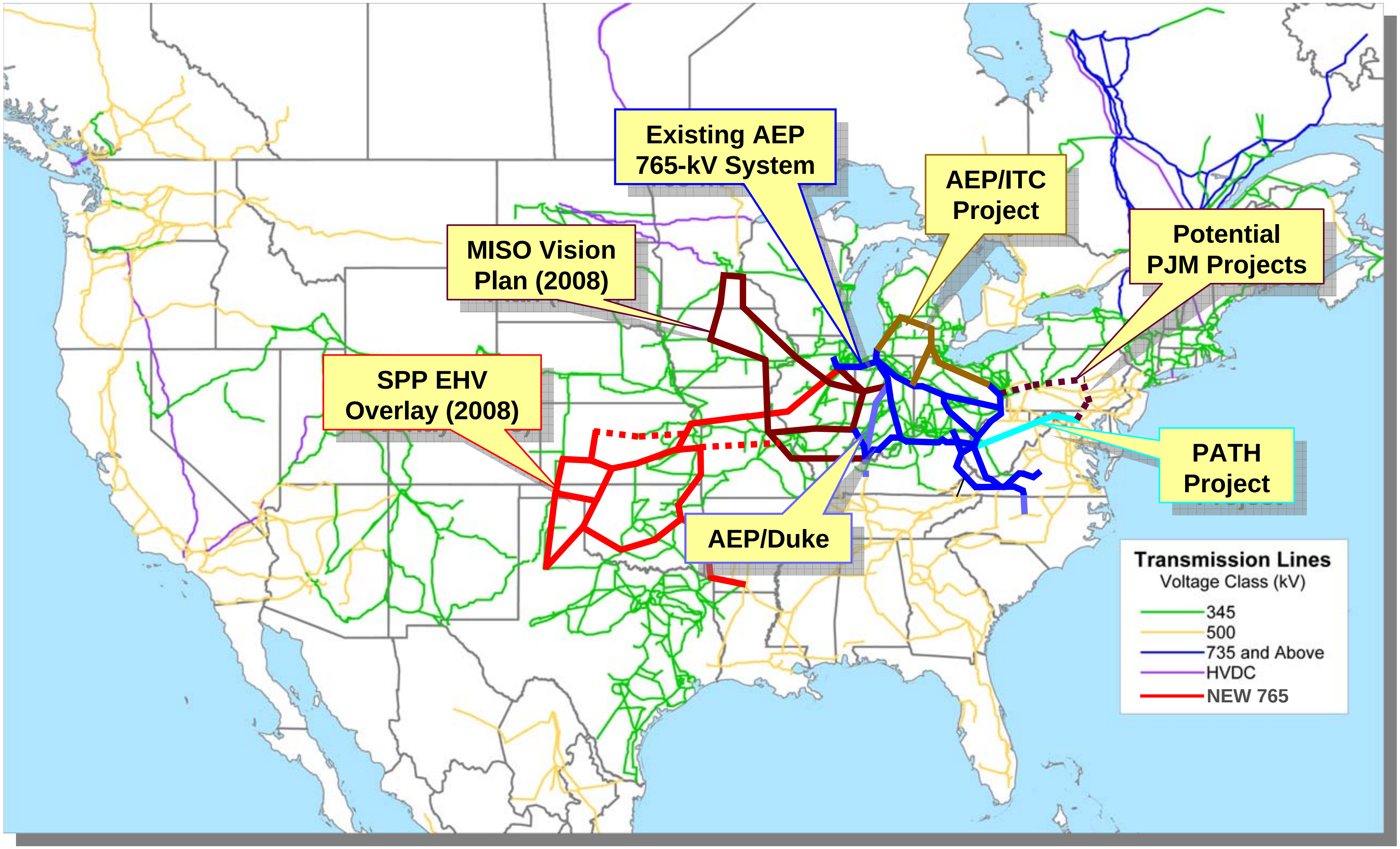
Coal Delivery

2007 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Making it Happen: EHV Projects Under Development

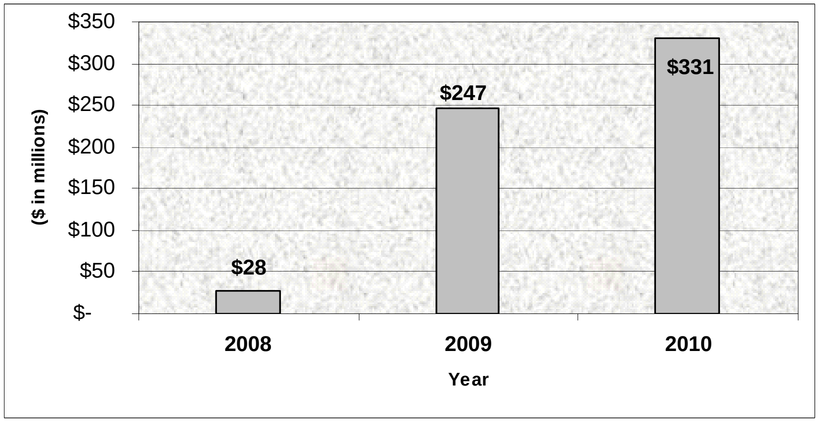


NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Transmission – Investments and Earnings Contributions

AEP

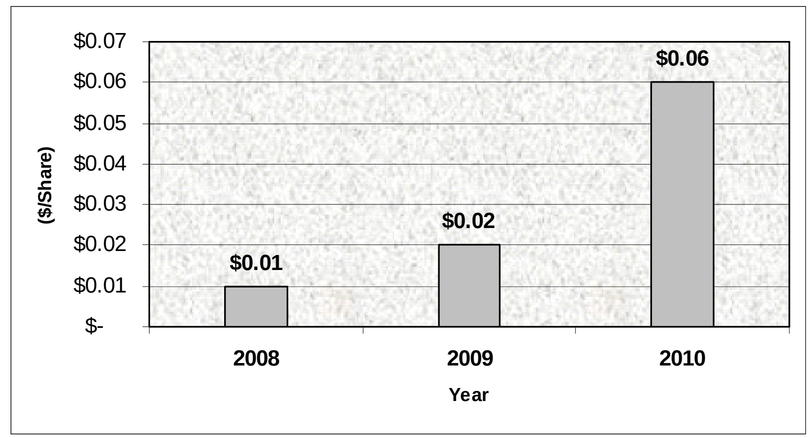
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

Projected Transmission EPS Contributions*



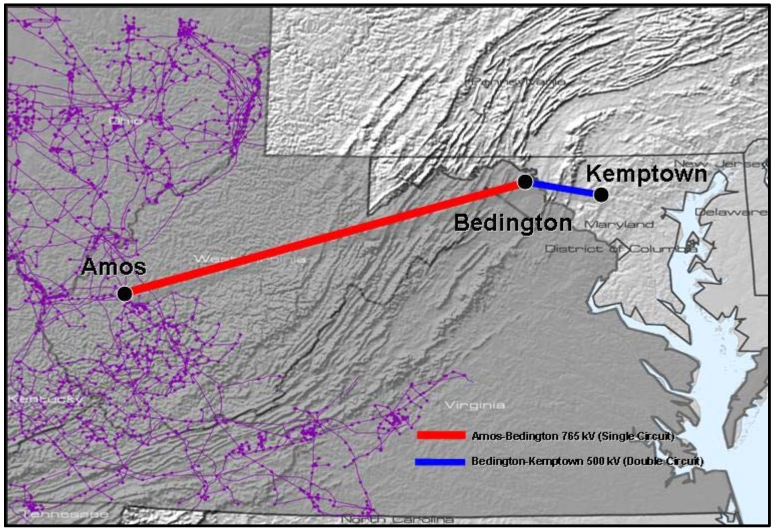
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PATH
Potomac-Appalachian Transmission Highline

Transmission will provide a near and long-term catalyst for earnings growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

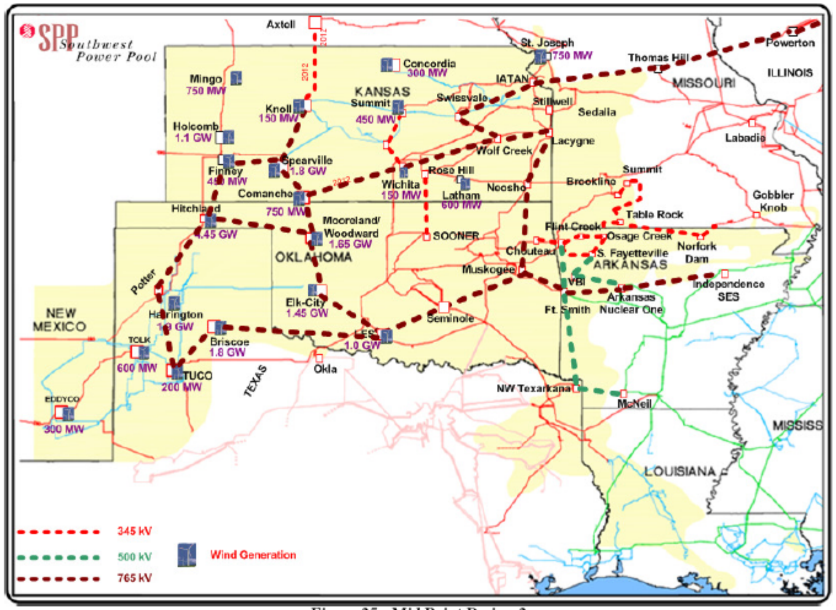


Figure 25: Mid Point Design 2

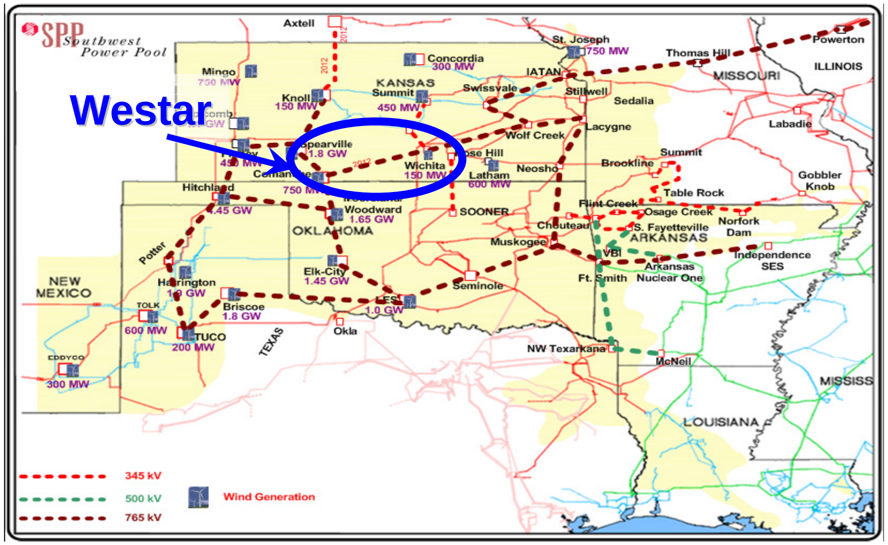
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - Filed CPCN – 2Q2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – Fall 2008
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



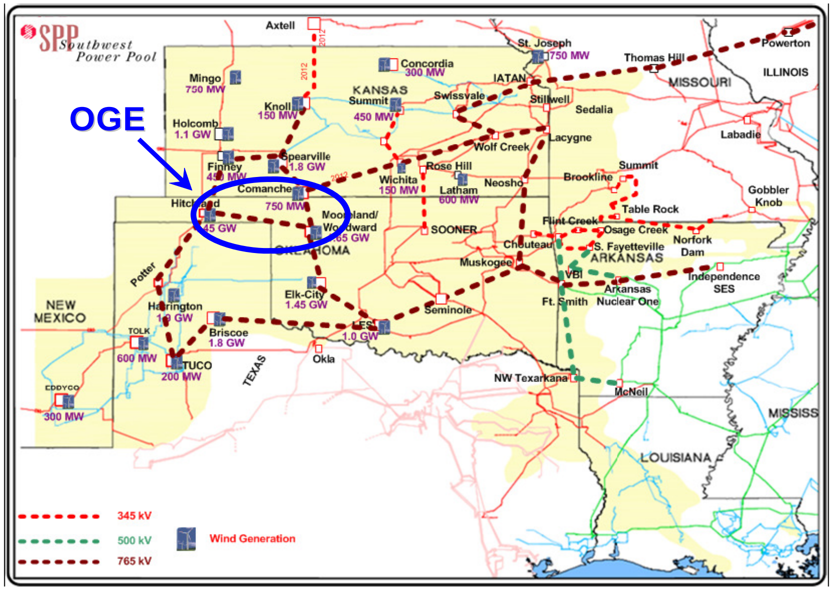
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- ***Next Steps***
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate – Fall 2008
  - SPP Cost Allocation Filing – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013

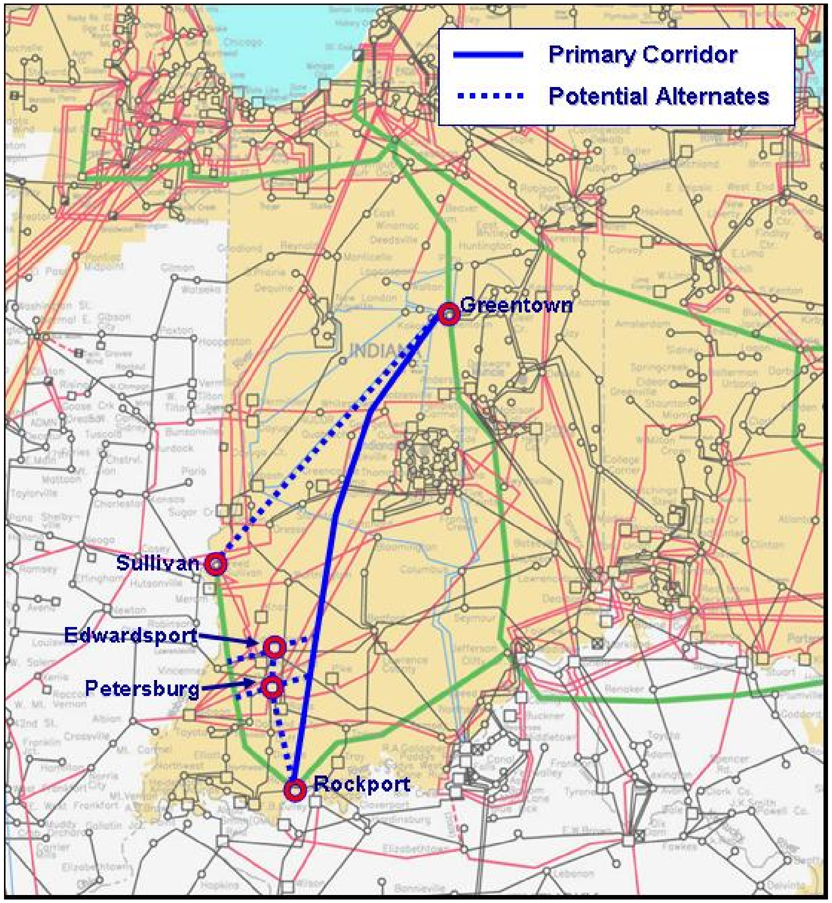


Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on the routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.
- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

Overview

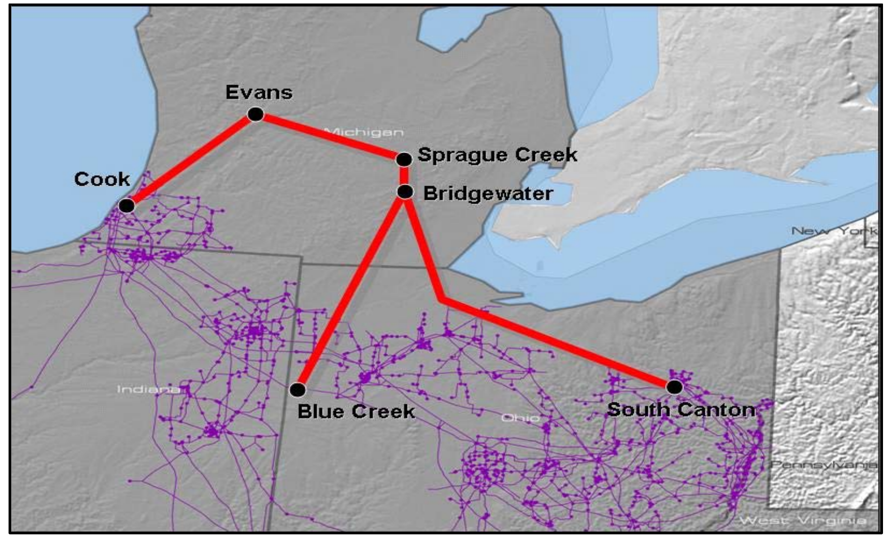
- ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
- Study was released Q3 2007
- 700 miles of 765-kV line in Ohio and Michigan
- $2.6 billion investment (before ownership division)
- AEP and ITC are in discussions to form a Joint Venture

Benefits

- Up to 5,000 MW improved transfer capability
- Reduces network line losses by 250 MW

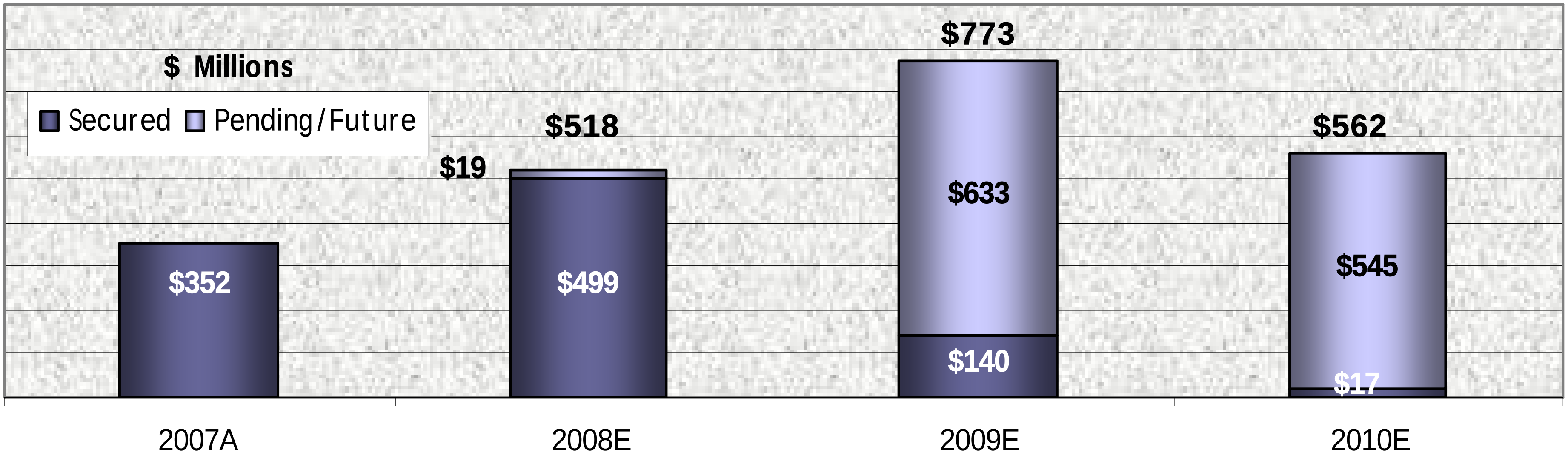
Next Steps

- Agreement on JV (AEP/ITC) - Summer 2008
- JV Formation - 2008
- MISO and PJM Review/Approval - 2009
- FERC Formula Rate & Cost Allocation Filing - 2009
- Siting Approval – 2011-2012
- Estimated Completion – 2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Incremental Rate Relief



- 96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Construction Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.
- 2008 Pending: Virginia base case rates subject to refund ($208MM requested).
- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM requested), Ohio ESP, other cases yet to be filed.

Secured $499MM of $518MM for 2008

Current Regulatory Calendar

	2008						2009					
	JUL	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order							Expected Order					

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing Begins						12/1/08						
Expected Order												Expected Order
Ohio - ESP Filing												
Company Testimony Filed	07/31/08											
Intervenor Testimony				10/31/08								
Staff Testimony				11/07/08								
Hearing Begins					11/17/08							
Expected Order						Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Staff/Intervenor Testimony				10/29/08								
Rebuttal Testimony					11/19/08							
Settlement Conference						12/01/08						
Hearing Begins						12/08/08						
Rates Effective *							01/08/09					

* Subject to refund, with interest

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval
- SWEPCo Stall Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- SWEPCo Stall Plant Filing in Arkansas

AEP Ohio Electric Security Plan

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART[SM] Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony is due October 31, Staff testimony is due November 7 and the public hearing commences on November 17, 2008. We anticipate an order at the end of 2008.

Highlights of AEP Ohio's ESP Filing

		2009		2010		2011		
		CSP	OPCo	CSP	OPCo	CSP	OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		**Other Components**		**Other Components**		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested phase-in of proposed incremental FAC expenses during the three-year ESP period. Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 &PJN-10 provides calculation of environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows the capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: Requested an annual 7% & 6.5% per year increase in Distribution for CSP & OPCo, respectively. Exhibit DMR-4 shows expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response & energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009		2011	
	CSP	OPCo	CSP	OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	-$80.7M	-$27.1M	$22.8M	$15.2M

A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1	*
Rate of Return		8.52%	
Operating Income Requirement	$	205.7	
Adjusted Operating Income	$	79.2	
Difference	$	126.5	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	207.9	

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony was received August 13, Staff testimony was received August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008. A draft air permit approval was released for public comment on August 11, 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued a written order approving construction of the plant on August 12, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding was suspended pending outcome in Louisiana. Now that Louisiana approval has been received, we will seek an expedited ruling from Arkansas.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- The Louisiana PSC approved the plant on September 10, 2008.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

BMO Capital Markets
5th Annual Utilities Conference
New York City
December 1, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

Investor Relations Contacts

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AEP AMERICAN® ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity
- $6.4 billion utility capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

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Transmission Investment Opportunities

- **ETT: Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B in the next decade

- **Transco: Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM

- **Joint Ventures: Outside of our footprint, with ETA or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

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Transco

- **Transco will be used to develop significant new on-system, AEP-owned investment**
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- **Next steps:**
  - Obtain state utility status where required and join PJM and SPP as a transmission owner
  - File FERC tariff for Transco in late 2009, with rates effective and first projects in service in 2010
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

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JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2013

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $600 million+*
- *ROE: 9.96%*

PJM

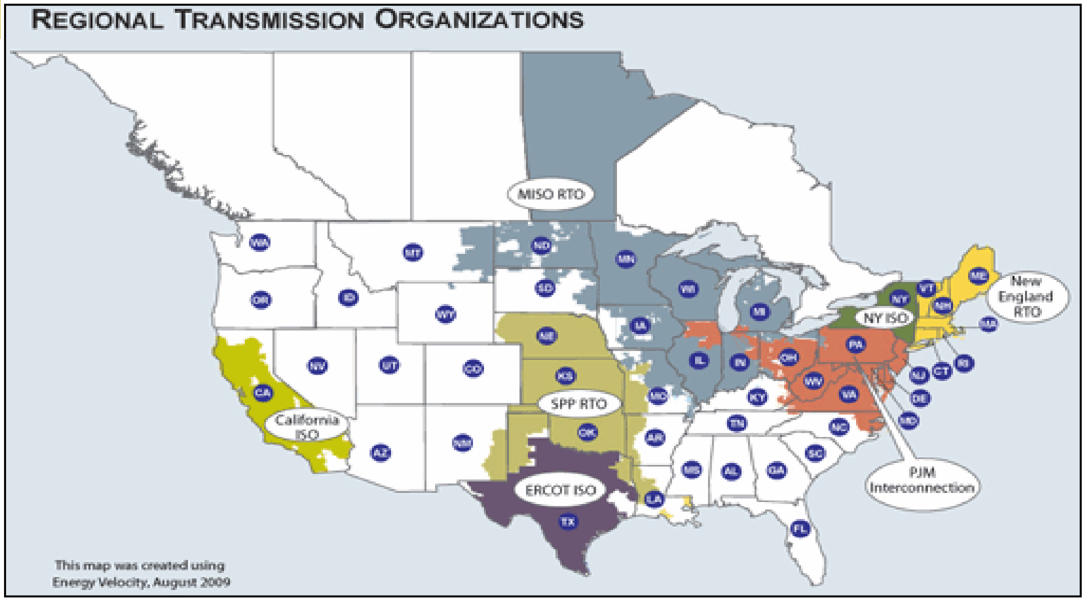
PATH-WV — COD: 2014

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — COD: various

- *Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)*

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP | ERCOT | PJM | PJM/MISO

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EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09

Key Challenges

- Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009 with a decision expected June, 2010.
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
- Estimated completion date: 2014

PATH
Potomac-Appalachian Transmission Highline

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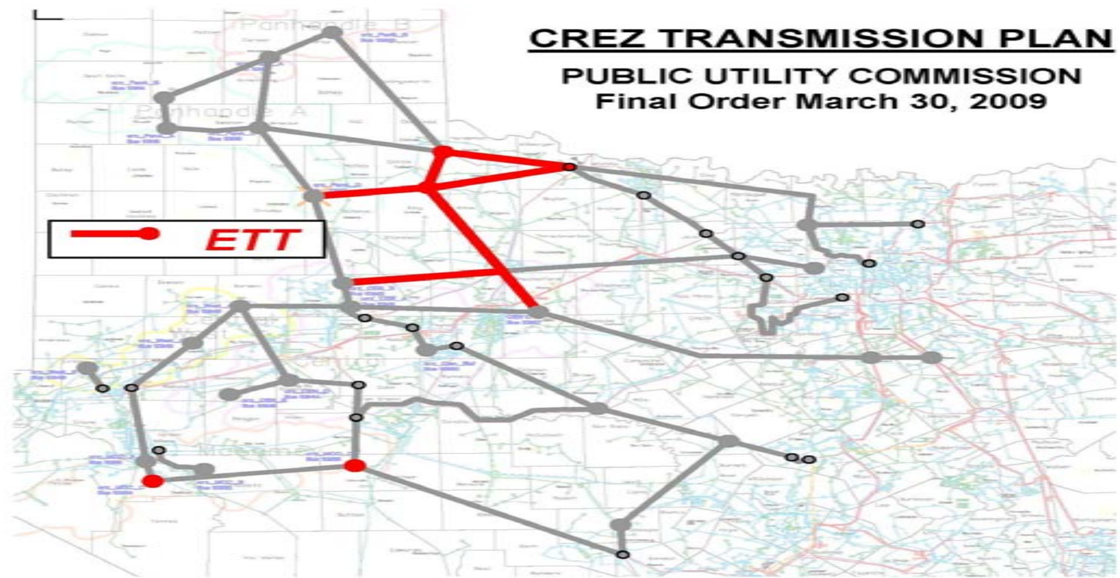
Texas CREZ Project

- On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
- Staging to occur in separate docket and consider timing of wind projects and congestion.
- PUCT established 2 categories based on priorities. ETT has no first priority lines.
- PUCT issued a final order assigning transmission service providers on March 30, 2009.
- ETT's share of CREZ investment is approx. $840MM of $4.9B total of which AEP's ownership is 50%.
- The filing calls for completion of the plan by 2013.



ETT
Electric Transmission Texas

Next Steps

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.

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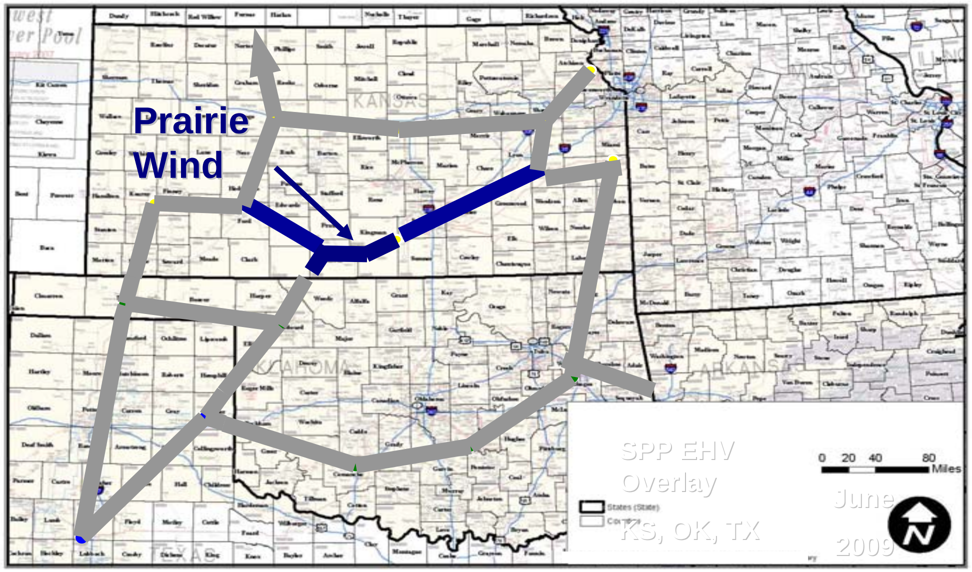
Prairie Wind Transmission, LLC

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- Following a settlement agreement with ITC both entities agreed to split the mileage and costs of building the 765-kV transmission superhighway. The newly revised project is expected to cost approximately $400 million and be in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Regional Cost allocation which enables the development of "system solutions"
- RTO Approval

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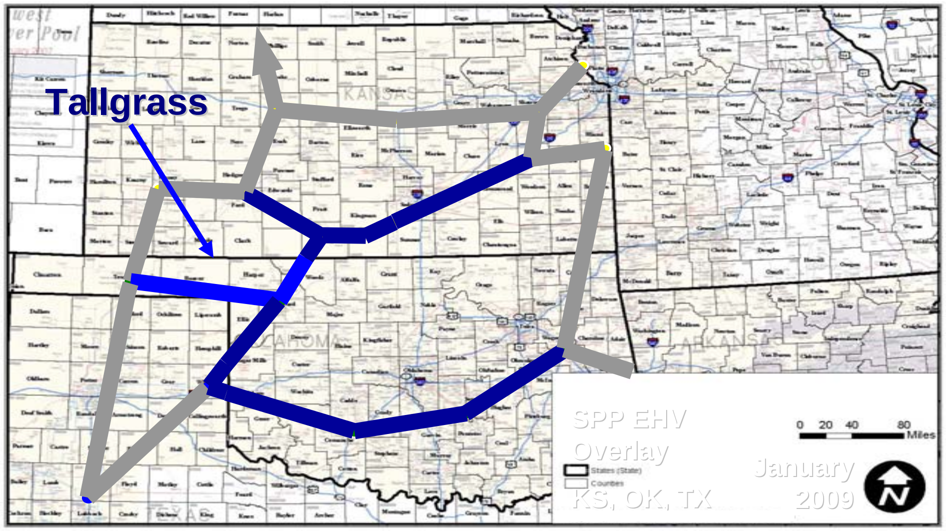
Tallgrass Transmission, LLC

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval

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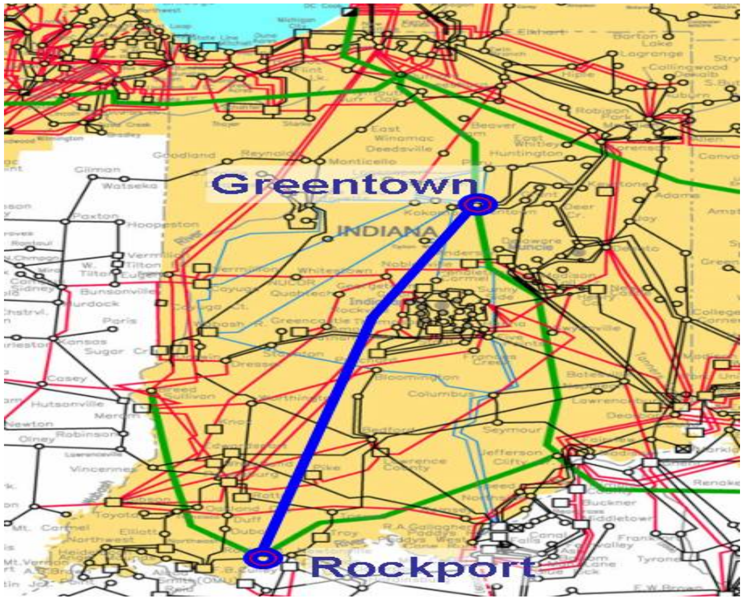
Pioneer Transmission, LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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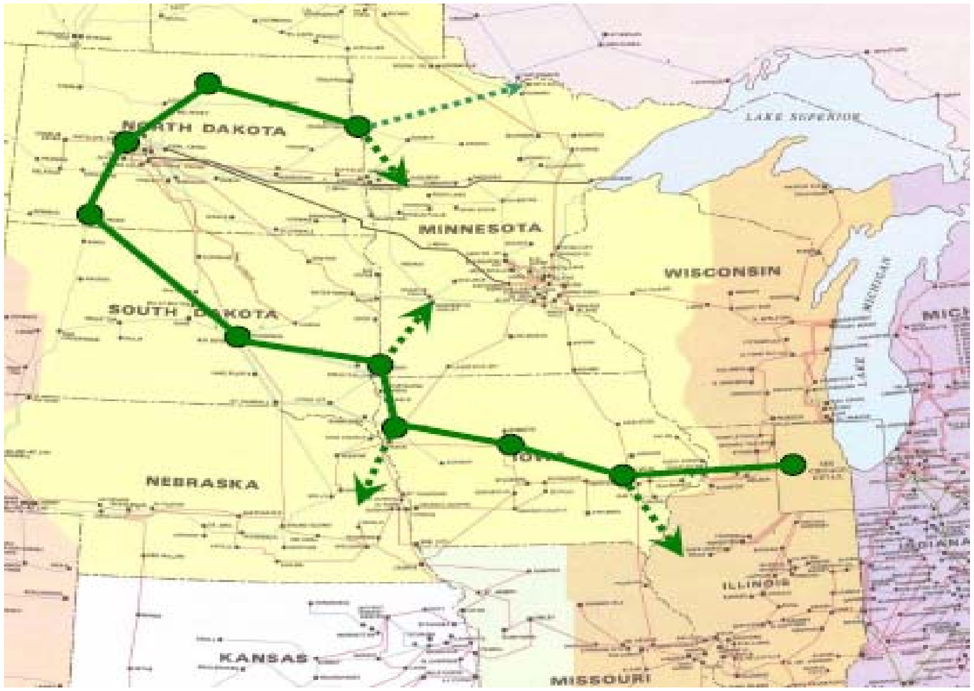
Upper Midwest EHV Development—SMART Study

- **Announced SMARTransmission Study in August 2009.**
  - Participants include ETA, Exelon, ATC, Northwestern, MidAmerican and Excel
  - Study due to be completed in early 2010 and will include “overlay” options and quantification of economic benefits.
- **Near Term Risks**
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including incentives
- **Mitigation**
  - Collaborative approach involving impacted utilities, RTOs, commissions and others



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New Generation Projects

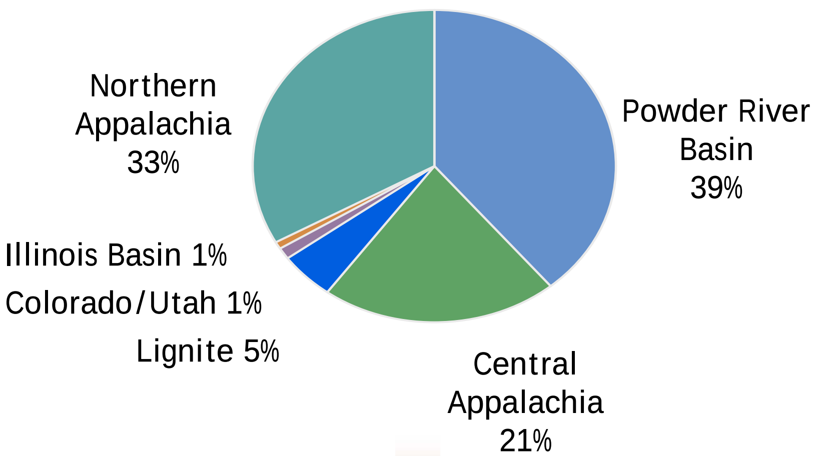
- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $378 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

Coal Procurement - 2010 Projected

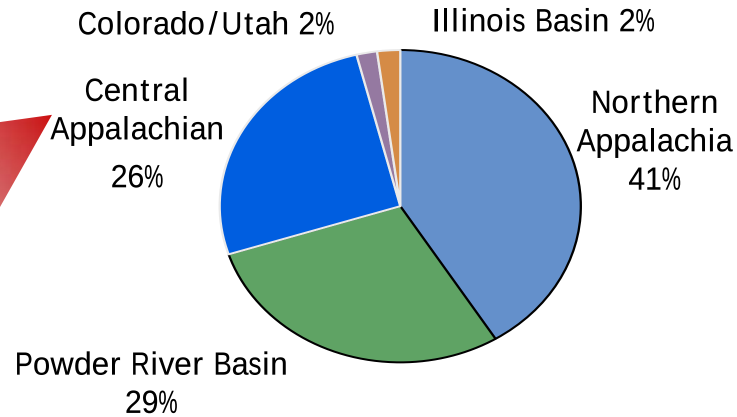
Total AEP System



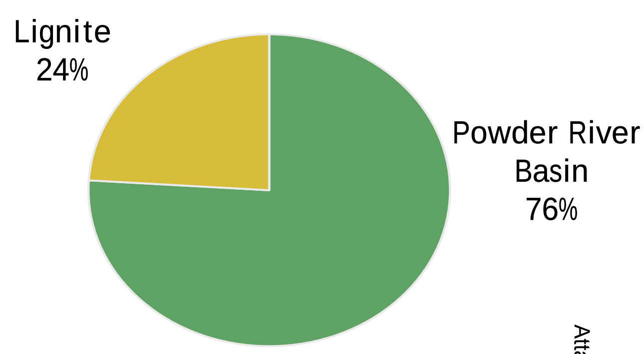
Coal Stats:

- 100% contracted for 2009 and 98% for 2010
- Avg. delivered price ~ $47/ton in 2008
- Approximate 10% price increase in 2009 ~ $51/ton
- Approximate 10% price decrease in 2010 ~$46/ton

AEP East



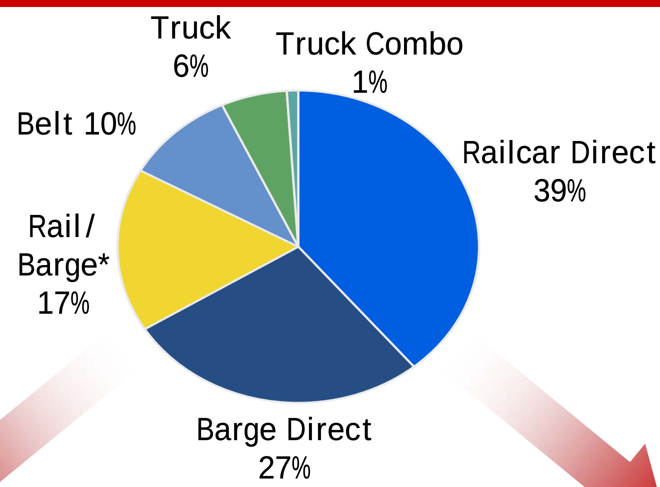
AEP West



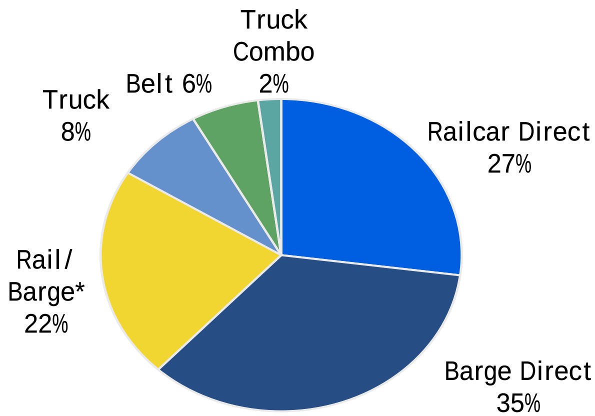
Coal Delivery

Total AEP System

2008 Actual



AEP East



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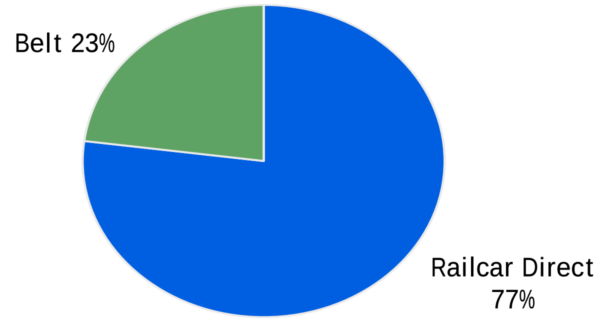
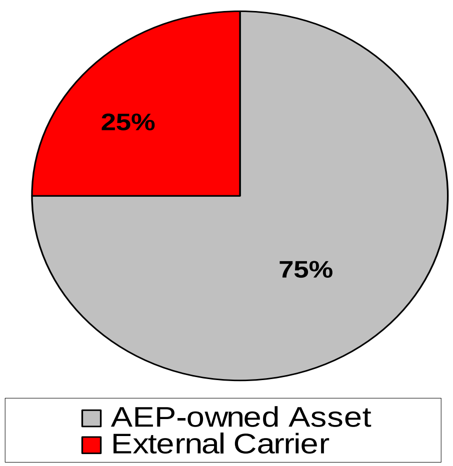


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Coal Transportation Assets

2008 Actual

Coal Transportation to AEP Plants*



***Represents close approximations**

Current Coal & Transportation Assets:

- Control over 9,000 railcars
- Own/lease and operate over 2,978
- barges & 58 towboats & 25 harbor boats
- Coal handling terminal with 20 million tons of capacity

AEP River Operations

- Full-service Inland Waterways carrier
  - 2,978 hopper barges
  - 58+ towboats/25 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

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AEP Supports Climate Legislation

Key Design Elements:

- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program –** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program –** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues –** Full, free allocation to electric sector and "Low" auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

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Mountaineer CCS Update

PROJECT STATUS

- September 2 – successfully captured CO_2
- October 1 - began underground injection and storage
- October 30 – facility dedicated

NEXT STEPS

- Monitor the CO_2 behavior once underground
- Assess the parasitic load impact of the equipment on the plant
- DOE funding requested for 50% of commercial phase of project ($334MM); project expected to be operational between 2012 and 2015

PROJECT DESCRIPTION

- Alstom's chilled ammonia process captures CO_2 from a 20 MWe slipstream of flue gas at AEP's Mountaineer plant located in New Haven, WV
- Captured CO_2, transformed to a semi-liquid state, is pumped into sandstone or dolomite layers approximately 1.5 miles underground. Caprock will hold the CO_2 in place permanently.

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030) A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

12/12/2009 Rates effective, subject to refund
12/28/2009 Intervenor testimony due
1/27/2010 Staff testimony due
2/17/2010 Rebuttal testimony due
3/16/2010 Evidentiary hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.
Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case

On August 28, 2009 SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. (Docket# 37364) An order is expected in 2010.

Projected Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Feb 8	Intervenor Testimony
Feb 15	Staff Testimony
March 1	SWEPCO Rebuttal Testimony
March 15	Hearing

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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2010 Ongoing Earnings Guidance

	2009E: $2.90-$3.05	2010E: $2.80-$3.20
Utility Operations	$ 2.92	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.18	$ 0.09
Parent & Other	$(0.14)	$(0.12)

EARNINGS DRIVERS

- ↑ $317MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

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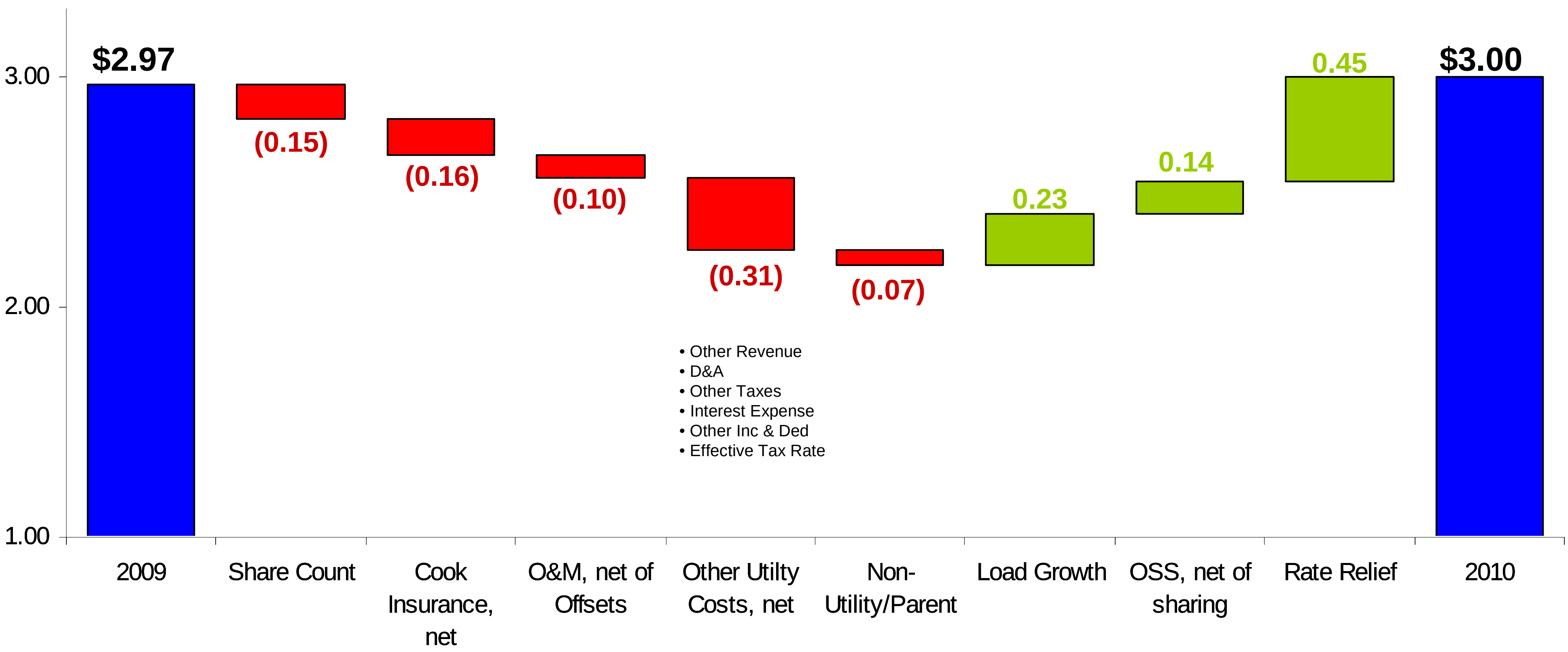
2010 Earnings Drivers



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Detailed Ongoing Earnings Guidance

2009E: $2.90 - $3.05

American Electric Power
2009 Guidance vs. 2010 Guidance

2010E: $2.80 - $3.20

#		Performance Driver	2009 Guidance ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,754 GWh @ $ 38.4 /MWhr =	2,562	68,249 GWh @ $ 42.1 /MWhr =	2,873
2	Ohio Companies	47,284 GWh @ $ 57.8 /MWhr =	2,733	47,922 GWh @ $ 61.9 /MWhr =	2,968
3	West Regulated Integrated Utilities	39,112 GWh @ $ 29.8 /MWhr =	1,166	41,495 GWh @ $ 31.3 /MWhr =	1,298
4	Texas Wires	27,208 GWh @ $ 21.1 /MWhr =	575	27,510 GWh @ $ 21.9 /MWhr =	602
5	Off-System Sales (Net of Sharing)	13,525 GWh @ $ 16.7 /MWhr =	226	23,992 GWh @ $ 13.4 /MWhr =	322
6	Transmission Revenue - 3rd Party		356		353
7	Other Operating Revenue		779		554
8	Utility Gross Margin		8,397		8,970
9	Operations & Maintenance		(3,309)		(3,546)
10	Depreciation & Amortization		(1,582)		(1,625)
11	Taxes Other than Income Taxes		(768)		(791)
12	Interest Exp & Preferred Dividend		(924)		(986)
13	Other Income & Deductions		124		168
14	Income Taxes		(597)		(742)
15	Utility Operations On-Going Earnings		1,341		1,448
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		36		2
	Non-Utility Operations On-Going Earnings		83		45
19	Parent & Other On-Going Earnings		(64)		(58)
20	ON-GOING EARNINGS		1,364		1,444

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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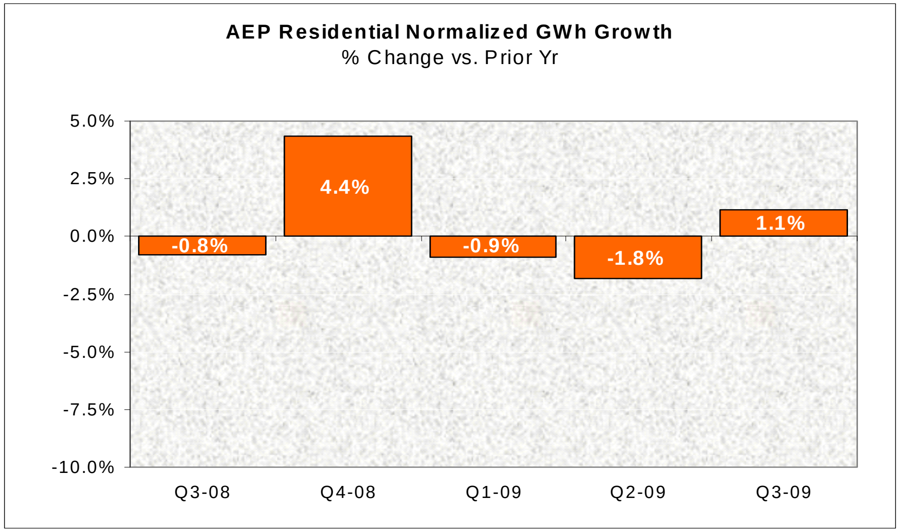
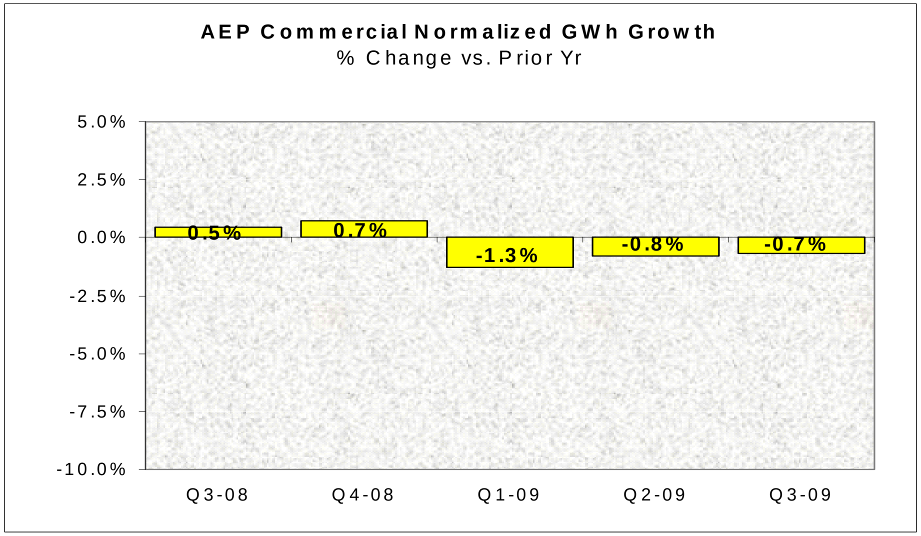
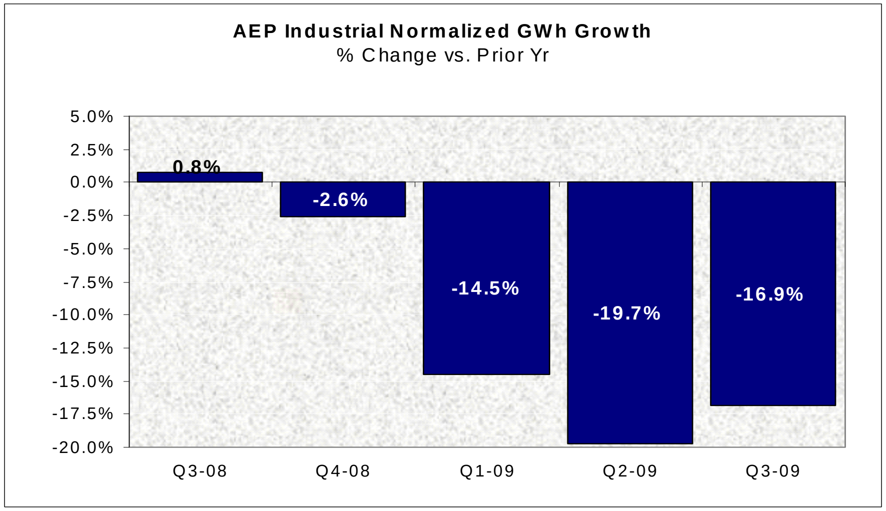
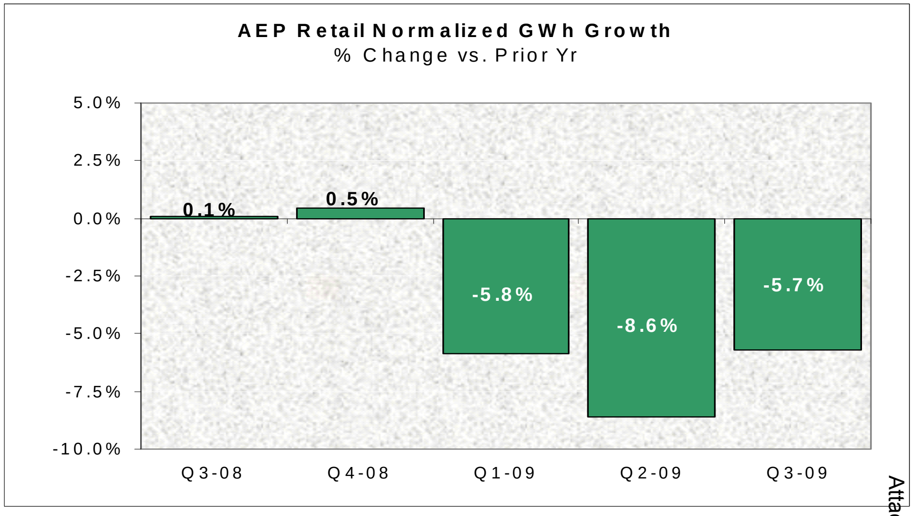
12-Month Normalized Retail Load Trends







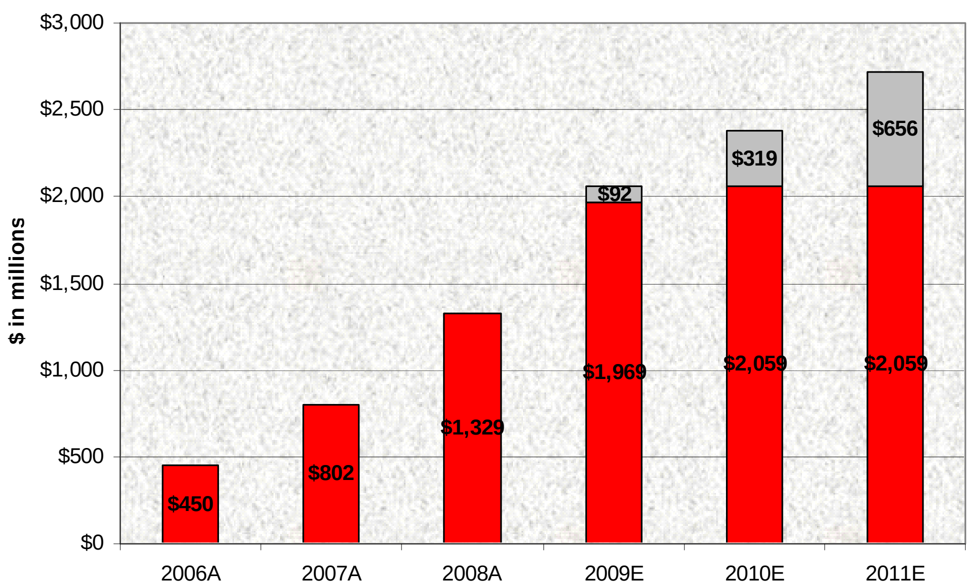


AMERICAN®
ELECTRIC
POWER

Investment in Utility Platform

Track Record of Rate Relief

Cumulative Rate Relief

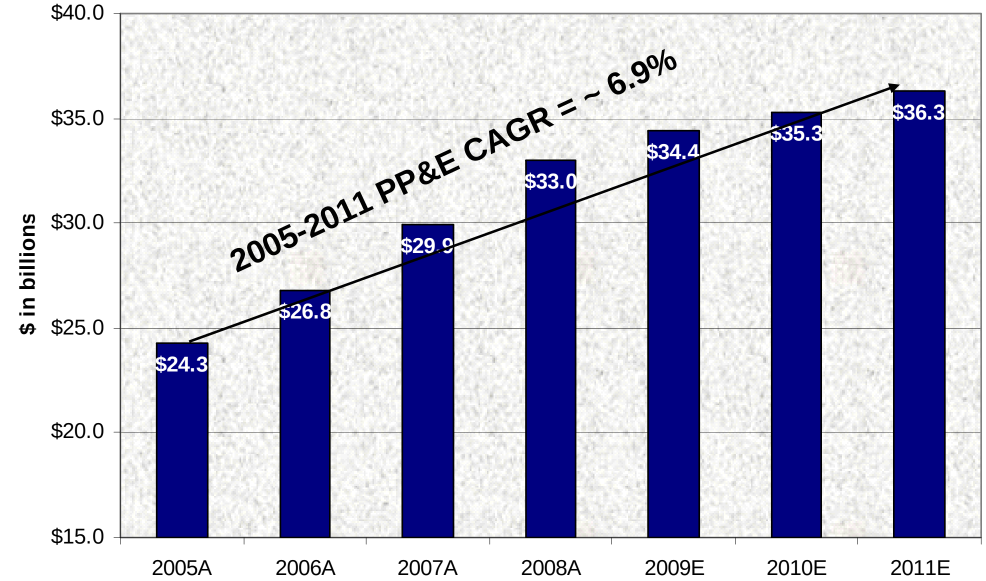


Annual rate increases, $mm	$450	$352	$527	$732	$317[1]	$337

[1] *$90mm was secured for 2010 as of October 30, 2009*

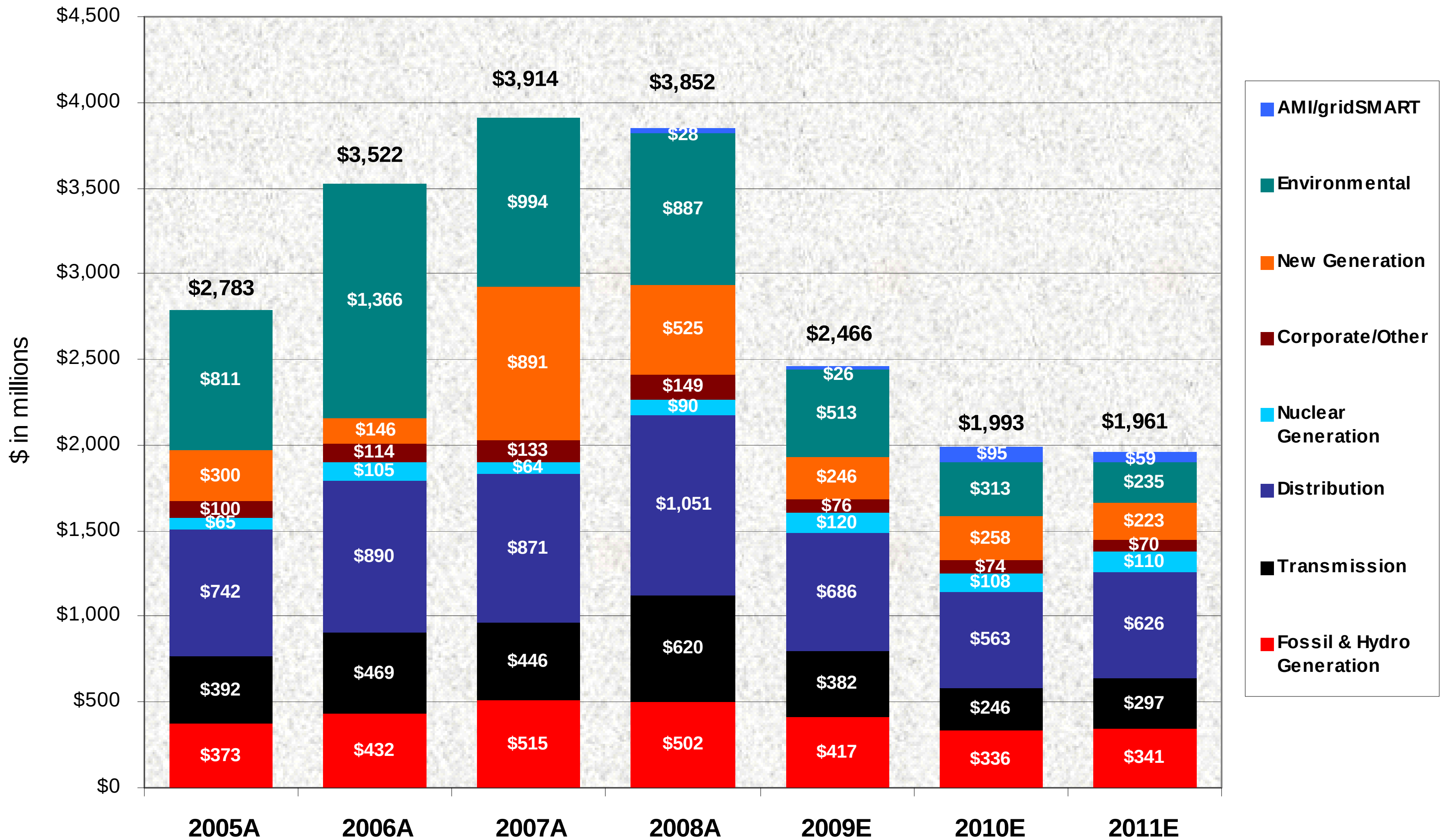
Growth in Net PP&E

Net PP&E



AEP AMERICAN® ELECTRIC POWER

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

AEP AMERICAN ELECTRIC POWER

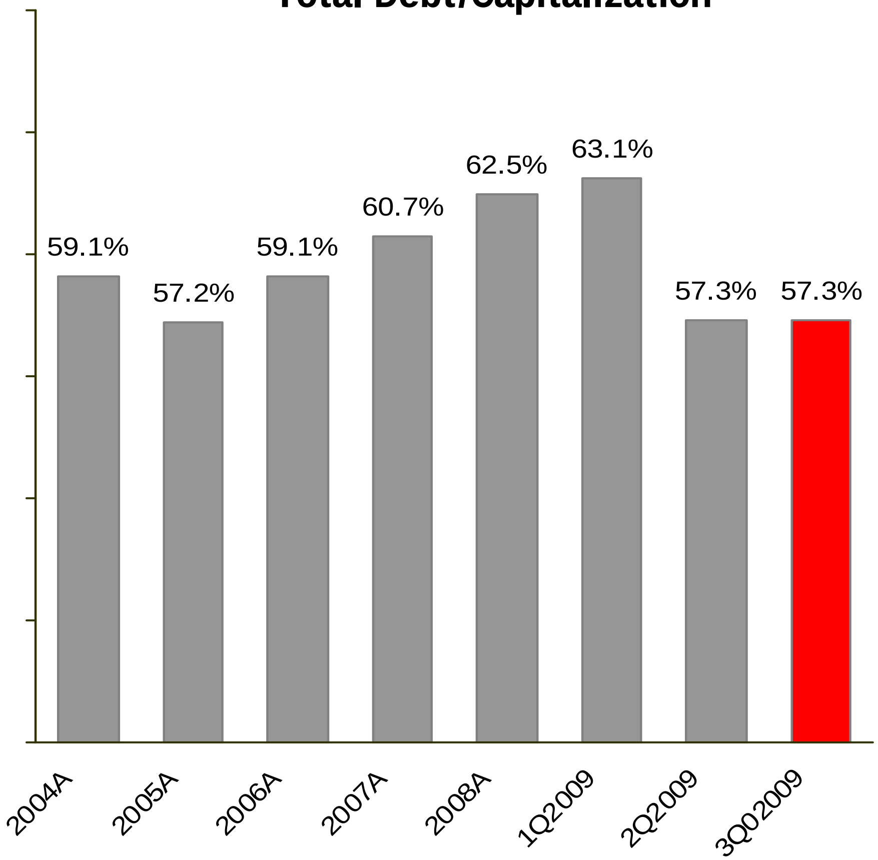
Multi-Year Capital Investment Funding Plan

		Actual 2008		Projection 2009			Projection 2010
Capital Expenditures (Excluding AFUDC)	$	(3,967)	$	(2,885)	*	$	(2,127)
Transmission Initiatives (JV Equity Contributions)		0		(49)			(93)
Dividend on Common Stock		(660)		(759)			(790)
Cash Sources (Uses)							
Cash from Operations		2,576		2,263			3,259
Proceeds from Sale of Assets		90		258			-
Common Stock Issued		159		1,744			150
Change in Debt, Net		2,266		(346)			(127)
Other		(231)		(436)			(274)
Change in Cash		233		(210)			(2)
Ending Cash Balance	$	411	$	201		$	199

* - 2009 capital expenditure projection includes $340MM of construction-related accounts payable at 12/31

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 09/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Ratings current as of September 30, 2009

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AEP AMERICAN ELECTRIC POWER®

Long-term Debt Maturity Profile

($ in millions)

Year		2010		2011		2012
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	680	$	-	$	-
Public Service of Oklahoma	$	150	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company (1)	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,735	$	623	$	415

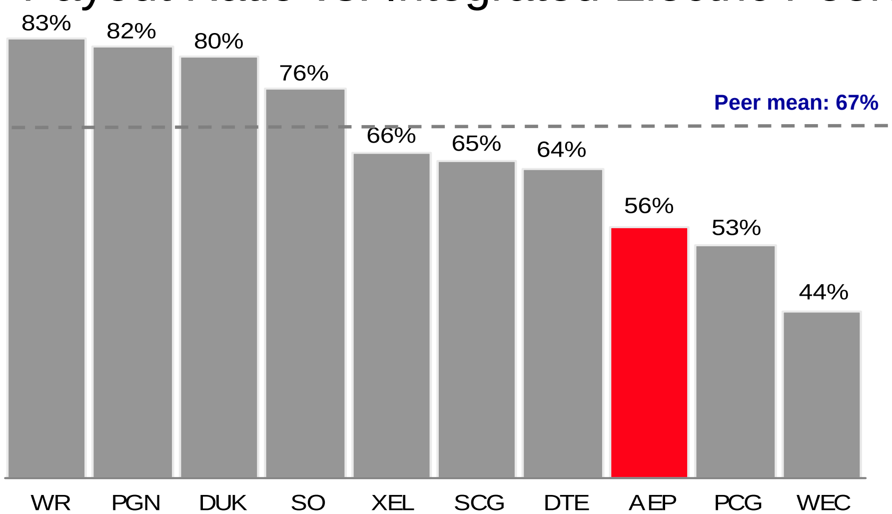
(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)
Data as of September, 30 2009

AEP AMERICAN ELECTRIC POWER

Dividend Overview

- We have declared 398 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

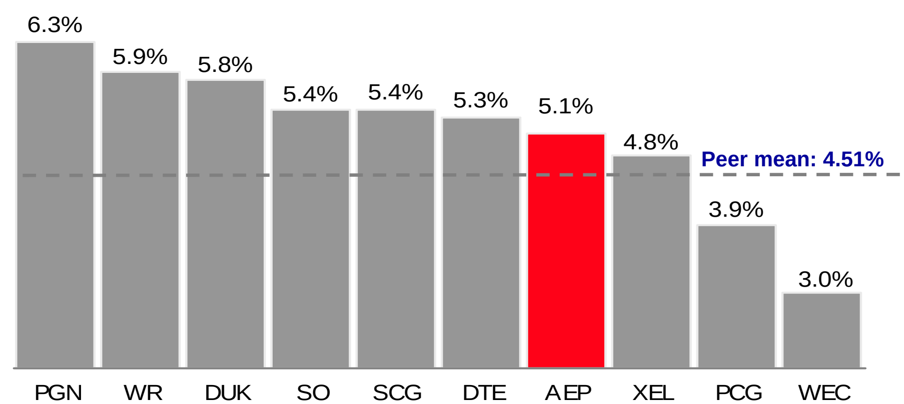
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 11/23/09

Dividend Yield vs. Integrated Electric Peers



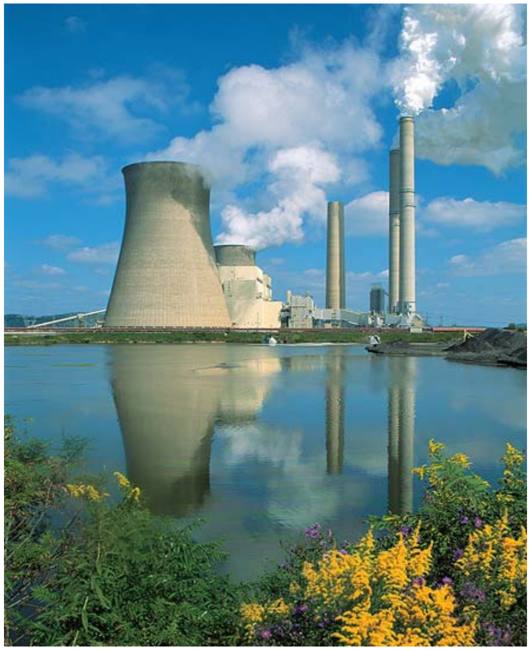
Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 11/23/09

AEP AMERICAN ELECTRIC POWER

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment
- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



General JM Gavin Plant (OH)

BMO Capital Markets
Investor Meeting


AEP AMERICAN ELECTRIC POWER®


March 21, 2007

Columbus, Ohio

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Participants:

Carl English	President, AEP Utilities
Craig Baker	SVP Regulatory Services
Kevin Walker	President, AEP Ohio

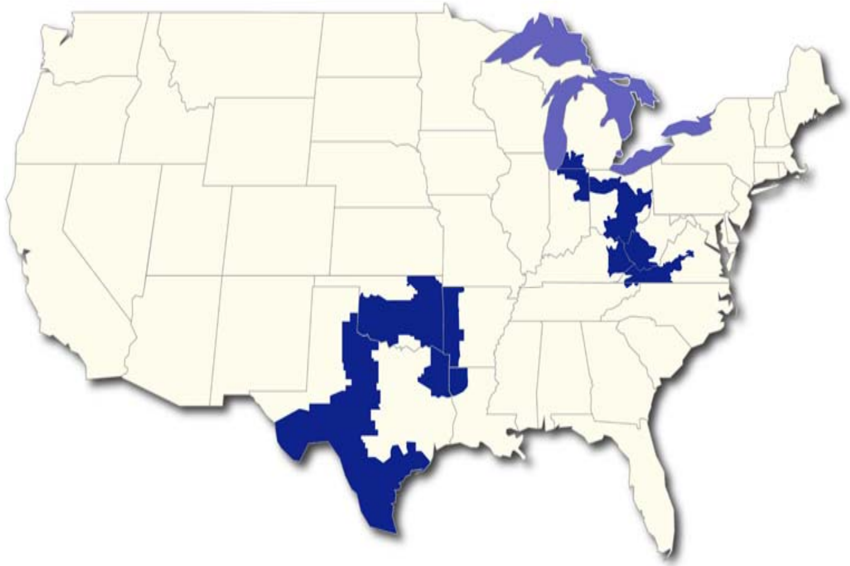
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

AEP®

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

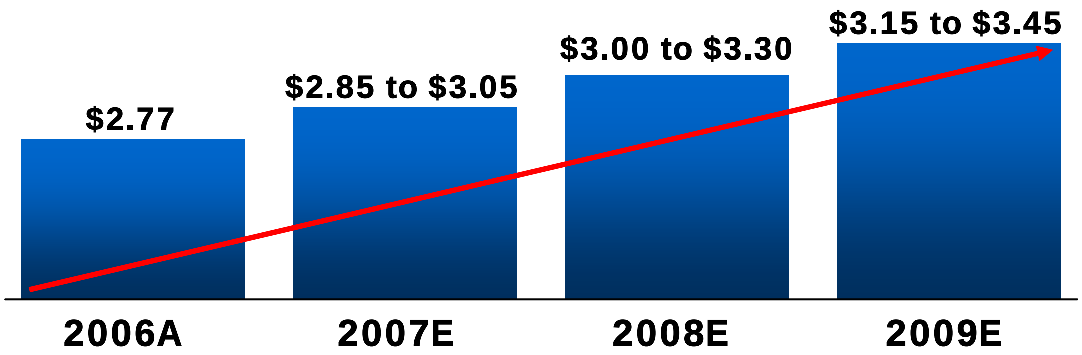
Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

AEP®

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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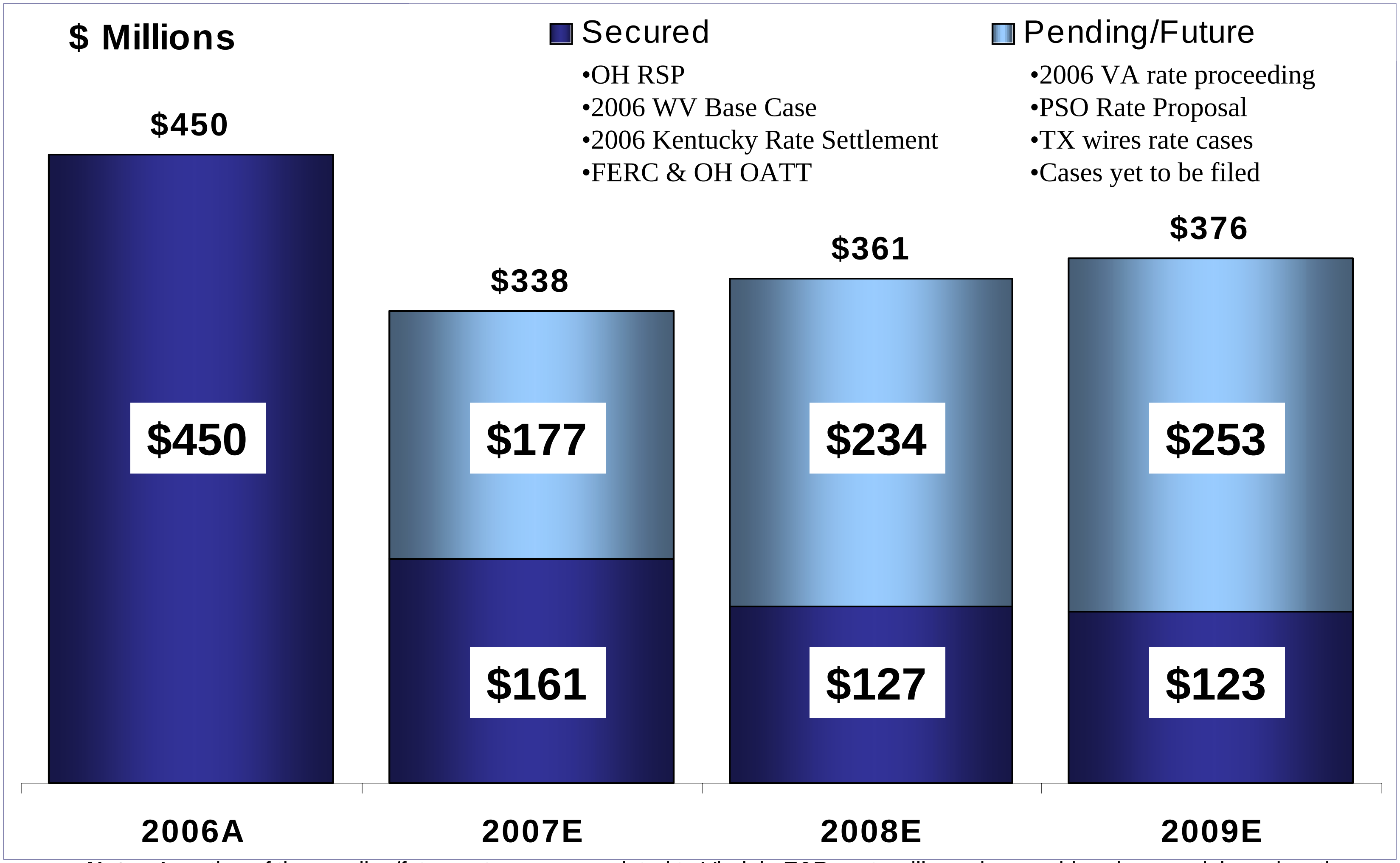
RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Incremental Rate Relief Composition



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

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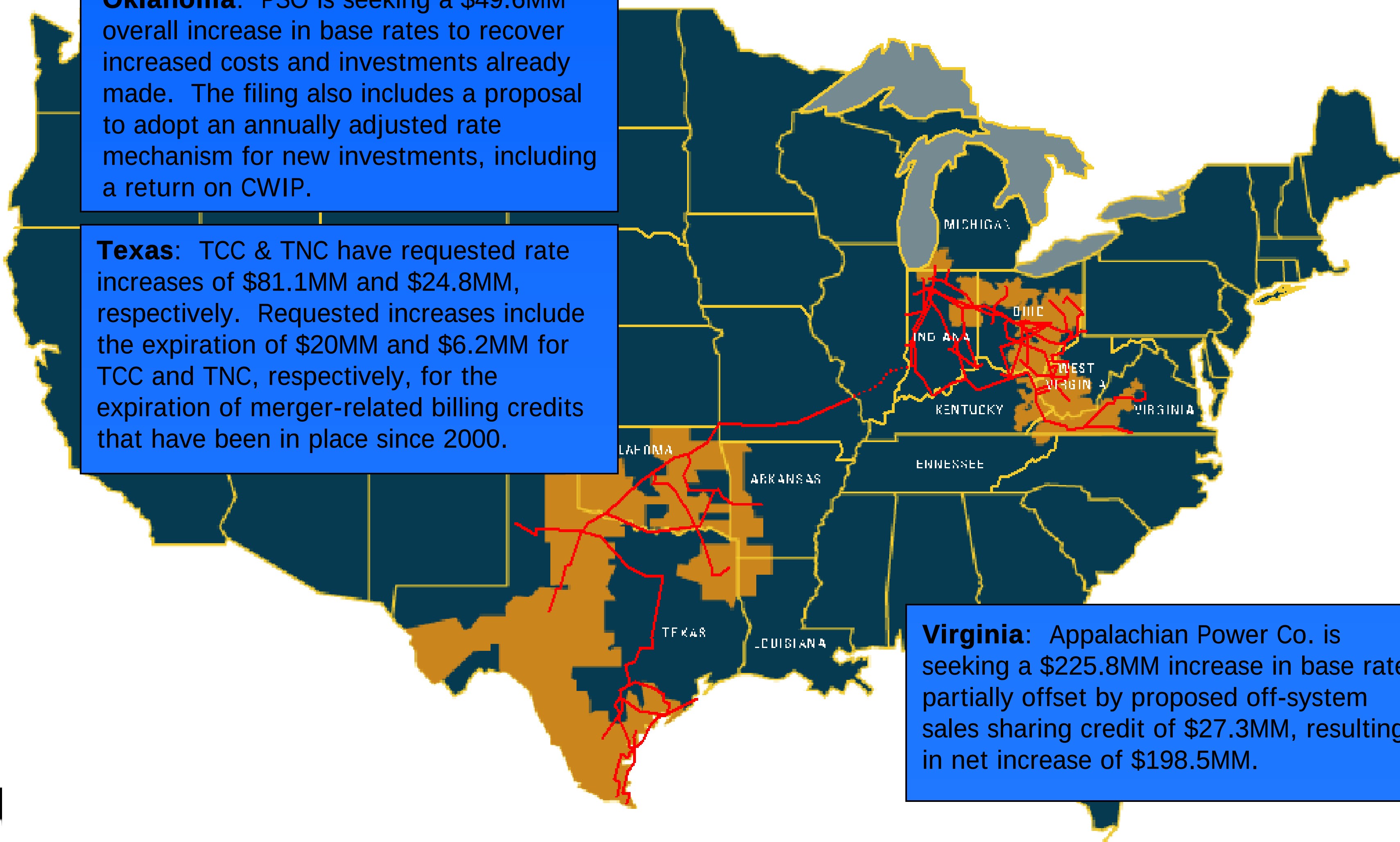
RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Base Case Regulatory Summary

Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.



Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval 1) to operate as an electric transmission utility in Texas; 2) to contribute transmission assets currently under construction by AEP subsidiary TCC to the joint venture company; and 3) establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%
  - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in early to mid-2007.

Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 6, 2006	Hearings commenced
February 5, 2007	Briefs filed

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base $2.3 billion

Next Steps

APCo is now awaiting an initial recommendation from the Hearing Examiner (HE). APCo will have an opportunity to respond to the HE recommendation after it has been issued. Following this action, we then await an order from the SCC. No statutory deadline.

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. TCC and TNC requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony filed
March 23, 2007	Staff testimony due
Mid-April 2007	Hearings to commence
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	11.25%	4.50%
Total	100%		8.02%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	11.25%	4.50%
Total	100%		7.97%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$588,170,858	$ 1,012,316,518
Cost of Capital	8.02%	8.02%
Return on Rate Base	$ 47,144,247	$ 81,141,219
Operation & Maintenance	$ 24,953,569	$ 234,900,166
Depreciation & Amortization	$ 16,050,664	$ 61,560,580
Income Taxes	$ 13,127,245	$ 21,909,492
Taxes other than Income	$ 14,691,850	$ 65,648,324
Total Cost of Service	$115,967,575	$ 465,159,781
Miscellaneous Revenues	$ (4,557,543)	$ (33,982,023)
Base Rate Revenue Requirement	$111,410,032	$ 431,177,758
Test Year Adjusted Base Rate Rev.	$ 90,790,725	$ 390,700,744
Requested Base Rate Increase	$ 20,619,307	$ 40,477,014

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$171,049,145	$ 288,872,851
Cost of Capital	7.97%	7.97%
Return on Rate Base	$ 13,639,241	$ 23,034,353
Operation & Maintenance	$ 12,775,116	$ 60,434,214
Depreciation & Amortization	$ 12,206,069	$ 28,670,726
Income Taxes	$ 3,126,651	$ 5,279,031
Taxes other than Income	$ 3,661,924	$ 12,093,639
Total Cost of Service	$ 45,409,001	$ 129,511,963
Miscellaneous Revenues	$ (365,848)	$ (7,216,050)
Base Rate Revenue Requirement	$ 45,043,153	$ 122,295,913
Test Year Adjusted Base Rate Rev.	$ 36,025,589	$ 112,706,901
Requested Base Rate Increase	$ 9,017,564	$ 9,589,012

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

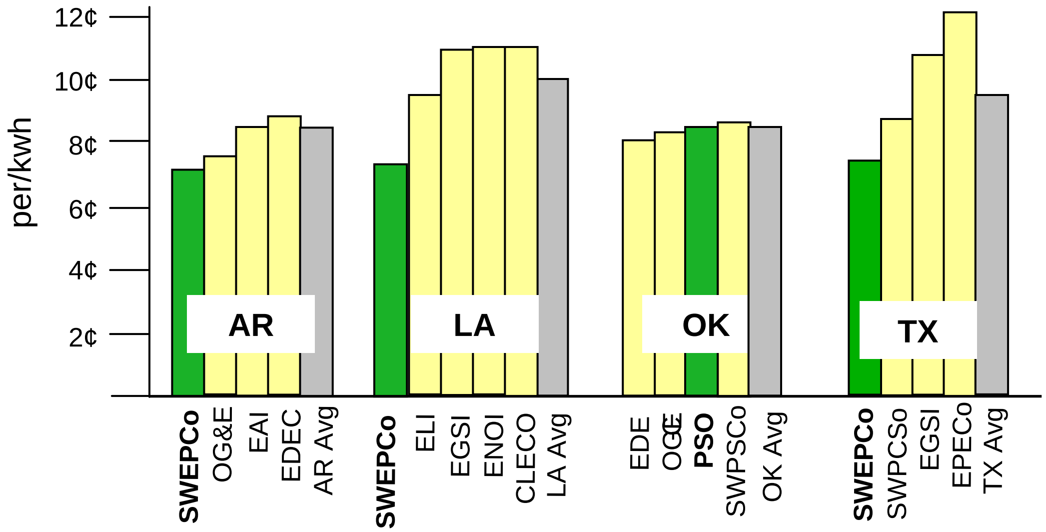
* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor testimony due
April 9, 2007	Rebuttal testimony due
May 1, 2007	Hearings to commence
June 20, 2007	Final order expected

AEP Provides Low Cost Electric Service

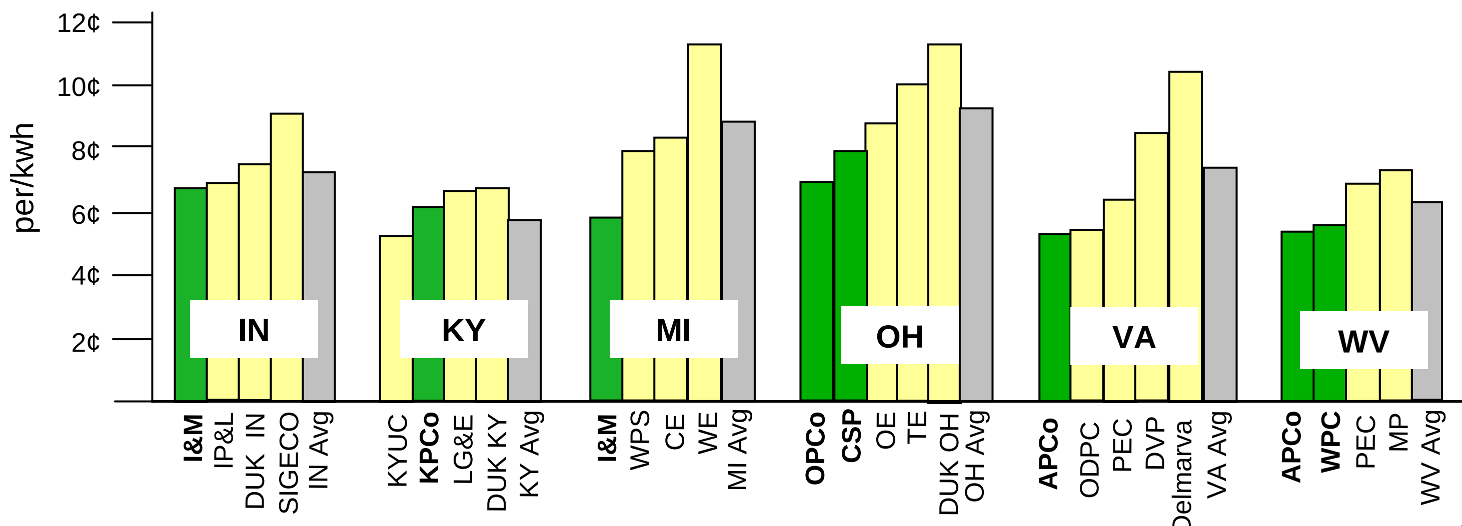
AEP West



Residential Average rates 12 months ended 6/30/2006

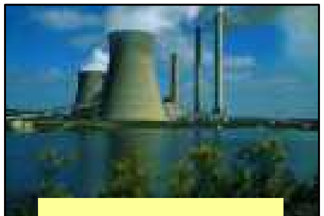
Source: Summer 2006 EEI Typical Bills and Average Rates Report.

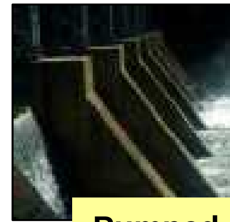
AEP East

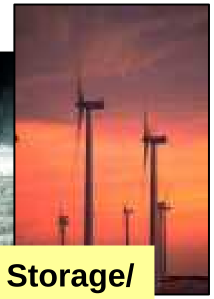


2006-2009 Projected Annual Rate Increase Of 3.8%

Domestic Generation Fleet







Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,292 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

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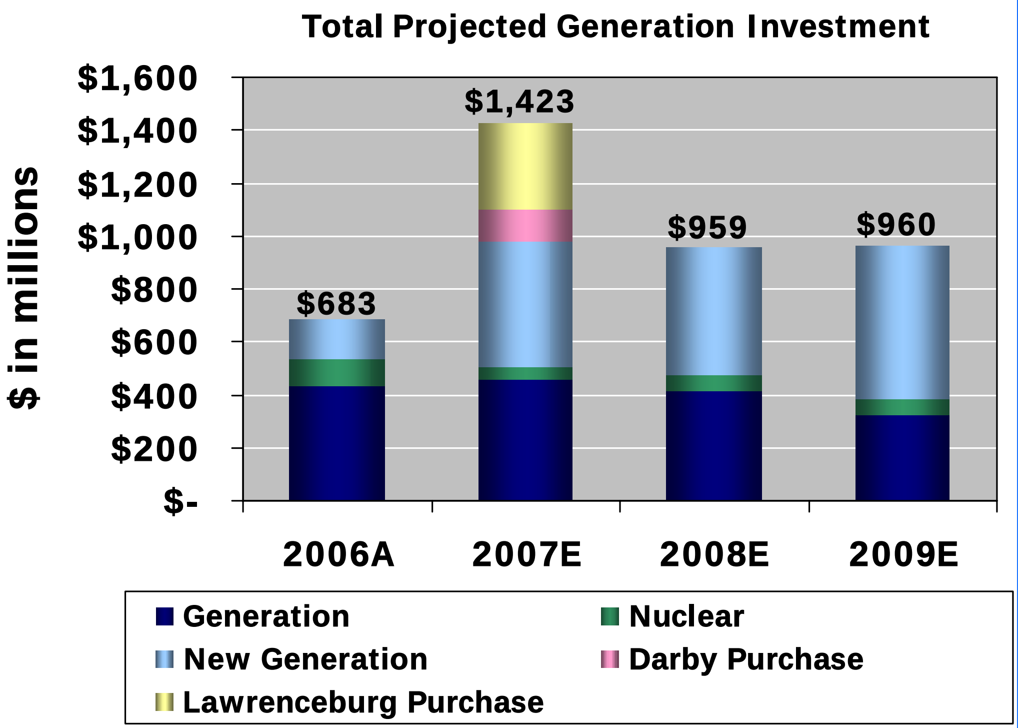
New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2011
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale expected to close 2Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP
- Purchased Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 45% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 48% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 25,746 MEGAWATTS

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	539*	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

* Oklaunion's MW capacity represents combination of PSO, TCC & TNC ownership. TCC's 54 MW ownership of Oklaunion is currently under negotiation for sale.

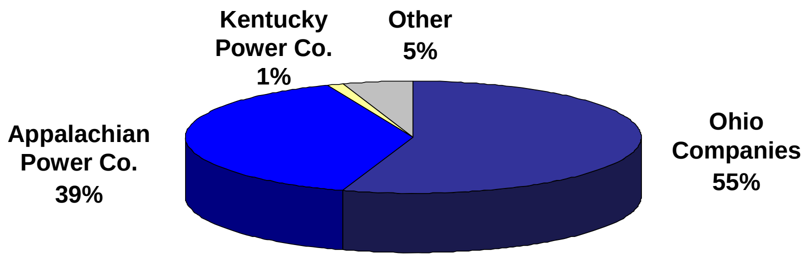
AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

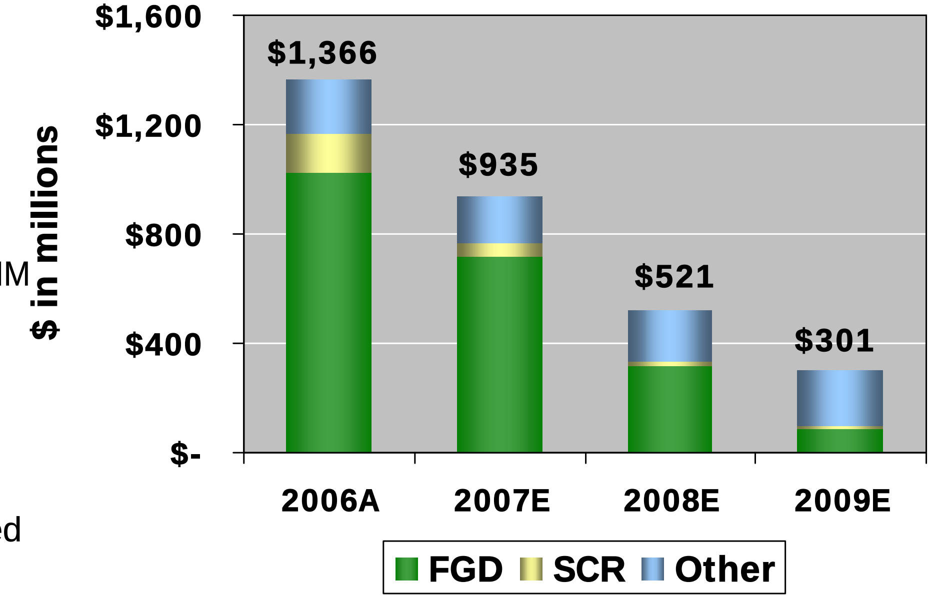
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures, pursuant to the 4% provision of the RSP
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

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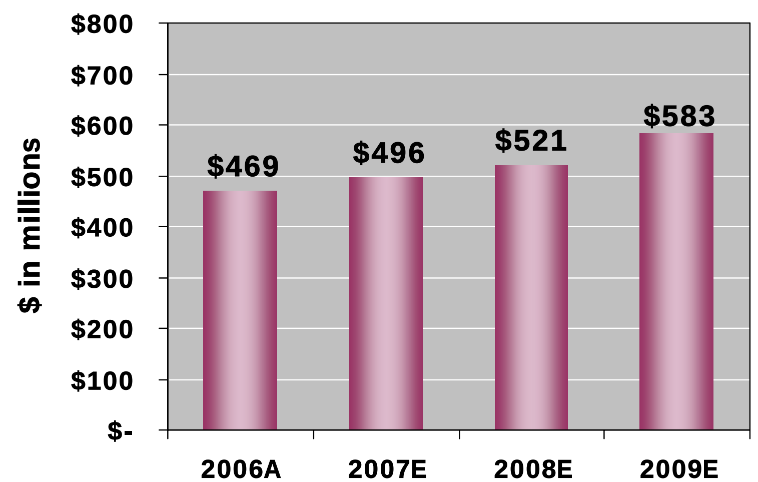
Transmission Investment Forecast

- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of “postage stamp” rate
  - Final order expected in early to mid-2007
- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services
- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company and to set initial rates
  - FERC filing to transfer transmission assets to ETT submitted Feb. 15, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

AEP Transmission Network – Largest in the Country

Operating Company Level
(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP ®

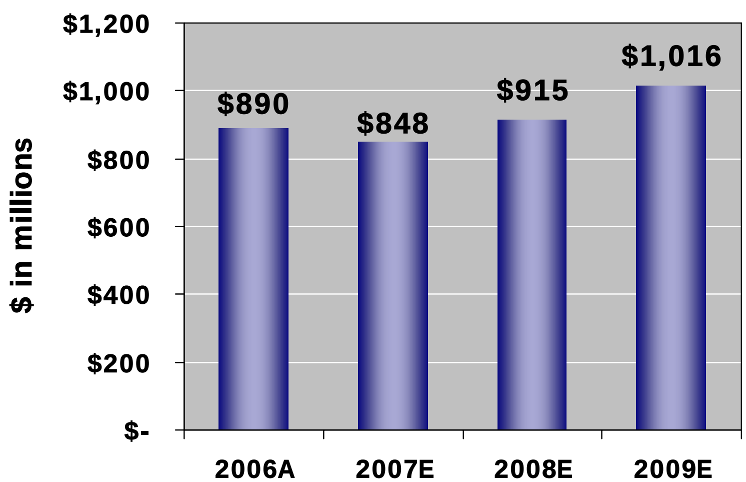
AEP Is The Leader In Transmission Expertise

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an average annual investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $60.8MM and $15.9MM for TCC & TNC distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP®

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

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2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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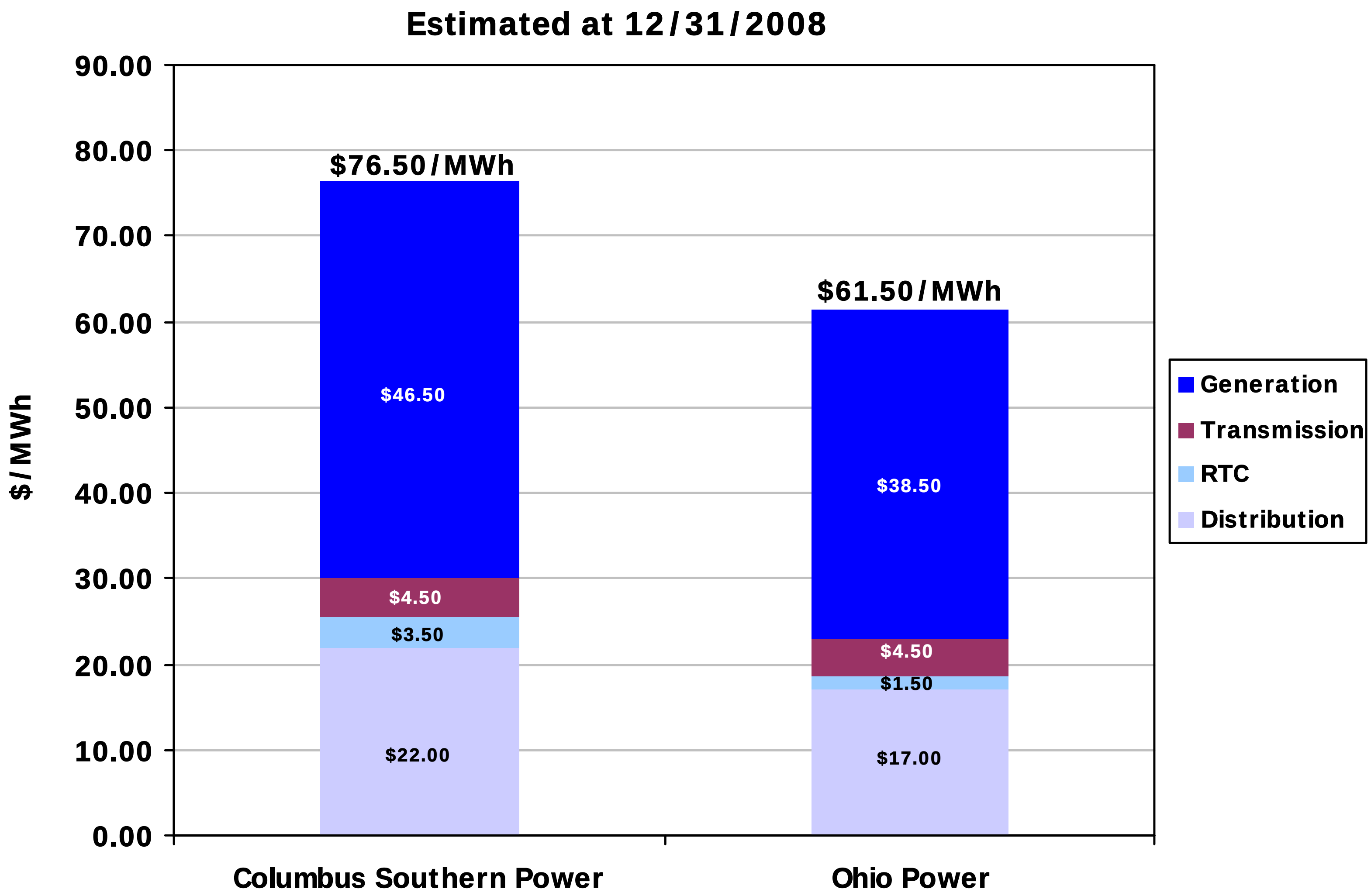
Average Unbundled AEP Ohio Rates



BMO Capital Markets Conference

New York, NY
December 5, 2006

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Chairman, President & CEO

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Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- **More than 36,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)**
- **Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.**
- **Nearly 208,000 miles of overhead and underground distribution lines**

With our coal and transportation assets we:

- **control over 7,000 railcars**
- **own and/or operate over 2,300 hopper barges and 53 towboats**
- **operate one active coal-handling terminal with 20 million tons of capacity**

We consume approximately 75 million tons of coal annually.

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

Deliver value to our investors

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Framework For Long-Range Performance

- 2006, 2007, 2008 & 2009 Earnings Guidance Ranges:

2006 Range $2.65 to $2.80	2007 Range $2.85 to $3.05
2008 Range $3.00 to $3.30	2009 Range $3.15 to $3.45

- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
    - AEP Transmission Company
  - Seek rate recovery for new investments
  - Control costs
- Maintain credit ratings
  - BBB/Baa2/BBB

OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

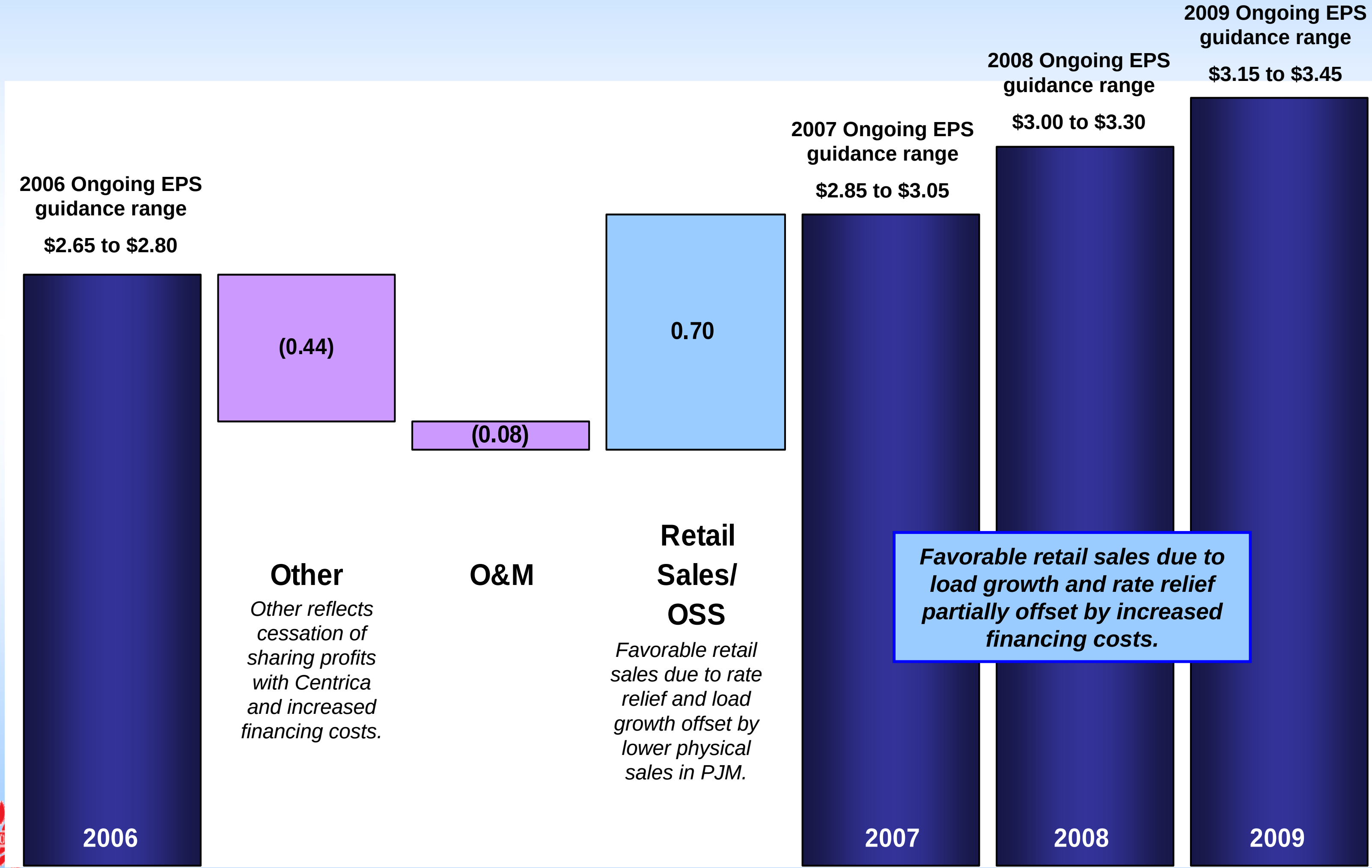
Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
  - Predicated on AEP's ability to economically dispatch at a high load capacity
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve high returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Composition of Long-Range EPS Drivers

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS



Current State Regulatory Activity

Virginia

VA Environmental & Reliability Order

- On Nov. 20, 2006, the VA SCC issued an order allowing APCo-VA to recover $21.3MM of incremental E&R spending covering the costs incurred July 1, 2004 through Sept. 30, 2005
- The surcharge will be collected Dec. 1, 2006 through Nov. 30, 2007
- The order established an ROE of 9.8% (applicable to incremental E&R investment), but allowed for adjustment of ROE in future E&R proceedings
- The next E&R proceeding would seek recovery of costs incurred Oct. 1, 2005 thru Oct. 1, 2006

VA General Rate Case

- Seeking $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM
- SCC ordered implementation of full $198.5MM rate increase to be effective October 2, subject to refund
- SCC staff filed testimony recommended a $12.7MM rate increase, which includes a 9.9% ROE and no off-system sales margin sharing; Hearings Dec. 6.

Texas

TCC & TNC Wires Rate Cases – filed 11/9/06

- TCC & TNC requested rate increases of $82.7MM and $25MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC for the expiration of merger-related billing credits that have been in place since 2000
- Requested ROE of 11.25% using capital structure of 60% debt / 40% equity

Oklahoma

PSO Rate Proposal – filed 11/21/06

- PSO's rate proposal contains the following major components:
  - $49.6MM overall increase in base rates to recover increased costs and investments already made
  - Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP
  - Requested ROE of 11.75% using capital structure of 54% debt / 46% equity

NEW RATE RELIEF TO CONTRIBUTE TO EARNINGS IN 2007

AEP Transmission Network – The Largest in the Country

Operating Company Level
(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
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AEP Is the Leader in Transmission Expertise

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- **~$1 billion in ERCOT via JV with MidAmerican**
- **~$2 billion 765-kV study with ITC in Michigan**
- **~$3 billion I-765 Project in PJM**
- **~$3 billion project filed with SPP**

BUILDING THE NEXT US INTERSTATE SYSTEM FOR ENHANCED RELIABILITY AND MARKET EFFICIENCY

*Note: ~$9 billion investment opportunity not included in current capital guidance forecasts with exception of ERCOT investment of $60MM in 2007 and $95MM 2008

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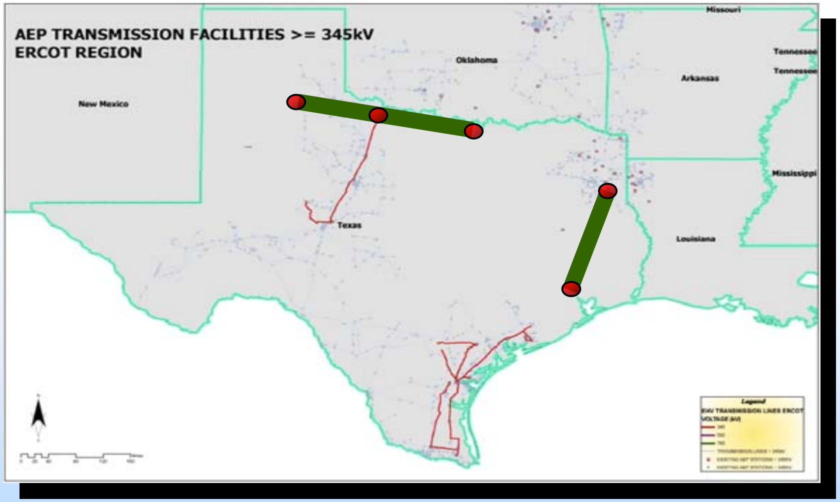
AEP AMERICAN ELECTRIC POWER

MIDAMERICAN ENERGY HOLDINGS COMPANY

- Jointly-owned utility company will design, construct and operate ERCOT transmission assets
- Up to $1B investment potential (before ownership division)
- Equity investment treatment for AEP
- AEP is also exploring 765-kV ERCOT transmission investment opportunity
  - 420 line miles
  - Up to 4000MW improved transfer capability*
  - Anticipated ERCOT rate impact 0.5mils/kWh
- This project may be considered by JV in future

- 2007 commercial operation for first JV projects
- Execution of operating agreement 2006
- Establish JV entity 2007

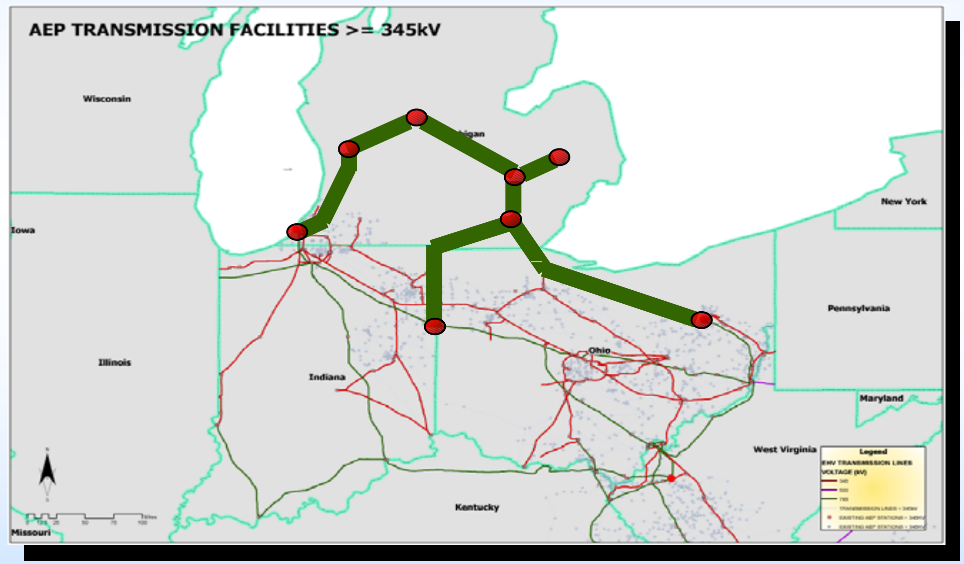


Conceptual ERCOT transmission project – proposed routes; not included in current JV plans

*Line segment capability; ERCOT is a free-flowing network

The First Large-scale Transmission Venture in Texas

- Agreement with ITC *Transmission* for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
    - 630 line miles
    - Over 5000MW improved transfer capability
    - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in late 2006



The ROW routes shown on this diagram are for illustrative purposes only and they may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Supporting Michigan's 21st Century Energy Plan to Address Severe Capacity Constraints Identified in MPSC Studies

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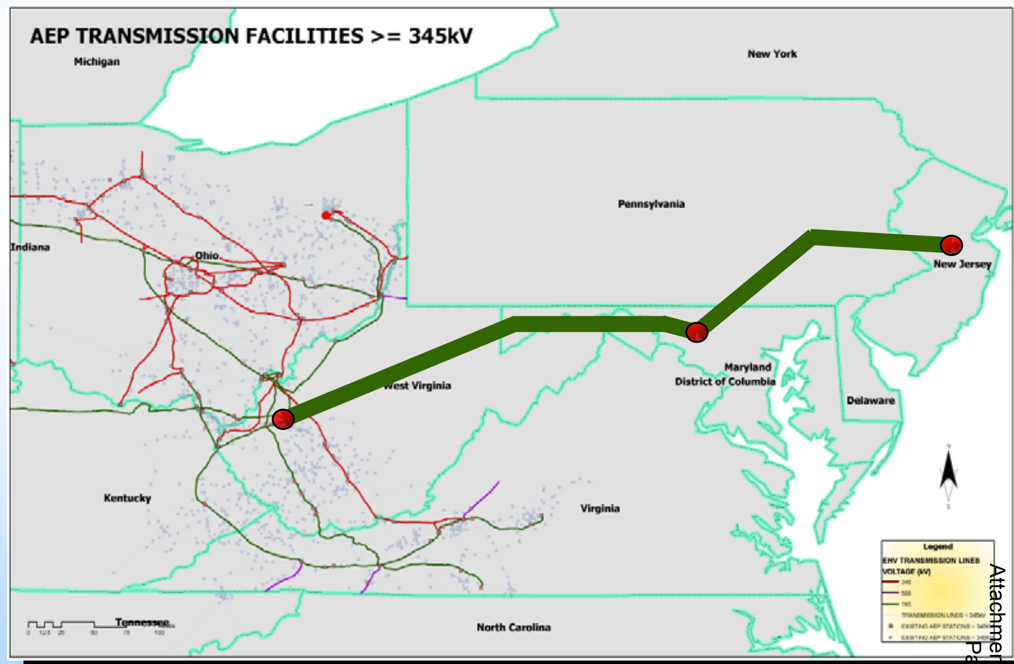
Cruise The I-765

- $3 billion investment
- 550 line miles
- 5000MW improved transfer capability
- Expected PJM rate impact 1mil/kWh
- 2014 estimated in-service date

Original line proposal connects AEP's Amos station to Allegheny Power's Doubs station in Maryland, and terminates at PSEG's Deans station in New Jersey. The final project will undoubtedly vary from the original proposal.



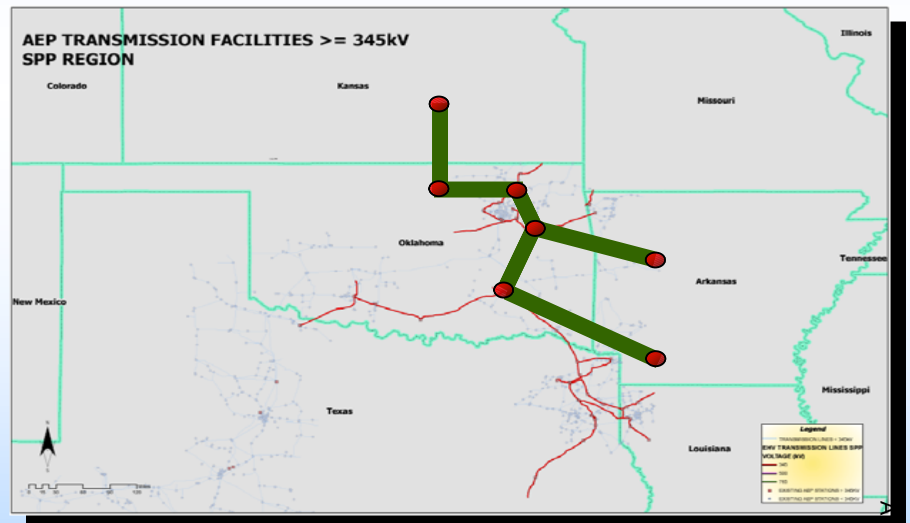
Our I-765 Line Will Be the Highest Capacity, Most Reliable Line in the United States

SPP Investment Potential

- June 2006 SPP requested proposal to address congestion, reliability & access for new generation
- July 2006 AEP submitted proposal:
  - Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
  - Investment ~$3 billion
    - ~4000MW improved transfer capability
    - Anticipated rate impact 2mils/kWh

Next steps:

- SPP conducting studies to evaluate proposals
- AEP providing technical assistance and support



Significant Opportunity for 765-kv Transmission in SPP

KPSC Case No. 2011-00401
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Environmental Investment

FGD – Reduces SO_2 by 95% to 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

* Plans underway to upgrade reductions from 75% to 95%

FGD – Completed

Plant Name	MW Capacity
Gavin 1 & 2	2620
Conesville 5 & 6	750
Pirkey	580
Oklaunion*	539
Zimmer	330
Dolet Hills*	262
Total	**5081**

SCR – Completed

Plant Name	MW Capacity
Gavin 1 & 2	2620
Amos 1-3	2900
Mountaineer	1320
Big Sandy 2	800
Stuart 1-4	620
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9775**

Planned or Under Construction

FGD – Planned or Under Construction

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1320	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	620	2009
Conesville 4	339	2009
Total	**7379**	

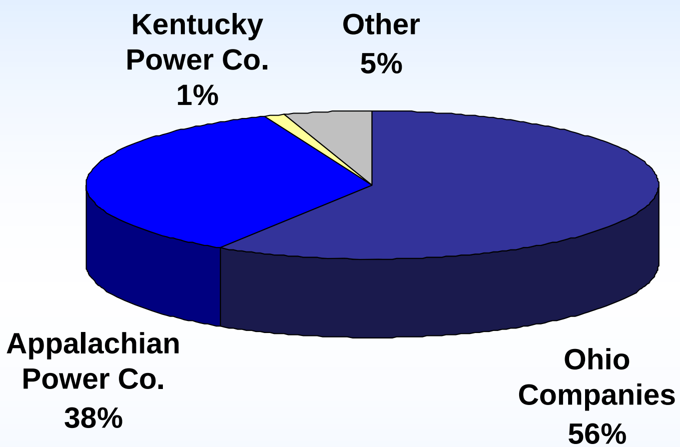
SCR – Planned or Under Construction

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

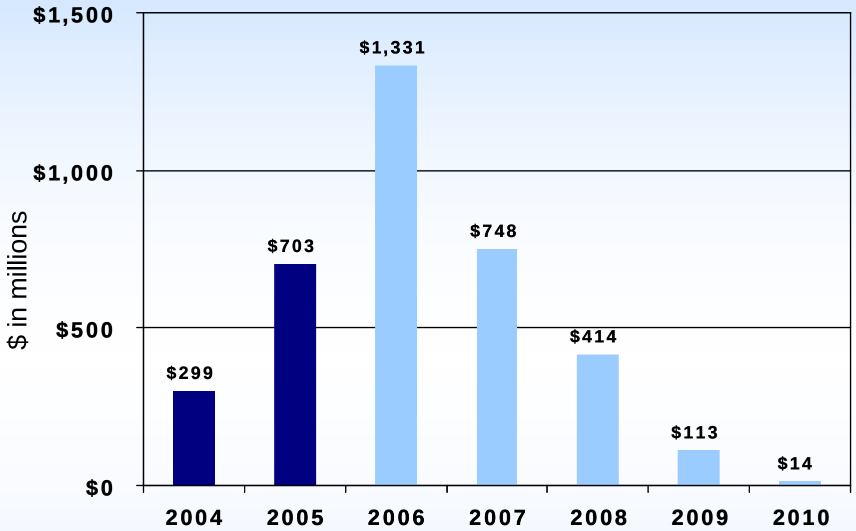
Installation Of SCR And FGD Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Environmental Investment: SO_2, NOx & Hg

Projected Environmental Investment Allocation



Environmental Investment: NOx, SO_2 & Hg (including AFUDC)



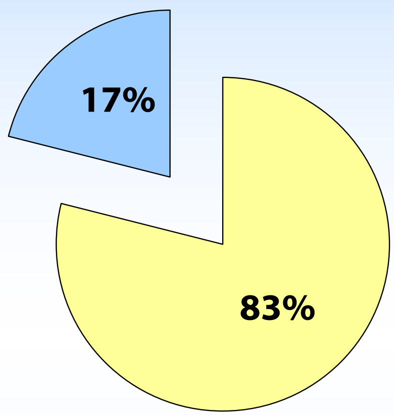
Note: 2004-2005 reflect actual investment level

$3.0 Billion SO_2 Investment + **$500 Million NOx Investment** + **$100 Million Hg Investment** = **$3.6 Billion Environmental Investment Through 2010**

$3.6 Billion Environmental Investment Projected 2004 Through 2010

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of IGCC facilities dependent on regulatory approvals
- Certificates of Convenience and Necessity (CCN) applications filed in OH and WV and are currently in process

SWEPCO

- May 31, 2006- Announced plans to build $1.7 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling 320 MW at Tontitown, AR and combined-cycle gas plant totaling 480 MW at Arsenal Hill
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – expected SWEPCO investment will be approx. 75%
- Commercial operation dates between 2007 and 2011

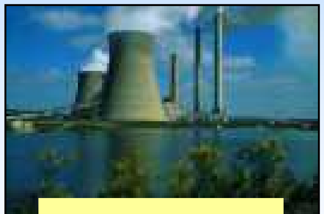
PSO

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build a $1.8 billion 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

CSP

- Announced on Nov. 29 purchase of Darby 480MW simple-cycle peaking facility for $102MM

Domestic Generation Fleet

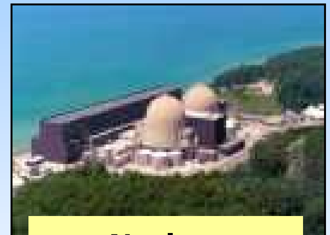


Coal/Lignite

72%

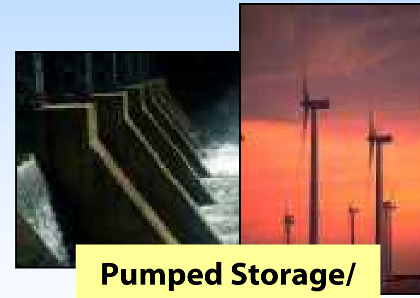
Nat. Gas/Oil

19%



Nuclear

6%



Pumped Storage/ Hydro/Wind

3%

AEP's Generation Fleet

35,660 MW Capacity*

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.50%	62.53%

NERC Regional Presence

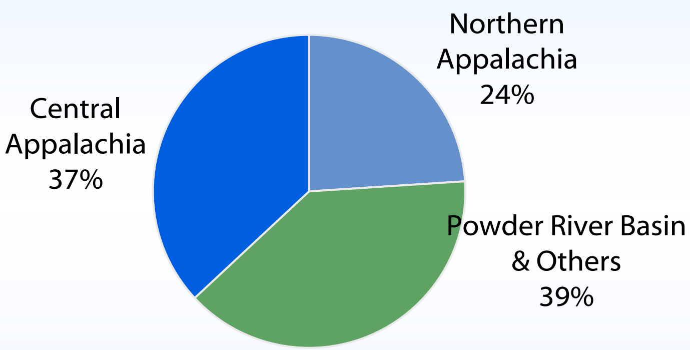
RFC (formerly ECAR)	73%
SPP	24%
ERCOT	3%

* Excludes 1,013 MW of mothballed / decommissioned / retired generating capacity.

Coal Procurement

AEP purchases approx. 75 million tons of coal per year

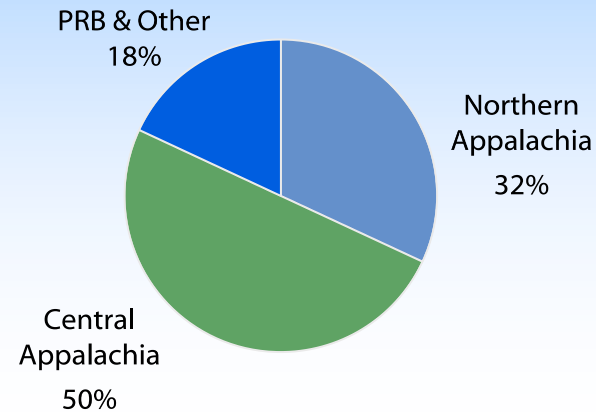
Total AEP System



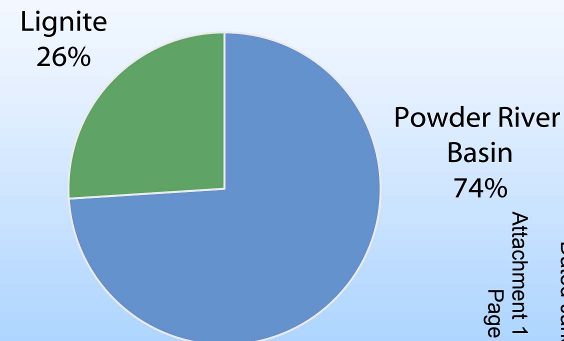
Coal Stats:

- Fully contracted for 2006; 95%+ contracted for 2007
- Avg. delivered price ~ $36.25/ton in 2006
- Approximate 6-8% price increase in 2007 -- ($38.80/ton)
  - Addition of Mountaineer & Mitchell scrubbers will allow for a greater mix of Northern Appalachian coal in 2007

AEP East

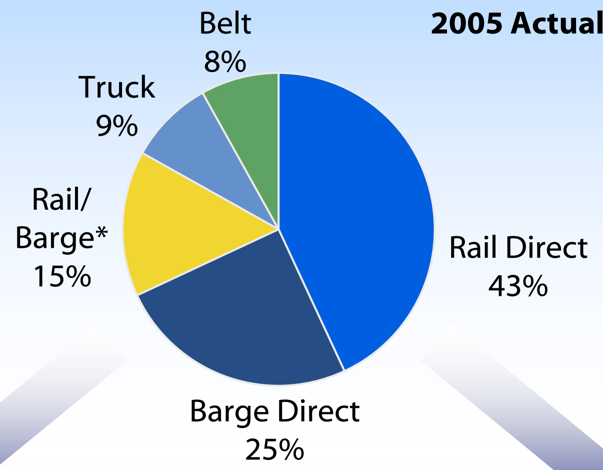


AEP West

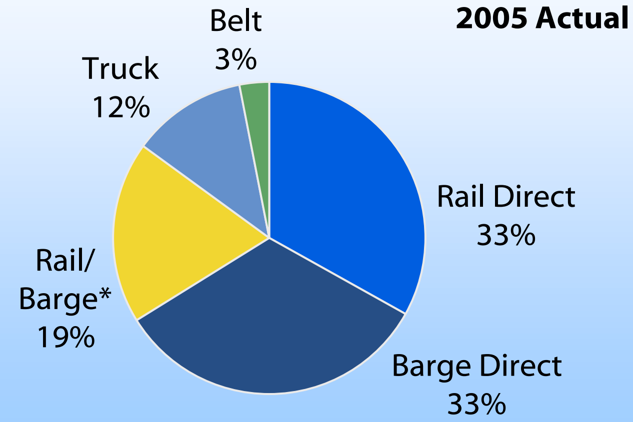


Coal Delivery

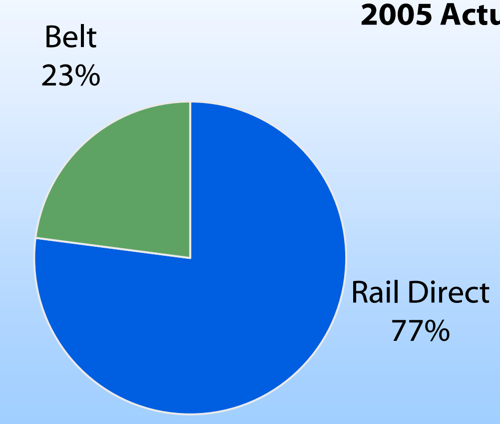
Total AEP System



AEP East

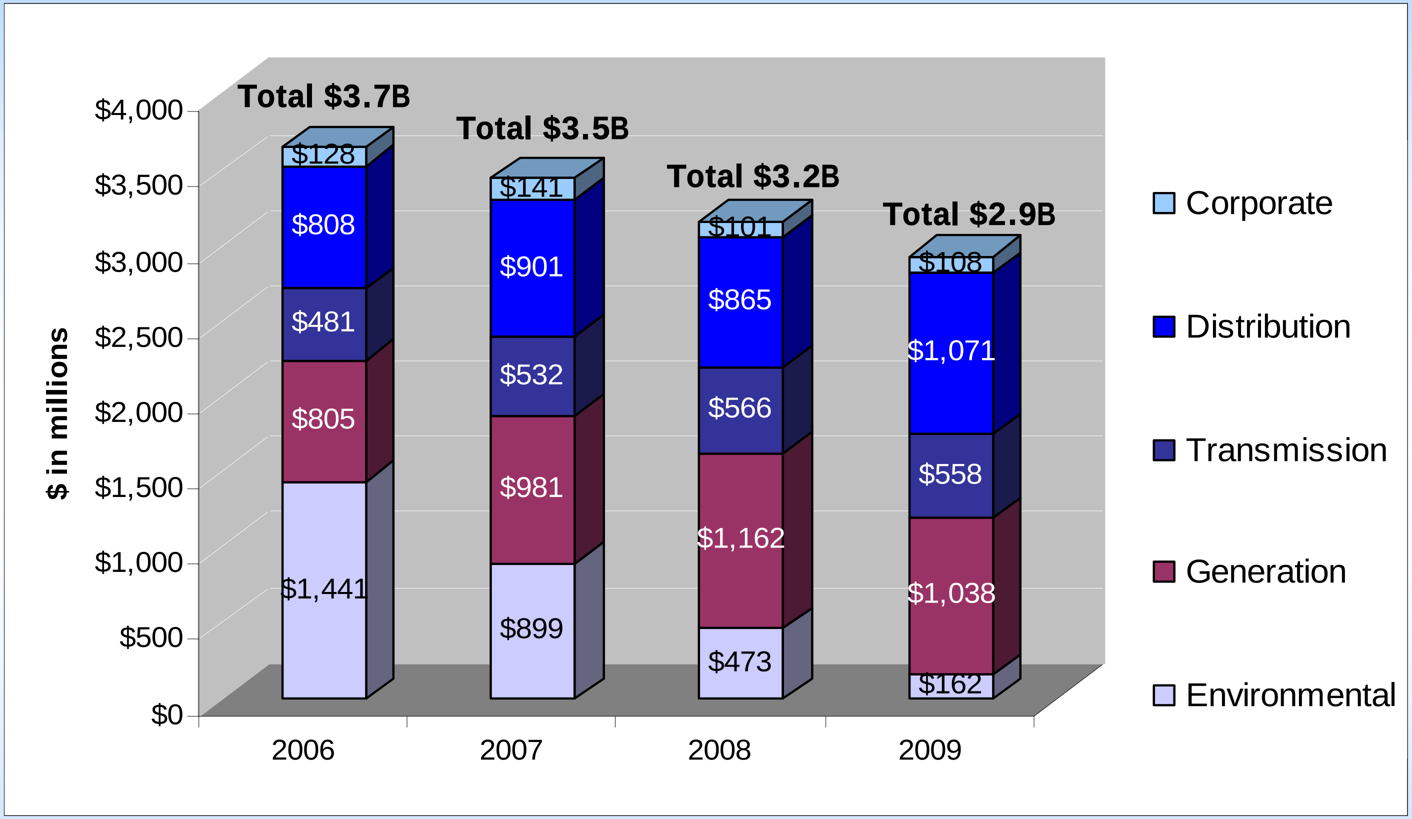


AEP West



* Reflects coal delivered to AEP plants transported through combination of rail and barge

Multi-Year Capital Investment Forecast



Note: Excludes AFUDC

Generation reflects New Build in 2007-2009 of $410MM, $522MM & $584MM; New Transmission is $60MM in 2007 & $95MM in 2008

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2005	**2006**	**2007**	**2008**	**2009**
Planned Capital Investment (Excluding AFUDC)	$ (2,499)	$ (3,663)	$ (3,454)	$ (3,167)	$ (2,937)
Dividend on Common	$ (553)	$ (591)	$ (618)	$ (621)	$ (624)
Cash Sources					
Cash from Operations *	$ 1,877	$ 1,890	$ 2,232	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 1,246	$ 175	$ -	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ (25)	$ 45	$ 80	$ 80	$ 80
Change in Debt, Net	$ (91)	$ 661	$ 1,738	$ 1,176	$ 967
TCC securitization bond issuance	$ -	$ 1,740			
Other	$ 126	$ (268)	$ (95)	$ (67)	$ (69)
Cash Sources Less Capital Expenditures, Dividends & Other	$ 81	$ (11)	$ (117)	$ 43	$ 88
Ending Cash Balance	$ 401	$ 390	$ 273	$ 316	$ 404

Projected 2006-2009 Credit Metric Ranges

Debt to book capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Capital Investment Is Funded By Cash From Operations And Debt Issuances

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Ongoing Guidance: $2.65 to $2.80 Per Share
2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Estimate vs. 2007 Estimate

		2006 Performance Driver	2006 Estimate ($ millions)	2007 Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,321 GWh @ $ 30.9 /MWhr =	2,141	71,033 GWh @ $ 33.7 /MWhr =	2,392
2	Ohio Companies	46,083 GWh @ $ 46.6 /MWhr =	2,147	47,902 GWh @ $ 49.5 /MWhr =	2,371
3	West Regulated Integrated Utilities	41,264 GWh @ $ 24.9 /MWhr =	1,026	40,795 GWh @ $ 25.9 /MWhr =	1,058
4	Texas Wires	26,506 GWh @ $ 14.4 /MWhr =	383	26,834 GWh @ $ 16.4 /MWhr =	441
5	Off-System Sales	35,100 GWh @ $ 23.1 /MWhr =	811	30,742 GWh @ $ 21.9 /MWhr =	672
6	Transmission Revenue - 3rd Party		282		255
7	Other Operating Revenue		579		715
8	Utility Gross Margin		7,369		7,904
9	Operations & Maintenance		(3,241)		(3,292)
10	Depreciation & Amortization		(1,316)		(1,413)
11	Taxes Other than Income Taxes		(747)		(785)
12	Interest Exp & Preferred Dividend		(664)		(813)
13	Other Income & Deductions		199		91
14	Income Taxes		(551)		(567)
15	Utility Operations On-Going Earnings		1,049		1,125
16	Investments On-Going Earnings		45		48
17	Parent Company On-Going Earnings		(1)		(6)

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Summary of 2007 Earnings Drivers

- Load growth of 1.5%
- Rate relief of $456MM; $161MM already secured (excluding Va. E&R which has not yet been quantified)
- Improved performance at Investments
- Rising fuel costs of 6-8%
- Increased retail load & higher muni/co-op sales to impact off system sales contribution
- Higher financing costs
- Higher O&M (inflationary pressures)
- Lower contribution from Centrica sharing agreement

TRADITIONAL UTILITY FACTORS WILL DRIVE EARNINGS

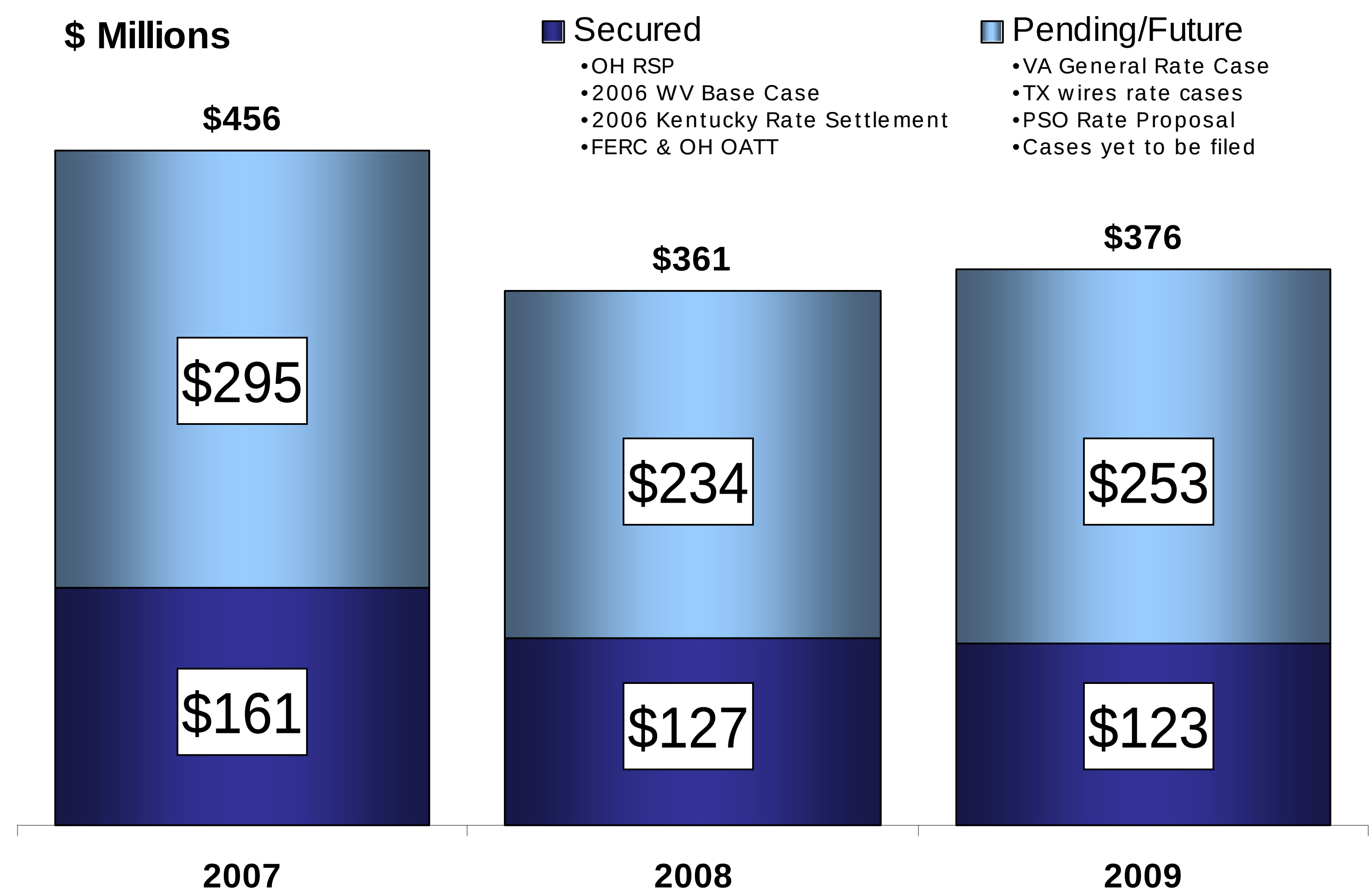
Risks and Uncertainties Within 2007 EPS Guidance Range

2007 EPS Guidance Range is $2.85 to $3.05

__2007__

- *Outcome of pending regulatory proceedings*
- *Wholesale market volatility*
- *Plant availability*
- *Rising fuel costs*
- *Weather*

Incremental Rate Relief Composition



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20th order in our E&R case. Further analysis is required to quantify these amounts.

RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Capital Structure

Capital Structure	Actual 12/31/2005			Actual 9/30/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,763	-	12,763
Short-term Debt	10	-	10	23	-	23
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,524	9,524
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,786**	**9,585**	**22,371**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(21)	-	(21)
Off-balance Sheet Leases	1,213	-	1,213	1,199	-	1,199
Securitization Bonds	(648)	-	(648)	(596)	-	(596)
Spent Nuclear Fuel Trust	(228)	-	(228)	(244)	-	(244)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,694**	**13,154**	**9,555**	**22,709**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.9%***	***42.1%***	***100.0%***

Adjusted debt-to-cap of 57.9% at 9/30/06

Commitment to Credit Quality

Forecast Parameters:

- Maintain minimum $200MM cash balance
- Dividend reinvestment plan activated September 2006
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

Company	Target Equity Ratio
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	45-48%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

We Are Committed To Maintaining Our Current Credit Ratings
BBB/Baa2/BBB

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Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

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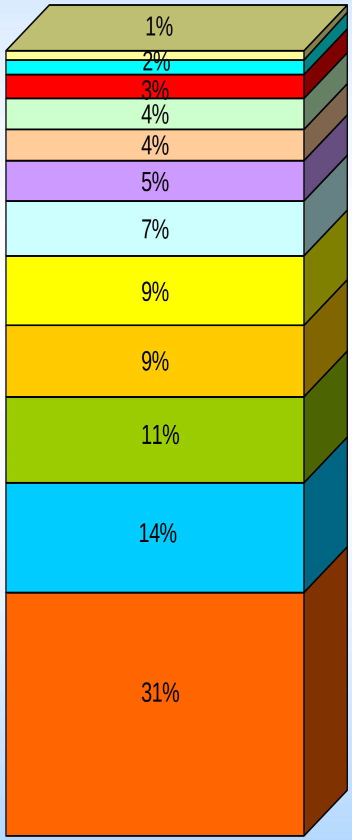
2005 Retail Revenue

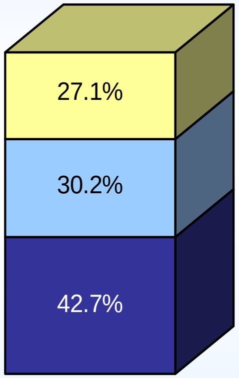
PERCENTAGE OF AEP SYSTEM RETAIL REVENUES

Tennessee	1%
Michigan	2%
Arkansas	3%
Kentucky	4%
Louisiana	4%
Texas SPP*	5%
Texas ERCOT*	7%
Virginia	9%
West Virginia	9%
Indiana	11%
Oklahoma	14%
Ohio	31%



Retail Revenue Composition by Customer Class**

Industrial	27.1%
Commercial	30.2%
Residential	42.7%



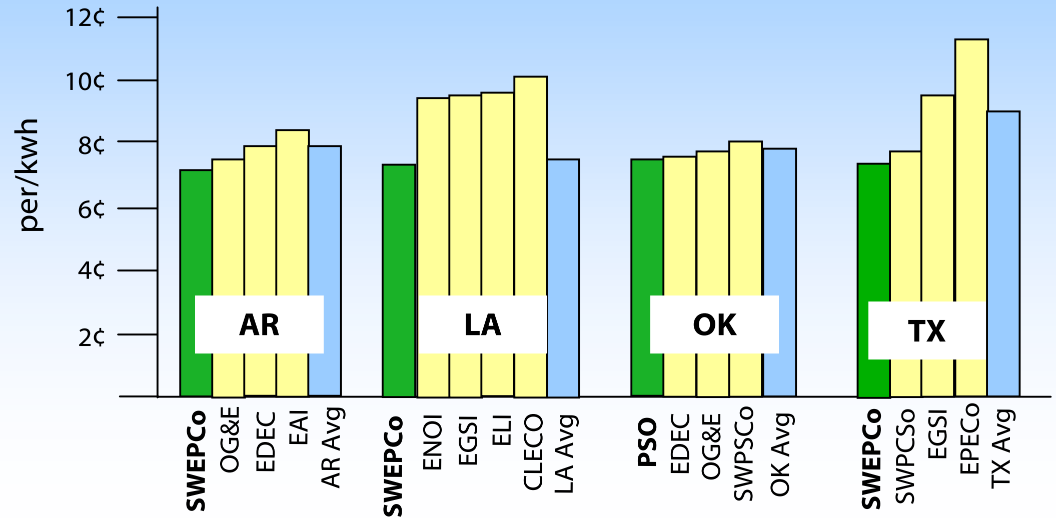
Source: Form 10-K

*Note: Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. Retail electric service in the SPP area of Texas is provided by SWEPCo and an affiliated REP.

**Note: Figures do not include Other Retail Sales

AEP Is The Low Cost Provider

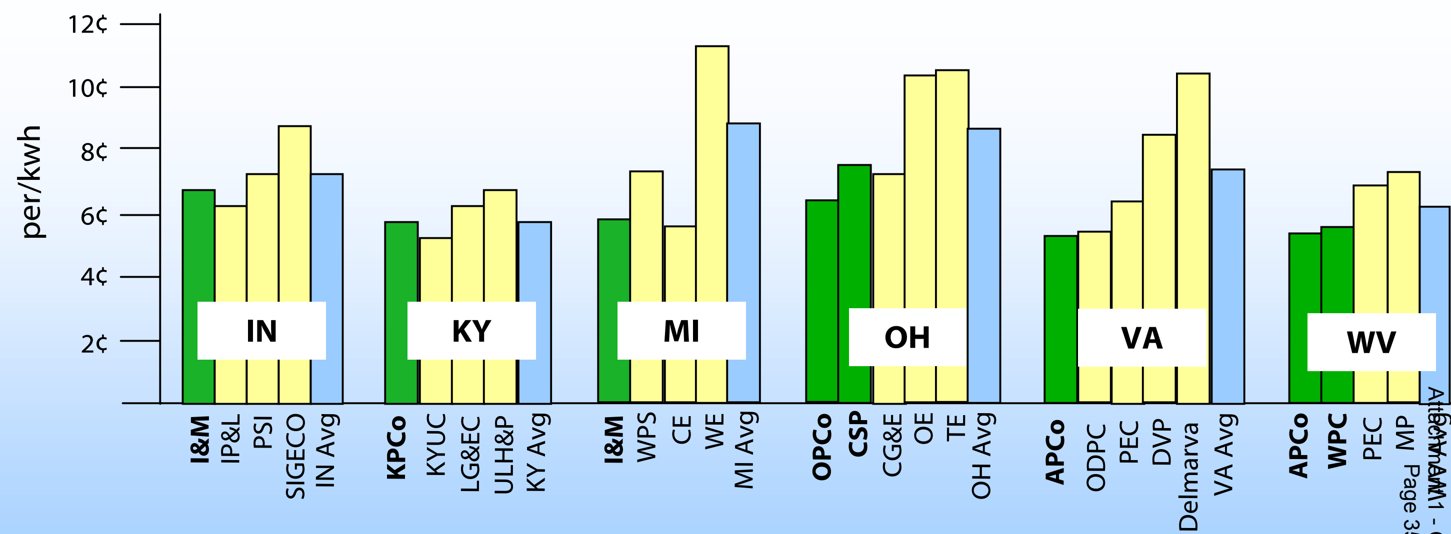
AEP West



Residential Average Realizations as of12/31/2005

Source: Winter 2006 EEI Typical Bills and Average Rates Report

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

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AMERICAN ELECTRIC POWER

Fourth Annual BMO Capital Markets Utility Day

Tuesday, December 2, 2008

New York

AEP AMERICAN ELECTRIC POWER

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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Bette Jo Rozsa – Managing Director Investor Relations

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2008 & 2009 Ongoing Earnings Guidance

2008 EPS: $3.15 - $3.25

2009 EPS: $3.00 - $3.40

American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance ($ millions)	2008 Original Guidance EPS	2009 Guidance ($ millions)	2009 Guidance EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Depreciation & Amortization	(1,451)		(1,546)	
Taxes Other than Income Taxes	(779)		(790)	
Interest Exp & Preferred Dividend	(839)		(929)	
Other Income & Deductions	127		120	
Income Taxes	(602)		(641)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations:				
AEP River Operations	57	0.14	62	0.15
Generation & Marketing	20	0.05	13	0.03
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

AEP AMERICAN ELECTRIC POWER

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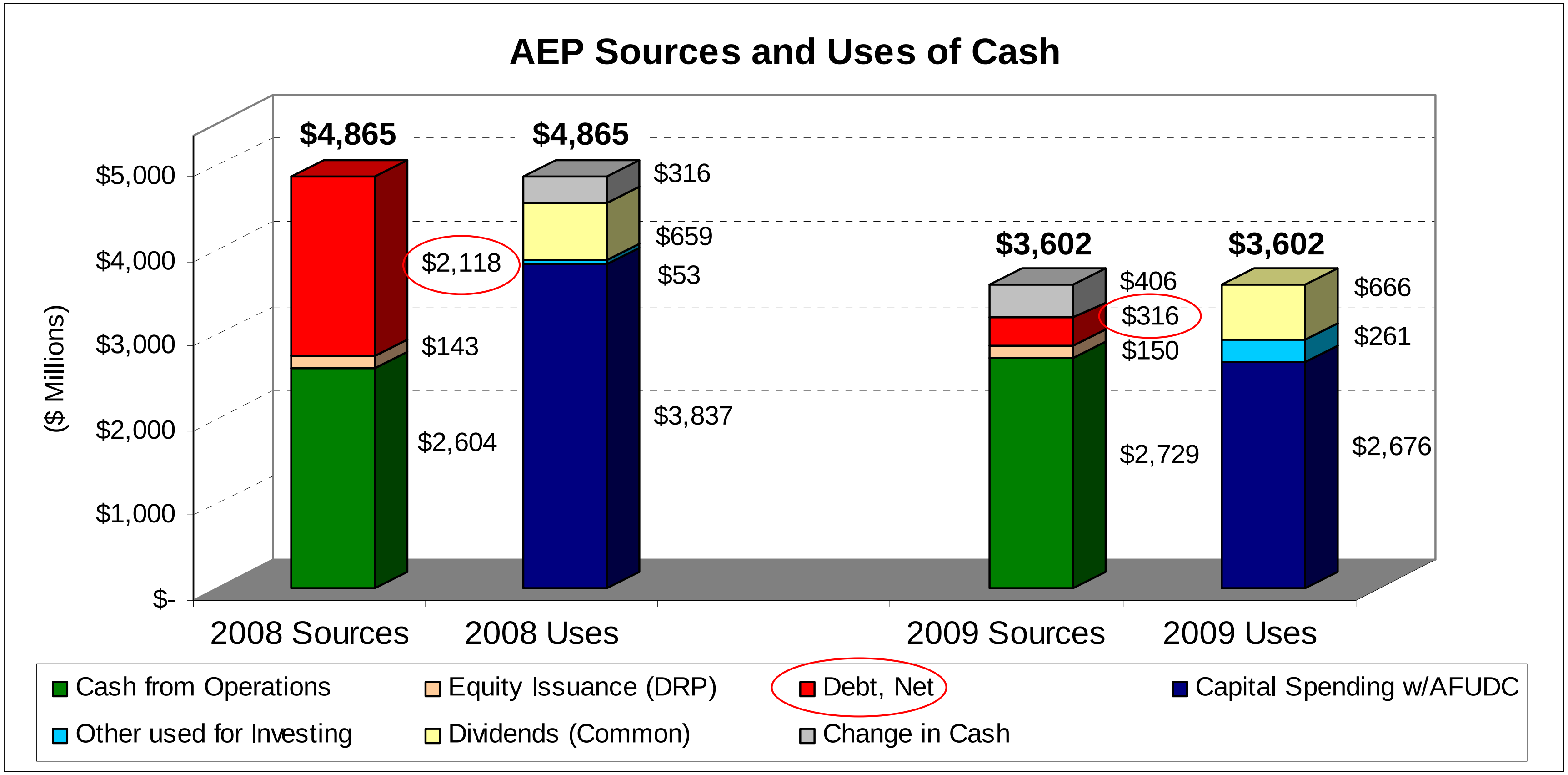
2008 & 2009 Cash Flow Forecast

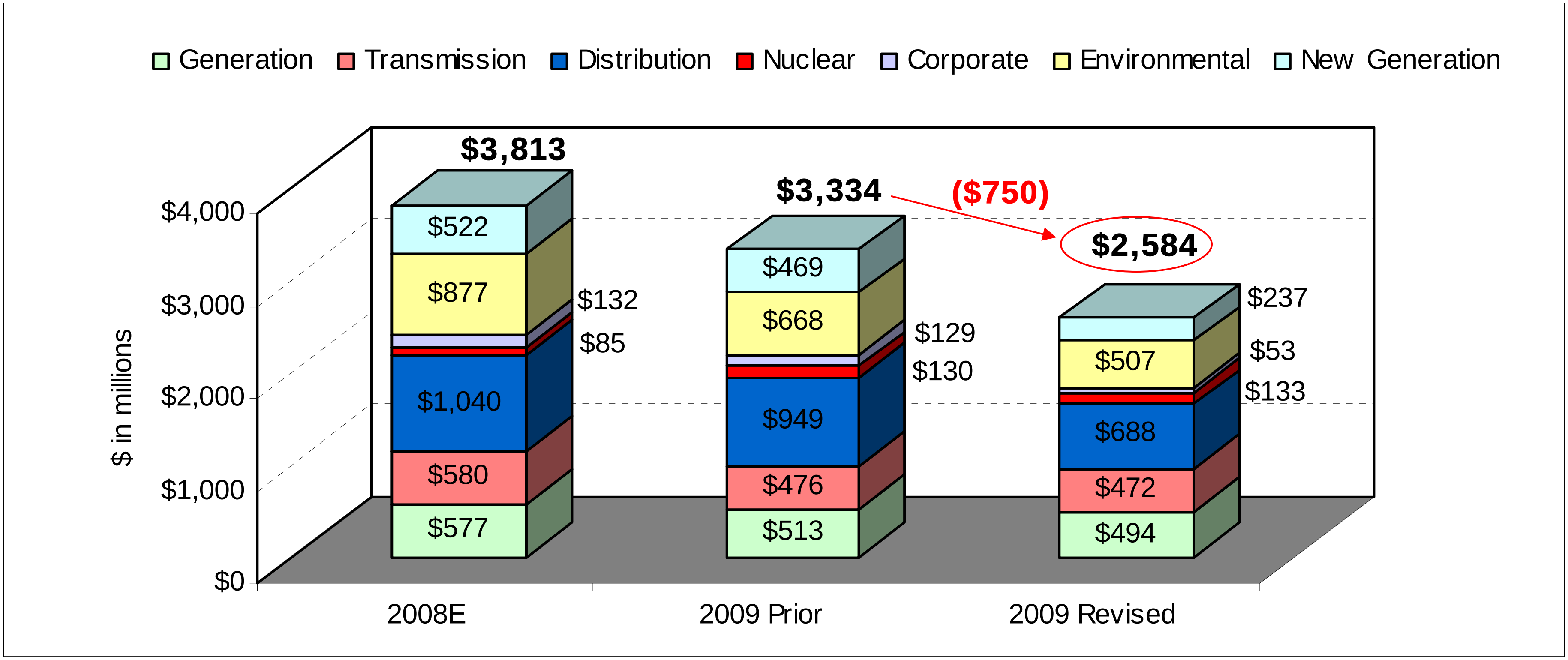


Capital spending closely matches cash flow from operations in 2009.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

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Liquidity

Liquidity Summary (unaudited)	Actual 10/28/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	1,366	
Less		
Draw on Credit Facilities	(1,969)	
Commercial Paper Outstanding	(178)	
Letters of Credit Issued	(439)	
Net Available Liquidity	**$2,699**	

AEP's liquidity position is $2.7 billion as of 10/28/08.

Capitalization

Capital Structure	Actual 12/31/2007			Actual 9/30/2008		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	14,993	-	14,993	16,007		16,007
Short-term Debt	660	-	660	1,302		1,302
Preferred Stock Not Subject to Mandatory Redemption	-	61	61		61	61
Common Equity	-	10,079	10,079		10,917	10,917
Total Capitalization per Balance Sheet	**15,654**	**10,139**	**25,793**	**17,309**	**10,978**	**28,286**
% of Capitalization per Balance Sheet	***60.7%***	***39.3%***	***100.0%***	***61.2%***	***38.8%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(19)	-	(19)	-	-	-
less: Cash and Marketable Securities	(178)	-	(178)	(781)	-	(781)
Capital and Operating Leases	1,522	-	1,163	1,470	-	1,470
Securitization Bonds	(2,257)	-	(2,257)	(2,132)	-	(2,132)
Receivables Securitization	507	-	507	555	-	555
Spent Nuclear Fuel Disposal Liability	(259)	-	(259)	(263)	-	(263)
Equity Portion of Hybrid Issuances	-	-	-	(158)	158	1
Total Adjusted Capitalization	**14,969**	**10,139**	**25,108**	**15,999**	**11,136**	**27,135**
% of Adjusted Capitalization [1]	***59.6%***	***40.4%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Credit Adjusted Ratios:						
FFO Interest Coverage			**4.3**			**4.7**
FFO to Total Debt			**19.6%**			**21.5%**

Our goal remains a maximum 60/40 debt-to-capital ratio on an adjusted basis.

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Long-term Debt Maturity Profile

($ in millions)

Year		2008 [1]		2009		2010
AEP, Inc.	$	-	$	-	$	490
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	-	$	150	$	150
Columbus Southern Power	$	-	$	-	$	150
Kentucky Power	$	30	$	-	$	-
Indiana Michigan Power	$	50	$	-	$	-
Ohio Power	$	37	$	82	$	600
Public Service of Oklahoma	$	-	$	50	$	150
Southwestern Electric Power	$	-	$	-	$	-
Texas Central Company[2]	$	-	$	-	$	203
Texas North Company	$	-	$	-	$	-
Total	$	117	$	282	$	1,743

(1) Maturities remaining as of September 30, 2008

(2) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date

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AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Ratings current as of October 17, 2008

	Moody's		S&P		Fitch	
	Senior		Senior		Senior	
Company	Unsecured	Outlook	Unsecured	Outlook	Unsecured	Outlook
American Electric Power Company Inc.	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
AEP, Inc. Short Term Rating	**P2**	**S**	**A2**	**S**	**F2**	**S**
AEP Texas Central Company	**Baa2**	**N**	**BBB**	**S**	**BBB+**	**S**
AEP Texas North Company	**Baa1**	**S**	**BBB**	**S**	**A-**	**S**
Appalachian Power Company	**Baa2**	**N**	**BBB**	**S**	**BBB+**	**N**
Columbus Southern Power Company	**A3**	**S**	**BBB**	**S**	**A-**	**S**
Indiana Michigan Power Company	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
Kentucky Power Company	**Baa2**	**S**	**BBB**	**S**	**BBB**	**S**
Ohio Power Company	**A3**	**N**	**BBB**	**S**	**BBB+**	**S**
Public Service Company of Oklahoma	**Baa1**	**S**	**BBB**	**S**	**BBB+**	**S**
Southwestern Electric Power Company	**Baa1**	**N**	**BBB**	**S**	**BBB+**	**S**

Pension and OPEB Estimate

- The Pension plan and OPEB funds investment returns are each down about 25% YTD as of October 16, 2008. The drop in assets is mitigated slightly by a corresponding decrease in plan liability caused by a higher discount rate (from 6% to 7% for pensions and from 6.25% to 7.25% for OPEB).
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- As of October 16, 2008, we expect 2009 pension expense to increase $10MM over 2008 and the estimated OPEB expense to increase $30MM year over year.
- These increases are reflected in our current guidance.
- We are currently not expecting any mandatory contributions to pension in 2009.

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- SWEPCo Stall Plant Filings in Arkansas
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART^{SM} Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony was filed October 31, Staff testimony was filed November 7 and the public hearing commenced on November 17, 2008. We anticipate an order in the first quarter of 2009.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $125.6 million ($80.1 million in base revenues and $45.6 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure – Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	1,999.1 *
Rate of Return		8.10%
Operating Income Requirement	$	161.9
Pro-Forma Operating Income	$	113.1
Difference	$	48.8
Revenue Conversion Factor		1.64
Revenue Deficiency	$	80.1
Reliability Enhancement Tracker	$	28.4
DSM / EE Tracker	$	4.4
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	44.4
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	125.6

* rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure – Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Required Rate Relief – Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Regulatory Activity Underway

SPP OATT Formula Rate Filing (Docket #:ER07-1069-000)

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing (Docket #:ER08-1329-000)

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to March 1, 2009, with rates subject to refund.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- ❑ Proceeding is pending.

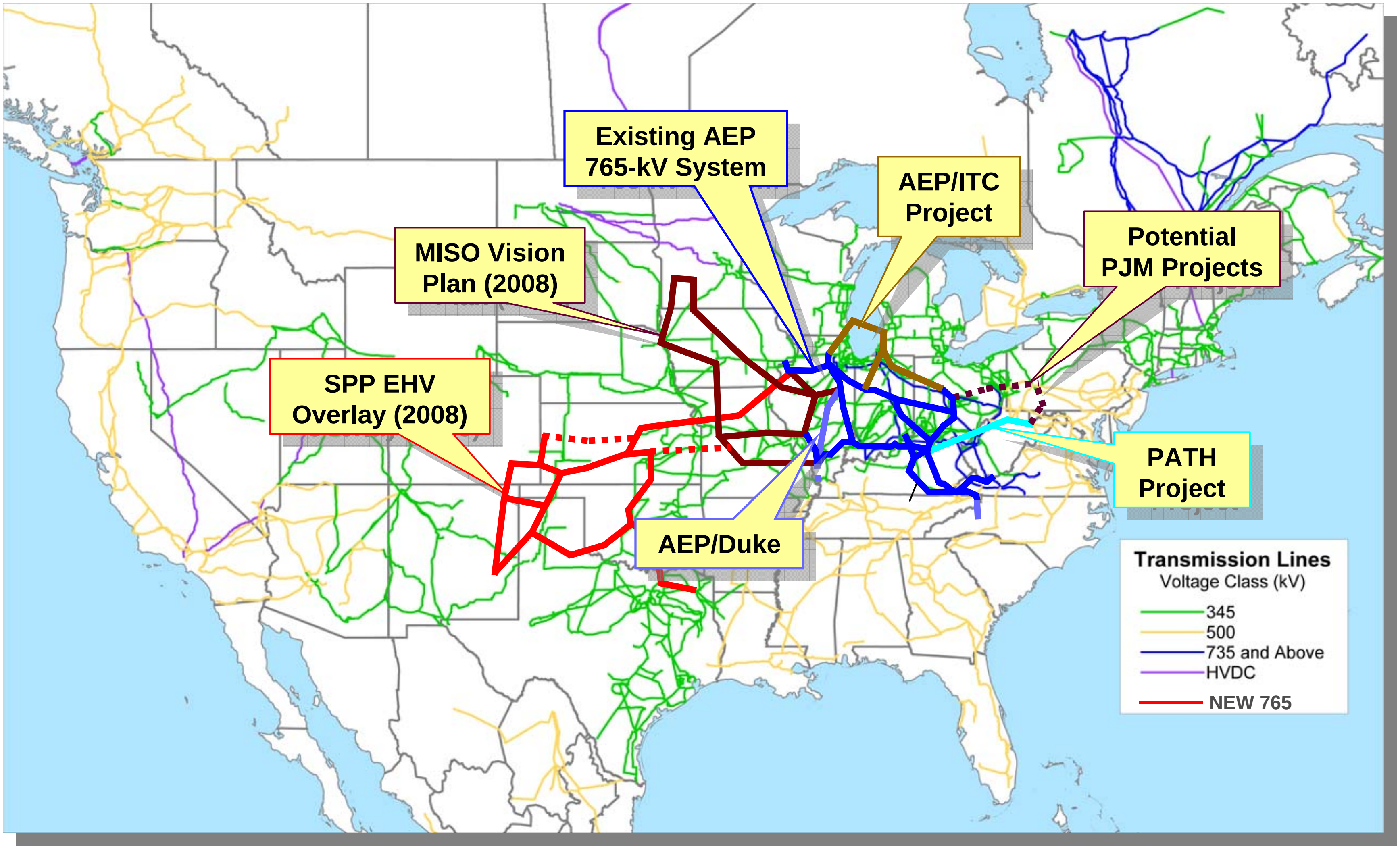
Louisiana

- ❑ On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- ❑ PSC approval was granted on September 10, 2008.
- ❑ Air permit received on March 20, 2008.

Texas

- ❑ PUCT order approving plant was issued on March 8, 2007.

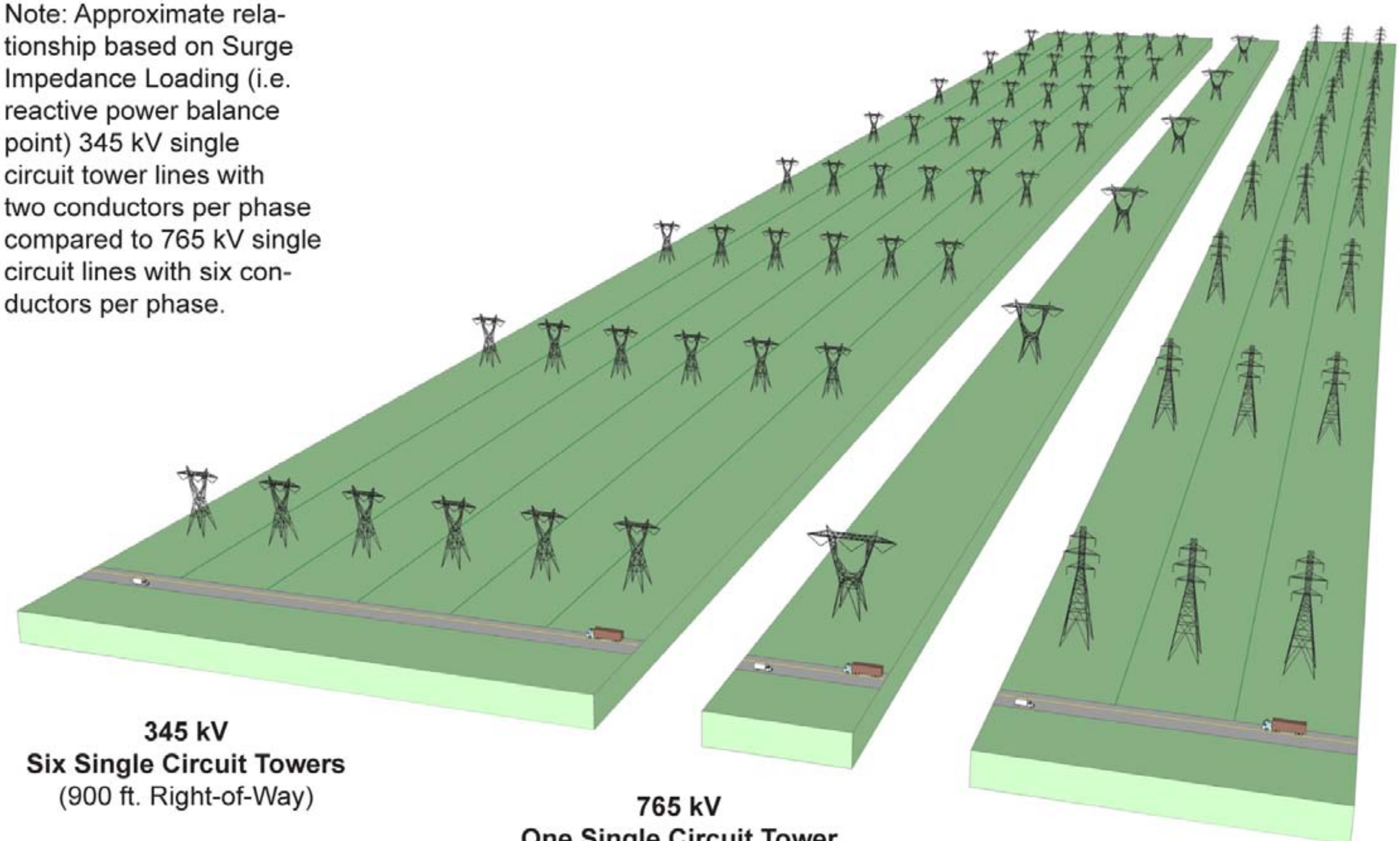
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

765 Right-of-Way Comparison

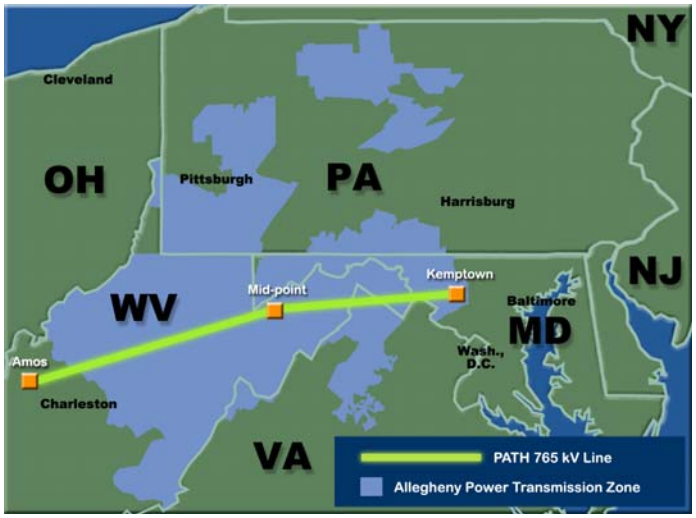
Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

EHV Transmission in PJM: PATH

- ***PATH Progress to Date***
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
  - In October 2008, PJM announced a reconfiguration of the PATH line which will eliminate the connection with the Bedington substation and the twin-circuit 500-kV lines from Bedington to Kemptown, and include a new mid-point substation near existing PATH alternative routes
    - The reconfiguration is a result of constraints identified as a result of comprehensive siting studies; interaction with government agencies; public input; and a desire to identify a solution that reduces line mileage and minimizes the impact on communities and the environment.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
- ***Key Challenges***
  - CPCN and Siting Approval from WV and MD



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

Joint Ventures with MidAmerican Energy Holdings Company

Electric Transmission Texas Update

- 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
- ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
- Services provided by AEP and investment opportunities can be offered by either partner
- Total initial investment of $70 million before ownership division
- In October 2008, the District Court found that the PUCT exceeded its authority by granting ETT a CCN. This decision is currently under appeal and ETT believes the ultimate outcome will validate its utility status.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - In 2008, ETA signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

Texas CREZ Project

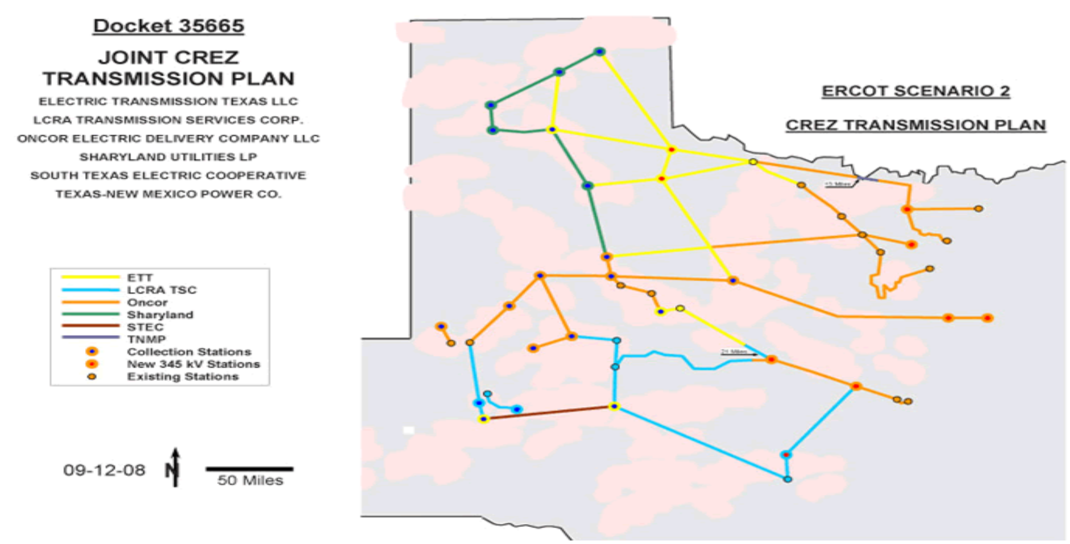
Strengthening the ERCOT grid to collect and deliver wind generation to load

❑ *Overview*

- ❑ In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the CREZ facilities approved by the Commission.
- ❑ ETT's requested share of the coordinated plan is approximately \$1.5 billion. Staff testimony in October 2008 recommended ETT's share at \$1.2 billion.
- ❑ The filing calls for completion of the plan by 2012.

❑ *Next Steps*

- ❑ PUCT hearings – December 2008
- ❑ Selection of transmission providers – 1Q 2009



Electric Transmission Texas

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

EHV Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development

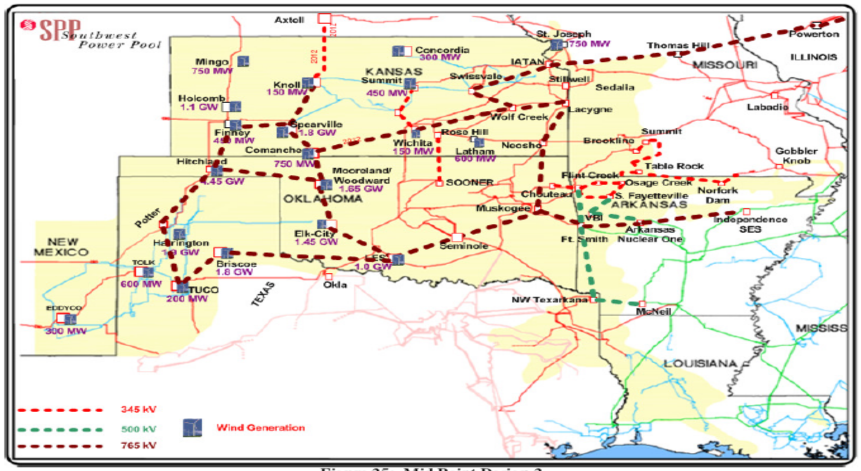


Figure 25: Mid Point Design 2

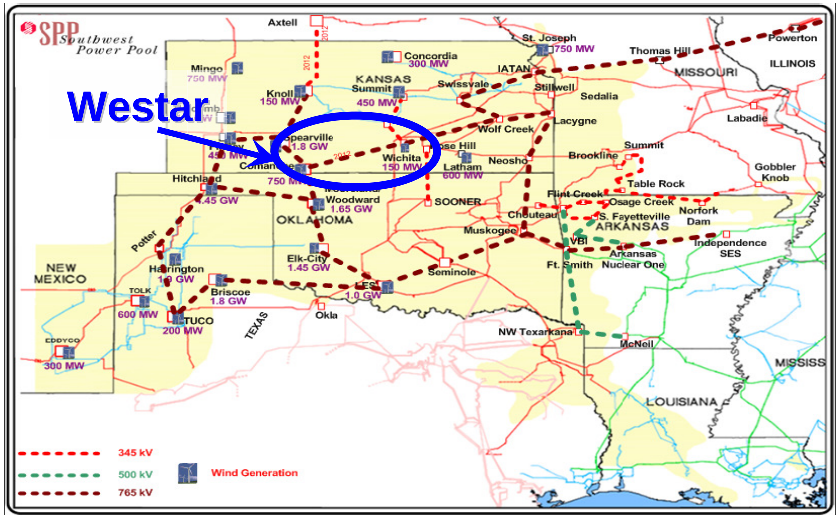
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ### *Overview*
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC formula rate filing submitted in October 2008 requesting:
    - Cash return on CWIP and 13.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

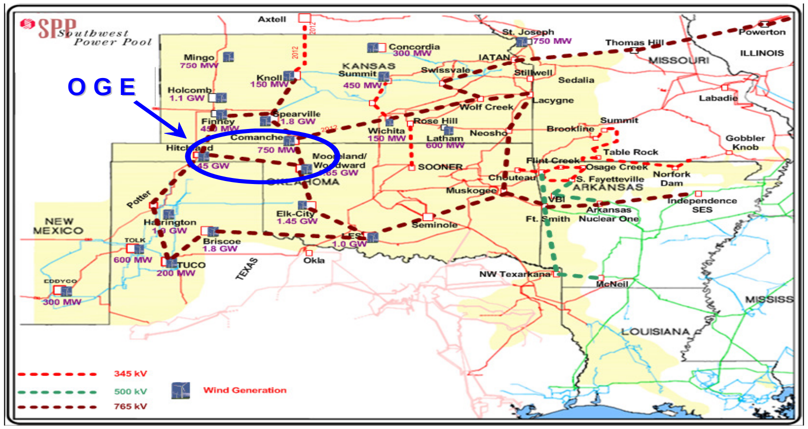
- ### *Key Challenges*
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

❑ *Overview*

- ❑ In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- ❑ TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- ❑ The project will promote wind development in the western half of Oklahoma.
- ❑ Project is expected to cost approximately $500 million and be in-service by 2013.
- ❑ AEP's ownership of the joint venture is 25%.
- ❑ Other responsibilities will be handled by the partners or outsourced.
- ❑ FERC formula rate filing submitted in October 2008:
  - ❑ Cash return on CWIP and 13.3% incentive ROE
  - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
  - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

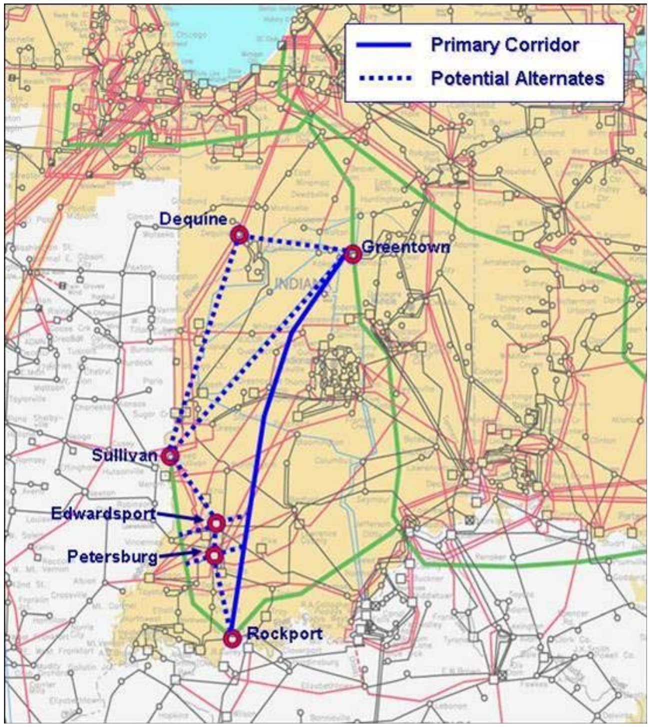
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

❑ *Key Challenges*

- ❑ Cost allocation which enables the development of "system solutions"
- ❑ RTO Approval

Pioneer Transmission, LLC

- ***Overview***
  - In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
  - PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
  - The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
  - Project is expected to cost approximately $1 billion and be in-service by 2015.
  - AEP's ownership of the joint venture is 50%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC formula rate filing submitted in October 2008 requesting:
    - Cash return on CWIP and 13.5% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



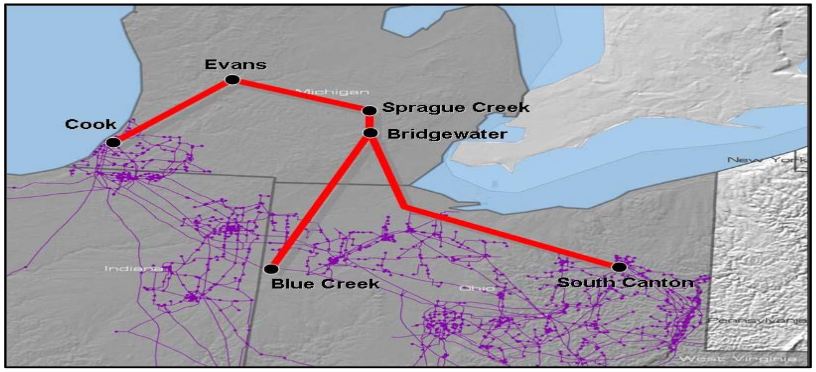
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Siting

EHV Transmission in Michigan

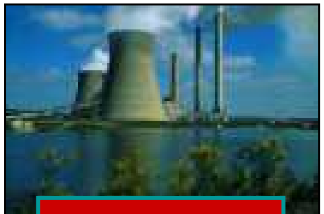
Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- ***Overview***
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (in 2007$, before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- ***Benefits***
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTOs Approvals



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

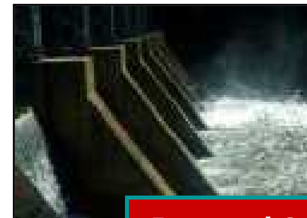
Domestic Generation Fleet

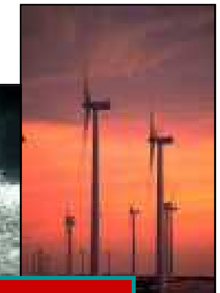


Coal/Lignite
66%

Nat. Gas/Oil
23%

Nuclear
6%





Pumped Storage/ Hydro/Wind
5%

AEP's Generation Fleet
38,721* MW Capacity

* Includes 270 MW of mothballed/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date
AEG	Dresden	Ohio	$309 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600(1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

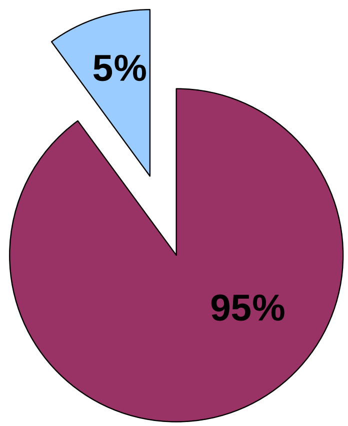
Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2013
Northeastern 3	450		N/A	☑	Projected 2014
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,646 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors - AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Actuals To Date & Firm Costs
Estimated Cost Exposure*

Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $162/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

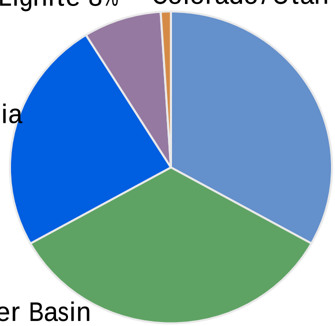
- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $262/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

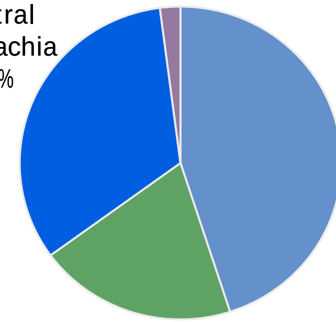
Total AEP System



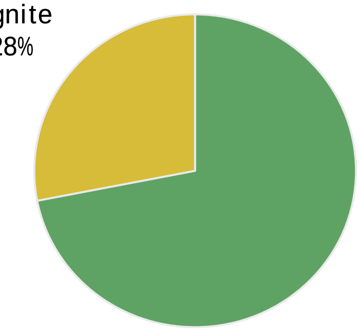
Coal Stats:

- 100% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 28% price increase in 2008 based on 2007 actual results.

AEP East



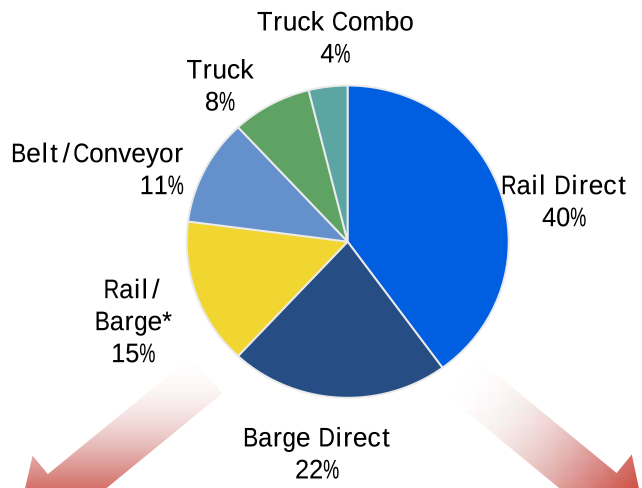
AEP West



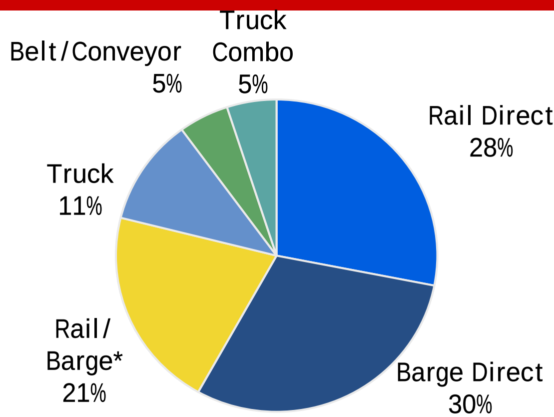
Coal Delivery

Total AEP System

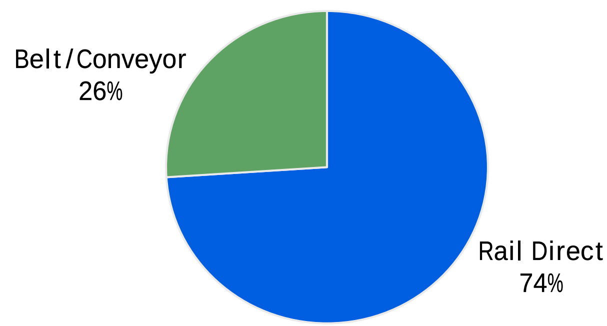
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

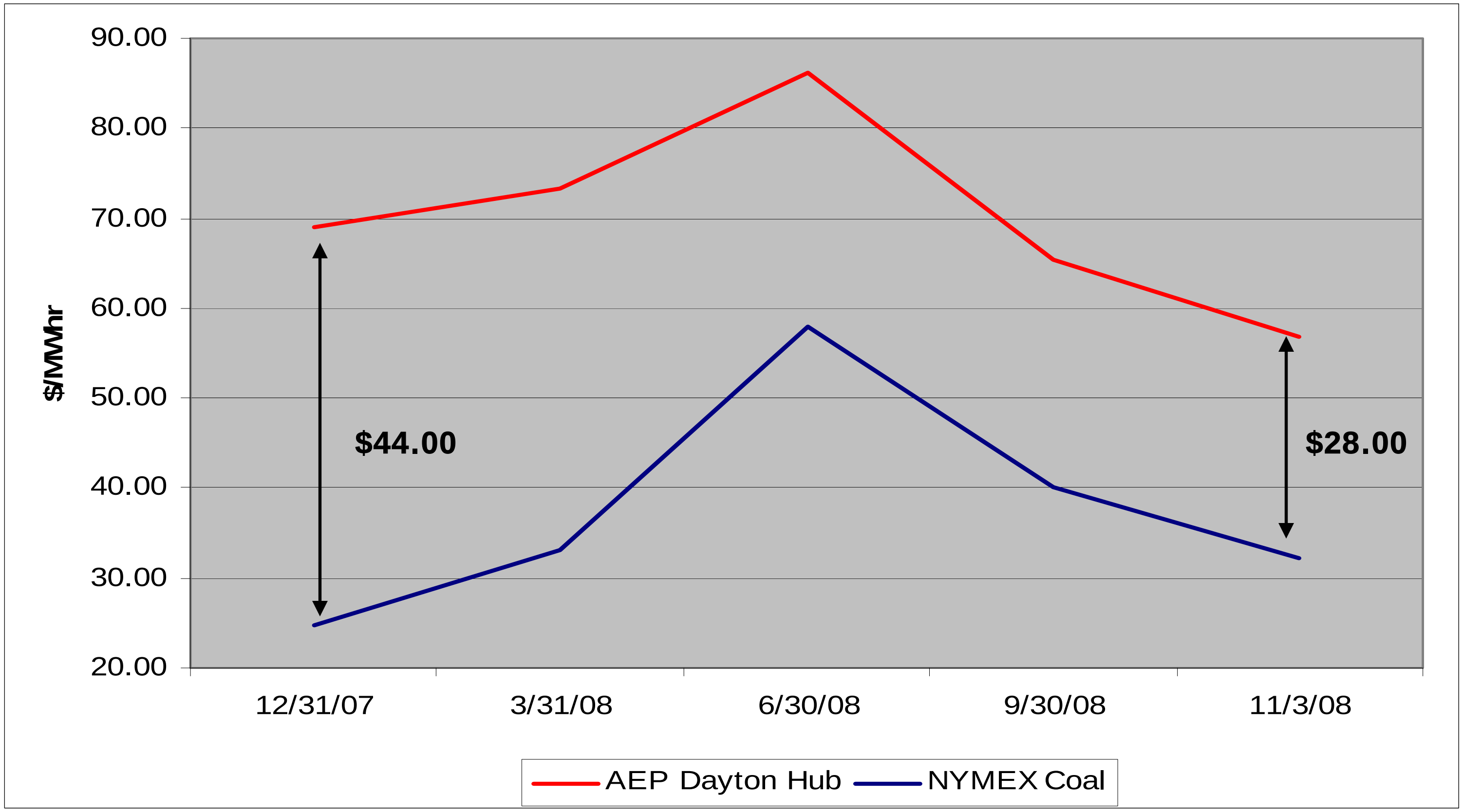
AEP River Operations

- Full-service Inland Waterways carrier
  - 2,900 hopper barges
  - 60+ towboats/20 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

Inland Waterway Routes For AEP River Operations

Dark Spread Comparison

NYMEX Coal vs. AEP-Dayton Hub Peak Electricity



Coal Purchases:
2009: 95+%
2010: 85+%

Del. Coal Prices:
2007A: $36.58/ton
2008E: $46.82/ton

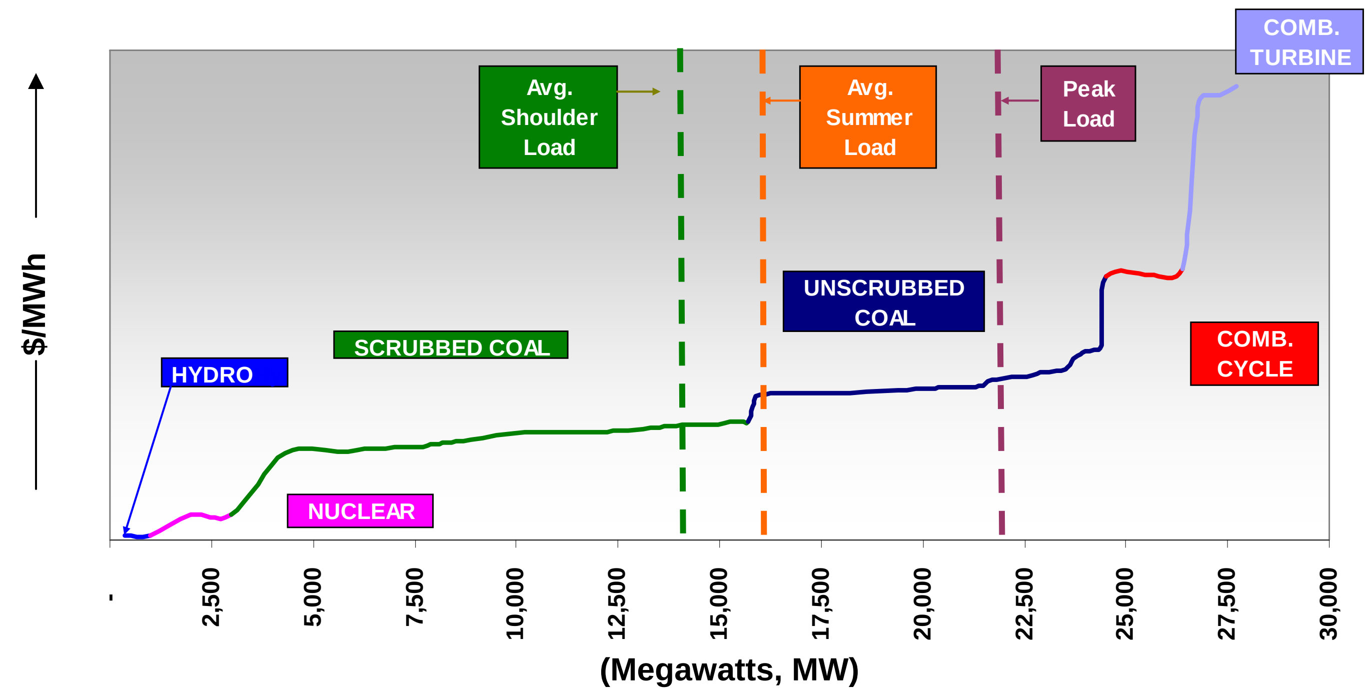
2009 estimated increase: 12%-15%

- ❑ Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- ❑ 10,000 heat rate used for conversion
- ❑ Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.

Typical AEP Supply Stack



With the loss of Cook 1 this fall season, a planned outage on a scrubbed coal unit was cancelled, leaving the supply stack in roughly the same position for off-system sales

AEP AMERICAN ELECTRIC POWER®

BMO Capital Markets 6th Annual Utilities Conference

November 30, 2010
New York, NY

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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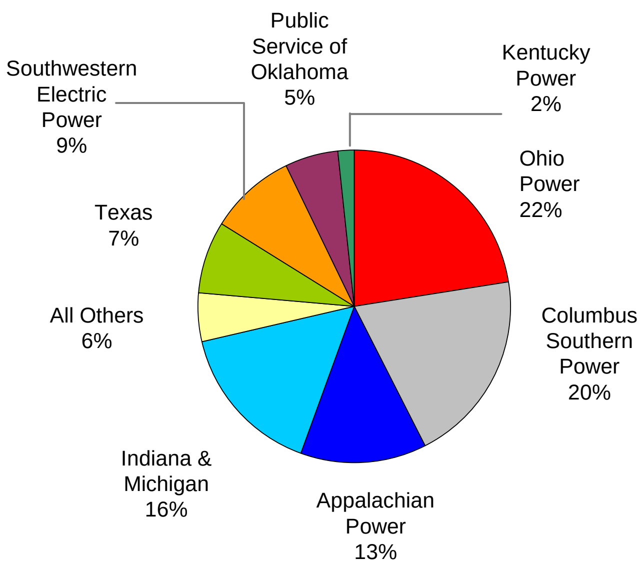
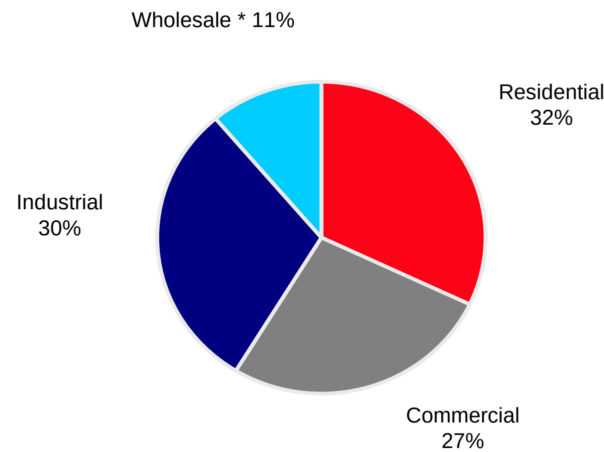
Highly Diversified Regulated Utility Platform

2009 Earnings Contribution



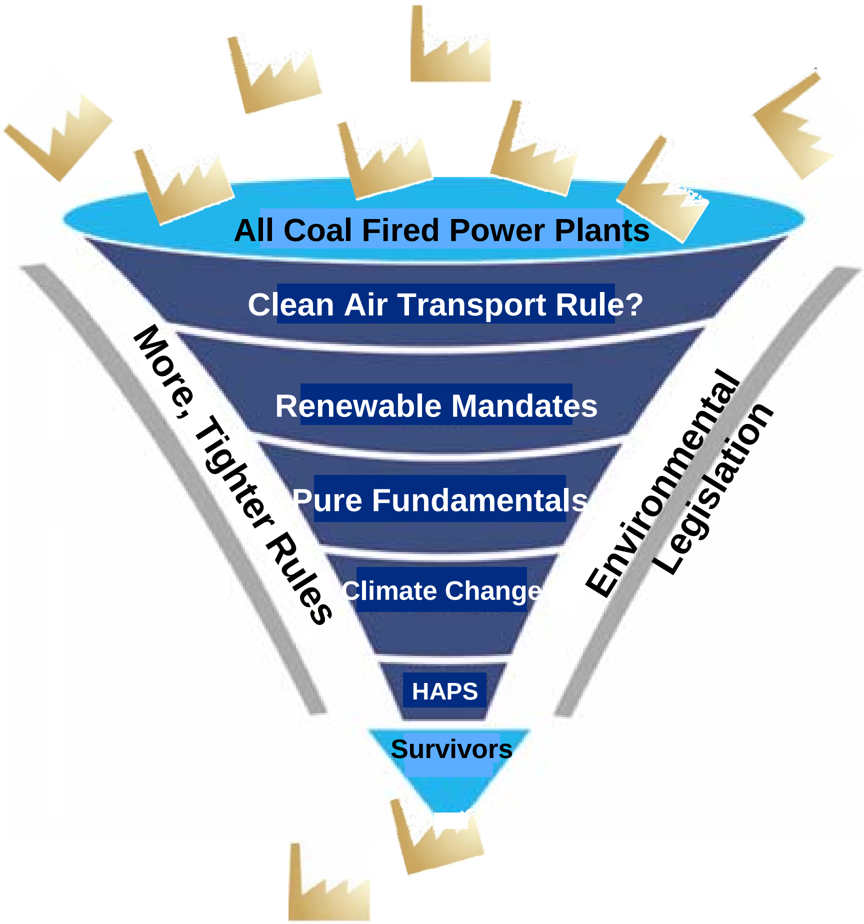
2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

The Pressure on Coal Generation



Dark Spread Compression

NYMEX coal

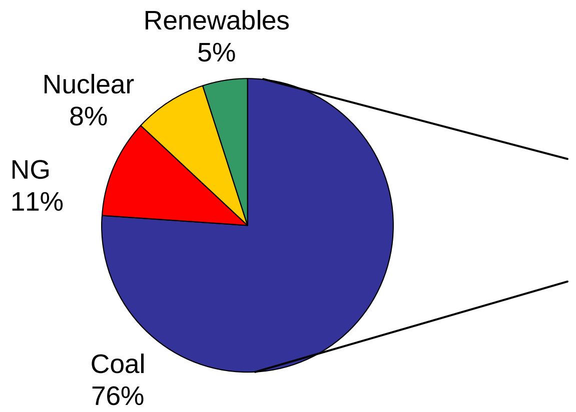
<u>Key EPA Actions Pending</u>

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in Spring 2011

The threshold level for coal is being defined

AEP Generation Capacity

East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

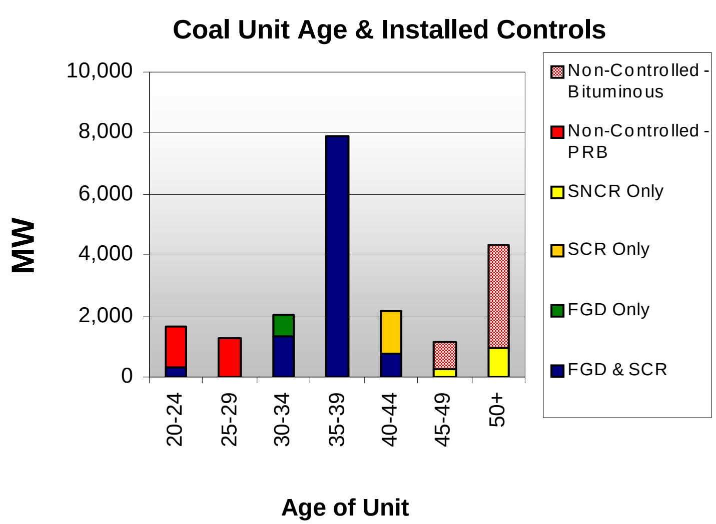


Coal Source

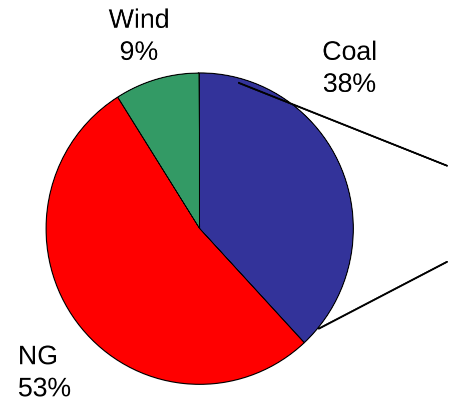
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind

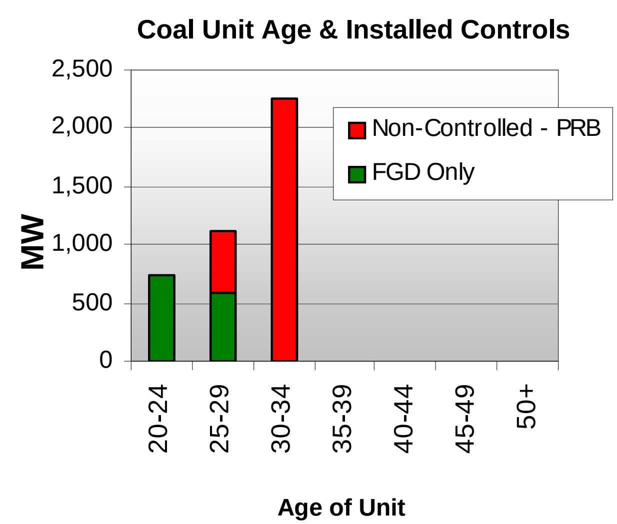


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

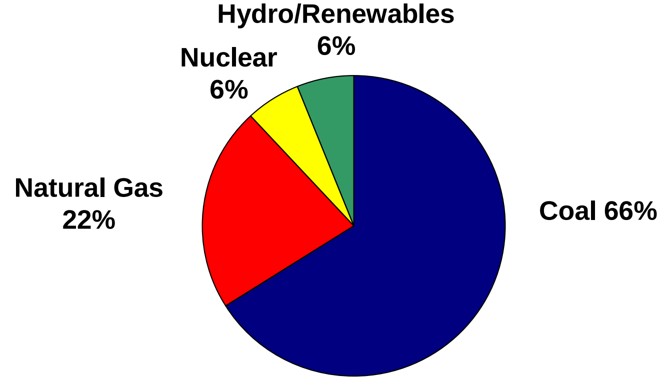
[1] Represents cost of committed position (90%)



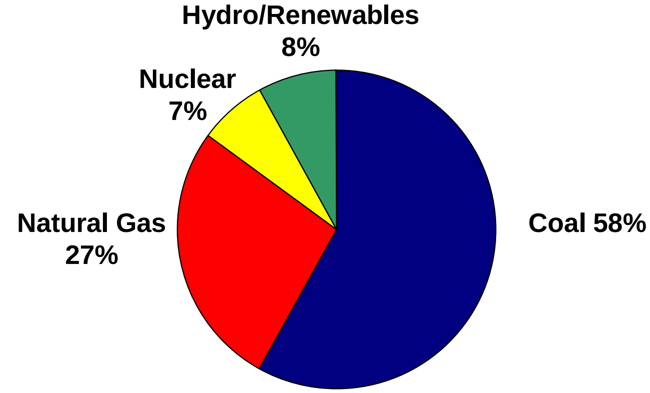
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of "partially exposed" units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

ETT: An Operating Utility

Electric Transmission Texas

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	Anticipated 10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

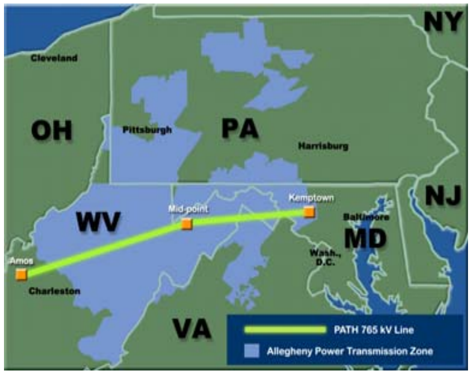
AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - Ohio application for public utility status pending; approval expected in 2010
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

Progress on Joint Ventures in 2010

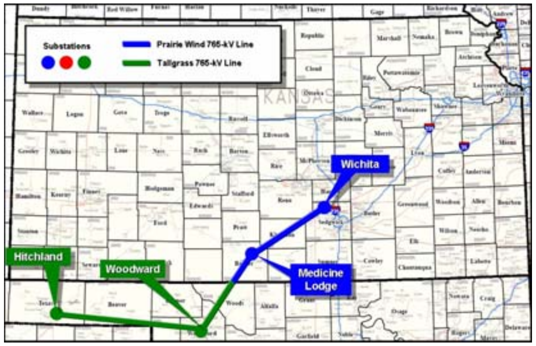
PATH:

- Re-filed for certification in VA
- Letter from PJM confirmed the 2015 in-service date
- PJM Testimony “RTEP final with respect to PATH”
- FERC approved formula rate (14.3% ROE), subject to rehearing



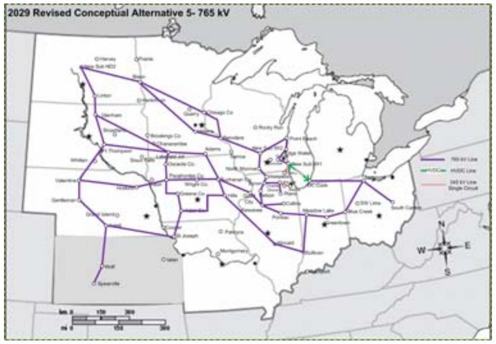
Prairie Wind:

- Approved by SPP as a Priority Project (Notice To Construct rcv’d)
- Cost allocation approved by SPP and FERC
- FERC approved formula rate (12.8% ROE)
- In-service date is 2013-2014



Pipeline of Future Projects:

- Pioneer
  - FERC approved formula rate (12.54% ROE)
  - Awaiting RTO project approval; MISO included Pioneer in its proposed EHV plan
- Tallgrass
  - Will move forward if approved at 765 kV
- Smart Transmission Study
  - Comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Two New Anchor Projects

ETA – AEP - Exelon: The RITE Line

Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

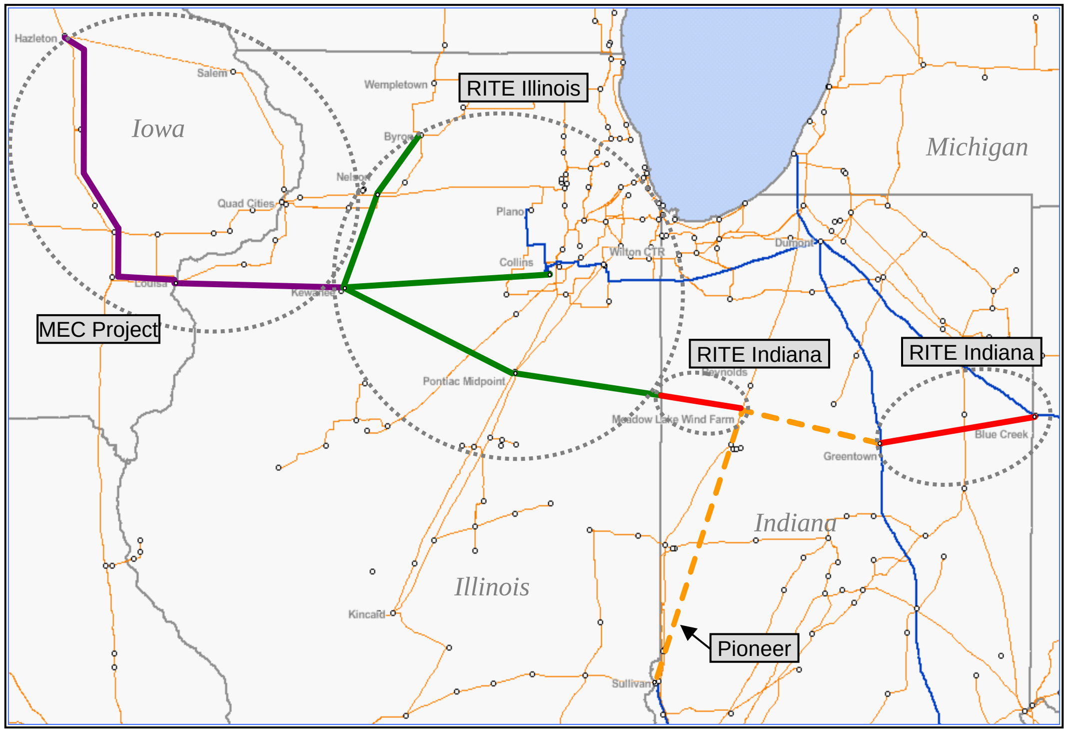
ETA – MidAmerican Energy Co: MEC Project

Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

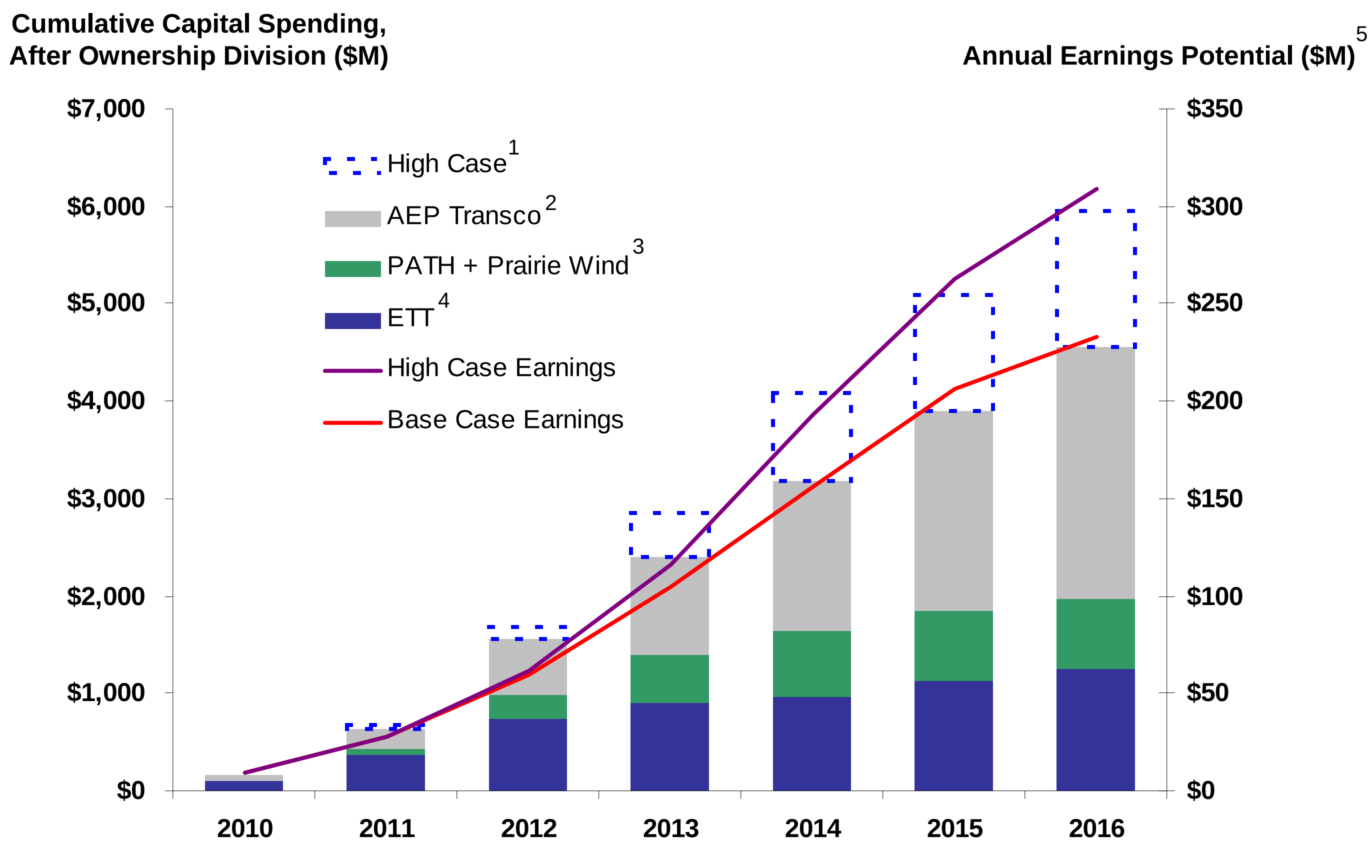
AEP Total Investment:

~$500M



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Capital Investment and Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

Capital for Growth

- Increased capital budget by $150M for 2011 to $2.6B
- Announced capital budget plan of $2.9B for 2012

Return of Capital to Shareholders

- 9.5% increase in quarterly dividend to $0.46/share declared by the board of directors on October 26th
- Future dividend increases will grow with earnings

Capital to Reduce Risk

- Voluntarily funding pension $500M in 2010
- Allocating an additional $150M of funding for pension in 2011

Detailed Ongoing Earnings Guidance

2010E: $2.95 - $3.05

2011E: $3.00 - $3.20

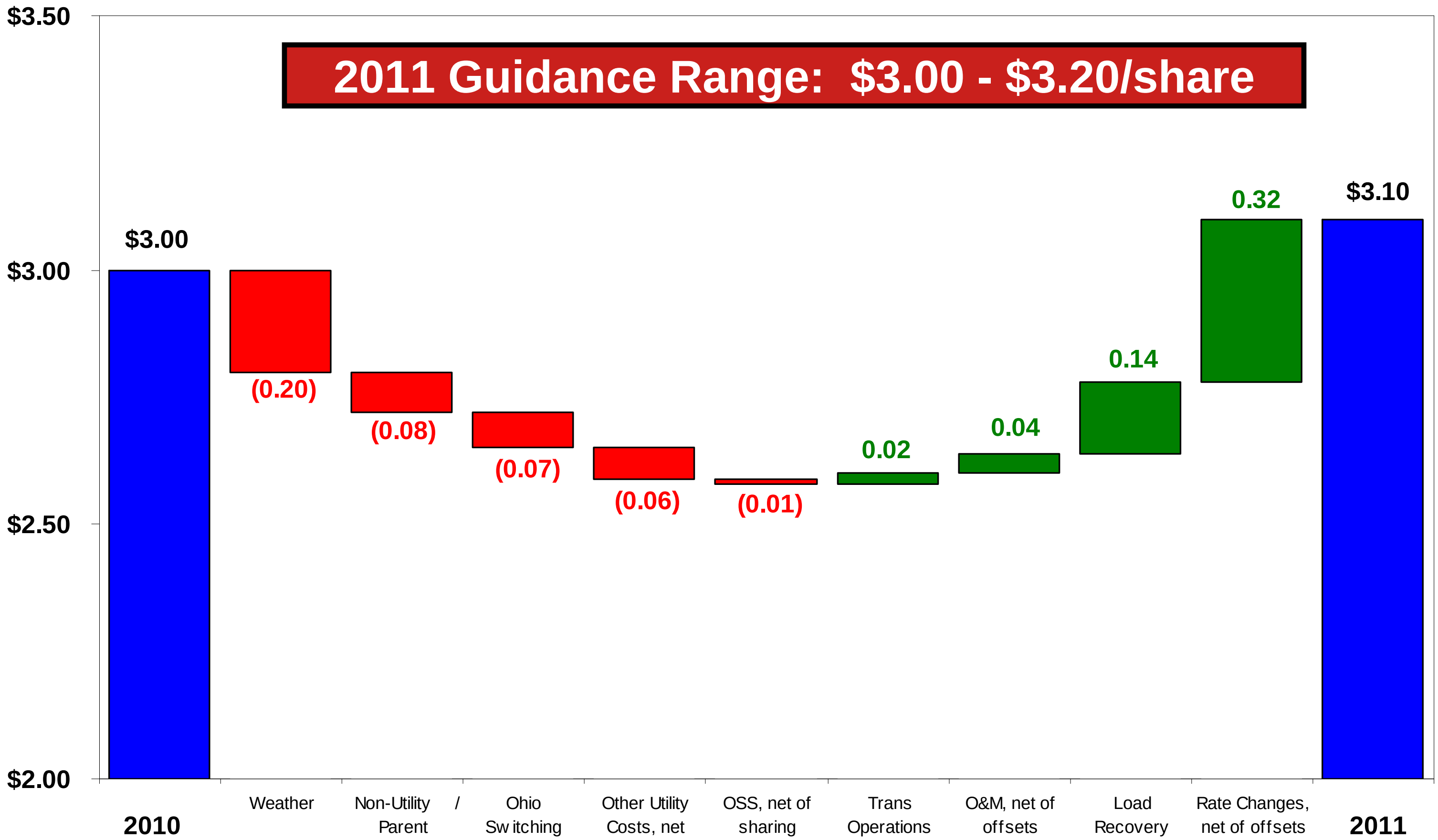
American Electric Power

Financial Results for 2011 Guidance vs 2010 Projection

		Performance Driver	2010 Projection ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		51
18	Generation & Marketing		20		2
19	Parent & Other On-Going Earnings		(22)		(53)
20	ON-GOING EARNINGS		1,439		1,496

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2011 Earnings Drivers



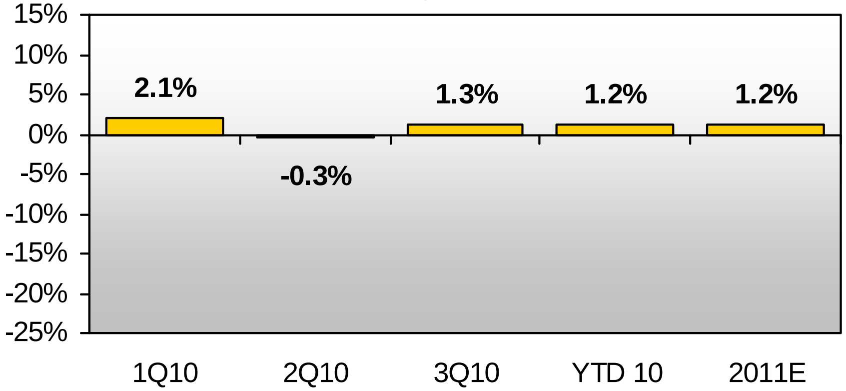
- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

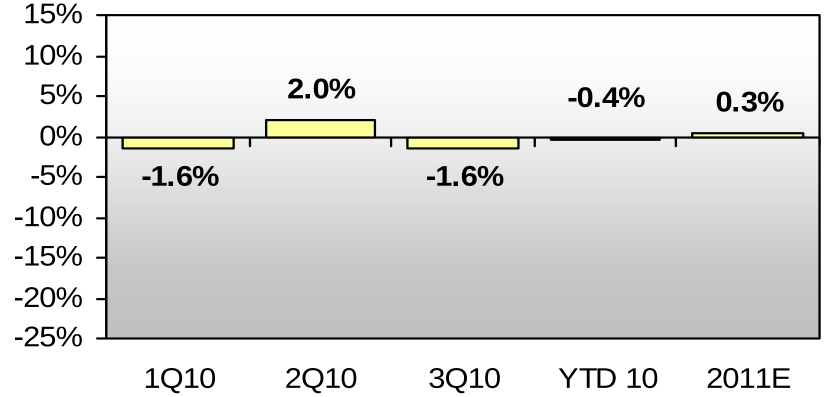
2012 EPS Target: $3.25/share

Normalized Load Trends

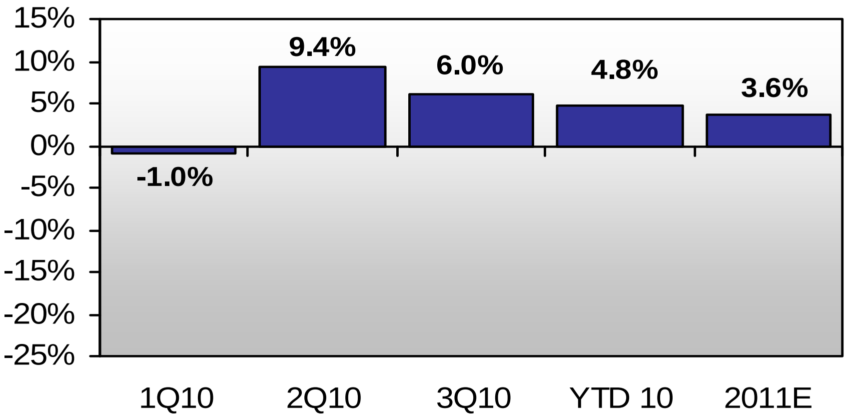
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



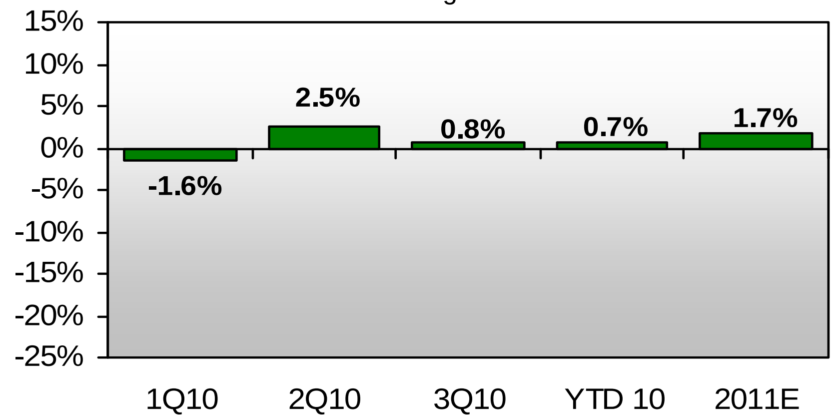
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



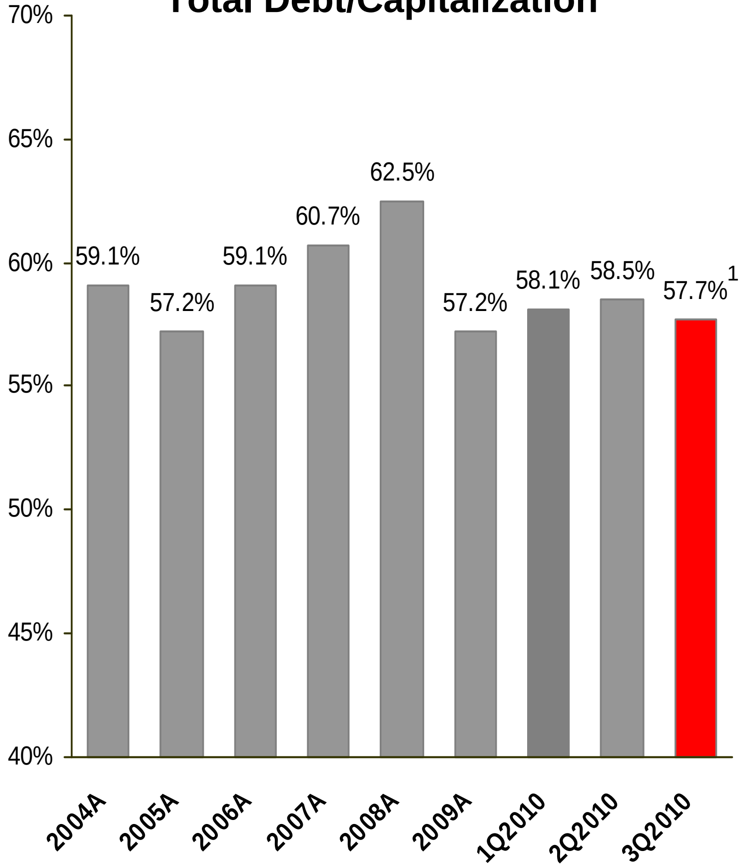
*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

Maintaining Strong Capitalization & Liquidity

AEP®

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

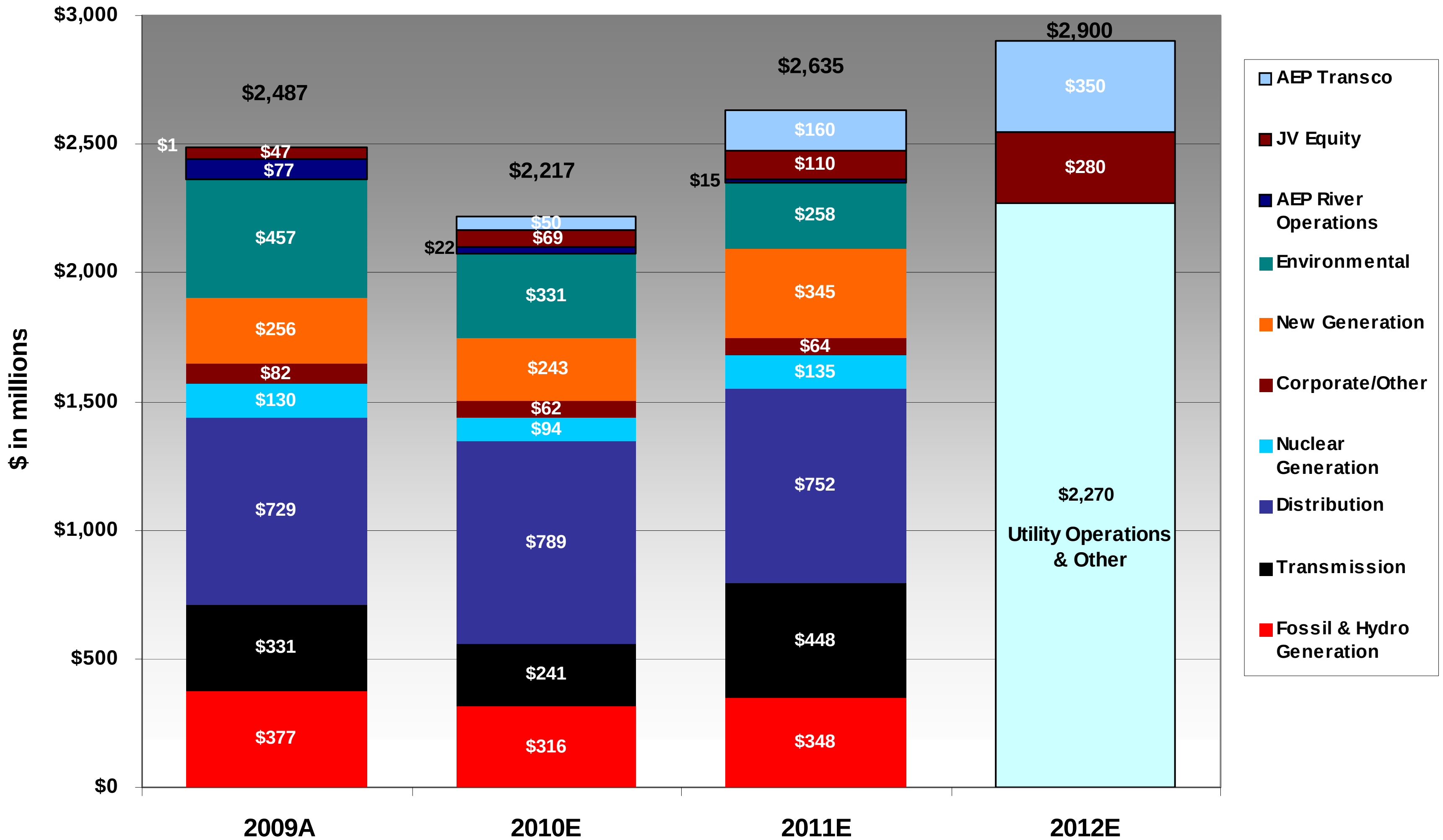
Cash Flow Guidance

$ in millions

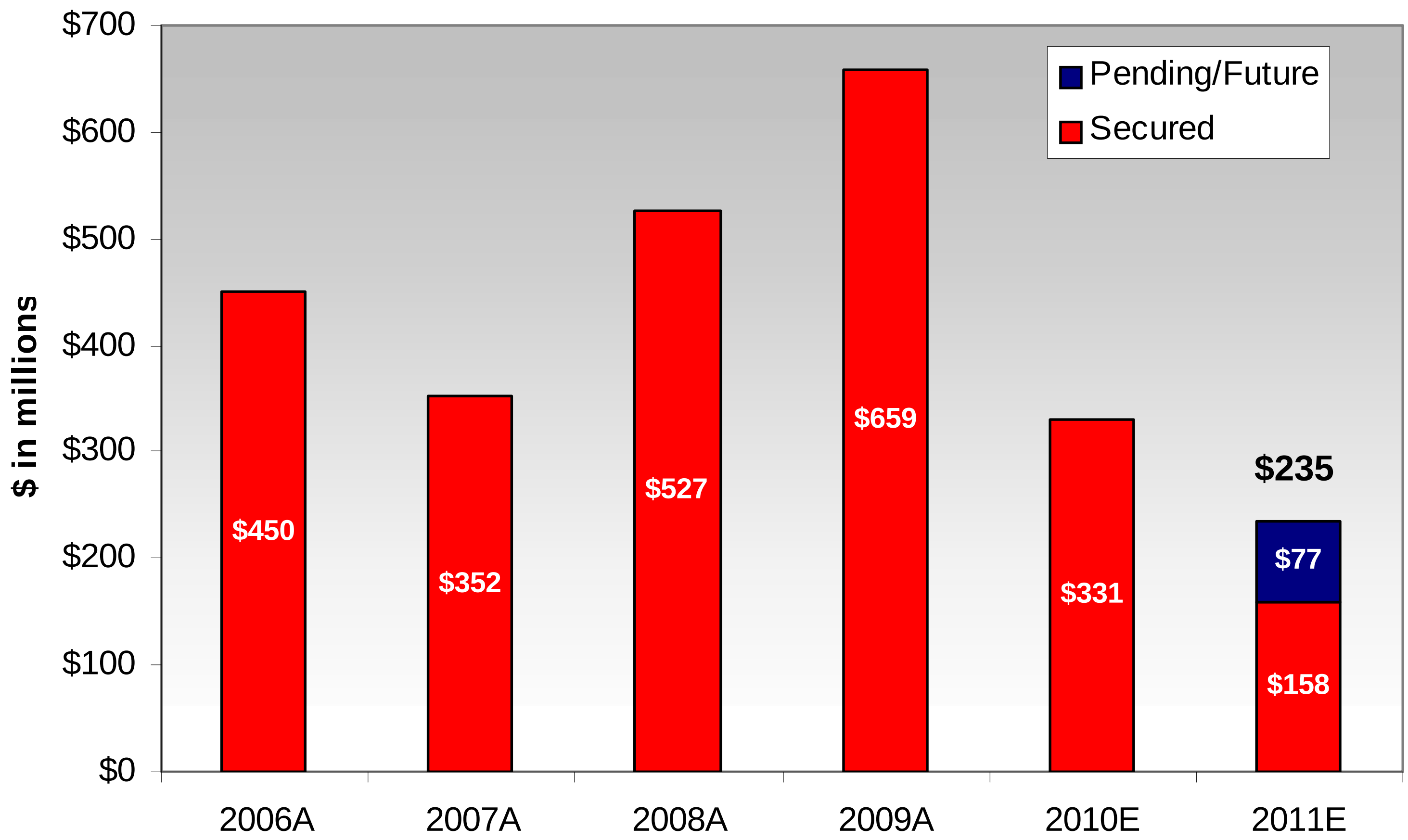
	2010E	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,205	$ 1,499
Depreciation & Amortization	1,654	1,588
Pension Funding	(500)	(150)
Other Cash Flow Items	653	234
Working Capital[1]	(218)	424
Cash From Operations	$ 2,794	$ 3,595
Investing Activities		
Construction Expenditures	(2,217)	(2,635)
Other Investing Activity	(352)	(265)
Total Investing Activities	$ (2,569)	$ (2,900)
Financing Activities		
Dividends	(826)	(893)
Net Debt Issued/(Retired)[1]	190	48
Common Equity	121	150
Total from Financing Activities	$ (515)	$ (695)
Beginning Cash Balance	$ 490	$ 200
Ending Cash Balance	$ 200	$ 200

[1]2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Capital Expenditures



Rate Changes



Note: Rate changes in this chart excludes revenues with offsetting costs

Active or pending rate cases include Oklahoma, West Virginia and others yet to be filed

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011. Staff and Intervenor testimony recommended increases in the range of $41MM--$57MM.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

PSO General Rate Case – Docket #201000050

On July 9, 2010, PSO filed a base rate case with the Oklahoma Corporation Commission requesting a net increase of $52.4 million, comprised of a $82.7 million base rate increase and a $30.3 million decrease in the capital investment rider. The requested ROE is 11.50%. A settlement agreement was filed on Nov. 19, 2010 resulting in no change to current rates and a 10.15% ROE. Hearing scheduled December 6, 2010, with rates going into effect February 2011.

Actual Capital Structure – Company Position (2/28/10)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	53.86%	6.52%	3.51%
Common Equity	45.84%	11.50%	5.27%
Preferred Stock	0.30%	4.02%	0.01%
Total	100.00%		8.79%

Procedural Schedule

October 26, 2010	Staff & Intervenor testimony due
November 16, 2010	Rebuttal testimony due
November 29, 2010	Settlement Conference
Debember 6-17, 2010	Hearing
January 5, 2011	Rates Effective, Subject to Refund

Required Rate Relief – Company Position (2/28/10)

($ in millions)

Rate Base	$	1,687.2
Rate of Return		8.79%
Operating Income Requirement	$	148.3
Adjusted Operating Income	$	97.9
Difference	$	50.4
Revenue Conversion Factor		1.6391
Total Revenue Requirement	$	82.7
Elimination of Capital Investment Rider	$	(30.3)
	$	52.4

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,467MM	10.50%	54/46	1/14/2009
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

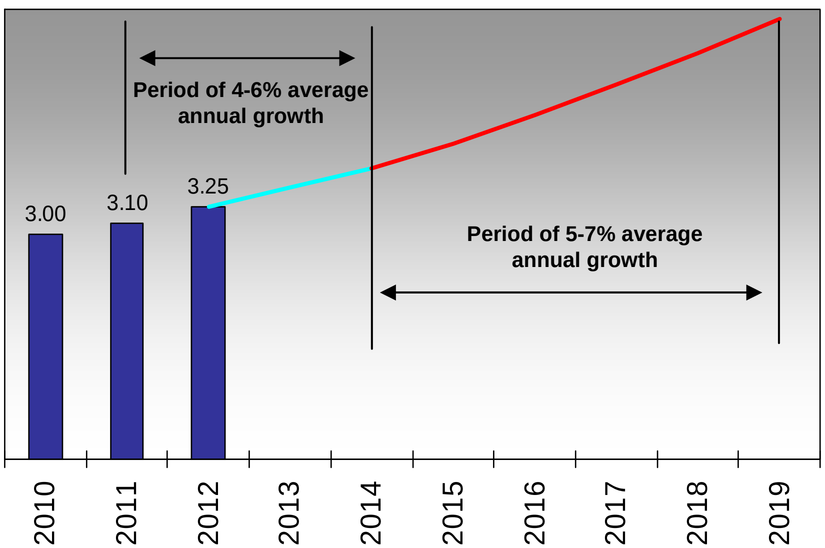
** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Value Proposition

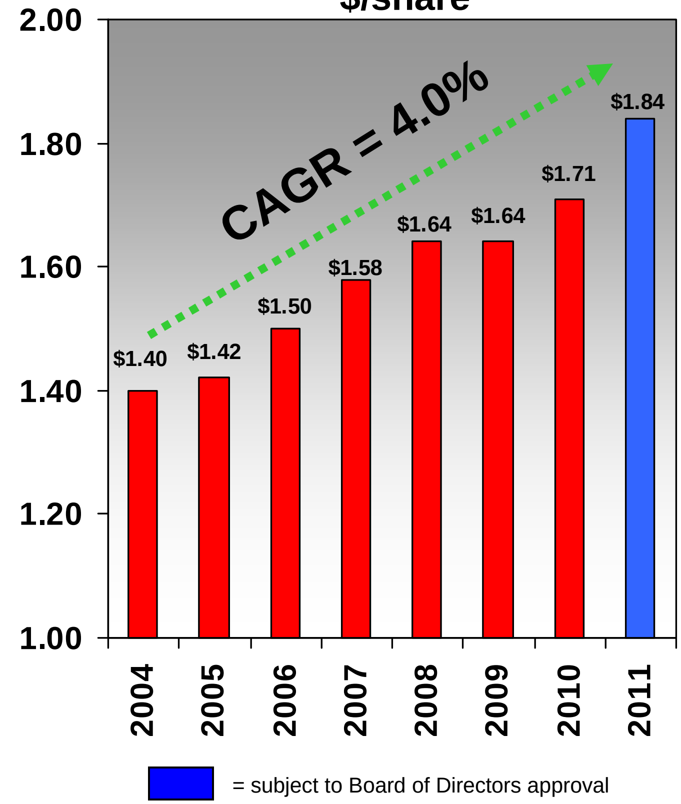
AEP®

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004 $/share



- 9.5% increase in quarterly dividend to $0.46/share declared on October 26th
- 402nd consecutive quarterly dividend will be paid December 10, 2010
- 50-60% payout ratio target
- Current yield about 5%

AEP AMERICAN® ELECTRIC POWER

BMO North American Pipeline &Utility Conference
Toronto, Canada
June 22, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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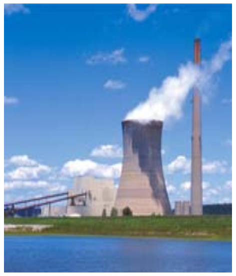
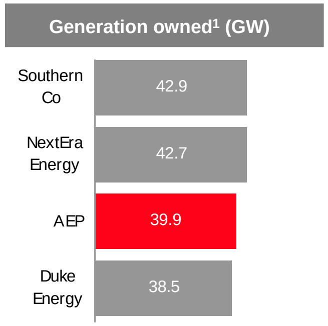
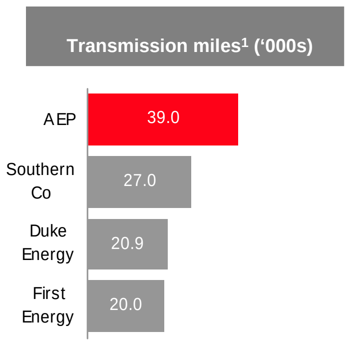
American Electric Power



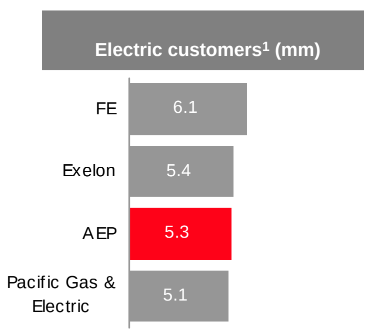
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

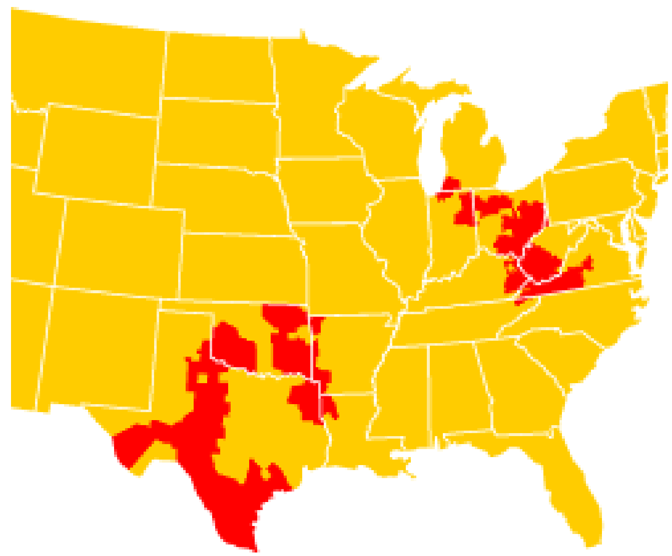


One of the largest U.S. electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

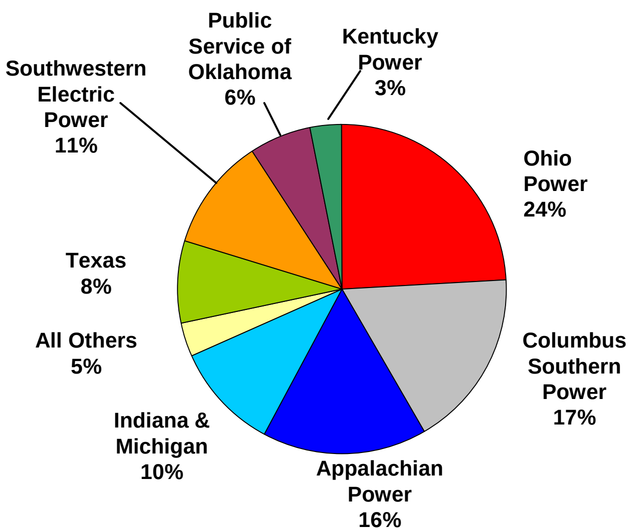
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$18.5B Market Capitalization
BBB/Baa2/BBB credit rating

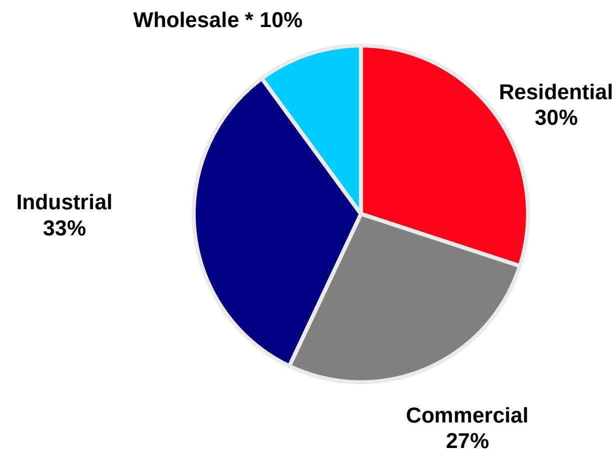
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load

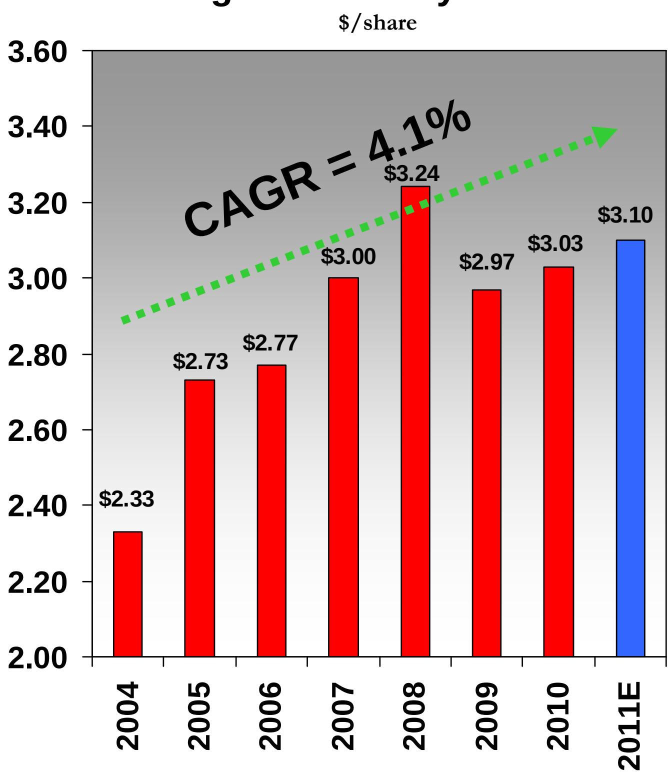


** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

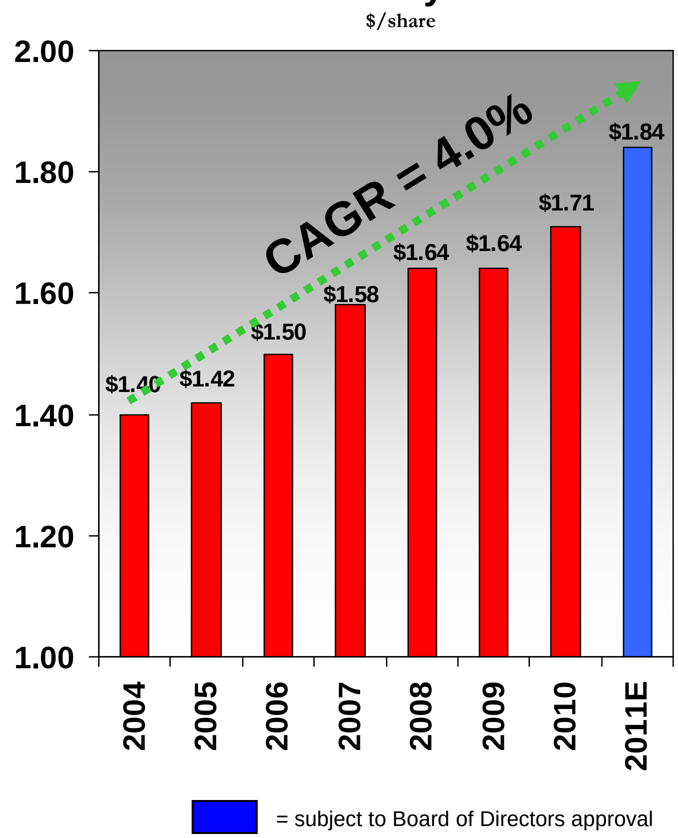
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

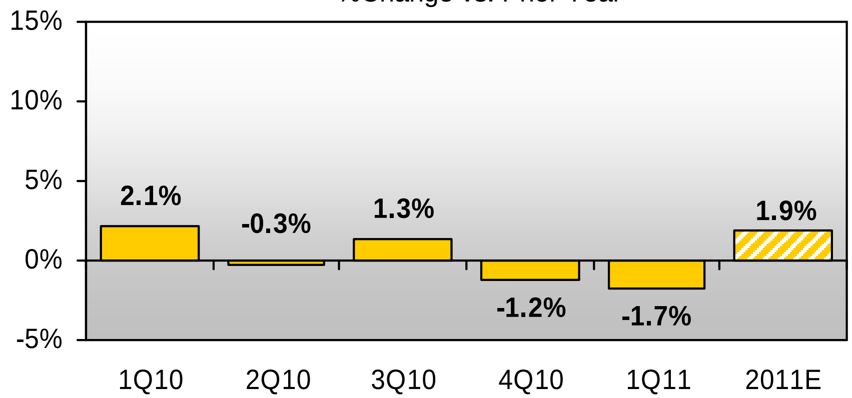
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

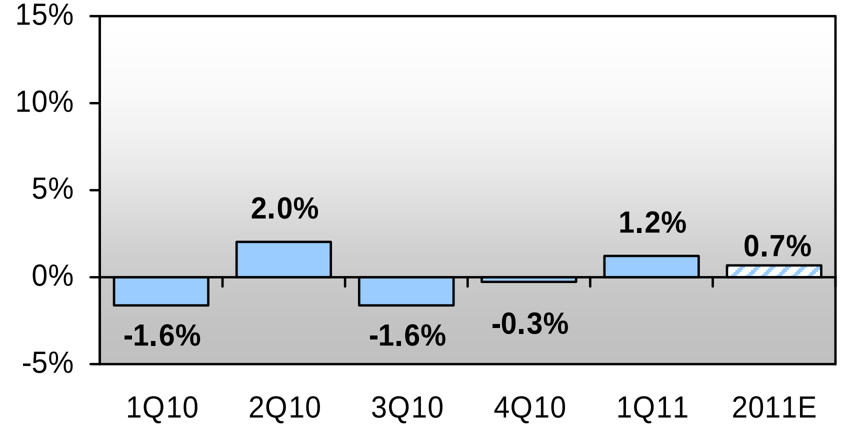
8

Normalized Load Trends

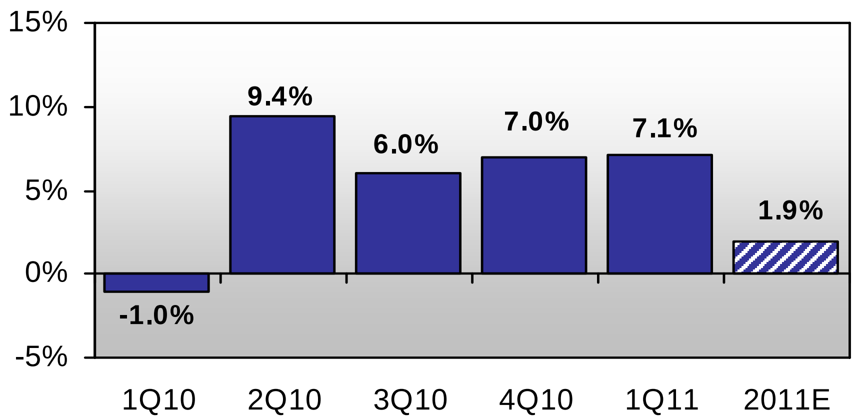
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



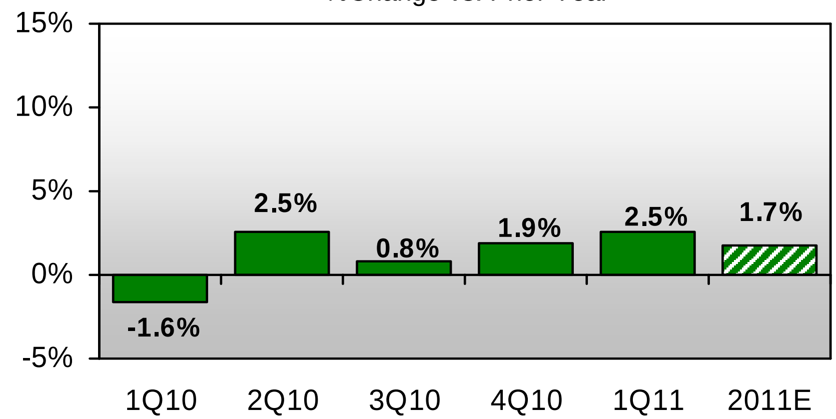
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



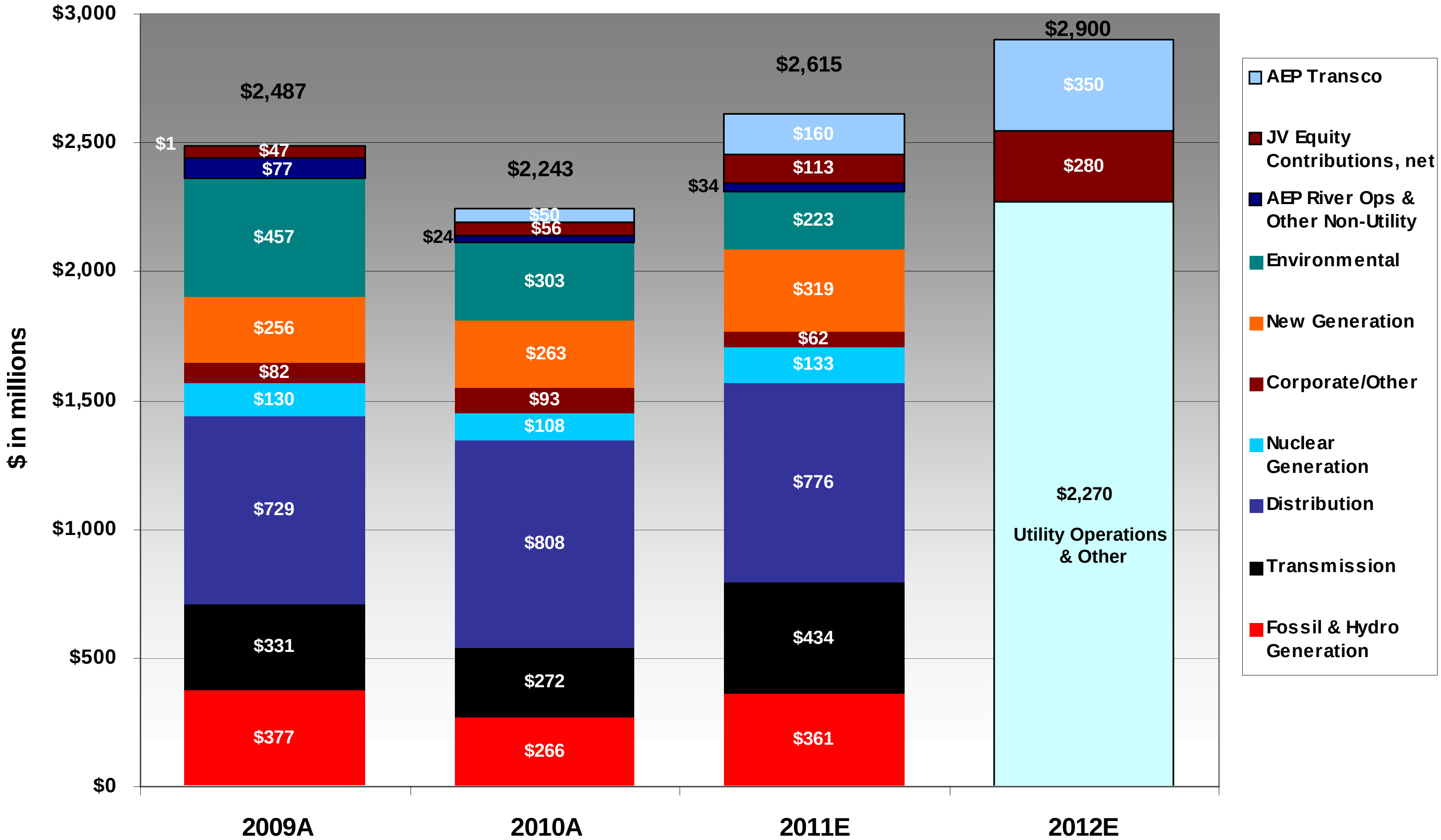
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

AEP®

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[1]	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

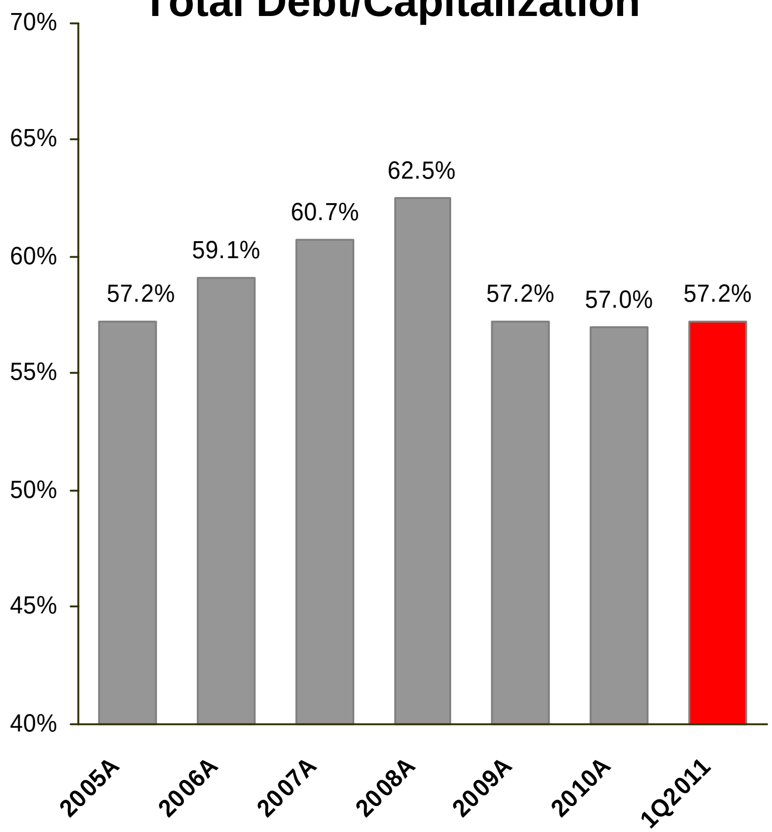
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

Total Debt/Capitalization

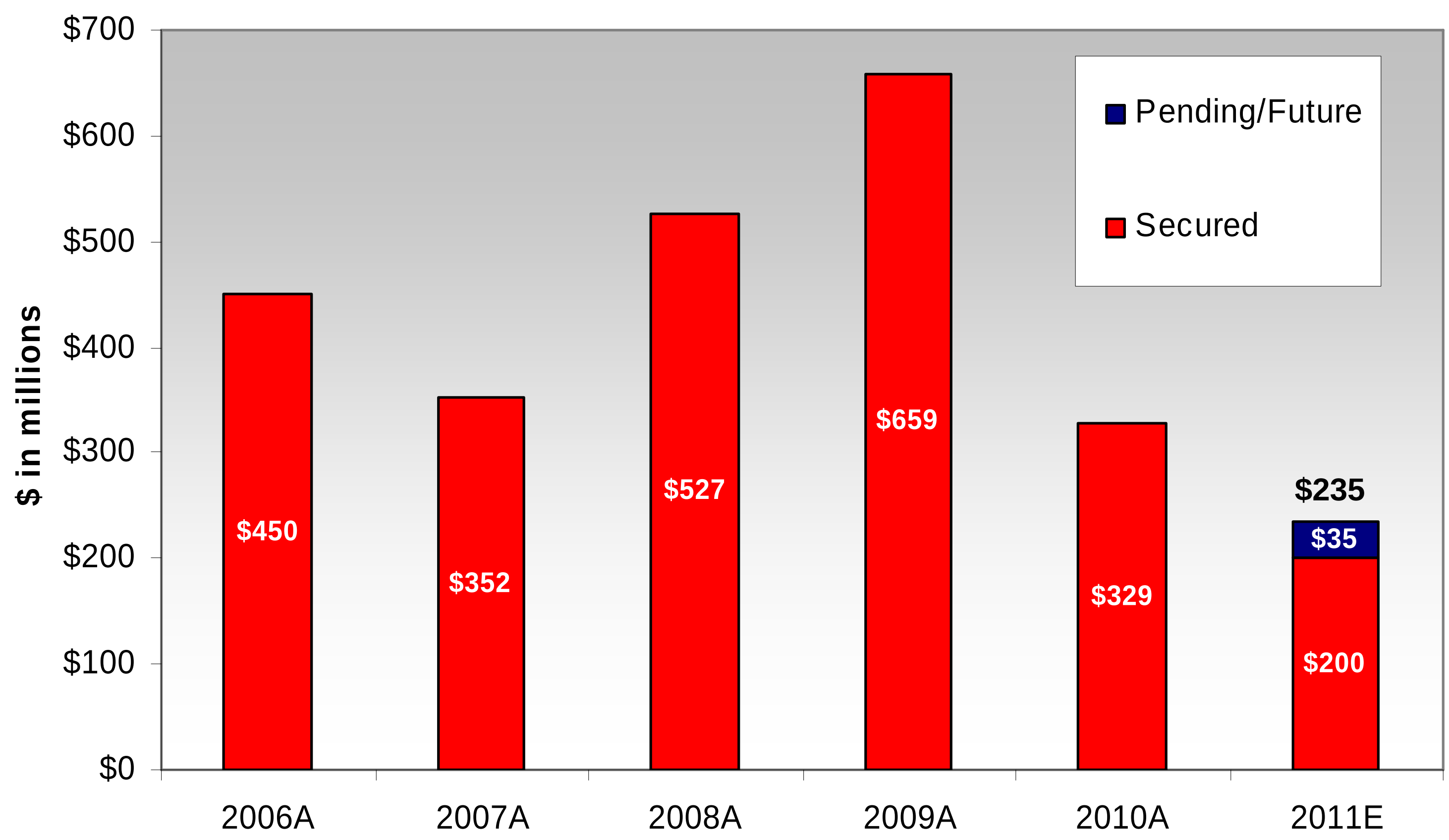


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 03/31/11	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – July 29; Hearing August 15**

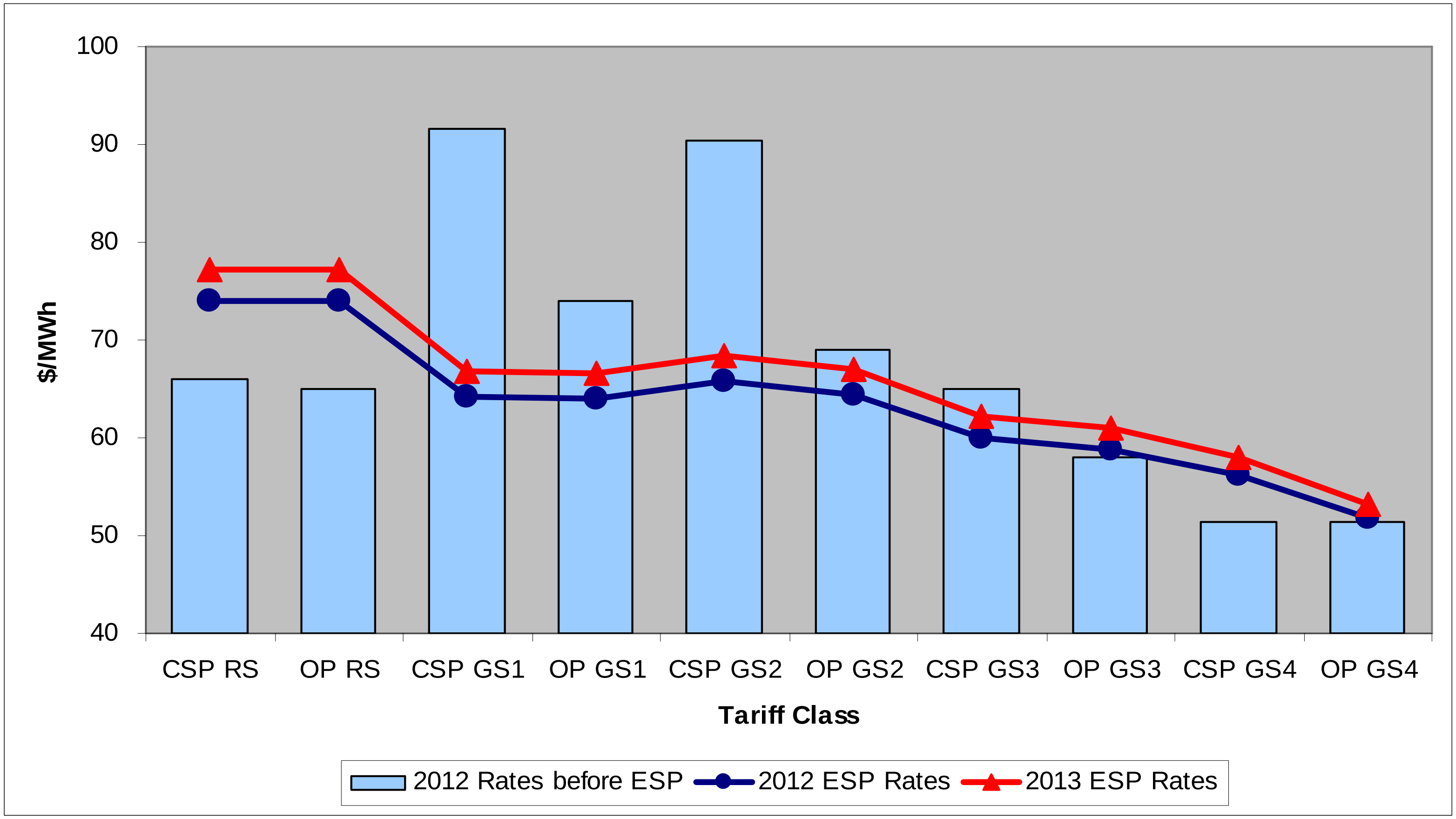
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

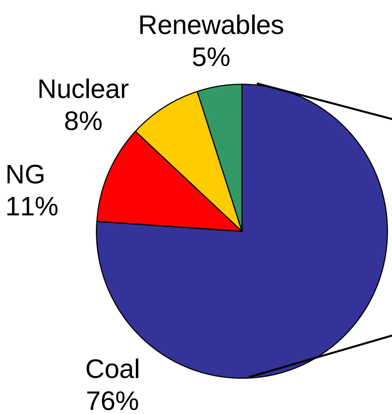
The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

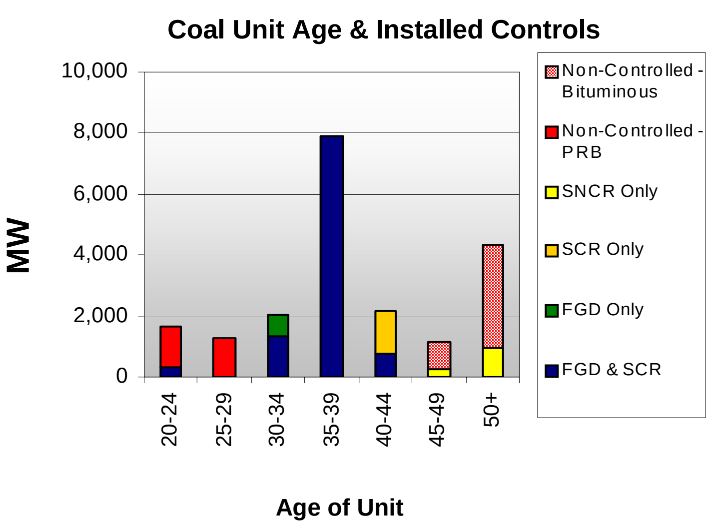
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



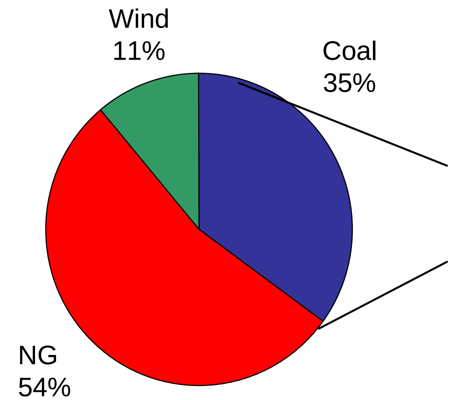
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



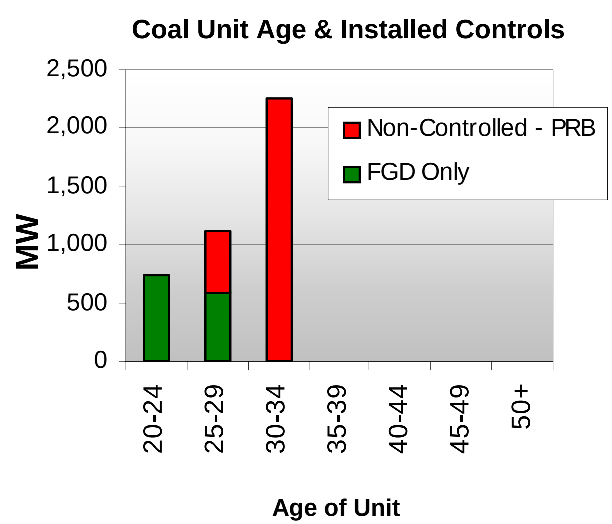
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

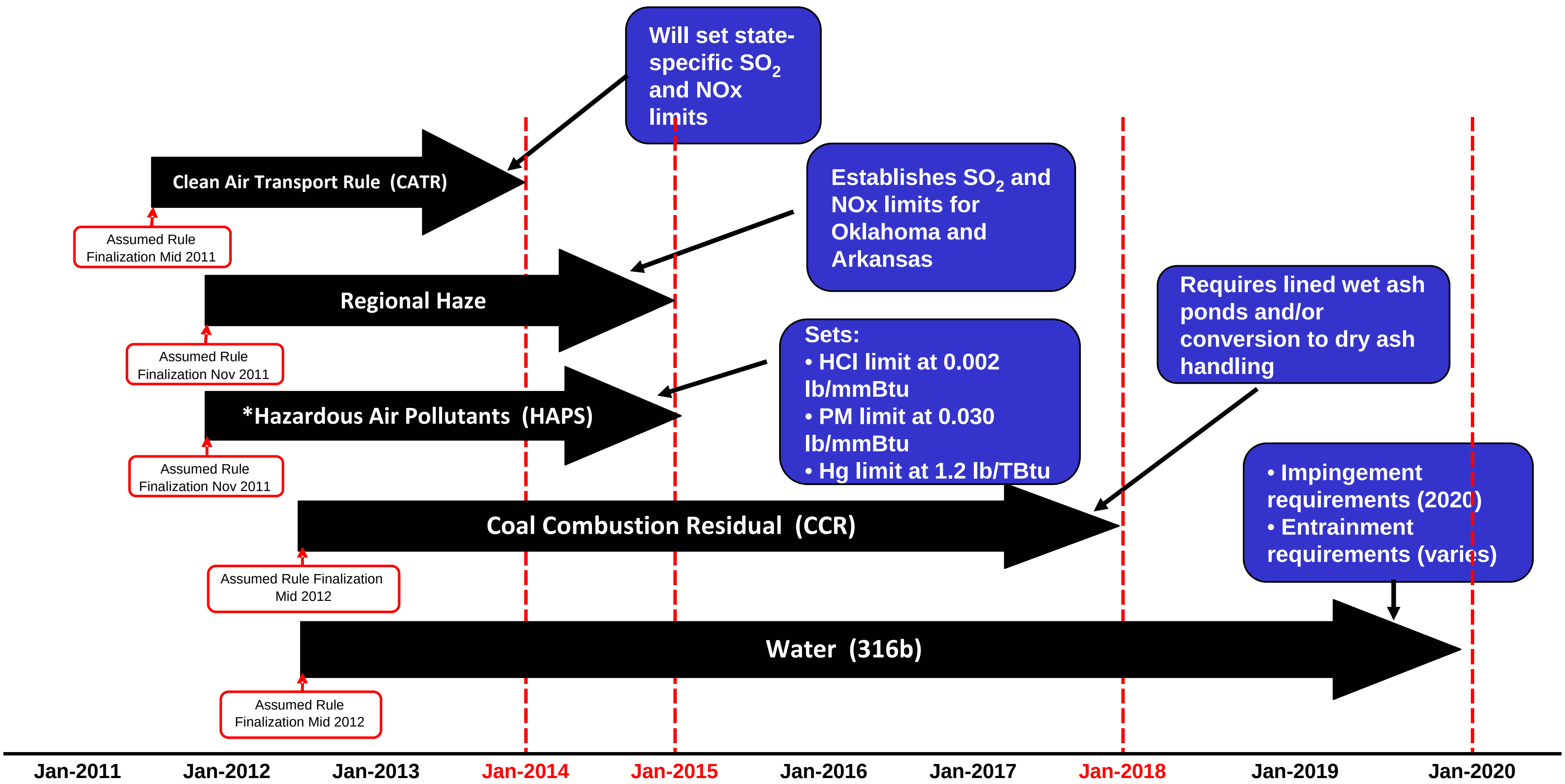


Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.
- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
Conesville 5	400	SCR, DSI			
Conesville 6	400	SCR, DSI			
Muskingum River 5	510	Refuel with Natural Gas			
Gavin 1	1320	FGD upgrade			
Gavin 2	1320	FGD upgrade			
Zimmer 1	330	FGD upgrade			
Total Expected Cost			**2,100**	**2,800**	*
Clinch River 1	211	Refuel with Natural Gas			
Clinch River 2	211	Refuel with Natural Gas			
Dresden	580	New Natural Gas			
Total Expected Cost			**580**	**765**	**
Rockport 1	1320	FGD, SCR			
Rockport 2	1320	FGD, SCR			
Tanners Creek 4	500	DSI, ACI			
Total Expected Cost			**1,240**	**1,670**	***
Big Sandy 1	640	New Natural Gas			
Total Expected Cost			**400**	**525**	

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 1	470	FGD, ACI, Baghouse		
	Northeastern 2	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total Expected Cost			**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total Expected Cost			**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total Expected Cost			**80**	**100**

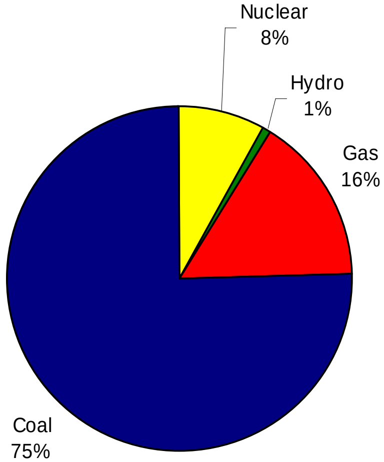
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Total MW	**2,485**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,856**	

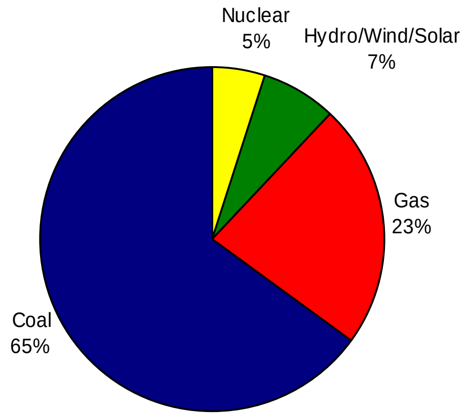
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

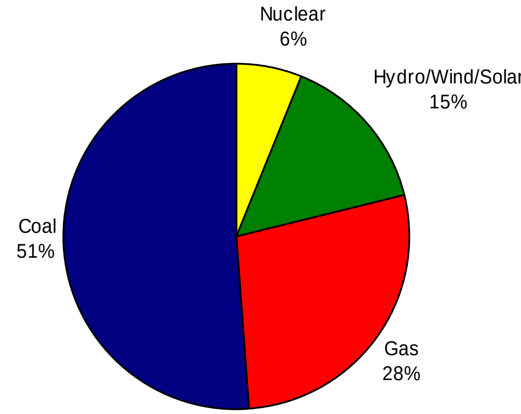
1990 AEP Generating Capacity by Fuel
37,428 total MW's



2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)

- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

AEP®

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

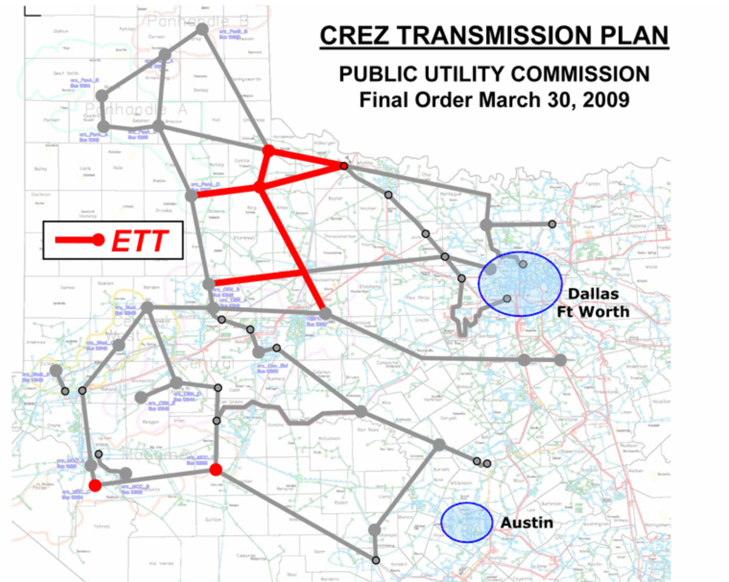
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

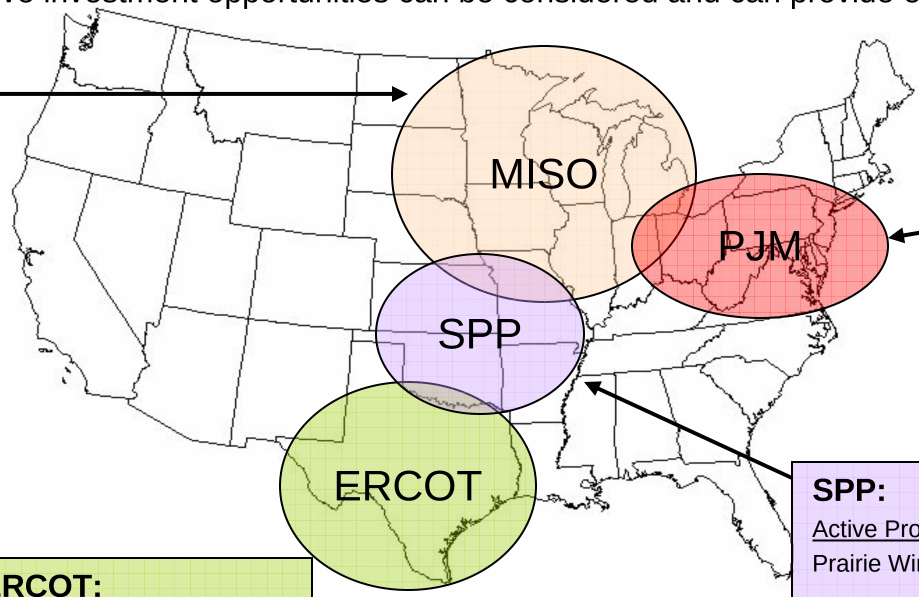
- **Strategy:** JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

AEP AMERICAN ELECTRIC POWER®

BMO & Clients
Office Visit
Columbus, OH
September 20, 2010

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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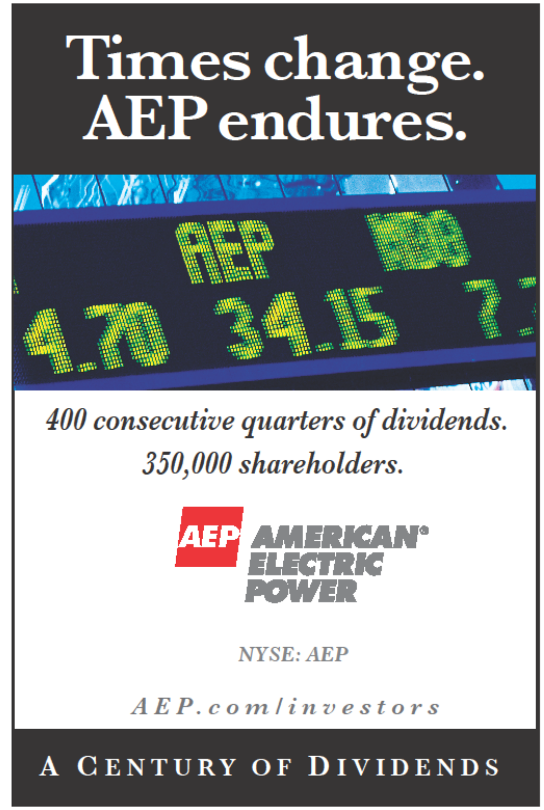
Value Proposition

- **Current Yield Opportunity of 4.7%[1]**
  - June 10th – 400th consecutive quarterly dividend paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

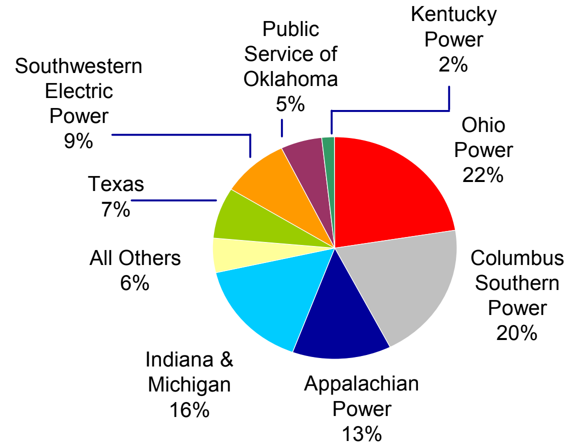
[1] yield percentage based on AEP closing price of $36.00 on 09/16/2010

Highly Diversified Regulated Utility Platform

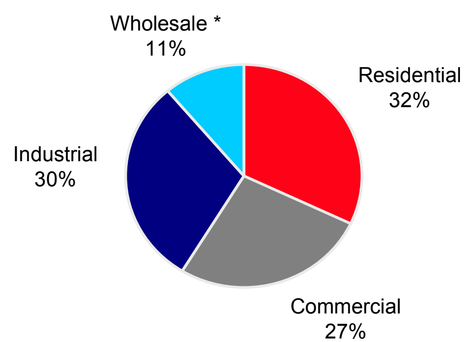
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



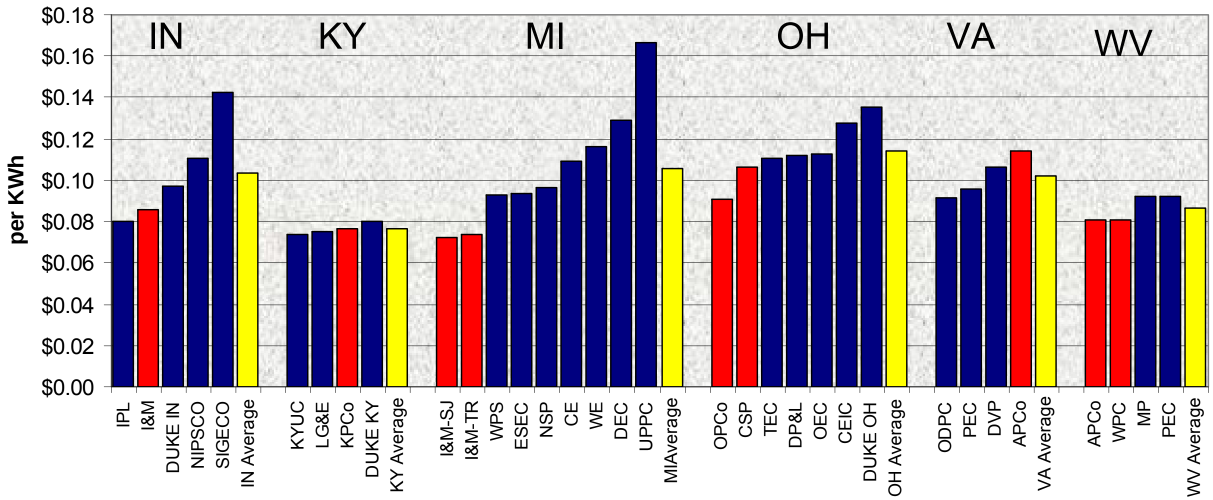
2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

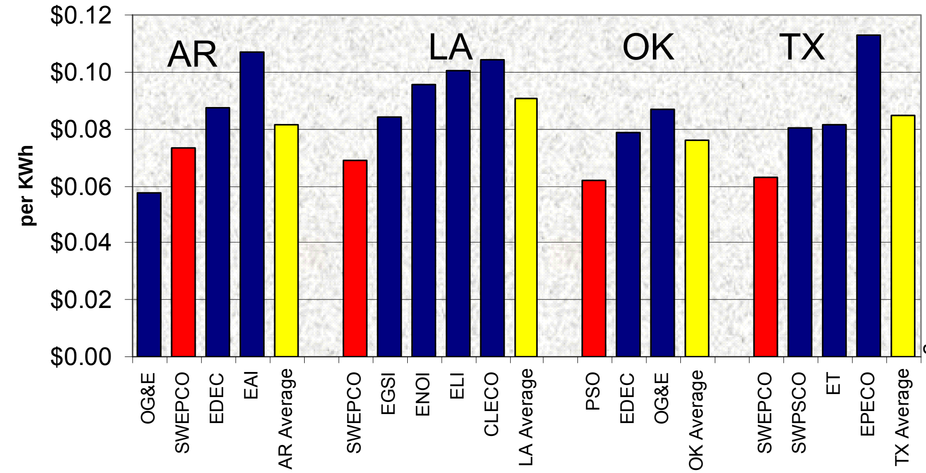
Residential Rates Comparison

AEP East



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP West



- AEP Company
- Other Utilities within state
- State Average

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

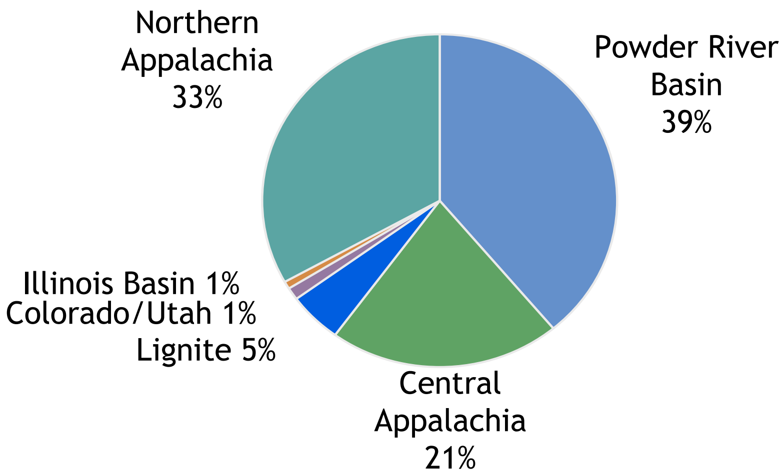
- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The final estimated cost of the plant is $433 million including $49MM of AFUDC.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

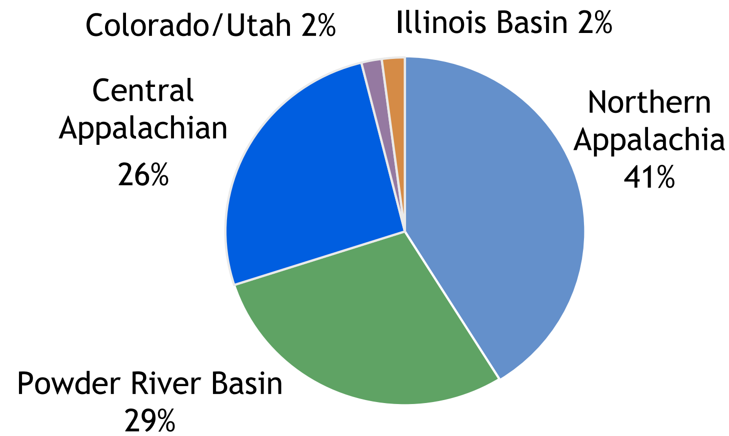
John W. Turk Jr. Ultra-Supercritical Coal Plant

Coal Procurement - 2010 Projected

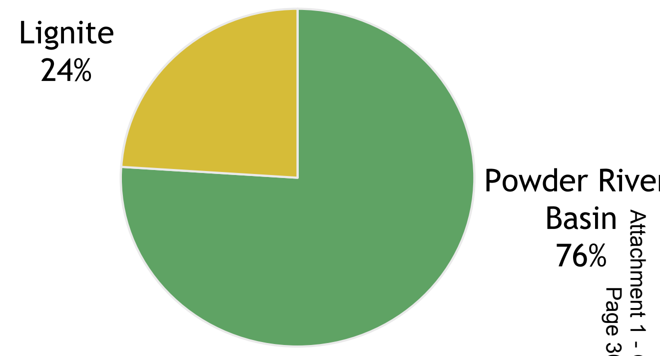
Total AEP System



AEP East



AEP West

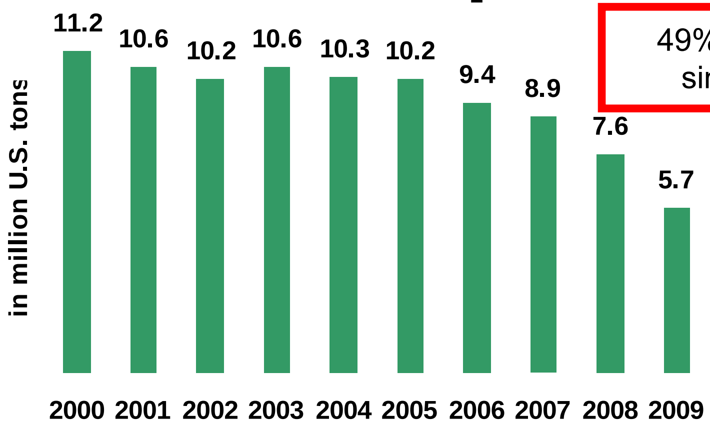


Coal Stats:

- 100% contracted for 2010 and 80% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

Significant Progress Has Been Made But . . .

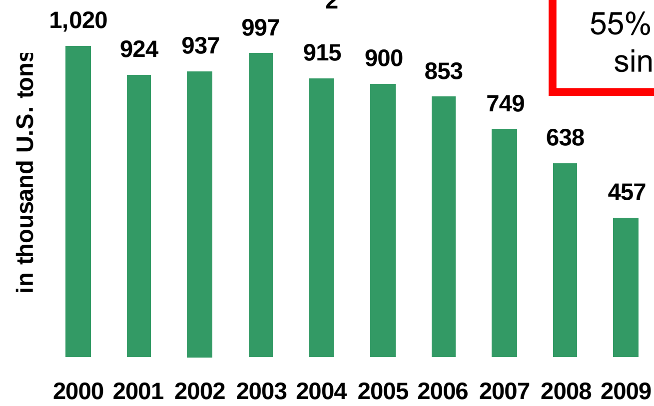
U.S. Power Plant SO_2 Emissions



49% reduction since 2000

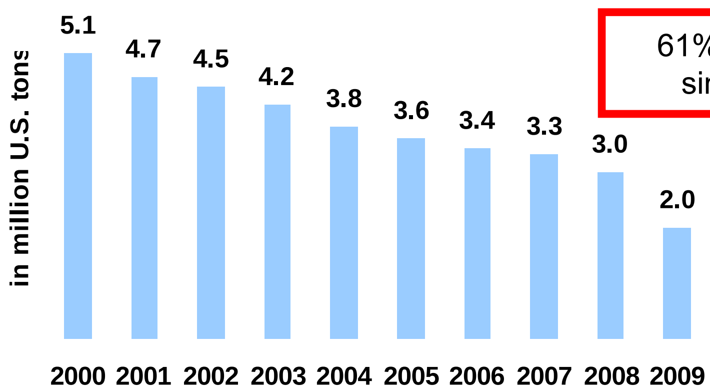
Source: EPA, 2010; Acid Rain Program

AEP SO_2 Emissions



55% reduction since 2000

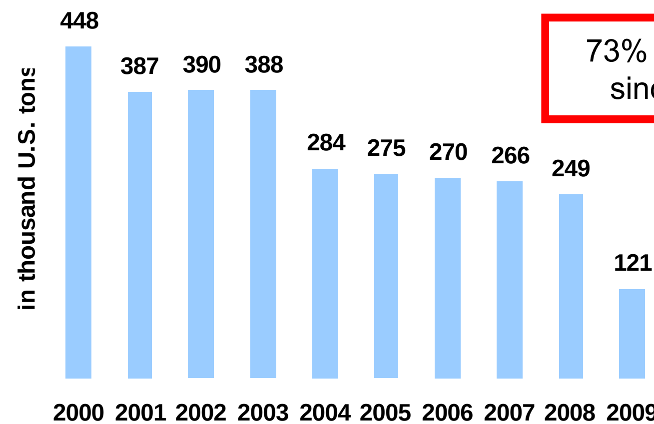
U.S. Power Plant NOx Emissions



61% reduction since 2000

Source: EPA, 2010; Acid Rain Program

AEP NOx Emissions



73% reduction since 2000

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

Recent and Major Upcoming EPA Actions

- **Transport Rule – Proposed July 2010**
  - Governs power plant emissions of SO_2 and NOx that affect downwind fine particle and ozone concentrations
  - 2012 program start date with stringent second phase beginning in 2014
  - Limited interstate trading and no use of previously banked SO_2 allowances from CAIR program
  - 2014 SO_2 limits in AEP-East states will require almost all coal units to be scrubbed or retired/use gas
  - AEP believes an extension of the compliance deadlines is essential to allow states to develop implementation plans and give companies time to install the retrofits needed to comply

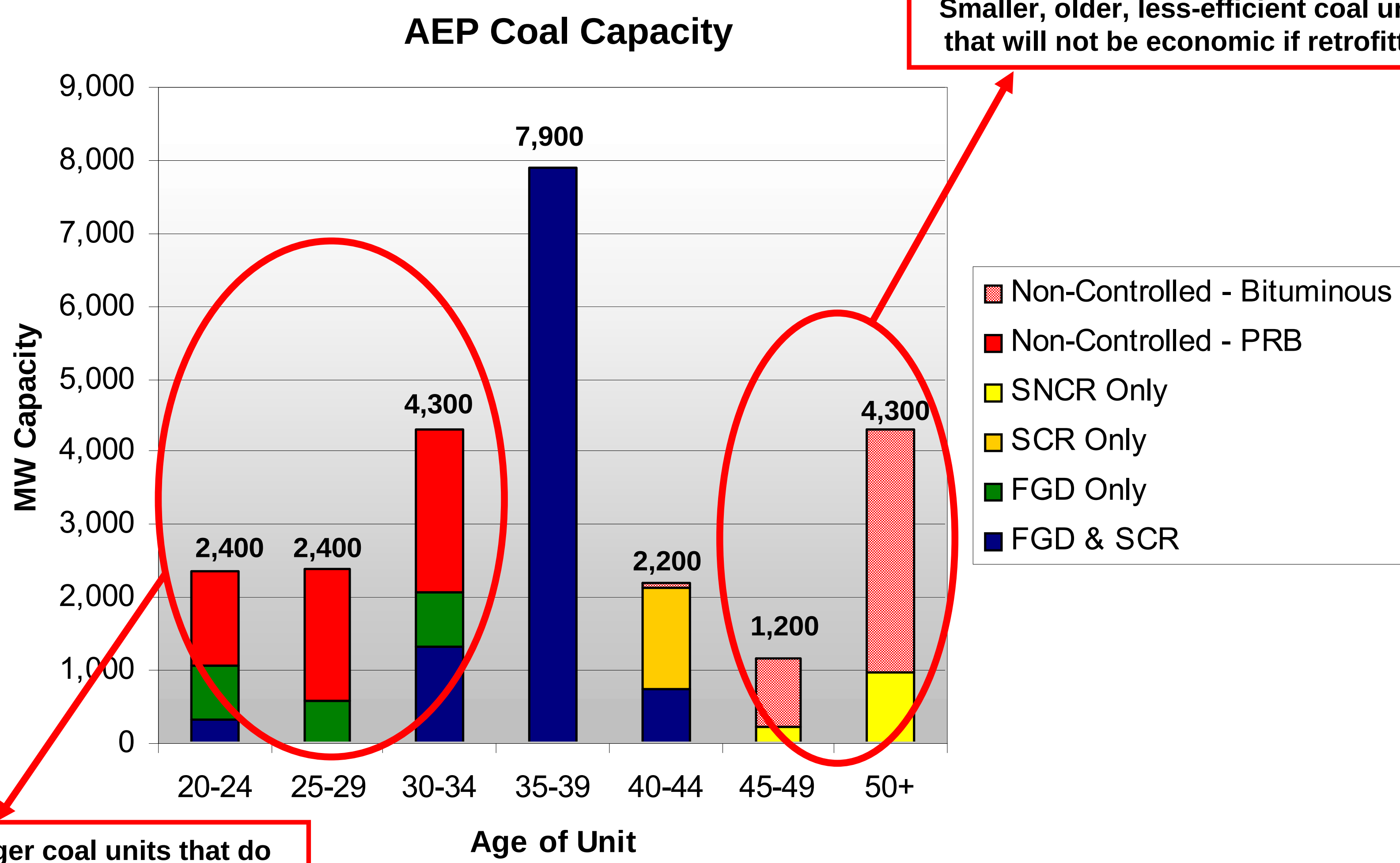
- **"Coal Ash" Rule – Proposed May 2010**
  - EPA proposed two different regulatory designations:
    - Solid waste – action required by ~2017
    - "Special" hazardous waste - action required by ~2018-2020
  - AEP supports regulation of coal ash under the Subtitle 'D Prime' option of the RCRA
  - Cost to AEP customers estimated at $3.9 billion by 2020 to comply with Subtitle D option

- **Mercury and other Hazardous Air Pollutants (HAPs) Rule**
  - Expect proposed rule in spring 2011, finalized in late 2011; likely compliance year - 2015
  - Could require major pollution control retrofits at most U.S. coal plants (FGD, baghouses, etc.)

Cumulative effects of EPA proposed rules and carbon legislation/regulation are a major concern for utility resource planning

Plant Retirements are Inevitable

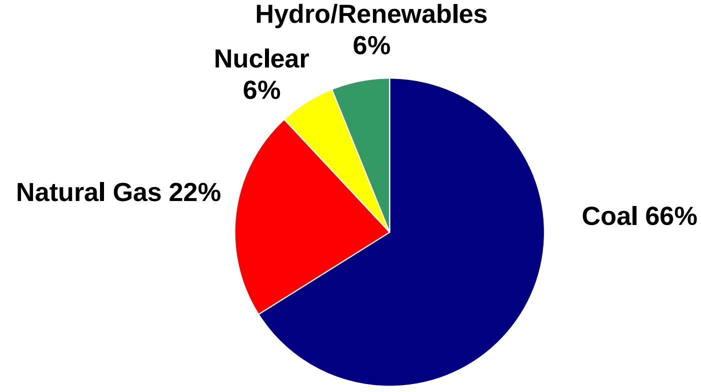
Smaller, older, less-efficient coal units that will not be economic if retrofitted



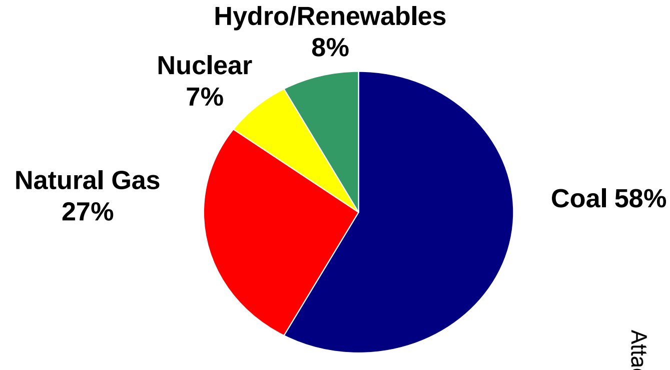
Newer and larger coal units that do not have SCRs and/or FGDs will be evaluated due to emerging and existing environmental requirements

AEP's Actions

- Operate uncontrolled, older and smaller units on a seasonal basis – minimizes capital and O&M spending
- Continue pursuit of CCS to take advantage of first-mover advantages such as DOE clean coal grants
- Complete the Dresden NGCC Plant and add renewables where regulatory recovery is provided
- Complete Cook Nuclear Plant uprate
- Transition toward retirement of approximately 5,000MW of coal units
- Influence federal and state policy to benefit our customers and shareholders
- Transformation plan that includes new technologies such as gridSMART and storage



Fuel Mix - 2009



Projected Fuel Mix - 2017

Carbon Legislation Update

- **Climate Cap and Trade Legislation (American Power Act of 2010) is dead in 2010**
  - Prospects for cap-and-trade legislation after 2010 will require truly bipartisan legislation given the expected changes in Congress

- **Cap and Trade Legislation that advanced in 2010 did include some improved provisions:**
  - Significantly higher electric utility allowance allocation
  - More generous CCS bonus allowances
  - Sound domestic offset provisions
  - Price collar that should help eliminate high price spikes

- **However, there were still some problem areas:**
  - Inadequate EPA preemption language on CO_2 would lead to duplicative CO_2 regulatory measures
  - More restrictive international offsets provisions could drive up compliance costs
  - Early action credit is very limited
  - Market trading provisions are overly restrictive

- **EPA is expected to move forward on CO_2 regulation in 2011**

AEP advocates delay in EPA regulatory action on CO_2 or legislation to enable significant multi-faceted study to determine overall economic and system reliability effects

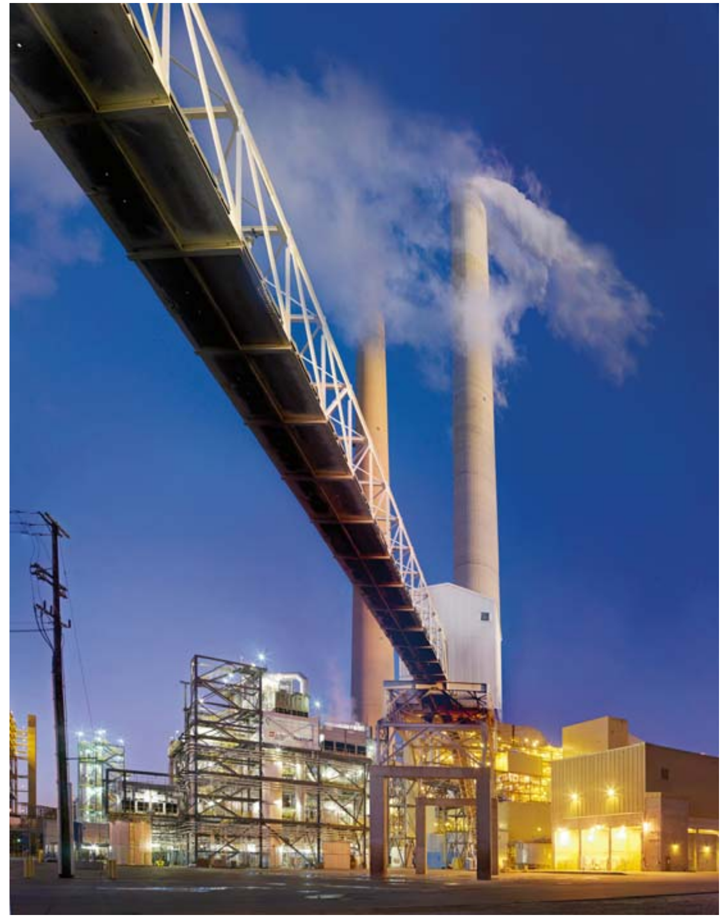
Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process



Carbon Capture and Storage project
Mountaineer Plant - New Haven, WV

Thoughts about the Energy Policy Debate

To make significant advancement in developing clean, domestic energy and reducing emissions, our nation needs a national energy policy with specific goals and guidelines, particularly as it relates to renewables, transmission and environmental regulations.

- Cap and trade
- Incentives to develop and deploy new technologies
- Timelines for emission reductions that provide a rational glide path for transitioning the existing generating fleet to a smaller environmental footprint
- Mandates to develop reasonable cost allocation methodologies to support EHV transmission
- Support for the siting of national-interest transmission lines

Trent Mesa Wind turbines in west Texas

Transmission Opportunities

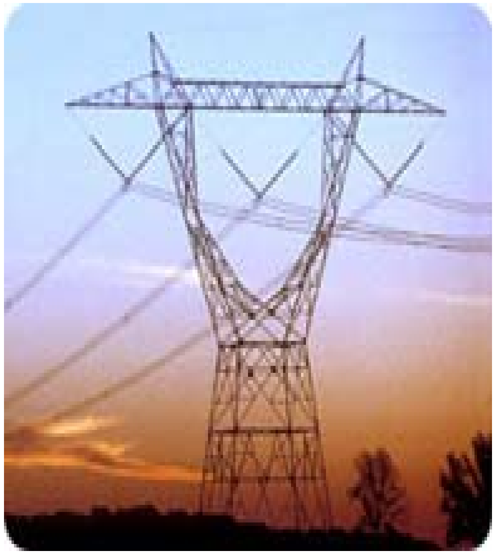
- **<u>Electric Transmission Texas (ETT)</u>: Projects in Texas ERCOT jurisdiction**
  - **In service assets $0.4 billion**
  - **CREZ opportunity $1.1 billion est. in service 2010 - 2013**
  - **Other ETT projects $1.6 billion est. in service 2010-2017**
  - **Framework in Texas allows for more expeditious siting and recovery**

- **<u>AEP Transmission Company (Transco)</u>: Within our existing footprint**
  - **Develop new AEP-only projects within AEP's footprint**
  - **Reduce regulatory lag through FERC formula rates adjusted annually**

- **<u>Joint Ventures (JVs)</u>: Outside of our footprint, with Electric Transmission America (ETA) or others**
  - **Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery**
  - **Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016**
  - **Robust pipeline of projects up to $15B**

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filings made in OH and WV
- FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
- Seek retail tracking mechanisms at the state level (OH, AR, VA, TX-ERCOT already secured)



765-kV Tower

JV Strategy – Nationwide Grid Expansion

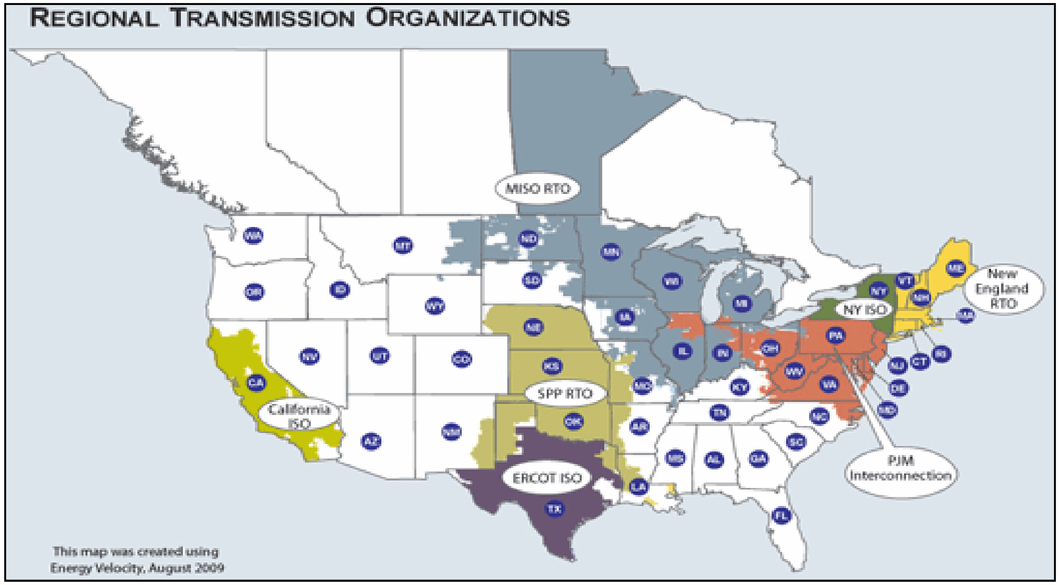
ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2014	**PATH-WV** COD: 2015	**Pioneer** COD: 2016
❑ *110 miles of 345 kV** ❑ *Partners: Westar (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $165 million* ❑ *ROE: 12.8%*	❑ *345 kV and below CREZ & ERCOT Expansion* ❑ *Partner: MidAmerican Energy (50%)* ❑ *Estimated Cost: $1.5 billion* ❑ *ROE: 9.96%*	❑ *275 miles of 765 kV* ❑ *Partner: Allegheny Energy (50%)* ❑ *Estimated Cost: $1.4 billion* ❑ *ROE: 14.3%*	❑ *240 miles of 765 kV* ❑ *Partner: Duke Energy (50%)* ❑ *Estimated Cost: $1 billion* ❑ *ROE: 12.54%*

Tallgrass COD: 2013-14

- ❑ *170 miles of 345 kV**
- ❑ *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- ❑ *Estimated Cost: $350 million*
- ❑ *ROE: 12.8%*

* May revert to 765 kV depending on 2010 SPP ITP results



FUTURE DEVELOPMENT

SMARTransmission Study

- ❑ *Interregional EHV & Wind Integration Study*
- ❑ *Sponsors: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
❑ *Regional Expansion of 765 kV Backbone*	❑ *Other Projects - $1.6 billion (COD 2010-2017)*	❑ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	❑ *700 miles of Proposed 765 kV*

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

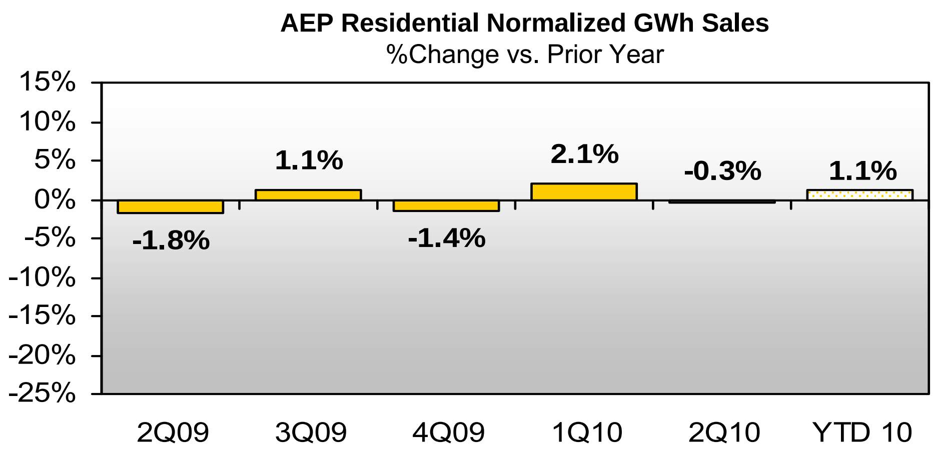
American Electric Power
2009 Actual vs. 2010 Guidance

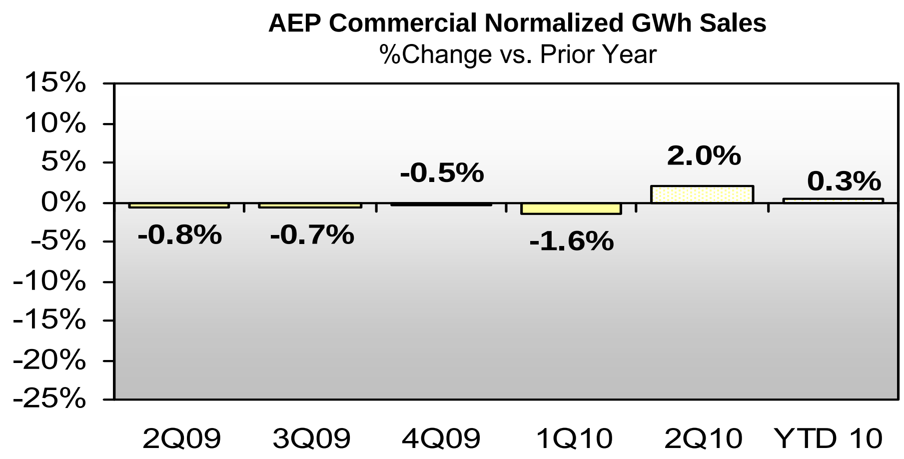
2010E: $2.80-$3.20

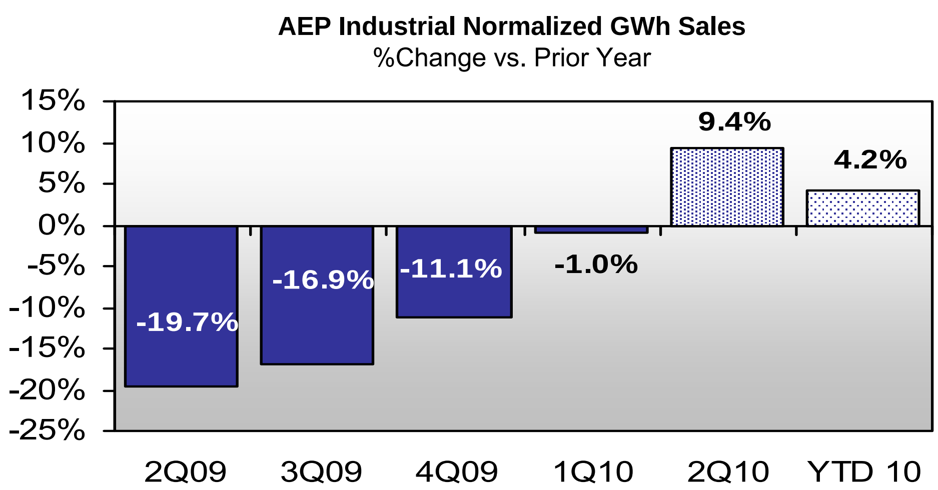
		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

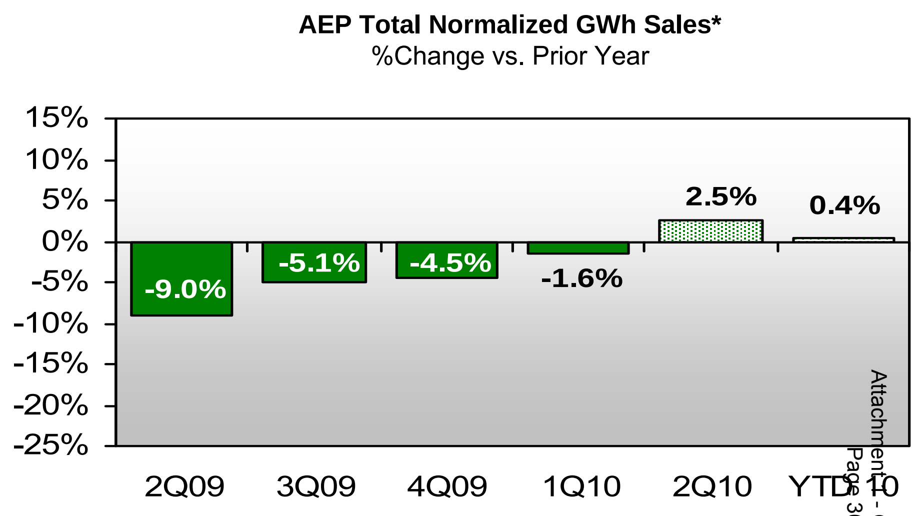
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends



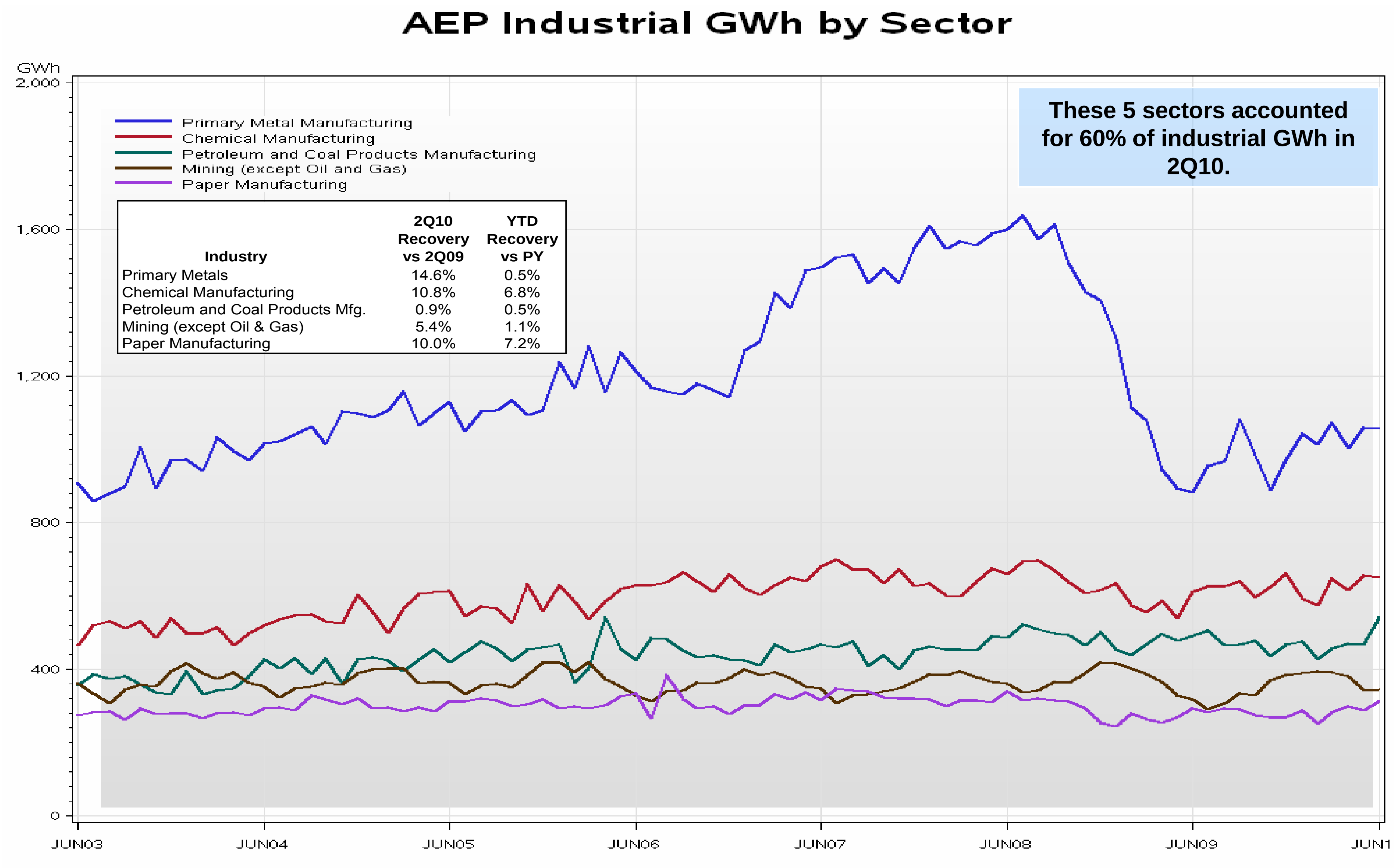






*includes firm wholesale load

Industrial Sales



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company[1]	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

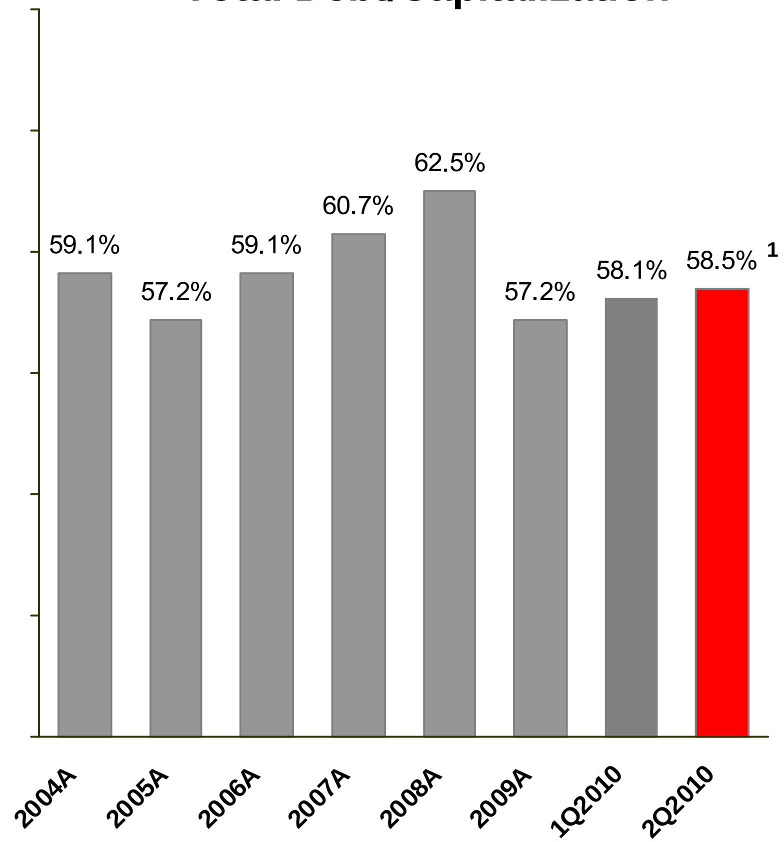
(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.

Current Liquidity Summary
As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

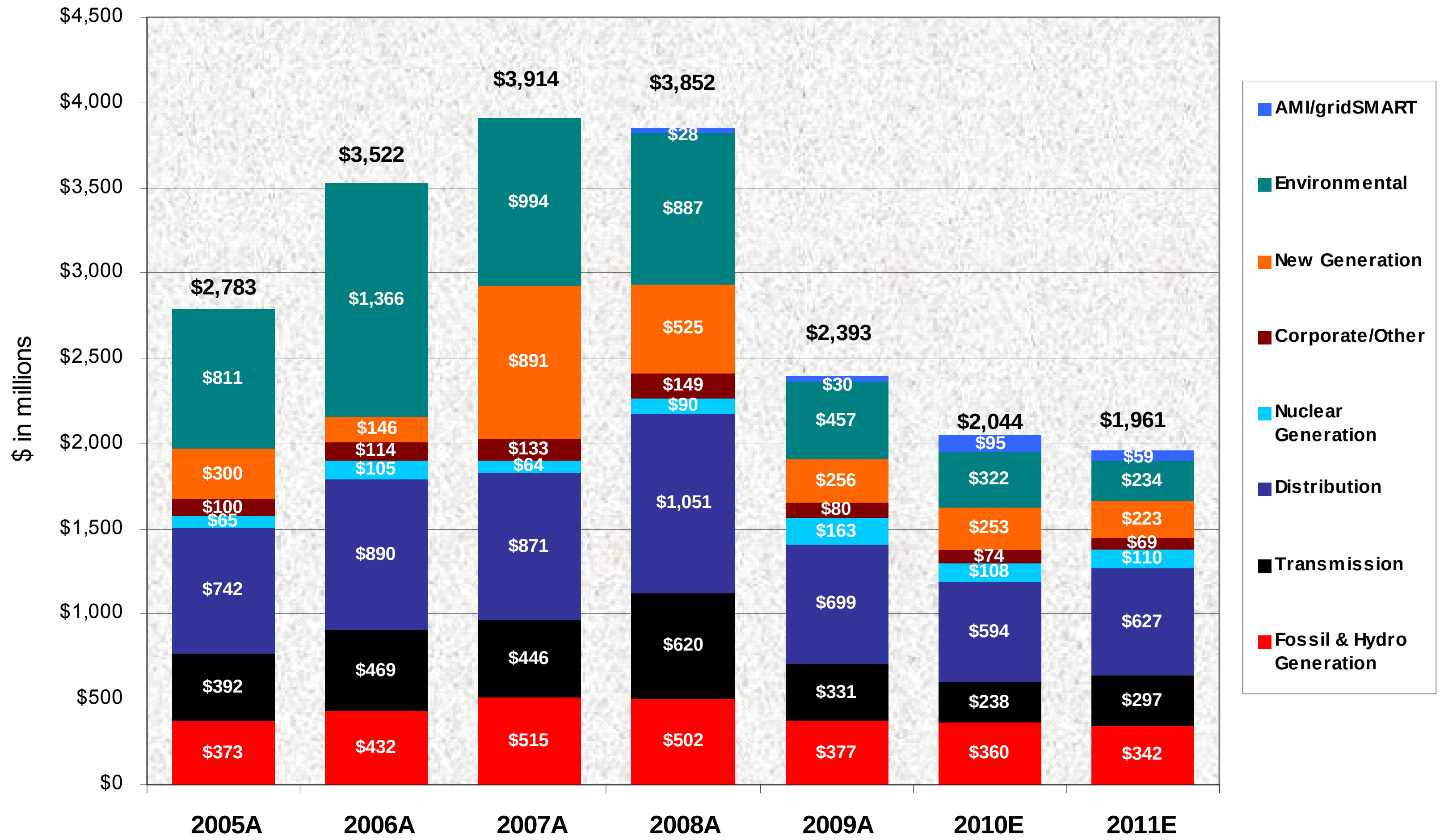
S=Stable

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

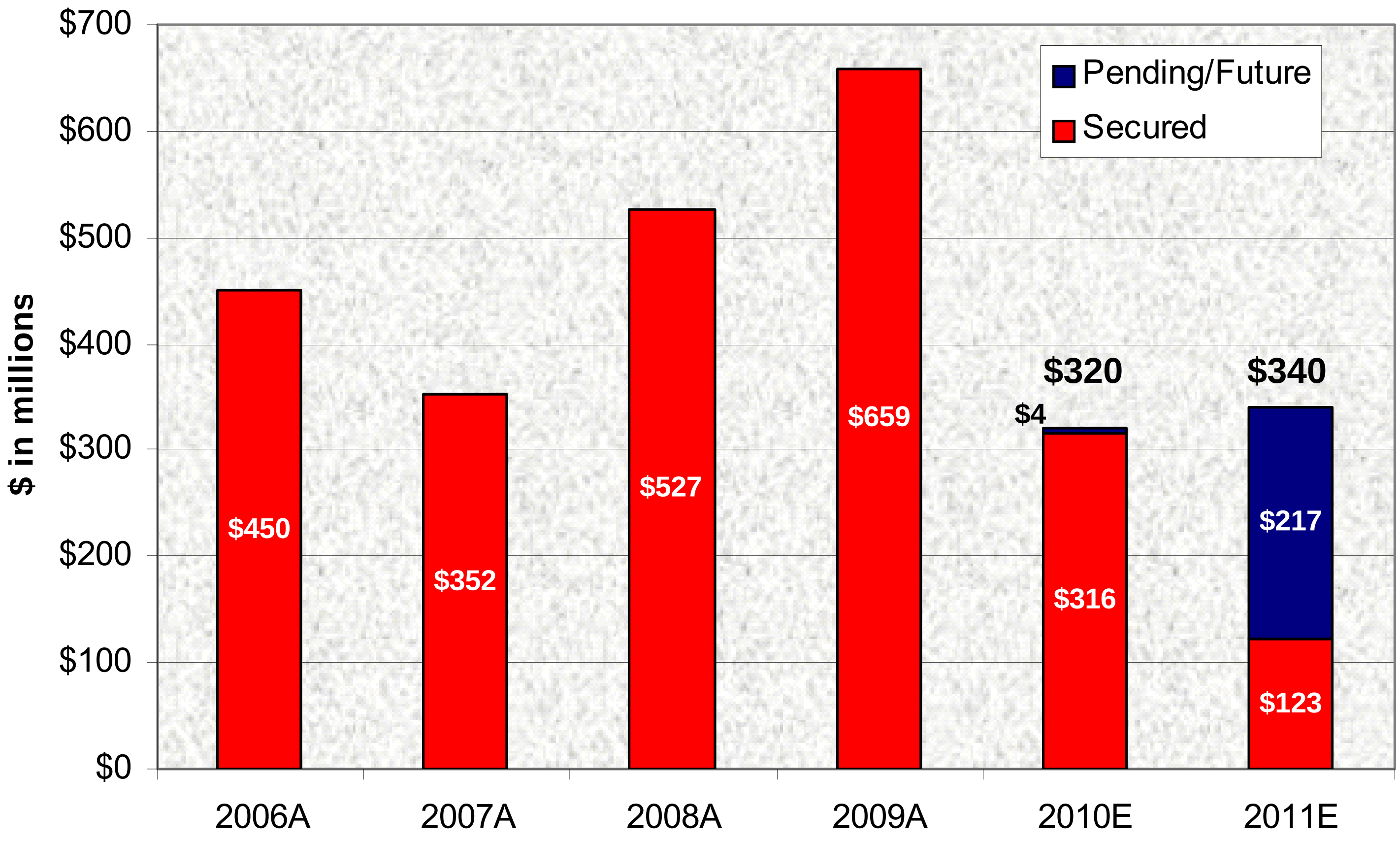
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Oklahoma, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Current Base Rate Cases

$ in millions

I&M - Michigan

I&M - Michigan	Company Filing	Staff Testimony
Rate increase	**$63**	$34
Rate base/investment	$601	$585
Return on equity	11.75%	10.35%
Equity component	44.19%	44.14%
Riders requested	Numerous	Denied except Net Lost Revenues

Status: Case filed on January 27, 2010. Hearing held August 9-10, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Order due January 25, 2011.

$370 million total base rate increase requests on file ($258 million net of existing riders)

APCo - West Virginia

APCo - West Virginia	Company Filing	Staff Testimony
Rate increase	**$224** *	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

* - net increase is $143 million after changes in Construction Surcharge

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

PSO - Oklahoma

PSO - Oklahoma	Company Filing	Staff Testimony
Rate increase	**$82** *	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

* - net increase is $52 million after elimination of existing Capital Investment Rider

Status: Case filed on July 9, 2010. Staff & Intervenor testimony due October 26, 2010.

American Electric Power

BMO Capital Markets Investor Day

New York City
December 4, 2007

AEP AMERICAN® ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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Holly Koeppel
EVP & Chief Financial Officer

Table of Contents

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

Financial Forecast Highlights

- Updated 2008 & 2009 earnings guidance ranges and introduction of 2010

  2007 Range $2.90 to $3.00

  2008 Range $3.05 to $3.25

  2009 Range $3.20 to $3.50

  2010 Range $3.45 to $3.80

- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Continued pursuit of Ohio post-2008 solution
  - Cost management
- 8-cent/share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Refined capital investment forecast and introduction of 2010 level

  2007E: $3,962 MM

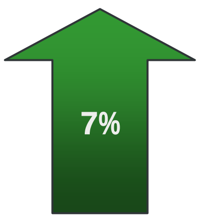
  2008E: $3,770 MM

  2009E: $3,600 MM

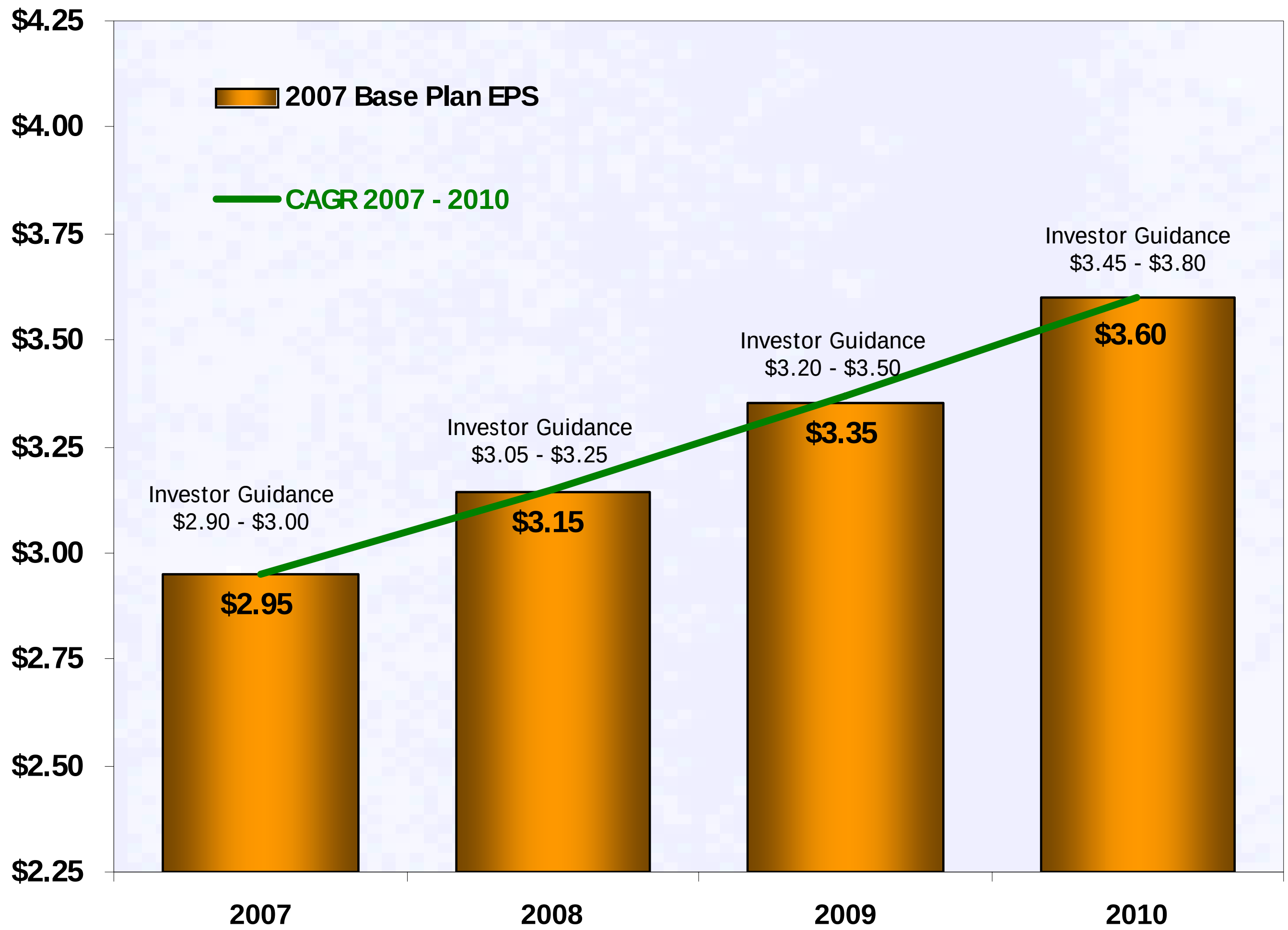
  2010E: $3,401 MM

- Maintain credit ratings: BBB/Baa2/BBB

4-Year Earnings Range Forecast

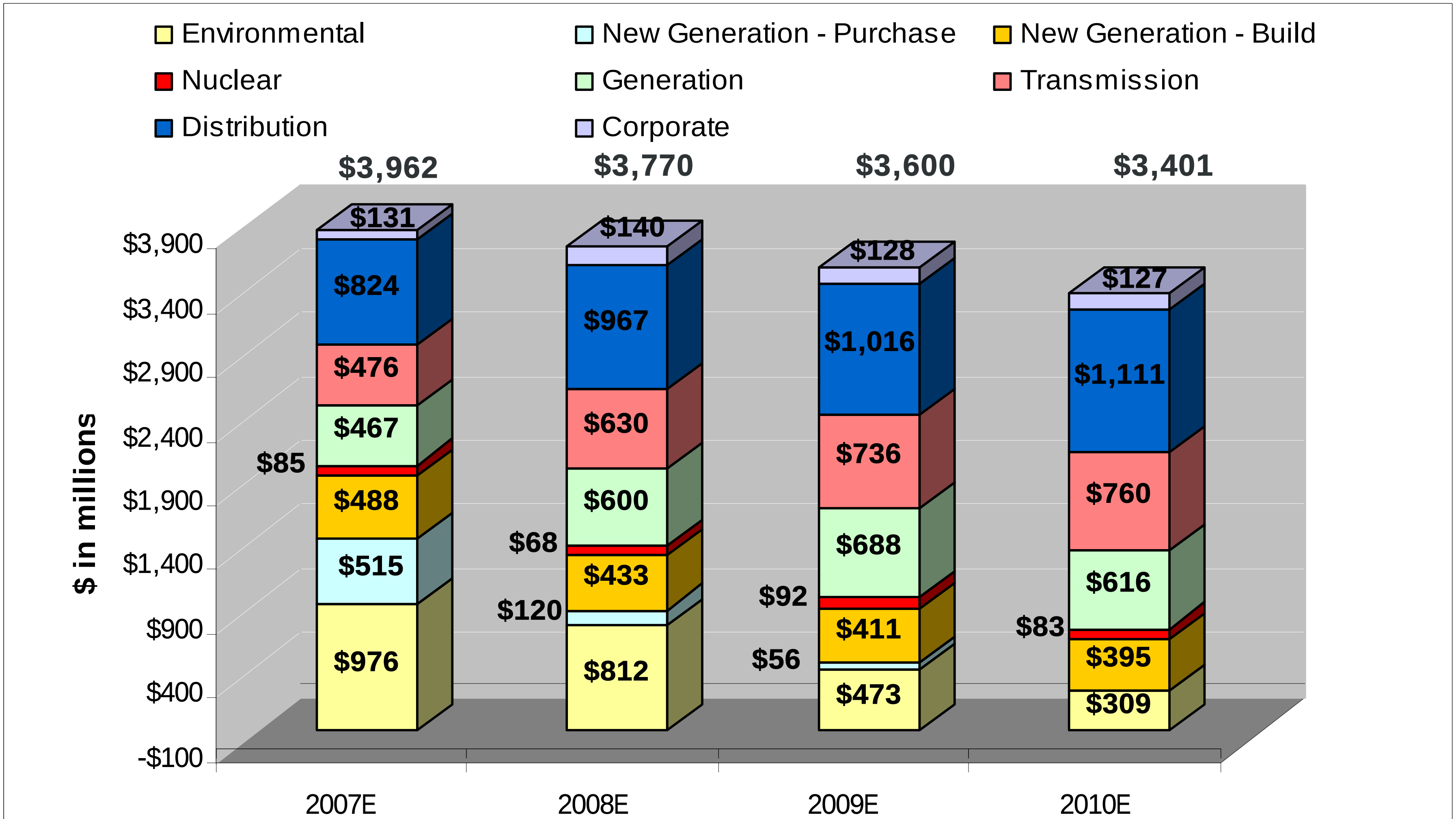


EPS 3-yr CAGR
(2007-2010)



5% to 9% earnings growth and a 4Q07 dividend increase.

4-Year Capital Investment Forecast



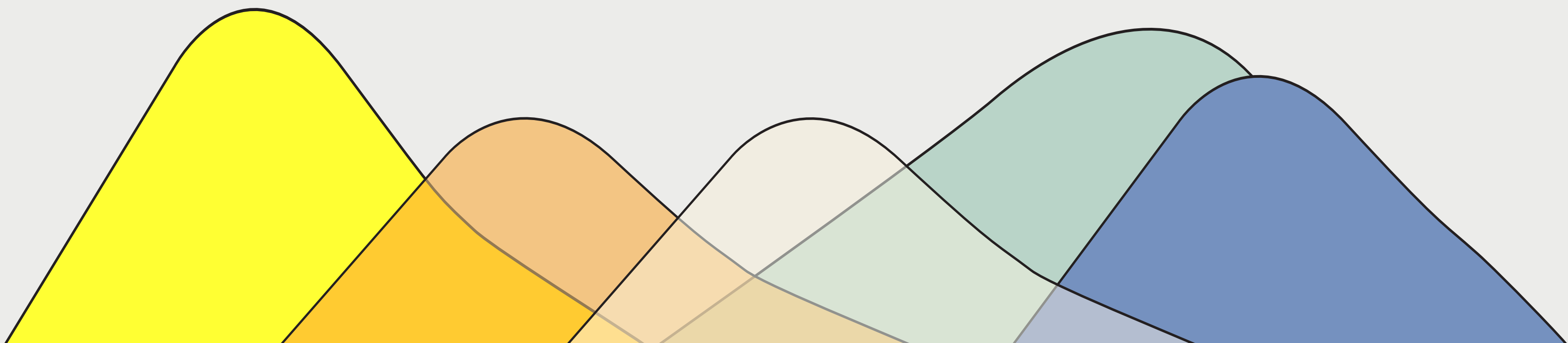
Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



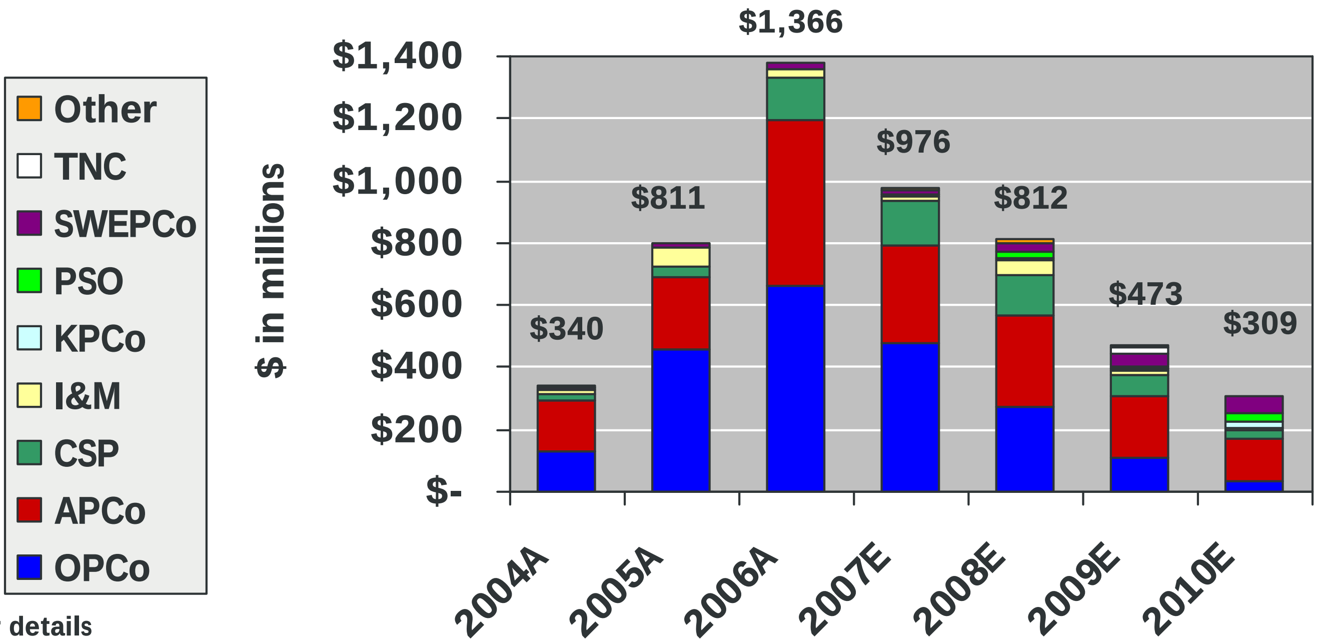
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 8. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

Environmental Investments Receive Timely Rate Recovery



See page 11 for details

($ in millions)	Completed (2004-2006)	Rate Recovery
AEG	$9	partial/pending
APCo	$923	yes
I&M	$98	pending
KPCo	$3	yes
SWEPCo	$37	pending
CSP	$194	yes
OPCo	$1,253	yes
Total Capex	**$2,517**	

($ in millions)	Remaining (2007-2010)	Rate Recovery
AEG	$27	partial/pending
APCo	$944	yes
I&M	$77	pending
KPCo	$33	yes
PSO	$67	pending
SWEPCo	$135	pending
TNC	$22	through mkt. rates
CSP	$374	partial/pending
OPCo	$891	partial/pending
Total Capex	**$2,570**	

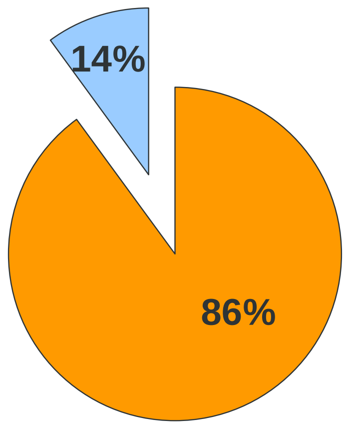
Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors – AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



- Actuals To Date & Firm Costs
- Estimated Cost Exposure*

Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

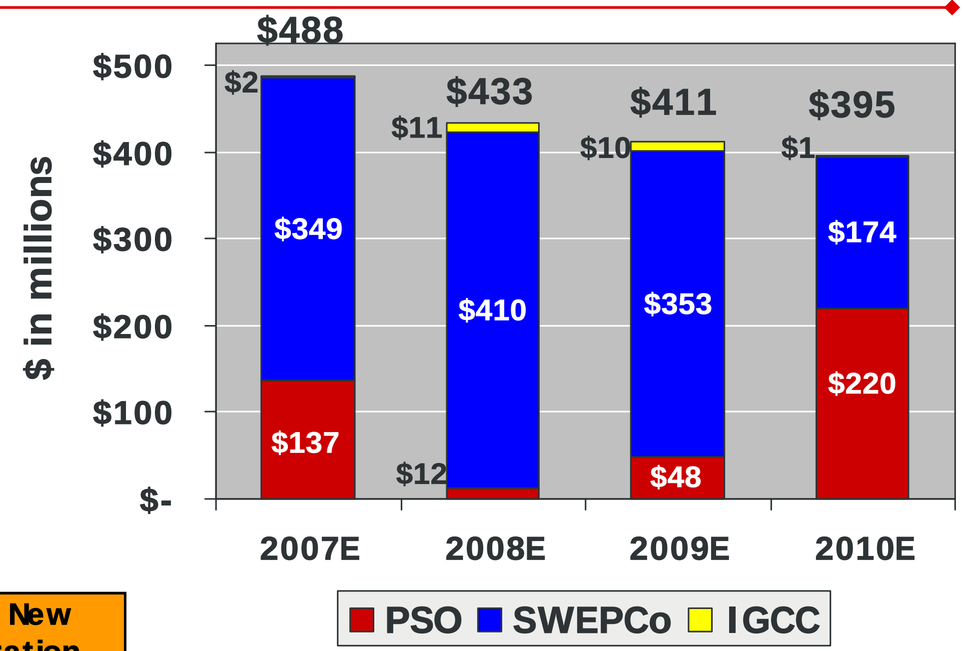
- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

New Generation Investments and Related Recovery

Secured Recovery Mechanism

- PSO Peaking Facilities Rider



($ in millions)	Projected Construction Completion	Total New Generation Investment (2007-10)
PSO - Peaking Facilities	2008	$102
PSO - Combined Cycle *	2012	$315
SWEPCo - Mattison	2007	$66
SWEPCo - Stall	2010	$422
SWEPCo - Turk	2011	$798
APCo - IGCC	tbd	$12
CSP/OPCo - IGCC	tbd	$12
Total Capex	Total Capex	$1,727

* - intended to source requirements to be met by Red Rock Plant prior to cancellation.

Additional Recovery Mechanisms Under Consideration:

- Formula based rates
- Requests for return on CWIP
- Current and future rate cases

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$122 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$265 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$375 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (2)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	TBD
CSP/OP	Great Bend	Ohio	Under Review (3)	Coal	IGCC	630	TBD

(1) 150MW declared in commercial operation on July 12, 2007.

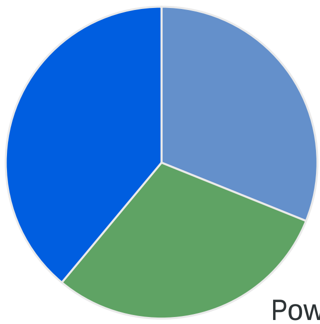
(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(3) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

Coal Procurement

AEP burns approx. 76 million tons of coal per year

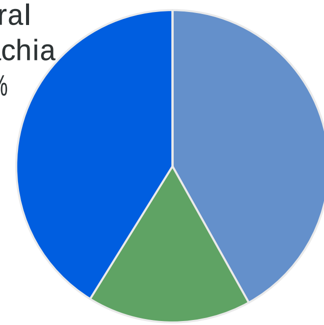
Total AEP System



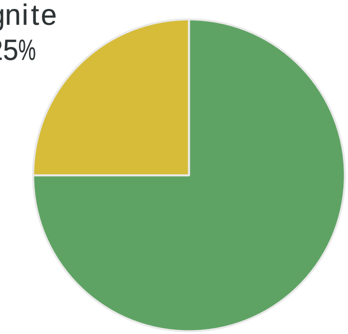
Coal Stats:

- Fully contracted for 2007; >93% for 2008
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-5% price increase in 2007 -- ($36.50 to $37.50/ton); 13% increase in 2008 based on anticipated 2007 actual results.
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

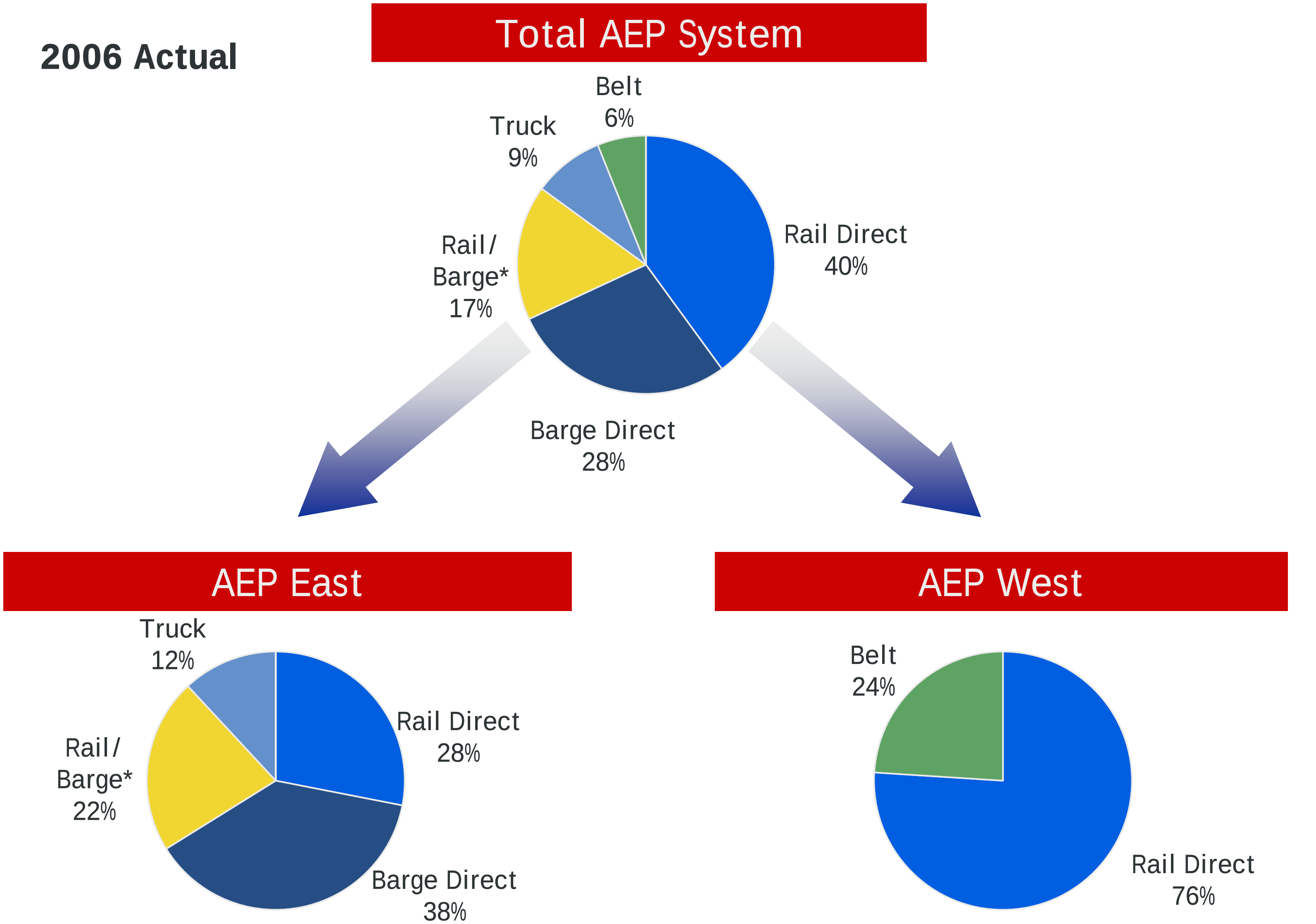


AEP West



Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

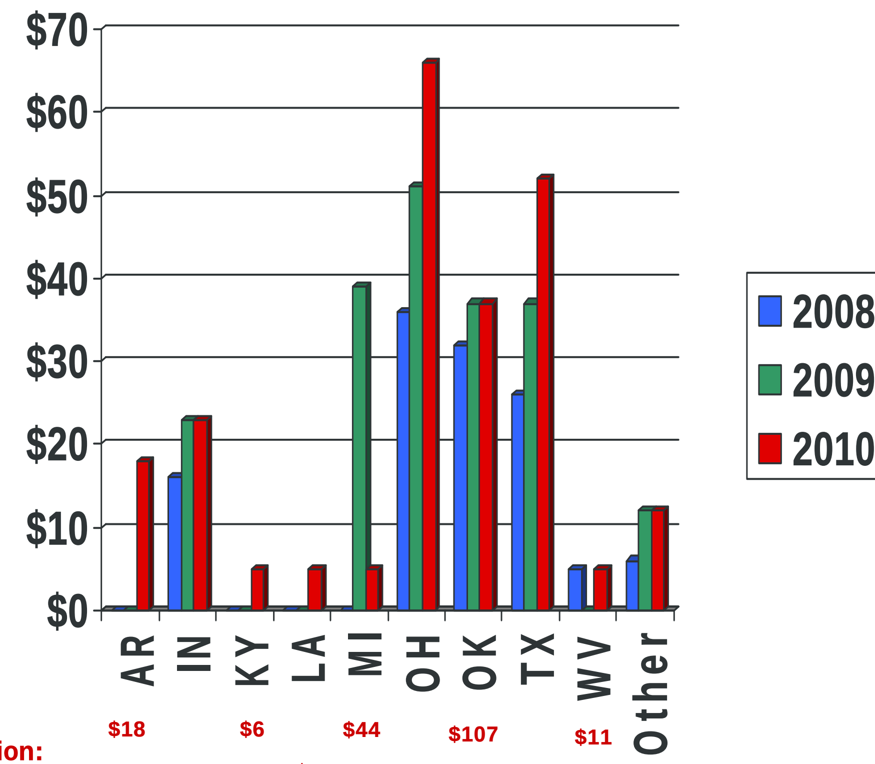
GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology	**2007**	**2008**	**2009**	**2010**
Metering & Communications	$0	$83	$138	$146
Distribution Technology Enhancements	$2	$40	$ 63	$ 82

*$452MM of the $554MM not in current forecast; spending contingent upon regulatory approval

$ in millions



3-Year Total by Jurisdiction: AR $18, IN $62, KY $6, LA $5, MI $44, OH $153, OK $107, TX $115, WV $11, Other $31

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

Contribution of Transmission Investments

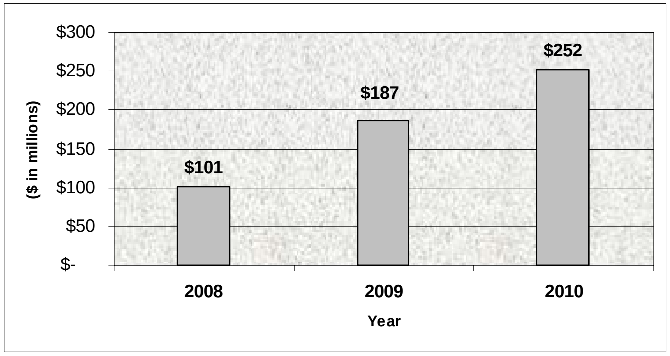
Potential Transmission Opportunities

~ $3 Billion I765™ Project in PJM
~ $2.6 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions

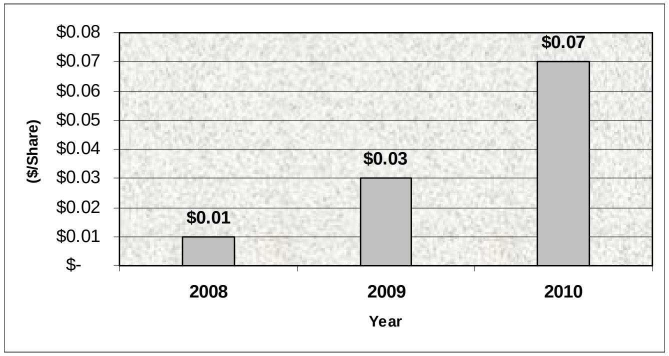
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 402 MM shares)	$0.60 - $1.00+

Projected Transmission Capital Spending*



* ~$9-$15 billion investment opportunity not included in current capital guidance forecasts, since it will be put into a JV. ETT base case and PATH projects included in above projection.

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

Electric Transmission Texas (ETT)

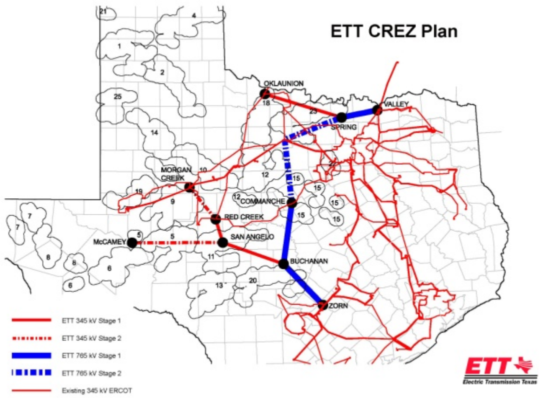
- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007
  - PUCT Recently Approved:
    - ROE of 9.96%
    - Establishment of Transmission Utility Status
  - Received FERC/PUCT approvals:
    - Asset transfer for TCC to ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

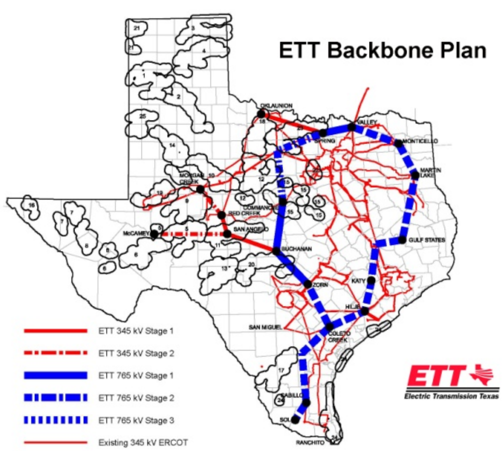
- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

- **Traditional ratemaking process through the PUCT will be utilized for investment cost recovery.**

ETT CREZ



ETT Backbone



Electric Transmission America (ETA)

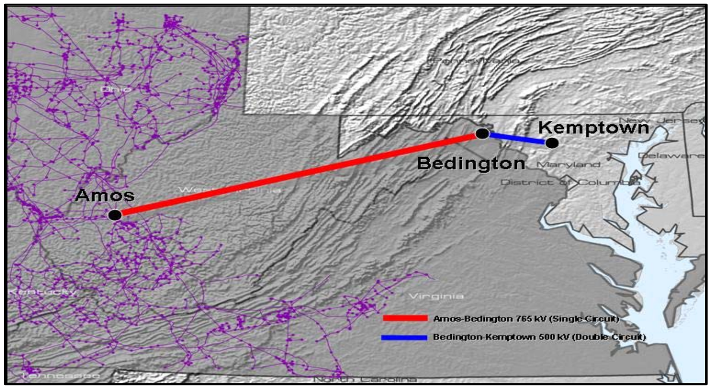
- *Electric Transmission America (ETA)*
  - AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
  - Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
  - Projects taken on by the Joint Venture would entail transmission facilities:
    - 345-kV and above
    - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
    - Greater than $100 million
  - ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
  - ETA will look to collaborate with qualified partners in each particular region.

This JV reflects a natural progression and expansion of our partnership with MidAmerican.

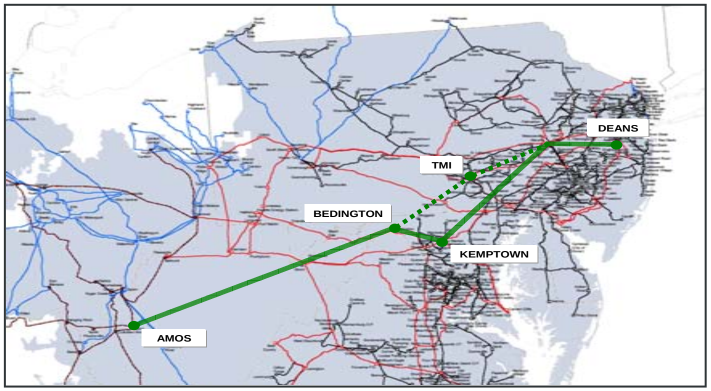
Transmission Project Updates - PJM

- *I-765 TM in PJM Phase I Update*
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012
- *Key Next Steps*
  - Complete FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Begin Routing Study – Fall 2007
  - State Filings – Fall 2008
  - Construction – Early 2010
  - Completion – Fall 2012
- *I-765 TM in PJM Phase II Update*
  - Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
  - Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
  - Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.
- *Regional Rate Design will be utilized for investment cost recovery.*

Phase I in PJM



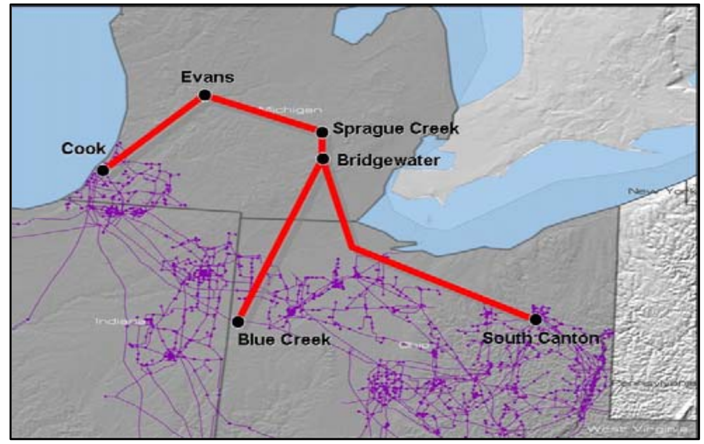
Phase II in PJM



Transmission Project Updates – cont'd

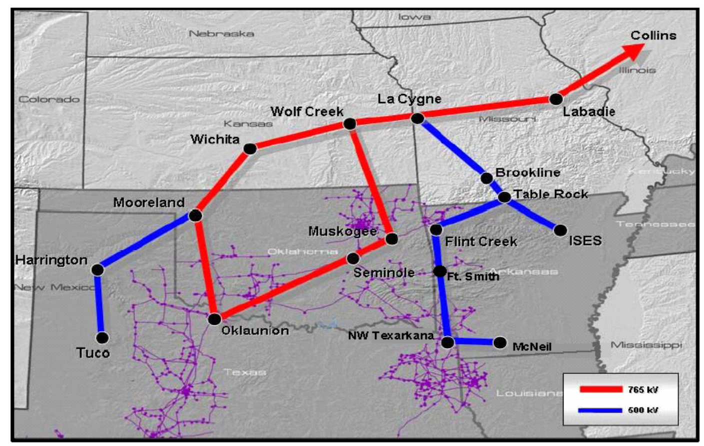
- *765 – kV in Michigan – Key Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2015

Michigan



- *765-kV in SPP – Key Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

Southwest Power Pool



- *Regional Rate Design will be utilized for investment cost recovery.*

Advanced Generation & CO_2

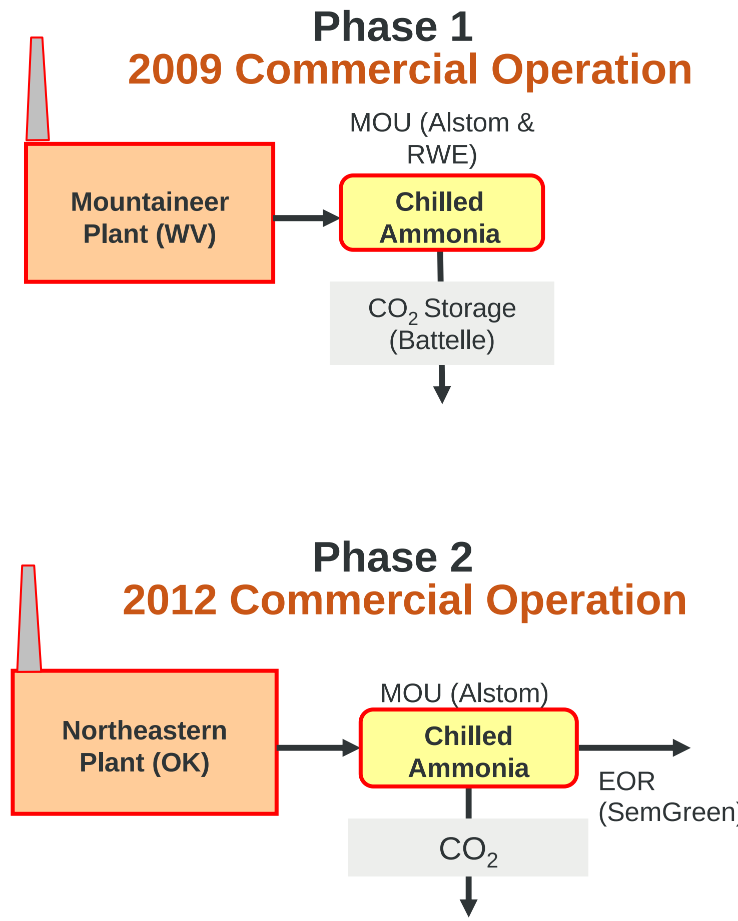
Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
	2007	2008	2009	2010
Mountaineer Chilled Ammonia Project	$4	$56	$11	$0

Long Term Strategy (Post 2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

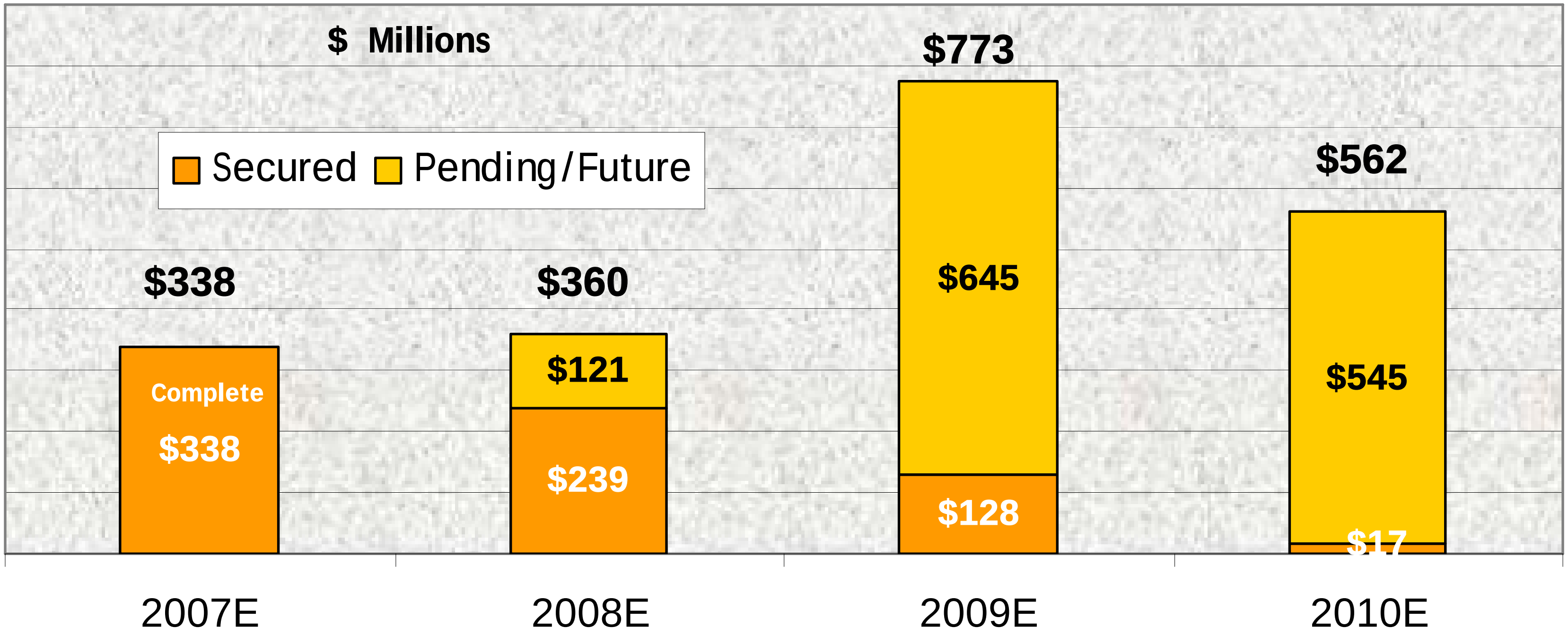
Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

- Key Components:
  - Start date for greenhouse-gas reductions is 2012
  - Goals: 2006 levels by 2020; 1990 levels by 2030
  - Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
  - Support for allowance allocations
  - International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

Incremental Rate Relief Assumptions



2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation and General Rate Case
TCC and TNC General Rate Cases

2007 - 2010 projected annual rate increases of 5.5%.

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Activity Completed

Company	Case	Order Date	Dollar Amount	ROE
APCo - Virginia	Base Rate Case	May 15, 2007	$24MM increase in annual base rates	10.0%
APCo - West Virginia	ENEC Filing	June 22, 2007	$29MM increase in annual revenues	10.5%
I&M - Indiana	Depreciation Study	June 13, 2007	$69MM estimated decrease in annual depreciation expense	N/A
I&M - Michigan	Depreciation Study	September 25, 2007	$10MM estimated decrease in annual depreciation expense	N/A
CSP/OPCo	4% RSP	October 3, 2007	$23MM increase in annual generation rates	N/A
TNC	Base Rate Case	May 24, 2007	$12MM increase in annual pre-tax earnings	9.96%
TCC	Base Rate Case	October 17, 2007	$50MM increase in annual pre-tax earnings	9.96%
ETT	Utility Status/ROE	October 17, 2007	N/A	9.96%
PSO	Base Rate Case	October 9, 2007	$20MM increase in annual pre-tax earnings	10.0%

Incremental rate relief requirements for 2007 have been satisfied.

Regulatory Activity Underway

- Ohio Post 2008
- CSPCo and OPCo Filing for 4% Provision on Generation Rates
- I&M - Indiana Rate Petition
- APCo Filings – E&R and Fuel Factor Adjustments
- SPP OATT Formula Rate Filing
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas for Certificates of Need

Regulatory Activity Underway

Ohio Post 2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearing schedule extends to the end of January 2008.

AEP Ohio Application For 4% Provision On Generation Rate

- On October 24, 2007, CSPCo and OPCo filed an application pursuant to the RSP at the PUCO to recover costs associated with additional generation-related expenditures the companies are encountering related to environmental (CAIR, CAMR and NPDES – Clean Water Act) and PJM marginal losses.
- CSPCo and OPCo are requesting to implement the provision to recover $37.4MM and $12.6MM, respectively, from January through December 2008. These amounts represent actual costs incurred, plus carrying costs, through October 31, 2007.

Regulatory Activity Underway

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.
- Hearings are expected in May 2008, and an order in the first quarter of 2009.

APCo E&R and Fuel Factor Adjustments

E&R:

- On July 16, 2007 a filing was made with the VA SCC requesting an additional $39MM be added to the current rider of $21MM. Therefore, at December 1, 2007, we will begin collecting $60MM.
- Intervenor testimony was filed on October 3, 2007, staff testimony filed on October 17, 2007, rebuttal testimony filed on October 24, 2007 and public hearings are were held on November 5 & 6, 2007.

Fuel Factor:

- On July 16, 2007, a filing was made with the VA SCC requesting the termination of the OSS base credit and reflected 75% of OSS margins as a credit to fuel expense, consistent with new Virginia legislation. Implementation of the fuel factor was approved effective September 1, 2007, subject to review/refund.
- Intervenor testimony was filed on October 5, 2007, staff testimony filed on October 15, 2007 and rebuttal testimony filed on October 22, 2007.
- Based on the addition of PJM marginal losses to the filing in October 2007, a new procedural schedule was agreed upon which stipulates staff and intervenor testimony due December 3, 2007, rebuttal testimony due December 10, 2007 and public hearings are expected to commence on December 18, 2007.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008. A request for rehearing was submitted on October 1, 2007.
- A technical conference was held on October 18, 2007. The purpose was to review and clarify the company's responses to discovery. A second technical conference was held November 6, 2007 with a settlement meeting held November 15, 2007 and another scheduled for December 4, 2007.

PSO Storm Cost Recovery Filing

- On October 24, 2007, Public Service Company of Oklahoma filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sale of sulfur dioxide (SO_2) emission allowances.
- Hearings are tentatively scheduled for February 27-28, 2008.

AEP®

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony filed November 19, 2007.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings commenced August 20, 2007 and final briefs were filed in October 2007.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected by year end.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in early 2008.

Rate Base & September 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	9/30/07 GAAP Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	8.93%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.87%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	9.00%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	21.77%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	12.70%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	1.28%
SWEPCo-LA	$434MM	11.10%	12/29/1999	5.97%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	8.10%
Texas-TNC	$530MM	9.96%	6/1/2007	10.71%

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

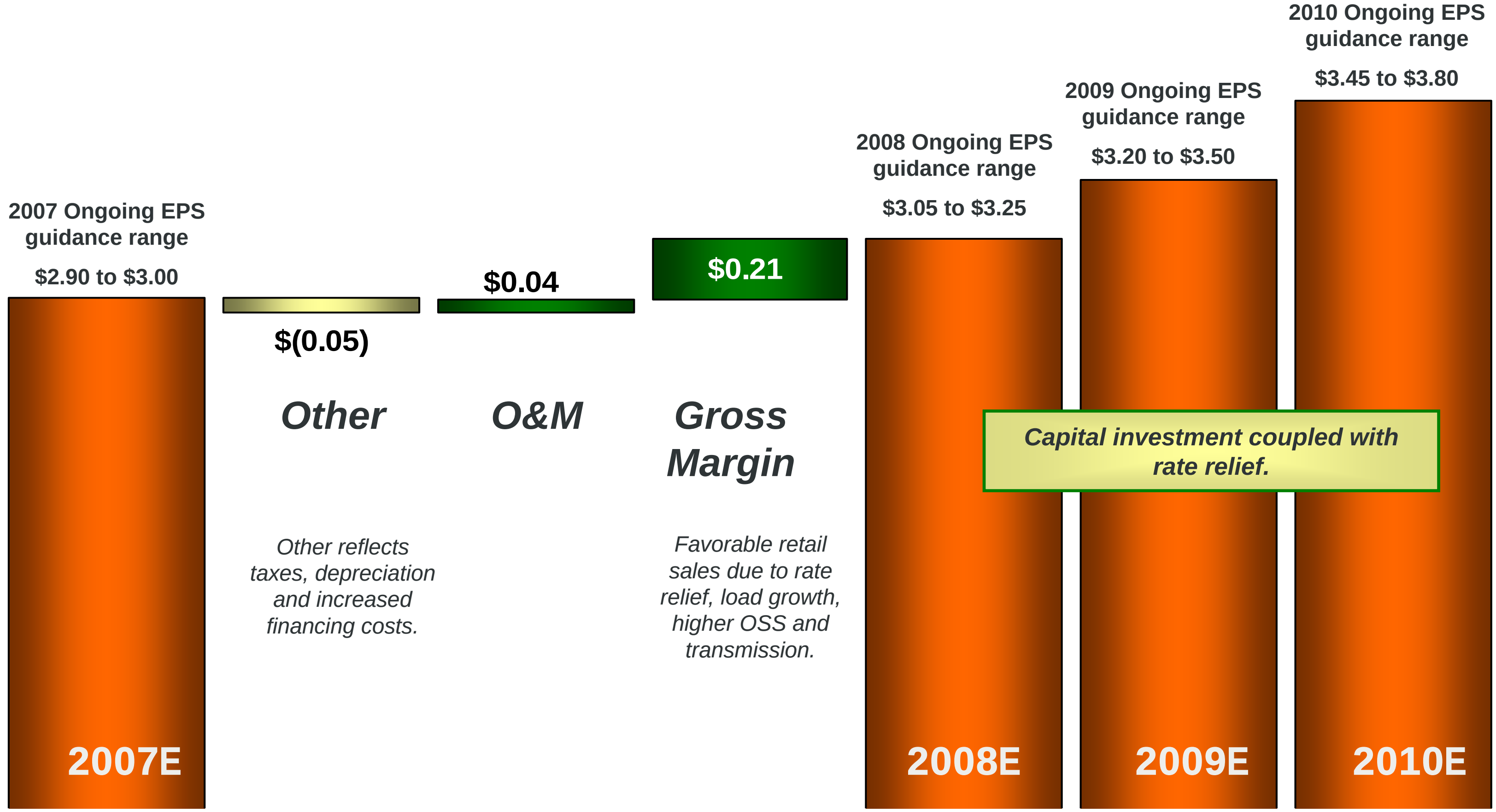
2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Transmission Revenue - 3rd Party		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

Long-Range Earnings Drivers



Traditional utility factors will drive earnings.

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital investment is funded from cash from operations and debt issuances.

2008 Projected Cash Flow

	2007 Estimate	2008 Estimate
Beginning Cash Balance	$ 301	$ 102
Cash from Operations:		
Income from Continuing Operations	1,173	1,269
Depreciation and Amortization	1,535	1,511
Other	(655)	45
Total from Operations	2,053	2,825
Cash from Investing:		
Construction Expenditures	(3,604)	(3,860)
Asset Sales	228	-
Distressed Generation Purchases	(515)	-
Investment in Non-Consolidating Subsidiaries	(13)	(34)
Other	138	(69)
Total from Investing	(3,766)	(3,963)
Cash from Financing:		
Common Equity	150	150
Long-Term Debt Issued/(Retired)	1,334	1,789
Short-Term Debt Change, Net	529	(111)
Common Dividends	(631)	(659)
Other Financing Activities	132	(28)
Total from Financing	1,514	1,141
Net Change in Cash	$ (199)	$ 3
Ending Cash Balance	$ 102	$ 105

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation. In addition, construction expenditures include AFUDC.

Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

2008 Key Operating Company Highlights

Dependent on Actual Capital Investment ($ in millions)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEP, Inc.	$0	$500-600 (b)	n/a
AEG	$138	$100-150	40%
APCo	$720	$500-600	42-44%
CSP	$393	$250-350	45-47%
I&M	$341	$0	40-42% (c)
KPCo	$122	$100-200	41-43%
OPCo	$666	$100-200	44-46%
PSO	$266	$0	43-45%
SWEPCo	$694	$300-500	43-45%
TCC	$197	$0	40% (d)
TNC	$171	$100-150	40%

(a) Includes tax-exempt issuances

(b) Represents hybrid securities

(c) Ratios include impact of Rockport 2 lease

(d) Excludes impact of securitization on the equity ratio

AEP will maintain the financial strength of its subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow.

Long-term Debt Maturity Profile

($ in millions)

Year		2007 (1)		2008		2009
AEP Service Corp.	$	-	$	36	$	-
AEP, Inc.	$	-	$	-	$	-
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	200	$	200	$	150
Columbus Southern Power	$	-	$	112	$	-
Kentucky Power	$	198	$	30	$	-
Indiana Michigan Power	$	-	$	50	$	45
Ohio Power Company	$	-	$	42	$	100
Public Service of Oklahoma	$	-	$	-	$	50
Southwestern Electric Power	$	-	$	2	$	-
Texas Central Company	$	-	$	48	$	-
Texas North Company	$	-	$	-	$	-
Total	$	398	$	520	$	345

(1) Maturities remaining as of September 30, 2007

Credit Quality Parameters

Forecast Parameters:

- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings
  - FFO to Interest range of 3.7x to 4.2x
  - FFO/Total Debt range of 16% to 19%

Capitalization

Capital Structure	Actual 12/31/2006			Actual 9/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,777	-	14,777
Short-term Debt	18	-	18	587	-	587
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,908	9,908
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,364**	**9,969**	**25,333**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.6%***	***39.4%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,257)	-	(2,257)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(256)	-	(256)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,995**	**9,969**	**23,964**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.4%***	***41.6%***	***100.0%***

Adjusted debt-to-capital ratio was 58.4% as of 9/30/07.

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	**Senior Unsecured**	**Senior Secured**	**Outlook**	**Business Profile**	**Senior Unsecured**	**Senior Secured**	**Outlook**	**Senior Unsecured**	**Senior Secured**	**Outlook**
American Electric Power Company, Inc.	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	BBB+	A-	N
AEP Texas North Company [1]	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) AEP Texas Central Company was downgraded and placed on negative outlook by Fitch in April 2007.

AEP is committed to maintaining current credit ratings.

Value Proposition

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Sustainable Business Model

AEP AMERICAN ELECTRIC POWER®

BofA Merrill Lynch Power & Gas Leaders Conference

New York, NY

September 29, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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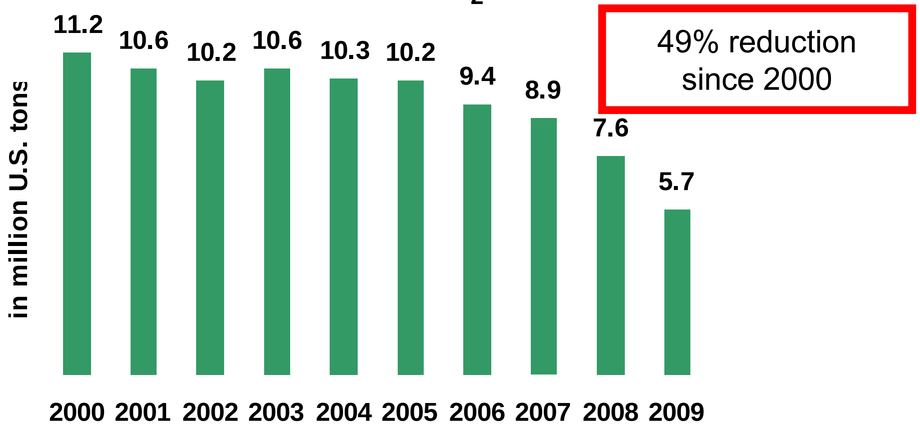
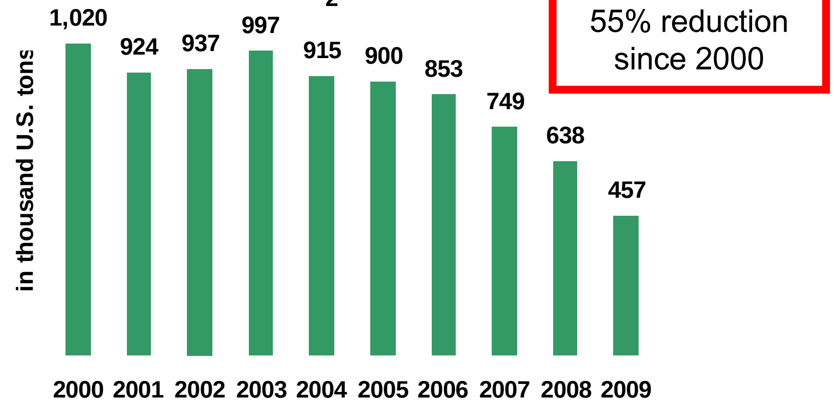
Significant Progress Has Been Made But . . .

U.S. Power Plant SO_2 Emissions

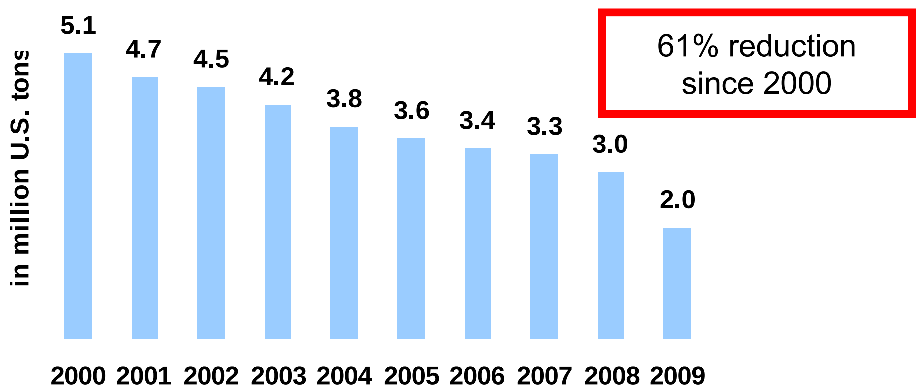


Source: EPA, 2010; Acid Rain Program

AEP SO_2 Emissions

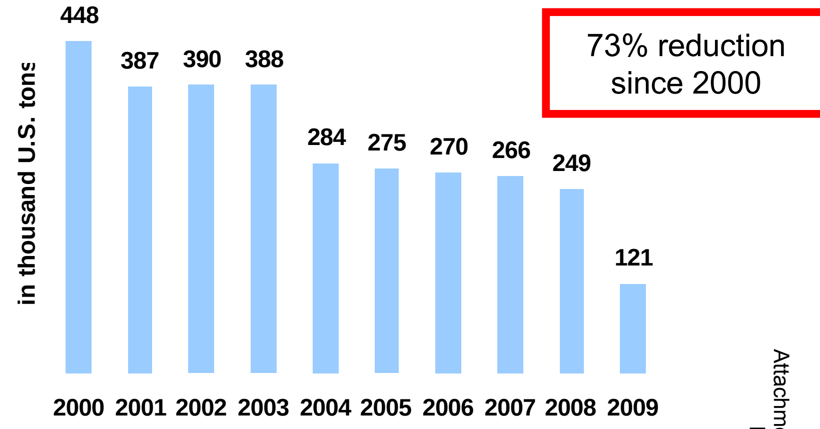


U.S. Power Plant NOx Emissions



Source: EPA, 2010; Acid Rain Program

AEP NOx Emissions



Over $5B capital invested by AEP from 2004-2010 to reduce emissions

Recent and Major Upcoming EPA Actions

- **Transport Rule – Proposed July 2010**
  - Governs power plant emissions of SO_2 and NOx that affect downwind fine particle and ozone concentrations
  - 2012 program start date with stringent second phase beginning in 2014
  - Limited interstate trading and no use of previously banked SO_2 allowances from CAIR program
  - 2014 SO_2 limits in AEP-East states will require almost all coal units to be scrubbed or retired/use gas
  - AEP believes an extension of the compliance deadlines is essential to allow states to develop implementation plans and give companies time to install the retrofits needed to comply

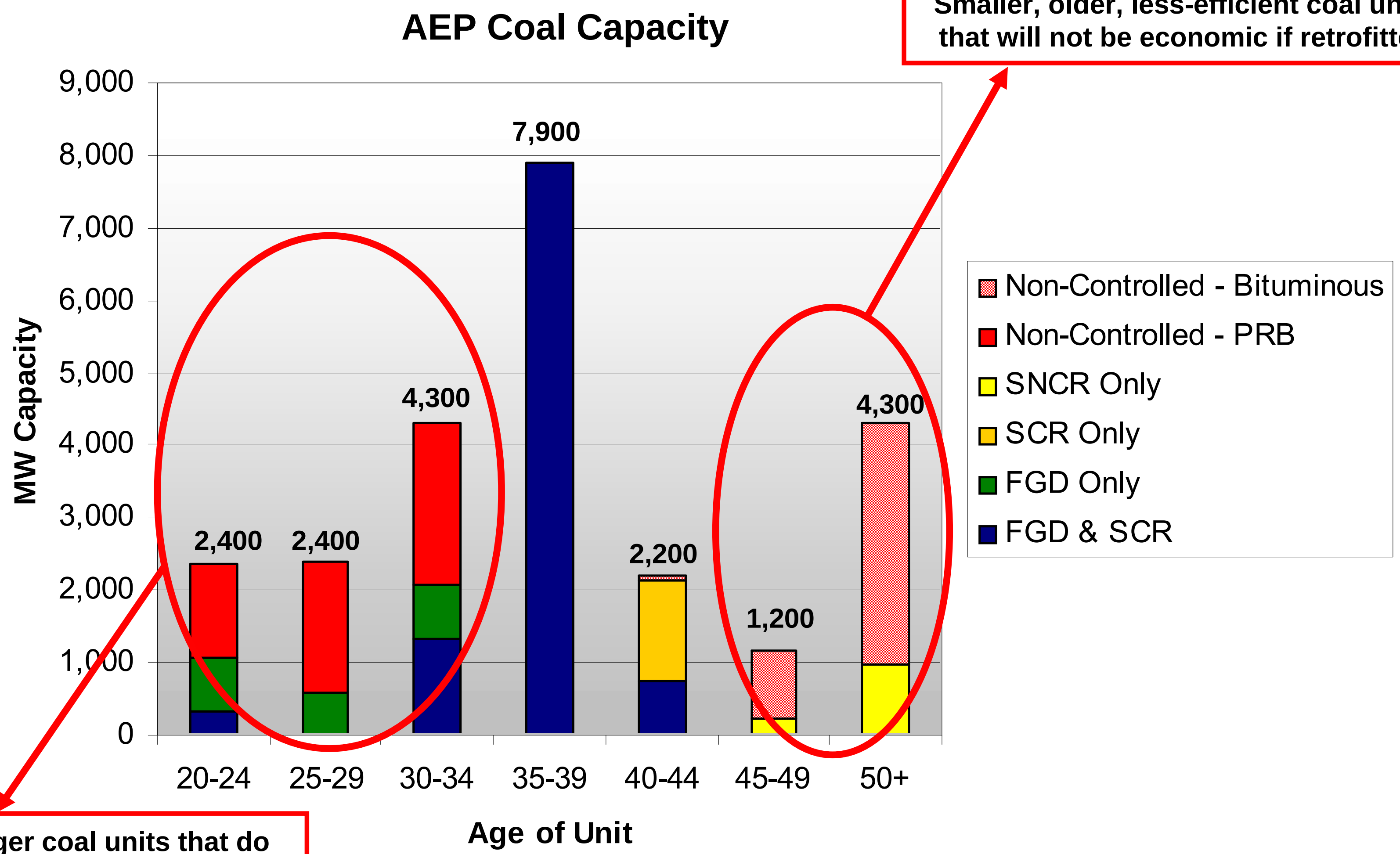
- **"Coal Ash" Rule – Proposed May 2010**
  - EPA proposed two different regulatory designations:
    - Solid waste – action required by ~2017
    - "Special" hazardous waste - action required by ~2018-2020
  - AEP supports regulation of coal ash under the Subtitle 'D Prime' option of the RCRA
  - Cost to AEP customers estimated at $3.9 billion by 2020 to comply with Subtitle D option

- **Mercury and other Hazardous Air Pollutants (HAPs) Rule**
  - Expect proposed rule in spring 2011, finalized in late 2011; likely compliance year - 2015
  - Could require major pollution control retrofits at most U.S. coal plants (FGD, baghouses, etc.)

Cumulative effects of EPA proposed rules and carbon legislation/regulation are a major concern for utility resource planning

Plant Retirements are Inevitable

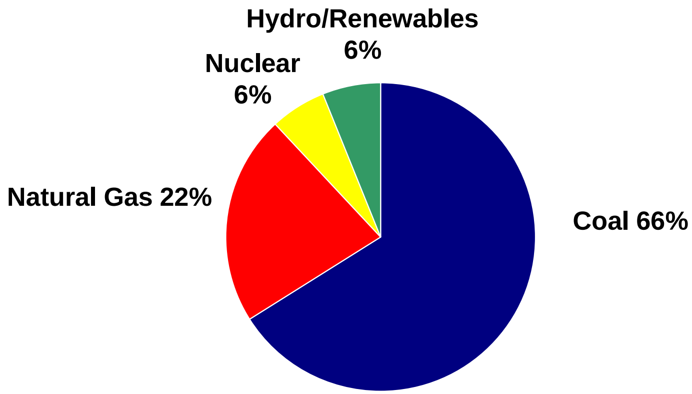
Smaller, older, less-efficient coal units that will not be economic if retrofitted



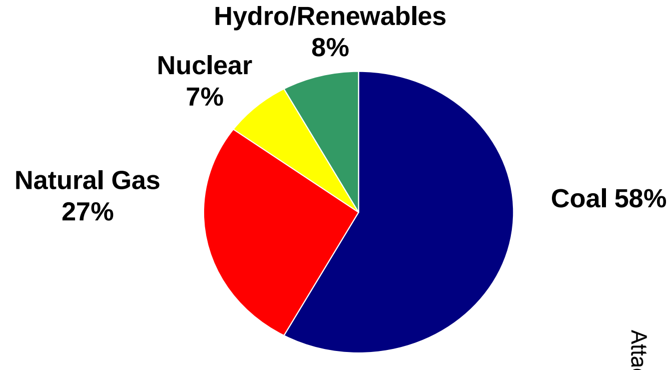
Newer and larger coal units that do not have SCRs and/or FGDs will be evaluated due to emerging and existing environmental requirements

AEP's Actions

- Operate uncontrolled, older and smaller units on a seasonal basis – minimizes capital and O&M spending
- Continue pursuit of CCS to take advantage of first-mover advantages such as DOE clean coal grants
- Complete the Dresden NGCC Plant and add renewables where regulatory recovery is provided
- Complete Cook Nuclear Plant uprate
- Transition toward retirement of approximately 5,000MW of coal units
- Influence federal and state policy to benefit our customers and shareholders
- Transformation plan that includes new technologies such as gridSMART and storage



Fuel Mix - 2009



Projected Fuel Mix - 2017

Carbon Legislation Update

- **Climate Cap and Trade Legislation (American Power Act of 2010) is dead in 2010**
  - Prospects for cap-and-trade legislation after 2010 will require truly bipartisan legislation given the expected changes in Congress

- **Cap and Trade Legislation that advanced in 2010 did include some improved provisions:**
  - Significantly higher electric utility allowance allocation
  - More generous CCS bonus allowances
  - Sound domestic offset provisions
  - Price collar that should help eliminate high price spikes

- **However, there were still some problem areas:**
  - Inadequate EPA preemption language on CO_2 would lead to duplicative CO_2 regulatory measures
  - More restrictive international offsets provisions could drive up compliance costs
  - Early action credit is very limited
  - Market trading provisions are overly restrictive

- **EPA is expected to move forward on CO_2 regulation in 2011**

AEP advocates delay in EPA regulatory action on CO_2 or legislation to enable significant multi-faceted study to determine overall economic and system reliability effects

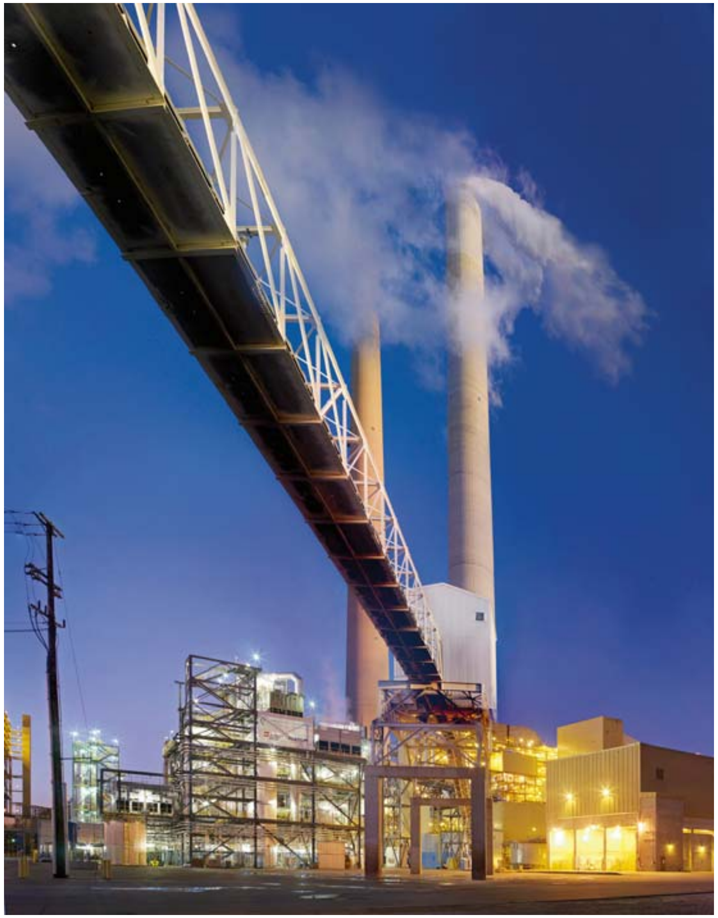
Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process



Carbon Capture and Storage project
Mountaineer Plant - New Haven, WV

Thoughts about the Energy Policy Debate

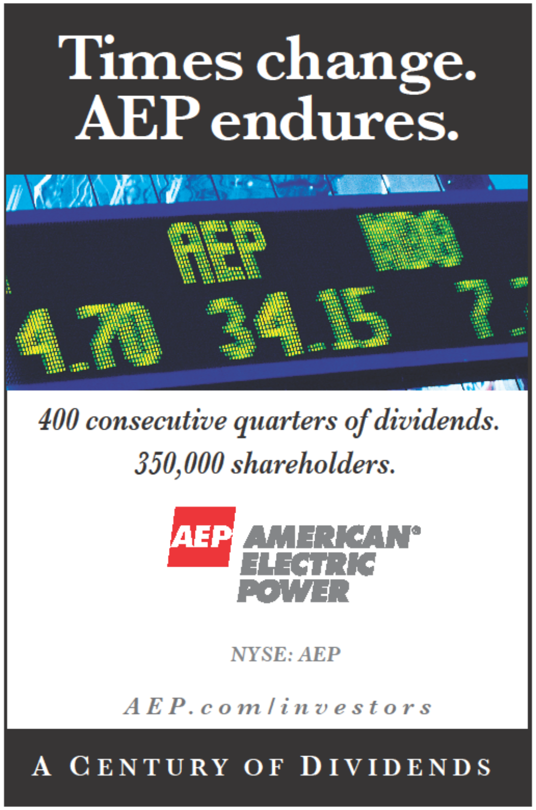
To make significant advancement in developing clean, domestic energy and reducing emissions, our nation needs a national energy policy with specific goals and guidelines, particularly as it relates to renewables, transmission and environmental regulations.

- **Cap and trade**
- **Incentives to develop and deploy new technologies**
- **Timelines for emission reductions that provide a rational glide path for transitioning the existing generating fleet to a smaller environmental footprint**
- **Mandates to develop reasonable cost allocation methodologies to support EHV transmission**
- **Support for the siting of national-interest transmission lines**

Trent Mesa Wind turbines in west Texas

Value Proposition

- **Current Yield Opportunity of 4.6%[1]**
  - June 10th – 400th consecutive quarterly dividend paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $36.50 on 09/24/2010

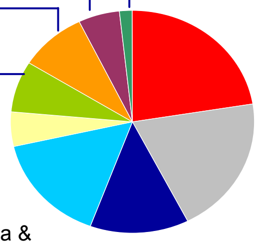
Appendix

Highly Diversified Regulated Utility Platform

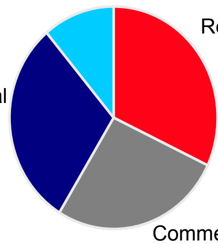
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

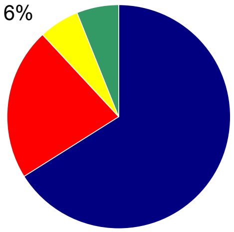


2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



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Transmission Opportunities

- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - **In service assets $0.4 billion**
  - **CREZ opportunity $1.1 billion est. in service 2010 - 2013**
  - **Other ETT projects $1.6 billion est. in service 2010-2017**
  - **Framework in Texas allows for more expeditious siting and recovery**

- **AEP Transmission Company (Transco): Within our existing footprint**
  - **Develop new AEP-only projects within AEP's footprint**
  - **Reduce regulatory lag through FERC formula rates adjusted annually**

- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - **Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery**
  - **Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016**
  - **Robust pipeline of projects up to $15B**

ETT Electric Transmission Texas

ETA ELECTRIC TRANSMISSION AMERICA, LLC

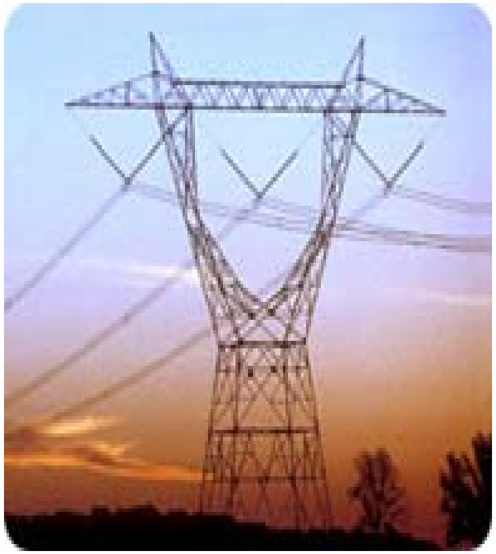
Prairie Wind Transmission
A joint venture between Westar Energy. and ETA

PATH
Potomac-Appalachian Transmission Highline

Tallgrass Transmission
A joint venture between OGE Energy Corp. and ETA

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filings made in OH and WV
- FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
- Seek retail tracking mechanisms at the state level (OH, AR, VA, TX-ERCOT already secured)



765-kV Tower

JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 345 kV**
- *Partners: Westar (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $165 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 345 kV**
- *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $350 million*
- *ROE: 12.8%*

* May revert to 765 kV depending on 2010 SPP ITP results

ERCOT

ETT — COD: 2010-2014

- *345 kV and below CREZ & ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.5 billion*
- *ROE: 9.96%*

PJM

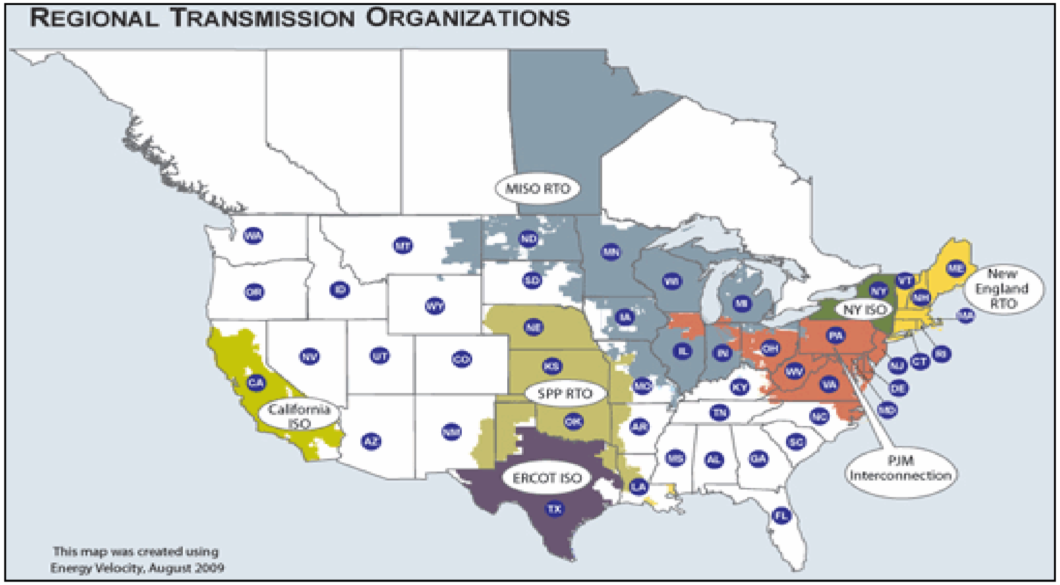
PATH-WV — COD: 2015

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2016

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Sponsors: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay	ETT — COD: various	PJM Expansion	EHV Michigan/Ohio
Regional Expansion of 765 kV Backbone	*Other Projects - $1.6 billion (COD 2010-2017)*	*Regional Expansion of 765 kV, 500 kV and 345 kV systems*	*700 miles of Proposed 765 kV*
SPP	ERCOT	PJM	PJM/MISO

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

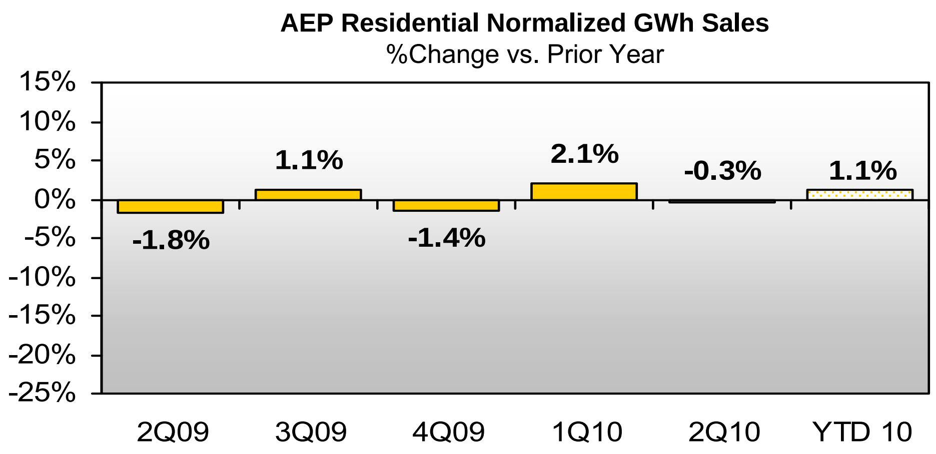
American Electric Power
2009 Actual vs. 2010 Guidance

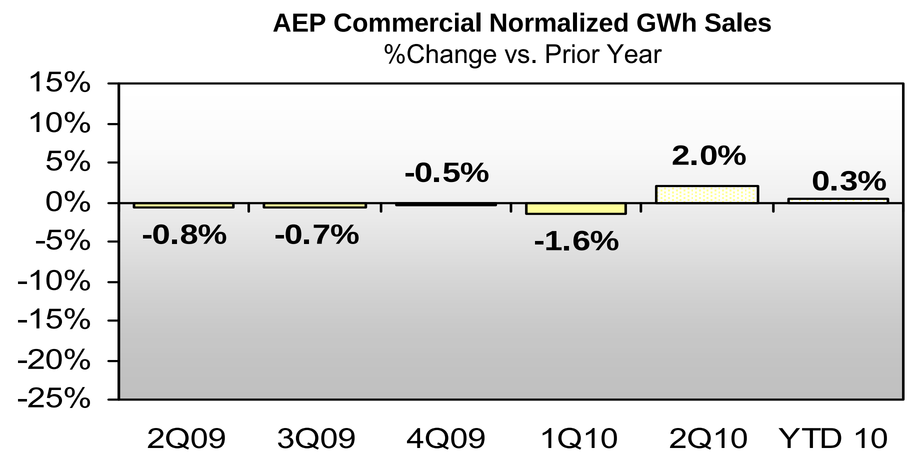
2010E: $2.80-$3.20

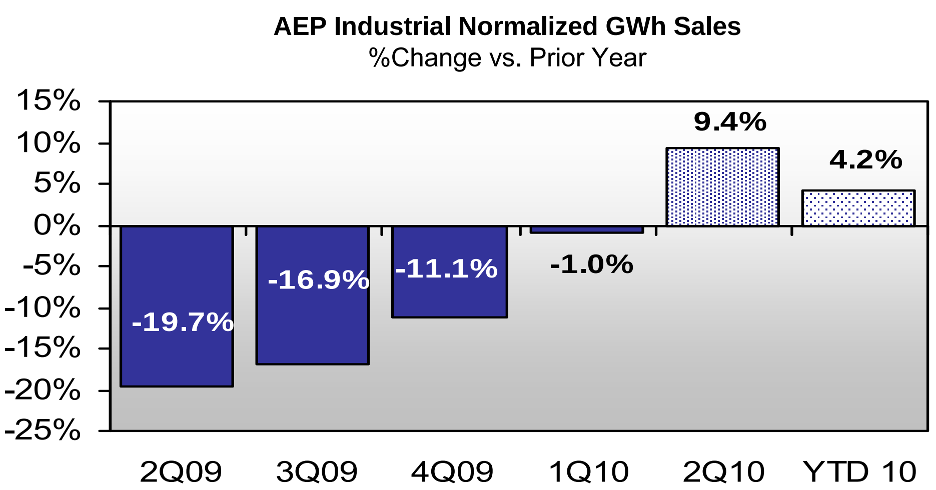
		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

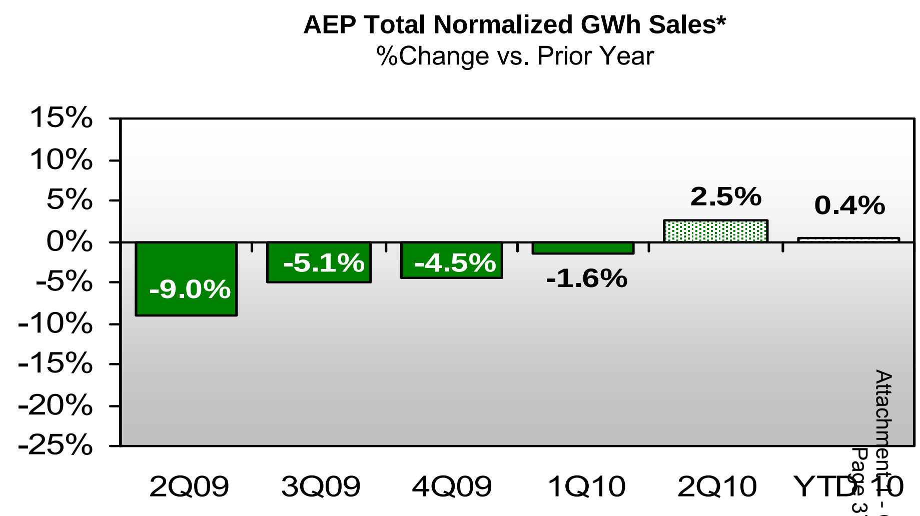
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends









*includes firm wholesale load

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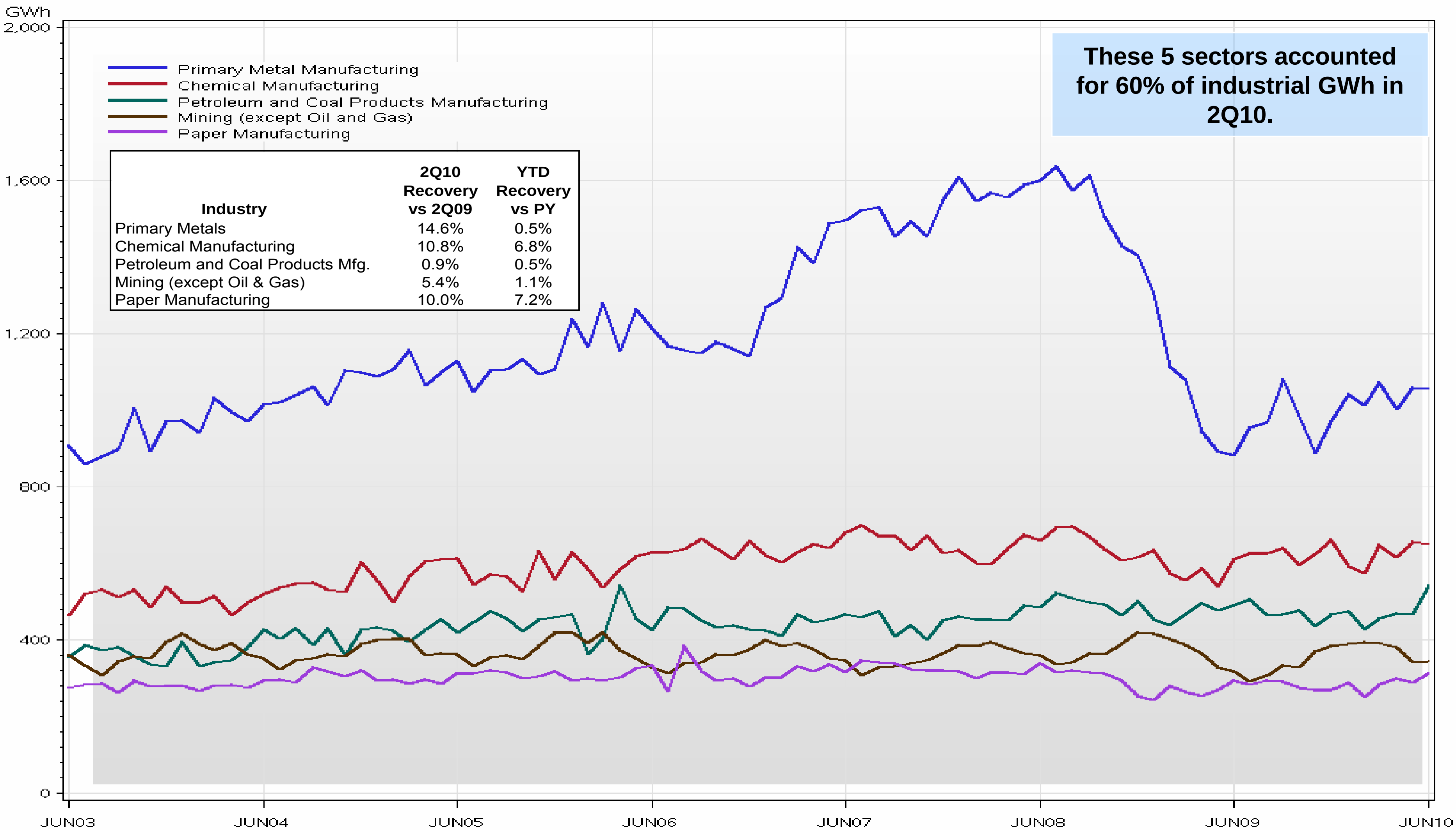
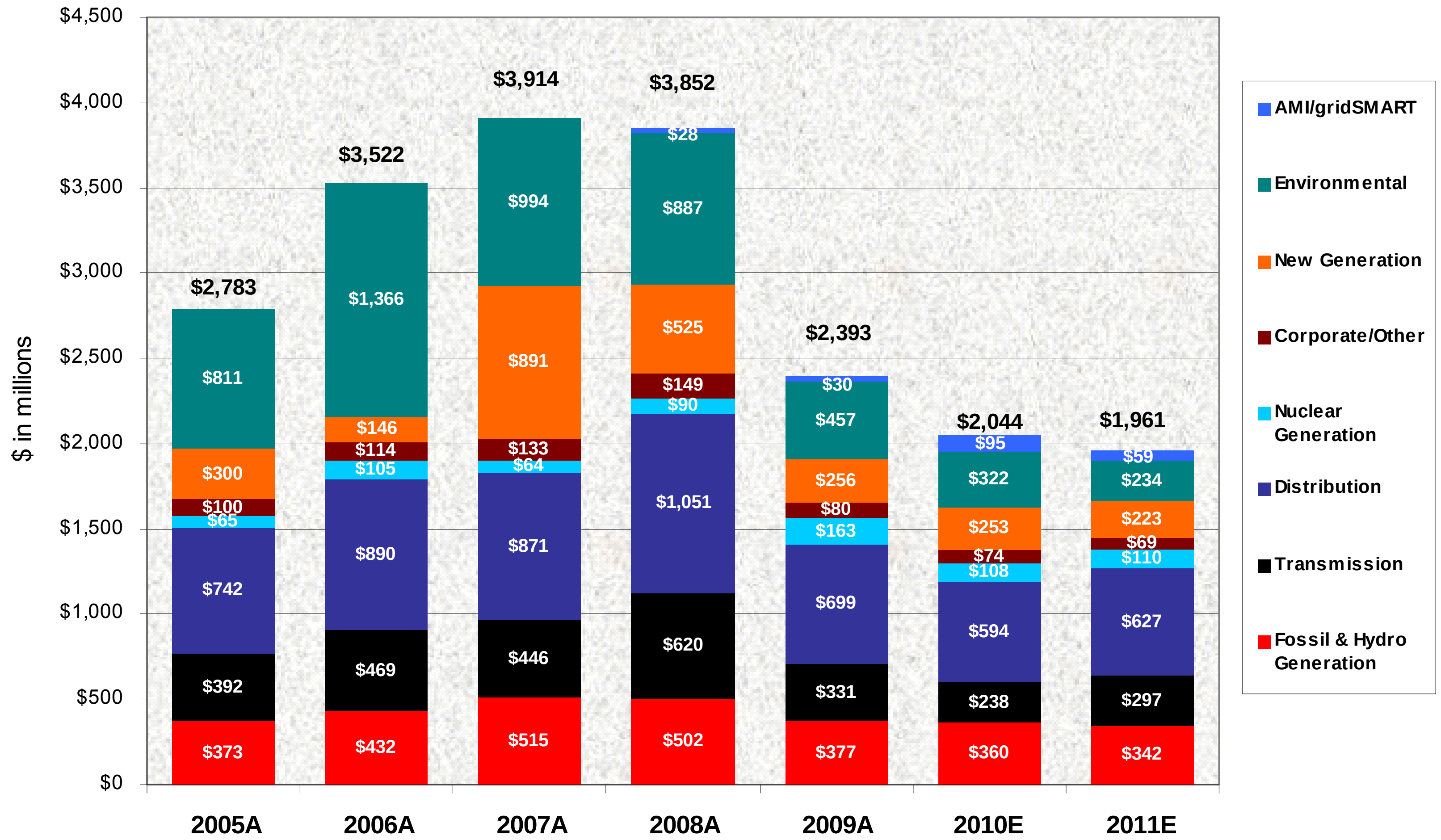
Industrial Sales

AEP Industrial GWh by Sector



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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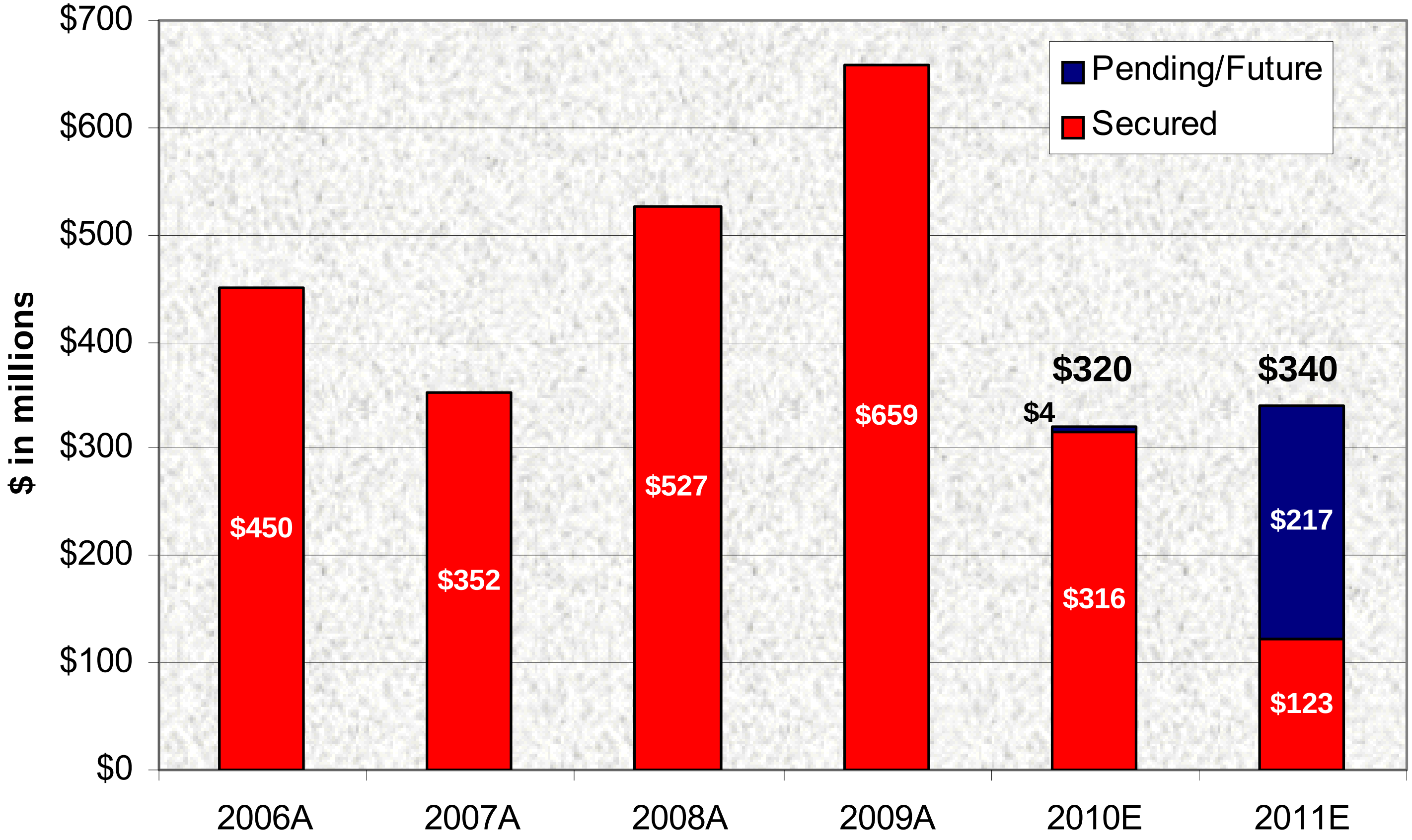
Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Pending/future rate cases include Oklahoma, West Virginia and others yet to be filed; Michigan settlement reached & expected shortly, so we will exceed 2010 target by $11MM)

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Current Base Rate Cases

$ in millions

APCo - West Virginia	Company Filing	Staff Testimony
Rate increase	**$224** *	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

* - net increase is $143 million after changes in Construction Surcharge

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

PSO - Oklahoma	Company Filing	Staff Testimony
Rate increase	**$82** *	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

* - net increase is $52 million after elimination of existing Capital Investment Rider

Status: Case filed on July 9, 2010. Staff & Intervenor testimony due October 26, 2010.

$306 million total base rate increase requests on file, and a settlement pending in Michigan for $36MM plus adjustments.

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company[1]	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

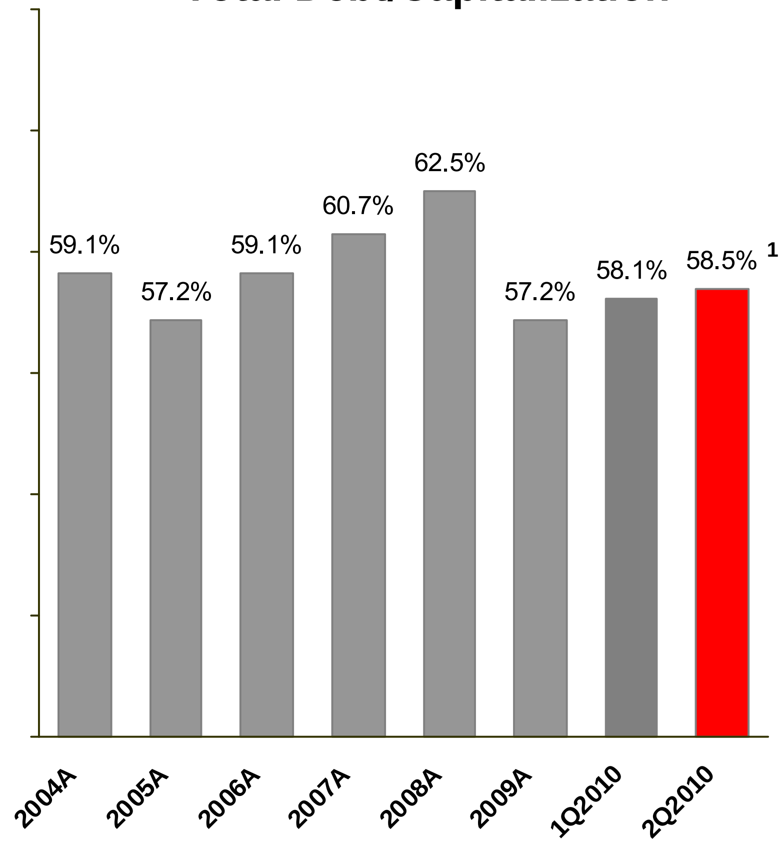
(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: *Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.*

Current Liquidity Summary
As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable

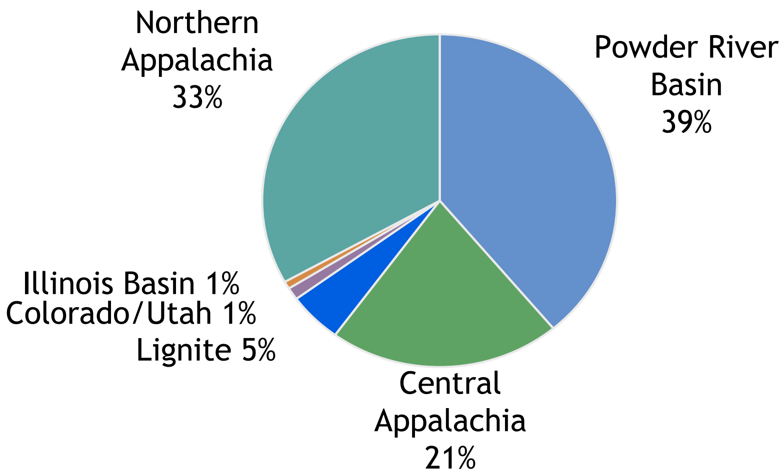
2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

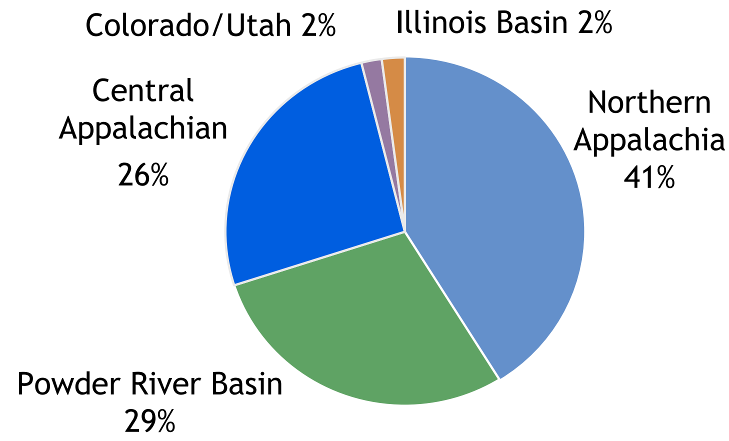
(1) Debt to Capitalization excludes securitization bonds

Coal Procurement - 2010 Projected

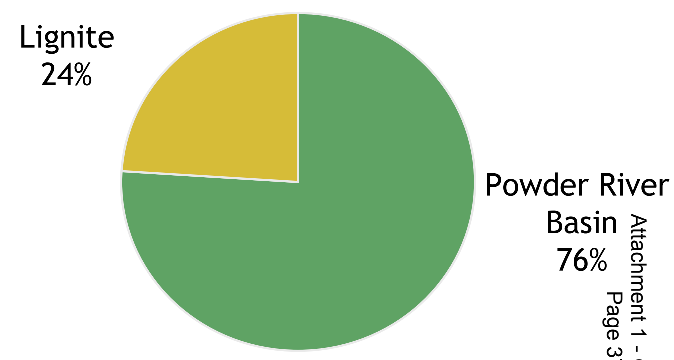
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 80% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

American Electric Power Company, Inc.

Boston Fixed Income Road Show

Hosted by Merrill Lynch

September 13, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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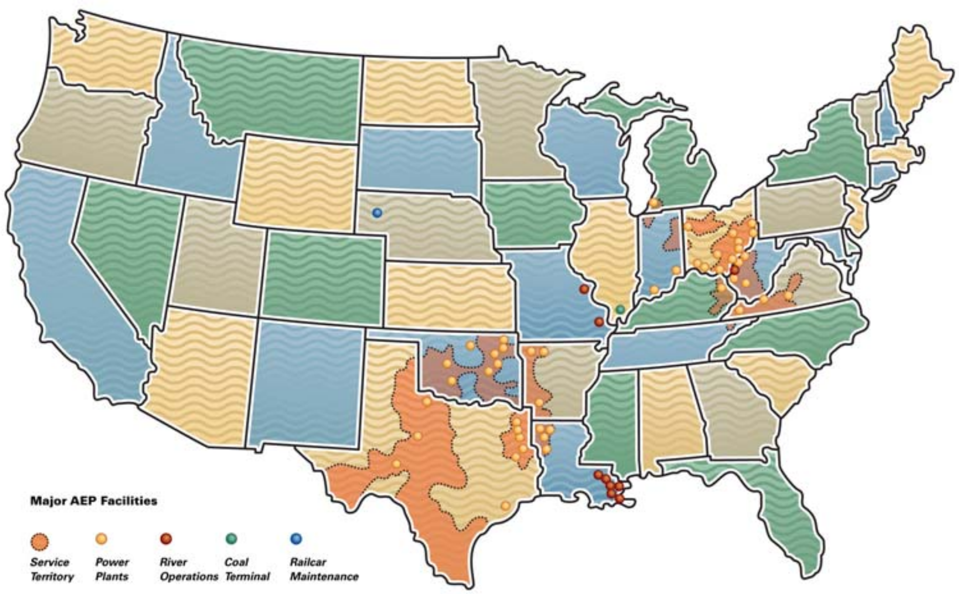
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
67%	**24%**	**6%**	**2%**	**1%**

AEP®

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

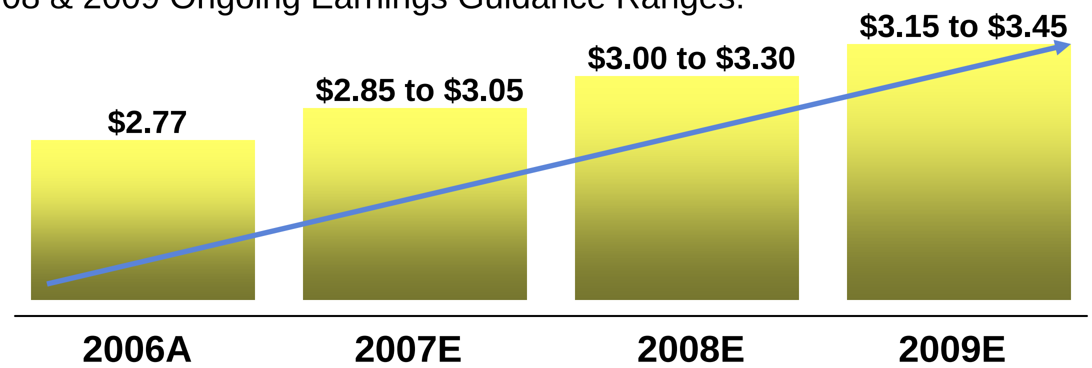
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

AEP®

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

AEP®

New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden	$85
2007 Including Lawrenceburg	**$3,952**

Note: Excludes AFUDC and previously announced CO_2 and transmission projects

*Includes Lawrenceburg and Dresden purchases in 2007

AEP®

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2009
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☐	Delayed
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5 & 6	750		N/A	☑	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service

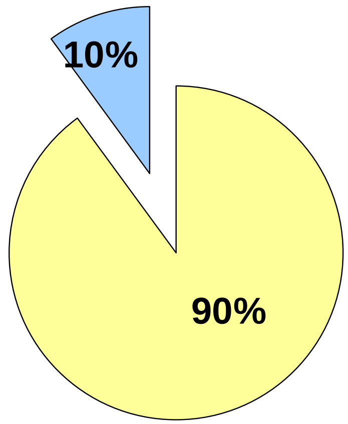
AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

•B&W/Alstom – FGD Spray Tower

•B&V/Chyioda – FGD Jet Bubbling Reactor

•Pullman Power – Stack Supplier

•Babcock Power – SCR

•Black & Veatch – Architect/Engineering

•Sargent & Lundy – Architect/Engineering

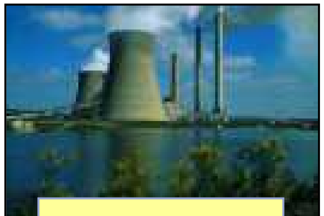
First-Mover Advantage:

- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- AEP capital costs for a scrubber average approximately $250/kW
- We have since seen a 30-60% increase in material costs and a 15% increase in labor rates
- An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

AEP®

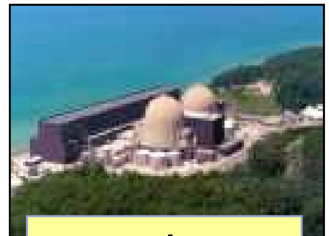
AEP Customers and Shareholders Benefit From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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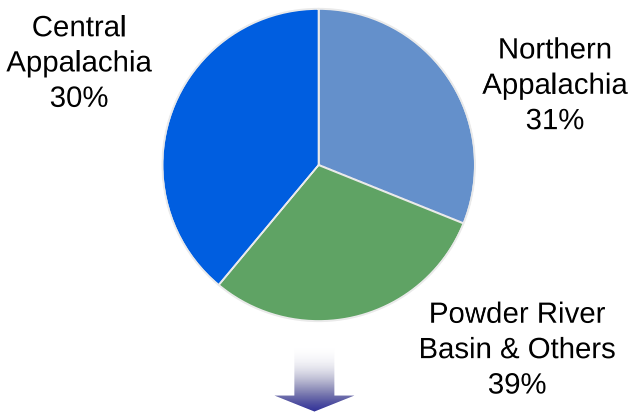
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

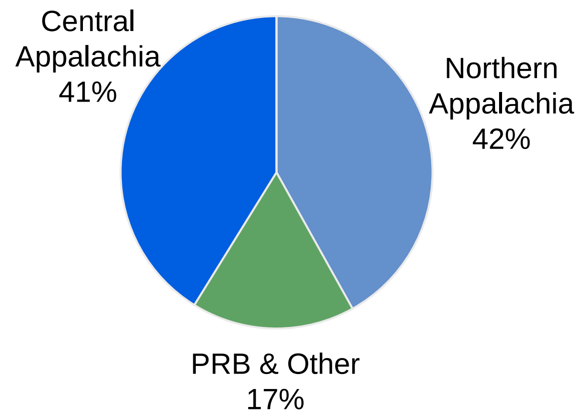
Total AEP System



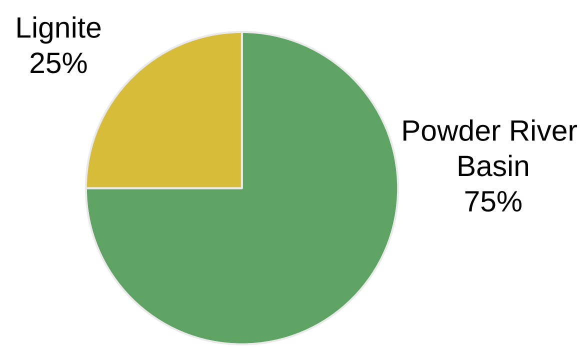
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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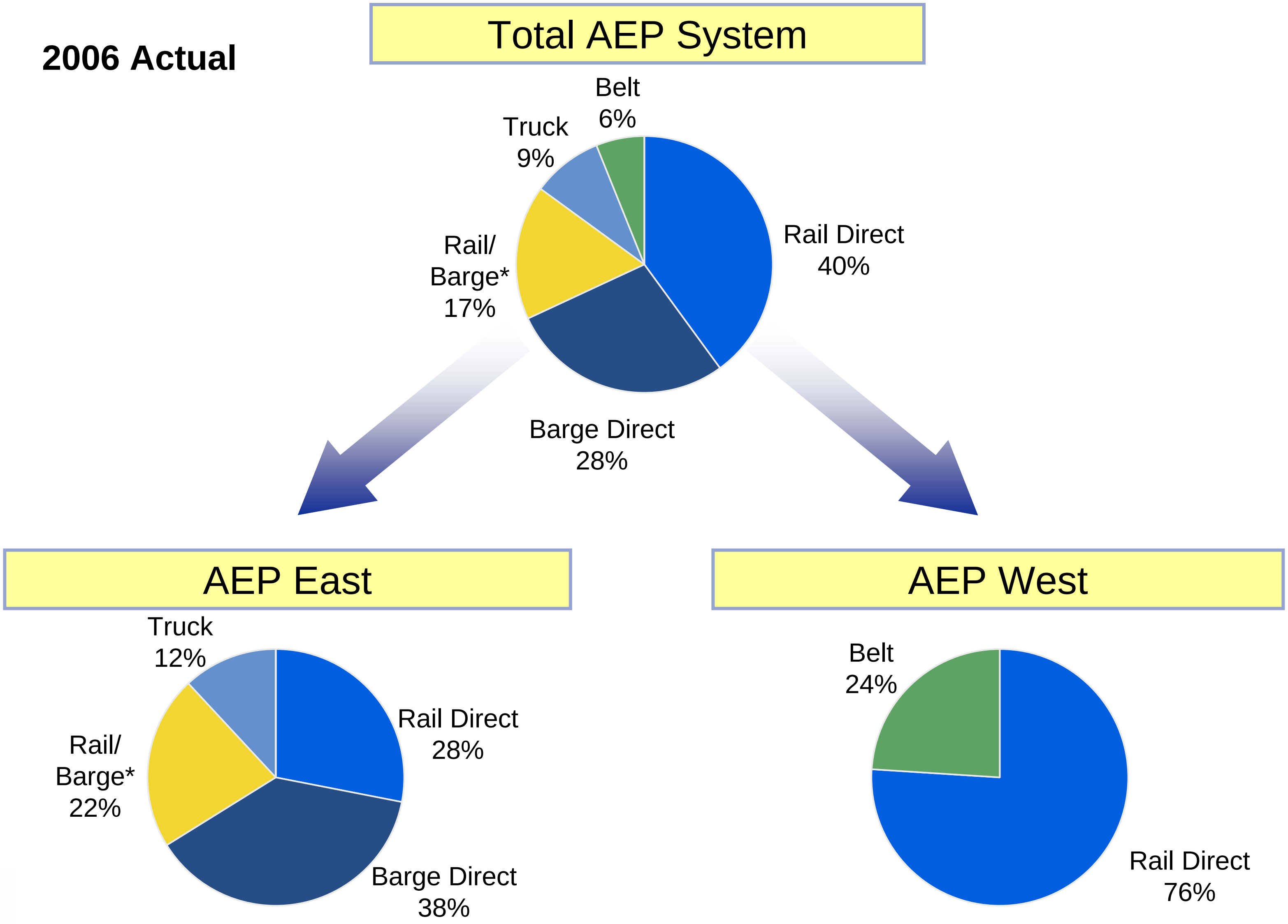
Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on September 28, 2005
- $268/kW

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007
- $295/kW

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007
- $227/kW

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on December 15, 2005
- $198/kW

AEP®

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis.
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

AEP®

New Ultra-Supercritical Coal Facility

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected in the fourth quarter of 2007
- Air permit approval expected in Fall 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM

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Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - West Virginia filing made in June 2007 – included request for cash recovery mechanism
  - Virginia filing made in July 2007 requesting cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

AEP®

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- ➢Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- ➢Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- ➢Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- ➢Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- ➢Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

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IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

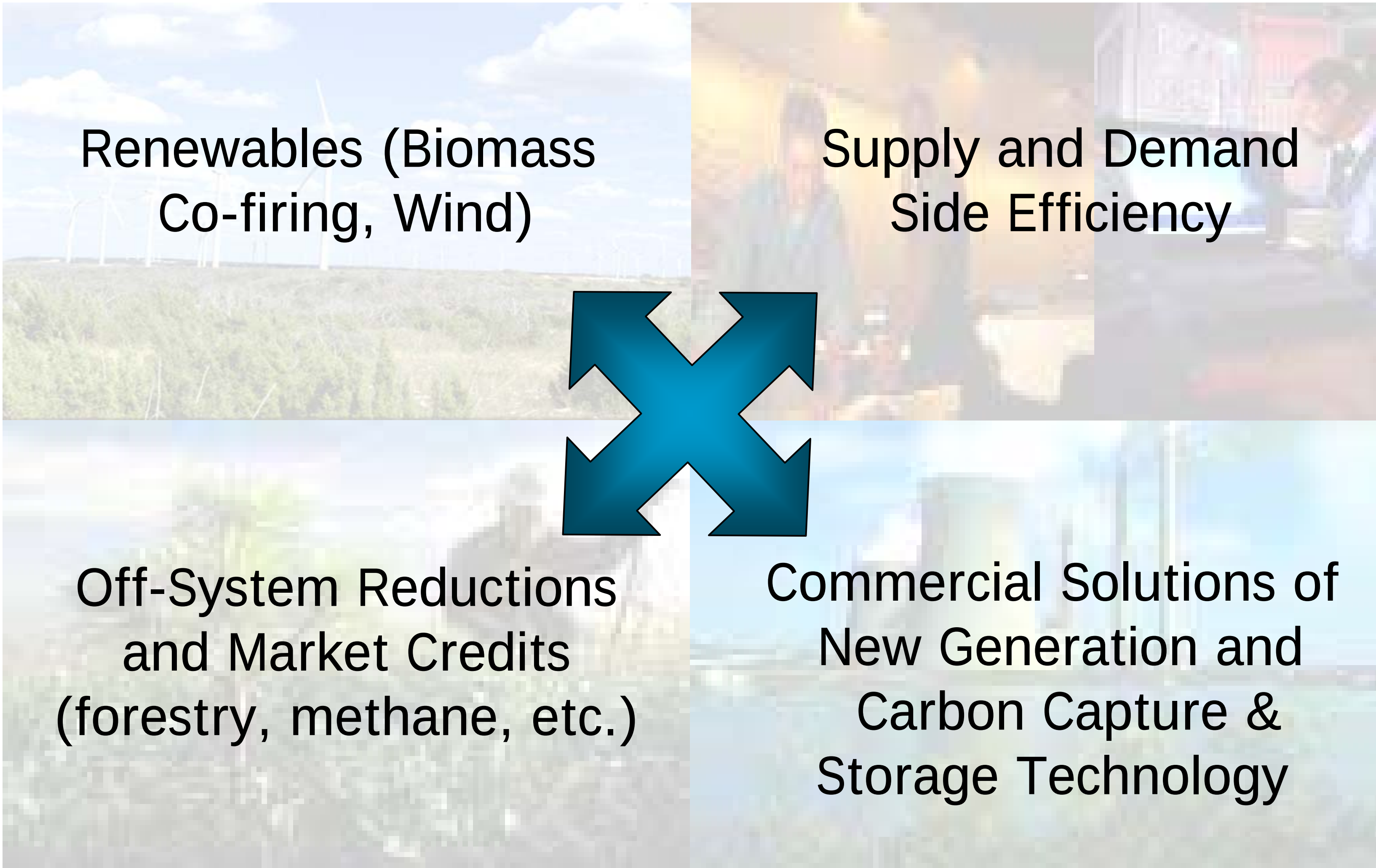
AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP’s Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

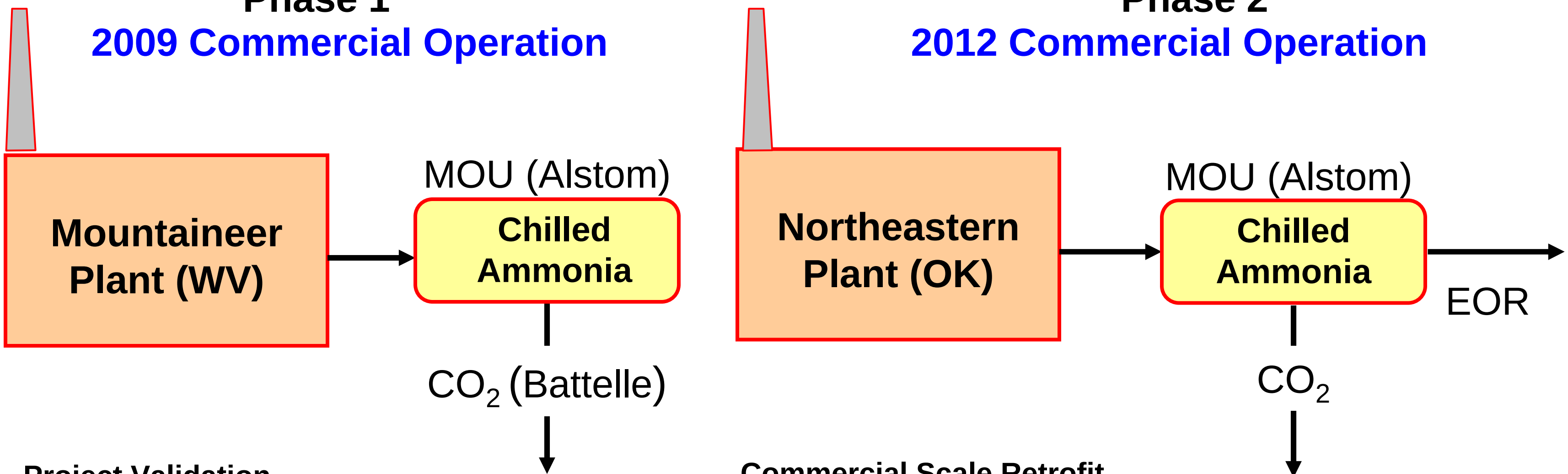
- New Technology Generation – IGCC and USC
- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

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Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

- ~ $3 Billion I765™ Project in PJM
- ~ $2 Billion 765-kV study in Michigan w/ ITC
- ~ $3 Billion Project filed with SPP
- ~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

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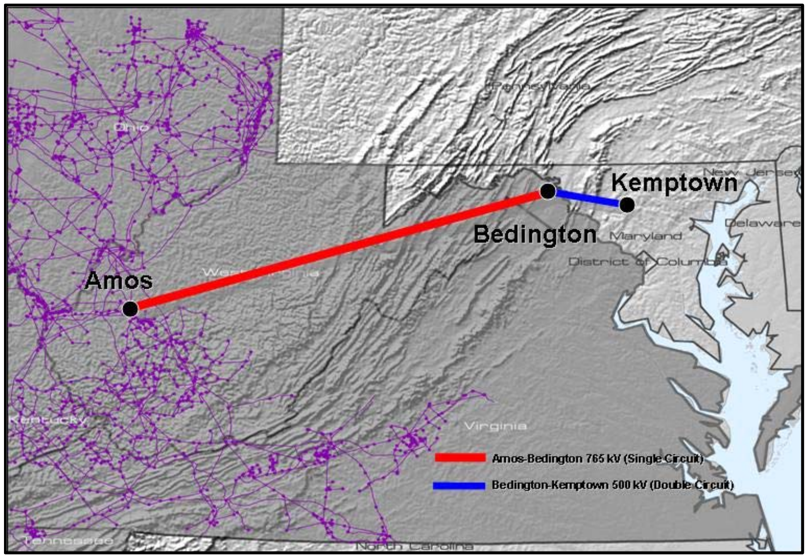
Building the next US interstate system for enhanced reliability and market efficiency

I-765™ in PJM

- *Overview*
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM-approved)
- *Benefits*
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation
- *Phase I Progress to Date*
  - On September 1, 2007, AEP and Allegheny formed a new joint venture Potomac- Appalachian Transmission Highline, LLC (PATH) and its subsidiaries) to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Targeted completion 2012



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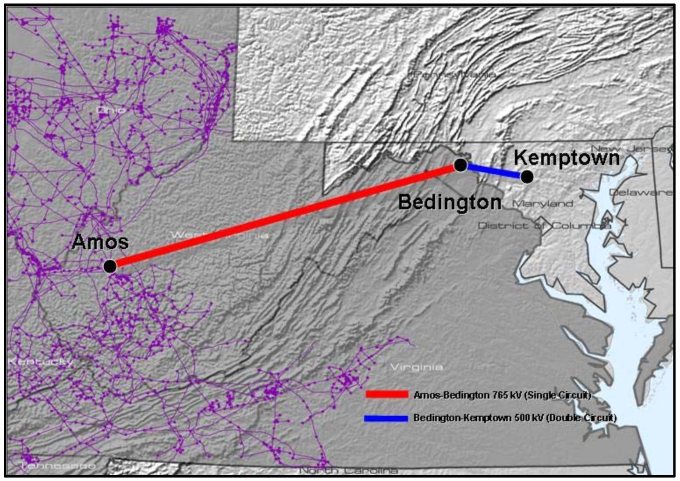
I-765™ in PJM - Phase I cont'd

Execution in Action

- *Funding Plans/Transaction Structure*
  - JV portion of the I-765™ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007
  - Equity – 50% AEP / 50% Allegheny
  - AEP's investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - I-765™ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007



- *Key Regulatory Activity Completed*
  - FERC declaratory order approved July 2006
  - PJM approved plan June 2007
- *Key Next Steps*
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012

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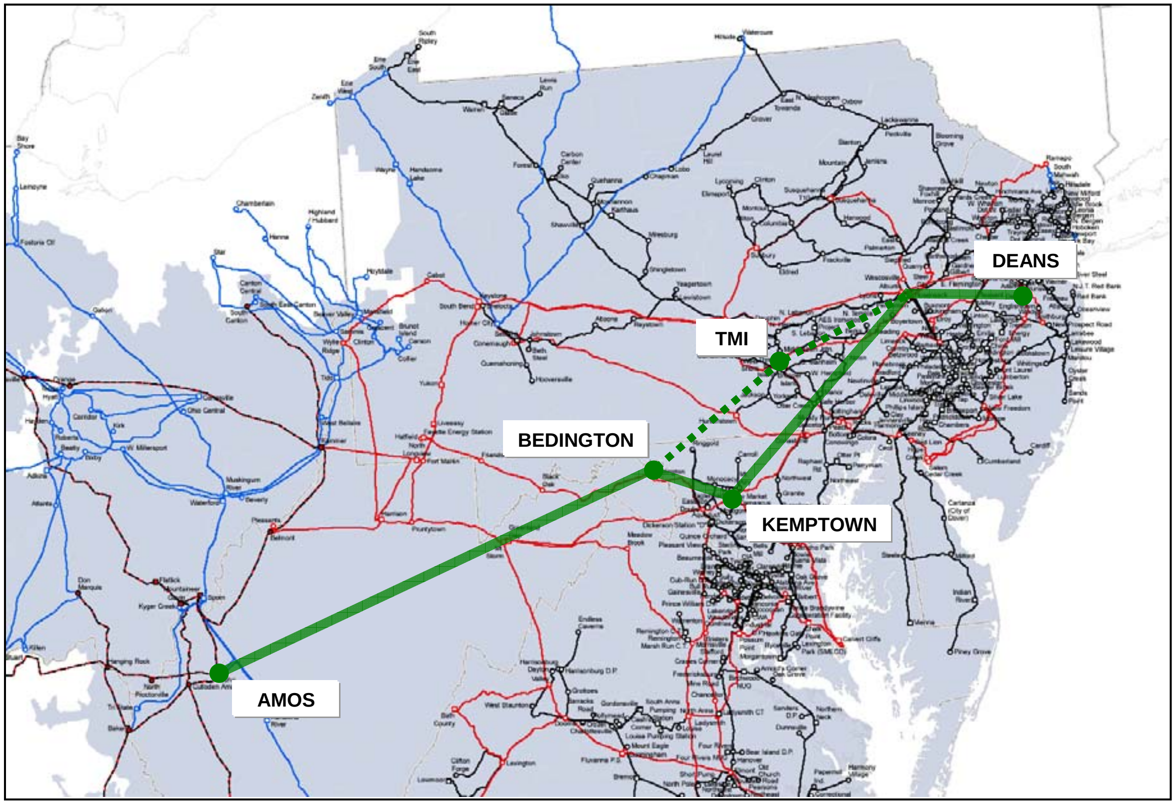
I-765TM in PJM - Phase II (Bedington-Deans)

Second phase of original AEP 550-mile I-765TM proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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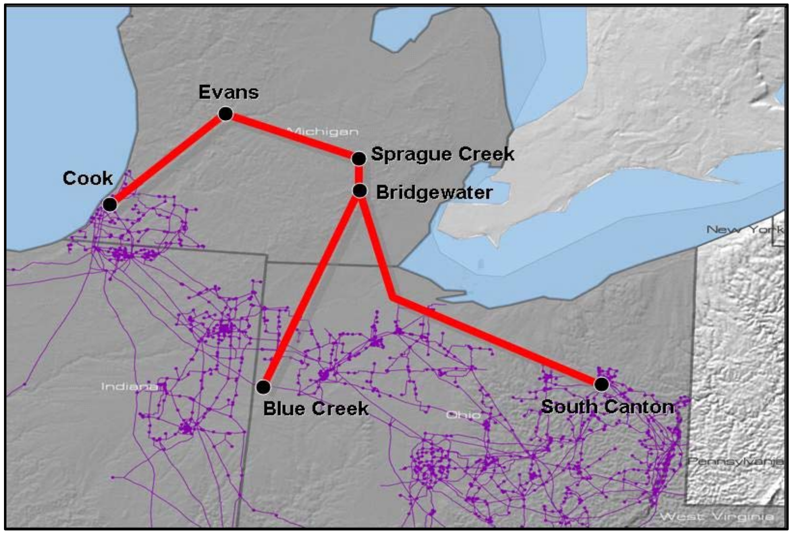
765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.0 billion investment (before ownership division)
- *Benefits*
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013

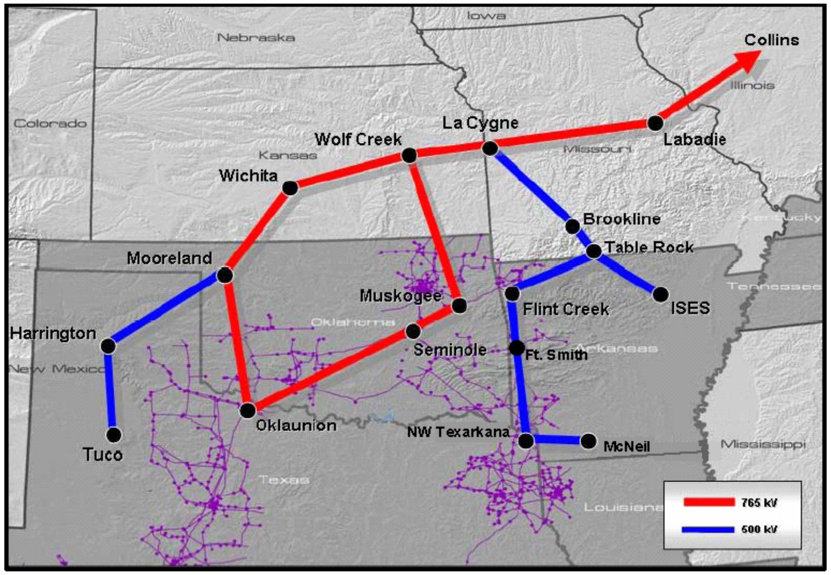


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Benefits*
  - 4,000 MVA capability

- *Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

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ETT Status Update

ETT: Delivering Power for Texas' Future

- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP; business manager provided by MidAmerican.
  - Investment opportunities can be offered by either partner.

- *Transaction Status*
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in September 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

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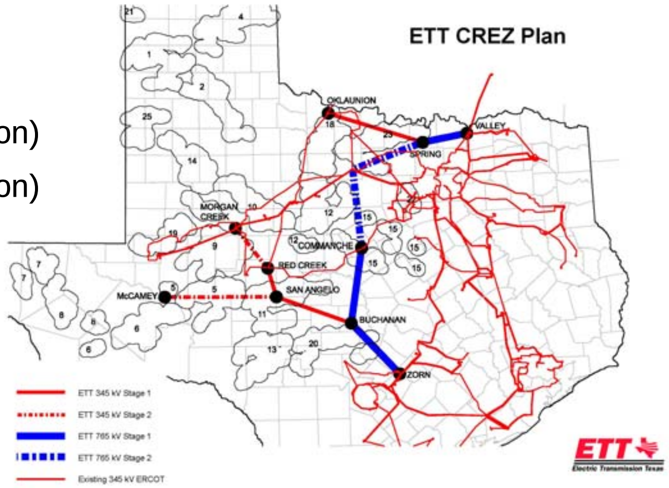
CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - \$1.5 billion investment Phase 1 – 2012 (before ownership division)
  - \$1.5 billion investment Phase 2 – 2015 (before ownership division)

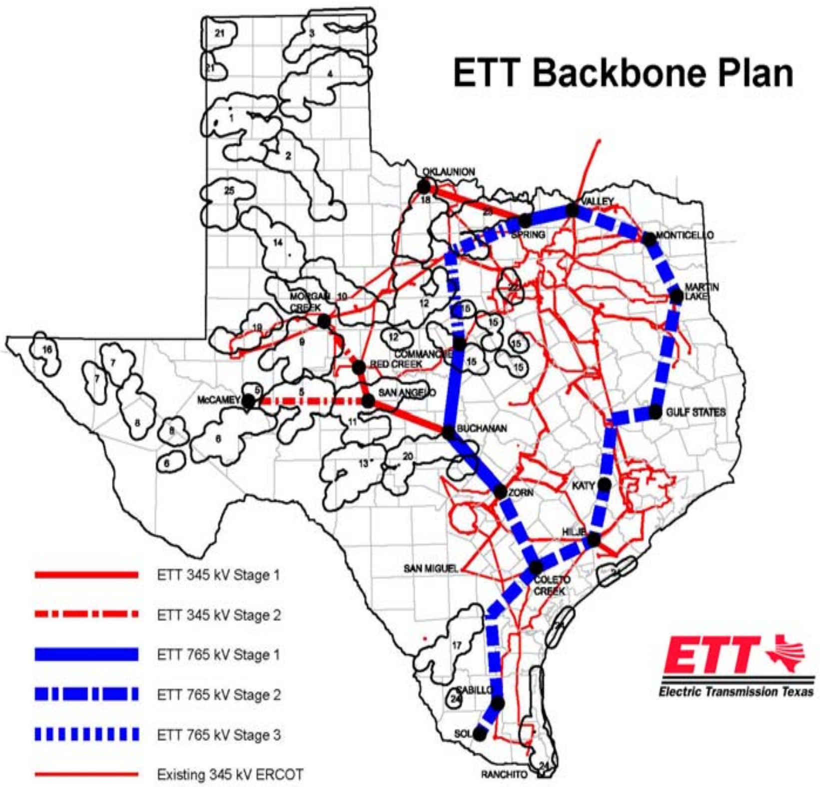


- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

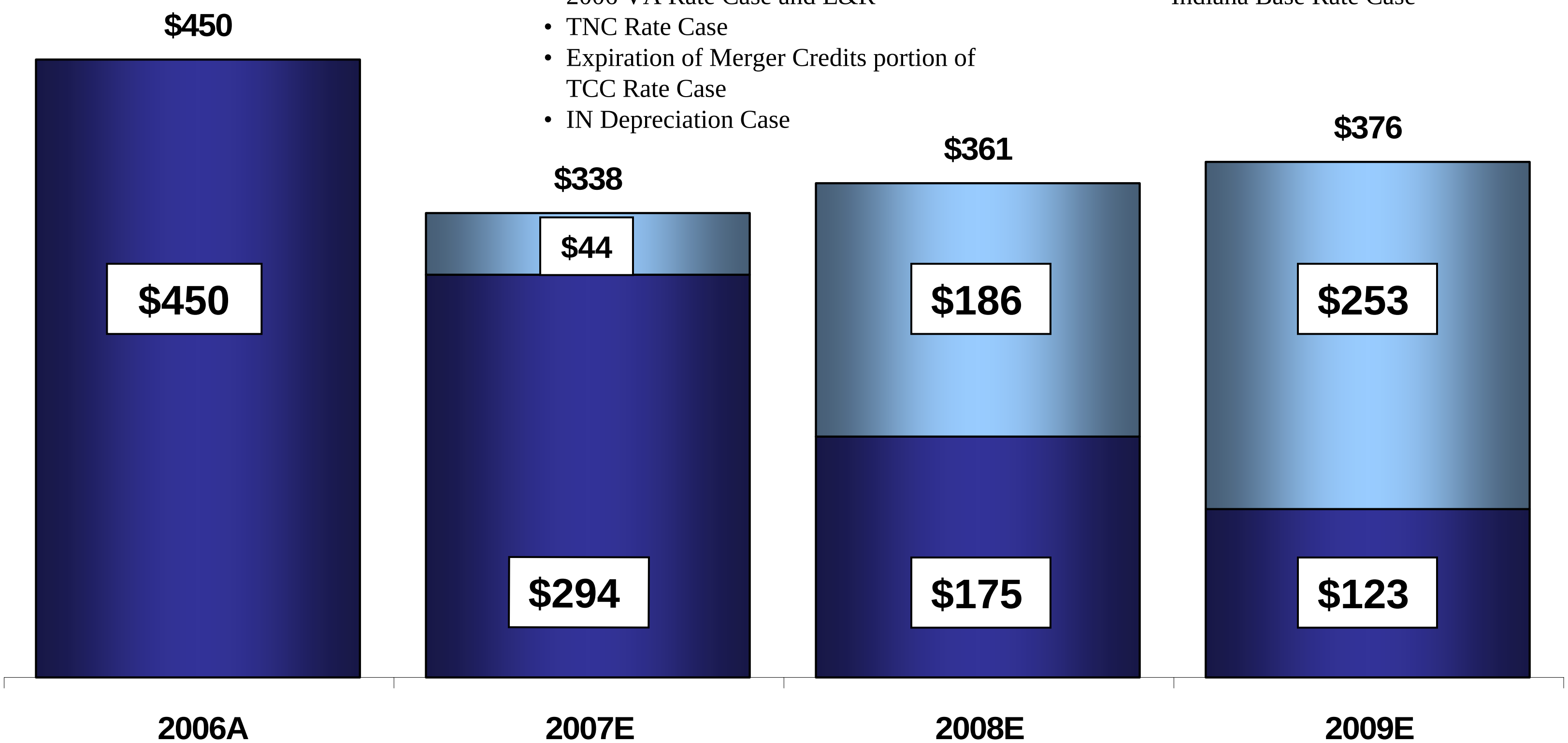


Incremental Rate Relief Composition

$ Millions

Secured
- OH RSP
- 2006 WV Rate Case, including ENEC
- 2006 Kentucky Rate Case
- FERC & OH OATT
- 2006 VA Rate Case and E&R
- TNC Rate Case
- Expiration of Merger Credits portion of TCC Rate Case
- IN Depreciation Case

Pending/Future
- PSO Rate Case - $49.6 increase requested
- TCC Rate Case - $49.9 increase requested
- SWEPCo proceedings
- Cases yet to be filed
  - Indiana Base Rate Case



Rate Relief Is A Critical Element To AEP's Financial Success

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2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓ $54.8 million covers increased costs related to coal and purchased power
  - ✓ $28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓ Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

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In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Virginia Filings – Fuel Factor and E&R
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
September 2007	Final order expected

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Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule is subject to IURC approval.

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Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff , which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings began August 20, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for October 17, 2007.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

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We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

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Capital Investment Is Funded By Cash From Operations And Debt Issuances

AMERICAN ELECTRIC POWER
FIXED INCOME
INVESTOR MEETING

BOSTON, MA

MARCH 29, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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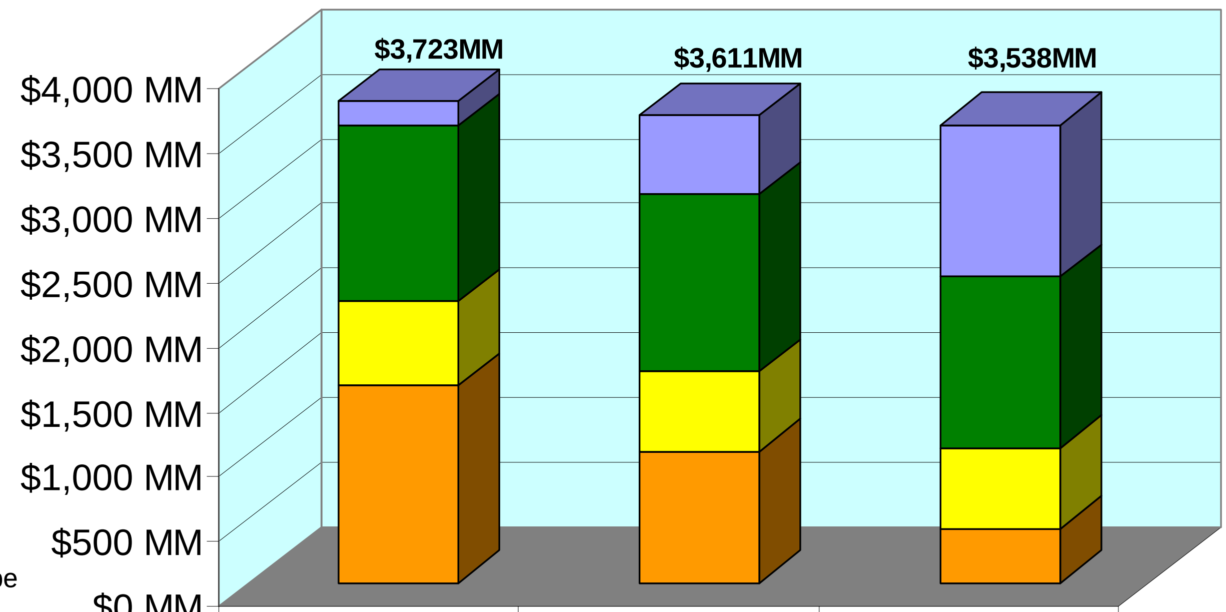
Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 3819 of 9556

New Generation

IGCC

- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 megawatt facility to begin in 2007
- Commercial operation date expected in 2010

PSO RFPs

- Submitted RFPs totaling 900 megawatts of baseload and peaking capacity
- Commercial operation dates expected in 2008 and 2011

SWEPCO RFPs

- Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity
- PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

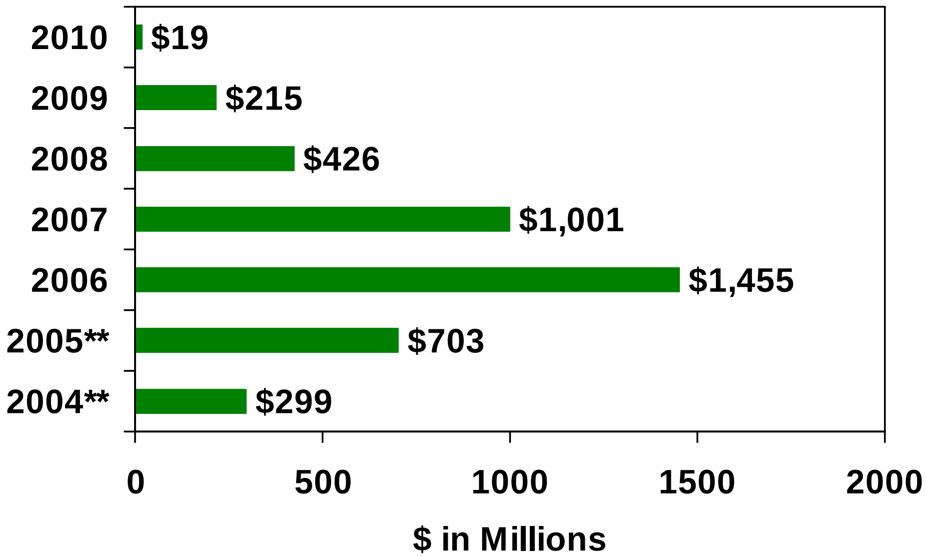
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

$4.1 Billion Environmental Investment

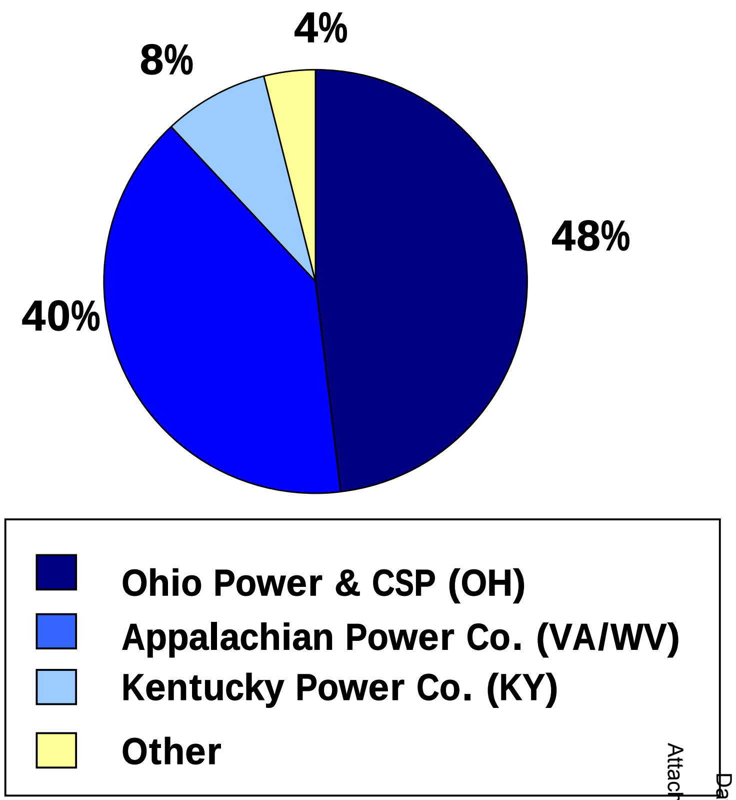
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation

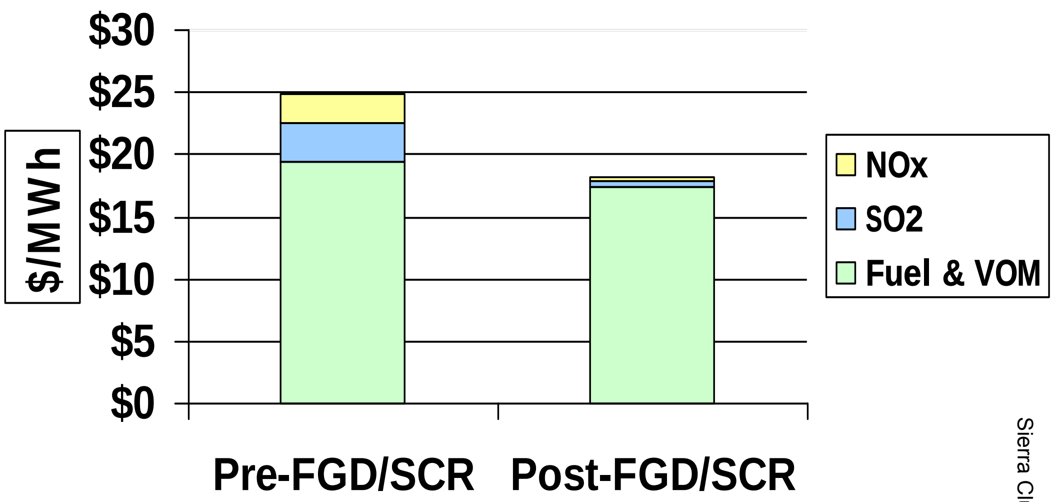


MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ Indiana Depreciation Petition
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
    - Final order expected in May 2006
    - September 1, 2006 - Issuance of securitization bonds if no appeal

Procedural Schedule for TCC Securitization

- ✓ April 17, 2006 – Intervenors File Testimony
- ✓ April 24, 2006 – Staff Files Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 2-4, 2006 – Hearings On Merit

- April 2006 – Request approval for CTC to address other true-up items
    - Expected $475 million credit to customers
    - Jan 2007 – CTC to be implemented

Regulatory Activity Underway

<u>Ohio Companies Pass through of FERC OATT Changes</u>

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

<u>Indiana Depreciation Filing</u>

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

Regulatory Activity Underway

Appalachian Power

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case – Gave notice to VA SCC on March 1, 2006 of intent to file general rate case no sooner than May 1, 2006

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million*
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

*Includes:
$16MM Base Rates
$56MM ENEC
$2MM Misc

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ April 7, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

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IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006–2007:

- ✓ Obtain permits and finalize engineering and procurement

2007–2010:

- ✓ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 - 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- ✓ $41 million annual increase in base rates
- ✓ To be effective March 30, 2006

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

Stephan Haynes
VP & Assistant Treasurer

Forecasted Capital Expenditures (in 000s)

Company	2006	2007	2008
AEP SYSTEM*	**3,722,600**	**3,611,400**	**3,537,700**
AEGCo	14,300	30,000	39,700
APCo	942,800	691,500	751,700
CSPCo	342,700	473,700	553,400
I&M	311,200	278,700	262,000
KPCo	100,000	127,100	144,000
OPCo	1,070,400	954,500	581,600
PSO	278,700	342,800	408,700
SWEPCo	287,900	366,700	458,400
TCC	278,400	247,000	222,100
TNC	72,500	71,600	89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

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Long-Term Debt Maturity Profile(1)

Year	2006(2)	2007	2008
AEP Service Corporation	$ -	$ -	$ 38,000,000
AEP Inc.	$ 395,860,000	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ 100,000,000	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Ohio Power Company	$ -	$ -	$ 50,395,732
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 6,215,000	$ 94,000,000	$ 122,886,096
Texas Central Company	$ -	$ -	$ 152,494,828
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 802,075,000**	**$ 1,112,615,000**	**$ 755,776,656**

(1) Excludes tax exempt bond remarketings
(2) Maturities remaining as of December 31, 2005

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2006 Key Operating Company Highlights

Dependent on Actual Capital Investment

(in millions)

Company	Projected Capital Expenditures	Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600	42-45%
CSP	$343	$100 - $150	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$50 - $75	42-45%
OPCo	$1,070	$450 - $550	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$100 - $150	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Long-Term Debt Guidelines

- Issuers:
  - Issue at operating companies.
- Size:
  - Make transactions index eligible if possible.
  - When possible, issue a size sufficient for competitive execution.
- Maturity:
  - Issue maturities for which the market has appetite.
  - Achieve weighted average life targets for operating companies, generally between 10-15 years.
- Timing:
  - Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Summary of Major 2006 Financial Performance Drivers

- ✓ **Load Growth of 2.5%**
- ✓ **$500MM rate recovery assured or in progress**
- ✓ **Rising fuel costs of 11-13%**
- ✓ **Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales**
- ✓ **Decline in utility O&M**
- ✓ **Parent Company improvement (debt & interest expense reduction)**

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 PERFORMANCE

APPENDIX

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

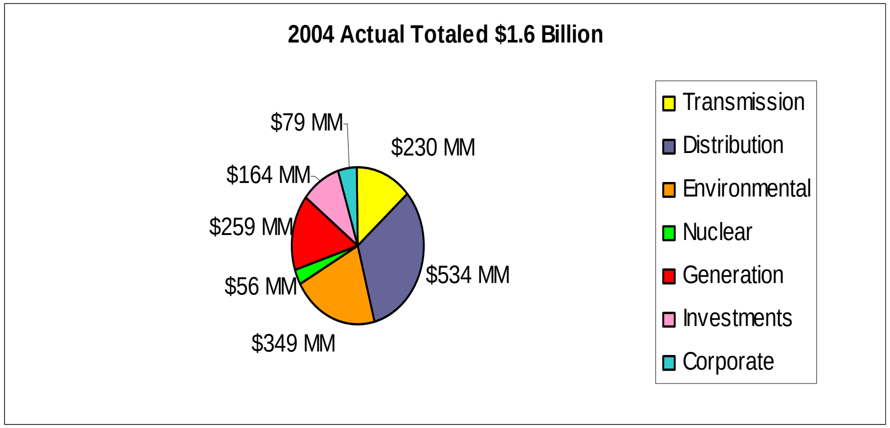
Company	Moody's Senior Unsecured	Moody's Senior Secured	Moody's Outlook	S&P Business Profile	S&P Senior Unsecured	S&P Senior Secured	S&P Outlook	Fitch Senior Unsecured	Fitch Senior Secured	Fitch Outlook
American Electric Power Company, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

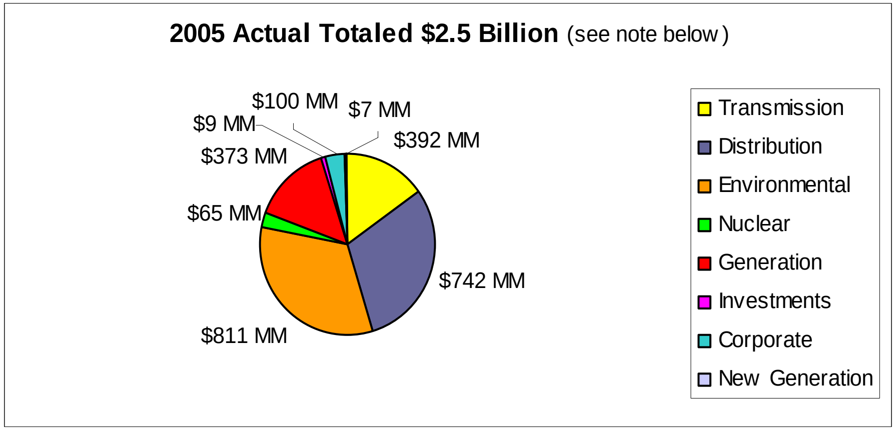
2005 Ratings Actions

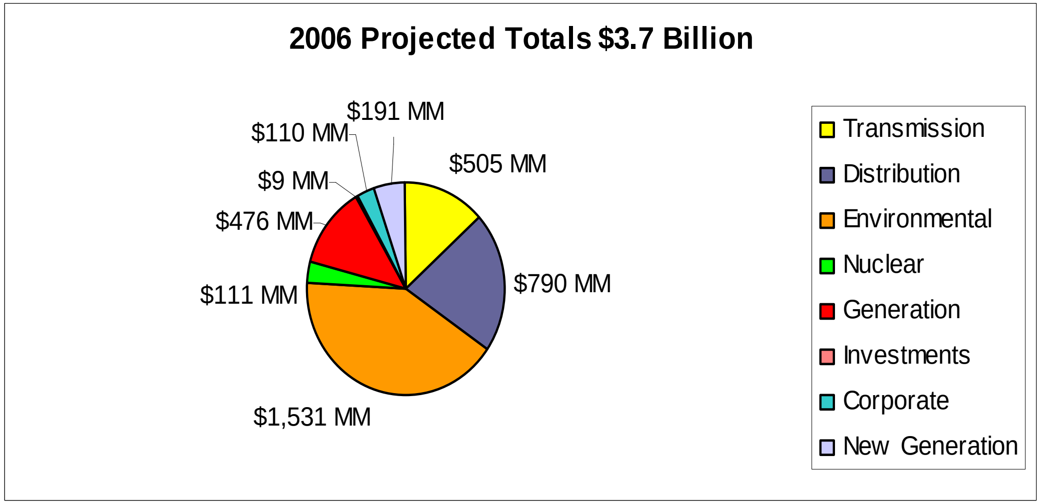
- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Capital Investment 2004-2006

Figures exclude AFUDC







Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

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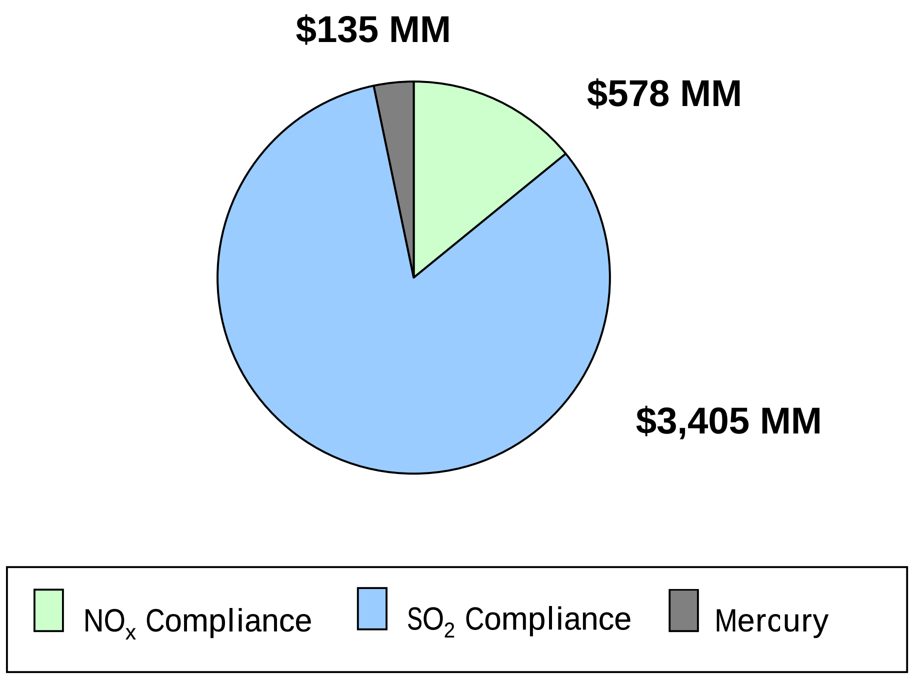
Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Figures Include AFUDC

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

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Capital Structure

Capital Structure	Actual 12/31/05		
$ in millions	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	12,226	-	12,226
Short-term Debt	10	-	10
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***
Adjustments			
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213
Securitization Bonds	(648)	-	(648)
Spent Nuclear Fuel Trust	(228)	-	(228)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***

Note: Totals may not foot due to rounding.

ADJUSTED DEBT/CAPITALIZATION: 58.00%

Debt Schedules

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Debt Schedules

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bond	5.010%	01/15/2008	$133,913,828
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.783%		$647,791,682

* TCC's First Mortgage Bond was defeased in May, 2004

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,817,600

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Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
First Mortgage Bond	6.800%	03/01/2006	$100,000,000
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Weighted Average or Total	4.728%		$2,079,783,600

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Debt Schedules

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Weighted Average or Total	4.971%		$1,220,083,600

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

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Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Notes Payable	6.810%	03/31/2008	$13,170,732
Notes Payable	6.270%	03/31/2009	$31,500,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Weighted Average or Total	4.548%		$1,821,666,932

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

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Debt Schedules

A Century of Firsts

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	04/23/2011	$26,682,219
Notes Payable	Floating	06/30/2008	$9,483,096
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/10/2008	$113,403,000
Weighted Average or Total	4.770%		$700,672,915

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2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

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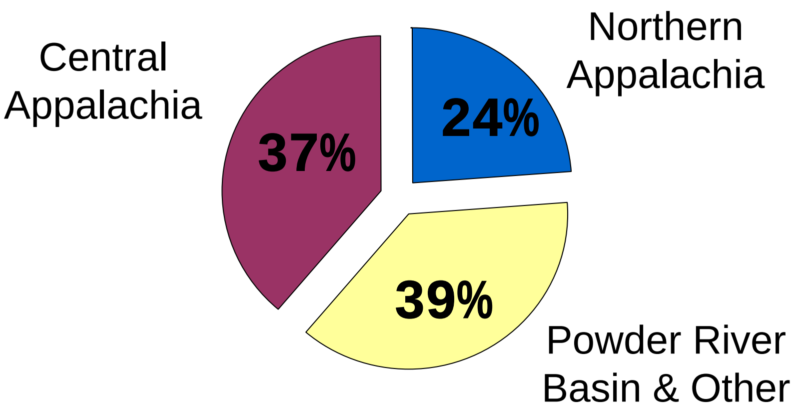
Coal Procurement

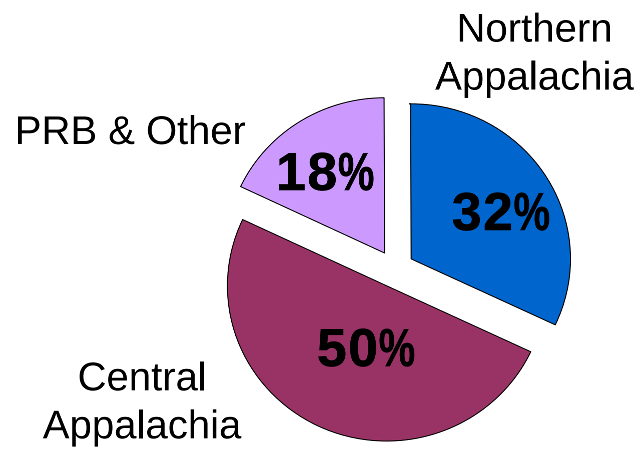
AEP SYSTEM



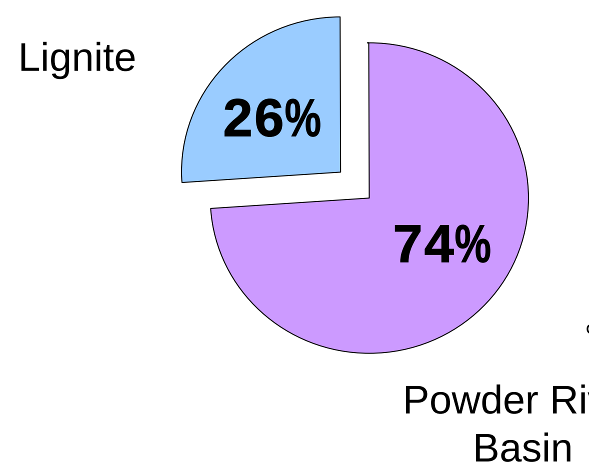
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Essentially >95% purchased for 2006
- Approximately 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM

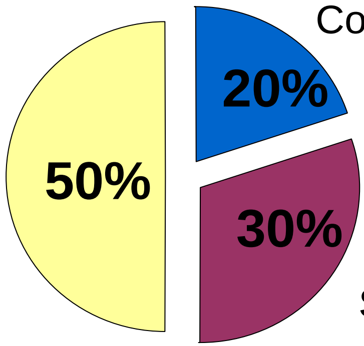


WESTERN SYSTEM



Fuel Recovery

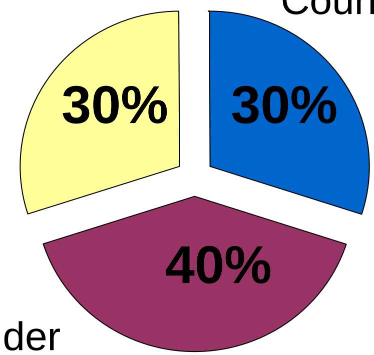
AEP SYSTEM



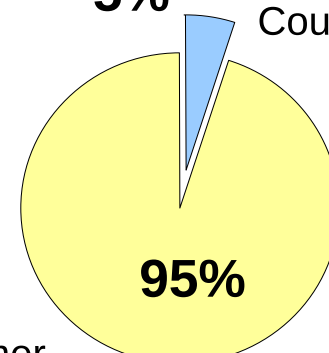
Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KGP, KPCo
  - AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

April 7, 2006 — Company Rebuttal Testimony

April 18-21, 2006 — Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order is issued

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

Total Customers:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**

Generating Capacity	**54 MW***

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

Principal industries served:
Oil and gas extraction
Food processing
Apparel
Metal refining
Chemical and petroleum refining
Plastics
Machinery equipment

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data (in thousands)

Revenue	$	793,000
% of AEP Retail		5%
Net Income (Loss)	$	(174,000)
Capital Expenditure	$	179,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	4,905,000
Net Plant Assets	$	2,021,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 278,400	$ 247,000	$ 222,100

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AEP Texas Central Company

AEP TEXAS CENTRAL
MAJOR CUSTOMERS

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
El Paso Energy Corp.
HEB Grocery Company LP
Ingleside Cogeneration Ltd Par
Citgo Petroleum Corporation
Wal-Mart Stores, Inc.
Formosa Utl Ven Ltd.

- **Top 10 customers = 67% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **53 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas Central Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

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Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: **R:3**

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

AEP Regulatory Status

• Operations for TCC and TNC have been functionally separated. Retail competition has been delayed by the PUCT in the Southwest Power Pool (SPP) area of Texas (including SWEPCO and TNC-SPP areas). • PUCT issued a final order in TCC stranded cost true-up case on 2-16-06, approving a true-up balance of $1.475 billion. We expect to appeal, seeking additional recovery consistent with Texas law. •TCC final fuel reconciliation (July 98-Dec 01). Final order received 6-3-05. TCC and other parties filed appeals in the District Court, which is currently in the briefing phase. Hearing on the Merits is set for 3-24-06. TCC has also filed at the U.S. District Court to ajoin the PUCT from enforcing their ruling regarding the allocation of the off-system sales margins; a briefing and procedural schedule has not been established. • New Transmission Cost Recovery Factors (TCRF) became effective 3-1-06. The impact of the TCRF update will be $1.5 million annual increase.

• TCC Rate Case. Final order received 8-15-05. TCC and other parties filed appeals in the District Court. No procedural schedule has been established. • TCC filed on 3-3-06 an application requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs. A procedural schedule has been established; hearings scheduled for May 2-4.

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Principal industries served:

Agriculture and the manufacturing or processing of Cotton seed products

Oil products

Precision and consumer metal products

Meat products

Gypsum products

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
Total	**183,000**

Generating Capacity	**377 MW**

(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,500**
Distribution Miles	**12,000**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data (in thousands)

Revenue	$	459,000
% of AEP Retail		1%
Net Income	$	33,000
Capital Expenditure	$	65,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,044,000
Net Plant Assets	$	807,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 72,500	$ 71,600	$ 89,400

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AEP Texas North Company

AEP TEXAS NORTH
MAJOR CUSTOMERS

Chevron Texaco Corporation
Kinder Morgan
Occidental Permian Ltd.
Crown Cork & Seal Co., Inc
Rhodia Inc.
Plains All American Pipeline (Equilon)
Georgia-Pacific Corporation
Ethicon, Inc.
Wal-Mart Stores, Inc.
Tyson Foods Inc. (Wright Brand)

- **Top 10 customers = 32% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas North Power Plants (excluding mothballed and decommissioned plants)

Name	Location	Megawatt Capacity	Fuel
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company **Texas North Company** **Southwestern Electric Power Company**

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: **R:3**

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

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• TCC Rate Case. Final order received 8-15-05. TCC and other parties filed appeals in the District Court. No procedural schedule has been established. • TCC filed on 3-3-06 an application requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs. A procedural schedule has been established; hearings scheduled for May 2-4.

Appalachian Power

President and Chief Operating Officer: Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 942,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

Principal industries served:
Coal mining
Primary metals
Chemicals
Textile mill products

Total Customers:

• **Residential**	**804,000**
• **Commercial**	**126,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**941,000**

Generating Capacity **6,389 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**79.4%**
• **Hydro/Pump:**	**12.5%**
• **Nat Gas**	**8.1%**

Transmission Miles	**6,700**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,947,075	1,360,131	3,307,206	1,995,658	1,427,502	3,423,160	2,345,511	1,821,484	4,166,995
% of Capitalization Per Balance Sheet	58.9%	41.1%	100.0%	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%
Adjusted Capitalization	1,947,075	1,360,131	3,307,206	2,004,550	1,418,610	3,423,160	2,354,403	1,812,593	4,166,996
% of Adjusted Capitalization	58.9%	41.1%	100.0%	58.6%	41.4%	100.0%	56.5%	43.5%	100.0%
FFO Interest Coverage			5.6			5.0			3.7
FFO Total Debt			27.2%			19.7%			12.4%

2005 Financial Data (in thousands)

Revenue	$	2,176,000
% of AEP Retail		17%
Net Income	$	131,000
Capital Expenditure	$	598,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	6,254,000
Net Plant Assets	$	4,652,000
Cash	$	1,741

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 942,800	$ 691,500	$ 751,700

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Appalachian Power

APCo Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	32,901,943	29,551,752	32,949,364	31,801,020
Coal Consumption (tons burned)	13,015,569	11,604,352	13,187,986	12,602,636

Operating Information

2005 retail electric sales in megawatt-hours	30,327,723
2005 firm wholesale sales in megawatt-hours	2,480,850
Average cost per kilowatt-hour (residential)	5.41 cents
2005 System Peak	6,978 (January 24)

Appalachian Power Plants

Name	Location	Megawatt Capacity	Fuel
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES

West Virginia	Customers
APCo	433,615
Allegheny	485,295

Virginia	Customers
APCo	496,994
Dominion Virginia	2,131,281
Allegheny	92,878
Kentucky Utilities	29,801
Conectiv	21,529

Tennessee	Customers
APCo	45,803

TYPICAL BILL COMPARISON*

West Virginia	
APCo	55.28
AEP – Wheeling	57.91
Allegheny	70.09

Virginia	
APCo	57.80
ODPCo	58.07
Dominion Virginia	87.18
Conectiv	103.13

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

APPALACHIAN POWER COMPANY MAJOR CUSTOMERS

Massey Energy Company
CONSOL Energy
Roanoke Electric Steel Corporation
Georgia-Pacific Corporation
Elkem Metals Company
Greif Brothers Corporation
The Dow Chemical Co., Inc.
Arch Coal, Inc.
Dan River Inc.
Peabody Group

- **Top 10 Customers = 23% of industrial sales**
- **Metropolitan areas account for 37% of ultimate sales**
- **85 persons per square mile (U.S. = 95)**

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Regulatory Information

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Wheeling Power Co.
Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R**: 1 **D:** 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office.

R. Michael Shaw, Commissioner (Rep.), since mid 2003, term expires June 2007. Attorney, former state legislator.

Jon W. McKinney, Chairman (Dem.), since 2005, term expires June, 2011. Formerly served as plant manager of Flexsys' Nitro, W Va operations, chairman of Chemical Industry Committee for W Va, board member of W Va Chamber of Commerce, W Va Manufacturer's Association, Chemical Alliance Zone, W Va Roundtable & Thomas Memorial Hospital.

AEP Regulatory Status

• Base rates not frozen • Annual ENEC proceedings are currently suspended. • On 8-26-05 AP & WP filed with the WVPSC for a $183 million revenue increase to be phased in over a four-year period beginning in mid 2006. The filing consists of a general rate case, reinstatement of the ENEC, implementation of scheduled incremental rate increases for major clean air & transmission investments, and the implementation of a system reliability tracker mechanism. In Jan 06, WVPSC approved a change in the procedural schedule setting hearings to begin 4-18-06, deferral accounting for ENEC costs to begin 7-1-06 and new rates to be effective 7-28-06. The Company is in the process of evaluating intervenor and WVPSC Staff testimony filed 3-8-06. Rebuttal and cross-rebuttal testimony is due 4-7-06..

Regulatory Information

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 1

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires February 2010. Current Chairman. Attorney, counsel to the Speaker of the House.

Judith Williams Jagdmann, (Rep.), since 2006, current term expires 2012. Law degree from T.C. Williams School of Law. Prior to being elected to the Commission, she served as 43rd Attorney General for the Commonwealth of Virginia. Prior to work in Attorney in the Office of Attorney General, served 13 years as counsel to the SCC.

AEP Regulatory Status

• Capped rates for default customers frozen through end of 2010 • Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms • Active annual fuel clause. • On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental actual and projected costs for environmental compliance and T&D System reliability (E&R). In an order dated 10-14-05, the Commission denied the Company's request for interim rate treatment and ruled that the Company may only seek to include actually incurred costs (i.e., no projected future costs) in the E & R cost recovery filing. The Company filed supplemental direct testimony on 11-14-05, which included updated incremental costs through 9-30-05 of $21.1 million. Hearings concluded 3-01-06. Briefs are due in early April. • On 3-1-06, AP gave notice to the Commission of its plan to file a general rate case no sooner than 5-1-06.

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSP Co covers a service territory of 3,701 miles and at December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

Total Customers:

• **Residential**	**636,000**
• **Commercial**	**71,000**
• **Industrial**	**3,000**
• **Other**	**300**
Total	**710,300**

Generating Cap	**3,270 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **72.5%**
- **Natural Gas** **26.1%**
- **Hydro:** **1.5%**

Transmission Miles	**2,200**
Distribution Miles	**17,200**

Principal industries served:

Food processing
Chemicals
Primary metals
Electronic machinery
Paper products

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Capitalization Per Balance Sheet	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
Adjusted Capitalization	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Adjusted Capitalization	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
FFO Interest Coverage			7.7			6.2			5.8
FFO Total Debt			37.9%			28.7%			24.3%

2005 Financial Data (in thousands)

Revenue	$ 1,542,000
% of AEP Retail	14%
Net Income	$ 134,000
Capital Expenditure	$ 165,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 3,433,000
Net Plant Assets	$ 2,526,000
Cash	$ 940

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$342,700	$473,700	$553,400

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	15,243,711	14,049,095	14,038,045	14,443,617
Coal Consumption (tons burned)	6,526,167	6,121,275	6,048,060	6,231,834

Operating Information

2005 retail sales in megawatt-hours	18,277,372
2005 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	7.56 cents (CSP)
2005 System Peak	4,105 megawatts (CSP-July 25)

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,260	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	627	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	48	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

Columbus Southern Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison = 162,117
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

COLUMBUS SOUTHERN POWER MAJOR CUSTOMERS

The Ohio State University
State of Ohio
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
The Kroger Company
Nationwide Insurance Enterprise
Ohio University
Griffin Wheel Company
OhioHealth
Limited Brands

- **Top 10 customers = 31% of industrial sales**
- **Metropolitan areas account for 84% of ultimate sales**
- **244 persons per square mile (U.S. = 95)**

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

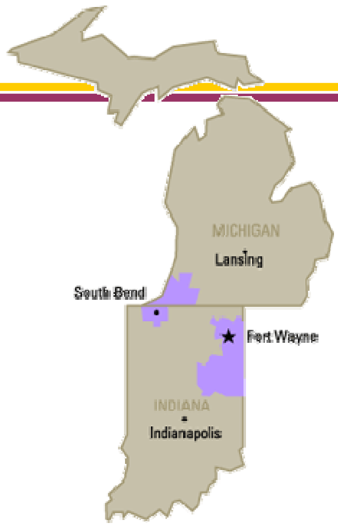
Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

AEP Regulatory Status

• Pursuant to RSP Plan approved by PUCO 1-26-05: • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008. • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs. • CSP "G" rates to increase 3% per year (2006-2008). • OP "G" rates to increase 7% per year (2006-2008). • Transmission rates can upon filing reflect change in RTO costs.
• No active fuel clause • Application for IGCC plant recovery filed on 3-18-05. Hearings and briefs are done. Awaiting a PUCO order.
• On 2-3-06, CSP and OP filed for a change to retail tariffs to reflect the increased FERC approved OATT. • On 2-6-06, the PUCO directed Staff to conduct an investigation of reliability related matters of CSP and OP. Staff's report is to be filed 4-17-06.

Indiana Michigan Power



President and Chief Operating Officer:
Marsha Ryan

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 581,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2005, I&M had 2,633 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

Total Customers:	
• **Residential**	**507,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**580,000**
Generating Capacity	**5,768 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.1%**
• **Hydro:**	**0.4%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Principal industries served:
Primary metals
Transportation equipment
Electrical and electronic machinery
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

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Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,438,181	1,149,593	2,587,774	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%
Adjusted Capitalization	1,823,681	1,149,593	2,973,274	1,761,432	1,095,540	2,856,972	1,921,435	1,224,134	3,145,569
% of Adjusted Capitalization	61.3%	38.7%	100.0%	61.7%	38.3%	100.0%	61.1%	38.9%	100.0%
FFO Interest Coverage			4.0			4.1			4.7
FFO Total Debt			22.70%			23.20%			22.80%

2005 Financial Data (in thousands)

Revenue	$	1,893,000
% of AEP Retail		13%
Net Income	$	146,000
Capital Expenditure	$	299,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	5,238,000
Net Plant Assets	$	3,116,000
Cash	$	854

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 311,200	$ 278,700	$ 262,000

Indiana Michigan Power

I&M Generation Production Statistics – 2003 – 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Avg.**
MWh Produced	28,075,125	21,258,001	31,535,226	26,956,117
Coal Consumption (tons burned)	7,189,655	7,186,066	7,011,370	7,129,030

Operating Information

2005 retail electric sales in megawatt-hours	19,248,200
2005 firm wholesale sales in megawatt-hours	2,169,221
Average cost per kilowatt-hour (residential)	6.61 cents
2005 System Peak	4,193 MW (August 3)

Indiana Michigan Power Plants

Name	Location	Megawatt Capacity	Fuel
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES

Indiana	Customers
I&M	452,050
IP & L	458,796
NIPSCO	442,554
Cinergy (PSI)	747,696
SIGECO	135,449

Michigan	Customers
I&M	124,583
CMS (Consumers)	1,760,882
DTE (Detroit Edison)	2,144,655

TYPICAL BILL COMPARISON*

Indiana	
I & M	68.94
IP & L	70.50
Cinergy (PSI)	79.53
SIGECo	88.67

Michigan	
I & M	61.43
Consumers Energy	82.97
Detroit Edison	93.80

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

INDIANA MICHIGAN POWER MAJOR CUSTOMERS

Steel Dynamics Inc.
Mittal Steel Company
Air Products & Chemicals, Inc.
Boc Gases
Saint Gobain Corporation USA
Ball State University
New Energy Corp
Dock Foundry
Michelin North America, Inc.
Guide Indiana

- **Top 10 Customers = 39% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 5	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup: R**:3 **D:** 2

<u>Qualifications for Commissioners</u>

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four year, staggered terms, full-time positions. Not more than three of the members of the IURC shall be members of the same political party. At lease one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

<u>Commissioners</u>

David L. Hardy, Chairman (Rep.), since September 2005, current term will expire April 2006. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include: negotiation, contracts, litigation, finance and administration. He has 35 years regulatory experience at the state and federal levels.

Larry S. Landis, Commissioner (Rep.), since December 2002, current term ends January 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.

David W. Hadley, Commissioner (Dem.), since 2000; current term ends January 2006. Executive officer for Indiana AFL-CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.

Greg Server, Commissioner (Rep.), since September 2005, current term ends in April 2009. Former state senator since 1981 and before that served in the Indiana House or Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.

David E. Ziegner, Commissioner (Dem.), since 1990, current term ends April 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.

AEP Regulatory Status

• Base rates are frozen and fuel cost recovery factors are capped at increasing rates through 6-30-07. • On 12/31/05 the company filed a petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in base rates, but for book depreciation rate decreases primarily as a result of longer depreciable property lives. Based on the depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 million on an after-tax Indiana jurisdictional basis.• Staff and intervenor testimony is due 3-30-06. Hearings scheduled for [illegible] 04-06.

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Regulatory Information

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R**:1 **D:** 2

Qualifications for Commissioners

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six-year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

Commissioners

J. Peter Lark, Chair, (Dem) since July 2003: current term expires July 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney.

Laura Chappelle, Commissioner, (Rep.) since 2001: current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney.

Monica Martinez, Commissioner, (Dem) since 2005, current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues.

AEP Regulatory Status

Customer choice began 1/02. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active annual fuel clause.

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers:	
• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,000**
• **Other**	**400**
Total	**175,400**
Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,200**
Distribution Miles	**10,000**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Capitalization Per Balance Sheet	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
Adjusted Capitalization	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Adjusted Capitalization	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
FFO Interest Coverage			4.7			3.9			3.4
FFO Total Debt			20.4%			16.6%			14.0%

2005 Financial Data (in thousands)

Revenue	$ 531,000
% of AEP Retail	4%
Net Income	$ 21,000
Capital Expenditure	$ 57,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 1,320,000
Net Plant Assets	$ 989,000
Cash	$ 526

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$100,000	$127,100	$144,000

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Kentucky Power

Kentucky Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	6,170,931	6,550,509	7,345,624	6,689,021
Coal Consumption (tons burned)	2,513,524	2,607,559	2,926,253	2,682,445

Operating Information

2005 retail electric sales in megawatt-hours	7,309,016
2005 firm wholesale sales in megawatt-hours	97,845
2005 average cost per kilowatt-hour (residential)	5.67 cents
2005 System Peak	1,685 MW (Jan 24)

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	Customers
KPCo	174,631
Kentucky Utilities	485,627
LG & E	389,196

KENTUCKY POWER
MAJOR CUSTOMERS

Marathon Ashland Petroleum
AK Steel Holding Corporation
James River Coal Co.
Massey Energy Company
TECO Energy, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC.
Alliance Coal, LLC
Consol Energy
Weyerhaeuser Company

TYPICAL BILL COMPARISON*

Kentucky	
KPCo	59.78
Kentucky Utilities	62.40
LG&E	66.31
CIN	68.54

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 61% of industrial sales**
- **Metropolitan areas account for 42% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Regulatory Information

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup:** R: 3
Qualifications for Commissioners Three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.			
Commissioners **Mark Goss (Chair) (Rep.),** since 2004; current term expires June 2007. Attorney in private practice. **Teresa Hill (V. Chair.) (Rep.),** since 2005; current term expires June 30, 2009. Served on the Governor's Executive Staff. She is an attorney. **Greg Coker (Rep.),** since 2004; current term expires June 30, 2008. Formally V.P. External Affairs at ALLTEL; public policy positions at Bell South.			

AEP Regulatory Status

• Fuel clause, adjusted monthly • Environmental surcharge costs are adjusted monthly for approved environmental compliance plan • On 9-26-05 the Company filed a base rate case requesting a $64.8 million annual increase. A settlement agreement was approved by the Commission on 3/14/06; terms include a $41 million increase effective 3-30-06.

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2005, OPCo had 2,220 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Principal industries served:

Primary metals
Rubber and plastic products
Stone, clay, glass and concrete products
Petroleum refining
Chemicals

Total Customers:

• **Residential**	**610,000**
• **Commercial**	**90,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**709,000**

Generating Capacity	**8,952 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**94.6%**
• **Hydro:**	**5.4%**

Transmission Miles	**6,500**
Distribution Miles	**26,000**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,082,195	1,487,920	3,570,115	2,053,641	1,490,479	3,544,120	2,280,107	1,784,586	4,064,693
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	57.9%	42.1%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,082,195	1,487,920	3,570,115	2,061,962	1,482,159	3,544,121	2,288,427	1,776,267	4,064,694
% of Adjusted Capitalization	58.3%	41.7%	100.0%	58.2%	41.8%	100.0%	56.3%	43.7%	100.0%
FFO Interest Coverage			6.5			4.9			6.2
FFO Total Debt			28.3%			22.6%			23.8%

2005 Financial Data (in thousands)

Revenue	$	2,635,000
% of AEP Retail		17%
Net Income	$	245,000
Capital Expenditure	$	711,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	6,331,000
Net Plant Assets	$	4,785,000
Cash	$	1,240

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 1,070,400	$ 954,500	$ 581,600

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Ohio Power

Ohio Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	53,099,905	52,156,749	52,080,585	52,445,746
Coal Consumption (tons burned)	20,936,936	20,534,361	20,382,116	20,617,804

Operating Information

2004 retail sales in megawatt-hours	28,929,494
2004 firm wholesale sales in megawatt-hours	2,225,194
Average cost per kilowatt-hour (residential)	6.56 cents (OPCo)
2004 System Peak	5,638 megawatts (OPCo-Aug 12)

Ohio Power Plants

Name	Location	Megawatt Capacity	Fuel
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	48	Hydro

Ohio Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
. OPCo = 706,840

** First Energy - Toledo Edison = 162,117
= CEI = 251,965
. Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

OHIO POWER MAJOR CUSTOMERS

Century Aluminum Company
The Timken Company
Wheeling Pittsburgh – WHX HQ
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Globe Metallurgical, Inc
Marathon Petroleum Company LLC
Duke Energy Corp
Linde Gas
Owens Corning Fiberglas Corp.

OPCo:

- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 52% of ultimate sales**
- **135 persons per square mile (U.S. = 95)**

KPSC Case No. 2011-00401
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Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.

Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

AEP Regulatory Status

• Pursuant to RSP Plan approved by PUCO 1-26-05: • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.• Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs. • CSP "G" rates to increase 3% per year (2006-2008). • OP "G" rates to increase 7% per year (2006-2008). • Transmission rates can upon filing reflect change in RTO costs. • No active fuel clause • Application for IGCC plant recovery filed on 3-18-05. Hearings and briefs are done. Awaiting a PUCO order. • On 2-3-06, CSP and OP filed for a change to retail tariffs to reflect the increased FERC approved OATT. • On 2-6-06, the PUCO directed Staff to conduct an investigation of reliability related matters of CSP and OP. Staff's report is to be filed 4-17-06.

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 514,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2005, PSO had 1,176 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

Total Customers:

• **Residential**	**442,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**7,000**
Total	**514,000**

Generating Capacity	**4,153 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**25%**
• **Natural Gas:**	**75%**
Transmission Miles	**3,600**
Distribution Miles	**21,000**

Principal industries served:

Natural gas and oil production
Oil refining
Steel processing
Aircraft maintenance
Paper manufacturing and timber products
Glass
Chemicals
Cement
Plastics
Aerospace manufacturing
Telecommunications
Rubber goods.

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	607,162	488,275	1,095,437	601,095	534,517	1,135,612	646,954	553,858	1,200,812
% of Capitalization Per Balance Sheet	55.4%	44.6%	100.0%	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%
Adjusted Capitalization	607,162	488,275	1,095,437	603,726	531,886	1,135,612	649,585	551,228	1,200,813
% of Adjusted Capitalization	55.4%	44.6%	100.0%	53.2%	46.8%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			3.8			5.5			2.8
FFO Total Debt			20.4%			28.2%			9.5%

2005 Financial Data (in thousands)

Revenue	$	1,304,000
% of AEP Retail		14%
Net Income	$	58,000
Capital Expenditure	$	134,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	2,355,000
Net Plant Assets	$	1,819,000
Cash	$	1,520

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 278,700	$ 342,800	$ 408,700

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	14,845,846	12,512,486	15,375,848	14,244,727
Coal Consumption (tons burned)	4,678,950	4,093,436	4,353,364	4,375,250

Operating Information

2005 retail electric sales in megawatt-hours	17,782,561
2005 firm wholesale sales in megawatt-hours	45,172
Average cost per kilowatt-hour (residential)	7.55 cents
2005 System Peak	4,043 MW (July 22)

Oklahoma Power Plants

Name	Location	Megawatt Capacity	Fuel
Tulsa	Tulsa, Oklahoma	338	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	Customers
PSO	507,214
OG&E	668,766

PUBLIC SERVICE COMPANY OF OKLAHOMA MAJOR CUSTOMERS

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Transok Inc
AMR Corporation
Sunoco Inc.
Terra Nitrogen Limited Partner
Republic Paperboard
Wal-Mart Stores, Inc.

TYPICAL BILL COMPARISON*

Oklahoma	
OG&E	73.33
PSO	74.20
SPSCo	82.52
Empire District	85.25

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **46 persons per square mile (U.S. = 95)**

Regulatory Information

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: 3	**Appointed/Elected:** Elected	**Term**: 6 years	**Political Makeup:** R: 3

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

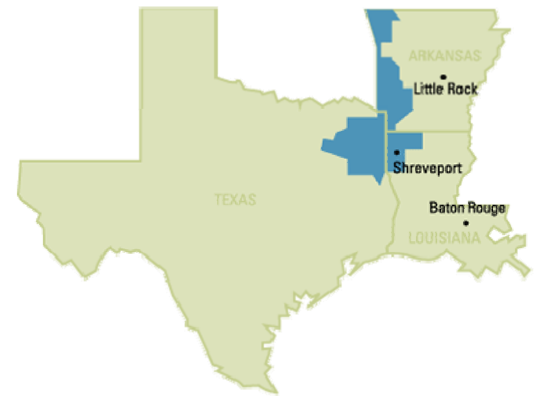
Denise A. Bode, Vice-Chairman (Rep.), since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

Bob Anthony, Commissioner (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

AEP Regulatory Status

• 2001 Fuel review case: Hearings held 2-7 and 2-8-06. Scope expanded to cover 2002-2004 margin allocation issue.Intervenors have submitted testimony, which substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error. Awaiting Commission order. • 2003 Fuel review case: Scope has been expanded to include a prudence review. No procedural schedule has been set. Discovery phase has been initiated. • 2004 Fuel review case: Staff has now filed for a review of PSO's 2004 fuel costs. Hearings scheduled to begin 8-10-06. Discovery phase has been initiated. • Applications seeking a used and useful determination for up to 500 mW of peaking capacity with a commercial operation date of 2008 and up to 600 mW of base load generation with a commercial operation date of 2011 were filed with the OCC on 12-21-05 and 2-1-06, respectively. Procedural schedules have not yet been established.

Southwestern Electric Power



President and Chief
Operating Officer: Nick Akins

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 450,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2005, SWEPCo had 1,498 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

Principal industries served:
- Natural gas and oil production
- Petroleum refining
- Manufacturing of pulp and paper
- Chemicals
- Food processing
- Metal refining.

Total Customers:

• **Residential**	**381,000**
• **Commercial**	**61,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**450,000**

Generating Capacity	**4,487 MW**
Generating Capacity by Fuel Mix:	
• **Coal/Lignite:**	**60%**
• **Natural Gas:**	**40%**
Transmission Miles	**3,500**
Distribution Miles	**19,300**

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	890,675	701,360	1,592,035	806,494	773,318	1,579,812	774,245	787,077	1,561,322
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	51.0%	49.0%	100.0%	49.6%	50.4%	100.0%
Adjusted Capitalization	890,675	701,360	1,592,035	808,844	770,968	1,579,812	776,595	784,727	1,561,322
% of Adjusted Capitalization	55.9%	44.1%	100.0%	51.2%	48.8%	100.0%	49.7%	50.3%	100.0%
FFO Interest Coverage			4.1			5.7			3.8
FFO Total Debt			22.9%			31.4%			18.1%

2005 Financial Data (in thousands)

Revenue	$	1,405,000
% of AEP Retail		12%
Net Income	$	74,000
Capital Expenditure	$	158,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	2,797,000
Net Plant Assets	$	2,230,000
Cash	$	3,049

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 287,900	$ 366,700	$ 458,400

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	20,539,365	20,071,578	20,167,754	20,259,566
Coal Consumption (tons burned)	12,536,179	13,032,475	12,420,979	12,663,211

Operating Information

2005 retail electric sales in megawatt-hours	17,069,455
2005 firm wholesale sales in megawatt-hours	5,554,340
Average cost per kilowatt-hour (residential)	6.92 cents
2005 System peak	4725 MW (Aug 23)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES

Arkansas	Customers
SWEPCO	107,220
Entergy AR	667,714

Louisiana	Customers
SWEPCO	169,079
CLECO	261,601

Texas	Customers
SWEPCO	279,729

TYPICAL BILL COMPARISON*

Arkansas	
SWEPCO	66.15
OG&E	72.11
Empire District	74.71
ETR	88.92

Louisiana	
SWEPCO	68.83
CLECO	90.13
Entergy Gulf St	92.69
Entergy NO	96.65
Entergy LA	102.08

Texas	
SWEPCO	63.95
SPSCo	83.19
ETR	93.43
EP	106.64
TXU	118.84

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

SOUTHWESTERN ELECTRIC POWER MAJOR CUSTOMERS

Lone Star Steel Company
Tyson Foods Inc
Domtar, Inc
International Paper Company
Pilgrim Pride Corporation
Calumet Lubricants
General Motors Corporation
Wal-Mart Stores, Inc.
Cooper Tire & Rubber Company
Superior Industries Int

- **Top 10 customers = 38% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **77 persons per square mile (U.S. = 95)**

Regulatory Information

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup:** R: 3

Qualifications for Commissioners

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

Commissioners

Sandra Hochstetter, Chairman (Rep.), since 1999; current term ends Jan 2011. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.

Randy Bynum, Commissioner (Rep.), since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.

Daryl E. Bassett, Commissioner (Rep.), since 2004; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

AEP Regulatory Status

Arkansas has an active fuel pass-through clause, adjusted annually. Base rates not frozen. Arkansas passed then repealed deregulation legislation.

Regulatory Information

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Elected	**Term**: 6 years	**Political Makeup**: **R**: 2 **D**: 3

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

James M. Field, (Rep.), since 1996; current term ends December 2006. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

AEP Regulatory Status

• Base rates not frozen • Currently under a merger required financial review • Fuel clause, adjusted monthly

Regulatory Information

Public Utility Commission of Texas

AEP Regulated Electric Utilities

Texas Central Company **Texas North Company** **Southwestern Electric Power Company**

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: R: 3

<u>Qualifications for Commissioners</u>
To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

<u>Commissioners</u>

Barry T. Smitherman, Commissioner, (Rep.), since April 2004, current term expires August 2007. Attorney; Assistant DA; Public Finance Investment Banker.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUC as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

AEP Regulatory Status

Retail competition has been delayed by the PUCT in the SPP area of Texas until at least 2007.Texas SWEPCO has an active fuel pass-through clause. On 1-12-06, PUCT approved a Settlement in the SWEPCO Fuel Factor/Surcharge filing. The stipulated fuel factors will increase SWEPCO's annual Texas retail fuel-related revenues by approximately $46 million. The interim surcharge will collect the under-recovery amount of $44 million (including interest).

American Electric Power, Inc.
Operating Company Detail

Boston Fixed Income Road Show

Hosted by Merrill Lynch

September 13, 2007

AEP®

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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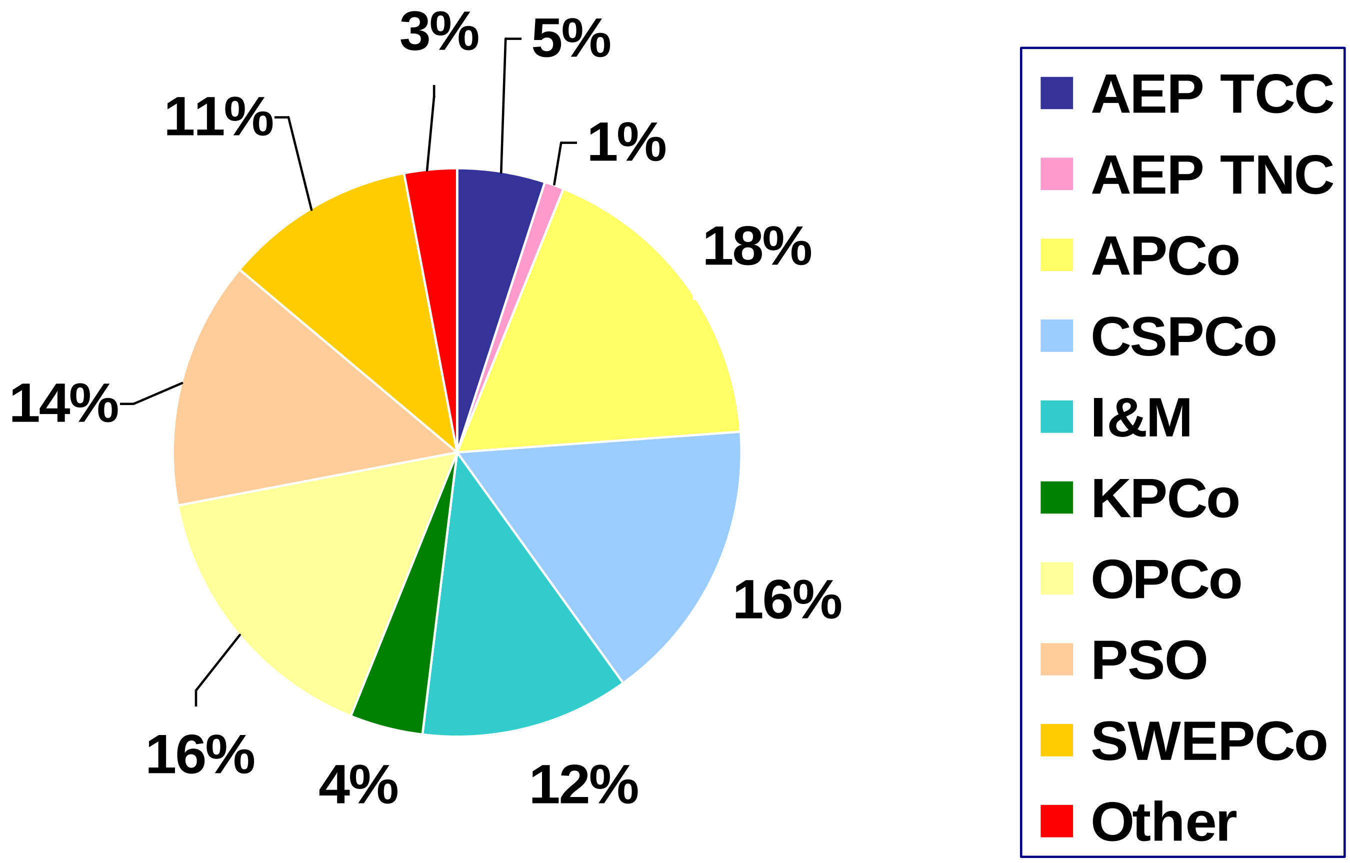
2006 Retail Revenue

Retail Revenue Composition by Operating Company



Earned ROEs

Company	6/30/07 Earned ROE
AEP Texas Central Company	6.22%
AEP Texas North Company	8.63%
Appalachian Power Company	4.56%
Columbus Southern Power Company	21.22%
Indiana Michigan Power Company	7.18%
Kentucky Power Company	9.89%
Ohio Power Company	12.79%
Public Service Company of Oklahoma	2.25%
Southwestern Electric Power Company	6.77%

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ROEs Calculated on a GAAP Basis

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Semi-annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate. Effective 7/1/07, legislation was enacted to allow company retention of at least 25% of OSS margins. We have a filing pending before the VA SCC to initiate this sharing.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

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2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Issuances (a)	Target Adjusted Equity Ratio
AEG	$343	$220	40%
APCo	$664	$600-$700	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$0	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

*Approx. $1B of issuances remaining in 2007 assuming appropriate market conditions

Maintain Financial Strength Of Utility Companies By Retaining And/Or Infusing Equity Capital Depending On Their Credit Ratios And Free Cash Flow

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Managing Subsidiary Cash Flows

- We monitor:
  - AEP consolidated cash requirements
  - Utility expected rates of return and potential regulatory lags
  - Amount of capital spending and internal cash needs
  - Free cash flow – cash available after construction
  - Credit ratios

- Dividends and equity:
  - We pay dividends based on free cash flow and credit metrics
  - When additional equity/cash is needed at the subsidiary level, the first option is dividend reductions, then capital infusions
  - We are currently evaluating hybrid securities as a source of equity

Our Objective Is To Maintain The Financial Strength And Capital Markets Access Of The AEP Operating Companies

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

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We Are Committed To Maintaining Our Current Credit Ratings

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

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Long-Term Debt Maturity Profile

($ in millions)

Year		2007		2008		2009
AEP, Inc.	$	345	$	-	$	-
Appalachian Power	$	200	$	200	$	150
Columbus Southern Power	$	-	$	112	$	-
Kentucky Power	$	323	$	30	$	-
Indiana Michigan	$	-	$	50	$	45
Ohio Power Company	$	-	$	42	$	100
Public Service of Oklahoma	$	-	$	-	$	50
Southwestern Electric Power	$	90	$	116	$	-
Texas Central Company *	$	-	$	68	$	-
Total	$	958	$	618	$	345

Note: Maturities remaining as of June 30, 2007

* - 2008 maturities include $19 million in first mortgage bonds that were defeased in May 2004

Debt Schedules – as of 6/30/07

American Electric Power, Inc.

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.102%		$1,077,775,000

American Electric Power Service Corp.

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

Debt Schedules – as of 6/30/07

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond *	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Preferred Stock	4.000%	N/A	$4,191,200
Preferred Stock	4.200%	N/A	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.898%		$695,017,300
Securitization Bond	5.010%	1/15/2008 **	$49,523,804
Securitization Bond	5.560%	1/15/2010 **	$107,094,258
Securitization Bond	5.960%	7/15/2013 **	$214,926,738
Securitization Bond	6.250%	1/15/2016 **	$191,856,858
Securitization Bond	4.980%	1/1/2010 **	$217,000,000
Securitization Bond	4.980%	7/1/2013 **	$341,000,000
Securitization Bond	5.090%	7/1/2015 **	$250,000,000
Securitization Bond	5.170%	1/1/2018 **	$437,000,000
Securitization Bond	5.306%	7/1/2020 **	$494,700,000
Weighted Average or Total	5.323%		$2,303,101,658

* TCC's First Mortgage Bond was defeased in May 2004

** represents scheduled final payment date, no ultimate maturity date

AEP Texas North

Series	Interest	Maturity	Amount
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Preferred Stock	4.400%	N/A	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.420%		$315,968,600

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Debt Schedules – as of 6/30/07

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	05/01/2037	$75,000,000
Preferred Stock	4.500%	N/A	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.294%		$2,480,038,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	12/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Debt Schedules – as of 6/30/07

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	N/A	$5,533,500
Preferred Stock	4.120%	N/A	$1,105,500
Preferred Stock	4.560%	N/A	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.811%		$1,320,080,200

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Debt Schedules – as of 6/30/07

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Notes Payable	6.810%	03/31/2008	$4,390,244
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	N/A	$1,459,500
Preferred Stock	4.200%	N/A	$2,282,400
Preferred Stock	4.400%	N/A	$3,148,200
Preferred Stock	4.500%	N/A	$9,737,300

Ohio Power Company (continued)

Series	Interest	Maturity	Amount
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	Floating	04/05/2010	$400,000,000
Weighted Average or Total	5.841%		$2,680,372,644

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Debt Schedules – as of 6/30/07

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Preferred Stock	4.000%	N/A	$4,454,800
Preferred Stock	4.240%	N/A	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Weighted Average or Total	5.489%		$689,281,700

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$16,888,366
Notes Payable	Floating	06/30/2008	$3,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	N/A	$3,767,300
Preferred Stock	4.650%	N/A	$190,700
Preferred Stock	4.280%	N/A	$738,600
Senior Notes	5.380%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.541%		$924,322,966

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**630,000**
• **Commercial**	**102,000**
• **Industrial**	**5,000**
• **Other**	**1,000**
Total	**738,000**
Transmission Miles	**5,000**
Distribution Miles	**28,000**

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AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data (in thousands)

Revenue	$ 665,000
% of AEP Retail	5%
Net Income (Loss)	$ 42,000
Capital Expenditure	$ 270,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 5,324,000
Net Plant Assets	$ 2,240,000

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 241,000	$ 247,000	$ 222,100

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:

Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

PRINCIPAL INDUSTRIES SERVED:

Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**6,000**
Total	**189,000**

Generating Capacity **377 MW**

Oklaunion Plant – Vernon, TX
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**4,500**
Distribution Miles	**14,000**

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AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data (in thousands)

Revenue	$ 329,000
% of AEP Retail	1%
Net Income	$ 15,000
Capital Expenditure	$ 70,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 968,000
Net Plant Assets	$ 842,000
Cash	$ 84

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$143,000	$188,000	$149,000

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Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers:

• **Residential**	**810,000**
• **Commercial**	**128,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**949,000**

Generating Capacity	**6,282 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **80.8%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas** **8.4%**

Transmission Miles	**6,750**
Distribution Miles	**49,000**

AEP®

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Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 7,016,000
Net Plant Assets	$ 5,524,000
Cash	$ 2,318

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 664,000	$ 531,000	$ 461,000

AEP®

Appalachian Power

APCo Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	5	Hydro
Byllesby #1, 2, 3, 4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	528	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	28	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lyn #1, 2	Glen Lyn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	9	Hydro
Niagara #1, 2	Roanoke, Virginia	1	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2 *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	12	Hydro
Marmet #1, 2, 3	Marmet, West Virginia	11	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES *

West Virginia	Customers
APCo	**434,504**
Allegheny	492,354

Virginia	Customers
APCo	**503,525**
Dominion Virginia	2,171,253
Allegheny	95,665
Kentucky Utilities	29,900
Conectiv	21,930

Tennessee	Customers
APCo	**45,960**

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- **Top 10 Customers = 49% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

TYPICAL BILL COMPARISON **

West Virginia	
APCo	**58.87**
AEP – Wheeling	**58.87**
Allegheny	70.46

Virginia	
ODPCo	64.69
APCo	**66.72 *****
Dominion Virginia	85.28
Conectiv	126.82

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

*** APCo Virginia rate adjusted for effect of rate case order received in May 2007.

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
CONSOL Energy (VA)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Dickenson-Russell Coal Co, LLC (VA)
Steel of WV, Inc. (WV)
Toyota Motor Manufacturing (WV)

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers:

• **Residential**	**662,000**
• **Commercial**	**76,000**
• **Industrial**	**4,000**
Total	**742,000**

Generating Cap	**3,708 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **63.2%**
- **Natural Gas** **36.1%**
- **Hydro:** **0.7%**

Transmission Miles	**2,400**
Distribution Miles	**17,200**

AEP®

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data (in thousands)

Revenue	$	1,807,000
% of AEP Retail		16%
Net Income	$	185,000
Capital Expenditure	$	307,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	3,521,000
Net Plant Assets	$	2,725,000
Cash	$	1,319

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 439,000	$ 354,000	$ 233,000

AEP®

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Columbus Southern Power

Columbus Southern Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,254	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	26	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	857	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	480	Nat Gas

Columbus Southern Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

Indiana Michigan Power

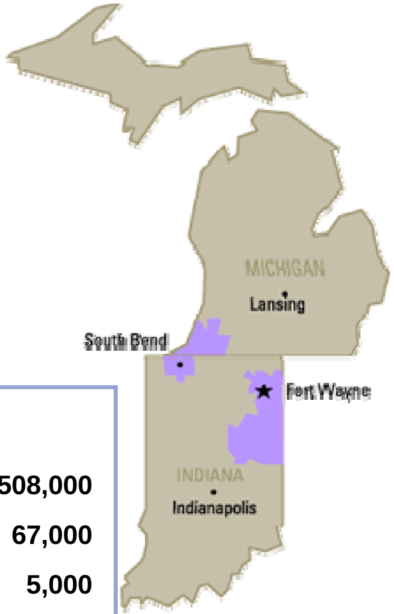
President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products



Total Customers:

• **Residential**	**508,000**
• **Commercial**	**67,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**582,000**

Generating Capacity	**5,753 MW**
(includes AEG Rockport)	

Generating Capacity by Fuel Mix:

• **Coal:**	**62.5%**
• **Nuclear:**	**37.2%**
• **Hydro:**	**0.3%**

Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data (in thousands)

Revenue	$	1,977,000
% of AEP Retail		12%
Net Income	$	121,000
Capital Expenditure	$	325,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,546,000
Net Plant Assets	$	3,313,000
Cash	$	1,369

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 252,000	$ 264,000	$ 294,000

AEP®

Indiana Michigan Power

I&M Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1 , 2 , 3	Berrien Springs, Michigan	5	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	2	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	2	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	1	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I & M	**453,788**
IP & L	462,831
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECo	144,632

Michigan	Customers
I & M	**125,588**
Consumers Energy	1,779,184
Detroit Edison	2,156,214

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	
I & M	**69.64**
IP & L	76.00
Duke Indiana (PSI)	78.82
SIGECo	94.62

Michigan	
I & M	**66.65**
Consumers Energy	101.43
Detroit Edison	111.93

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**

Generating Capacity **1,060 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**1,200**
Distribution Miles	**9,700**

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

AEP®

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Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data (in thousands)

Revenue	$ 586,000
% of AEP Retail	4%
Net Income	$ 35,000
Capital Expenditure	$ 78,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 1,311,000
Net Plant Assets	$ 1,002,000
Cash	$ 702

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 70,000	$ 114,000	$ 100,000

Kentucky Power

Kentucky Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY UTILITIES *

Kentucky	Customers
KPCo	**175,255**
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	58.57
LG&E	65.40
KPCo	**69.40**
Duke Kentucky	76.70

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Total Customers:

• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**

Generating Capacity	**8,498 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.9%**
- **Hydro:** **0.1%**

Transmission Miles	**6,500**
Distribution Miles	**26,200**

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

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Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data (in thousands)

Revenue	$	2,725,000
% of AEP Retail		16%
Net Income	$	229,000
Capital Expenditure	$	1,000,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	6,819,000
Net Plant Assets	$	5,569,000
Cash	$	1,625

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 832,000	$ 368,000	$ 389,000

Ohio Power

Ohio Power Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak – August 2nd	5,260 MW

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	26	Hydro

Ohio Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers:

• Residential	447,000
• Commercial	58,000
• Industrial	7,000
• Other	8,000
Total	520,000

Generating Capacity	4,219 MW
Generating Capacity by Fuel Mix:	
• Coal:	25%
• Natural Gas:	75%
Transmission Miles	3,600
Distribution Miles	21,200

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data (in thousands)

Revenue	$ 1,442,000
% of AEP Retail	14%
Net Income	$ 37,000
Capital Expenditure	$ 240,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 2,579,000
Net Plant Assets	$ 1,999,000
Cash	$ 1,651

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 319,000	$ 330,000	$ 466,000

AEP®

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	**511,924**
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	70.73
PSO	**73.67**
OG&E	74.60

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.

- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

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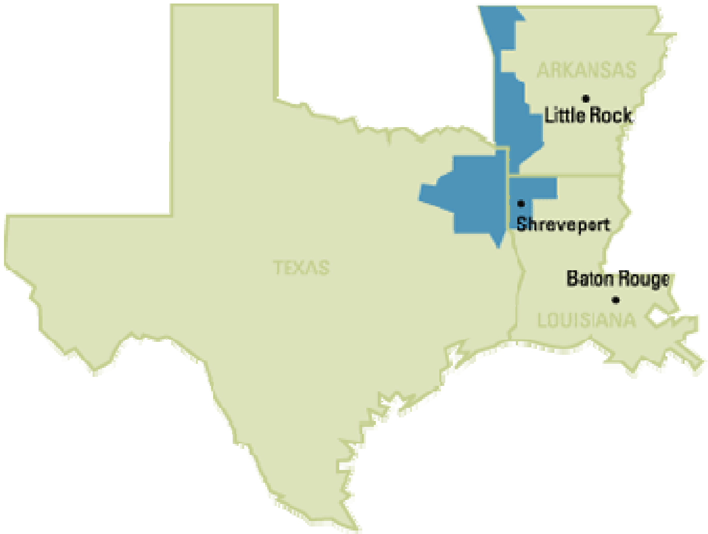
Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.



Total Customers:

• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**456,000**

Generating Capacity	**4,637 MW**
Generating Capacity by Fuel Mix:	
• **Coal/Lignite:**	**58%**
• **Natural Gas:**	**42%**
Transmission Miles	**3,500**
Distribution Miles	**19,300**

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

AEP®

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data (in thousands)

Revenue	$	1,432,000
% of AEP Retail		11%
Net Income	$	92,000
Capital Expenditure	$	323,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	3,191,000
Net Plant Assets	$	2,494,000
Cash	$	2,618

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 537,000	$ 605,000	$ 540,000

AEP®

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas
Mattison #3, 4	Tontitown, Arkansas	150	Gas

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Southwestern Electric Power

SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	**109,760**
Entergy AR	672,890

Louisiana	Customers
SWEPCo	**171,564**
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	**166,906**
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	**74.63**
OG&E	77.70
Empire District	86.30
ETR	102.43

Louisiana	
SWEPCo	**63.91**
Entergy LA	99.63
Entergy Gulf St	100.81
Entergy NO	104.20
CLECO	110.19

Texas	
SWEPCo	**60.80**
SPSCo	80.91
ETR	114.79
EP	128.32
TXU	144.11

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

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AMERICAN ELECTRIC POWER

Boston Investor Meetings

Hosted by Barclays

August 5, 2009

STRONG
FLEXIBLE
ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

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AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

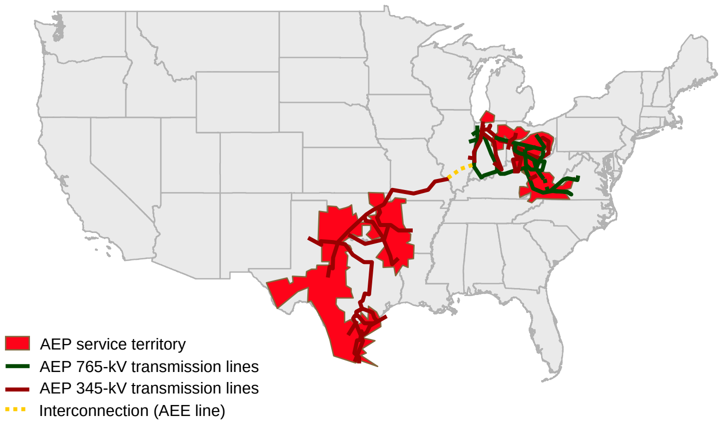
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

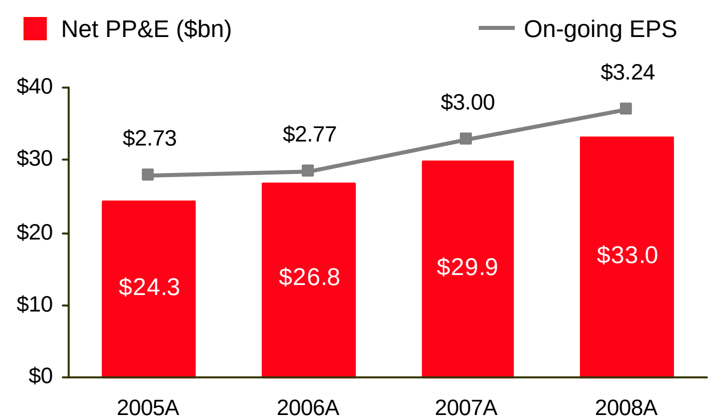


AEP's Leadership Position

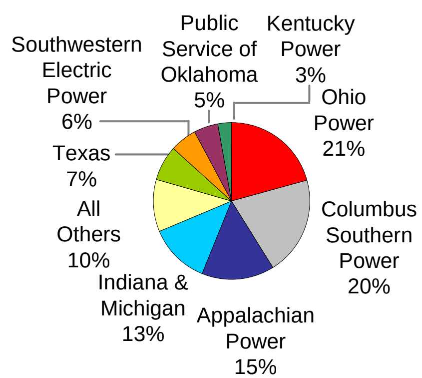
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

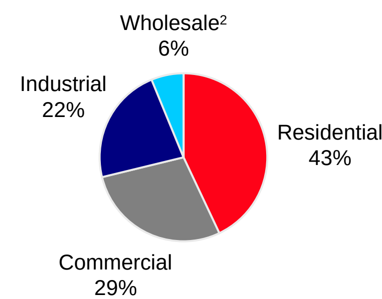
Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] Source: Company filings
[2] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop "transmission superhighway" to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America's power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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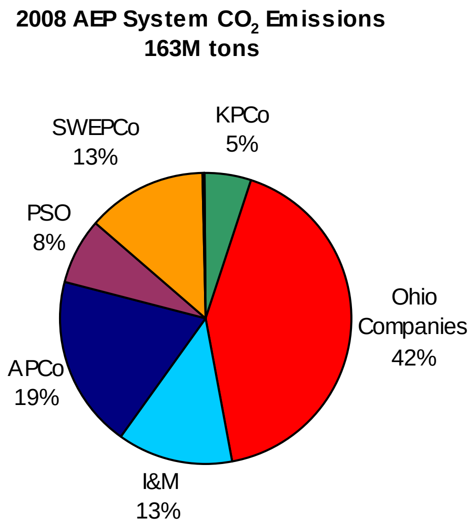
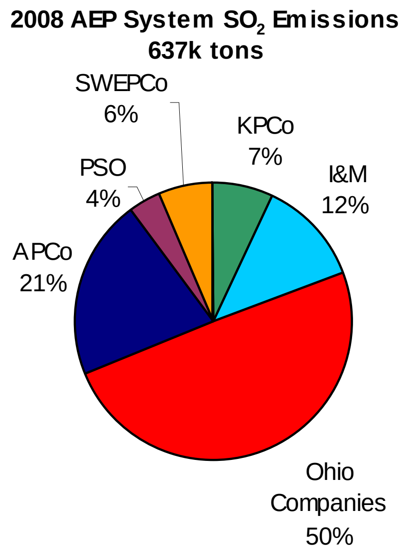
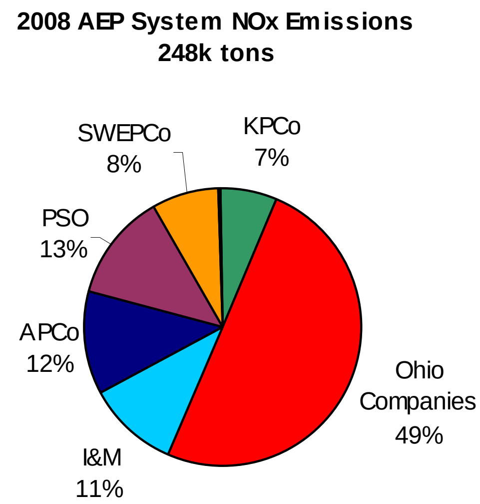
AEP AMERICAN ELECTRIC POWER

CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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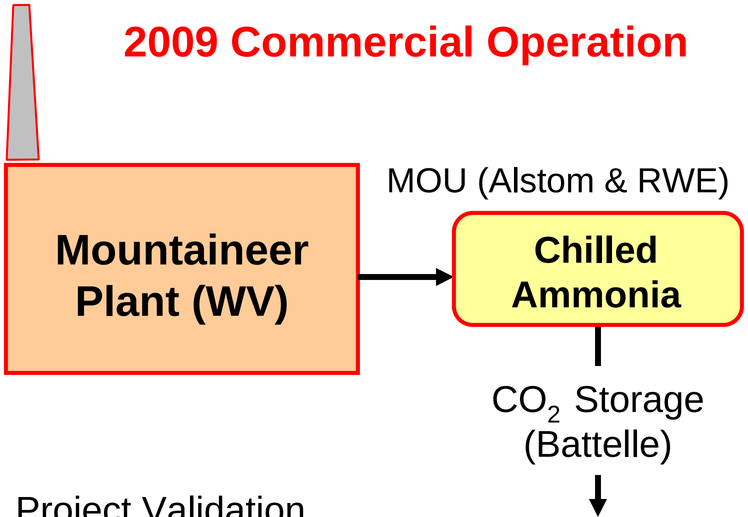
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- Alstom “Chilled Ammonia” Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies’ Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Geologic storage for CO_2
- Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the ‘economic’ hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

AEP AMERICAN ELECTRIC POWER

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1.2 billion in capital investment.

- Turk – In June 2009, the Arkansas Court of Appeals overturned APSC decision granting CECPN & AEP filed appeal to Supreme Court. Air permit appeal hearings were held in June 2009 and a decision is expected by year end. Construction continues.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

AMERICAN® ELECTRIC POWER

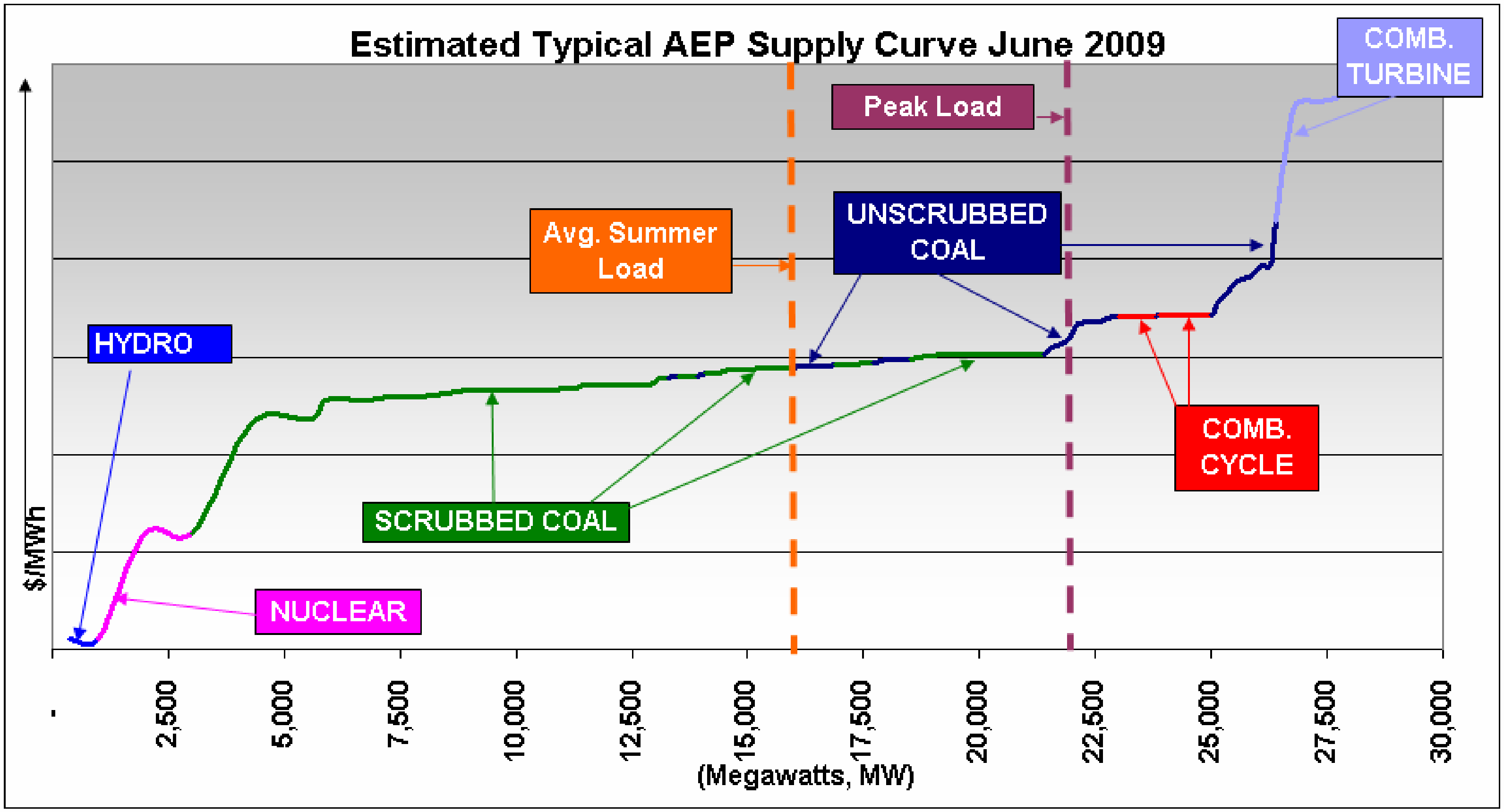
DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 2009 YTD, approximately 40% of the insurance payments ($40MM) were used to offset increased fuel costs to customers

AEP AMERICAN ELECTRIC POWER

AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



AEP AMERICAN ELECTRIC POWER

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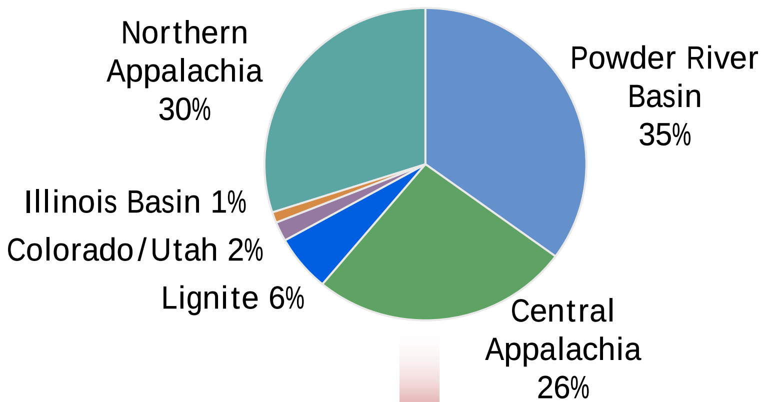
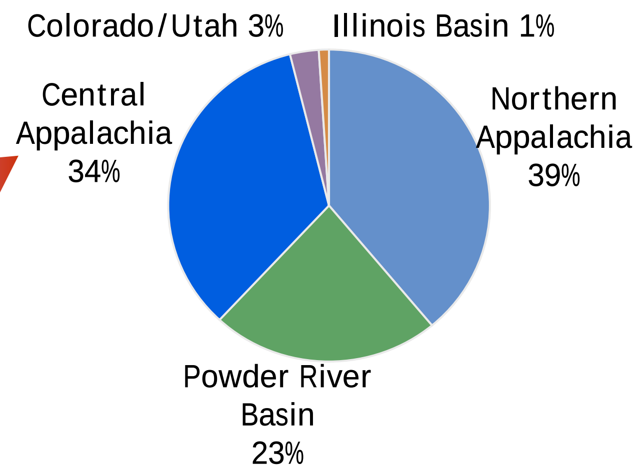
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

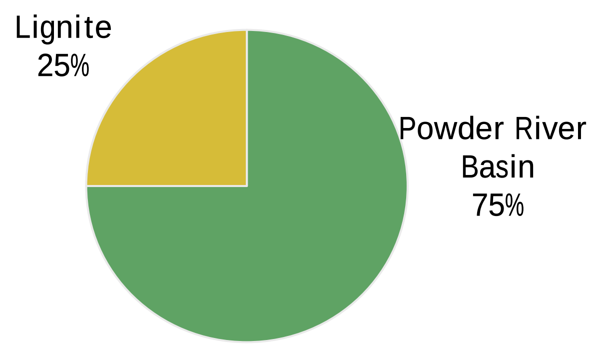
Total AEP System



AEP East



AEP West

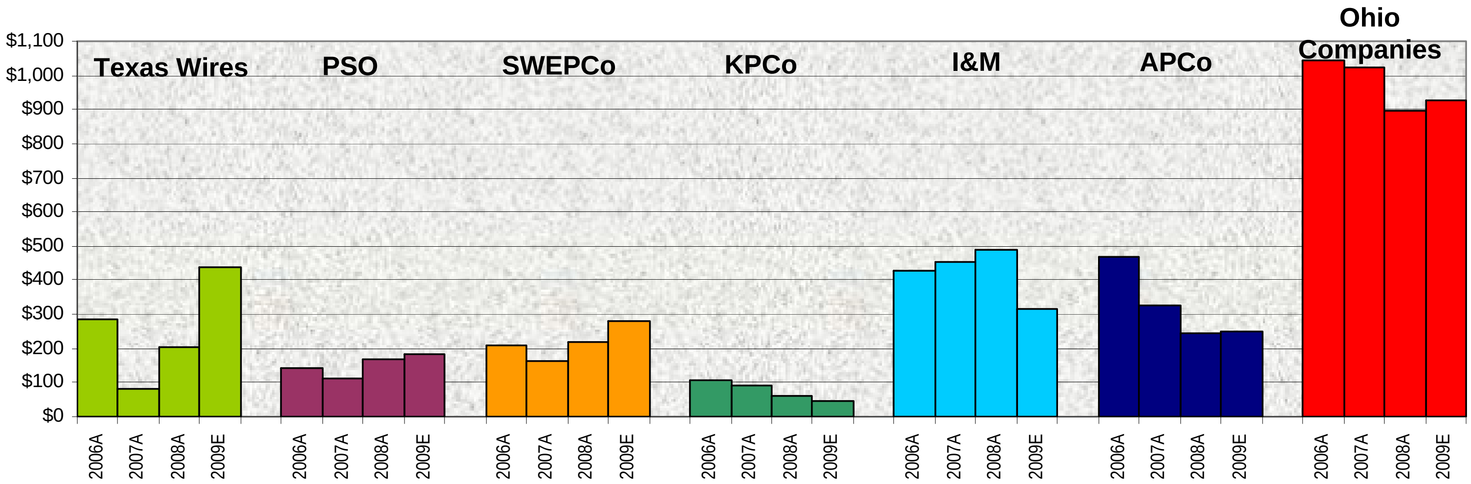


Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

AEP AMERICAN ELECTRIC POWER

Cash Flow and Capex by Operating Company

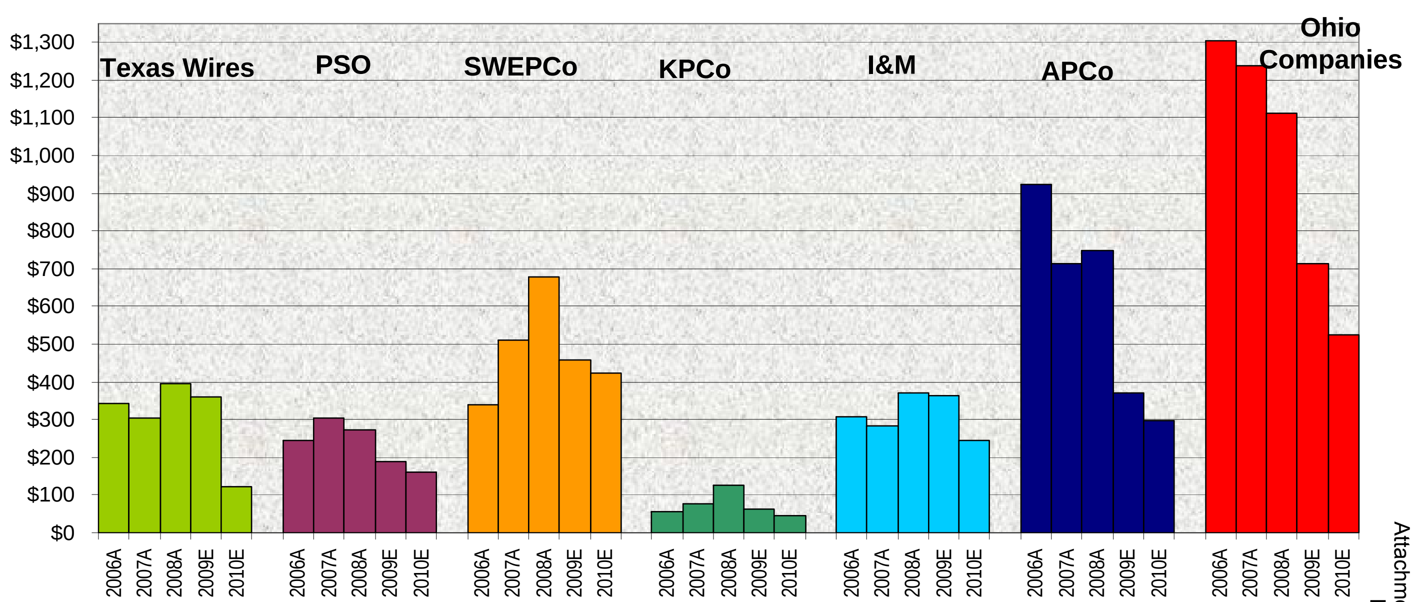


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



AMERICAN ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AMERICAN ELECTRIC POWER

Overview of 2009 Guidance

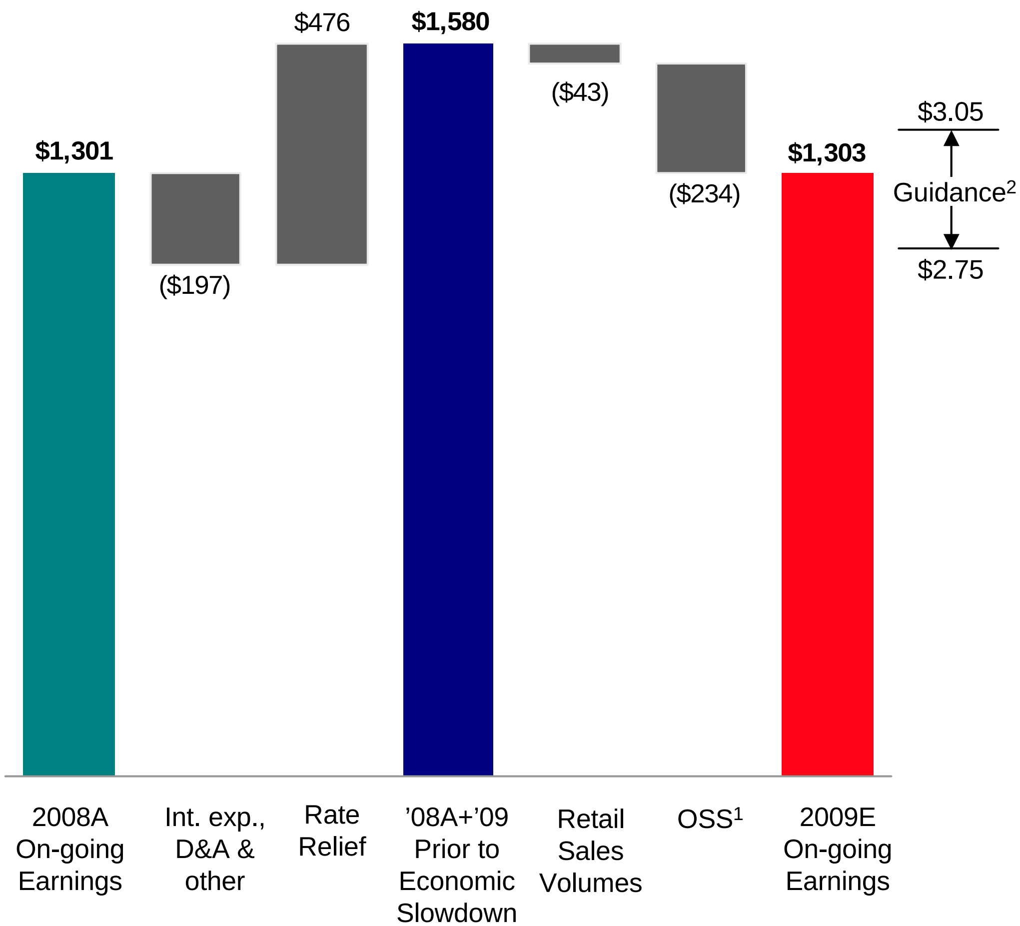
<u>2009 Earnings Drivers:</u>

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

<u>Long-term Earnings Drivers:</u>

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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Sierra Club's First Set of Data Requests
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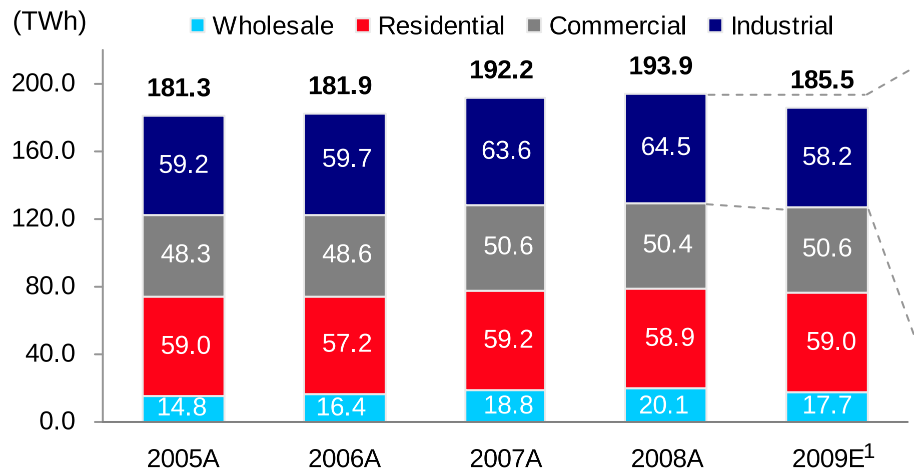
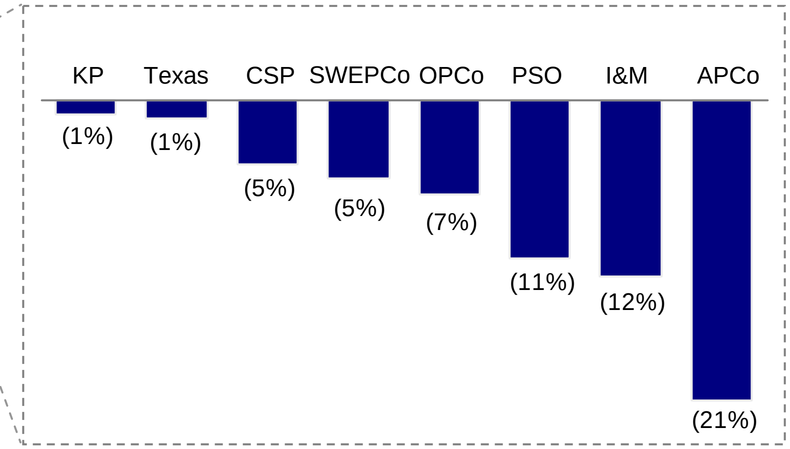
Key Drivers of 2009 Guidance: Retail Sales

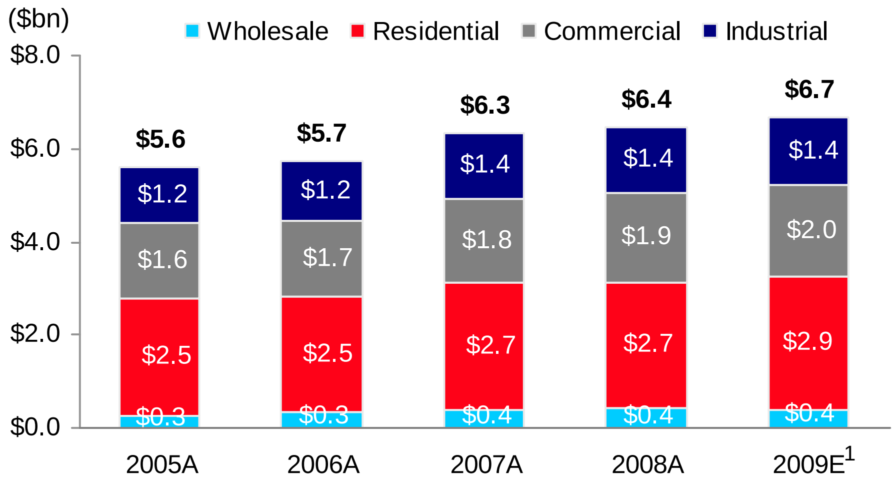
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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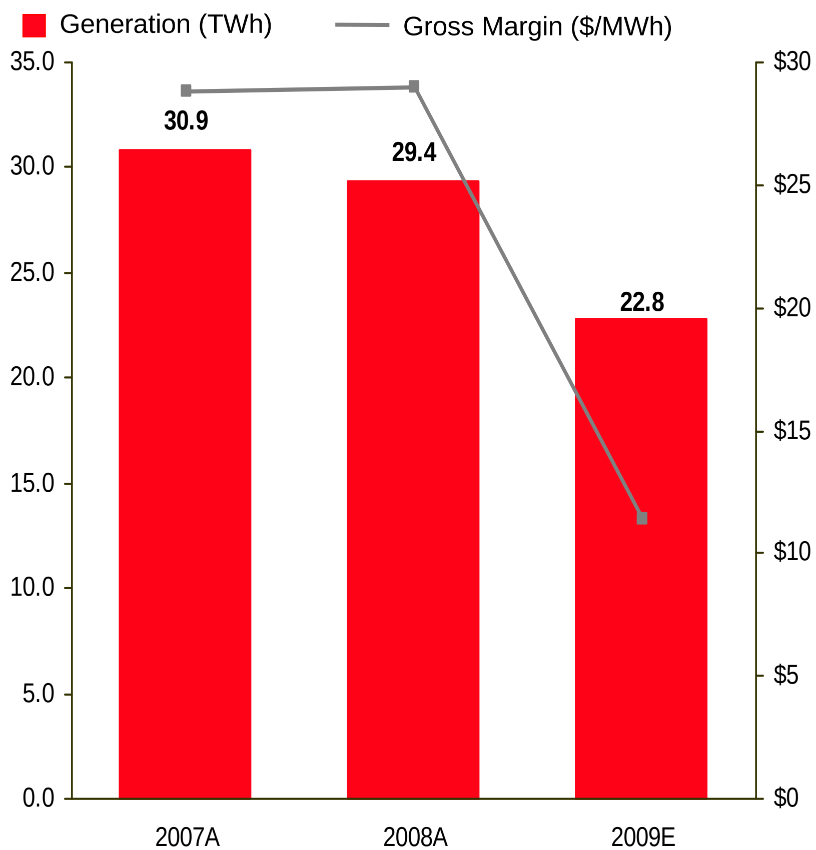
[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

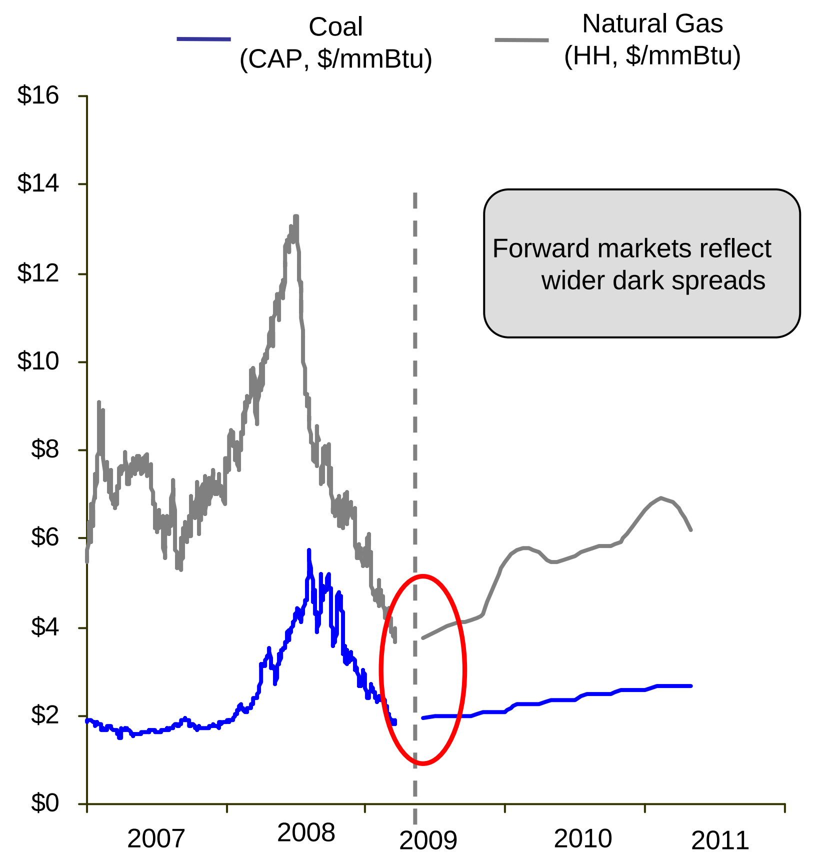
Key Drivers of 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions	2007A	2008A	2009E
OSS Physical Sales	$ 674	$ 718	$ 106
Oklaunion Payment	46	45	49
Marketing/Trading	170	82	105
Pre-sharing Gross Margin	$ 890	$ 845	$ 260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb

- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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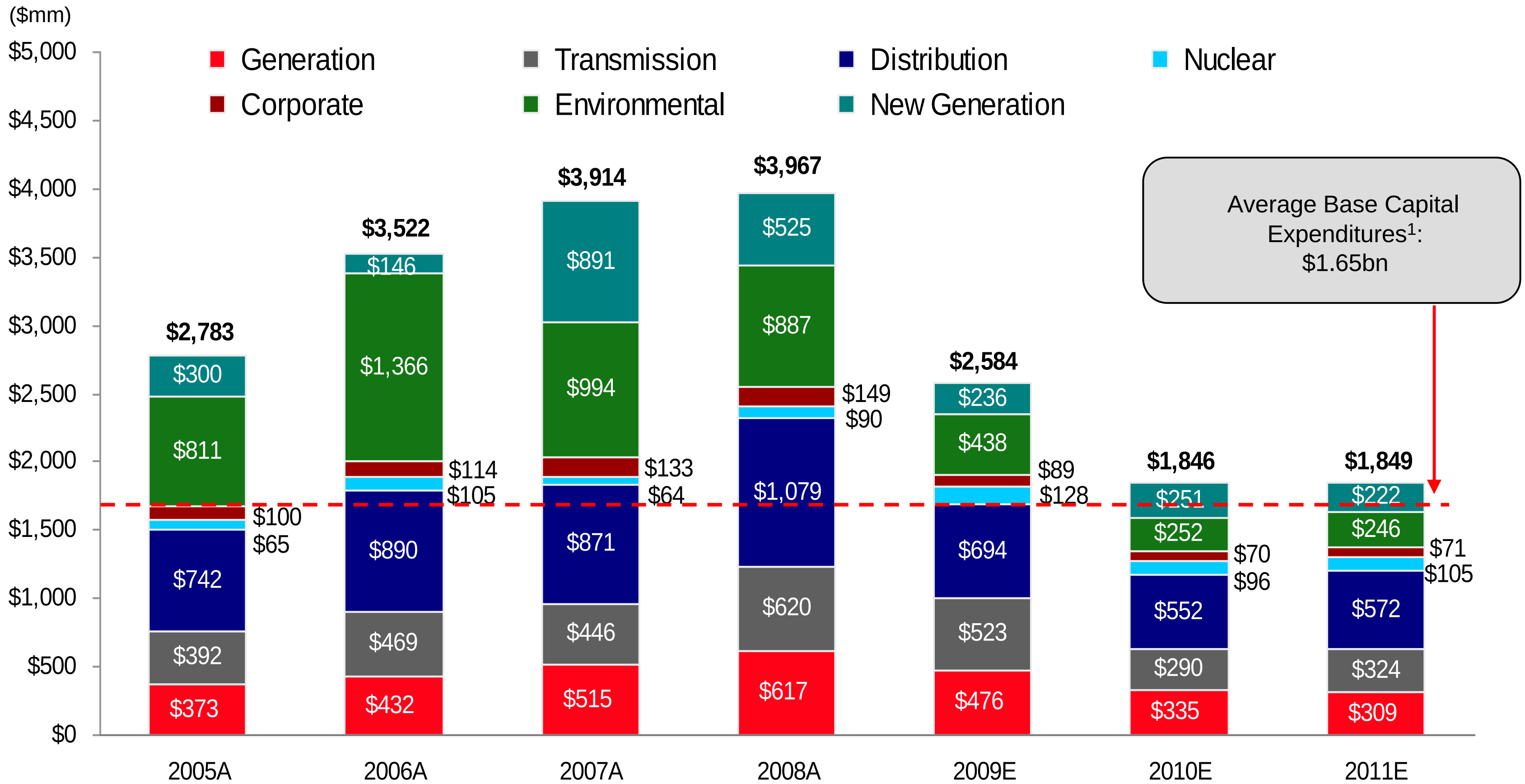
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
¹ Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

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Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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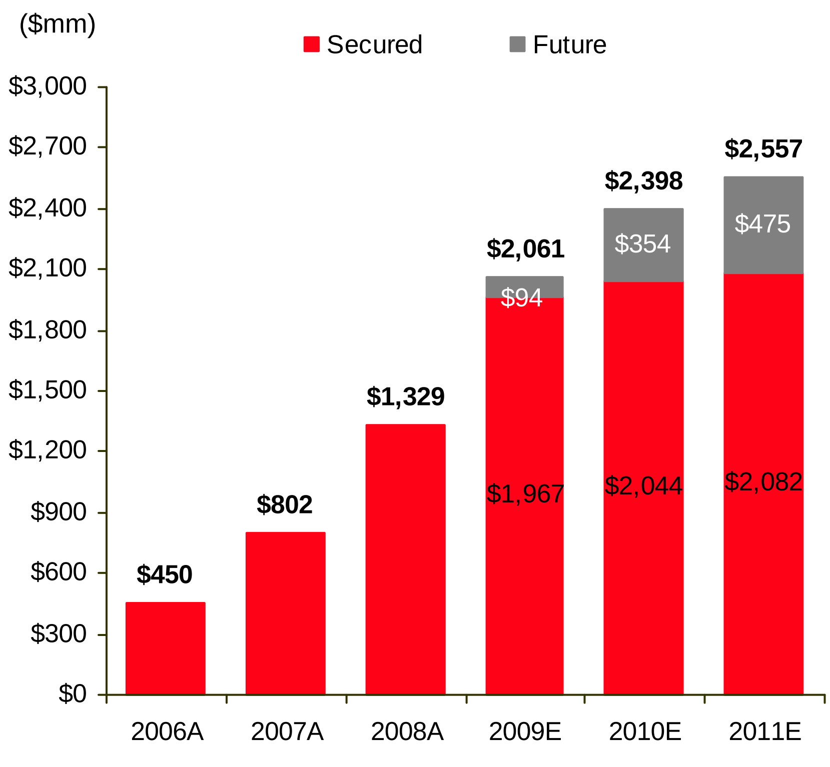
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $77mm and $38mm was secured for 2010 and 2011, respectively, as of July 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
  - ✓ APCo VA ($169MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Rehearing Order	2010 ESP Appl.	2010 PUCO Rehearing Order	2011 ESP Appl.	2011 PUCO Rehearing Order	Cumulative ESP Appl.	Cumulative PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Summary Rate Case Information

APCo Virginia General Rate Case

On July 15, 2009 APCo filed a pre-biennial base rate case with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $169.2 million. (Docket #: PUE-2009-00030) A procedural schedule is pending from the VSCC. A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure - Company Position* (11/30/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.015%	1.365%	0.00%
Long-Term Debt	56.007%	6.383%	3.57%
Preferred Stock	0.280%	4.352%	0.01%
Common Equity	43.665%	13.350%	5.83%
Other Items	0.033%	9.421%	0.00%
Total	100.00%		9.42%

*AEP will refile by August 14, 2009 using an end-of-test-year capital structure per the recent Virginia SCC decision in case No. PUE-2009-00019.

Procedural Schedule TBD

Required Rate Relief - Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.42%
Operating Income Requirement	$	193.8
Adjusted Operating Income	$	90.9
Difference	$	102.9
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	169.2

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

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Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

($ in millions)
(as of June 30, 2009)

Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

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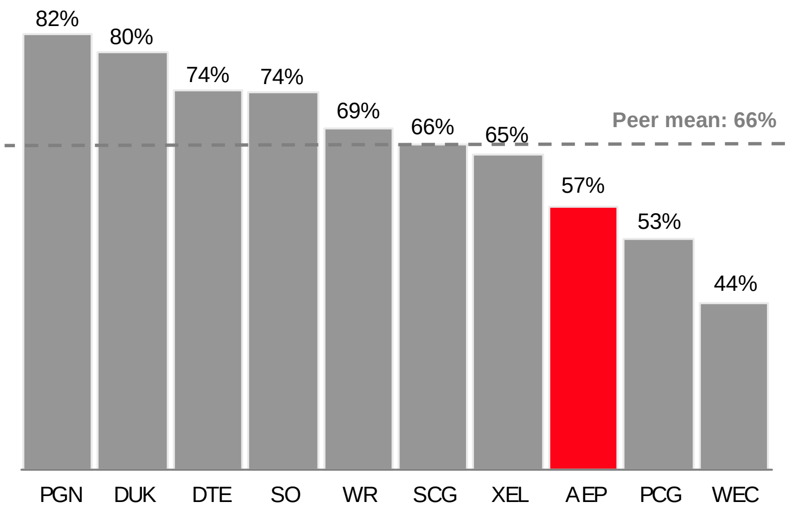
Dividend Overview

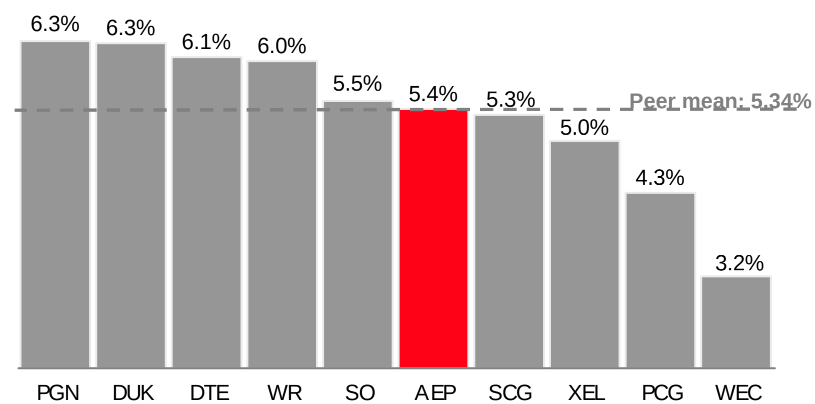
- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 7/28/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 7/28/09

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Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

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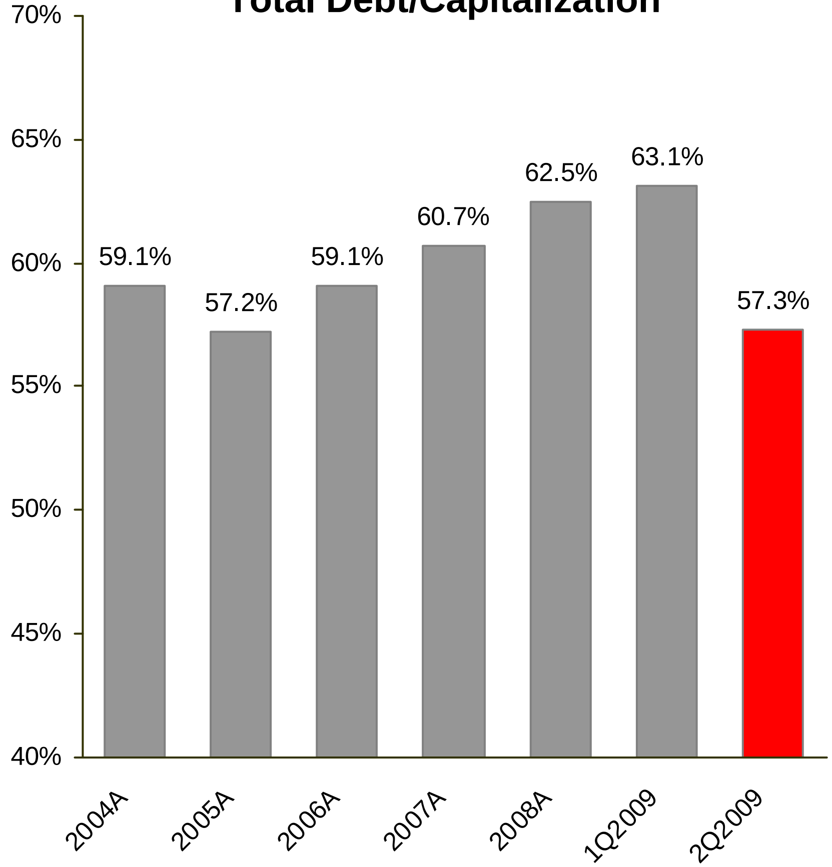
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 6/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

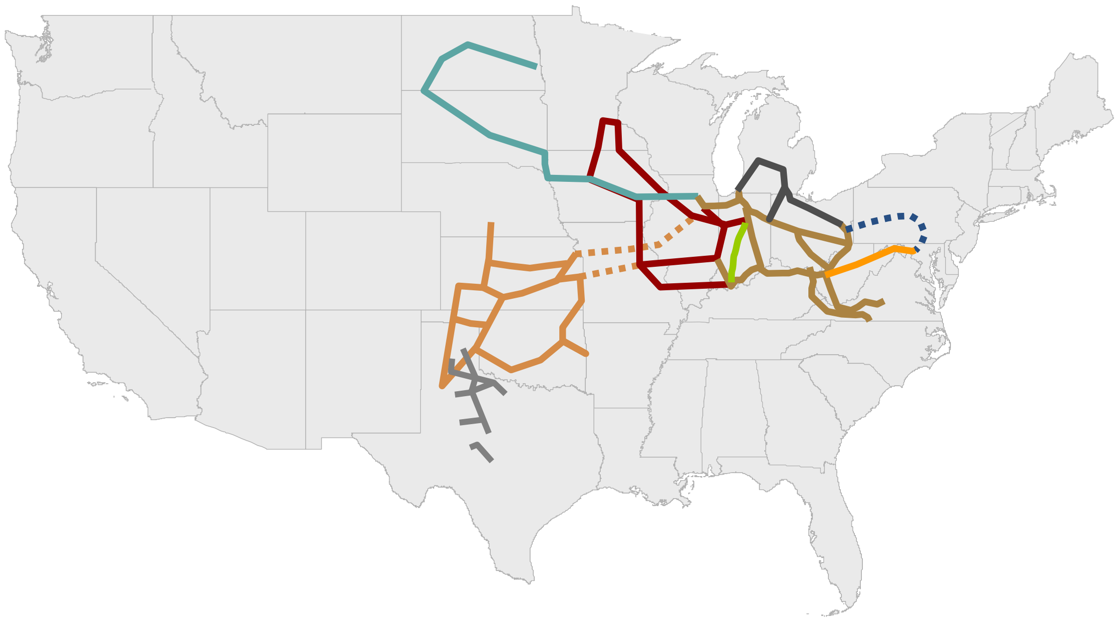
Pioneer	COD: 2015
■ *240 miles of 765 kV*	
■ *Partner: Duke Energy (50%)*	
■ *Estimated Cost: $1 billion*	
■ *ROE: 12.54%*	

PATH-WV	COD: 2014
■ *275 miles of 765 kV*	
■ *Partner: Allegheny Energy (50%)*	
■ *Estimated Cost: $1.2 billion*	
■ *ROE: 14.3%*	

Tallgrass	COD: 2013-14
■ *170 miles of 765 kV*	
■ *Partners: OG&E (50%) & MidAmerican Energy (25%)*	
■ *Estimated Cost: $500 million*	
■ *ROE: 12.8%*	

Prairie Wind	COD: 2013
■ *110 miles of 765 kV*	
■ *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*	
■ *Estimated Cost: $400 million*	
■ *ROE: 12.8%*	

ETT	COD: 2013
■ *345 kV in ERCOT*	
■ *Partner: MidAmerican Energy (50%)*	
■ *Estimated Cost: $400 million*	
■ *ROE: 9.96%*	



Future Projects:

EHV Michigan	COD: ~2020
■ *700 miles of 765 kV*	

PJM Projects
■ *Enhance existing 765/345 kV*

Hartland	COD: ~2020
■ *1000+ miles of 765 kV*	

MISO Vision Plan
■ *765 kV Backbone*

SPP Overlay	COD: 2013-14
■ *765 kV Backbone*	

ETT	COD: ~2018
■ *345 kV in ERCOT*	
■ *Additional CREZ spend of $750-$850 million*	

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

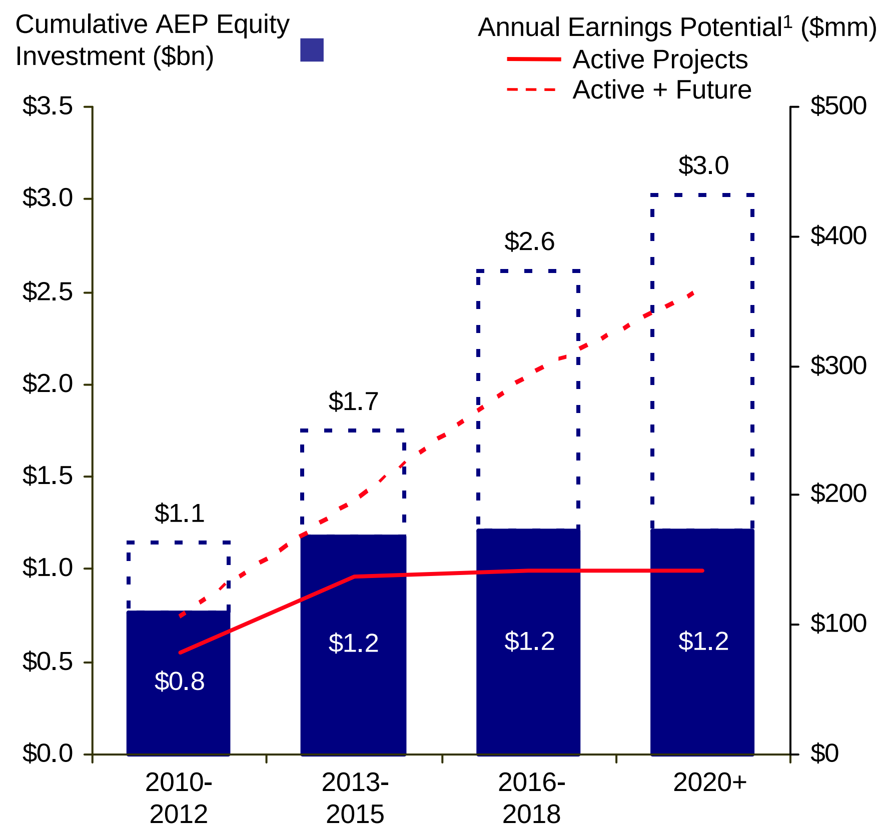
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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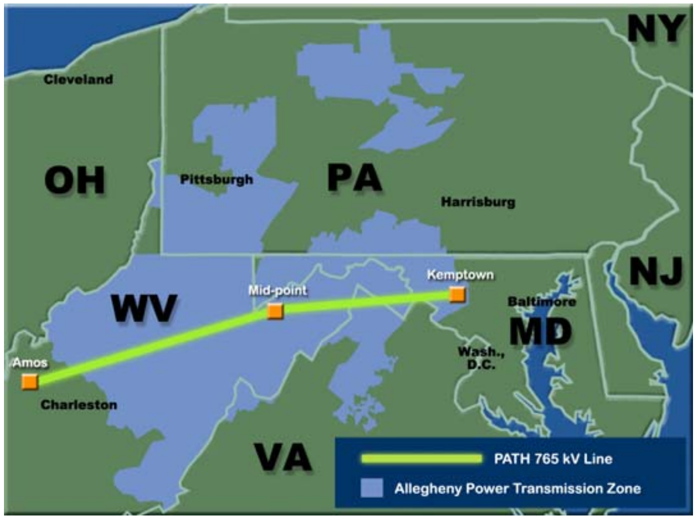
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



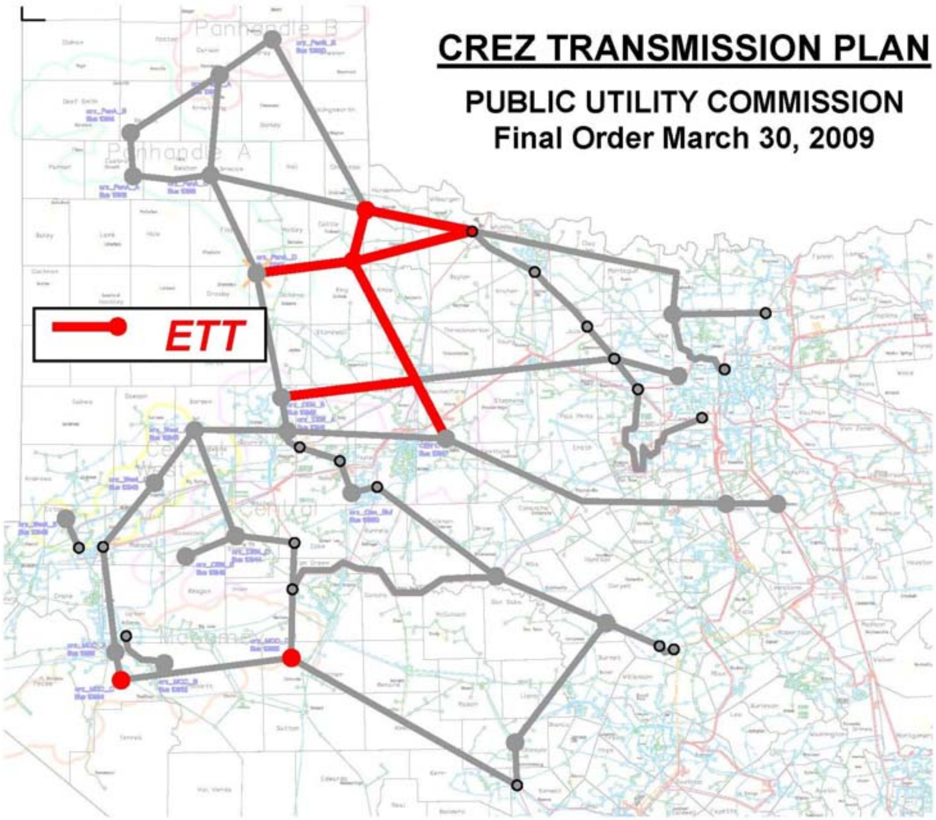
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

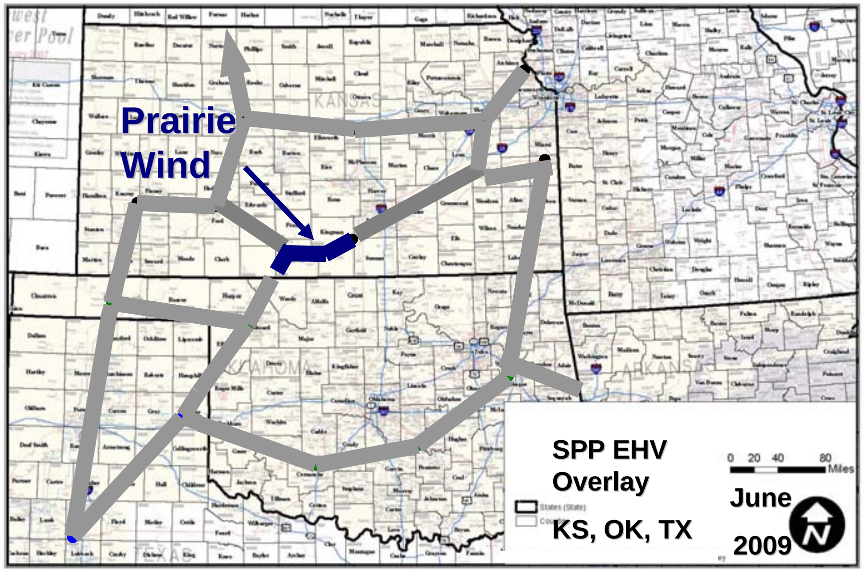
Electric Transmission Texas

AMERICAN ELECTRIC POWER

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

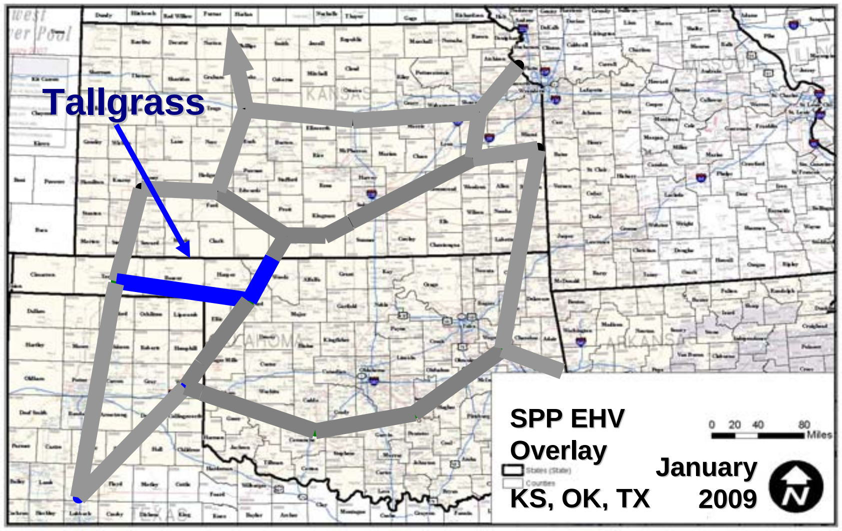
- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

AEP AMERICAN ELECTRIC POWER

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

AEP AMERICAN ELECTRIC POWER

Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

AEP AMERICAN® ELECTRIC POWER

Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

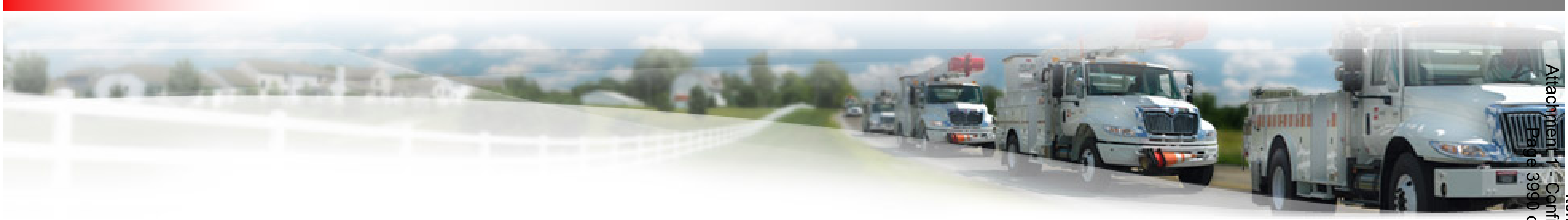
- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

AEP AMERICAN ELECTRIC POWER®

Boston Investor Meetings Hosted by Barclays Capital
July 7, 2011



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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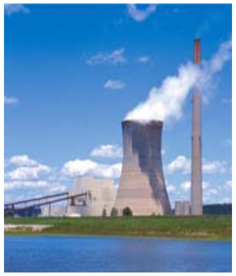
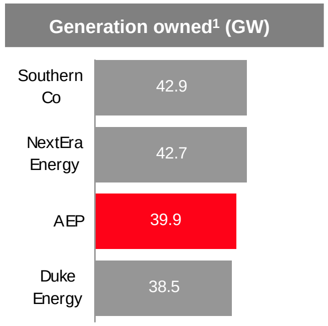
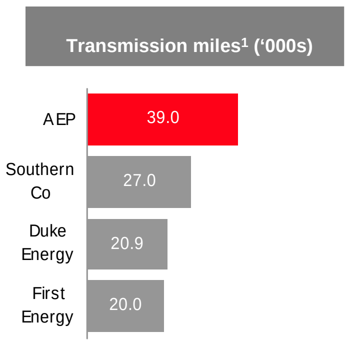
American Electric Power



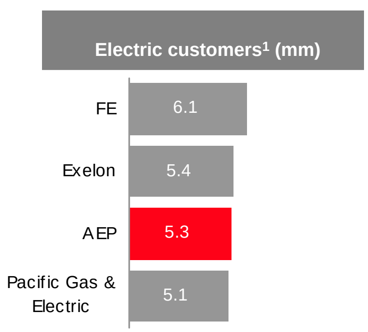
One of the largest
U.S. electricity generators



The largest U.S. electricity transmitter

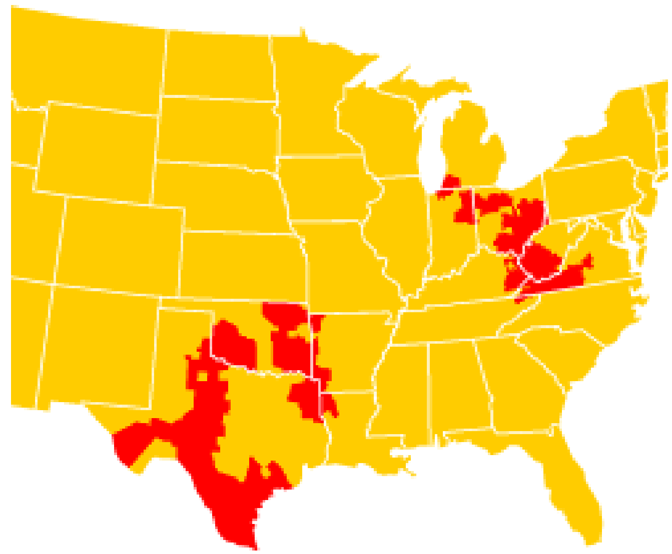


One of the largest U.S. electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

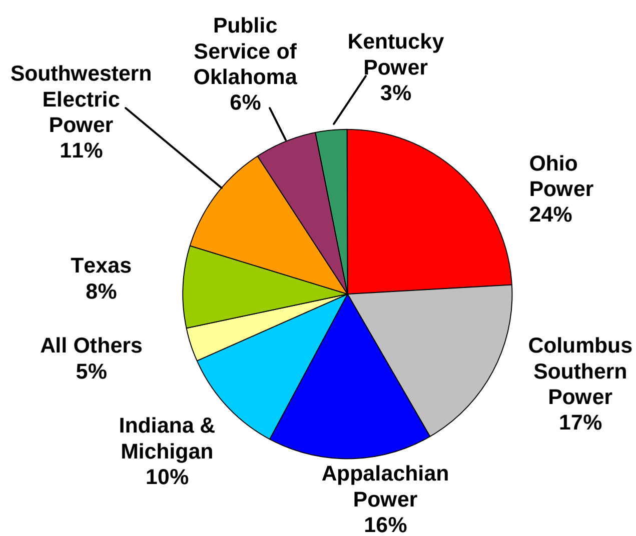
$18.5B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

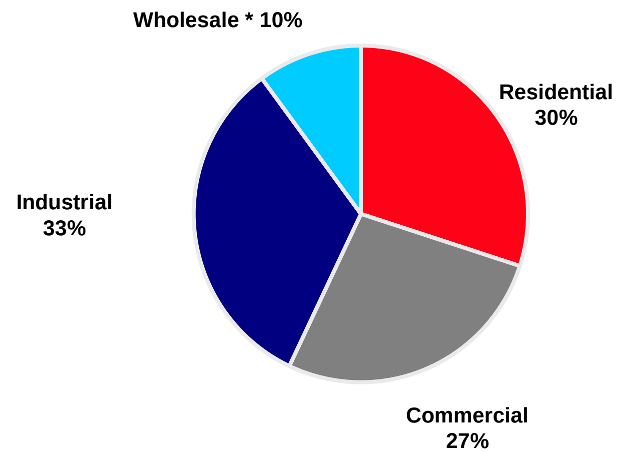
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



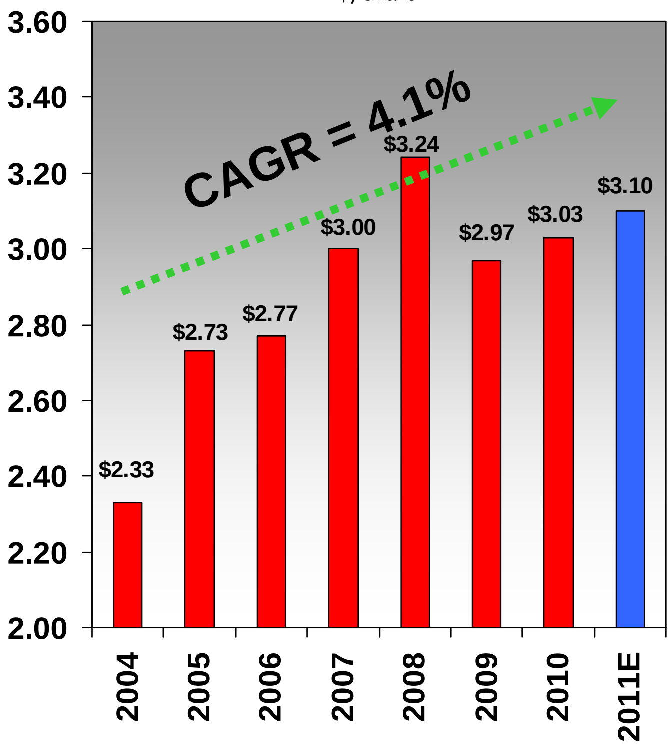
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

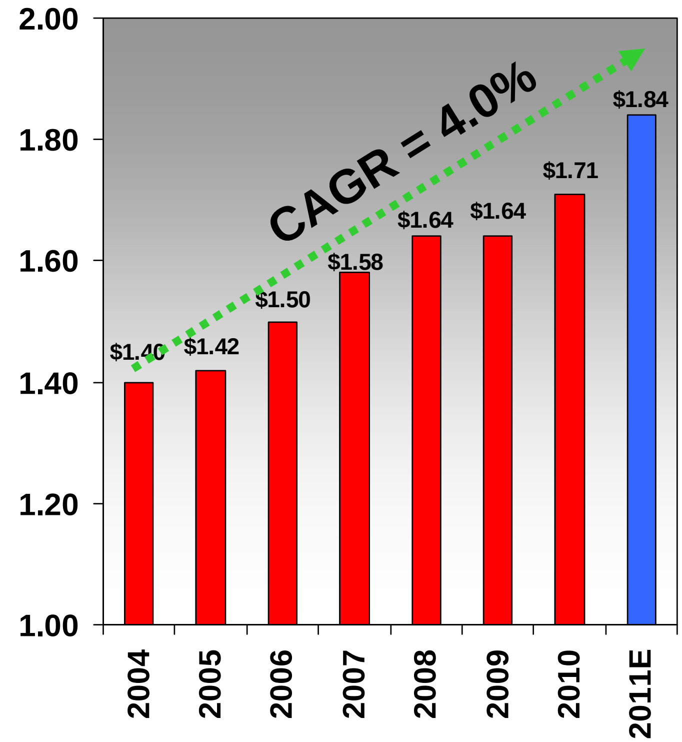
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

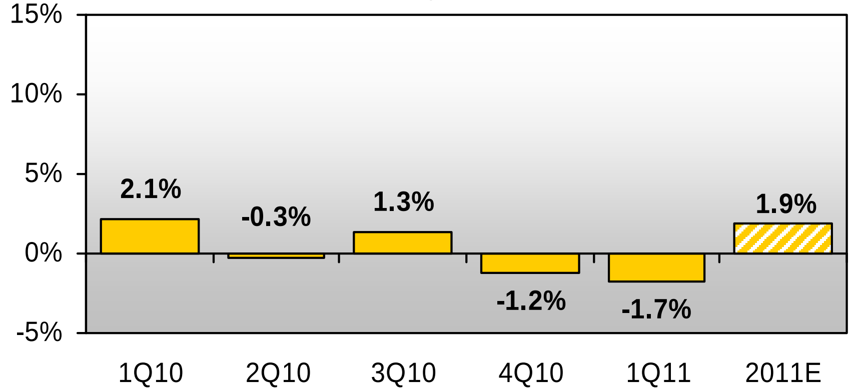
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

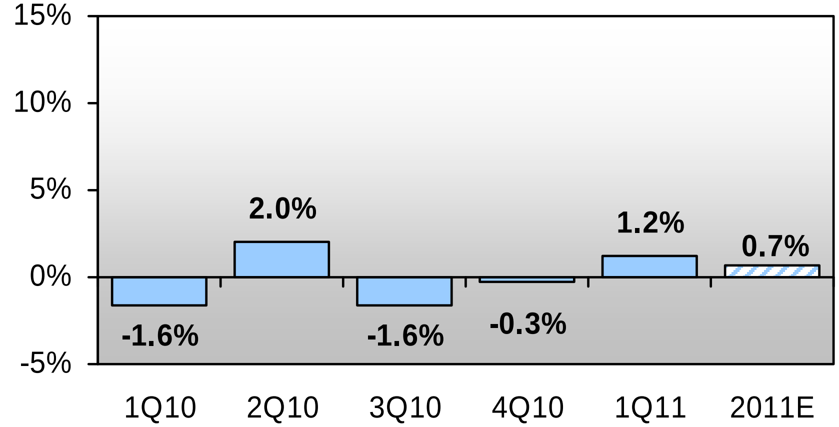
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

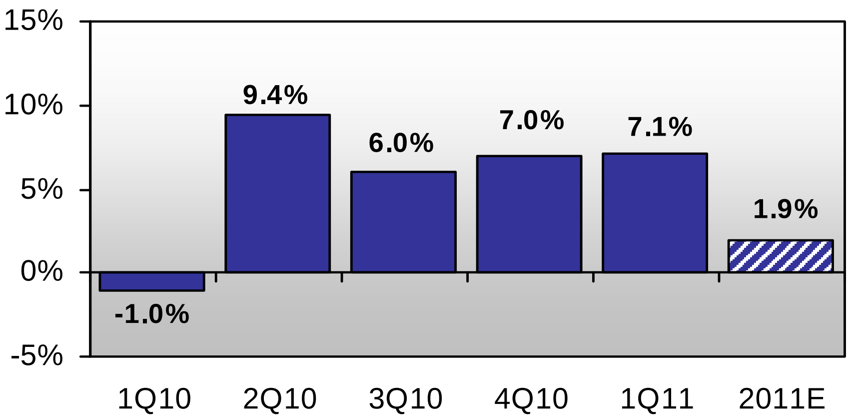
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



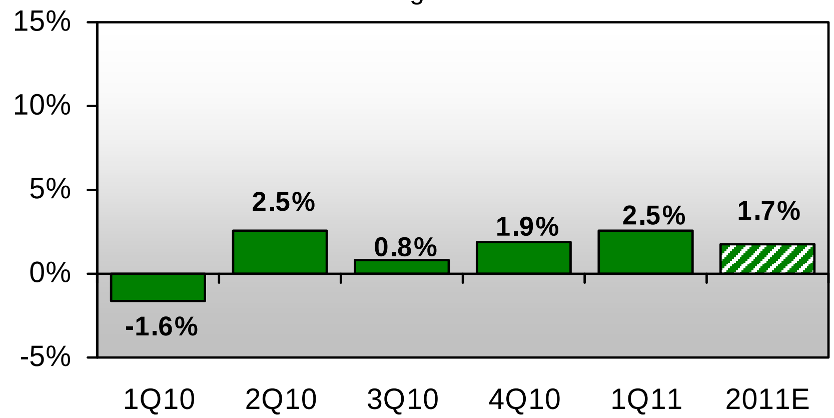
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



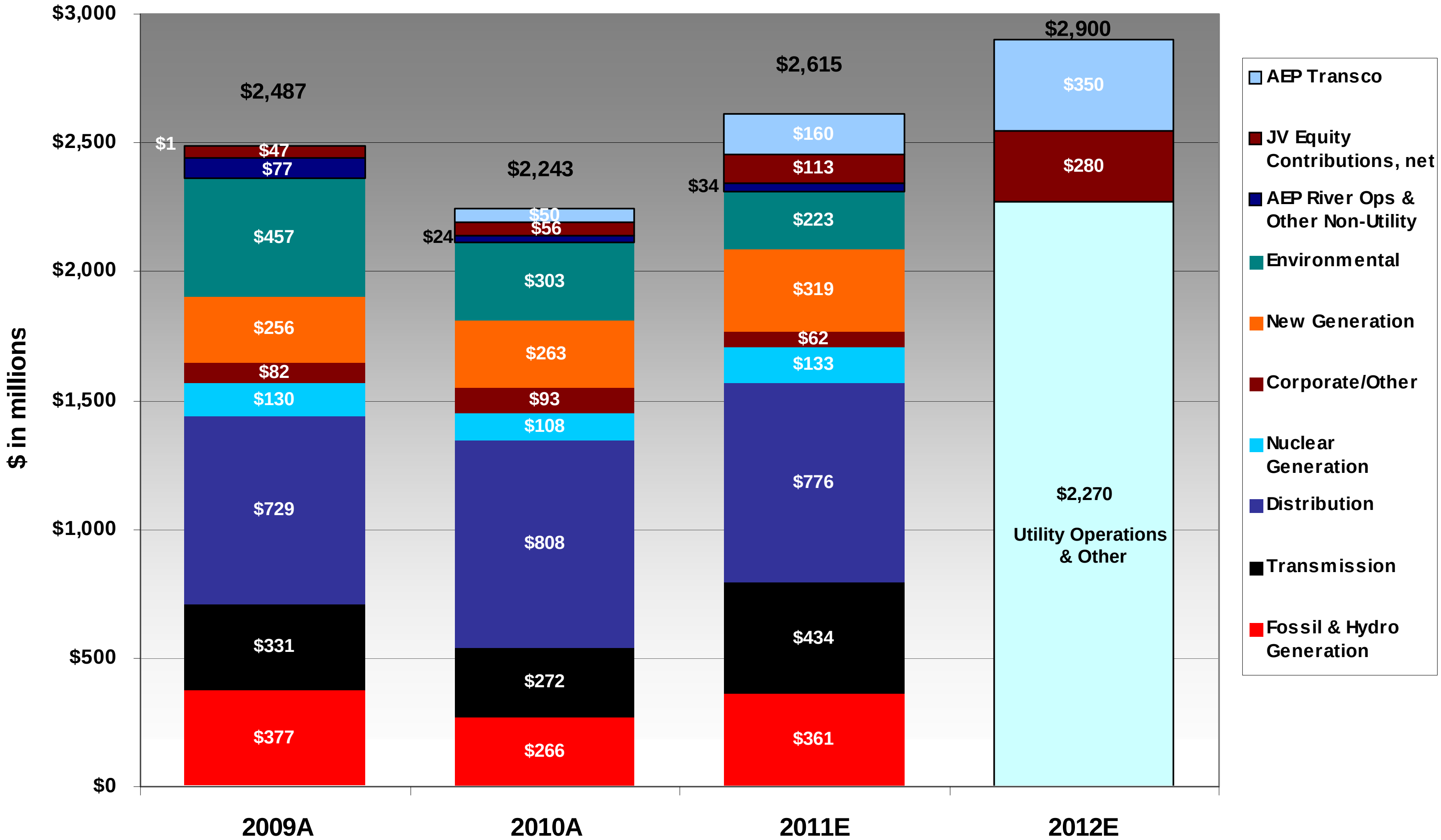
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

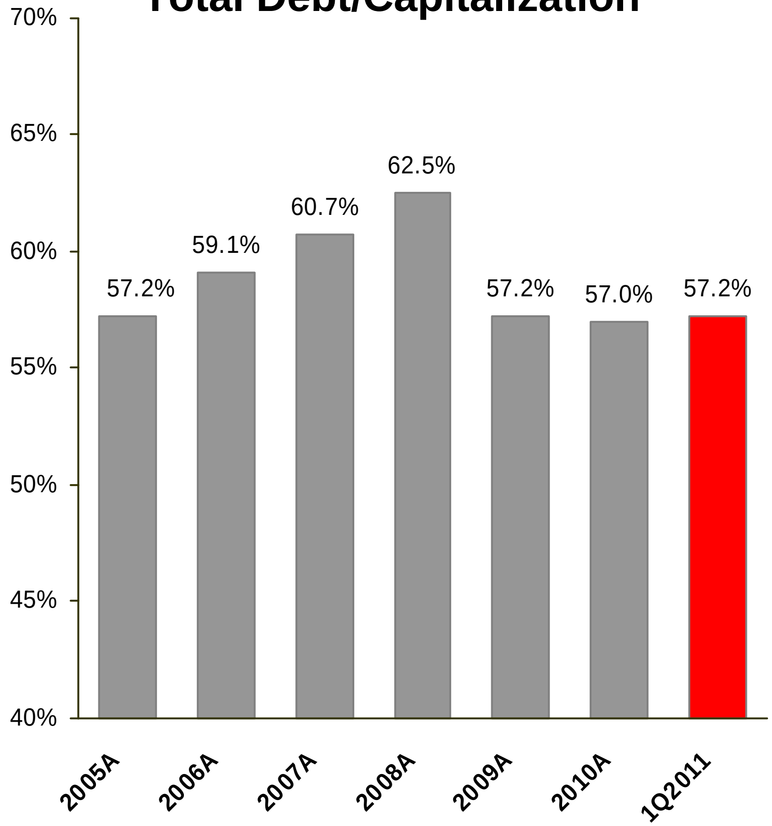
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

Total Debt/Capitalization

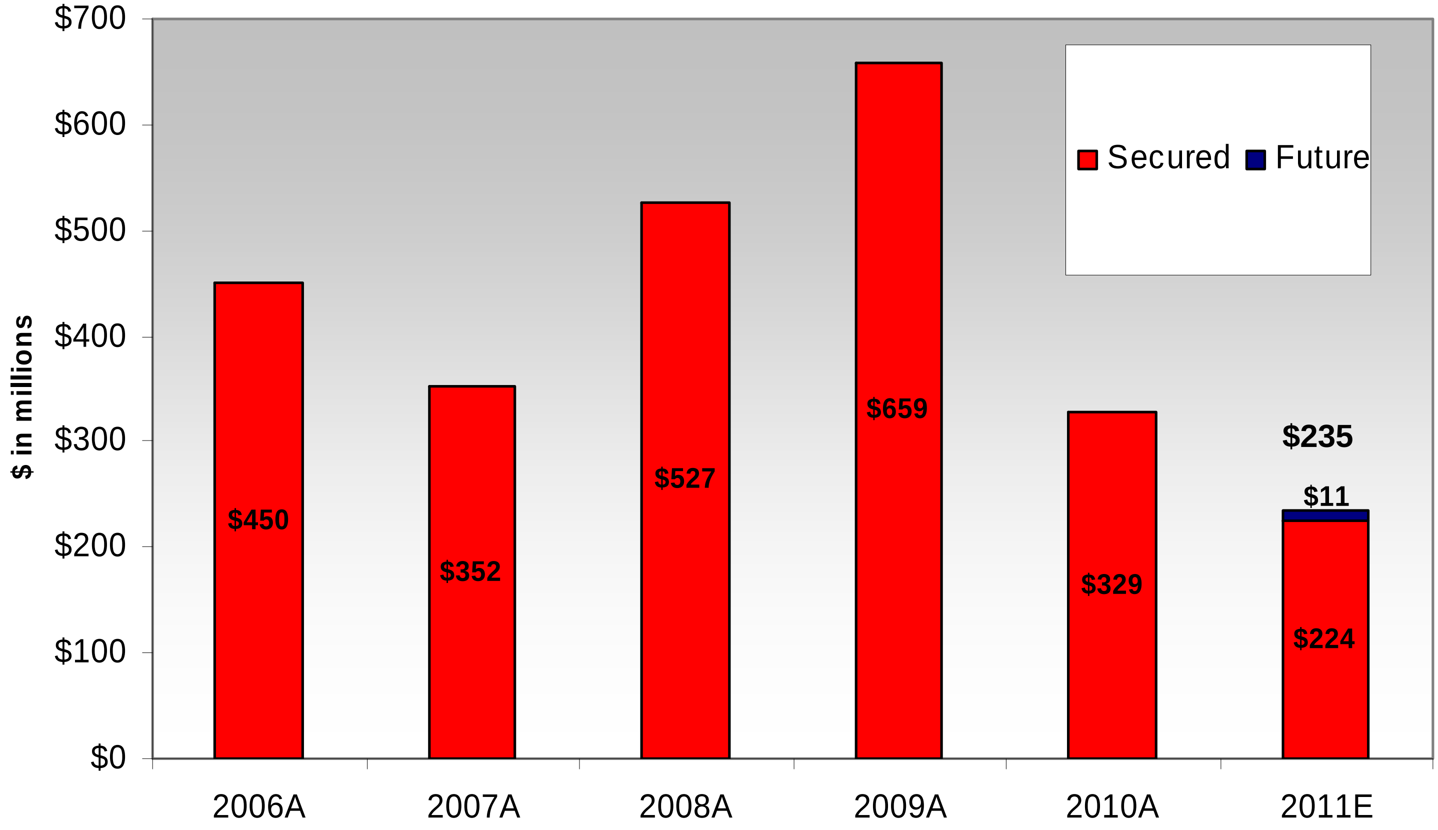


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 03/31/11**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case (Docket# U-16801)

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law, I&M intends to implement rates, subject to refund on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure - Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule - TBD

Required Rate Relief - Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – July 29; Hearing August 15**

	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

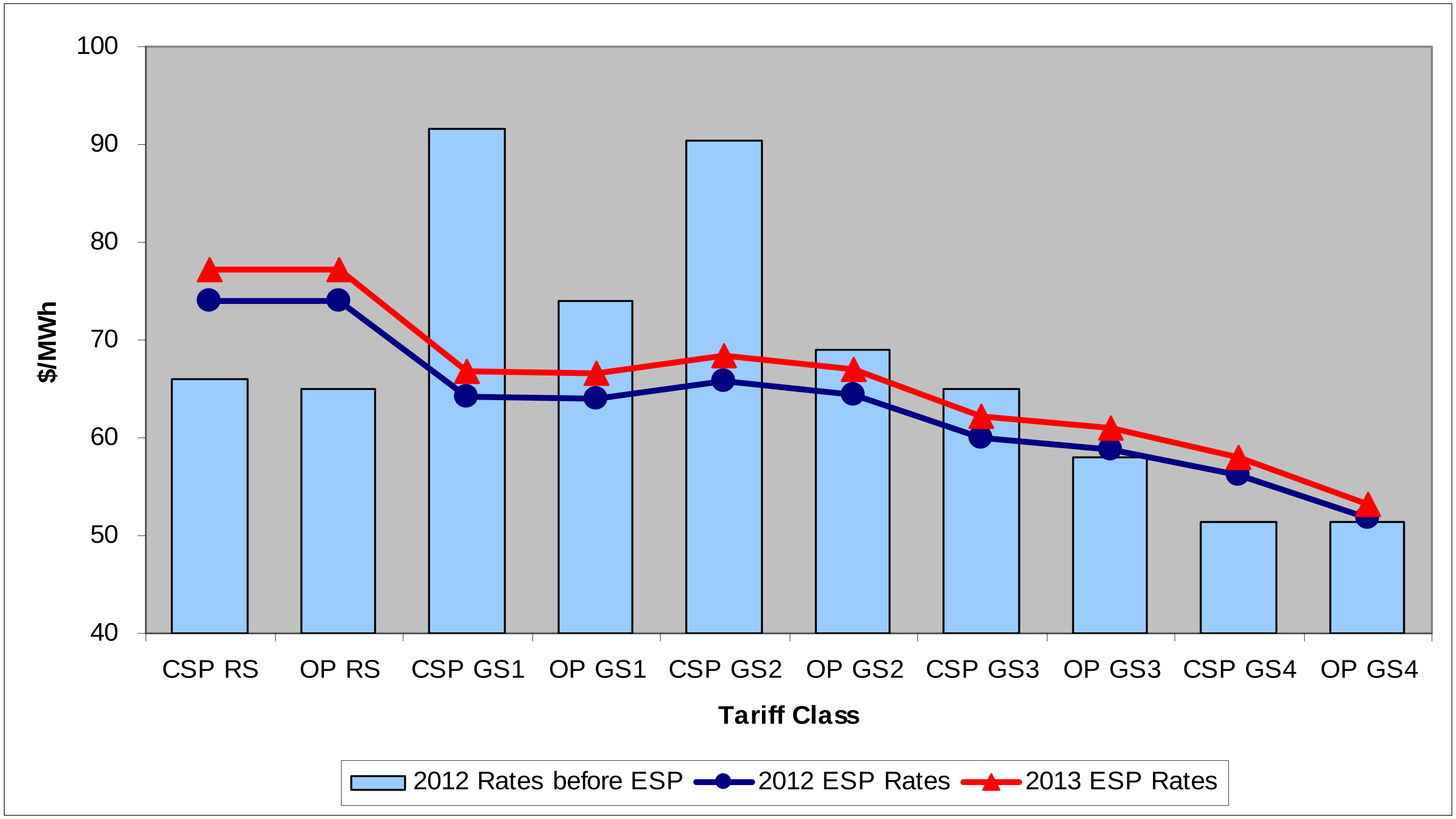
N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

AEP®

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

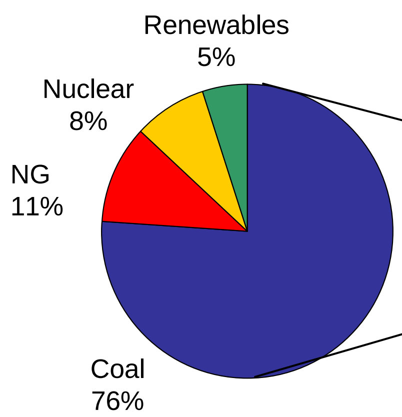
List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

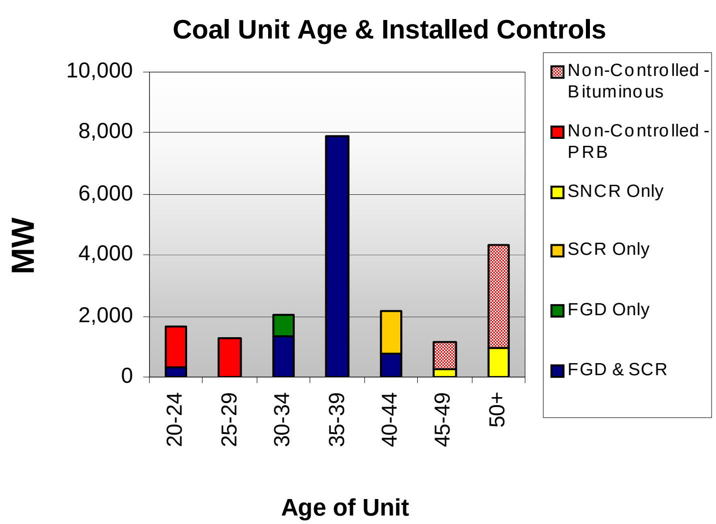


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

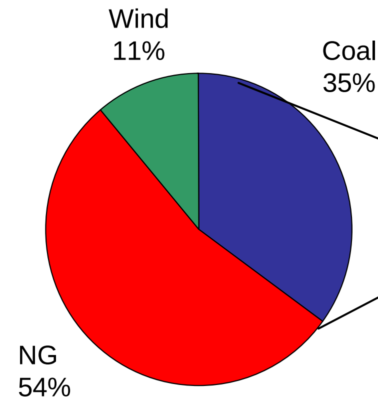
Avg. Delivered Cost

2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

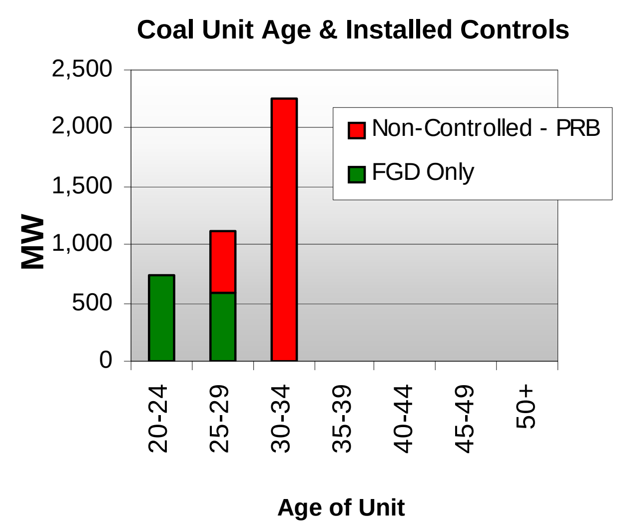


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

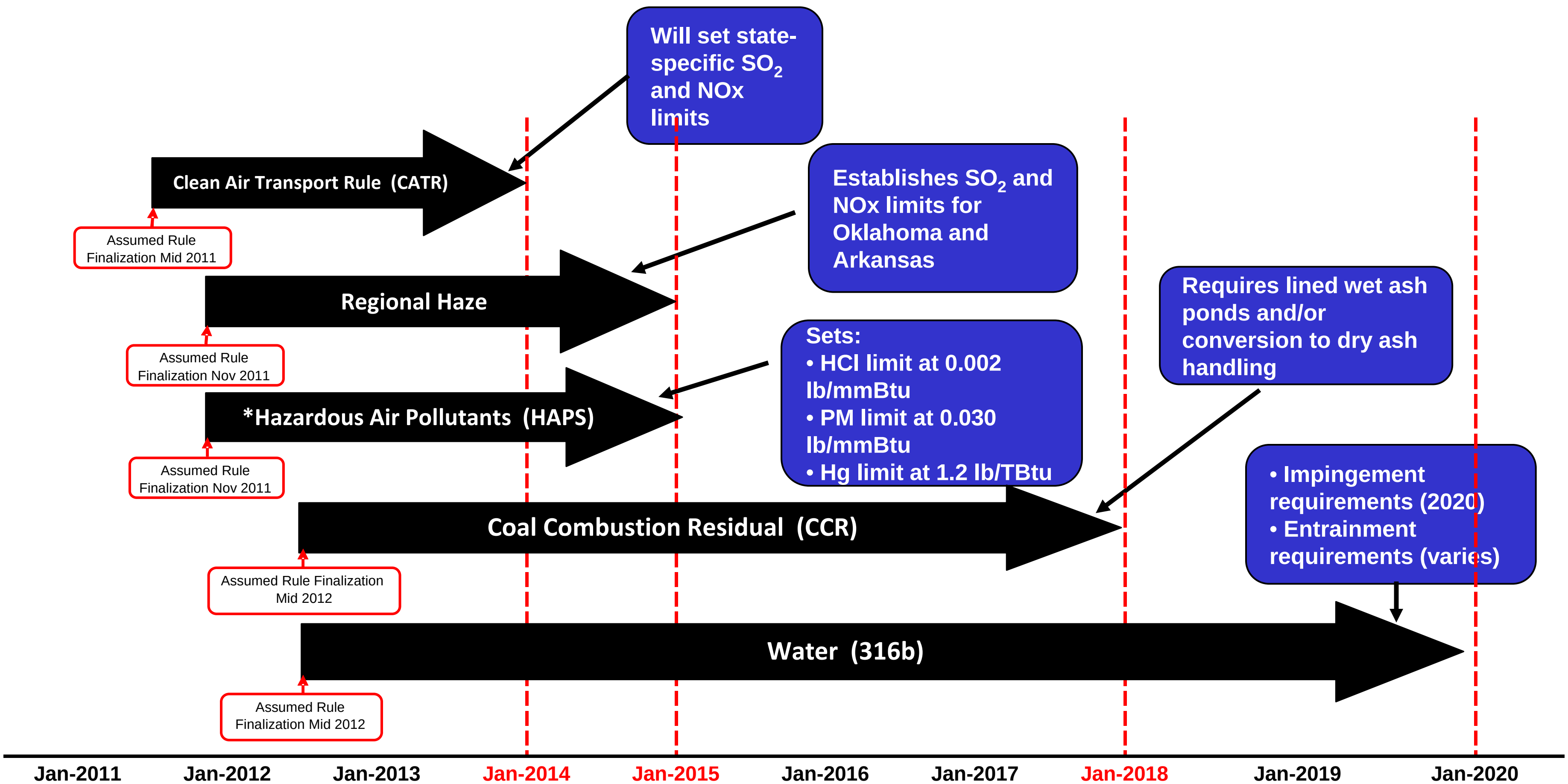
- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5	510	Refuel with Natural Gas			
	Gavin 1	1320	FGD upgrade			
	Gavin 2	1320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	*
APCO	Clinch River 1	211	Refuel with Natural Gas			
	Clinch River 2	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	**
I&M	Rockport 1	1320	FGD, SCR			
	Rockport 2	1320	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670**	***
KPCO	Big Sandy 1	640	New Natural Gas			
	Total MW	**640**	**Total Expected Cost**		**525**	

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 1	470	FGD, ACI, Baghouse		
	Northeastern 2	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

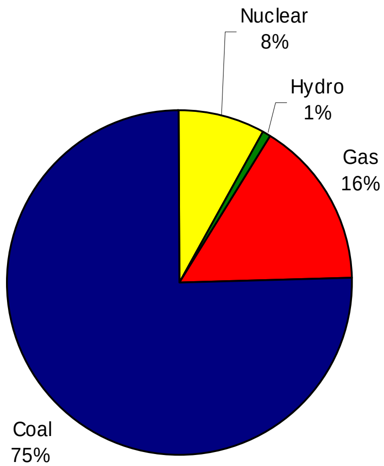
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Total MW	**2,485**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,856**	

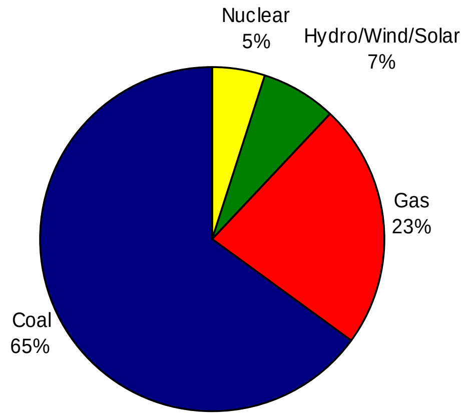
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

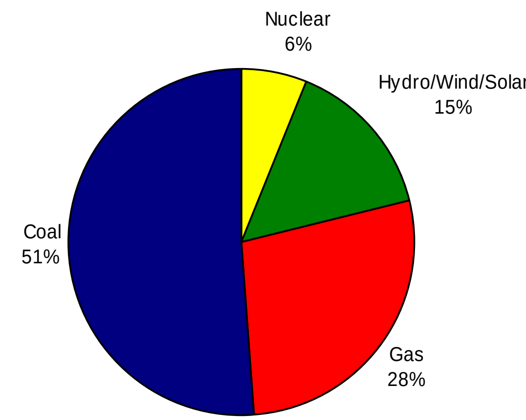
1990 AEP Generating Capacity by Fuel
37,428 total MW's



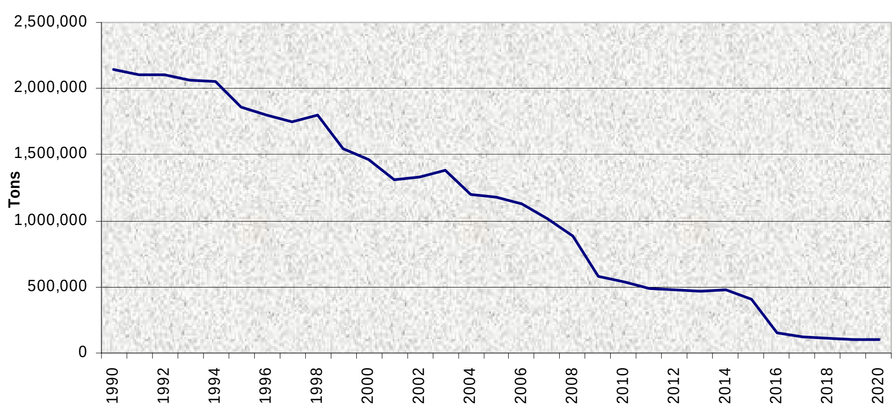
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

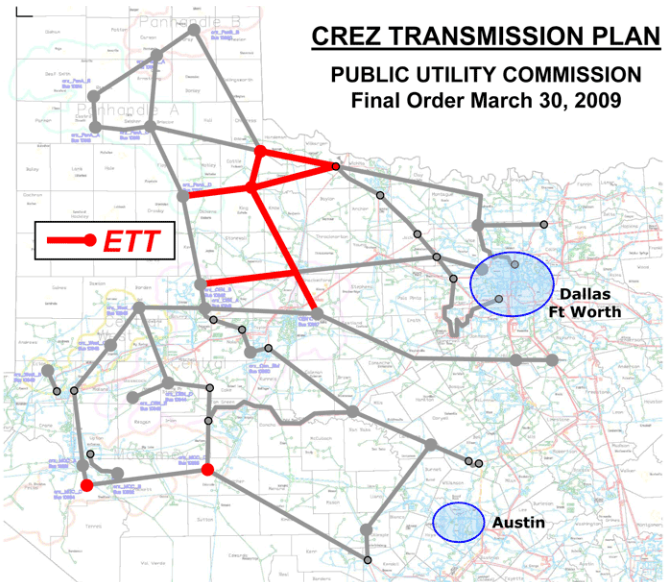
Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

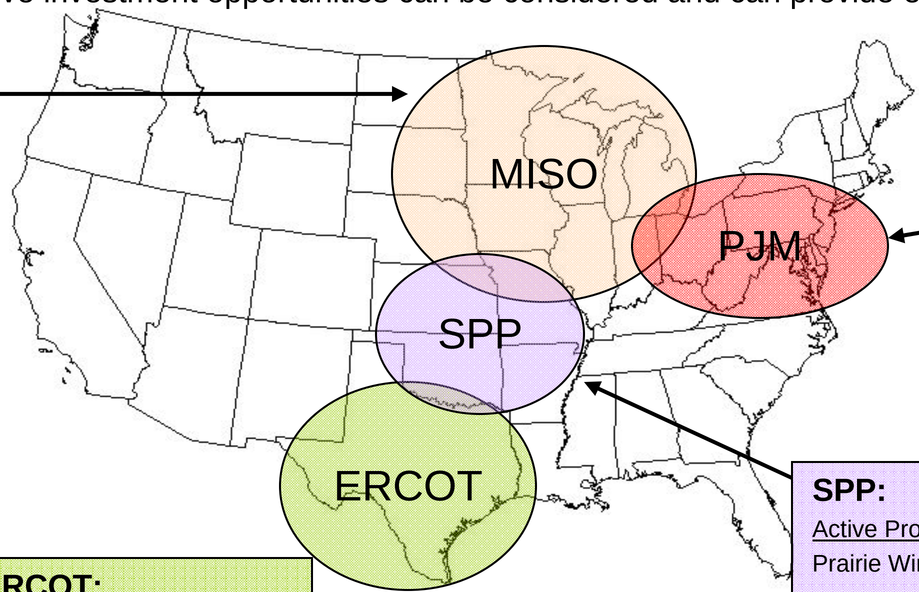
- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission



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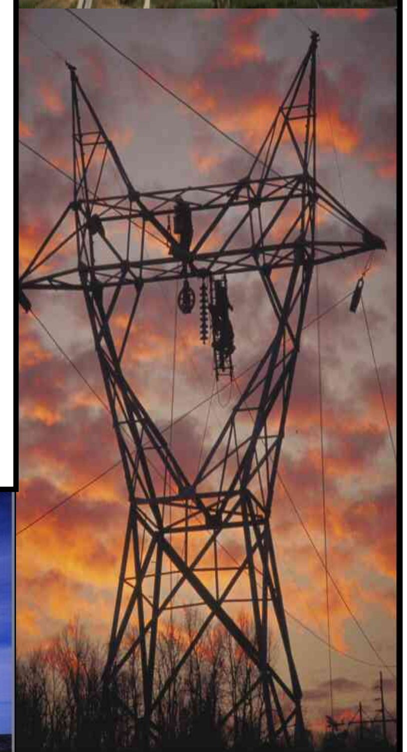
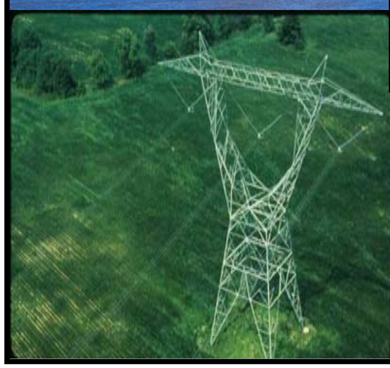

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Chairman, President & CEO

Table of Contents

Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

<u>Asset</u>	<u>Size</u>	Industry <u>Rank</u>
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
68%	**23%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

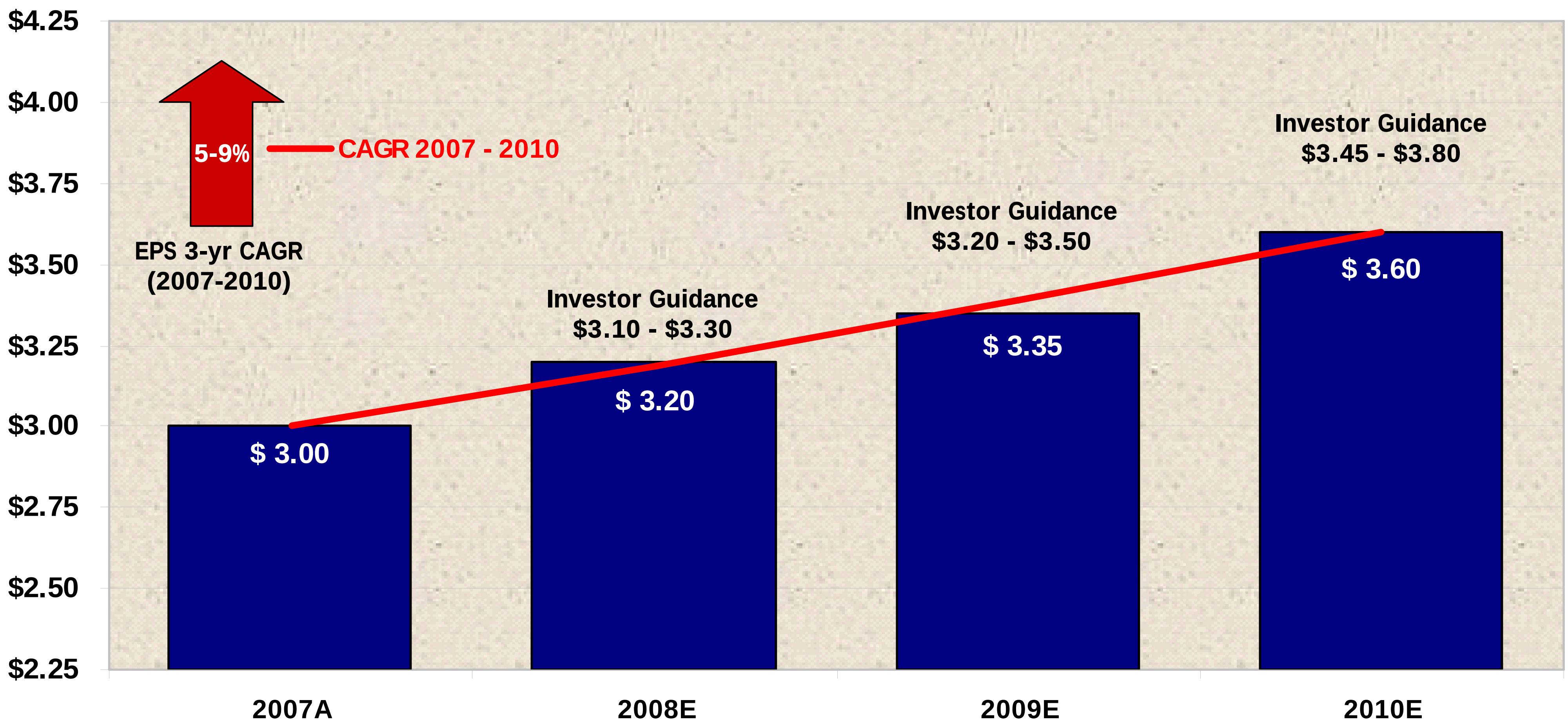
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast



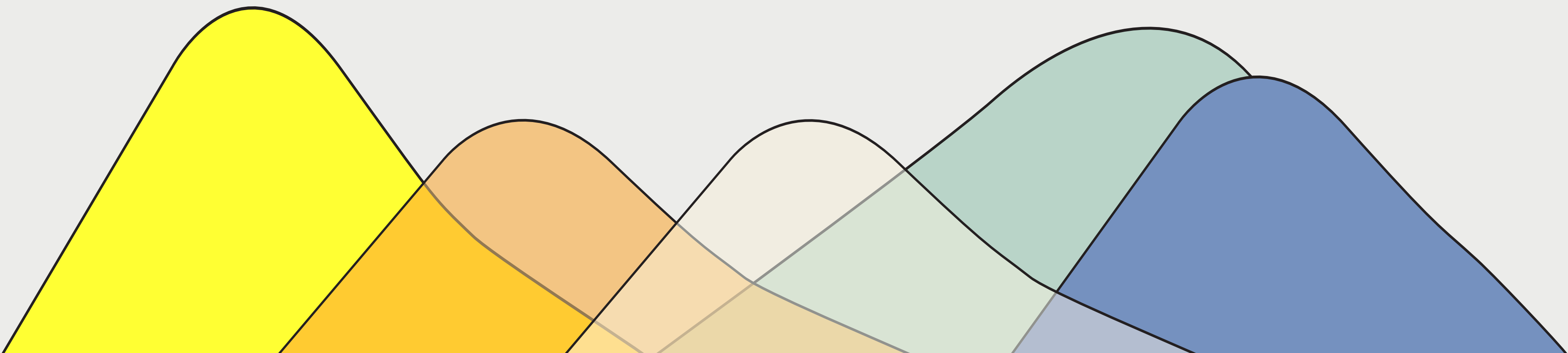
5% to 9% earnings growth

AEP®

Capital Investment Earnings Catalysts

Capital Investment - Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1-2B	$2.25B - $3.75B*	$2.0B+



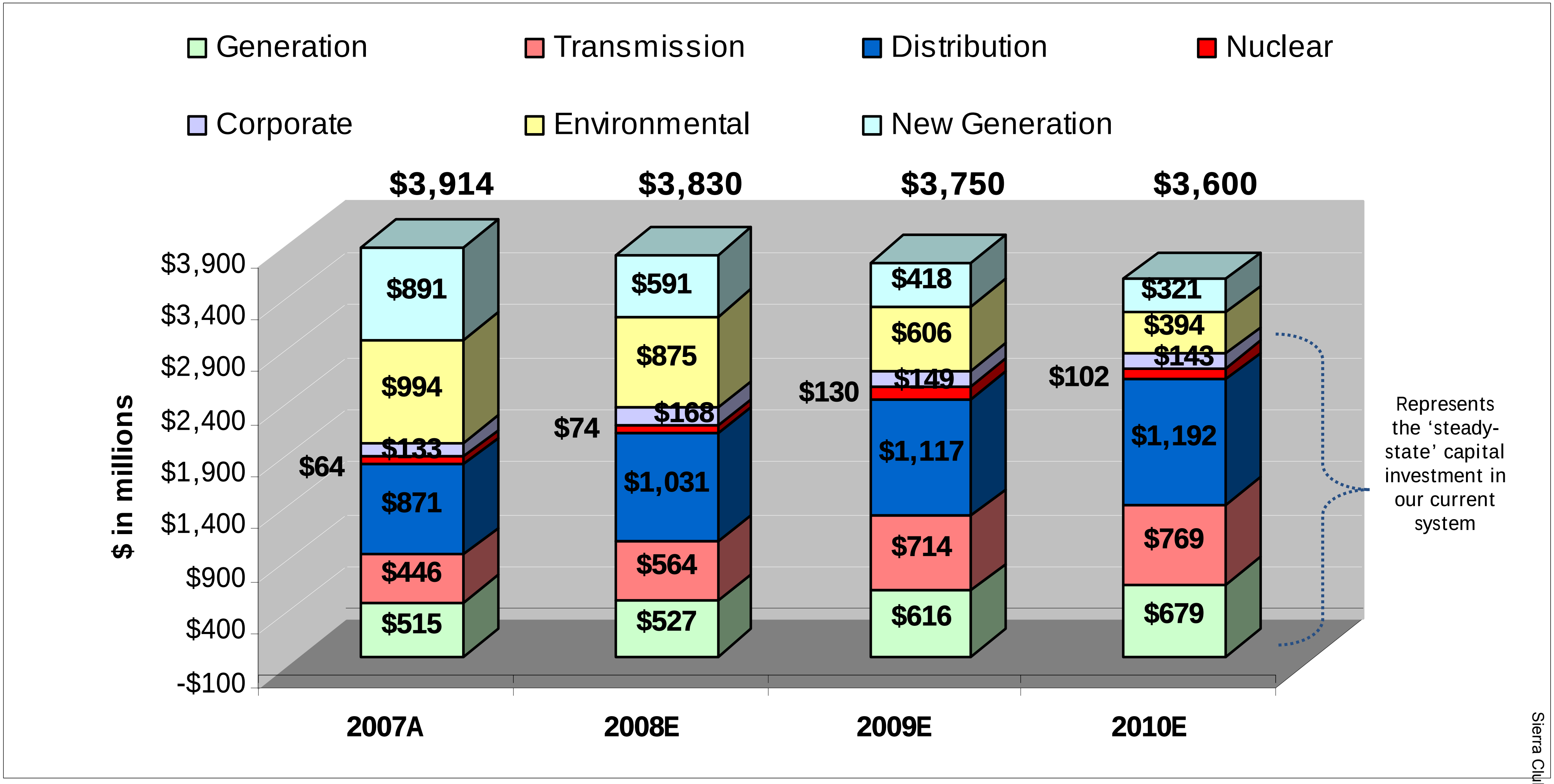
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

KPSC Case No. 2011-00401
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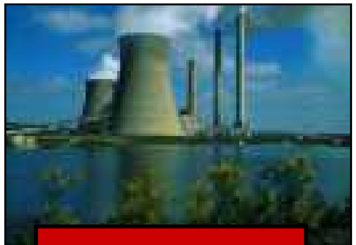
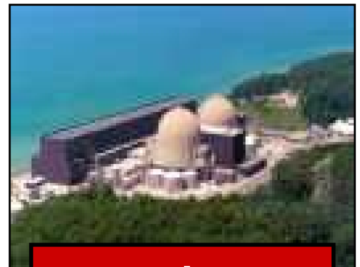
Domestic Generation Fleet

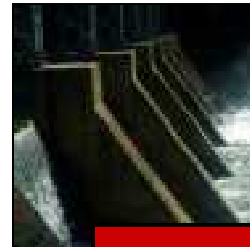


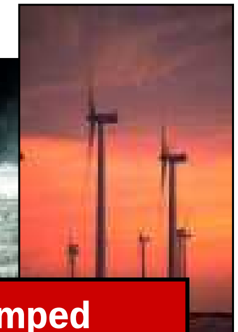
Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%





Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

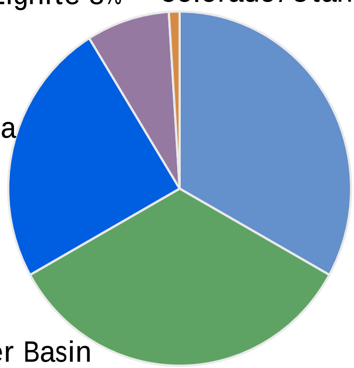
NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

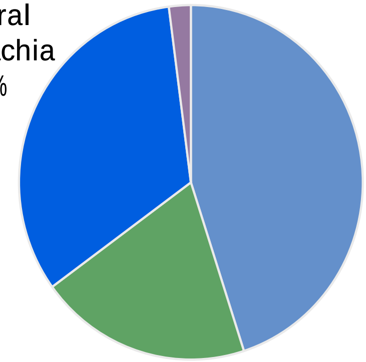
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

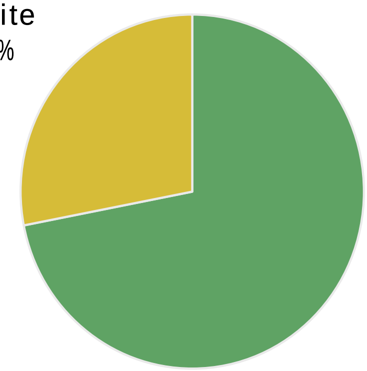
Total AEP System



AEP East



AEP West



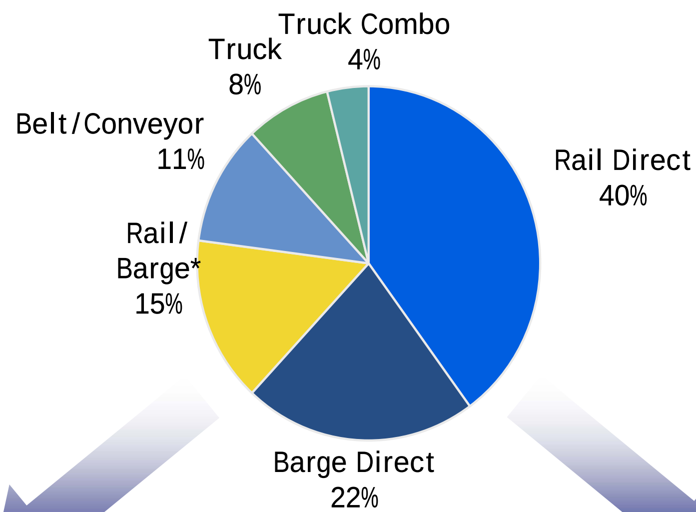
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

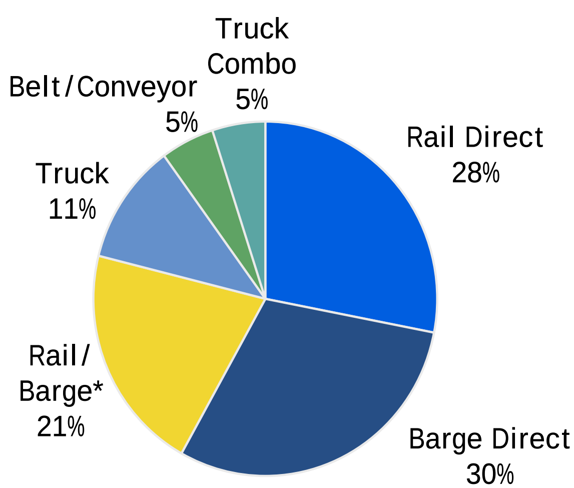
Coal Delivery

Total AEP System

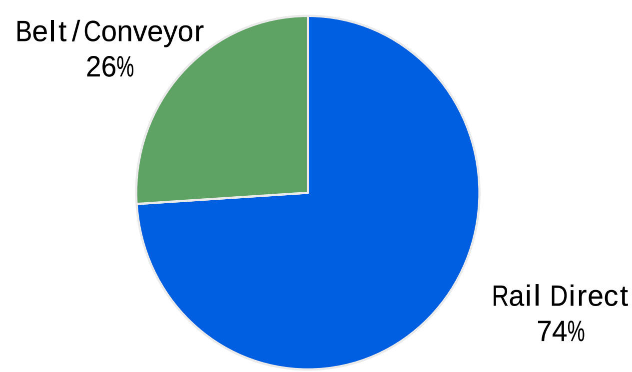
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	tbd

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $950 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the current Supreme Court of Ohio remand to the PUCO of the PUCO's April 10, 2006 Opinion and Order.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

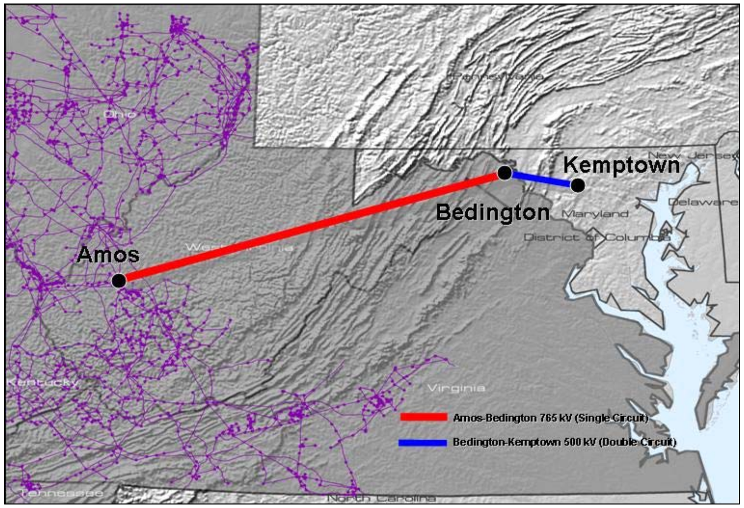
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

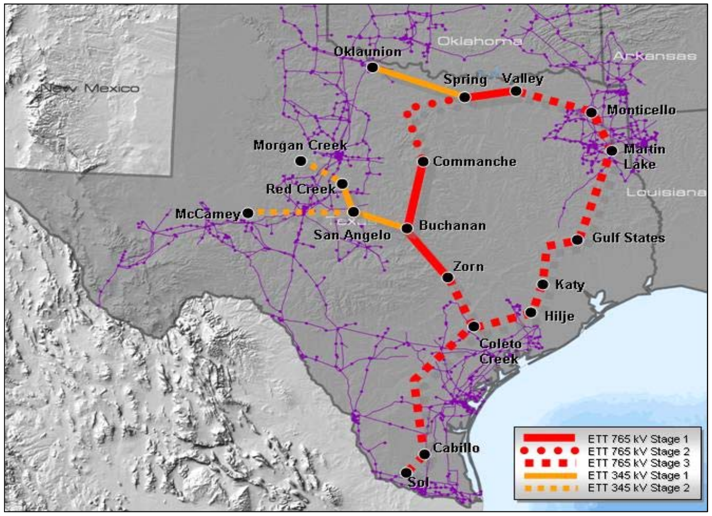
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

I-765™ Transmission: Investment Opportunities

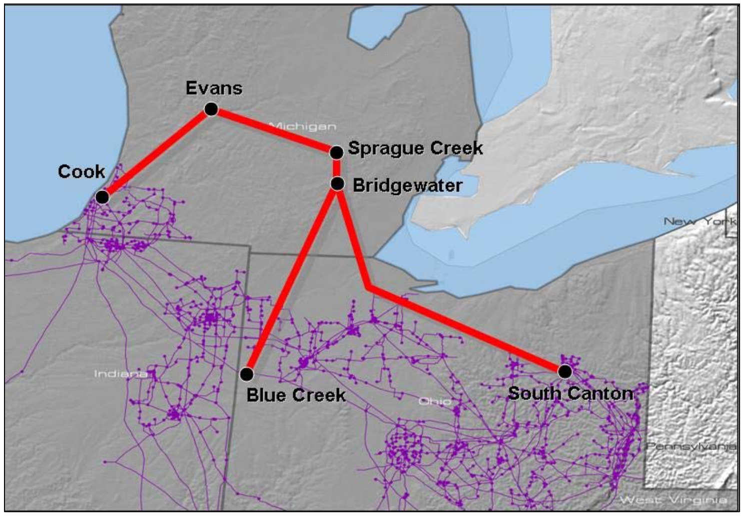
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

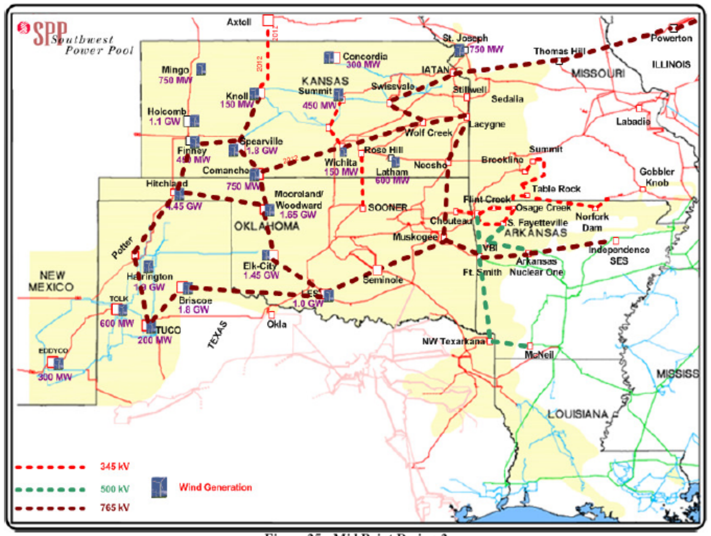
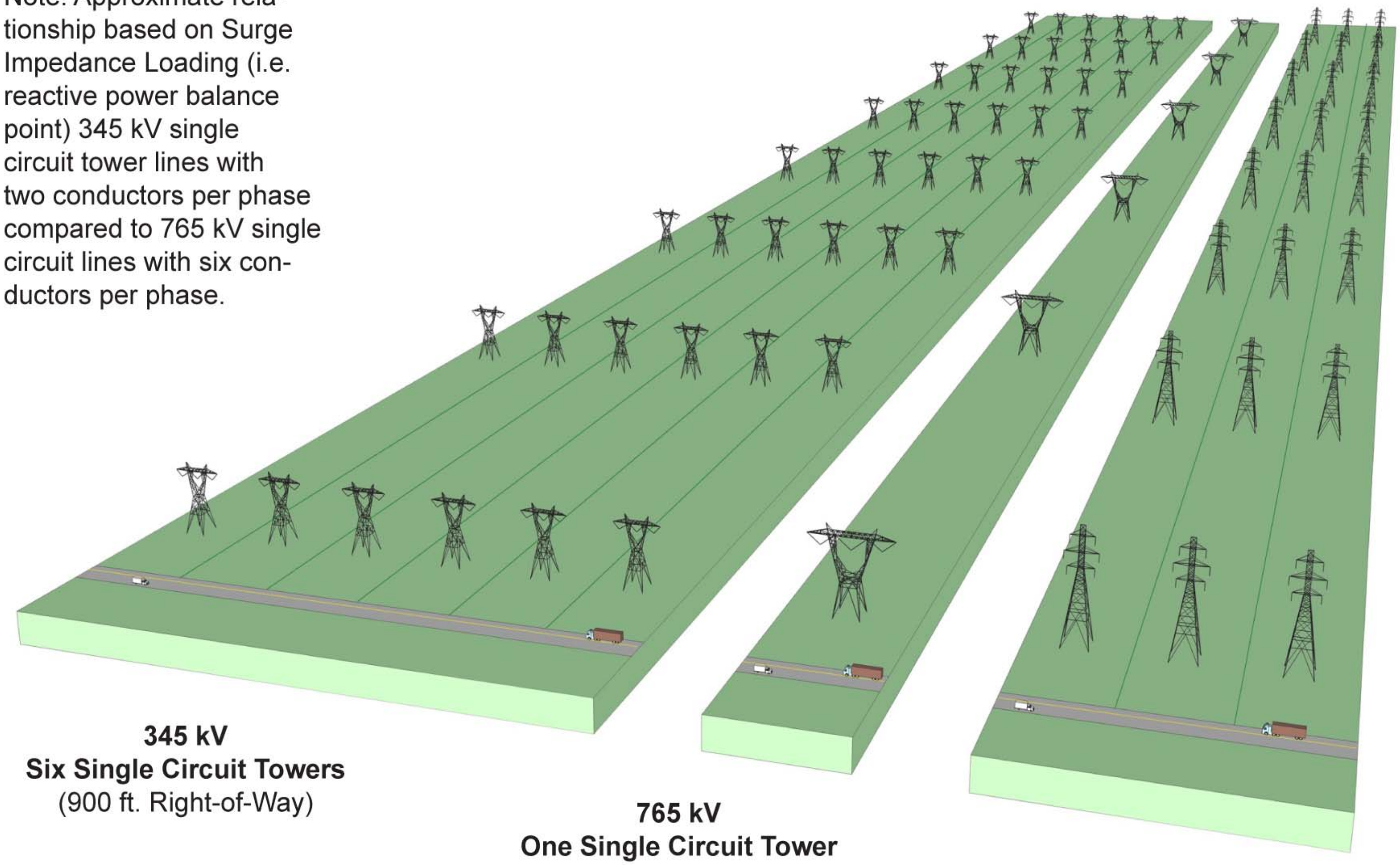


Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

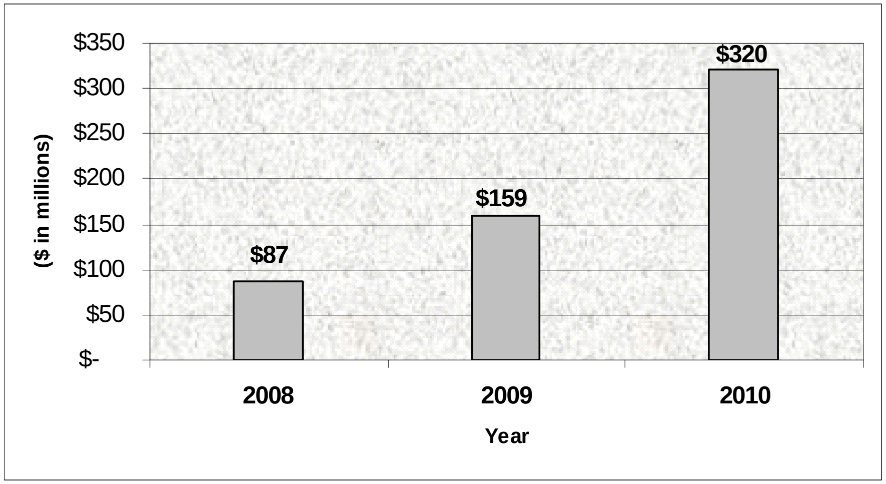
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission – Investments and Earnings Contributions

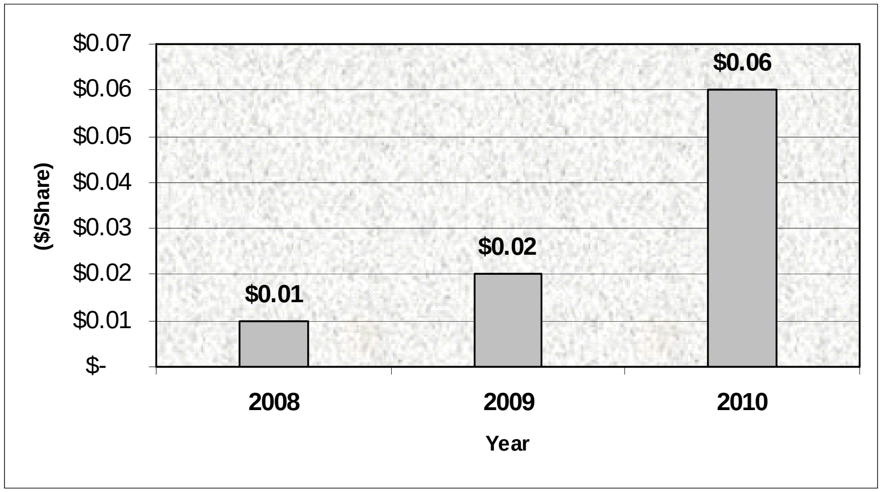
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

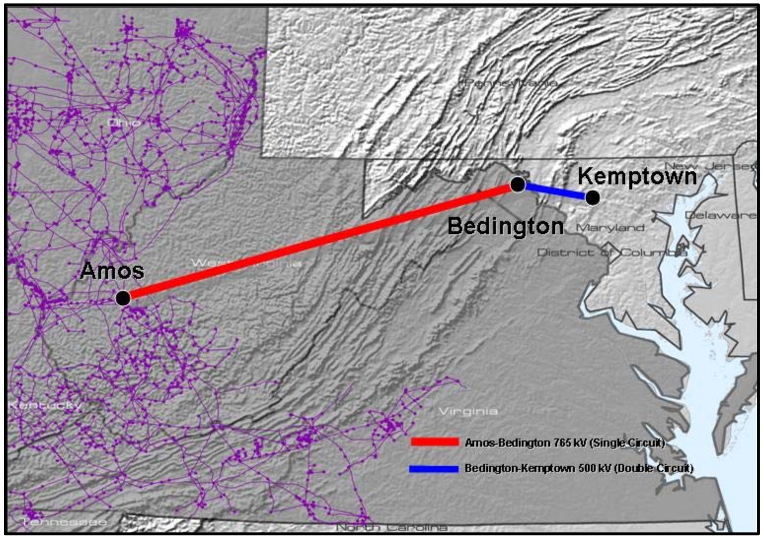
PATH Potomac-Appalachian Transmission Highline

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

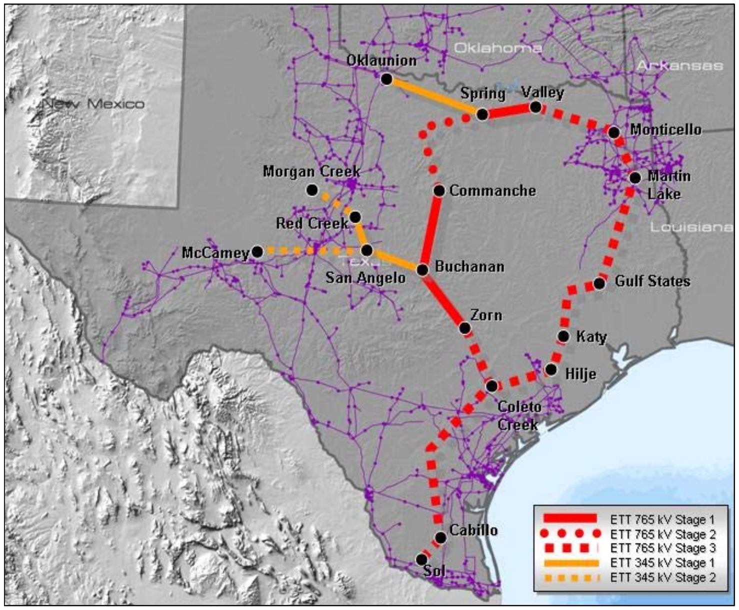
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- ### *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- ### *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- ### *ETT ERCOT Backbone Proposal*
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

Electric Transmission America (ETA)

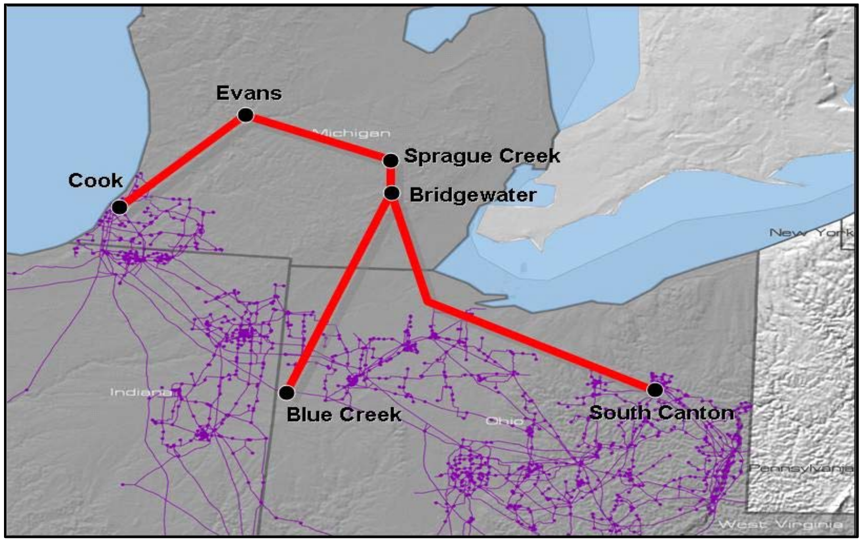
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765[TM] Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ### *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ### *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

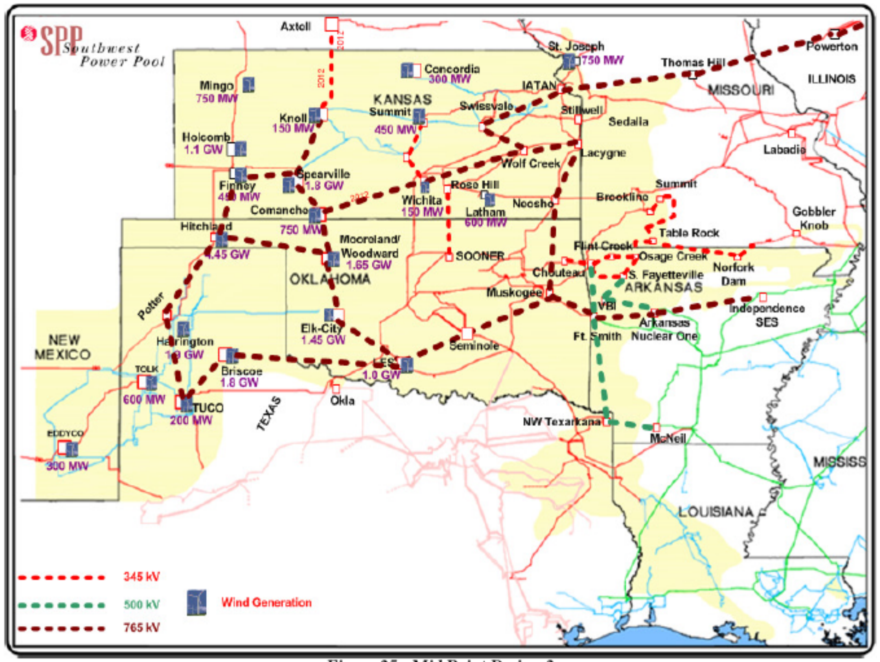


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

KPSC Case No. 2011-00401
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AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

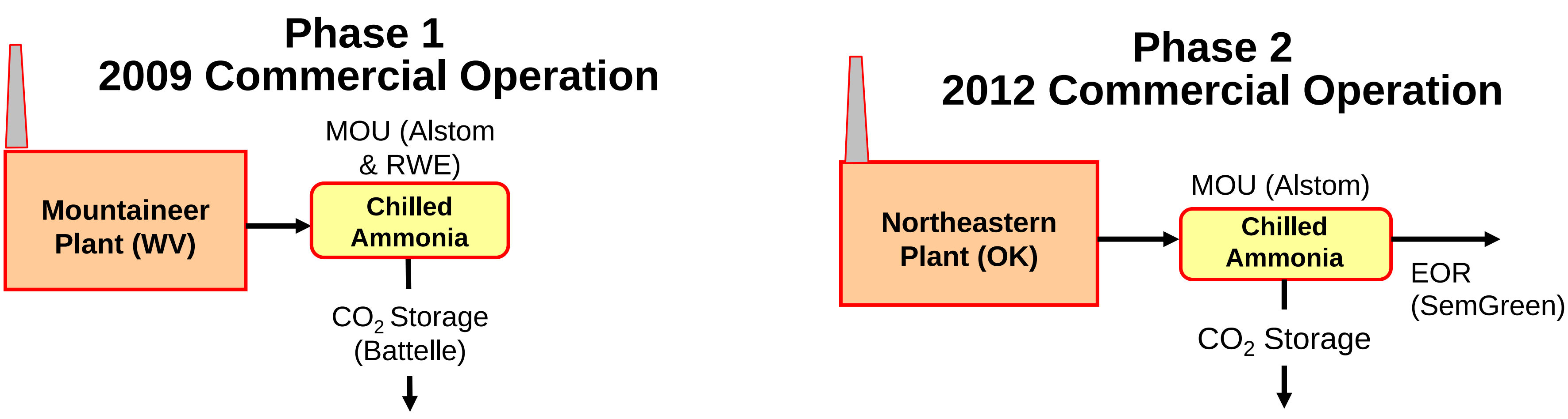
We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**



CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

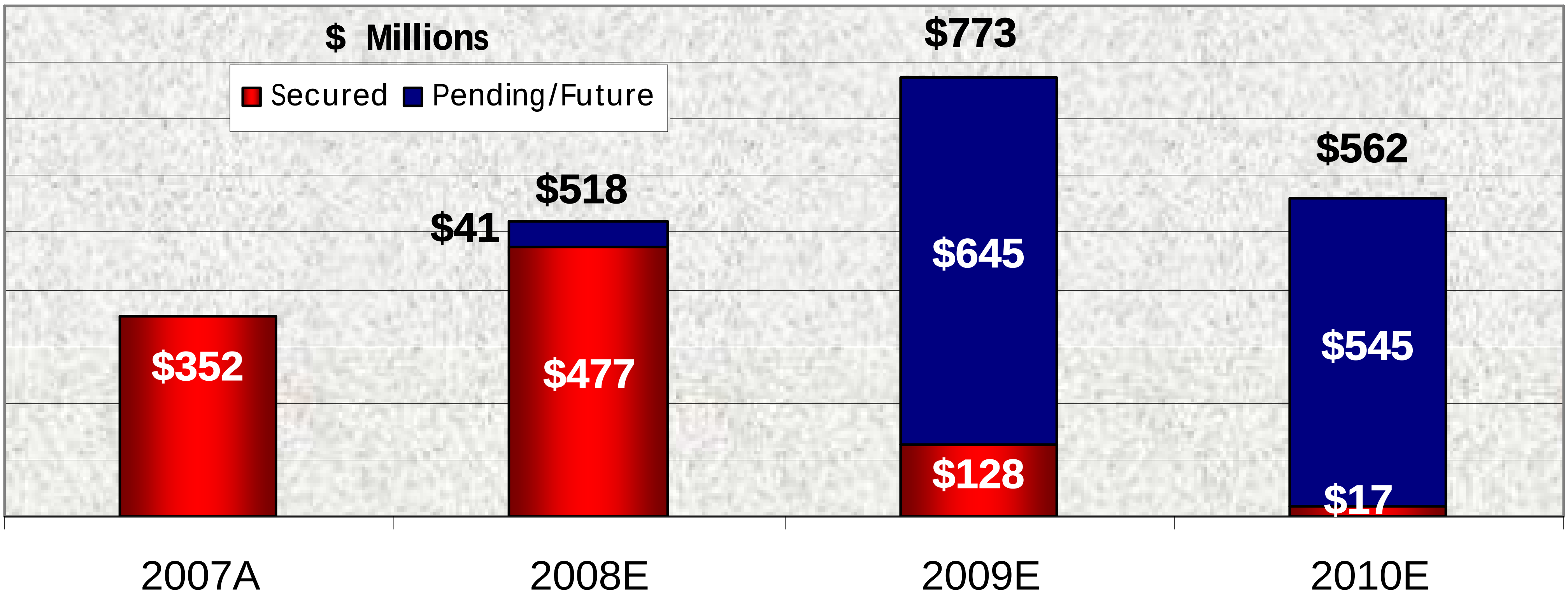
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Incremental Rate Relief Assumptions

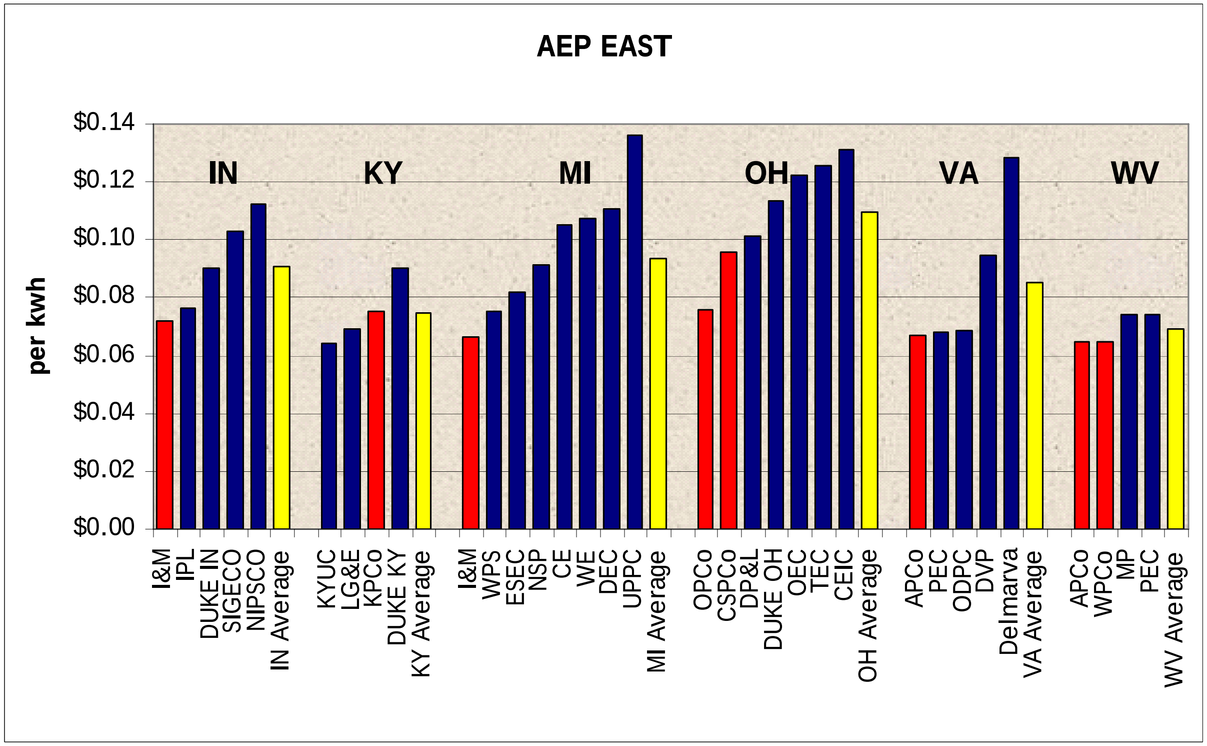


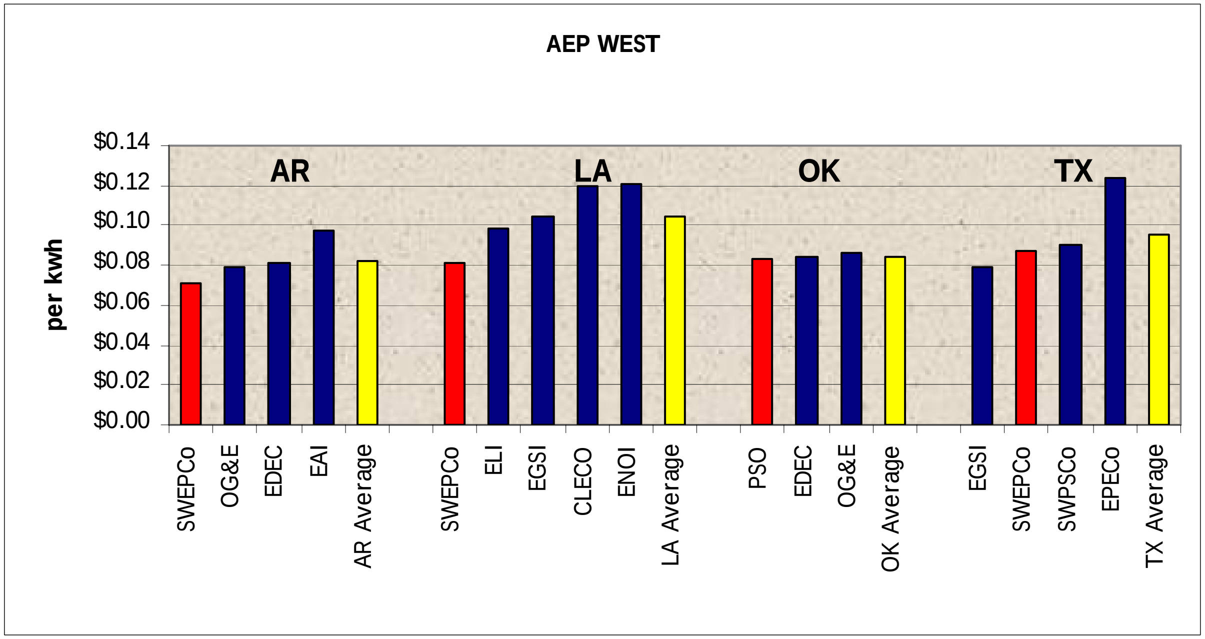
- **92% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery.**

- **2008 Pending: SWEPCo – LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia - approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio - on hold pending resolution of Supreme Court remand to PUCO
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order in April 2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. A positive ALJ report was issued on February 8, 2008 recommending approval of the plant. An order is expected in March 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. A procedural schedule is being developed and the hearing most likely will occur in May or June 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings will commence on April 8, 2008. Staff testimony was favorable.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

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Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo - Virginia	$2,022MM	10.00%	10/2/2006	8.15%
APCo - West Virginia	$1,656MM	10.50%	7/28/2006	
KPCo - Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M - Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M - Michigan	$268MM	13.00%	4/1/1991	
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992	23.86%
OPCo - Ohio	$2,183MM	12.81%	3/23/1995	13.01%
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo - Louisiana	$434MM	11.10%	12/29/1999	8.74%
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999	
SWEPCo - Texas	$474MM	15.70%	2/15/1983	
TCC - Texas	$1,566MM	9.96%	6/1/2007	11.33%
TNC - Texas	$530MM	9.96%	6/1/2007	8.32%

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Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

American Electric Power

Boston Investor Meetings
Hosted by A.G. Edwards
May 3, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

A Century of Firsts

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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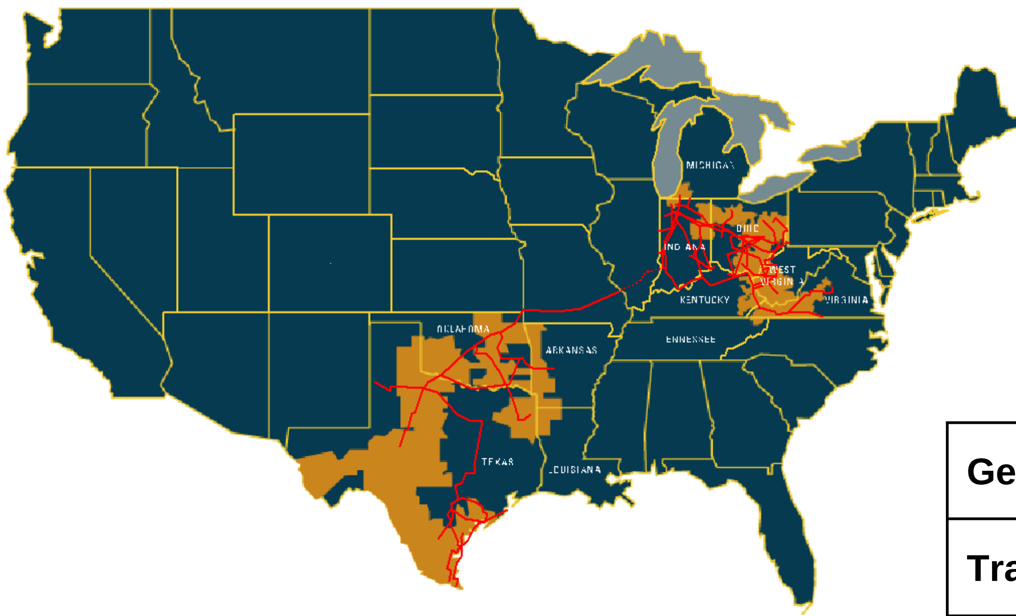
A Century of Firsts

Mike Morris
Chairman, President & Chief Executive Officer

Asset Portfolio

Strength & Scale in Assets & Operations

A Century of Firsts



Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

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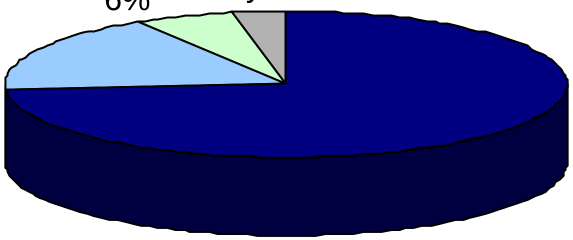
Asset Portfolio: Generation Fleet Composition

A Century of Firsts

- 35,600 MW Domestic Capacity
- 85% System Availability Factor YE 2005
- 63% System Capacity Factor YE 2005

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	23,985	0	1,954
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**29,902**	**3,516**	**2,142**

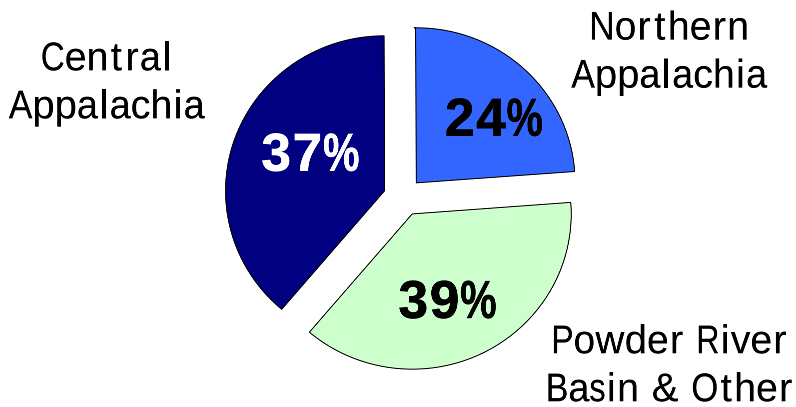
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel

Coal Procurement

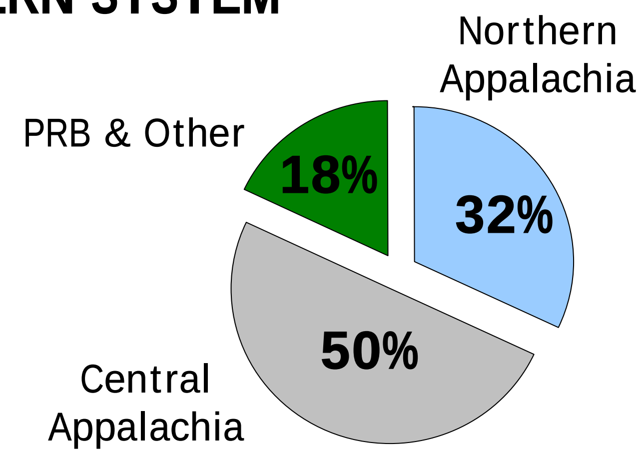
AEP SYSTEM



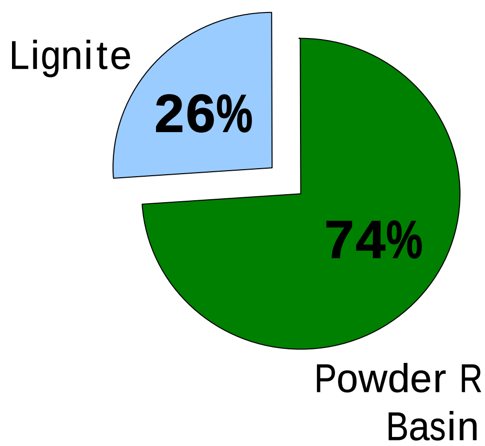
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Essentially >97% purchased for 2006
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM

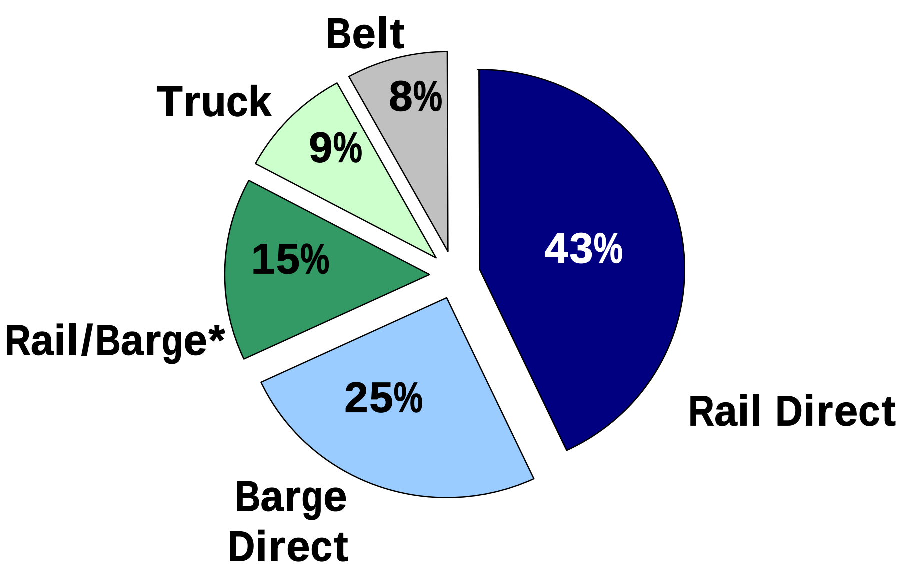


WESTERN SYSTEM

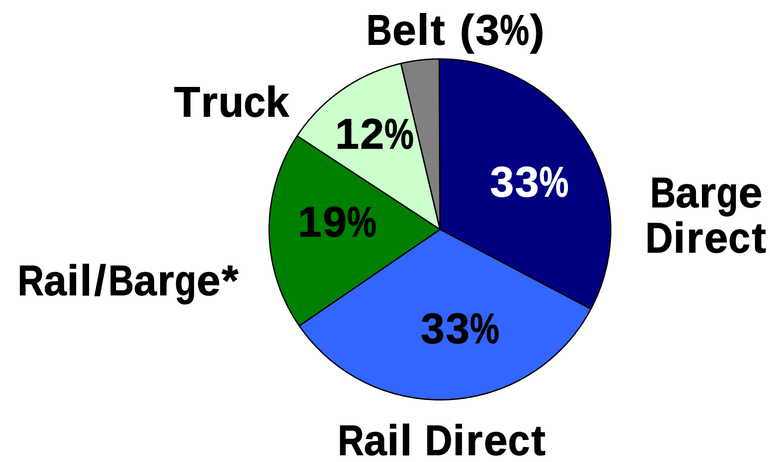


Coal Delivery

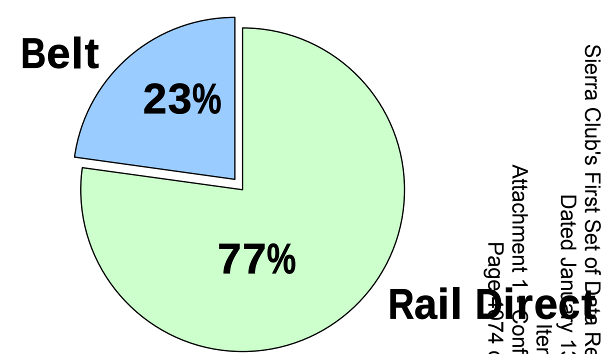
AEP SYSTEM
DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



WESTERN SYSTEM
2005 Actual

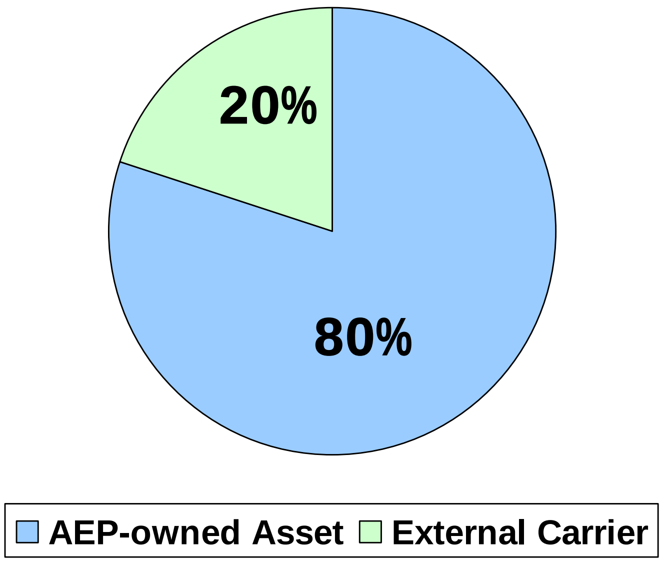


* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

A Century of Firsts

Coal Transportation to AEP Plants*
2005 Actual



AEP's substantial coal transportation assets include:

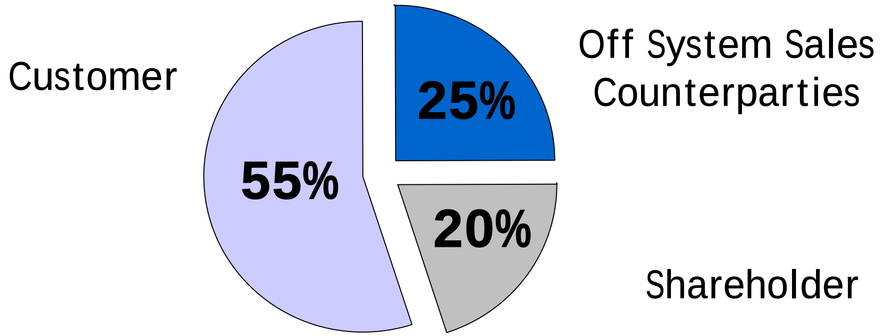
- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

* Represents close approximations

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KGP, KPCo
  - AEP WEST: PSO, SWEPCO

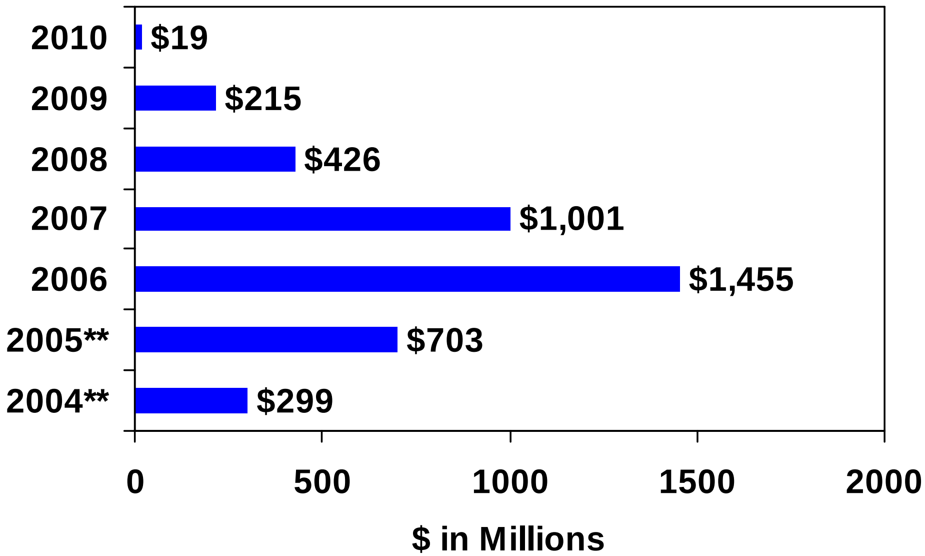
Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

Environmental

$4.1 Billion Environmental Investment

A Century of Firsts

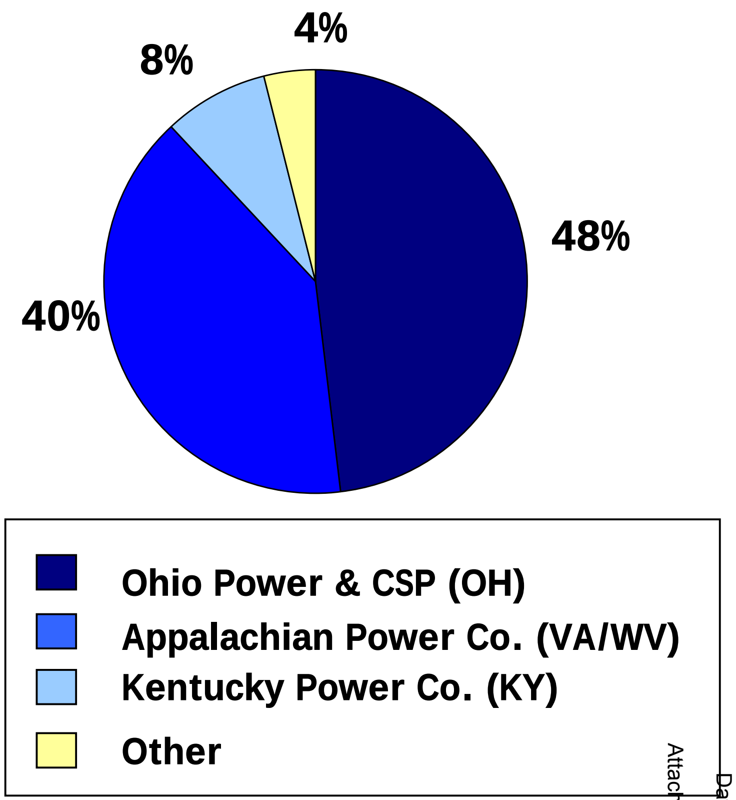
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

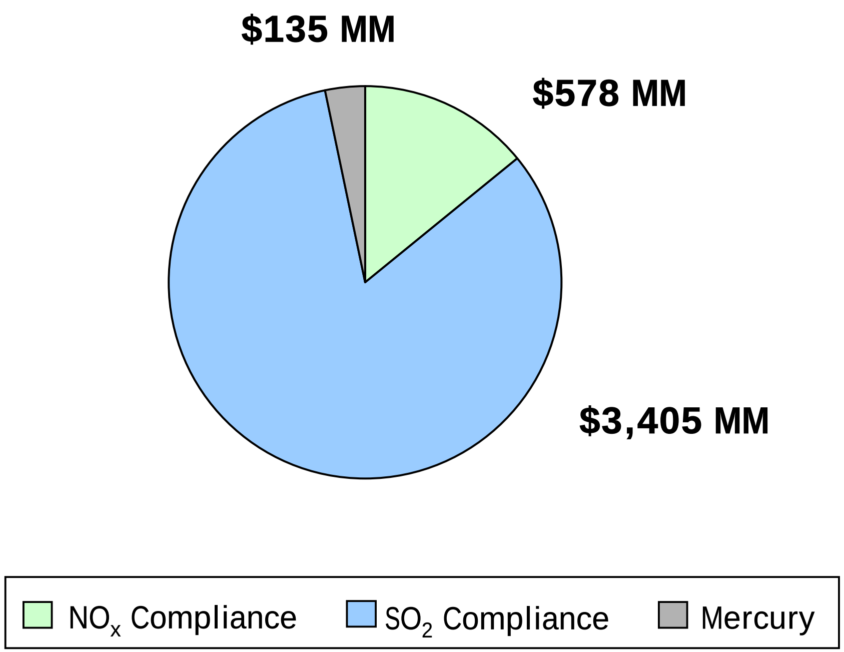
Projected Environmental Investment Allocation



MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT
PROJECTED 2004 THROUGH 2010

Figures Include AFUDC.

Environmental Installations

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FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

2006 – 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

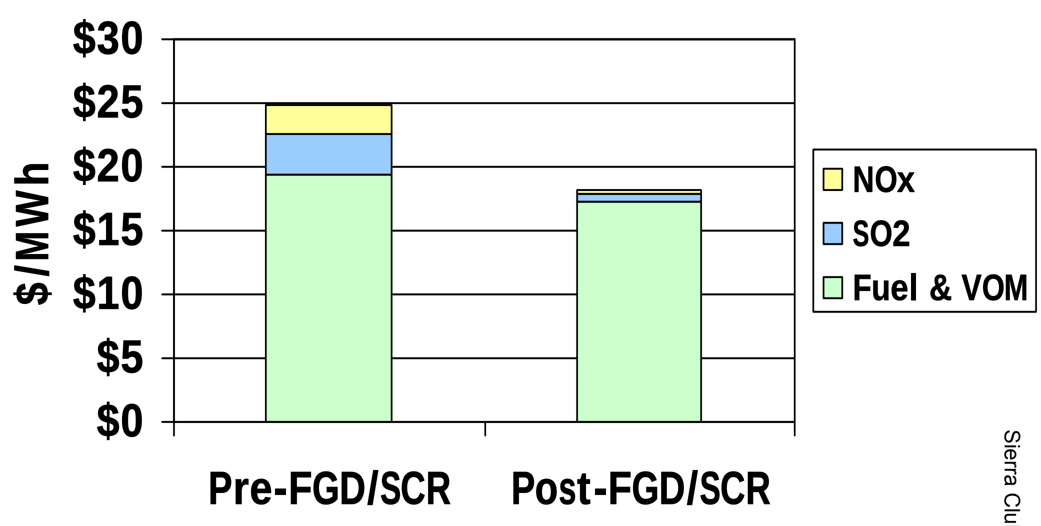
Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Investing in IGCC

Integrated Gasification Combined Cycle

A Century of Firsts

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

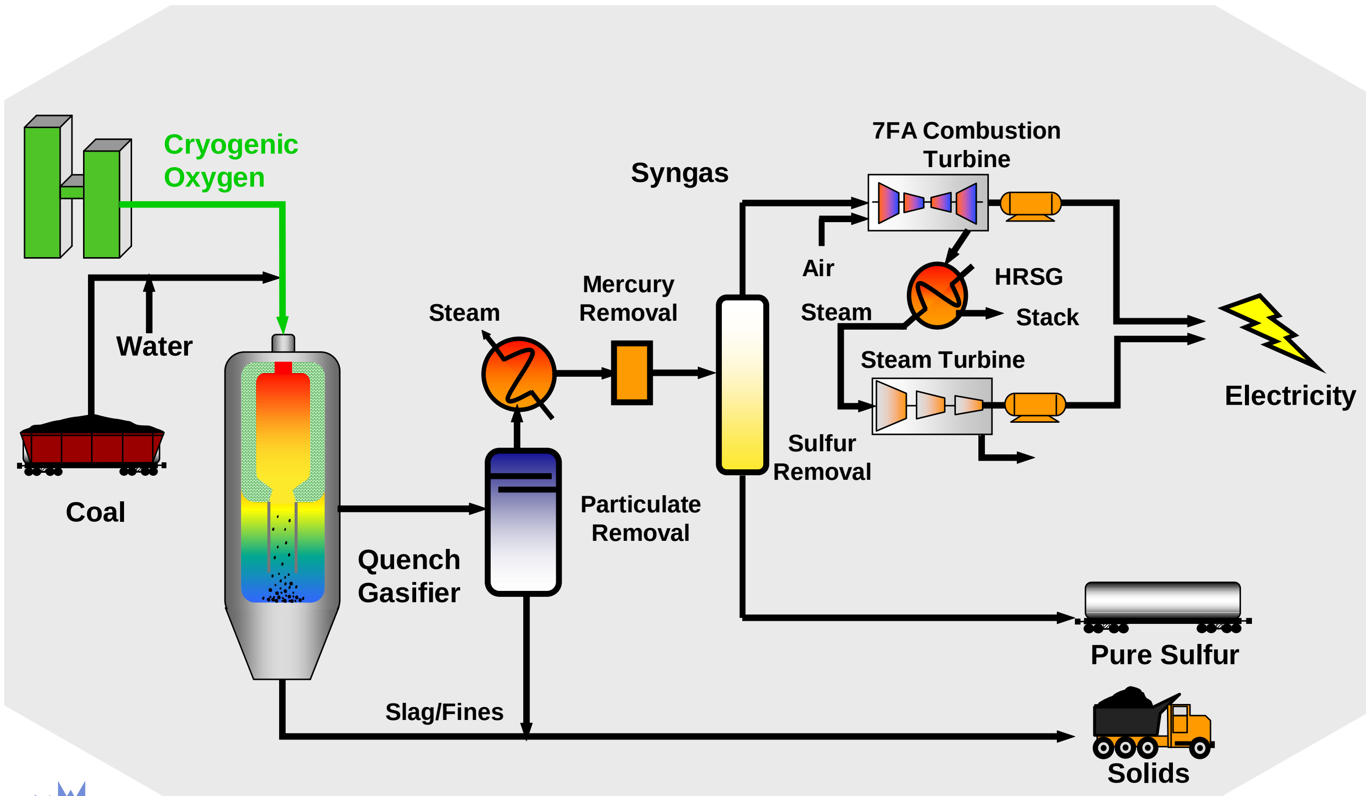
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Regulatory Overview

Regulatory Activity Underway

A Century of Firsts

- ✓ TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ Indiana Depreciation Petition
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia – Settlement Pending
- ✓ IGCC – Received Rate Authorization of Pre – Construction Costs

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Texas Regulatory Activity

A Century of Firsts

<u>TCC Stranded Cost Recovery Case</u>

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - ➢ Final order expected in June or July 2006
  - ➢ September 2006 - Issuance of securitization bonds if no appeal

<u>Procedural Schedule for TCC Securitization</u>

- ✓ April 17, 2006 – Intervenors Files Testimony
- ✓ April 24, 2006 – Staff File Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 25-26, 2006 – Hearings On Merit

- May / June 2006 – Request approval for CTC to address other true-up items
  - ➢ Expected $475 million credit to customers
  - ➢ Sept 2006 – CTC to be implemented

Regulatory Activity Underway

A Century of Firsts

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in third quarter 2006

Appalachian Power

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case – Gave notice to VA SCC on March 1, 2006 of intent to file general rate case no sooner than May 1, 2006

Regulatory Activity – Settlement Pending

A Century of Firsts

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Filed April 25, 2006 - Joint Settlement Agreement

- ✓ Estimated Overall impact of Revenue increases to be phased-in through 2009
  - ➢ $129 Million
  - ➢ 16% Increase
- ✓ Provides for timely recovery of Wyoming-Jacksons Ferry 765 kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC Over-Recovery Negative Surcharge

** Estimated

Settlement Details

✓ Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
$23MM	WJF & FGD @ 12/31/05
$61MM	Gross Revenue Increase
($17MM)	ENEC Over-Recovery Negative Surcharge
$44MM	Net Increase effective 7/28/06

✓ Phased-In Revenue Increases on July 1 in each year 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

IGCC Regulatory Activity

A Century of Firsts

Ohio - Cost Recovery Filing

Phase 1 - PUCO AUTHORIZED

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ **Secure cost recovery plan**
  - **April 10, 2006 - PUCO authorized implementation of Phase 1 Rates**
  - **Phase 2 & 3 ruling - Post October 2006 - after completion of FEED study**
- ✓ **Finalize site selection**
- ✓ **Negotiate with suppliers**

2006—2007:

- ✓ **Obtain permits and finalize engineering and procurement**

2007—2010:

- ✓ **Construct and start-up plant**

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

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Ohio - Rate Stabilization Plan (2006 - 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- ✓ $41 million annual increase in base rates
- ✓ Rates implemented March 30, 2006

In Hand to Date - $350MM of the $500MM Rate Recovery in 2006 Guidance

Summary Rate Case Information

A Century of Firsts

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	1,676	1,970	2,018	2,253

Remaining Procedural Schedule*

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order issued.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Summary Rate Case Information

A Century of Firsts

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

A Century of Firsts

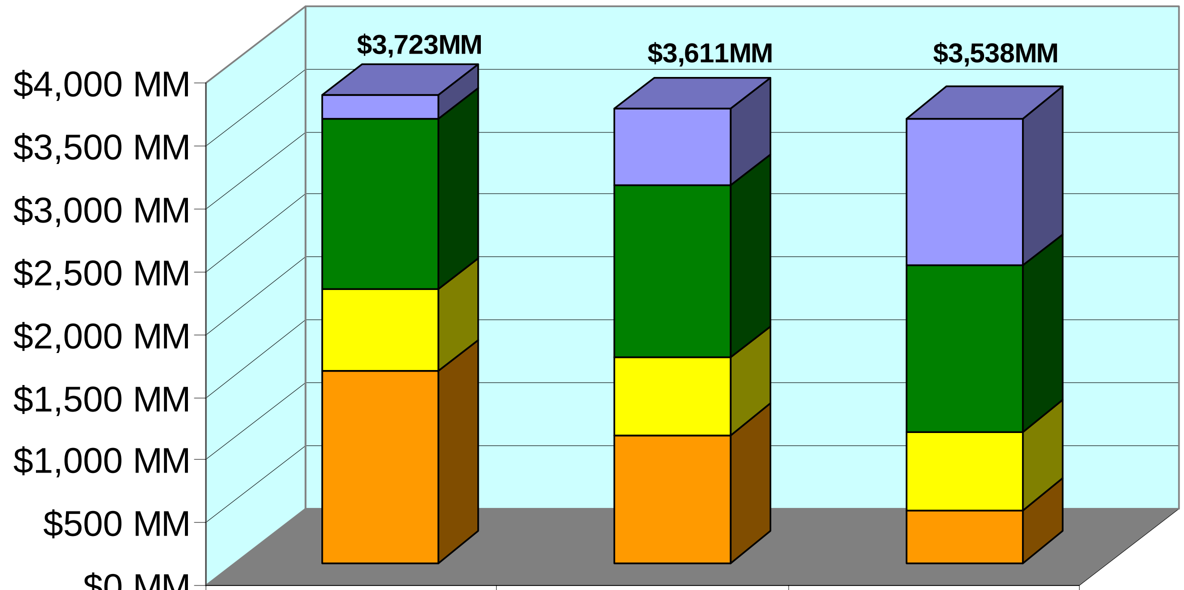
Capital Investment

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC

New Build Generation & Ongoing Infrastructure Replacement investment can be throttled



	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Forecasted Capital Expenditures

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Company	2006	2007	2008
		(in thousands)	
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

New Generation

A Century of Firsts

IGCC

- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 megawatt facility to begin in 2007
- Commercial operation date expected in 2010

PSO RFPs

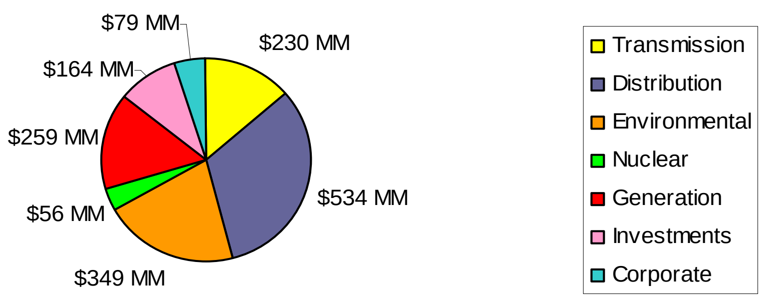
- Submitted RFPs totaling 900 megawatts of baseload and peaking capacity
- Commercial operation dates expected in 2008 and 2011

SWEPCO RFPs

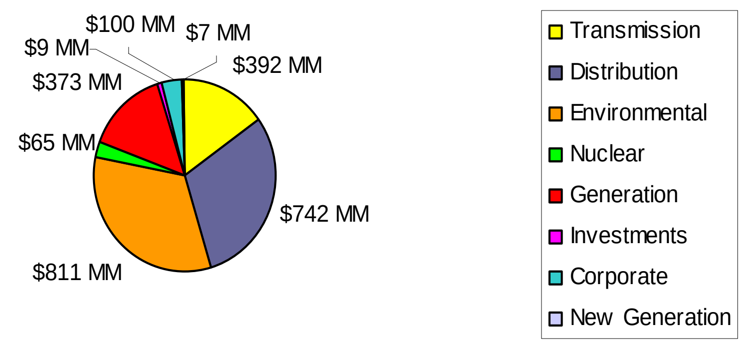
- Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity
- PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment 2004 - 2006

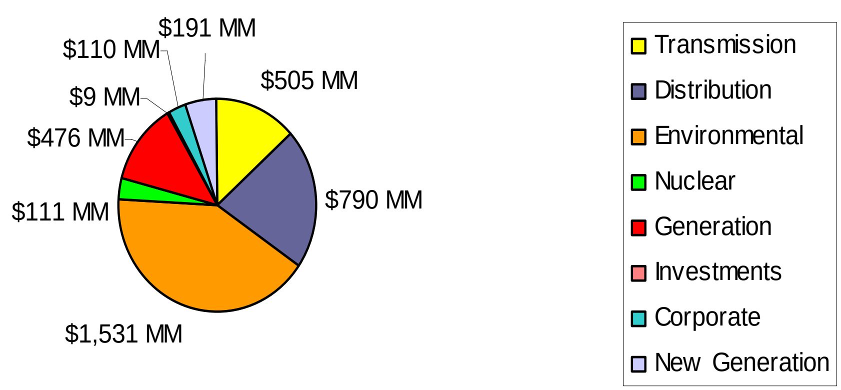
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Finance

2006 Earnings Guidance Range: $2.50 - $2.70

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		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

2006 Projected Cash Flow

A Century of Firsts

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capitalization

A Century of Firsts

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.5% at 3/31/06

Appendix

Framework For 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Summary of Major 2006 Earnings Drivers

- ✓ Load growth of 2.5%
- ✓ $500MM rate recovery assured or in progress
- ✓ Rising fuel costs of 11-13%
- ✓ Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- ✓ Decline in utility operations O&M
- ✓ Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

A Century of Firsts

2006 EPS Guidance Range is \$2.50 to \$2.70

2006

- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

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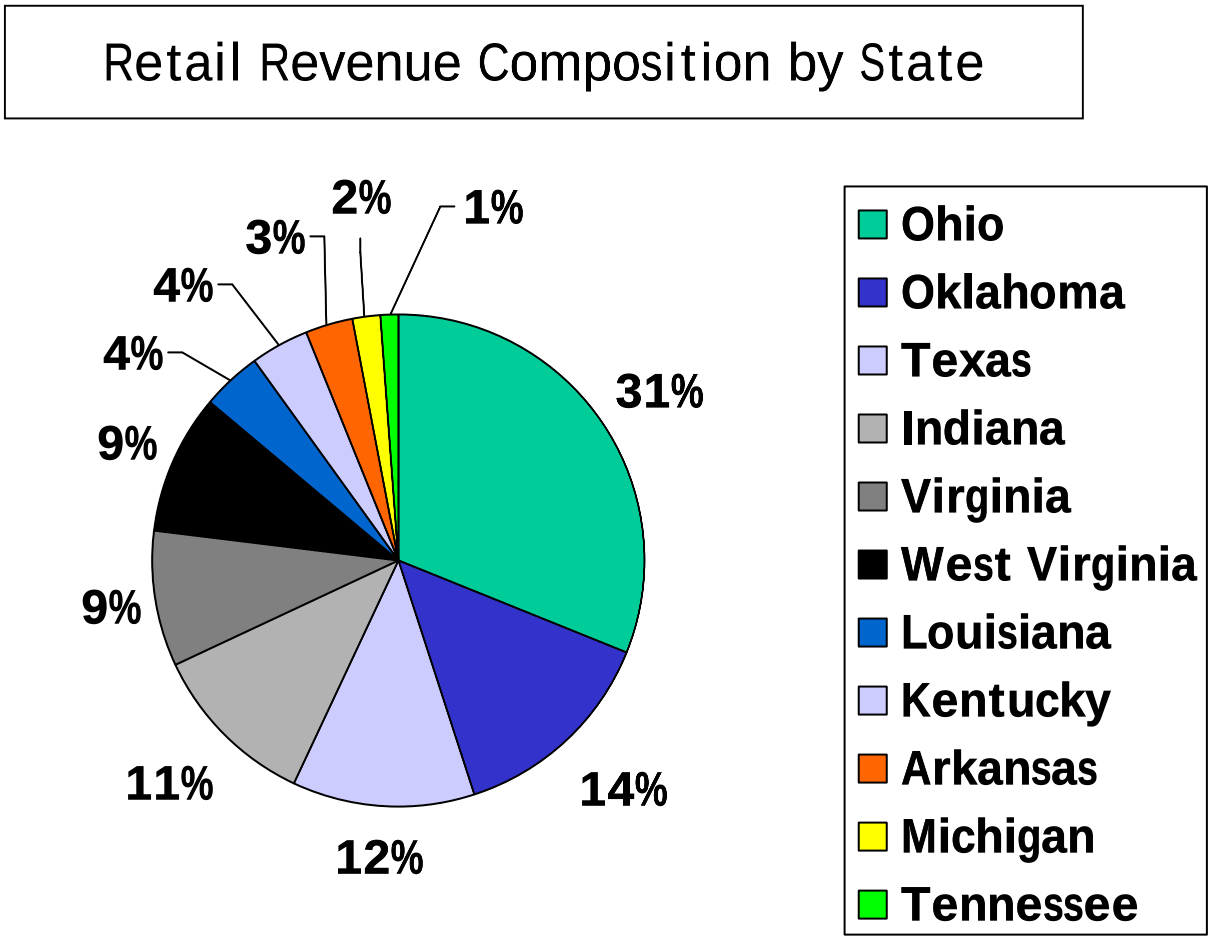
2005 Retail Revenue



What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

Boston Investor Meetings

July 12, 2005

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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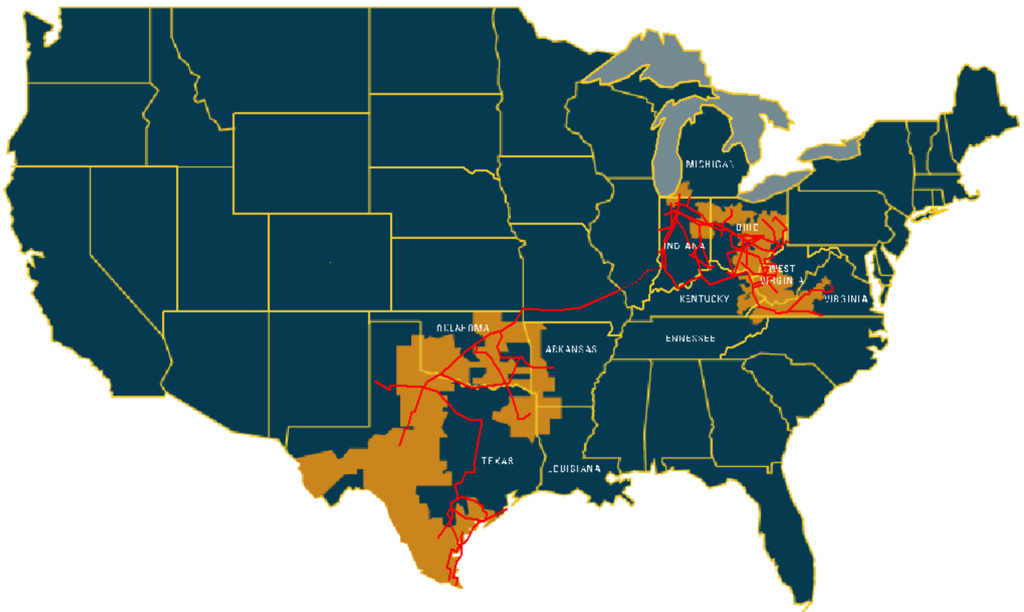
Asset Portfolio

Strength & Scale in Assets & Operations



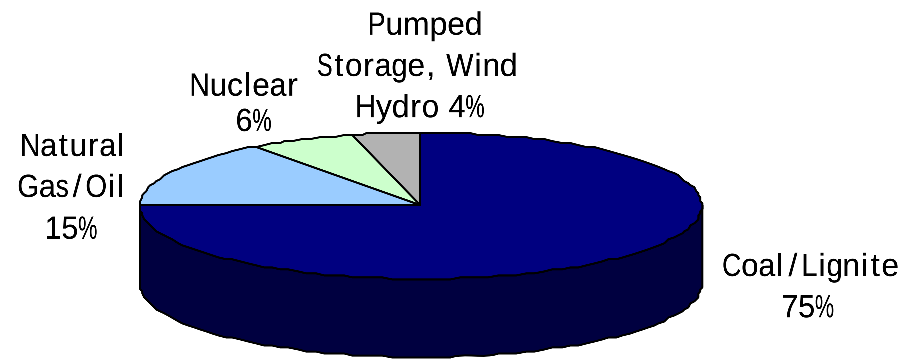
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

Capacity by Fuel Mix

- ➢ 35,500 MW Domestic Capacity
- ➢ 85% System Availability Factor YE 2004
- ➢ 62% System Capacity Factor YE 2004



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

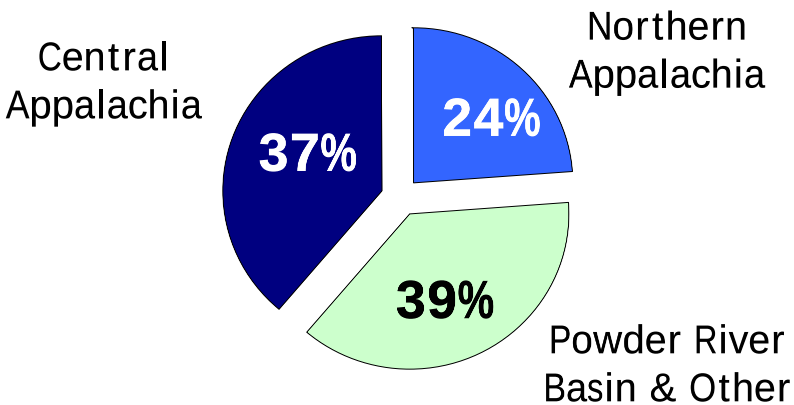
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Coal Procurement

AEP SYSTEM

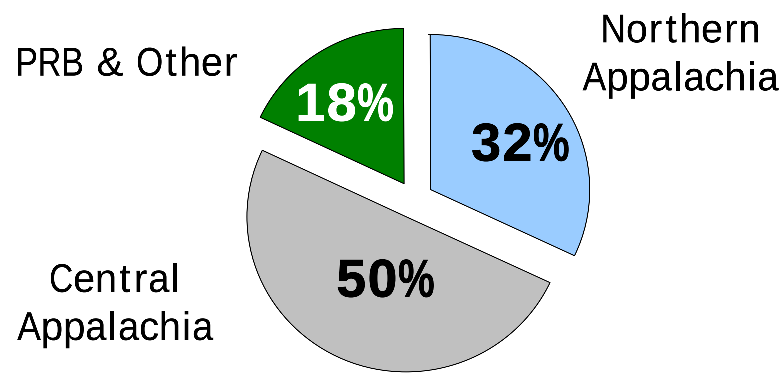


Coal Supply

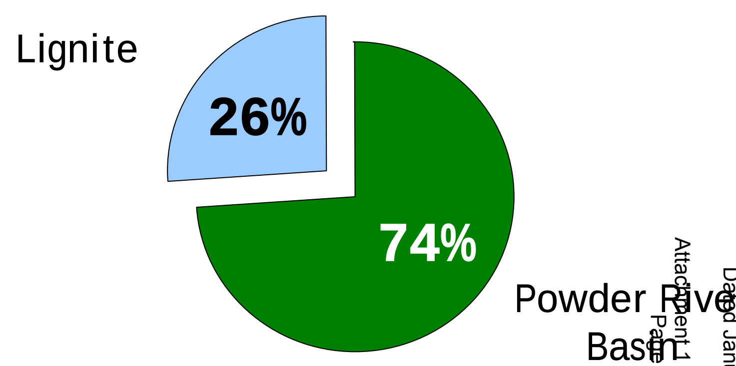
(on average)

- ➢Purchase 75 MM tons per year
- ➢Avg. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM

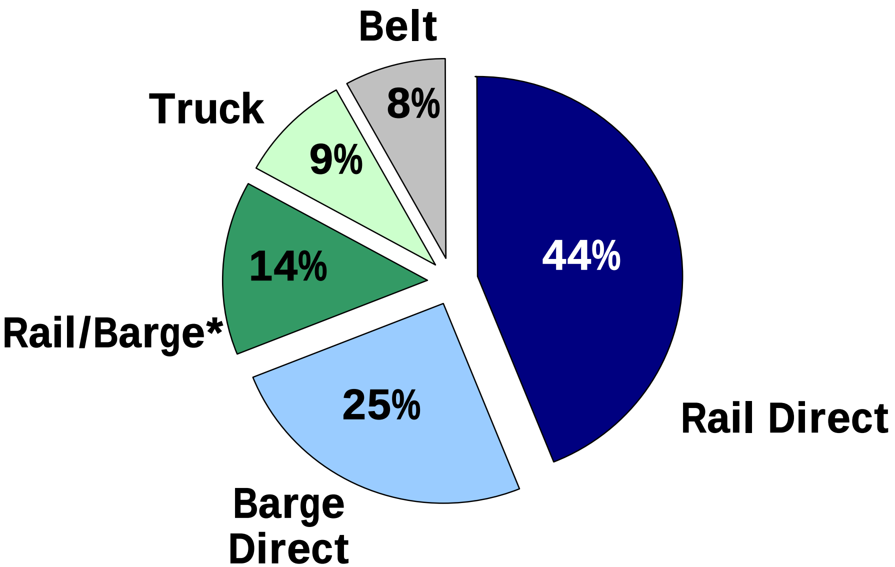


WESTERN SYSTEM

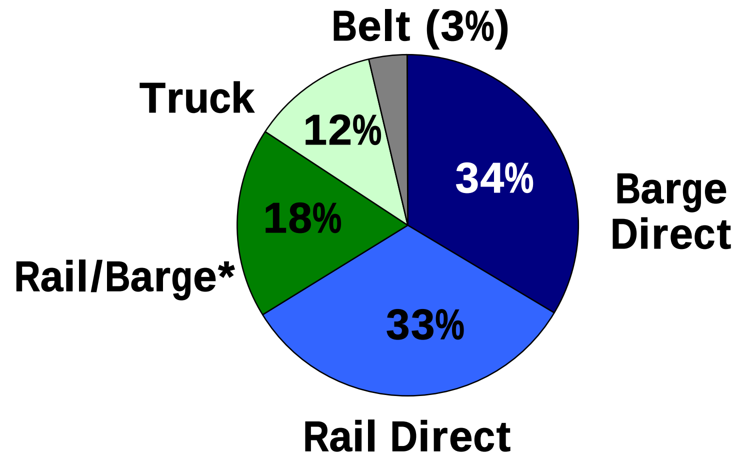


Coal Delivery Mix

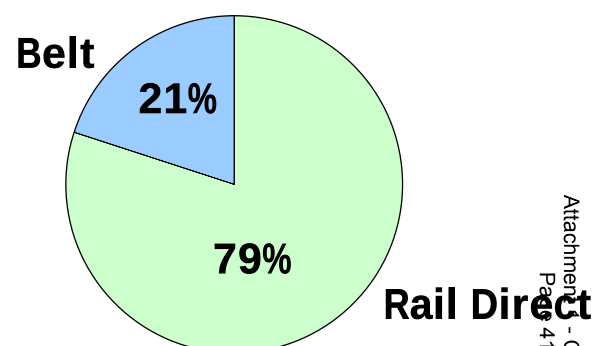
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



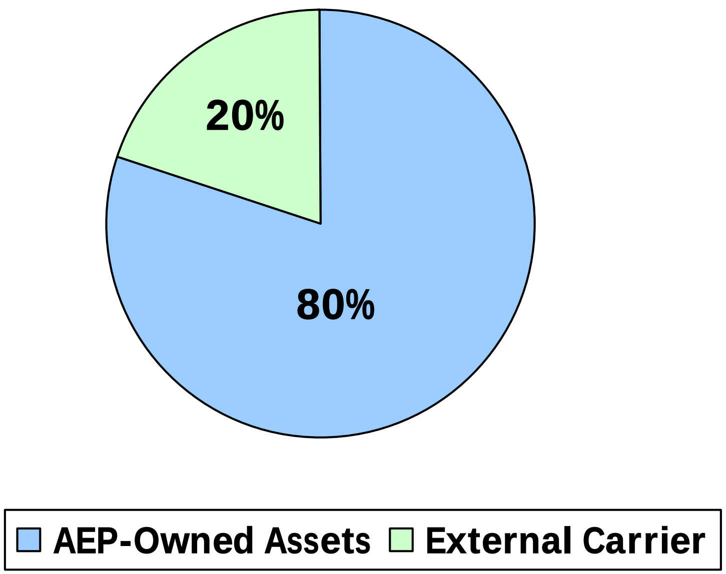
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

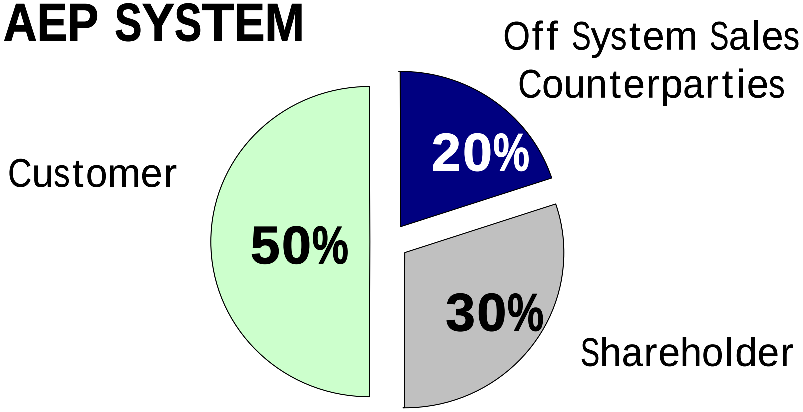
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM

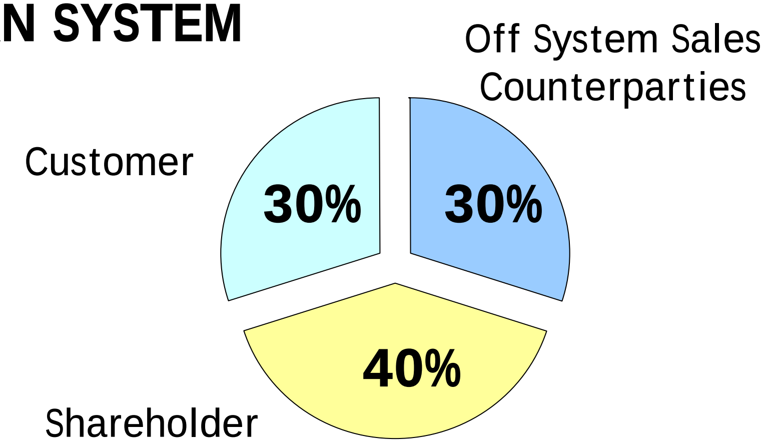


Fuel Cost Recovery
(on average)

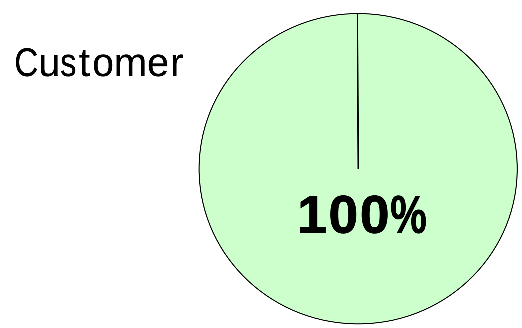
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



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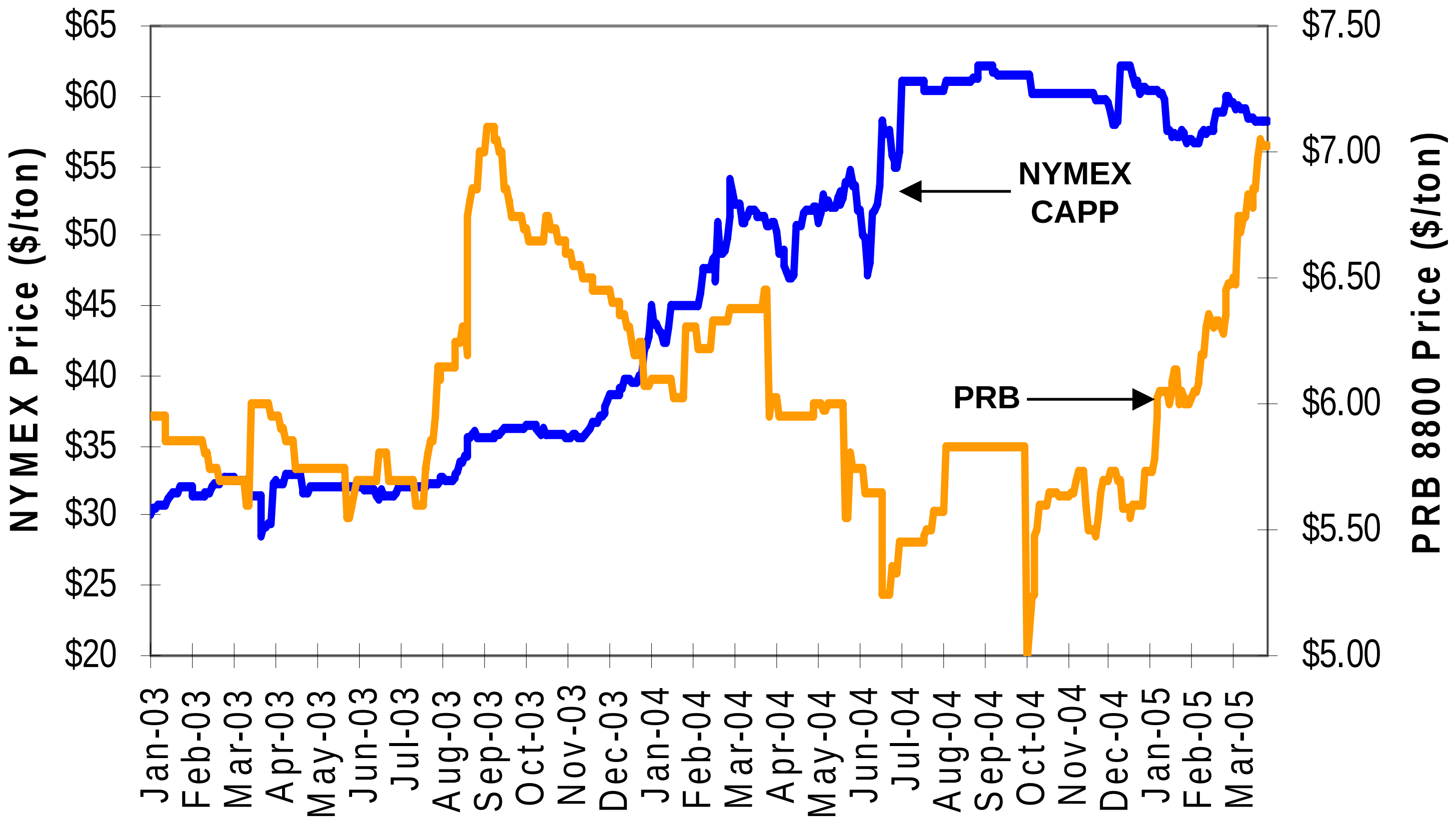
Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



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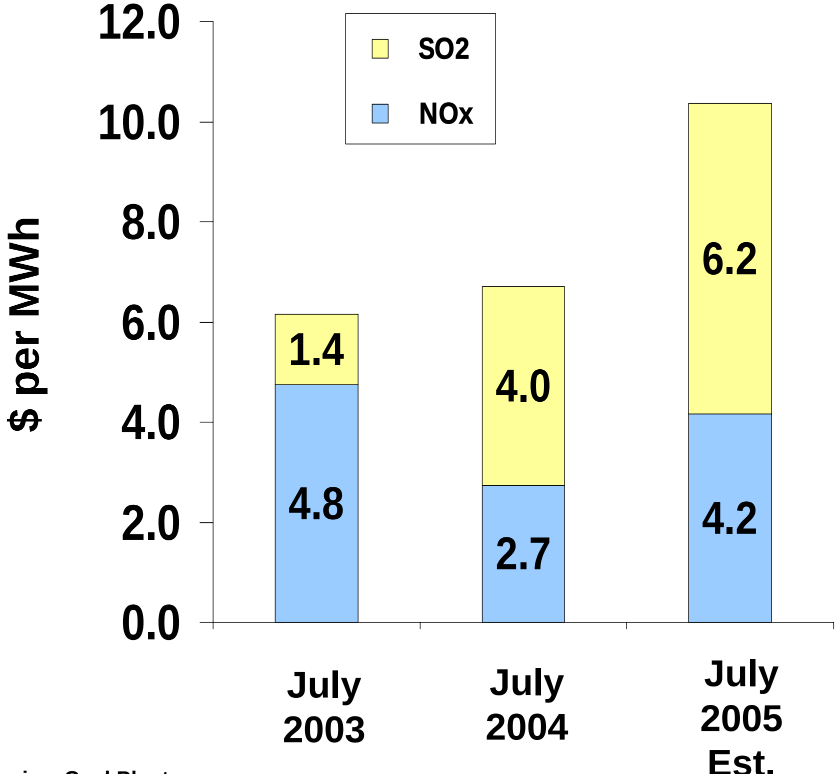
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003

Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



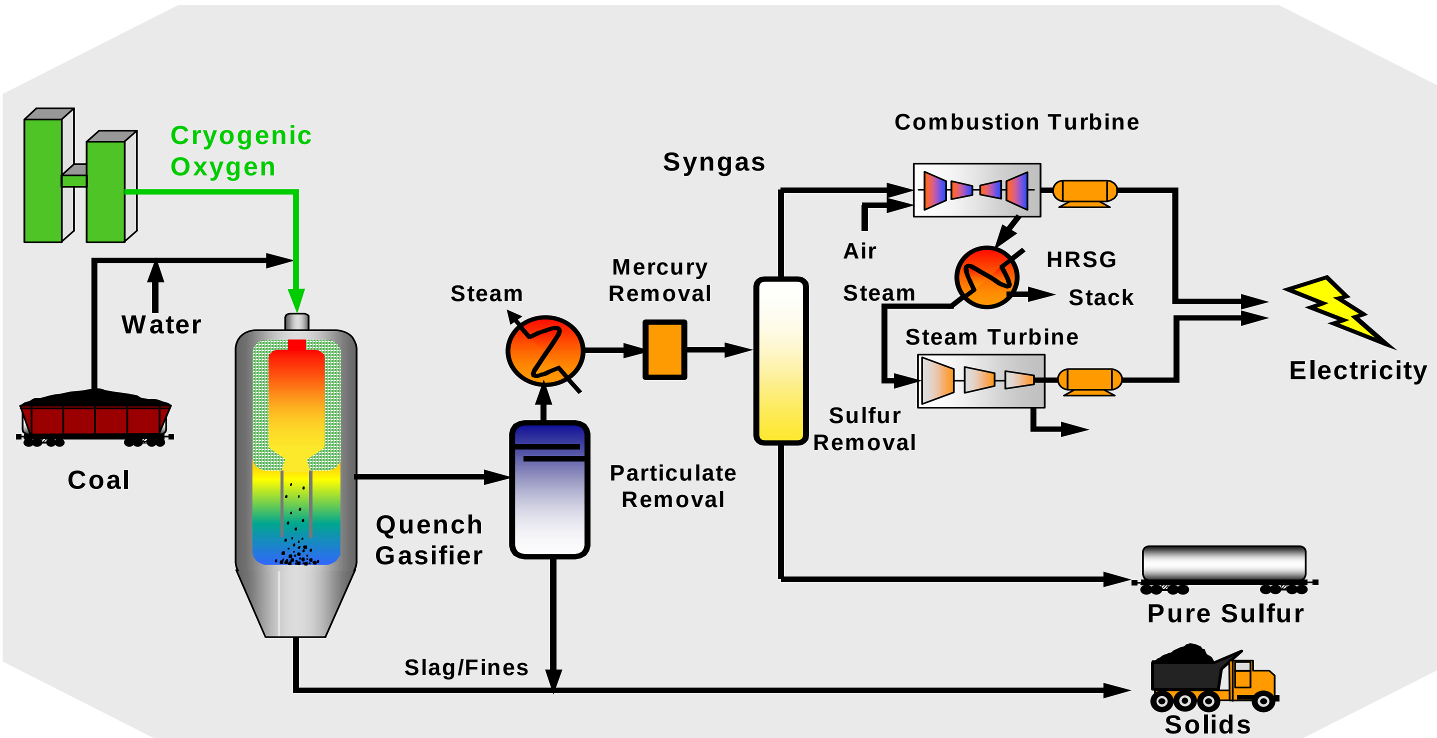
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B as of YE 2004)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- ➢ Secure cost recovery plan – Summer
- ➢ Finalize site selection - Fall
- ➢ Negotiate with suppliers – Throughout 2005

- ➢ 2005—2007: Obtain permits and finalize engineering and procurement

- ➢ 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

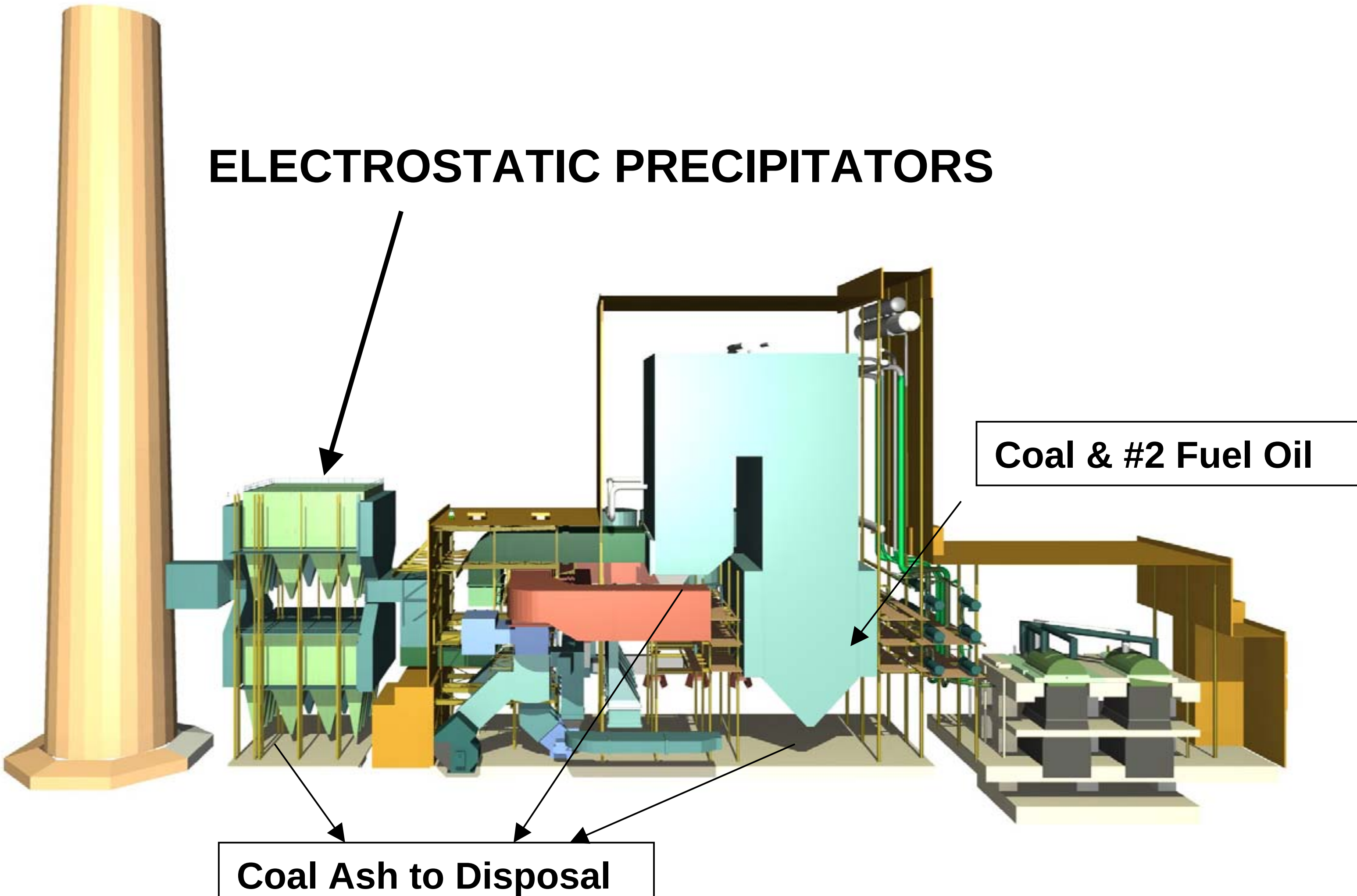
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

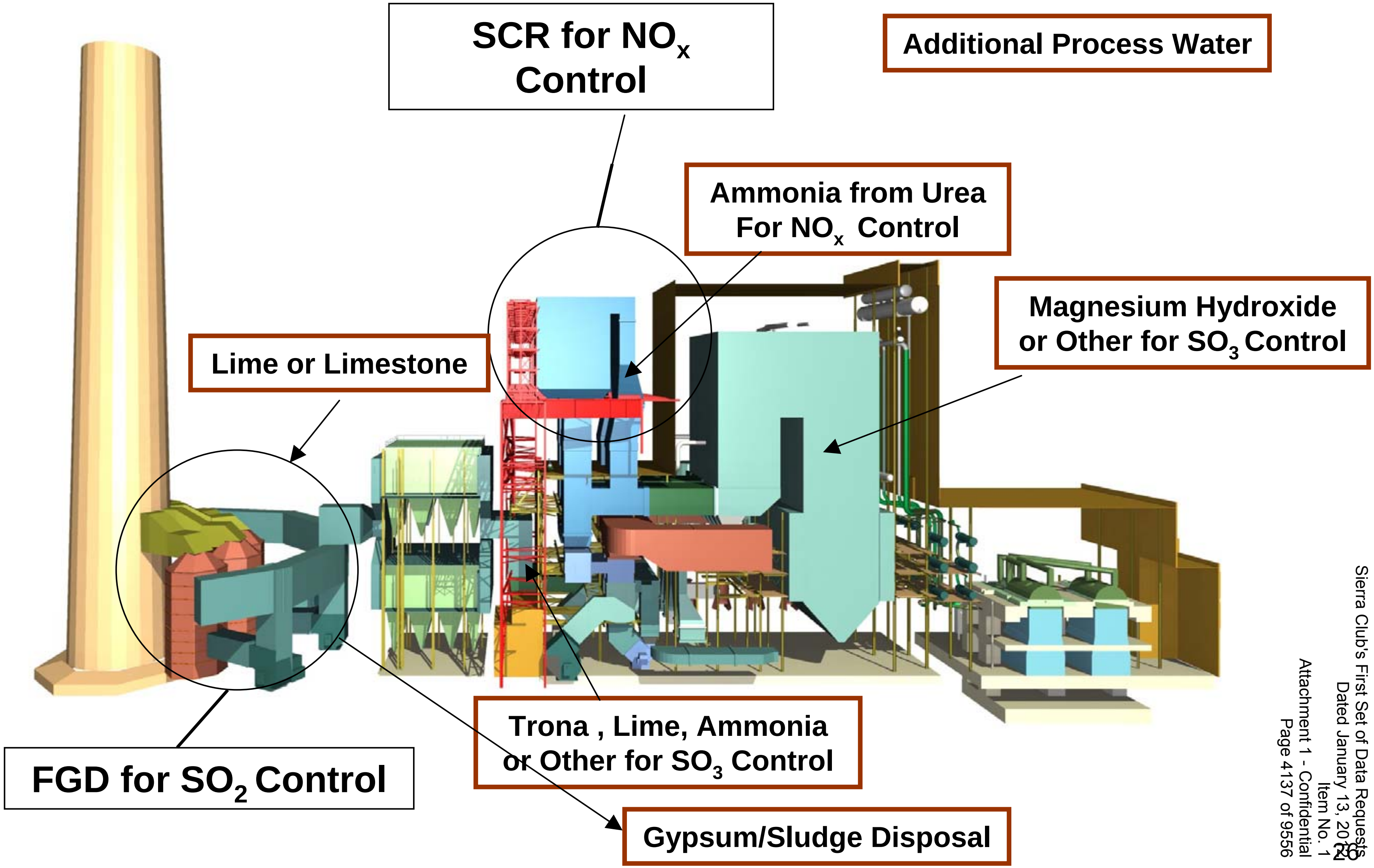
- ➢Rule Finalized March 2005
- ➢Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- ➢Reductions occur in phases: Phase I (2010); Phase II (2018)
- ➢Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s

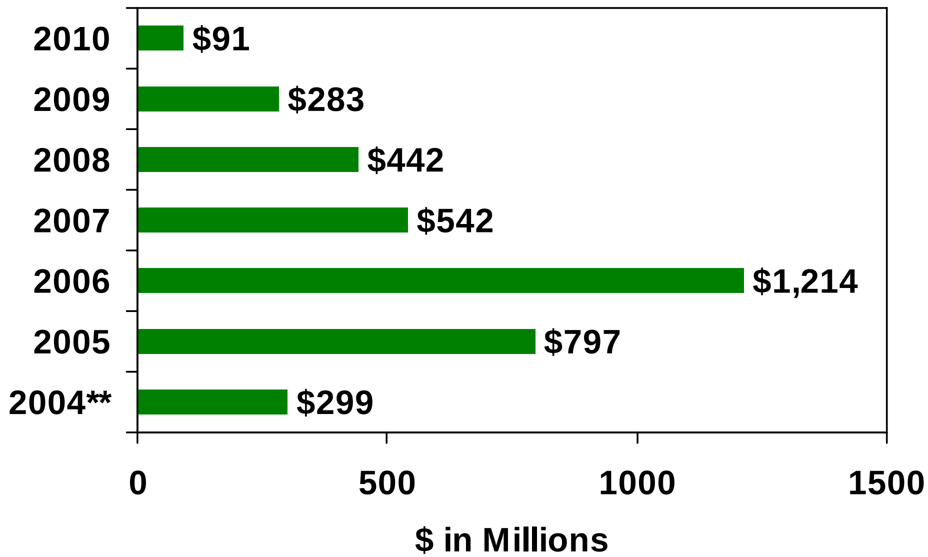


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



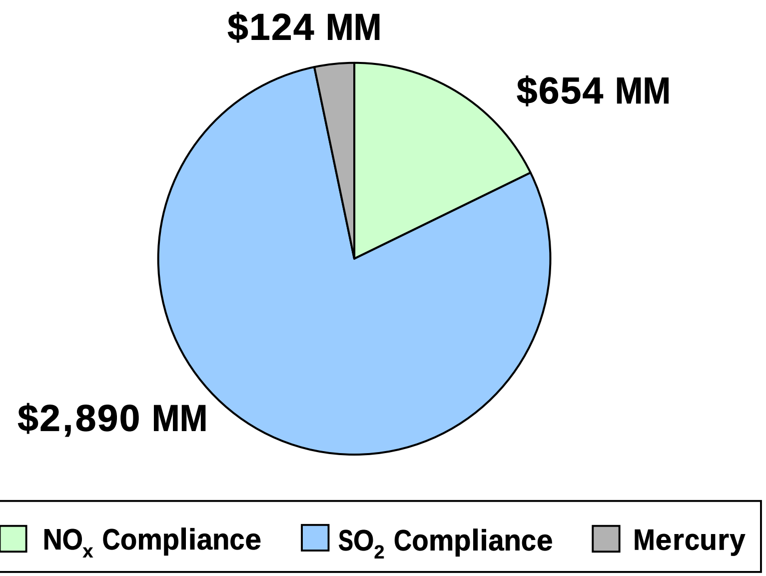
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs
$1.9 Billion:
$0.6 billion for NOx
$1.2 billion for SO_2

Future Programs
$1.8 Billion:
$1.7 billion for SO_2
$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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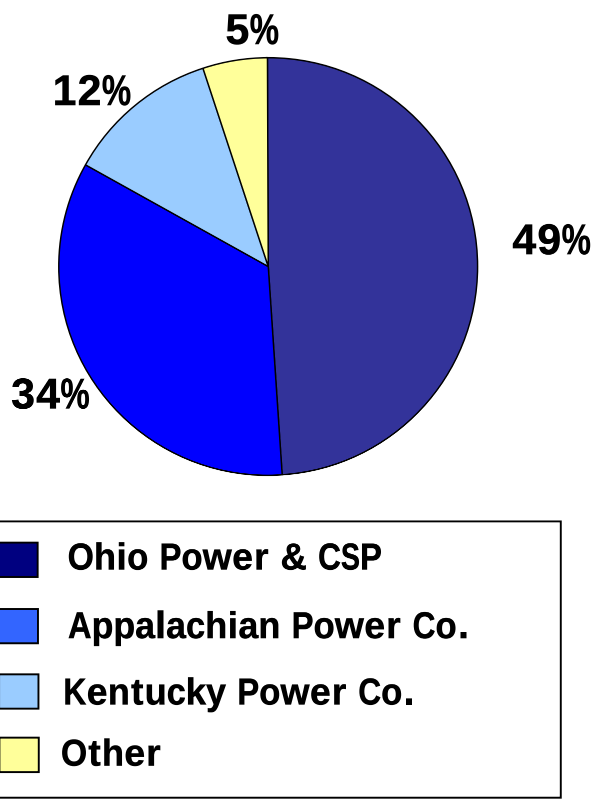
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

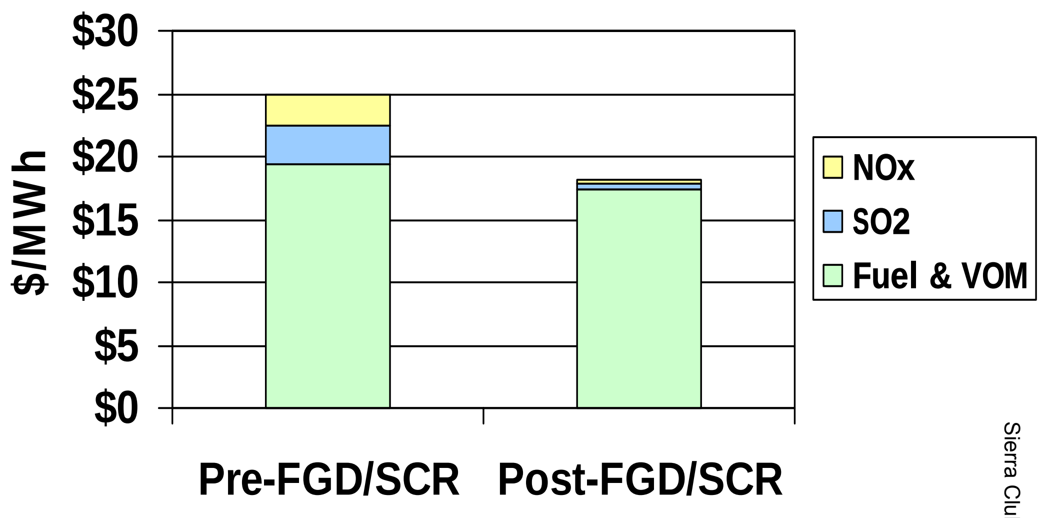
2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

Low Cost Production Supports Investment

- ➢ Lowers exposure to high cost emission allowances
- ➢ Creates opportunity to burn wider variety of lower cost fuels
- ➢ Improves baseload operation, (higher capacity factor, higher margin)
- ➢ All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Stranded Cost Recovery
  - Virginia Environmental & Reliability Factor
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Carrying charges for 2005 expected to be $87 million

Equity Component:$154 million to be recognized in income as collected

TCC SEEKING STRANDED COST RECOVERY OF $2.4 BILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, Hearings scheduled to begin 8-8-05.

West Virginia (Regulated)
- Base rates not frozen; No active fuel clause
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- On 7-1-05 AP & WP provided a 30-day notice to the WVPSC of their intent to file a general rate case, reinstate the ENEC, & implement scheduled incremental rate increases for major clean air & transmission investments.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause
- On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental costs for environmental compliance and T&D System reliability (E&R) of $62.1 million, effective on an interim basis beginning 8-1-05.

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) Hearings-late Sept.
- TCC wires rate case PUCT approved affiliate transaction settlement in June 2005. Written order expected in July 2005. Final order will result in slight rate decrease with a positive earnings impact.
- TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing issued in June 2005 updating rate case expenses. TCC will appeal decision.
- TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval.
- On 5-2-05 the OCC issued an order approving a settlement agreement in this general rate case which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider.
- 2001 Fuel review case
  Hearings scheduled for Sept. 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
  Scope has been expanded to include a prudence review.

Louisiana (Regulated)
- Base rates not frozen
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	POLR Rider	Revenues & POLR Rider*			Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs***	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit**	0	25	25	26	0	25	25	26
Recovery of RTO costs***	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Incremental over 2004 base year

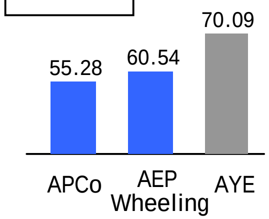
** Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

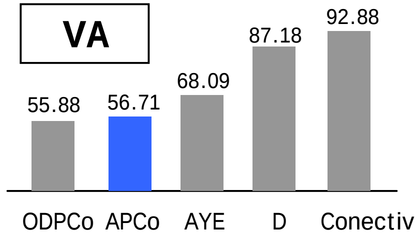
*** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

AEP: The Low Cost Provider

Regulated Rates

WVA


VA


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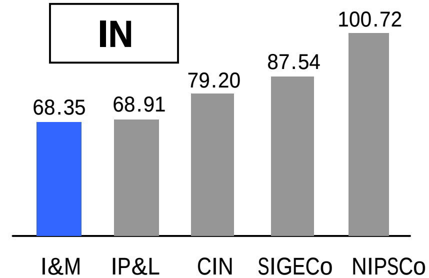

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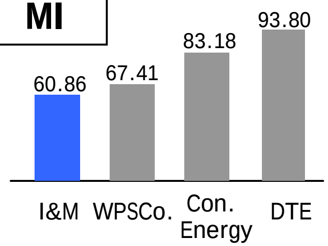

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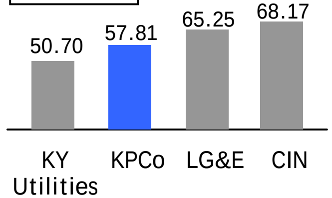

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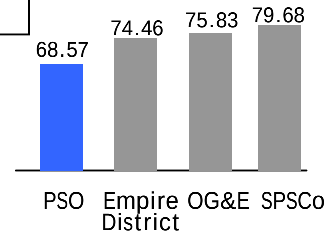

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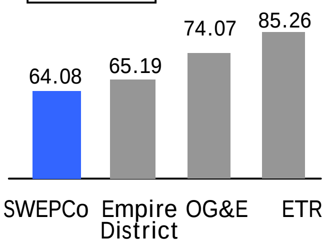

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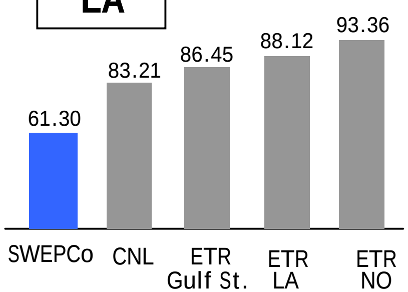
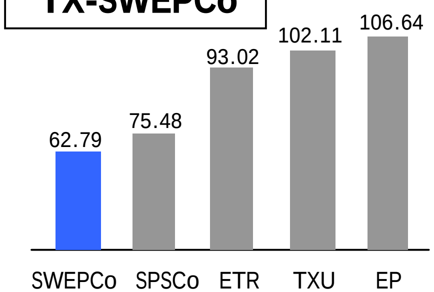
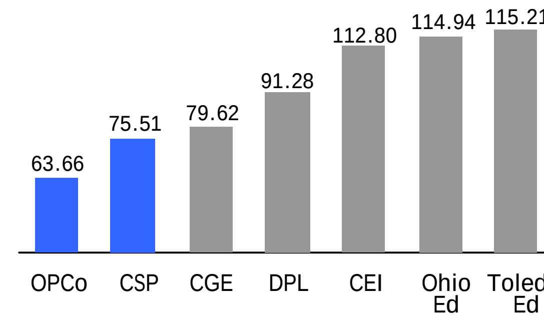


TX-SWEPCo


Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

AEP System fossil fleet average variable book cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

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Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

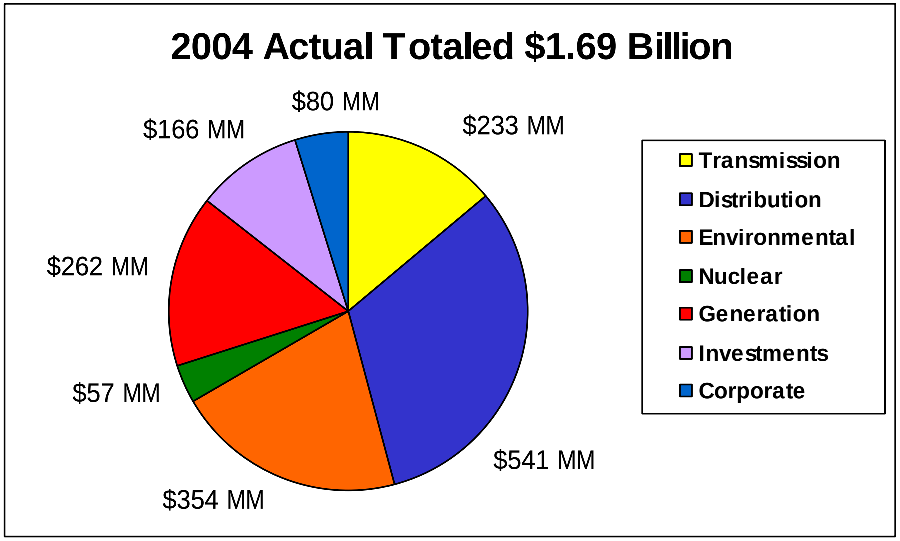
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

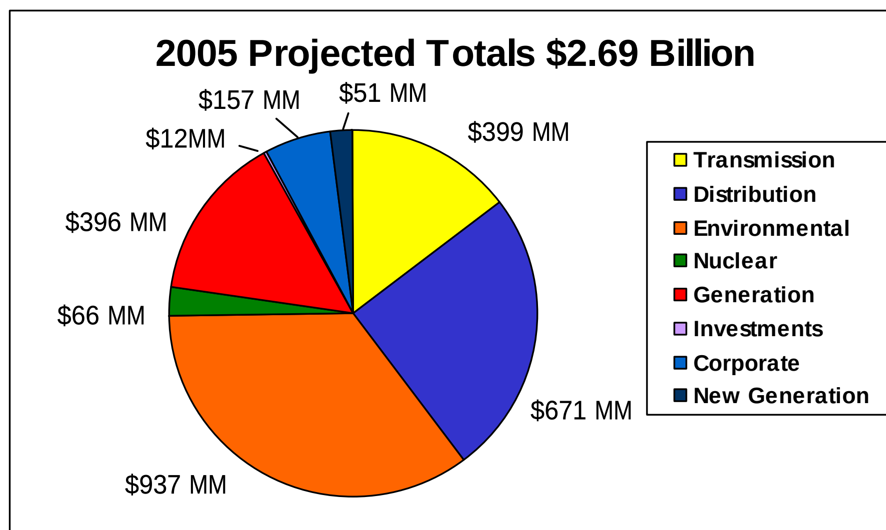
**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex





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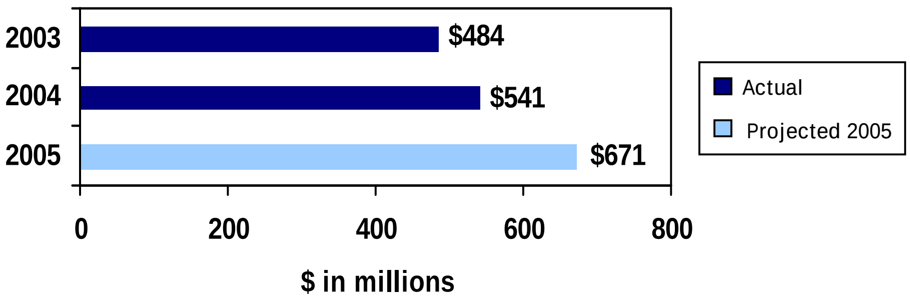
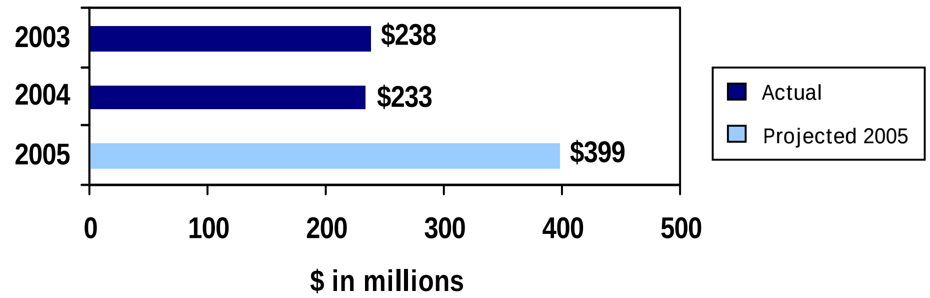
Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



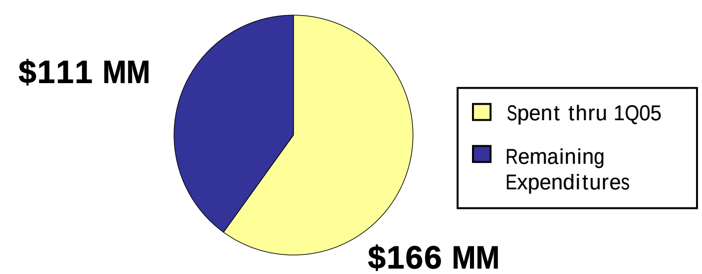
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Investment in Asset Base Will Drive Earnings

Potential Return On Investment

Assumptions	Environmental Investment	600MW IGCC Investment*
Projected Investment	$3.7 Billion	$1.0 Billion
Debt/Equity Ratio	60% debt / 40% equity	52% debt / 48% equity**
Return on Equity	12.00%	11.75%***
Potential EPS Impact (based on 393 MM shares)	+ $0.45	+ $0.14

* Assume a similar return for an additional 600 MW IGCC facility

** Requested debt/equity ratio per AEP Ohio IGCC filing

*** Requested ROE in AEP Ohio IGCC filing

EPS CONTRIBUTION WILL DEPEND ON FAVORABLE REGULATORY OUTCOMES

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

KPSC Case No. 2011-00401
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Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**875,376,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Excludes $65.8 million of mortgage bonds due in 2005 that were defeased

(4) Excludes TCC securitization bonds

Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

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Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- *Outcome of pending regulatory proceedings*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

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2005 Earnings Guidance

		2004 Actual			2005 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

British Steel Pension Fund

Investor Office Visit

February 27, 2008

Columbus, OH

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Chairman, President & CEO

Table of Contents

Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,600 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

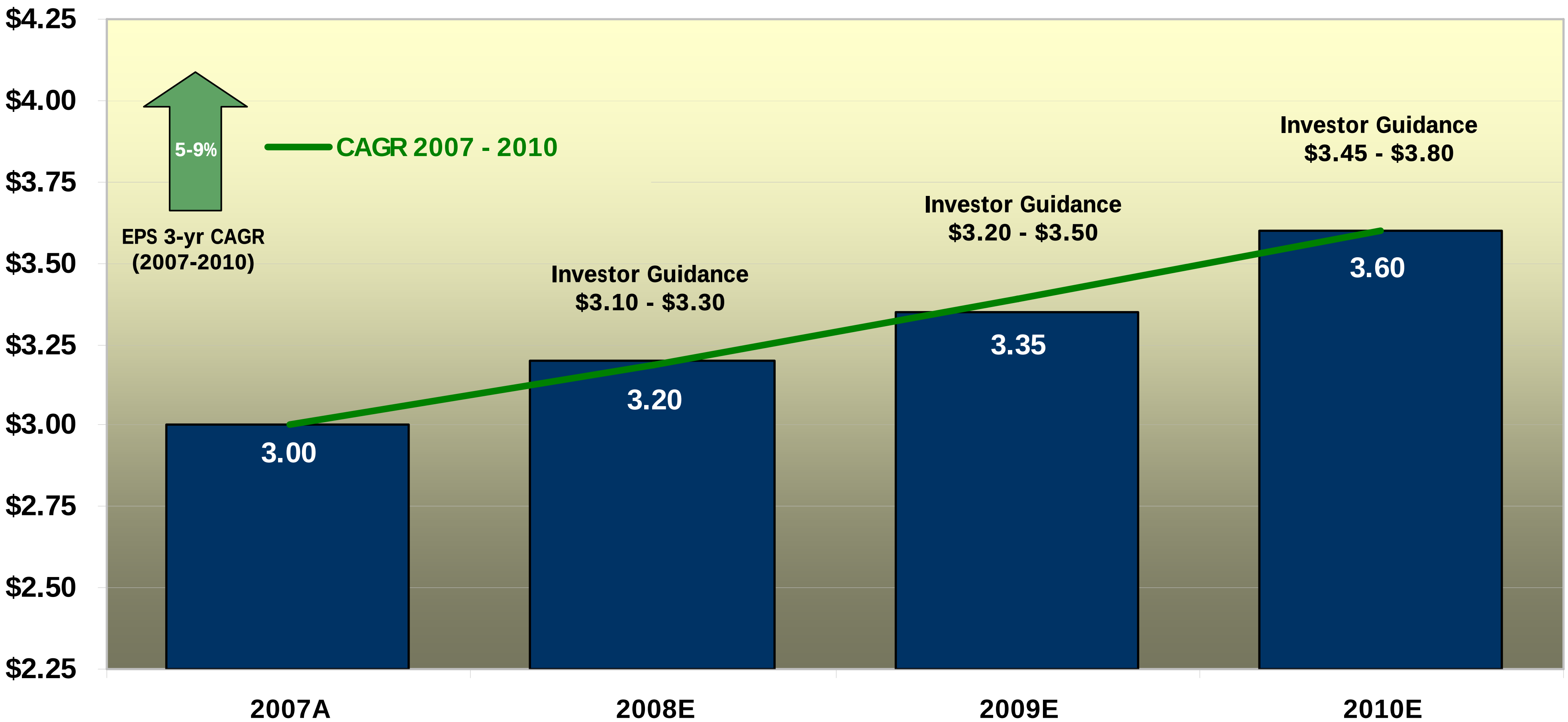
Strategy: grow our core utility business at a consistent rate trough major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast



5% to 9% earnings growth

Vision for Sustainability

Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

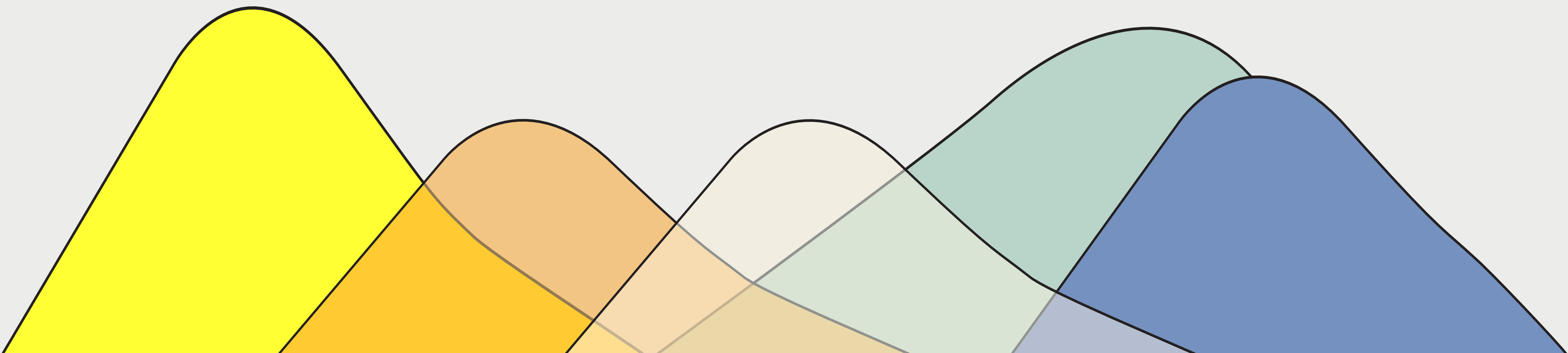
Existing generation and transmission control systems	**gridSMART**℠: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



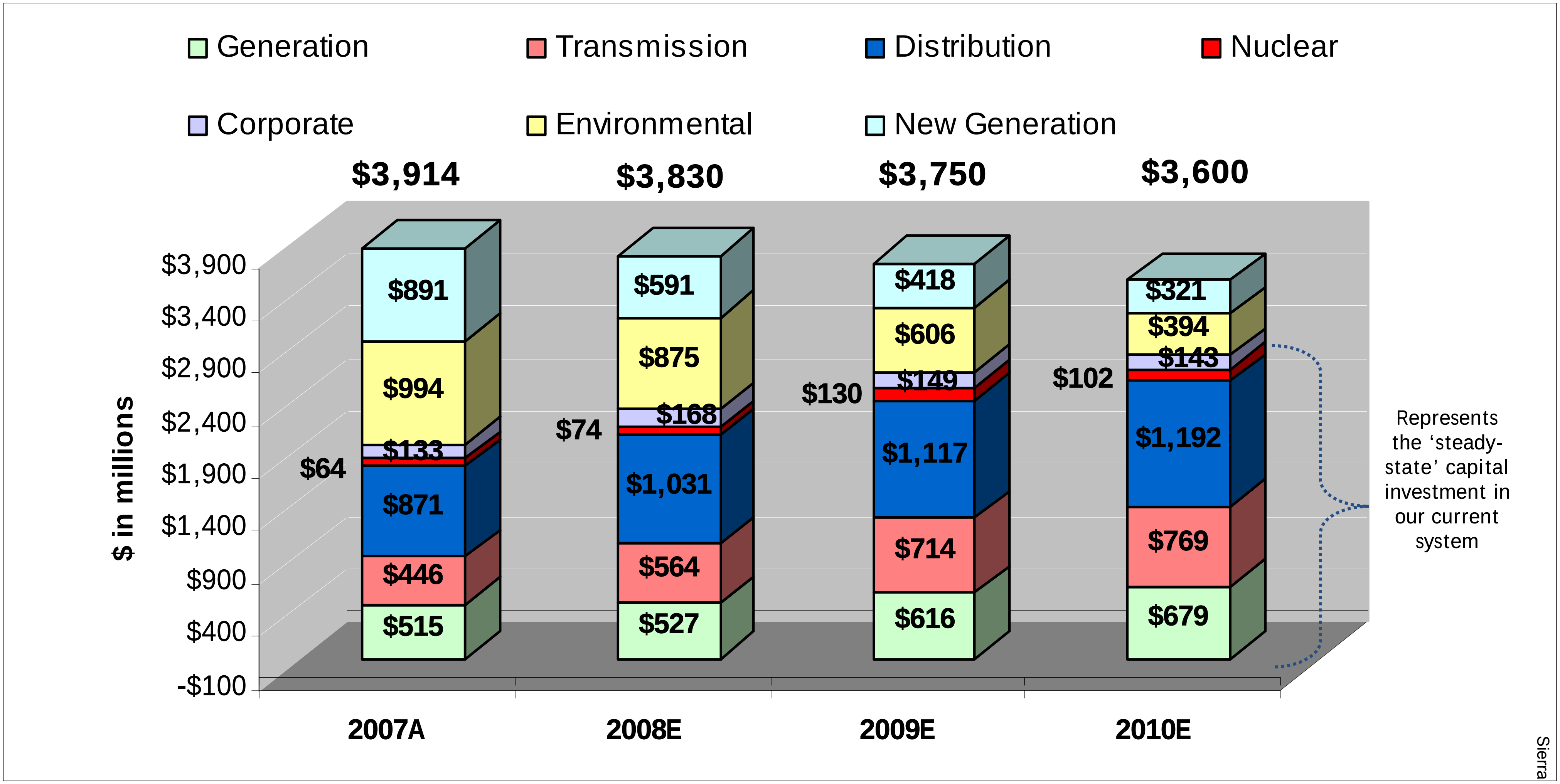
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B(2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

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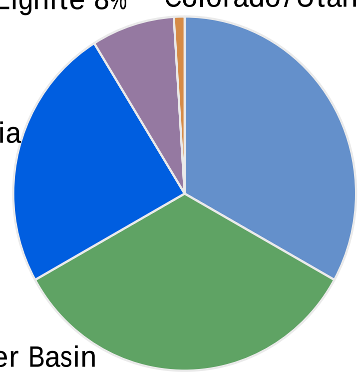
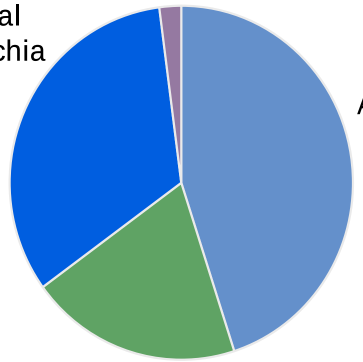
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

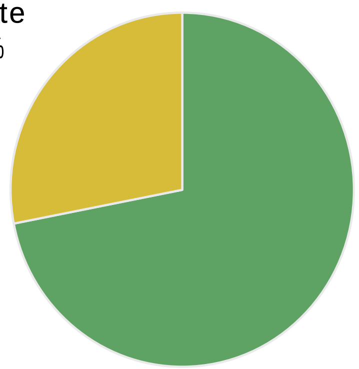
Total AEP System



AEP East



AEP West



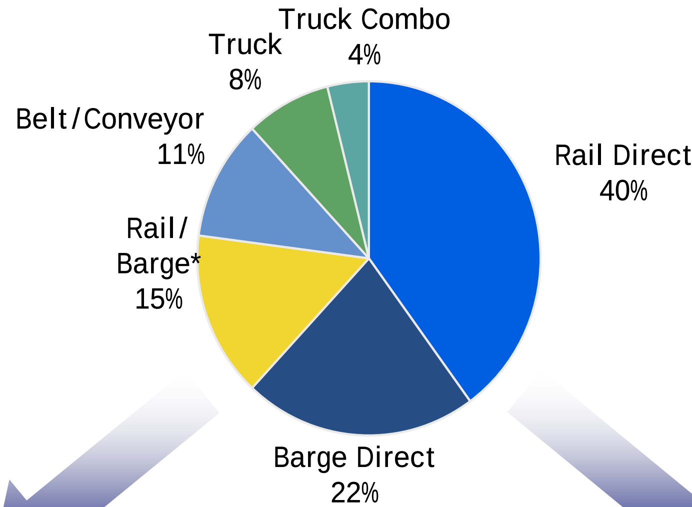
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

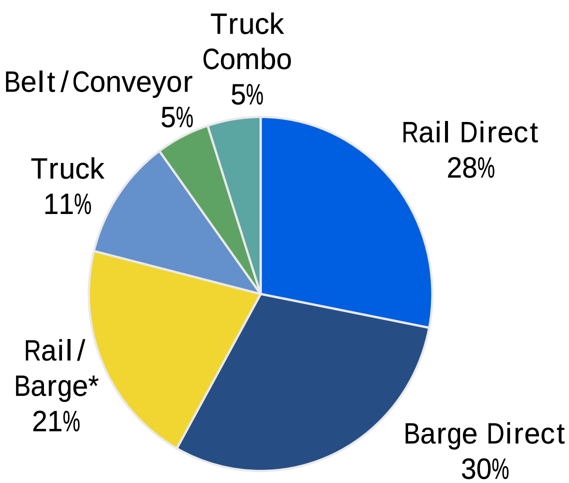
Coal Delivery

Total AEP System

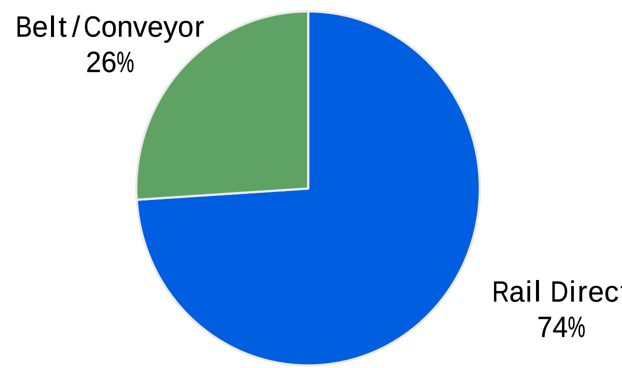
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

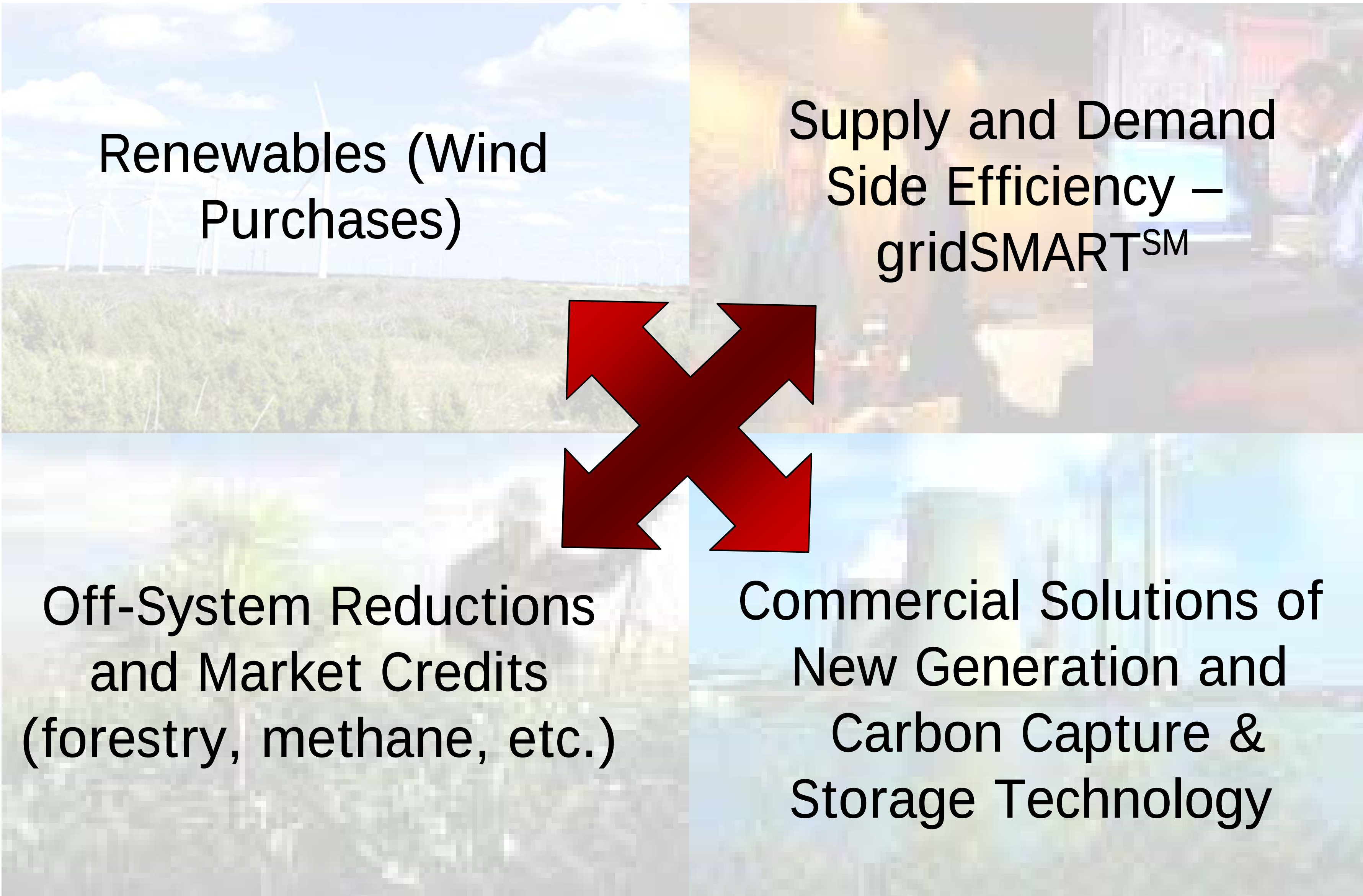
"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives.

AEP Wind Operations/Purchases

Trent Mesa (2001)

150 MW (100 - 1.5 MW turbines)
Abilene/Sweetwater, TX

Southwest Mesa (1999)

- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser

Desert Sky (2002)

160 MW (107 - 1.5 MW turbines)
Bakersfield, TX

Summary

•Owned/Operated 385 MW

•Wind Purchases 392 MW

•Total Existing Wind at end of 2006: 777 MW

•**New Wind Purchases in 2007: 275 MW**

AEP will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011.

Off-System Reductions

Existing AEP Programs:

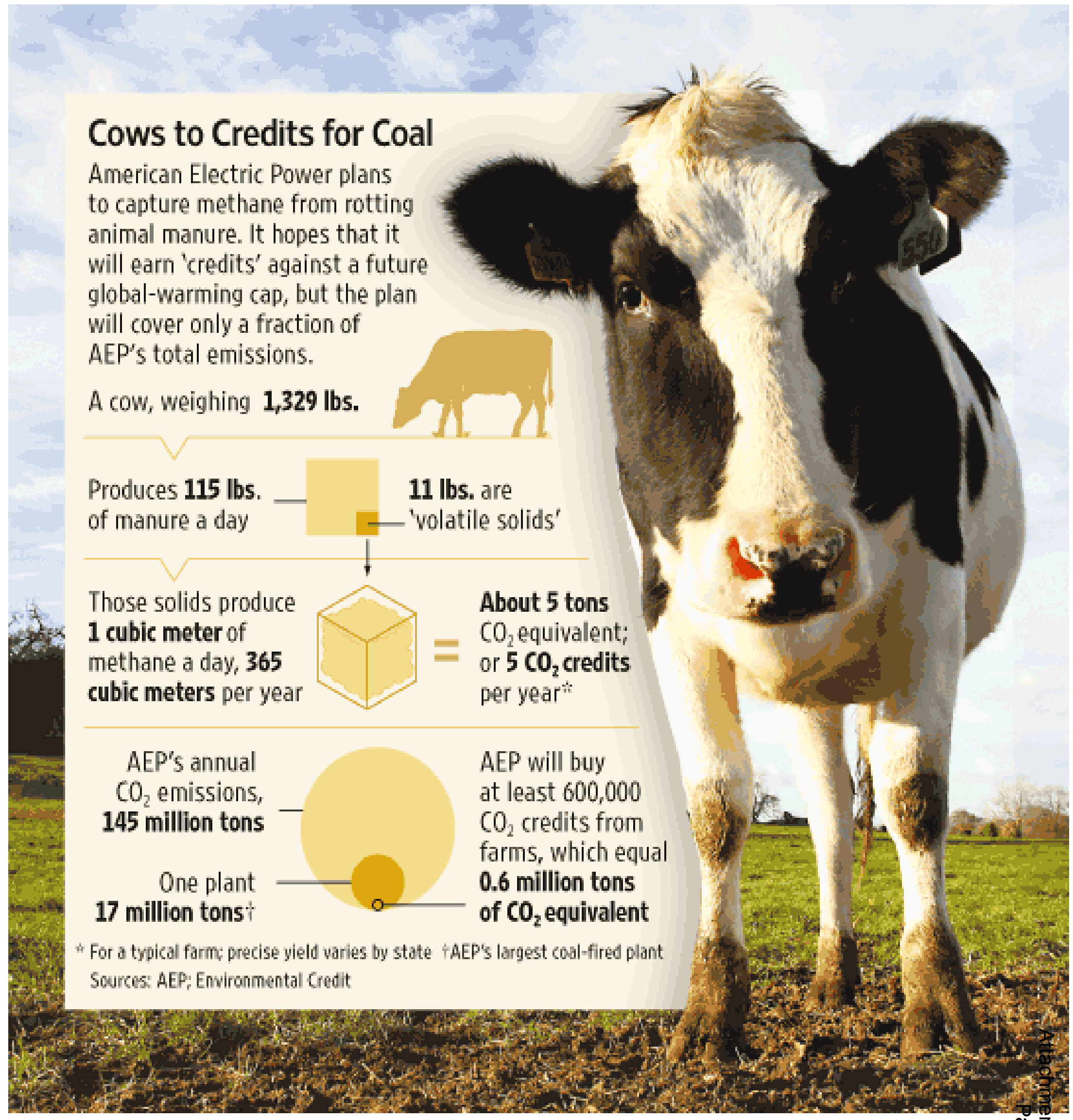
- Forestry - Domestic
  - 350,000 tons / yr
  - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 600,000 CCX carbon credits per year
  - Begins 2010
  - Runs through 2017
  - 51% of credits sourced from “AEP States”



Source: Wall Street Journal June 14, 2007

Advanced Generation & CO_2

Near Term:

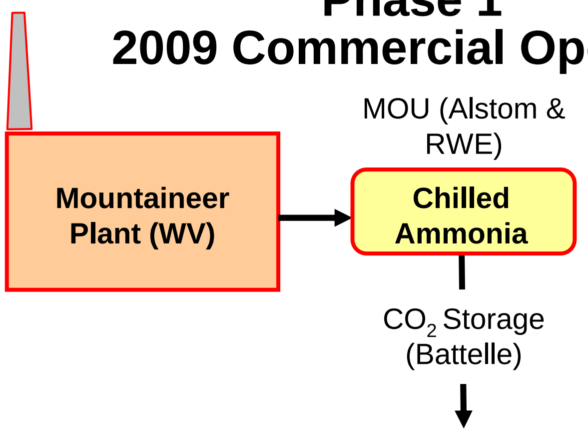
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

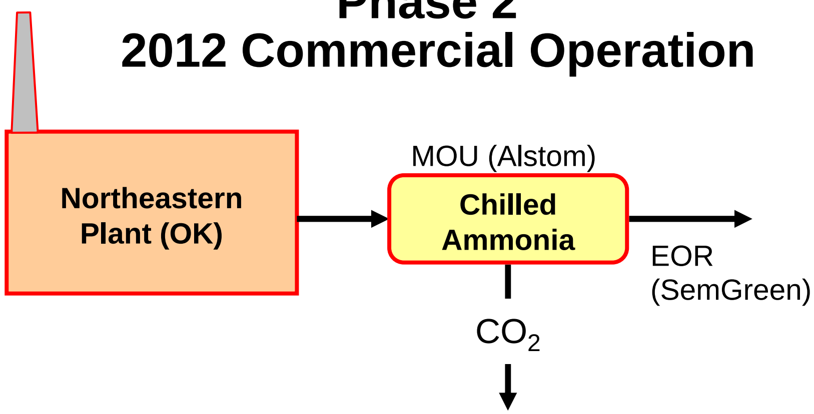
Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade

USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100ºF) coal plant in U.S (AR)

AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Oxy-Coal--AEP will also demonstrate (10MWe) and then install oxy-coal CO_2 capture & storage at a commercial sized coal unit (about 200 MWe)—feasibility study to be completed in 2008.

CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **very** clean flue gas

Modified-Combustion Capture

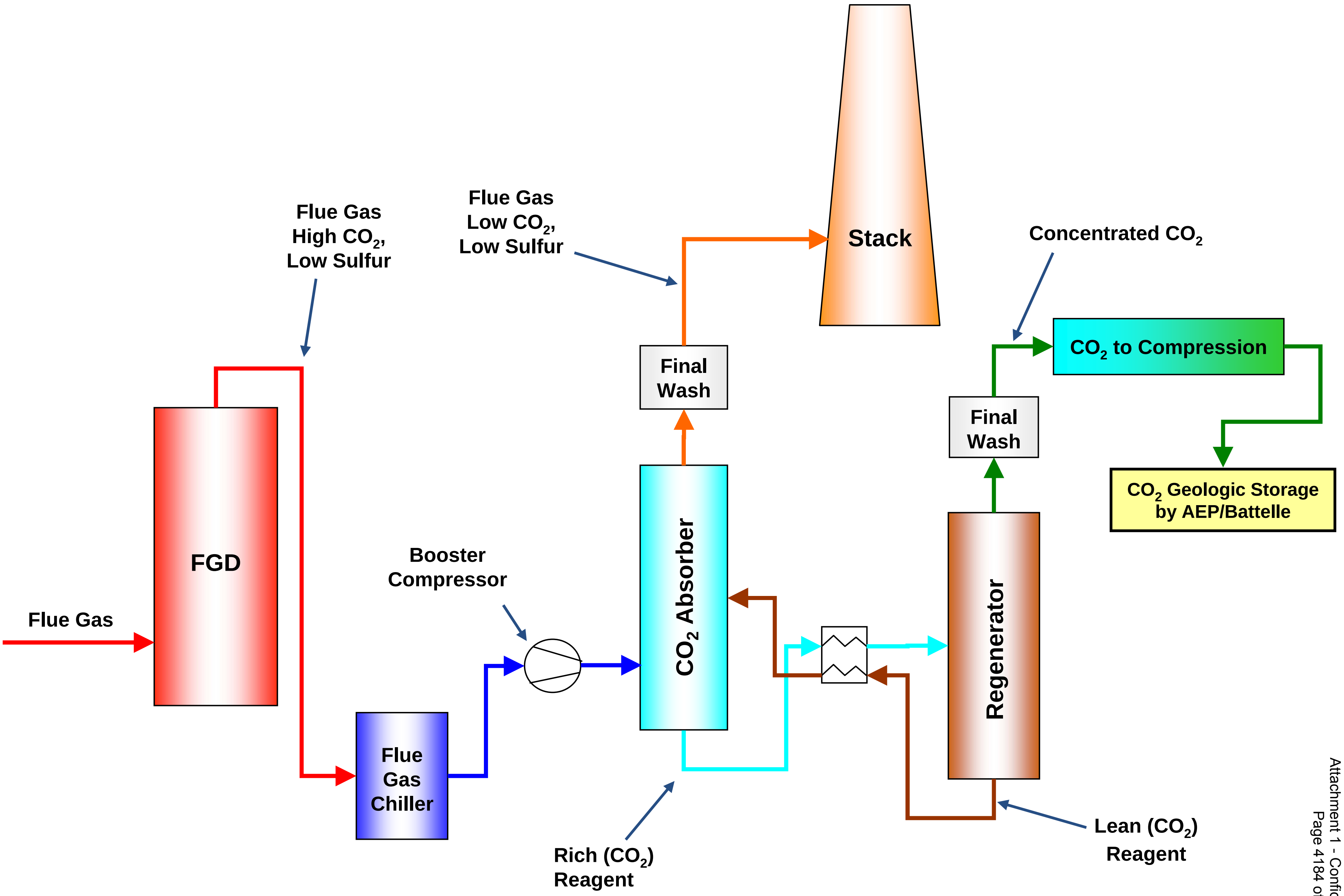
- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

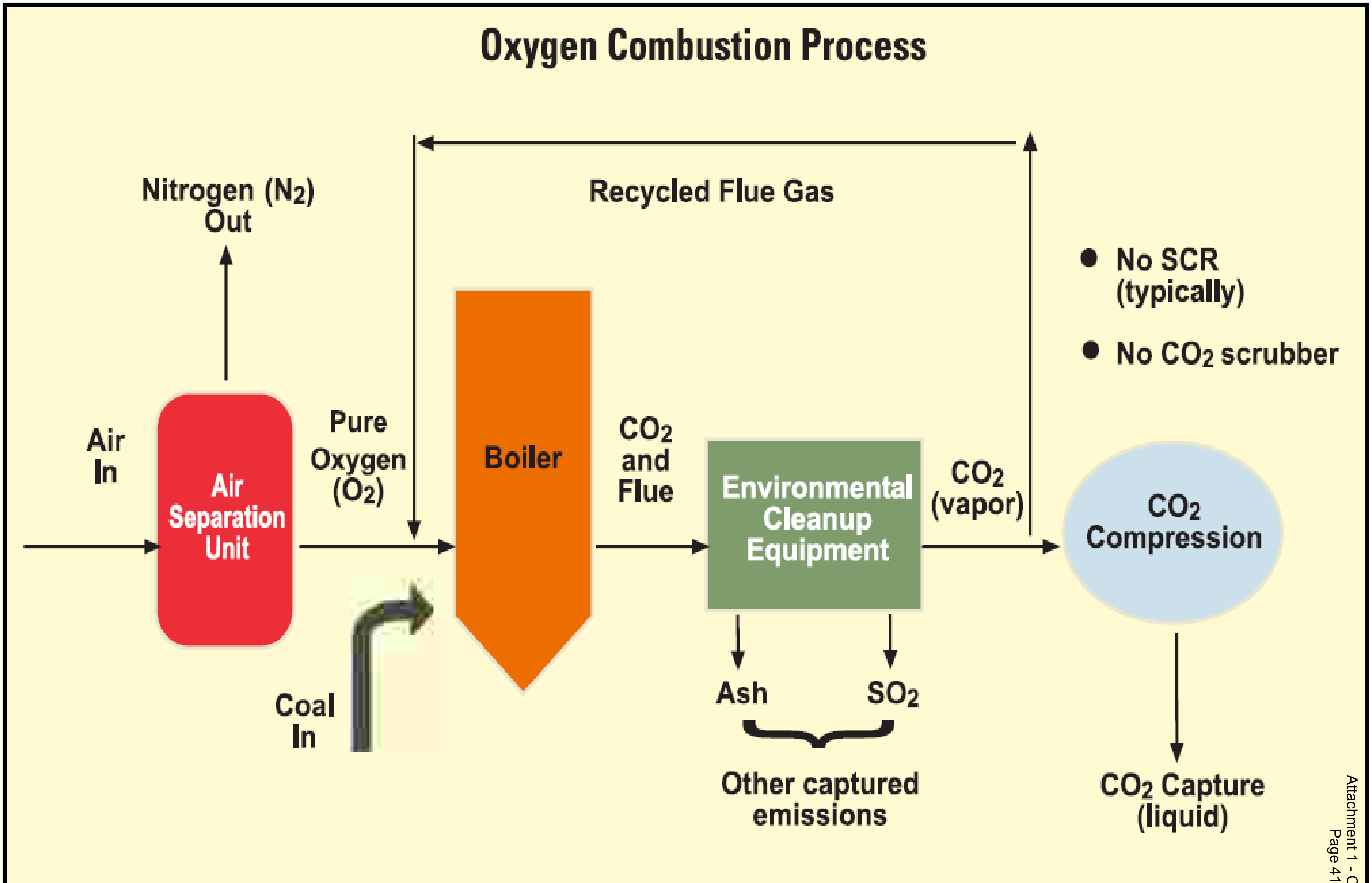
Alstom's Chilled Ammonia Process

Post-Combustion Capture

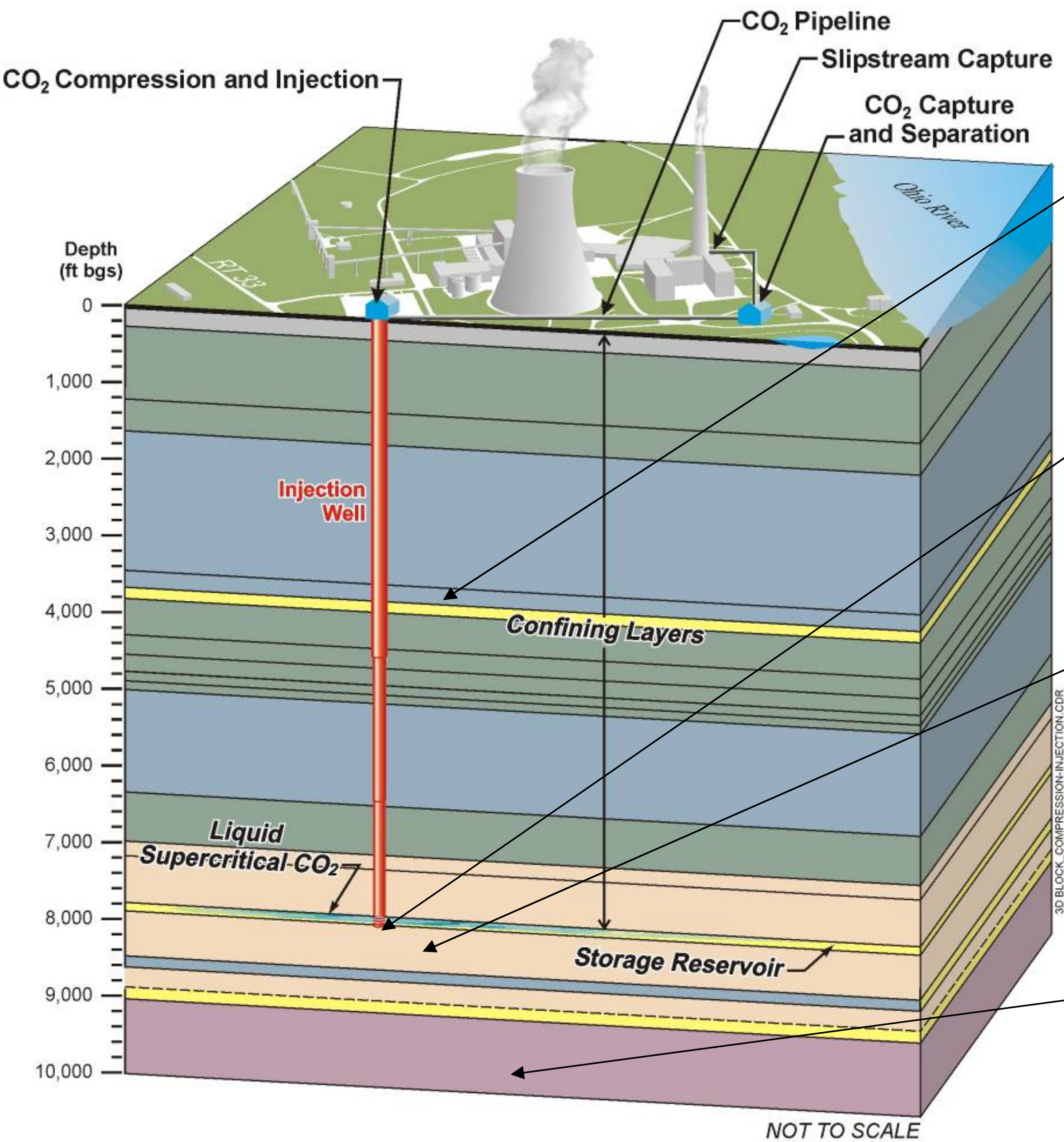


Babcock & Wilcox Oxy-Coal Process

Modified Combustion Capture



CO_2 Injectivity in the Mountaineer Area



CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the "B zone" within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

Distribution - gridSMART℠

gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

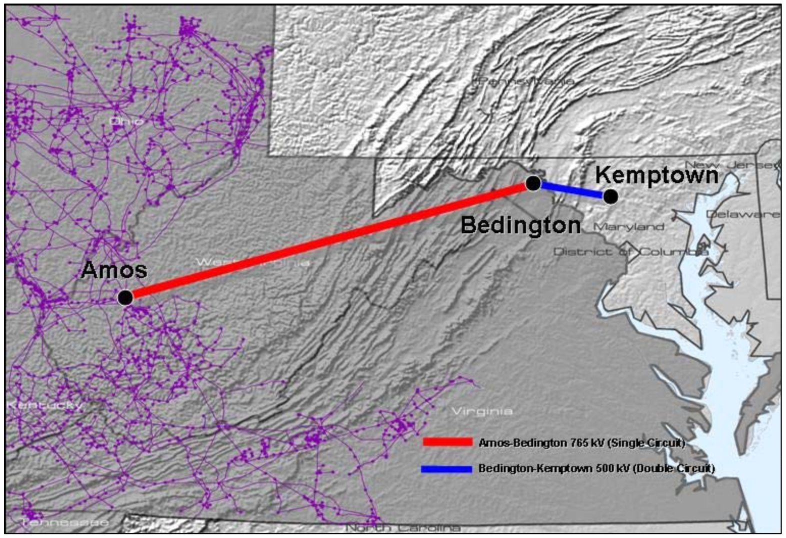
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$40**	**$ 63**	**$ 82**

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

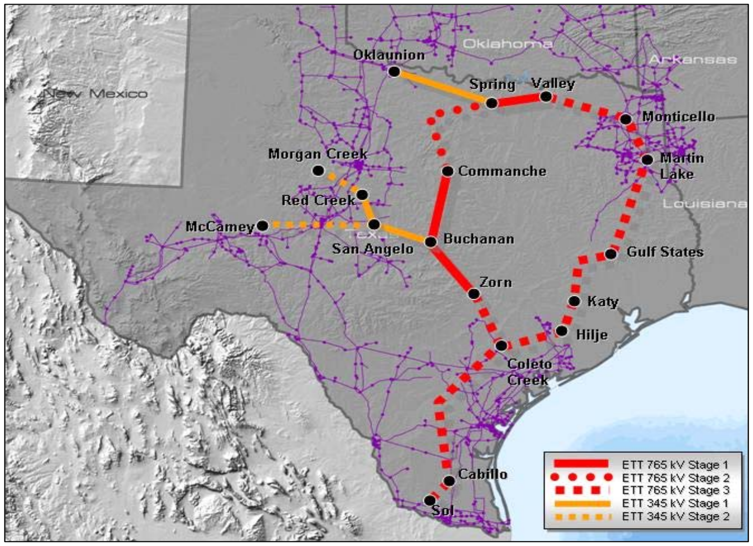
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

I-765TM Transmission: Investment Opportunities

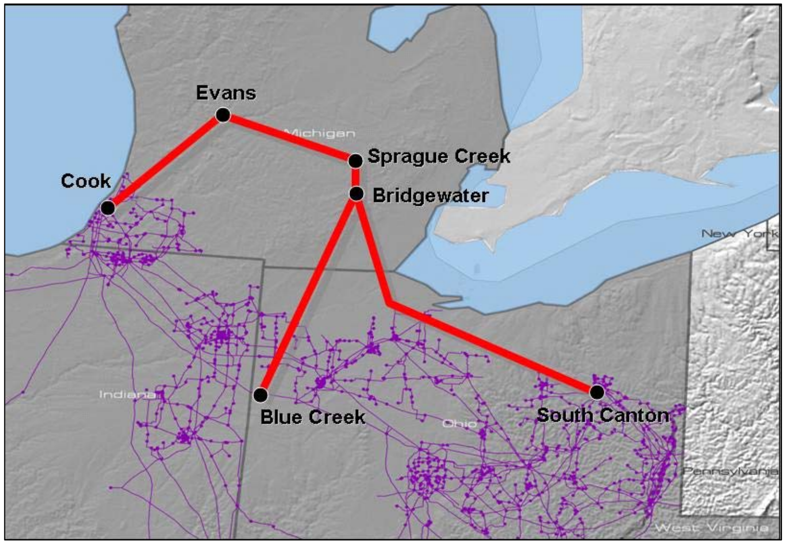
AEP is Advancing the Development of a National Interstate Today



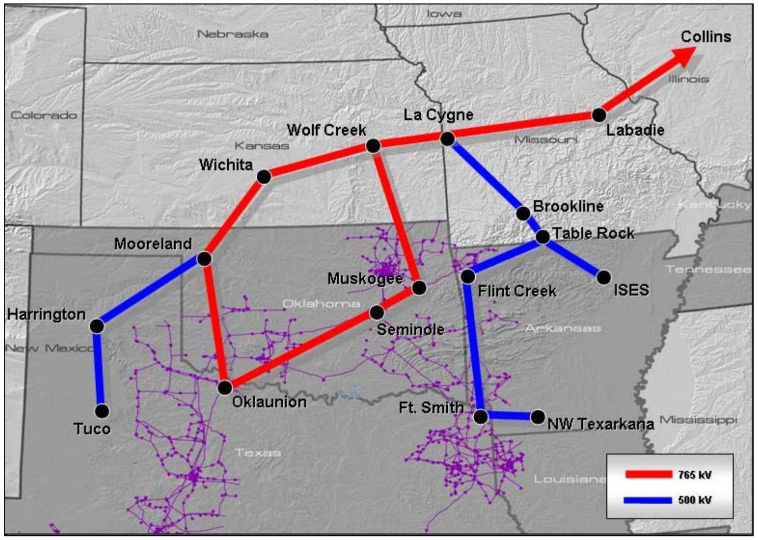
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

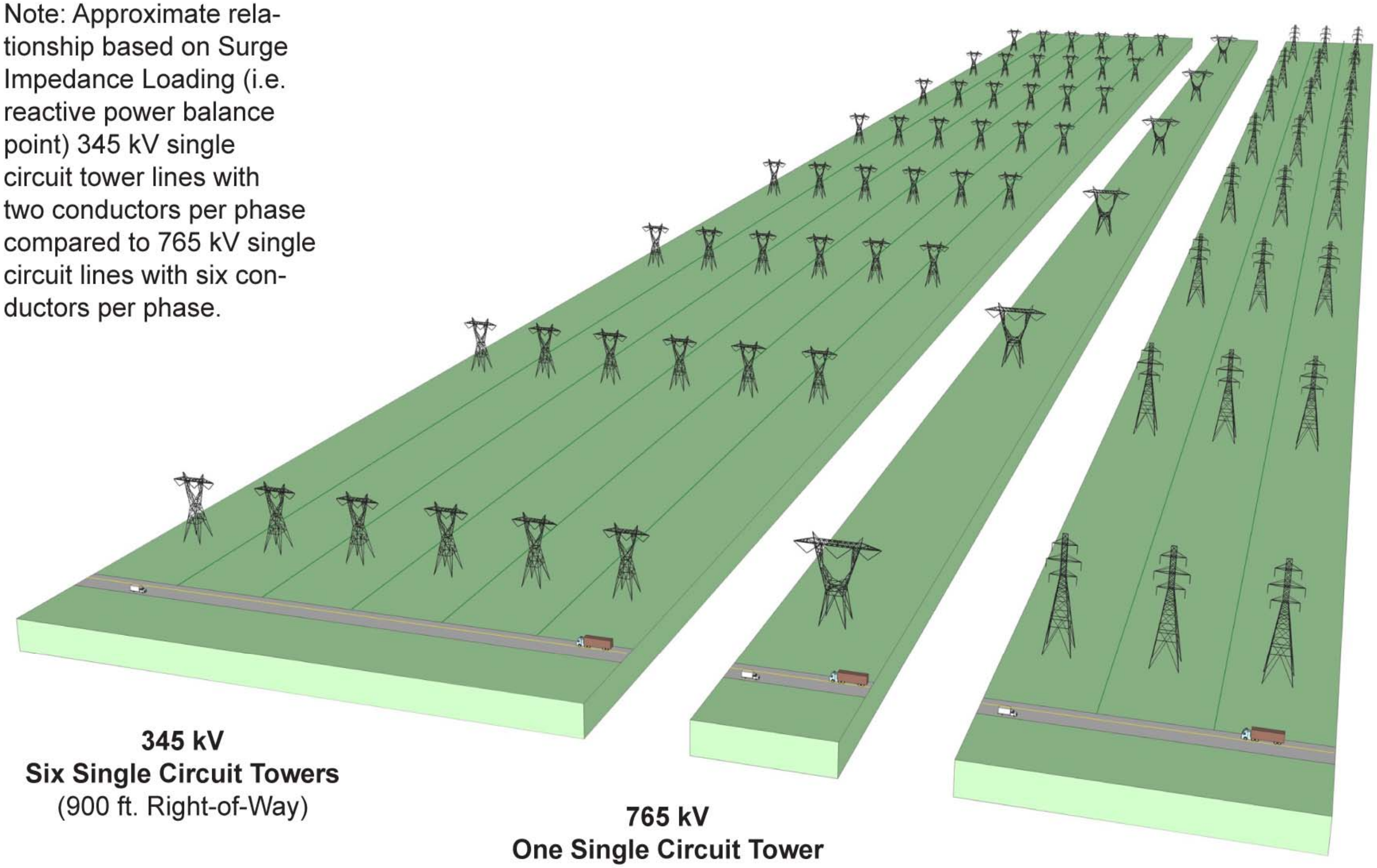


SPP Overlay Study

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4188 of 9556

765 Right-of-Way Comparison

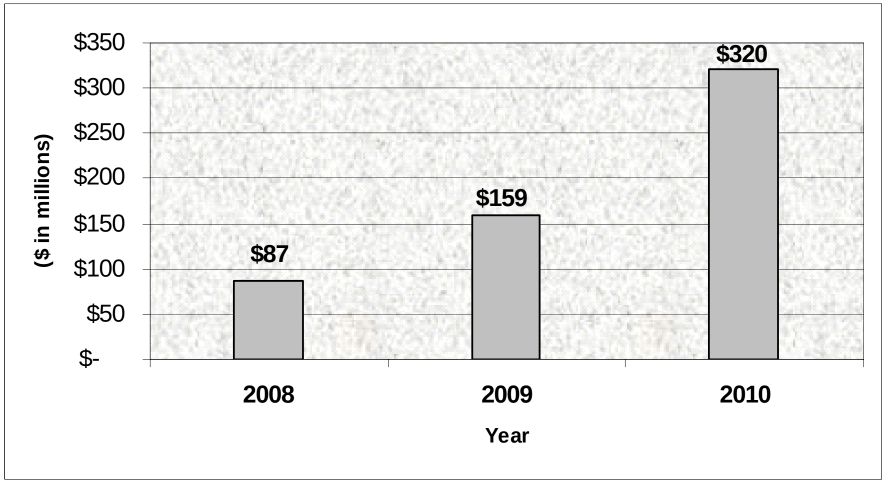
Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

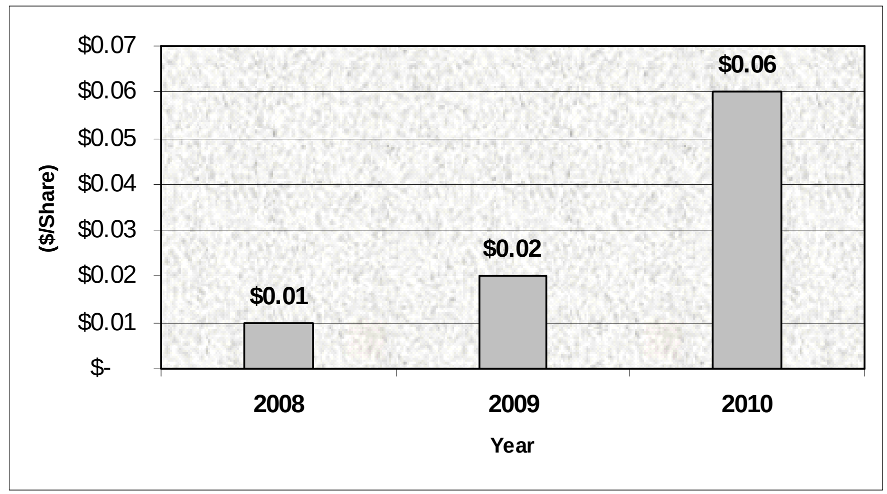


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

PATH
Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



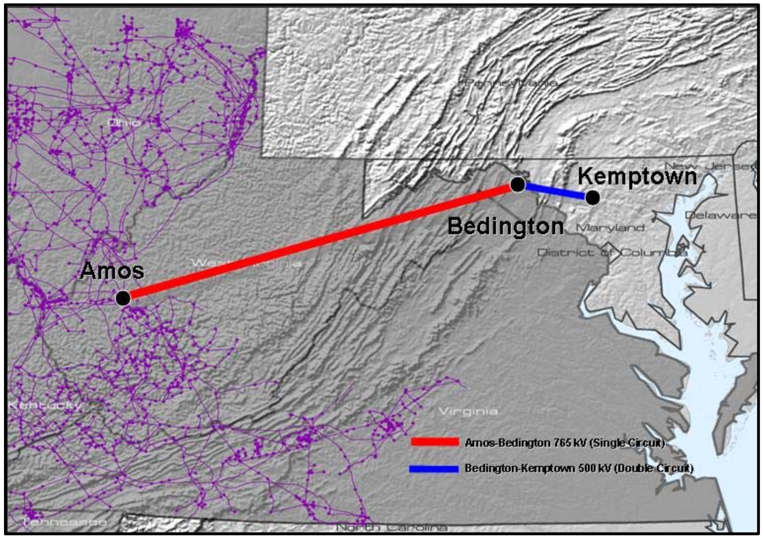
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765^{TM} Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, 14.3% ROE, recovery of all costs incurred prior to the time rates go into effect, and recovery of all prudently incurred development and construction costs if the project is abandoned.*
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

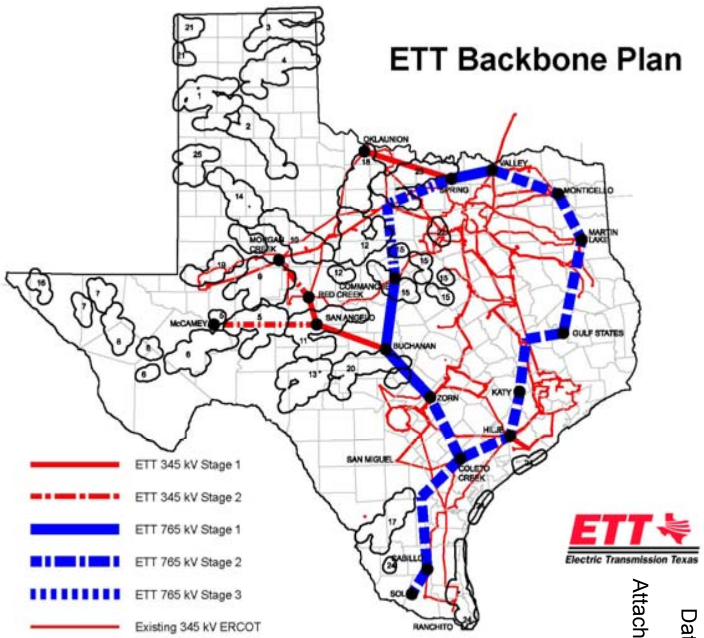
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- ***Transaction Structure***
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- ***Next Steps***
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- ***ETT ERCOT Backbone Proposal***
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



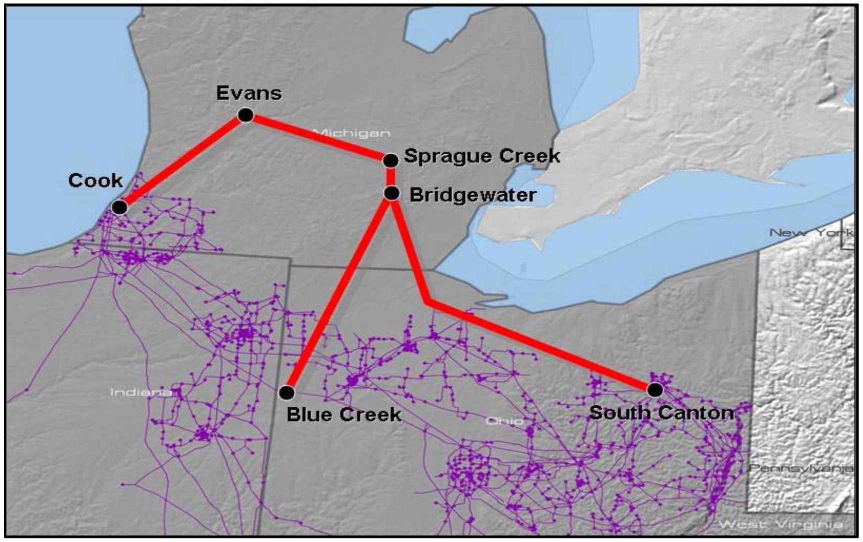
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015

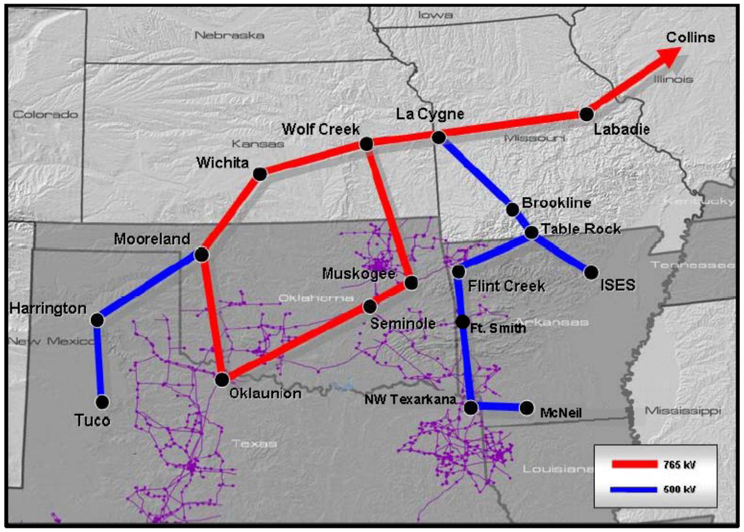


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765TM Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Detailed Ongoing Earnings Guidance

2007A: $3.00

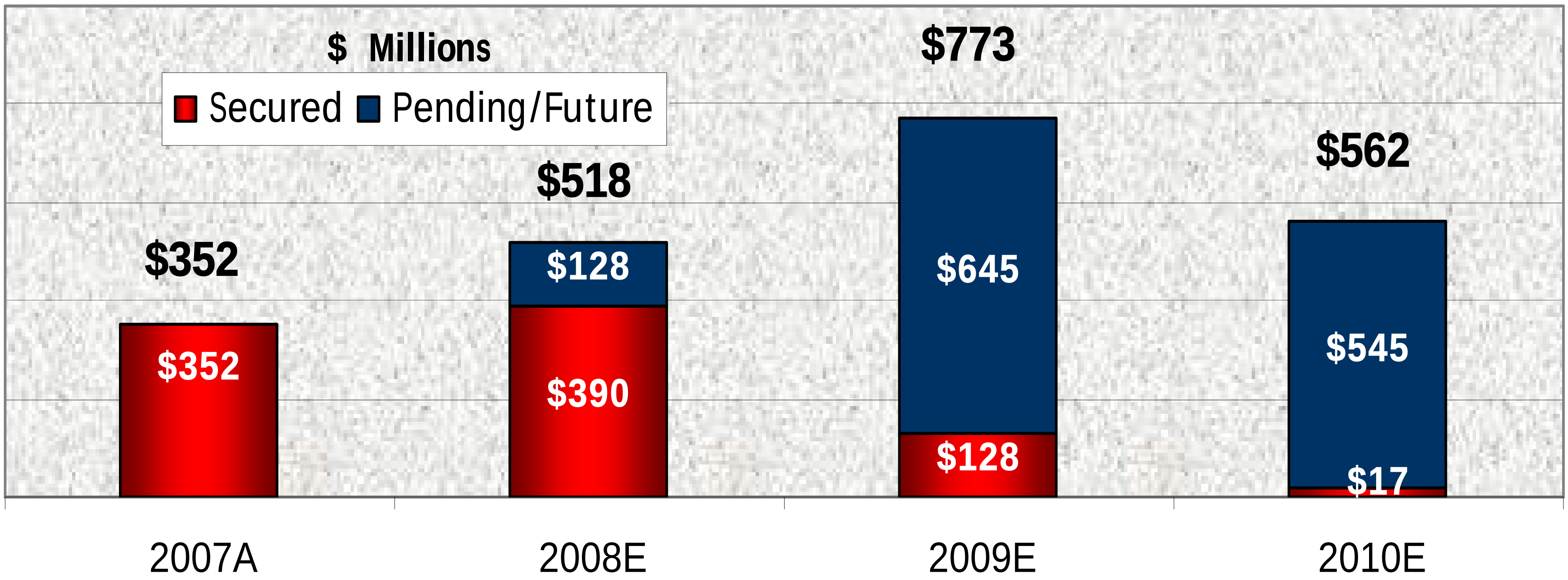
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		2007 Performance Driver	2007 Actual ($ millions)	2008 Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Incremental Rate Relief Assumptions



- **75% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings.**
- **2008 Pending: PSO 2007 Ice Storm Recovery, SWEPCo - LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Activity Underway

- Ohio Post 2008
- I&M - Indiana Base Rate Case
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

2008 Projected Cash Flow

	2007 Actual	2008 Estimate
Beginning Cash Balance	$ 301	$ 178
Cash from Operations:		
Income from Continuing Operations	1,065	1,284
Depreciation and Amortization	1,513	1,484
Other	(190)	(196)
Total from Operations	2,388	2,572
Cash used for Investing:		
Construction Expenditures	(3,556)	(3,916)
Asset Sales	222	-
Distressed Generation Purchases	(512)	-
Other	(62)	(39)
Total used for Investing	(3,908)	(3,955)
Cash from Financing:		
Issuance of Common Stock, Net	143	150
Long-Term Debt Issued/(Retired), Net	1,260	1,883
Short-Term Debt Change, Net	642	(87)
Common Dividends	(630)	(659)
Other Financing Activities	(18)	44
Total from Financing	1,397	1,331
Net Change in Cash	$ (123)	$ (52)
Ending Cash Balance	$ 178	$ 126

Note: For analysis purposes, construction expenditures include AFUDC.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

California Investor Meetings

Arranged by Banc of America Securities, LLC

August 16-17, 2006

AMERICAN ELECTRIC POWER • 100TH ANNIVERSARY 1906 AEP 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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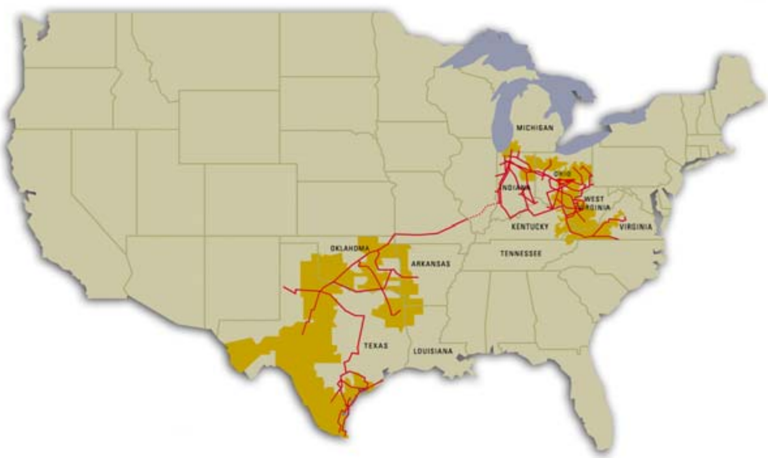
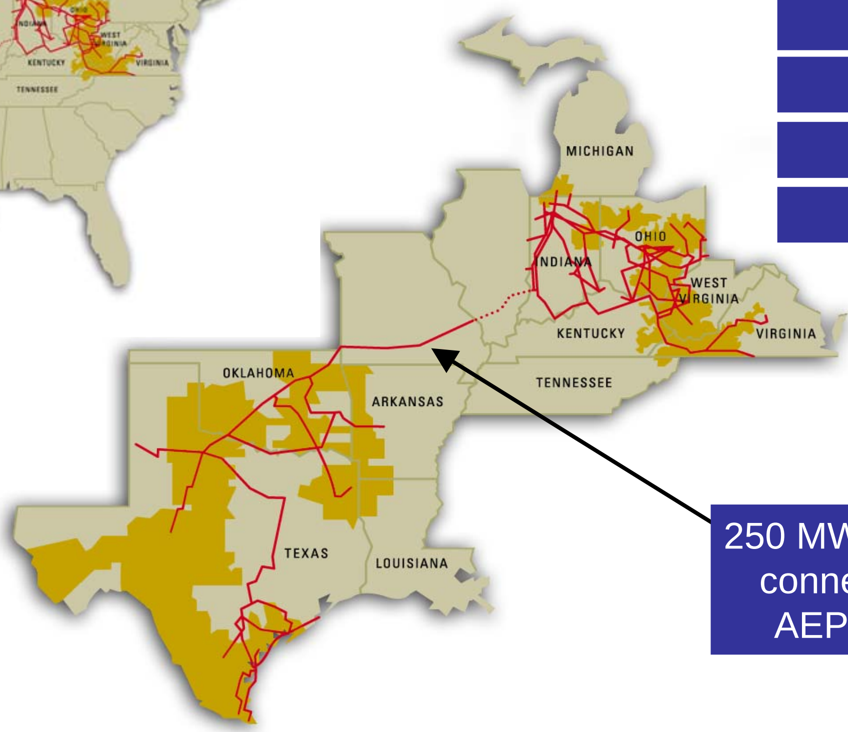
Where We Operate





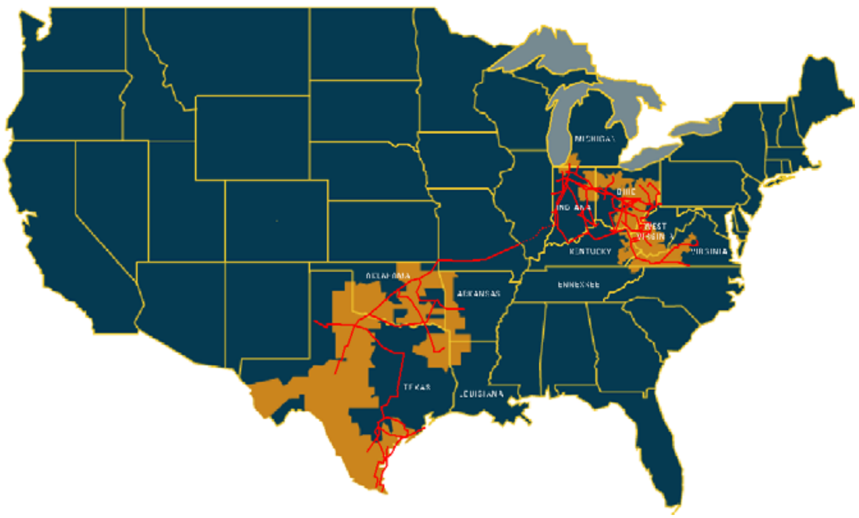
- Ohio
- Indiana
- West Virginia
- Virginia
- Kentucky
- Michigan
- Tennessee

- Oklahoma
- Texas
- Louisiana
- Arkansas

250 MW transmission line connects AEP East & AEP West territories

Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



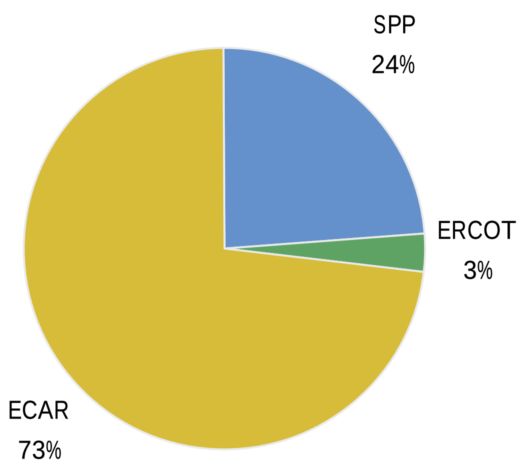
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

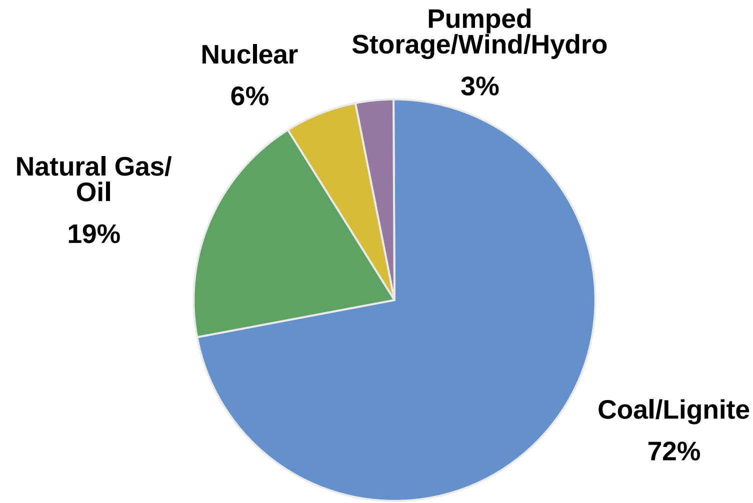
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

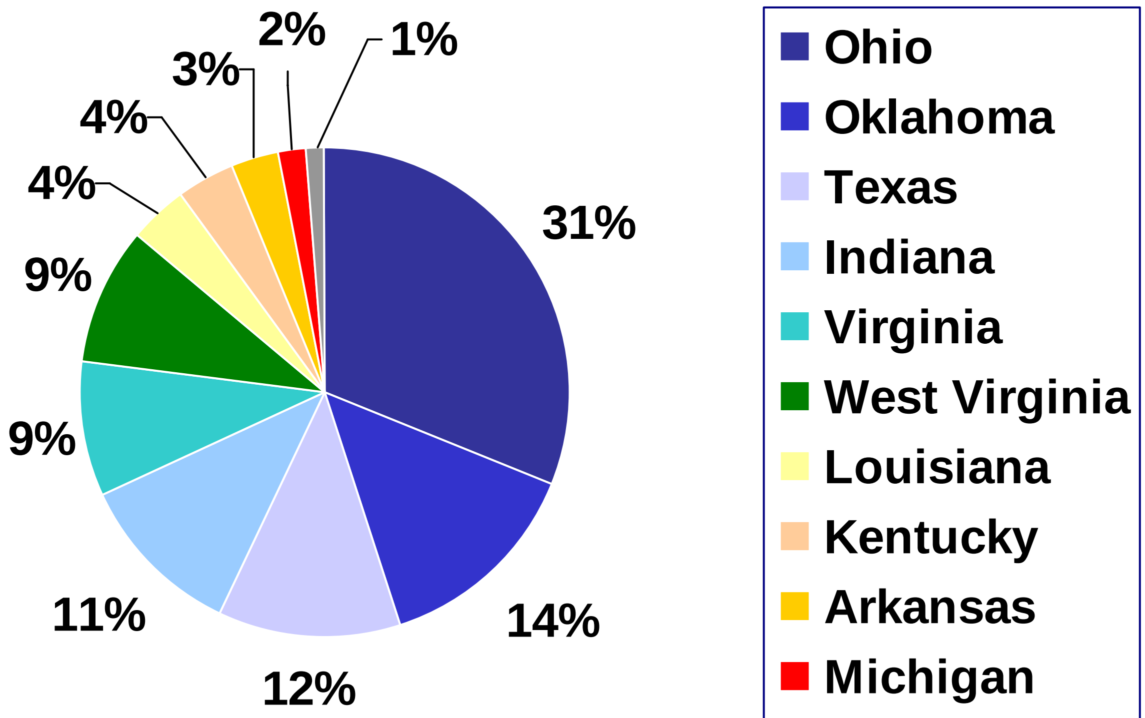
Operating Statistics

Commercial Availability Factor	
2004	85.24%
2005	84.50%

Capacity Factor	
2004	62.06%
2005	62.53%

2005 Retail Revenue

Retail Revenue Composition by State



Regulatory

Regulatory Activity Underway

- TCC Securitization of Stranded Costs
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- IGCC – Received Rate Authorization of Pre-Construction Costs
- FERC Regional Rate Design

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- April 4, 2006 – Final order, following rehearing, which provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
- May 22, 2006 – Settlement agreement filed with PUCT in securitization proceeding
  - Securitization financing order received June 20
  - Issuance of securitization bonds expected late 3Q06

<u>Securitization Order:</u>

- Securitization amount of $1.697 billion plus estimated bond issuance costs ($23 million resulting in $1.72 billion requested to be securitized)
- Securitization order not appealable
- $315 million cost-of-money benefit for ADFIT to be included in CTC
- The treatment of EDFIT and ADITC ($61 million in total) as a reduction to the securitized amount

- June 2006 – Requested approval for CTC to address other true-up items
  - Requested $355 million net credit to customers over 8 years
    - $475 million gross CTC refund proposed, offset by $7 million in rate case expense recovery
    - Requested portion be deferred, pending the outcome of 2 contingent federal matters
      - –$16 million of FERC jurisdictional fuel over-recoveries
      - –$97 million related to ADITC and EDFIT
  - Hearings set for Sept 2006

Regulatory Activity Underway

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Hearings have been held with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- Hearings held, awaiting Commission Order

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, upon which, the full rate increase requested by APCO-VA will be implemented, subject to refund.

<u>Procedural Schedule</u>

Oct 4, 2006	Intervenor testimony due
Oct 24, 2006	SCC Staff testimony due
Nov 9, 2006	Company to file rebuttal testimony
Dec 6, 2006	Evidentiary Hearings to commence

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Underway

FERC Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service proved by high voltage facilities they own that benefit customers throughout PJM
- July 13, 2006 ALJ rendered initial decision finding:
  - License Plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006 when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective

•Next Steps
  - Briefs on Exceptions to the initial decision by all parties
  - Order by the Commission late 2006/early 2007

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate, for certain specific incremental costs
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- $41 million annual increase in base rates
- Rates effective March 30, 2006

Regulatory Activity Completed

APCo & WPCo West Virginia Rate Case

Settlement approved July 2006

- $44MM initial overall increase in rates effective July 28, 2006 comprised of:
  - $56MM increase in ENEC for fuel & purchased power expenses;
  - $23MM special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry (WJF) 765kV line;
  - $18MM general base rate reduction based on ROE of 10.5%, of which $9MM relates to a reduction in depreciation expense (affects cash flows but not earnings);
  - $17MM credit to refund a portion of deferred prior over-recoveries of ENEC costs of $51MM, currently recorded in regulatory liabilities; therefore, this item impacts cash flows but has no effect on earnings;
- Agreement also provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments and the costs of WJF
- Reinstatement of the ENEC mechanism effective July 1, 2006

CSP & OPCO Storm Related Service Restoration Cost Recovery

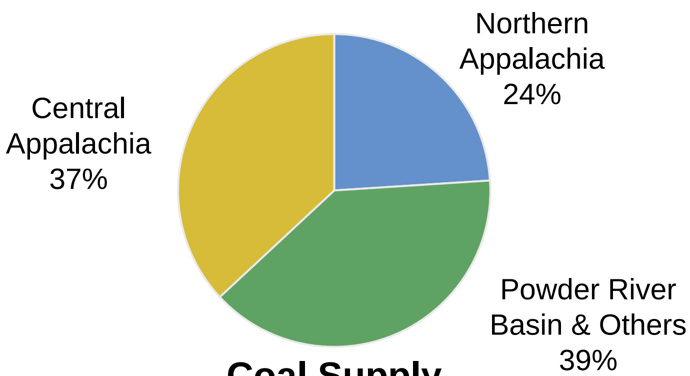
August 9, 2006 – PUCO issued ruling allowing CSP and OPCO to recover costs associated with service restoration activities during the back-to-back December 2004 and January 2005 ice storms.

- CSP Recovery - $11.9MM
- OP Recovery - $11.7MM

Fuel

Coal Procurement

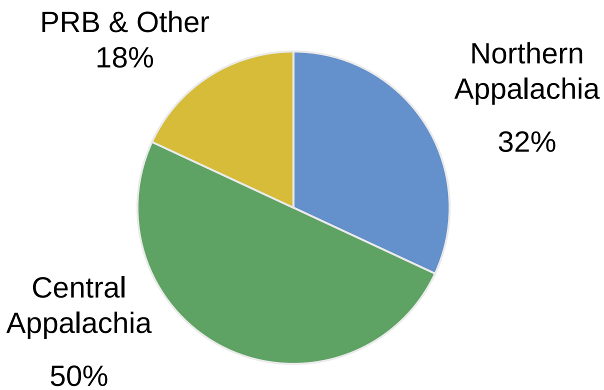
Total AEP System



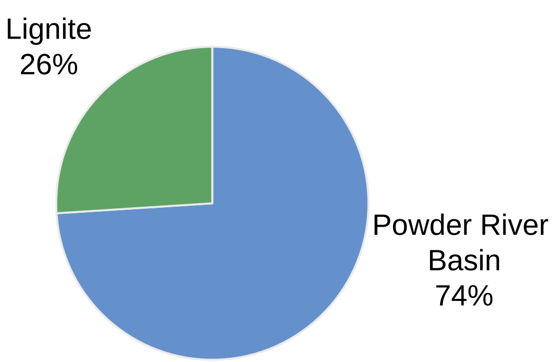
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 95%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System

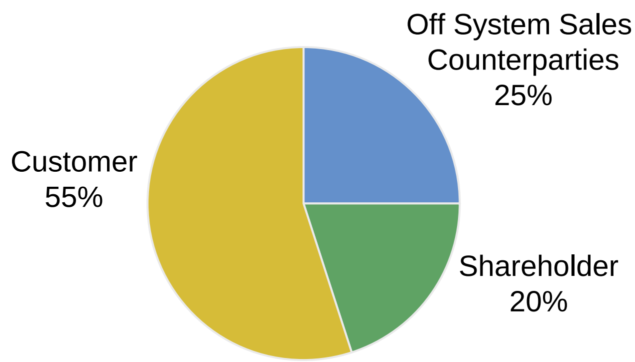


AEP Western System



Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

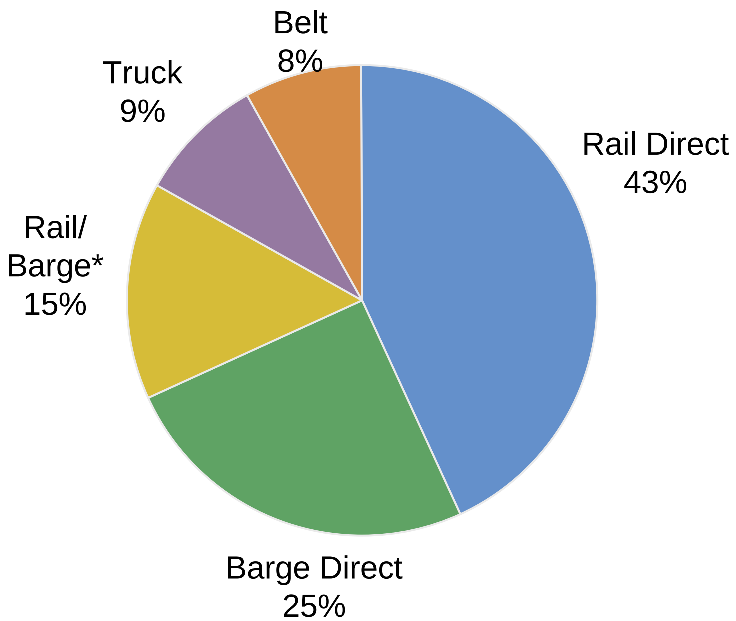
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Annually
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Semi-annually
Virginia	Yes	Annually
West Virginia	Yes	Annually; Deferral accounting for ENEC began July 1, 2006 and new rates became effective July 28, 2006.

Coal Delivery

Total AEP System

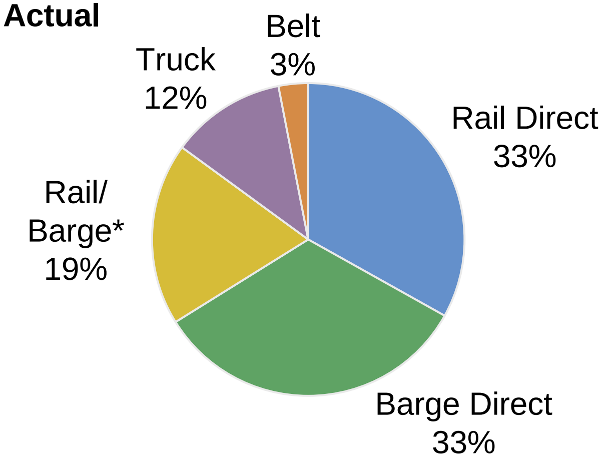
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

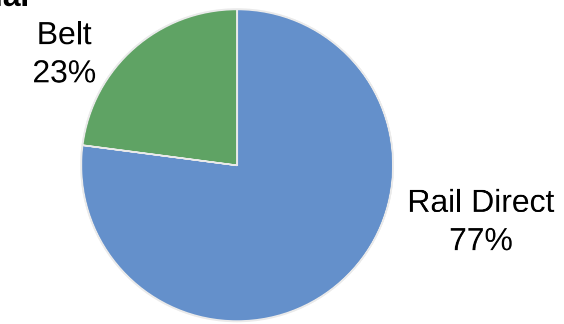
AEP Eastern System

2005 Actual



AEP Western System

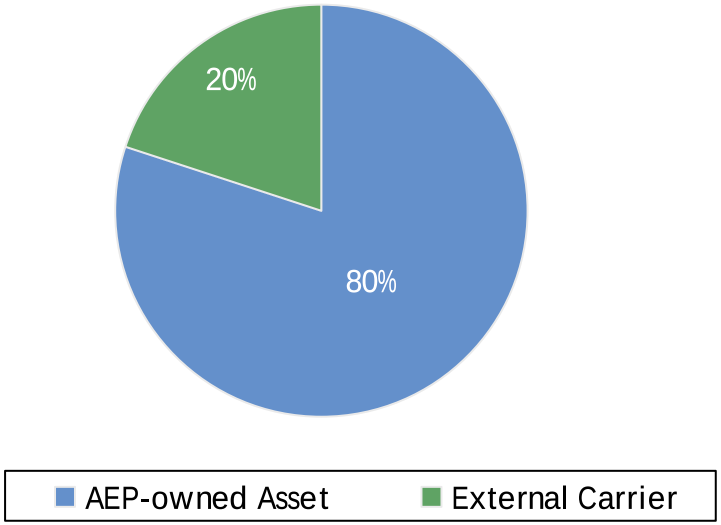
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- ➢7,065 railcars
- ➢2,318 barges
- ➢53 towboats
- ➢1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Environmental

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

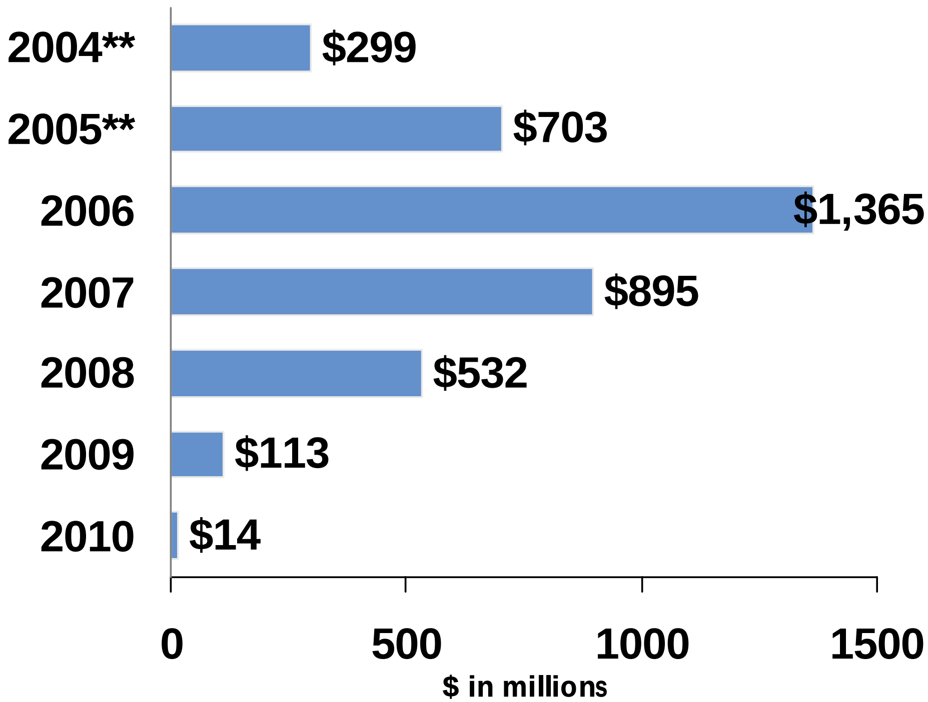
Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Environmental Investment: $3.9 Billion Through 2010

Environmental Capital Investment*

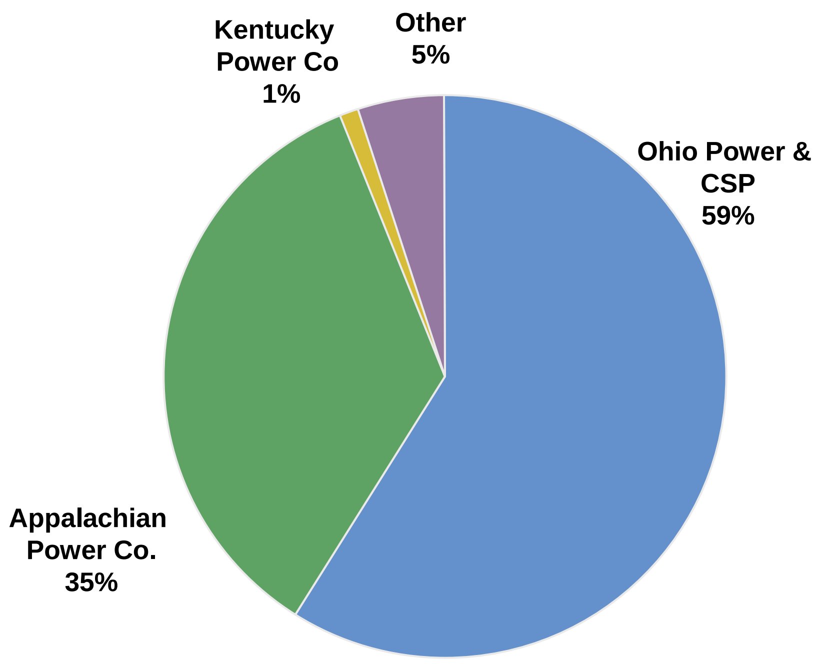


*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

($3.9 billion figure reflects delay of Big Sandy 2 investment)

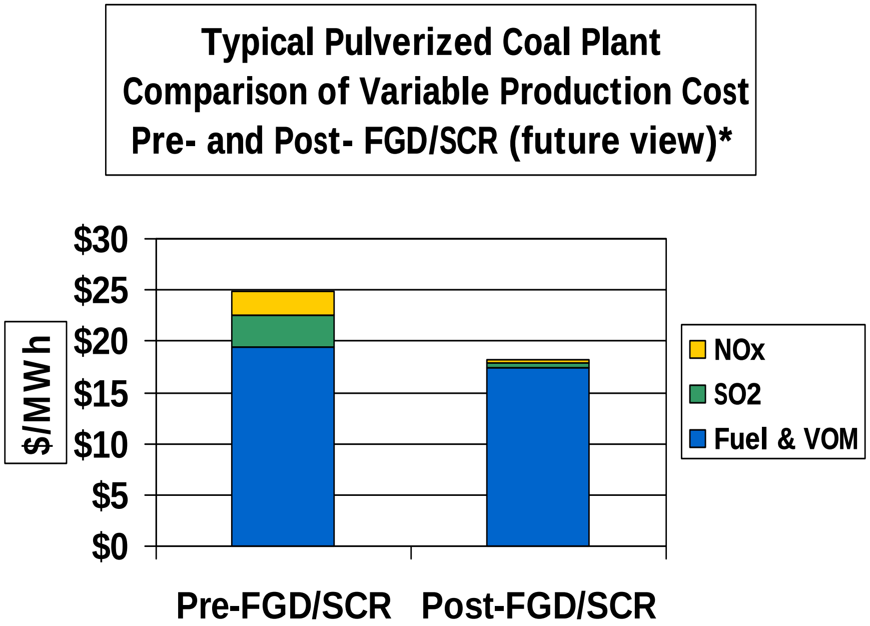
Projected Environmental Investment Allocation



Majority of 2006 & 2007 dollars will be invested in Ohio & APCo

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

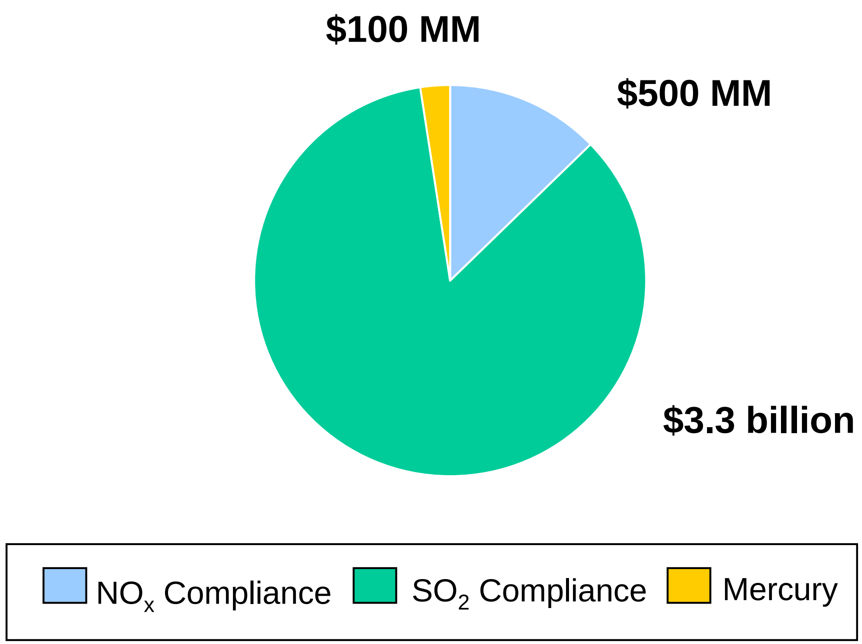


* Assumes annual NOx program

AEP will remain the low cost producer following completion of environmental retrofit projects

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$1.9 Billion:

$1.8 Billion for SO_2

$0.1 Billion for Other

$3.9 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC; $3.9 billion figure reflects delay of Big Sandy 2 investment

Environmental Investment

FGD – Reduces SO_2 by 95% to 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1300	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	627	2009
Muskingum 5	585	2008
Conesville 4	339	2009
Total	**7951**	

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Cost of Control Technology

AEP's compliance plan largely relies on SCR & FGD technology to meet the requirements of CAIR and CAMR. AEP also deployed other combustion related controls, such as low NOx burners and optimized boiler controls throughout the system.

Conventional Technology

	SCR	**FGD**
AEP Capital Cost	~$121/kW avg.	~$250/kW avg.
Pollutant(s)	NO_x	SO_2 (& Hg as co-benefit)
Removal Efficiency	85 to 93%	95%-98% (&~80%)
Aux. Power	Approx. 1%	1.5% to 3.0%

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

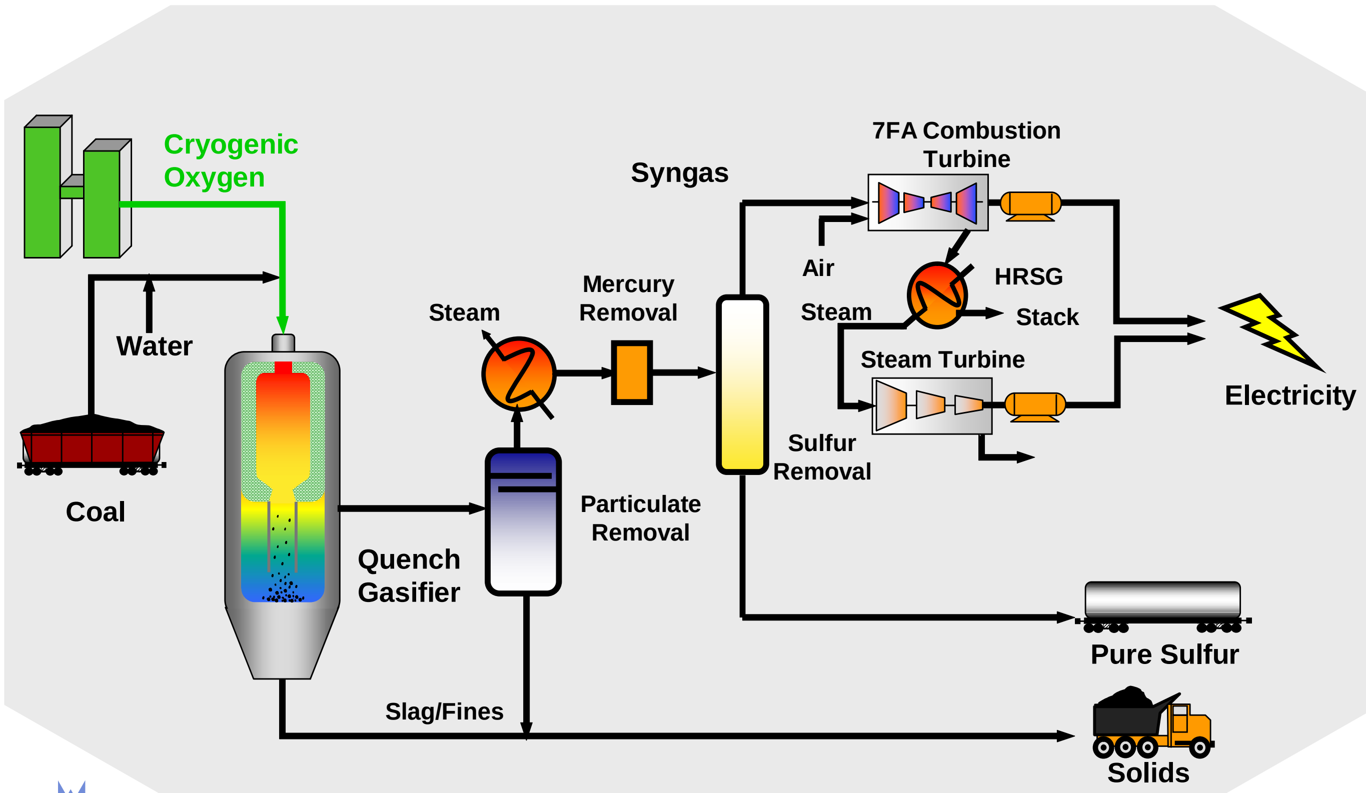
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



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AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

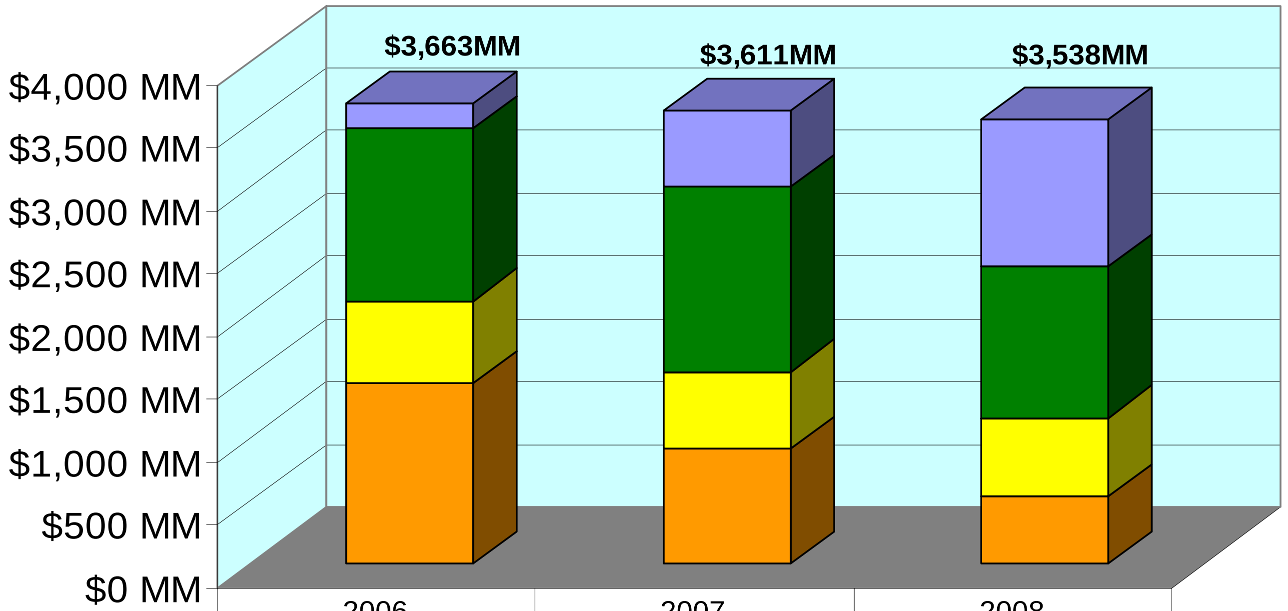
IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Capital Investment

2006 Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,381	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in 2007

SWEPCO

- May 31, 2006- Announced plans to build $1.4 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling up to 480 MW and combined-cycle gas plant totaling 480 MW
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – of which SWEPCO's investment will be approx. 75%
- Commercial operation dates between 2008 and 2011

PSO RFPs

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

2006 Capital Investment Funding Revised

	Actual		Projection		
	2004	**2005**	**2006**	**2007**	**2008**
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,499)	$ (2,091)	$ (1,261)	$ (950)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,572)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,499)	$ (3,663)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,632	$ 1,877	$ 1,736	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 111	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ 6	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 663	$ 1,758	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,705		
Other	$ -	$ 126	$ (117)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (141)	$ (60)	$ -
Ending Cash Balance	$ 320	$ 401	$ 260	$ 200	$ 200

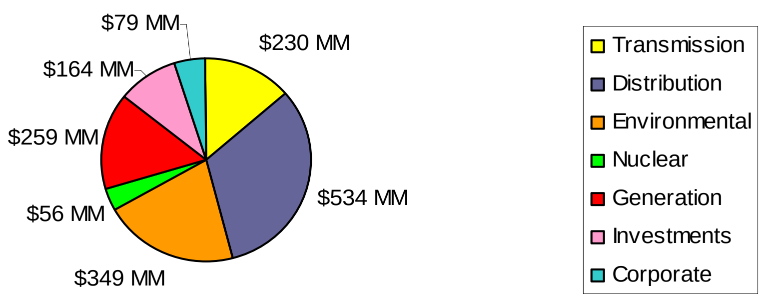
* Cash Flow from Operations assumes full rate recovery on capital expenditures.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

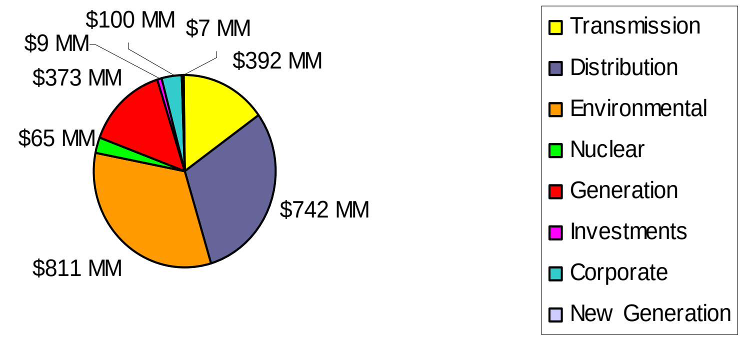
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Investment 2004 - 2006

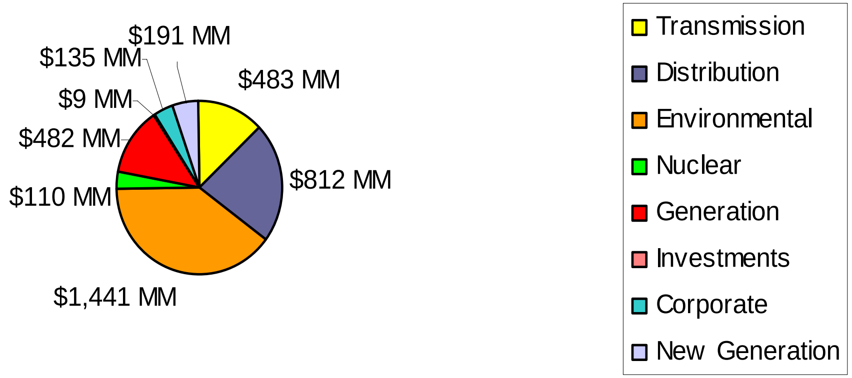
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.

Figures exclude AFUDC.

Finance

2006 Guidance: $2.65 to $2.80 Per Share

American Electric Power
Financial Results for 2005 Actual vs. 2006 Forecast

		2005 Actual Performance Driver	2005 Actual ($ millions)	2005 Actual EPS	2006 Forecast Performance Driver	2006 Forecast ($ millions)	2006 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	65,656 GWh @ $31.5 /MWhr =	2,069		69,550 GWh @ $31.2 /MWhr =	2,173	
2	Ohio Companies	48,877 GWh @ $39.6 /MWhr =	1,937		46,185 GWh @ $47.3 /MWhr =	2,185	
3	West Regulated Integrated Utilities	40,213 GWh @ $22.3 /MWhr =	895		39,649 GWh @ $25.0 /MWhr =	990	
4	Texas Wires	26,525 GWh @ $17.4 /MWhr =	462		26,506 GWh @ $13.8 /MWhr =	366	
5	Off-System Sales	38,493 GWh @ $22.2 /MWhr =	853		37,280 GWh @ $17.7 /MWhr =	661	
6	Transmission Revenue - 3rd Party		411			262	
7	Other Operating Revenue		479			571	
8	Utility Gross Margin		7,106			7,208	
9	Operations & Maintenance		(3,142)			(3,139)	
10	Depreciation & Amortization		(1,285)			(1,280)	
11	Taxes Other than Income Taxes		(743)			(747)	
12	Interest Exp & Preferred Dividend		(595)			(666)	
13	Other Income & Deductions		264			199	
14	Income Taxes		(514)			(525)	
15	Utility Operations On-Going Earnings		1,091	2.80		1,050	2.66
	INVESTMENTS:						
16	Investments On-Going Earnings		24	0.06		26	0.07
17	Parent Company On-Going Earnings		(52)	(0.13)		(10)	(0.03)
18	ON-GOING EARNINGS		1,063	2.73		1,066	2.70
	Shares Outstanding (in millions)			390			394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Cash Flow

	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,066
Depreciation and Amortization	1,318	1,311 *
Pension Funding in Excess of Expense	(626)	-
Extraordinary Items	225	-
Other	173	(641)
Total from Operations	**$ 1,877**	**$ 1,736**
Cash from Investing:		
Capital Expenditures ***	(2,404)	(3,663) **
Asset Sales	1,246	111
Other	153	(114)
Total from Investing	**$ (1,005)**	**$ (3,666)**
Cash from Financing:		
Common Equity	(25)	6
Net Long Term Debt Issued/(Retired)	(12)	2,235 ***
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	133
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,789**
Net Change in Cash	**$ 81**	**$ (141)**
Ending Cash Balance	**$ 401**	**$ 260**

* Assumes point EPS estimate $2.70 per share.

** 2006 guidance excludes AFUDC; 2005 figure excludes equity portion of AFUDC

*** Assumes $1.7 billion of securitization bonds issued in September 2006

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

CASH ON HAND EXPECTED TO BE $260 MILLION AT YEAR END 2006

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Ratings Actions

- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Forecasted Capital Expenditures

Company	2006	2007	2008
AEP SYSTEM*	**$3,663,500**	**$3,611,400**	**$3,537,700**
AEGCo	$12,100	$30,000	$39,700
APCo	$928,300	$691,500	$751,700
CSPCo	$318,700	$473,700	$553,400
I&M	$329,800	$278,700	$262,000
KPCo	$53,400	$127,100	$144,000
OPCo	$1,065,400	$954,500	$581,600
PSO	$262,000	$342,800	$408,700
SWEPCo	$314,900	$366,700	$458,700
TCC	$286,100	$247,000	$222,100
TNC	$72,300	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

Long-Term Debt Maturity

Year	2006(3)	2007	2008
AEP Service Corporation	$ 2,000,000 (2)	$ 2,000,000 (2)	$ 34,000,000
AEP Inc.	$ -	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Ohio Power Company	$ 6,177,000 (2)	$ 17,854,000	$ 55,188,000 (2)
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 9,361,000 (2)	$ 95,312,000 (2)	$ 5,000,000 (2)
Texas Central Company	$ -	$ -	$ 18,581,000
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 317,538,000**	**$ 1,133,781,000**	**$ 504,769,000**

(1) Excludes tax exempt bond remarketings and securitization bonds.
(2) Includes sinking fund payments, where applicable.
(3) Maturities remaining as of June 30, 2006.

2006 Key Operating Company Highlights

(in millions)

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 *	42-45%
CSP	$343	$0	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$0	42-45%
OPCo	$1,070	$350 - $400	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$150 - $200	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

*Issuances include potential new money tax-exempt issuances

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

Maintain financial strength of subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Debt Schedules

American Electric Power Service Corp			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.134%		$1,077,775,000

AEP Generating			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,339,800
Securitization Bond	5.010%	01/15/2008	$103,272,491
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,766,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,041,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of June 30, 2006

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Debt Schedules

Indiana Michigan Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Weighted Average or Total	4.702%		$1,220,083,600

Kentucky Power			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$10,243,904
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,737,500
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	4.638%		$2,230,479,504

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$23,288,281
Notes Payable	6.360%	02/22/2007	$7,000,000
Notes Payable	7.030%	02/22/2012	$23,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/10/2008	$113,403,000
Weighted Average or Total	4.135%		$693,795,881

Note: Debt Schedules as of June 30, 2006

Appendix

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Completed APCo West Virginia Rate Case

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2006 – Joint Settlement Agreement

- Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs
- Settlement Agreement approved July 26

Phased-In Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Approved Settlement Details

- ✓ Increase effective July 28, 2006:

($18MM) Base Rates

$56MM ENEC

$23MM WJF & FGD investment @ 12/31/05

$61MM Gross revenue increase

($17MM) ENEC over-recovery negative surcharge

$44MM Net increase effective 7/28/06

- ✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

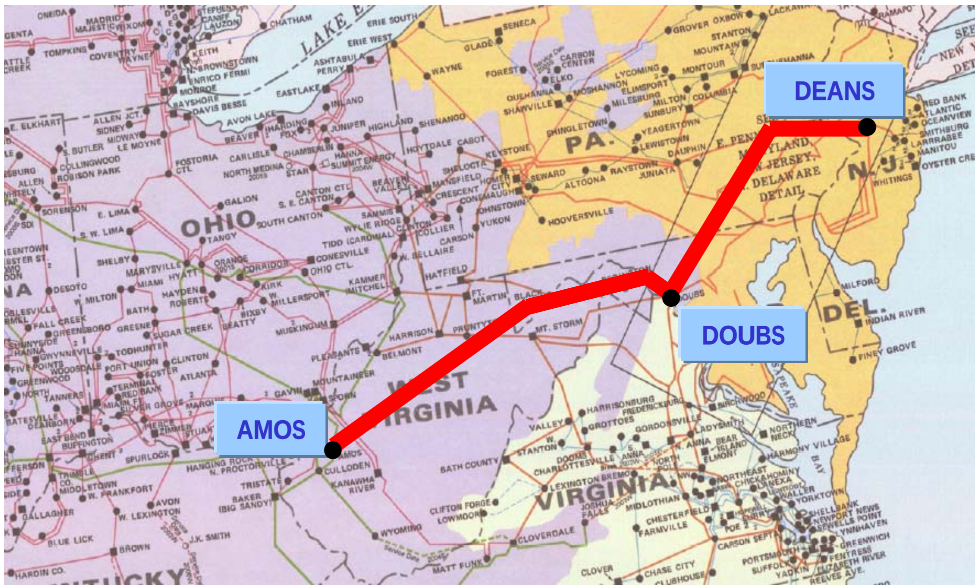
Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

OPERATING COMPANY DETAIL

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

As of 12/31/2005

Total Customers:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**
Generating Capacity	**54 MW***
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**5,000**
Distribution Miles	**28,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

Principal industries served:

Oil and gas extraction
Food processing
Apparel
Metal refining
Chemical and petroleum refining
Plastics
Machinery equipment

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data (in thousands)

Revenue	$ 793,000
% of AEP Retail	5%
Net Income (Loss)	$ (174,000)
Capital Expenditure	$ 179,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 4,905,000
Net Plant Assets	$ 2,021,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 286,100	$ 247,000	$ 222,100

AEP Texas Central Company

AEP TEXAS CENTRAL
MAJOR CUSTOMERS

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
El Paso Energy Corp.
HEB Grocery Company LP
Ingleside Cogeneration Ltd Par
Citgo Petroleum Corporation
Wal-Mart Stores, Inc.
Formosa Utl Ven Ltd.

- **Top 10 customers = 67% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **53 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas Central Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

As of 12/31/2005

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
Total	**183,000**

Generating Capacity **377 MW**
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,500**
Distribution Miles	**12,000**

Principal industries served:

Agriculture and the manufacturing or processing of Cotton seed products

Oil products

Precision and consumer metal products

Meat products

Gypsum products

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data (in thousands)

Revenue	$	459,000
% of AEP Retail		1%
Net Income	$	33,000
Capital Expenditure	$	65,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,044,000
Net Plant Assets	$	807,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 72,300	$ 71,600	$ 89,400

AEP Texas North Company

AEP TEXAS NORTH
MAJOR CUSTOMERS

Chevron Texaco Corporation
Kinder Morgan
Occidental Permian Ltd.
Crown Cork & Seal Co., Inc
Rhodia Inc.
Plains All American Pipeline (Equilon)
Georgia-Pacific Corporation
Ethicon, Inc.
Wal-Mart Stores, Inc.
Tyson Foods Inc. (Wright Brand)

- **Top 10 customers = 32% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas North Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company Texas North Company Southwestern Electric Power Company

Commissioners

Number**: 3**	Appointed/Elected**: Appointed**	Term**: 6 years**	Political Makeup**:** R:3

<u>Qualifications for Commissioners</u>

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

<u>Commissioners</u>

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

Appalachian Power

President and Chief Operating Officer: Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 942,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

Principal industries served:

Coal mining
Primary metals
Chemicals
Textile mill products

As of 12/31/2005

Total Customers:

• **Residential**	**804,000**
• **Commercial**	**126,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**941,000**

Generating Capacity	**6,389 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**79.4%**
• **Hydro/Pump:**	**12.5%**
• **Nat Gas**	**8.1%**

Transmission Miles	**6,700**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,947,075	1,360,131	3,307,206	1,995,658	1,427,502	3,423,160	2,345,511	1,821,484	4,166,995
% of Capitalization Per Balance Sheet	58.9%	41.1%	100.0%	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%
Adjusted Capitalization	1,947,075	1,360,131	3,307,206	2,004,550	1,418,610	3,423,160	2,354,403	1,812,593	4,166,996
% of Adjusted Capitalization	58.9%	41.1%	100.0%	58.6%	41.4%	100.0%	56.5%	43.5%	100.0%
FFO Interest Coverage			5.6			5.0			3.7
FFO Total Debt			27.2%			19.7%			12.4%

2005 Financial Data (in thousands)

Revenue	$ 2,176,000
% of AEP Retail	17%
Net Income	$ 131,000
Capital Expenditure	$ 598,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 6,254,000
Net Plant Assets	$ 4,652,000
Cash	$ 1,741

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 928,300	$ 691,500	$ 751,700

Appalachian Power

APCo Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	32,901,943	29,551,752	32,949,364	31,801,020
Coal Consumption (tons burned)	13,015,569	11,604,352	13,187,986	12,602,636

Operating Information

2005 retail electric sales in megawatt-hours	30,327,723
2005 firm wholesale sales in megawatt-hours	2,480,850
Average cost per kilowatt-hour (residential)	5.41 cents
2005 System Peak	6,978 (January 24)

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES

West Virginia	Customers
APCo	**433,615**
Allegheny	485,295

Virginia	Customers
APCo	**496,994**
Dominion Virginia	2,131,281
Allegheny	92,878
Kentucky Utilities	29,801
Conectiv	21,529

Tennessee	Customers
APCo	**45,803**

TYPICAL BILL COMPARISON*

West Virginia	
APCo	**55.28**
AEP – Wheeling	**57.91**
Allegheny	70.09

Virginia	
APCo	**57.80**
ODPCo	58.07
Dominion Virginia	87.18
Conectiv	103.13

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

APPALACHIAN POWER COMPANY MAJOR CUSTOMERS

Massey Energy Company
CONSOL Energy
Roanoke Electric Steel Corporation
Georgia-Pacific Corporation
Elkem Metals Company
Greif Brothers Corporation
The Dow Chemical Co., Inc.
Arch Coal, Inc.
Dan River Inc.
Peabody Group

- **Top 10 Customers = 23% of industrial sales**
- **Metropolitan areas account for 37% of ultimate sales**
- **85 persons per square mile (U.S. = 95)**

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Wheeling Power Co.
Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup R:** 1 **D:** 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office.

R. Michael Shaw, Commissioner (Rep.), since mid 2003, term expires June 2007. Attorney, former state legislator.

Jon W. McKinney, Chairman (Dem.), since 2005, term expires June, 2011. Formerly served as plant manager of Flexsys' Nitro, W Va operations, chairman of Chemical Industry Committee for W Va, board member of W Va Chamber of Commerce, W Va Manufacturer's Association, Chemical Alliance Zone, W Va Roundtable & Thomas Memorial Hospital.

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 1

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires February 2010. Current Chairman. Attorney, counsel to the Speaker of the House

Judith Williams Jagdmann, (Rep.), since 2006, current term expires 2012. Law degree from T.C. Williams School of Law. Prior to being elected to the Commission, she served as 43rd Attorney General for the Commonwealth of Virginia. Prior to work in Attorney in the Office of Attorney General, served 13 years as counsel to the SCC.

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSP Co covers a service territory of 3,701 miles and at December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

As of 12/31/2005

Total Customers:	
Residential	**636,000**
• **Commercial**	**71,000**
• **Industrial**	**3,000**
• **Other**	**<u>300</u>**
Total	**710,300**
Generating Cap	**3,270 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**72.5%**
• **Natural Gas**	**26.1%**
• **Hydro:**	**1.5%**
Transmission Miles	**2,200**
Distribution Miles	**17,200**

Principal industries served:

Food processing
Chemicals
Primary metals
Electronic machinery
Paper products

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Capitalization Per Balance Sheet	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
Adjusted Capitalization	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Adjusted Capitalization	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
FFO Interest Coverage			7.7			6.2			5.8
FFO Total Debt			37.9%			28.7%			24.3%

2005 Financial Data (in thousands)

Revenue	$	1,542,000
% of AEP Retail		14%
Net Income	$	134,000
Capital Expenditure	$	165,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	3,433,000
Net Plant Assets	$	2,526,000
Cash	$	940

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 318,700	$ 473,700	$ 553,400

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	15,243,711	14,049,095	14,038,045	14,443,617
Coal Consumption (tons burned)	6,526,167	6,121,275	6,048,060	6,231,834

Operating Information

2005 retail sales in megawatt-hours	18,277,372
2005 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	7.56 cents (CSP)
2005 System Peak	4,105 megawatts (CSP-July 25)

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,260	Coal
J. M. Stuart #*1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	627	Coal
Wm. H. Zimmer #*1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

Columbus Southern Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

COLUMBUS SOUTHERN POWER MAJOR CUSTOMERS

The Ohio State University
State of Ohio
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
The Kroger Company
Nationwide Insurance Enterprise
Ohio University
Griffin Wheel Company
OhioHealth
Limited Brands

- **Top 10 customers = 31% of industrial sales**
- **Metropolitan areas account for 84% of ultimate sales**
- **244 persons per square mile (U.S. = 95)**

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.
Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

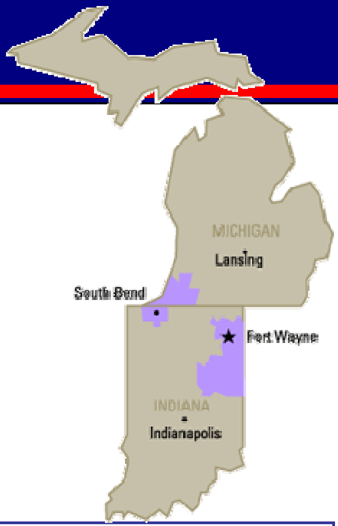
Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

Indiana Michigan Power



President and Chief Operating Officer:
Marsha Ryan

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 580,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 8,620 square miles and at December 31, 2005, I&M had 2,633 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

Principal industries served:
Primary metals
Transportation equipment
Electrical and electronic machinery
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

As of 12/31/2005

Total Customers:	
• **Residential**	**507,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**580,000**
Generating Capacity	**5,768 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.1%**
• **Hydro:**	**0.4%**
Transmission Miles	**4,039**
Distribution Miles	**19,700**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,438,181	1,149,593	2,587,774	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%
Adjusted Capitalization	1,823,681	1,149,593	2,973,274	1,761,432	1,095,540	2,856,972	1,921,435	1,224,134	3,145,569
% of Adjusted Capitalization	61.3%	38.7%	100.0%	61.7%	38.3%	100.0%	61.1%	38.9%	100.0%
FFO Interest Coverage			4.0			4.1			4.7
FFO Total Debt			22.70%			23.20%			22.80%

2005 Financial Data (in thousands)

Revenue	$	1,893,000
% of AEP Retail		13%
Net Income	$	146,000
Capital Expenditure	$	299,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	5,238,000
Net Plant Assets	$	3,116,000
Cash	$	854

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 329,800	$ 278,700	$ 262,000

Indiana Michigan Power

I&M Generation Production Statistics – 2003 – 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Avg.**
MWh Produced	28,075,125	21,258,001	31,535,226	26,956,117
Coal Consumption (tons burned)	7,189,655	7,186,066	7,011,370	7,129,030

Operating Information

2005 retail electric sales in megawatt-hours	19,248,200
2005 firm wholesale sales in megawatt-hours	2,169,221
Average cost per kilowatt-hour (residential)	6.61 cents
2005 System Peak	4,193 MW (August 3)

Indiana Michigan Power			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville	Mottville, Michigan	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES

Indiana	Customers
I&M	**454,760**
IP & L	460,000
NIPSCO	450,000
Duke Energy Indiana	750,000
Vectren	136,000

Michigan	Customers
I&M	**126,146**
CMS (Consumers)	1,779,184
DTE (Detroit Edison)	2,158,201

TYPICAL BILL COMPARISON*

Indiana	
I & M	**69.63**
IP & L	73.10
Duke Energy Indiana	81.80
Vectren	98.76

Michigan	
I & M	**62.08**
Consumers Energy	84.19
Detroit Edison	104.48

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report.

INDIANA MICHIGAN POWER
MAJOR CUSTOMERS

Steel Dynamics Inc.
Mittal Steel Company
Air Products & Chemicals, Inc.
Boc Gases
Saint Gobain Corporation USA
Ball State University
New Energy Corp
Michelin North America, Inc.
Dock Foundry
Honeywell International Inc.

- **Top 10 Customers = 29% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Number: 5	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup: R** 3 **D:** 2

<u>Qualifications for Commissioners</u>

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four year, staggered terms, full time positions. Not more than three of the members of the IURC may be members of the same political party. At lease one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

<u>Commissioners</u>

David L. Hardy, Chairman (Rep.), since September 2005, current term will expire April 2010. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include: negotiation, contracts, litigation, finance and administration. He has 35 years regulatory experience at the state and federal levels.

Larry S. Landis, Commissioner (Rep.), since December 2002, current term ends January 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.

David W. Hadley, Commissioner (Dem.), since Feb 2000; current tem ends January 2010. Executive officer for Indiana AFL CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.

Greg Server, Commissioner (Rep.), since August 2005, current term ends in April 2009. Former state senator since 1981 and before that served in the Indiana House or Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.

David E. Ziegner, Commissioner (Dem.), since Aug 1990, current term ends April 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.			
Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R**:1 **D:** 2

Qualifications for Commissioners

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

Commissioners

J. Peter Lark, Chair, (Dem) since August 2003: current term expires July 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney.

Laura Chappelle, Commissioner, (Rep.) since January 2001: current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney.

Monica Martinez, Commissioner, (Dem) since July 2005, current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues.

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

As of 12/31/2005
Total Customers:

• Residential	145,000
• Commercial	29,000
• Industrial	1,000
• Other	400
Total	175,400

Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• Coal:	100%
Transmission Miles	**1,200**
Distribution Miles	**10,000**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Capitalization Per Balance Sheet	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
Adjusted Capitalization	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Adjusted Capitalization	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
FFO Interest Coverage			4.7			3.9			3.4
FFO Total Debt			20.4%			16.6%			14.0%

2005 Financial Data (in thousands)

Revenue	$	531,000
% of AEP Retail		4%
Net Income	$	21,000
Capital Expenditure	$	57,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,320,000
Net Plant Assets	$	989,000
Cash	$	526

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 53,400	$ 127,100	$ 144,000

Kentucky Power

Kentucky Power Generation Production Statistics – 2003 - 2005

Production Stat	2003	2004	2005	Three-Year Average
MWh Produced	6,170,931	6,550,509	7,345,624	6,689,021
Coal Consumption (tons burned)	2,513,524	2,607,559	2,926,253	2,682,445

Operating Information

2005 retail electric sales in megawatt-hours	7,309,016
2005 firm wholesale sales in megawatt-hours	97,845
2005 average cost per kilowatt-hour (residential)	5.67 cents
2005 System Peak	1,685 MW (Jan 24)

Kentucky Power Plants

Name	Location	Megawatt Capacity	Fuel
Big Sandy #1, 2	**Louisa, Kentucky**	**1,060**	**Coal**

Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	**Customers**
KPCo	**174,631**
Kentucky Utilities	485,627
LG & E	389,196

KENTUCKY POWER MAJOR CUSTOMERS

Marathon Ashland Petroleum
AK Steel Holding Corporation
James River Coal Co.
Massey Energy Company
TECO Energy, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC.
Alliance Coal, LLC
Consol Energy
Weyerhaeuser Company

TYPICAL BILL COMPARISON*

Kentucky	
KPCo	**59.78**
Kentucky Utilities	62.40
LG&E	66.31
CIN	68.54

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 61% of industrial sales**
- **Metropolitan areas account for 42% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>
Three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.

<u>Commissioners</u>

Mark Goss (Chair) (Rep.), since 2004; current term expires June 2007. Attorney in private practice.

Teresa Hill (V. Chair.) (Rep.), since 2005; current term expires June 30, 2009. Served on the Governor's Executive Staff. She is an attorney.

Greg Coker (Rep.), since 2004; current term expires June 30, 2008. Formally V.P. External Affairs at ALLTEL; public policy positions at Bell South.

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2005, OPCo had 2,220 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Principal industries served:

Primary metals
Rubber and plastic products
Stone, clay, glass and concrete products
Petroleum refining
Chemicals

As of 12/31/2005
Total Customers:

• **Residential**	**610,000**
• **Commercial**	**90,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**709,000**

Generating Capacity	**8,952 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**94.6%**
• **Hydro:**	**5.4%**
Transmission Miles	**6,500**
Distribution Miles	**26,000**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,082,195	1,487,920	3,570,115	2,053,641	1,490,479	3,544,120	2,280,107	1,784,586	4,064,693
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	57.9%	42.1%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,082,195	1,487,920	3,570,115	2,061,962	1,482,159	3,544,121	2,288,427	1,776,267	4,064,694
% of Adjusted Capitalization	58.3%	41.7%	100.0%	58.2%	41.8%	100.0%	56.3%	43.7%	100.0%
FFO Interest Coverage			6.5			4.9			6.2
FFO Total Debt			28.3%			22.6%			23.8%

2005 Financial Data (in thousands)

Revenue	$ 2,635,000
% of AEP Retail	17%
Net Income	$ 245,000
Capital Expenditure	$ 711,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 6,331,000
Net Plant Assets	$ 4,785,000
Cash	$ 1,240

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 1,065,400	$ 954,500	$ 581,600

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Ohio Power

Ohio Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	53,099,905	52,156,749	52,080,585	52,445,746
Coal Consumption (tons burned)	20,936,936	20,534,361	20,382,116	20,617,804

Operating Information

2004 retail sales in megawatt-hours	28,929,494
2004 firm wholesale sales in megawatt-hours	2,225,194
Average cost per kilowatt-hour (residential)	6.56 cents (OPCo)
2004 System Peak	5,638 megawatts (OPCo-Aug 12)

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	48	Hydro

Ohio Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison = 162,117
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

OHIO POWER
MAJOR CUSTOMERS

Century Aluminum Company
The Timken Company
Wheeling Pittsburgh – WHX HQ
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Globe Metallurgical, Inc
Marathon Petroleum Company LLC
Duke Energy Corp
Linde Gas
Owens Corning Fiberglas Corp.

OPCo:

- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 52% of ultimate sales**
- **135 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 514,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2005, PSO had 1,176 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

Principal industries served:

Natural gas and oil production
Oil refining
Steel processing
Aircraft maintenance
Paper manufacturing and timber products
Glass
Chemicals
Cement
Plastics
Aerospace manufacturing
Telecommunications
Rubber goods

As of 12/31/2005

Total Customers:	
• **Residential**	**442,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**7,000**
Total	**514,000**

Generating Capacity **4,153 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **25%**
- **Natural Gas:** **75%**

Transmission Miles **3,600**

Distribution Miles **21,000**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	607,162	488,275	1,095,437	601,095	534,517	1,135,612	646,954	553,858	1,200,812
% of Capitalization Per Balance Sheet	55.4%	44.6%	100.0%	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%
Adjusted Capitalization	607,162	488,275	1,095,437	603,726	531,886	1,135,612	649,585	551,228	1,200,813
% of Adjusted Capitalization	55.4%	44.6%	100.0%	53.2%	46.8%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			3.8			5.5			2.8
FFO Total Debt			20.4%			28.2%			9.5%

2005 Financial Data (in thousands)

Revenue	$	1,304,000
% of AEP Retail		14%
Net Income	$	58,000
Capital Expenditure	$	134,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	2,355,000
Net Plant Assets	$	1,819,000
Cash	$	1,520

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 262,000	$ 342,800	$ 408,700

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	14,845,846	12,512,486	15,375,848	14,244,727
Coal Consumption (tons burned)	4,678,950	4,093,436	4,353,364	4,375,250

Operating Information

2005 retail electric sales in megawatt-hours	17,782,561
2005 firm wholesale sales in megawatt-hours	45,172
Average cost per kilowatt-hour (residential)	7.55 cents
2005 System Peak	4,043 MW (July 22)

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	338	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	Customers
PSO	507,214
OG&E	**668,766**

PUBLIC SERVICE COMPANY OF OKLAHOMA MAJOR CUSTOMERS

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Transok Inc
AMR Corporation
Sunoco Inc.
Terra Nitrogen Limited Partner
Republic Paperboard
Wal-Mart Stores, Inc.

TYPICAL BILL COMPARISON*

Oklahoma		
OG&E	**73.33**	
PSO	**74.20**	
SPSCo	**82.52**	
Empire District	**85.25**	

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **46 persons per square mile (U.S. = 95)**

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: **3**	**Appointed / Elected:** Elected	Term**: 6 years**	Political Makeup: **R: 3**

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

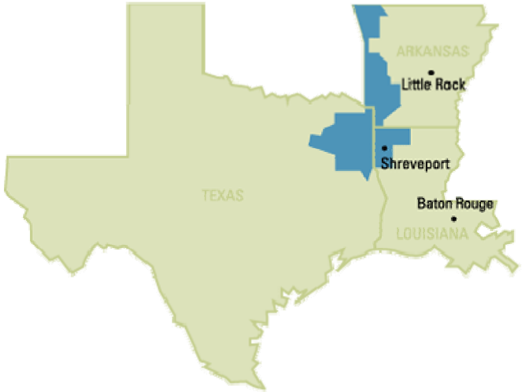
Commissioners

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

Denise A. Bode, Vice-Chairman (Rep.), since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

Bob Anthony, Commissioner (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

Southwestern Electric Power



President and Chief Operating Officer: Nick Akins

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 450,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2005, SWEPCo had 1,498 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

As of 12/31/2005

Total Customers:

• Residential	381,000
• Commercial	61,000
• Industrial	7,000
• Other	1,000
Total	450,000

Generating Capacity **4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite: 60%**
- **Natural Gas: 40%**

Transmission Miles	3,500
Distribution Miles	19,300

Principal industries served:
Natural gas and oil production
Petroleum refining
Manufacturing of pulp and paper
Chemicals
Food processing
Metal refining.

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	890,675	701,360	1,592,035	806,494	773,318	1,579,812	774,245	787,077	1,561,322
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	51.0%	49.0%	100.0%	49.6%	50.4%	100.0%
Adjusted Capitalization	890,675	701,360	1,592,035	808,844	770,968	1,579,812	776,595	784,727	1,561,322
% of Adjusted Capitalization	55.9%	44.1%	100.0%	51.2%	48.8%	100.0%	49.7%	50.3%	100.0%
FFO Interest Coverage			4.1			5.7			3.8
FFO Total Debt			22.9%			31.4%			18.1%

2005 Financial Data (in thousands)

Revenue	$ 1,405,000
% of AEP Retail	12%
Net Income	$ 74,000
Capital Expenditure	$ 158,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 2,797,000
Net Plant Assets	$ 2,230,000
Cash	$ 3,049

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 314,900	$ 366,700	$ 458,400

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	20,539,365	20,071,578	20,167,754	20,259,566
Coal Consumption (tons burned)	12,536,179	13,032,475	12,420,979	12,663,211

Operating Information

2005 retail electric sales in megawatt-hours	17,069,455
2005 firm wholesale sales in megawatt-hours	5,554,340
Average cost per kilowatt-hour (residential)	6.92 cents
2005 System peak	4725 MW (Aug 23)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES

Arkansas	Customers
SWEPCO	**107,220**
Entergy AR	667,714

Louisiana	Customers
SWEPCO	**169,079**
CLECO	261,601

Texas	Customers
SWEPCO	**279,729**

TYPICAL BILL COMPARISON*

Arkansas	
SWEPCO	**66.15**
OG&E	**72.11**
Empire District	**74.71**
ETR	**88.92**

Louisiana	
SWEPCO	**68.83**
CLECO	90.13
Entergy Gulf St	92.69
Entergy NO	96.65
Entergy LA	102.08

Texas	
SWEPCO	**63.95**
SPSCo	83.19
ETR	93.43
EP	106.64
TXU	118.84

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

Lone Star Steel Company
Tyson Foods Inc
Domtar, Inc
International Paper Company
Pilgrim Pride Corporation
Calumet Lubricants
General Motors Corporation
Wal-Mart Stores, Inc.
Cooper Tire & Rubber Company
Superior Industries Int

- **Top 10 customers = 38% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **77 persons per square mile (U.S. = 95)**

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

<u>Commissioners</u>

Sandra Hochstetter, Chairman (Rep.), since 1999; current term ends Jan 2011. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.

Randy Bynum, Commissioner (Rep.), since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.

Daryl E. Bassett, Commissioner (Rep.), since 2004; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

Regulatory Information

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected:** Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 3

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

James M. Field, (Rep.), since 1996; current term ends December 2006. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

AEP AMERICAN ELECTRIC POWER®

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A CENTURY OF DIVIDENDS • 1910 - 2010

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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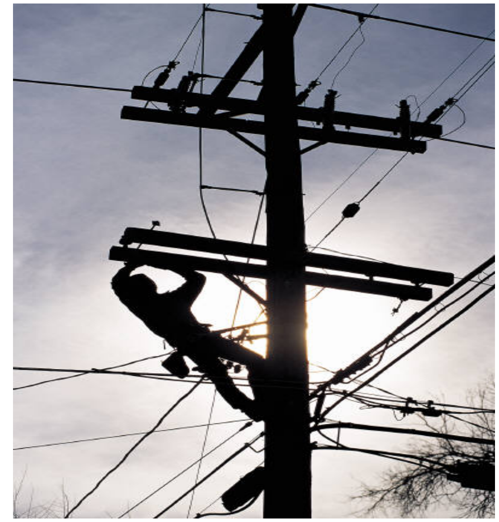
Industry Leadership

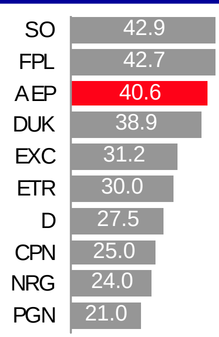
One of the largest U.S. electricity generators

The largest U.S. electricity transmitter

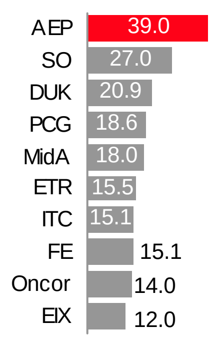


One of the largest U.S. electricity distributors serving 5.2MM customers

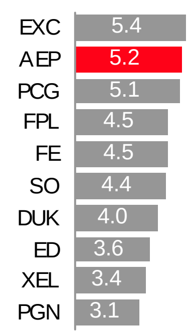
Generation owned[1] (GW)



Transmission miles[1] ('000s)



Electric customers[1] (mm)



[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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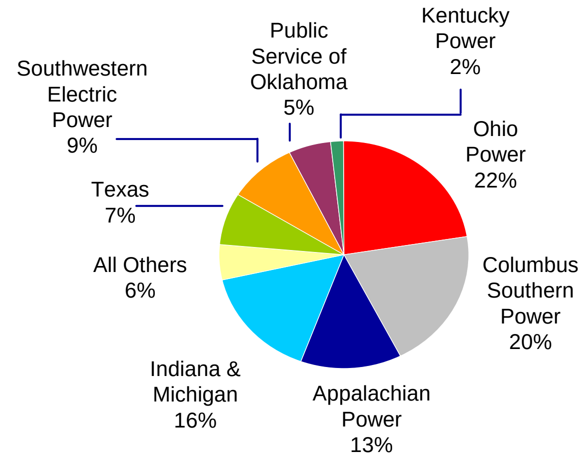
Highly Diversified Regulated Utility Platform

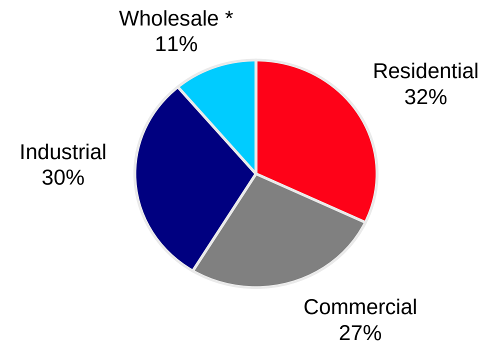
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



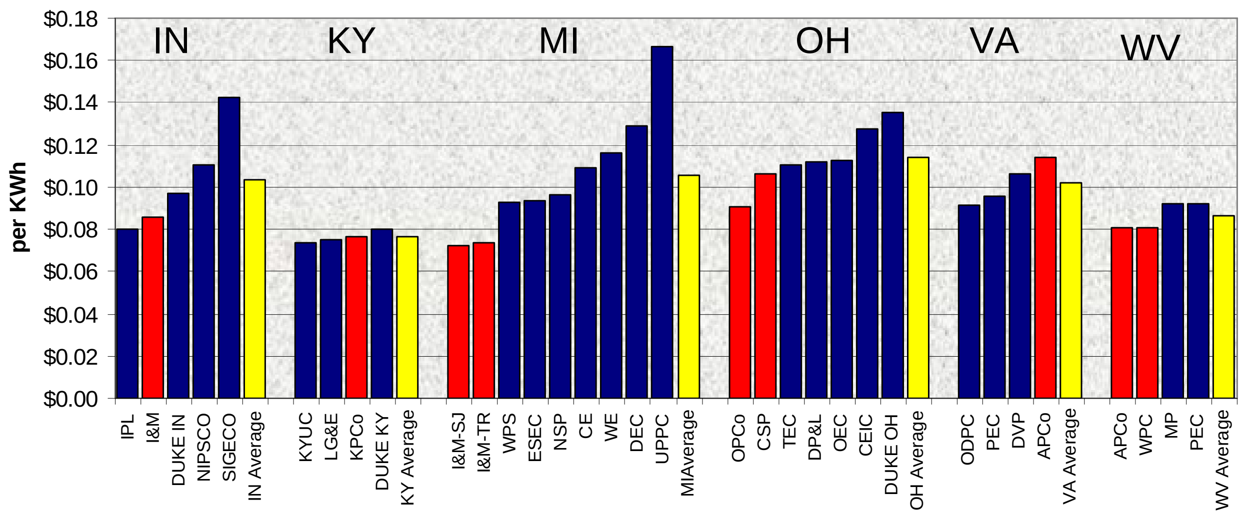
2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

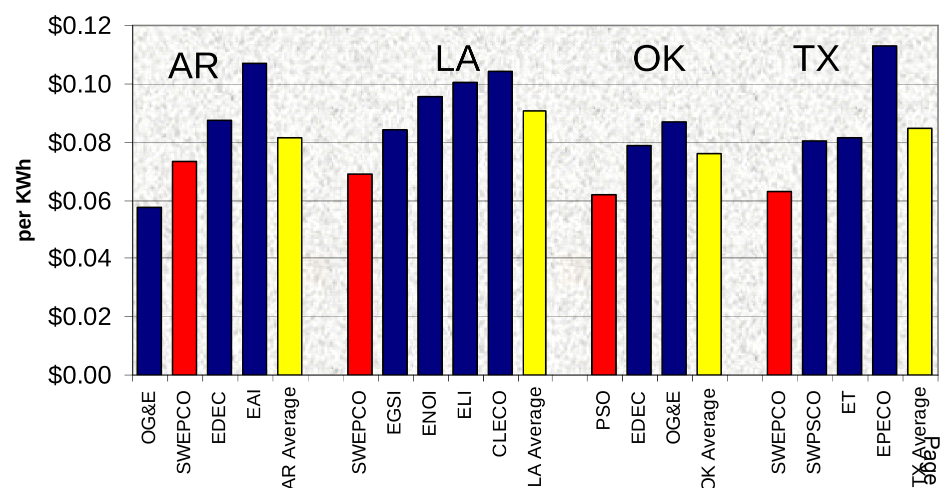
Residential Rates Comparison

AEP East



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP West



AEP Company
Other Utilities within state
State Average

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

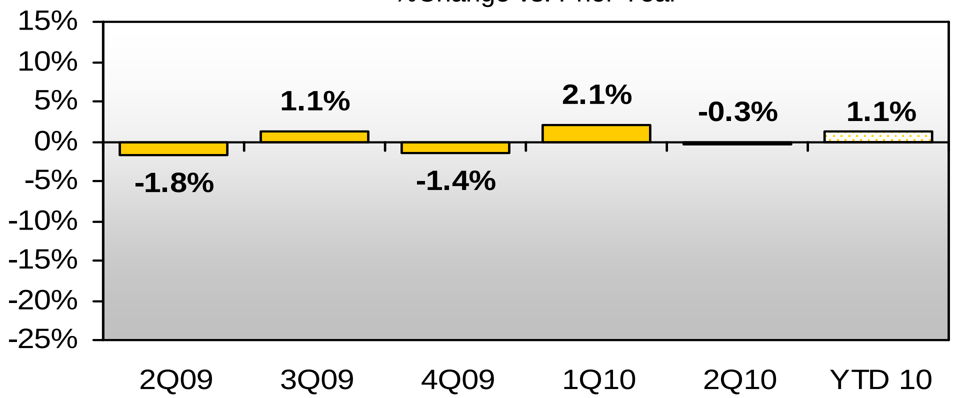
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

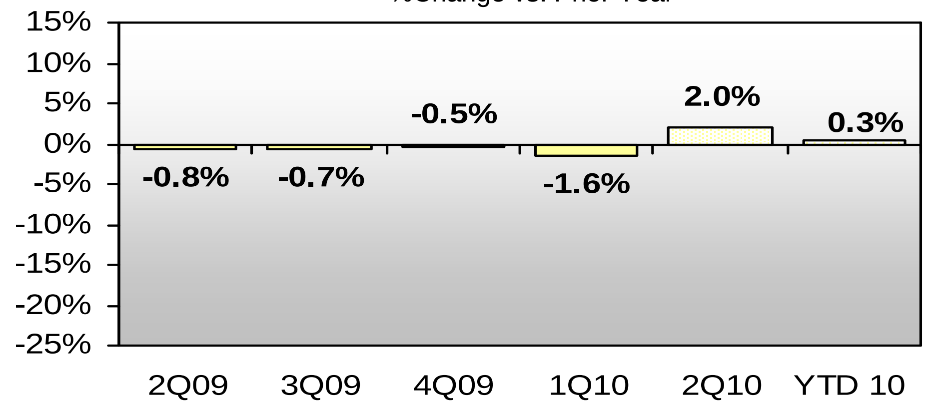
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends

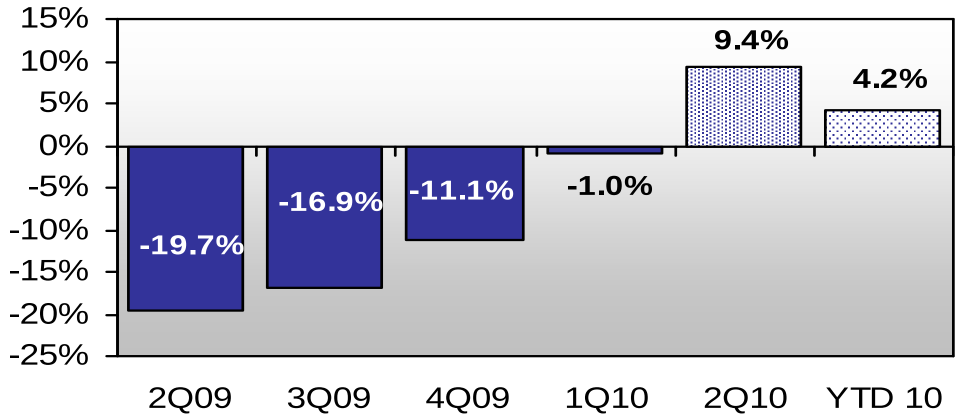
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



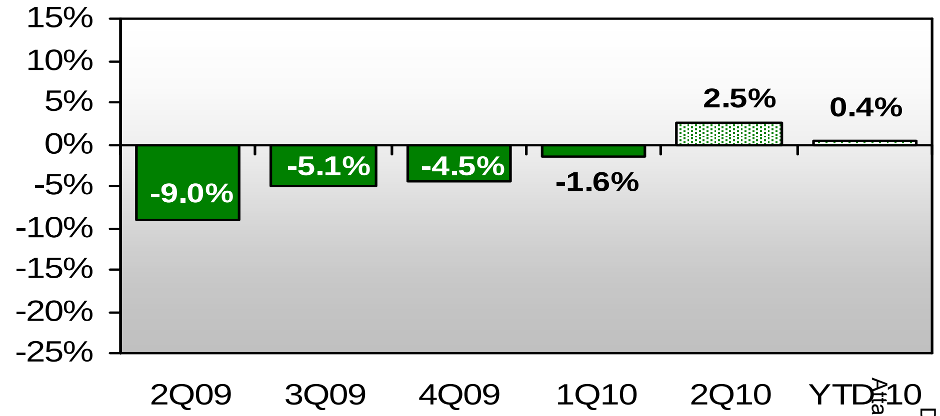
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



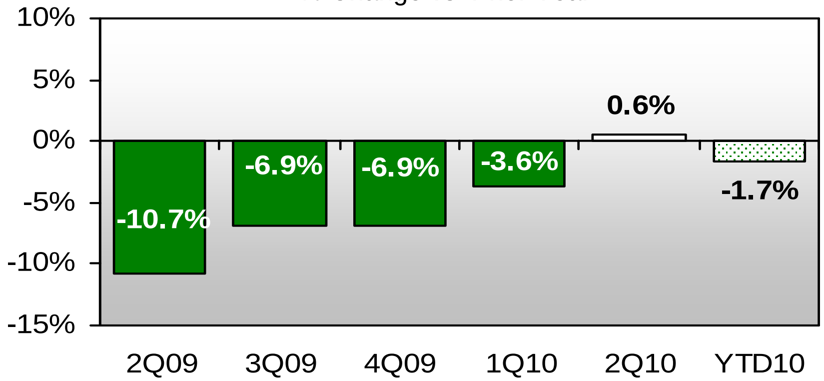
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



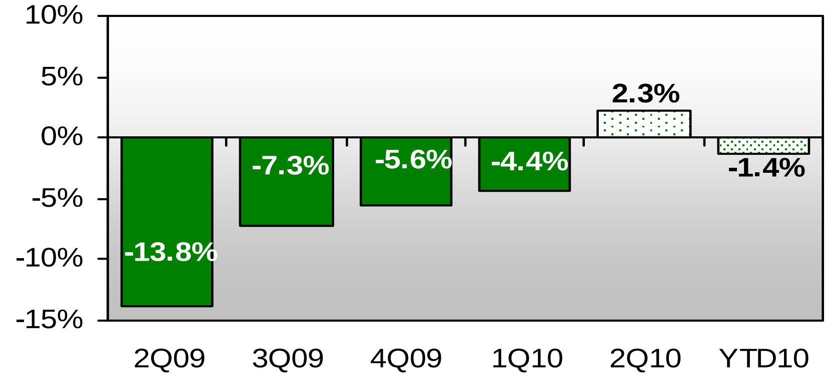
*includes firm wholesale load

Normalized Load Trends by Region

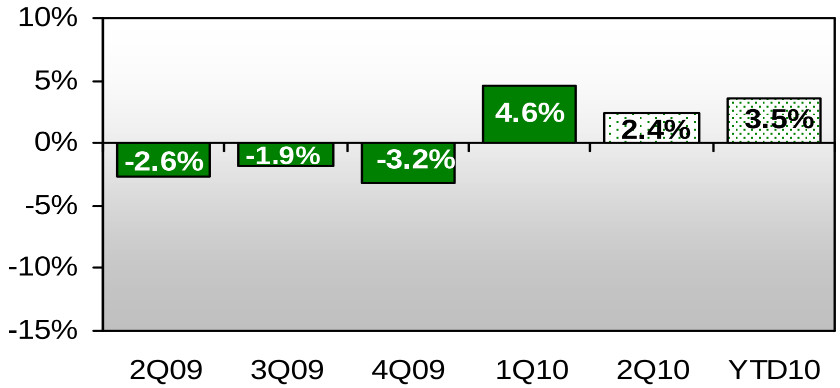
Reg East Total Normalized GWh Sales*
% Change vs. Prior Year



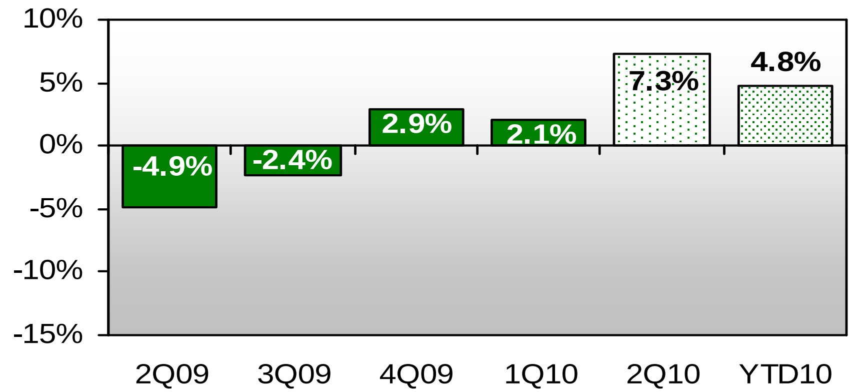
Ohio Total Normalized GWh Sales*
% Change vs. Prior Year



Reg West Total Normalized GWh Sales*
% Change vs. Prior Year

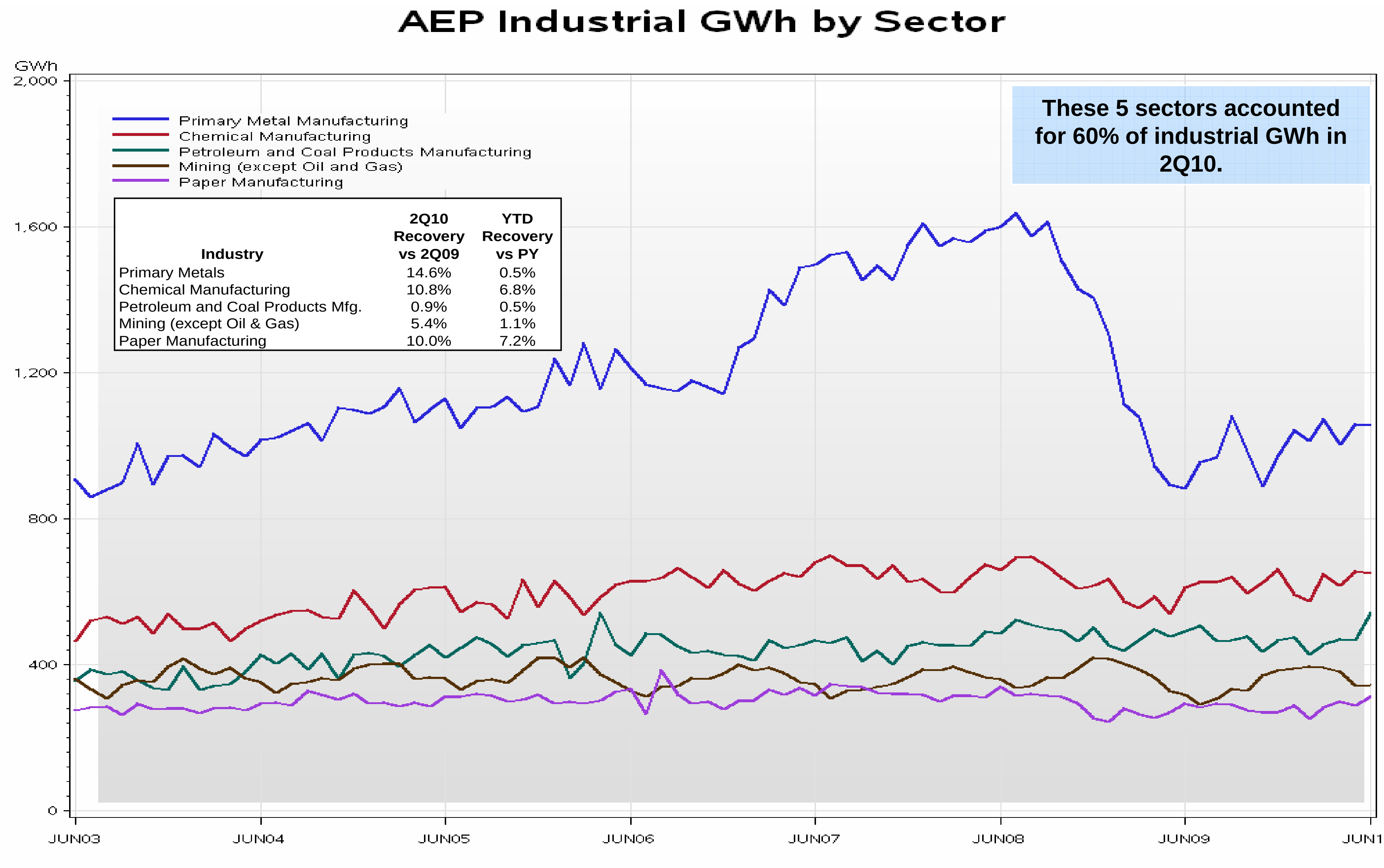


Texas Wires Total Normalized GWh Sales*
% Change vs. Prior Year



*includes firm wholesale load

Industrial Sales



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

These 5 sectors accounted for 60% of industrial GWh in 2Q10.

Off System Sales Gross Margin Detail

2Q10

	2Q09			2Q10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	3,622	$ 10.13	$ 37	3,980	$ 11.21	$ 45
Marketing/Trading	-		$ 52	-		$ 31
Pre-Sharing Gross Margin	3,622		$ 88	3,980		$ 76
Margin Shared			$ (19)			$ (18)
Net OSS			$ 70			$ 58

- Physical off-system sales margins exceeded last year by $8M
- Volumes up 10% versus last year led by a 37% increase in June
- Improved AEP/Dayton Hub pricing: 13% increase in liquidation prices
- Lower Trading & Marketing results by $20M

YTD10

	YTD09			YTD10		
	GWh	Realization	($millions)	GWh	Realization	($millions)
OSS Physical Sales	6,213	$ 12.91	$ 80	8,724	$ 12.24	$ 107
Marketing/Trading	-		$ 93	-		$ 69
Pre-Sharing Gross Margin	6,213		$ 173	8,724		$ 176
Margin Shared			$ (42)			$ (44)
Net OSS			$ 131			$ 132

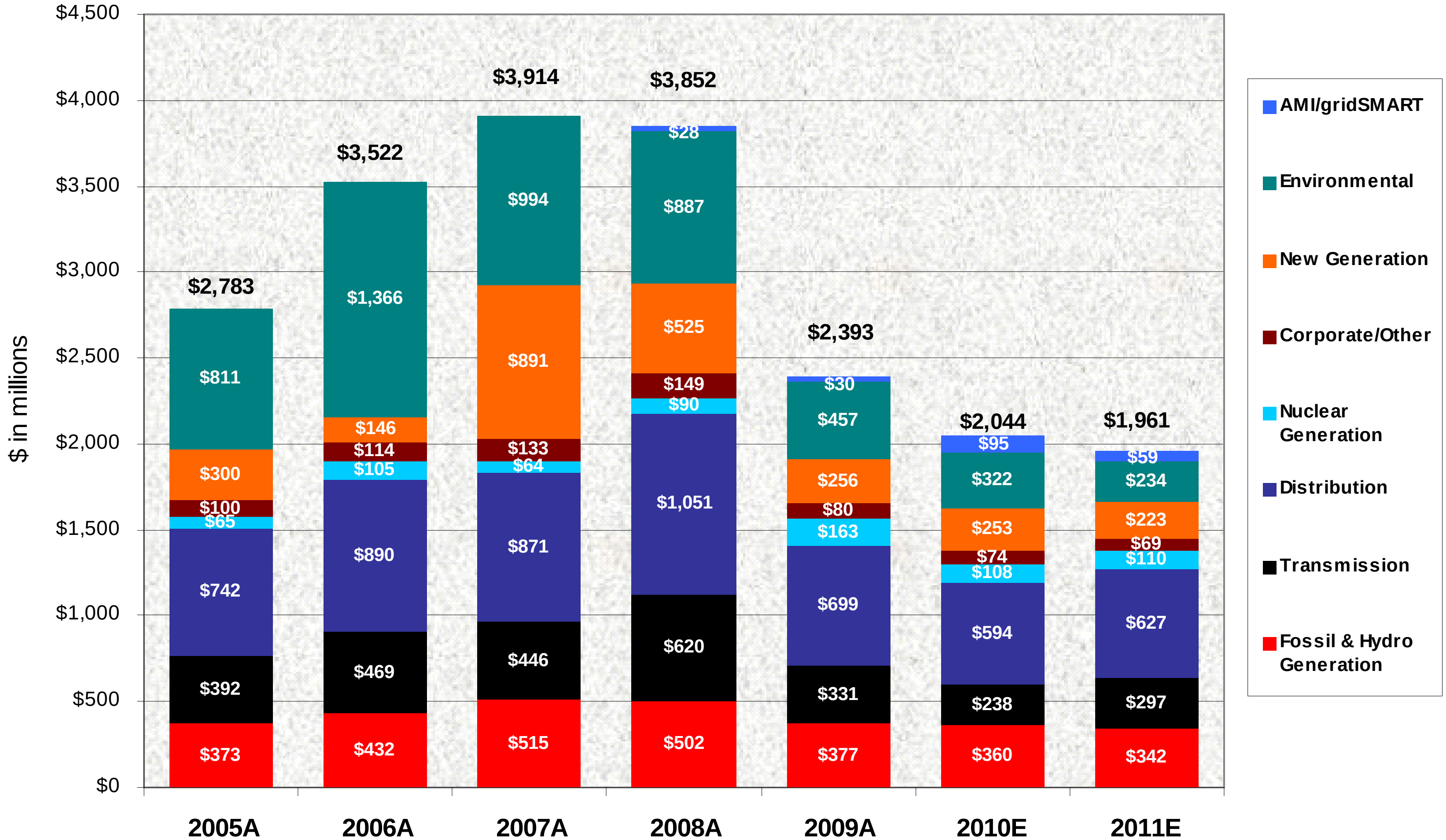
* May not foot due to rounding

- Physical off-system sales margins exceeded last year by $27M
- Volumes up 40% versus last year
- Improved AEP/Dayton Hub pricing: 5% increase in liquidation prices
- Lower Trading & Marketing results by $24M

Outlook

- Retail Load Volume & Margin recovery slower than previously anticipated
- Off-System Sales margin challenged by market prices
- Rate Changes on target for remainder of the year
- O&M Cost Reduction & Restructuring Program
  - Severance of 2,461 employees
- Operating Company Refinements
- 2010 Earnings Guidance $2.80 - $3.20 per share

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

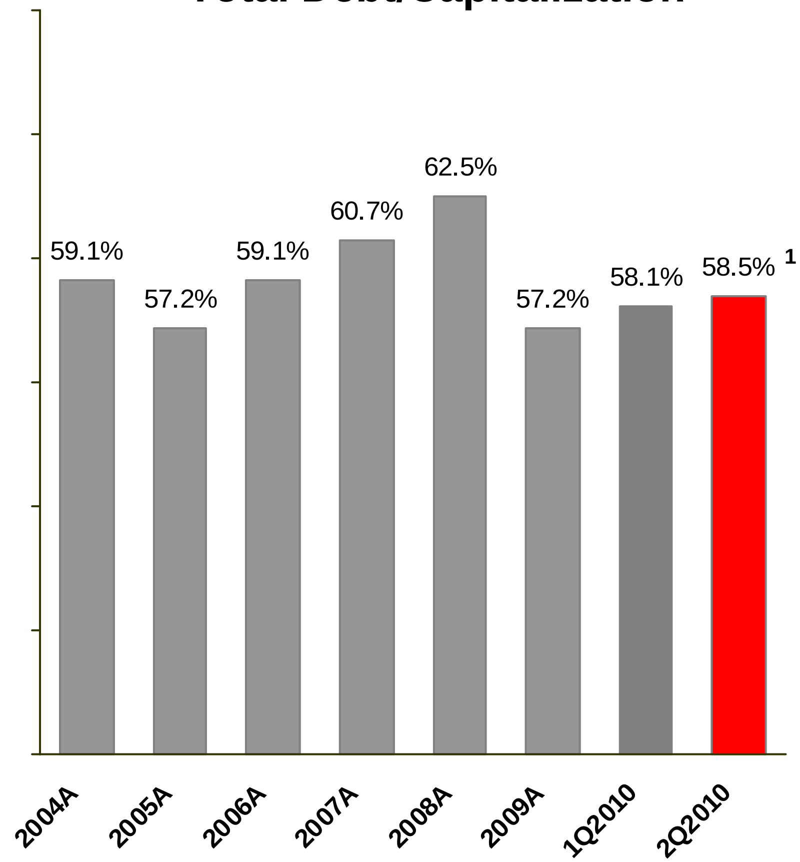
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.

Current Liquidity Summary
As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company[1]	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

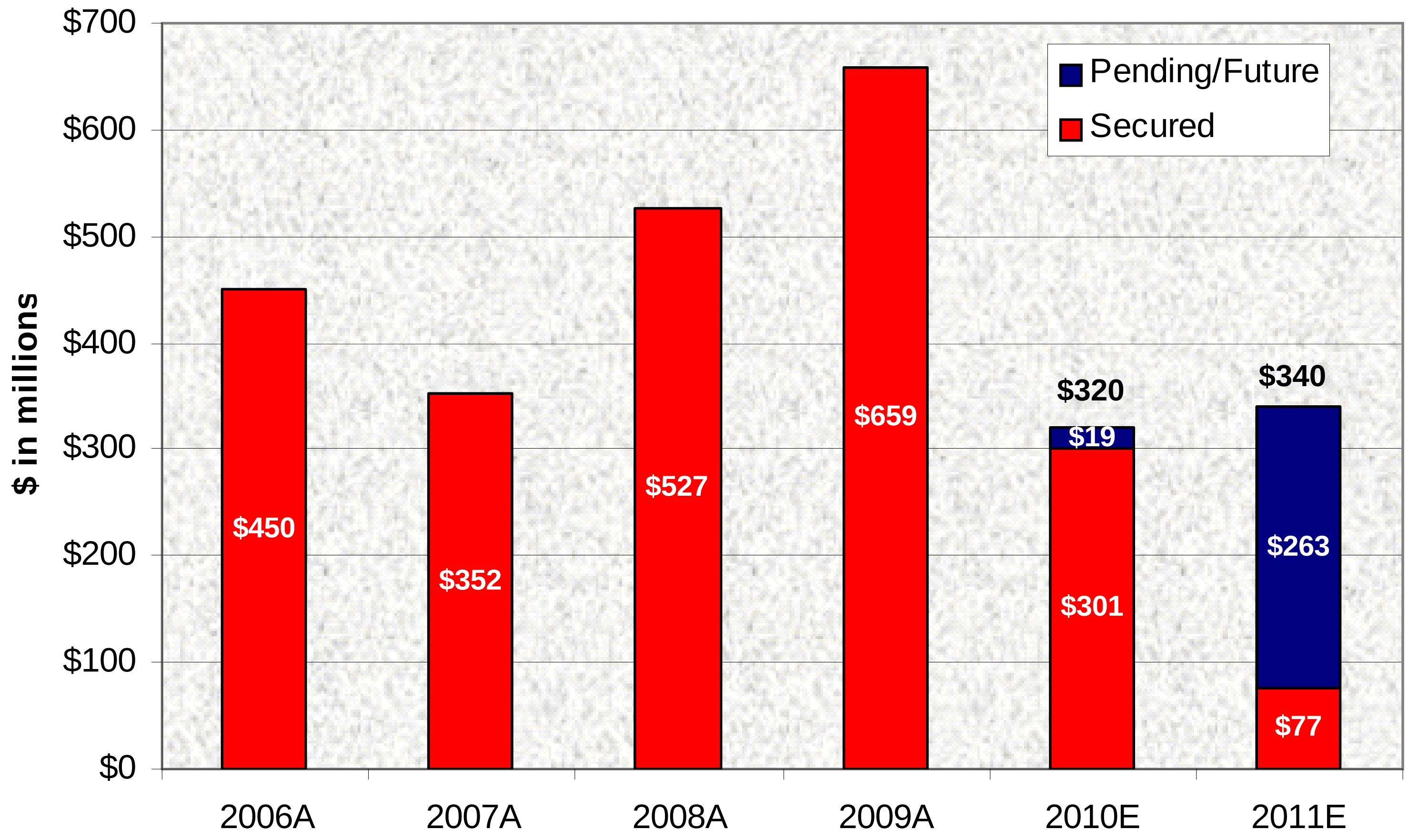
S=Stable

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Oklahoma, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Recent Rate Case Outcomes

APCo – Virginia Base Rate Case

	(Millions)
Company's Proposed Request	$ 167.0
Adjustments:	
Rate Base/Revenue Adj.	$ 3.5
Return on Equity 10.53% vs. 13.35%	$ (41.0)
Member Load Ratio	$ (15.0)
Capacity Rate	$ (12.8)
CCS Project	$ (9.8)
PJM Ancillaries	$ (7.4)
Environmental	$ (5.3)
ICP @ 50%	$ (4.2)
ADITC	$ (3.6)
Deferred Fuel Balance	$ (2.4)
Umbrella Trust	$ (1.3)
Deferred Wind Balance	$ (1.2)
Other Miscellaneous	$ (5.0)
Total Adjustments	$ (105.5)
Commission Order	$ 61.5

KPCo – Kentucky Base Rate Case

	(Millions)
Company's Proposed Request	$ 123.6
Adjustments:	
Wind Purchased Power Agreements	$ (14.5)
Depreciation	$ (10.7)
Return on Equity 10.5% vs. 11.75%	$ (8.5)
System Sales	$ (7.5)
Capacity Payments	$ (7.2)
Reliability Expenditures	$ (6.3)
Storm Adjustments	$ (5.6)
OATT Transmission	$ (2.2)
Other Miscellaneous	$ 2.6
Total Adjustments	$ (59.9)
Approved Settlement	$ 63.7

Current Base Rate Cases

$ in millions

I&M - Michigan

	Company Filing	Staff Testimony
Rate increase	**$63**	$34
Rate base/investment	$601	$585
Return on equity	11.75%	10.35%
Equity component	44.19%	44.14%
Riders requested	Numerous	Denied except Net Lost Revenues

Status: Case filed on January 27, 2010. Hearings scheduled for August 9-17, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Order due January 25, 2011.

APCo - West Virginia

	Company Filing	Staff Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

PSO - Oklahoma

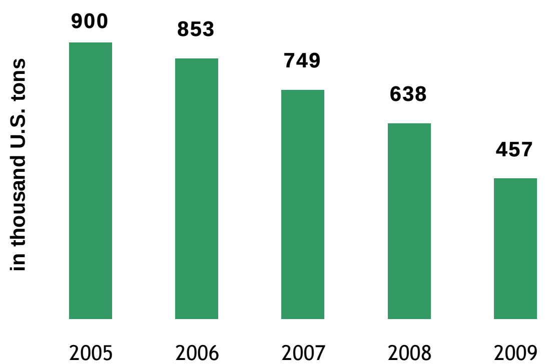
	Company Filing	Staff Testimony
Rate increase	**$83**	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

Status: Case filed on July 9, 2010. Procedural schedule pending.

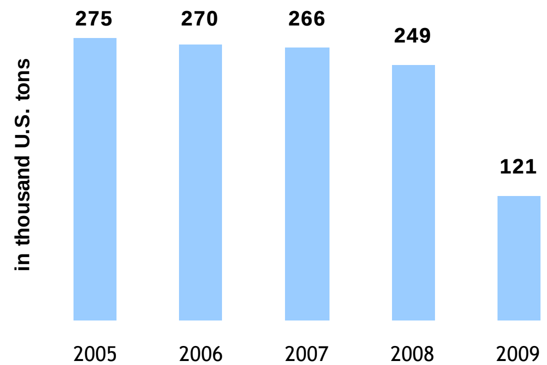
$370 million total base rate increase requests on file

Our Fleet Will Continue to Transform

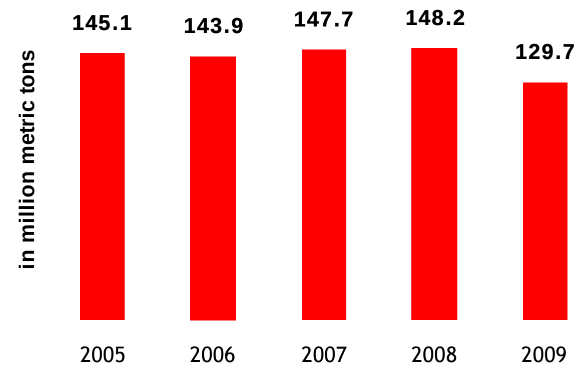
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



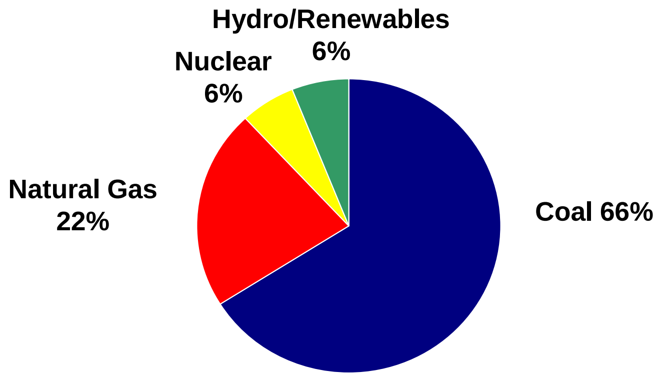
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



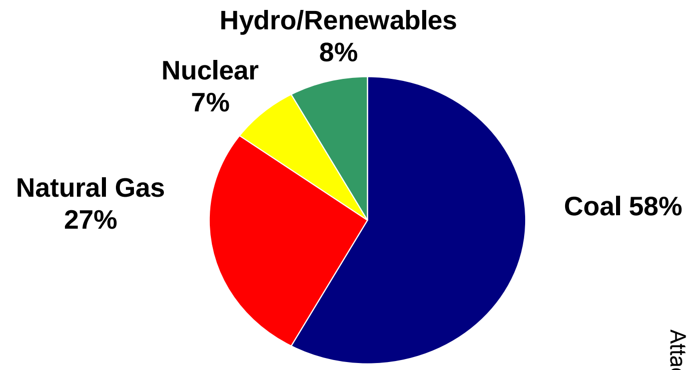
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ \$5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The final estimated cost of the plant is $433 million including $49MM of AFUDC.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009

Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — COD: 2013-14

- 110 miles of 765 kV
- Partners: Westar (50%) & Electric Transmission America (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14

- 170 miles of 765 kV
- Partners: OG&E (50%) & Electric Transmission America (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

ETT — COD: 2010-2017

- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

PJM

PATH-WV — COD: 2014

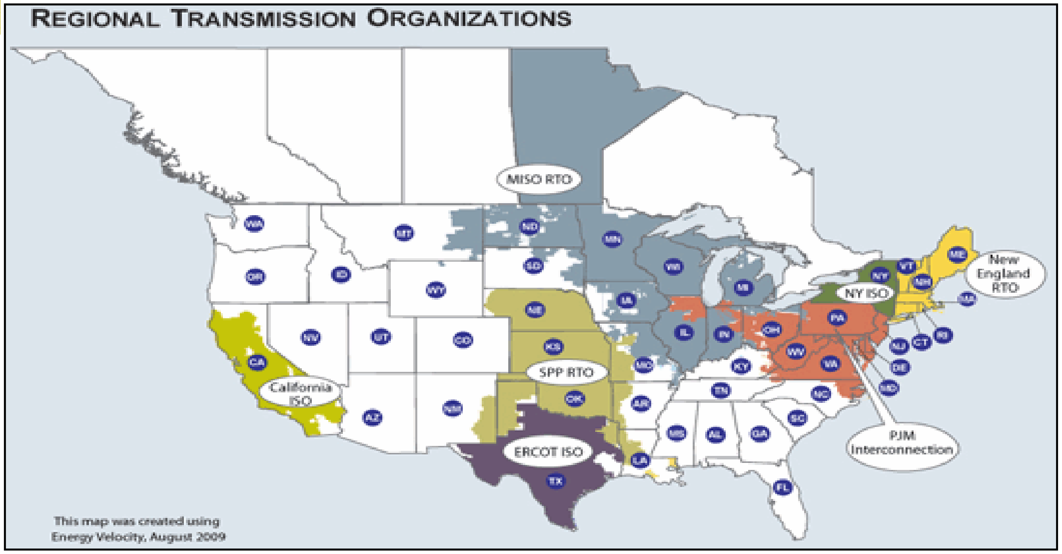
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015

- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

ACTIVE PROJECTS



FUTURE DEVELOPMENT

SMARTransmission Study

- Interregional EHV & Wind Integration Study
- Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP EHV Overlay

- Regional Expansion of 765 kV Backbone

ETT — COD: various

- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM Expansion

- Regional Expansion of 765 kV, 500 kV and 345 kV systems

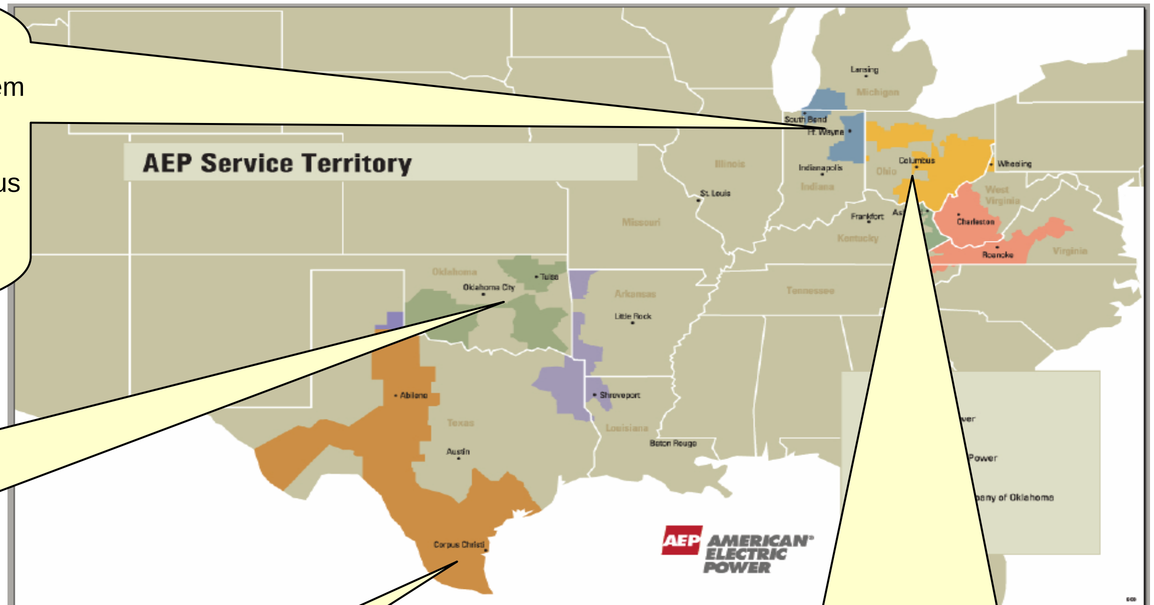
EHV Michigan/Ohio

- 700 miles of Proposed 765 kV

SPP | ERCOT | PJM | PJM/MISO

AEP's "Smart Grid" Deployment Status

Indiana Michigan Power (Completed, 12/2008)
- 10,000 AMI pilot program (GE meters, Silver Spring AMI Network)
- Distribution automation (GE ENMAC Distribution Management System and Integrated Volt-Var Control (IVVC))
- Two-tiered, two-season time-of-use tariffs with Critical Peak Pricing
- Customer web portal displaying 15-minute interval data up-to-previous day
- Field testing direct load control using Programmable communicating thermostats



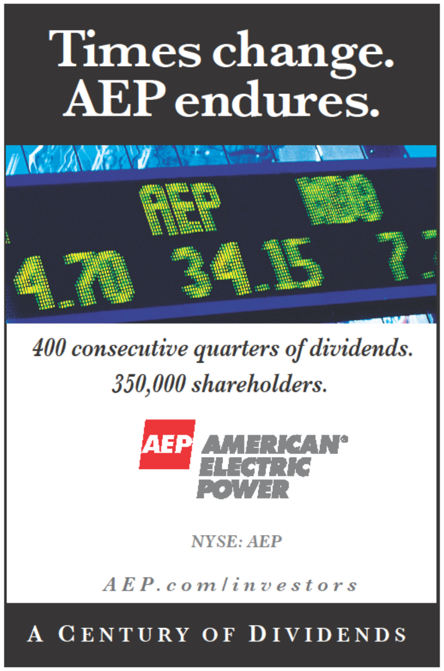
Public Service of Oklahoma (Final Planning)
- Applied for and approved for $7million low interest loan from OK Department of Commerce (ARRA source)
- Planned scope is 10,000 meters
- Increased penetration of In Home Devices for usage monitoring
- Distribution technologies include DA and IVVC

AEP Texas (underway)
- Legislature enabled and commission directing TDSPs to deploy advanced metering
- Enables REPs to innovate around electricity pricing and consumer technologies
- Filed and received approval from PUCT for 4-year deployment of 970,000 meters, $270 million project
- AEP Texas to collect a surcharge over 11 years
- Includes 10,000 in-home displays for low income customers
- Landis & Gyr Meters and AMI network

AEP Ohio (underway)
- PUCO-Approved 110,000 AMI deployment in NE Central Ohio
- Selected by DOE as a Smart Grid Demonstration Project for $75million in federal funding, 42-month deployment/evaluation
- Partnered with Battelle
- Full suite of distribution grid management technologies on over 70 distribution circuits
- Advanced technology deployment (Energy storage, PHEVs)
- Enhanced time-of-use tariffs, including a field trial of realtime pricing
- Home area networks & grid-friendly appliances

Value Proposition

- **Current Yield Opportunity of 4.7%[1]**
  - June 10th – 400th consecutive quarterly dividend was paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $36.10 on 07/29/2010

California Investor Meetings

June 27-28, 2005

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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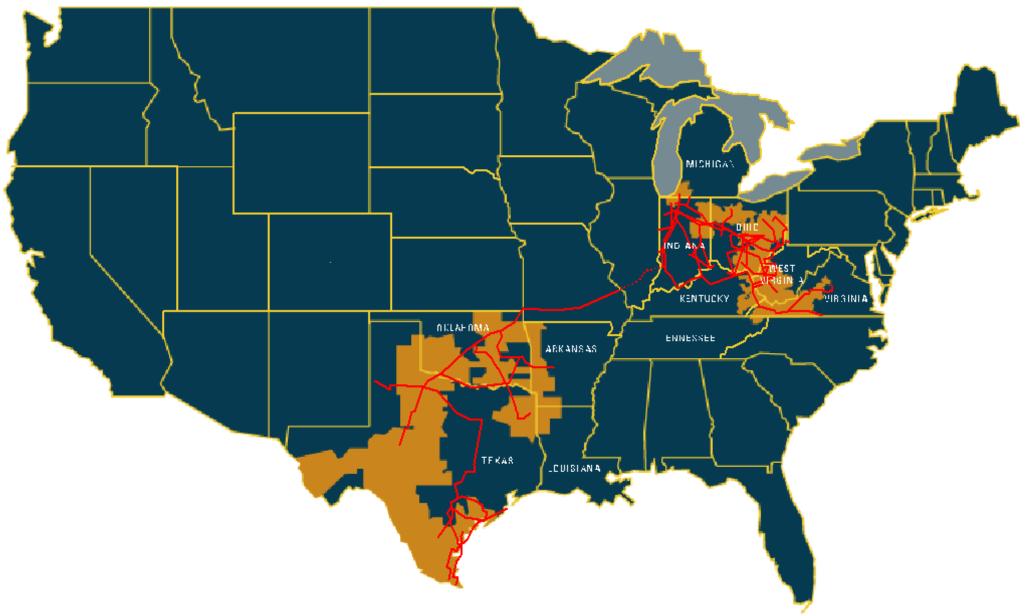
Asset Portfolio

Strength & Scale in Assets & Operations



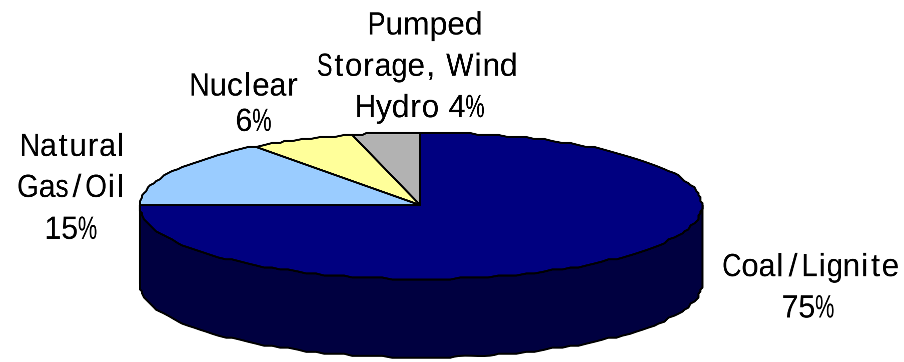
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

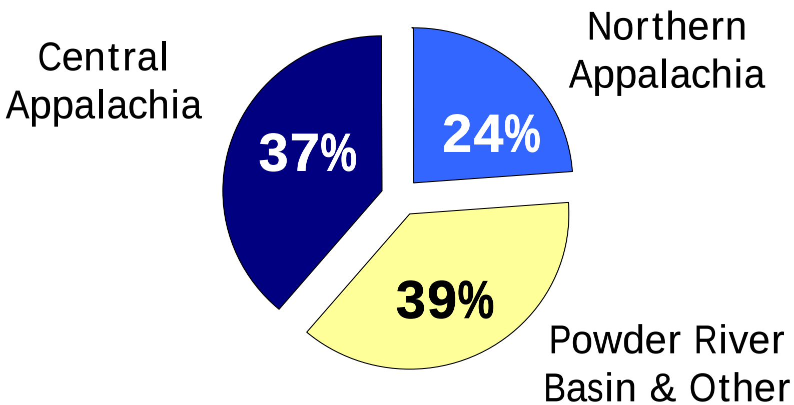
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Coal Procurement

AEP SYSTEM

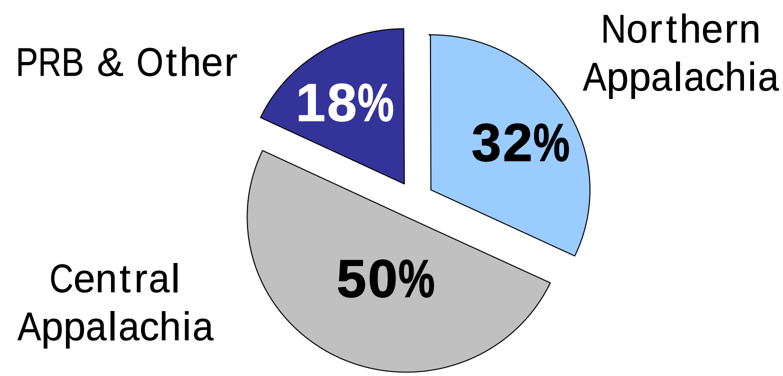


Coal Supply

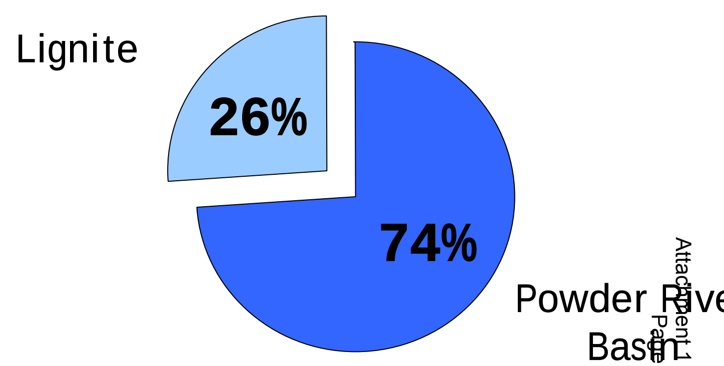
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

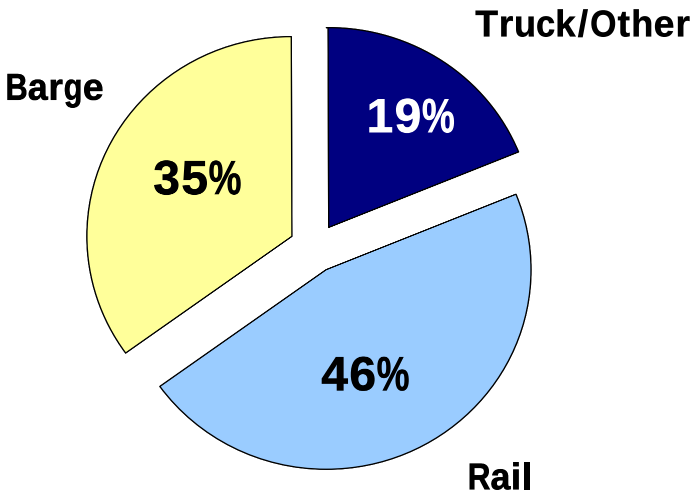


WESTERN SYSTEM



Coal Delivery Mix

DELIVERY MODE DIVERSITY
25 GW coal capacity



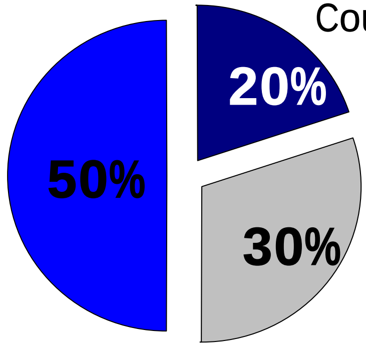
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM



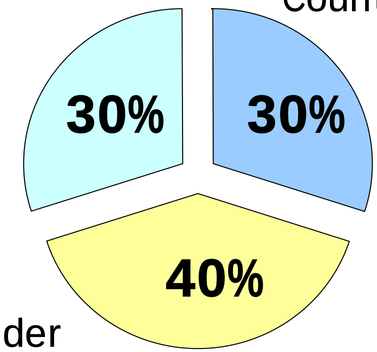
Fuel Cost Recovery

(on average)

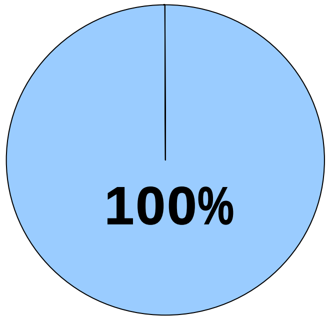
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



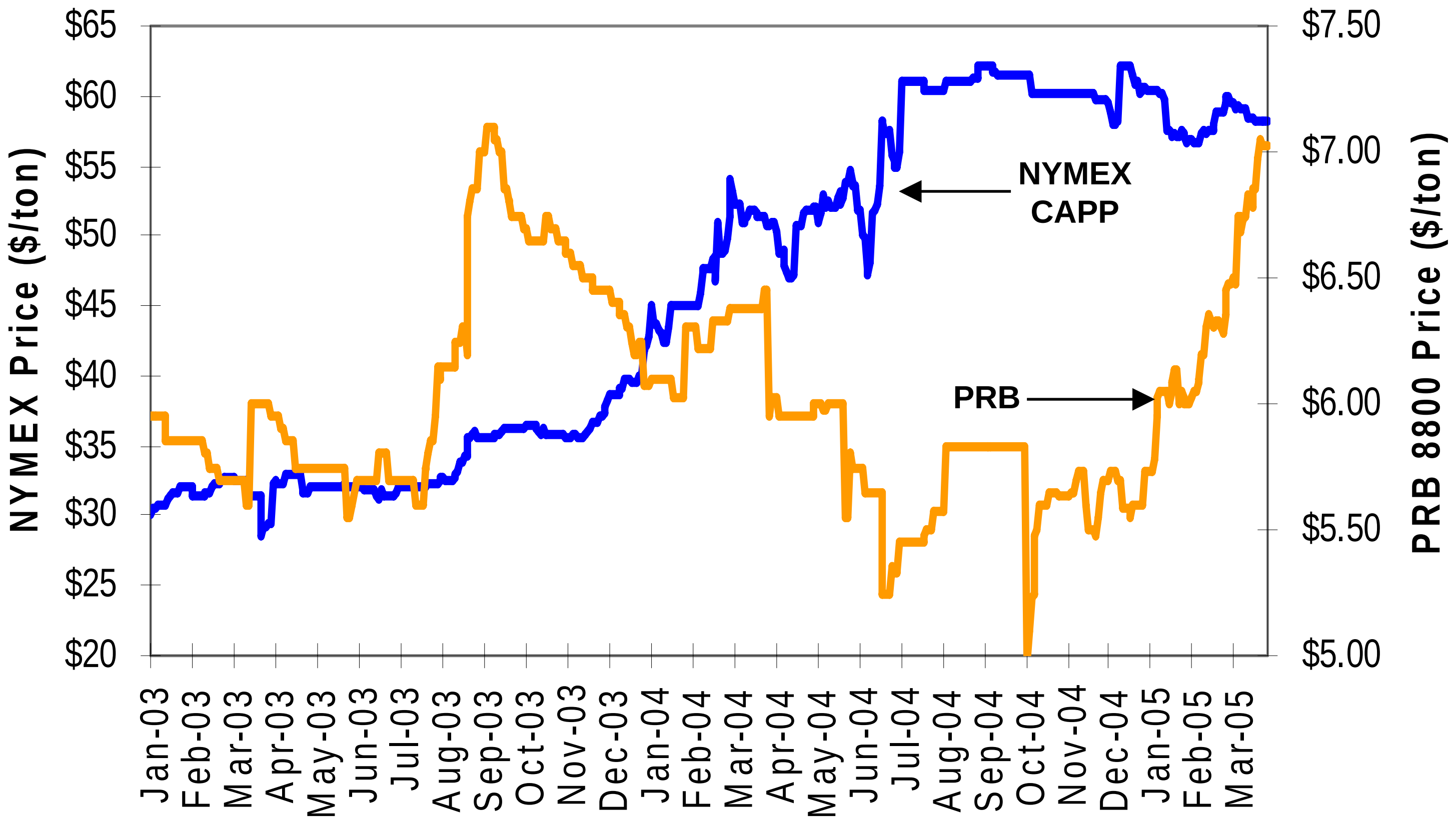
WESTERN SYSTEM



AEP®

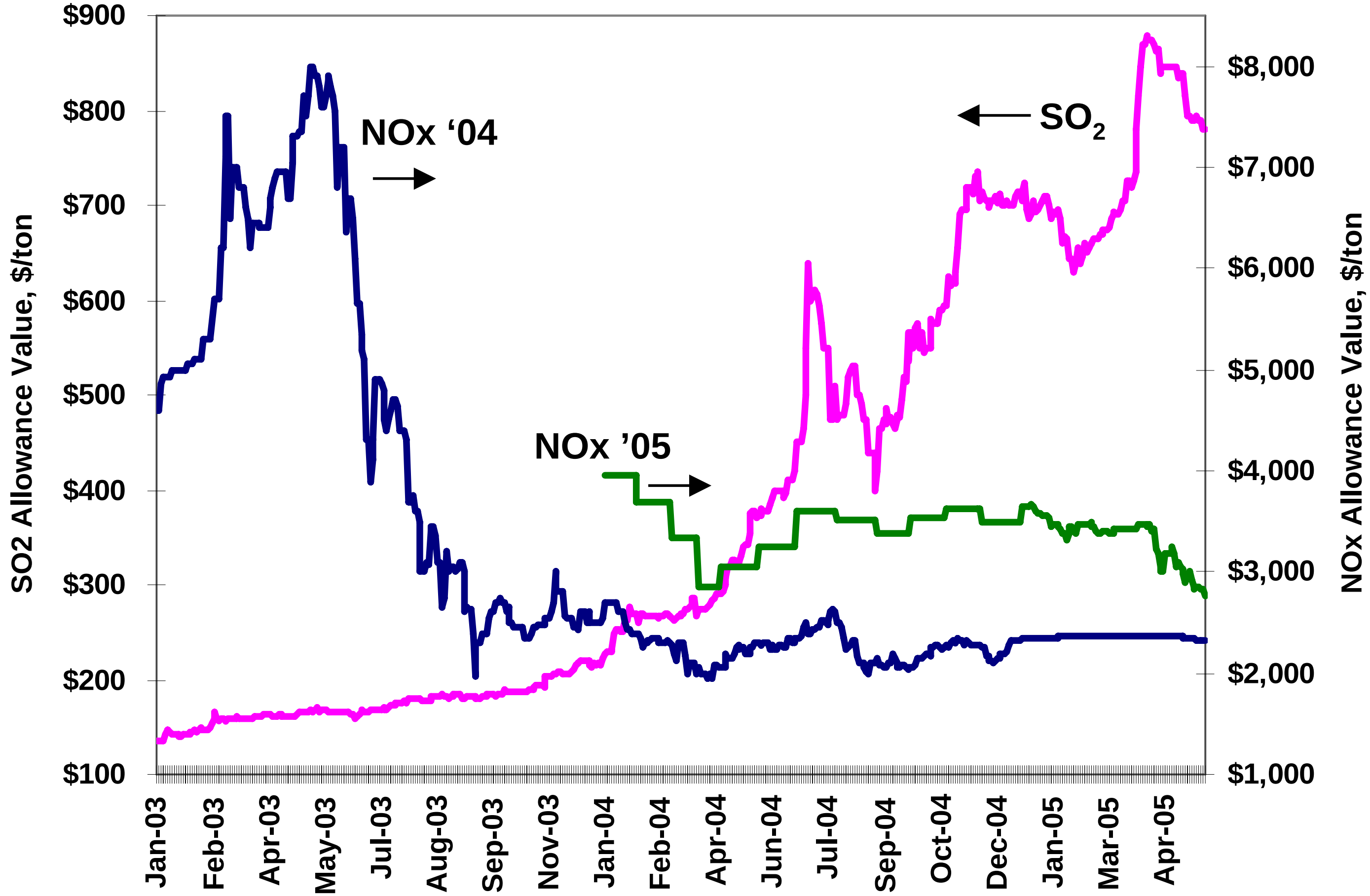
Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



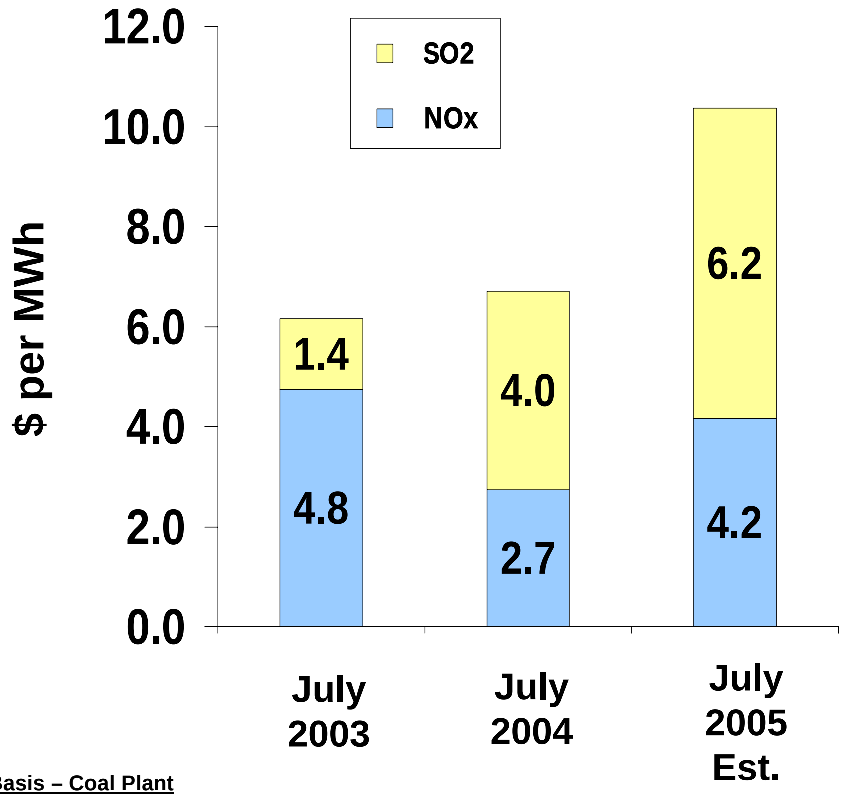
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



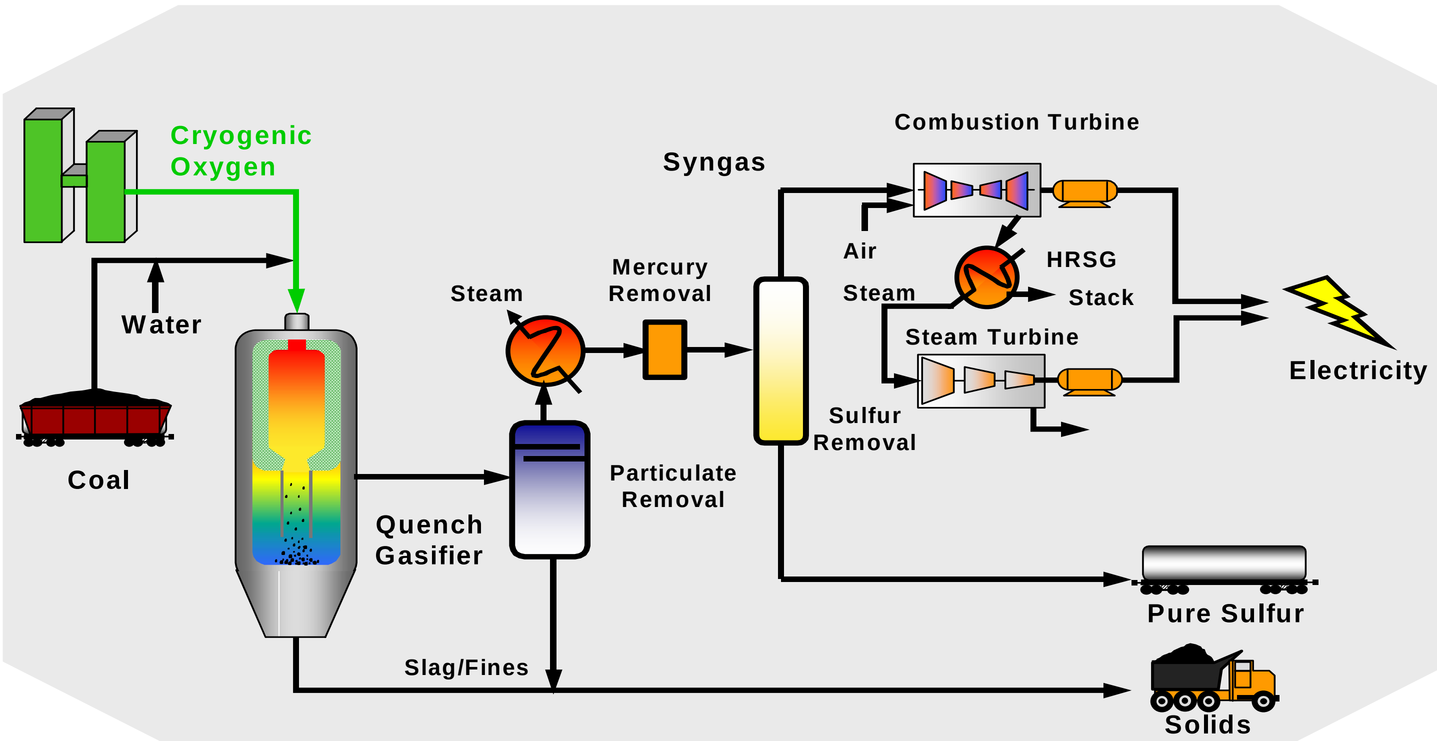
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B as of YE 2004)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

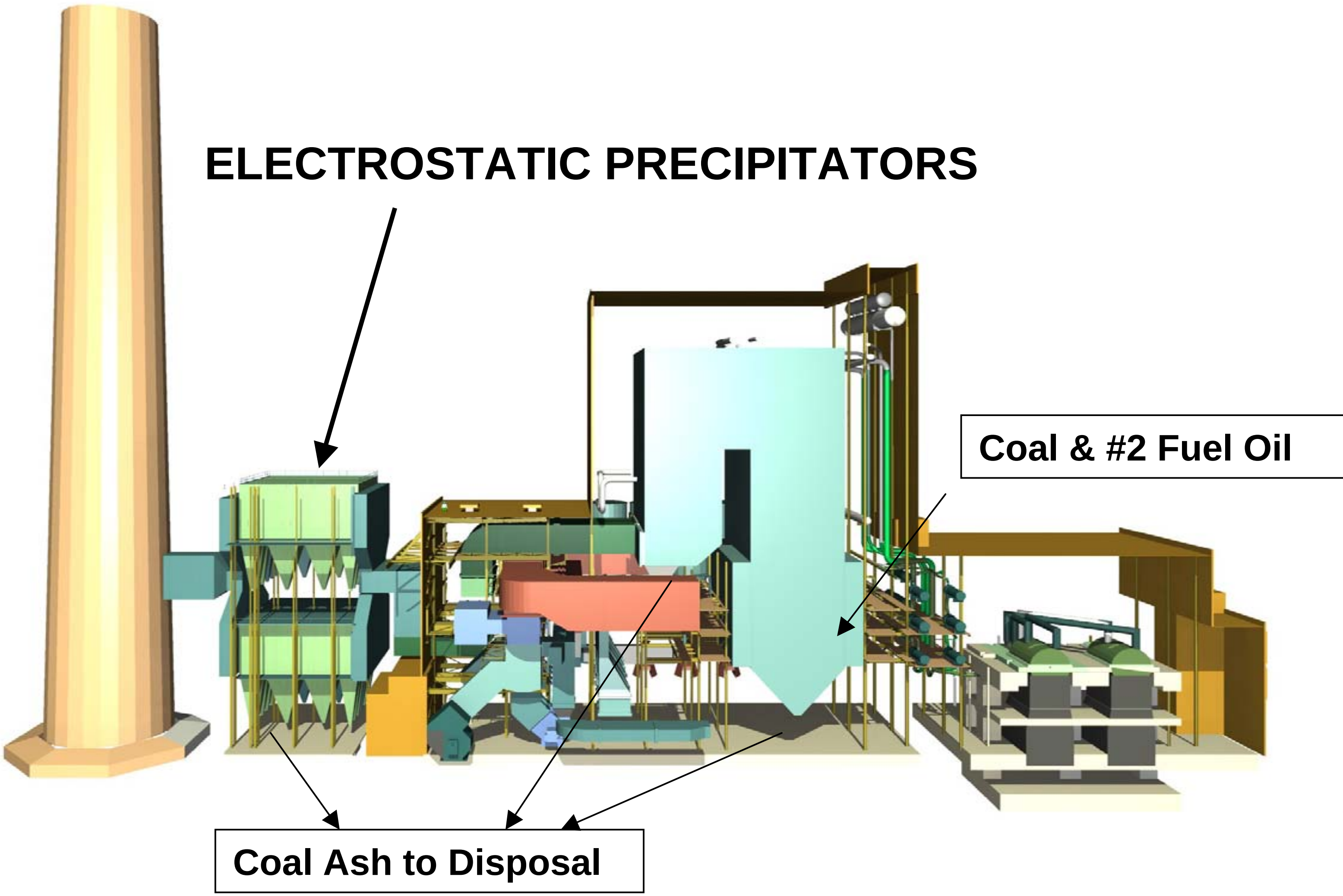
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

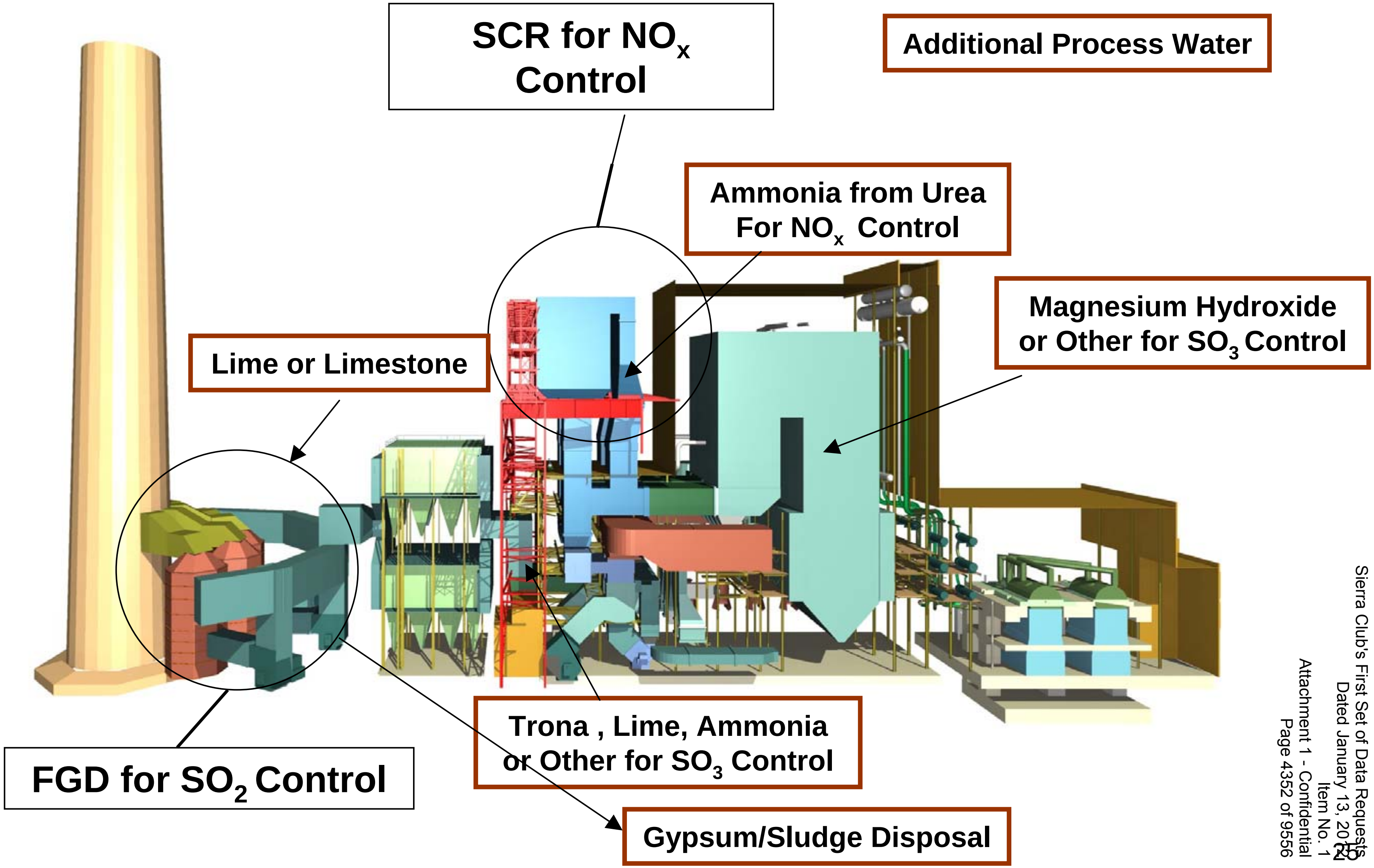
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s



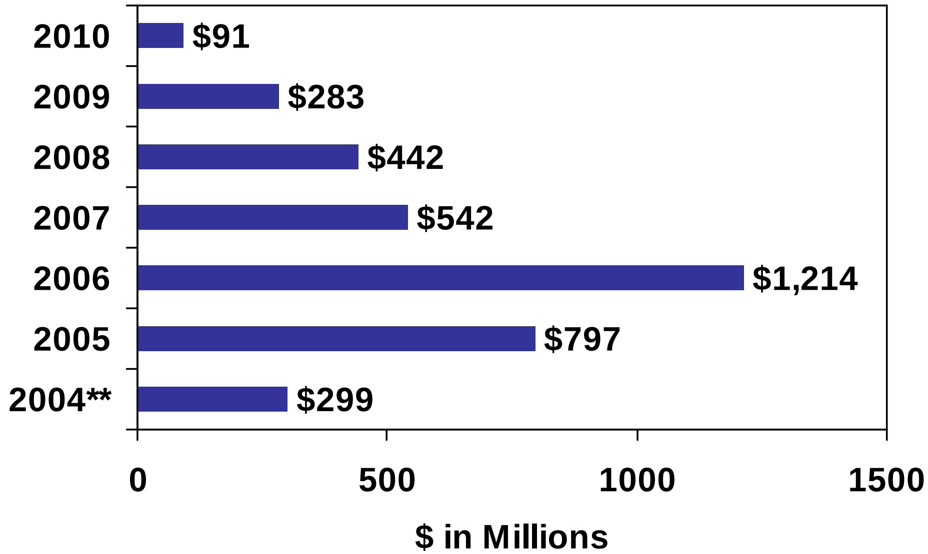
Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4352 of 9556

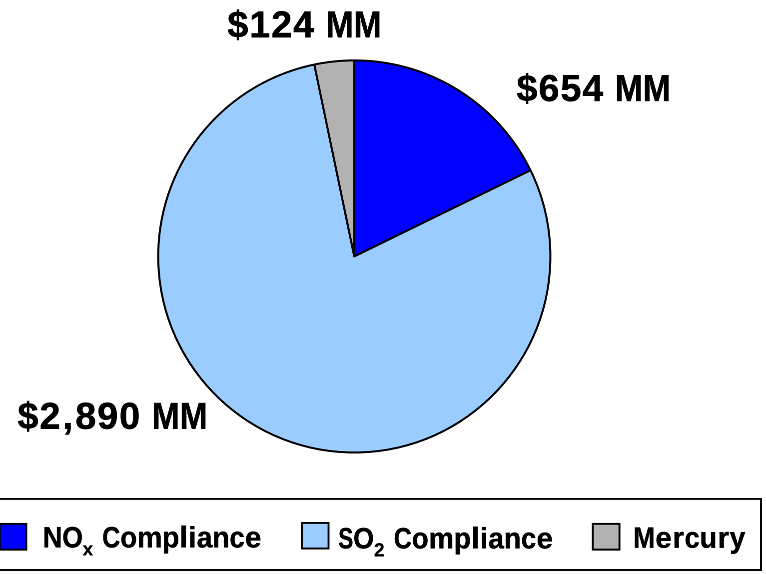
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

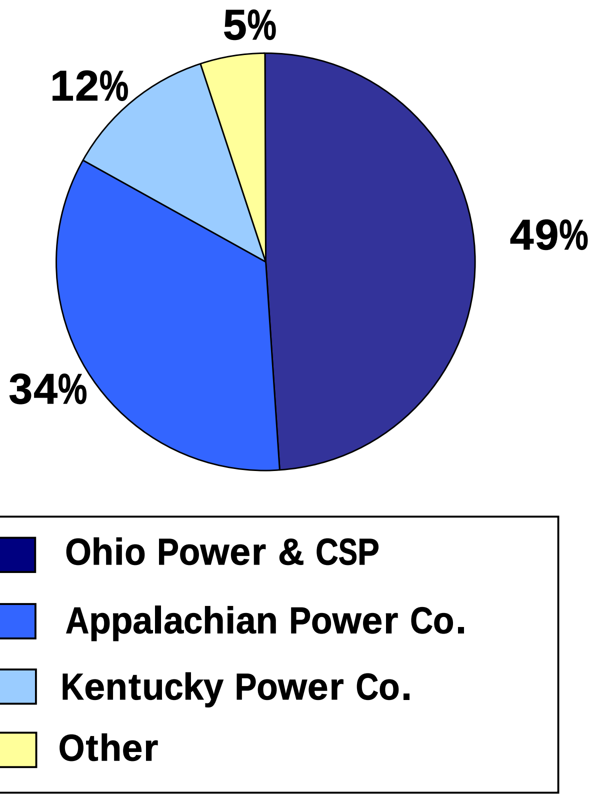
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

	FGD	SCR

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

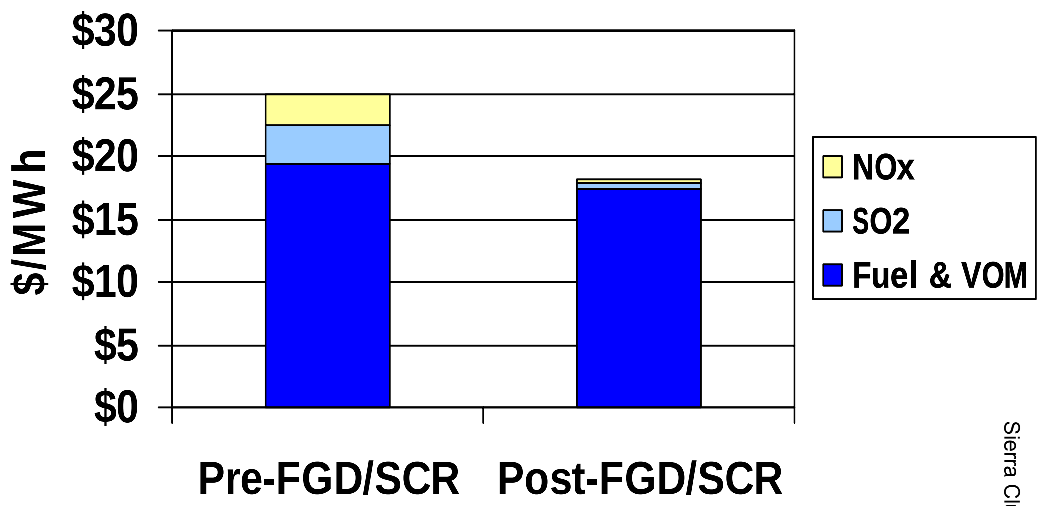
2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

Low Cost Production Supports Investment

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation, (higher capacity factor, higher margin)
- All-in cost of electricity, including FDG/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* - Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, Hearings scheduled to begin 8-8-05.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause

West Virginia (Regulated)
- Base rates not frozen
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- No active fuel clause

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) Hearing in October.
- TCC wires rate case PUCT approved affiliate transaction settlement in June 2005. Written order expected in July 2005. Final order will result in slight rate decrease with a positive earnings impact.
- TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing issued in June 2005 updating rate case expenses. TCC will appeal decision.
- TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval.
- On 5-2-05 the OCC issued an order approving a settlement agreement in this general rate case which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider.
- 2001 Fuel review case
  Hearings scheduled for Sept. 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
  Scope has been expanded to include a prudence review.

Louisiana (Regulated)
- Base rates not frozen
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	POLR Rider	Revenues & POLR Rider*			Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs***	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit**	0	25	25	26	0	25	25	26
Recovery of RTO costs***	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Incremental over 2004 base year

** Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

*** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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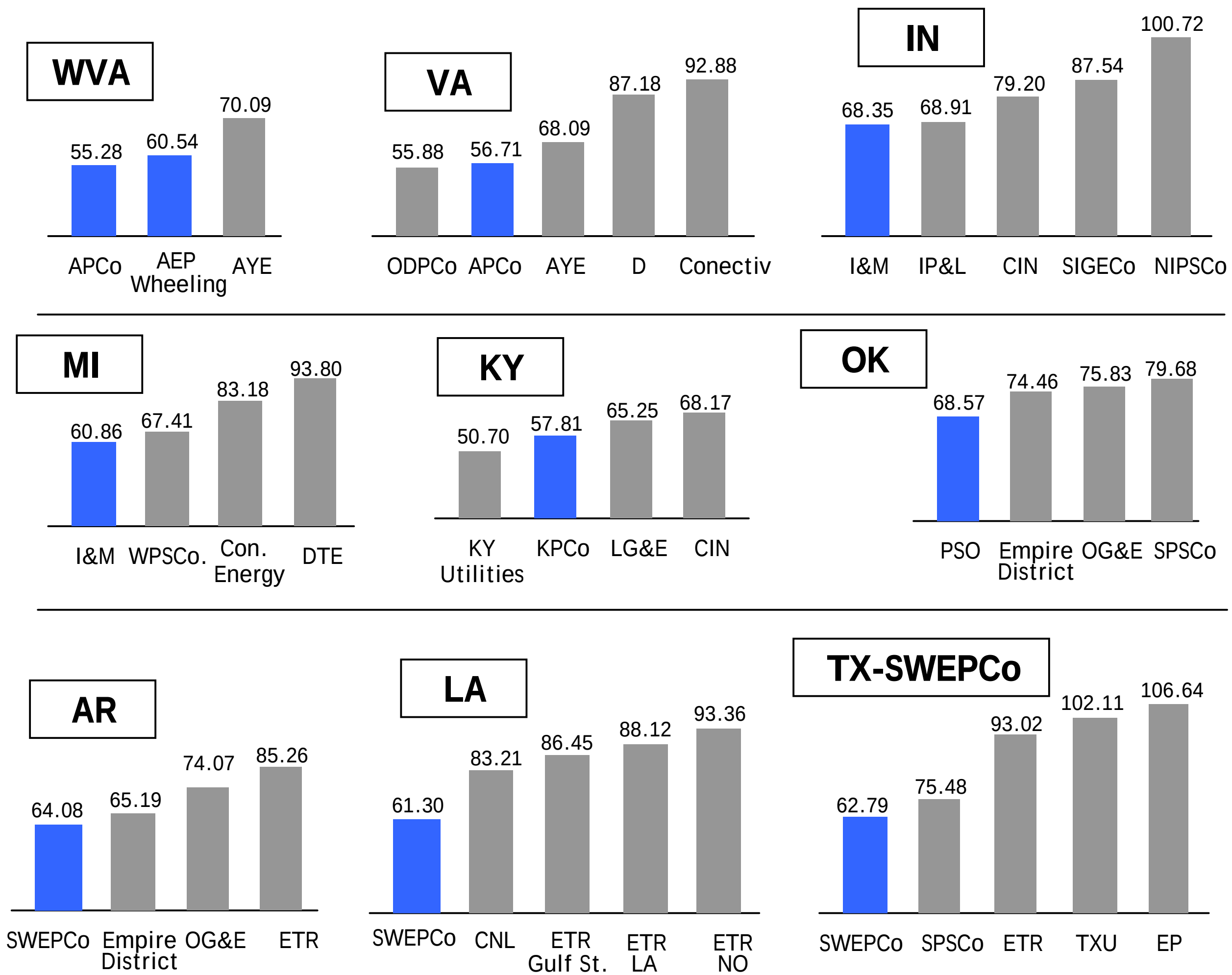
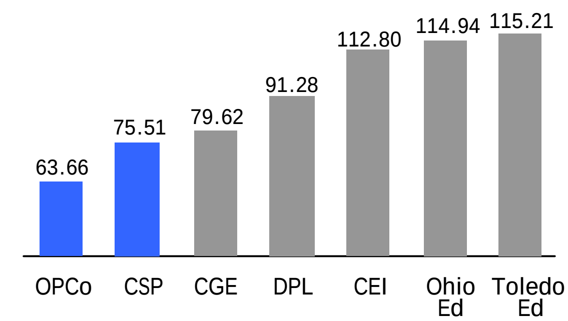
AEP: The Low Cost Provider

Regulated Rates



Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

AEP System fossil fleet average variable book cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

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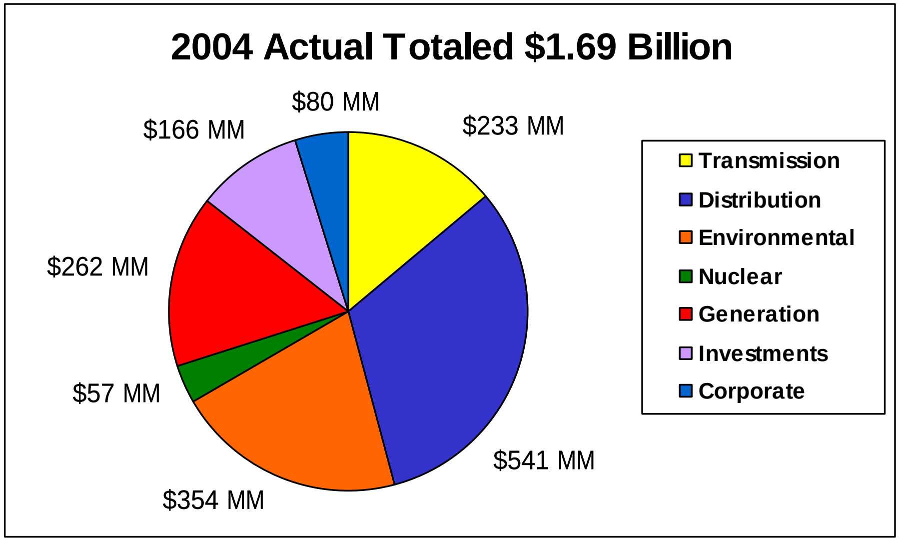
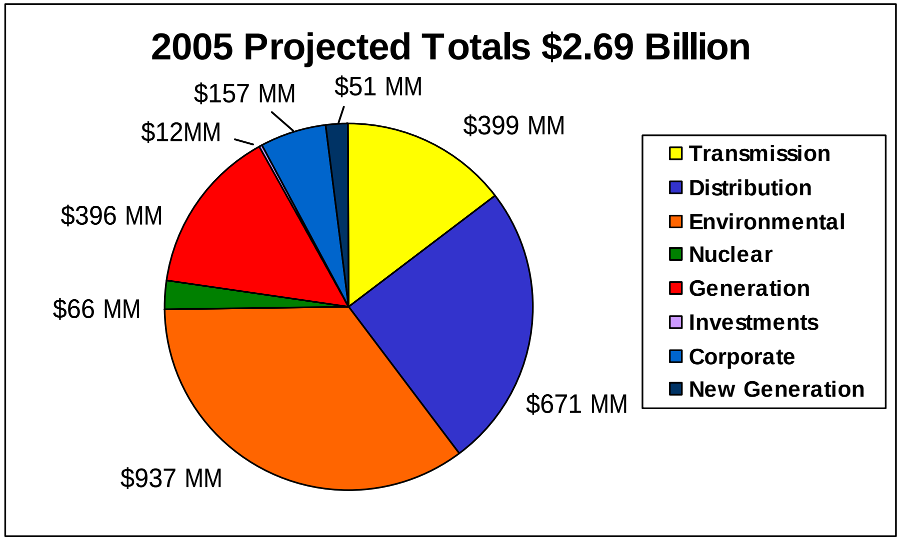
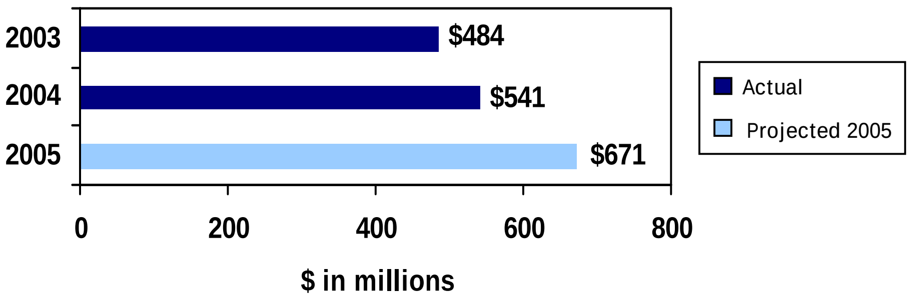
2005 Capex


2004 Actual Totaled $1.69 Billion
$80 MM
$233 MM
$166 MM
$262 MM
$57 MM
$541 MM
$354 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate

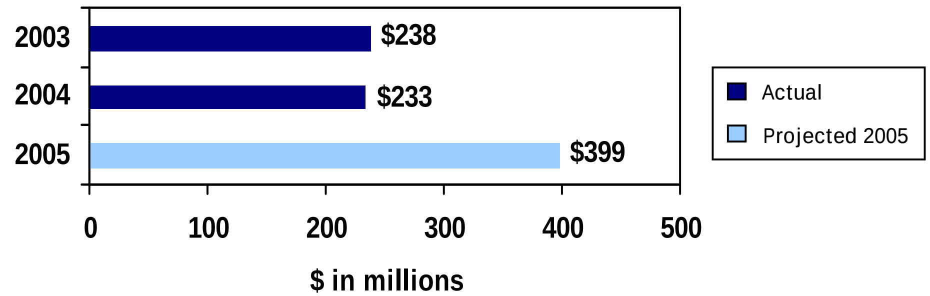

2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$12MM
$399 MM
$396 MM
$66 MM
$671 MM
$937 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



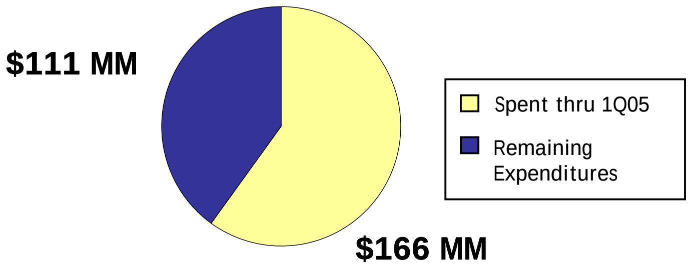
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Investment in Asset Base Will Drive Earnings

Potential Return On Investment

Assumptions	Environmental Investment	600MW IGCC Investment*
Projected Investment	$3.7 Billion	$1.0 Billion
Debt/Equity Ratio	60% debt / 40% equity	52% debt / 48% equity**
Return on Equity	12.00%	11.75%***
Potential EPS Impact (based on 393 MM shares)	+ $0.45	+ $0.14

* Assume a similar return for an additional 600 MW IGCC facility
** Requested debt/equity ratio per AEP Ohio IGCC filing
*** Requested ROE in AEP Ohio IGCC filing

EPS CONTRIBUTION WILL DEPEND ON FAVORABLE REGULATORY OUTCOMES

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**875,376,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005
(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005
(3) Excludes $65.8 million of mortgage bonds due in 2005 that were defeased
(4) Excludes TCC securitization bonds

Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- *Outcome of pending regulatory proceedings*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Earnings Guidance

		Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.40
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Capital Group Yield Conference

Jefferson Hotel
Washington D.C.
May 26, 2005

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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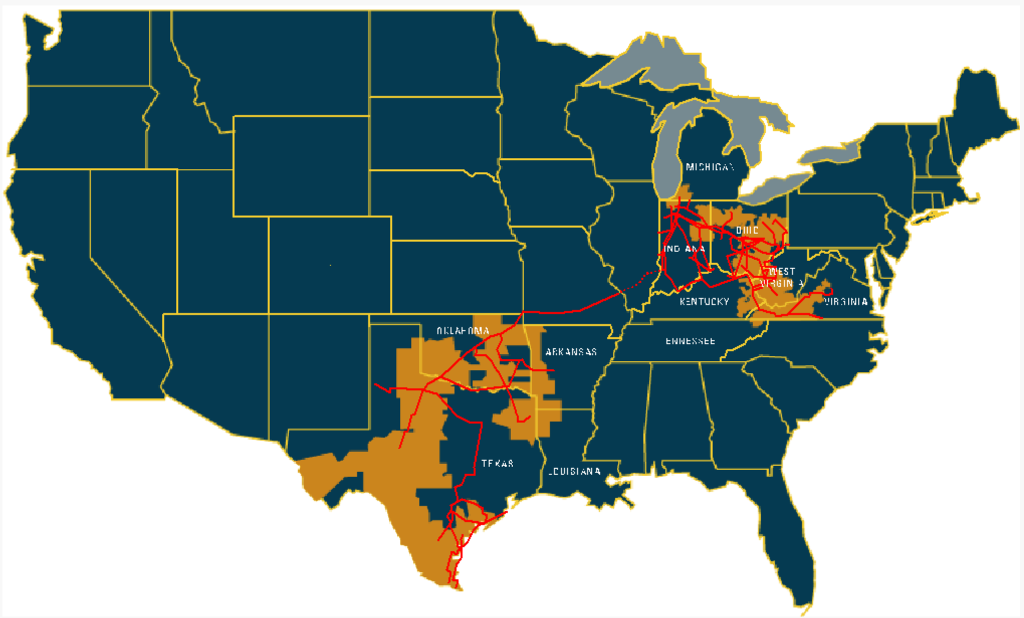
Asset Portfolio

Strength & Scale in Assets & Operations



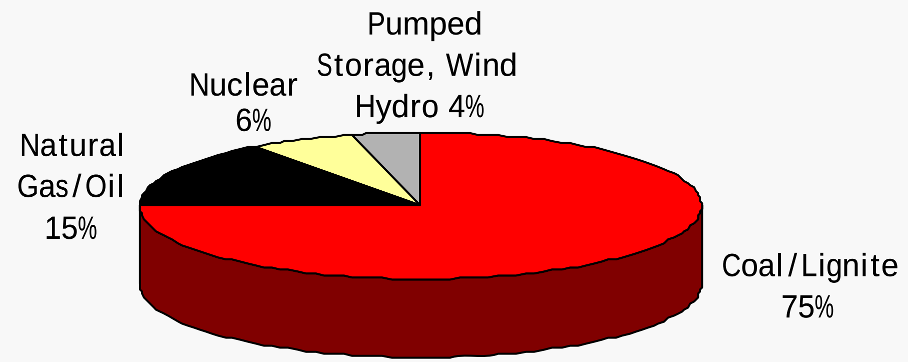
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

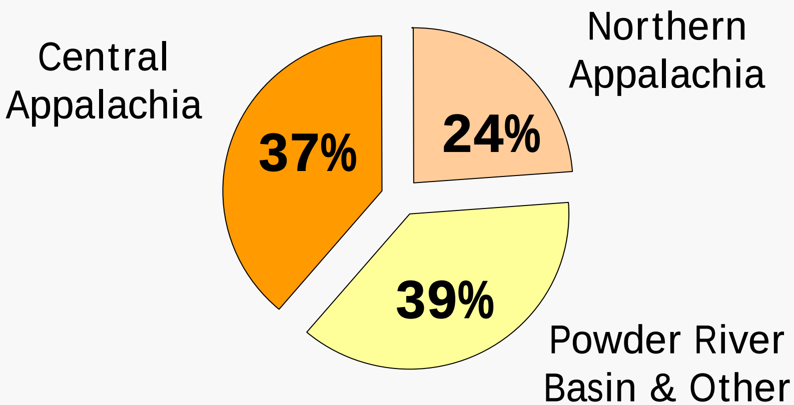
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Coal Procurement

AEP SYSTEM

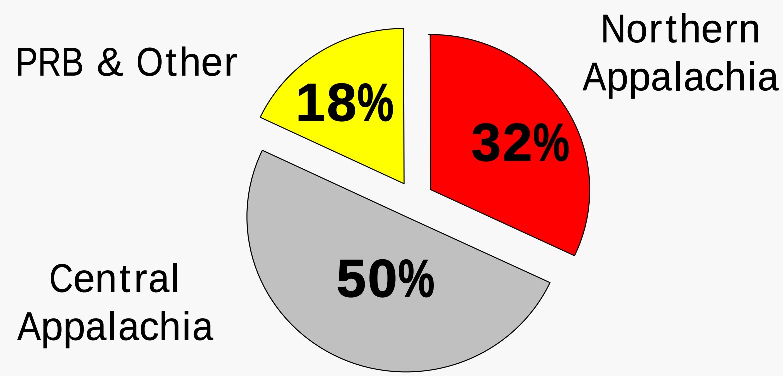


Coal Supply

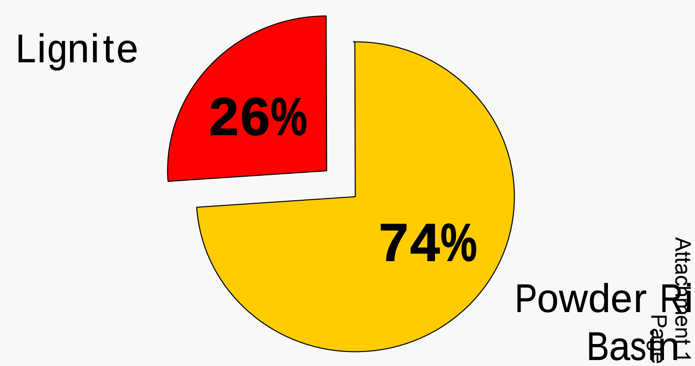
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

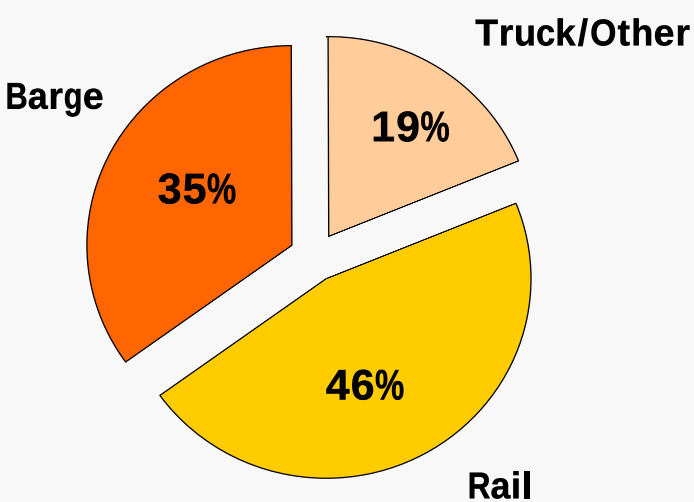


WESTERN SYSTEM



Coal Delivery Mix

DELIVERY MODE DIVERSITY
25 GW coal capacity



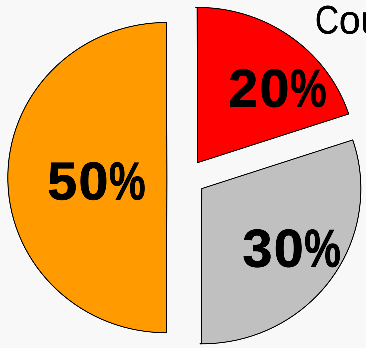
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM



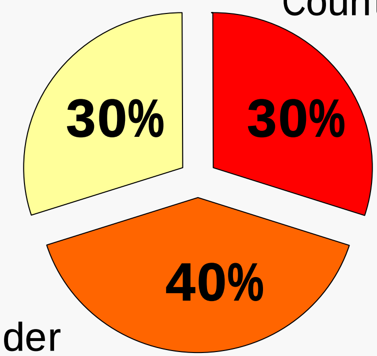
Fuel Cost Recovery

(on average)

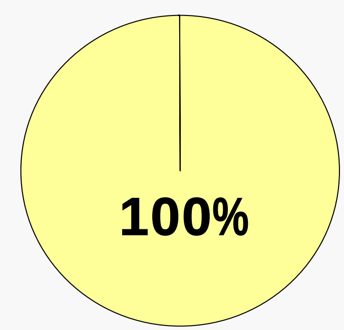
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

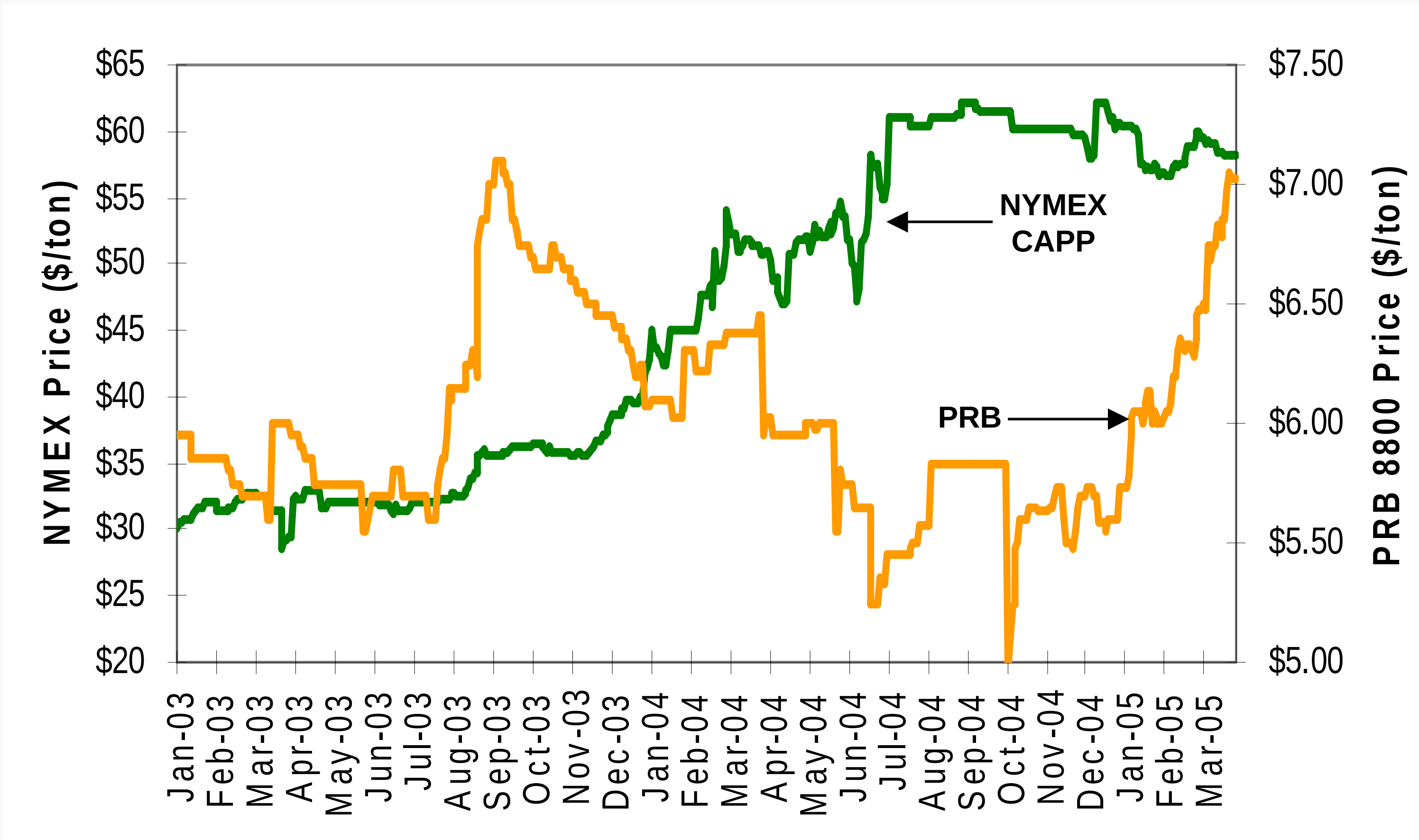


WESTERN SYSTEM



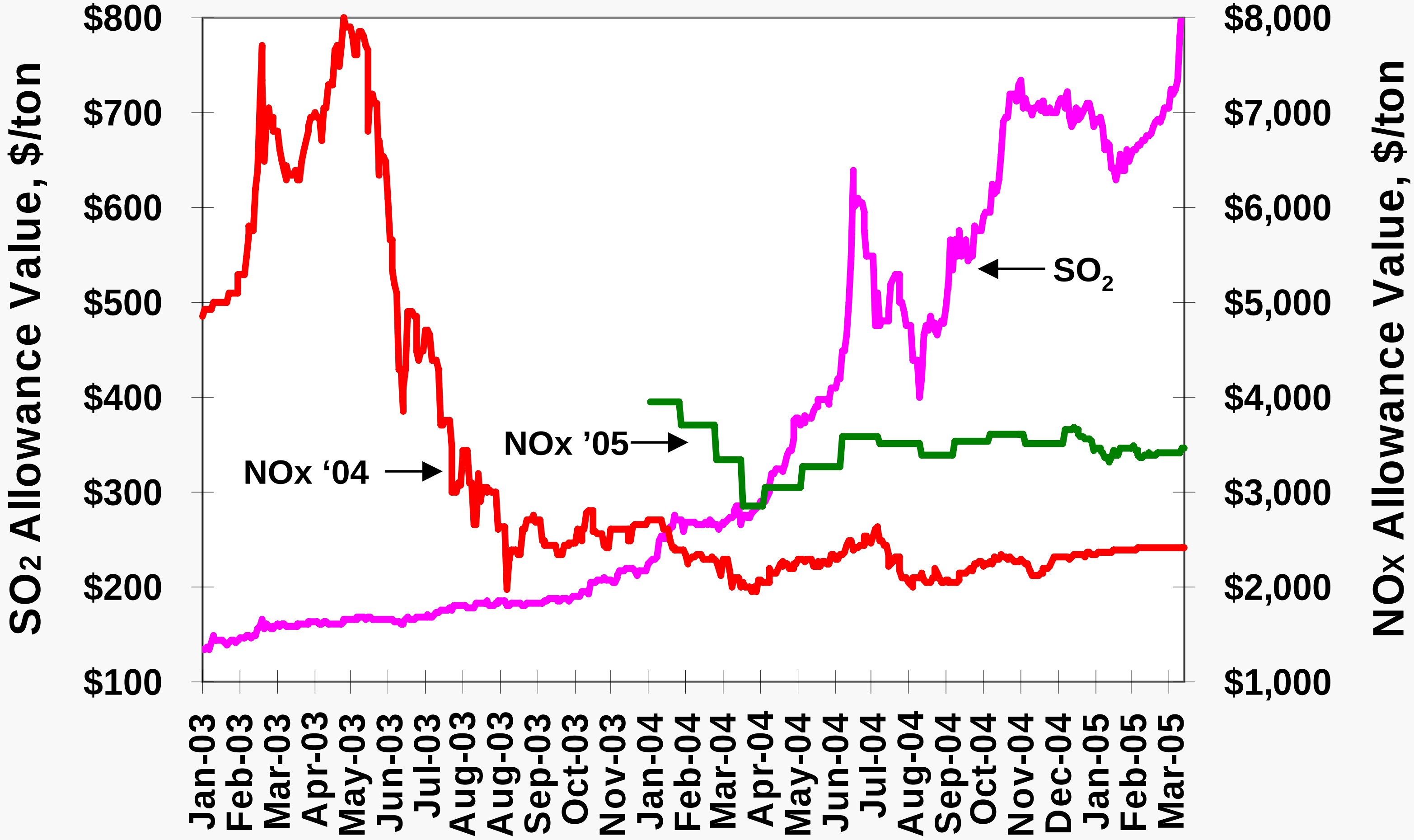
Coal Markets

The tale of two markets - one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



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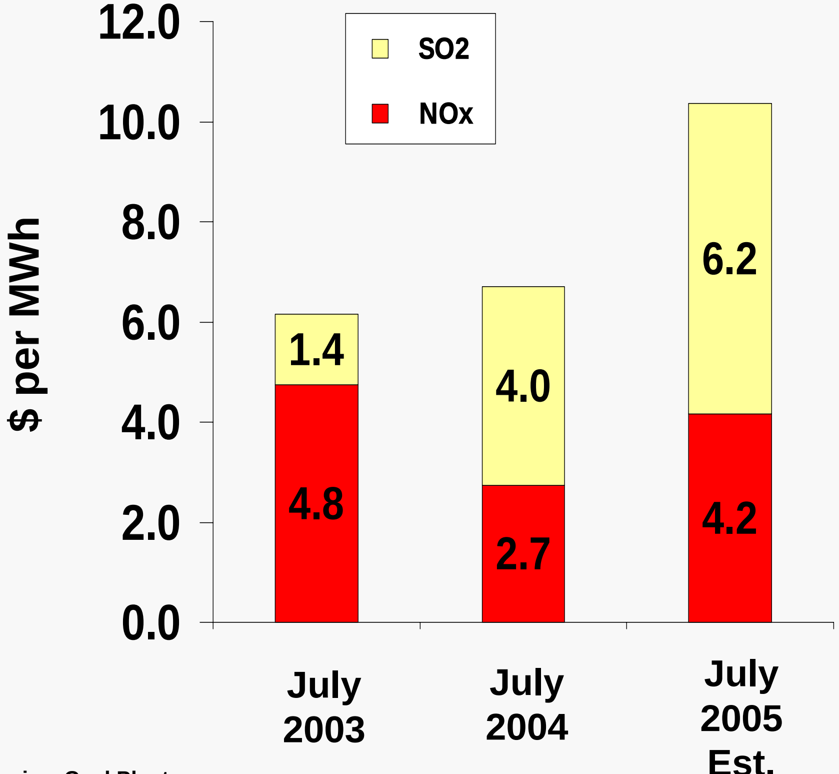
Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



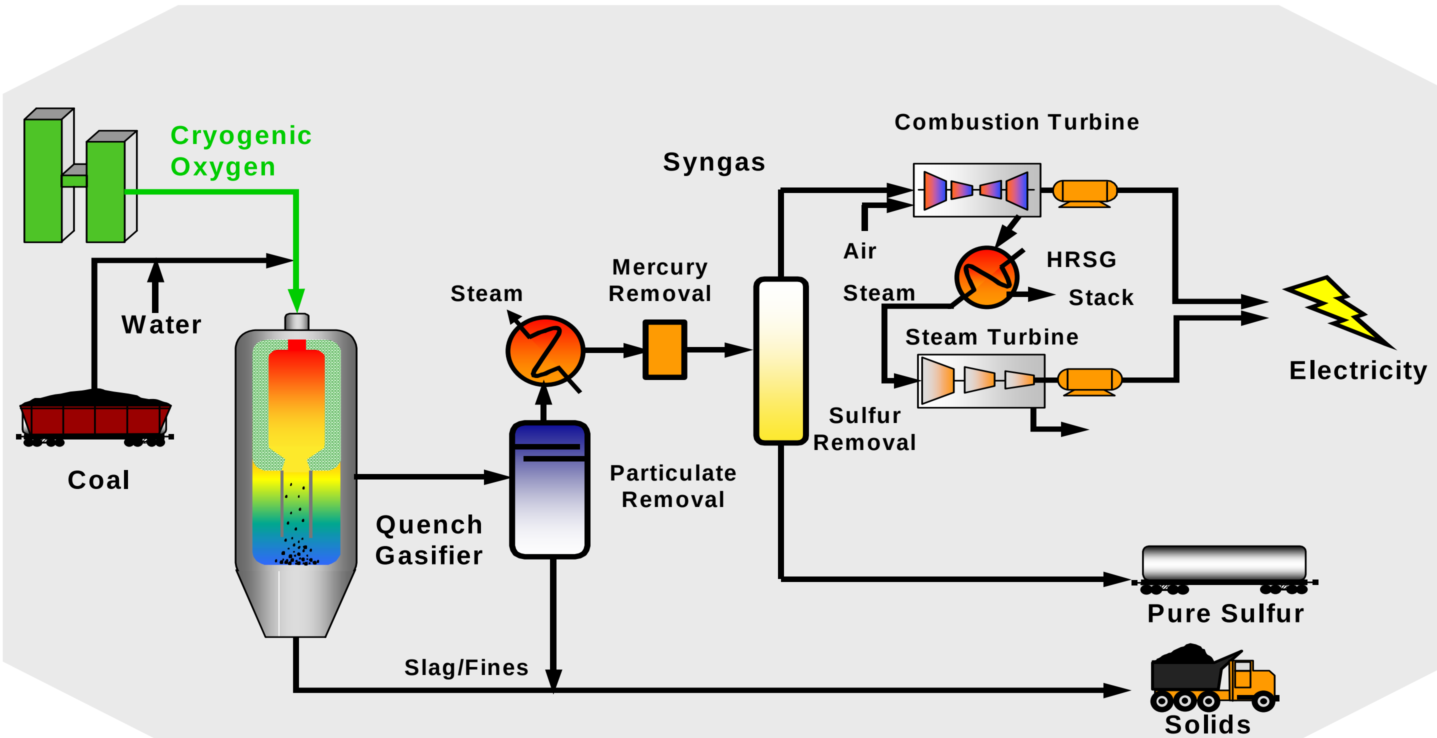
<u>Basis – Coal Plant</u>
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

<u>2005</u>

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

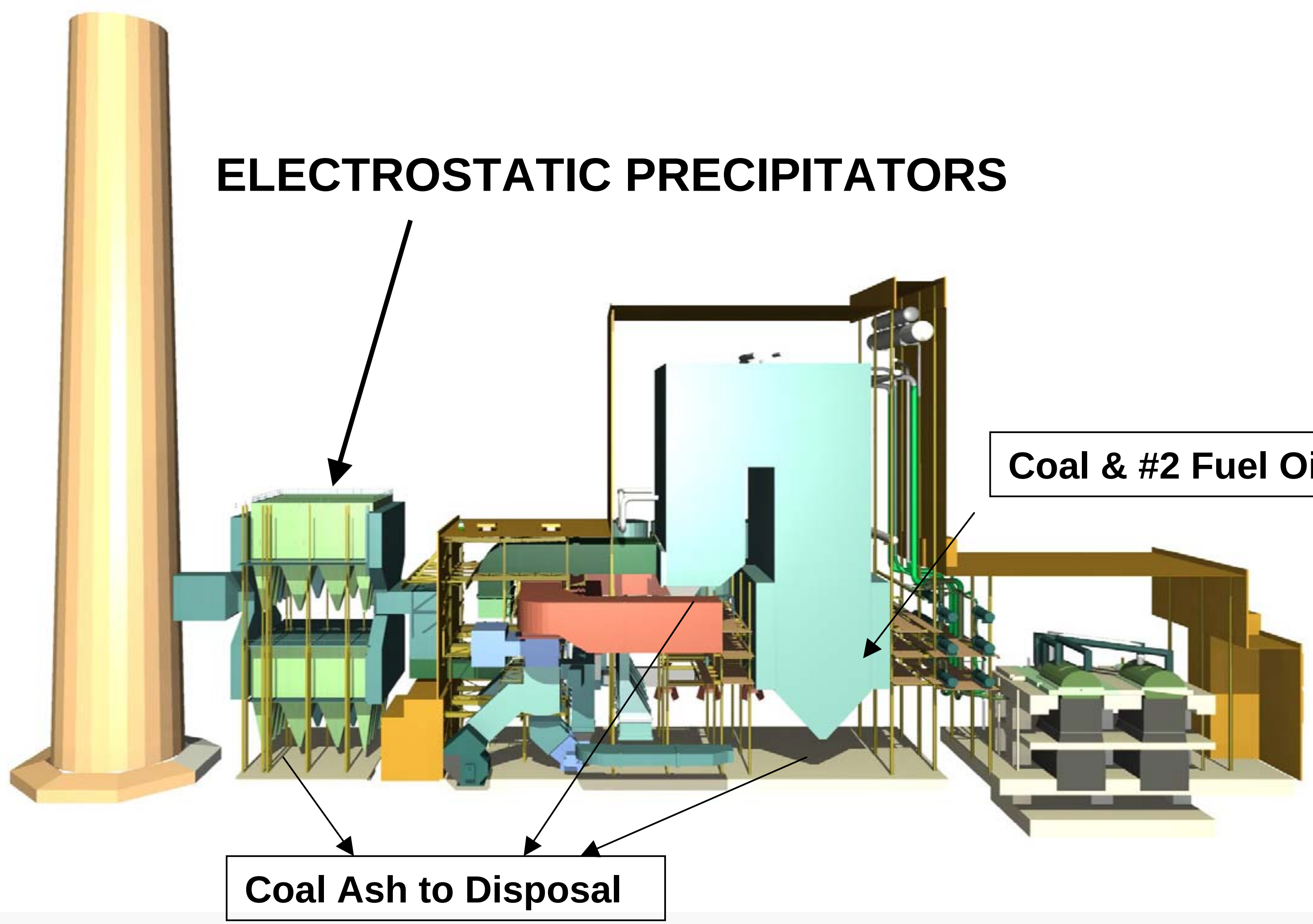
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

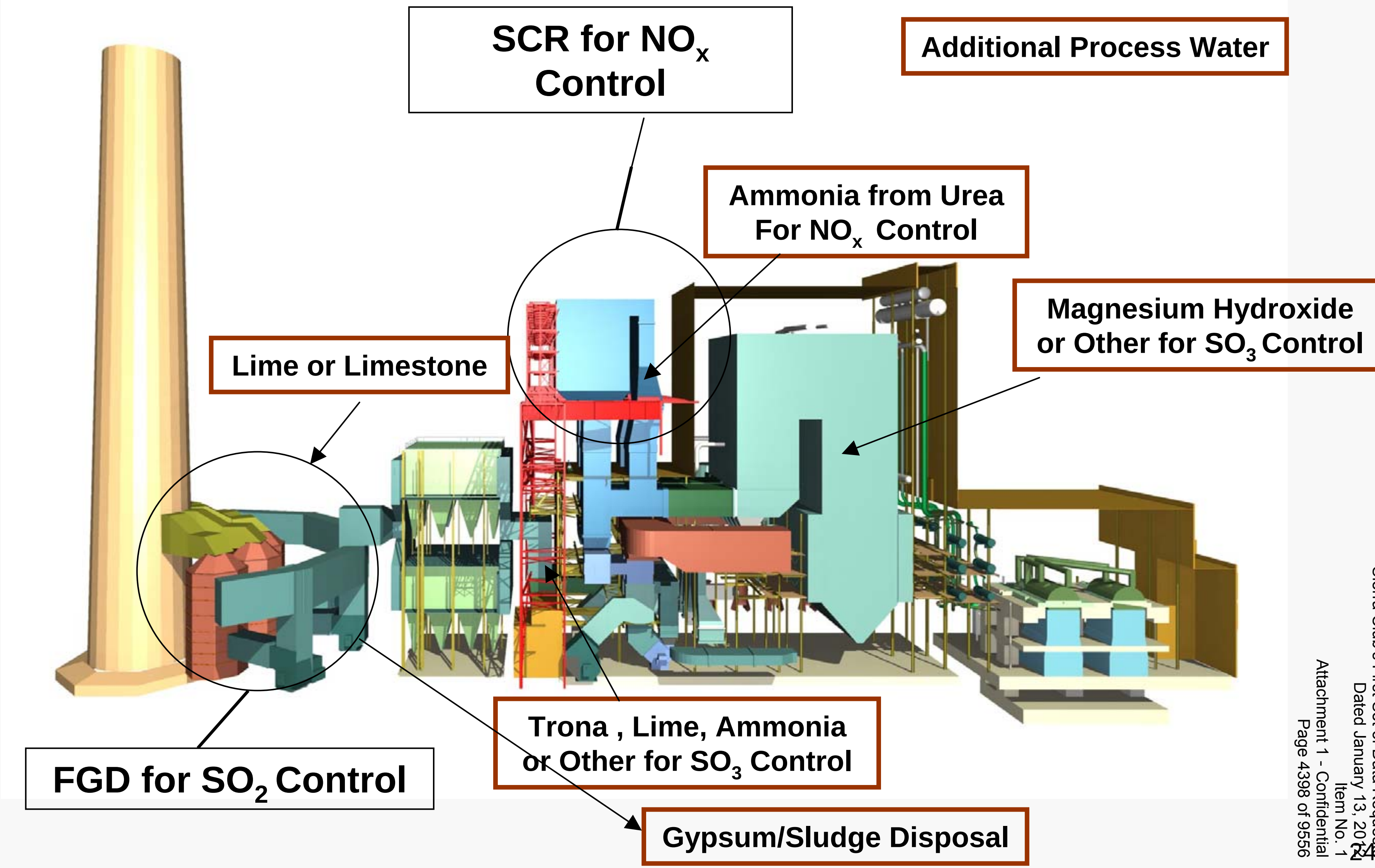
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s



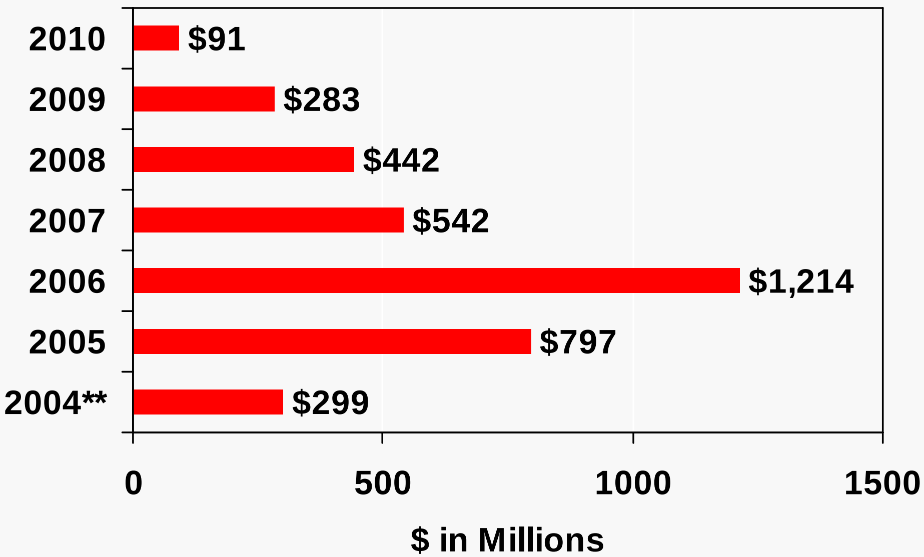
Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



Environmental Investment: $3.7 Billion Through 2010

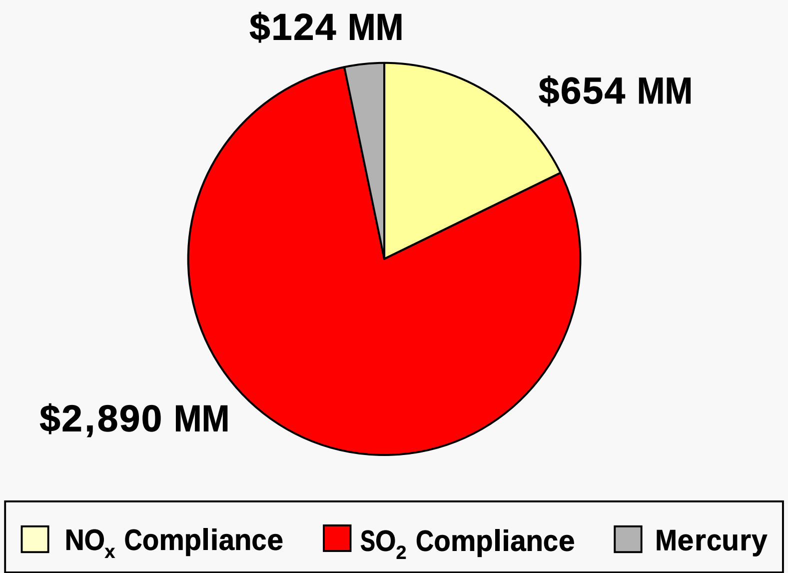
AEP®

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

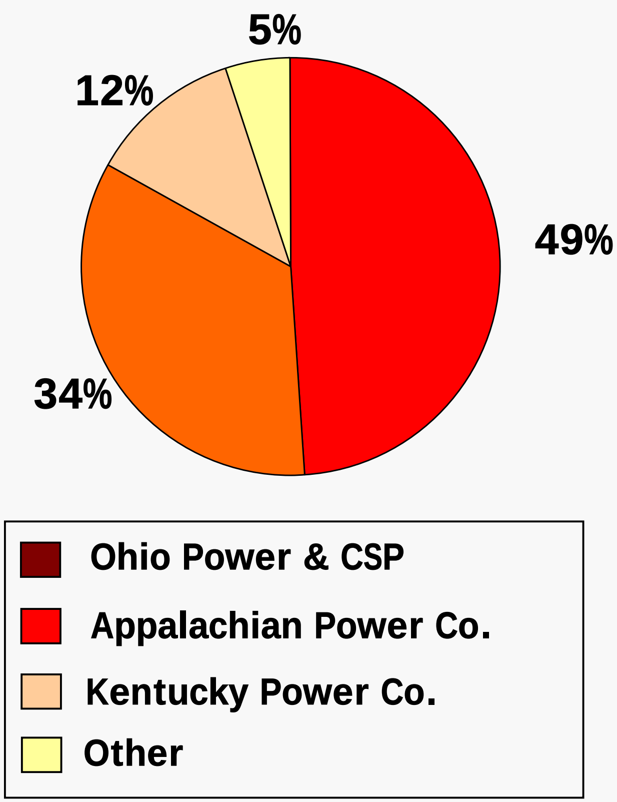
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Planned or Under Construction

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05		31-Dec-04	
	(in millions)			
Stranded Generation Plant Costs	$	898	$	897
Net Generation-related Regulatory Asset		249		249
Unrefunded Excess Earnings		(6)		(10)
Net Stranded Generation Costs		1141		1136
Carrying Costs on Stranded Generation Plant Costs		205		225
Net Stranded Generation Costs Designated for Securitization		1346		1361
Wholesale Capacity Auction True-up		483		483
Carrying Costs on Wholesale Capacity Auction True-up		91		77
Retail Clawback		(61)		(61)
Deferred Over-recovered Fuel Balance		(215)		(212)
Net Other Recoverable True-up Amounts		298		287
Total Recorded Net True-up Regulatory Asset	$	1,644	$	1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix - East

Ohio (Restructured)
• Unbundled rates for default customers frozen until 12/31/2005
• Pursuant to RSP Plan approved by PUCO 1-26-05:
  • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  • CSP ”G” rates to increase 3% per year (2006-2008).
  • OP “G” rates to increase 7% per year (2006-2008).
  • Transmission rates can upon filing reflect change in RTO costs.
• No active fuel clause
• Application for IGCC plant recovery filed on 3-18-05, hearings scheduled to begin 8-8-05.
	Virginia (Restructured)
	• Capped rates for default customers frozen through end of 2010
	• Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
	• Active annual fuel clause

West Virginia (Regulated) • Base rates not frozen • Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels. • No active fuel clause	**Indiana (Regulated)** • Subject to IURC order approving a settlement agreement, base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.
Kentucky (Regulated) • Base rates not frozen • Fuel clause, adjusted monthly • Environmental surcharge costs are adjusted monthly for approved environmental compliance plan • Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004	**Michigan (Restructured, but Regulated)** • Base rates not frozen. • Active annual fuel clause.
Tennessee (Regulated) • Base rates not frozen • Automatic fuel clause, adjusted monthly	

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in first half of 2005. TCC wires rate case order expected in June 2005.
- TCC final fuel reconciliation (July 98-Dec. 01) decision issued in April 2005. TCC will appeal decision.
- TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- General rate case filed Oct. 31, 2003
    - On 5-2-05 the OCC issued an order approving a settlement agreement which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider.
- 2001 Fuel review case
    - Hearings expected in August 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
- Likely to include motions to expand scope to include prudence review

Louisiana (Regulated)
- Base rates capped through June 15, 2005
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Revenues				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

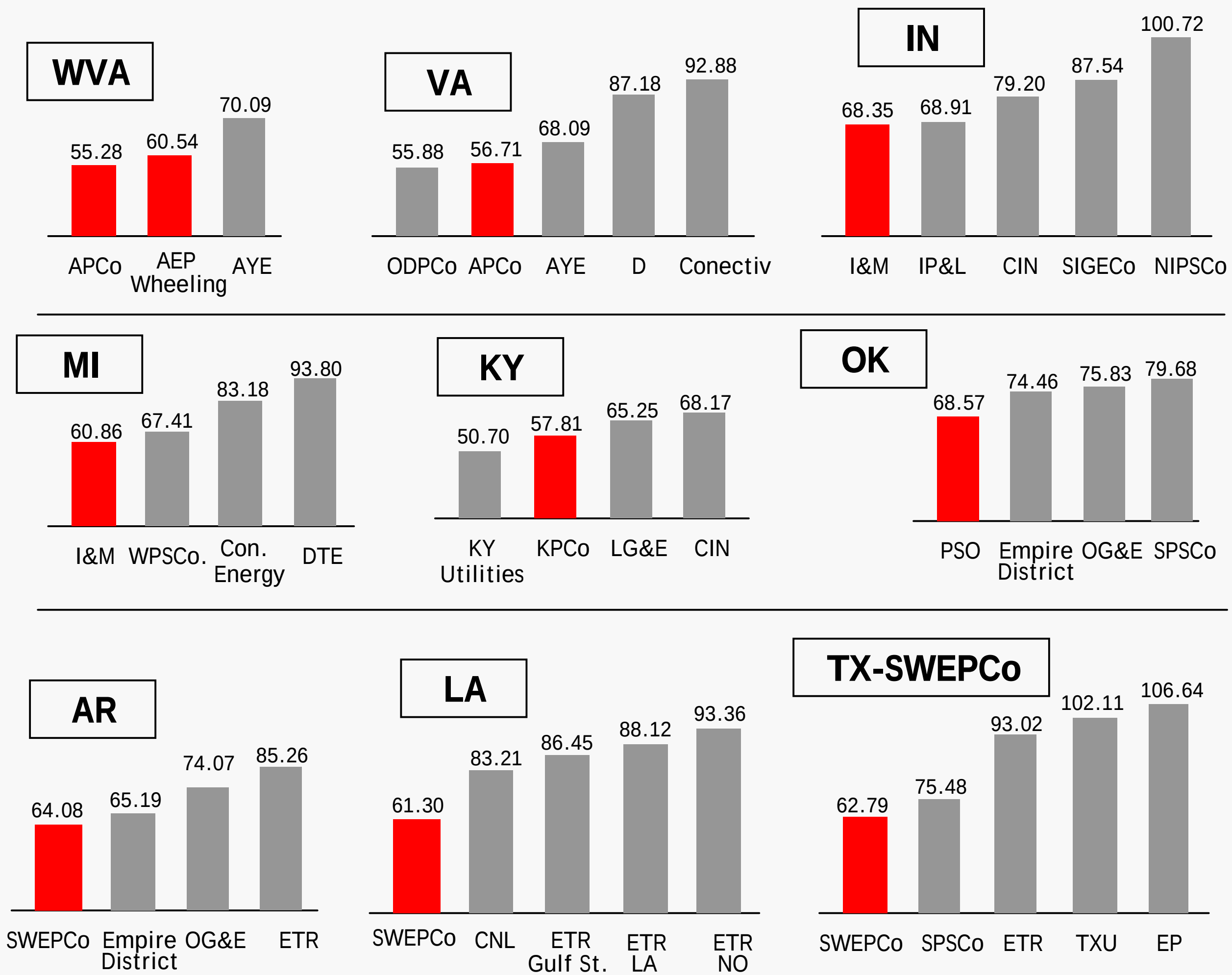
* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

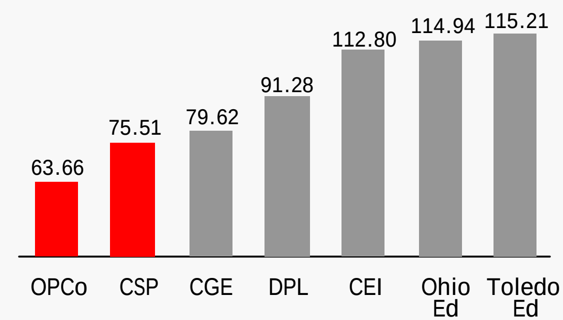
AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

AEP: The Low Cost Provider

Regulated Rates



Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

Fossil fleet variable cost of production:

- Today: \$16-\$18/MWh
- Tomorrow: \$18-\$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in \$/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	936 *
Depreciation & Amortization	1,300	1,305
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	136
Total from Operations	**$ 2,597**	**$ 1,923**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,690)
Asset Sales	1,357	1,498 **
Other	(40)	(529) ***
Total from Investing	**$ (376)**	**$ (1,721)**
Cash from Financing:		
Common Equity	17	(155) ****
Net Long Term Debt Issued/(Retired)	(1,829)	621
Preferred Stock Redeemed	(10)	(66)
Short Term Debt Change, Net	(400)	16
Common Dividends	(555)	(545)
Total from Financing	**$ (2,777)**	**$ (129)**
Net Change in Cash	**$ (556)**	**$ 73**
Ending Cash Balance	**$ 420**	**$ 493**

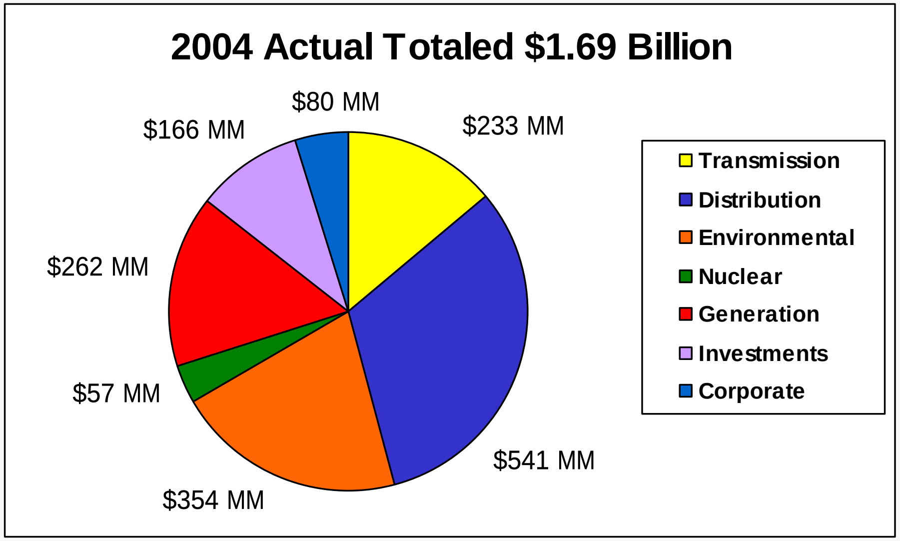
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

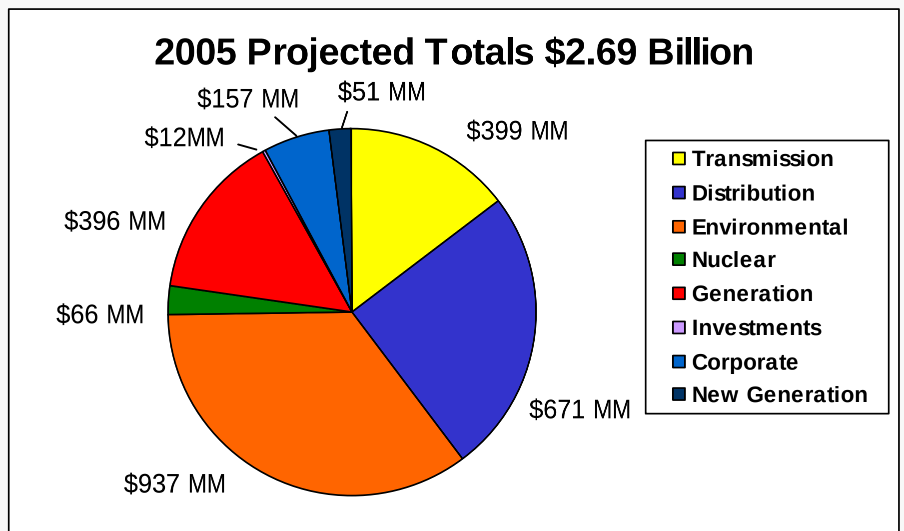
***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex



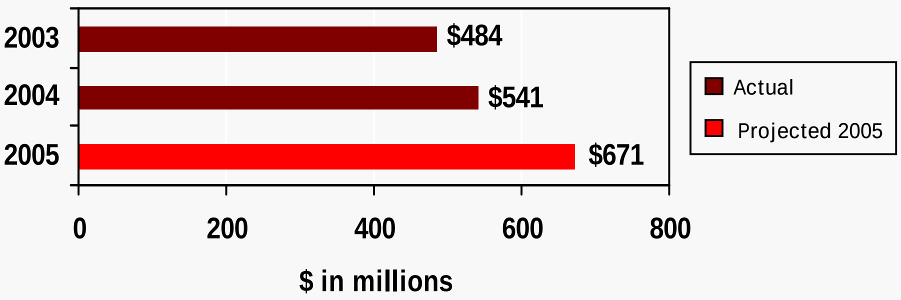
2004 Actual Totaled $1.69 Billion
$80 MM
$166 MM
$233 MM
$262 MM
$57 MM
$541 MM
$354 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate



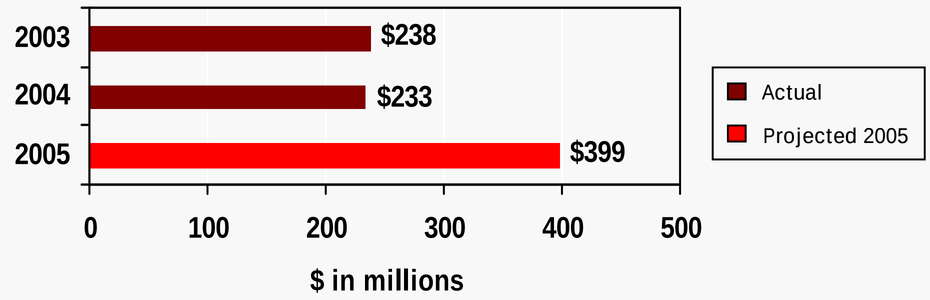
2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$12MM
$399 MM
$396 MM
$66 MM
$671 MM
$937 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



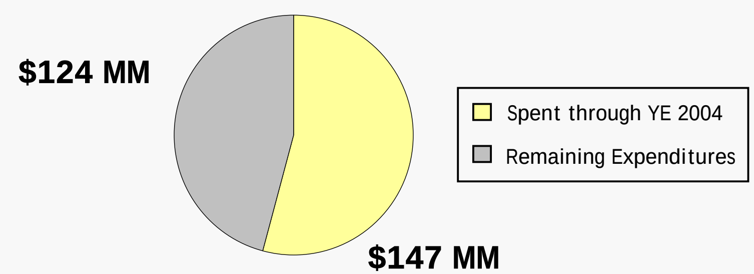
	Transmission & Distribution		
Operating Company	2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year		2005[1]		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	65,800,000	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**941,176,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Total includes $65.8 million of defeased mortgage bonds in 2005

(4) Excludes TCC securitization bonds

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

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Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- Outcome of pending regulatory proceedings
- Operations within PJM environment
- Plant availability
- Rising fuel costs
- Weather (storm damage and effect on sales)

2005 Earnings Guidance

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AMERICAN ELECTRIC POWER FIXED INCOME INVESTOR MEETING

CHICAGO, IL

MAY 16, 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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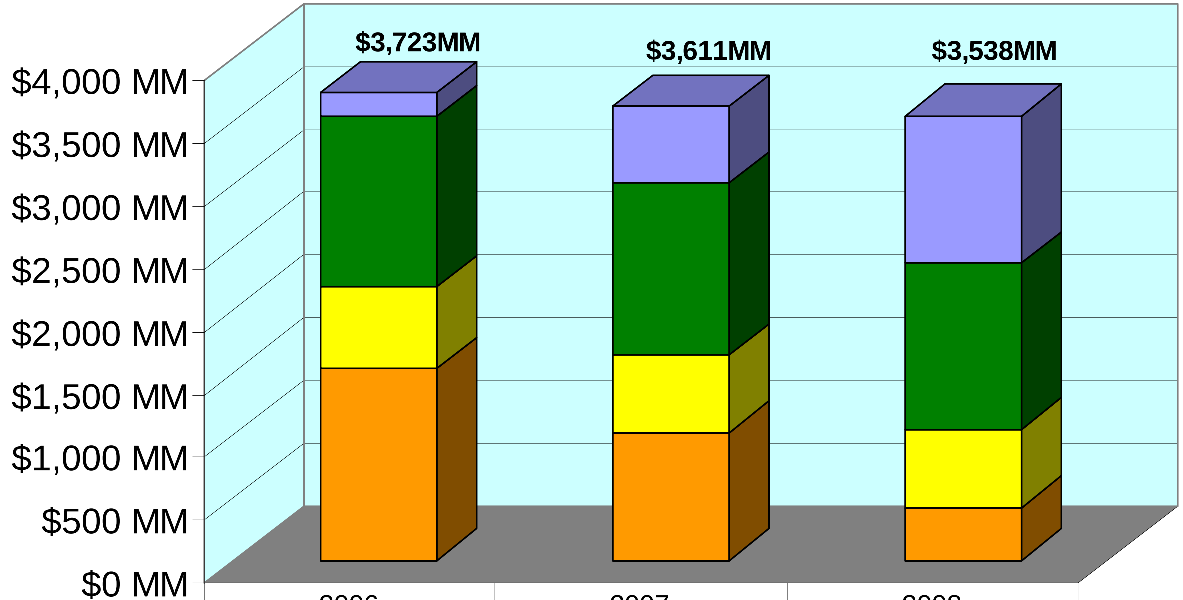
Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC

New Build Generation & Ongoing Infrastructure Replacement investment can be throttled



	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

Much of capital investment is adjustable - investment level will be adjusted based on rate recovery and/or cash generation

New Generation

IGCC

- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 megawatt facility to begin in 2007
- Commercial operation date expected in 2010

PSO RFPs

- Submitted RFPs totaling 900 megawatts of baseload and peaking capacity
- Two peaking RFPs totaling 340 MWs awarded
- Commercial operation dates expected in 2008 and 2011

SWEPCO RFPs

- Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity
- PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment Funding

($ in millions)	Actual		Projection		
	2004	**2005**	**2006**	**2007**	**2008**
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

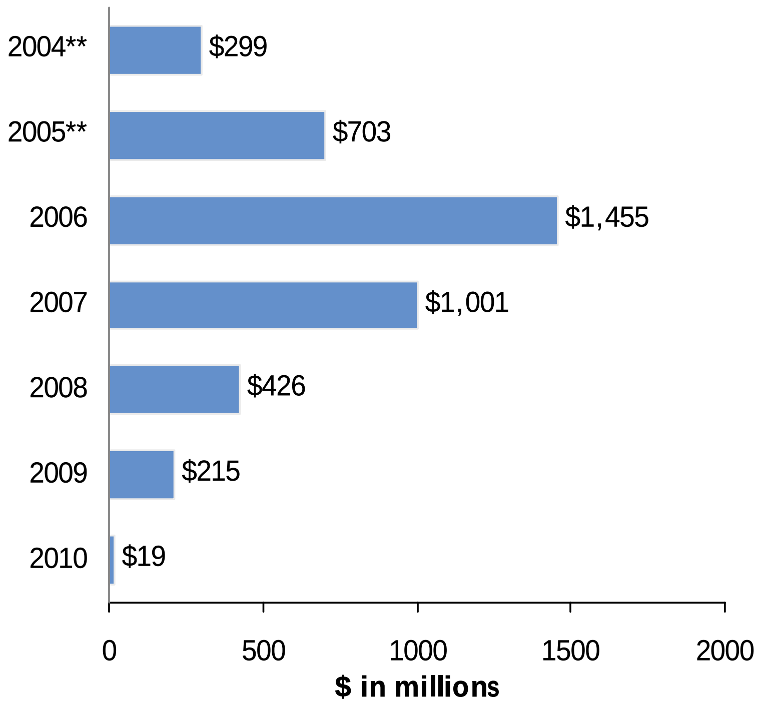
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

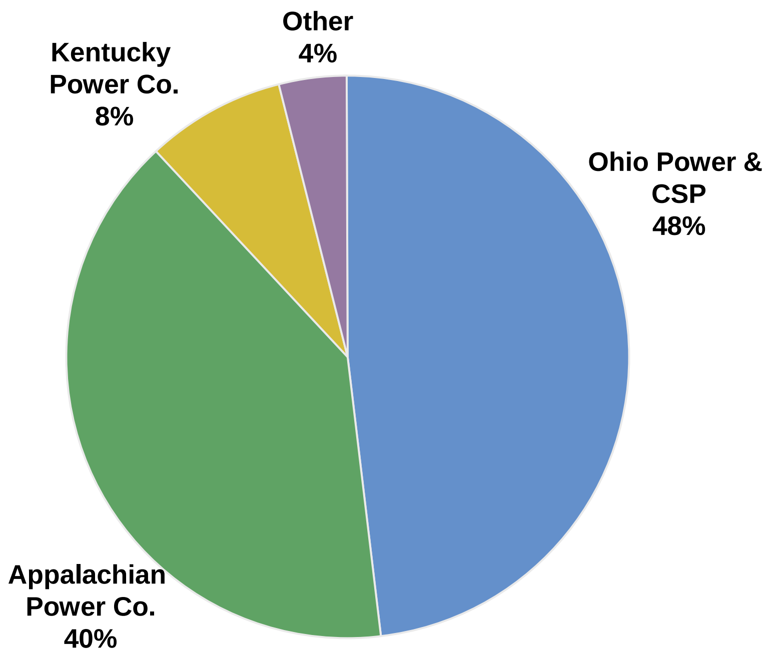
Regulatory recovery will drive capital investment throttle

$4.1 Billion Environmental Investment

Environmental Capital Investment*



Projected Environmental Investment Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

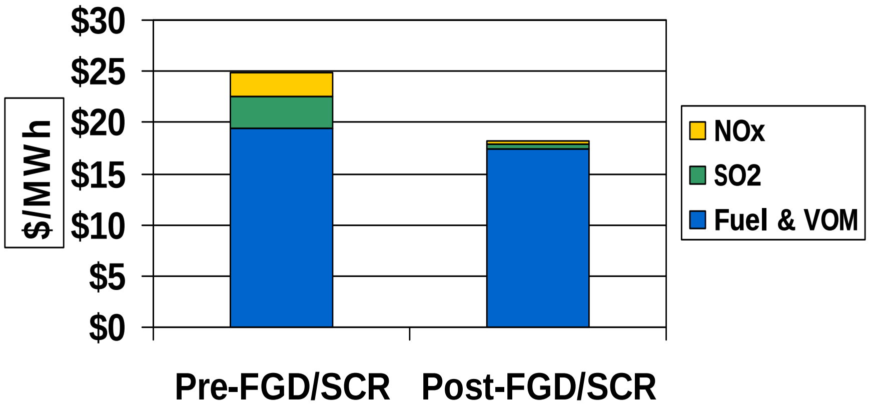
** Actual investment level in 2004 and 2005

Majority of 2006 & 2007 dollars will be invested in Ohio & ApCo

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP will remain the low cost producer following completion of environmental retrofit projects

Regulatory Activity Underway

- TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- Ohio Companies filing for pass through of FERC OATT changes
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia – Settlement Pending
- IGCC – Received Rate Authorization of Pre-Construction Costs

Year-to-date, secured $350 million of the $500 million rate recovery assumed in 2006 earnings guidance range

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - Final order expected in June or July 2006
  - September 2006 - Issuance of securitization bonds if no appeal

<u>Procedural Schedule for TCC Securitization</u>

- ✓ April 17, 2006 – Intervenors File Testimony
- ✓ April 24, 2006 – Staff Files Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 25-26, 2006 – Hearing On Merits

- May/June 2006 – Request approval for CTC to address other true-up items
  - Expected $491 million credit to customers
  - Sept 2006 – CTC to be implemented

Regulatory Activity Underway

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Procedural schedule has been set with final order expected in third quarter 2006

Regulatory Activity Underway

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ➢ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ➢ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2005 – Joint Settlement Agreement

- ➢ Estimated overall impact of revenue increases to be phased-in through 2009;
  - ➢$129 Million
  - ➢16% Increase
- ➢ Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases:

- ✓July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

*Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Settlement Details

✓Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
<u>$23MM</u>	WJF & FGD investment @ 12/31/05
$61MM	Gross revenue increase
<u>($17MM)</u>	ENEC over-recovery negative surcharge
$44MM	Net increase effective 7/28/06

✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- ➢ Effective during 2006
- ➢ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ➢ Approximately $23.7 Million

Phase 2

- ➢ Effective 2007- mid 2010 (Construction Phase)
- ➢ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ➢ Effective mid 2010 (Commercial Operation begins)
- ➢ Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- ➢ Secure cost recovery plan
  - – April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - – Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- ➢ Finalize site selection
- ➢ Negotiate with suppliers

2006—2007:

- ➢ Obtain permits and finalize engineering and procurement

2007—2010:

- ➢ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

Seeking authority for three phase recovery approach in Ohio

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- Interim surcharge will collect the under-recovery amount of $44 Million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- $41 million annual increase in base rates
- To be effective March 30, 2006

Steve Smith
Senior Vice President & Treasurer

Forecasted Capital Expenditures

Company	2006	2007	2008
		(in thousands)	
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

Long-Term Debt Maturity

Year		2006 (3)		2007		2008
AEP Service Corporation	$	2,000,000 (2)	$	2,000,000 (2)	$	34,000,000
AEP Inc.	$	395,860,000	$	345,000,000	$	-
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	-	$	342,500,000	$	200,000,000
Columbus Southern Power	$	-	$	-	$	112,000,000
Kentucky Power	$	-	$	322,964,000	$	30,000,000
Indiana Michigan	$	300,000,000	$	-	$	50,000,000
Ohio Power Company	$	7,640,000 (2)	$	17,854,000 (2)	$	55,188,409 (2)
Public Service of Oklahoma	$	-	$	-	$	-
Southwestern Electric Power	$	11,047,000 (2)	$	95,312,136 (2)	$	12,538,117 (2)
Texas Central Company	$	-	$	-	$	18,581,000
Texas North Company	$	-	$	8,151,000	$	-
Total	**$**	**716,547,000**	**$**	**1,133,781,136**	**$**	**512,307,526**

(1) Excludes tax exempt bond remarketings and securitization bonds

(2) Includes sinking fund payments, where applicable

(3) Maturities remaining as of March 31, 2006

2006 Key Operating Company Highlights

(in millions)

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 (completed*)	42-45%
CSP	$343	$100 - $150	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$50 - $75	42-45%
OPCo	$1,070	$450 - $550	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$100 - $150	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

*Issuances completed in 2006 totaling $550 Million

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

Maintain financial strength of subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

APPENDIX

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

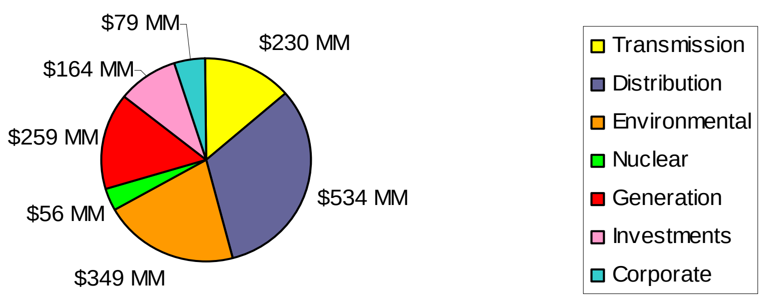
	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Ratings Actions

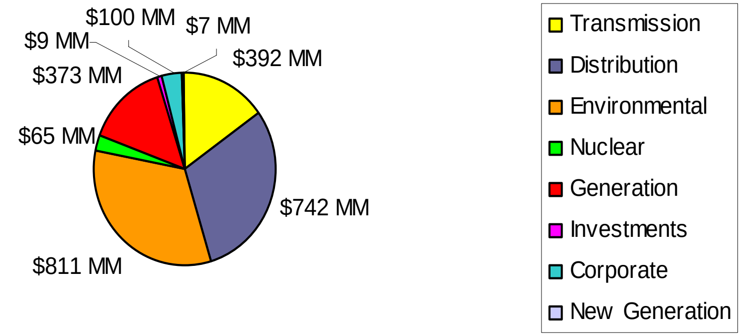
- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Capital Investment 2004 - 2006

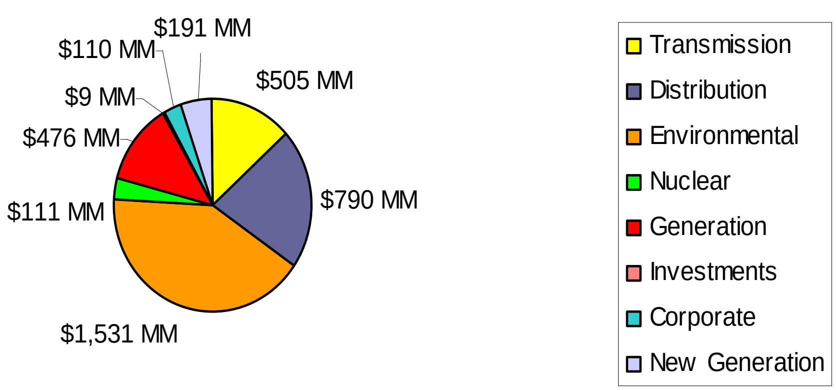
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



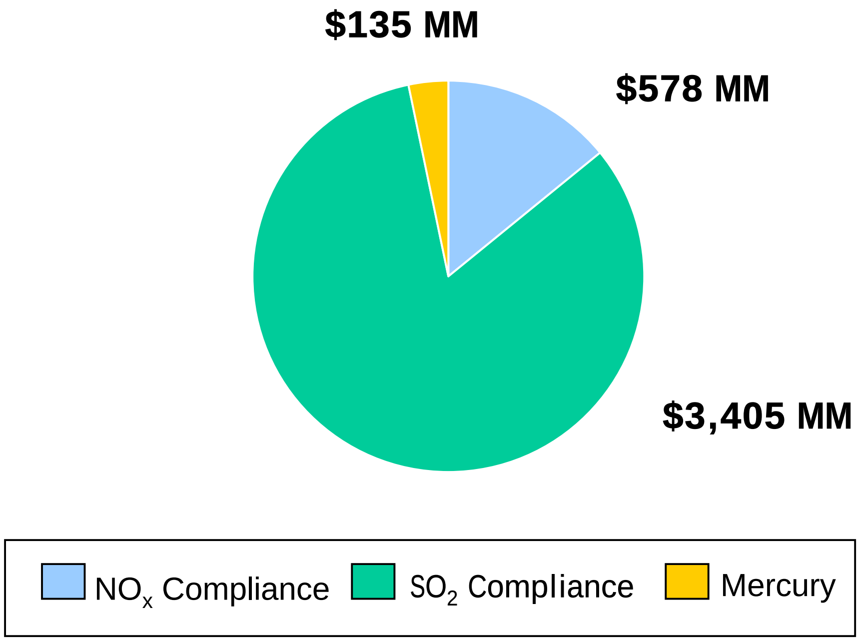
2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 Billion environmental investment projected 2004 through 2010

Note: Figures Include AFUDC

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

Cash on hand expected to be $326 million at year end 2006

Capital Structure

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

Adjusted Debt-to-Cap of 57.5% at 3/31/06

Debt Schedules

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	4.709%	08/16/2007	$345,000,000
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bonds	5.010%	01/15/2008	$103,272,491
Securitization Bonds	5.560%	01/15/2010	$107,094,258
Securitization Bonds	5.960%	07/15/2013	$214,926,738
Securitization Bonds	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,817,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of March 31, 2006

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Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,058,600

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Indiana Michigan Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/1/2015	$125,000,000
Weighted Average or Total	4.971%		$1,220,083,600

Kentucky Power			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$11,707,314
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/1/2015	$200,000,000
Weighted Average or Total	4.386%		$1,881,953,514

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of March 31, 2006

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Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$24,974,947
Notes Payable	Floating	06/30/2008	$12,538,117
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	4.750%		$702,020,664

Note: Debt Schedules as of March 31, 2006

Summary of Major 2006 Financial Performance Drivers

- Load Growth of 2.5%
- $500MM rate recovery assured or in progress
- Rising fuel costs of 11-13%
- Higher planned outages, increased retail load and sale of TCC generation to impact off system sales
- Decline in utility O&M
- Parent Company improvement (debt & interest expense reduction)

Traditional utility factors will drive 2006 performance

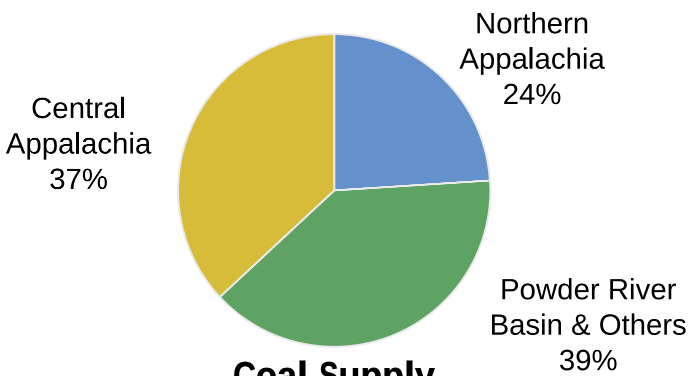
2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

Coal Procurement

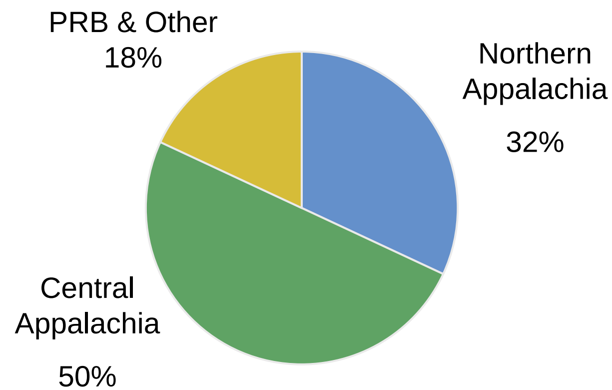
Total AEP System



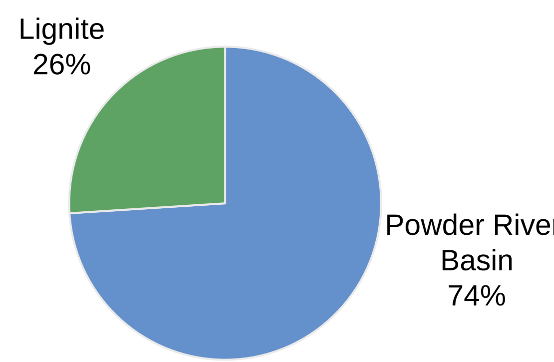
Coal Supply (on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- 95% purchased for 2006
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System



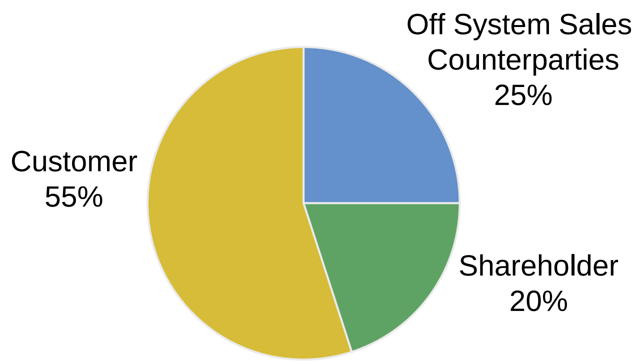
AEP Western System



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: AP-VA, I&M - MI, KGP, KP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. On April 24th, APCo and Wheeling Power, together with the PSC staff and the Consumer Advocate in WV, filed a joint settlement agreement in the companies' rate case. The agreement provides for an initial $44 million increase in revenues, effective July 28, 2006. The initial increase consists of a $56 million increase for fuel and purchased power expenses, and $23 million for recovery of WJF transmission line costs and environmental investments to date. These increases are partially offset by an $18 million base rate reduction and a $17 million credit to customers for previously over-recovered fuel costs. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Procedural Schedule

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearing
April 24, 2006	Settlement agreement filed
May 4, 2006	Legal briefs filed
May 15, 2006	Response briefs filed

Statutory Deadline: July 28, 2006

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	**Company Position** (filed 7/1/05)	**Staff Position** (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	**Company Position** (filed 11/14/05)	**Staff Position** (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

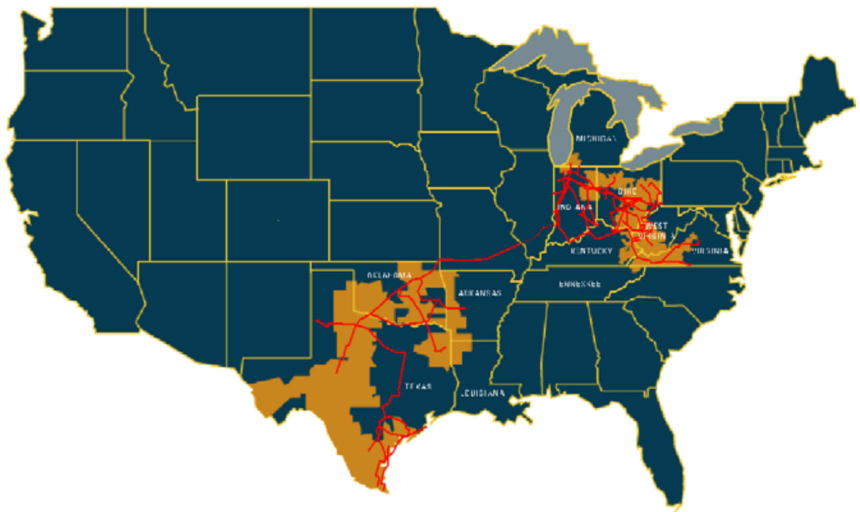
What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth

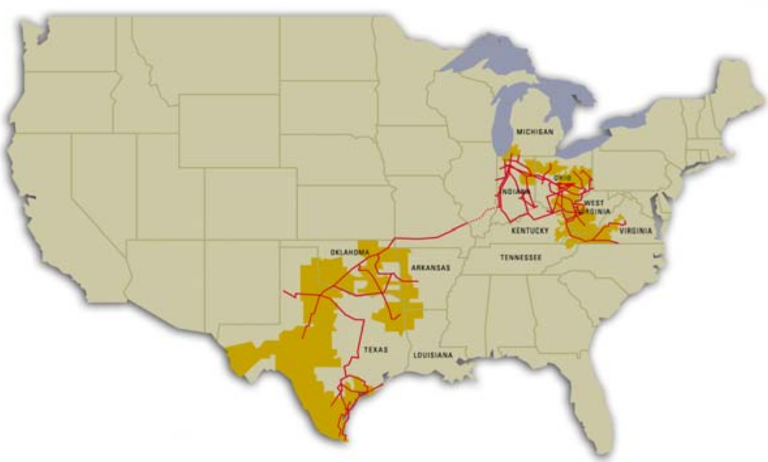


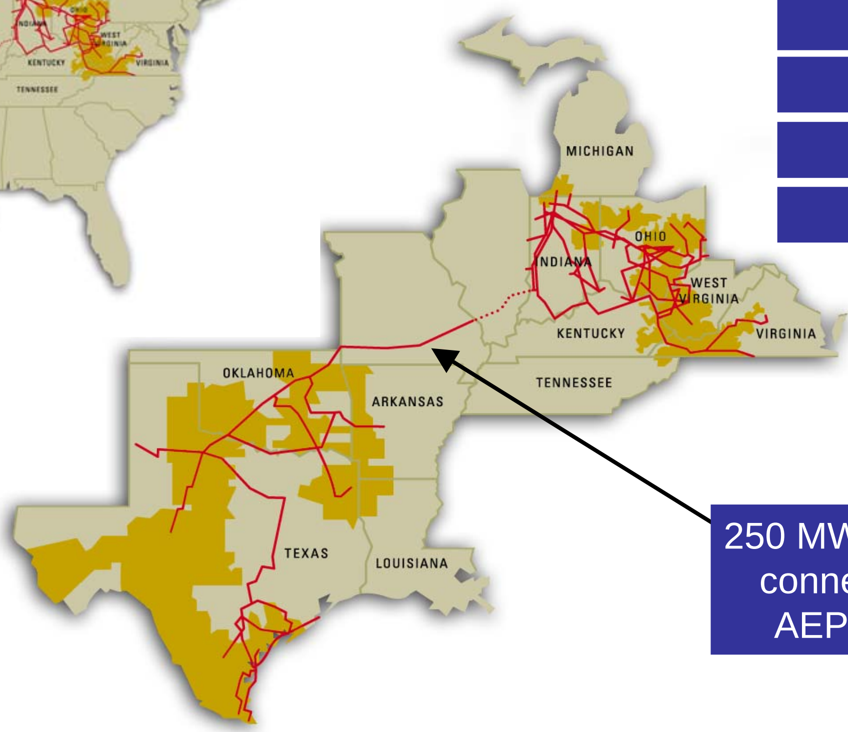
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,483 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

Future earnings growth driven by native load growth & substantial utility investment opportunity

Where We Operate



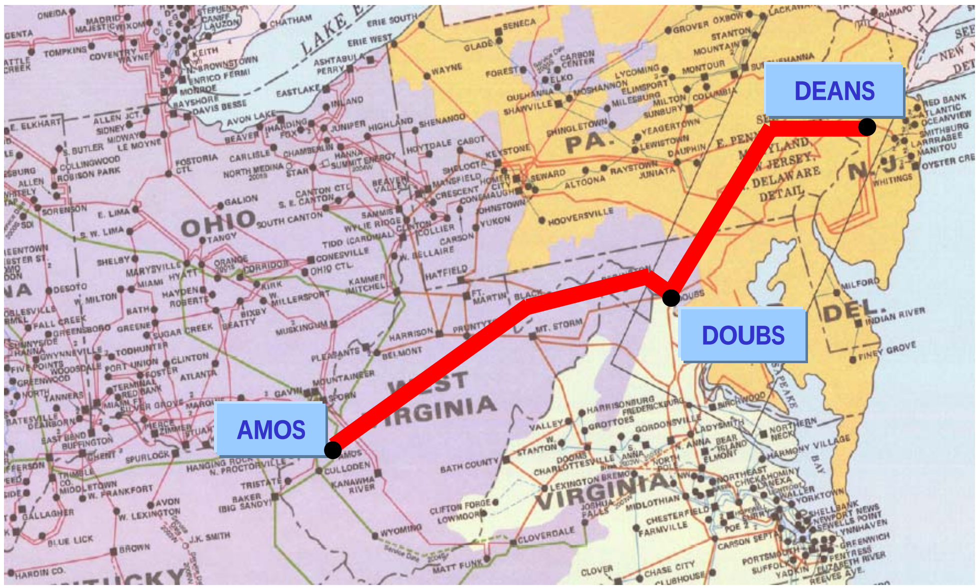


- Ohio
- West Virginia
- Virginia
- Indiana
- Michigan
- Kentucky
- Tennessee

- Texas
- Oklahoma
- Arkansas
- Louisiana

250 MW transmission line connects AEP East & AEP West territories

AEP Interstate Project

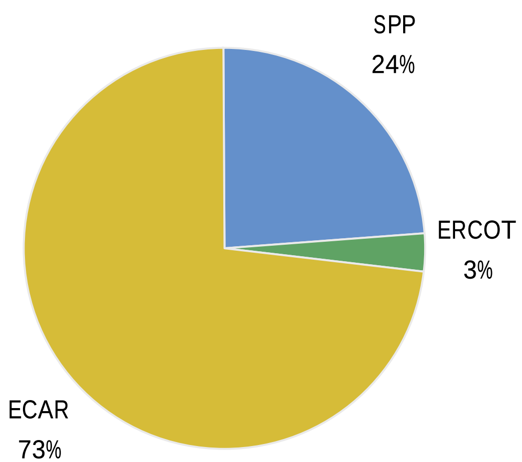


Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

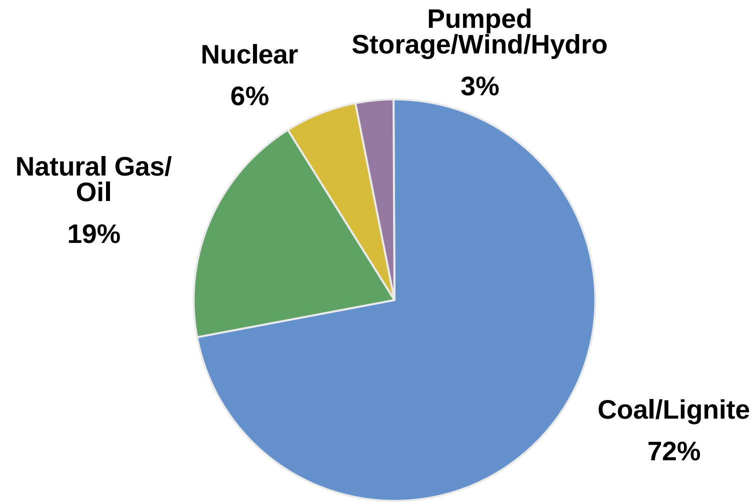
- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

Operating Statistics

Commercial Availability Factor

2004	85.24%
2005	84.50%

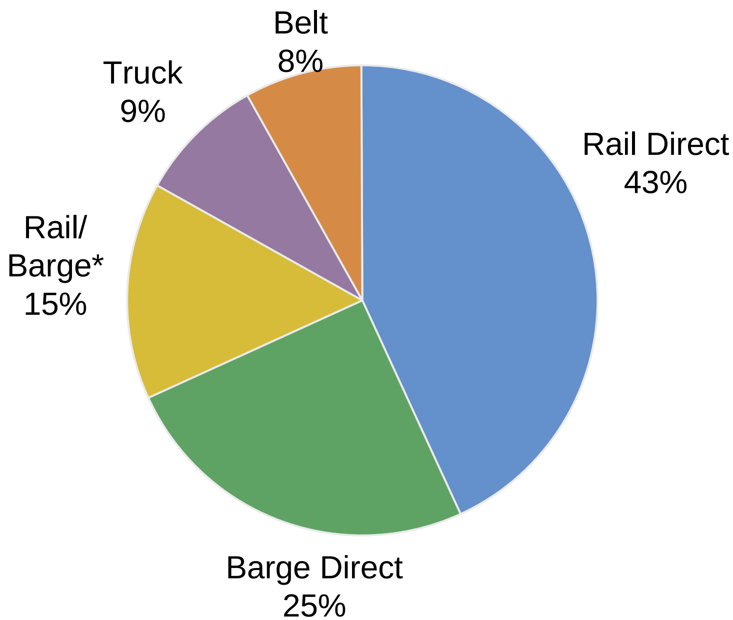
Capacity Factor

2004	62.06%
2005	62.53%

Coal Delivery

Total AEP System

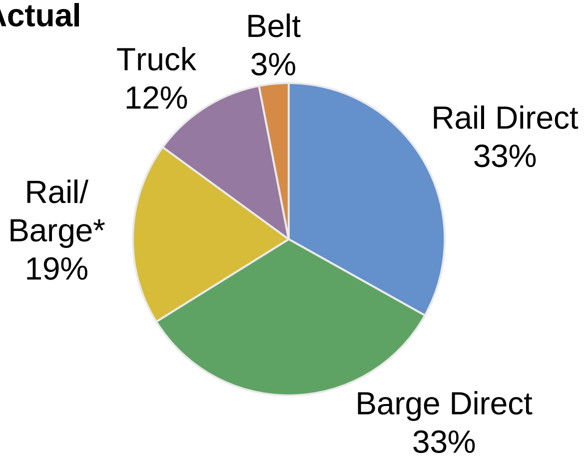
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

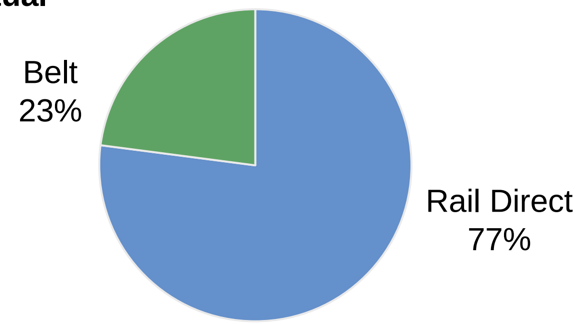
AEP Eastern System

2005 Actual



AEP Western System

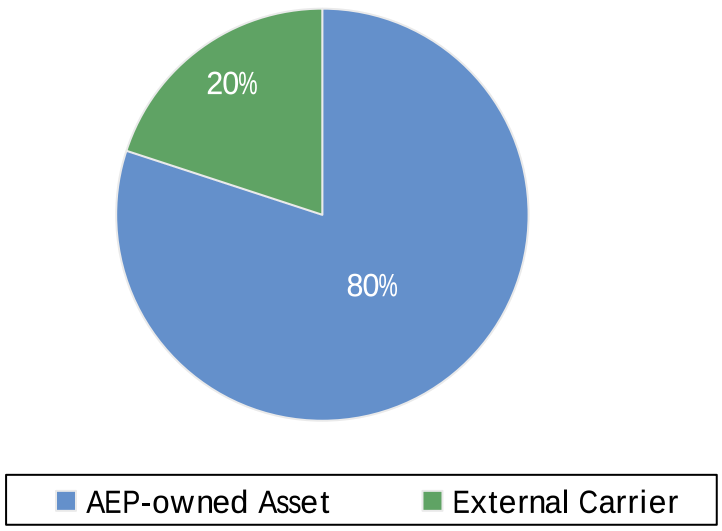
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP's transportation assets provide flexibility in a constrained delivery environment

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC

organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

Total Customers:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**

Generating Capacity	**54 MW***

Generating Capacity by Fuel Mix:

• **Coal: 100%**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

Principal industries served:

Oil and gas extraction
Food processing
Apparel
Metal refining
Chemical and petroleum refining
Plastics
Machinery equipment

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data (in thousands)

Revenue	$	793,000
% of AEP Retail		5%
Net Income (Loss)	$	(174,000)
Capital Expenditure	$	179,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	4,905,000
Net Plant Assets	$	2,021,000

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$278,400	$247,000	$222,100

AEP Texas Central Company

AEP TEXAS CENTRAL
MAJOR CUSTOMERS

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
El Paso Energy Corp.
HEB Grocery Company LP
Ingleside Cogeneration Ltd Par
Citgo Petroleum Corporation
Wal-Mart Stores, Inc.
Formosa Utl Ven Ltd.

- **Top 10 customers = 67% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **53 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas Central Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: **3**	Appointed/Elected: **Appointed**	Term: **6 years**	Political Makeup: R:3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

AEP Regulatory Status

• Operations for TCC and TNC have been functionally separated. Retail competition has been delayed by the PUCT in the Southwest Power Pool (SPP) area of Texas (including SWEPCO and TNC-SPP areas). • PUCT issued a final order in TCC stranded cost true-up case on 2-16-06, approving a true-up balance of $1.475 billion. We expect to appeal, seeking additional recovery consistent with Texas law. •TCC final fuel reconciliation (July 98-Dec 01). Final order received 6-3-05. TCC and other parties filed appeals in the District Court, which is currently in the briefing phase. TCC has also filed at the U.S. District Court to ajoin the PUCT from enforcing their ruling regarding the allocation of the off-system sales margins; a briefing and procedural schedule has not been established. • New Transmission Cost Recovery Factors (TCRF) became effective 3-1-06. The impact of the TCRF update will be $1.5 million annual increase. • TCC Rate Case. Final order received 8-15-05. TCC and other parties filed appeals in the District Court. No procedural schedule has been established. The PUCT approved recovery of $4.2 million of rate case expenses, with the distribution portion becoming effective with the April 2006 bills for a 3-year period.• TCC filed on 3-3-06 an application requesting to securitize $1.8 billion of regulatory assets, stranded costs and related carrying costs. Hearings before the Commissioners begin on May 25.

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
Total	**183,000**

Generating Capacity	**377 MW**

(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,500**
Distribution Miles	**12,000**

Principal industries served:

Agriculture and the manufacturing or processing of Cotton seed products

Oil products

Precision and consumer metal products

Meat products

Gypsum products

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data (in thousands)

Revenue	$	459,000
% of AEP Retail		1%
Net Income	$	33,000
Capital Expenditure	$	65,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,044,000
Net Plant Assets	$	807,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 72,500	$ 71,600	$ 89,400

AEP Texas North Company

AEP TEXAS NORTH
MAJOR CUSTOMERS

Chevron Texaco Corporation
Kinder Morgan
Occidental Permian Ltd.
Crown Cork & Seal Co., Inc
Rhodia Inc.
Plains All American Pipeline (Equilon)
Georgia-Pacific Corporation
Ethicon, Inc.
Wal-Mart Stores, Inc.
Tyson Foods Inc. (Wright Brand)

- **Top 10 customers = 32% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas North Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company **Texas North Company** **Southwestern Electric Power Company**

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup: R:** 3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

AEP Regulatory Status

• Operations for TCC and TNC have been functionally separated. Retail competition has been delayed by the PUCT in the Southwest Power Pool (SPP) area of Texas (including SWEPCO and TNC-SPP areas). • The results of TNC's true-up case were filed in TNC's Competition Transition Charge (CTC) proceeding in August 2005, which was abated in November 2005 pending resolution of the PUCT's ruling regarding off-system sales margins (see below). • TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Texas District Court affirmed PUCT on September 9, 2005. TNC and other parties filed appeals in the Court of Appeals for the Third District of Austin, Texas and briefs were submitted in early April. Parties are now awaiting an opinion from the Court. On September 29, 2005, the U.S. District Court issued a ruling precluding the PUCT from enforcing their ruling regarding the allocation of off-system sales margins. Parties have filed appeals of the U. S District Court ruling and briefs were filed on April 19, 2006.

Appalachian Power

President and Chief Operating Officer: Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 942,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

Principal industries served:

Coal mining
Primary metals
Chemicals
Textile mill products

Total Customers:	
• **Residential**	**804,000**
• **Commercial**	**126,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**941,000**
Generating Capacity	**6,389 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**79.4%**
• **Hydro/Pump:**	**12.5%**
• **Nat Gas**	**8.1%**
Transmission Miles	**6,700**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,947,075	1,360,131	3,307,206	1,995,658	1,427,502	3,423,160	2,345,511	1,821,484	4,166,995
% of Capitalization Per Balance Sheet	58.9%	41.1%	100.0%	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%
Adjusted Capitalization	1,947,075	1,360,131	3,307,206	2,004,550	1,418,610	3,423,160	2,354,403	1,812,593	4,166,996
% of Adjusted Capitalization	58.9%	41.1%	100.0%	58.6%	41.4%	100.0%	56.5%	43.5%	100.0%
FFO Interest Coverage			5.6			5.0			3.7
FFO Total Debt			27.2%			19.7%			12.4%

2005 Financial Data (in thousands)

Revenue	$	2,176,000
% of AEP Retail		17%
Net Income	$	131,000
Capital Expenditure	$	598,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	6,254,000
Net Plant Assets	$	4,652,000
Cash	$	1,741

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$942,800	$691,500	$751,700

Appalachian Power

APCo Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	32,901,943	29,551,752	32,949,364	31,801,020
Coal Consumption (tons burned)	13,015,569	11,604,352	13,187,986	12,602,636

Operating Information

2005 retail electric sales in megawatt-hours	30,327,723
2005 firm wholesale sales in megawatt-hours	2,480,850
Average cost per kilowatt-hour (residential)	5.41 cents
2005 System Peak	6,978 (January 24)

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES

West Virginia	Customers
APCo	**433,615**
Allegheny	485,295

Virginia	Customers
APCo	**496,994**
Dominion Virginia	2,131,281
Allegheny	92,878
Kentucky Utilities	29,801
Conectiv	21,529

Tennessee	Customers
APCo	**45,803**

TYPICAL BILL COMPARISON*

West Virginia	
APCo	**55.28**
AEP – Wheeling	**57.91**
Allegheny	70.09

Virginia	
APCo	**57.80**
ODPCo	58.07
Dominion Virginia	87.18
Conectiv	103.13

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

APPALACHIAN POWER COMPANY MAJOR CUSTOMERS

Massey Energy Company
CONSOL Energy
Roanoke Electric Steel Corporation
Georgia-Pacific Corporation
Elkem Metals Company
Greif Brothers Corporation
The Dow Chemical Co., Inc.
Arch Coal, Inc.
Dan River Inc.
Peabody Group

- **Top 10 Customers = 23% of industrial sales**
- **Metropolitan areas account for 37% of ultimate sales**
- **85 persons per square mile (U.S. = 95)**

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4476 of 9556

Regulatory Information

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Wheeling Power Co.
Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup R:** 1 **D:** 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office.

R. Michael Shaw, Commissioner (Rep.), since mid 2003, term expires June 2007. Attorney, former state legislator.

Jon W. McKinney, Chairman (Dem.), since 2005, term expires June, 2011. Formerly served as plant manager of Flexsys' Nitro, W Va operations, chairman of Chemical Industry Committee for W Va, board member of W Va Chamber of Commerce, W Va Manufacturer's Association, Chemical Alliance Zone, W Va Roundtable & Thomas Memorial Hospital.

AEP Regulatory Status

• Base rates not frozen • Annual ENEC proceedings are currently suspended. • On April 21, 2006 a settlement agreement in the AP & WP base rate case proceeding was filed with the WVPSC. Terms of the settlement agreement include: reinstatement of the ENEC with deferral accounting commencing July 1, 2006; creation of a surcharge mechanism to provide for timely recovery of a return on CWIP and a return of and on plant in service related to Wyoming-Jackson's Ferry and scrubbers at Mountaineer and Amos Units 1, 2 and 3, under such mechanism a $23.21 million surcharge to be recovered in rates effective July 28, 2006; and a base rate reduction of $18.43 million effective July 28. • On January 11, 2006, APCo filed an application with the WVPSC seeking authority to construct a 600 mw IGCCC plant.

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 1

<u>Qualifications for Commissioners</u>

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

<u>Commissioners</u>

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires February 2010. Current Chairman. Attorney, counsel to the Speaker of the House

Judith Williams Jagdmann, (Rep.), since 2006, current term expires 2012. Law degree from T.C. Williams School of Law. Prior to being elected to the Commission, she served as 43rd Attorney General for the Commonwealth of Virginia. Prior to work in Attorney in the Office of Attorney General, served 13 years as counsel to the SCC.

AEP Regulatory Status

• Capped rates for default customers frozen through end of 2010 • Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms • Active annual fuel clause. • On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental actual and projected costs for environmental compliance and T&D System reliability (E&R). In an order dated 10-14-05, the Commission denied the Company's request for interim rate treatment and ruled that the Company may only seek to include actually incurred costs (i.e., no projected future costs) in the E & R cost recovery filing. The Company filed supplemental direct testimony on 11-14-05, which included updated incremental costs through 9-30-05 of $21.1 million. Hearings concluded 3-01-06. Briefs were file in early April. • On May 4, 2006, APCo filed a general rate case requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). We are awaiting the issuance of the procedural schedule by the Commission.

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSP Co covers a service territory of 3,701 miles and at December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

Total Customers:

Residential	**636,000**
• **Commercial**	**71,000**
• **Industrial**	**3,000**
• **Other**	**300**
Total	**710,300**

Generating Cap **3,270 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **72.5%**
- **Natural Gas** **26.1%**
- **Hydro:** **1.5%**

Transmission Miles **2,200**

Distribution Miles **17,200**

Principal industries served:

Food processing
Chemicals
Primary metals
Electronic machinery
Paper products

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Capitalization Per Balance Sheet	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
Adjusted Capitalization	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Adjusted Capitalization	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
FFO Interest Coverage			7.7			6.2			5.8
FFO Total Debt			37.9%			28.7%			24.3%

2005 Financial Data (in thousands)

Revenue	$	1,542,000
% of AEP Retail		14%
Net Income	$	134,000
Capital Expenditure	$	165,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	3,433,000
Net Plant Assets	$	2,526,000
Cash	$	940

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$342,700	$473,700	$553,400

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	15,243,711	14,049,095	14,038,045	14,443,617
Coal Consumption (tons burned)	6,526,167	6,121,275	6,048,060	6,231,834

Operating Information

2005 retail sales in megawatt-hours	18,277,372
2005 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	7.56 cents (CSP)
2005 System Peak	4,105 megawatts (CSP-July 25)

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,260	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	627	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

Columbus Southern Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

COLUMBUS SOUTHERN POWER MAJOR CUSTOMERS

The Ohio State University
State of Ohio
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
The Kroger Company
Nationwide Insurance Enterprise
Ohio University
Griffin Wheel Company
OhioHealth
Limited Brands

- **Top 10 customers = 31% of industrial sales**
- **Metropolitan areas account for 84% of ultimate sales**
- **244 persons per square mile (U.S. = 95)**

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.
Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications,

Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

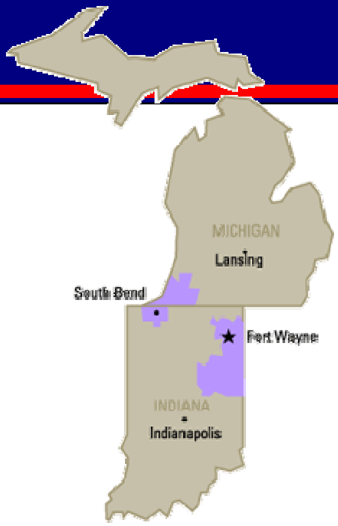
Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

AEP Regulatory Status

• Pursuant to RSP Plan approved by PUCO 1-26-05: • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008. • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs. • CSP "G" rates to increase 3% per year (2006-2008). • OP "G" rates to increase 7% per year (2006-2008). • Transmission rates can upon filing reflect change in RTO costs. • No active fuel clause • Application for IGCC plant recovery filed on 3-18-05. On 4-10-06, PUCO issued the IGCC order providing for recovery of Phase 1 costs and requiring additional hearings before issuing an order on recovery of costs to be incurred in Phases 2 and 3. Companies filed compliance tariffs to implement Phase I cost recovery on April 20.• On 2-3-06, CSP and OP filed for a change to retail tariffs to reflect the increased FERC approved OATT and to defer for future recovery unrecovered transmission costs as a result of the loss of SECA revenues effective 4-1-06 if new rates do not go into effect by that time. In March, the PUCO suspended the effective date of the new rates to provide more time for review. We are awaiting an order.• On 2-6-06, the PUCO directed Staff to conduct an investigation of reliability related matters of CSP and OP. On April 17, 2006, the staff submitted a PUCO – ordered investigative report on the Ohio Companies' compliance with the Stipulation Agreement in which they asserted that the Ohio companies failed to fulfill the terms of the Stipulation Agreement and recommend various consequences for PUCO consideration. On May 3, the PUCO directed AEP to file a response to the possible consequences outlined in the Staff report within 20 days. In addition, they directed the Companies to begin to develop a plan to enhance service reliability for their consideration.

Indiana Michigan Power



President and Chief Operating Officer:
Marsha Ryan

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 581,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2005, I&M had 2,633 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

Principal industries served:
Primary metals
Transportation equipment
Electrical and electronic machinery
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers:

• **Residential**	**507,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**580,000**

Generating Capacity **5,768 MW**
(includes AEG Rockport)

Generating Capacity by Fuel Mix:

- **Coal:** **62.5%**
- **Nuclear:** **37.1%**
- **Hydro:** **0.4%**

Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana *Michigan Power*

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,438,181	1,149,593	2,587,774	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%
Adjusted Capitalization	1,823,681	1,149,593	2,973,274	1,761,432	1,095,540	2,856,972	1,921,435	1,224,134	3,145,569
% of Adjusted Capitalization	61.3%	38.7%	100.0%	61.7%	38.3%	100.0%	61.1%	38.9%	100.0%
FFO Interest Coverage			4.0			4.1			4.7
FFO Total Debt			22.70%			23.20%			22.80%

2005 Financial Data (in thousands)

Revenue	$	1,893,000
% of AEP Retail		13%
Net Income	$	146,000
Capital Expenditure	$	299,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	5,238,000
Net Plant Assets	$	3,116,000
Cash	$	854

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 311,200	$ 278,700	$ 262,000

Indiana Michigan *Power*

I&M Generation Production Statistics – 2003 – 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Avg.**
MWh Produced	28,075,125	21,258,001	31,535,226	26,956,117
Coal Consumption (tons burned)	7,189,655	7,186,066	7,011,370	7,129,030

Operating Information

2005 retail electric sales in megawatt-hours	19,248,200
2005 firm wholesale sales in megawatt-hours	2,169,221
Average cost per kilowatt-hour (residential)	6.61 cents
2005 System Peak	4,193 MW (August 3)

Indiana Michigan Power			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville	Mottville	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES

Indiana	
I&M	**452,050**
IP & L	458,796
NIPSCO	442,554
Cinergy (PSI)	747,696
SIGECO	135,449

Michigan	Customers
I&M	**124,583**
CMS (Consumers)	1,760,882
DTE (Detroit Edison)	2,144,655

TYPICAL BILL COMPARISON*

Indiana	
I & M	**68.94**
IP & L	70.50
Cinergy (PSI)	79.53
SIGECo	88.67

Michigan	
I & M	**61.43**
Consumers Energy	82.97
Detroit Edison	93.80

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

INDIANA MICHIGAN POWER
MAJOR CUSTOMERS

Steel Dynamics Inc.
Mittal Steel Company
Air Products & Chemicals, Inc.
Boc Gases
Saint Gobain Corporation USA
Ball State University
New Energy Corp
Dock Foundry
Michelin North America, Inc.
Guide Indiana

- **Top 10 Customers = 39% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Number: 5	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup: R** 3 **D:** 2

Qualifications for Commissioners

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four year, staggered terms, full time positions. Not more than three of the members of the IURC be members of the same political party. At lease one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

Commissioners

David L. Hardy, Chairman (Rep.), since September 2005, current term will expire April 2006. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas o expertise include: negotiation, contracts, litigation, finance and administration. He has 35 years regulatory experience at the state and federal levels.

Larry S. Landis, Commissioner (Rep.), since December 2002, current term ends January 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.

David W. Hadley, Commissioner (Dem.), since 2000; current term ends January 2006. Executive officer for Indiana AFL CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.

Greg Server, Commissioner (Rep.), since September 2005, current term ends in April 2009. Former state senator since 1981 and before that served in the Indiana House or Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.

David E. Ziegner, Commissioner (Dem.), since 1990, current term ends April 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.

- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through 6-30-07. • On 12/31/05 the company filed a petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service. This petition is not a request for a change in base rates, but for book depreciation rate decreases primarily as a result of longer depreciable property lives. Based on the depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 million on an after-tax Indiana jurisdictional basis.
- Remaining procedural schedule has been set with an order expected in 3rd Quarter 2006.

Regulatory Information

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup:** :1 **D:** 2

<u>Qualifications for Commissioners</u>

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

<u>Commissioners</u>

<u>J. Peter Lark, Chair, (Dem)</u> since July 2003: current term expires July 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney.

<u>Laura Chappelle, Commissioner, (Rep.)</u> since 2001: current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney.

<u>Monica Martinez, Commissioner, (Dem)</u> since 2005, current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues.

AEP Regulatory Status

Customer choice began 1/02. Generation was not deregulated. Retail rates were unbundled (though they continue to be regulated) to allow customers to evaluate generation costs. Michigan has an active annual fuel clause.

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,000**
• **Other**	**400**
Total	**175,400**

Generating Capacity	**1,060 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**1,200**
Distribution Miles	**10,000**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Capitalization Per Balance Sheet	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
Adjusted Capitalization	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Adjusted Capitalization	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
FFO Interest Coverage			4.7			3.9			3.4
FFO Total Debt			20.4%			16.6%			14.0%

2005 Financial Data (in thousands)

Revenue	$	531,000
% of AEP Retail		4%
Net Income	$	21,000
Capital Expenditure	$	57,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,320,000
Net Plant Assets	$	989,000
Cash	$	526

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$100,000	$127,100	$144,000

Kentucky Power

Kentucky Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	6,170,931	6,550,509	7,345,624	6,689,021
Coal Consumption (tons burned)	2,513,524	2,607,559	2,926,253	2,682,445

Operating Information

2005 retail electric sales in megawatt-hours	7,309,016
2005 firm wholesale sales in megawatt-hours	97,845
2005 average cost per kilowatt-hour (residential)	5.67 cents
2005 System Peak	1,685 MW (Jan 24)

Kentucky Power Plants			
Name	Location	Megawatt Capacity	Fuel
Big Sandy #1, 2	**Louisa, Kentucky**	**1,060**	**Coal**

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Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	Customers
KPCo	**174,631**
Kentucky Utilities	485,627
LG & E	389,196

TYPICAL BILL COMPARISON*

Kentucky	
KPCo	**59.78**
Kentucky Utilities	62.40
LG&E	66.31
CIN	68.54

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

KENTUCKY POWER MAJOR CUSTOMERS

Marathon Ashland Petroleum
AK Steel Holding Corporation
James River Coal Co.
Massey Energy Company
TECO Energy, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC.
Alliance Coal, LLC
Consol Energy
Weyerhaeuser Company

- **Top 10 customers = 61% of industrial sales**
- **Metropolitan areas account for 42% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Regulatory Information

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>
Three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.

<u>Commissioners</u>

Mark Goss (Chair) (Rep.), since 2004; current term expires June 2007. Attorney in private practice.

Teresa Hill (V. Chair.) (Rep.), since 2005; current term expires June 30, 2009. Served on the Governor's Executive Staff. She is an attorney.

Greg Coker (Rep.), since 2004; current term expires June 30, 2008. Formally V.P. External Affairs at ALLTEL; public policy positions at Bell South.

AEP Regulatory Status

• Fuel clause, adjusted monthly • Environmental surcharge costs are adjusted monthly for approved environmental compliance plan • On 9-26-05 the Company filed a base rate case requesting a $64.8 million annual increase. A settlement agreement was approved by the Commission on 3/14/06; terms include a $41 million increase effective 3-30-06.

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2005, OPCo had 2,220 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Principal industries served:

Primary metals
Rubber and plastic products
Stone, clay, glass and concrete products
Petroleum refining
Chemicals

Total Customers:

• **Residential**	**610,000**
• **Commercial**	**90,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**709,000**

Generating Capacity	**8,952 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **94.6%**
- **Hydro:** **5.4%**

Transmission Miles	**6,500**
Distribution Miles	**26,000**

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,082,195	1,487,920	3,570,115	2,053,641	1,490,479	3,544,120	2,280,107	1,784,586	4,064,693
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	57.9%	42.1%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,082,195	1,487,920	3,570,115	2,061,962	1,482,159	3,544,121	2,288,427	1,776,267	4,064,694
% of Adjusted Capitalization	58.3%	41.7%	100.0%	58.2%	41.8%	100.0%	56.3%	43.7%	100.0%
FFO Interest Coverage			6.5			4.9			6.2
FFO Total Debt			28.3%			22.6%			23.8%

2005 Financial Data (in thousands)

Revenue	$	2,635,000
% of AEP Retail		17%
Net Income	$	245,000
Capital Expenditure	$	711,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	6,331,000
Net Plant Assets	$	4,785,000
Cash	$	1,240

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 1,070,400	$ 954,500	$ 581,600

Ohio Power

Ohio Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	53,099,905	52,156,749	52,080,585	52,445,746
Coal Consumption (tons burned)	20,936,936	20,534,361	20,382,116	20,617,804

Operating Information

2004 retail sales in megawatt-hours	28,929,494
2004 firm wholesale sales in megawatt-hours	2,225,194
Average cost per kilowatt-hour (residential)	6.56 cents (OPCo)
2004 System Peak	5,638 megawatts (OPCo-Aug 12)

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	48	Hydro

Ohio Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison = 162,117
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2004 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

OHIO POWER
MAJOR CUSTOMERS

Century Aluminum Company
The Timken Company
Wheeling Pittsburgh – WHX HQ
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Globe Metallurgical, Inc
Marathon Petroleum Company LLC
Duke Energy Corp
Linde Gas
Owens Corning Fiberglas Corp.

OPCo:

- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 52% of ultimate sales**
- **135 persons per square mile (U.S. = 95)**

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.
Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications,

Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

AEP Regulatory Status

• Pursuant to RSP Plan approved by PUCO 1-26-05: • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008. • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs. • CSP "G" rates to increase 3% per year (2006-2008). • OP "G" rates to increase 7% per year (2006-2008). • Transmission rates can upon filing reflect change in RTO costs. • No active fuel clause • Application for IGCC plant recovery filed on 3-18-05. On 4-10-06, PUCO issued the IGCC order providing for recovery of Phase 1 costs and requiring additional hearings before issuing an order on recovery of costs to be incurred in Phases 2 and 3. Companies filed compliance tariffs to implement Phase I cost recovery on April 20.• On 2-3-06, CSP and OP filed for a change to retail tariffs to reflect the increased FERC approved OATT and to defer for future recovery unrecovered transmission costs as a result of the loss of SECA revenues effective 4-1-06 if new rates do not go into effect by that time. In March, the PUCO suspended the effective date of the new rates to provide more time for review. We are awaiting an order.• On 2-6-06, the PUCO directed Staff to conduct an investigation of reliability related matters of CSP and OP. On April 17, 2006, the staff submitted a PUCO – ordered investigative report on the Ohio Companies' compliance with the Stipulation Agreement in which they asserted that the Ohio companies failed to fulfill the terms of the Stipulation Agreement and recommend various consequences for PUCO consideration. On May 3, the PUCO directed AEP to file a response to the possible consequences outlined in the Staff report within 20 days. In addition, they directed the Companies to begin to develop a plan to enhance service reliability for their consideration.

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 514,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2005, PSO had 1,176 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

Total Customers:

• **Residential**	**442,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**7,000**
Total	**514,000**

Generating Capacity	**4,153 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **25%**
- **Natural Gas:** **75%**

Transmission Miles	**3,600**
Distribution Miles	**21,000**

Principal industries served:

Natural gas and oil production
Oil refining
Steel processing
Aircraft maintenance
Paper manufacturing and timber products
Glass
Chemicals
Cement
Plastics
Aerospace manufacturing
Telecommunications
Rubber goods

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	607,162	488,275	1,095,437	601,095	534,517	1,135,612	646,954	553,858	1,200,812
% of Capitalization Per Balance Sheet	55.4%	44.6%	100.0%	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%
Adjusted Capitalization	607,162	488,275	1,095,437	603,726	531,886	1,135,612	649,585	551,228	1,200,813
% of Adjusted Capitalization	55.4%	44.6%	100.0%	53.2%	46.8%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			3.8			5.5			2.8
FFO Total Debt			20.4%			28.2%			9.5%

2005 Financial Data (in thousands)

Revenue	$	1,304,000
% of AEP Retail		14%
Net Income	$	58,000
Capital Expenditure	$	134,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	2,355,000
Net Plant Assets	$	1,819,000
Cash	$	1,520

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 278,700	$ 342,800	$ 408,700

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Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	14,845,846	12,512,486	15,375,848	14,244,727
Coal Consumption (tons burned)	4,678,950	4,093,436	4,353,364	4,375,250

Operating Information

2005 retail electric sales in megawatt-hours	17,782,561
2005 firm wholesale sales in megawatt-hours	45,172
Average cost per kilowatt-hour (residential)	7.55 cents
2005 System Peak	4,043 MW (July 22)

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	338	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	Customers
PSO	507,214
OG&E	**668,766**

PUBLIC SERVICE COMPANY OF OKLAHOMA MAJOR CUSTOMERS

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Transok Inc
AMR Corporation
Sunoco Inc.
Terra Nitrogen Limited Partner
Republic Paperboard
Wal-Mart Stores, Inc.

TYPICAL BILL COMPARISON*

Oklahoma		
OG&E	**73.33**	
PSO	**74.20**	
SPSCo	**82.52**	
Empire District	**85.25**	

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **46 persons per square mile (U.S. = 95)**

Regulatory Information

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: **3**	**Appointed / Elected:** Elected	Term**: 6 years**	Political Makeup: **R: 3**

<u>Qualifications for Commissioners</u>

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

<u>Commissioners</u>

Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

Denise A. Bode, Vice-Chairman (Rep.), since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

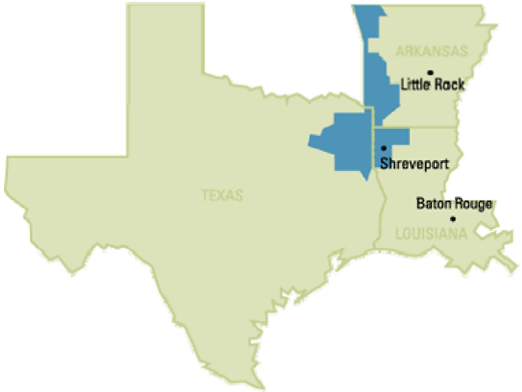
Bob Anthony, Commissioner (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

AEP Regulatory Status

• 2001 Fuel review case: Hearings held 2-7 and 2-8-06. Scope expanded to cover 2002-2004 margin allocation issue.Intervenors have submitted testimony, which substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error. Awaiting Commission order. • 2003 Fuel review case: Scope has been expanded to include a prudence review. No procedural schedule has been set. Discovery phase has been initiated. • 2004 Fuel review case: Staff has now filed for a review of PSO's 2004 fuel costs. Hearings scheduled to begin 8-10-06. Discovery phase has been initiated. • Applications seeking a used and useful determination for up to 500 mW of peaking capacity with a commercial operation date of 2008 and up to 600 mW of base load generation with a commercial operation date of 2011 were filed with the OCC on 12-21-05 and 2-1-06, respectively. Procedural schedules have not yet been established.

Southwestern Electric Power

President and Chief Operating Officer: Nick Akins



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 450,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2005, SWEPCo had 1,498 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

Total Customers:

• **Residential**	**381,000**
• **Commercial**	**61,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**450,000**

Generating Capacity **4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite:** **60%**
- **Natural Gas:** **40%**

Transmission Miles **3,500**

Distribution Miles **19,300**

Principal industries served:

Natural gas and oil production
Petroleum refining
Manufacturing of pulp and paper
Chemicals
Food processing
Metal refining.

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	890,675	701,360	1,592,035	806,494	773,318	1,579,812	774,245	787,077	1,561,322
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	51.0%	49.0%	100.0%	49.6%	50.4%	100.0%
Adjusted Capitalization	890,675	701,360	1,592,035	808,844	770,968	1,579,812	776,595	784,727	1,561,322
% of Adjusted Capitalization	55.9%	44.1%	100.0%	51.2%	48.8%	100.0%	49.7%	50.3%	100.0%
FFO Interest Coverage			4.1			5.7			3.8
FFO Total Debt			22.9%			31.4%			18.1%

2005 Financial Data (in thousands)

Revenue	$ 1,405,000
% of AEP Retail	12%
Net Income	$ 74,000
Capital Expenditure	$ 158,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 2,797,000
Net Plant Assets	$ 2,230,000
Cash	$ 3,049

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 287,900	$ 366,700	$ 458,400

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	20,539,365	20,071,578	20,167,754	20,259,566
Coal Consumption (tons burned)	12,536,179	13,032,475	12,420,979	12,663,211

Operating Information

2005 retail electric sales in megawatt-hours	17,069,455
2005 firm wholesale sales in megawatt-hours	5,554,340
Average cost per kilowatt-hour (residential)	6.92 cents
2005 System peak	4725 MW (Aug 23)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES

Arkansas	Customers
SWEPCO	**107,220**
Entergy AR	667,714

Louisiana	Customers
SWEPCO	**169,079**
CLECO	261,601

Texas	Customers
SWEPCO	**279,729**

TYPICAL BILL COMPARISON*

Arkansas	
SWEPCO	**66.15**
OG&E	**72.11**
Empire District	**74.71**
ETR	**88.92**

Louisiana	
SWEPCO	**68.83**
CLECO	90.13
Entergy Gulf St	92.69
Entergy NO	96.65
Entergy LA	102.08

Texas	
SWEPCO	**63.95**
SPSCo	83.19
ETR	93.43
EP	106.64
TXU	118.84

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

Lone Star Steel Company
Tyson Foods Inc
Domtar, Inc
International Paper Company
Pilgrim Pride Corporation
Calumet Lubricants
General Motors Corporation
Wal-Mart Stores, Inc.
Cooper Tire & Rubber Company
Superior Industries Int

- **Top 10 customers = 38% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **77 persons per square mile (U.S. = 95)**

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

<u>Commissioners</u>

Sandra Hochstetter, Chairman (Rep.), since 1999; current term ends Jan 2011. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.

Randy Bynum, Commissioner (Rep.), since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.

Daryl E. Bassett, Commissioner (Rep.), since 2004; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

AEP Regulatory Status

Arkansas has an active fuel pass-through clause, adjusted annually. Base rates not frozen. Arkansas passed then repealed deregulation legislation.

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected:** Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 3

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

James M. Field, (Rep.), since 1996; current term ends December 2006. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

AEP Regulatory Status

• Base rates not frozen • Currently under a merger required financial review • Fuel clause, adjusted monthly

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: **3**	Appointed/Elected: **Appointed**	Term: **6 years**	Political Makeup: R:3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

AEP Regulatory Status

- Retail competition has been delayed by the PUCT in the SPP area of Texas until at least 2007.Texas SWEPCO has an active fuel pass-through clause. On 1-12-06, PUCT approved a Settlement in the SWEPCO Fuel Factor/Surcharge filing. The stipulated fuel factors will increase SWEPCO's annual Texas retail fuel-related revenues by approximately $46 million. The interim surcharge will collect the under-recovery amount of $44 million (including interest).

AMERICAN ELECTRIC POWER

CHICAGO INVESTOR MEETINGS

Hosted by Jefferies

September 8, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

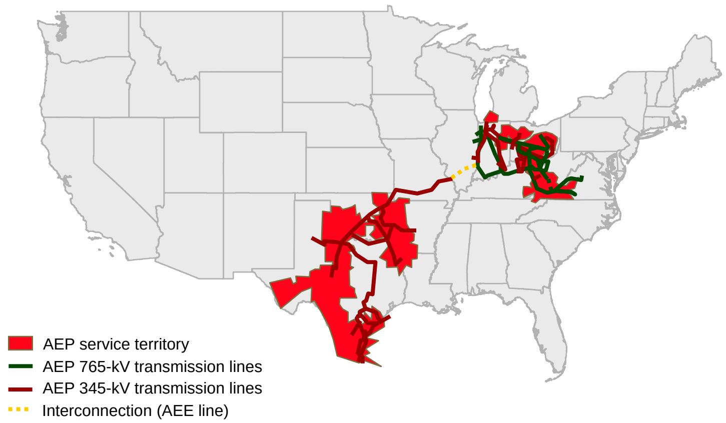
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

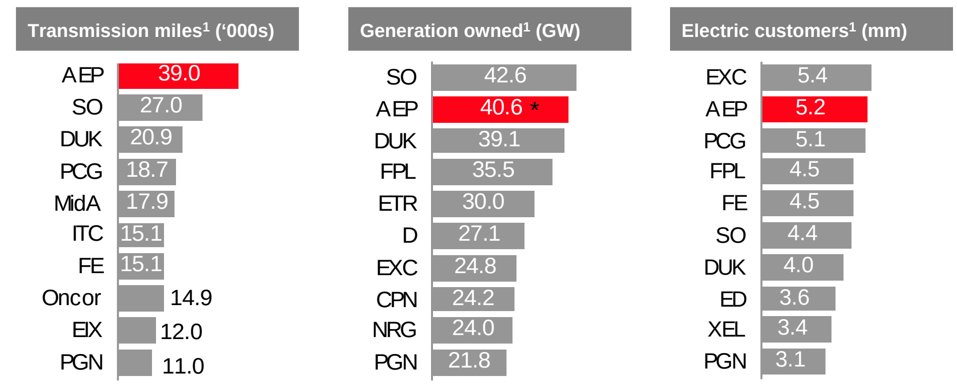
AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

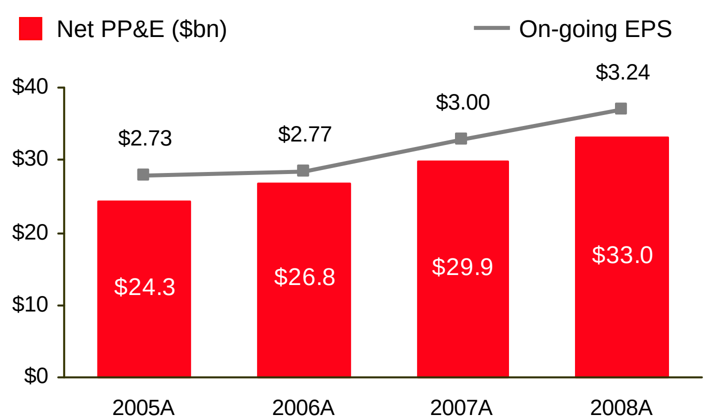


AEP's Leadership Position

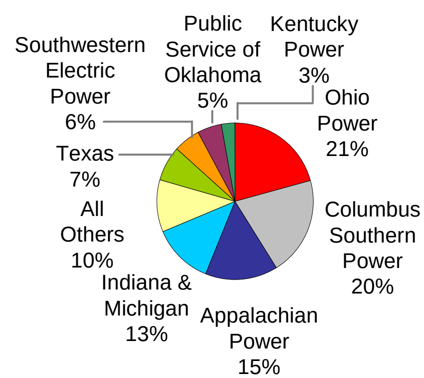


* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn

- *Highly diversified regulated utility earnings contribution*

¹ Source: Company filings

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4516 of 9556

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

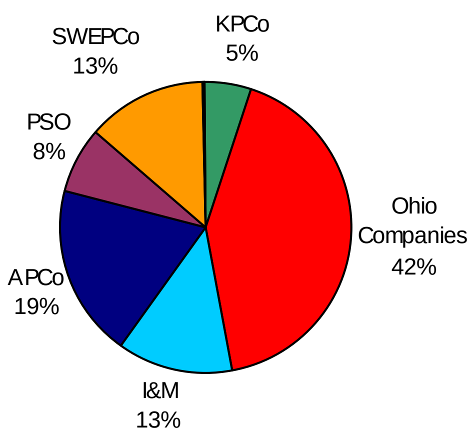
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

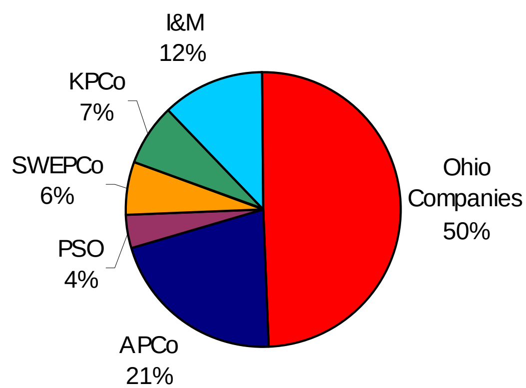
AEP AMERICAN ELECTRIC POWER

CO_2 Cost Recovery – Should Follow SO_2 & NOx

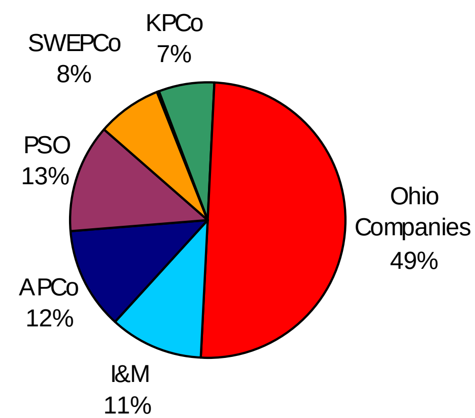
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



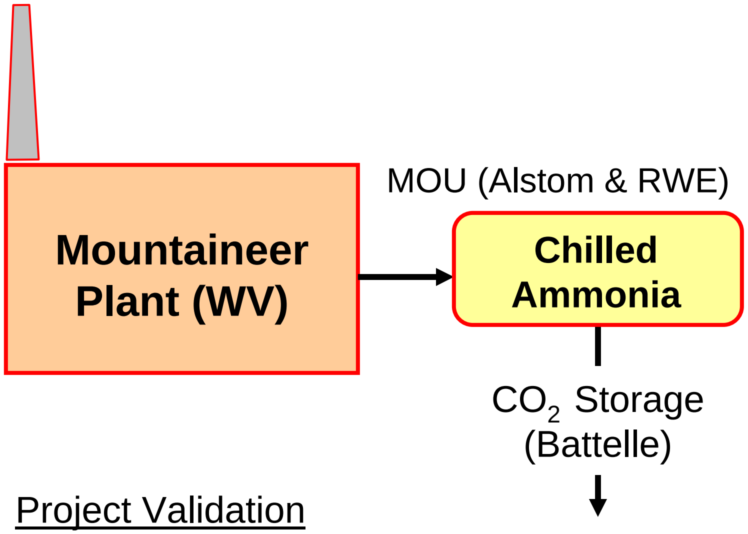
2008 AEP System NOx Emissions
248k tons



- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

17

Carbon Capture & Storage



Project Validation

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **Operations commenced September 2009**
- **Geologic storage for CO_2**
- **Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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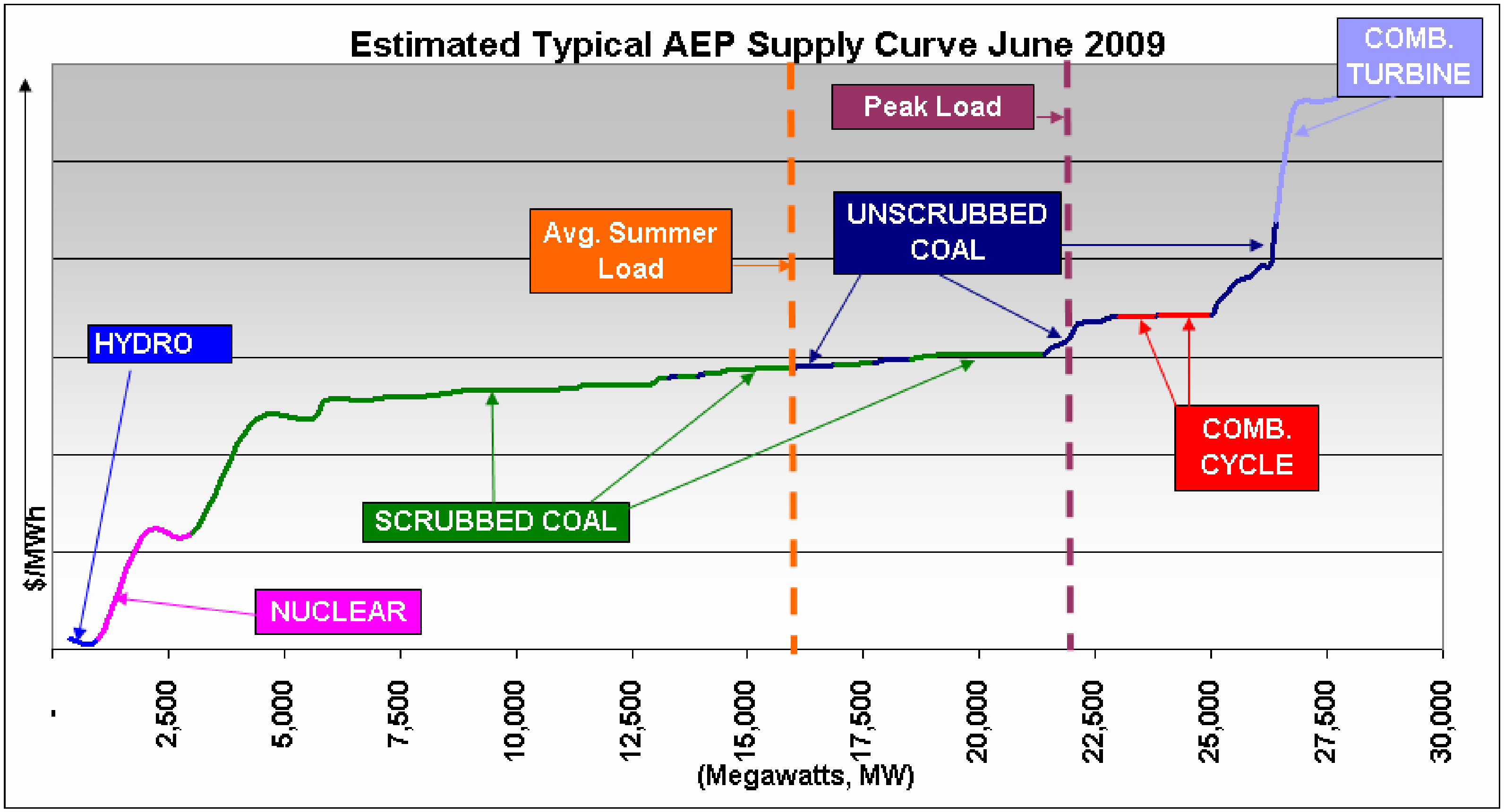
AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.

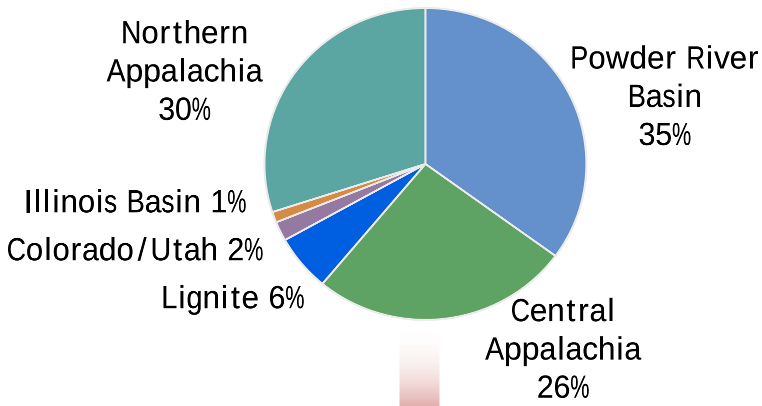


AMERICAN ELECTRIC POWER

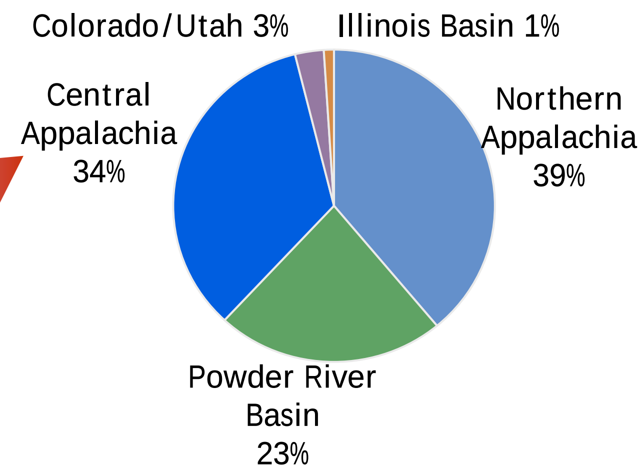
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

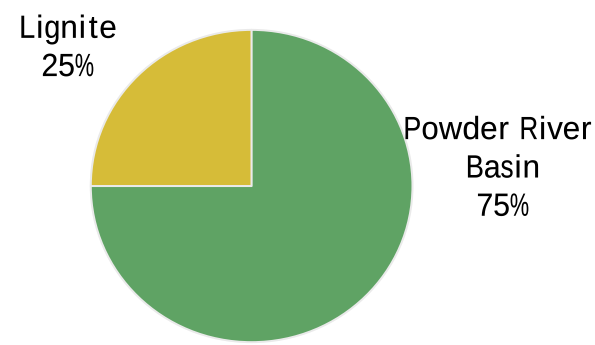
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

AEP AMERICAN ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

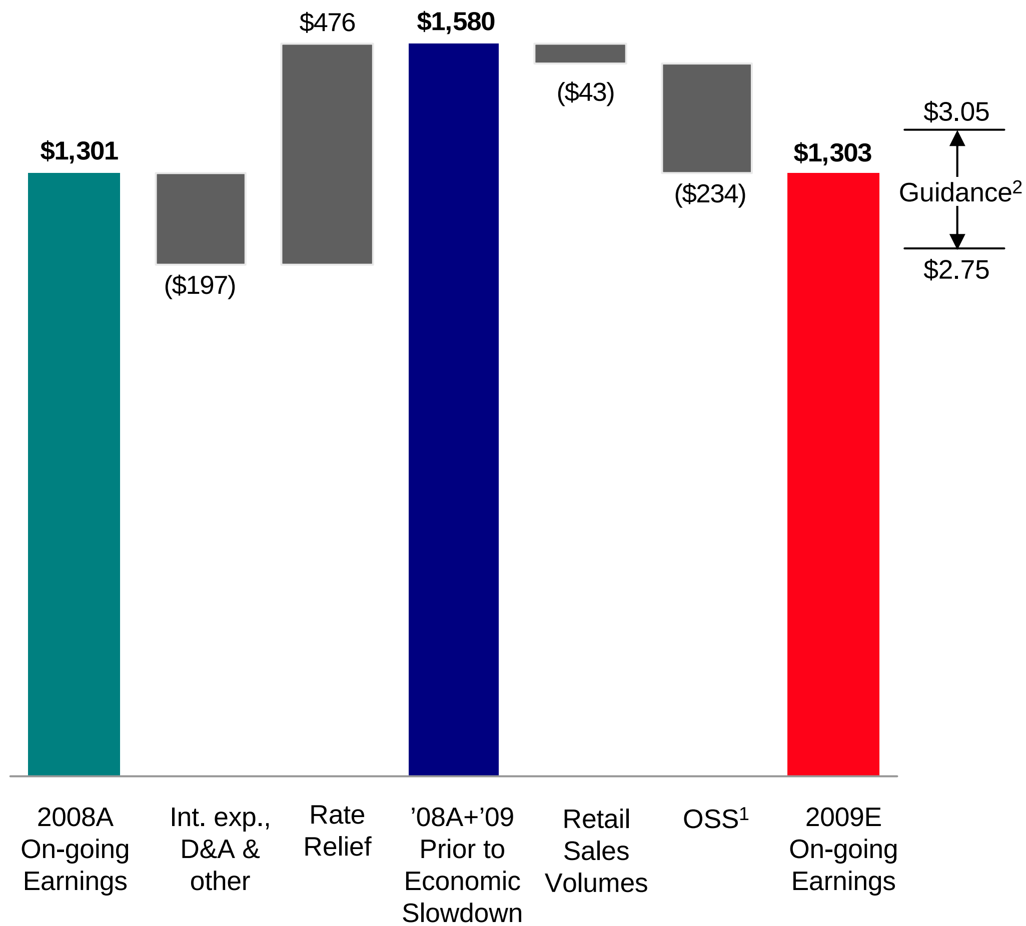
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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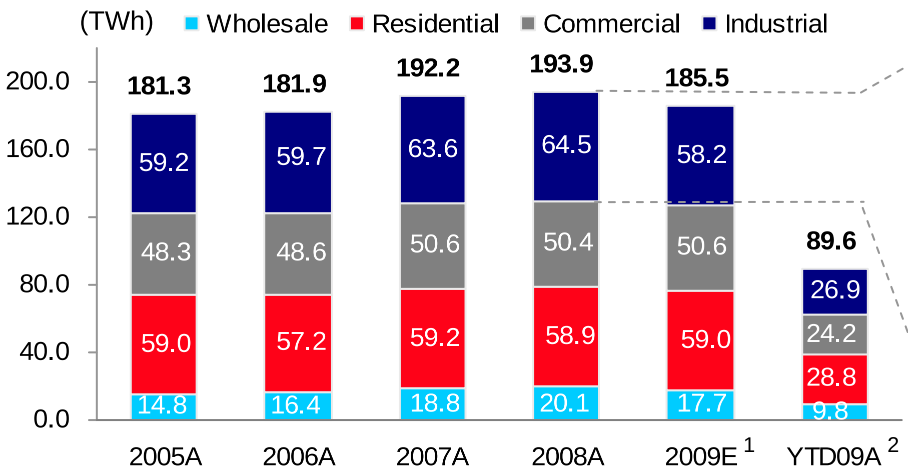
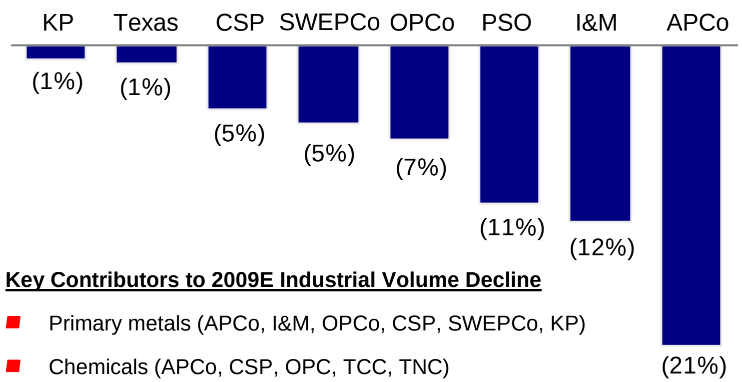
Key Drivers of 2009 Guidance: Retail Sales

Retail Load by Customer Class



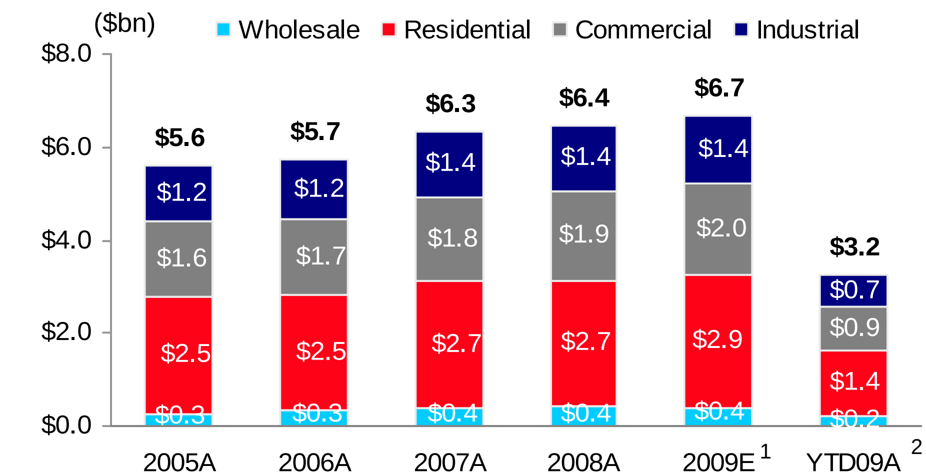
Forecast Drop in 2009 Industrial Sales

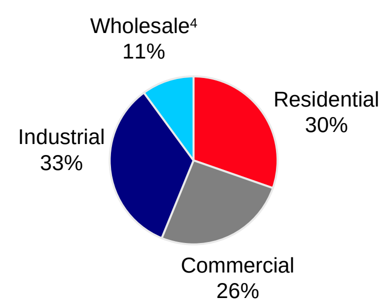


Key Contributors to 2009E Industrial Volume Decline

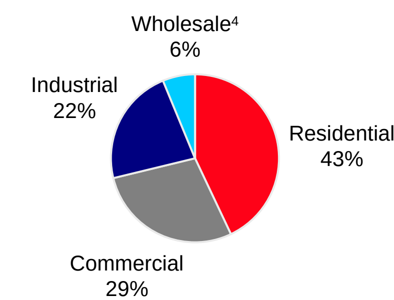
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Chemicals (APCo, CSP, OPC, TCC, TNC)
- Paper (APCo, PSO, SWEPCo)
- Plastics & Rubber (APCo, CSP, OPCo, I&M)

Retail Base Revenue[3] by Customer Class





2008 Retail Load = 193.9 TWh



2008 Retail Base Revenue [3] = $6.4bn

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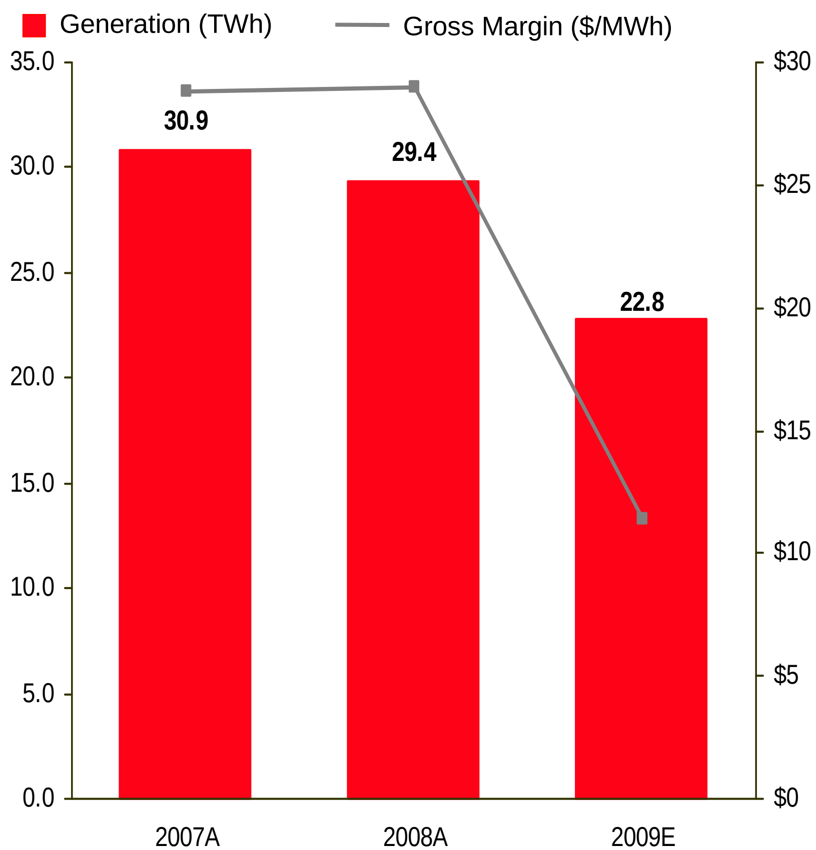
[1] 2009E assumes normalized weather
[2] YTD09A represents actual results through June 30, 2009

[3] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables
[4] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

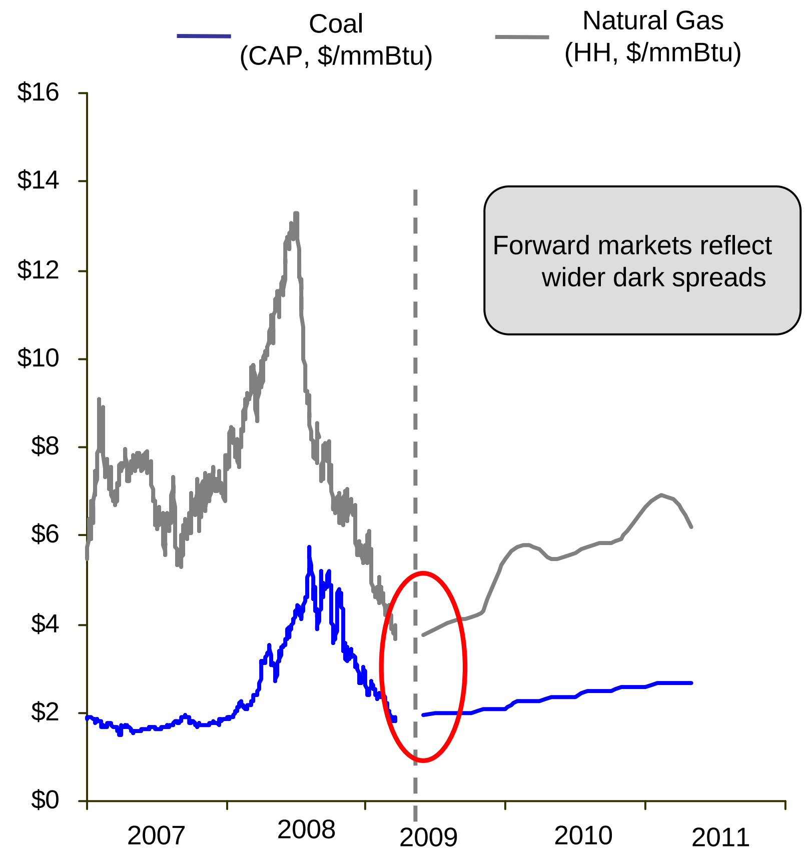
Key Drivers of 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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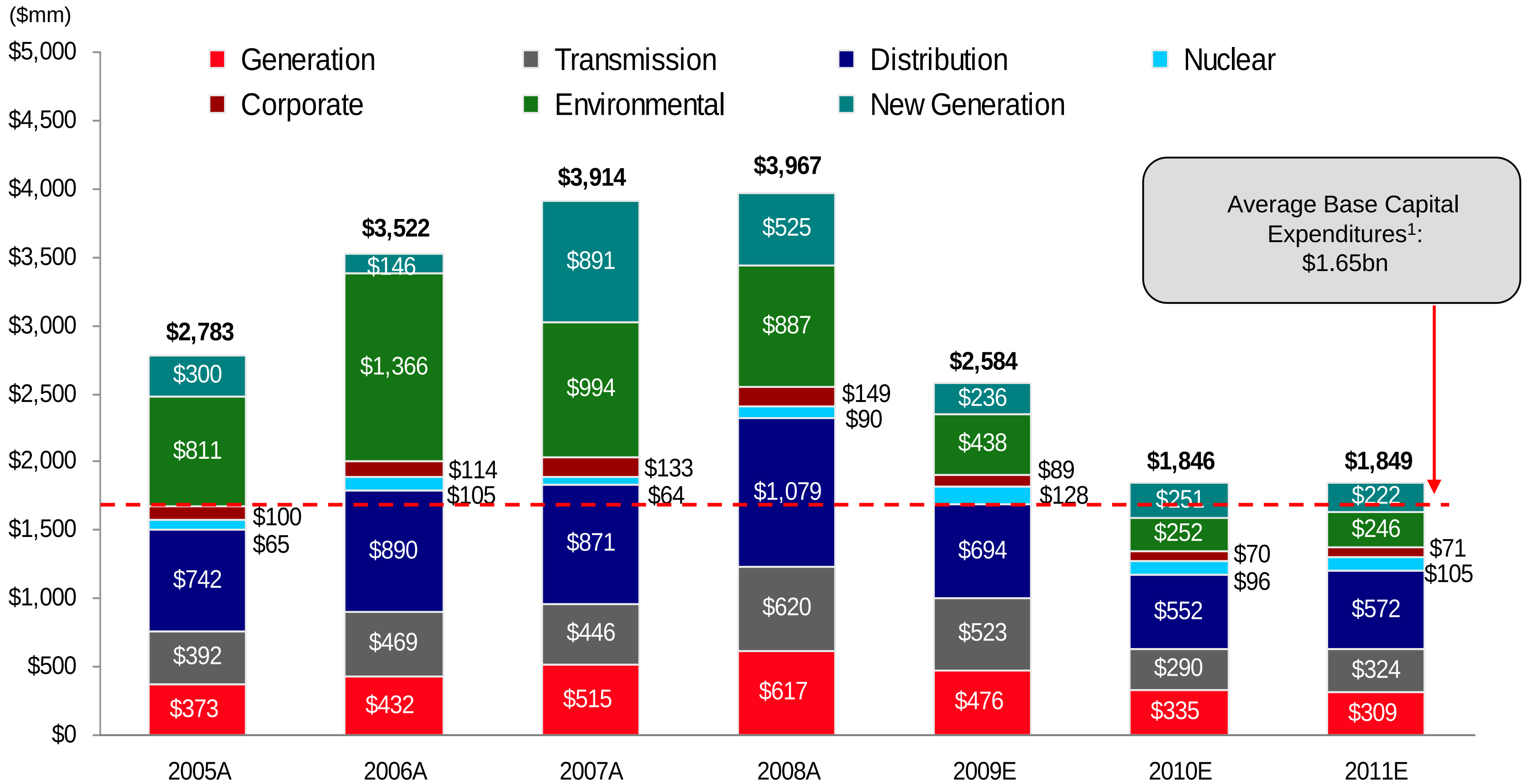
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



	2005A	2006A	2007A	2008A	2009E	2010E	2011E
Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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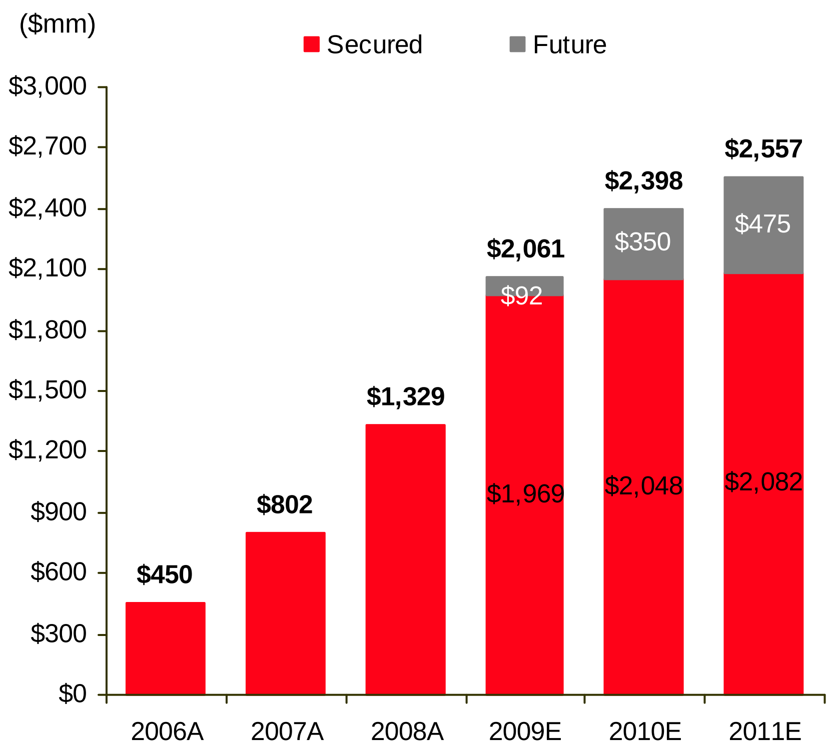
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



	2006A	2007A	2008A	2009E	2010E	2011E
Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $79mm and $38mm was secured for 2010 and 2011, respectively, as of August 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ APCo VA ($178MM)
  - ✓ PSO ($30MM)
  - ✓ SWEPCo AR ($54MM) TX ($75MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009		2010		2011		Cumulative	
	ESP Appl.	PUCO Rehearing Order	ESP Appl.	PUCO Rehearing Order	ESP Appl.	PUCO Rehearing Order	ESP Appl.	PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC

- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030) A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

December 12, 2009	Rates Effective, Subject to Refund
December 28, 2009	Intervenor Testimony due
January 27, 2010	Staff Testimony due
February 17, 2010	APCo Rebuttal Testimony due
March 16, 2010	Hearing Commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

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Summary Rate Case Information

SWEPCo Texas General Rate Case

On August 28, 2009 SWEPCo filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to recover concurrent financing costs related to the construction of the Stall and Turk plants as well as increased operating costs and enhanced distribution reliability spending. (Docket# 37364) An order is expected in 2010.

Projected Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule TBD

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recovery Riders	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

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Long-term Debt Maturity Profile

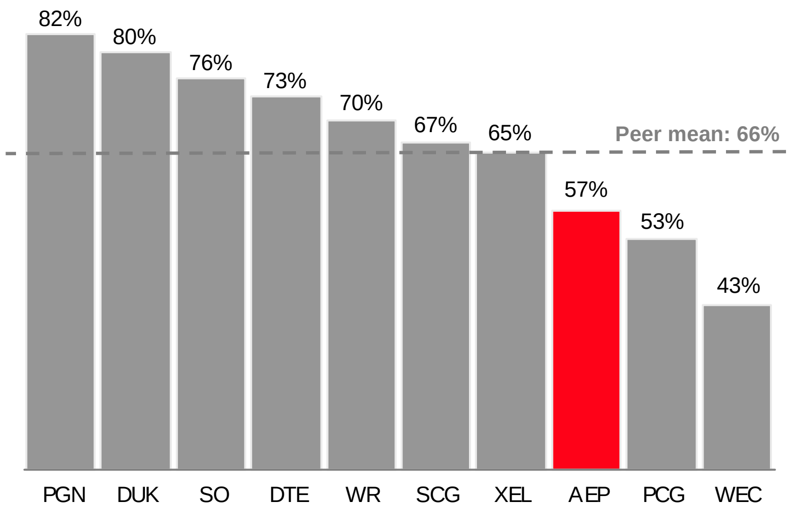
($ in millions)
(as of June 30, 2009)

Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

Dividend Overview

- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

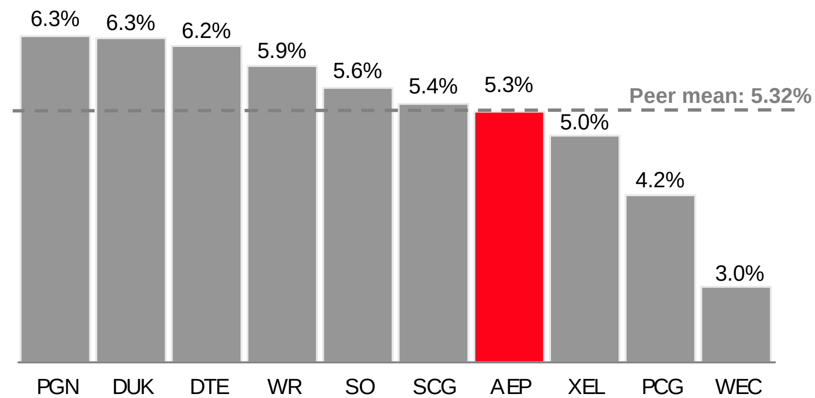
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 9/1/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 9/1/09

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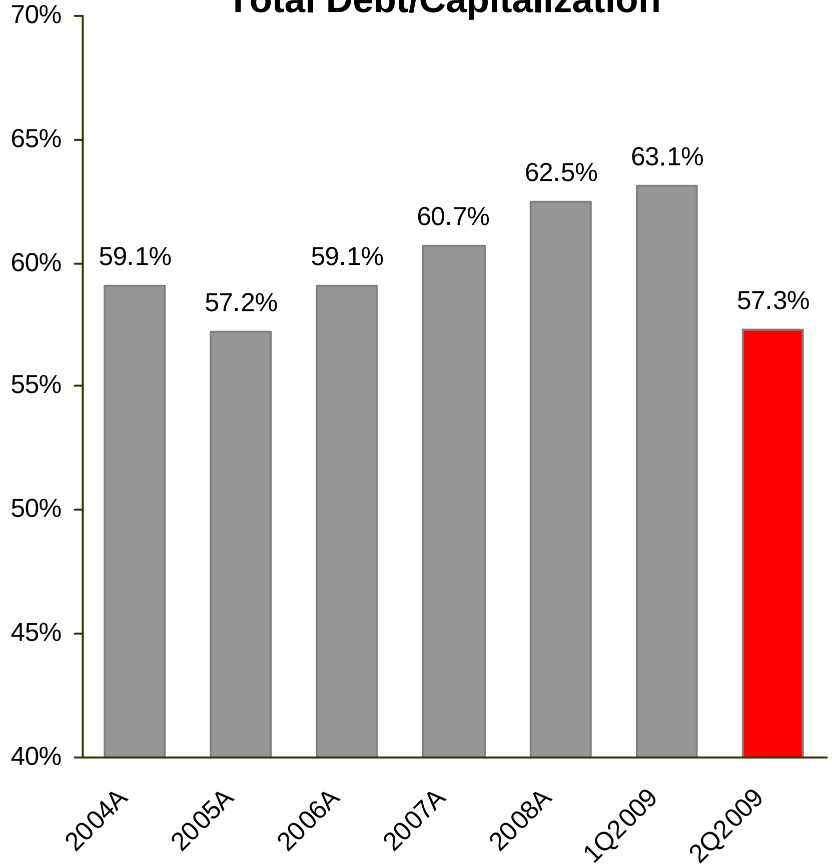
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 6/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

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Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

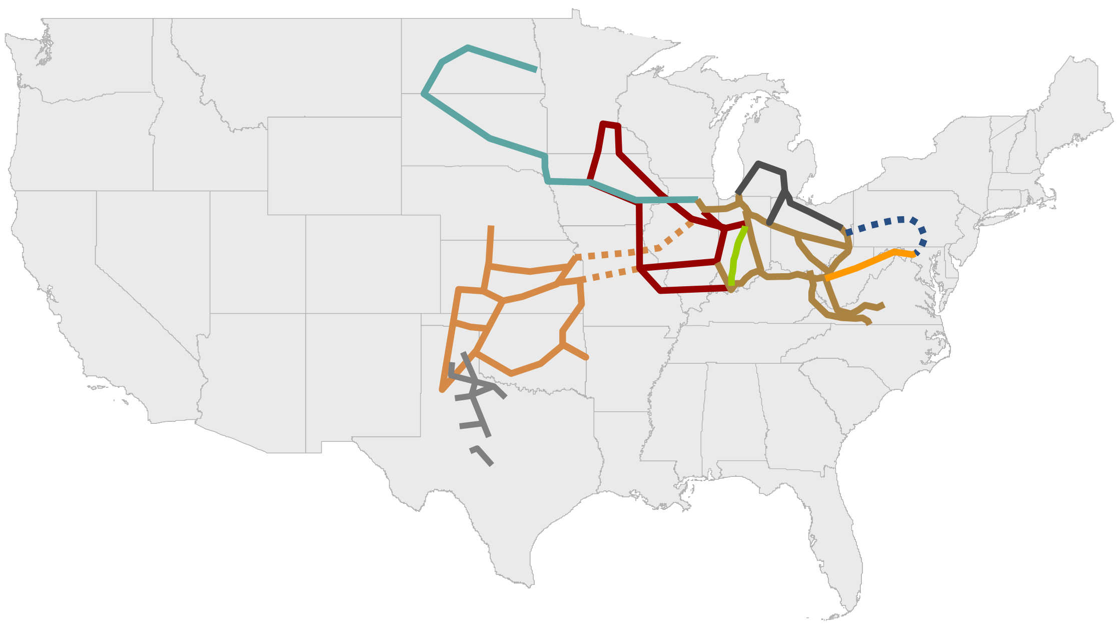
Pioneer — **COD: 2015**
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013**
- *110 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

ETT — **COD: 2013**
- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**
- *700 miles of 765 kV*

PJM Projects
- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**
- *1000+ miles of 765 kV*

MISO Vision Plan
- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**
- *765 kV Backbone*

ETT — **COD: ~2018**
- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

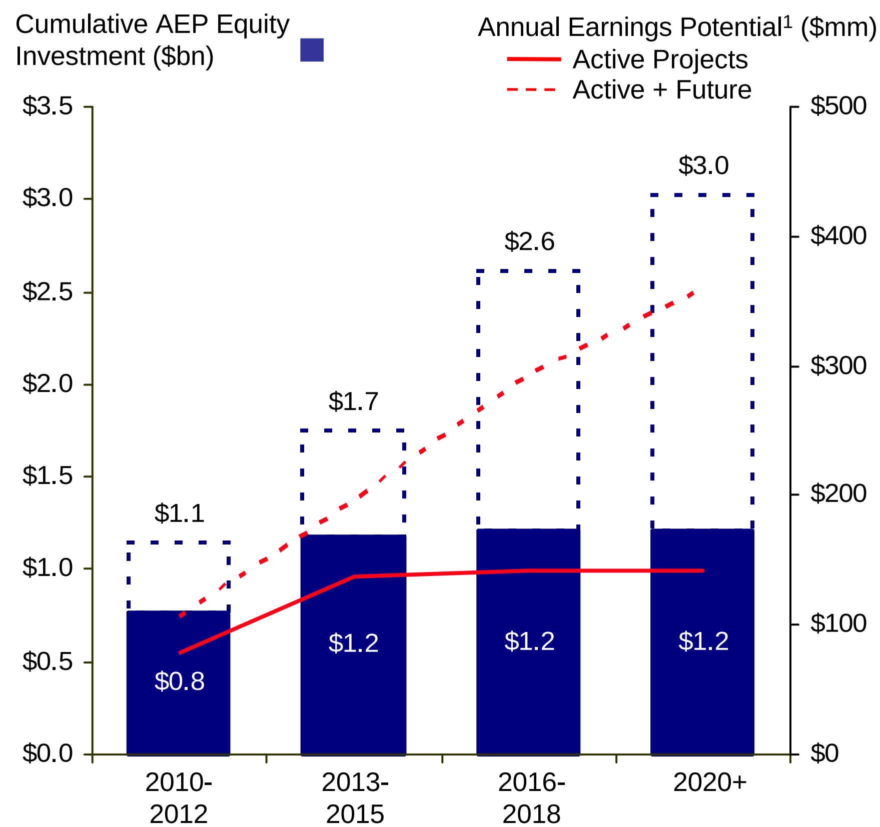
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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Chicago Investor Meetings

June 30, 2005

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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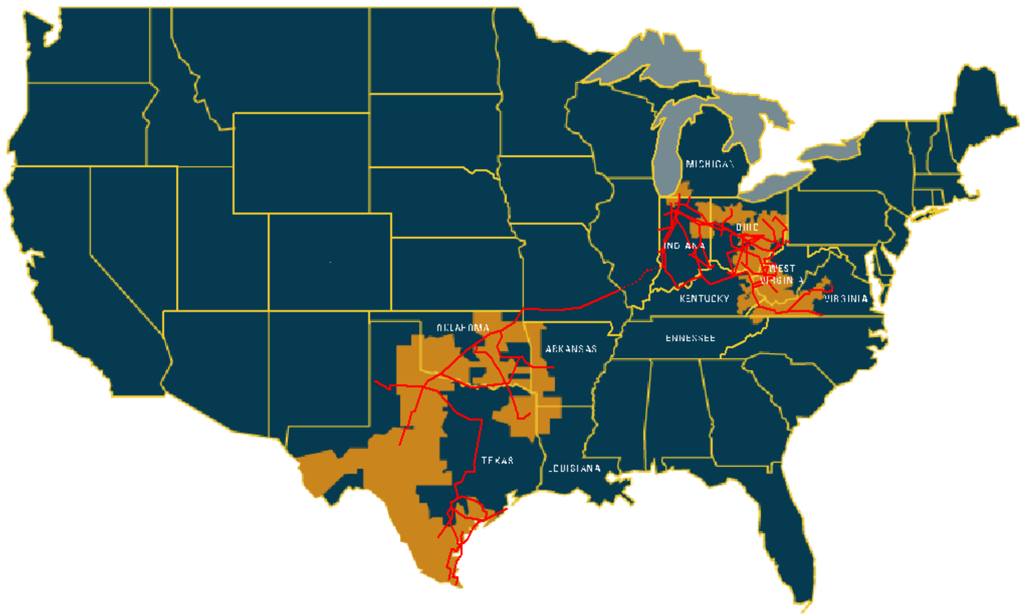
Chairman, President & Chief Executive Officer

3

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4541 of 9556

Asset Portfolio

Strength & Scale in Assets & Operations



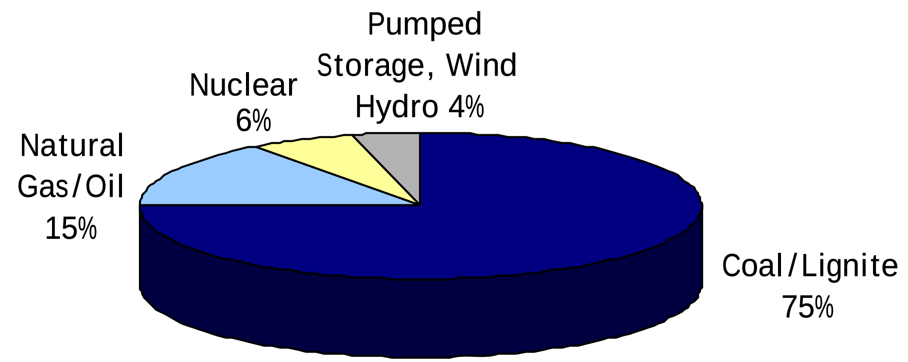
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

Capacity by Fuel Mix

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

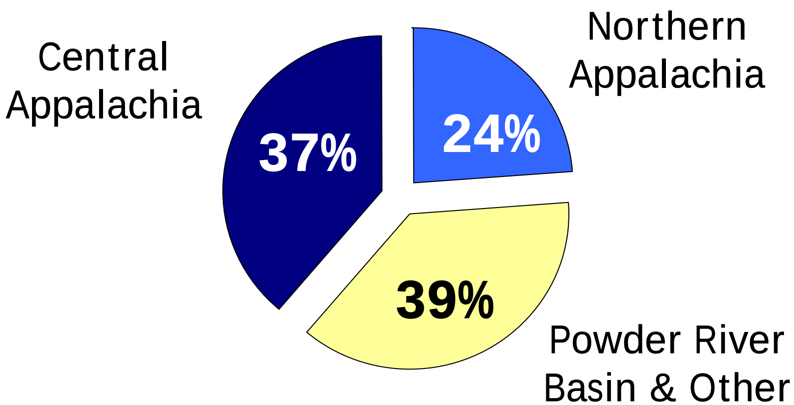
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Coal Procurement

AEP SYSTEM

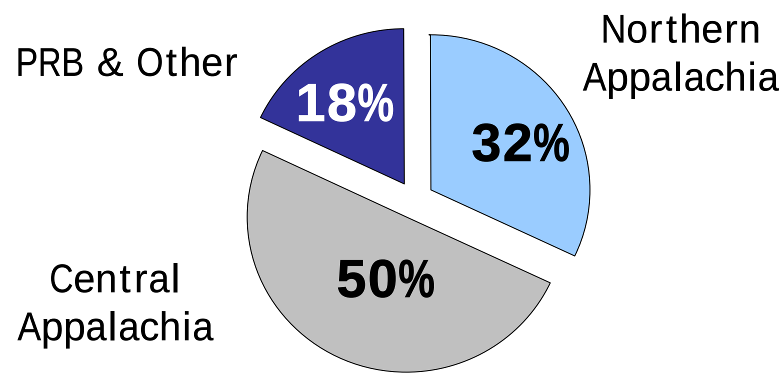


Coal Supply

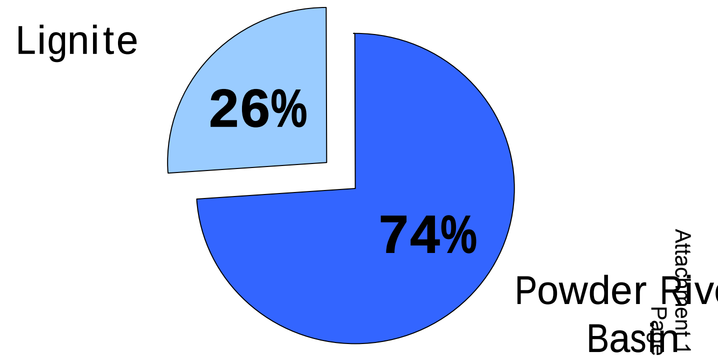
(on average)

- ➢Purchase 75 MM tons per year
- ➢Avg. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM

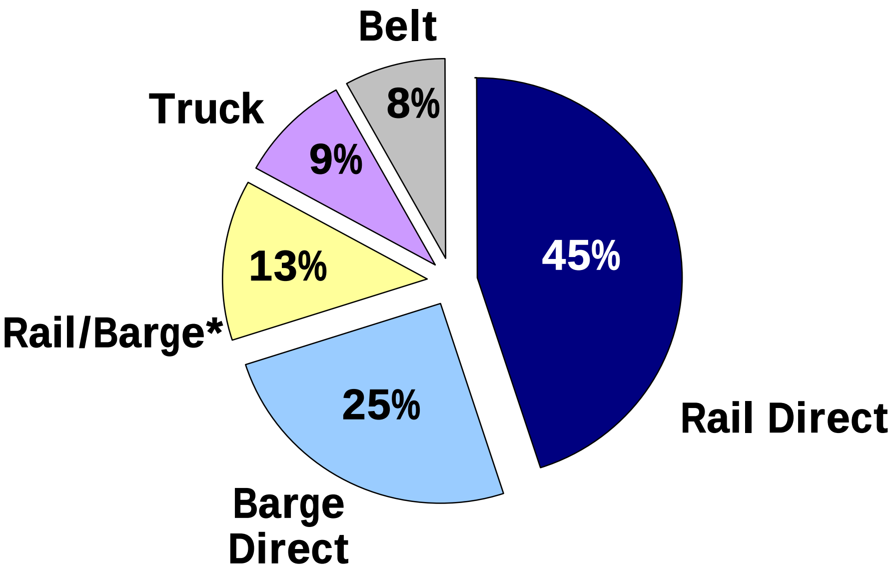


WESTERN SYSTEM

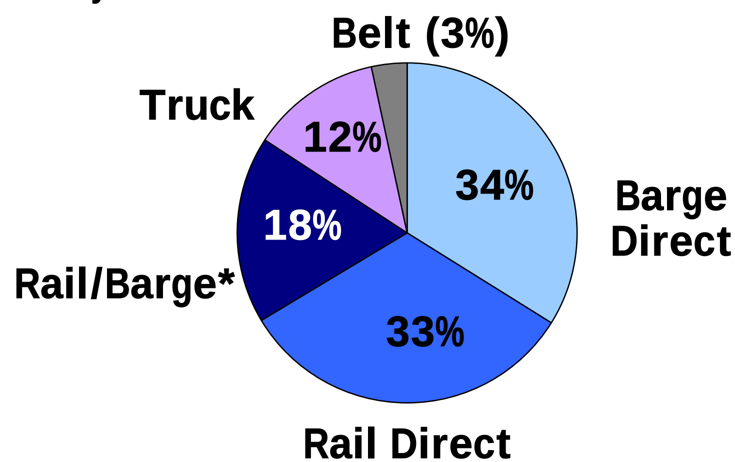


Coal Delivery Mix

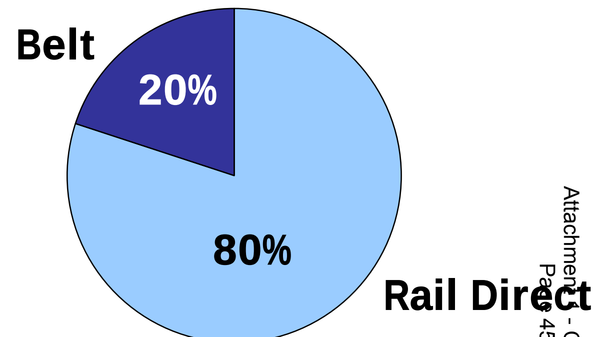
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-May 2005 Actual



EASTERN SYSTEM
Jan-May 2005 Actual



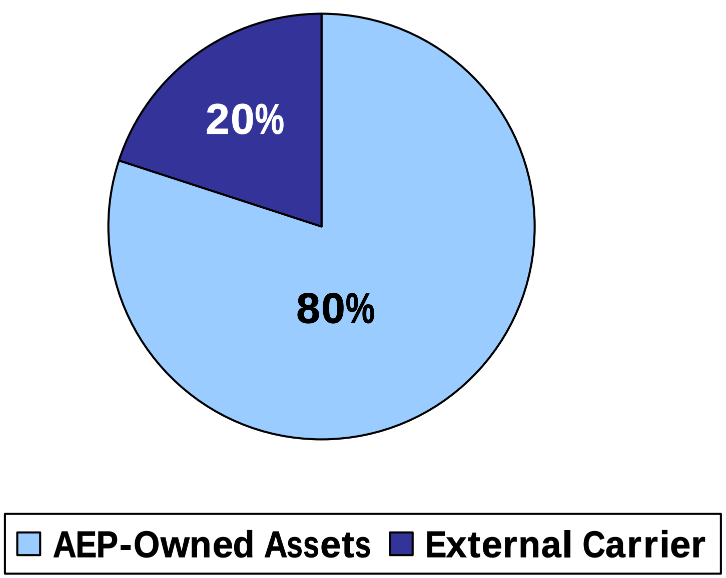
WESTERN SYSTEM
Jan-May 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-May 2005 Actual



* Represents close approximations

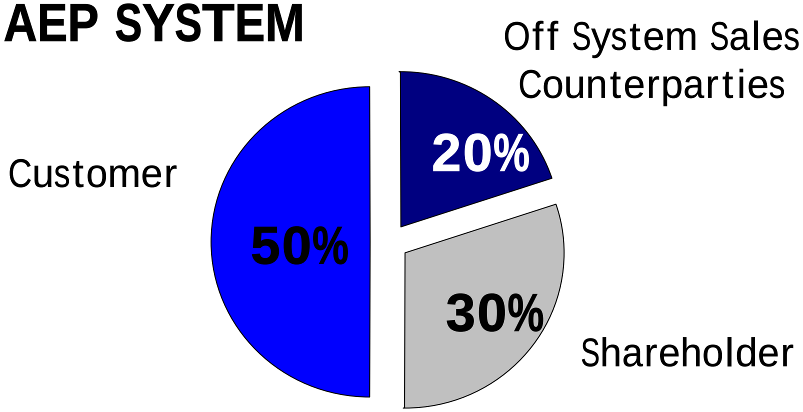
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM

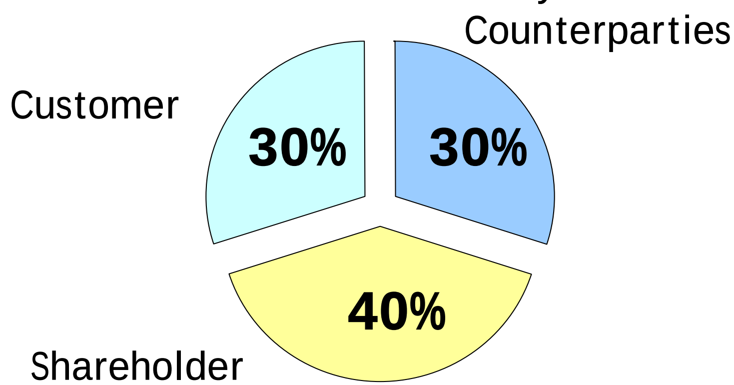


Fuel Cost Recovery
(on average)

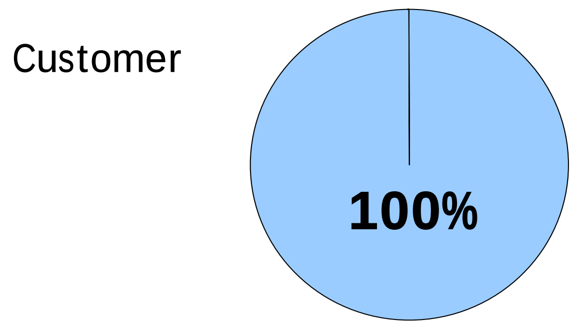
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



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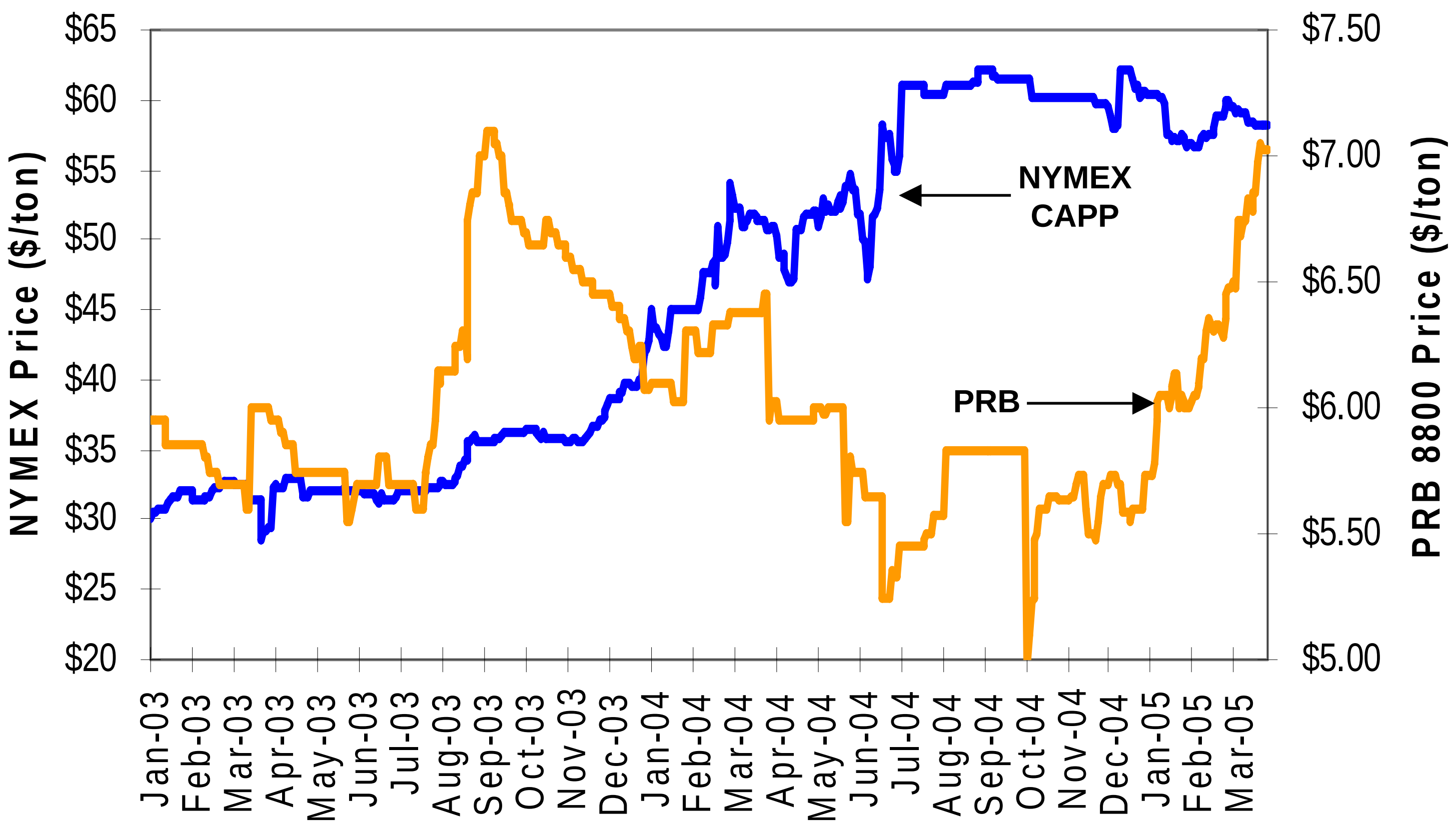
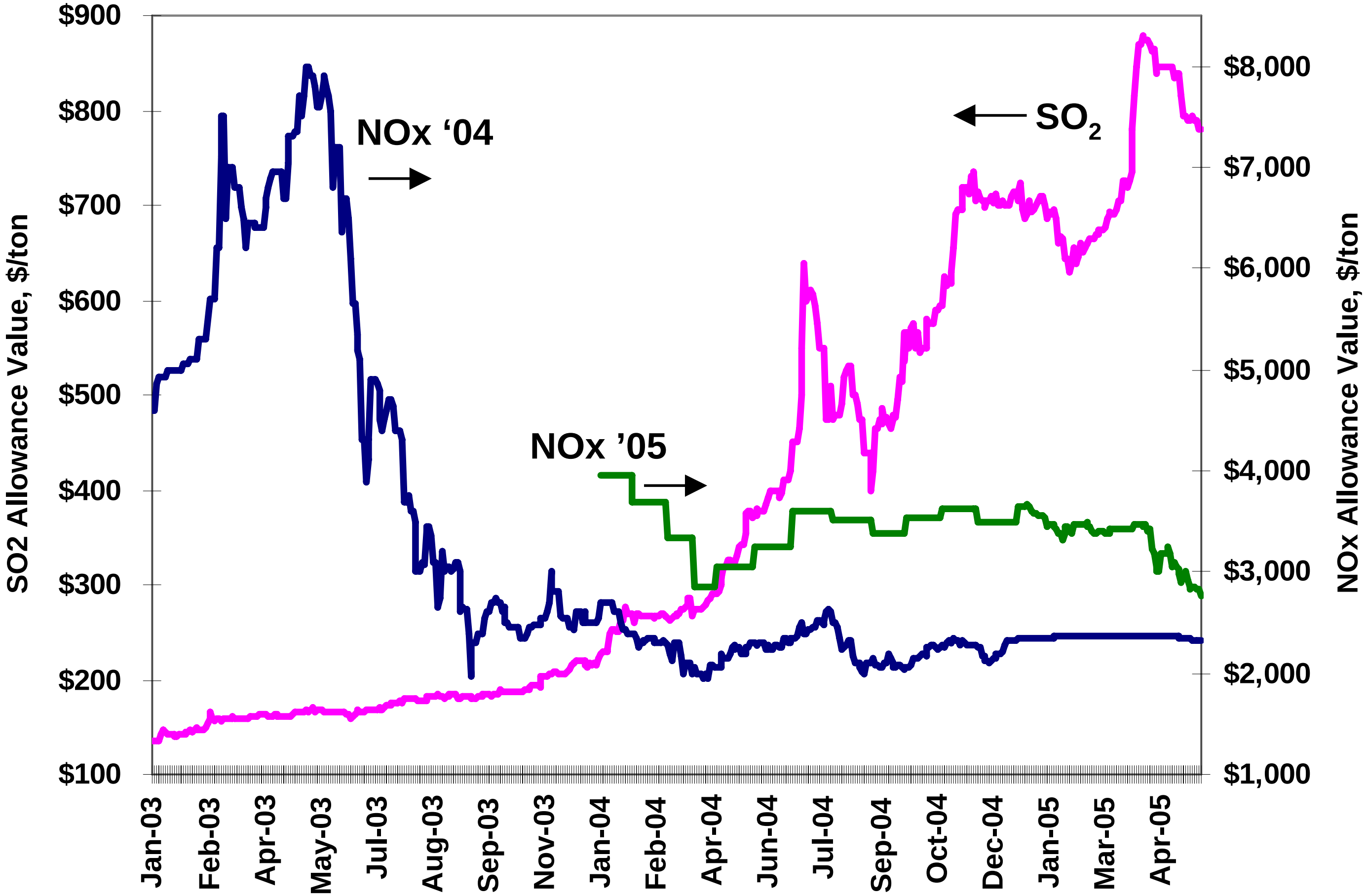
Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited “immediate” substitution capability (PRB) but gaining strength



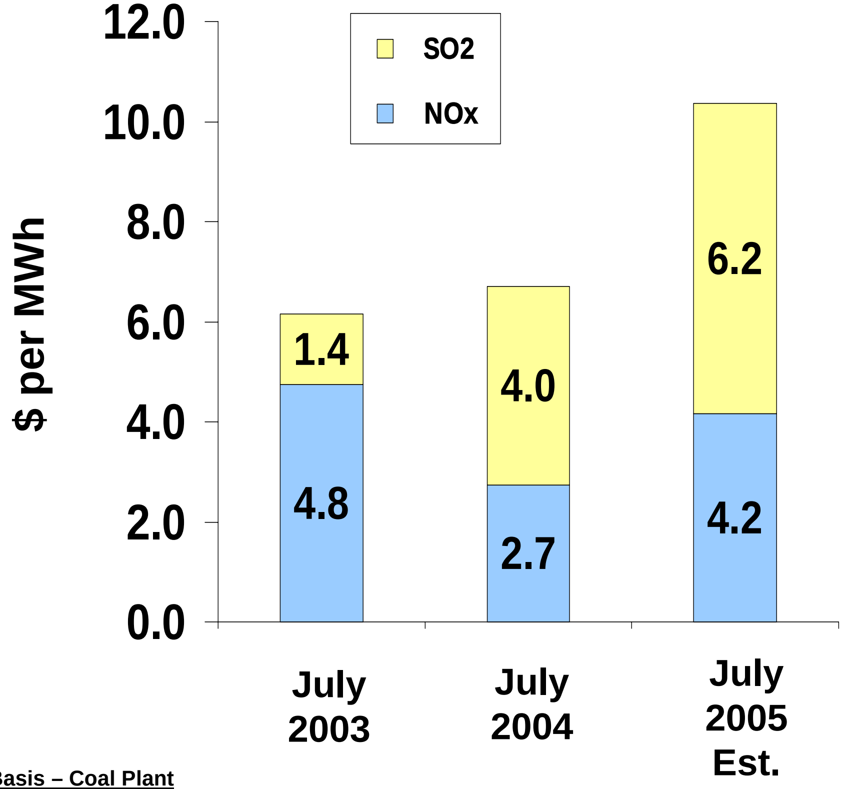
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



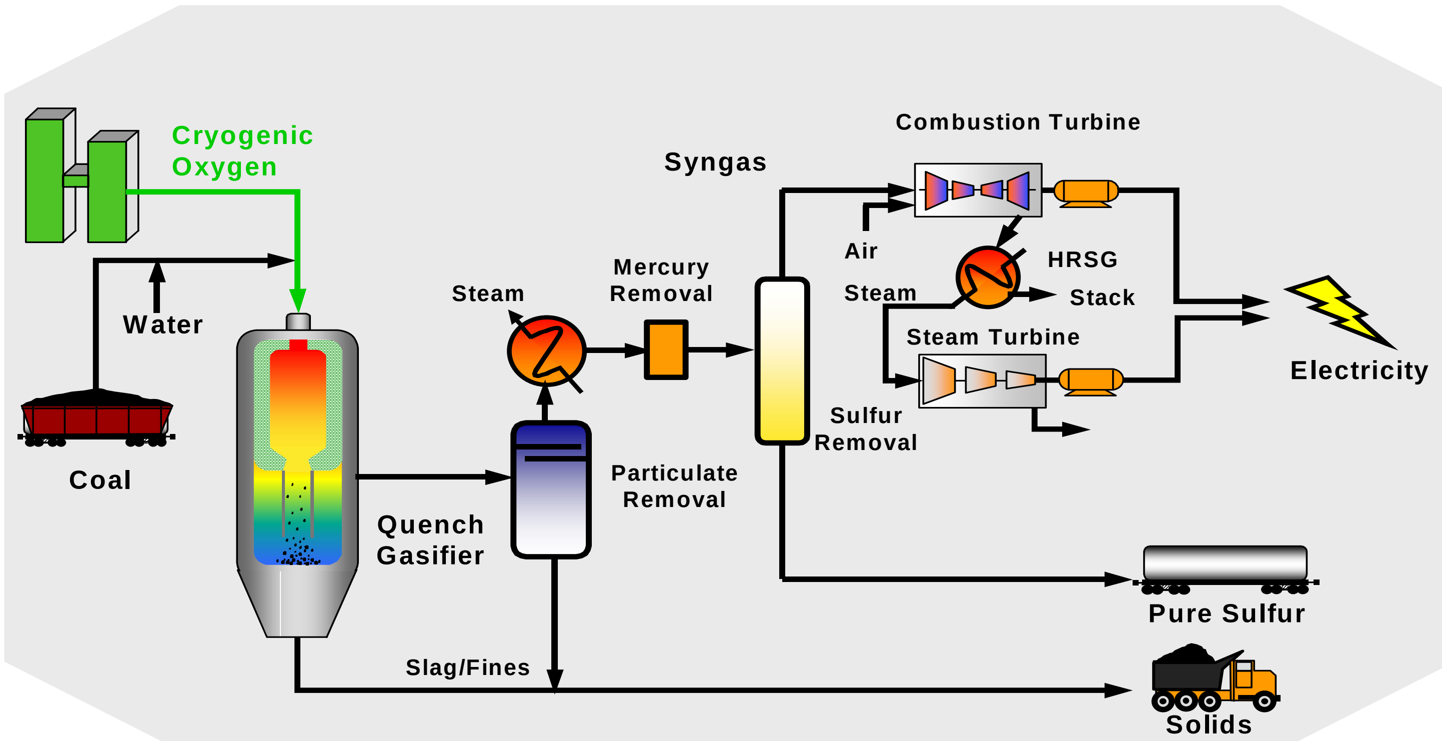
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B as of YE 2004)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO_2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO_2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

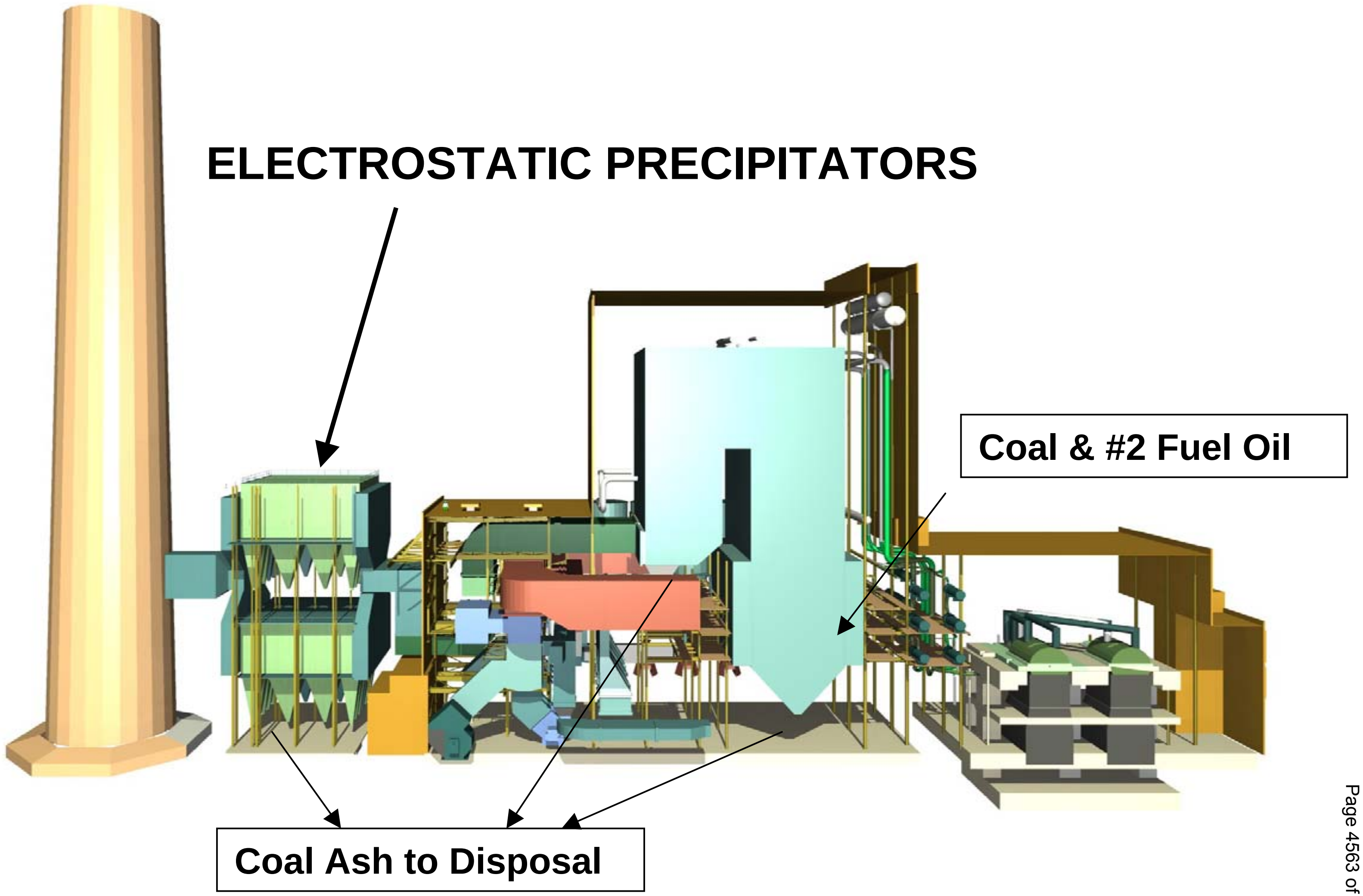
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

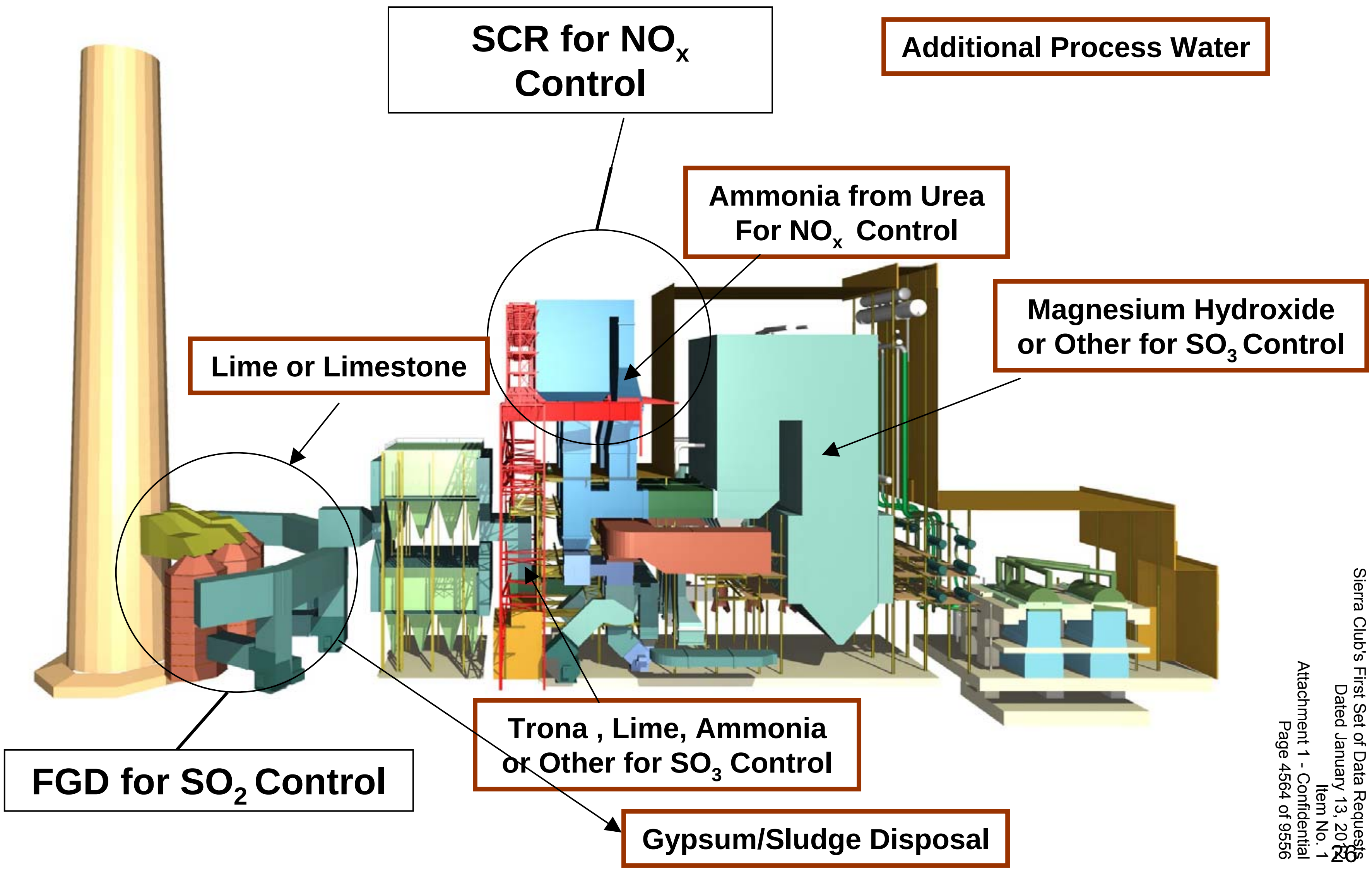
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s

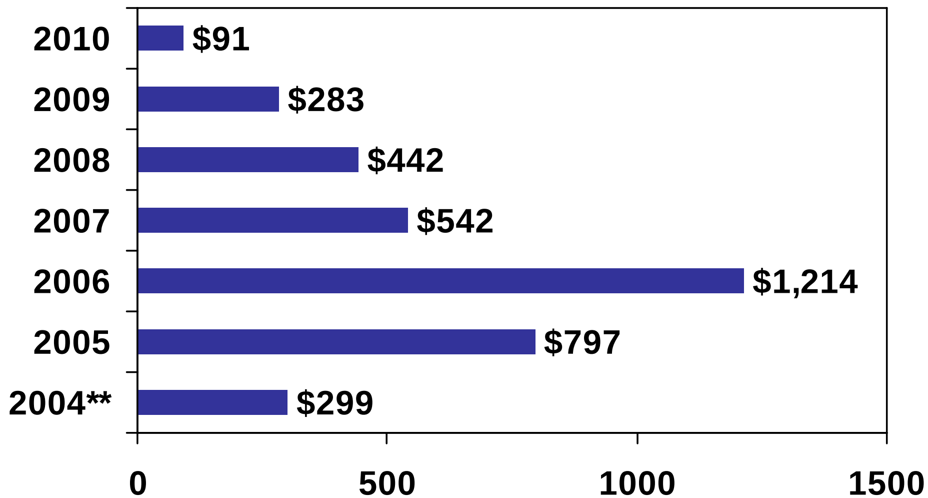


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



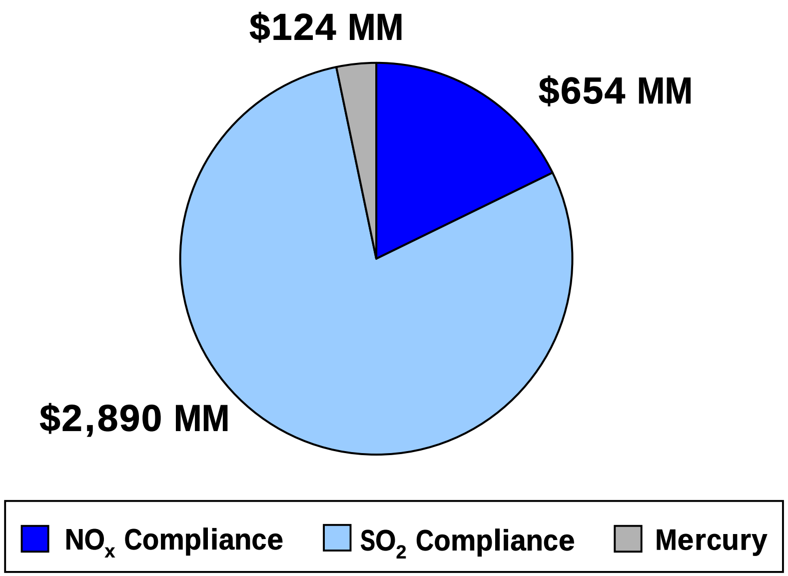
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation

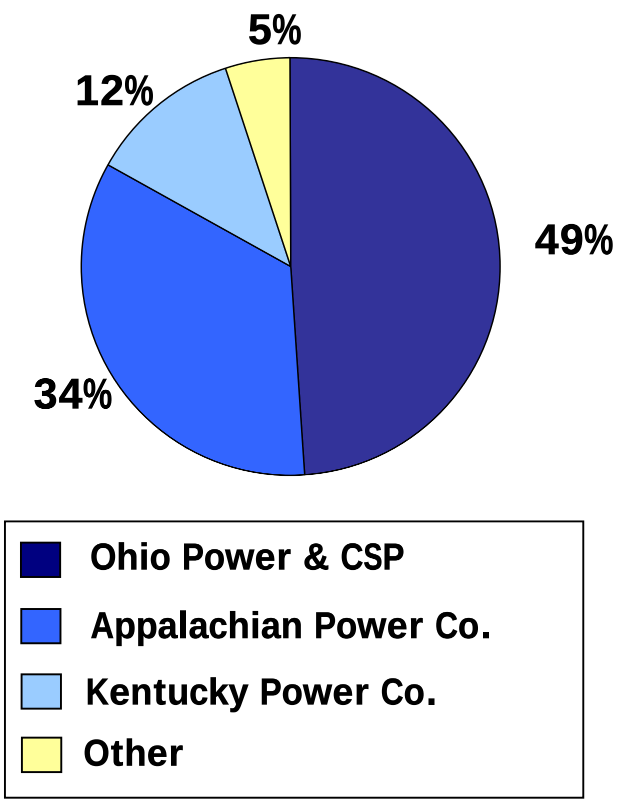


Current Programs	Future Programs
$1.9 Billion:	**$1.8 Billion:**
$0.6 billion for NOx	**$1.7 billion for SO_2**
$1.2 billion for SO_2	**$0.1 billion for Other**

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD		SCR	

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

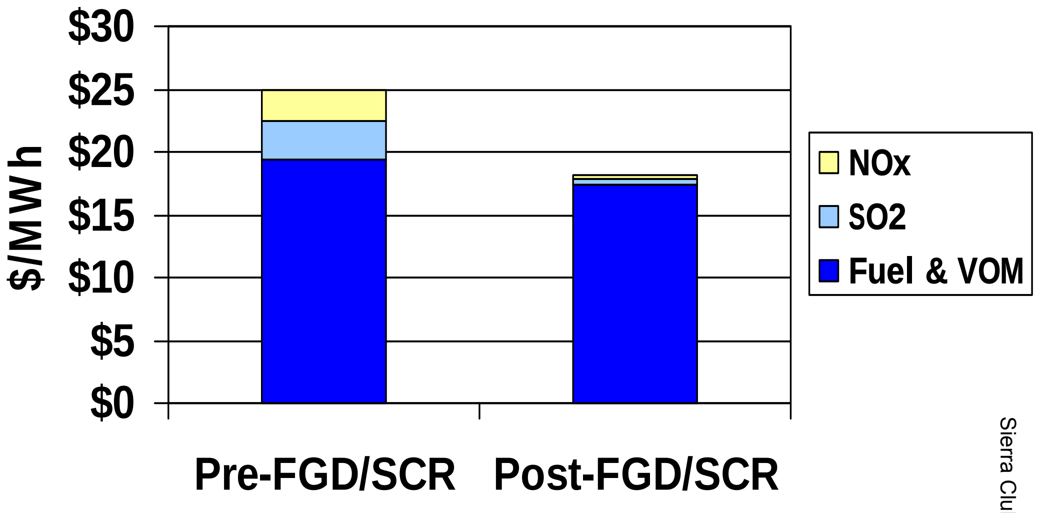
2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

Low Cost Production Supports Investment

- ➢ Lowers exposure to high cost emission allowances
- ➢ Creates opportunity to burn wider variety of lower cost fuels
- ➢ Improves baseload operation, (higher capacity factor, higher margin)
- ➢ All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05		31-Dec-04	
	(in millions)			
Stranded Generation Plant Costs	$	898	$	897
Net Generation-related Regulatory Asset		249		249
Unrefunded Excess Earnings		(6)		(10)
Net Stranded Generation Costs		1141		1136
Carrying Costs on Stranded Generation Plant Costs		205		225
Net Stranded Generation Costs Designated for Securitization		1346		1361
Wholesale Capacity Auction True-up		483		483
Carrying Costs on Wholesale Capacity Auction True-up		91		77
Retail Clawback		(61)		(61)
Deferred Over-recovered Fuel Balance		(215)		(212)
Net Other Recoverable True-up Amounts		298		287
Total Recorded Net True-up Regulatory Asset	$	1,644	$	1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, Hearings scheduled to begin 8-8-05.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause

West Virginia (Regulated)
- Base rates not frozen
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- No active fuel clause

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

AEP®

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) Hearing in October.
- TCC wires rate case PUCT approved affiliate transaction settlement in June 2005. Written order expected in July 2005. Final order will result in slight rate decrease with a positive earnings impact.
- TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing issued in June 2005 updating rate case expenses. TCC will appeal decision.
- TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval.
- On 5-2-05 the OCC issued an order approving a settlement agreement in this general rate case which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider.
- 2001 Fuel review case
  Hearings scheduled for Sept. 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
  Scope has been expanded to include a prudence review.

Louisiana (Regulated)
- Base rates not frozen
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

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Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	POLR Rider	Revenues & POLR Rider*			Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs***	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit**	0	25	25	26	0	25	25	26
Recovery of RTO costs***	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

* Incremental over 2004 base year

** Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

*** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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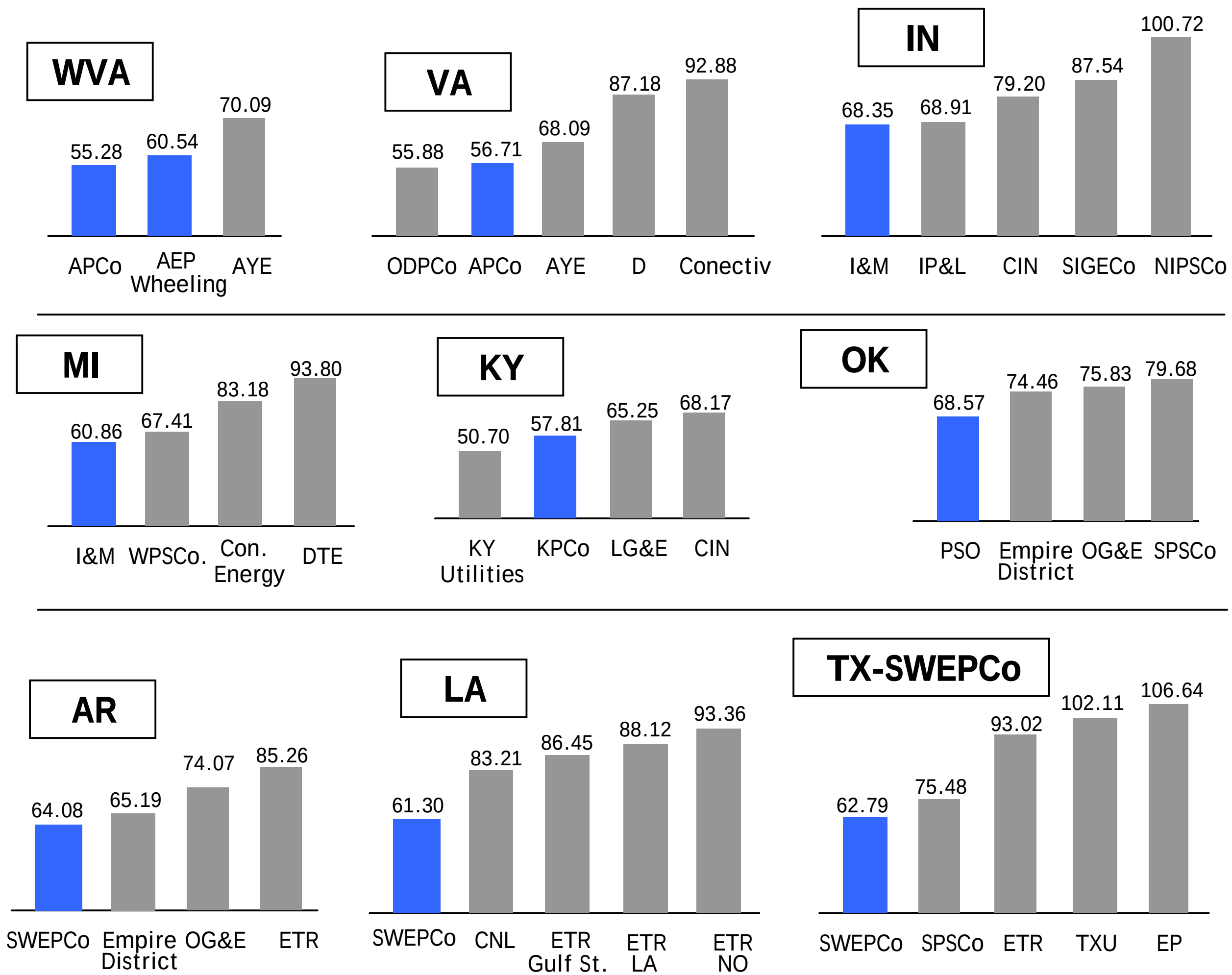
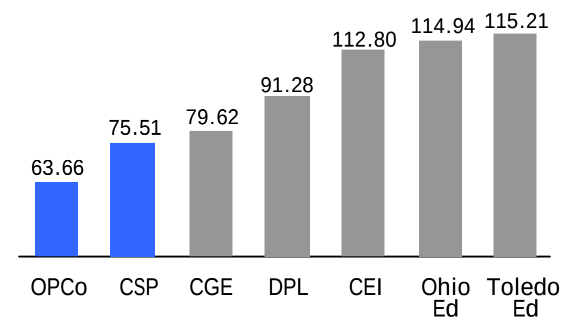
AEP: The Low Cost Provider

Regulated Rates



Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

AEP System fossil fleet average variable book cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

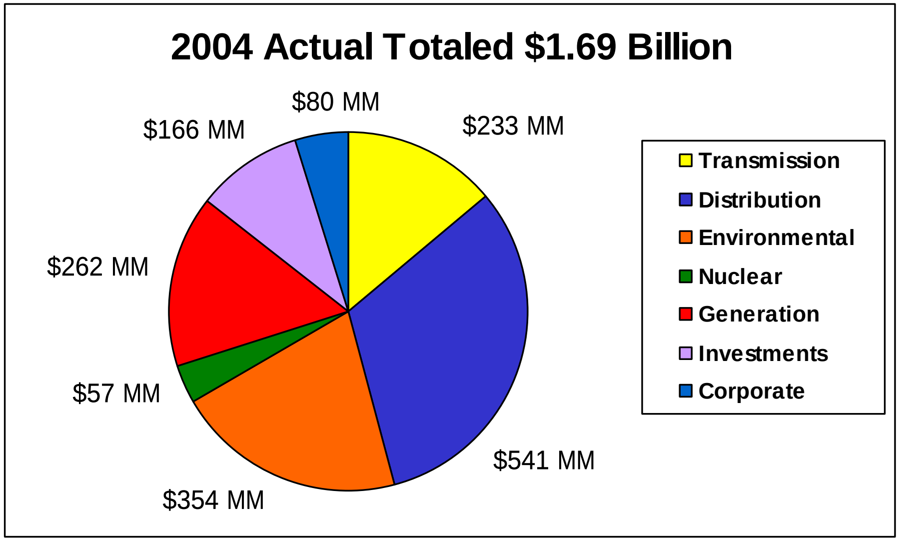
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

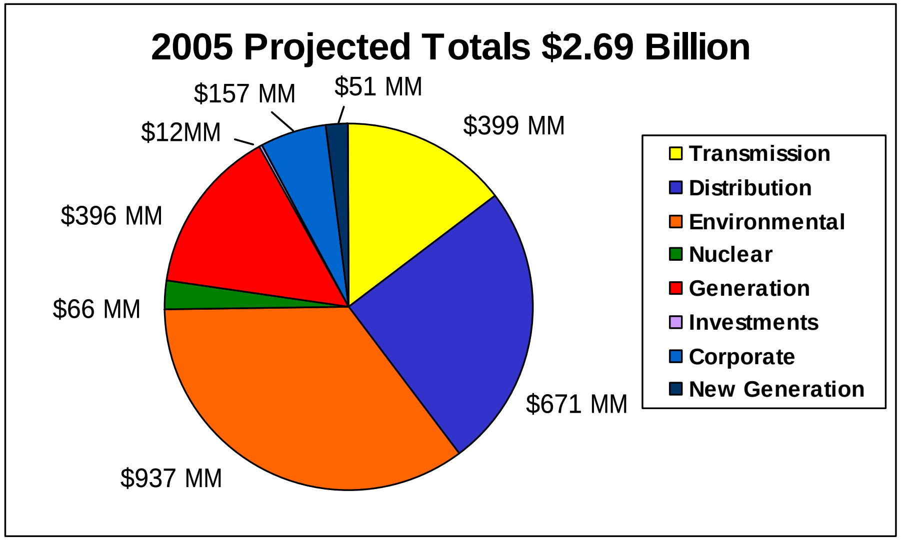
**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex





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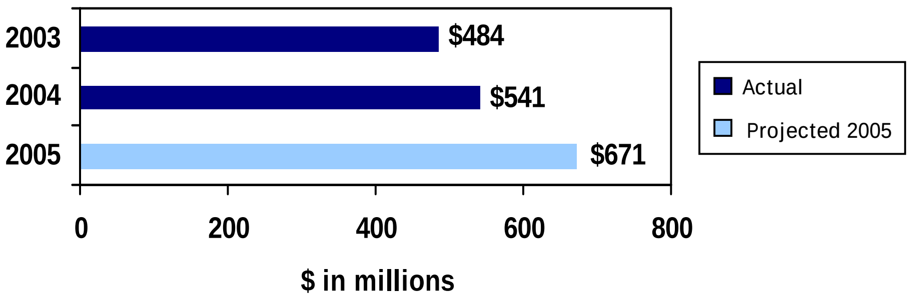
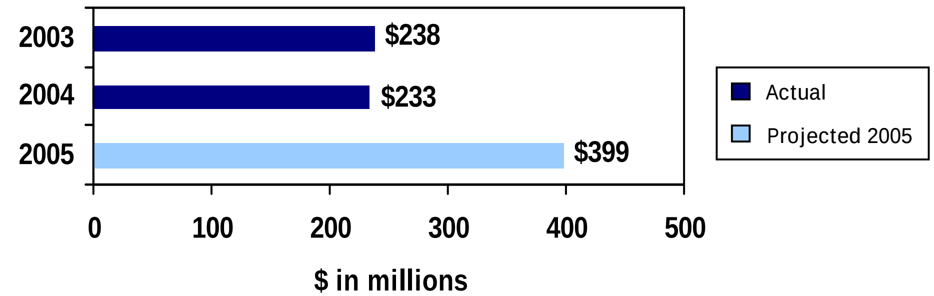
Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



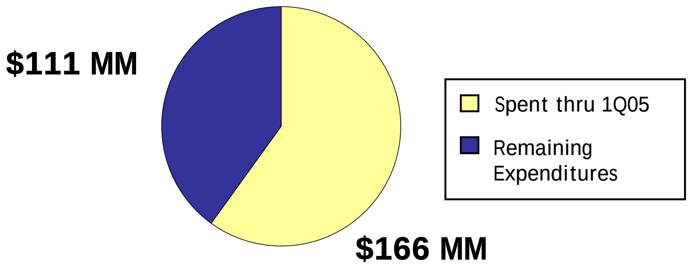
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Investment in Asset Base Will Drive Earnings

Potential Return On Investment

Assumptions	Environmental Investment	600MW IGCC Investment*
Projected Investment	$3.7 Billion	$1.0 Billion
Debt/Equity Ratio	60% debt / 40% equity	52% debt / 48% equity**
Return on Equity	12.00%	11.75%***
Potential EPS Impact (based on 393 MM shares)	+ $0.45	+ $0.14

* Assume a similar return for an additional 600 MW IGCC facility

** Requested debt/equity ratio per AEP Ohio IGCC filing

*** Requested ROE in AEP Ohio IGCC filing

EPS CONTRIBUTION WILL DEPEND ON FAVORABLE REGULATORY OUTCOMES

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**875,376,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Excludes $65.8 million of mortgage bonds due in 2005 that were defeased

(4) Excludes TCC securitization bonds

AEP®

Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

<u>2005</u>

- *Outcome of pending regulatory proceedings*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Earnings Guidance

		2004 Actual			2005 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2011 Citi Power & Gas Conference

Boston, MA
June 2, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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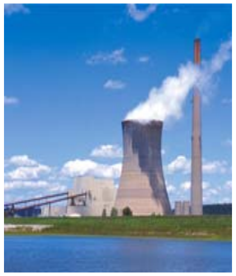
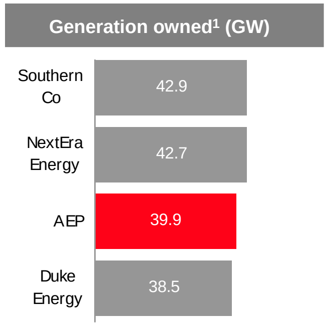
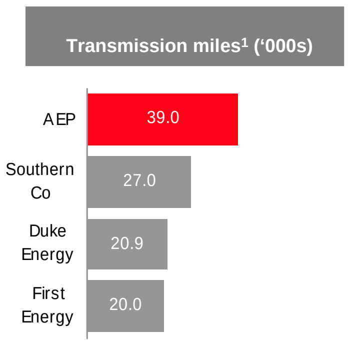
American Electric Power



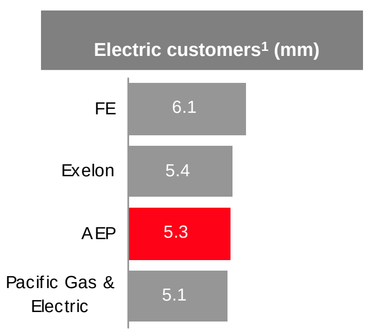
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

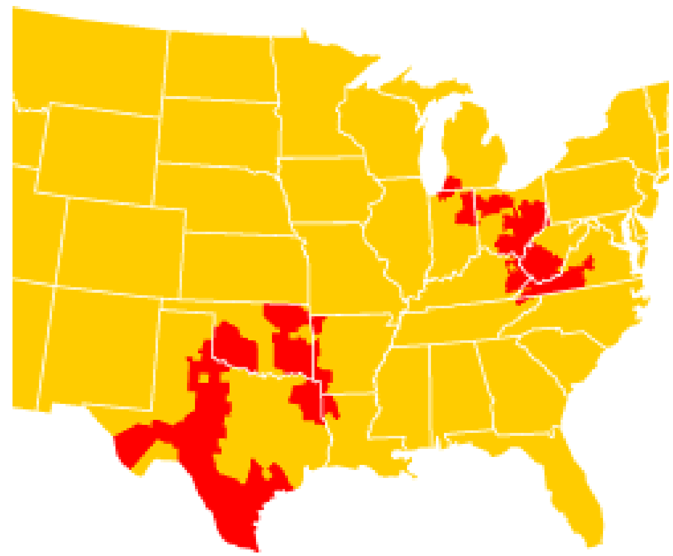


One of the largest U.S. electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

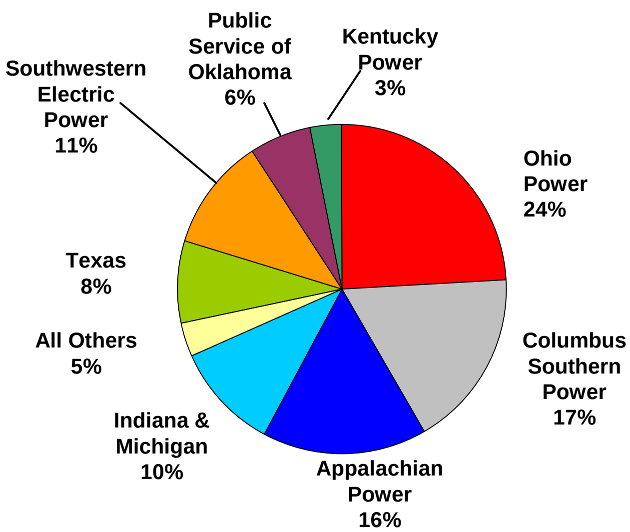
$18.5B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

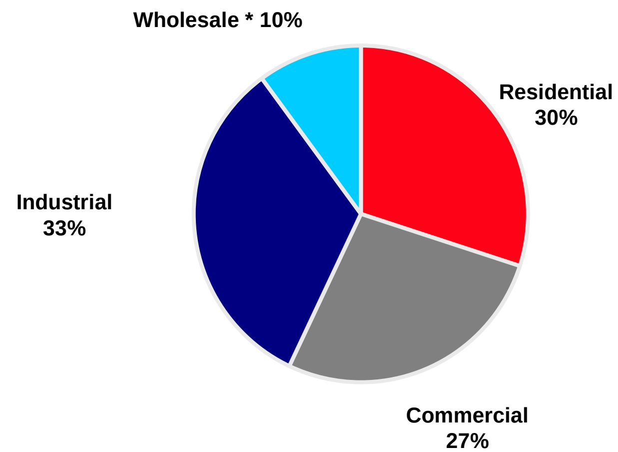
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



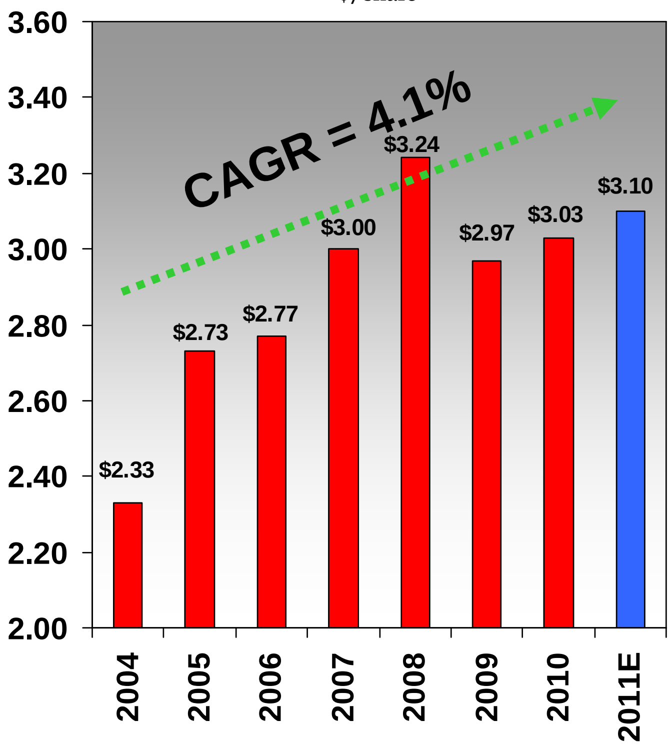
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

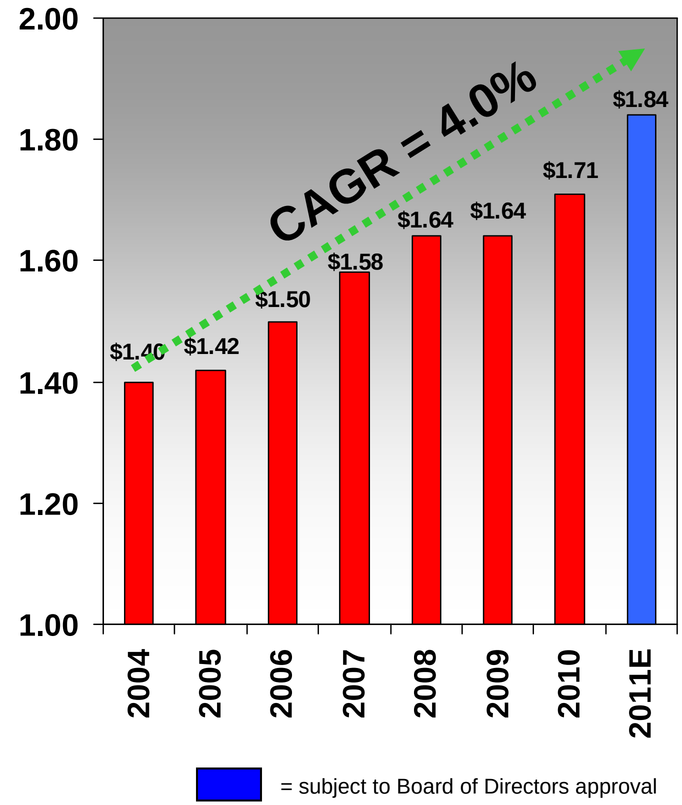
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend will be paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

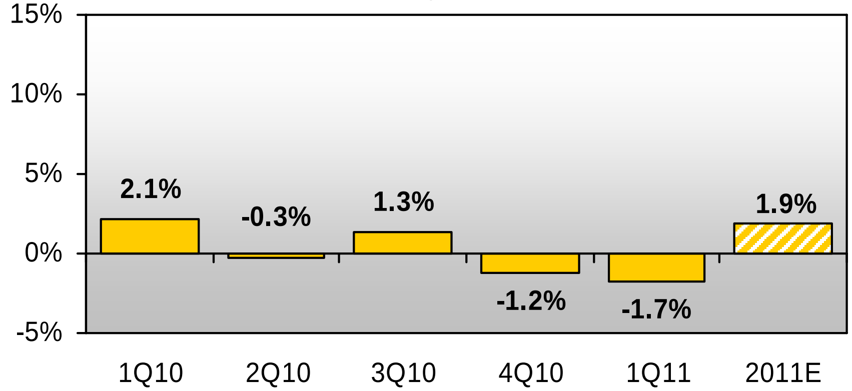
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

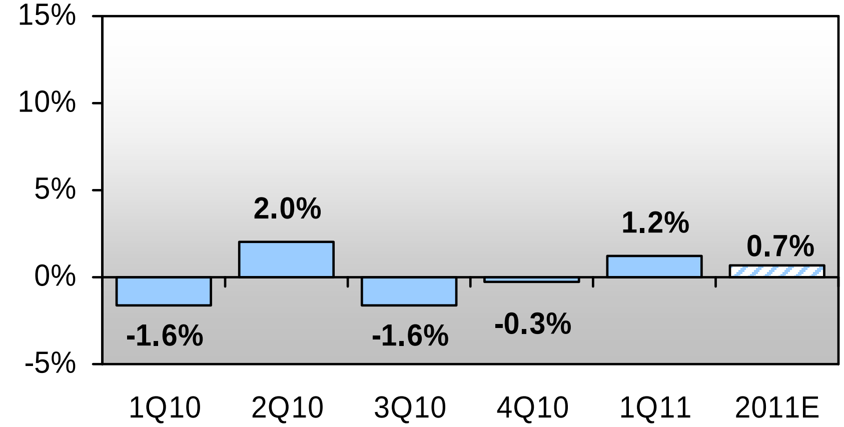
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

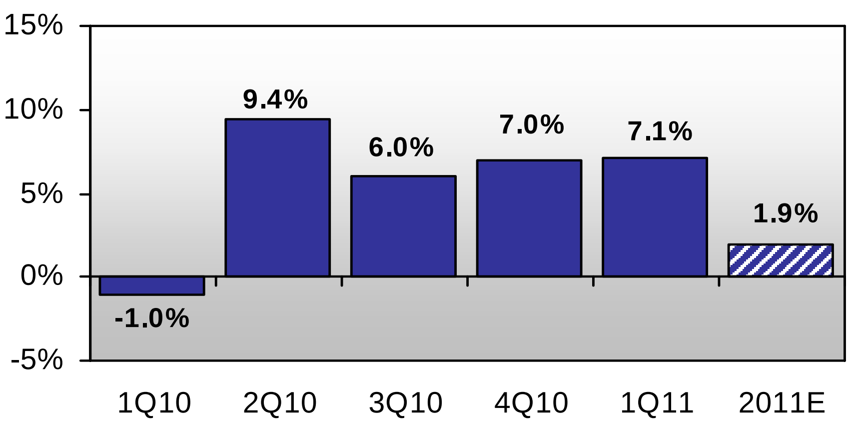
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



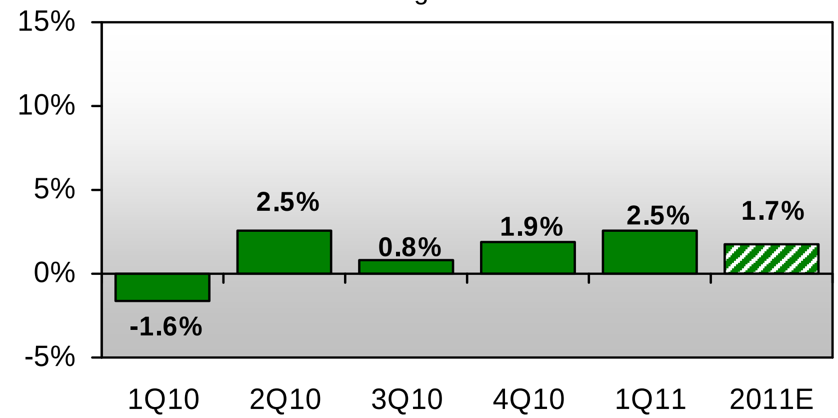
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



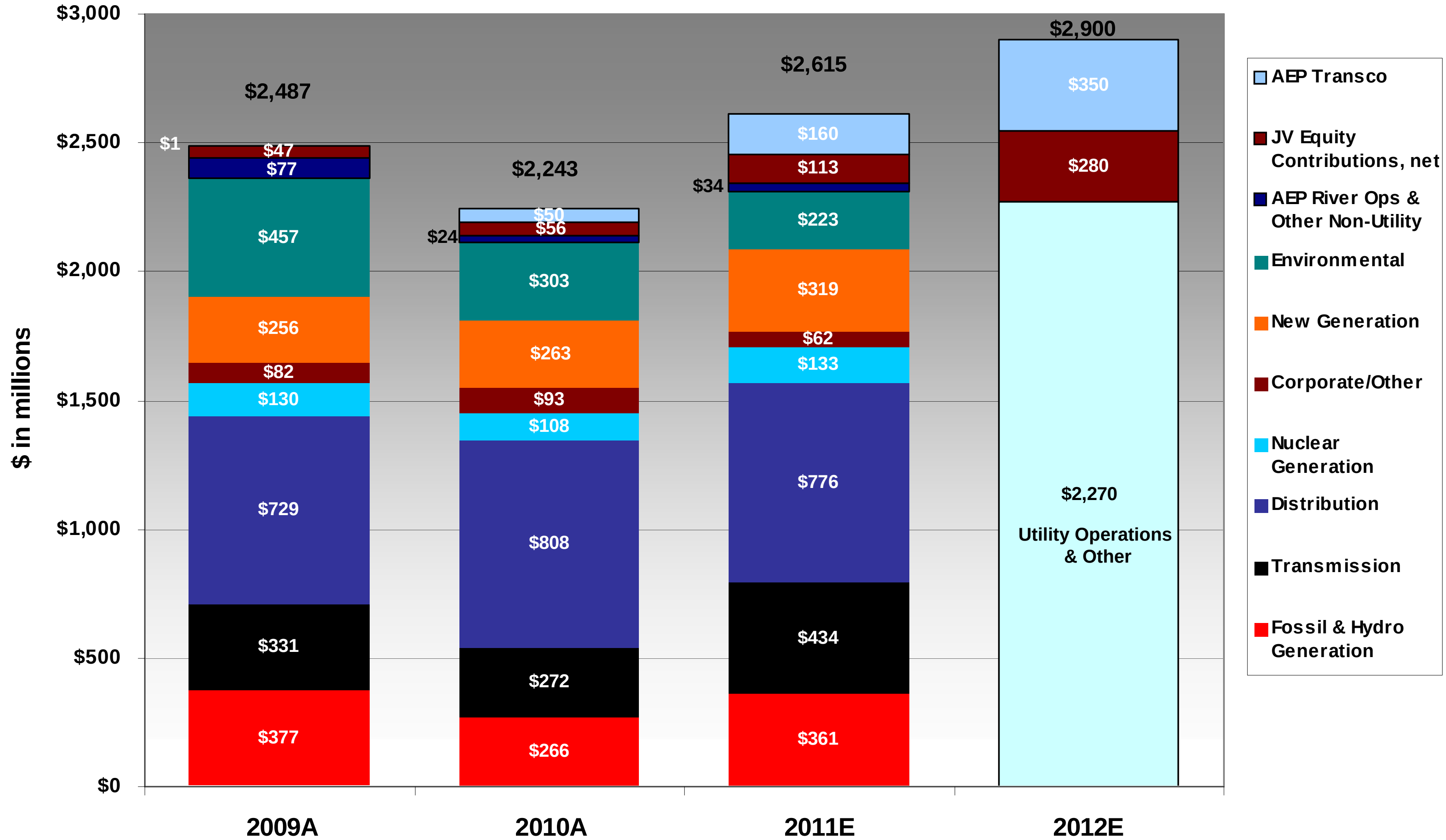
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	\$ in millions 2010A	 2011E
Cash From Operations		
Income from Continuing Operations	\$ 1,218	\$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	\$ 3,297	\$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	\$ (2,502)	\$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	\$ (991)	\$ (581)
Beginning Cash Balance	\$ 490	\$ 294
Ending Cash Balance	\$ 294	\$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[(1)]	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

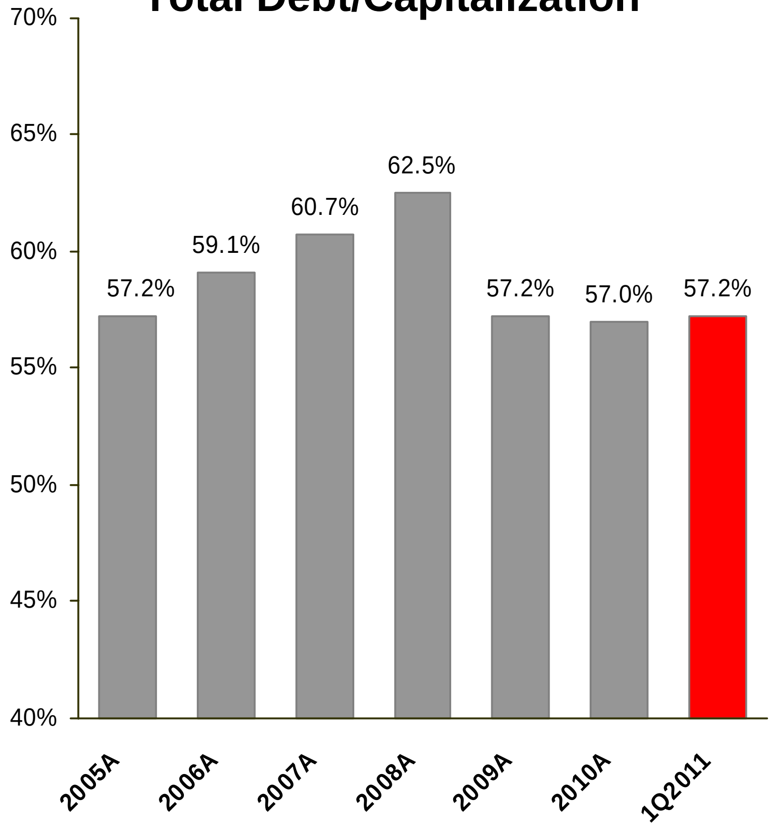
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

Total Debt/Capitalization

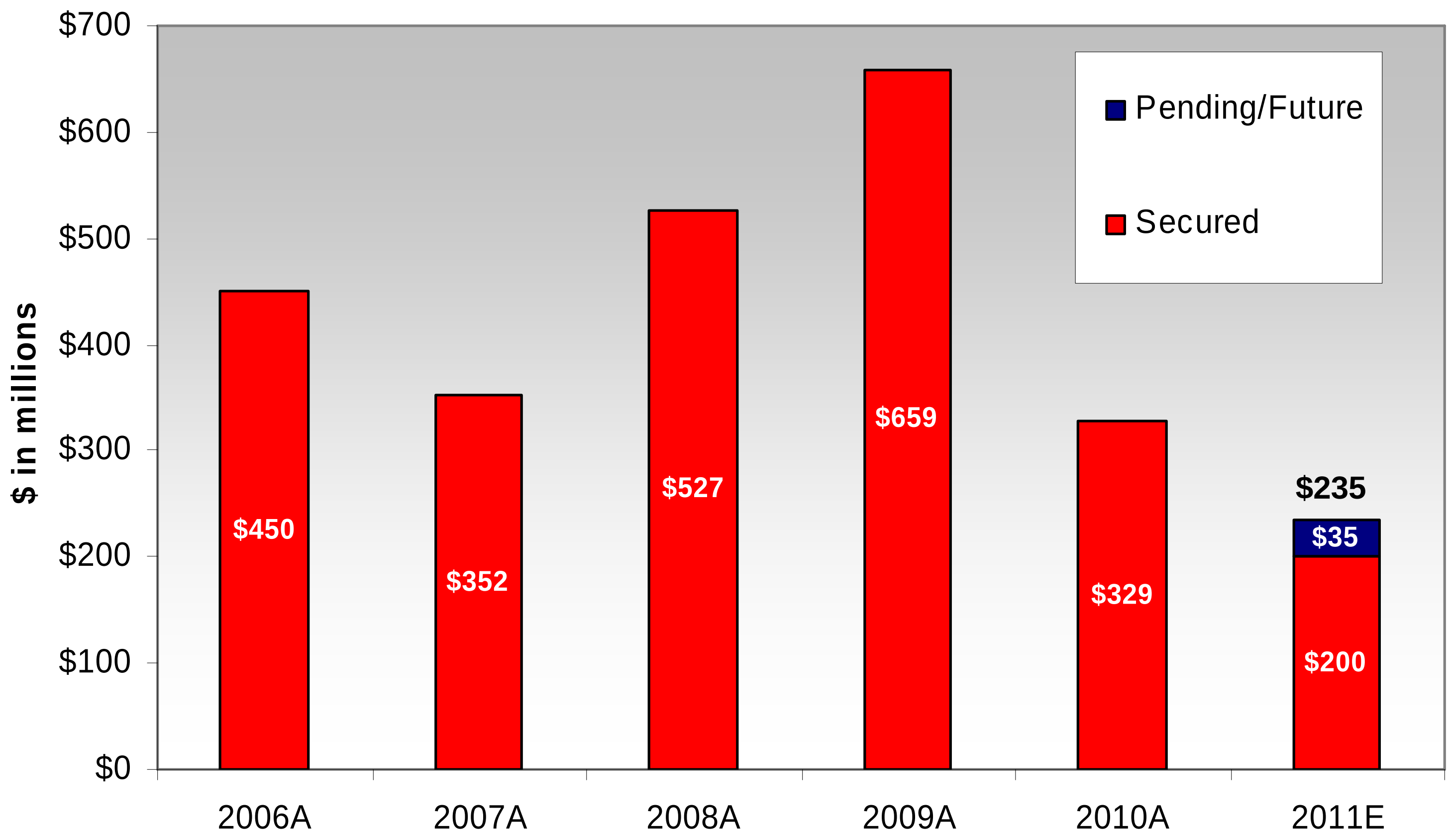


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 03/31/11**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – June 13; Staff testimony – June 27; Hearing July 20**

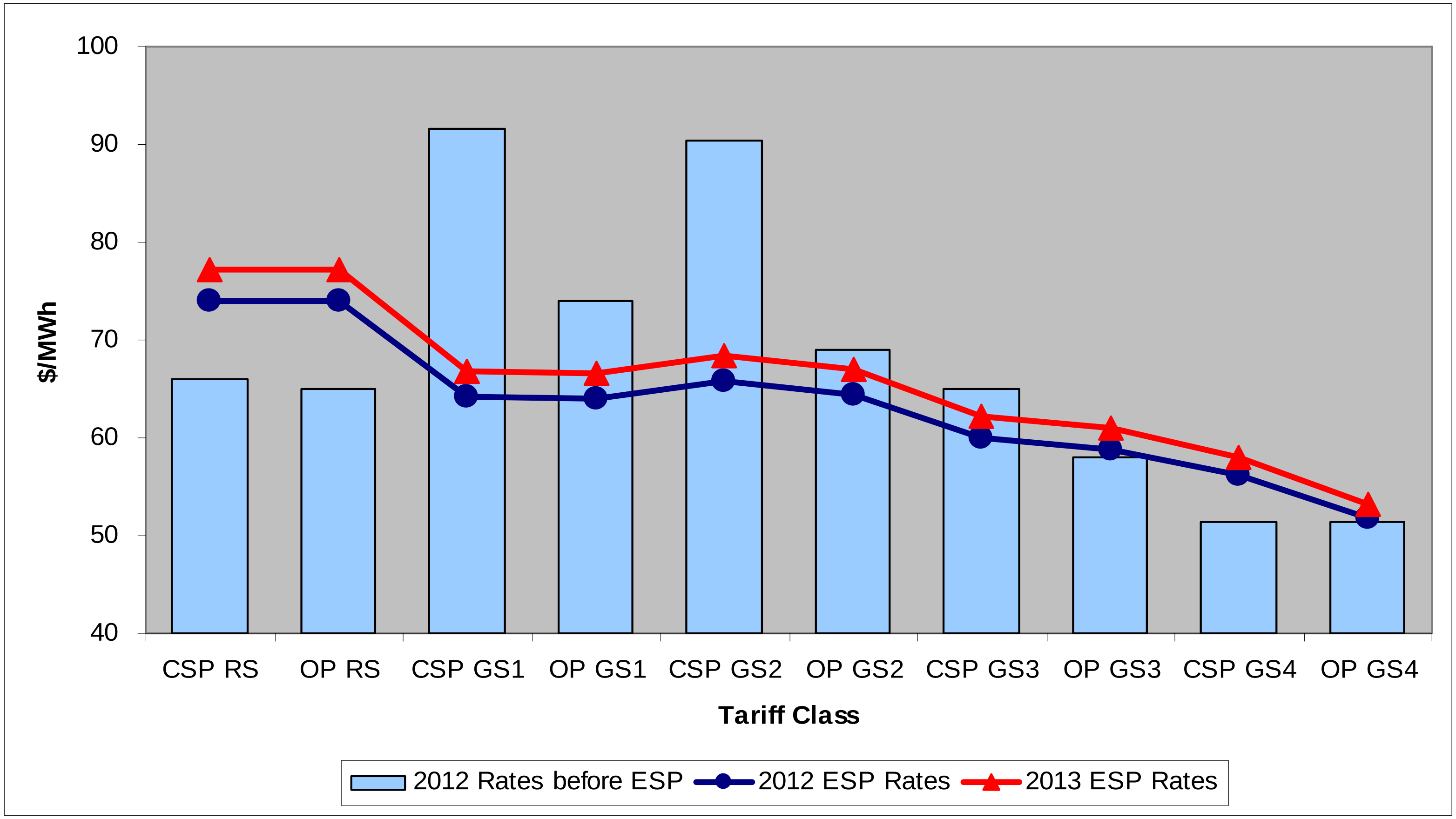
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

AEP®

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

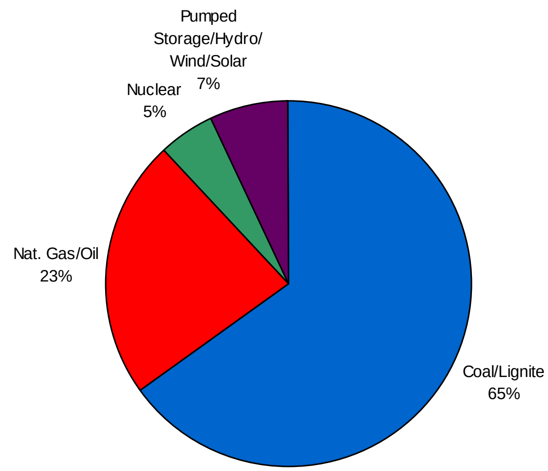
The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

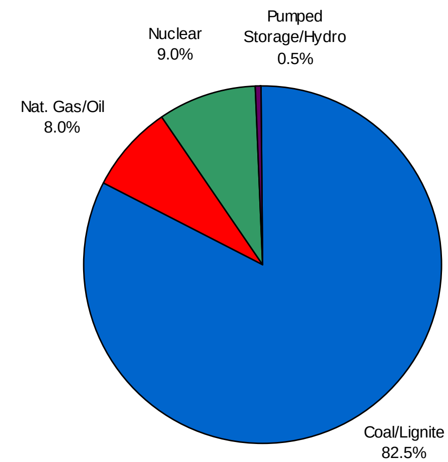
Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Domestic Generation Fleet

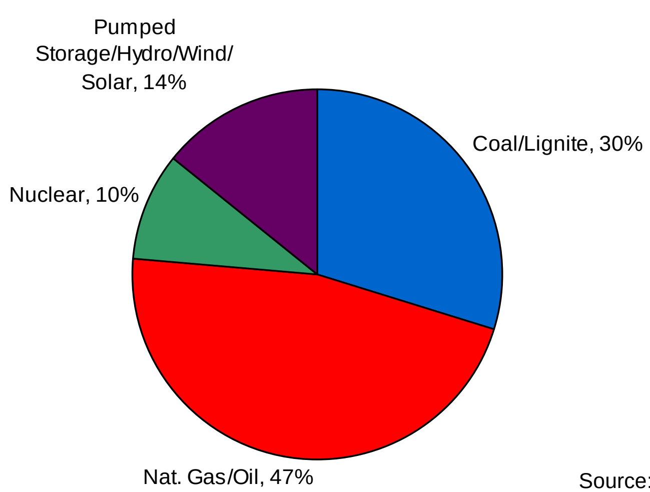
Generation Capacity by Fuel Type
Based on 39,910 MW



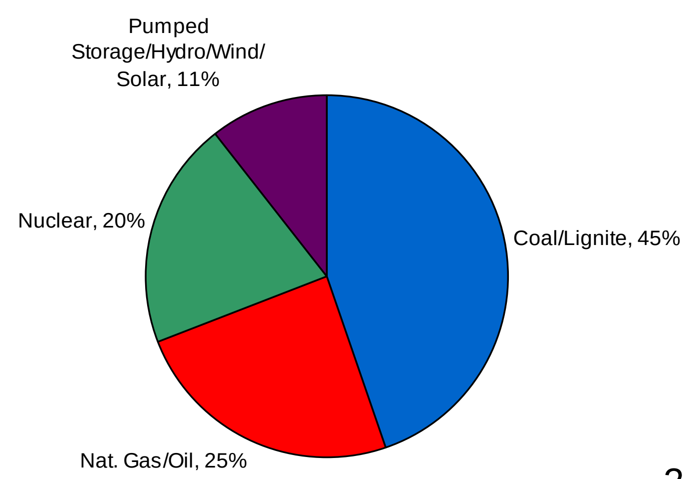
2010 Generation Production by Fuel Type
Based on 173.2 TWh



Generation Capacity by Fuel Type
Based on 1,063,848 MW



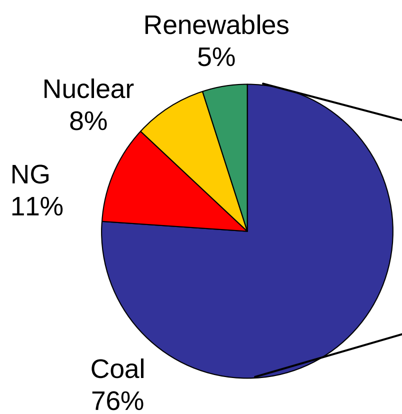
2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

AEP Generation Capacity

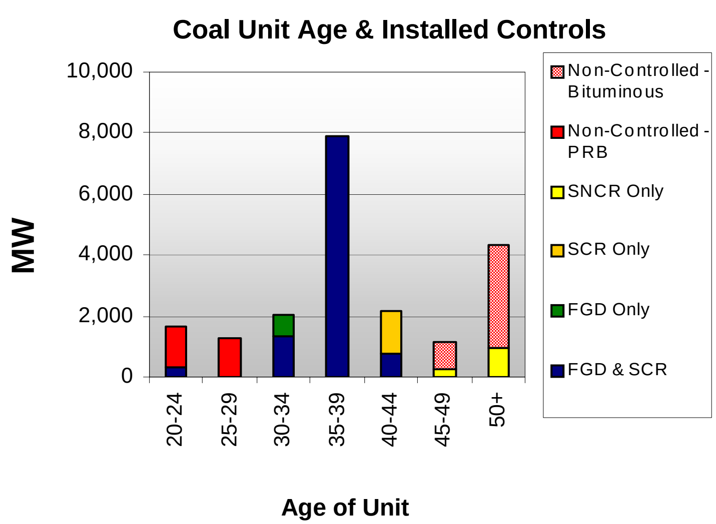
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



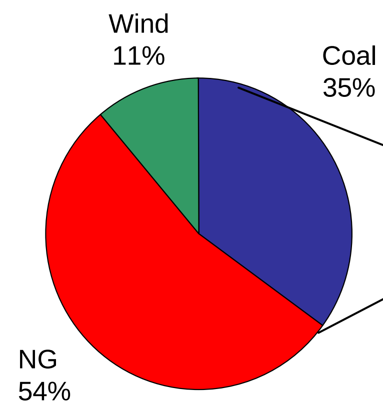
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



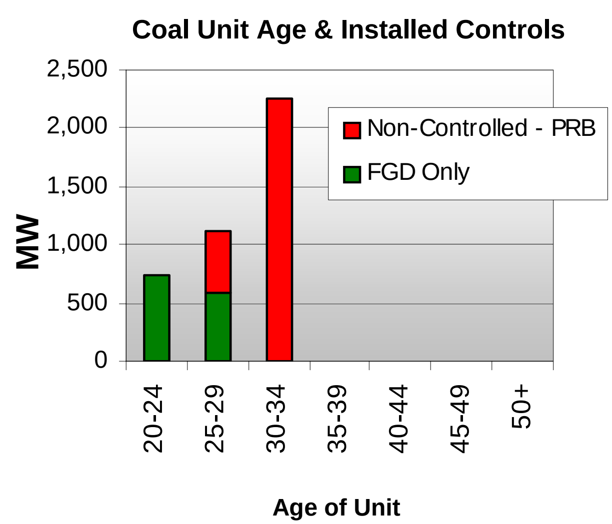
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.
- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Pending EPA Regulations

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion (including AFUDC) for solid waste option
- “Hazardous” option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28, 2011
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

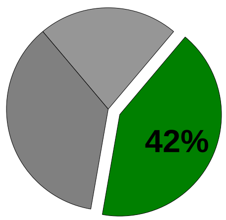
The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($Millions) [1]

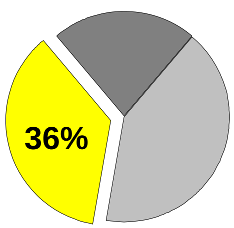
Least Exposed



Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

Proposed Rules		Low		High
Water Rules [2]	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules [3]	$	766	$	1,046

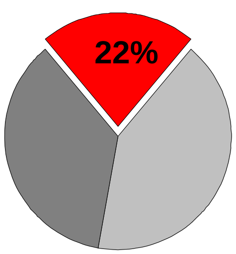
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High [4]
Water Rules [2]	$	26	$	46
CCR Rules	$	357	$	726
Air Rules [3] [5]	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

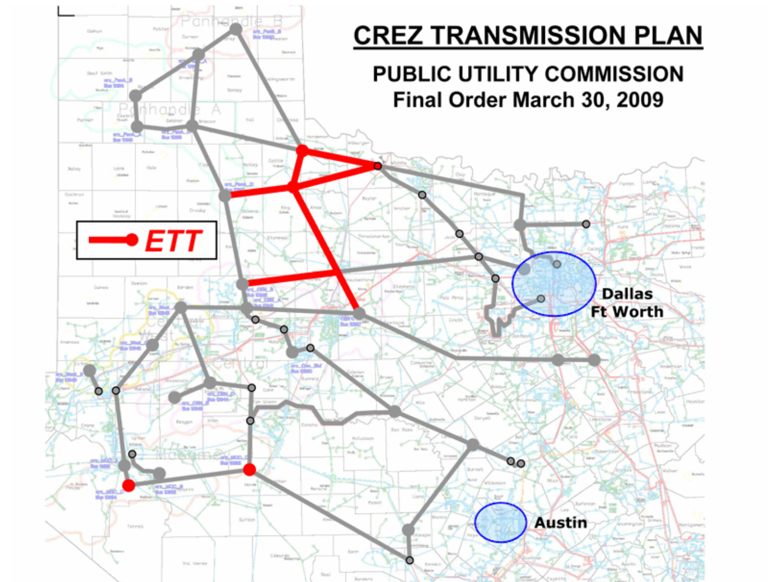
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transcos is 11.49%
  - ROE order for West Transcos is 11.20%

State Filing Status Update:

- **Ohio** – PUCO approved the Ohio Transco December 29, 2010
- **West Virginia** – Filing made January 6, 2011; Hearings in June
- **Arkansas** – Filing in Arkansas made May 6, 2011
- **Louisiana –** Expecting LA filing in 3Q 2011
- **Texas-SPP** – Expecting TX filing in mid 2011
- **Kentucky** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- **Indiana** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- **Virginia** – Filing withdrawn to give additional time to resolve issues with Staff
- **Michigan and Oklahoma** – Do not require state filing

$160M capital spend forecasted for 2011; $350MM for 2012

Joint Venture Strategy: Long-term

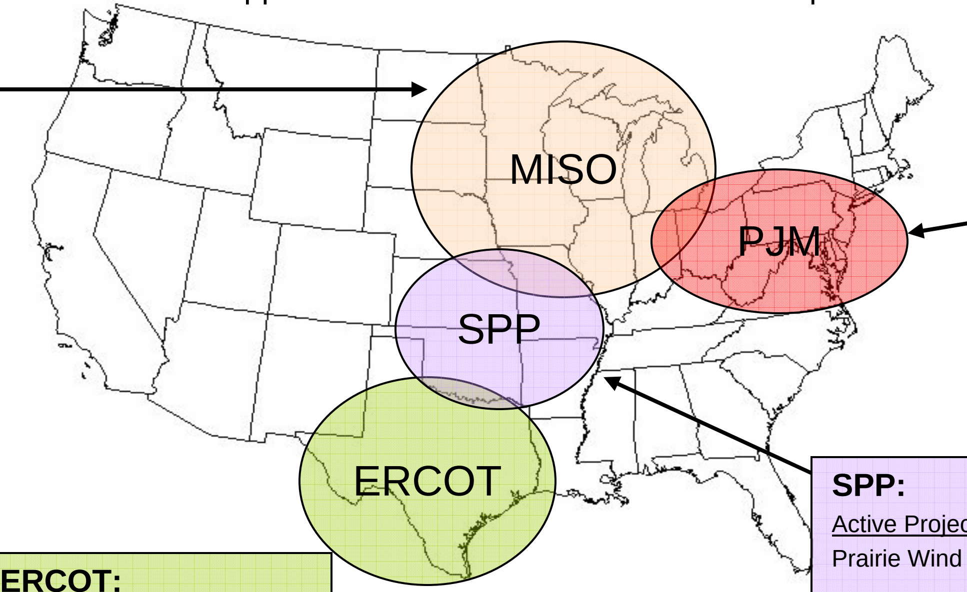
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Citi Power, Gas, Coal and Alternative Energy Conference
Washington, D.C.
June 8, 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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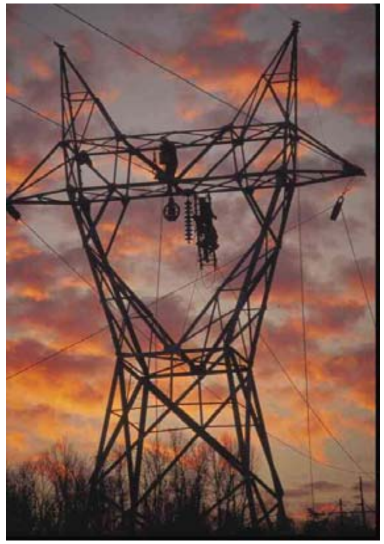
Industry Leadership

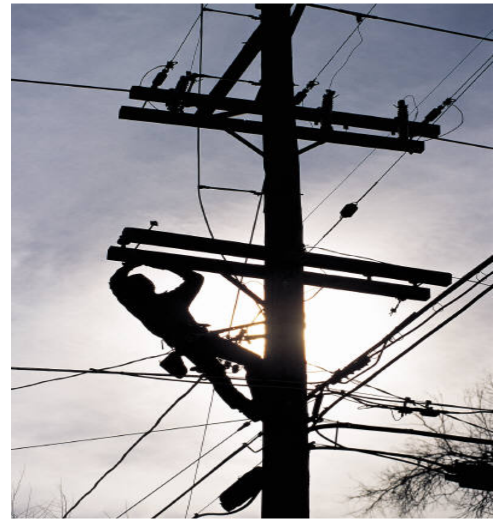
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



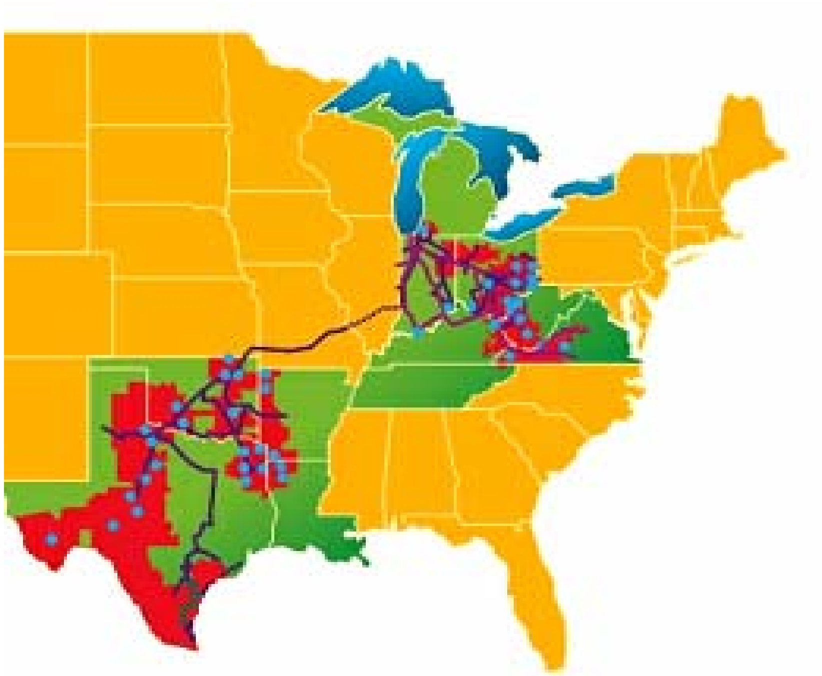
One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

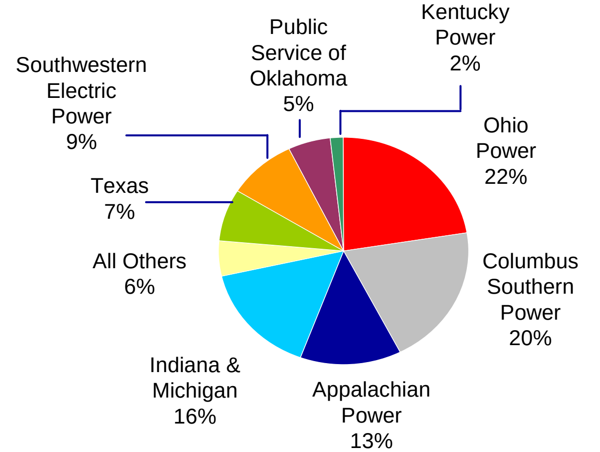
Highly Diversified Regulated Utility Platform

5.2 million customers in 11 states

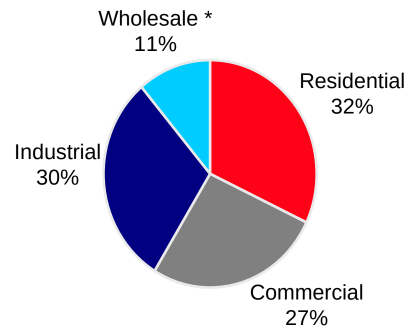


Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

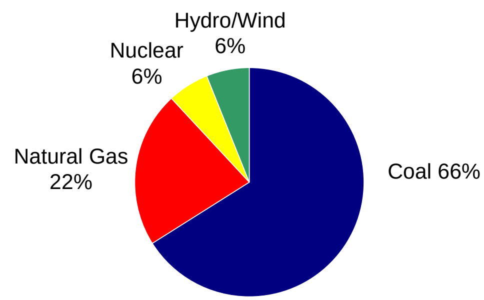


2009 Retail Load



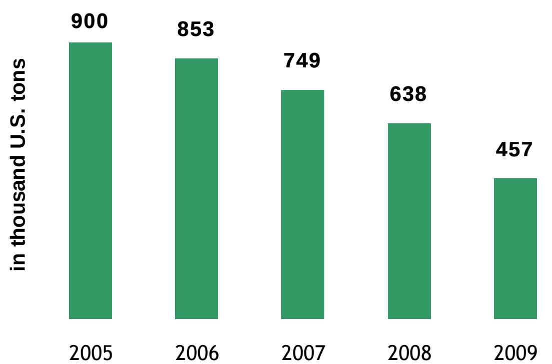
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix

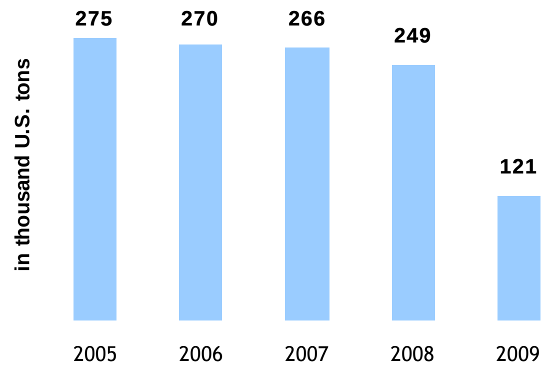


Our Fleet Will Continue to Transform

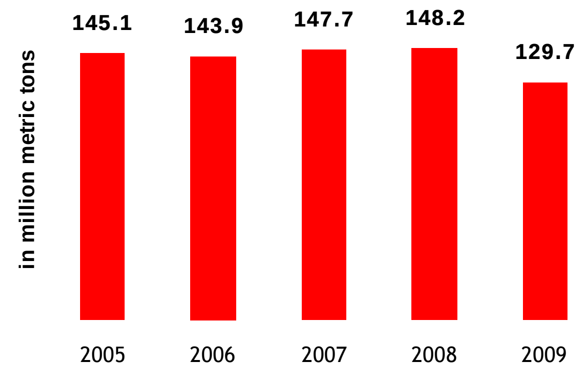
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



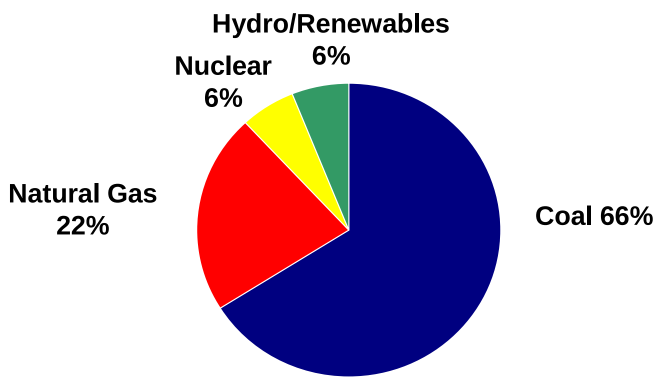
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



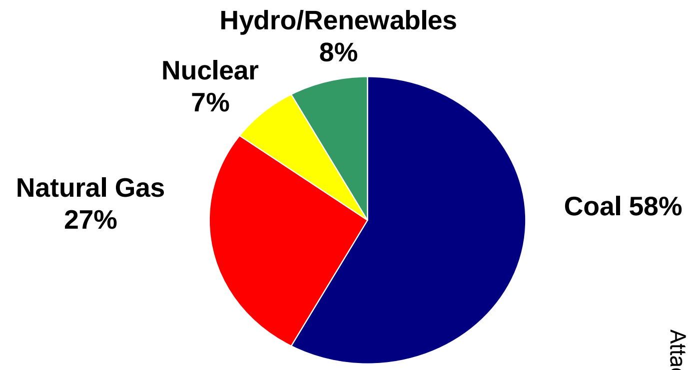
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ \$5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions

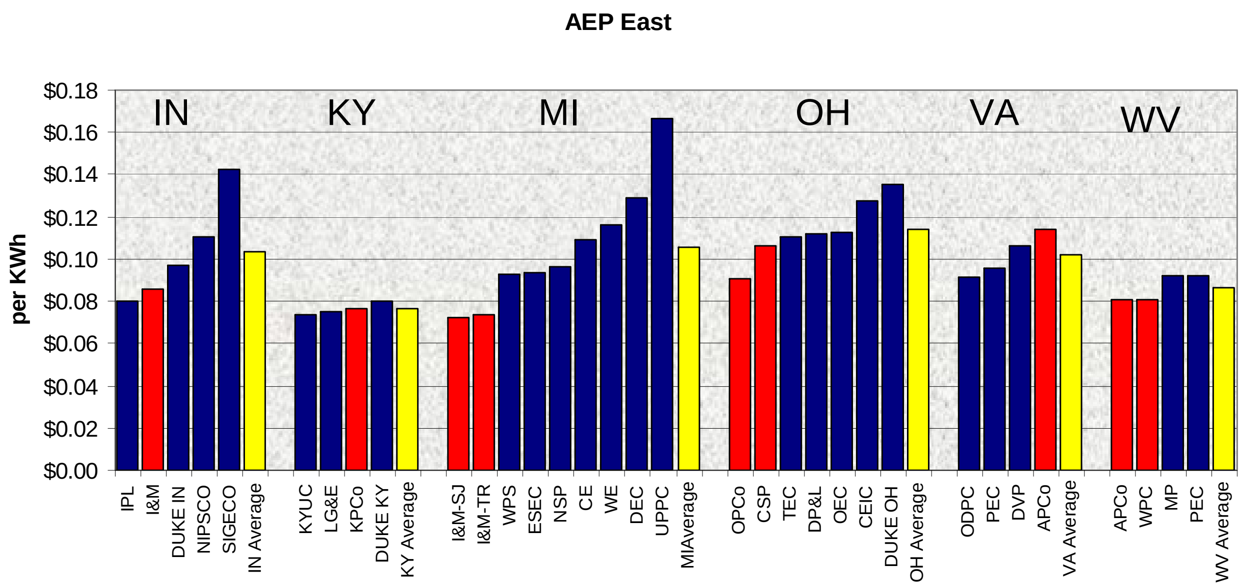


Fuel Mix - 2009

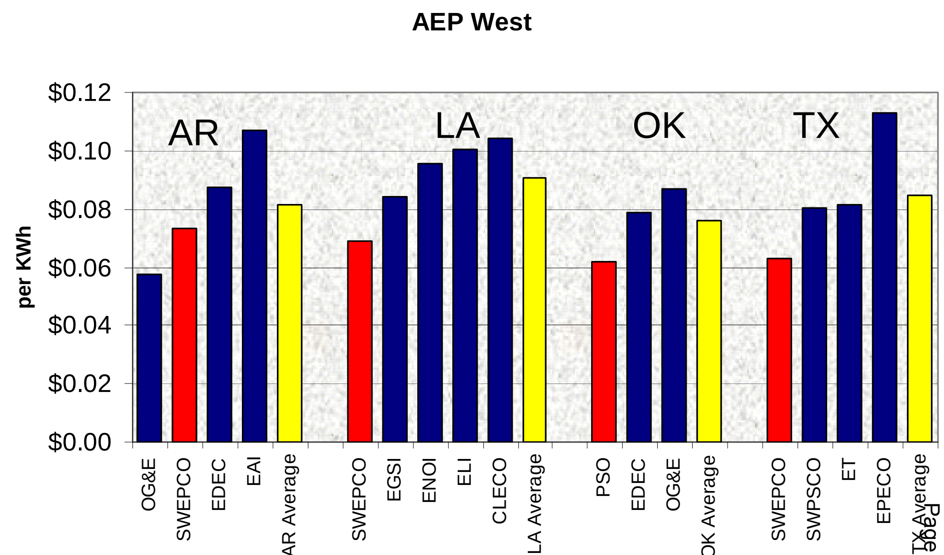


Projected Fuel Mix - 2017

Residential Rates Comparison



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report



■ AEP Company
■ Other Utilities within state
■ State Average

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — **COD: 2013-14**

- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — **COD: 2013-14**

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — **COD: 2010-2017**

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — **COD: 2014**

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — **COD: 2015**

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — **COD: various**

- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP **ERCOT** **PJM** **PJM/MISO**

Electric Transmission Texas, LLC

Overview:

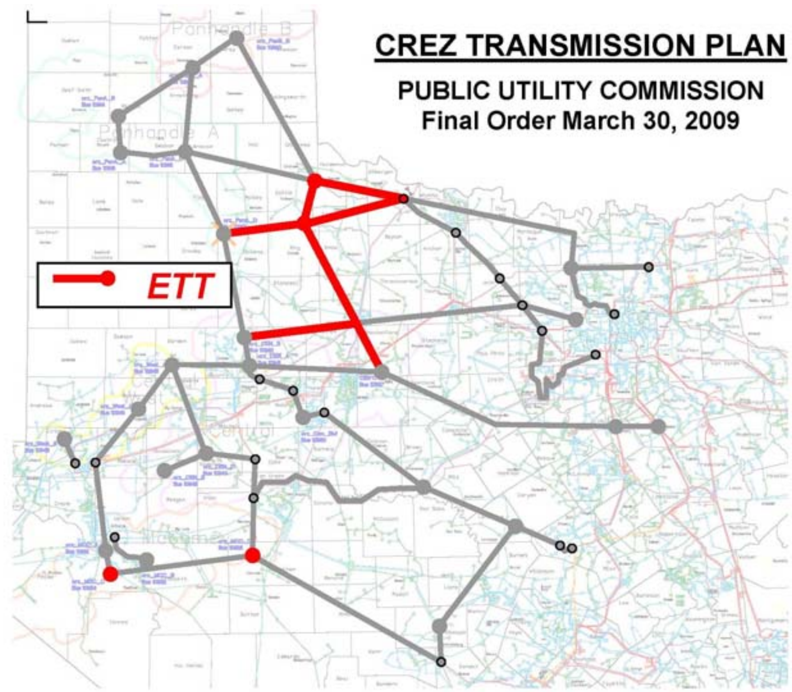
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

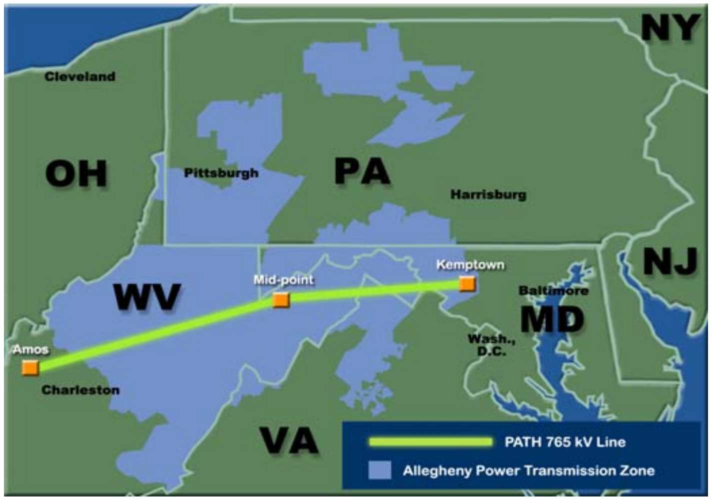
Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

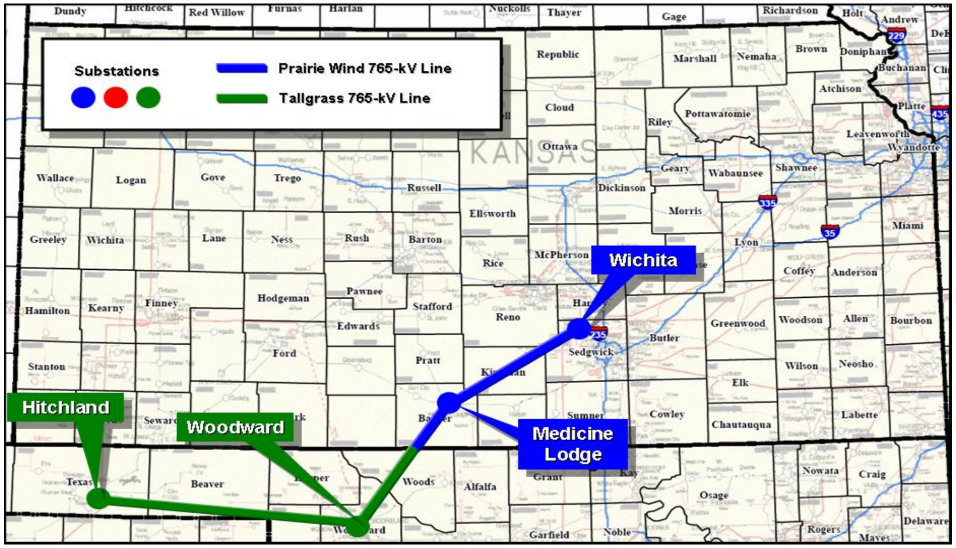
- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

PATH
Potomac-Appalachian Transmission Highline

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

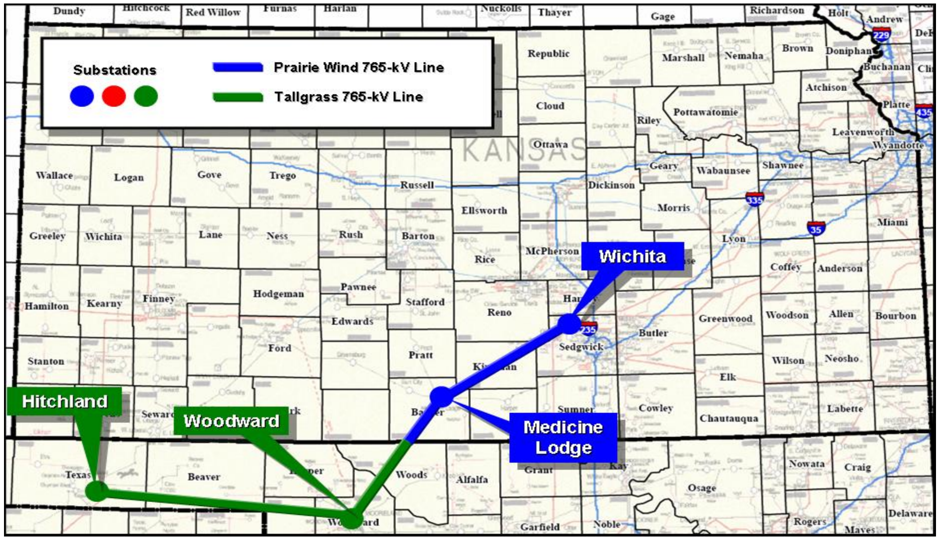
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

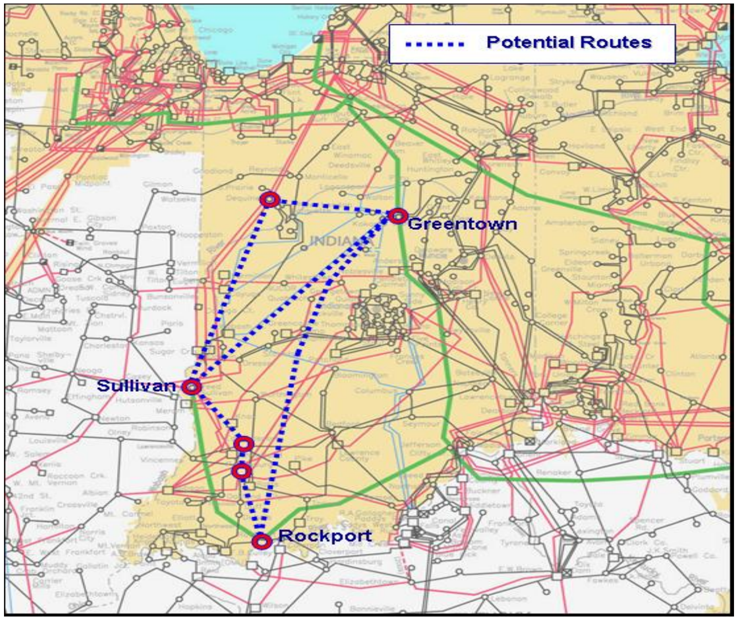
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

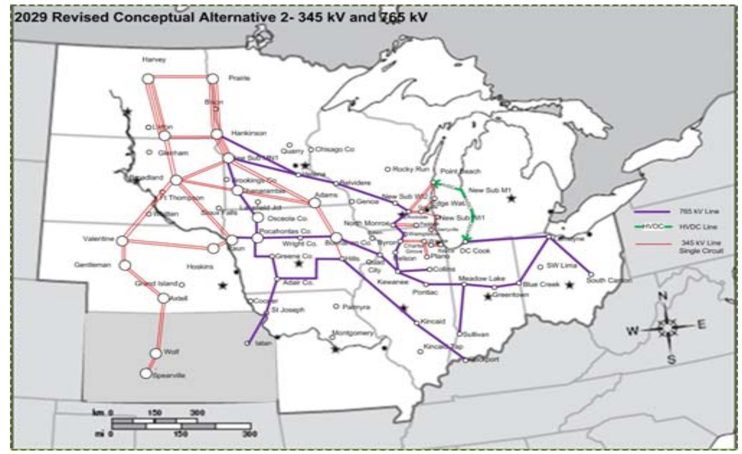
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

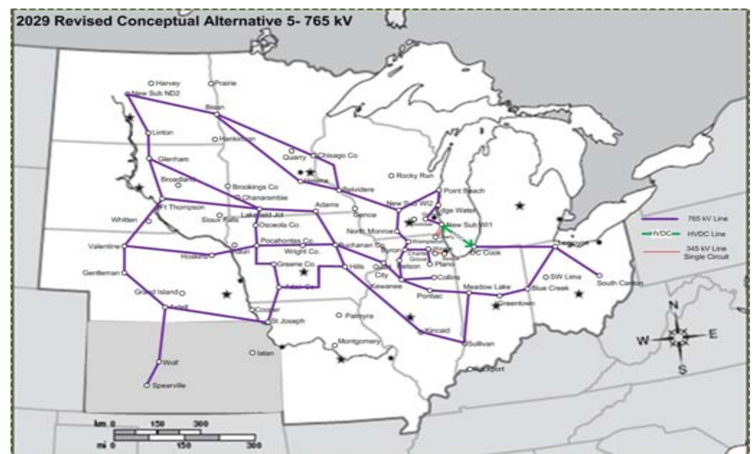
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives





The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

2010 Ongoing Earnings Guidance

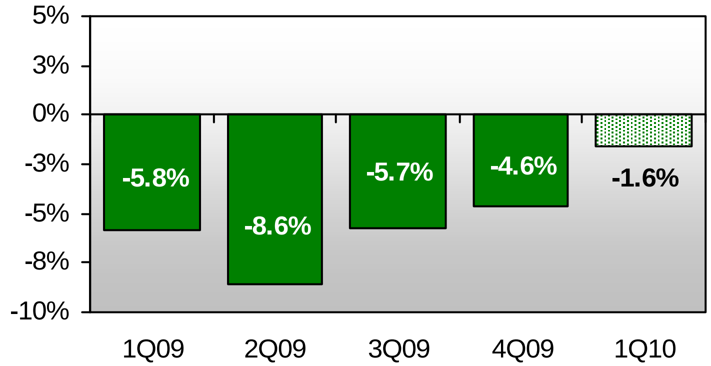
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**

AEP Total Normalized GWh Sales
Quarter %Change vs. Prior Year



<u>Quarter over Quarter change by segment:</u>
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

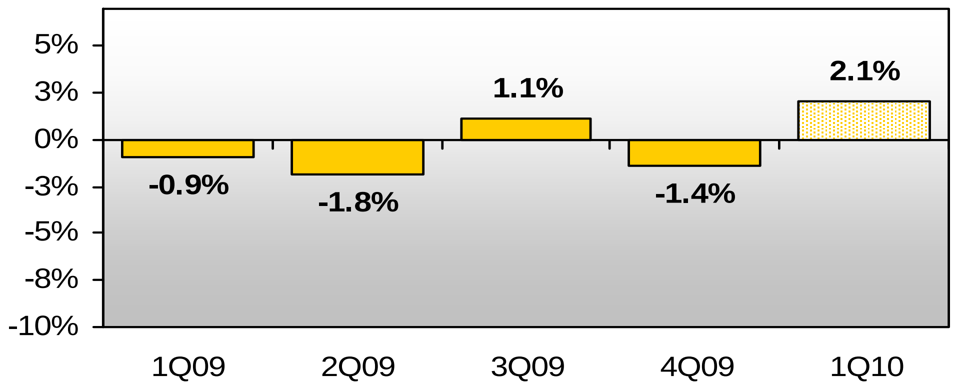
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

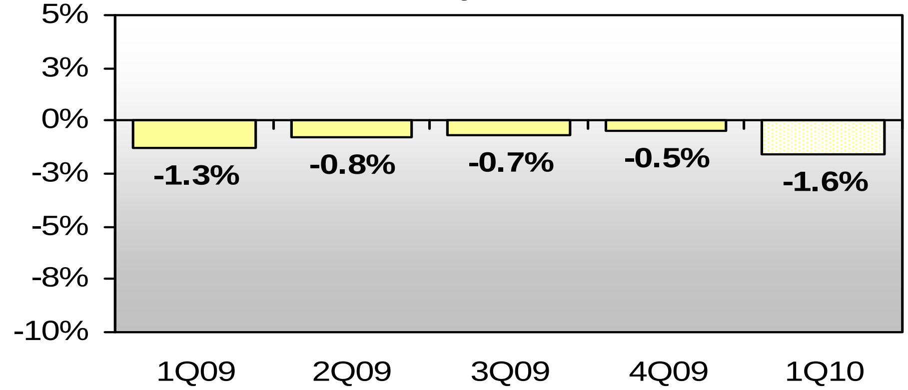
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends

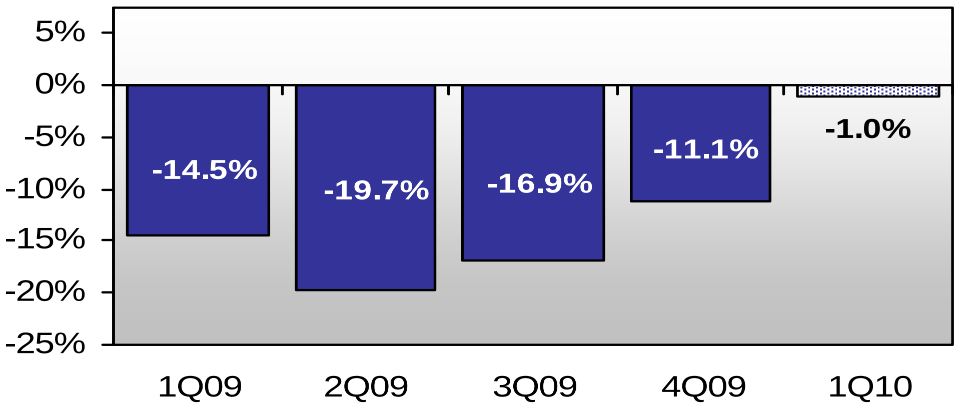
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



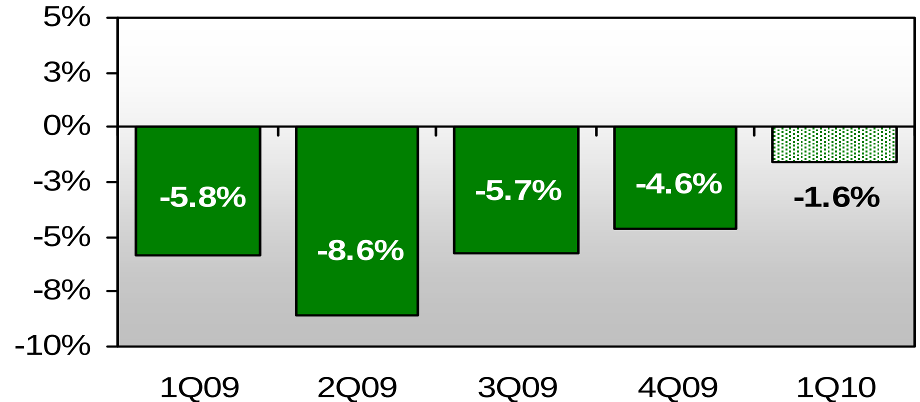
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year

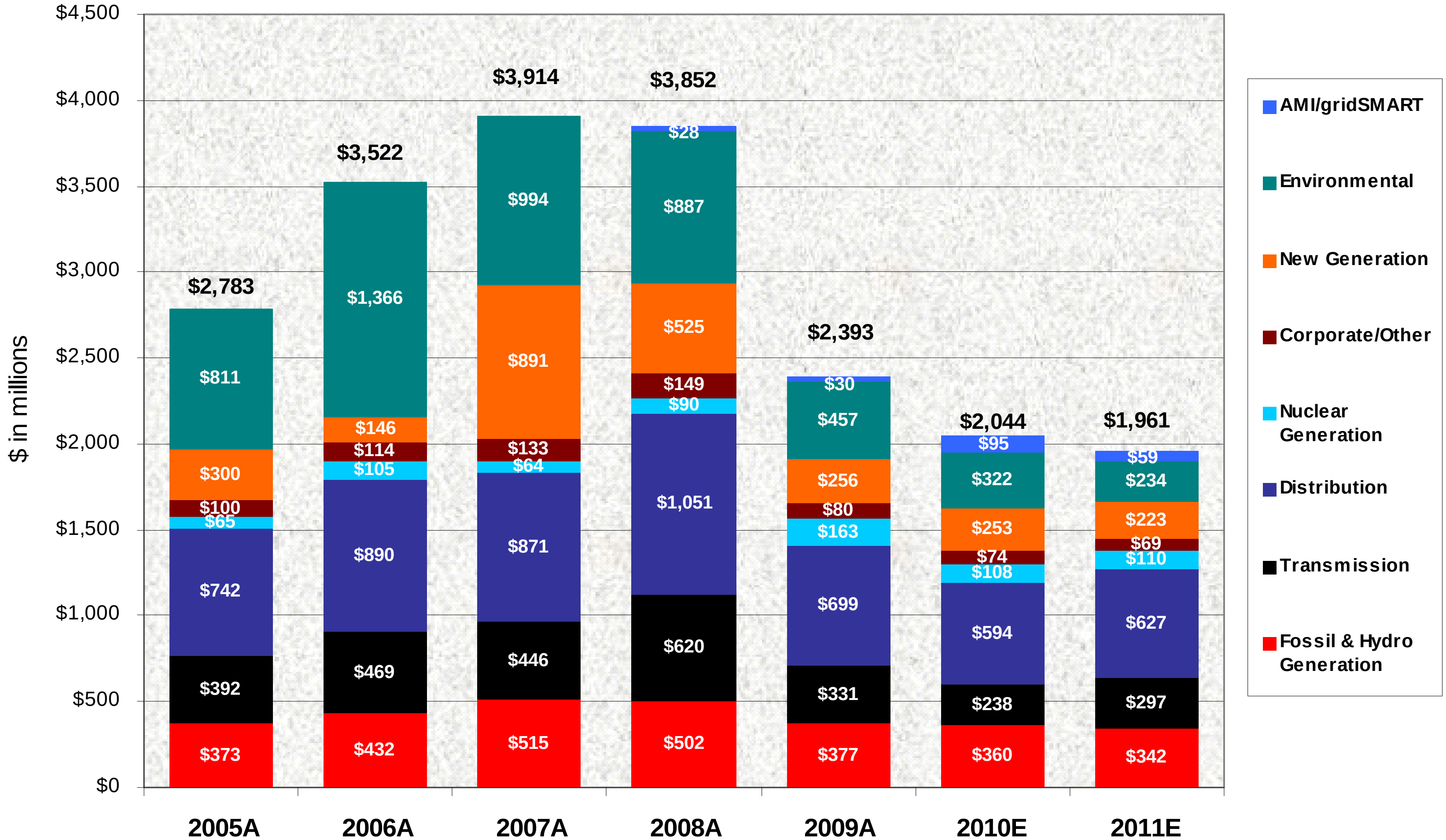


AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

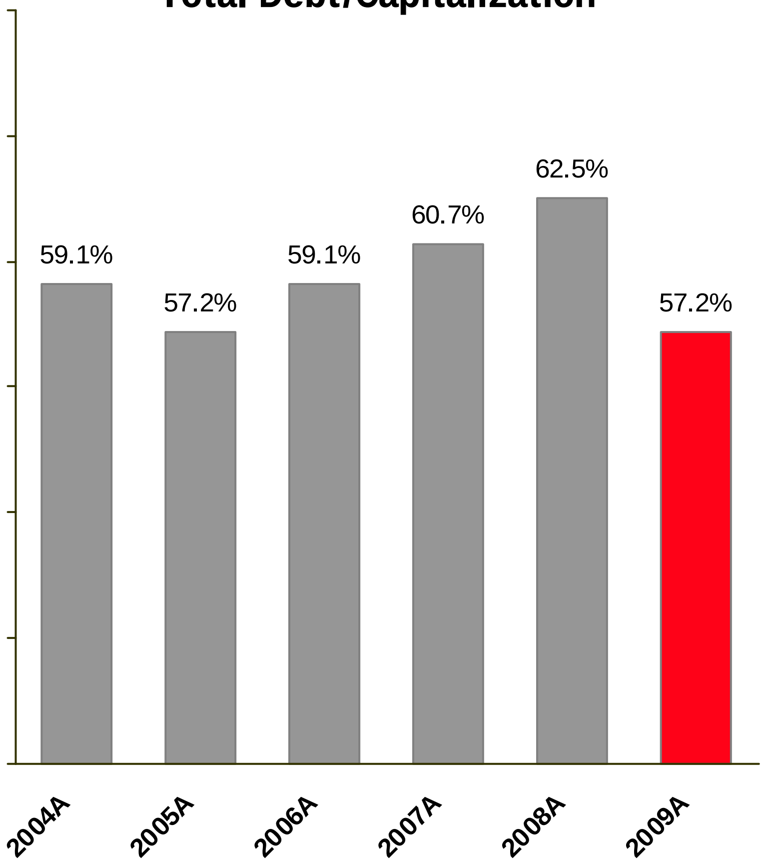
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

March 31, 2010

		Amount (in millions)	Maturity
Commercial Paper Backup:			
Revolving Credit Facility	$	1,500	March 2011
Revolving Credit Facility		1,454	April 2012
Revolving Credit Facility		627	April 2011
Total		3,581	
Cash and Cash Equivalents		818	
Total Liquidity Sources		4,399	
Less: AEP Commercial Paper Outstanding		399	
Letters of Credit Issued		652	
Net Available Liquidity	$	3,348	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	$150	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company[1]	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$500	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)
Data as of May 21, 2010

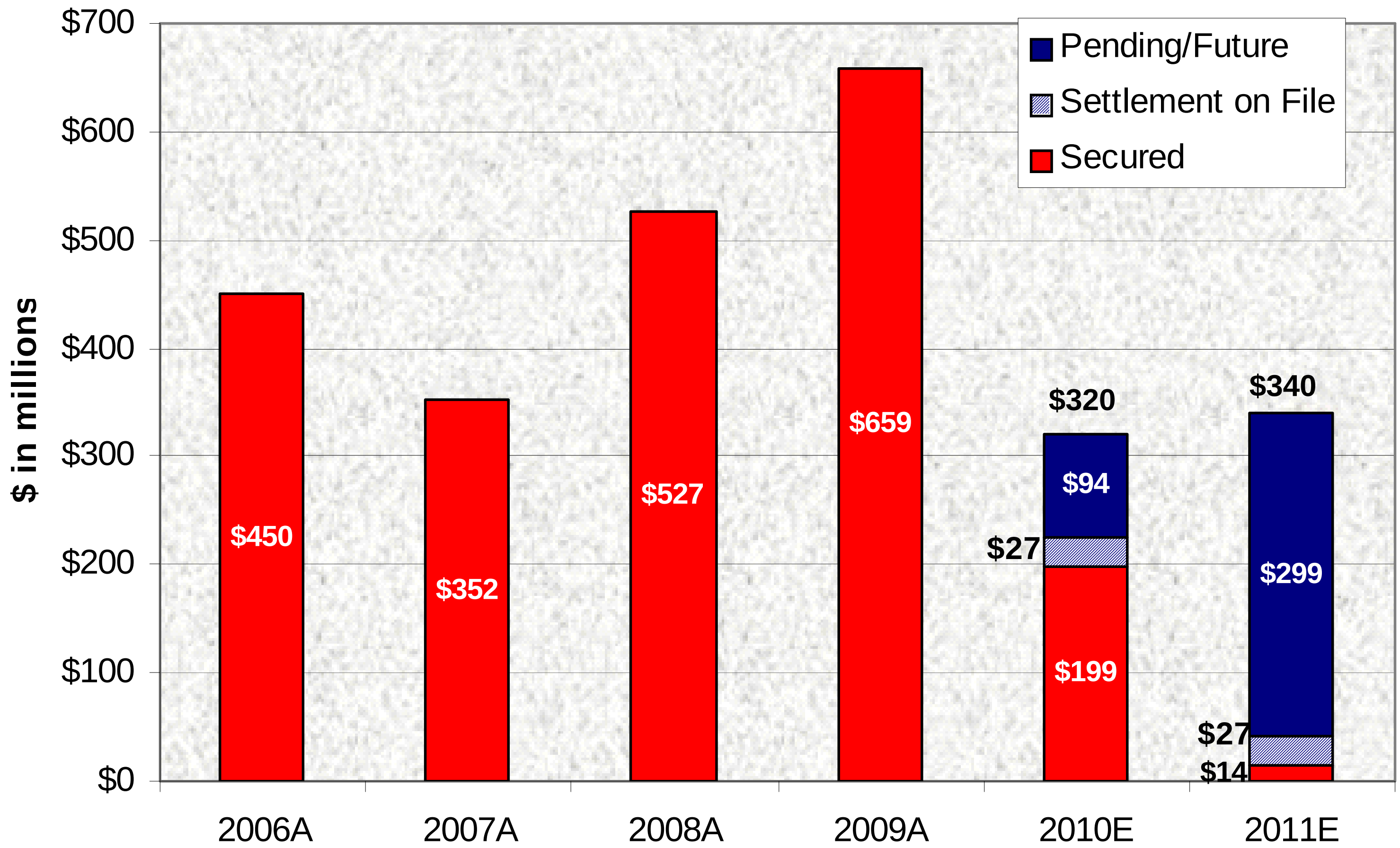
AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable, N=Negative Outlook

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Virginia, West Virginia and others yet to be filed

Settlement on File represents the Kentucky rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$ 2,057.4 *
Rate of Return	9.03%
Operating Income Requirement	$ 185.7
Adjusted Operating Income	$ 92.0
Difference	$ 93.7
Revenue Conversion Factor	1.64
Total Required Rate Relief	$ 154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. A settlement agreement was filed with the KPSC on May 20, 2010. Commission approval is pending.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
May 25, 2010	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. A procedural schedule is pending from the WVPSC. An order is expected in March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule - tbd

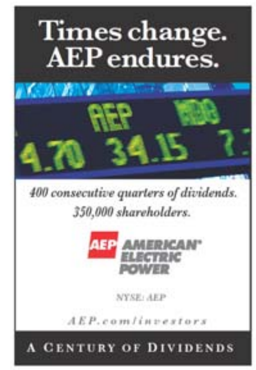
Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Value Proposition

- **Current Yield Opportunity of 5.4%[1]**
  - **June 10th – 400th consecutive quarterly dividend will be paid to shareholders**
  - **50-60% payout ratio targeted**
  - **Dividend increased 2.44% on April 27th**
- **Earnings Growth Prospects**
  - **Investment in utility platform greater than depreciation level (2 - 4%)**
  - **With transmission opportunities (4 - 8%)**



Attractive total return potential

[1] yield percentage based on AEP closing price of $31.20 on 06/01/2010

Third Annual Citi

Power, Gas & Utilities Conference

June 5, 2008

Washington, D.C.

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Table of Contents

Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

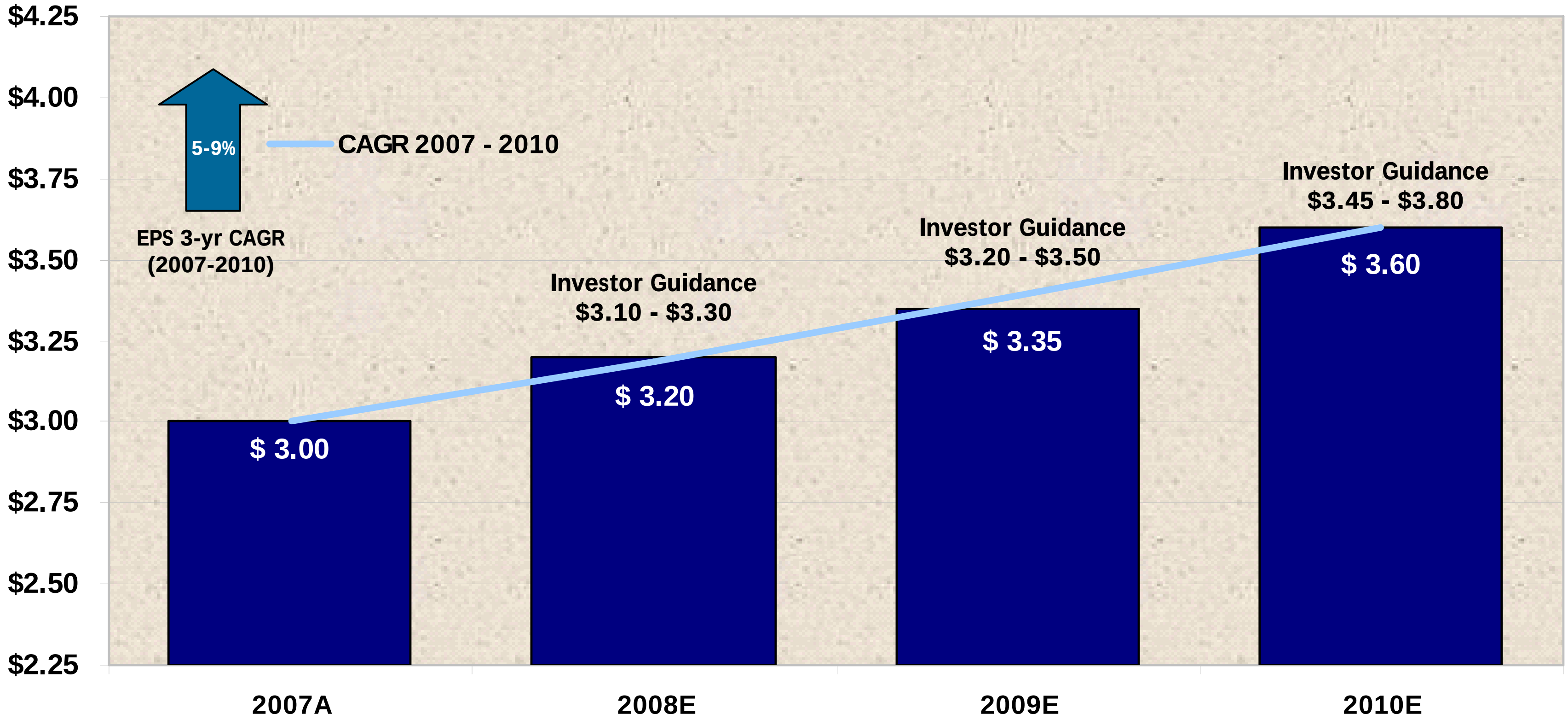
- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP has significant presence throughout the energy value chain.

AEP®

4-Year Earnings Range Forecast



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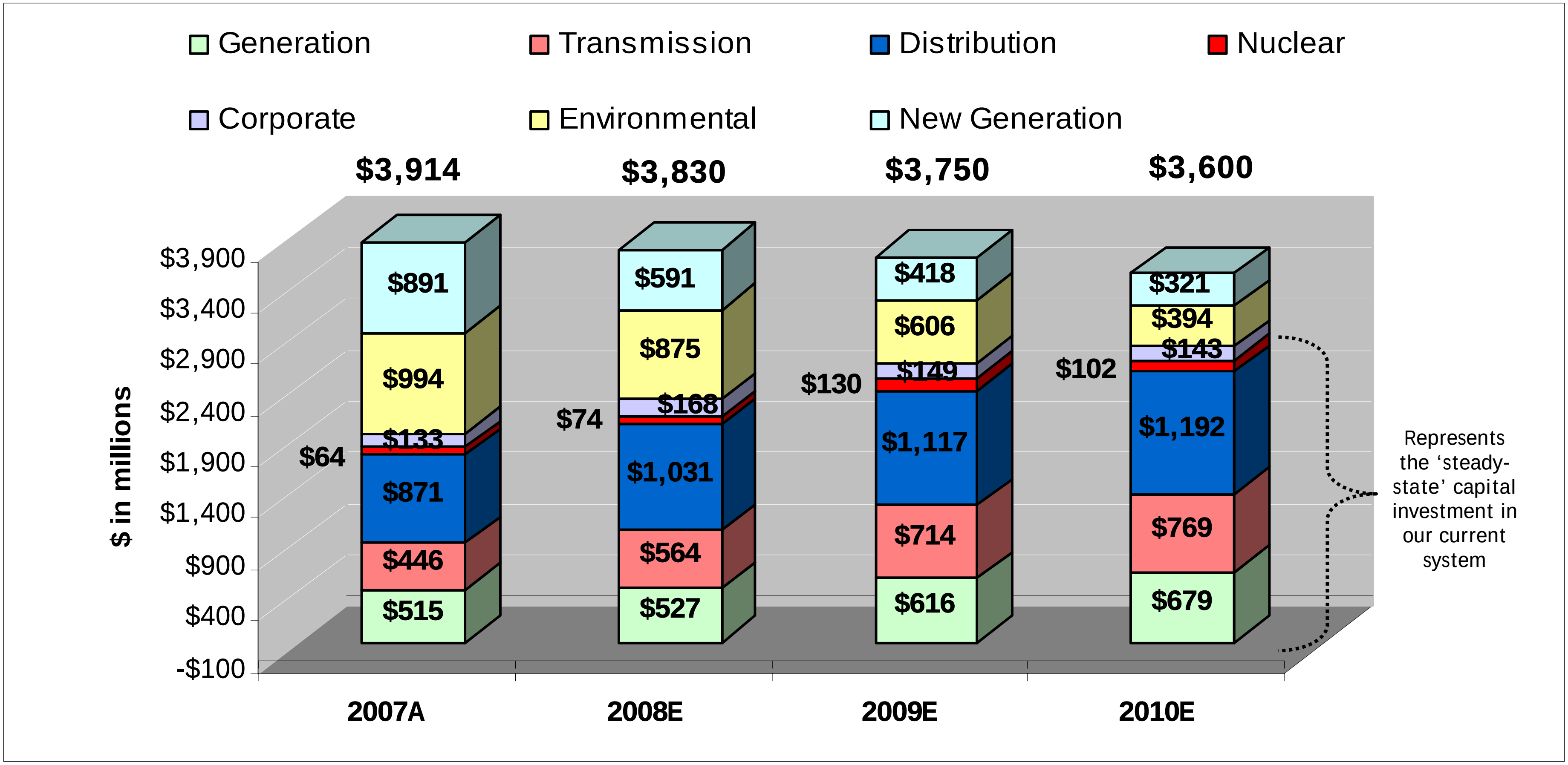
5% to 9% earnings growth

Annual Capital Investment Cycle



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects.

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Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

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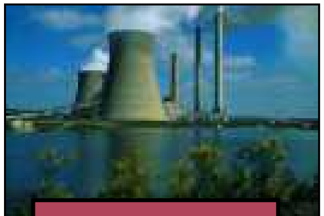
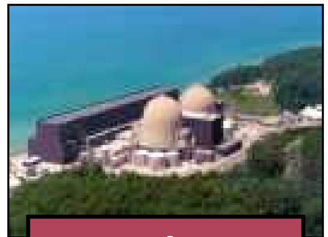
Domestic Generation Fleet

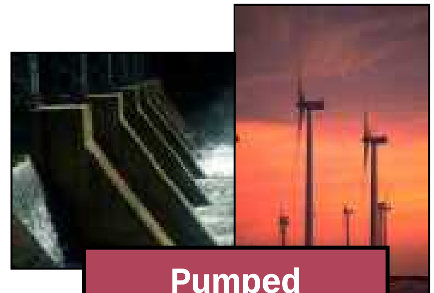


Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

*** Includes 270MW of retired/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

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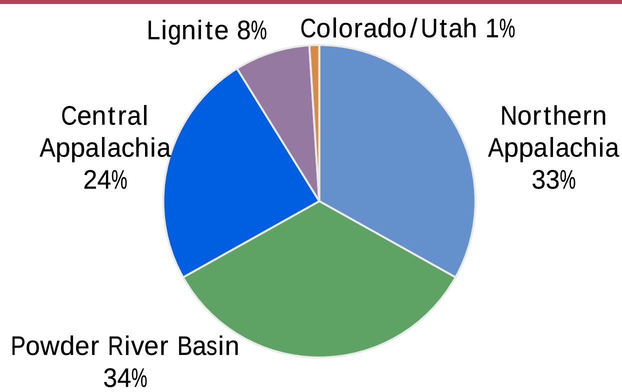
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

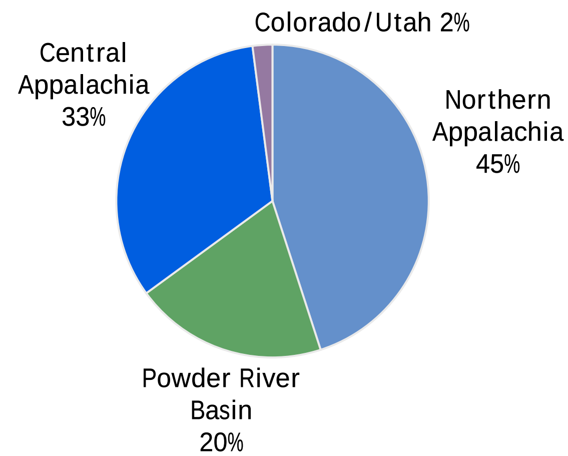
Total AEP System



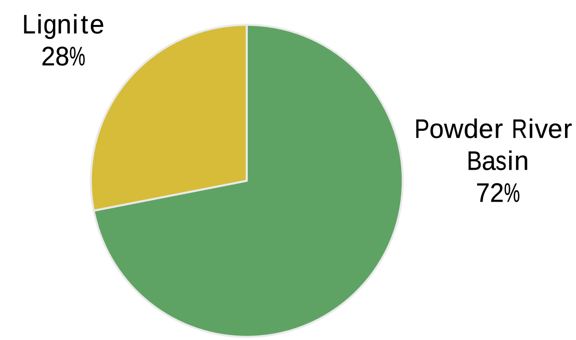
Coal Stats:

- Approximately 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 14%-18% price increase in 2008 based on 2007 actual results.

AEP East



AEP West



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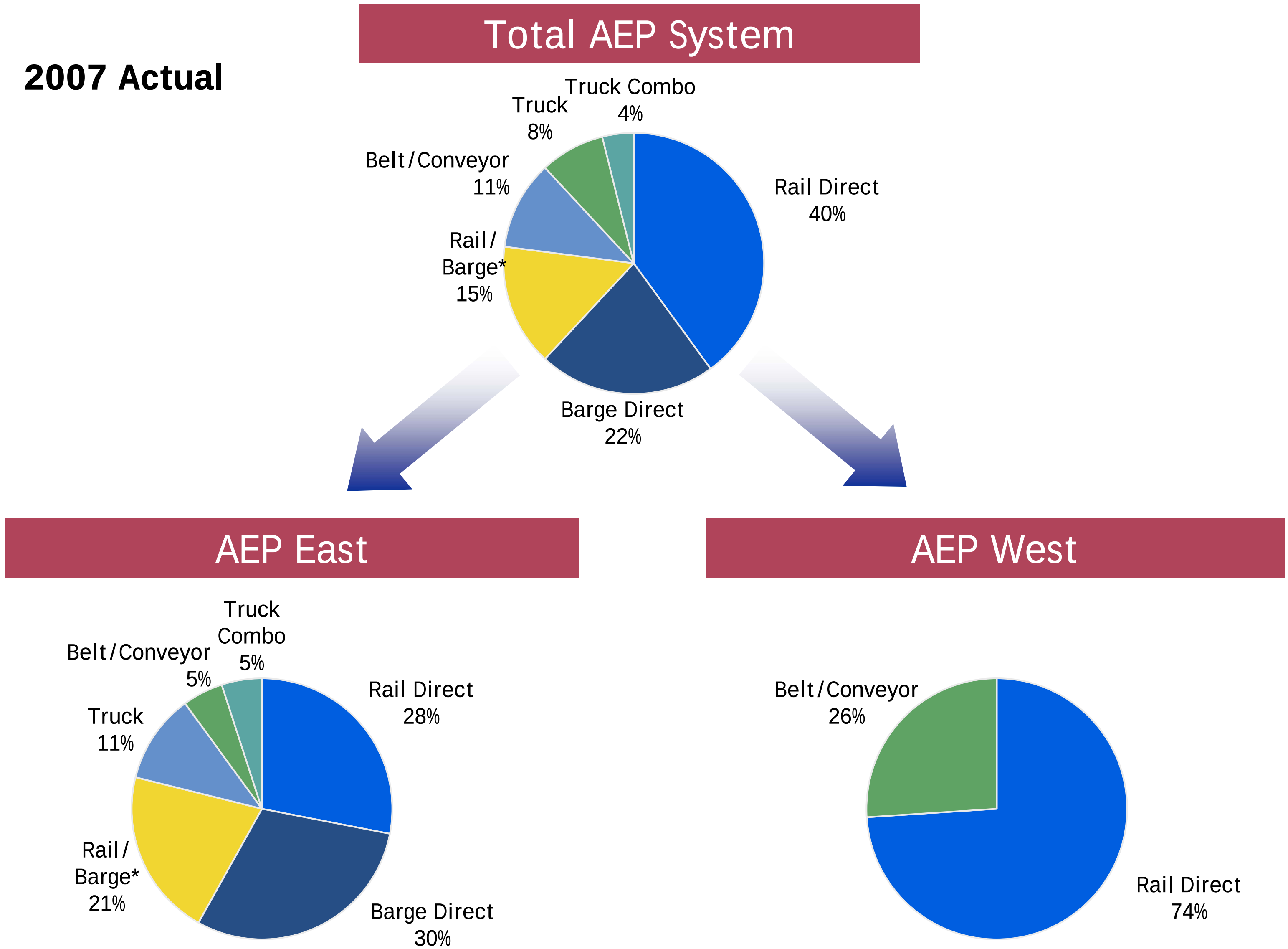
Coal Delivery

2007 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

AEP®

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$305 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Distribution - gridSMART[SM]

•gridSMART[SM]: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

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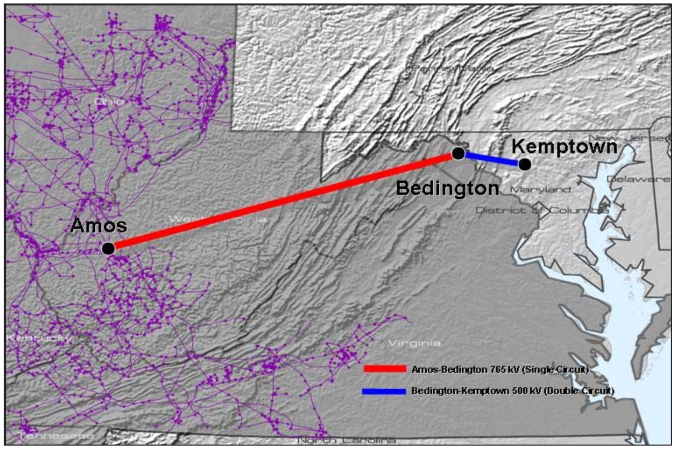
I-765™ Transmission: Investment Opportunities

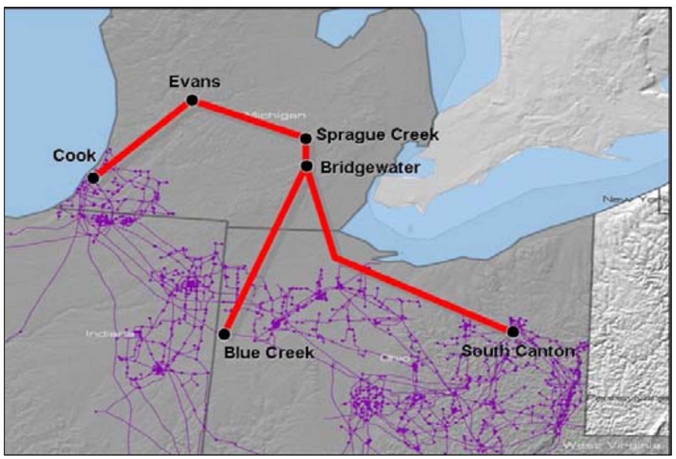
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)

Electric Transmission Texas

ETT (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

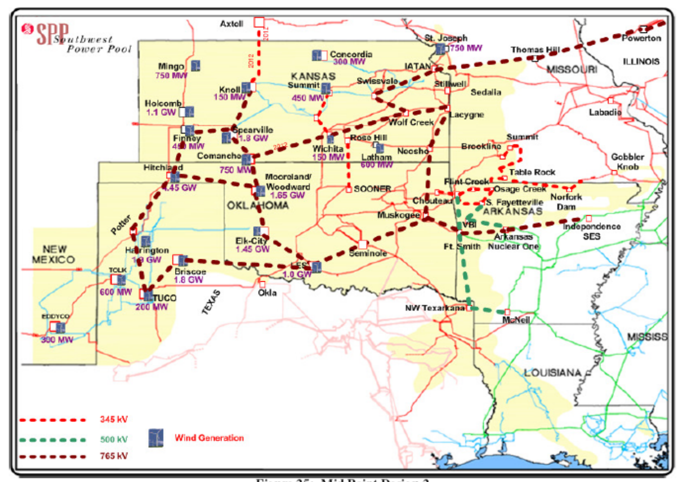


Figure 25: Mid Point Design 2

SPP Overlay Study - Mid Design 2

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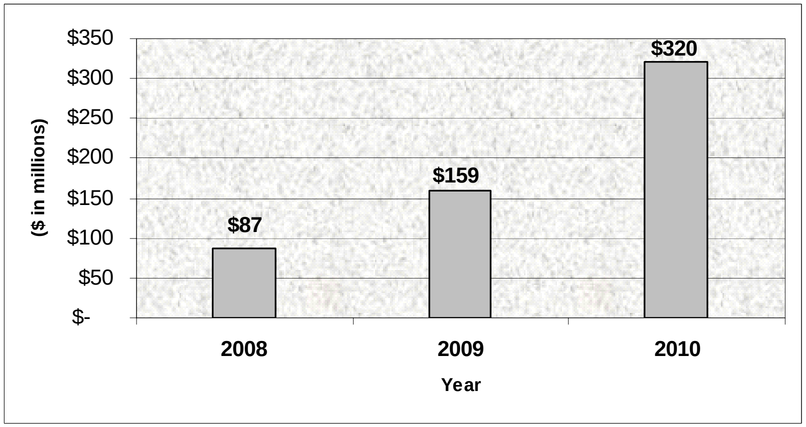
Transmission - Investments and Earnings Contributions

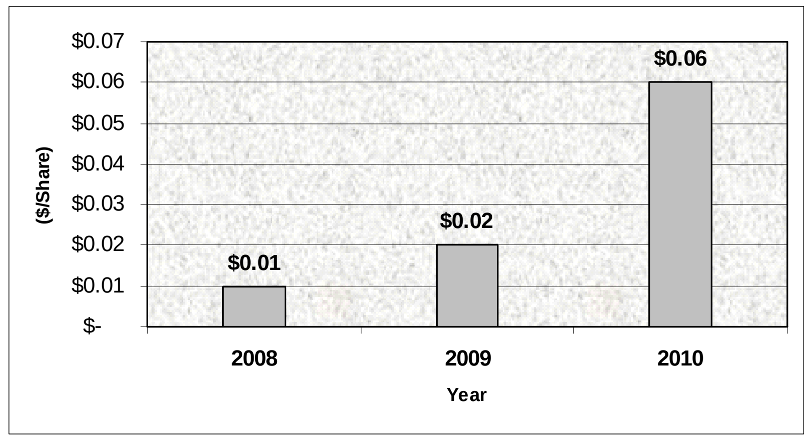
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

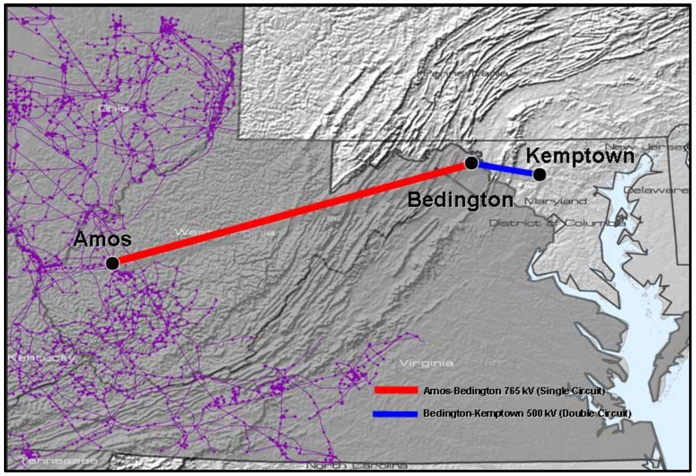
PATH Potomac-Appalachian Transmission Highline

AEP

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
- To that end, ETA recently signed an agreement with Westar forming Prairie Wind Transmission, LLC proposing to build the first segment of the 765-kv Overlay Plan in SPP

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I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

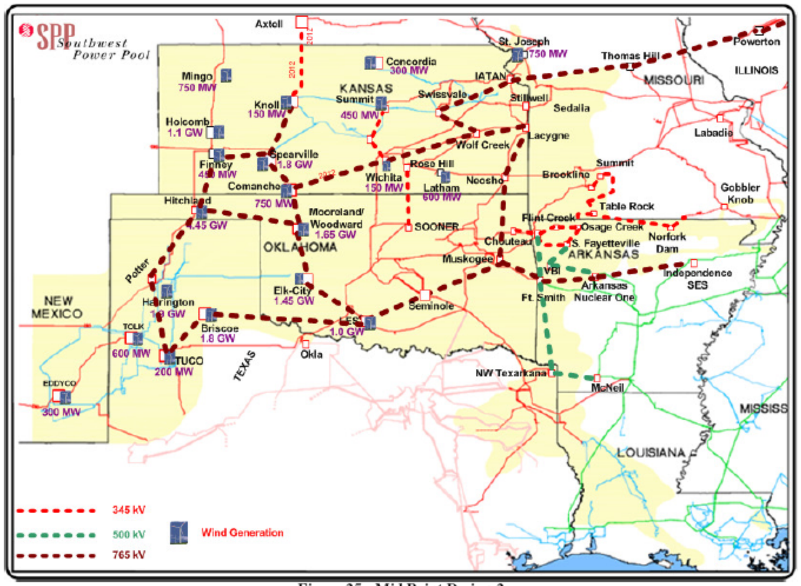


Figure 25: Mid Point Design 2

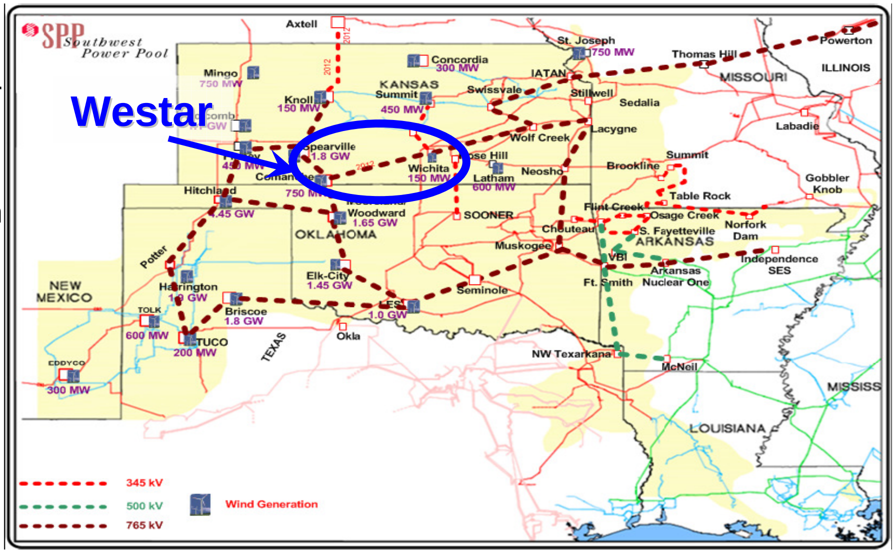
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765 kV Engineering, 765 kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



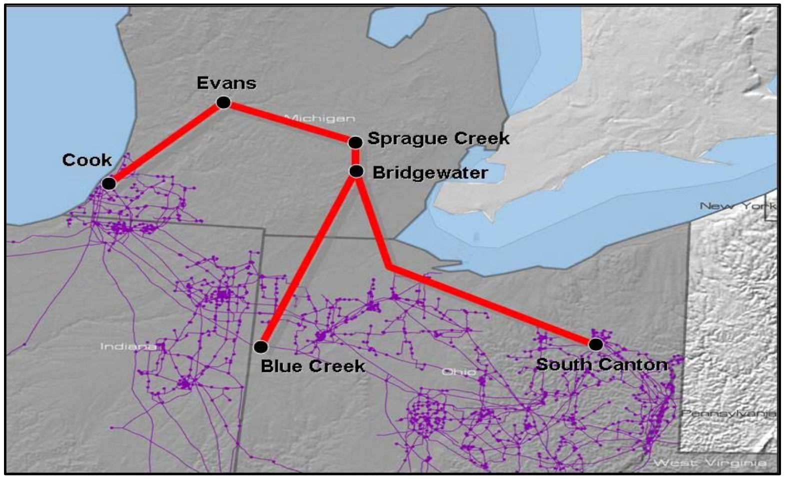
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

AEP®

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP®

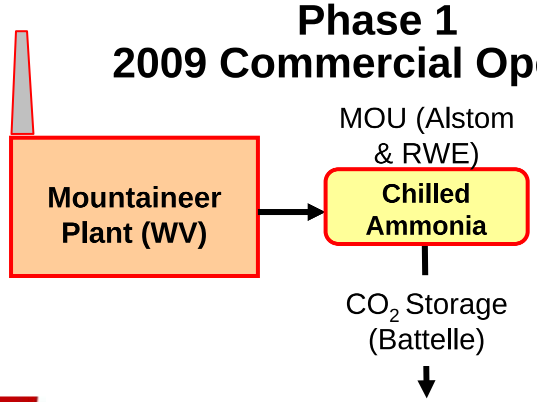
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

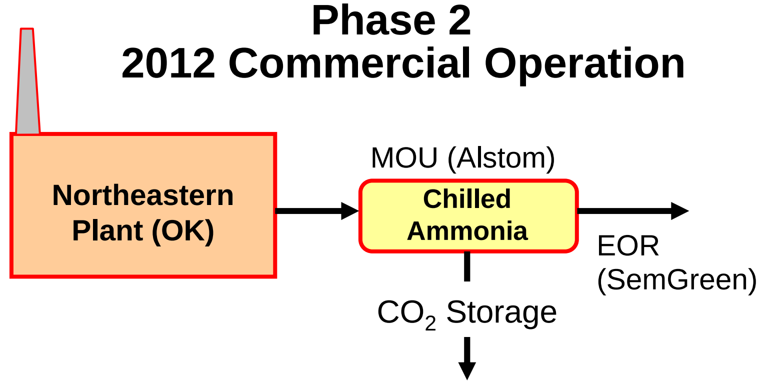
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



CO_2 Capture Techniques

- **Post-Combustion Capture**
  - Conventional or Advanced Amines, Chilled Ammonia
    - Amine technologies commercially available in other industrial applications
    - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
    - High parasitic demand
      - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
    - Amines require **very** clean flue gas
- **Modified-Combustion Capture**
  - Oxy-Coal
    - Technology not yet proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - High parasitic demand, >25%
- **Pre-Combustion Capture**
  - IGCC with Water-Gas Shift
    - Most of the processes commercially available in other industrial applications
      - Have never been integrated together
    - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

AEP®

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- APCo-VA – Base Rate Case
- PSO—Base Rate Case to be filed mid-summer
- SPP OATT Formula Rate Filing
- New Generation:
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas
  - IGCC

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

Appalachian Power-Virginia Base Rate Case filing

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. If an order is not received by the end of October 2008, interim rates can go into effect at that time subject to refund. (Docket # PUE-2008-00045)

Key Rate Case components:	
Requested Rate Base	**$2,415MM**
Requested ROE	**11.75%**
Requested ROR	**8.516%**
Test Year	**12 months ended 12/31/07 adjusted through 6/30/2008**

Appalachian Power-Virginia E&R filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filing with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009.(Docket # PUE-2008-00046

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred:	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/04 -- 9/30/05	12/1/06 --11/30/07	$21.3 MM
II	PUE-2007-00069	10/1/05 -- 9/30/06	1/1/2008 --12/31/08	$48.9 MM
III	PUE-2008-tbd	10/1/06 --12/31/07	Proposed 1/1/09-12/31/09	$66.5 MM

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on April 29, 2008, and on May 29, 2008 the SCC denied our request to reconsider the previous rejection. We are now reviewing various options.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as resolution of pending rulemaking related to SB221 in Ohio.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearings were held May 29-30, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

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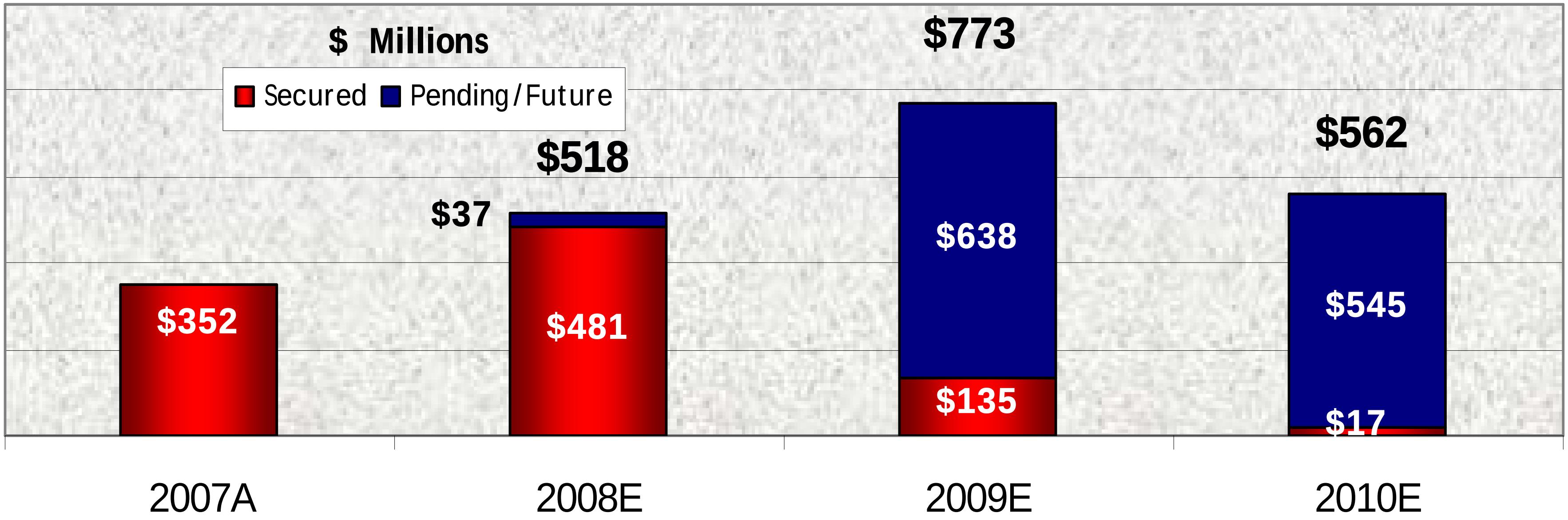
Incremental Rate Relief



- 93% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan.

- 2008 Pending: 2008 TCC/TNC TCRF filings, other cases yet to be filed including Virginia base case.
- 2009 rate relief includes OH, IN, VA, OK, and miscellaneous other jurisdictions

Secured $481MM of $518MM for 2008

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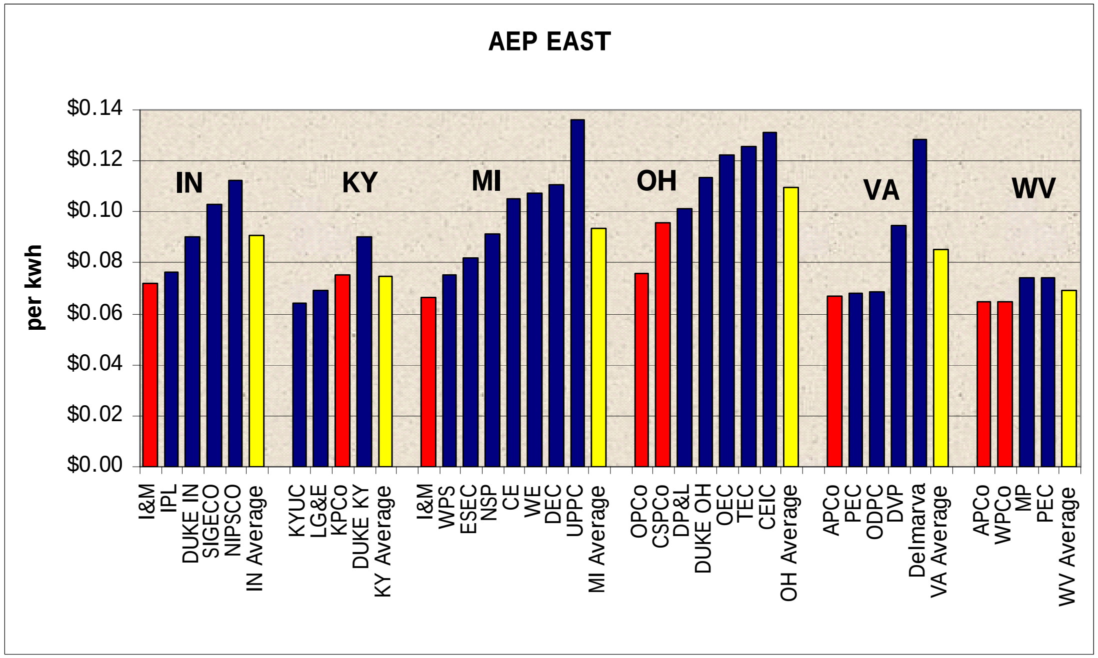
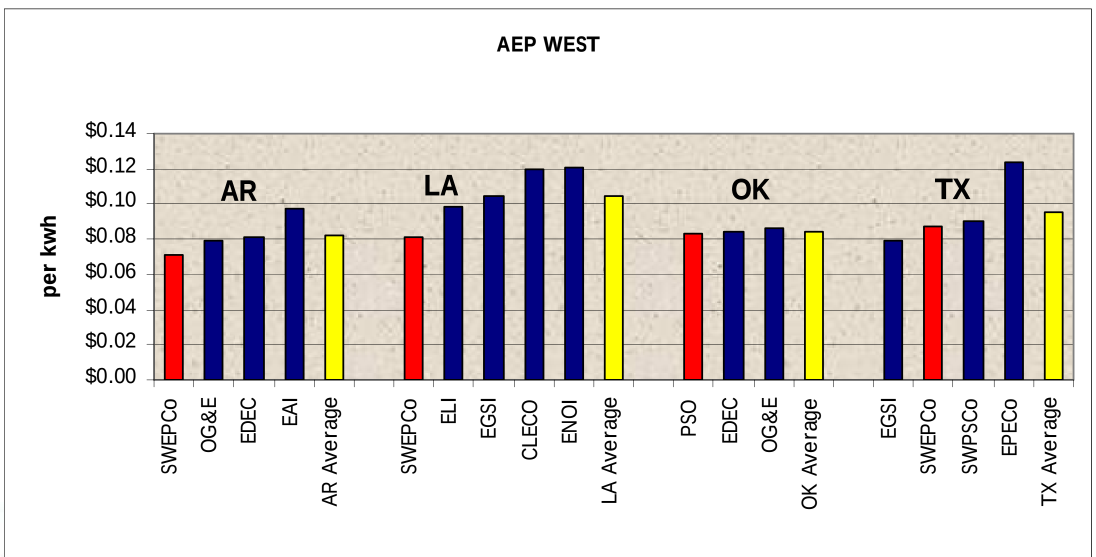
AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

Our low cost provider status in most of our jurisdictions, coupled with our scale and scope, allows us the flexibility to navigate current and future macro-economic issues.

- AEP Company
- Other Company within state
- State Average

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4682 of 9556

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP®

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

AEP®

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

AEP®

AEP AMERICAN® ELECTRIC POWER

Citi and Clients Office Visit

Columbus, OH
August 30, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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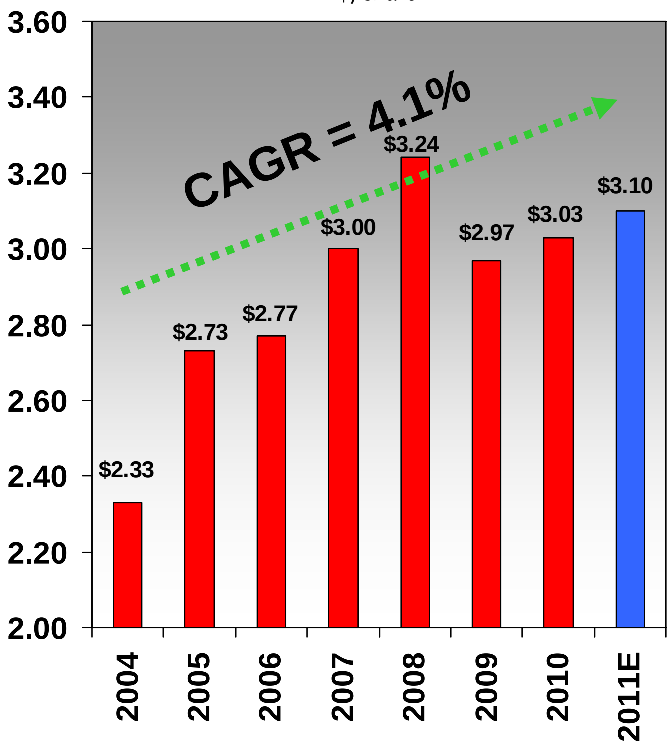
Table of Contents

Earnings and Dividends

On-Going EPS History Since 2004

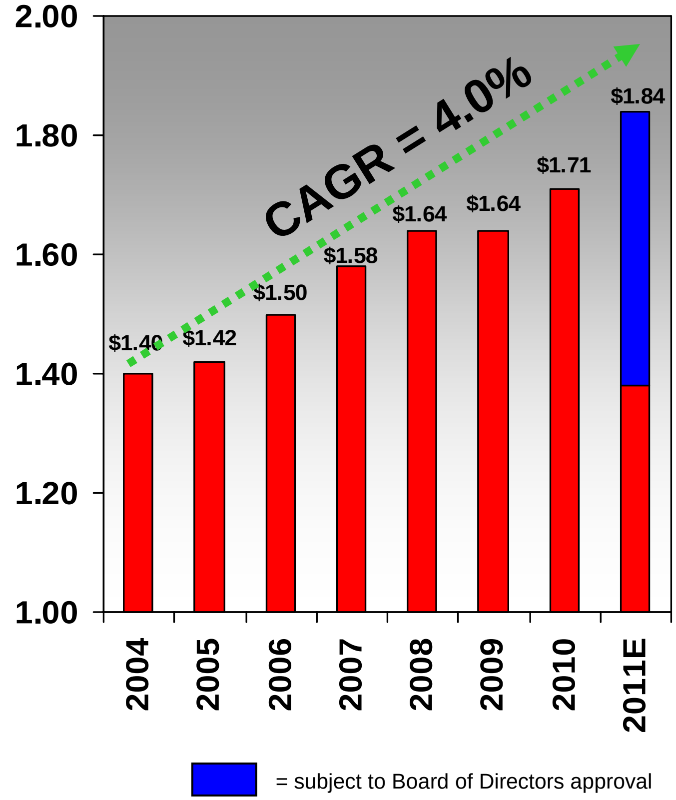
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield near 5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

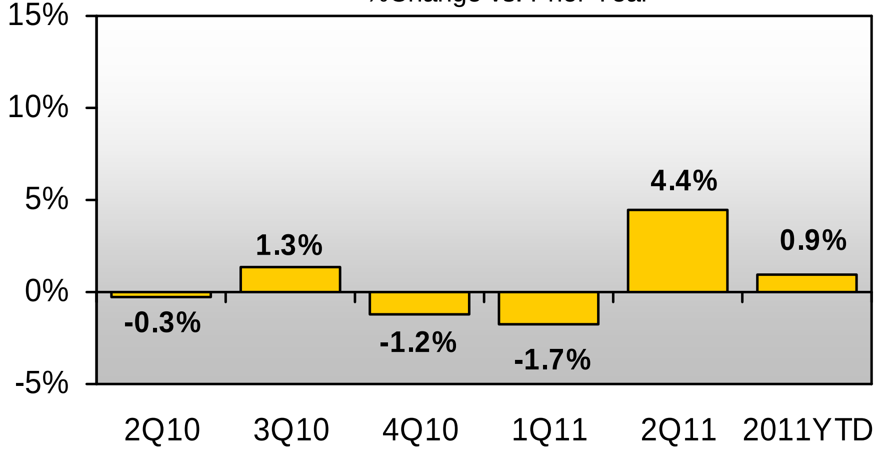
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

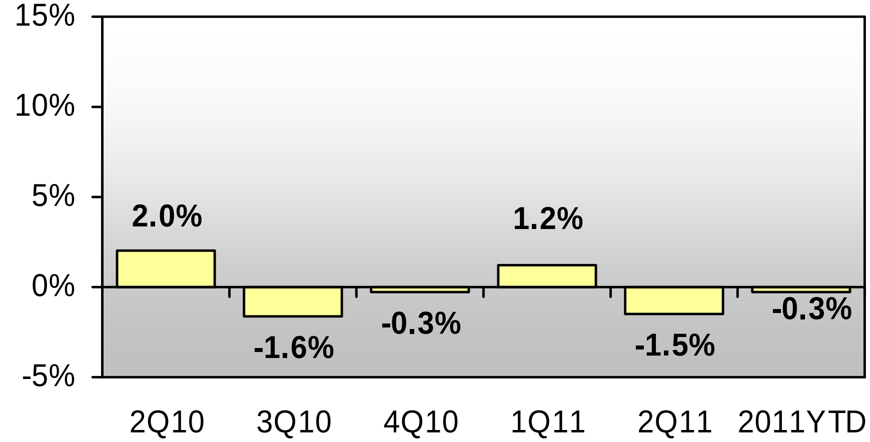
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

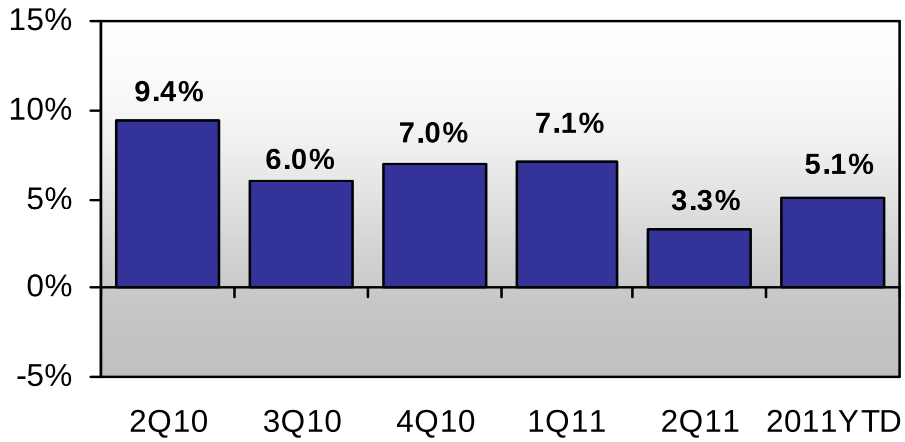
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



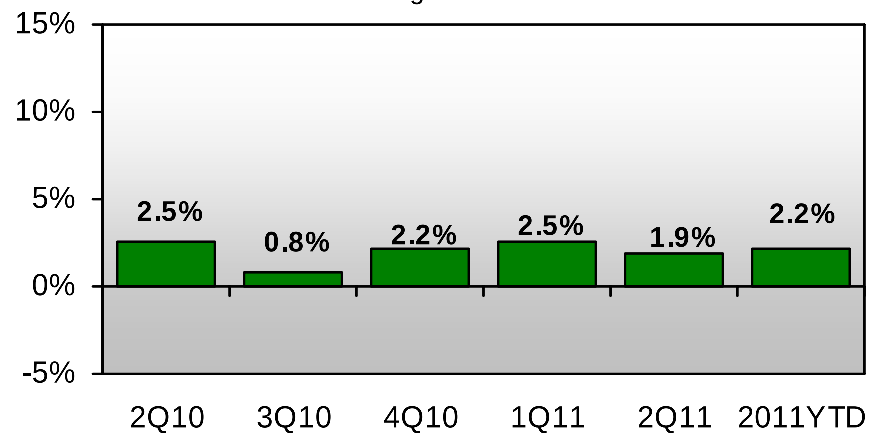
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



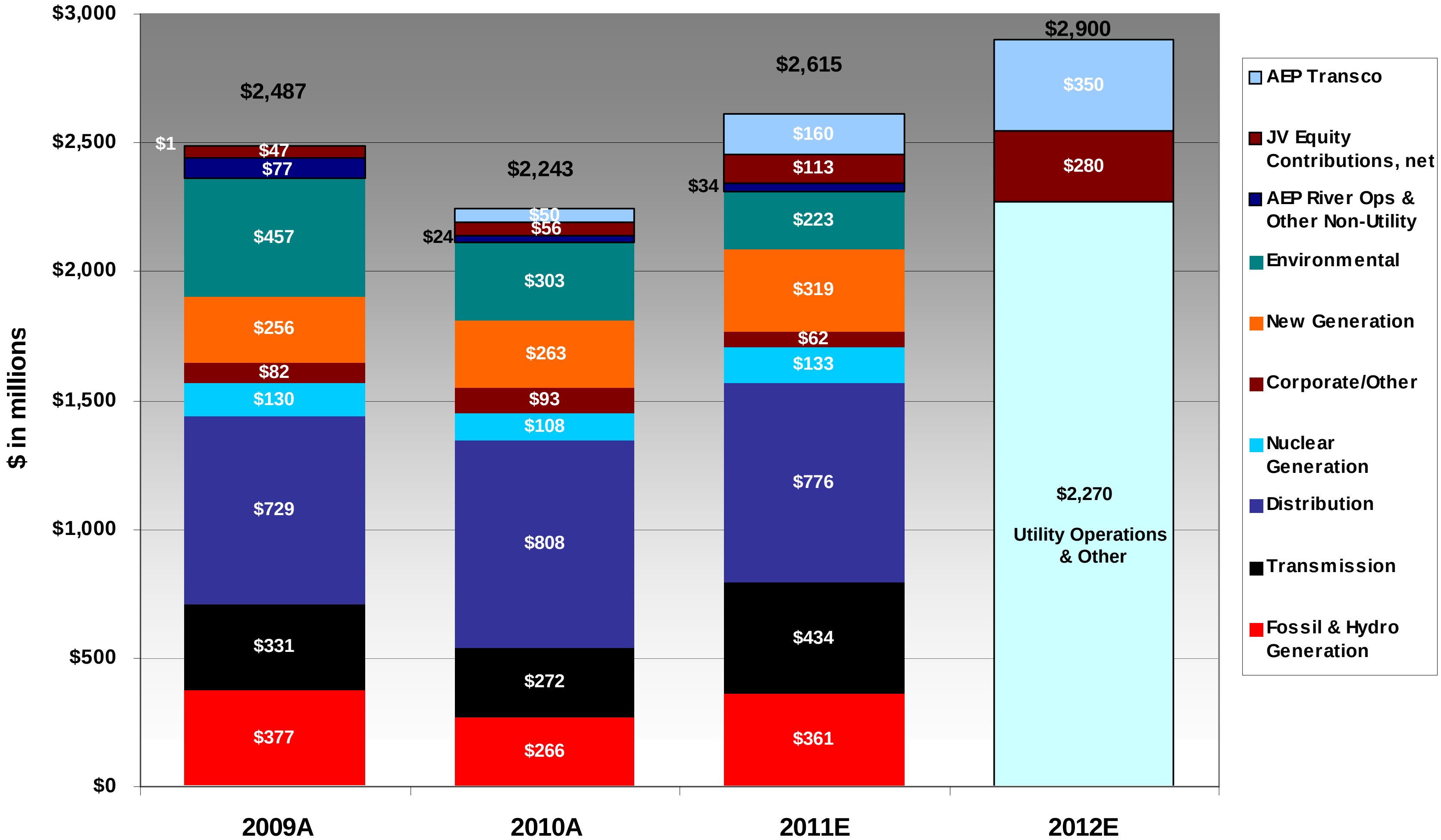
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Cash Flow Guidance

$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

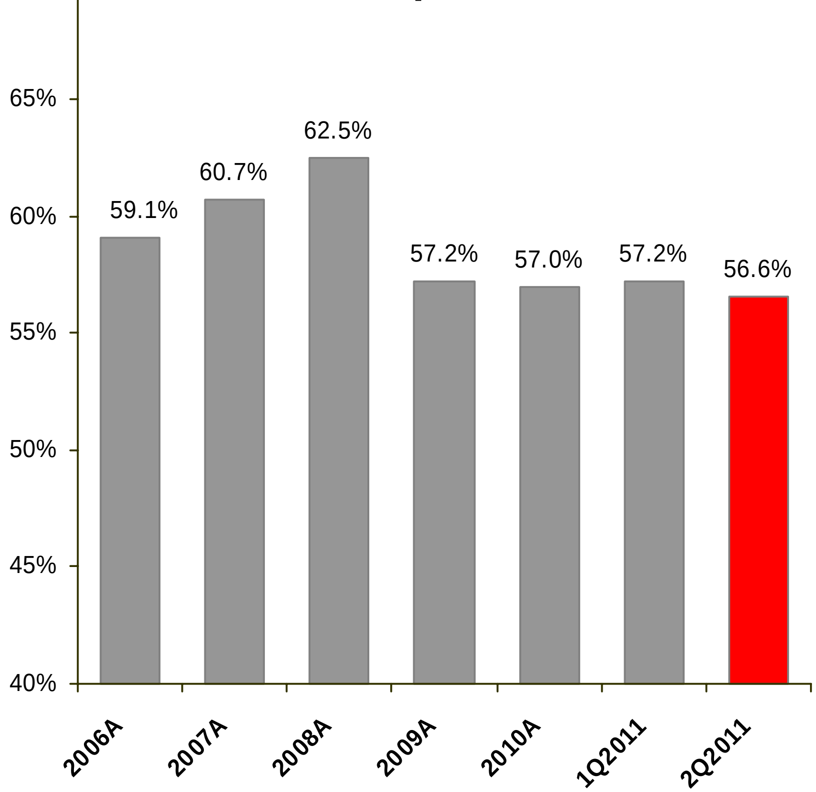
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

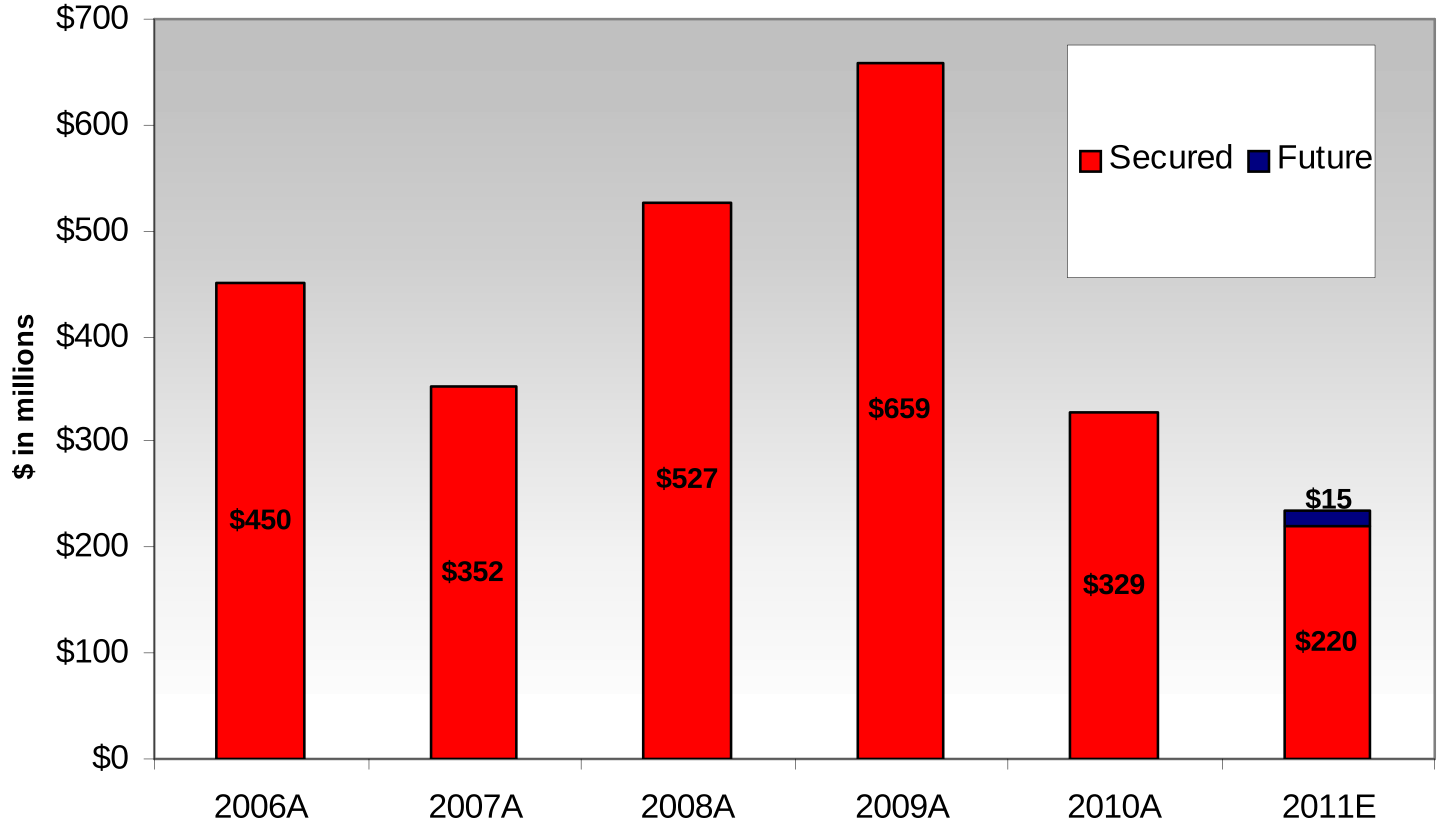
Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Procedural Schedule - tbd

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Summary Rate Case Information

AEP®

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed.   APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Rates Implemented, subject to refund	January 1, 2012
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 25; Staff testimony – August 4; Hearing – August 31**

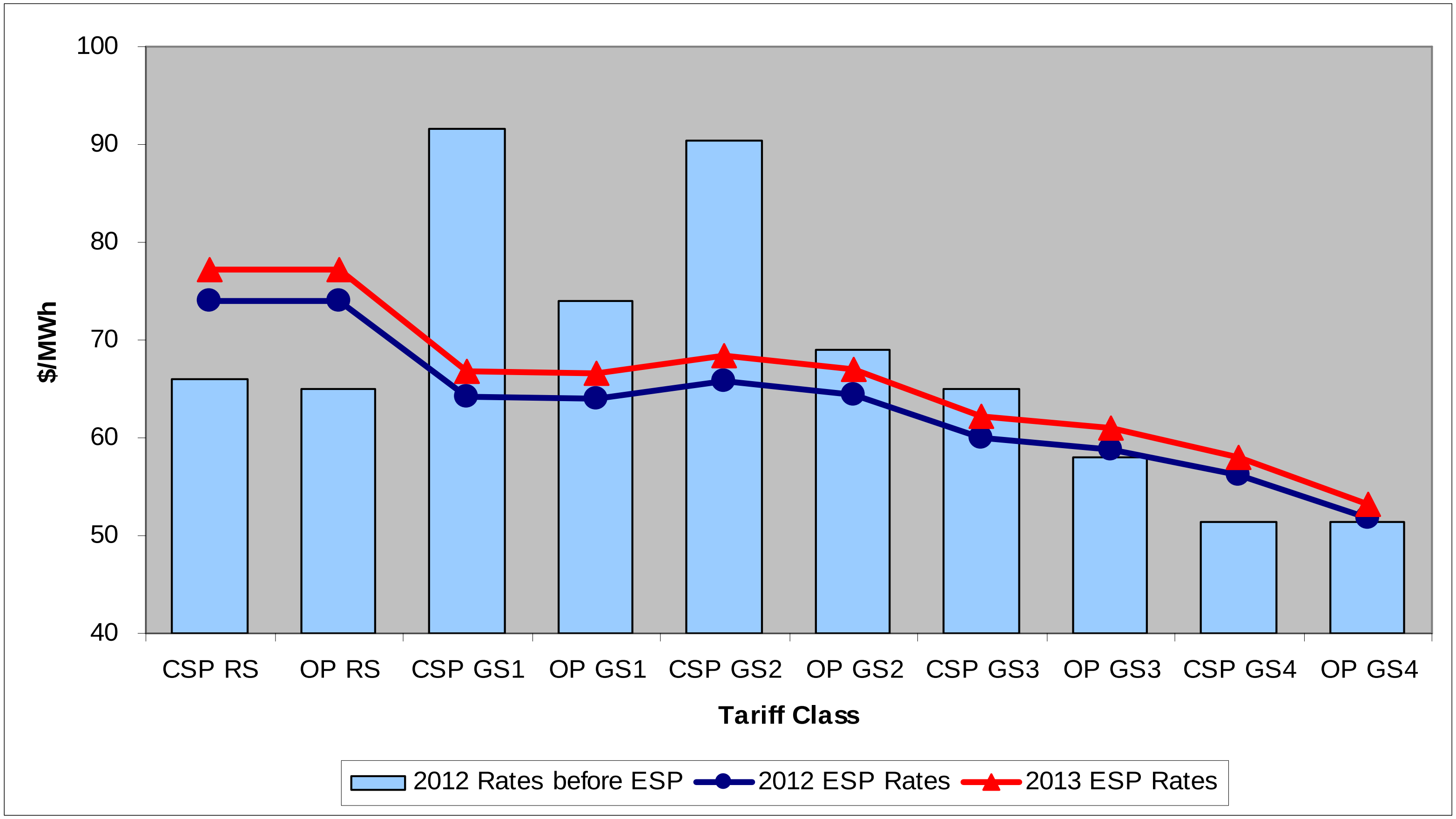
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

AEP®

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP AMERICAN ELECTRIC POWER®

2010 Citi North American Credit Conference

November 17, 2010
New York, NY

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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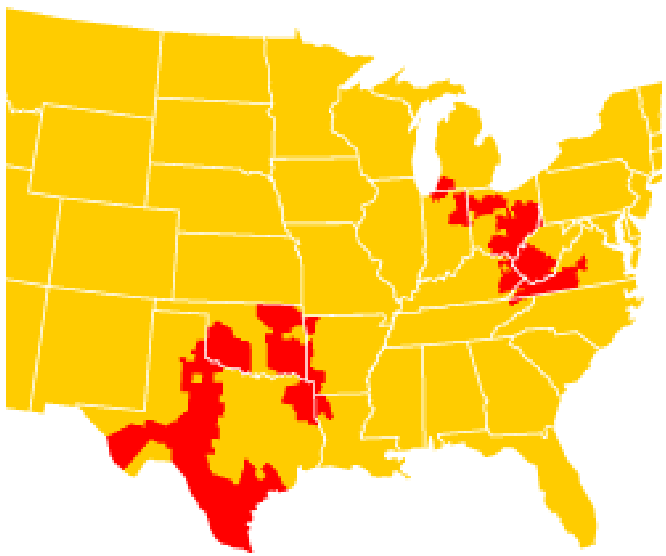
American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield near 5%

Serving electric customers in 11 states



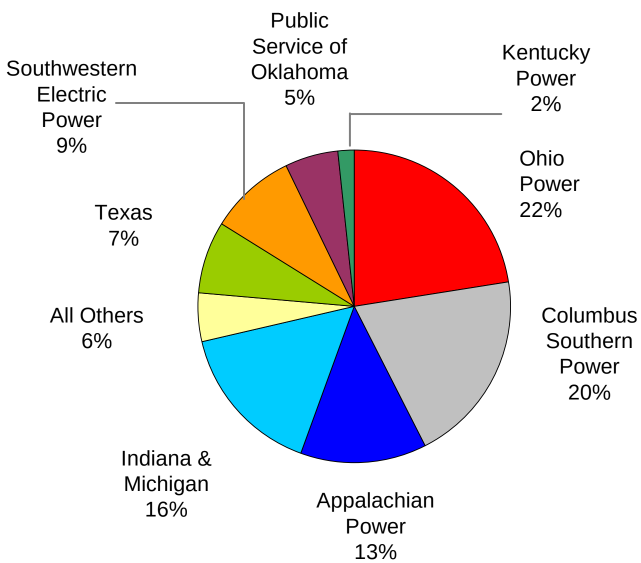
AEP Fast Facts

5.2 million customers
40 GW of generation capacity
39,000 miles of transmission lines

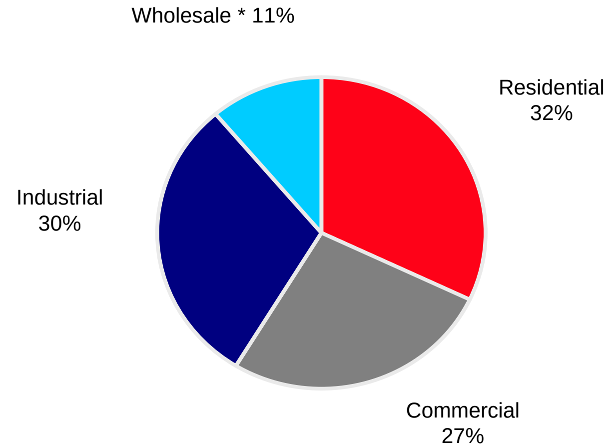
$17.5B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2009 Earnings Contribution



2009 Retail Load

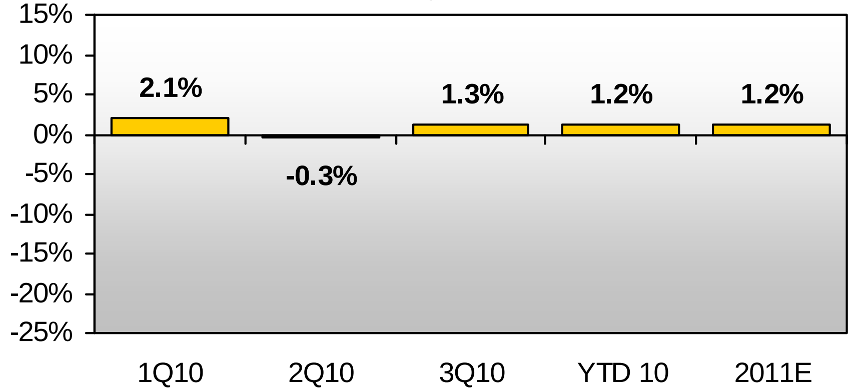


* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

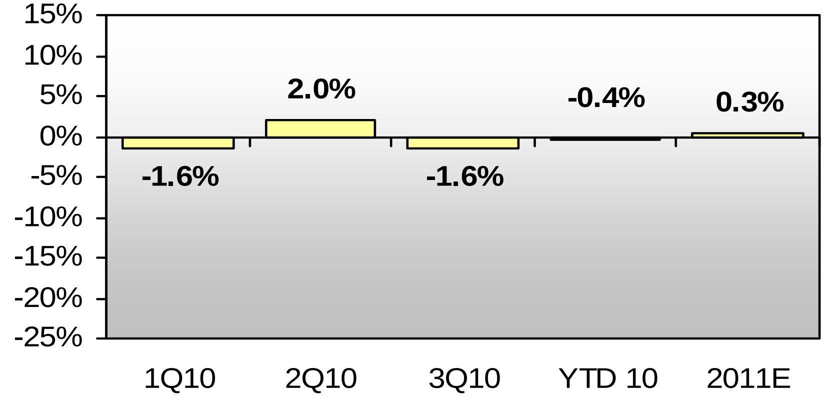
Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

Normalized Load Trends

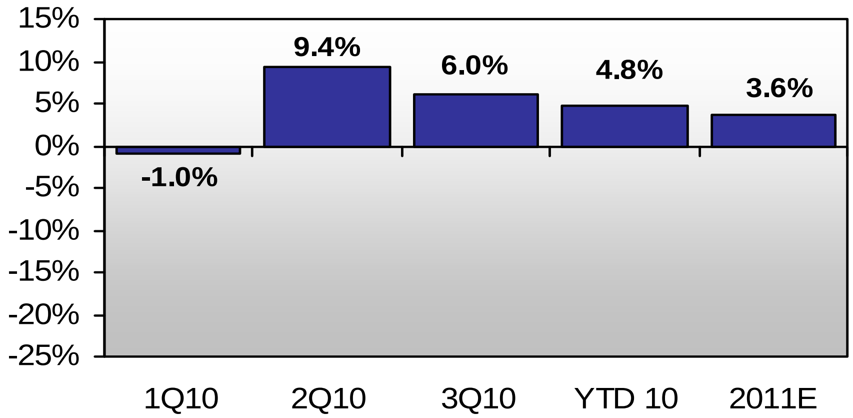
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



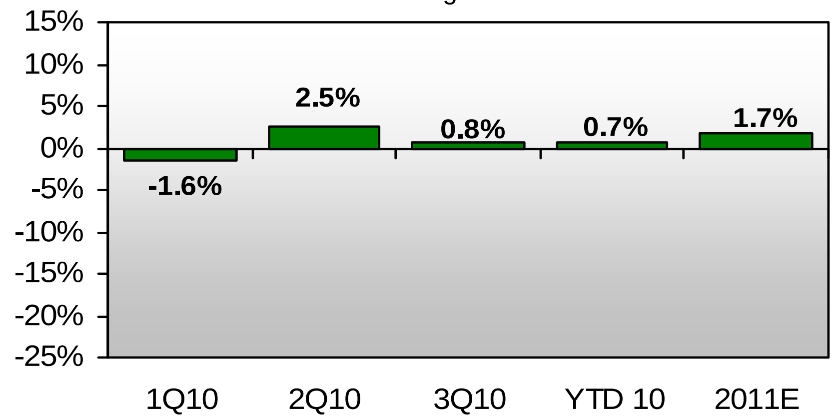
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



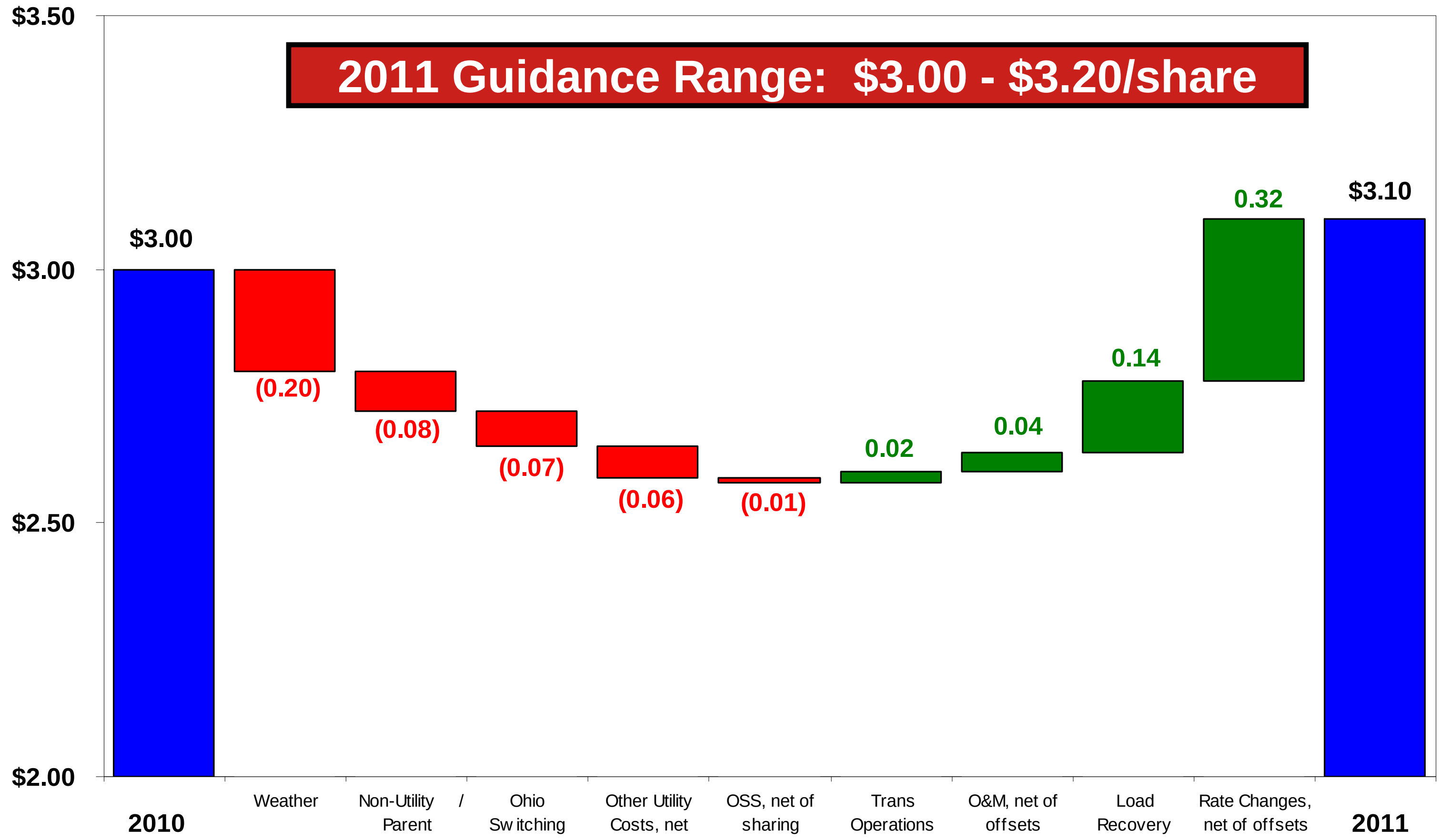
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

2011 Earnings Drivers

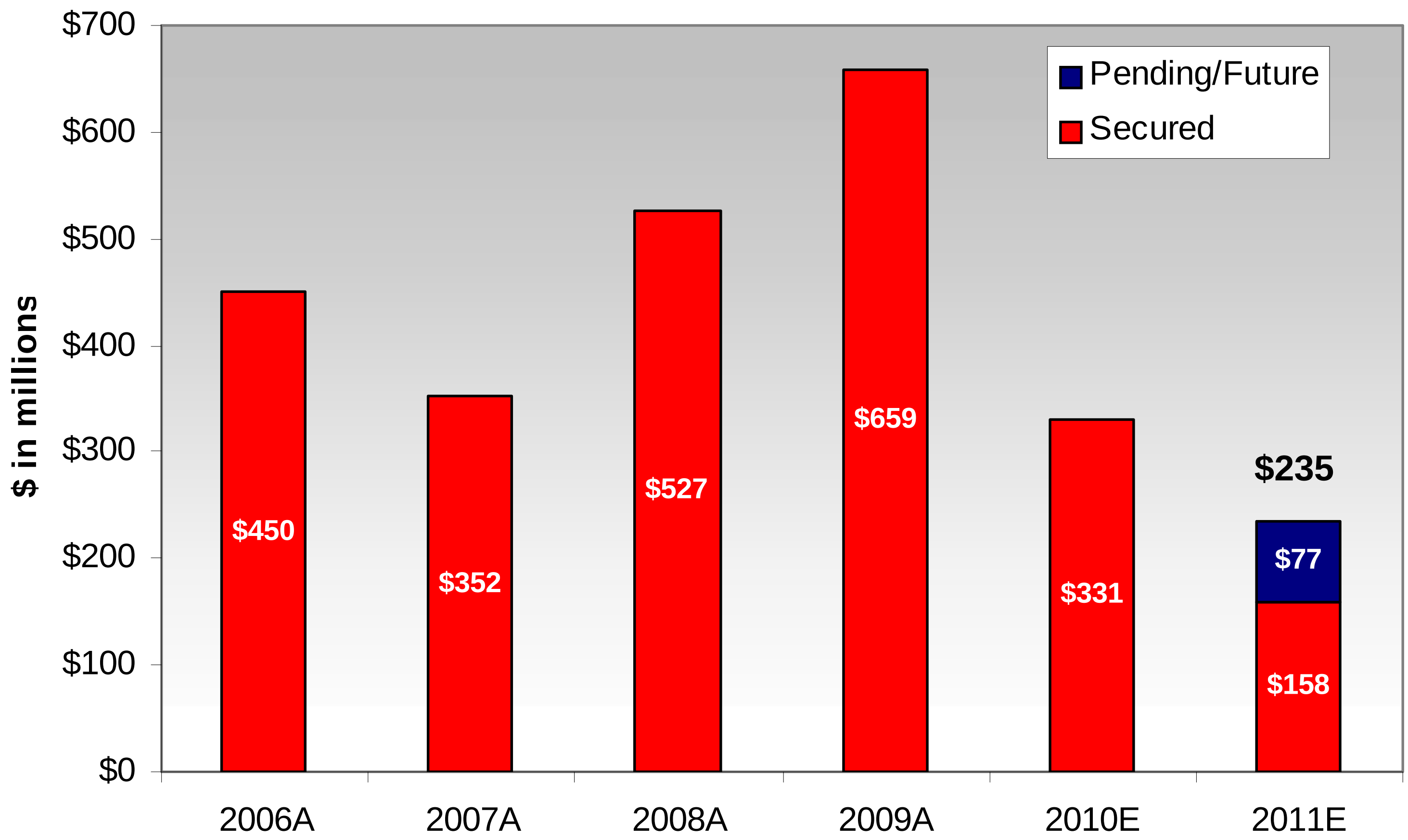


- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

2012 EPS Target: $3.25/share

Rate Changes



Note: Rate changes in this chart excludes revenues with offsetting costs

Active or pending rate cases include Oklahoma, West Virginia and others yet to be filed

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

Capital for Growth

- Increased capital budget by $150M for 2011 to $2.6B
- Announced capital budget plan of $2.9B for 2012

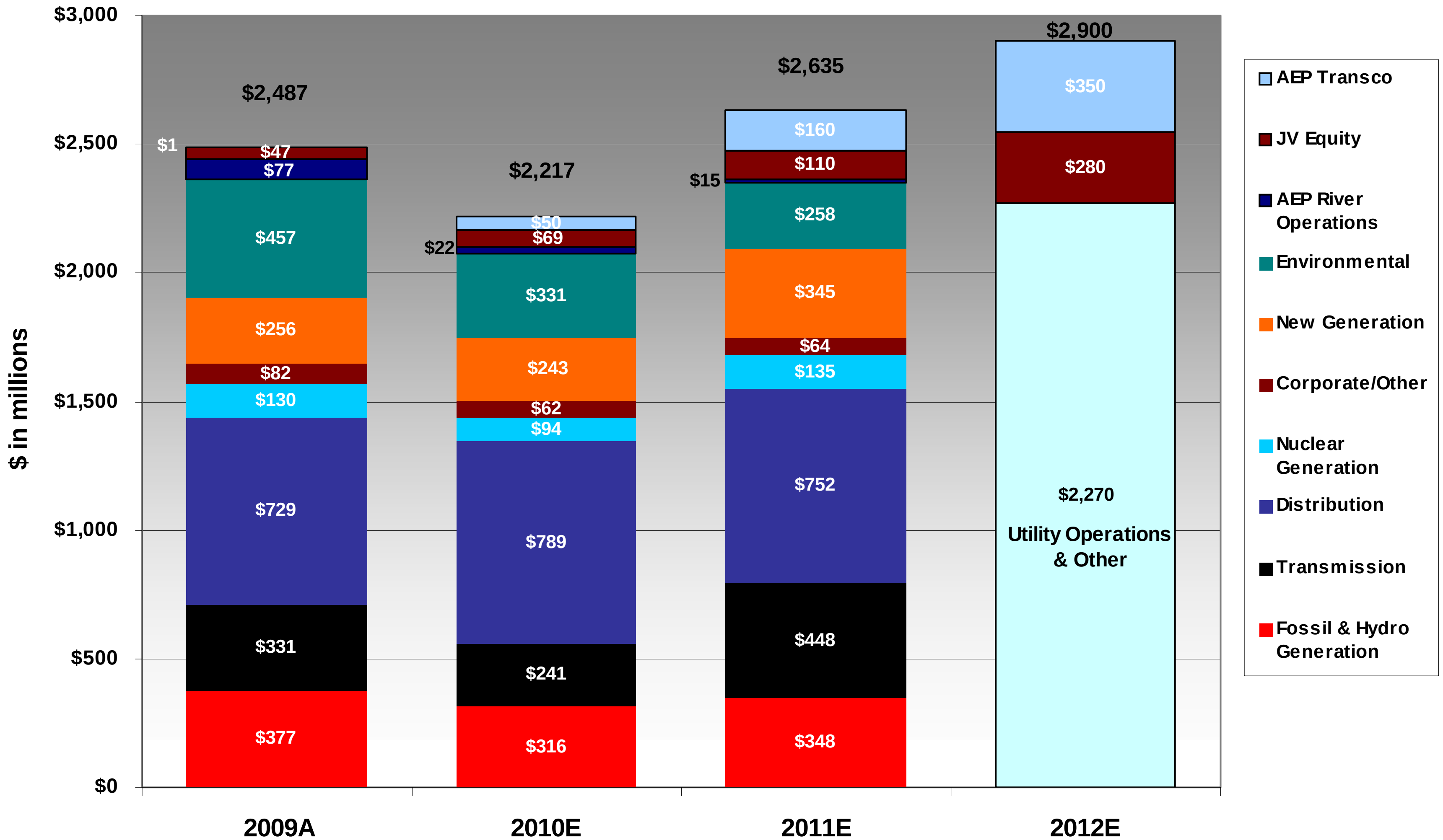
Return of Capital to Shareholders

- 9.5% increase in quarterly dividend to $0.46/share declared by the board of directors on October 26th
- Future dividend increases will grow with earnings

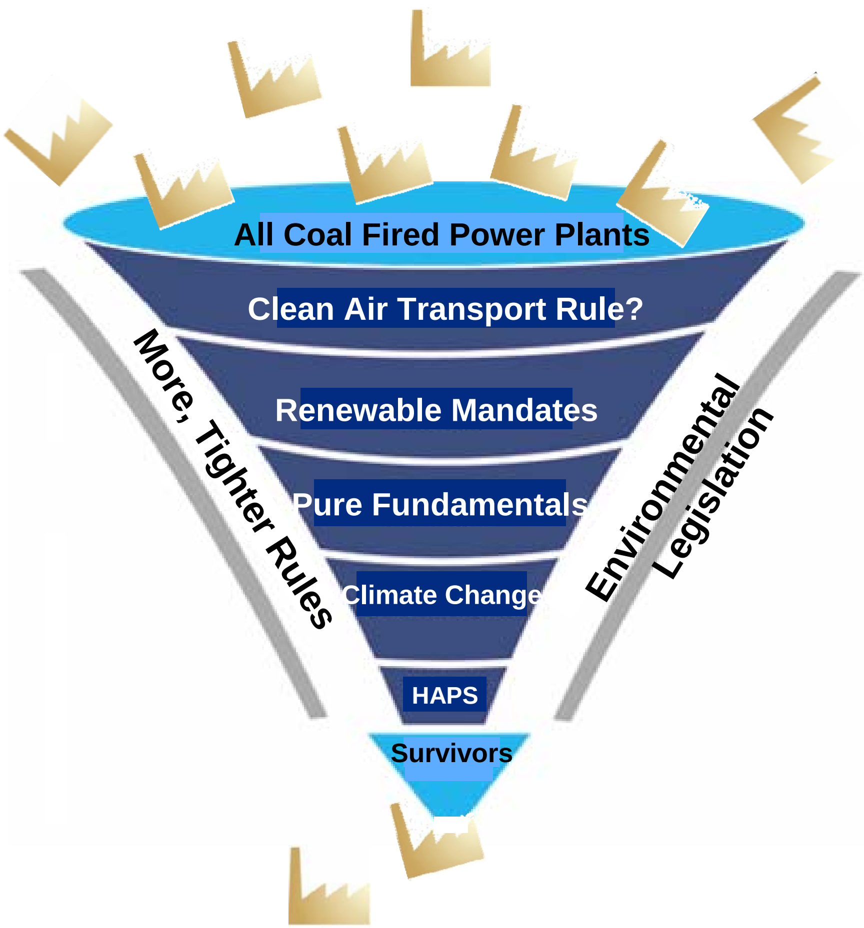
Capital to Reduce Risk

- Voluntarily funding pension $500M in 2010
- Allocating an additional $150M of funding for pension in 2011

Capital Expenditures



The Pressure on Coal Generation



Dark Spread Compression

NYMEX coal

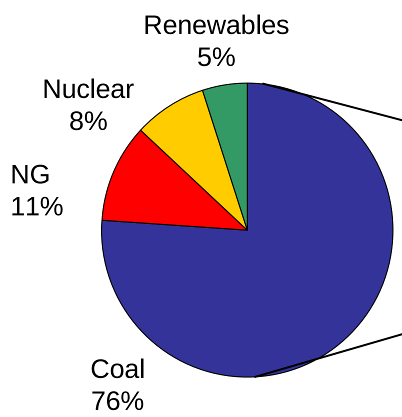
<u>Key EPA Actions Pending</u>

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in Spring 2011

The threshold level for coal is being defined

AEP Generation Capacity

East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

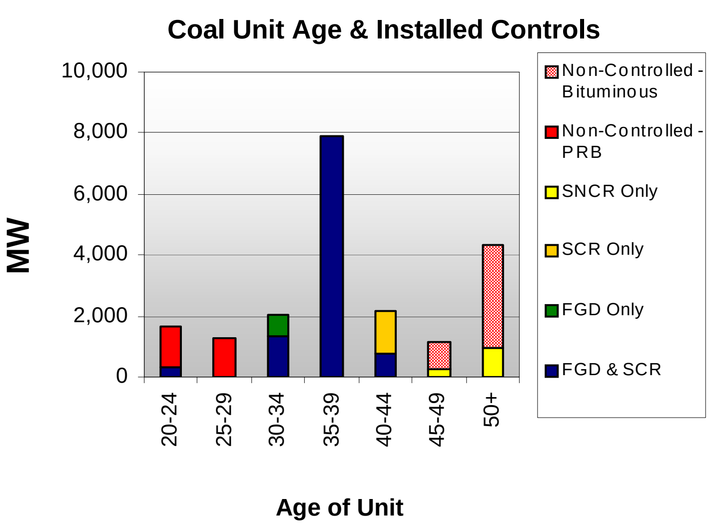


Coal Source

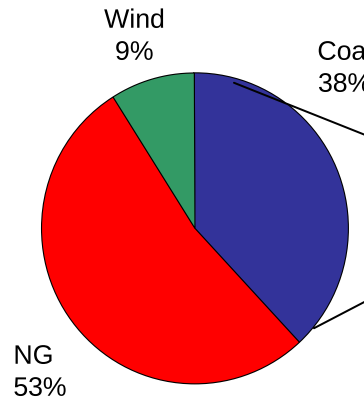
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind

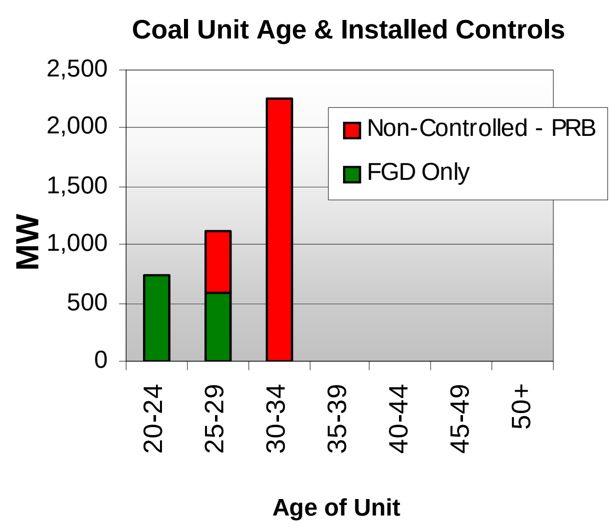


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

[1] Represents cost of committed position (90%)



Transmission as a Growth Engine

AEP®

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

ETT Electric Transmission Texas

ETA ELECTRIC TRANSMISSION AMERICA, LLC

PATH Potomac-Appalachian Transmission Highline

Prairie Wind Transmission

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

Liquidity, Credit and Financing

- Strong liquidity position supported by core Credit Facilities
  - Two $1.5B credit lines underpin liquidity position
    - Renewed 3-year $1.5B credit line in June 2010
    - Other $1.5B facility expires in April 2012, expect to address this renewal in 2011
  - Both facilities are undrawn

- Stable credit outlook

- Financing highlights
  - Cash flow and capital spending plan keep balance sheet stable
  - Committed to solid-investment grade credit metrics (BBB/Baa2)
    - Debt-to-Capital of 55-59%
    - FFO/Debt in the mid- to high teens
  - Debt Financing
    - Maturities total $620M in 2011
    - Net debt increases about $50M

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	-
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,636

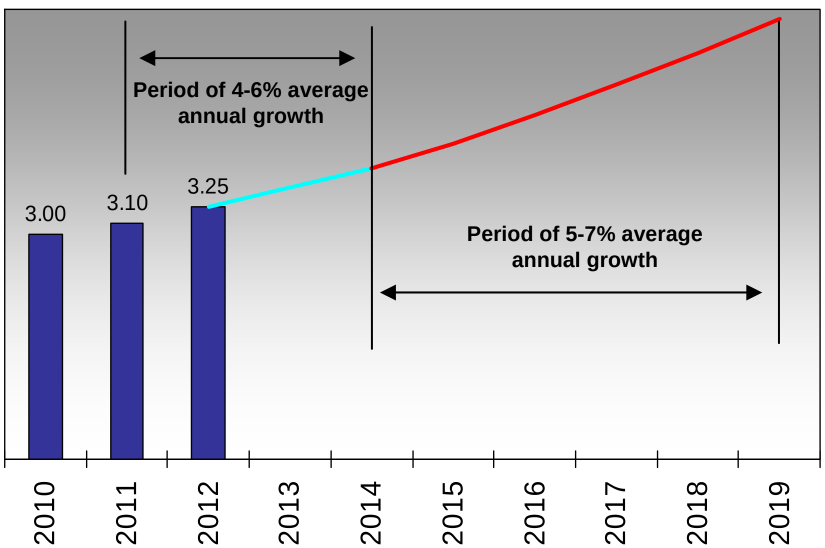
(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of September 30, 2010

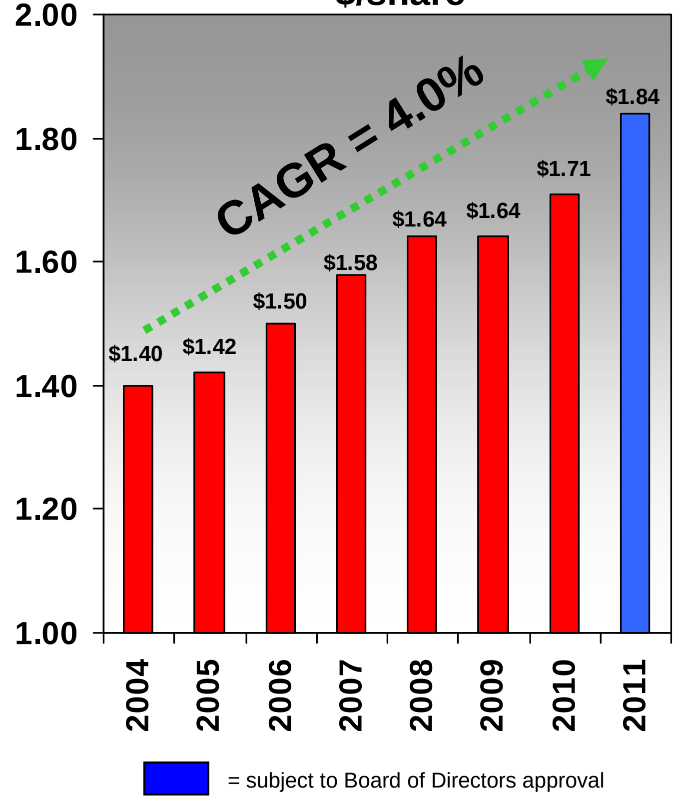
American Electric Power

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004 $/share



- 9.5% increase in quarterly dividend to $0.46/share declared on October 26th
- 401st consecutive quarterly dividend paid in September
- 50-60% payout ratio target
- Current yield about 5%

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Appendix

Detailed Ongoing Earnings Guidance

2010E: $2.95 - $3.05

2011E: $3.00 - $3.20

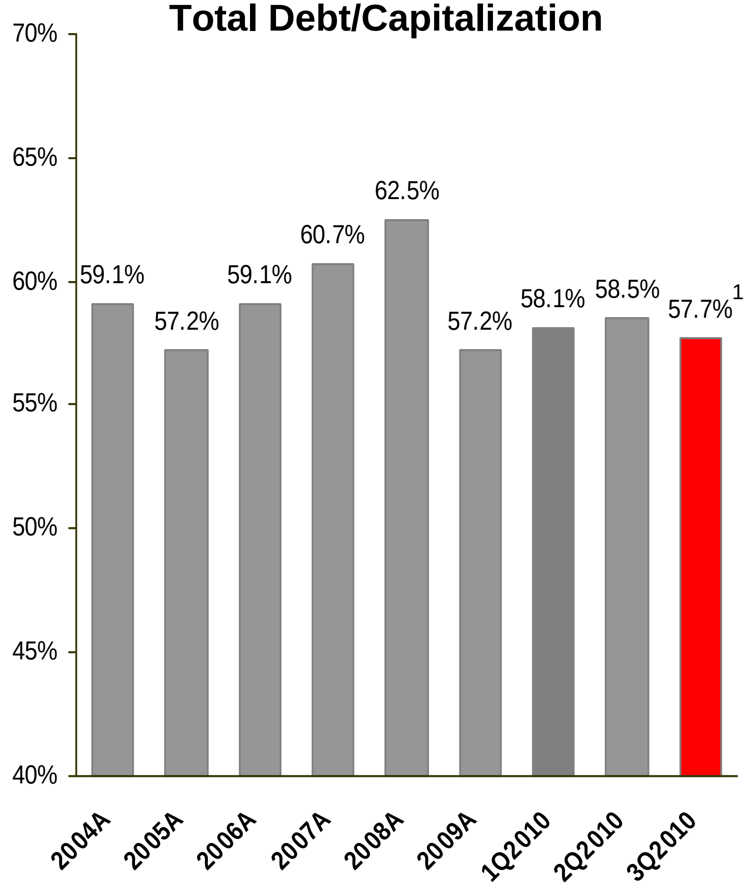
American Electric Power
Financial Results for 2011 Guidance vs 2010 Projection

		Performance Driver	2010 Projection ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		51
18	Generation & Marketing		20		2
19	Parent & Other On-Going Earnings		(22)		(53)
20	ON-GOING EARNINGS		1,439		1,496

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

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AEP Credit Ratings

Ratings current as of September 30, 2010

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable

Cash Flow Guidance

$ in millions

	2010E	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,205	$ 1,499
Depreciation & Amortization	1,654	1,588
Pension Funding	(500)	(150)
Other Cash Flow Items	653	234
Working Capital[1]	(218)	424
Cash From Operations	$ 2,794	$ 3,595
Investing Activities		
Construction Expenditures	(2,217)	(2,635)
Other Investing Activity	(352)	(265)
Total Investing Activities	$ (2,569)	$ (2,900)
Financing Activities		
Dividends	(826)	(893)
Net Debt Issued/(Retired)[1]	190	48
Common Equity	121	150
Total from Financing Activities	$ (515)	$ (695)
Beginning Cash Balance	$ 490	$ 200
Ending Cash Balance	$ 200	$ 200

[1]2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Pension and OPEB Estimate

- Investment returns for our pension plan and OPEB funds are solid so far this year. Year-to-date, the pension fund is up about 8% through September, with similar gains in the OPEB funds.
- After making a discretionary contribution of $350 million in September, cash contributions to the pension will total $500 million for 2010.
- We currently would have no required cash contributions to the pension for 2011 but are allocating a voluntary contribution up to $150 million.
- We expect combined pension and OPEB expense to decrease $34M from 2010 to 2011 (pre-tax and pre-capitalization).
- Discount rates are assumed to be 5.6% for pension and 5.85% for OPEB for 2010, and 4.75% and 5.0% for 2011 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

AEP®

PSO General Rate Case – Docket #201000050

On July 9, 2010, PSO filed a base rate case with the Oklahoma Corporation Commission requesting a net increase of $52.4 million, comprised of a $82.7 million base rate increase and a $30.3 million decrease in the capital investment rider. The requested ROE is 11.50%. Staff testimony supports a $0.3 million increase at an ROE of 10.04% and recommends continued collection of the $30.3 million capital investment rider.

Actual Capital Structure – Company Position (2/28/10)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	53.86%	6.52%	3.51%
Common Equity	45.84%	11.50%	5.27%
Preferred Stock	0.30%	4.02%	0.01%
Total	100.00%		8.79%

Required Rate Relief – Company Position (2/28/10)

($ in millions)

Rate Base	$	1,687.2
Rate of Return		8.79%
Operating Income Requirement	$	148.3
Adjusted Operating Income	$	97.9
Difference	$	50.4
Revenue Conversion Factor		1.6391
Total Revenue Requirement	$	82.7
Elimination of Capital Investment Rider	$	(30.3)
	$	52.4

Procedural Schedule

October 26, 2010	Staff & Intervenor testimony due
November 16, 2010	Rebuttal testimony due
November 29, 2010	Settlement Conference
Debember 6-17, 2010	Hearing
January 5, 2011	Rates Effective, Subject to Refund

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,467MM	10.50%	54/46	1/14/2009
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

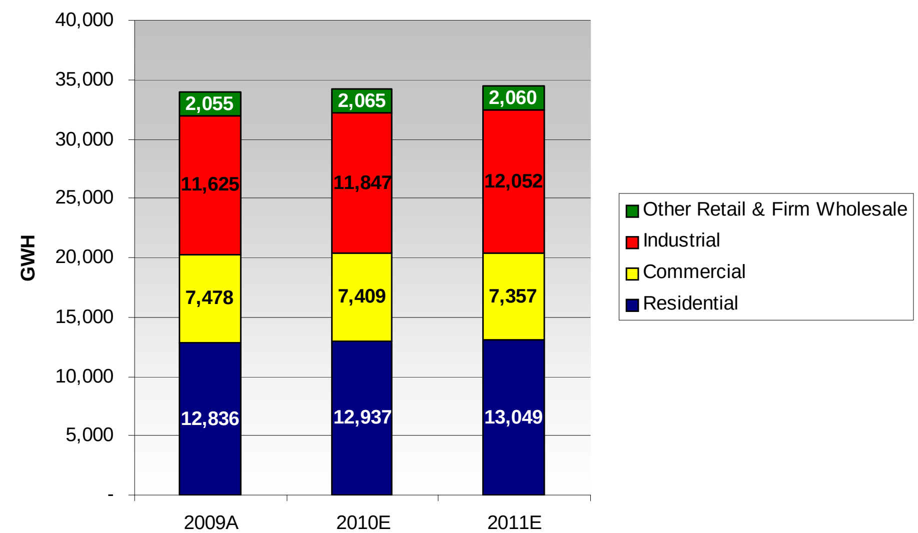
Overview of Appalachian Power

Total Customers at 12/31/09:

Residential	817,600	85%
Commercial	129,800	14%
Industrial	4,300	<1%
Other	7,100	1%
Total	958,800	

Generating Capacity 6,287 MW

Normalized Retail Load



Load represents Appalachian Power and Wheeling Power

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Coal Mining – 27%

Primary Metals – 14%

Electric/Gas/Sanitary Services – 9%

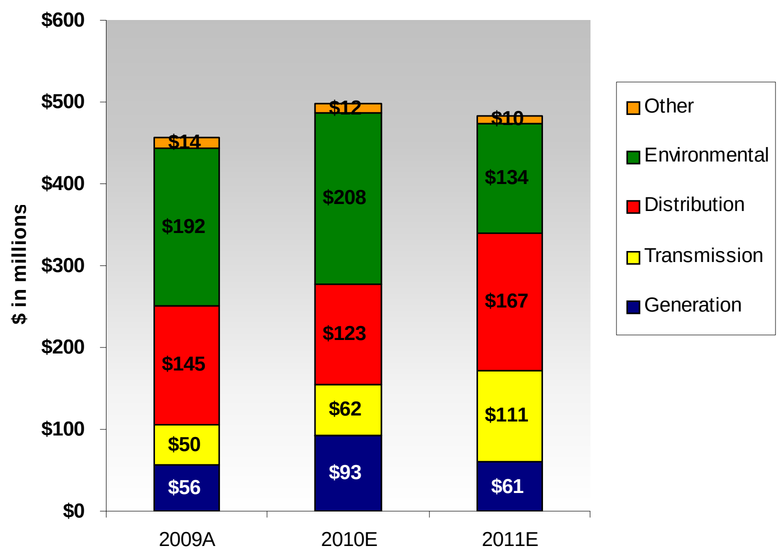
Chemical Products – 8%

Paper Products – 7%

Overview of Appalachian Power

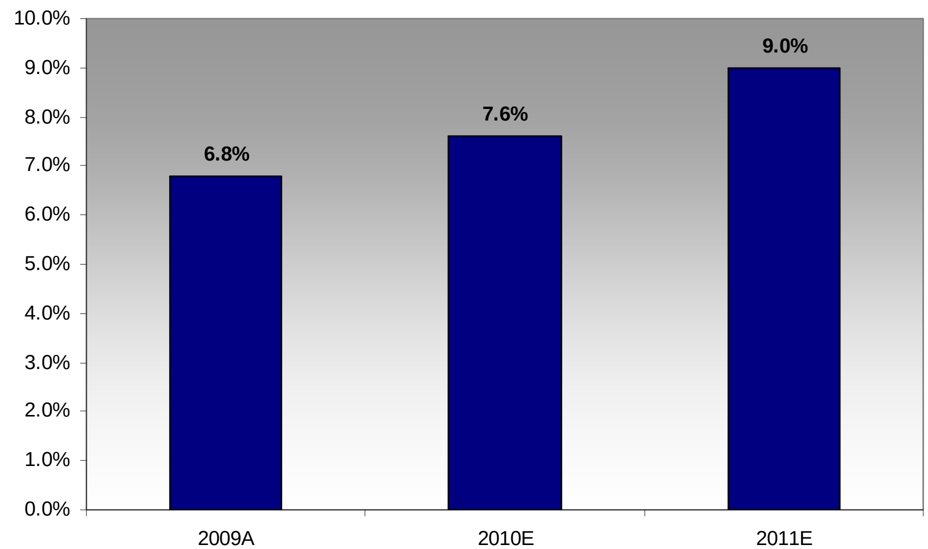
AEP®

Capital Forecast



Capital represents Appalachian Power and Wheeling Power

Forecasted ROEs



ROEs represent Appalachian Power and Wheeling Power

Major Capital Project:
Amos Plant Unit 1 Scrubber

Current and Future Regulatory Activity:
WV Base Rate Case
VA Biennial Base Rate Case – March 31, 2011

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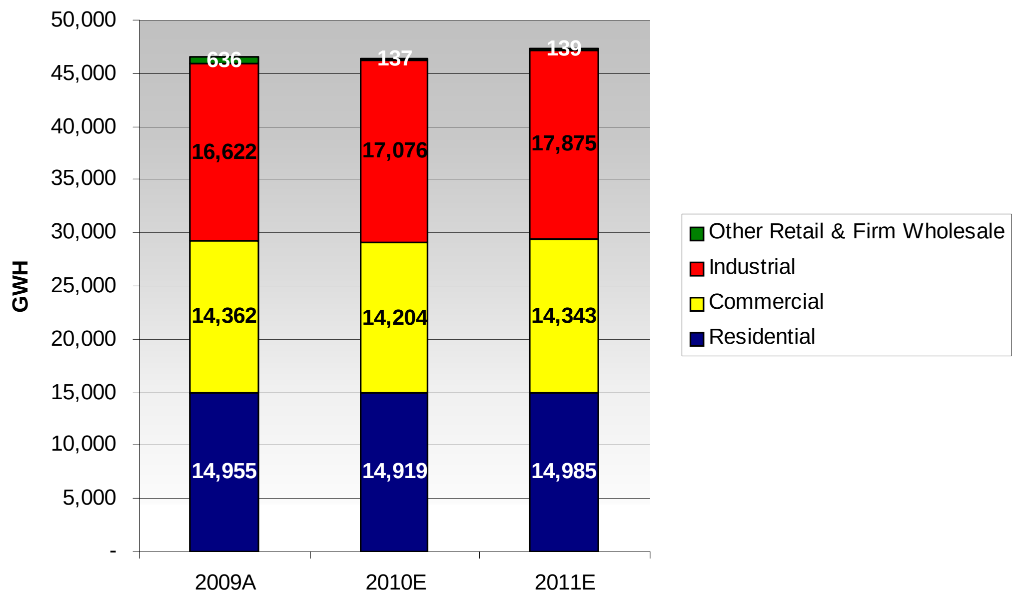
Overview of AEP Ohio

Normalized Retail Load



2010E and 2011E represent connected load

Total Customers at 12/31/09:

Residential	1,274,800	87%
Commercial	170,900	12%
Industrial	10,500	1%
Other	2,800	<1%
Total	1,459,000	

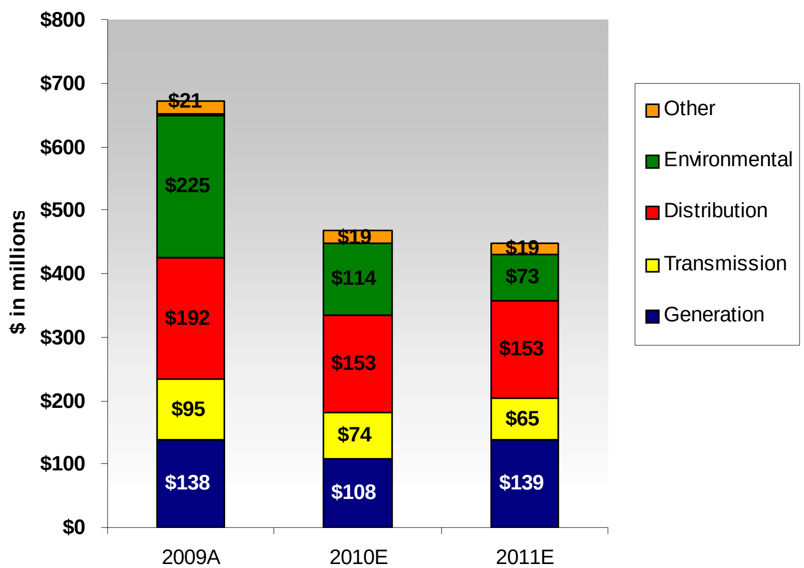
Generating Capacity 12,246 MW

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

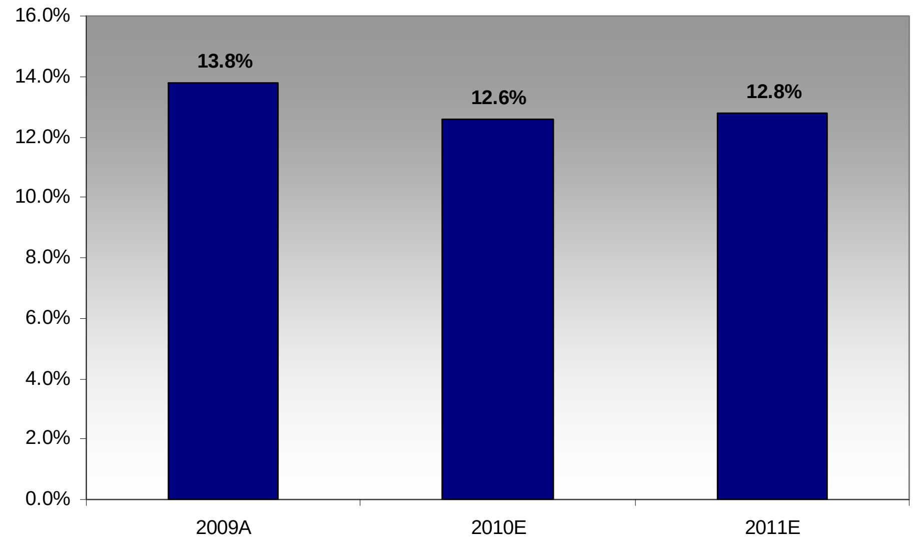
Primary Metals – 42%
Chemical Products – 9%
Petroleum Refining – 8%
Rubber/Plastic Products – 6%
Stone/Clay/Glass Products – 4%

Overview of AEP Ohio

Capital Forecast



Forecasted ROEs



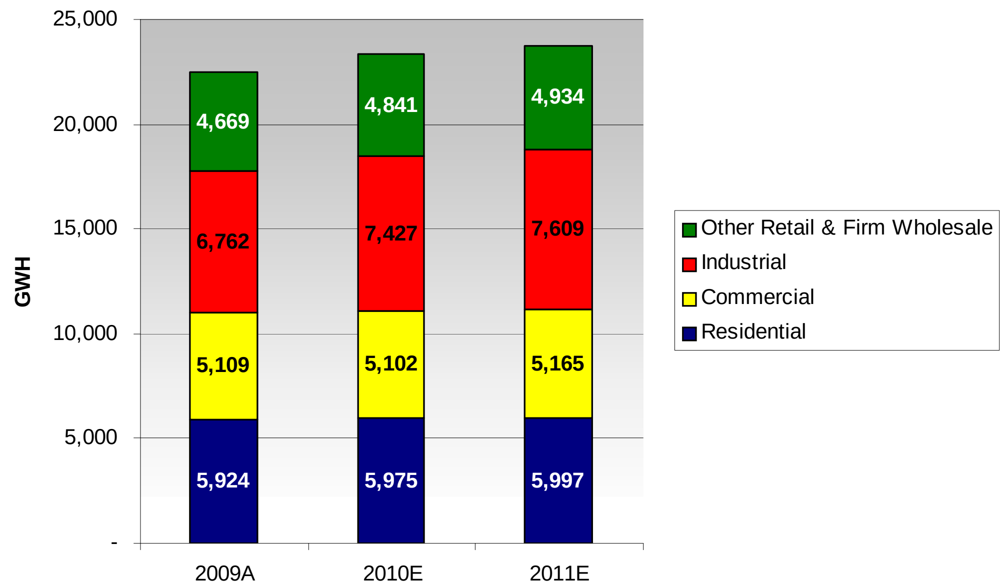
Major Capital Projects:
Conesville Plant Unit 4 Scrubber
Conesville Plant Mercury Mitigation

Current and Future Regulatory Activity:
2009 SEET
CSPCo/OPCo Merger
2010 SEET
2010 Environmental Rider
Electric Security Plan
Distribution Base Rate Case

Overview of Indiana Michigan Power

Total Customers at 12/31/09:		
Residential	507,200	87%
Commercial	68,400	12%
Industrial	5,100	1%
Other	2,000	<1%
Total	582,700	
Generating Capacity	4,511 MW	

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Primary Metals – 38%

Chemical Products – 11%

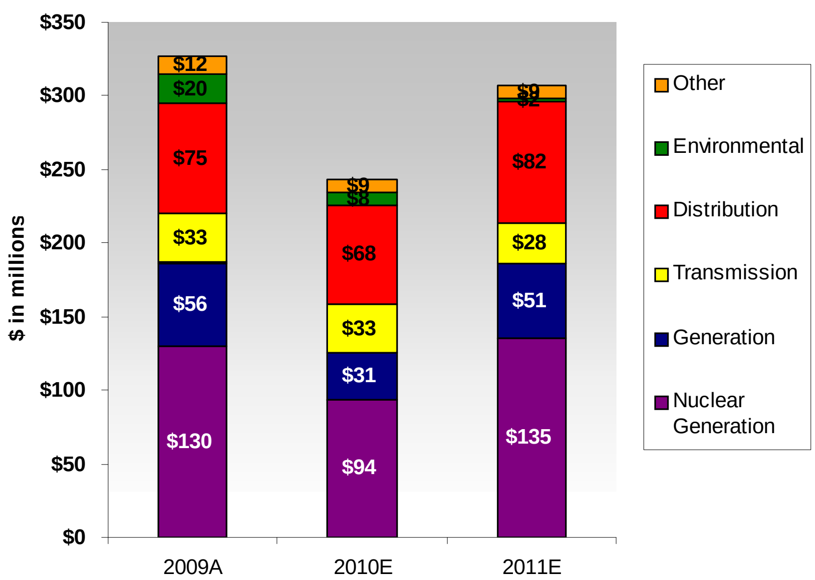
Transportation Equipment – 7%

Rubber/Plastic Products – 9%

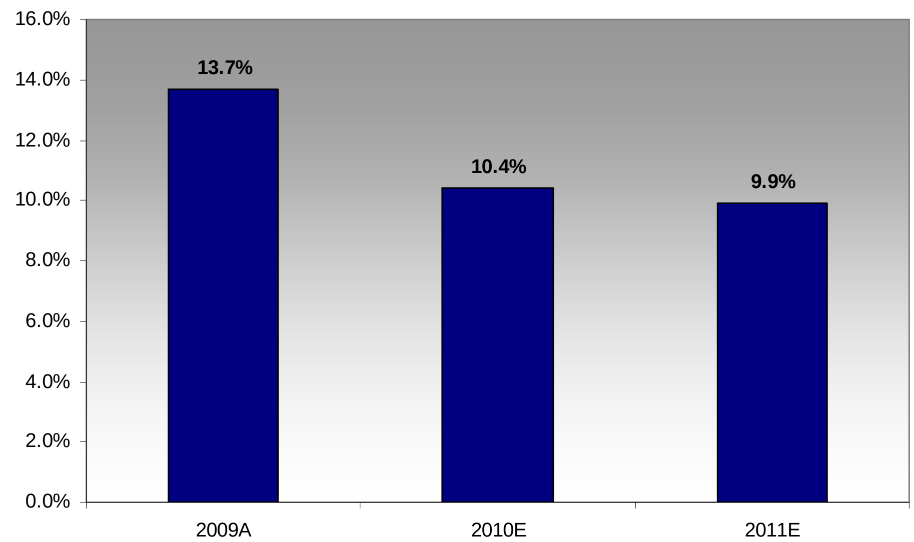
Fabricated Metal Products – 6%

Overview of Indiana Michigan Power

Capital Forecast



Forecasted ROEs



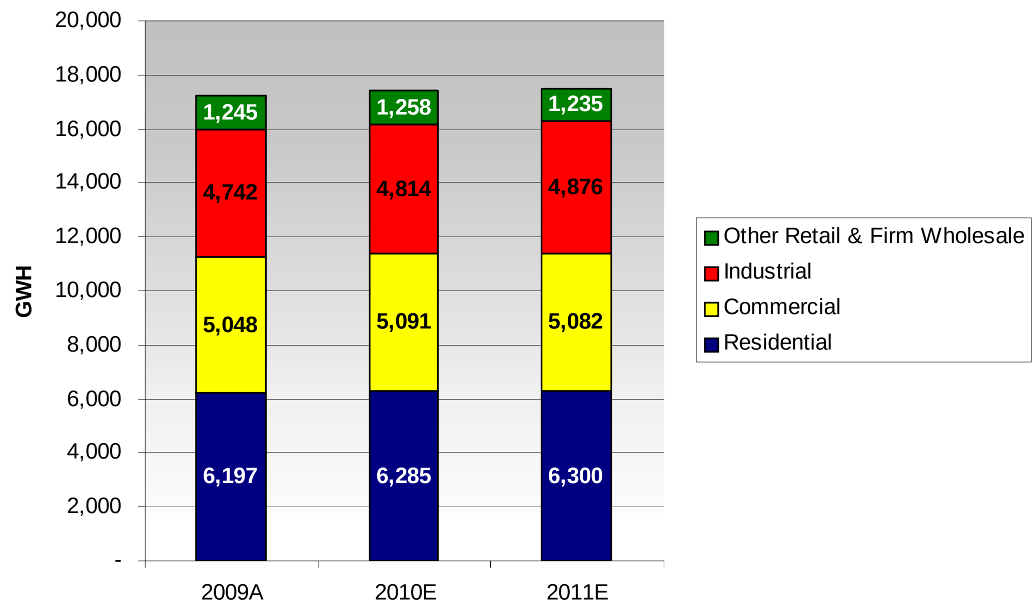
Major Capital Projects:
Cook Plant Life Cycle Management and Dry Cask Fuel Storage

Current and Future Regulatory Activity:
No major filings announced

Overview of PSO

Total Customers at 12/31/09:		
Residential	457,000	87%
Commercial	59,900	11%
Industrial	6,600	1%
Other	7,200	1%
Total	530,700	
Generating Capacity	4,408 MW	

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Paper Products – 17%

Oil & Gas Extraction – 13%

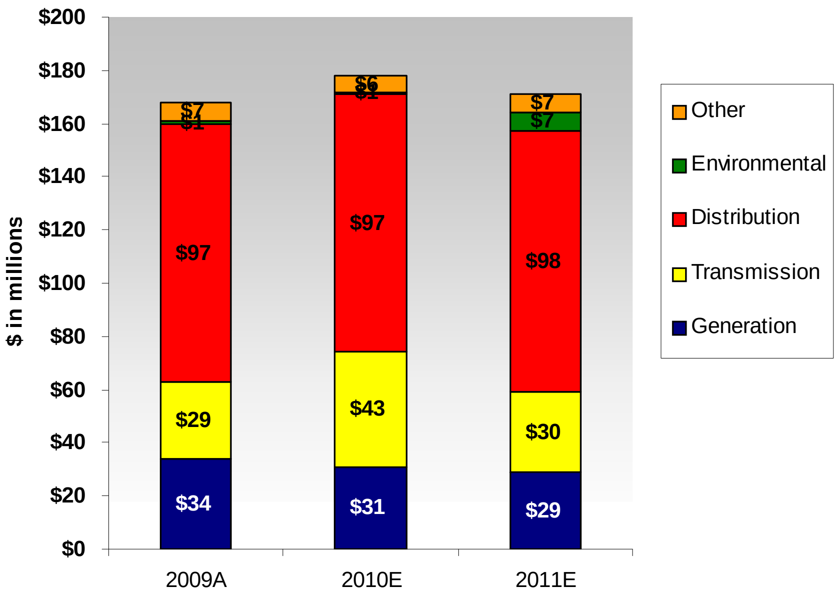
Transportation Equipment – 8%

Stone/Clay/Glass Products – 8%

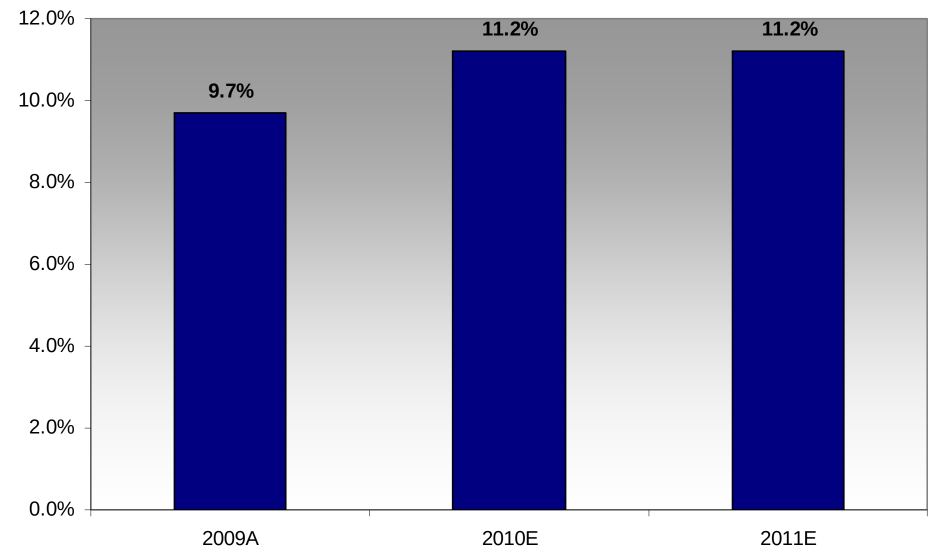
Petroleum Refining – 8%

Overview of PSO

Capital Forecast



Forecasted ROEs



Major Capital Projects:
No major projects

Current and Future Regulatory Activity:
OK Base Rate Case

Overview of SWEPCO

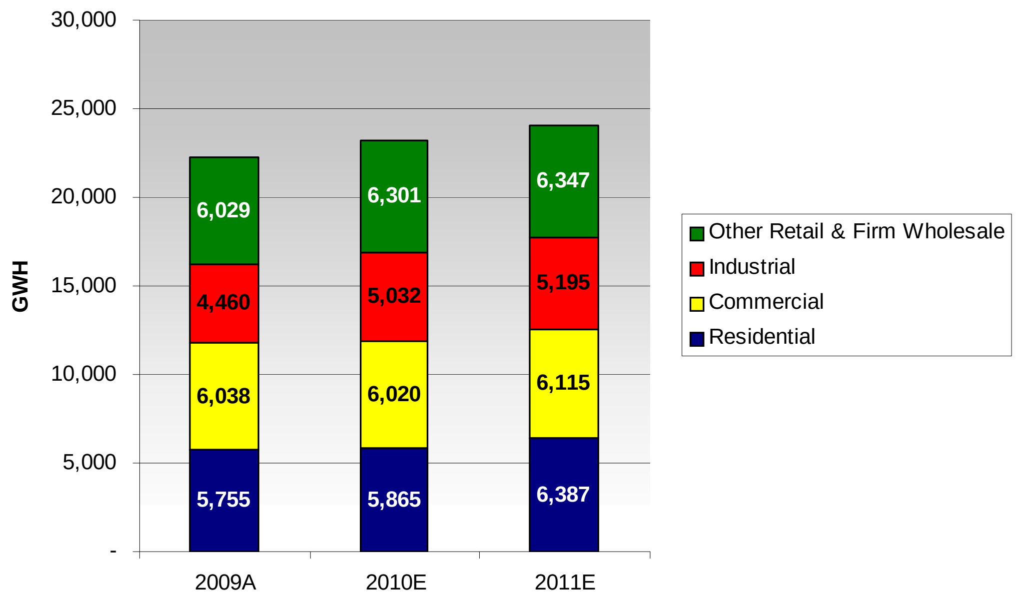
Total Customers at 12/31/09:

Residential	400,000	84%
Commercial	66,300	14%
Industrial	7,200	2%
Other	500	<1%
Total	474,000	

Generating Capacity 5,307 MW *

* - includes Stall Plant capacity (509MW) that came on line in June 2010

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Food Products – 16%

Oil & Gas Extraction – 15%

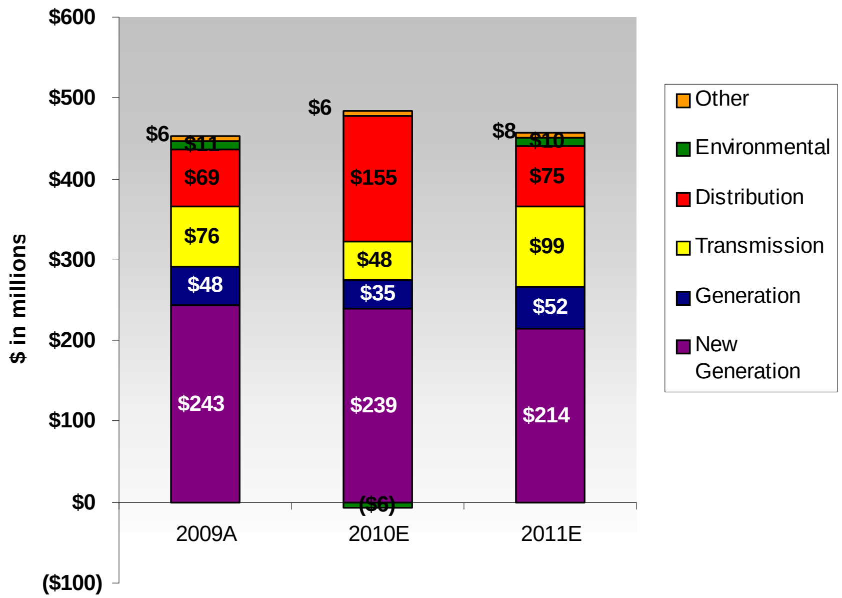
Paper Products – 14%

Petroleum Refining – 6%

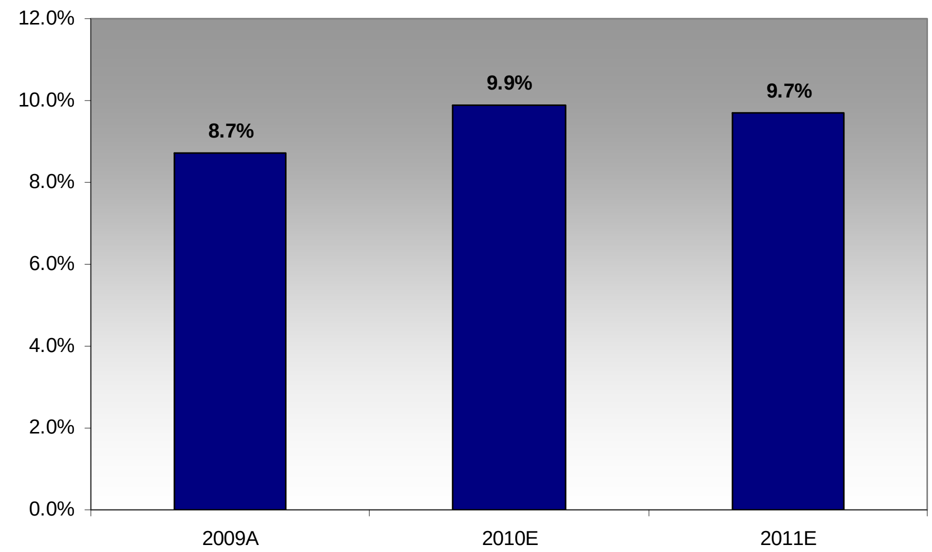
Chemical Products – 6%

Overview of SWEPCO

Capital Forecast



Forecasted ROEs

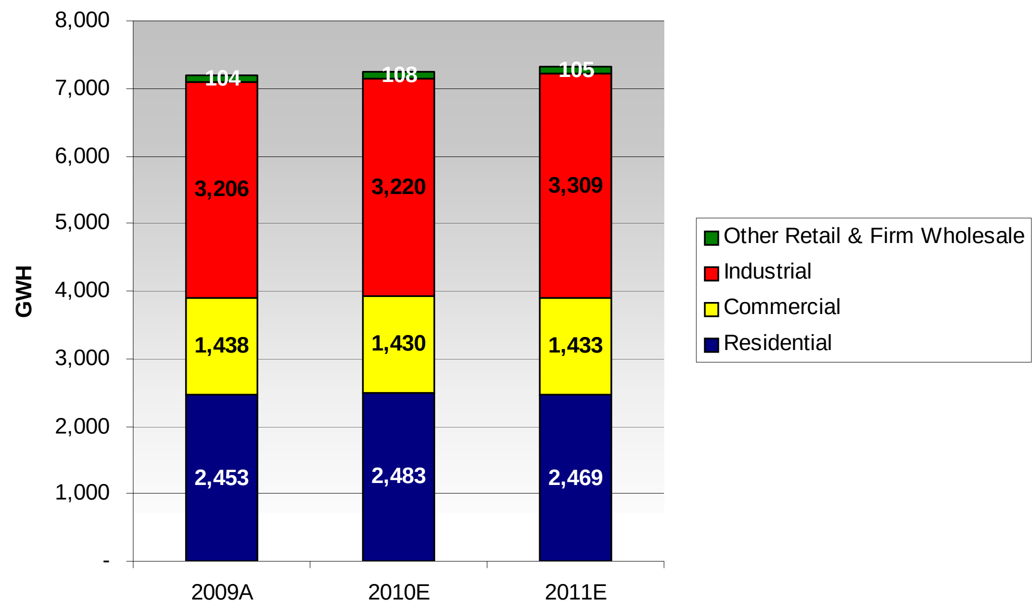


Major Capital Project:
John W. Turk Plant

Current and Future Regulatory Activity:
Turk Plant Recovery – LA and TX

Overview of Kentucky Power

Normalized Retail Load



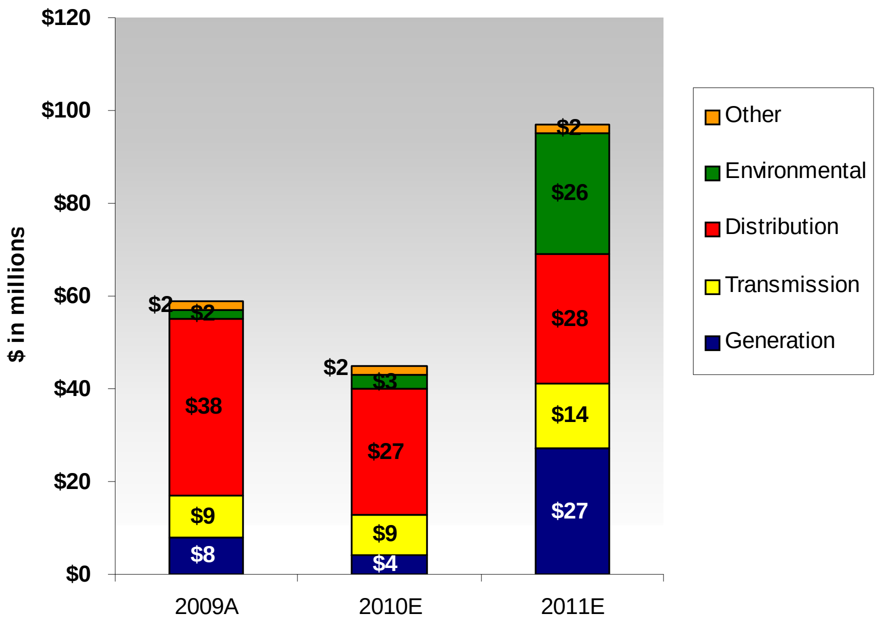
Total Customers at 12/31/09:		
Residential	143,600	82%
Commercial	29,600	17%
Industrial	1,400	1%
Other	400	<1%
Total	175,000	
Generating Capacity	1,078 MW	

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

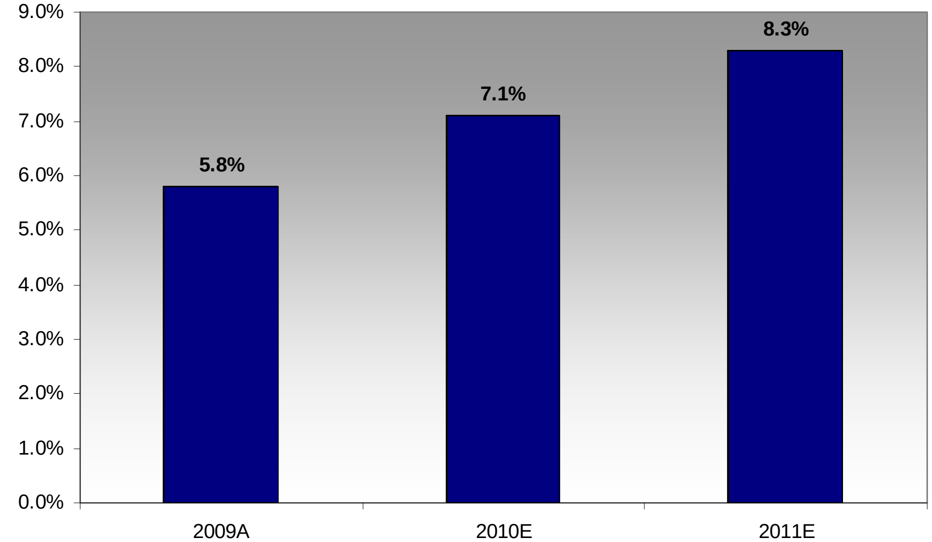
Petroleum Refining – 36%
Coal Mining – 32%
Primary Metals – 11%
Chemical Products – 10%
Electric/Gas/Sanitary Services – 5%

Overview of Kentucky Power

Capital Forecast



Forecasted ROEs



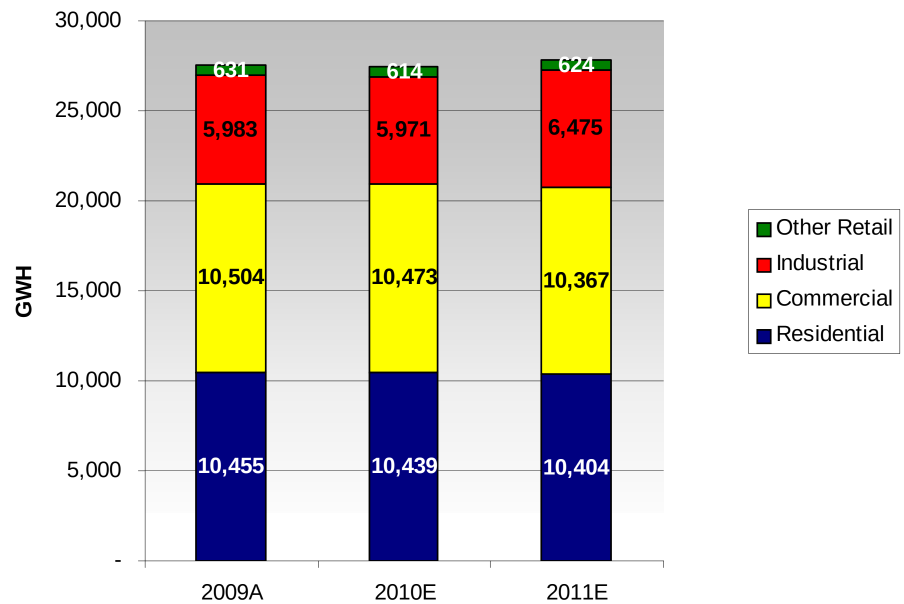
Major Capital Project:
No Major Projects

Future Regulatory Activity:
No major filings announced

Overview of AEP Texas

Total Customers at 12/31/09:		
Residential	799,400	84%
Commercial	135,100	14%
Industrial	9,700	1%
Other	7,000	1%
Total	951,200	
Generating Capacity	377 MW	

Normalized Retail Load

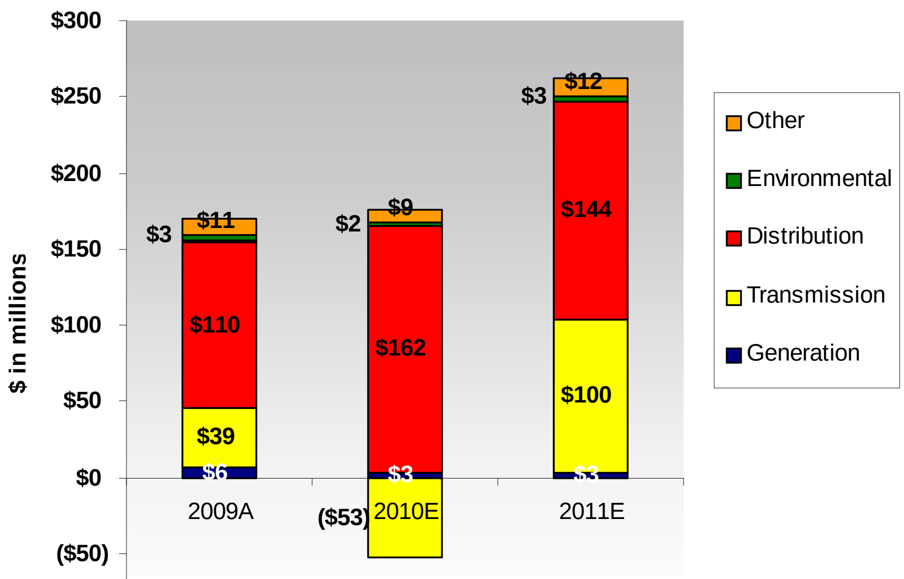


PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Petroleum Refining – 39%
Chemical Products – 29%
Oil & Gas Extraction – 12%
Food Products – 4%
Pipelines (excluding Nat Gas) – 1%

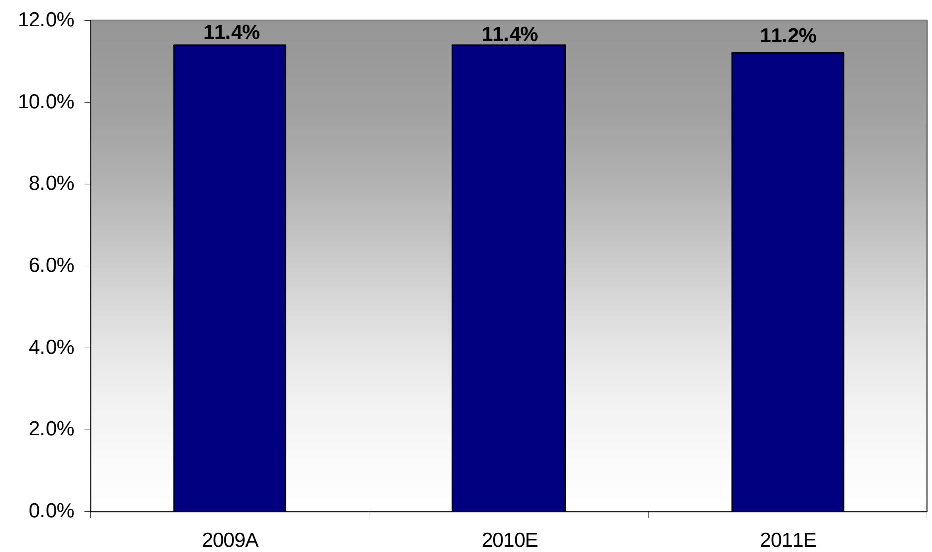
Overview of AEP Texas

Capital Forecast



Note: ($53) million in 2010E capital represents transfer of assets to Electric Transmission Texas

Forecasted ROEs



Major Capital Projects: AMI Deployment

Future Regulatory Activity: TCOS Filings

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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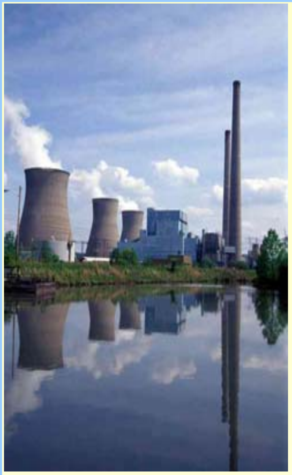

Second Annual Citi Power Gas and Utilities Conference

Charleston, SC

June 7, 2007

AEP AMERICAN® ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Mike Morris
Chairman, President & CEO

KPSC Case No. 2011-00401
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Table of Contents

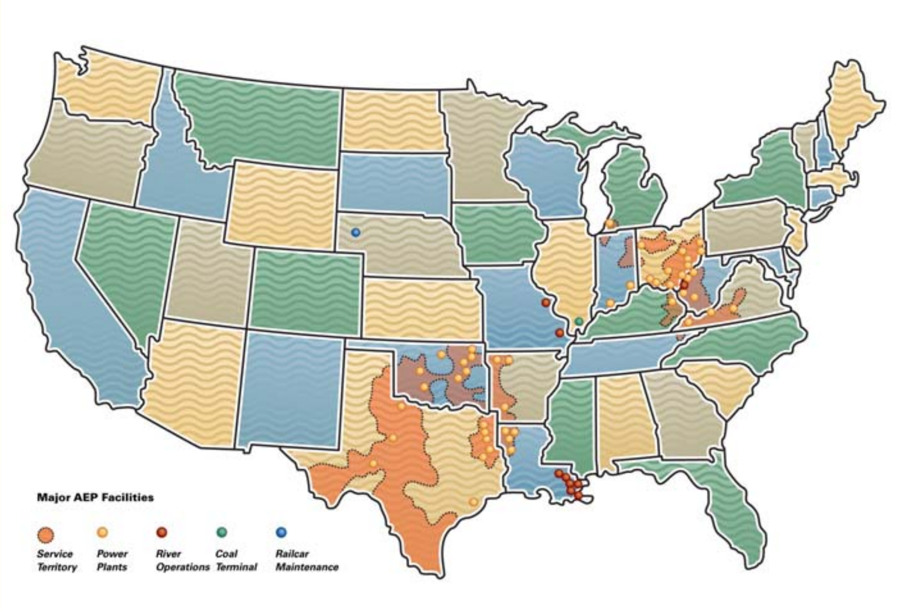
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

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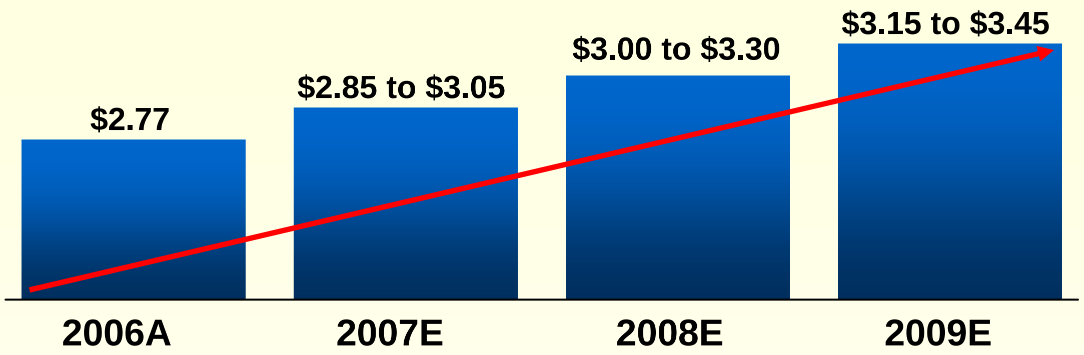
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

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New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison (Tontitown)	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall (Arsenal Hill)	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk (Hempstead)	Arkansas	$1.3 B[(1)]	Coal	Ultra-supercritical	600[(1)]	2011
PSO	Red Rock	Oklahoma	$1.8 B[(2)]	Coal	Ultra-supercritical	950[(2)]	2012
CSP/OP	Great Bend	Ohio	Under Review[(3)]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[(3)]	Coal	IGCC	600	TBD

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(2) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(3) FEED (front-end engineering and design) study is completed. Final results will be available in June.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

Purchased Generation

2,946 MW of gas-fired generation added since 2005

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit filed and approved in Feb 2007
  - Units 3 and 4 online by summer peaking-season 2007; Units 1 and 2 online by Jan 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by Mar 2008

PSO

- Southwestern & Riverside Additions
  - Air permit received March 22, 2007
  - Commercial operation date of Dec 2007
  - Projects to be completed by Q1 2008
  - Regulatory Recovery
    - Settlement and final order in the Lawton Cogen case authorizes costs for Southwestern and Riverside peakers to be recovered through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

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SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

- Turk Plant (Fulton, AR)
  - Certificate of Need approvals (LA, AR, TX) expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for Sept 2007
    - AR and TX rate recovery will be addressed in separate filings
  - Approximately 85-90% of costs are firm
    - EPC contract for balance of plant work awarded in May 2007
    - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

- Red Rock Plant (Red Rock, OK)
  - Used and useful determination filed in Feb 2006 – approval expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Order expected in PSO rate filing by June 19, 2007 – filing includes request for CWIP treatment for new projects
  - Original cost estimate of $1.8 billion – revised cost estimate expected in July 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

AEP®

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Procedural Schedules and Details

- Red Rock Facility - Oklahoma
  - PSO and OG&E Cases were consolidated by the OCC
  - PSO Docket Nos. 200500516 and 200600030
  - OG&E Docket No. 200700012
  - Staff/Intervenor Testimony - received May 21
  - Rebuttal Testimony – June 18
  - Hearings re. Used and Useful Determination – July 2
  - Hearings re. OG&E Cost Recovery – July 19
  - ALJ Report – August 6
  - Order – August 21

- Turk Plant - Arkansas
  - Docket No. 06-154-U
  - Staff/Intervenor Testimony – June 29
  - Rebuttal Testimony – July 13
  - Public Hearings – July 19 or August 9

- Turk Plant - Louisiana
  - Docket No. U-29702
  - Staff/Intervenor Testimony – June 15
  - Rebuttal Testimony – July 16
  - Public Hearings – September 11-14

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Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results to be filed in June 2007. Cost estimates expected to be in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony due June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – pre-draft report is expected in June 2007
- Regulatory Recovery Filing
  - Filing expected in June 2007 – will include request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

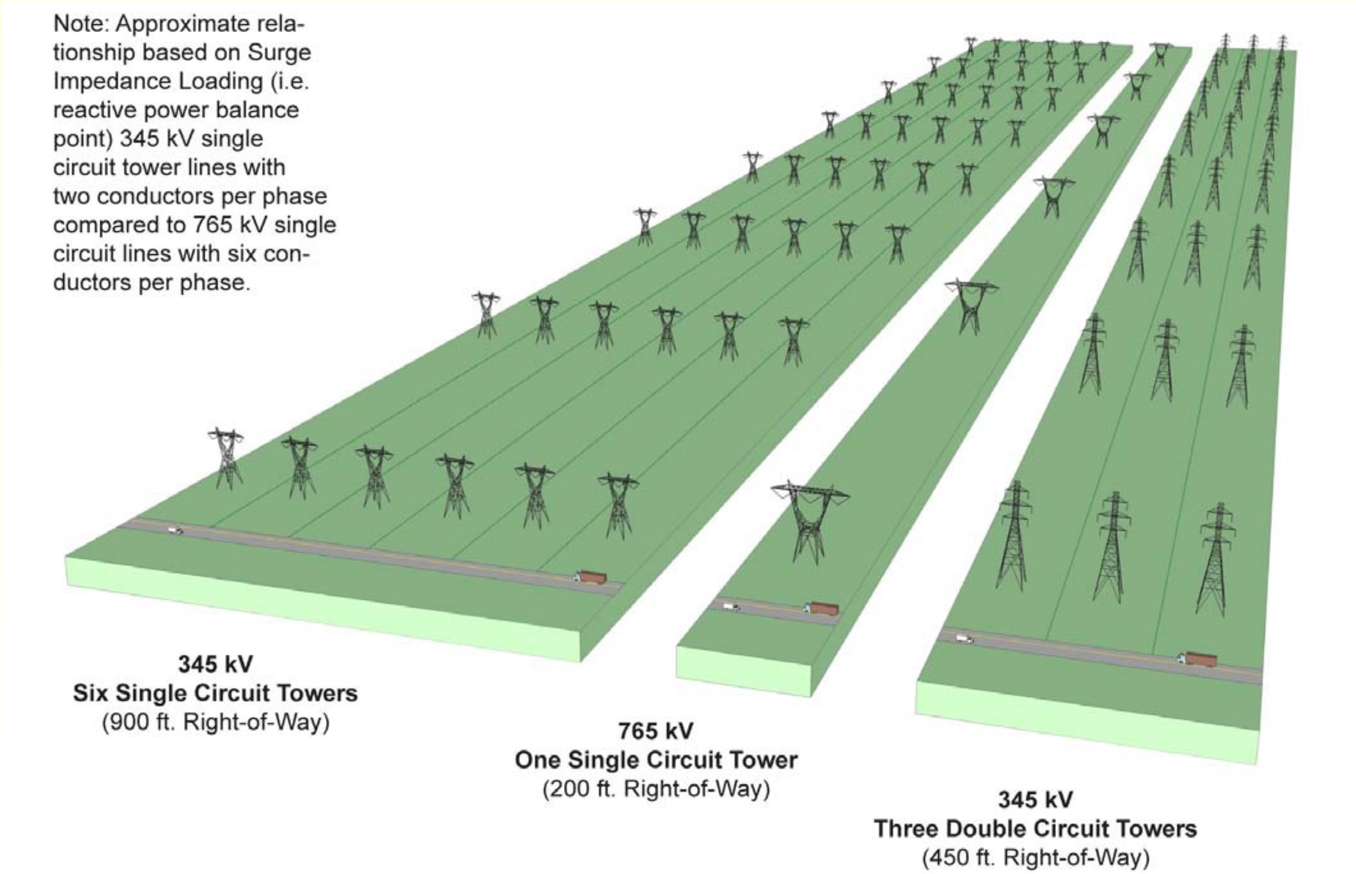
New Transmission Investment Funding Plans

- **Electric Transmission Texas LLC**
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% MidAmerican Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- **AEP I-765$_{\text{TM}}$ Interstate Project**
  - Forming a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- **Other Transmission Projects**
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

765 Right-of-Way Comparison



From a siting standpoint, 765 kV is much more efficient in terms of economies of scale and right-of-way than lower capacity lines

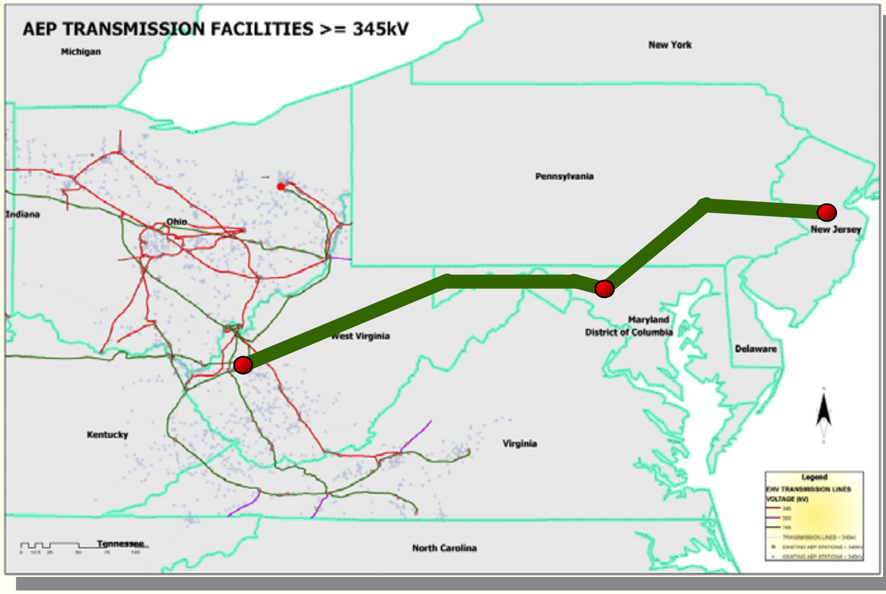
I-765$_{TM}$ PJM Transmission Project

Joint Venture with AYE

- 290 miles of the proposed 550 mile project
- Line will link AEP's Amos station in WV to AYE's proposed Kemptown station in MD with an intermediate station at AYE's Bedington station in WV
- JV project costs will encompass $1.1 billion, with each company owning 50%
- AEP's investment will total approximately $700 million, including ancillary projects
- Entire I-765$_{TM}$ project included in DOE's draft National Interest Electric Transmission Corridor
- FERC incentive rate treatment applies
- Operations to commence in the 2H07

Remaining I-765$_{TM}$ Project

- PJM is evaluating the Kemptown (MD) - Deans (NJ) line as a separate alternative



- ➢Jointly owned with Allegheny, will improve eastern grid reliability
- ➢Enhance Midwest-Mid-Atlantic power transfer capability by 5000 MW
- ➢Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.

PJM's Targeted In-Service Date For the 290-Mile Project Is 2012

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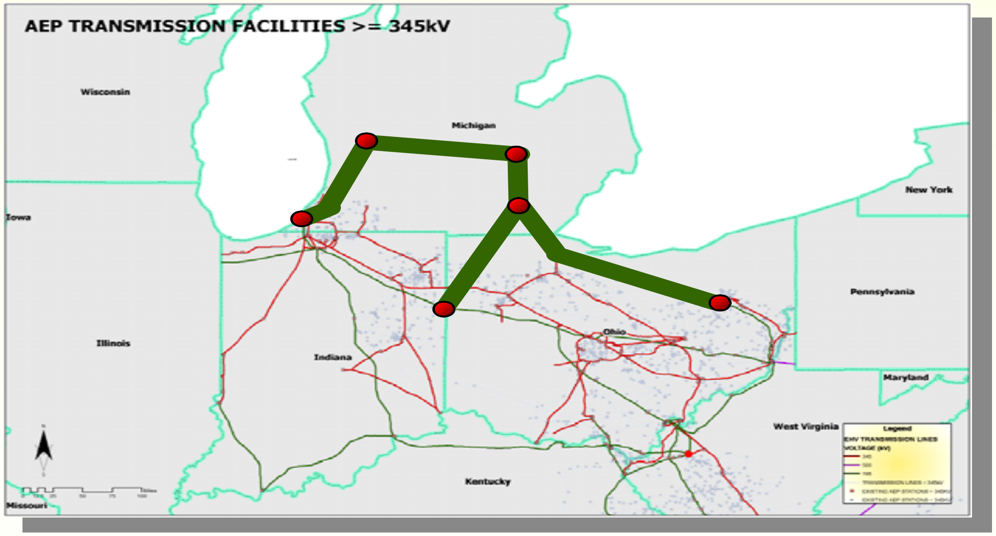
Michigan 765kV Study

- Agreement with ITC Transmission for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
  - 630 line miles
  - Over 5000MW improved transfer capability
  - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in 2Q07
- We anticipate signing an MOU with ITC on joint ownership in mid-2007



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Project Construction Would Not Proceed Until Proper Regulatory Approvals Are Received And Cost Allocation Is Clarified

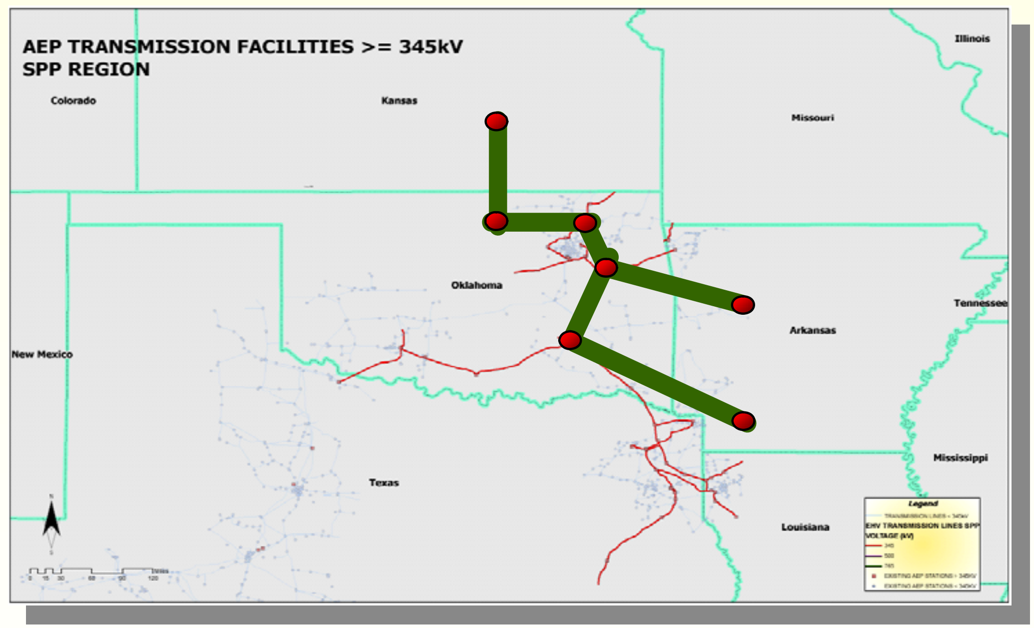
SPP Transmission Potential

- June 2006 SPP requested proposal to address congestion, reliability & access for new generation

- July 2006 AEP submitted proposal:

- Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
- Investment ~$3 billion
    - ~4000MW improved transfer capability
    - Anticipated rate impact 2mils/kWh

Next steps:
SPP issued EHV Overlay Study RFP to review 345 kV, 500 kV, and 765 kV potential projects in SPP with results expected in mid-2007



Long-term Opportunity For Large Transmission Investments to Reduce Congestion, Enhance Reliability and Access New Generation

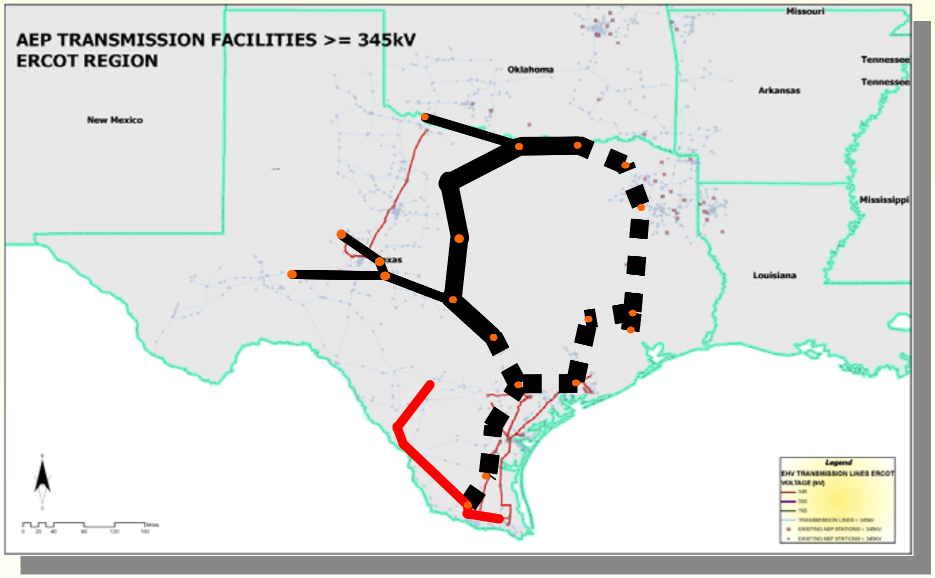
Electric Transmission Texas, LLC

Joint Venture with MidAmerican Energy

- Ownership – 50% AEP / 50% MidAmerican Energy
- 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
- AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
- Hearings with PUCT to be held July 16-19, 2007
- Initial funding in 3Q07 after regulatory approvals
- Debt – Initially bank financing

Competitive Renewable Energy Zone (CREZ) docket

- In February 2007, ETT proposed the development of a long-term transmission plan for ERCOT to address the Texas legislature's CREZ initiative. The plan includes:
  - $1.5 billion for Stage I of CREZ development by 2012
  - $1.5 billion for Stage II of CREZ development by 2015
  - $4.2 billion for Stage III for completion of ERCOT transmission backbone needed for long-term



Operations of JV Could Begin As Soon As 3Q07 Upon Receipt of Regulatory Approvals

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-10
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	In-service	☑	In-service
Mitchell 2	800	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	Upgrade In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2008
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	Upgrade In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

AEP's Climate Strategy

FutureGen™ ALLIANCE
Clean Energy for a Secure Future

GLOBAL ROUNDTABLE ON CLIMATE CHANGE

CLIMATE LEADERS®
U.S. Environmental Protection Agency

CCX
Chicago Climate Exchange™

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

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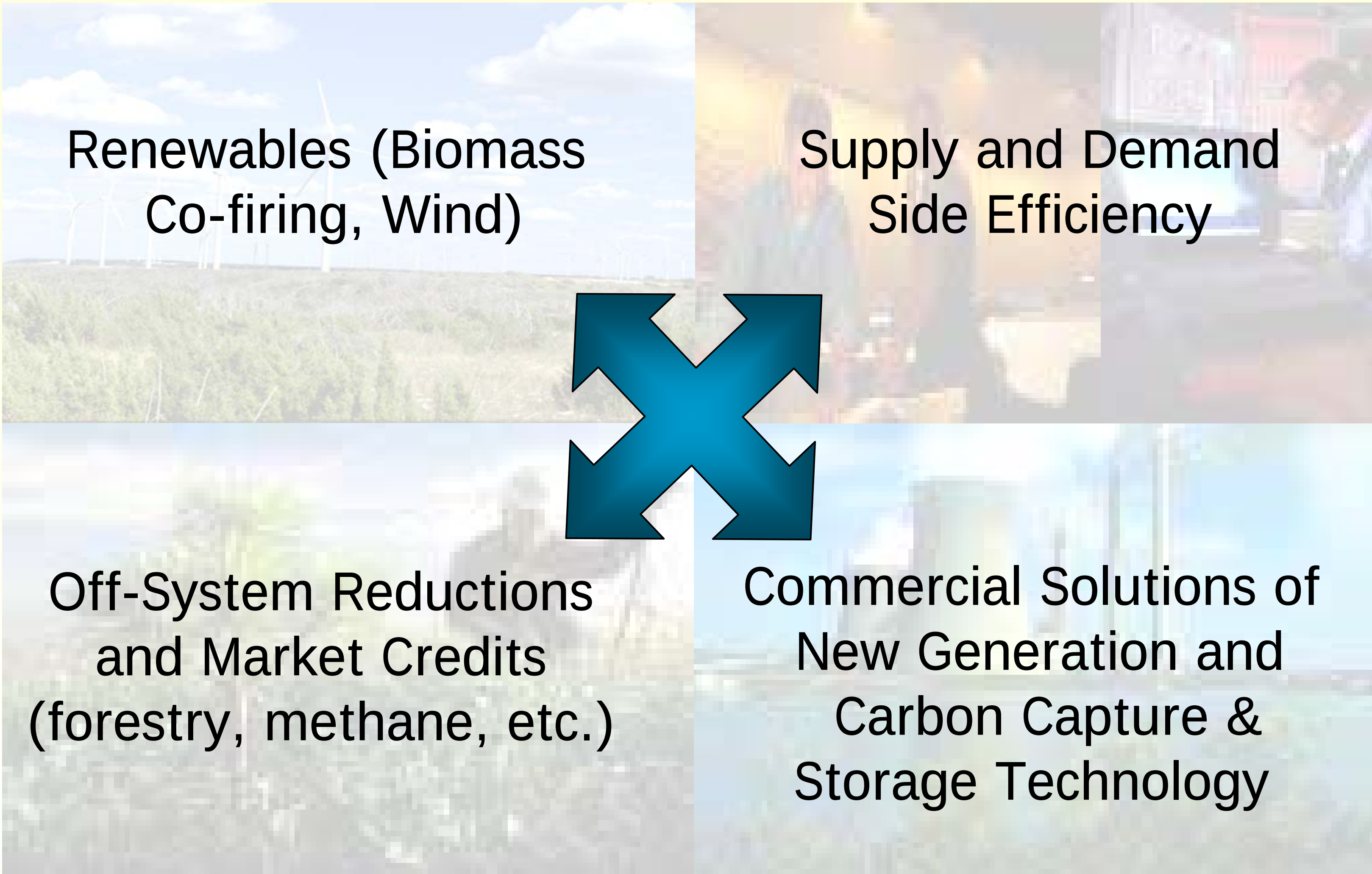
AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio



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AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

AEP®

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Mountaineer Plant (WV) → MOU (Alstom) **Chilled Ammonia** → CO_2 (Battelle)

Project Validation

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost $50 – $80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Phase 2
2011 Commercial Operation

Northeastern Plant (OK) → MOU (Alstom) **Chilled Ammonia** → EOR; CO_2

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~$225 – $300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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Post-combustion Carbon Solution Provides Pure Co_2 Stream For Capture

Oxy-Fuel Technology Initiative

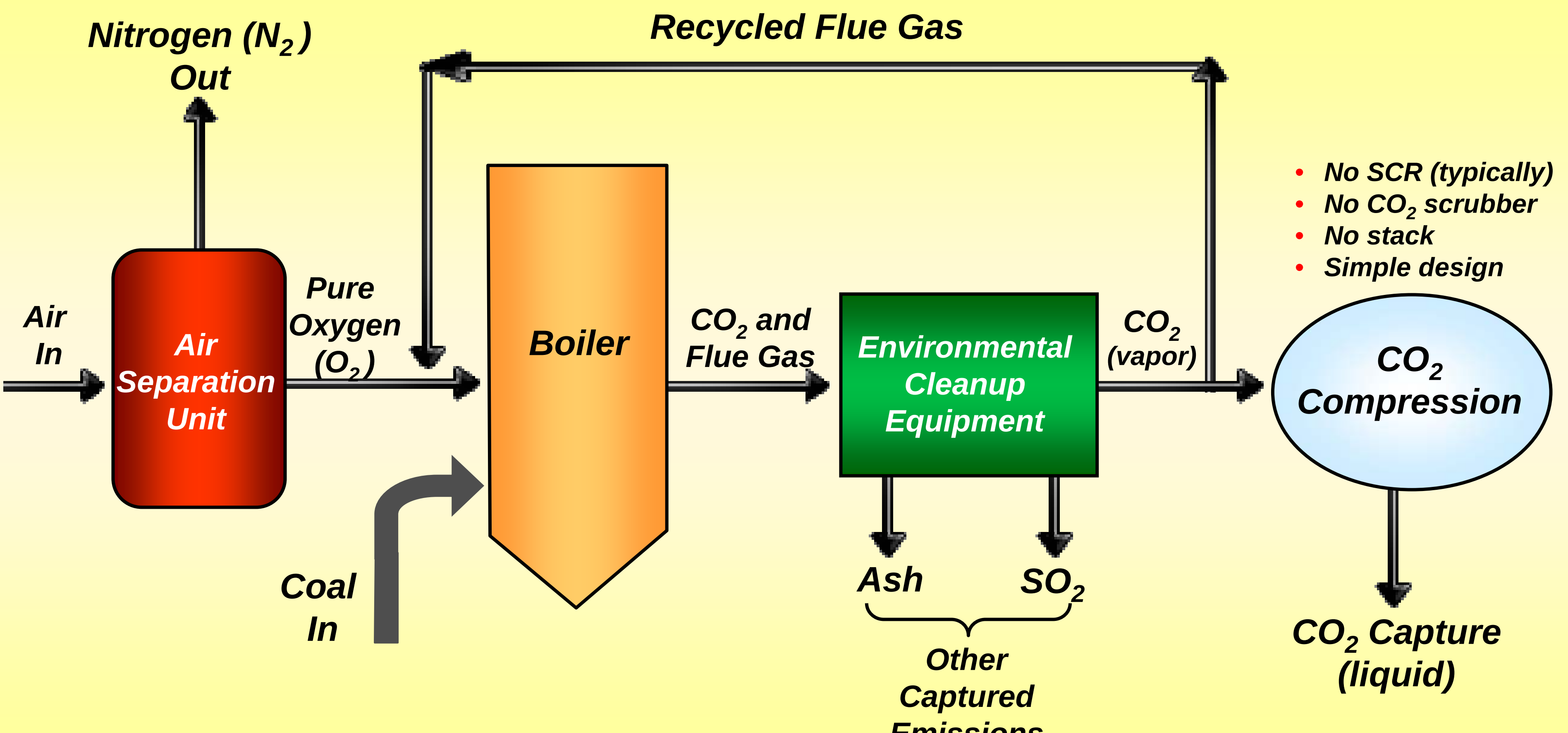

Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-zero Emissions Using Oxy-fuel Combustion Technology

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Evidentiary hearing commenced May 22, 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT. (Docket No. 33734)
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due June 8, 2007. Staff testimony is due June 18, 2007. Hearings are scheduled for July 16-19, 2007. Public Hearings are July 16-19.
    - Final order and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. Rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement for $13.7MM rate increase.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

TCC Final Order expected in Sept.-Oct. 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

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Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

ALJ report issued May 30, 2007, requesting revised revenue requirements based on a 10.5% ROE and other adjustments, and allowing CWIP on new projects.

Oral arguments to be presented to new Commissioner June 13.

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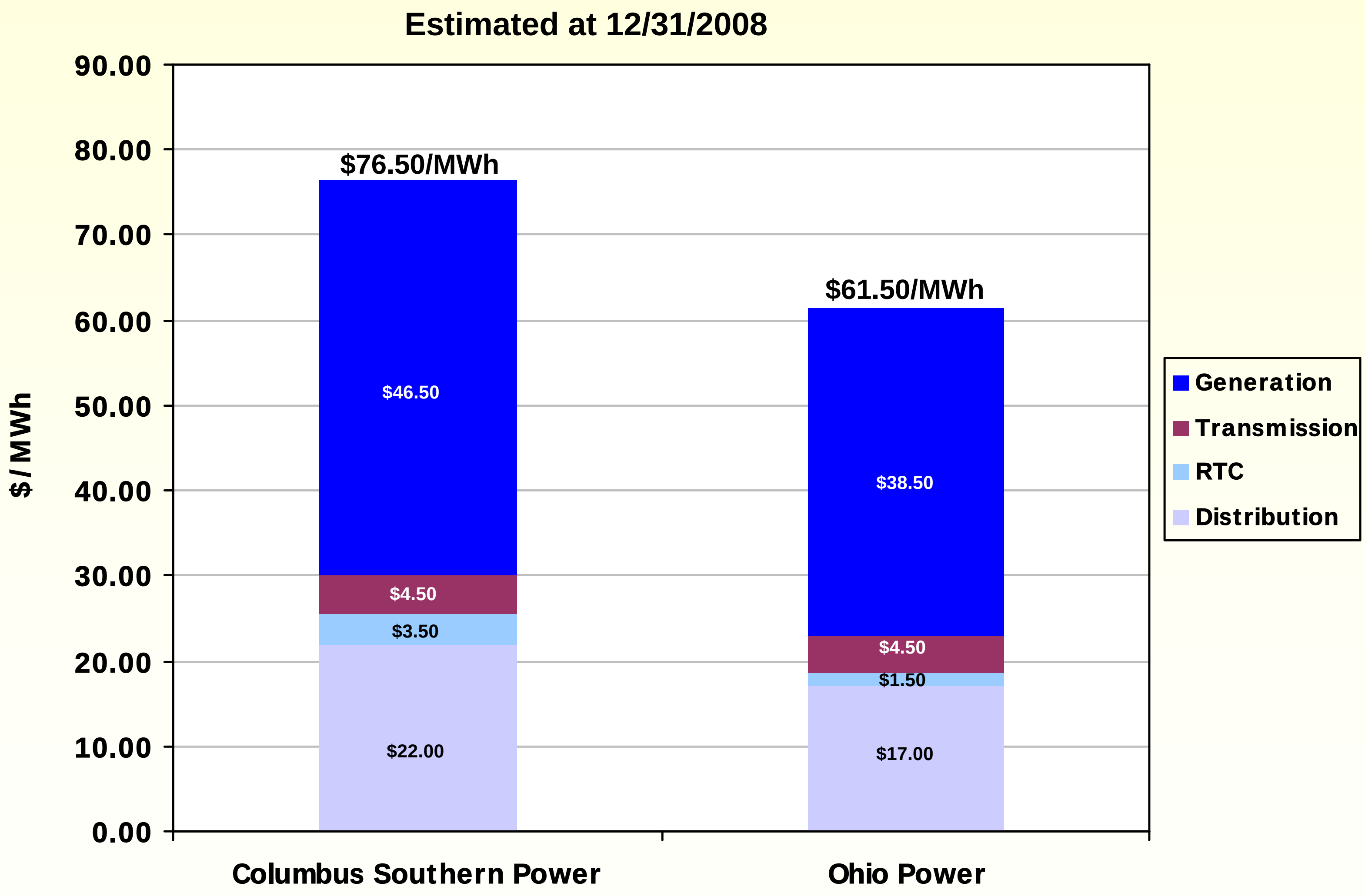
Average Unbundled AEP Ohio Rates



Earned ROE's

Company	Earned ROE as of March 31, 2007
AEP Texas Central Company	**5.81%**
AEP Texas North Company	**5.24%**
Appalachian Power Company	**8.97%**
Columbus Southern Power Company	**17.14%**
Indiana Michigan Power Company	**7.12%**
Kentucky Power Company	**11.06%**
Ohio Power Company	**10.57%**
Public Service Company of Oklahoma	**3.75%**
Southwestern Electric Power Company	**10.11%**

These ROE's are based on GAAP, Not Rate Base

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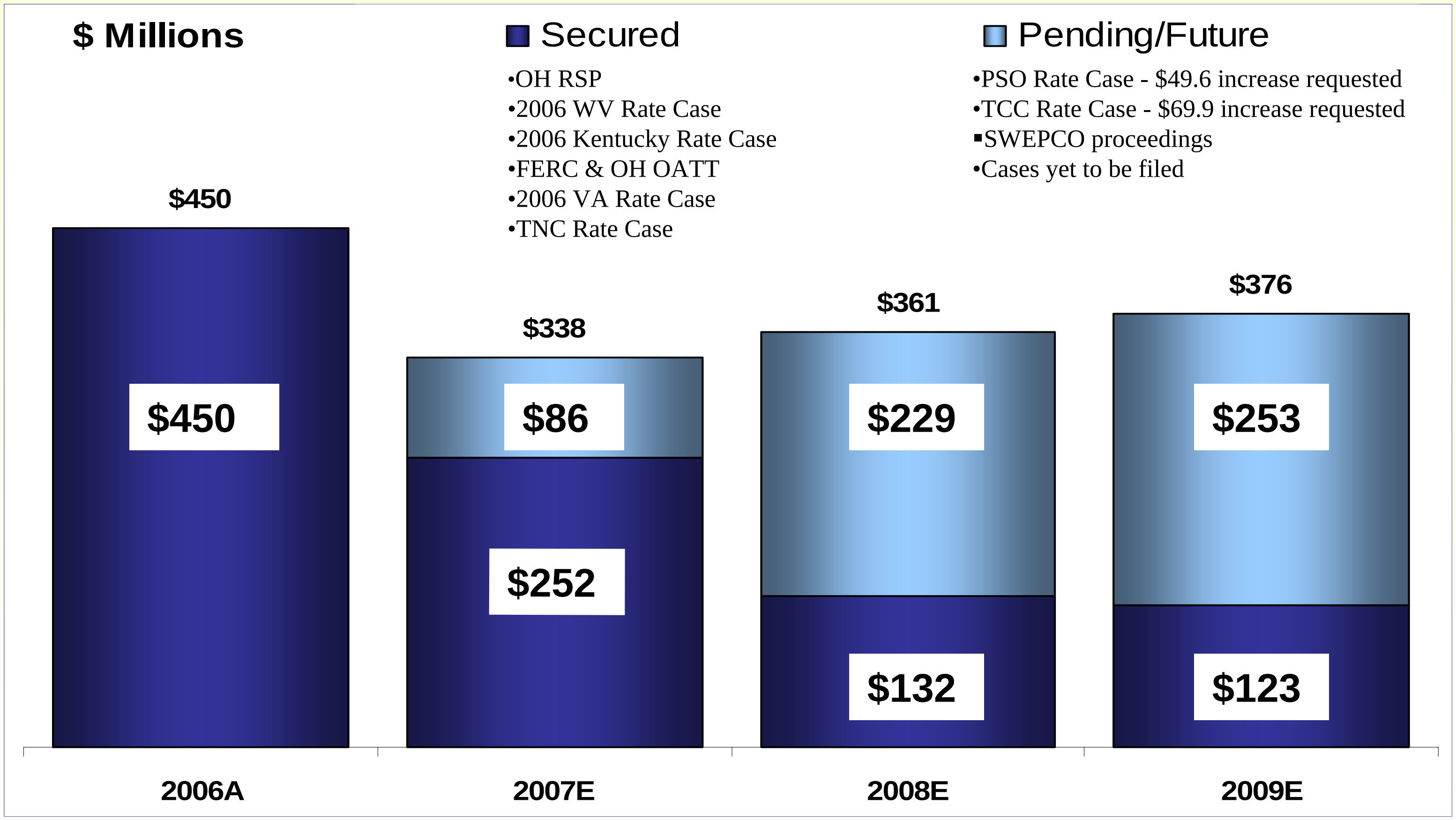
Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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AMERICAN ELECTRIC POWER

Citigroup

Power, Gas & Utilities Conference

New York, NY

June 4, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG

FLEXIBLE

ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

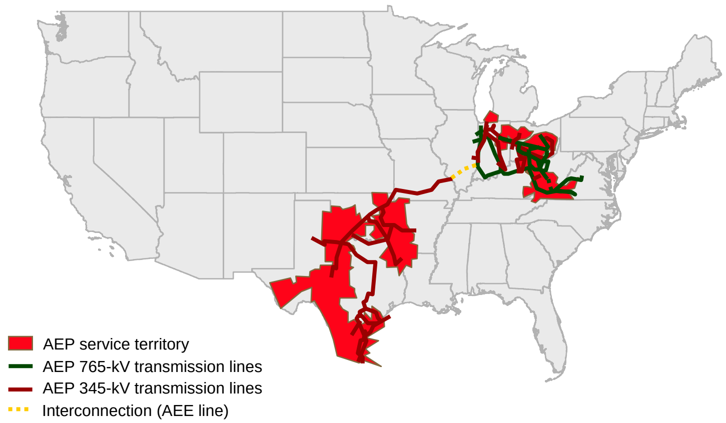
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview



AEP's Leadership Position

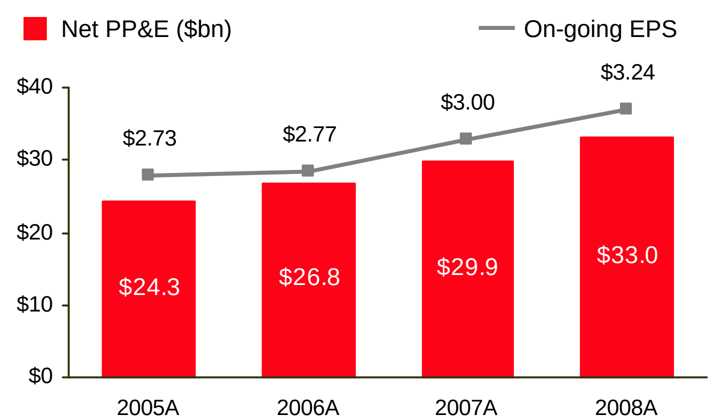
Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

Generation owned[1] (GW)	
SO	42.6
AEP	40.6 *
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

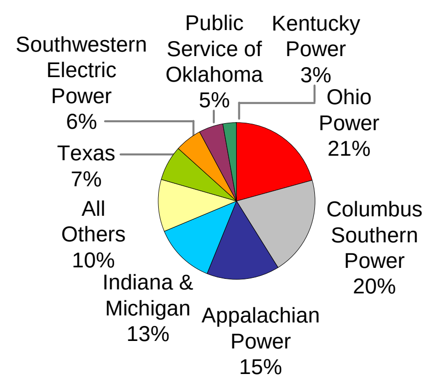
Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

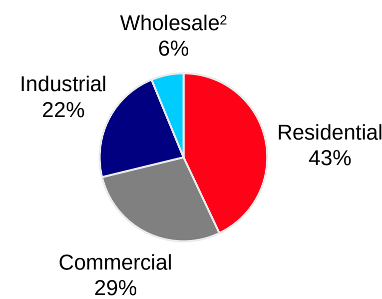
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

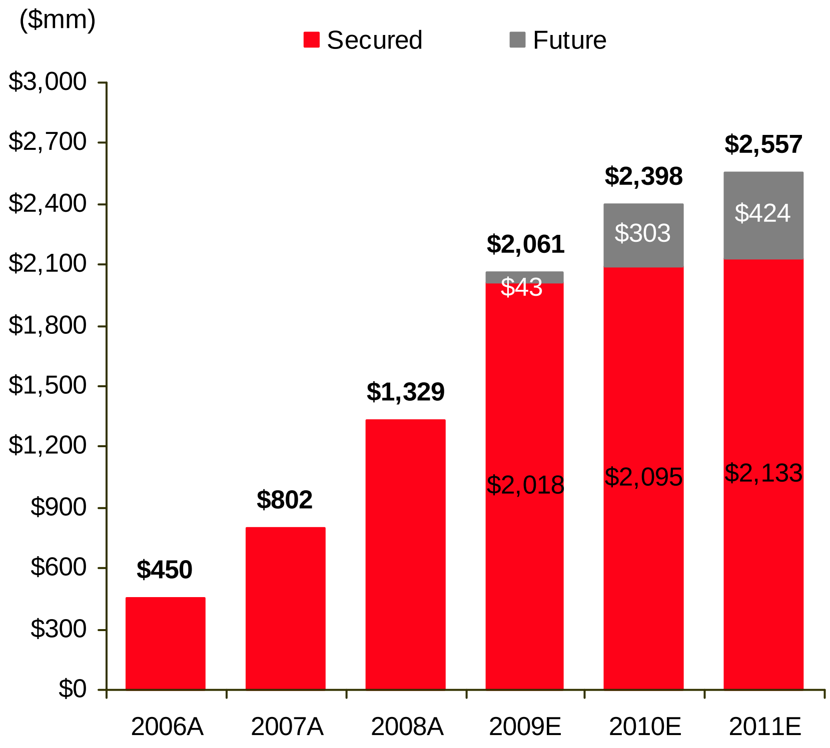
- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

AEP AMERICAN ELECTRIC POWER

Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $77mm and $38mm was secured for 2010 and 2011, respectively, as of May 15, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN
FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 15, 2009, Appalachian Power filed the fourth and final tranche of E&R surcharge filings with the SCC, requesting a $41.6 MM increase for environmental and reliability costs incurred during the period January 1, 2008 through December 31, 2008, with a proposed one year recovery period commencing January 1, 2010. No procedural schedule has been set by the SCC.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	07/01/2004 thru 09/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/01/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008- 00045	10/01/2006 thru 12/31/2007	01/01/2009 thru 12/31/2009	$60.6 million
IV	PUE-2009-00039	01/01/2008 thru 12/31/2008	Proposed 01/01/2010 thru 12/31/2010	$41.6 million

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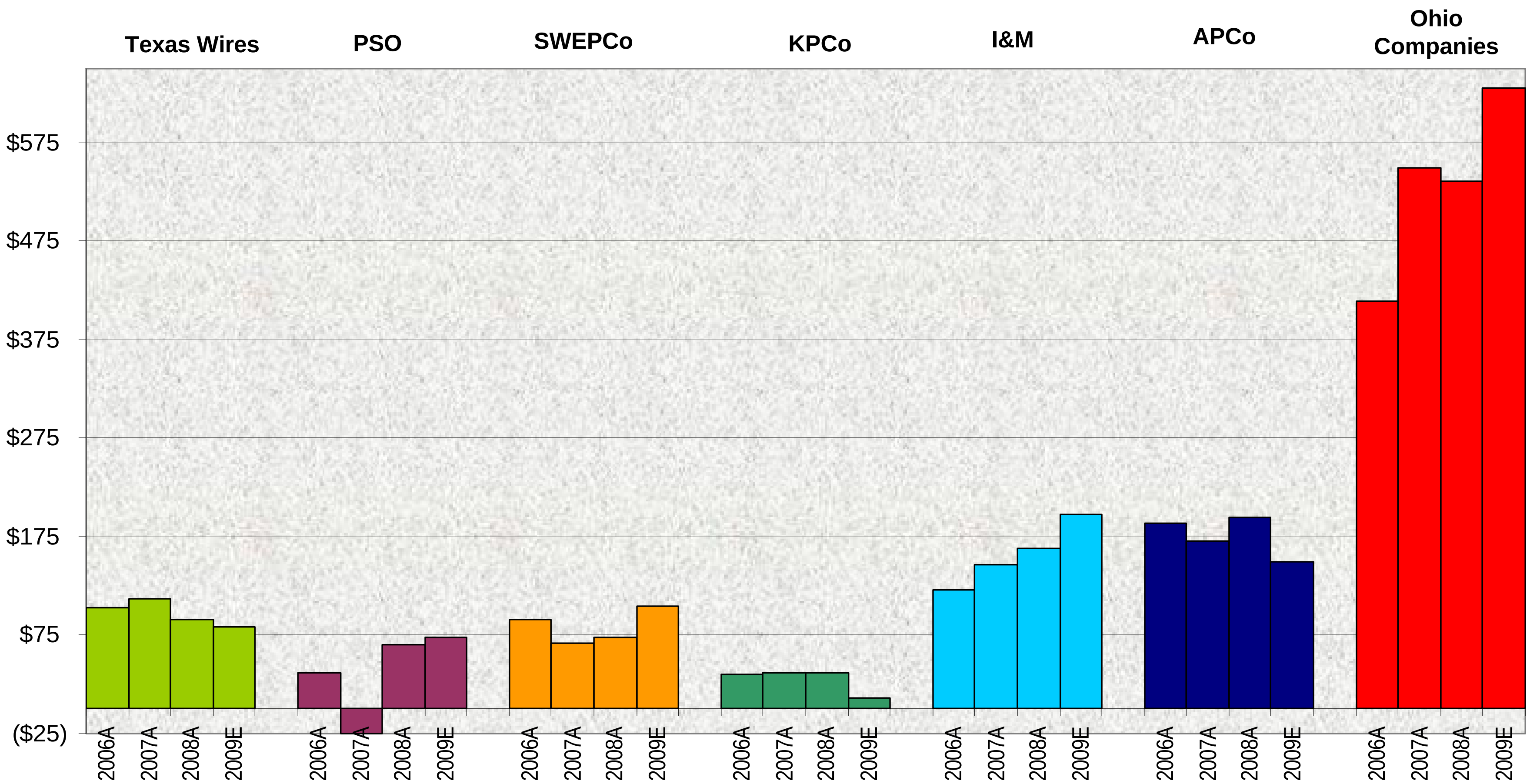
Net Income by Operating Company



Net Income by Operating Company

($ in millions)

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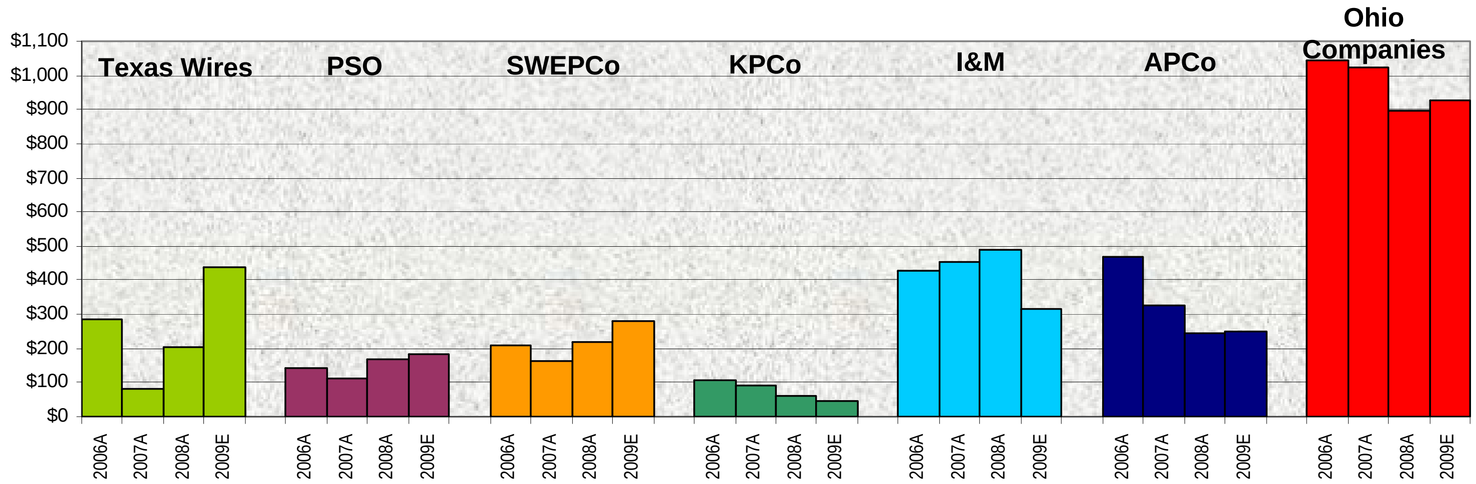
Cash Flow and Capex by Operating Company

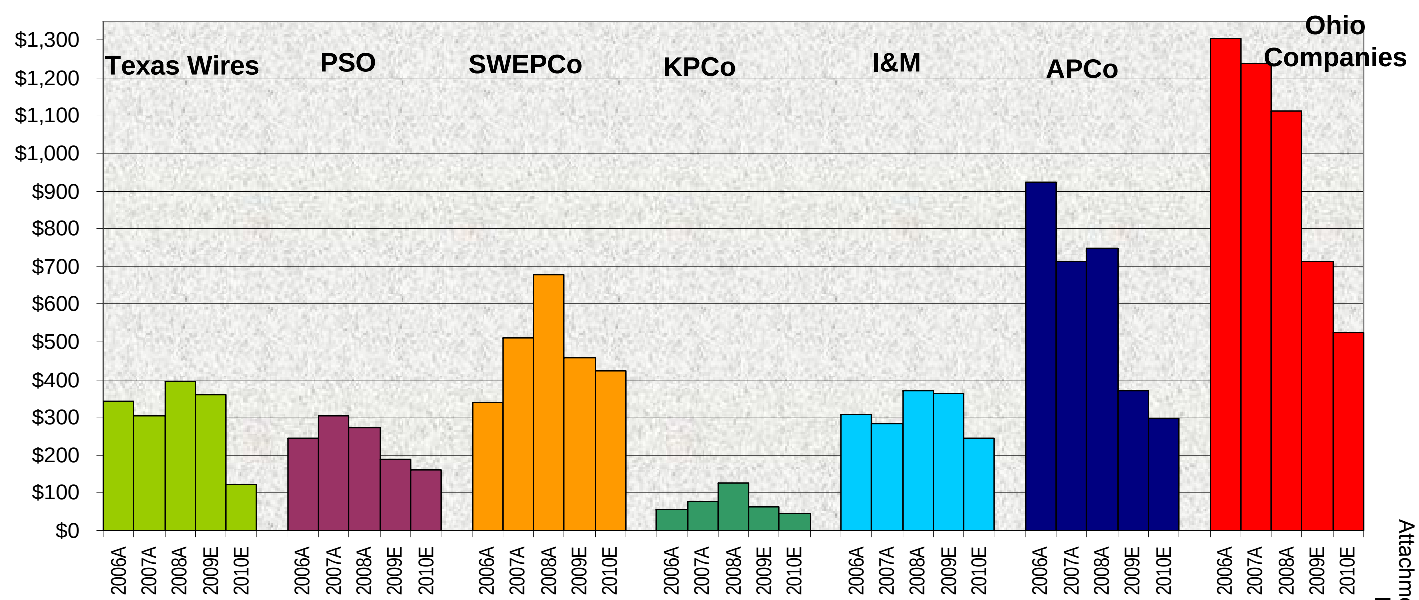


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

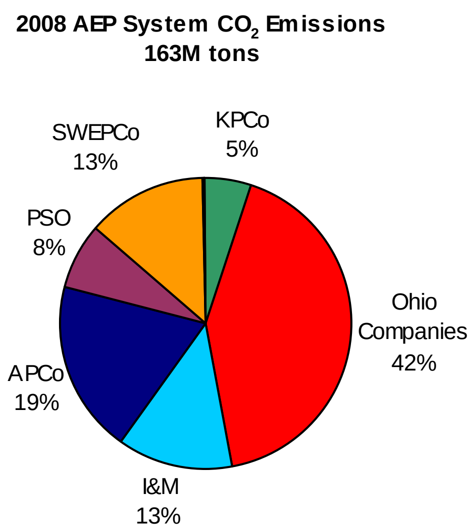
- Develop "transmission superhighway" to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

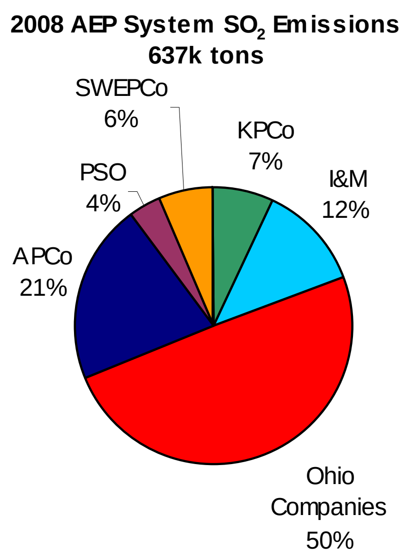
Energy Efficiency, Security & Reliability

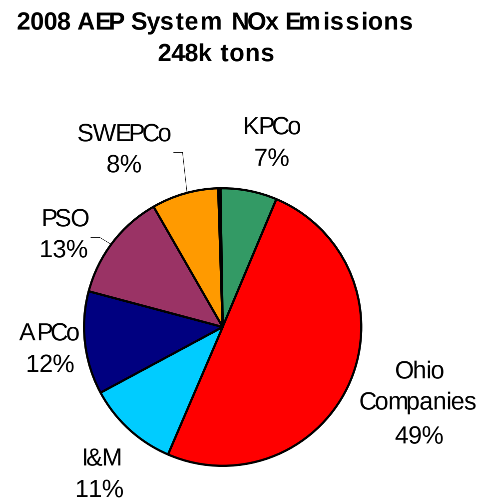
- Develop high-voltage transmission projects to strengthen America's power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

AEP AMERICAN ELECTRIC POWER

CO_2 Cost Recovery – Should Follow SO_2 & NOx





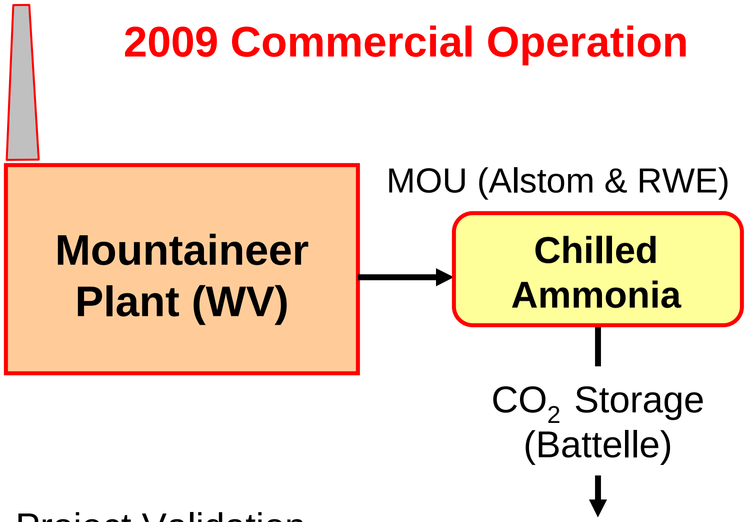


- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

AEP AMERICAN ELECTRIC POWER

Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – AEP self-reported impacts to jurisdictional wetlands in March 2009. Work continues outside the jurisdictional areas. Hearing on the air permit appeal is scheduled for June 2009.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

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DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

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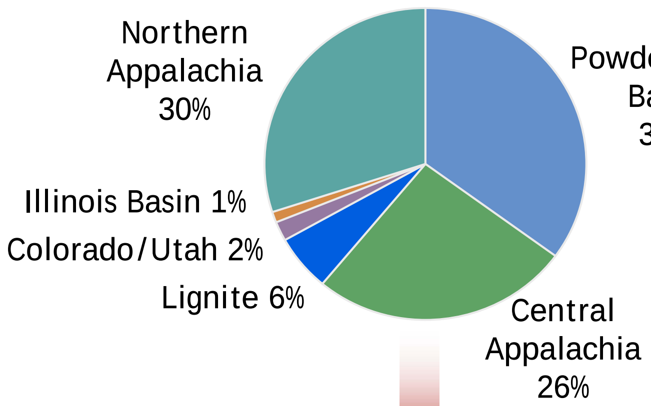
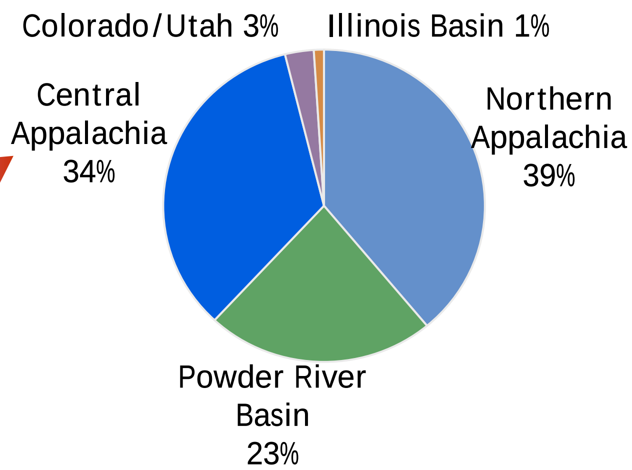
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

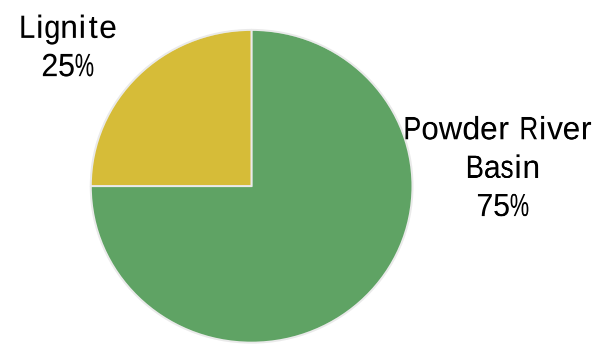
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

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Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

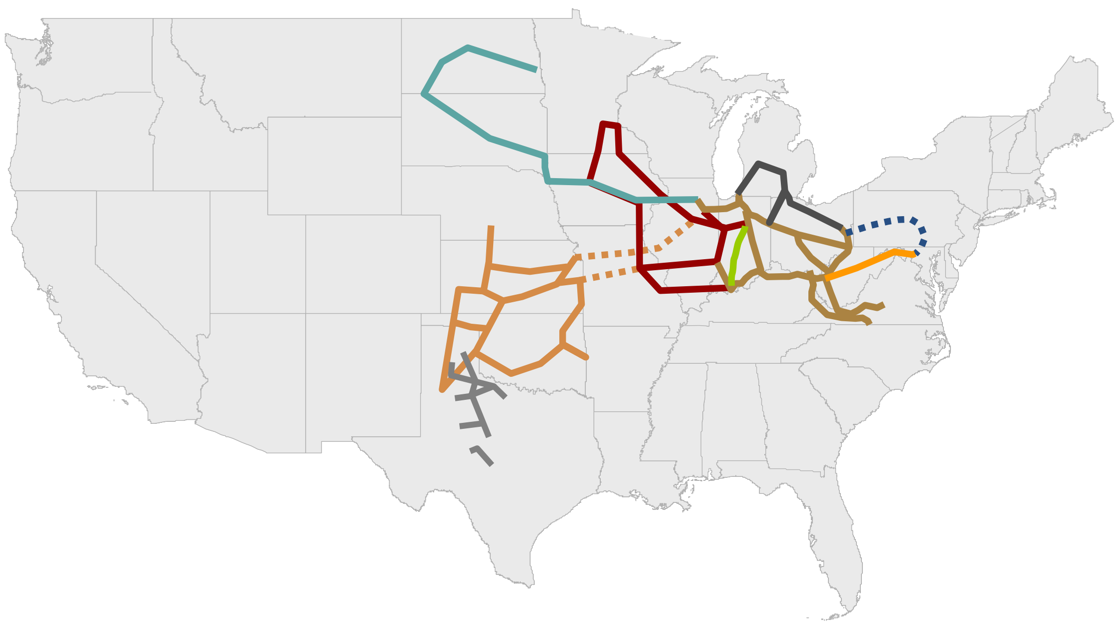
Pioneer — **COD: 2015**
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV — **COD: 2014**
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass — **COD: 2013-14**
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind — **COD: 2013**
- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT — **COD: 2013**
- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan — **COD: ~2020**
- 700 miles of 765 kV
- Partner: ITC

PJM Projects
- Enhance existing 765/345 kV

Hartland — **COD: ~2020**
- 1000+ miles of 765 kV
- Partner: Hartland Wind LLC

MISO Vision Plan
- 765 kV Backbone

SPP Overlay — **COD: 2013-14**
- 765 kV Backbone

ETT — **COD: ~2018**
- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

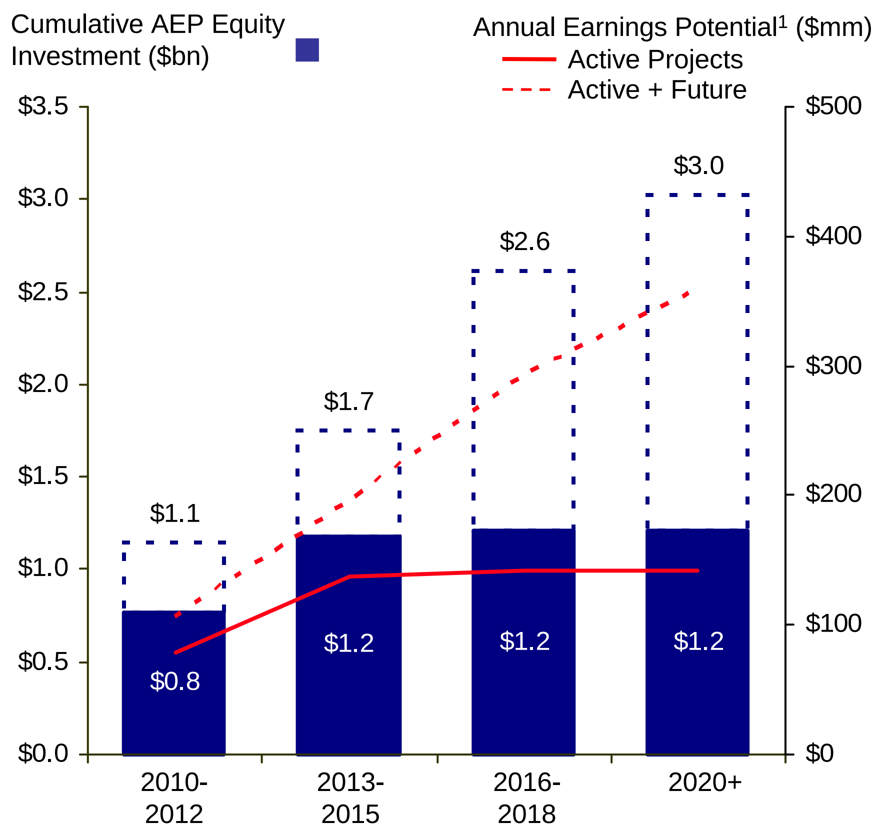
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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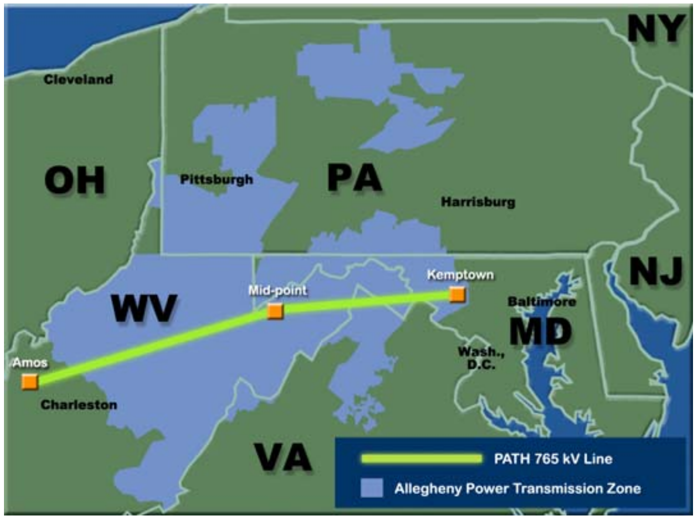
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



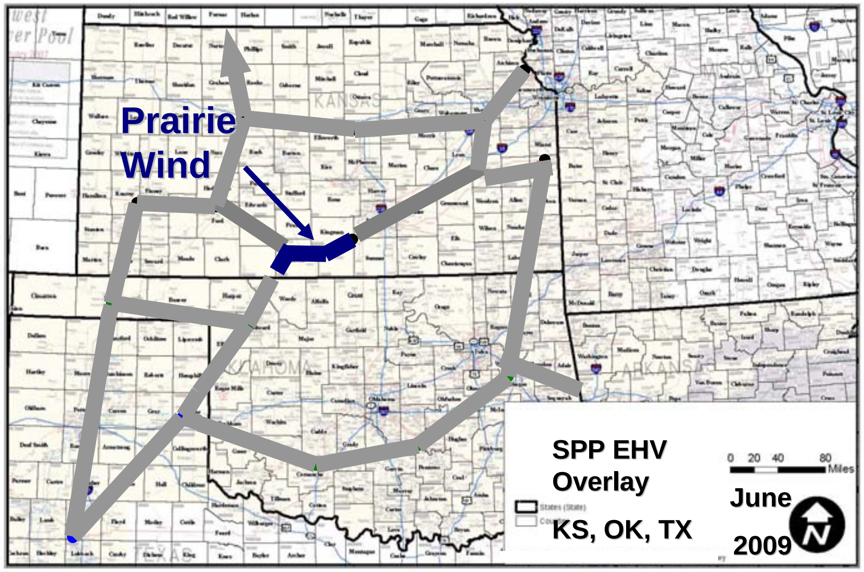
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement approval by the KCC is still pending.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
- The original proposed mileage prior to settlement was approximately 230 miles.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

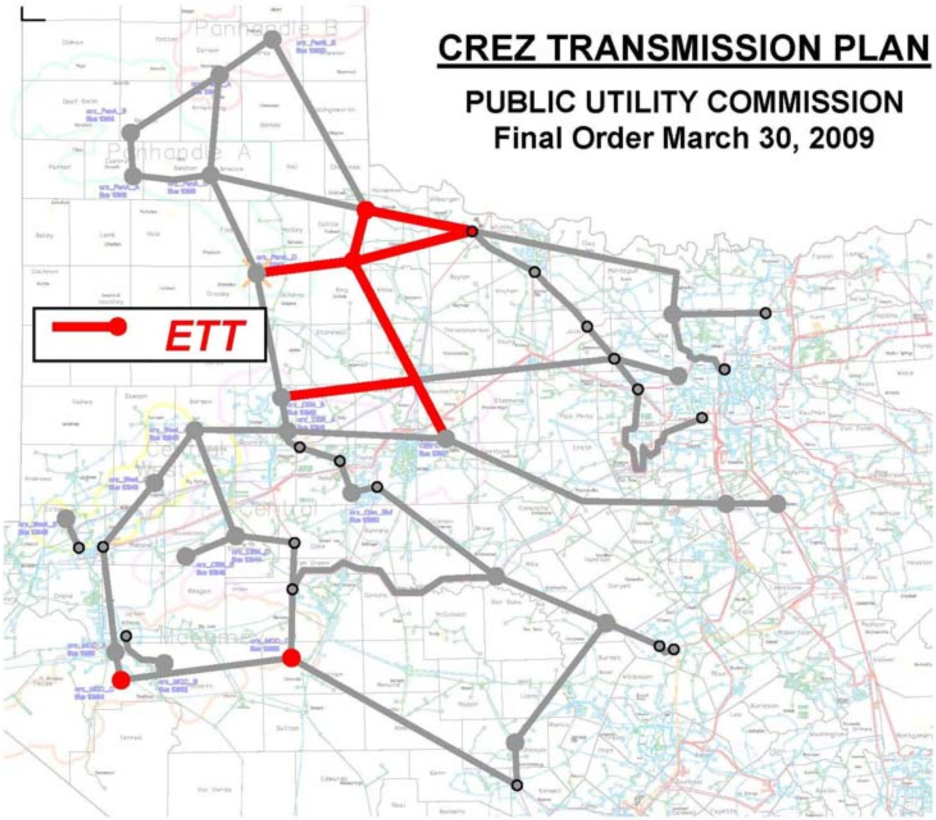
Key Challenges

- Regional Cost allocation which enables the development of "system solutions"
- RTO Approval

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

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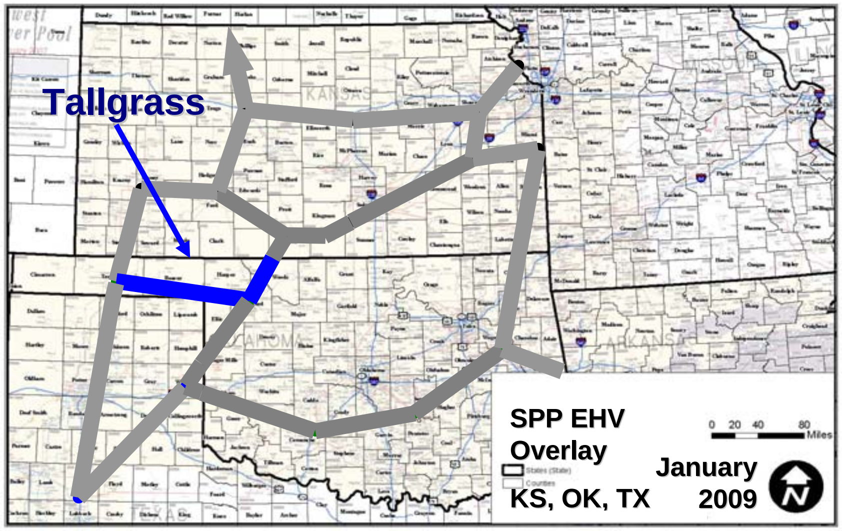
Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

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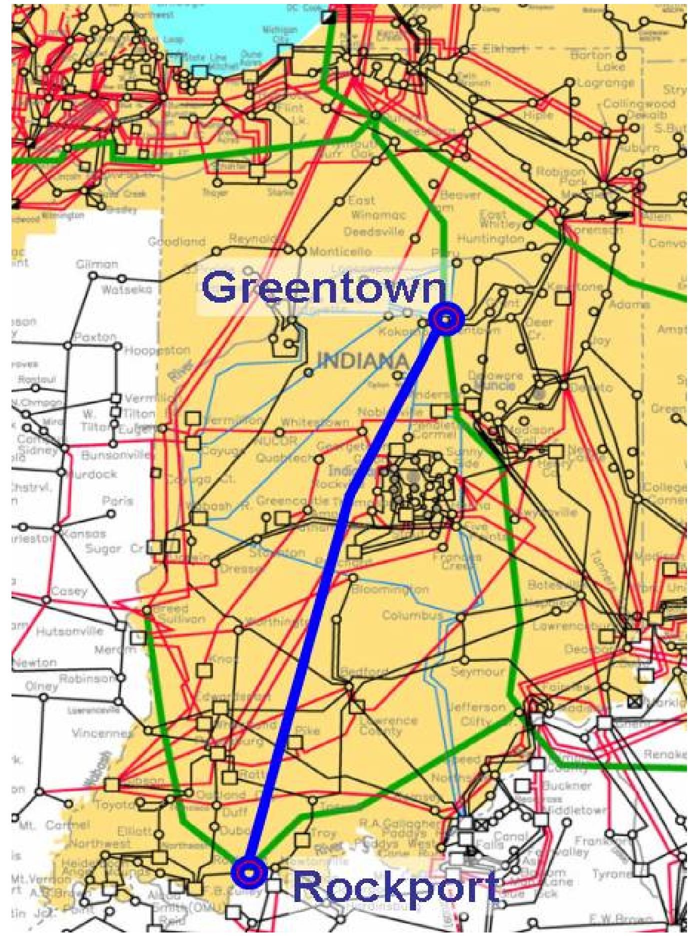
Pioneer Transmission LLC

- ***Overview***
  - In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
  - PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
  - The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
  - Project is expected to cost approximately $1 billion and be in-service by 2015.
  - AEP's ownership of the joint venture is 50%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received March 2009:
    - Cash return on CWIP and 12.54% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
    - Certain formula rate issues were set for hearing



- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval - touches two RTOs – PJM & MISO
  - Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

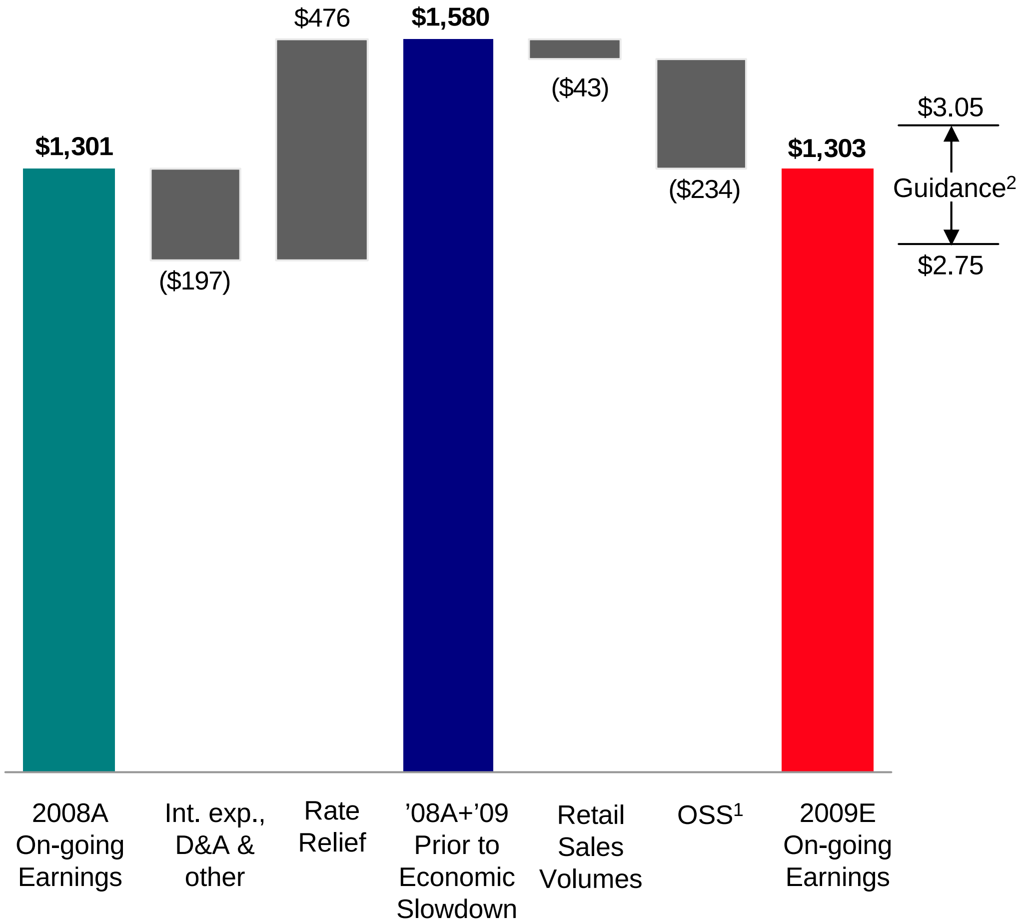
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax

[1] Net of sharing

[2] Assumes 2009 average shares outstanding ~ 450 million

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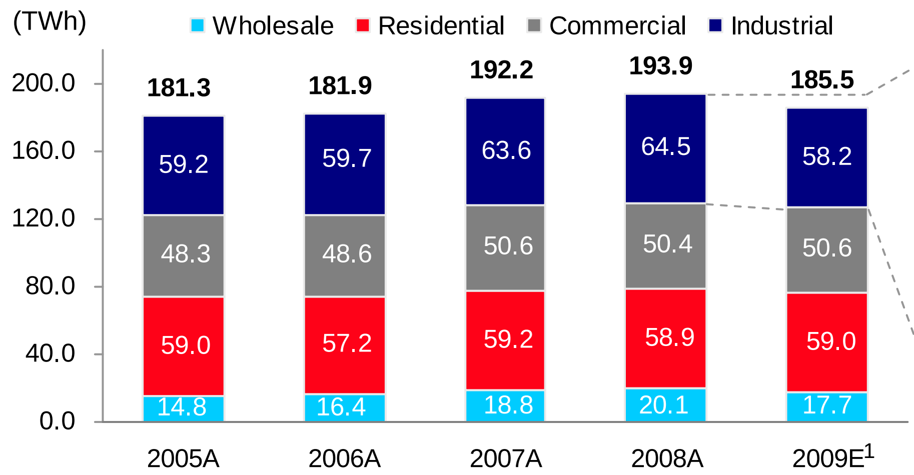
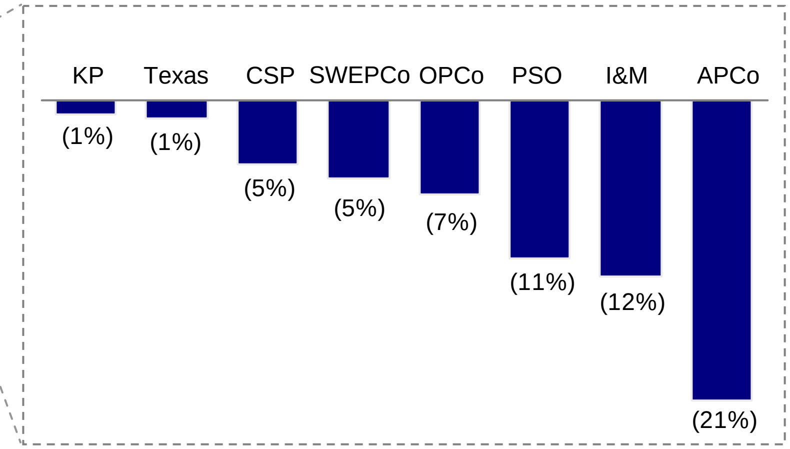
Key Drivers of Revised 2009 Guidance: Retail Sales

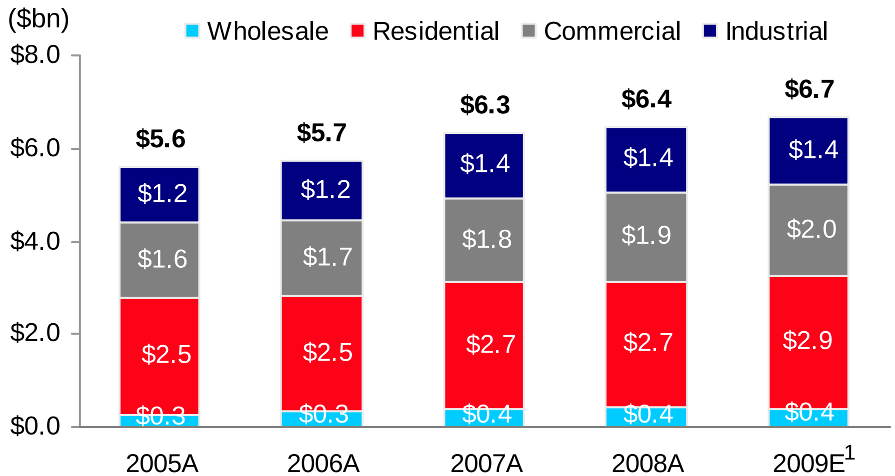
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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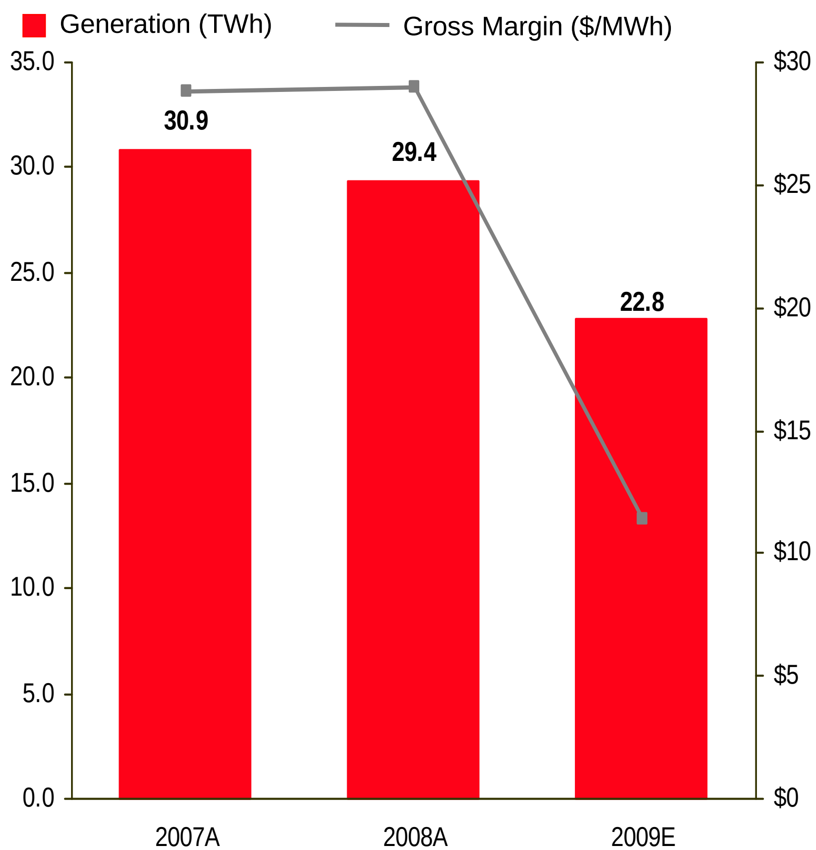
[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

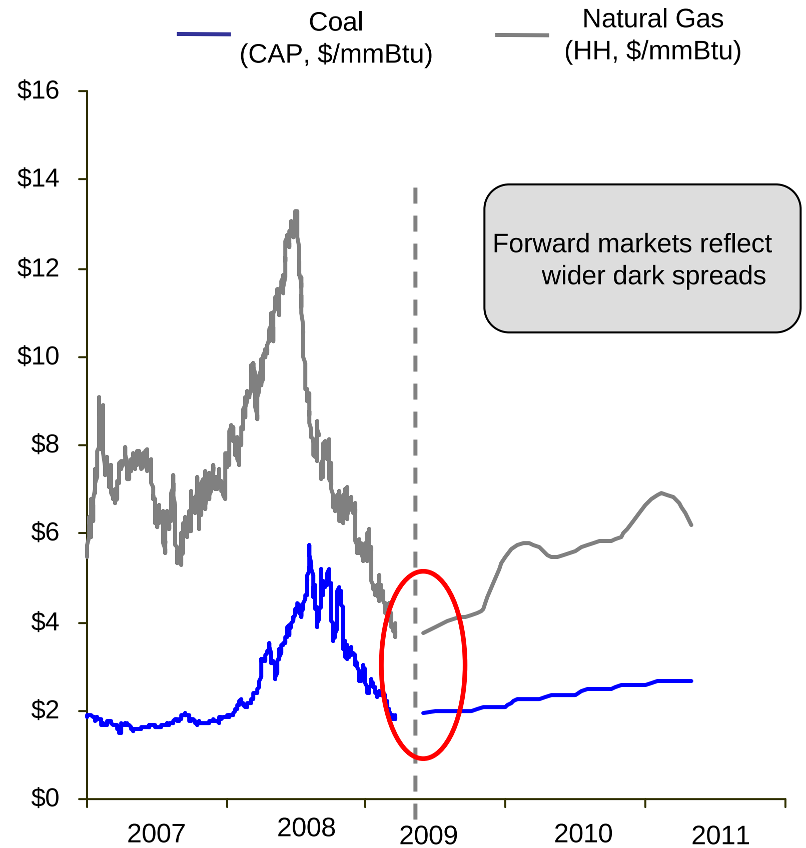
Key Drivers of Revised 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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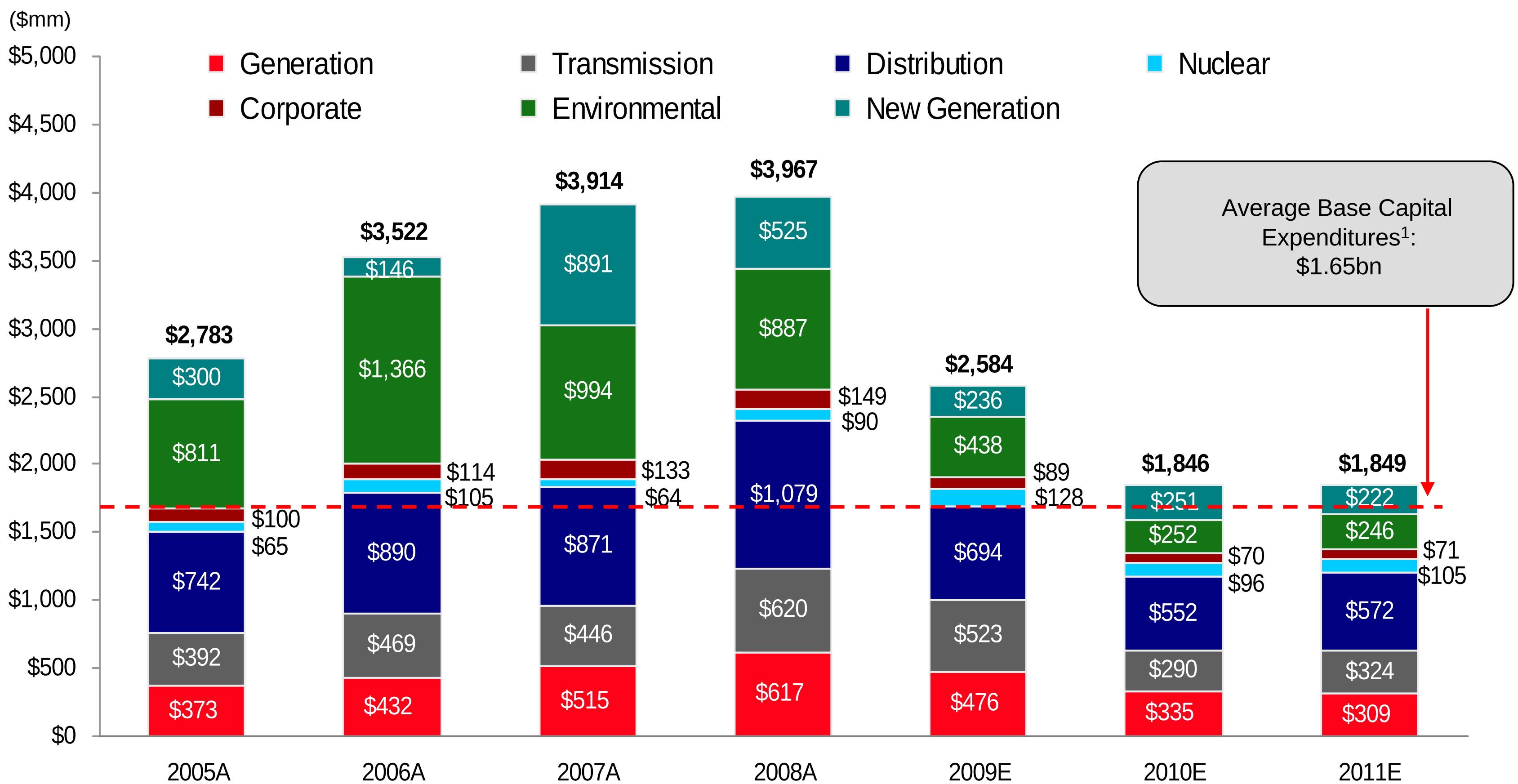
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
¹ Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

AEP AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4812 of 9556

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	R	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

($ in millions)
(as of March 31, 2009)

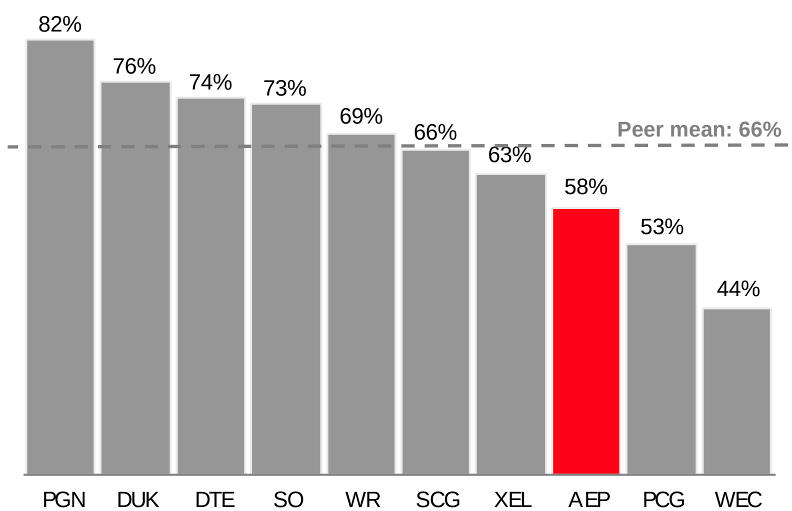
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ 150	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ 70	$ 679	$ -
Public Service of Oklahoma	$ 50	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 270	$ 1,791	$ 625

AEP AMERICAN ELECTRIC POWER

Dividend Overview

- We have paid 395 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

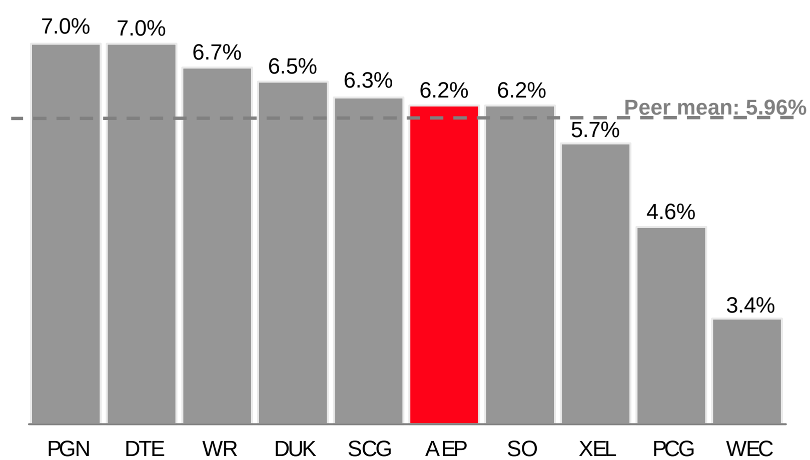
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 5/29/09

Dividend Yield vs. Integrated Electric Peers



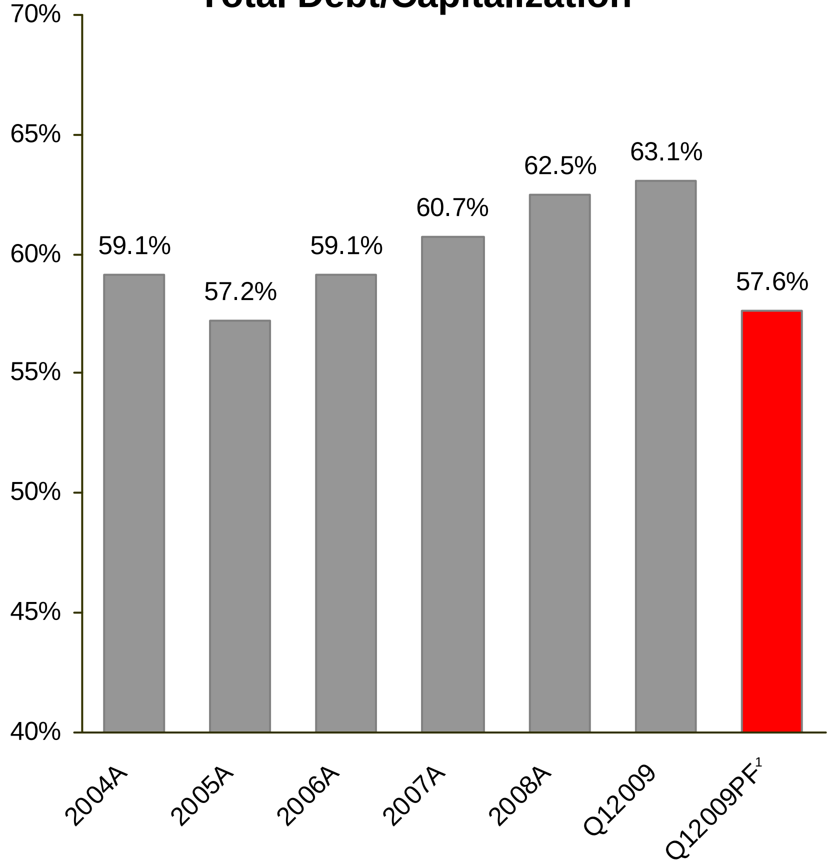
Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 5/29/09

AEP AMERICAN ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	**04/20/2009**	**Maturity**
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)[1]	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

1- An additional $500MM has been repaid subsequent to 4/20/09.

AEP AMERICAN ELECTRIC POWER

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Cleveland Research Group
November 13, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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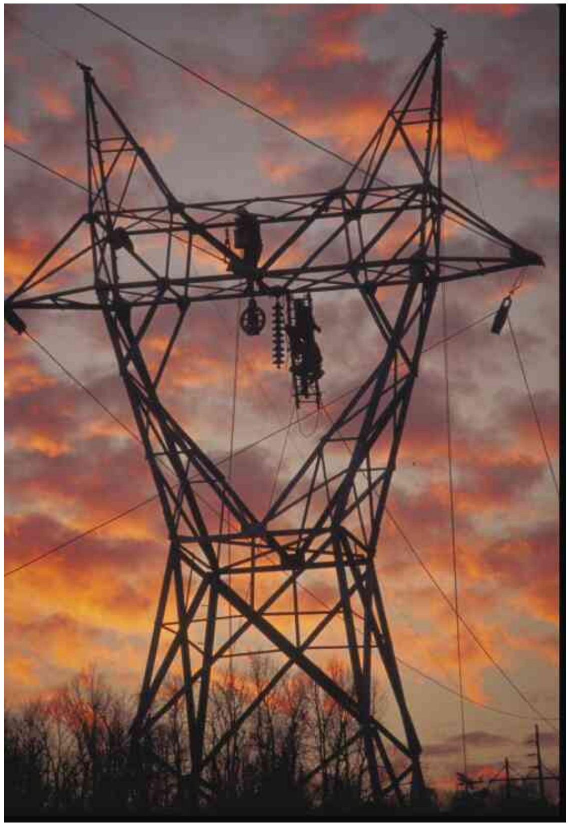
AMERICAN ELECTRIC POWER

AEP is . . .

One of the largest electricity generators in the United States, owning over 39,000 MW of generating capacity



The largest electricity transmitter in the United States, owning over 39,000 miles of transmission

The largest electricity distributor in the United States, owning and operating over 213,000 miles of distribution

AEP AMERICAN® ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity
- $6.4 billion utility capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

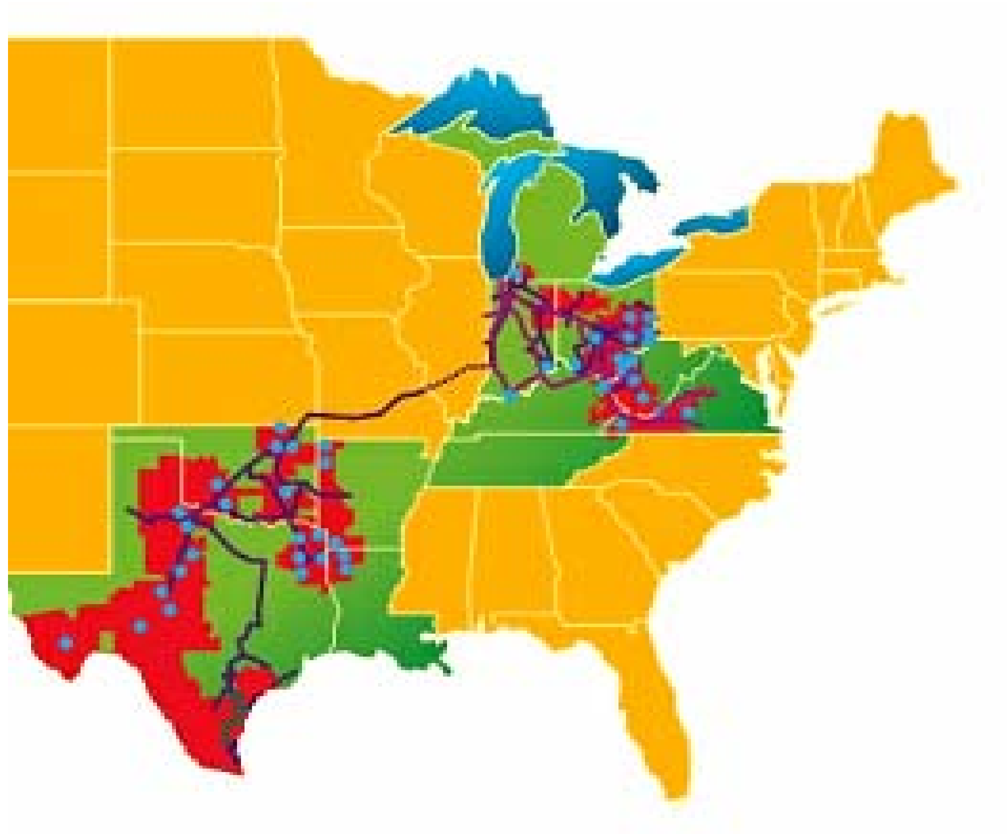
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER®

Company Overview

- 5.2 million customers in 11 states
- 21,700 employees
- Industry-leading size and scale of assets
- 11 Operating Companies
  - Appalachian Power Co. (VA, WV)
  - Columbus Southern Power Co. (OH)
  - Indiana Michigan Power Co. (IN, MI)
  - Kentucky Power Co. (KY)
  - Kingsport Power Co. (TN)
  - Ohio Power Co. (OH)
  - Public Service Co. of Oklahoma (OK)
  - Southwestern Electric Power Co. (LA, AR, TX)
  - Texas Central Co. (TX)
  - Texas North Co. (TX)
  - Wheeling Power Co. (WV)

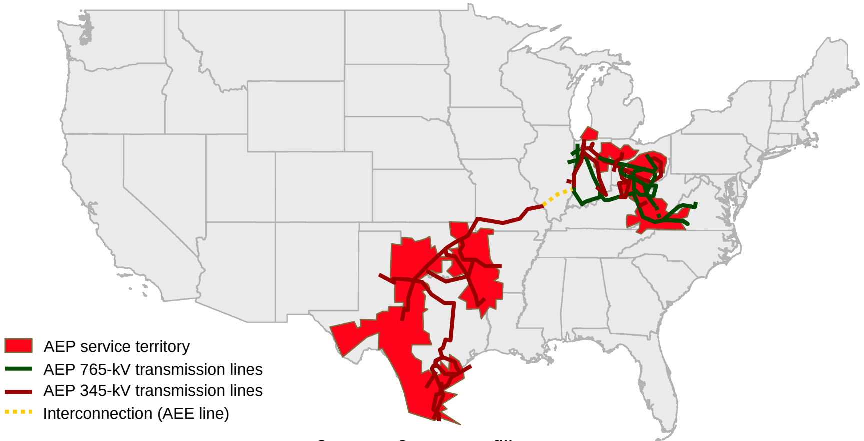


AEP AMERICAN® ELECTRIC POWER

AEP enjoys a diverse geographic footprint

Premier Regulated Utility Platform

Overview



[1] *Source: Company filings*

AEP's Leadership Position

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

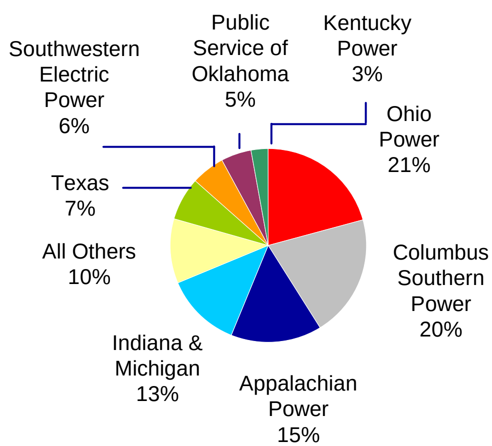
Generation owned[1] (GW)	
SO	42.6
AEP	40.6*
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

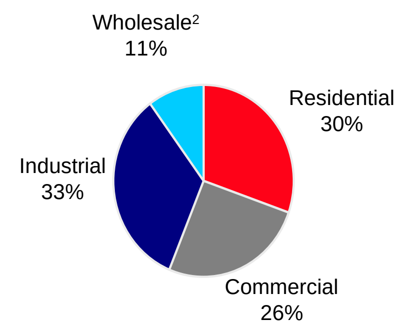
* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations

2008 On-going Earnings = $1.3bn



2008 Retail Load = 193.9 TWh



[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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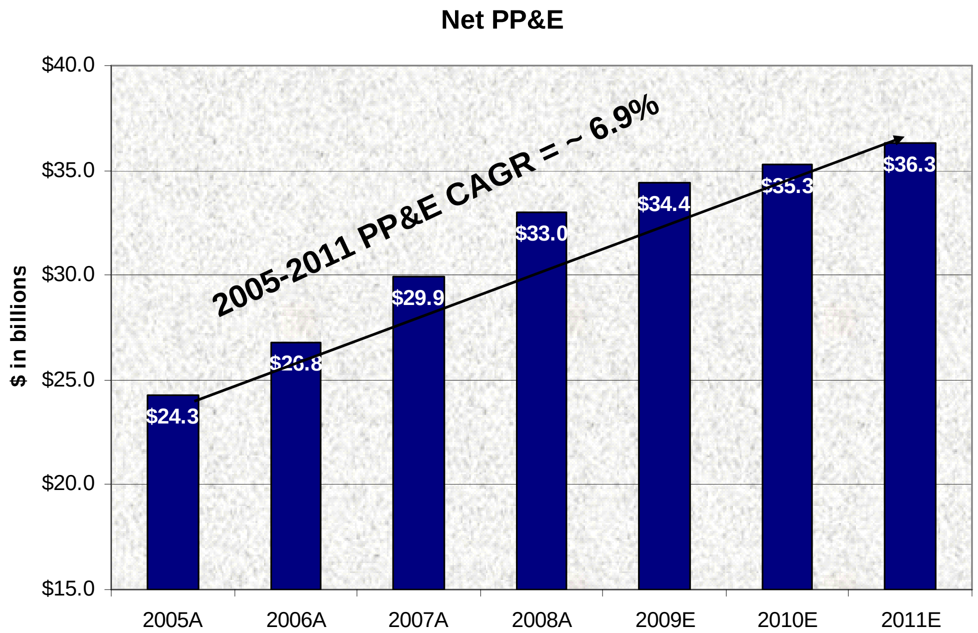
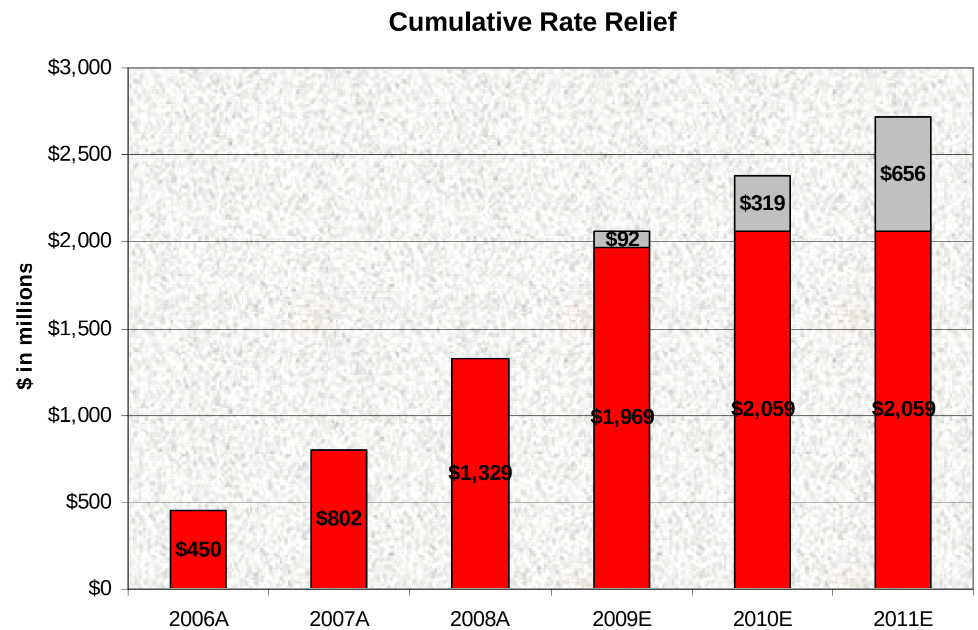
6

Investment in Utility Platform

Growth in Net PP&E



Track Record of Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$317[1]	$337

[1] *$90mm was secured for 2010 as of November 12, 2009*

2010 Ongoing Earnings Guidance

	2009E: $2.90-$3.05	2010E: $2.80-$3.20
Utility Operations	$ 2.92	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.18	$ 0.09
Parent & Other	$(0.14)	$(0.12)

EARNINGS DRIVERS

- ↑ $317MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

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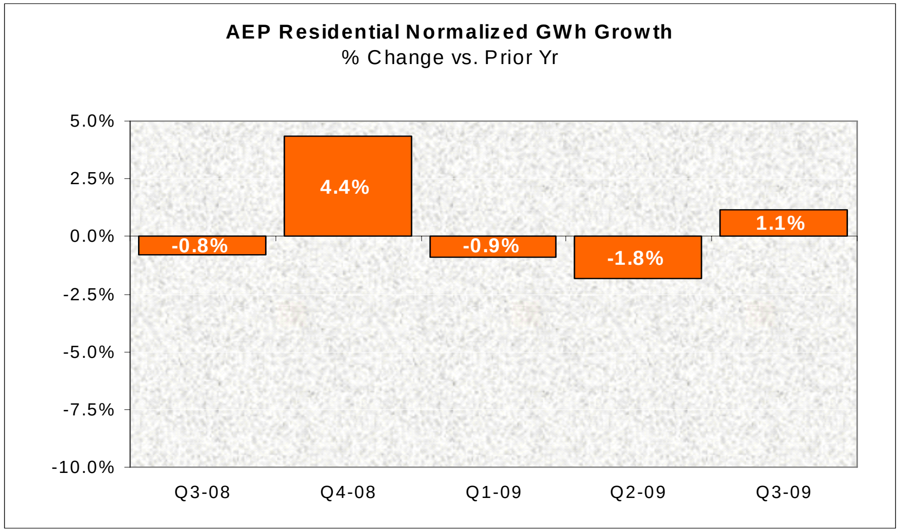
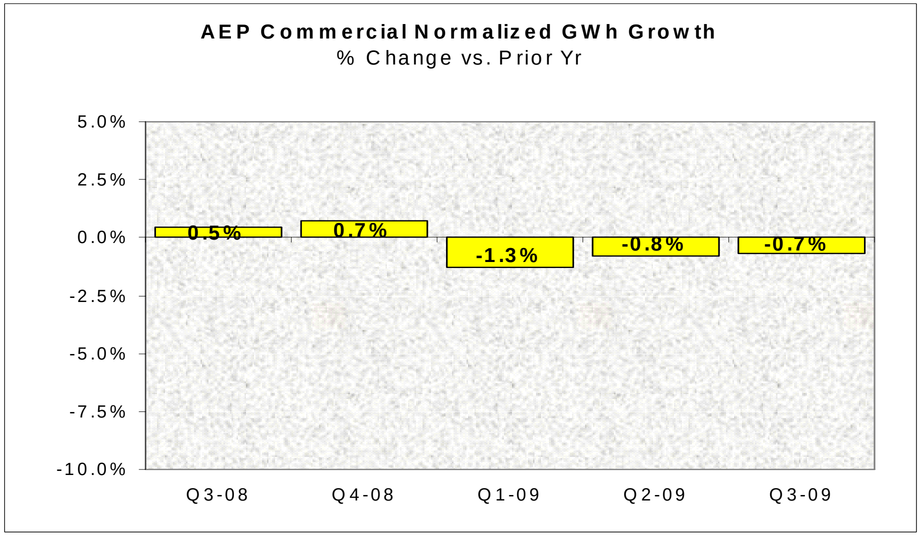
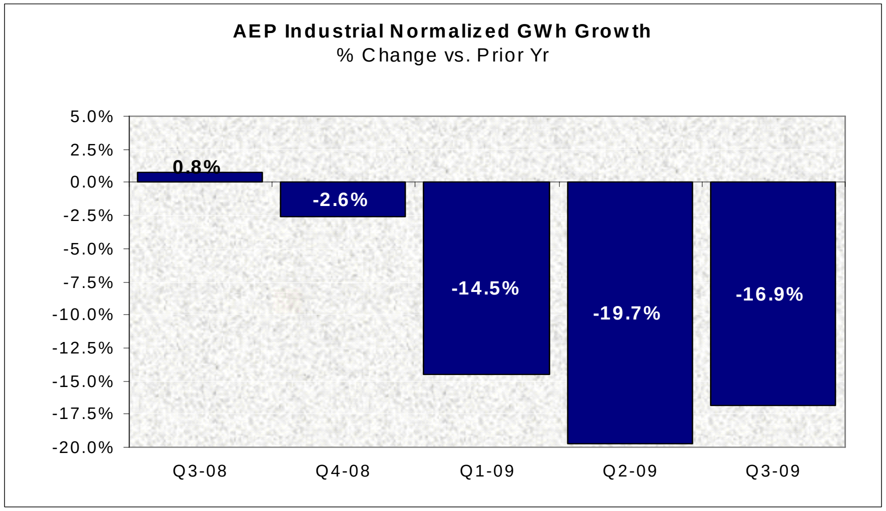
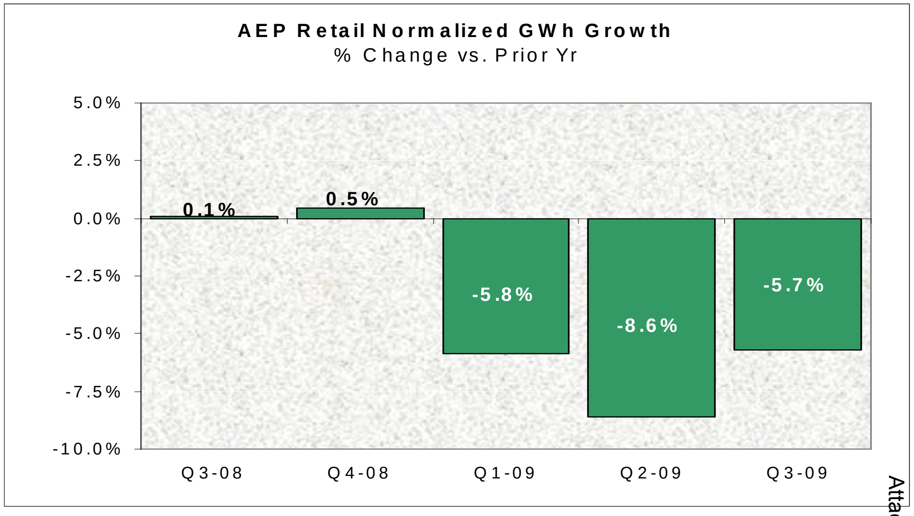
12-Month Normalized Retail Load Trends









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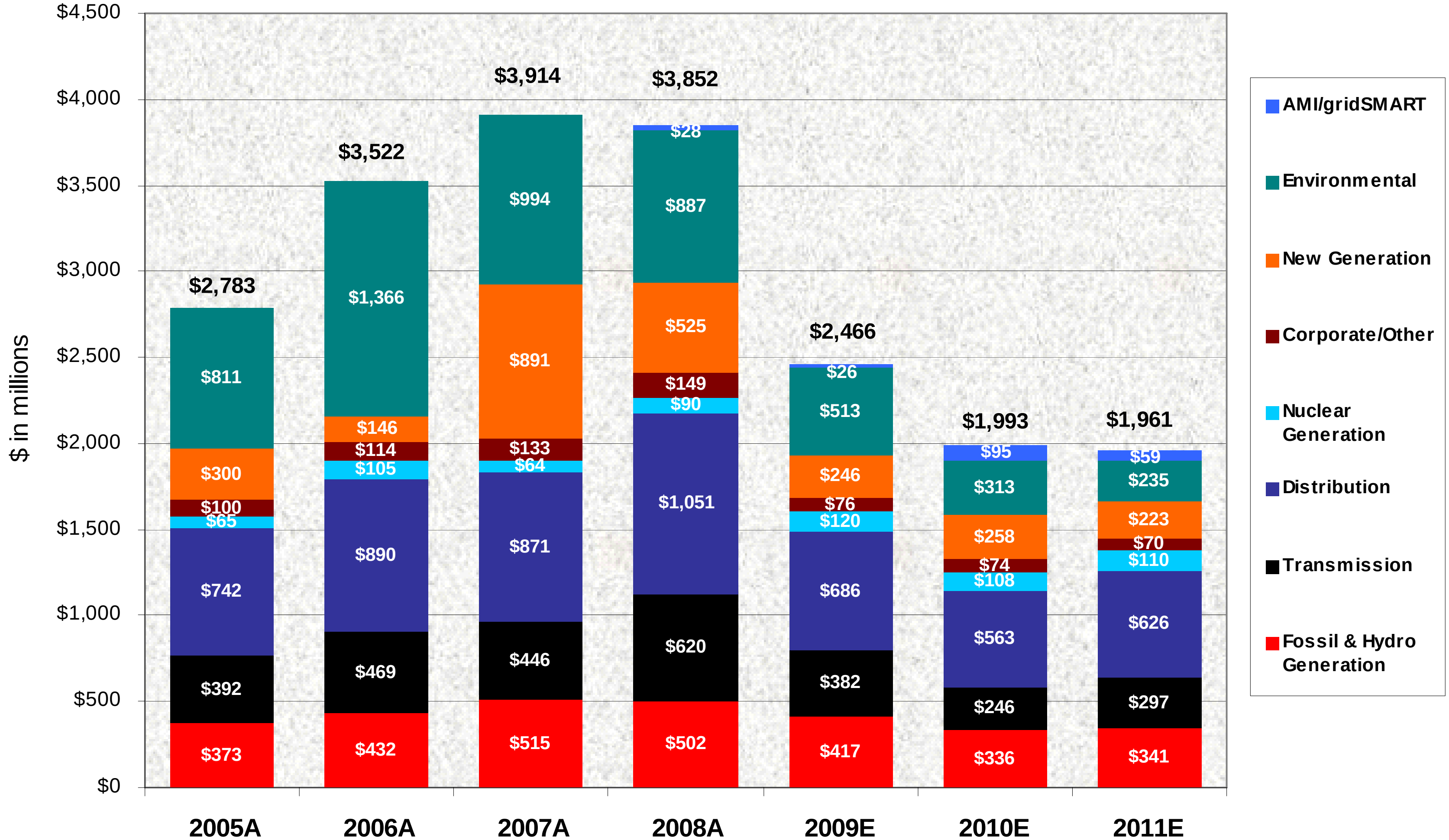
9

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

AEP AMERICAN ELECTRIC POWER®

Transmission Investment Opportunities

- **<u>ETT</u>: Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B in the next decade

- **<u>Transco</u>: Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM

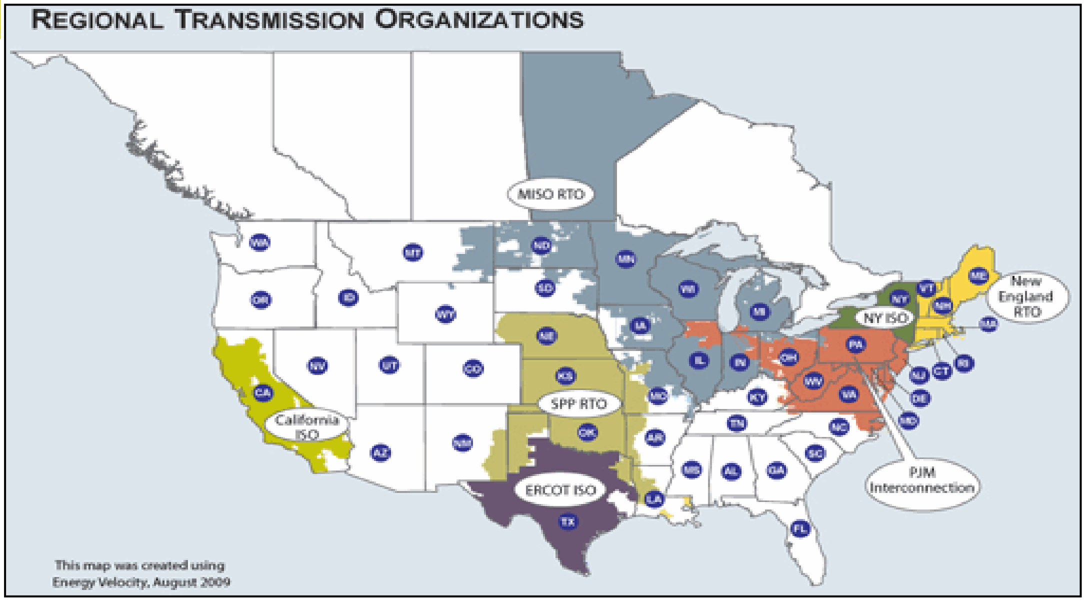
- **<u>Joint Ventures</u>: Outside of our footprint, with ETA or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

JV Strategy – Nationwide Grid Expansion

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind — COD: 2013-14	**ETT — COD: 2010-2013**	**PATH-WV — COD: 2014**	**Pioneer — COD: 2015**
❑ *110 miles of 765 kV* ❑ *Partners: Westar (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $400 million* ❑ *ROE: 12.8%*	❑ *345 kV ERCOT Expansion* ❑ *Partner: MidAmerican Energy (50%)* ❑ *Estimated Cost: $600 million+* ❑ *ROE: 9.96%*	❑ *275 miles of 765 kV* ❑ *Partner: Allegheny Energy (50%)* ❑ *Estimated Cost: $1.2 billion* ❑ *ROE: 14.3%*	❑ *240 miles of 765 kV* ❑ *Partner: Duke Energy (50%)* ❑ *Estimated Cost: $1 billion* ❑ *ROE: 12.54%*

Tallgrass — COD: 2013-14

- ❑ *170 miles of 765 kV*
- ❑ *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- ❑ *Estimated Cost: $500 million*
- ❑ *ROE: 12.8%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- ❑ *Interregional EHV & Wind Integration Study*
- ❑ *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay	ETT — COD: various	PJM Expansion	EHV Michigan/Ohio
❑ *Regional Expansion of 765 kV Backbone*	❑ *Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)* ❑ *Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)*	❑ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	❑ *700 miles of Proposed 765 kV*
SPP	ERCOT	PJM	PJM/MISO

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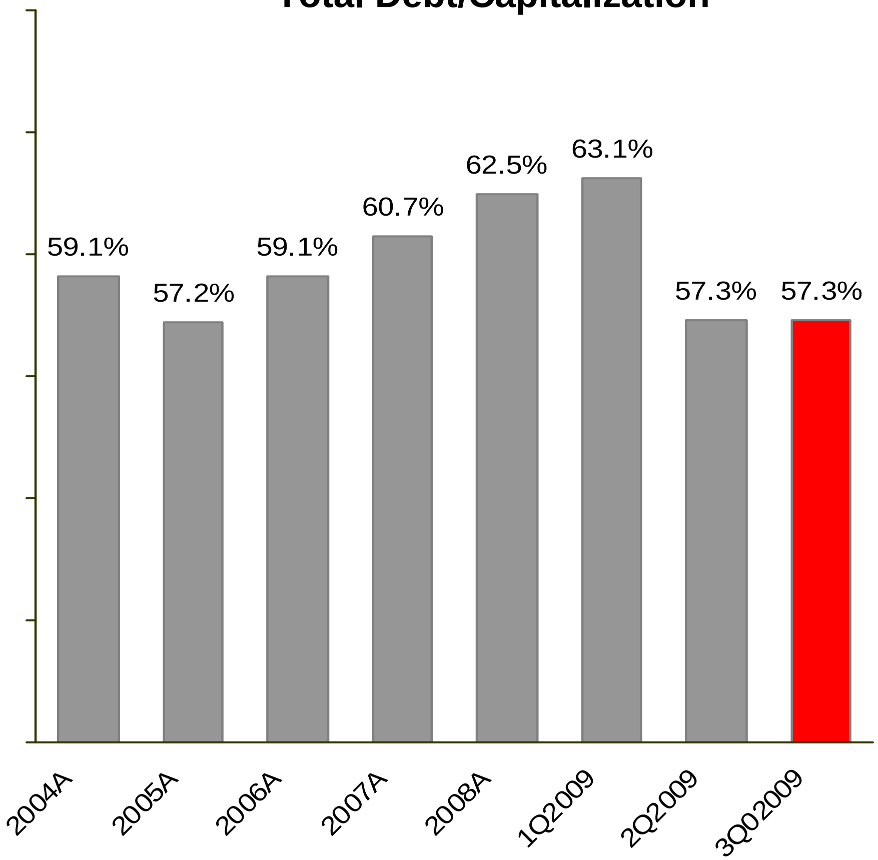
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4830 of 9556

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

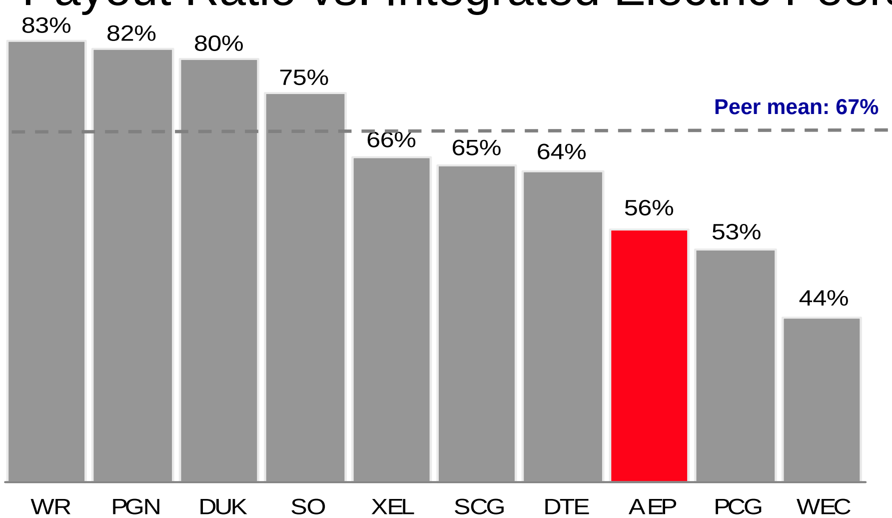
Liquidity Summary (unaudited)	**Actual 09/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

AEP AMERICAN® ELECTRIC POWER

Dividend Overview

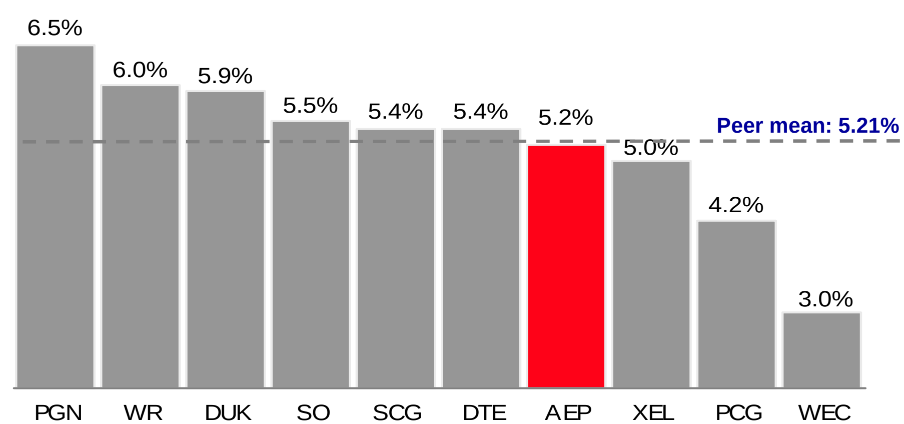
- We have declared 398 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 11/11/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 11/11/09

AEP AMERICAN® ELECTRIC POWER

AEP Supports Climate Legislation

Key Design Elements:

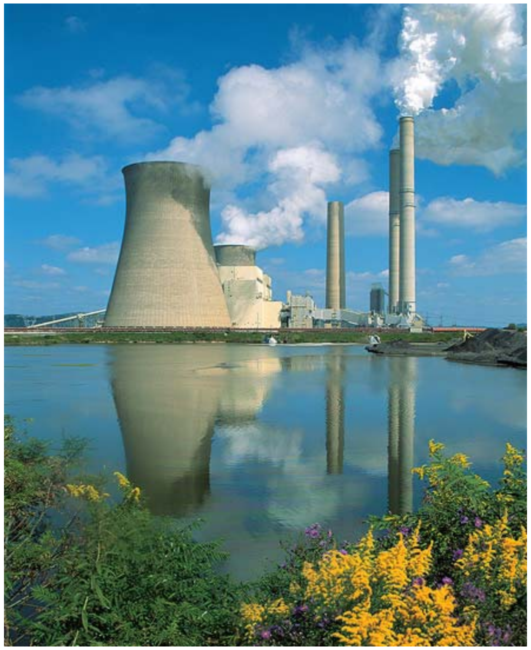
- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program –** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program –** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues –** Full, free allocation to electric sector and “Low” auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

AEP supports *The American Clean Energy and Security Act of 2009* introduced by Rep. Waxman and Rep. Markey

AEP AMERICAN® ELECTRIC POWER

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment
- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



General JM Gavin Plant (OH)

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AEP AMERICAN ELECTRIC POWER®

Credit Suisse 2011 Energy Summit

February 7-8, 2011

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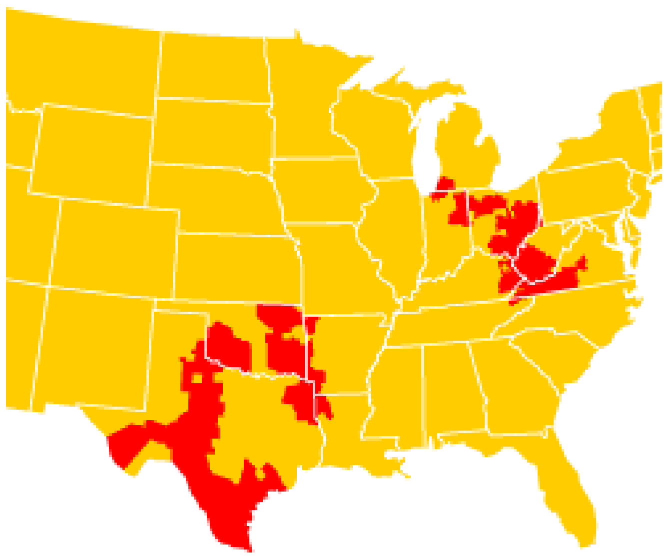
Brian X. Tierney - EVP and CFO

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states

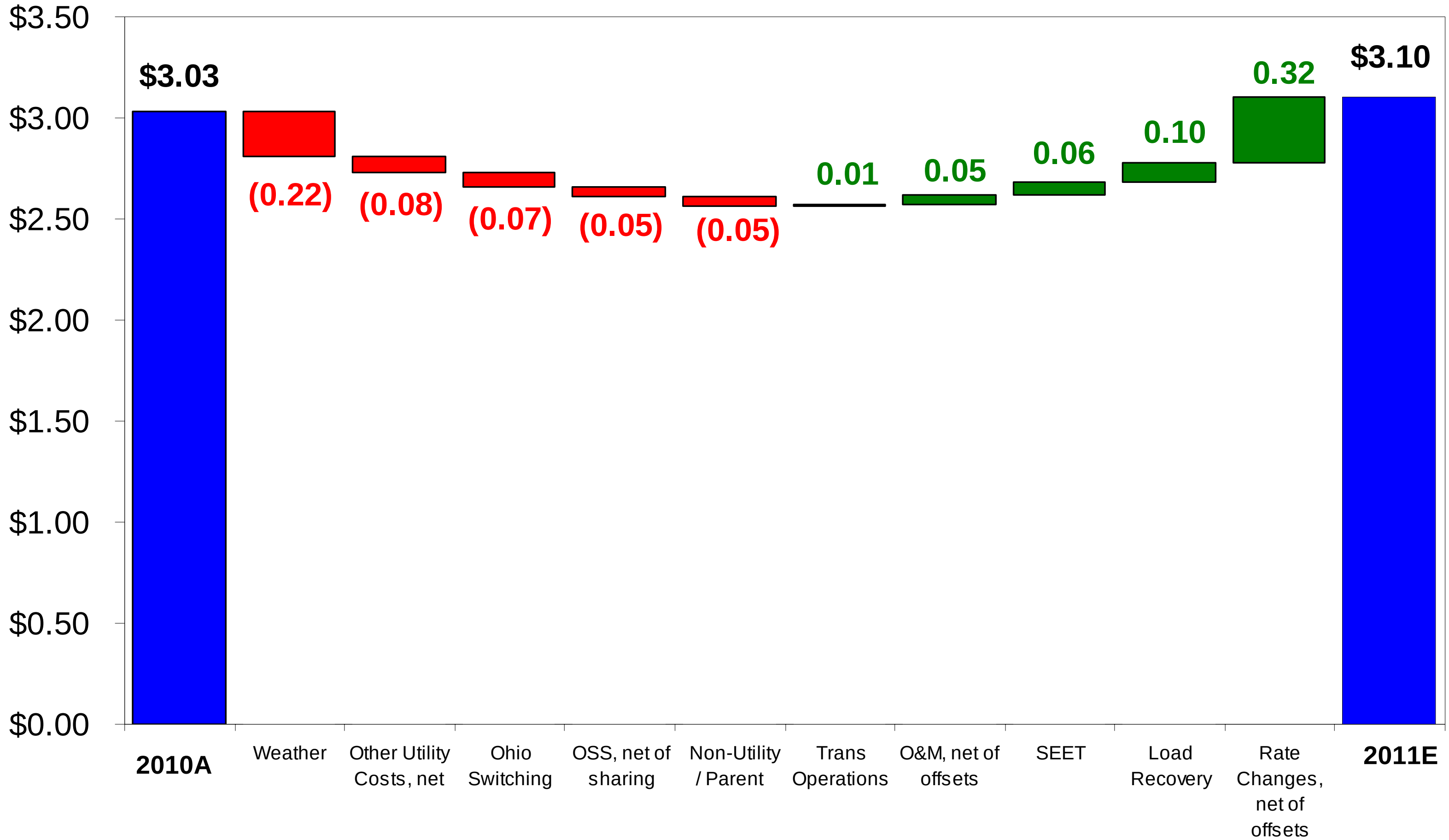


AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$17.3B Market Capitalization
BBB/Baa2/BBB credit rating

2011 Earnings Drivers

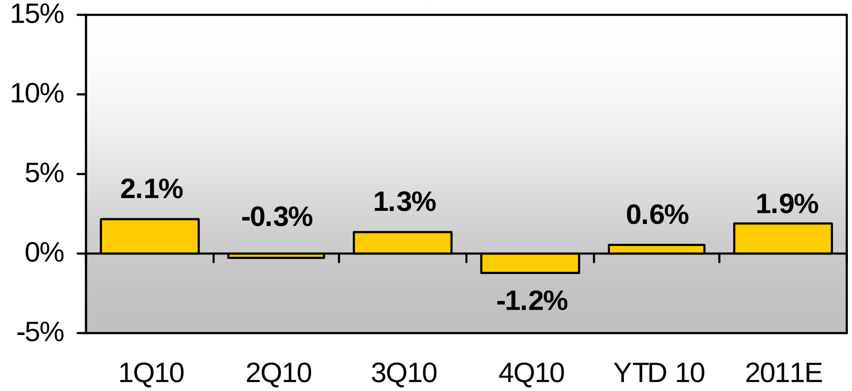


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

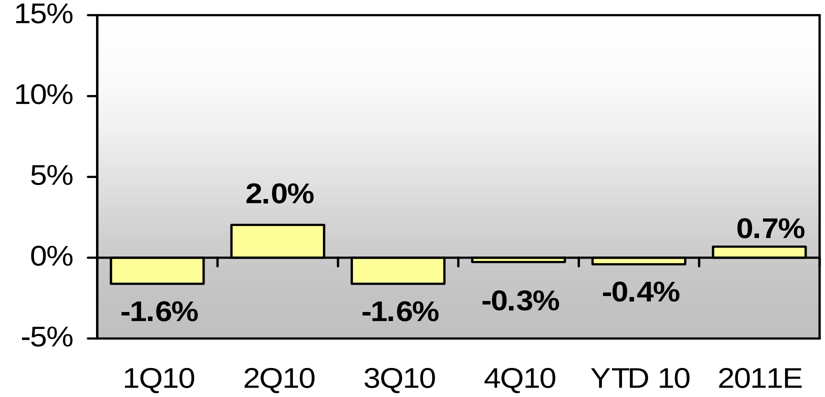
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

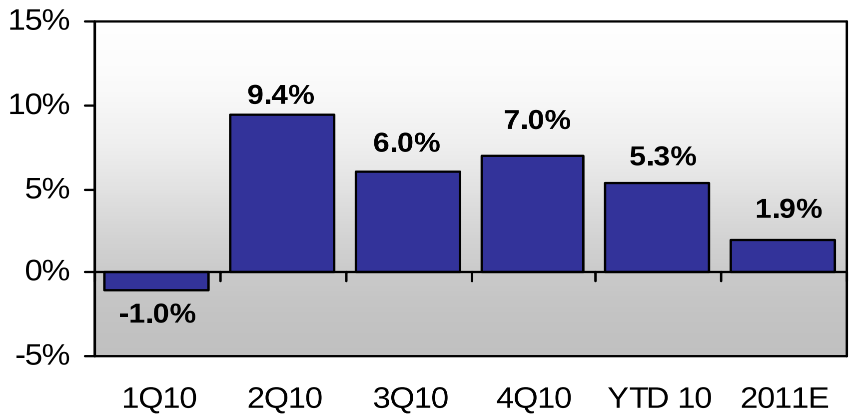
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



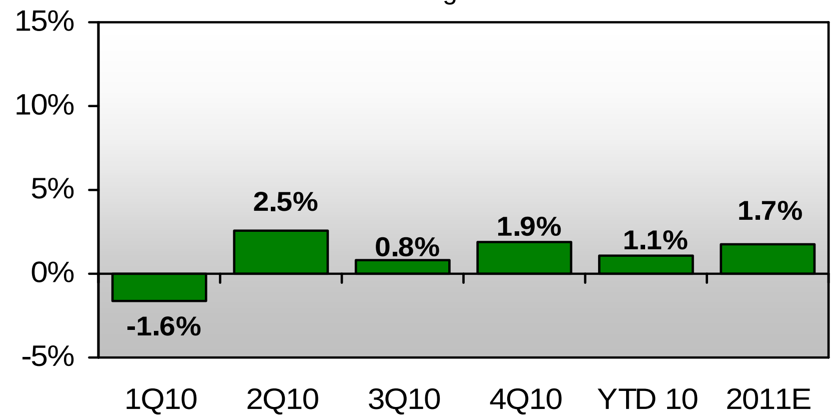
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

2011 Guidance and Business Initiatives

2011 Guidance: $3.00 - $3.20 per share

2011 Earnings Drivers

- Recovering Economy
- Rate changes (69% secured)
- Continued O&M discipline - $34M decrease net of offsets
- Customer switching – Ohio
- 2010 SEET at Columbus Southern Power

Business Initiatives

- Operating Transcos in OH, OK and MI; filings pending in other states
- AEP Eastern System Interconnection Agreement
- Bonus Depreciation
- Capital Allocation

AEP Ohio ESP Filing – Core Policy Issues

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

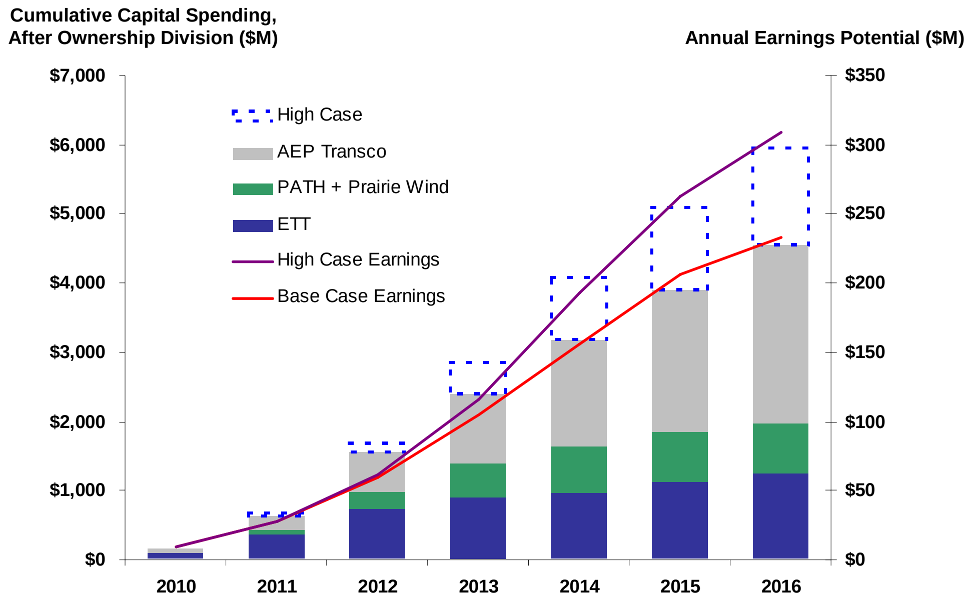
Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on one CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - MEC & RITELine



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

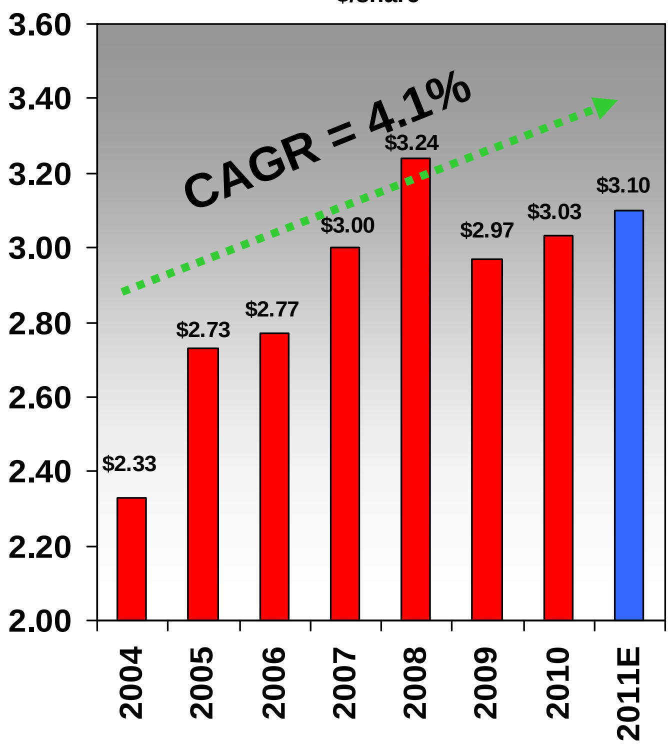
[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

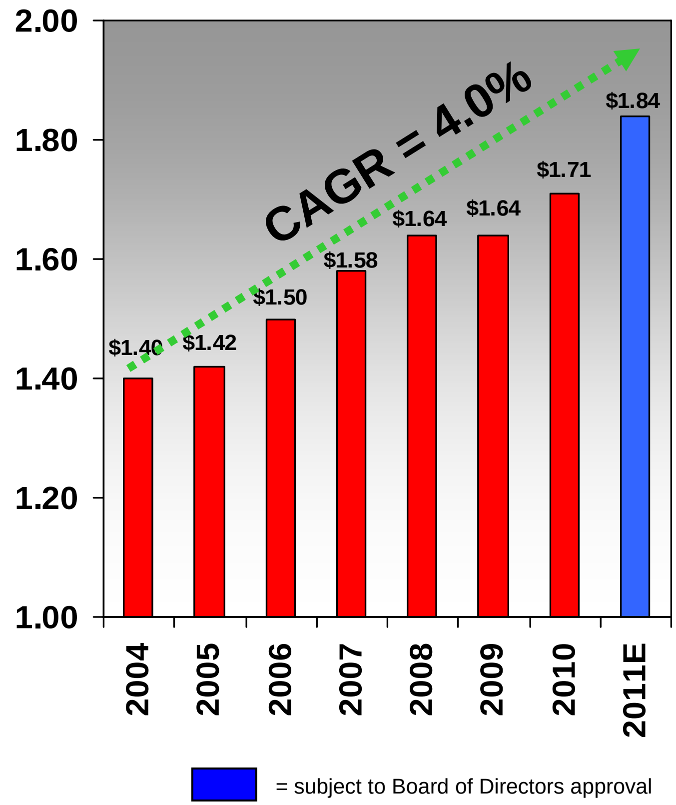
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

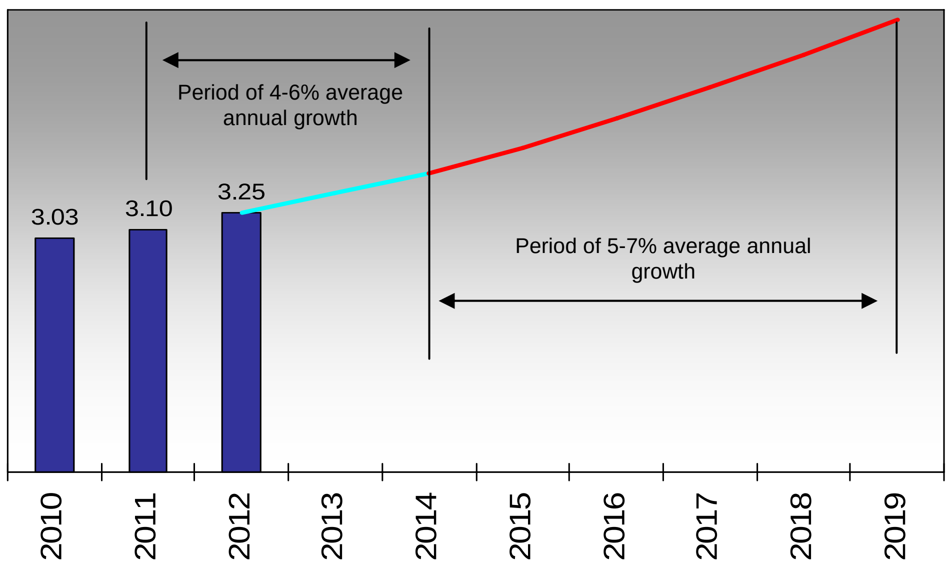


- Dividend increased 12% in 2010
- 403rd consecutive quarterly dividend declared in January 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Highlights

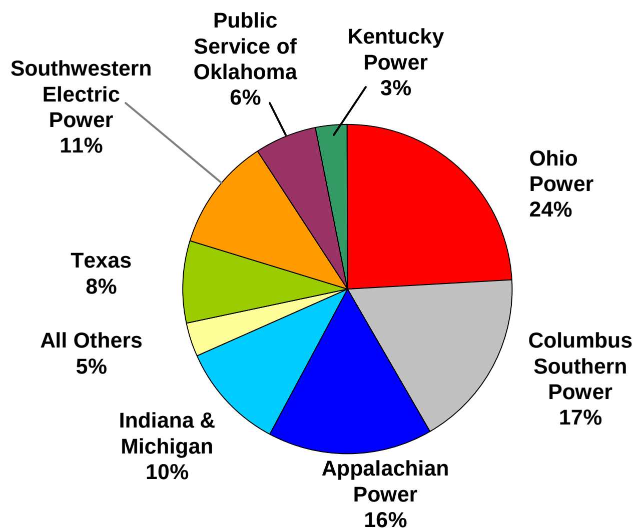
- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
- Strong Value and Total Return Proposition

Mountaineer Plant (WV)

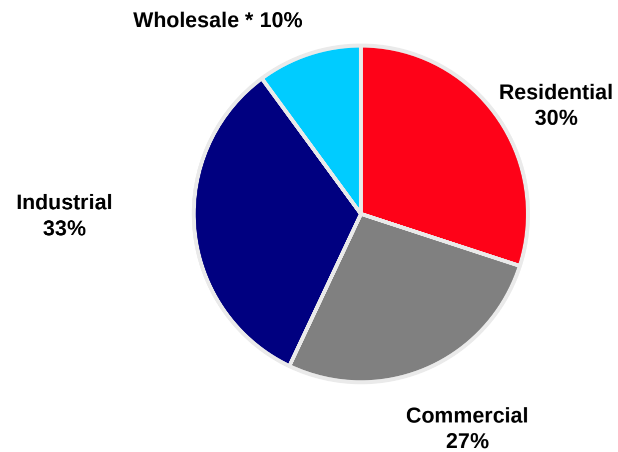
Appendix

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Detailed Ongoing Earnings Guidance

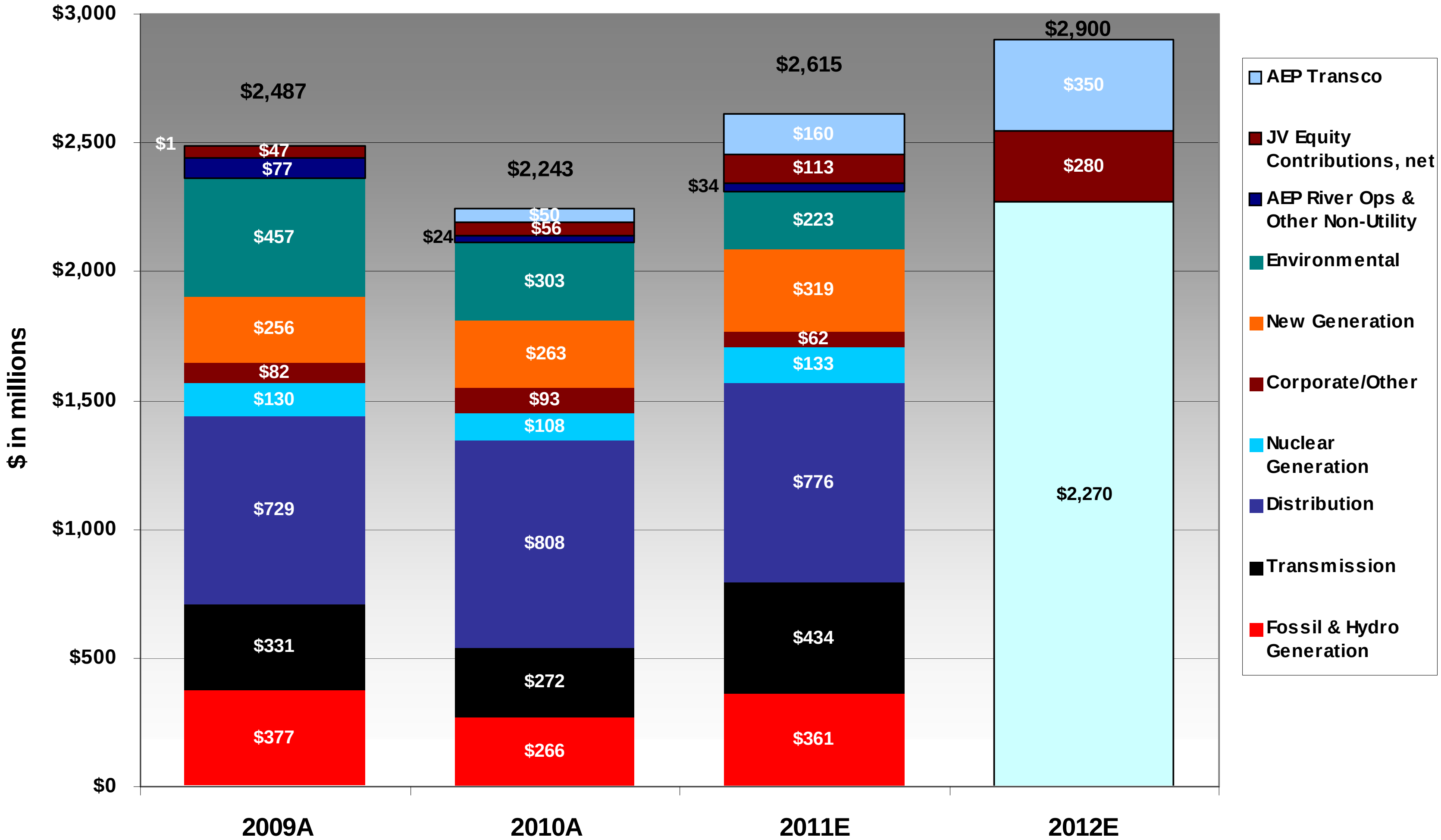
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

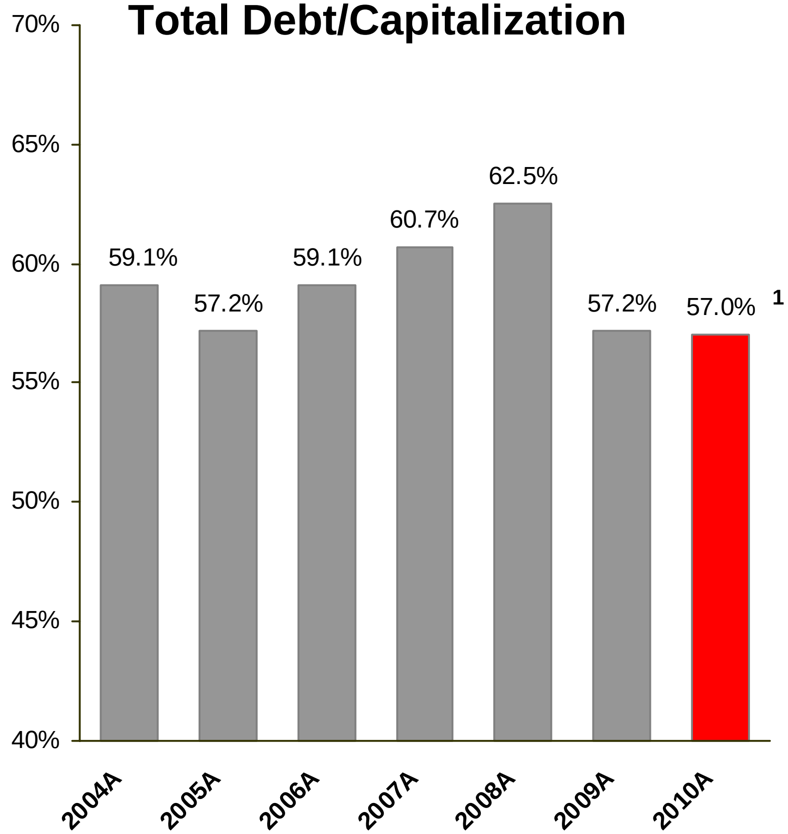
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Capitalization & Liquidity

Total Debt/Capitalization



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

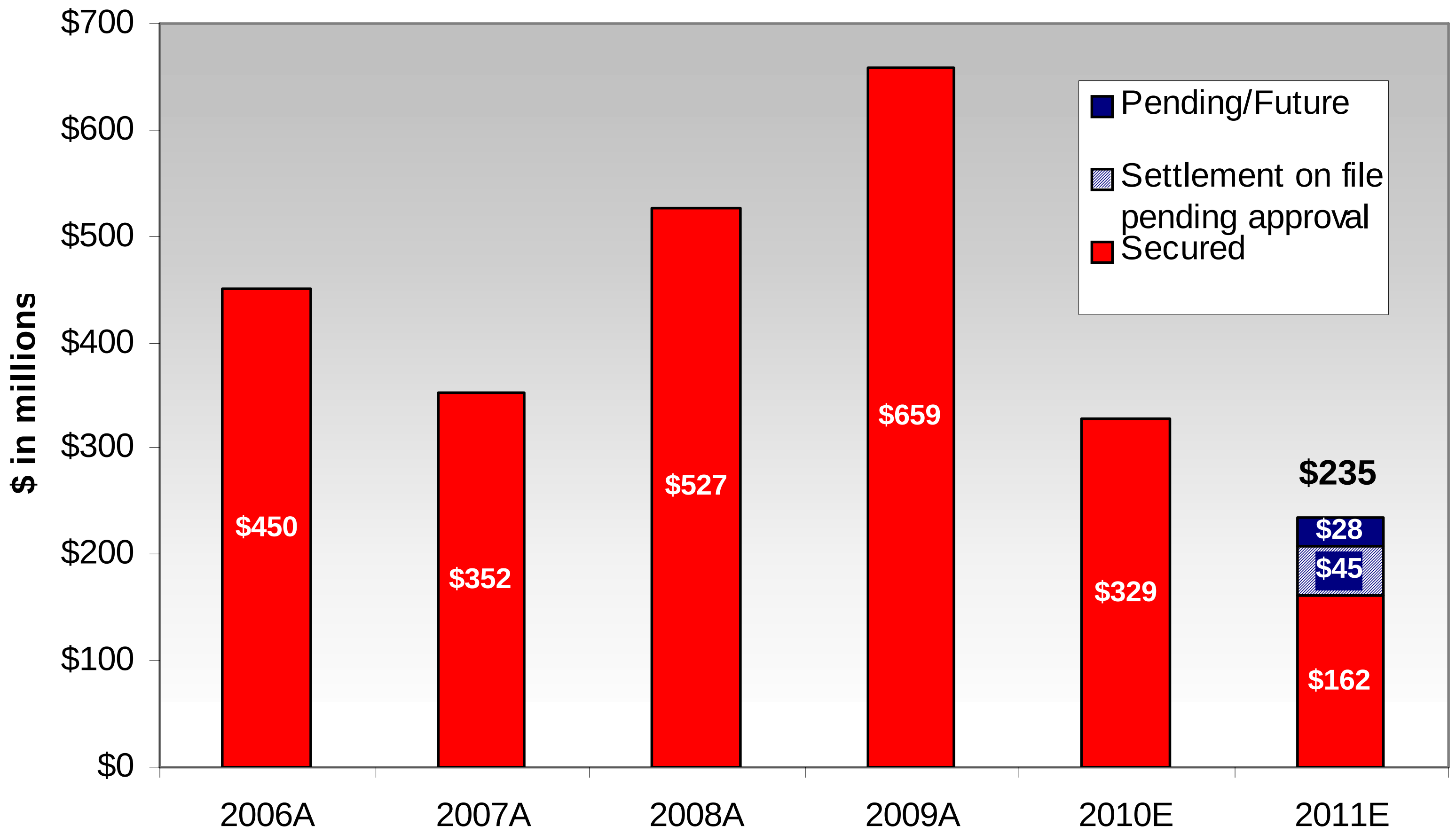
Cash Flow Guidance

	2010A	2011E
	$ in millions	
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to September 30, 2010 10Q *Enron Bankruptcy* pages 56-57 for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Active or pending rate cases include West Virginia and others yet to be filed

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

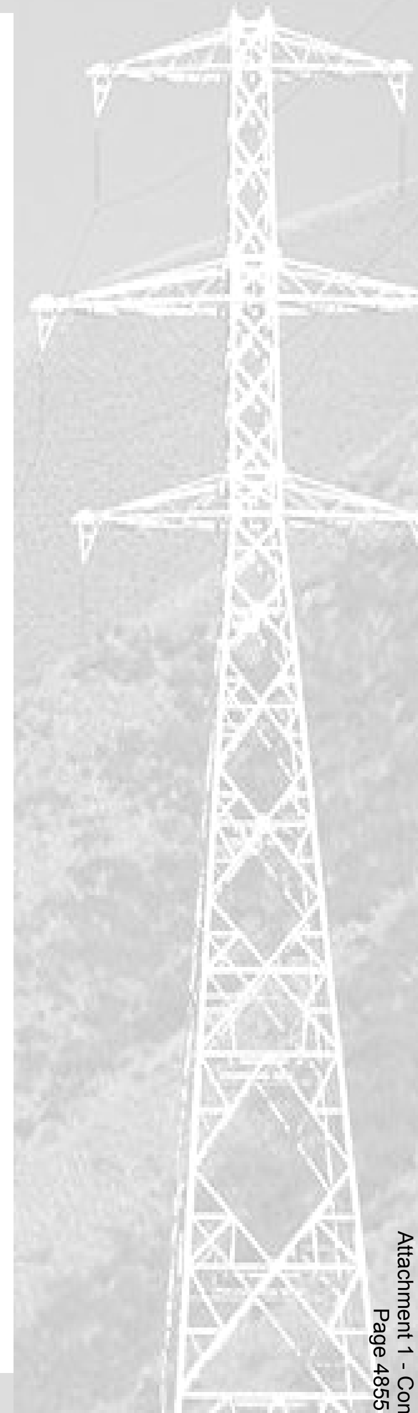
** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

CREDIT SUISSE 2009 ENERGY SUMMIT

Tuesday, February 3, 2009

Vail, Colorado



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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President – AEP Transmission

AEP's Strategic Priorities Remain the Same

- "Keep the lights on"
  - Maintain our low-cost and reliable energy production and delivery system
  - Invest to replace aging infrastructure and ensure adequacy of capacity
  - Manage commodity costs
- Environmental priorities
  - Complete our $5.2 billion environmental controls program ($1.0 billion to be spent in 2009-2010)
  - Work to ensure a balanced and logical carbon legislation outcome
- Collaborate with regulators to more closely match spending with rate recovery
- **Lead the development of America's high-voltage transmission system**

AEP's strategic priorities remain the same, but the steps and timing may be different.

Building the Nation's Leading Interstate Electric Transmission Company

Our Goal: Contribute sustainable shareholder growth by leveraging AEP's position as the nation's leading transmission provider to become the nation's leading developer and owner of interstate transmission investment.

EXPERIENCE

- AEP is recognized as the industry leader in transmission.

PLATFORM

- AEP's asset base provides a strong starting point for new transmission investment within our footprint.

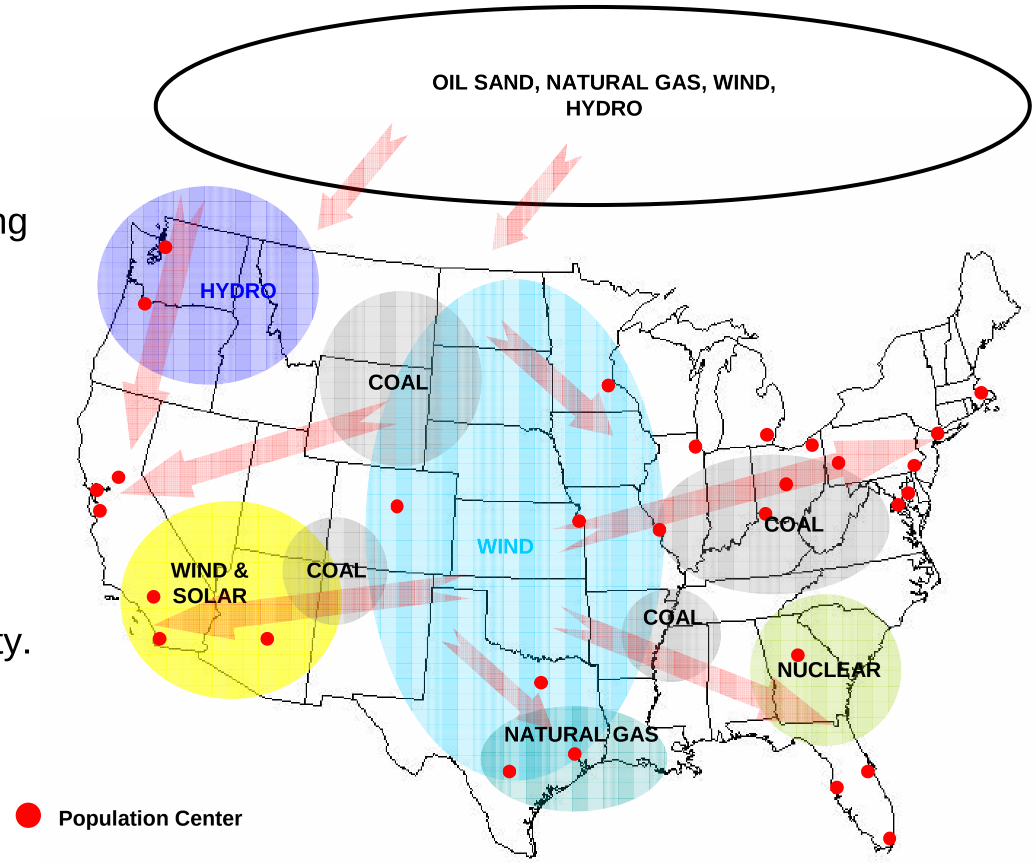
GROWTH

- AEP assets and leadership will open opportunities for significant new regional investments, beyond our traditional retail service territory boundaries.

By leveraging existing assets, expertise and leadership, AEP will grow shareholder value by creating a significant new transmission investment opportunity.

Vision of the Nation's Transmission System

- A national interstate EHV transmission grid contributes to sustainable energy development:
  - A more sustainable long term national electricity supply portfolio, including tapping extraordinary renewable energy and generation technology potential.
  - Broader impact of demand-side options and load leveling, lowering the need for new generation.
  - Strengthened national security by enhancing reliability, removing barriers to supply options and enhancing fuel diversity.
  - An alternative path to emission and CO_2 reductions.
- Economic growth remains closely tied to energy and climate related initiatives, requiring policies which understand these interdependencies.



"Many of our resources, whether it's wind or sun or geothermal, they're out in rural areas...and we just don't have any infrastructure. If we're going to take this whole energy piece on the renewable side seriously ... we've got to get the transmission and infrastructure piece right" *Utah Gov. Jon Huntsman - AP Western Governors, Utility Heads Seeks Energy Solutions July 1, 2008*

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4860 of 9556

Improved federal and regional policies are critical to growing AEP & investment opportunities

- To advance our transmission business strategy, AEP has taken a leadership position in national and regional public policy debates
- Emerging policies must support and encourage development of new transmission investment to meet our nation's future energy needs
- AEP's goal is to remove barriers to timely transmission investment through improved and clear rules to encourage transmission investment
- We are vigorously pursuing comprehensive Federal legislation to create federal siting authority, broad cost allocation, and expedited planning
- Within the current regional framework we are seeking to expedite planning for EHV systems and establish broad cost allocation principles within and across RTOs
- We continue to strongly support Federal incentives for capital investment in transmission infrastructure

> "We need a true nationwide transmission version of our interstate highway system; a grid of extra-high voltage backbone transmission lines reaching out to remote resources and overlaying, reinforcing, and tying together the existing grid in each interconnection to an extent never before seen." *Suedeen Kelly-Commissioner FERC*

AEP is actively involved in Transmission related Energy Policy

❑ 2008 Activity

- In August, AEP testified before the U.S. Senate Committee on Energy and Natural Resources on the state of the nation's transmission grid and implementation of the 2005 Energy Policy Act
- Began related discussions with Obama transition team
- Seeded the development of third party sponsored white papers and the drafting of legislation
- Actively participated in PJM, ERCOT and SPP proceedings to advocate EHV development, address cost allocation and improve planning

❑ Planned 2009 Activity

- Help to shape Obama administration energy initiatives to eliminate barriers to transmission investment
- Continue state, federal and regional outreach relative to siting, project approval, and cost allocation
- Aggressively support comprehensive Federal siting legislation

The Business Potential

- **Faced with ever rising energy costs, aging infrastructure and emerging climate change policies; transmission development is needed more than ever before.**

- **Diversified Approach to Planned Investments:**

  - Capital investment within AEP's service territory will be significant, generally averaging between $400 to $600 million annually.

  - In the Eastern US, AEP is actively pursing development of over 1,200 miles of 765kV transmission in PJM and eastern MISO, at a total cost before ownership division of approximately $6.1 billion.

  - In the Southwest, AEP is actively pursing nearly 400 miles of 765kV transmission in SPP, at a total cost in excess of $1 billion.

  - In Texas, AEP continues to pursue EHV transmission expansion throughout the state, with a potential capital spend in excess of $2.5 billion before ownership division.

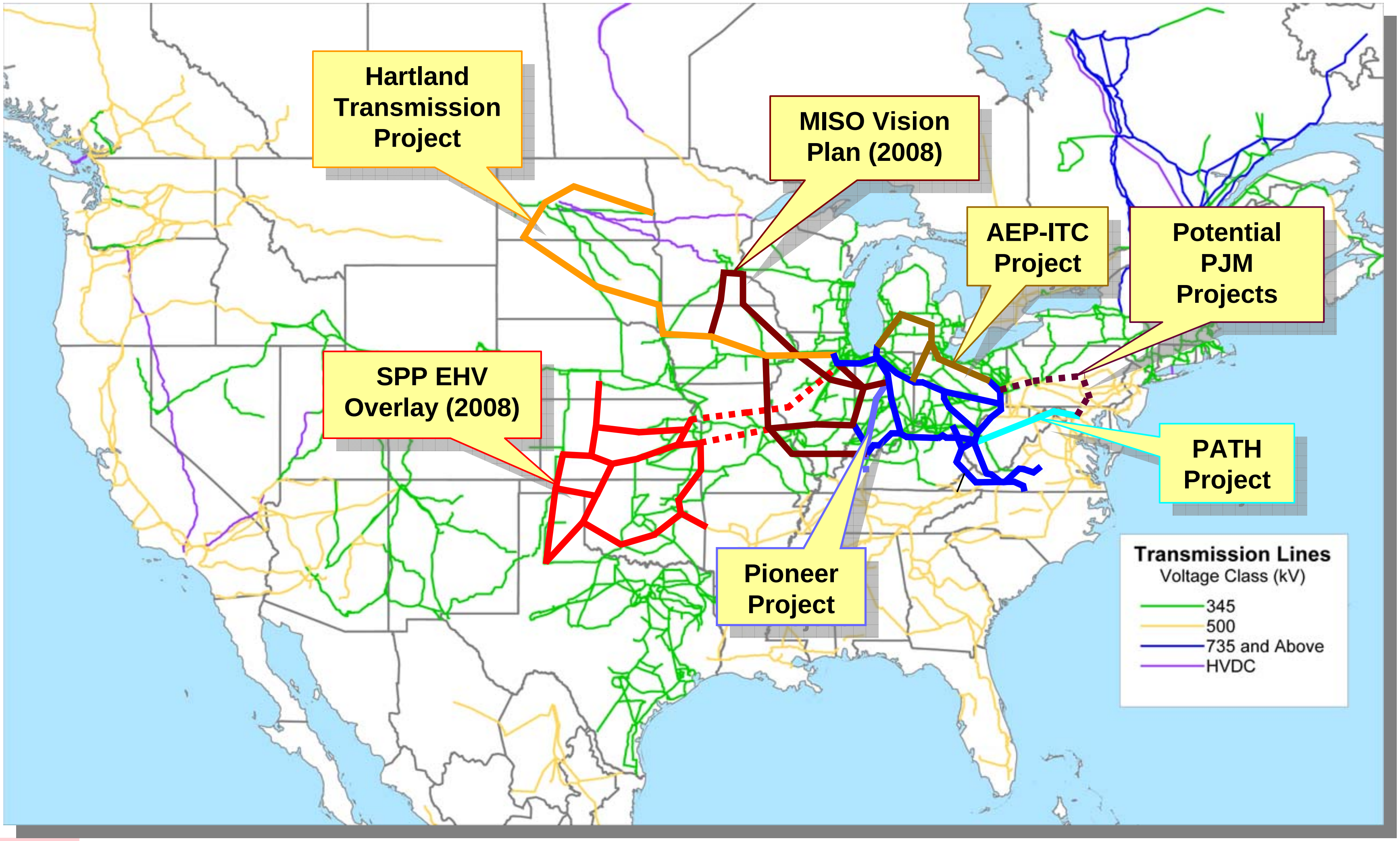
  - In the Upper-Midwest, AEP has a taken a leadership role with the announcement of over 1,000 miles of potential 765kV transmission development, at a total cost of $5 to $10 billion.

- **Challenges: Making it Happen**

EHV Transmission investments can assist in ensuring a reliable, adequate and affordable energy supply for the nation.

Making it Happen: EHV Projects Under Development

Eastern U.S. - Potential 765 kV Plans Under Development



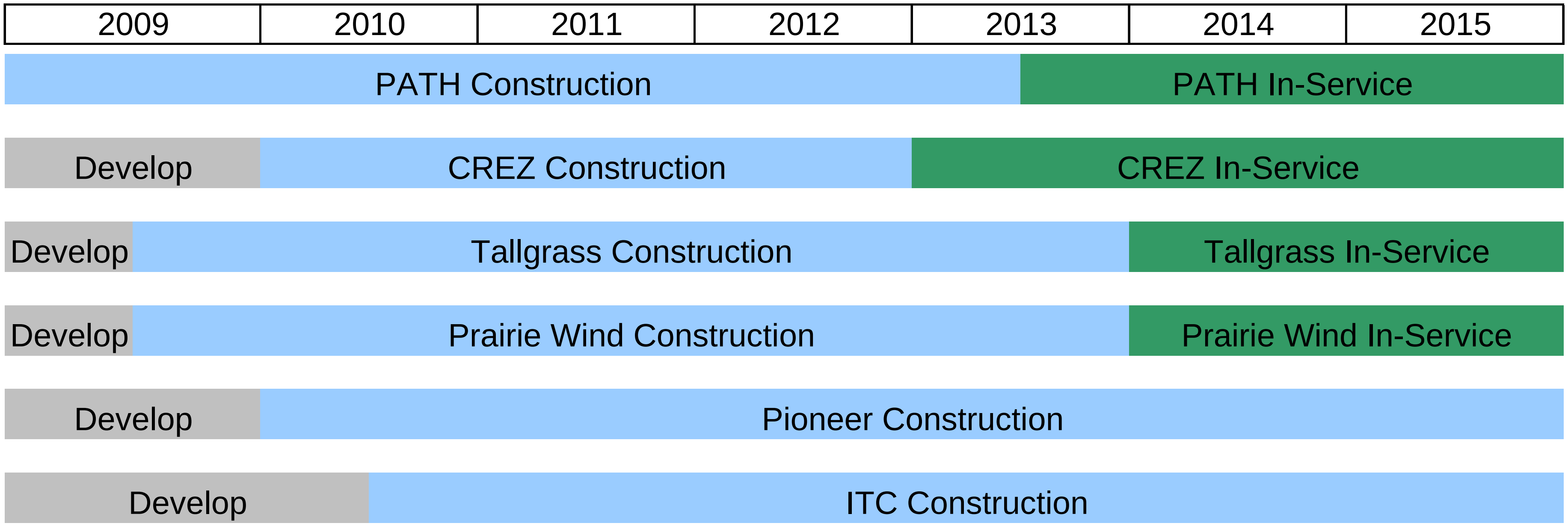
NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Joint Venture Execution

AEP Transmission has made significant strides towards our goal of becoming the nations leading developer and owner of interstate transmission investments; Major milestones include:

PATH	- Change approved by PJM for 765kV in Maryland (instead of 500kV)
ETT	- Awaiting CREZ order from PUCT; expected in 1Q 2009
Prairie Wind	- Discussions with SPP regarding cost allocation are progressing well - Submitted CCN application for utility status in Kansas - Received FERC approval for 12.8% ROE, with potential for a 0.5% ROE technology adder.
Tallgrass	- Signed LLC agreement in July 2008 - Received FERC approval for 12.8% ROE, with potential for a 0.5% ROE technology adder.
Pioneer	- Signed LLC agreement in August 2008 - Submitted FERC 205 filing. Received deficiency letter requiring additional need studies before ruling can be made. - Joint cost allocation study with PJM and MISO ongoing.
ITC	- LLC negotiations continue for potential 765kV project in Ohio and Michigan
Hartland Wind	- Announced 765kV concept in Upper-Midwest spanning over 1,000 miles at a total cost of $5-$10 Billion over the next decade.
Other	- Discussions underway with several potential partners regarding further EHV development in Texas, Kansas, Oklahoma, New Jersey, Pennsylvania, Maryland, Arkansas, and Missouri.

Transmission Joint Venture Timeline



Development activities include formation of the Joint Venture and satisfaction of the conditions precedent, including, but not limited to, receiving a favorable FERC 205 order with appropriate incentives and intra- and inter-RTO cost allocation. Development may also include engineering, siting and the CCN process, if applicable.

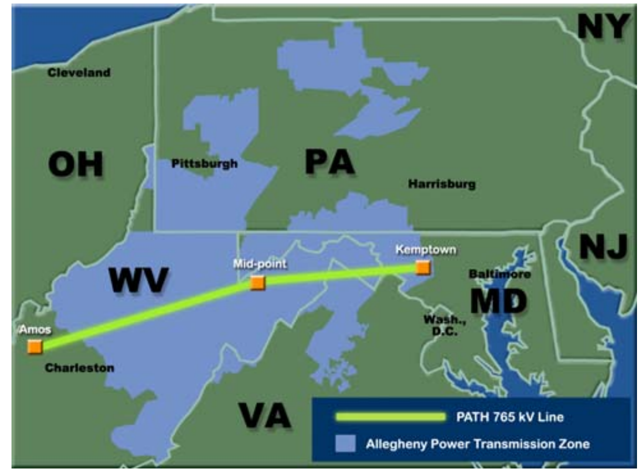
Provide a pipeline of investment opportunities that will contribute to sustainable earnings growth for AEP shareholders, regardless of the ultimate policy direction at the Federal and regional levels.

Appendix

Transmission Investments Pursued by Region: East

PATH

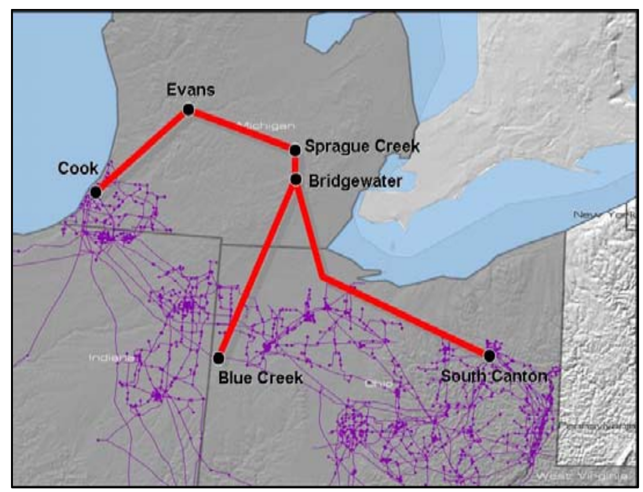
Project Description: 277 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.



- ❑ **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN
  - Execution risk: Schedule, budget, materials pricing, scarcity of labor, etc.
- ❑ **Mitigation**
  - FERC 205 filing, including cash return on 100% of CWIP, recovery of $6.1 million development costs, abandonment
  - Control spending through Authorization Policy and Contracting Protocols. Closely monitor execution via risk reports, variance reporting, etc.

ITC & AEP

Project Description: 700 miles of 765-kV line in OH and MI to improve transfer capability and reduce network line losses.



- ❑ **Near Term Risks**
  - Interregional cost allocation between MISO & PJM
  - RTO Technical Approvals
  - Competing ITC EHV project in SPP may hamper relationship
  - Favorable 205 Order including 679 incentives
- ❑ **Mitigation**
  - Actively participating and advocating for changes in RTO cost allocation methodologies and the cost/benefit analysis
  - Provide input to MISO's and PJM's need studies
  - Prepare a comprehensive regulatory filing, including incentives

AEP®

Transmission Investments Pursued by Region: East (cont.)

Pioneer Transmission, LLC.

Project Description: 240 mile 765-kV transmission line from AEP's Rockport Station to Duke's Greentown Station.

❑ Near Term Risks

- Interregional cost allocation between MISO & PJM
- RTO Technical Approvals
- Favorable 205 Order including 679 incentives

❑ Mitigation

- Actively participating and advocating for changes in RTO cost allocation methodologies and the cost/benefit analysis
- Interregional cost allocation between MISO & PJM
- Provide input to MISO's and PJM's need studies
- Prepare a comprehensive regulatory filings, including incentives

Current Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
  - In October 2008, the District Court found that the PUCT exceeded its authority by granting ETT a CCN. This decision is currently under appeal and ETT believes the ultimate outcome will validate its utility status
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Competitive Renewable Energy Zones (CREZ) initiative is anticipated to provide ETT with an investment of approximately $1 billion over the next 5-7 years
  - Selection of transmission providers by the PUCT is scheduled for 1Q 2009

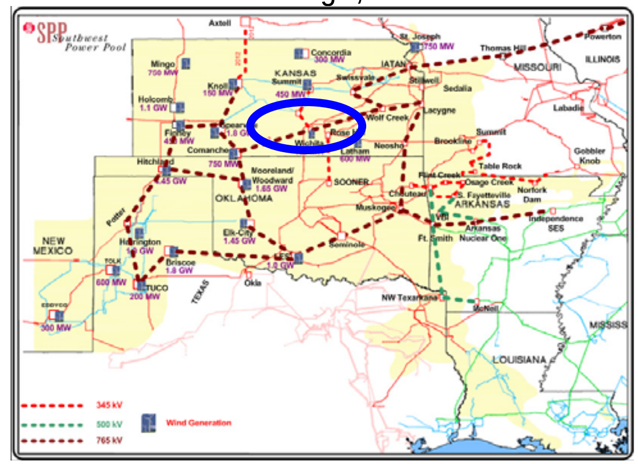
Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
- To that end, ETA recently signed agreements with Westar forming Prairie Wind Transmission LLC, and Oklahoma Gas & electric forming Tallgrass Transmission LLC, proposing to build the first and second segments of the 765-kv Overlay Plan in SPP

Transmission Investments by Region: Southwest

Prairie Wind Transmission, LLC.

Project Description: First segment of proposed SPP 765 kV Overlay Plan of 230 miles of lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.

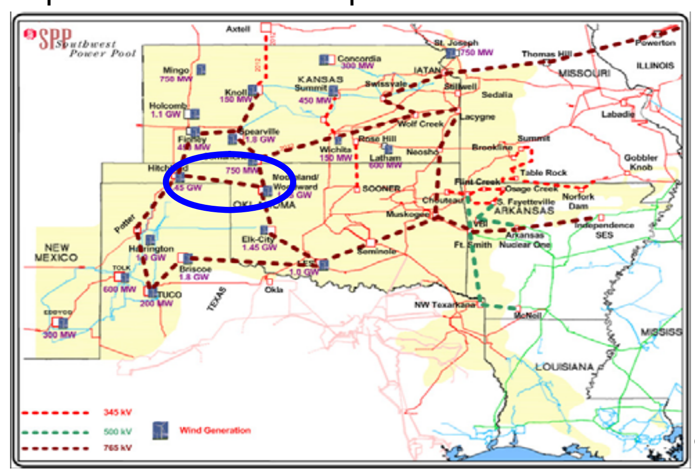


- **Near Term Risks**
  - Obtaining regional cost allocation in SPP
  - Competing ITC Great Plains project
  - Satisfy Conditions Precedent
- **Mitigation**
  - Collaboration in regulatory process for SPP regional cost allocation and technical approvals.
  - Compromise plans with competing ITC project are being pursued in collaboration with KETA and KCC.
  - AEP responsible for 25% project costs, including 3rd party expenses. AEP responsible for its internal costs prior to obtaining CPs.

ETA
ELECTRIC TRANSMISSION AMERICA, LLC

Tallgrass Transmission, LLC

Project Description: Second segment of SPP 765 kV Overlay Plan of 165 miles to promote wind development in the western half of Oklahoma.



- **Near Term Risks**
  - Obtaining regional cost allocation in SPP
  - Satisfy Conditions Precedent
- **Mitigation**
  - Collaboration in regulatory process for SPP regional cost allocation
  - Created development budget. Maintain work orders to monitor work streams and costs; Share development costs with JV partners
  - AEP only responsible for its 25% share of 3rd party expenses plus its internal costs prior to obtaining CPs

AEP®

Hartland Wind Concept EHV Development in Upper-Midwest

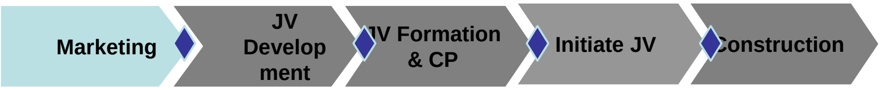
Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost \$5-\$10 billion over a 10 year period.

❑ Near Term Risks

- Technical feasibility study
- Identification of willing and able partners
- Obtaining cost allocation between states, PJM, and MISO
- RTO Technical Approvals
- Favorable 205 Order including 679 incentives

❑ Mitigation

- Target the identified need for the project and its ability to provide access for wind energy to load centers
- Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
- Prepare comprehensive regulatory filing, including incentives



2008 & 2009 Ongoing Earnings Guidance

2008A EPS: $3.24

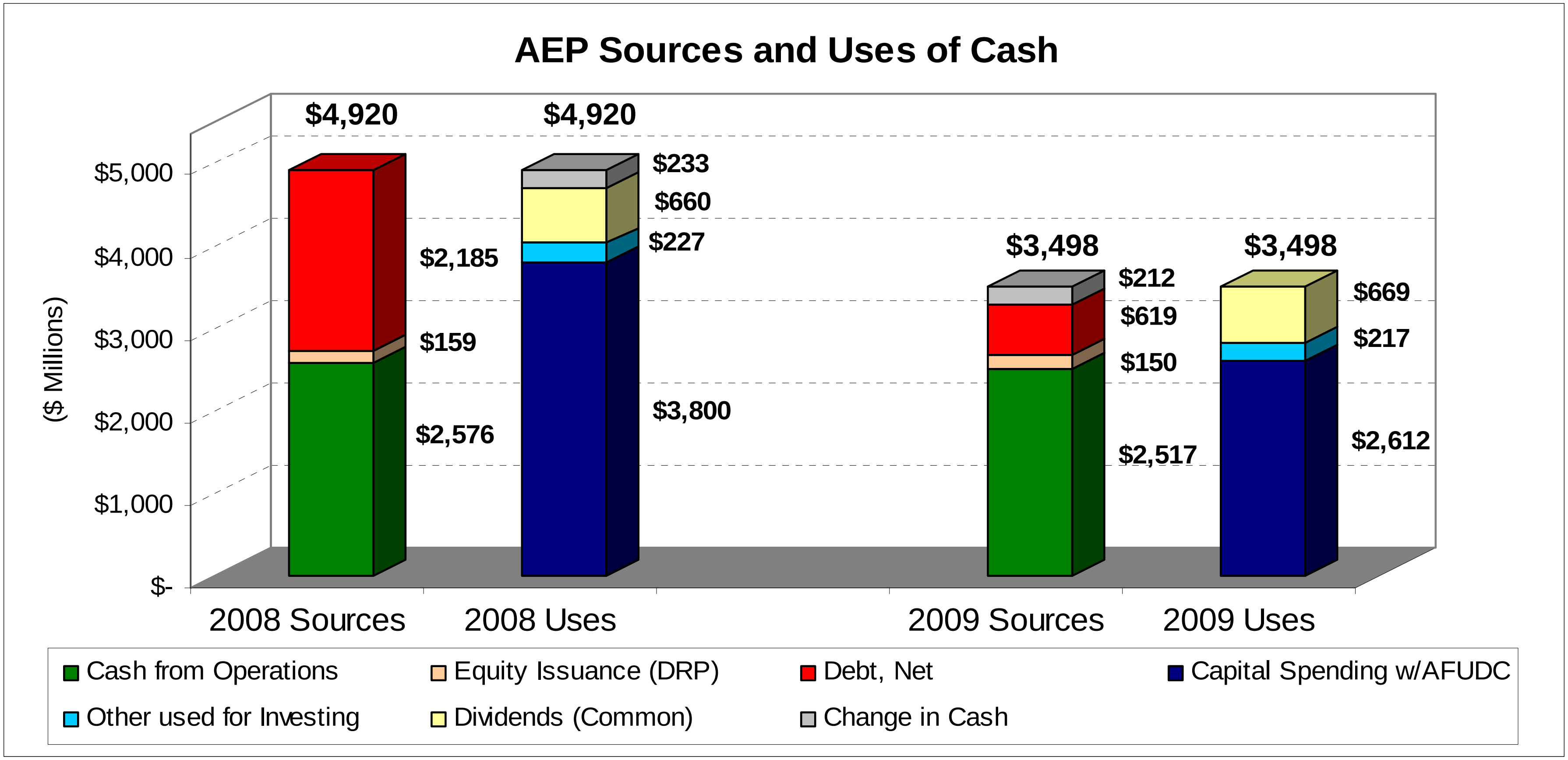
2009E EPS: $3.00 - $3.40

American Electric Power
2008 Actual vs 2009 Guidance

	2008 Actual ($ millions)	**2009 Guidance ($ millions)**
Utility Operations Gross Margin	8,046	8,433
Operations & Maintenance	(3,366)	(3,337)
Depreciation & Amortization	(1,450)	(1,546)
Taxes Other than Income Taxes	(749)	(790)
Interest Exp & Preferred Dividend	(872)	(929)
Other Income & Deductions	168	120
Income Taxes	(567)	(641)
Utility Operations	1,210	1,310
Transmission Operations	2	5
Non-Utility Operations	120	75
Parent & Other	(31)	(91)
ON-GOING EARNINGS	**1,301**	**1,299**

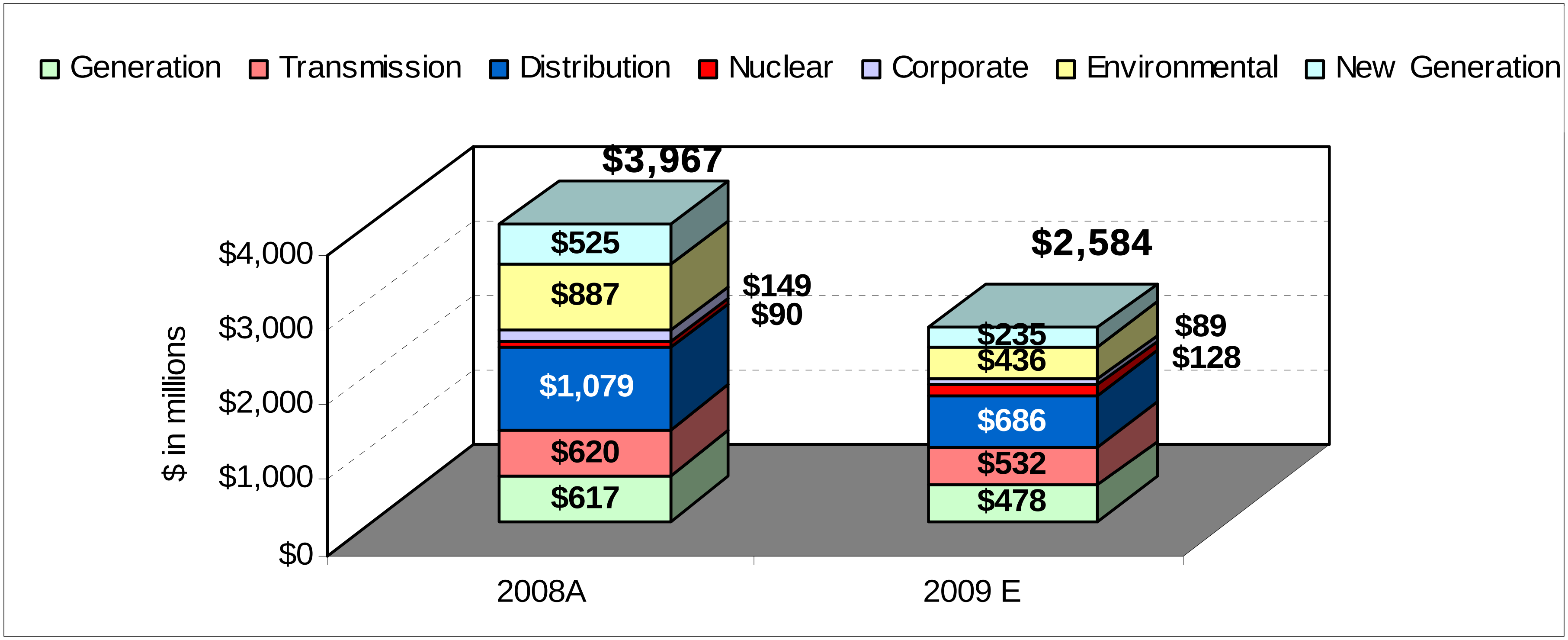
2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

2008 & 2009 Capital Spending



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	Total
APCo	$749	$367	**$1,116**
I&M	$372	$362	**$734**
KPCo	$126	$62	**$188**
TCC	$265	$290	**$555**
TNC	$129	$78	**$207**
PSO	$274	$188	**$462**
SWEPCo	$680	$457	**$1,137**
CSP	$438	$270	**$708**
OPCo	$675	$439	**$1,114**
Other Companies	$259	$71	**$330**
Total Capex	**$3,967**	**$2,584**	**$6,551**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Rate Base & Allowed ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo-VA	$2,424MM *	10.20%	11/17/2008
APCo-WV	$1,656MM	10.50%	7/28/2006
Kentucky	$858MM	10.50%	3/31/2006
I&M-Indiana	$1,805MM	12.00%	11/19/1993
I&M-Michigan	$268MM	13.00%	4/1/1991
PSO-Oklahoma	$1,467MM	10.50%	1/14/2009
SWEPCo-LA	$577MM	10.565% **	8/1/2008
SWEPCo-AR	$408MM	10.75%	9/23/1999
SWEPCo-Texas	$474MM	15.70%	2/15/1983
Texas-TCC	$1,566MM	9.96%	10/17/2007
Texas-TNC	$530MM	9.96%	6/1/2007

*** - represents assumed rate base interpreted from settlement**

**** - represents midpoint of the ROE range approved in the formula rate case settled in April 2008**

Liquidity

Liquidity Summary (unaudited)	Actual 12/31/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	411	
Less		
Draw on Credit Facilities	(1,969)	
Letters of Credit Issued	(436)	
Net Available Liquidity	**$1,925**	

AEP's liquidity position is $1.9 billion as of December 31, 2008.

Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009.

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- SWEPCo Stall Plant Filing in Arkansas
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART^{SM} Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony was filed October 31, Staff testimony was filed November 7 and 10 and the public hearing commenced on November 17, 2008. We anticipate an order in the first quarter of 2009.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $125.6 million ($80.1 million in base revenues and $45.6 million in tracker mechanisms). (Docket #: 43306). In December 2008 a unanimous settlement was filed with the IURC supporting a revenue increase of $44.2MM with an ROE of 10.5%. We await an order.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	1,999.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	161.9	
Pro-Forma Operating Income	$	113.1	
Difference	$	48.8	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	80.1	
Reliability Enhancement Tracker	$	28.4	
DSM / EE Tracker	$	4.4	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	44.4	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	125.6	

* rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

SPP OATT Formula Rate Filing (Docket #:ER07-1069-000)

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$88.7MM and the new revenue requirement requested is \$140MM. Approximately \$10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing (Docket #:ER08-1329-000)

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to March 1, 2009, with rates subject to refund.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an application to purchase, operate, own and install peaking, intermediate and baseload generating facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing.

Arkansas

- ❑ Proceeding is pending. Updated cost estimates were filed in December 2008 and we await a procedural schedule from the APSC.

Louisiana

- ❑ PSC approval was granted on September 10, 2008.
- ❑ Air permit received on March 20, 2008.

Texas

- ❑ PUCT order approving plant was issued on March 8, 2007.

Generation - Environmental Project Status Report

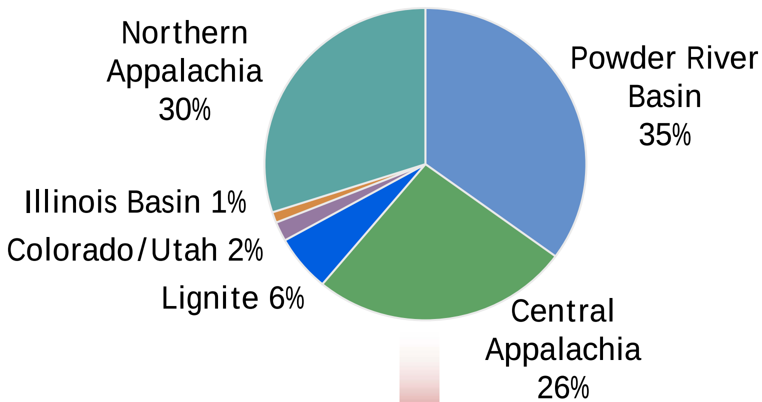
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2013
Northeastern 3	450		N/A	☑	Projected 2014
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,646 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

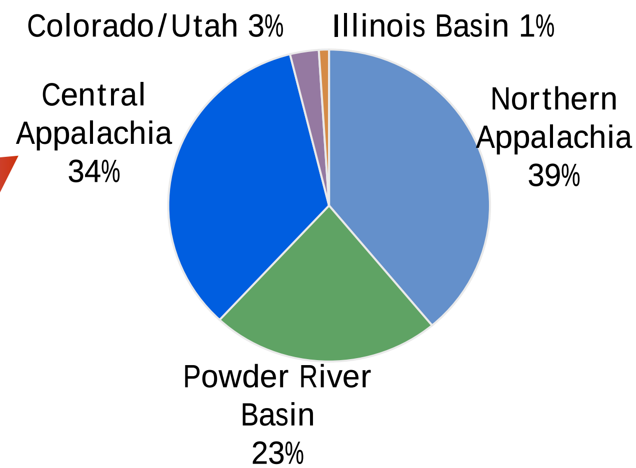
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

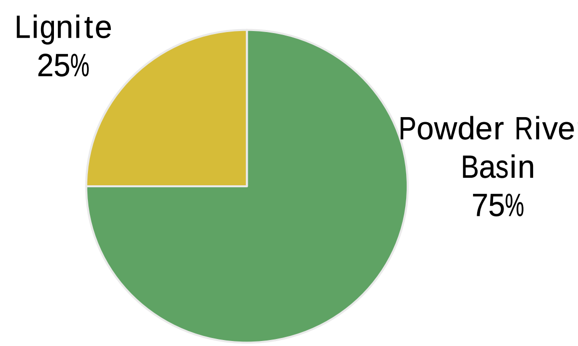
Total AEP System



AEP East



AEP West

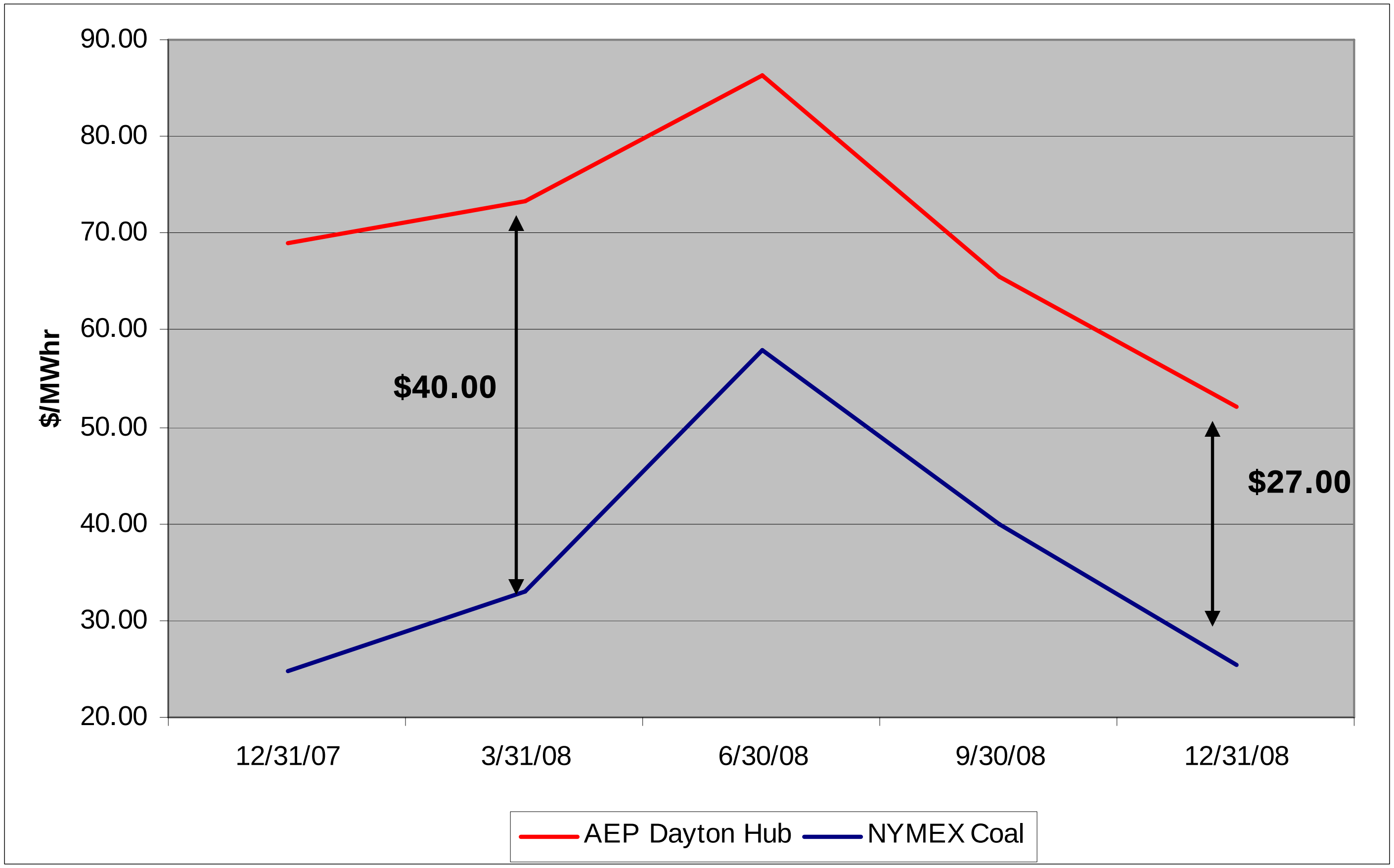


Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 15% price increase in 2009 ~ $52.45/ton

Dark Spread Comparison

NYMEX Coal vs. AEP-Dayton Hub Peak Electricity



Coal Purchases:
2009: 98%
2010: 89%

Del. Coal Prices:
2007A: $36.58/ton
2008A: $46.61/ton

2009 estimated increase: 15%

- Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- 10,000 heat rate used for conversion
- Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

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CREDIT SUISSE 2010 ENERGY SUMMIT
Vail, CO
February 2, 2010

Mountaineer Plant (WV)

345-kV Transmission Line

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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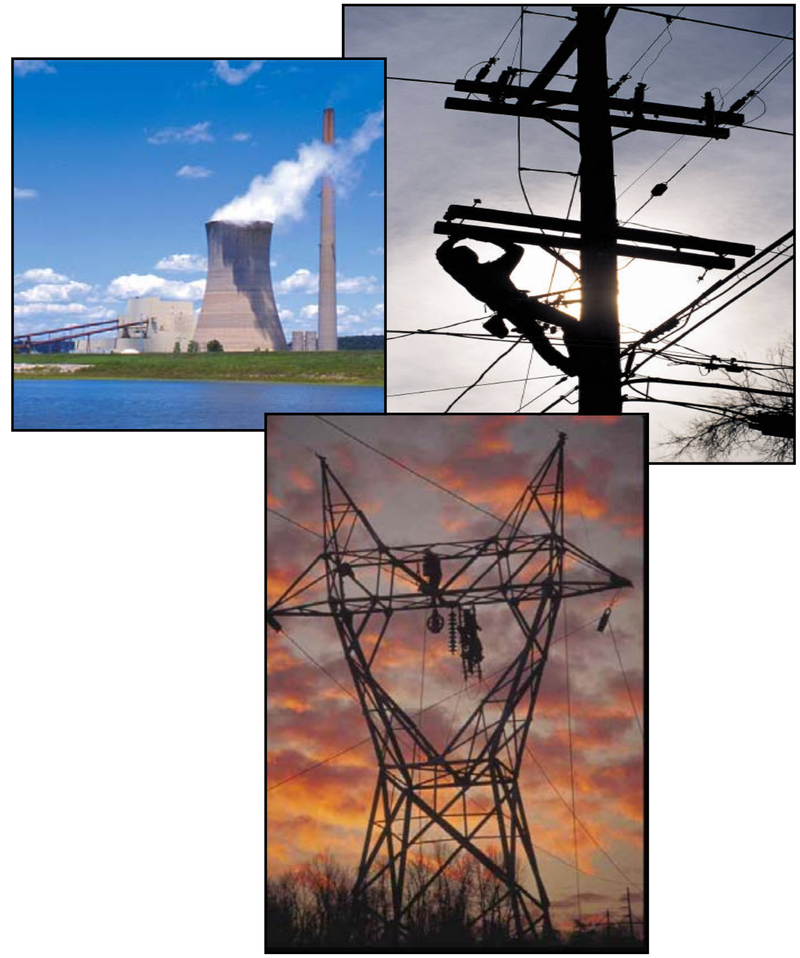
Brian X. Tierney - EVP and CFO

AEP Value Proposition



- **Regulated Utility Platform**
  - Diversified service territory
  - Successful regulatory track record
  - Value compared to regulated peer group
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
- **Attractive Yield Opportunity of 4.6%**[1]
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders

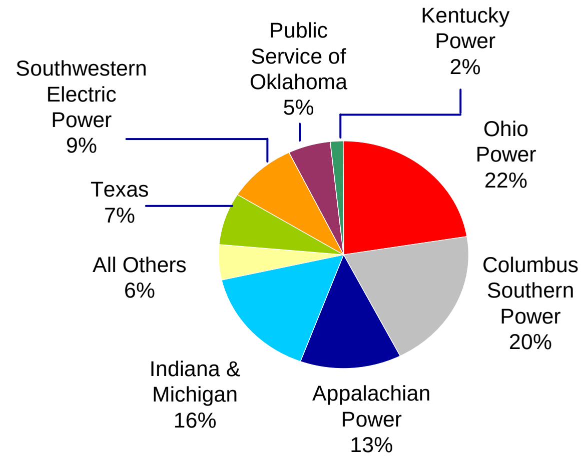
AEP AMERICAN ELECTRIC POWER®

[1] yield percentage based on AEP closing price of $35.62 on 01/25/2010

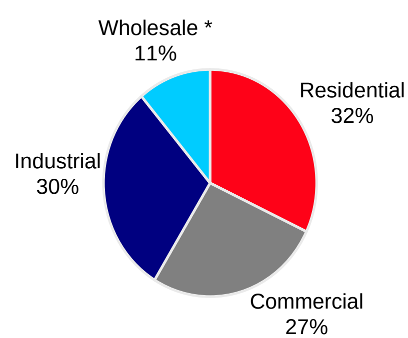
Highly Diversified Regulated Utility Platform

Serving 5.2 million customers in 11 states

2009 Earnings Contribution

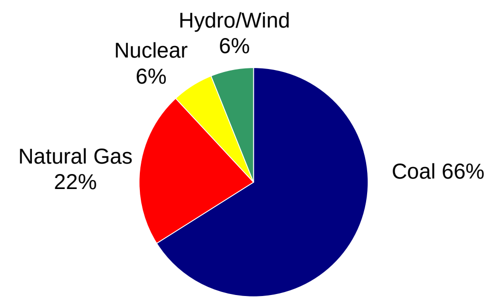


2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

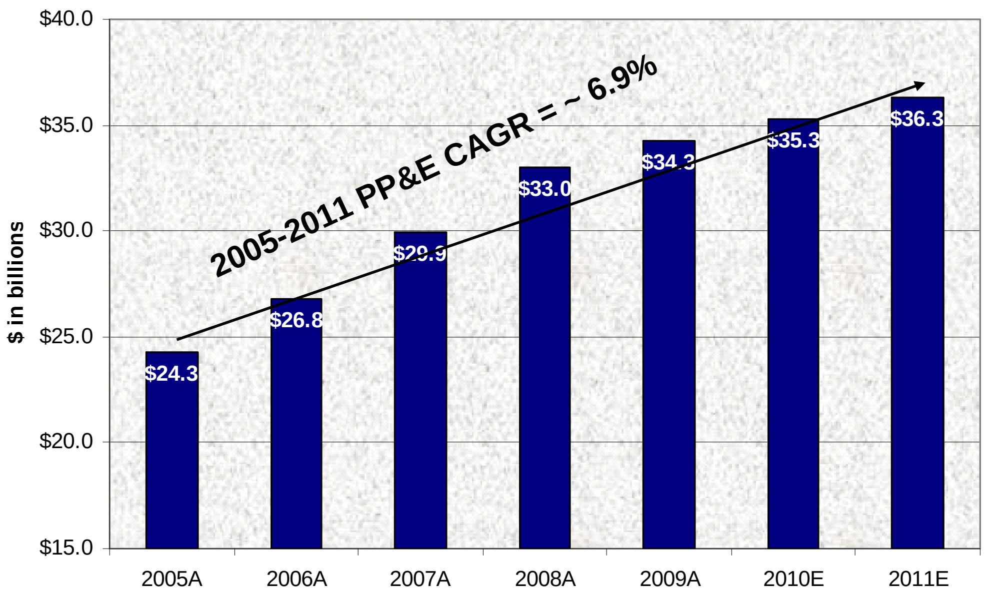
Fuel Mix



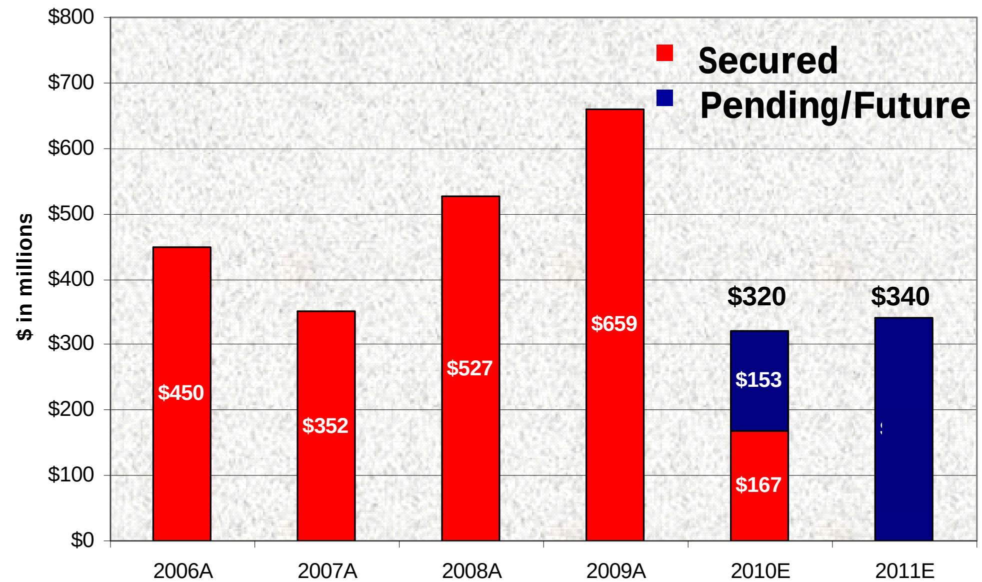
AMERICAN ELECTRIC POWER

Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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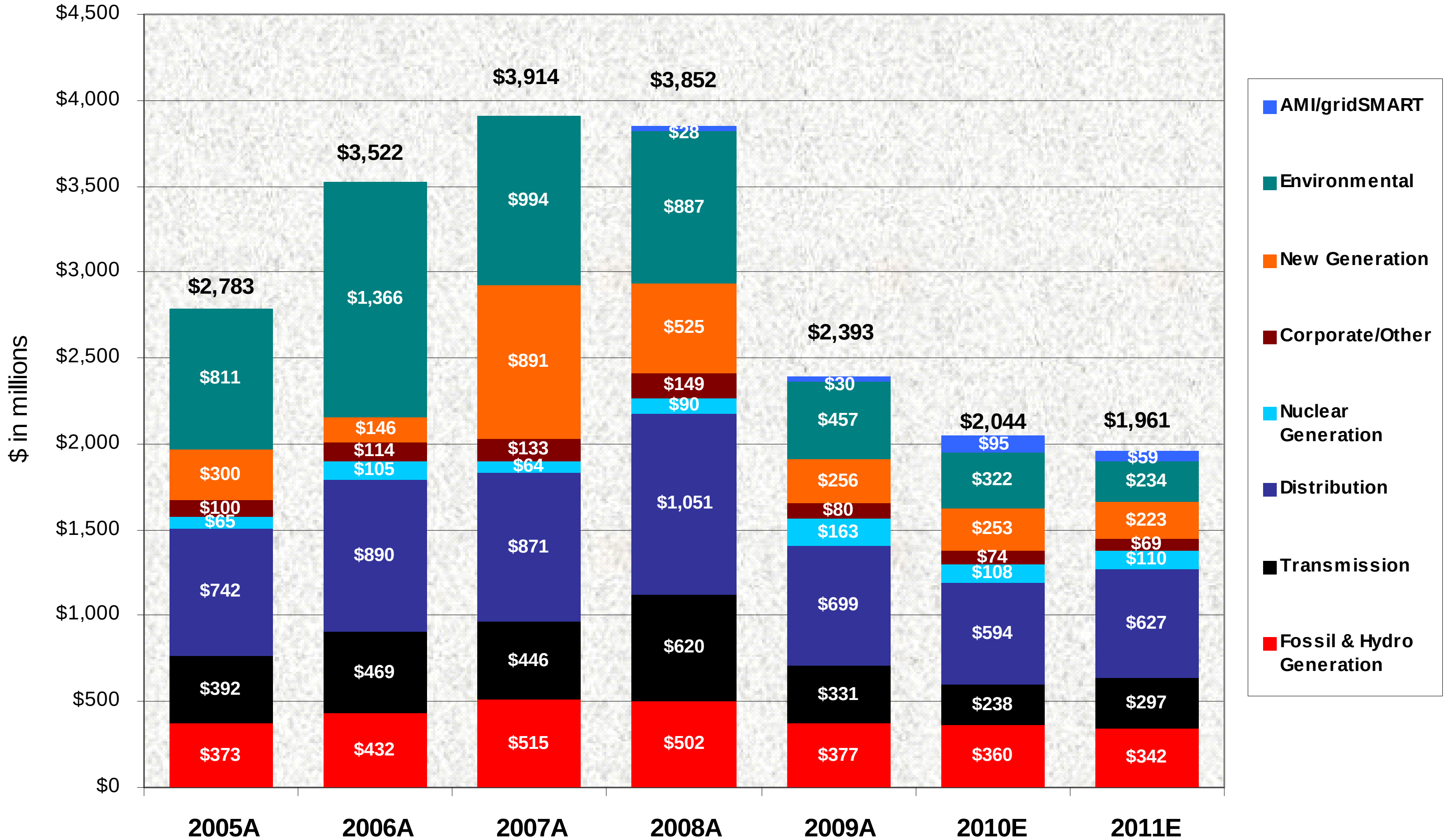
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in the next decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

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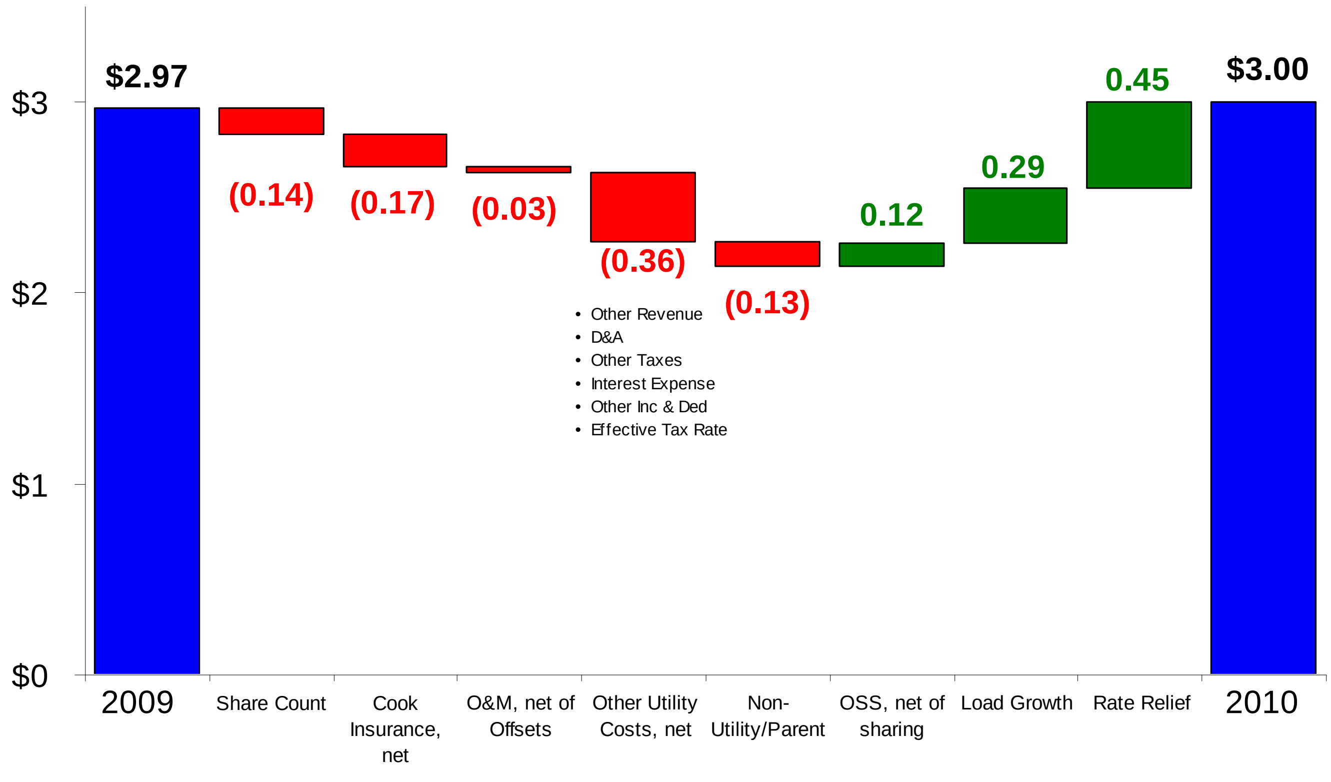
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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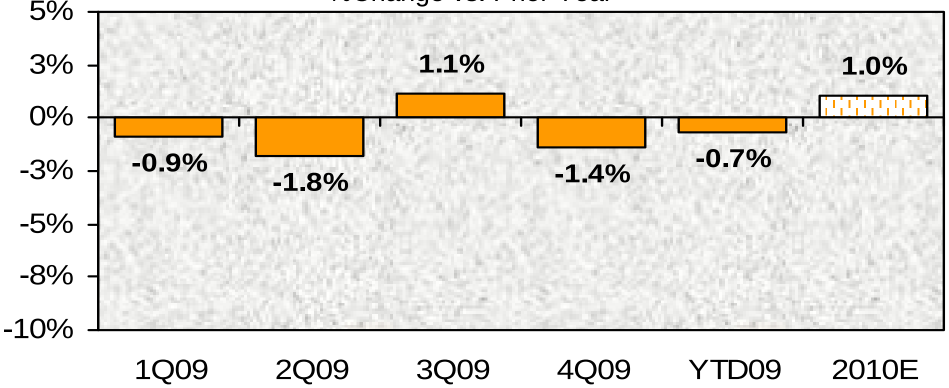
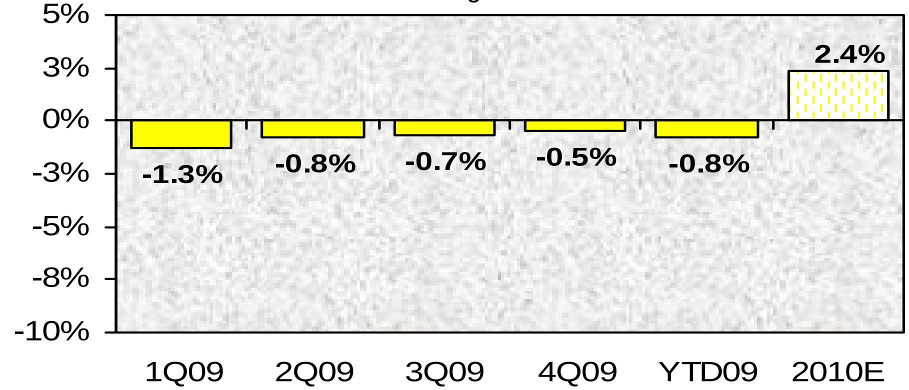
Normalized Load Trends

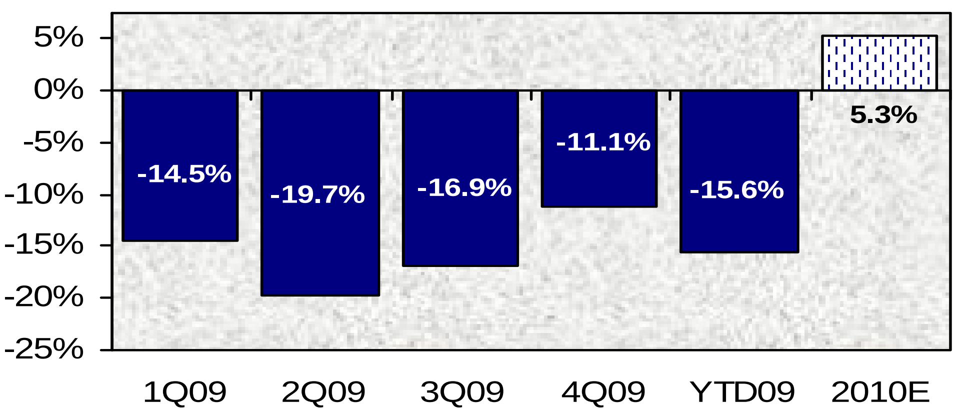
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



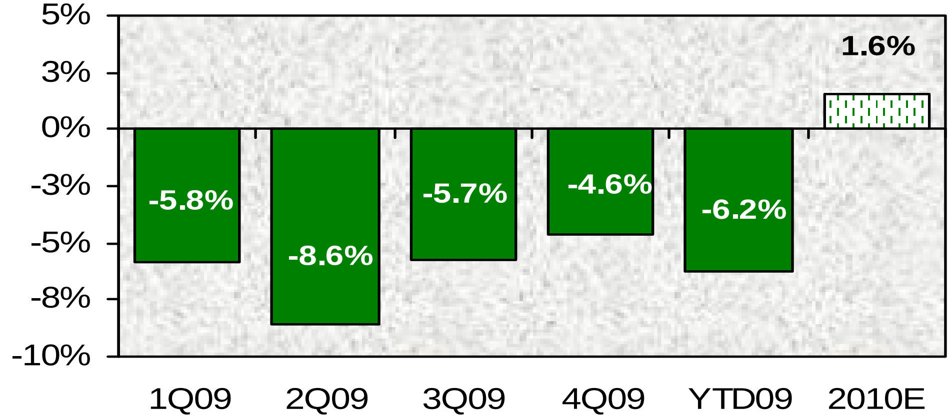
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

AEP AMERICAN® ELECTRIC POWER

Additional 2010 Earnings Drivers

O&M Assumptions

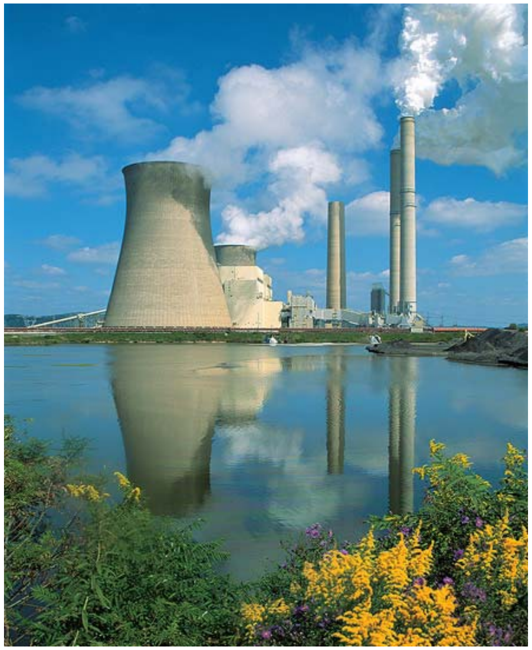
- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment
- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



General JM Gavin Plant (OH)

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Appendix

Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

AEP AMERICAN ELECTRIC POWER®

Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

AEP AMERICAN® ELECTRIC POWER

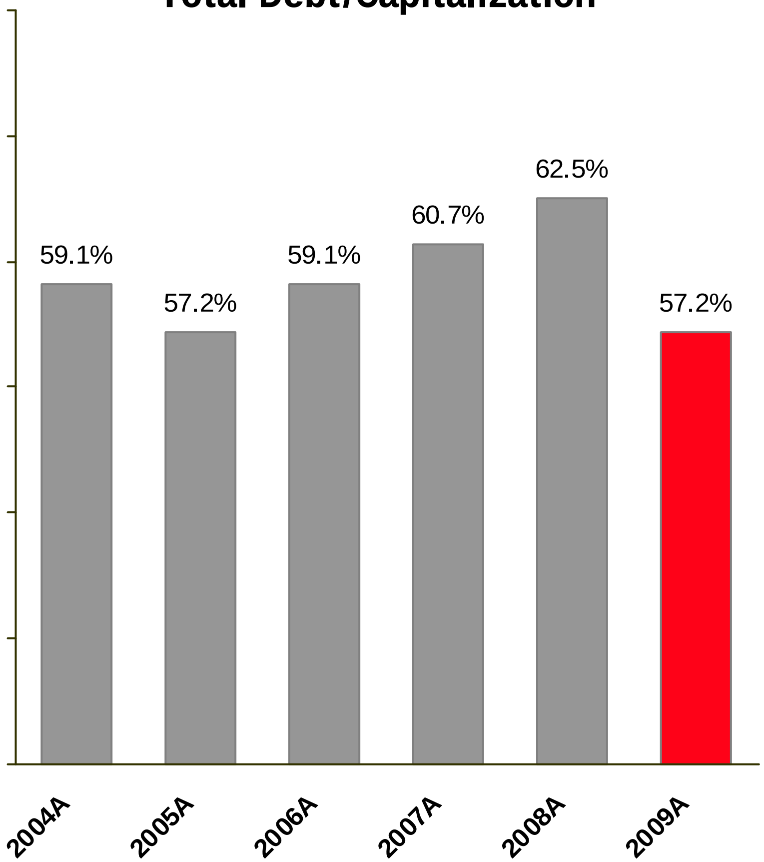
Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

AEP AMERICAN ELECTRIC POWER®

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	N
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

Ratings current as of December 31, 2009

S=Stable, N=Negative Outlook

AEP AMERICAN® ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ 490	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 45
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 679	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company(1)	$ 66	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,585	$ 623	$ 415

(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

December 12, 2009	Rates Effective, Subject to Refund
February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009 SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

February 8, 2010	Intervenor Testimony due
February 15, 2010	Staff Testimony due
March 1, 2010	SWEPCO Rebuttal Testimony due
March 15, 2010	Hearing Commences
April 30, 2010	Rates Effective, Subject to Refund
July 15, 2010	Final Order Expected

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule - TBD

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

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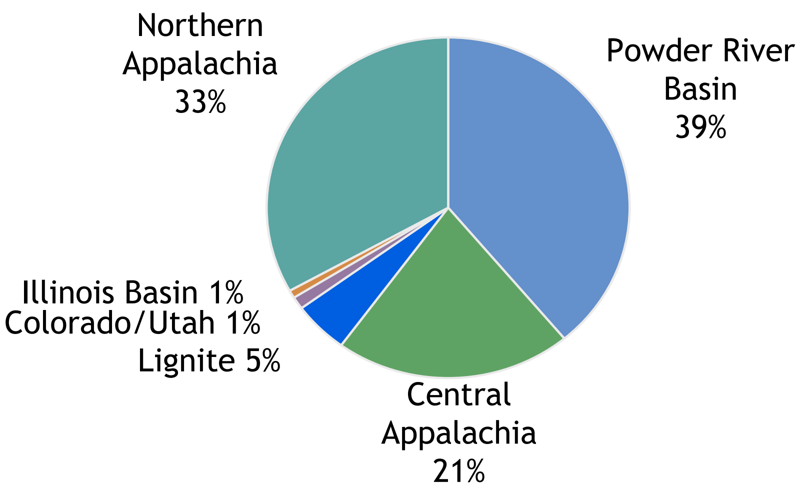
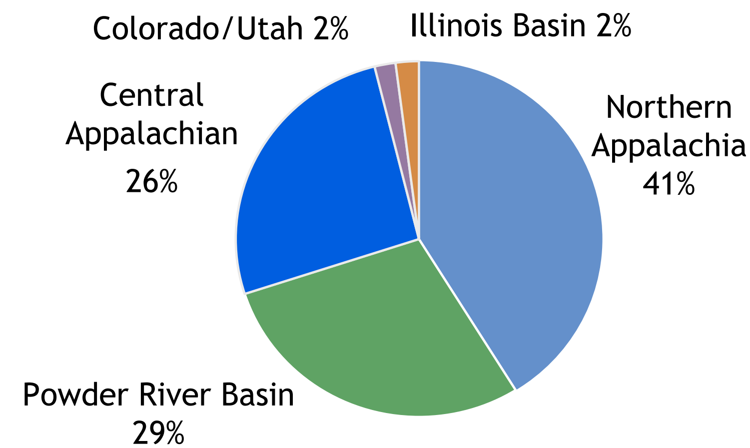
Coal Procurement - 2010 Projected

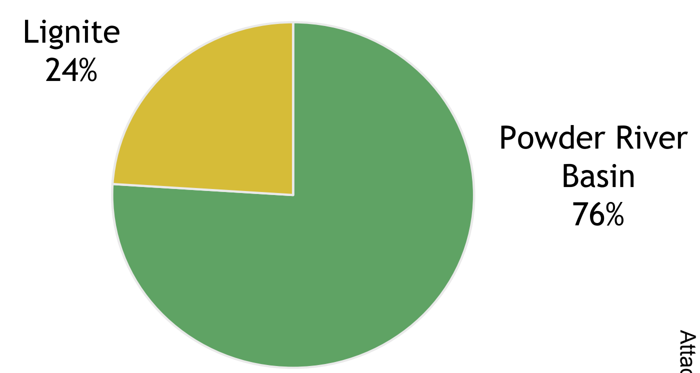
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 765 kV
- Partners: Westar (50%) & MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

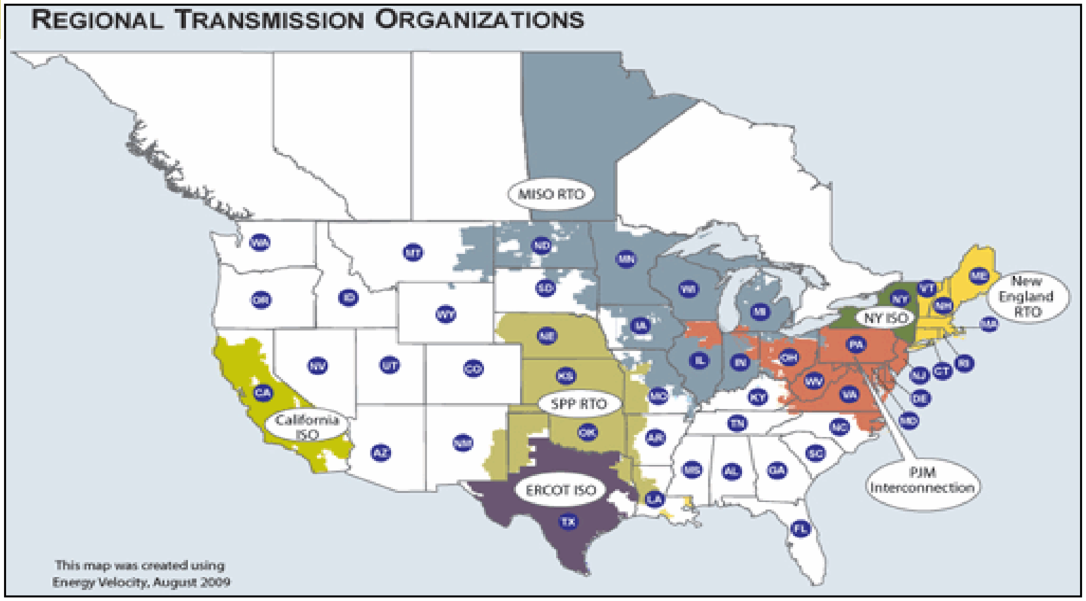
ETT — COD: 2010-2017
- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

PJM

PATH-WV — COD: 2014
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%



FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay
- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various
- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM

PJM Expansion
- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio
- 700 miles of Proposed 765 kV

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 4913 of 9556

Electric Transmission Texas, LLC

Overview:

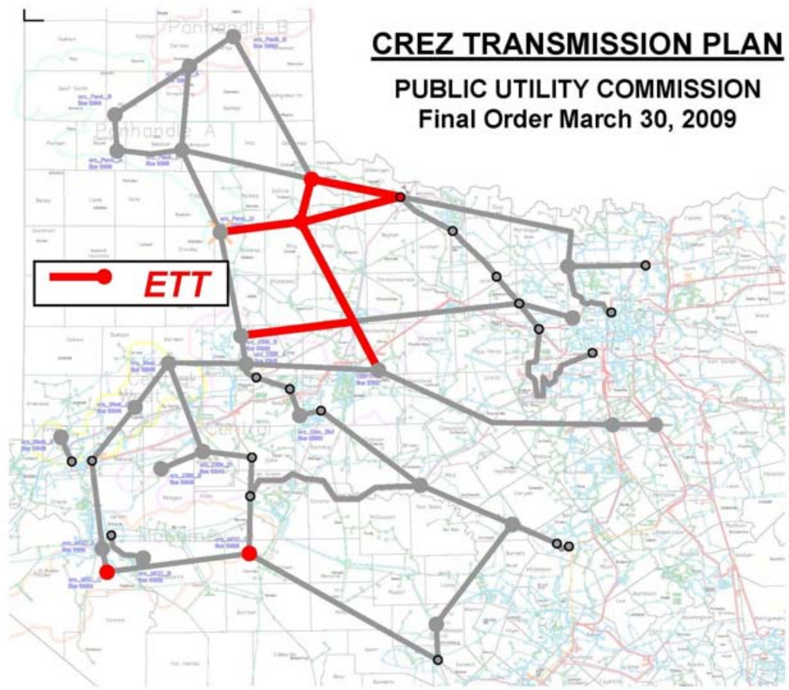
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2017: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects pending transfer in service 2010-2013: $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

PATH
Potomac-Appalachian Transmission Highline

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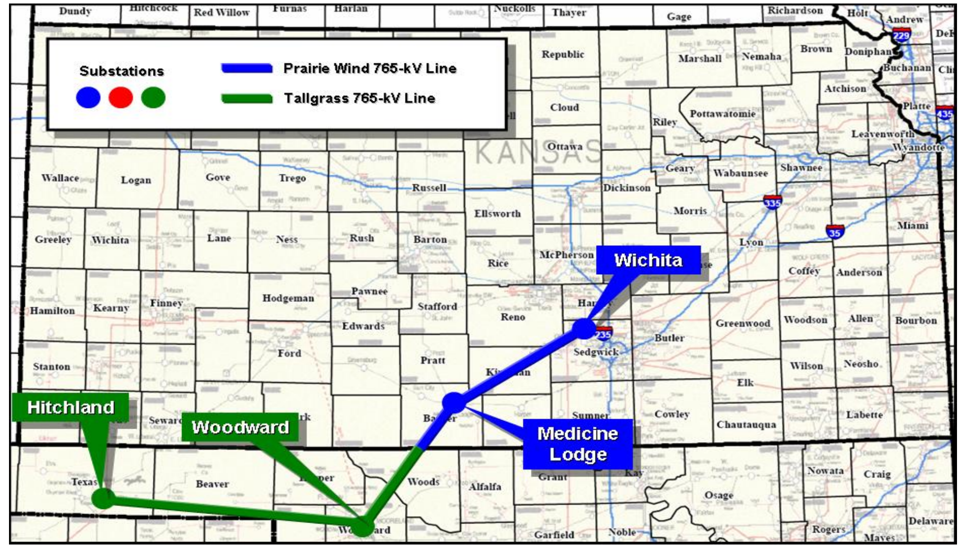
Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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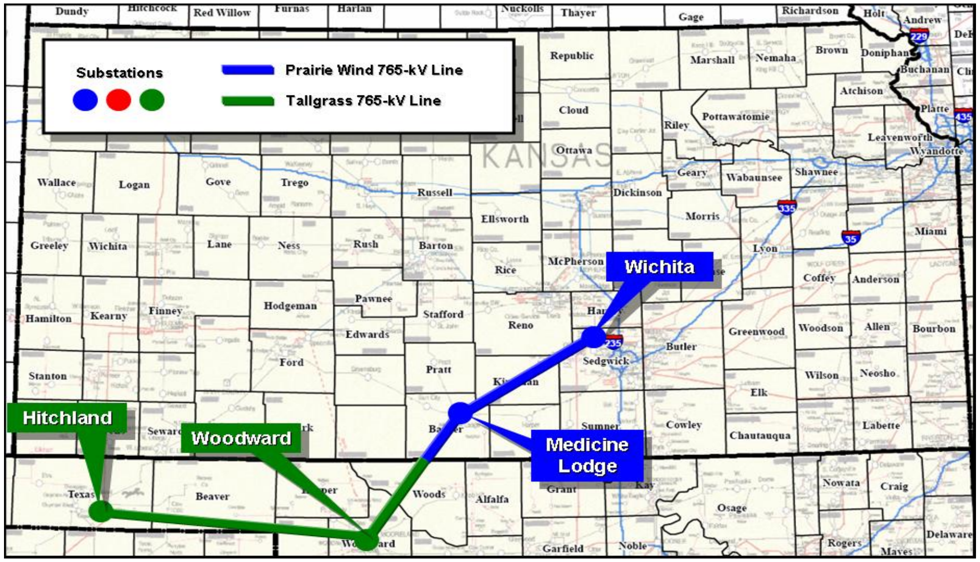
Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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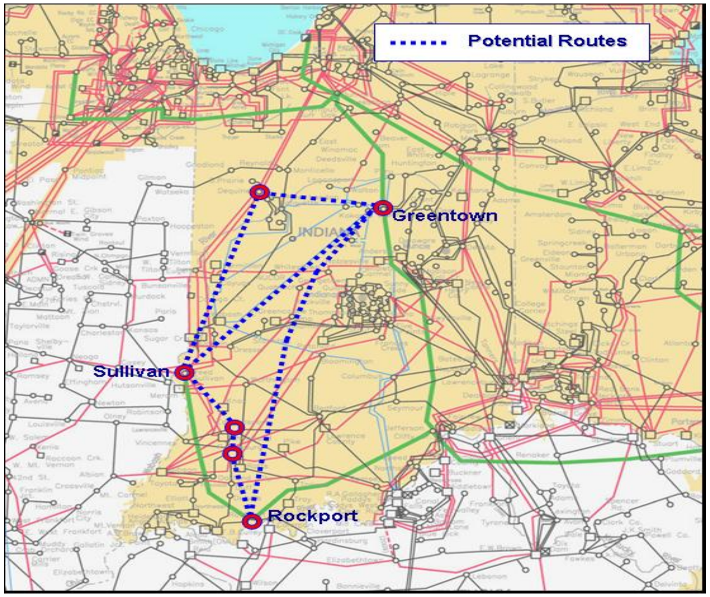
Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

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Upper Midwest EHV Development—SMART Study

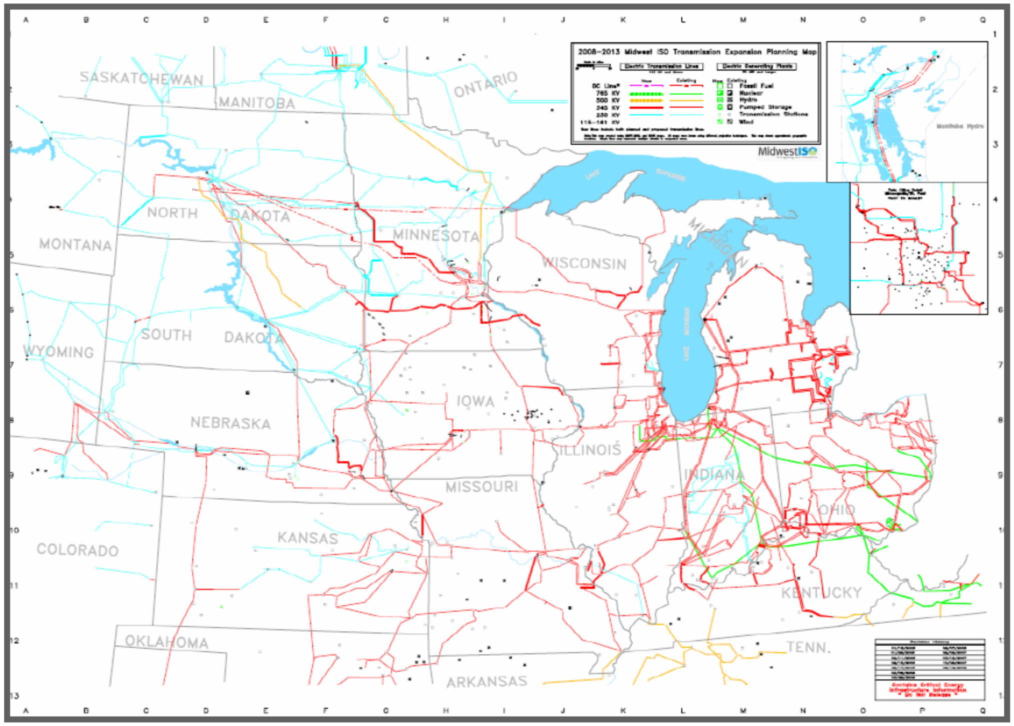
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2nd Qtr 2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

Mitigation:

- Collaborative approach involving impacted utilities, RTOs, commissions and others

AEP AMERICAN® ELECTRIC POWER

Dinner Meeting Hosted by Deutsche Bank


AEP AMERICAN ELECTRIC POWER®


April 3, 2007

Columbus, Ohio

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Participants:

Michael G. Morris, Chairman, President & CEO

Holly Koeppel, EVP & Chief Financial Officer

Craig Baker, SVP-Regulatory Services

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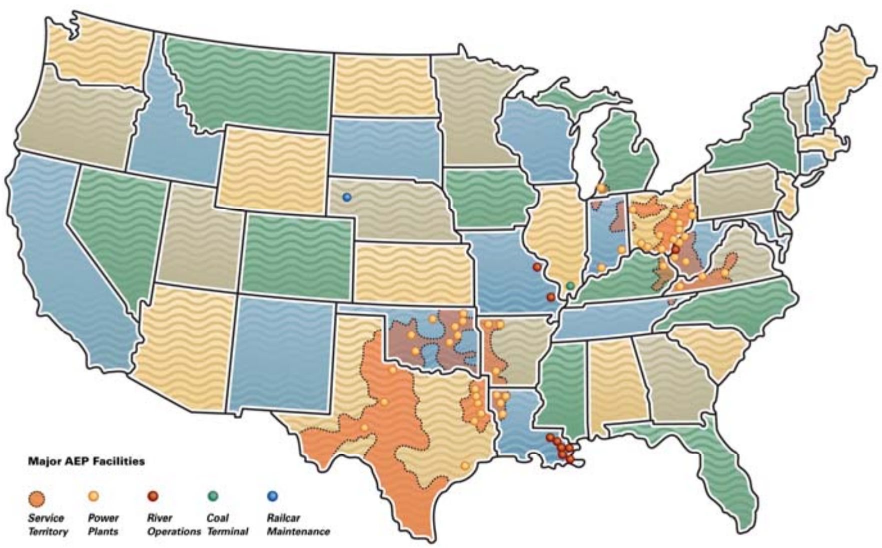
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

→ **Deliver value to investors and cost effective service to our customers**

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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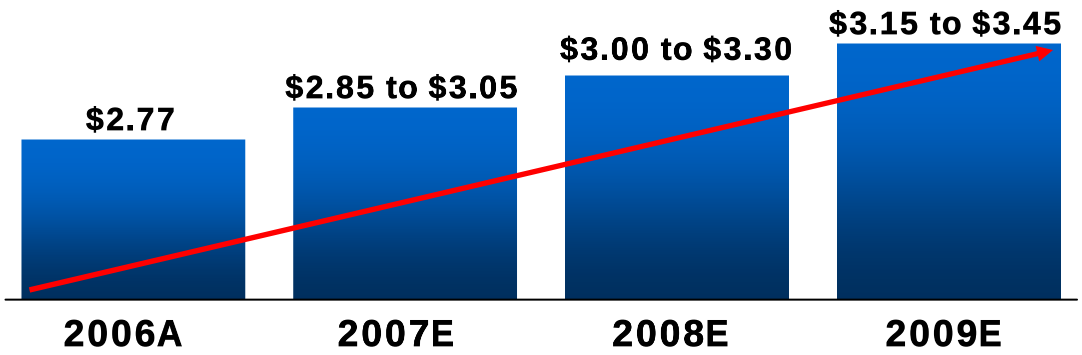
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

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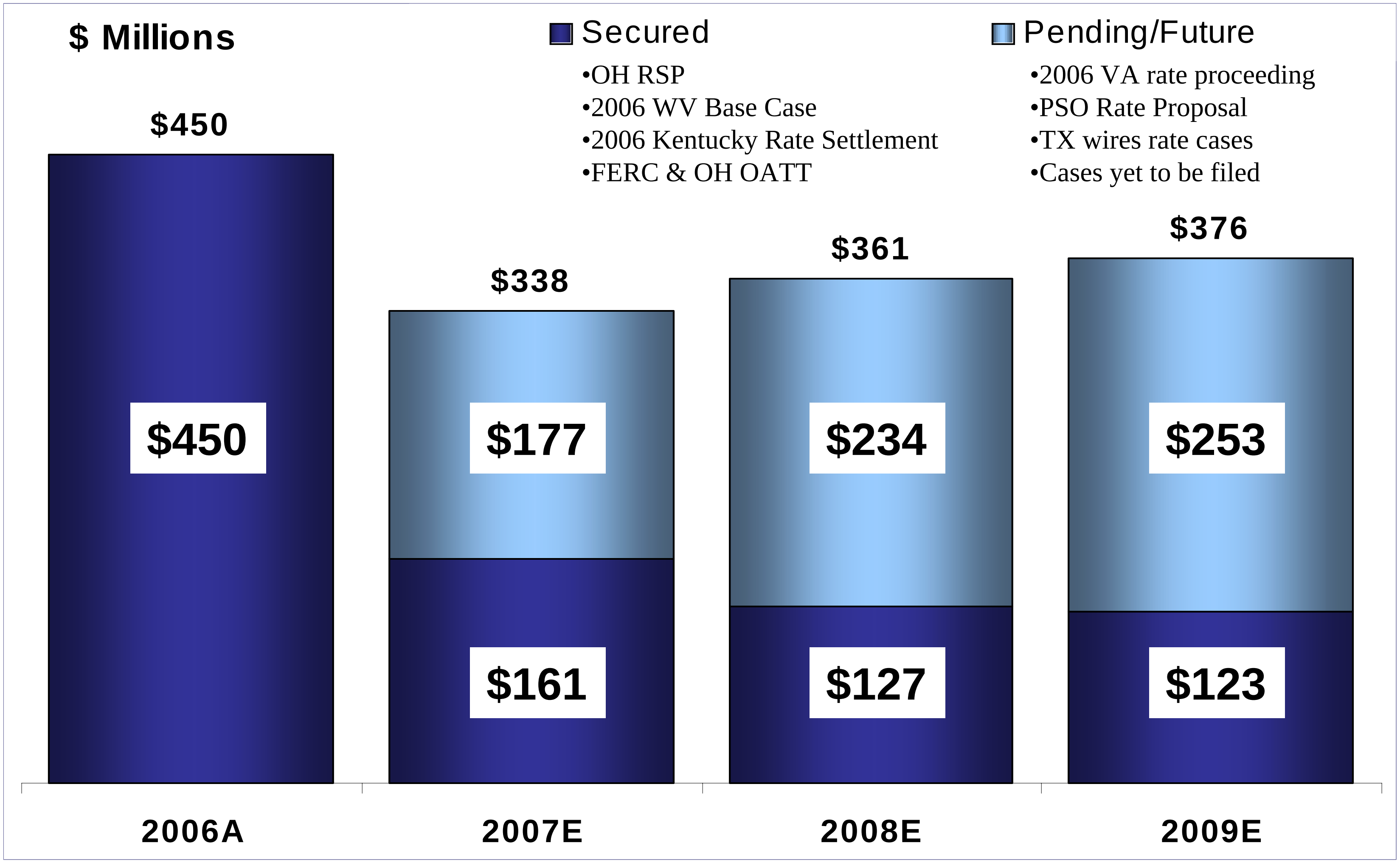
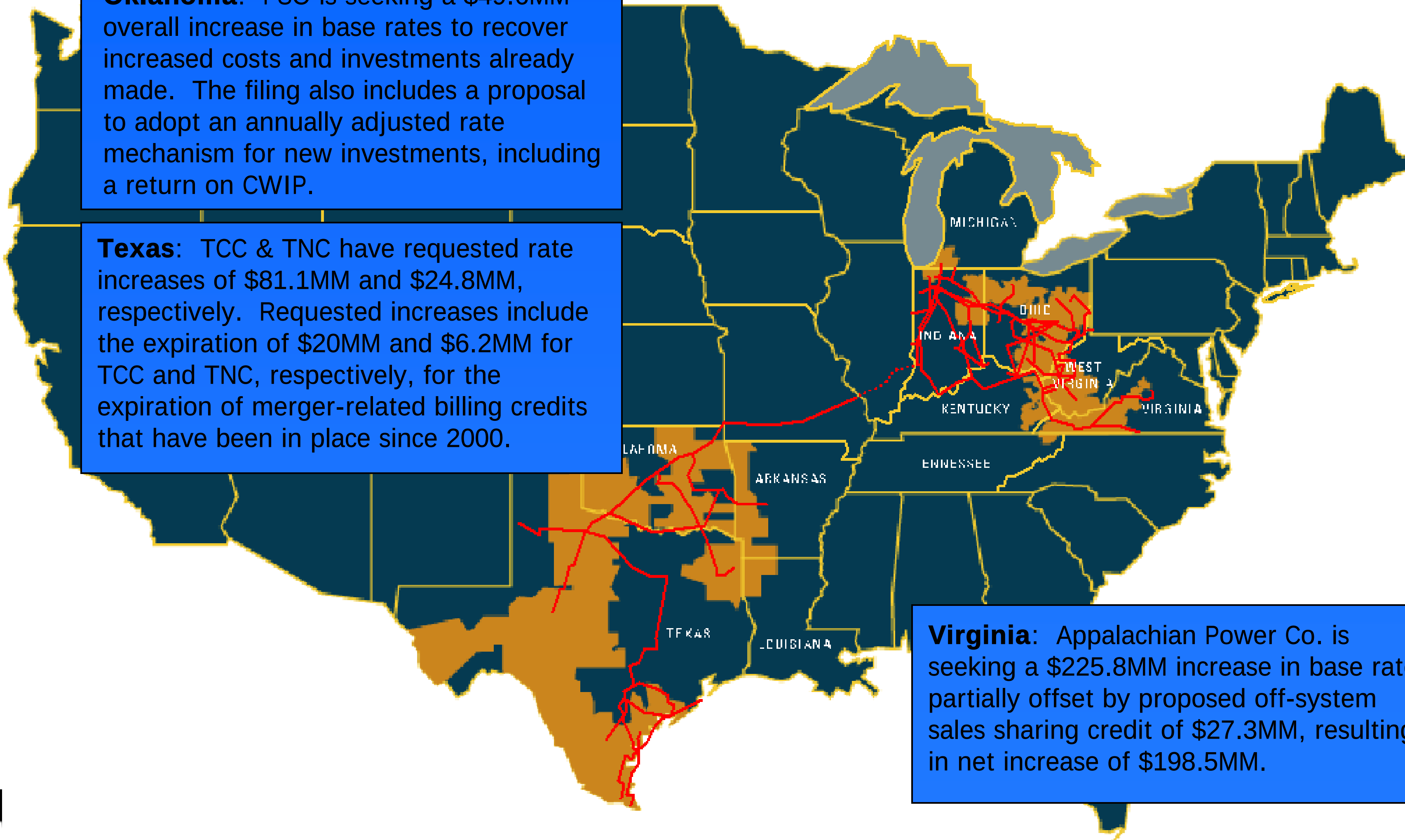
Incremental Rate Relief Composition



RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.

Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
    - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 7, 2007; Evidentiary hearing to commence May 22, 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in mid-2007.

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 7, 2006	Hearings commenced
February 5, 2007	Briefs filed
March 28, 2007	Hearing Examiner Recommendation filed

APCo has until April 18, 2007 to comment on the Hearing Examiner's report. Following this action, we will await an order from the SCC. No statutory deadline.

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. TCC and TNC requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	11.25%	4.50%
Total	100%		8.02%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	11.25%	4.50%
Total	100%		7.97%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$588,170,858	$ 1,012,316,518
Cost of Capital	8.02%	8.02%
Return on Rate Base	$ 47,144,247	$ 81,141,219
Operation & Maintenance	$ 24,953,569	$ 234,900,166
Depreciation & Amortization	$ 16,050,664	$ 61,560,580
Income Taxes	$ 13,127,245	$ 21,909,492
Taxes other than Income	$ 14,691,850	$ 65,648,324
Total Cost of Service	$115,967,575	$ 465,159,781
Miscellaneous Revenues	$ (4,557,543)	$ (33,982,023)
Base Rate Revenue Requirement	$111,410,032	$ 431,177,758
Test Year Adjusted Base Rate Rev.	$ 90,790,725	$ 390,700,744
Requested Base Rate Increase	$ 20,619,307	$ 40,477,014

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$171,049,145	$ 288,872,851
Cost of Capital	7.97%	7.97%
Return on Rate Base	$ 13,639,241	$ 23,034,353
Operation & Maintenance	$ 12,775,116	$ 60,434,214
Depreciation & Amortization	$ 12,206,069	$ 28,670,726
Income Taxes	$ 3,126,651	$ 5,279,031
Taxes other than Income	$ 3,661,924	$ 12,093,639
Total Cost of Service	$ 45,409,001	$ 129,511,963
Miscellaneous Revenues	$ (365,848)	$ (7,216,050)
Base Rate Revenue Requirement	$ 45,043,153	$ 122,295,913
Test Year Adjusted Base Rate Rev.	$ 36,025,589	$ 112,706,901
Requested Base Rate Increase	$ 9,017,564	$ 9,589,012

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

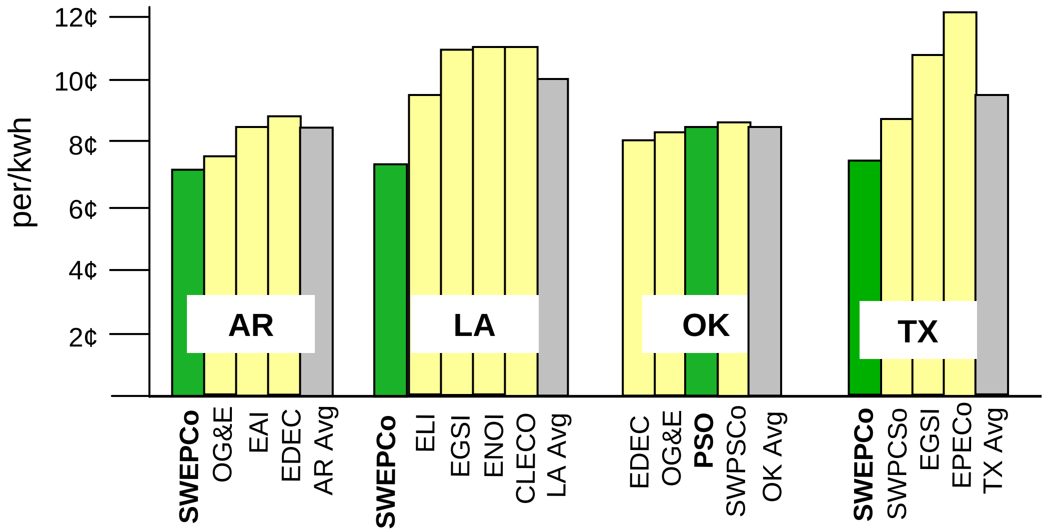
* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

AEP Provides Low Cost Electric Service

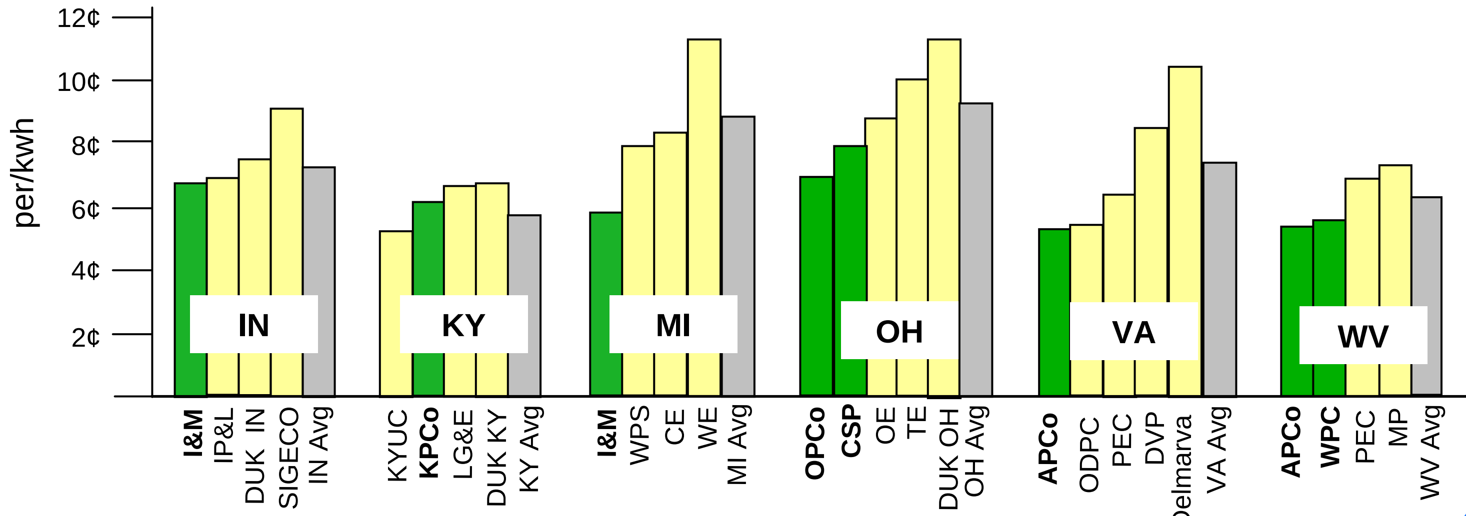
AEP West



Residential Average rates 12 months ended 6/30/2006

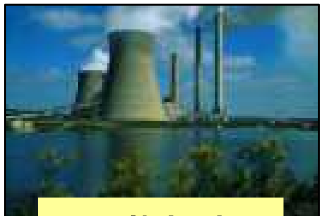
Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

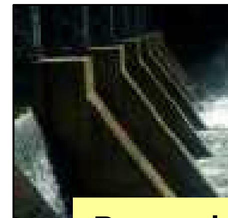
Domestic Generation Fleet

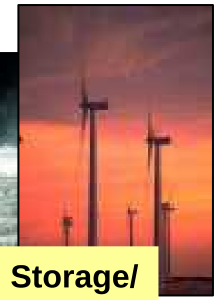


Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%





Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2011
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale expected to close 2Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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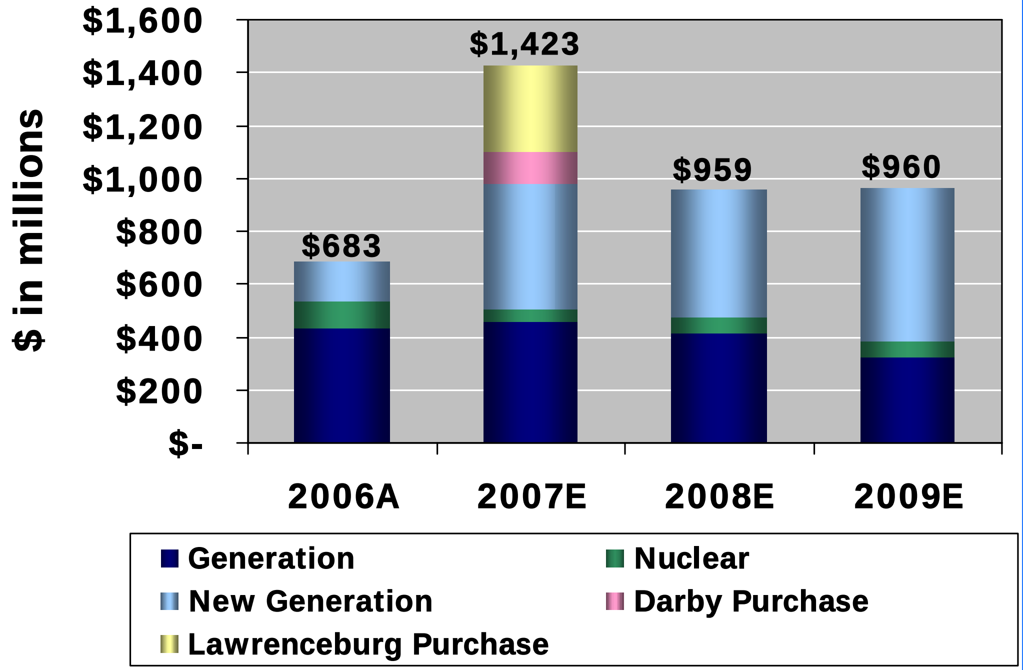
Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP
- Purchased Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006

Total Projected Generation Investment



Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008-09
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	Projected 2007	✓	Projected 2007
Mitchell 2	800	✓	Projected 2007	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	✓	In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2007
Muskingum River 5	585	✓	In-service	☐	Delayed
Pirkey	580	☐	N/A	✓	In-service
Oklaunion	485	☐	N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262	☐	N/A	✓	In-service

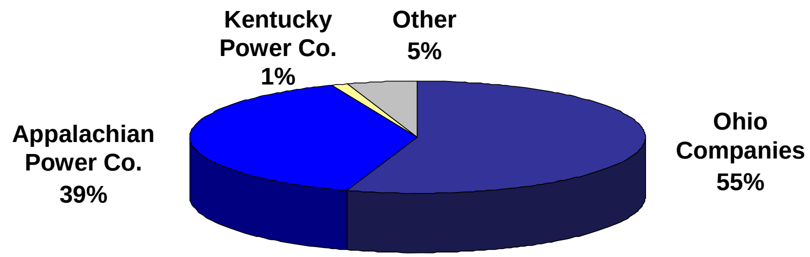
*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

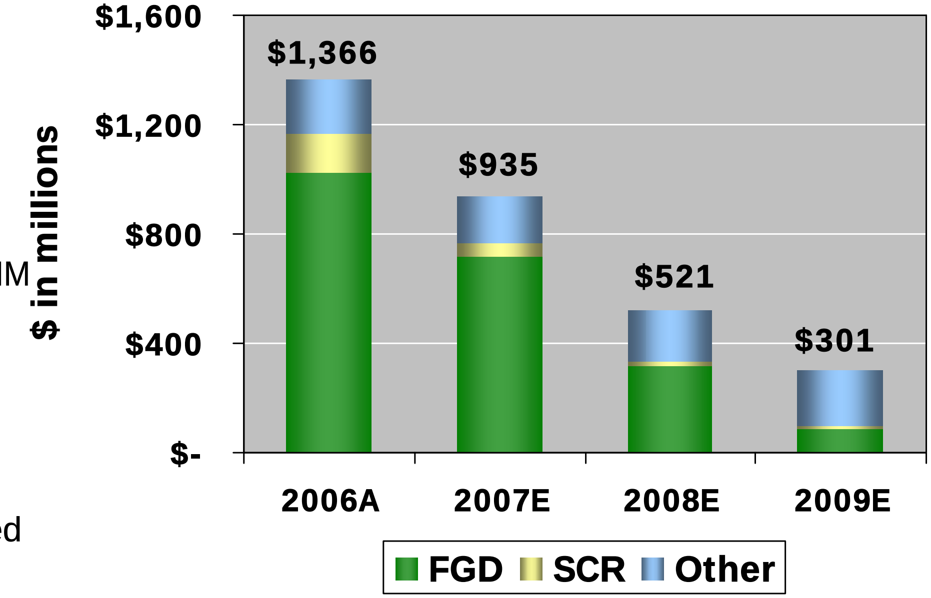
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures, pursuant to the 4% provision of the RSP
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

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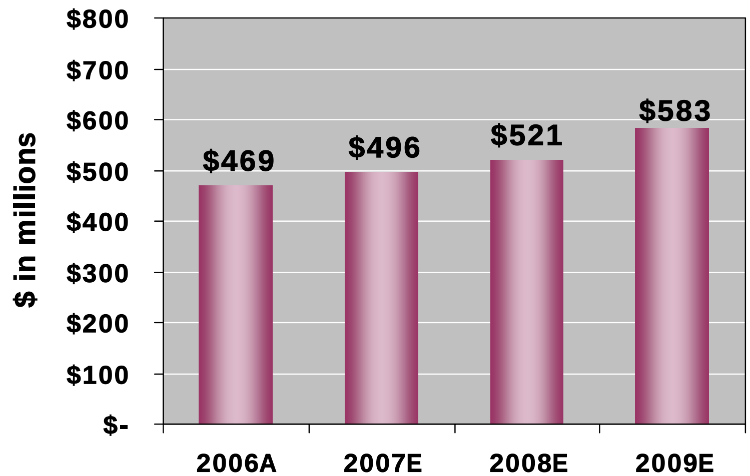
Transmission Investment Forecast

- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of "postage stamp" rate
  - Final order expected in mid-2007
- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services
- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company and to set initial rates
  - FERC filing to transfer transmission assets to ETT submitted Feb. 15, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

AEP Transmission Network – Largest in the Country

Operating Company Level
(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

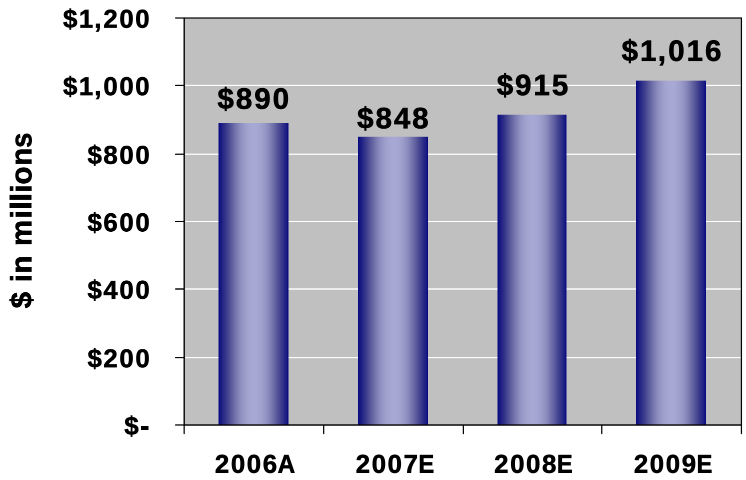
AEP Is The Leader In Transmission Expertise

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an average annual investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $60.8MM and $15.9MM for TCC & TNC distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

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AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP®

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

AEP®

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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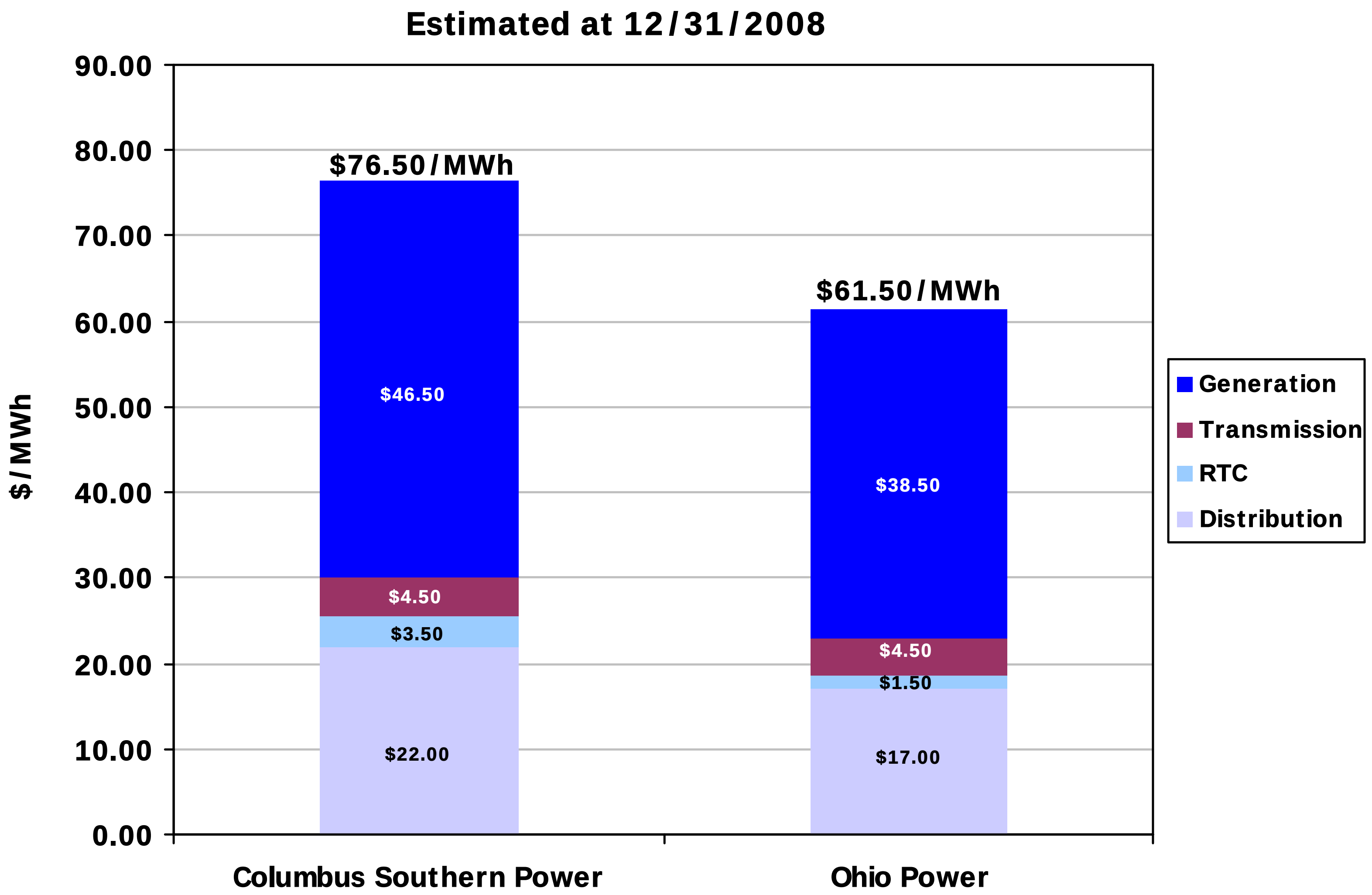
Average Unbundled AEP Ohio Rates



AEP®

Deutsche Bank

2008 Energy & Utilities Conference

May 29, 2008

Miami Beach, FL

AEP AMERICAN ELECTRIC POWER®

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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Addressing Industry Concerns

- Rising Commodity Costs – Fuel and Transportation
- Rising Capital Costs – Environmental Retrofit and New Generation
- Declining Reserve Margins
- Need for Additional Transmission
- Regulatory Pressures Due to Rising Rates

AEP

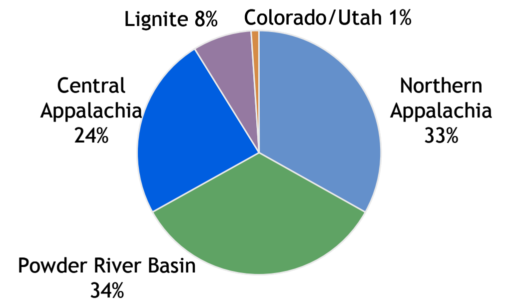
AEP is well positioned to manage each of these industry concerns.

Industry Concern: Rising Commodity Costs – Fuel and Transportation

AEP SOLUTION – FUEL PROCUREMENT STRATEGY:

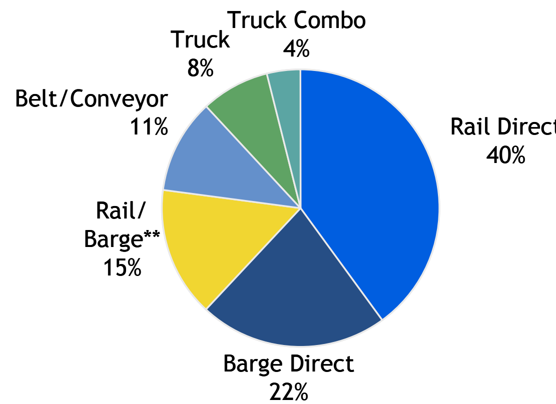
- **Portfolio of Coal Contracts**
  - Geographic and supplier diversity
  - Diversity of terms – currently ranging from 2008 to 2022
- **Portfolio of Transportation Resources**
  - 8,400 rail cars
  - 2,650 barges and 52 towboats
  - coal handling terminal-20MM tons capacity
- **Portfolio of Options to Manage the Economics of Converting BTUs to MWhs**
  - Manage emission allowance exposure
  - Blending capabilities at many plants
  - Transportation fleet to reposition coal
- **Regulatory Recovery**
  - Active fuel clauses in ten of eleven jurisdictions, with Ohio recovery beginning in 2009

AEP Supply Diversity *



* 2008 Projected

AEP Transportation Diversity *



* 2007 Actual

** Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP strategy: manage coal supply sources and transportation assets to mitigate price increases and market disruptions.

Industry Concern: Rising Capital Costs

AEP SOLUTION – Completed Environmental Retrofit

Lower Capital, Lower Operating Costs, Successful Operating Performance

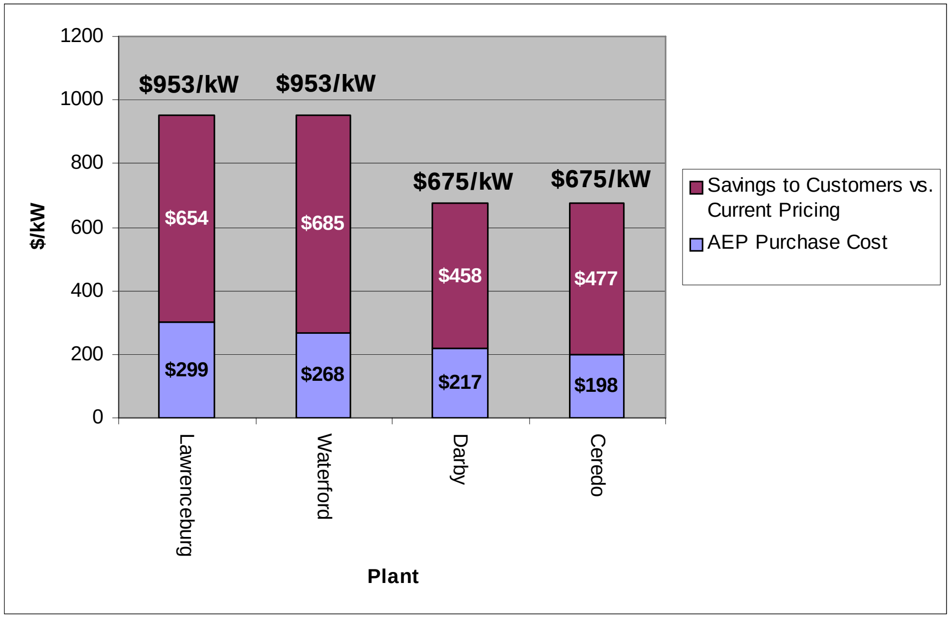
- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- Capital cost comparison for wet scrubber:
  - AEP average ~ $250/kW
  - 2007 pricing for a 600MW plant ~ $320/kW
  - 2012 forecast for a 600MW plant ~ $470/kW

- **11,076 MW FGDs currently in service or under construction equates to cost savings to rate payers based on 2007 $ of $775 million.**

AEP SOLUTION – Purchased Low-Cost Generation

Lower Capital, Successful Operating Performance, Delayed Need for Baseload

- Cost to replace plants in 2008 are estimated at $675/kW for simple-cycle and $953/kW for combined-cycle. Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections. This equates to cost savings to rate payers of $1.7 billion.



By moving early, AEP avoided approximately $2.5 billion of capital. Nearly all of these investments are currently reflected in rates.

AEP

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Add Generation:

Harry D. Mattison Plant – commercial operations achieved in 2007

Generation:

- **Adequate reserves in East due to purchased generation (Waterford, Ceredo, Lawrenceburg &Darby)**
- **Build peaking, intermediate and baseload generation in the West**

Project Name	State	Fuel Type	Plant Type	MW Capacity	Original In Service Date	As Contracted Cost	Cost if Contracted in 2008	In Service if Contracted in 2008
Mattison	Arkansas	Gas	Simple-cycle	340	2007	$333/kW	$675/kW	2010
Stall	Louisiana	Gas	Combined-cycle	500	2010	$671/kW	$953/kW	2011
Turk	Arkansas	Coal	Ultra-supercritical	600	2011	$2,123/kW	$2,605/kW	2014

Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections.

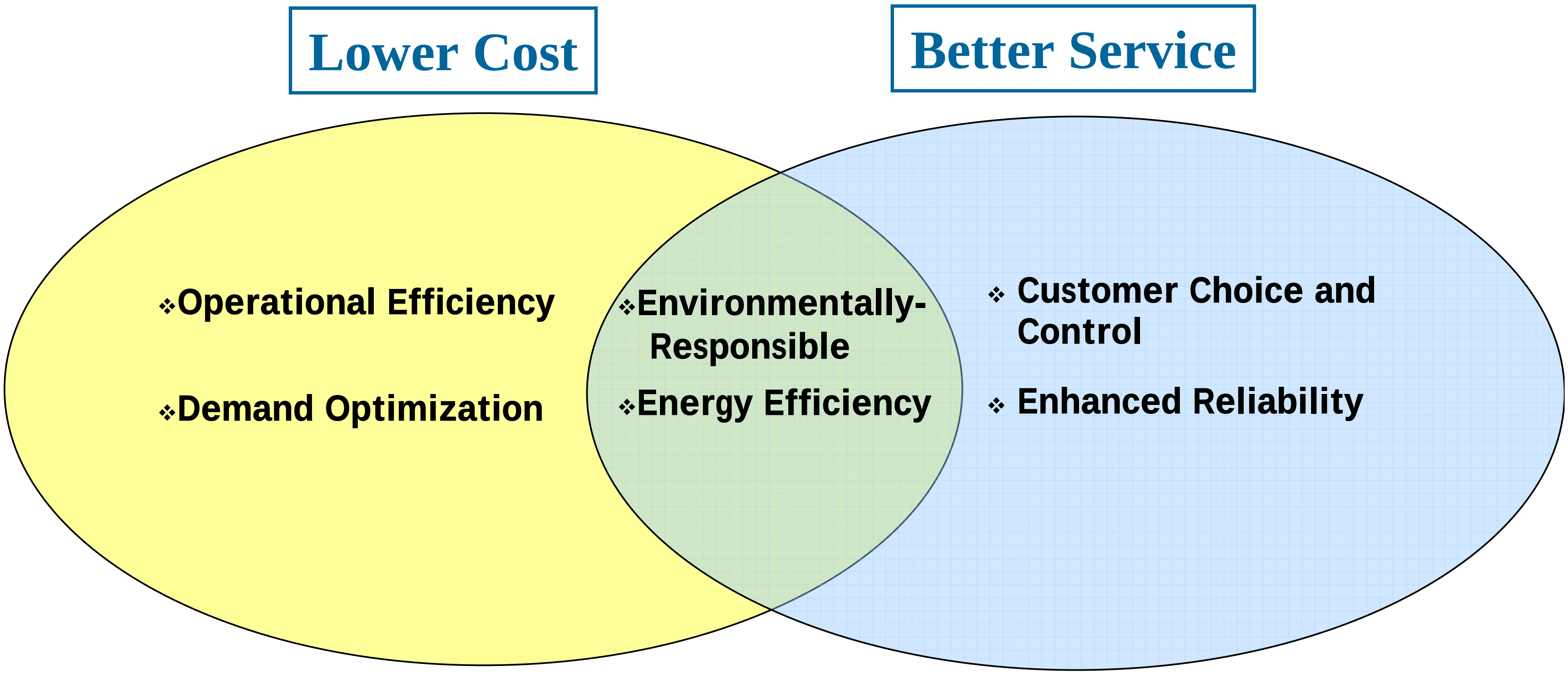
AEP's current initiatives help mitigate both the supply and demand issues facing the U.S.

AEP®

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Improve Efficiency and Demand Management:

AEP's **gridSMART**^{SM} initiative will develop a deployment plan for new customer programs and advanced technologies to support pursuit of the following value propositions:

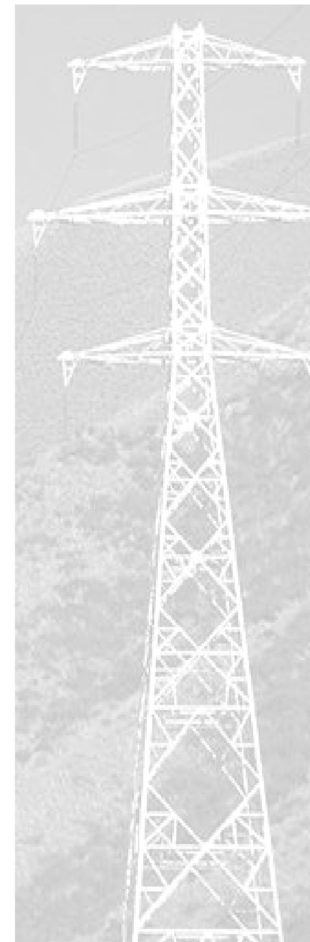


Increased efficiency reduces cost and GHG emissions. It also delays the need for new generation.

Industry Concern: Need for Additional Transmission

AEP SOLUTION:

Our status as the largest transmission owner in the U.S. affords us technical, operational and economic advantages:



- Efficient System Design - 765-kV Technology
- Advanced Technology Solutions - Laredo Variable Frequency Transformer
- Strong Supplier Relationships - Long-term Equipment and Construction Contracting
- Joint Venture Partnerships - Investment opportunities identified
  - MidAmerican Energy Holdings Company
    - Electric Transmission Texas - $1 billion - $4 billion opportunity
    - Electric Transmission America - $3 billion opportunity in SPP
      - Signed agreement with Westar forming Prairie Wind Transmission--$600MM (AEP share-25%)
  - Allegheny Energy Inc.
    - PATH - $1.8 billion opportunity

Our customers and shareholders benefit from the scope, scale and expertise of our transmission operations.

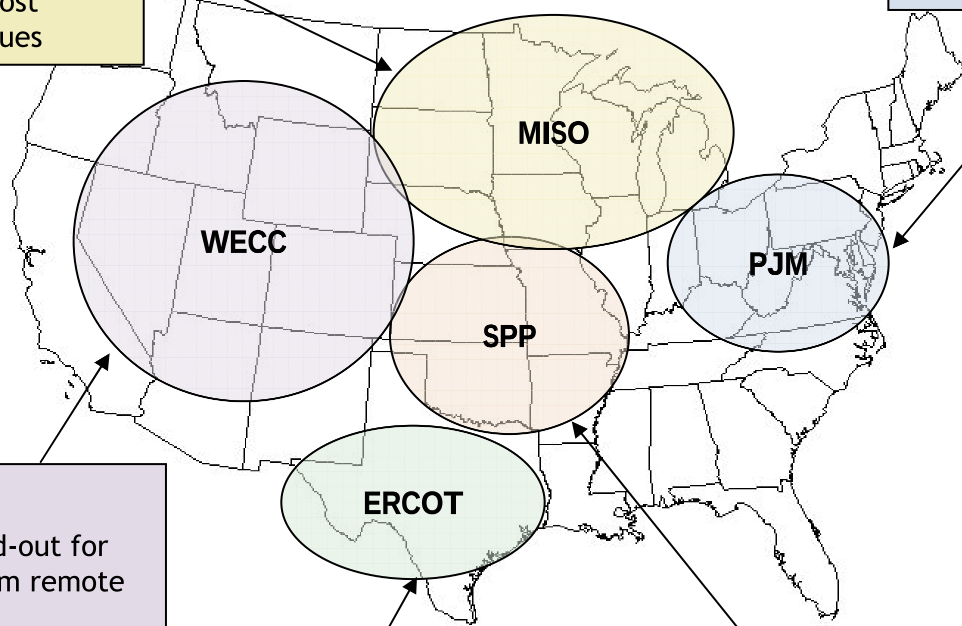
Transmission Investment Opportunities Allow Broader Market Access

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues

PJM

Congestion will be reduced and reliability will be increased



WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

ERCOT

Load growth and access to wind resources driving transmission investment

AEP's transmission initiative addresses regional supply/demand issues (congestion) and is required for more robust deployment of renewable generation sources.

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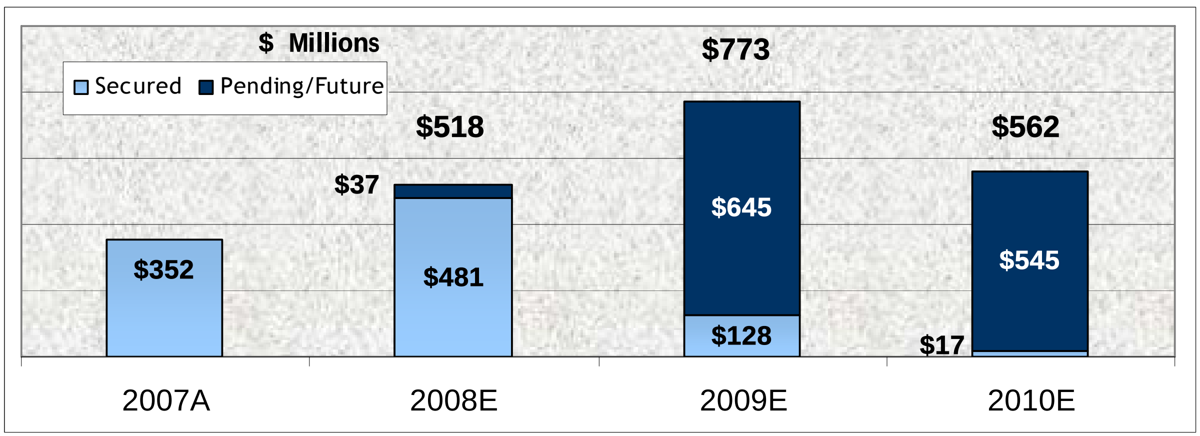
Industry Concern: Regulatory Pressures Due to Rising Rates

AEP SOLUTION:

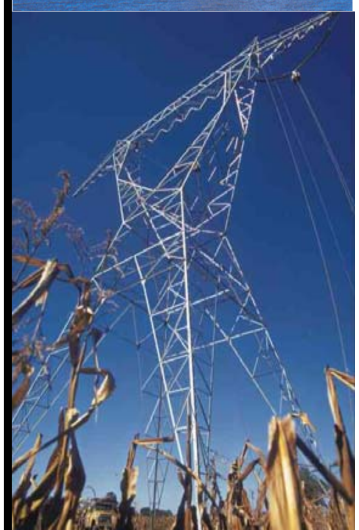
- **History of Regulatory Success/Proven Track Record**
- **Lowest Cost Provider to 93% of our customers (8 of 10 Jurisdictions)**
- **Capital Reallocation will be considered where ROE's are not sufficient**
- **gridSMART[SM] Initiative to reduce customer bills**
  - Benefit: more power to sell off-system creates increased sharing for retail customers, further reducing customer bills
- **AEP Track Record of Success – Anticipated 2007 rate relief of $338MM; Achieved $352MM; Already secured 93% of 2008 rate relief.**



Note: 2009 rate relief includes Ohio, IN, VA, OK, and miscellaneous other jurisdictions

AEP is well-positioned for continued favorable regulatory treatment.

American Electric Power - Solid Track Record of Successful Execution



- *Economies of scope and scale in assets & operations*
  - *2nd Largest Generating Fleet in the U.S. including largest supercritical units at 1300 MW*
  - *Largest Transmission and Distribution Network in the U.S.*
- *Continued innovation and first-mover deployment of leading technology advancements*
  - *Ultra-supercritical and IGCC coal generation*
  - *765-kV leadership*
  - *gridSMART^{SM} initiative*

Poised for Continued Success

Questions

Appendix

Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

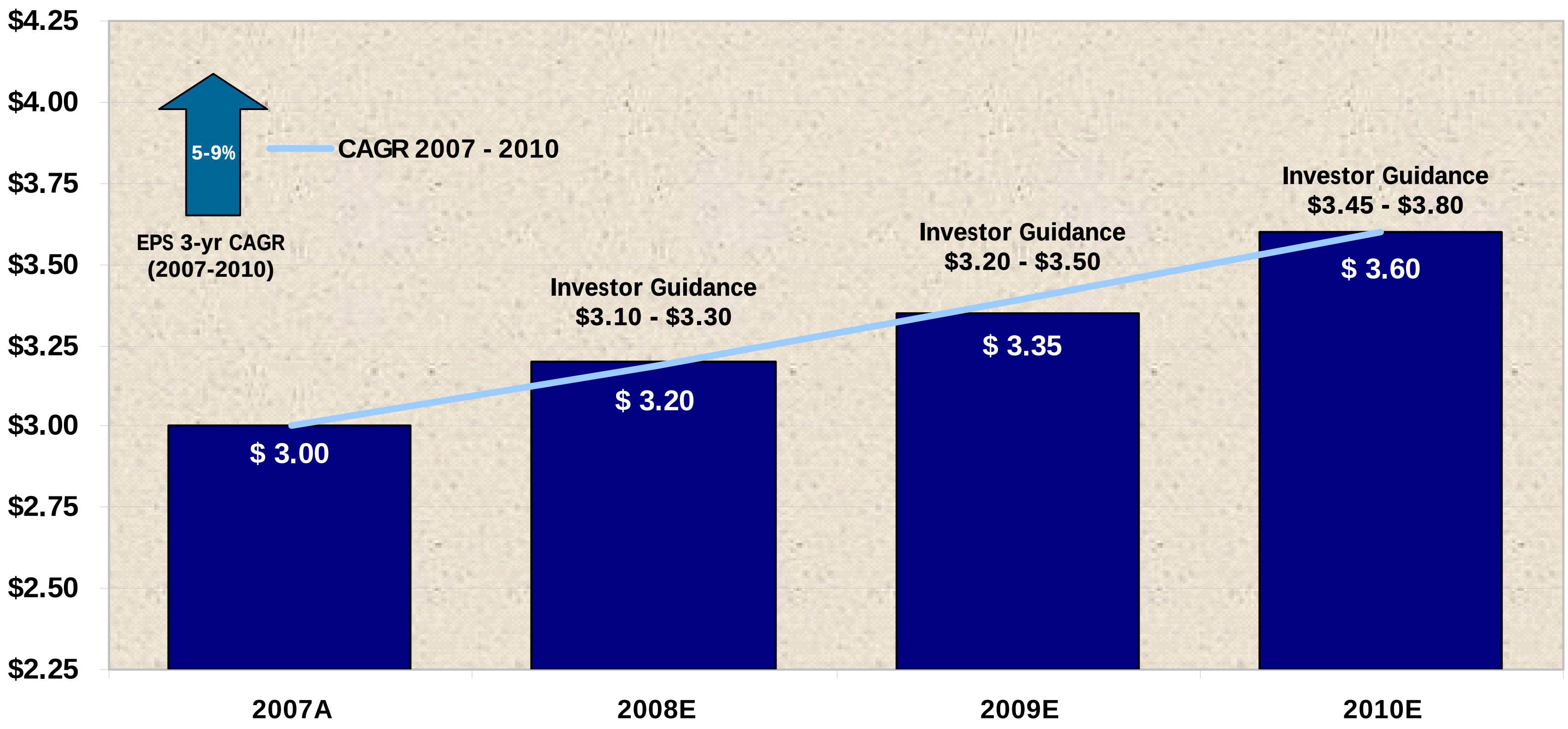
- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP has significant presence throughout the energy value chain.

AEP®

4-Year Earnings Range Forecast



5% to 9% earnings growth

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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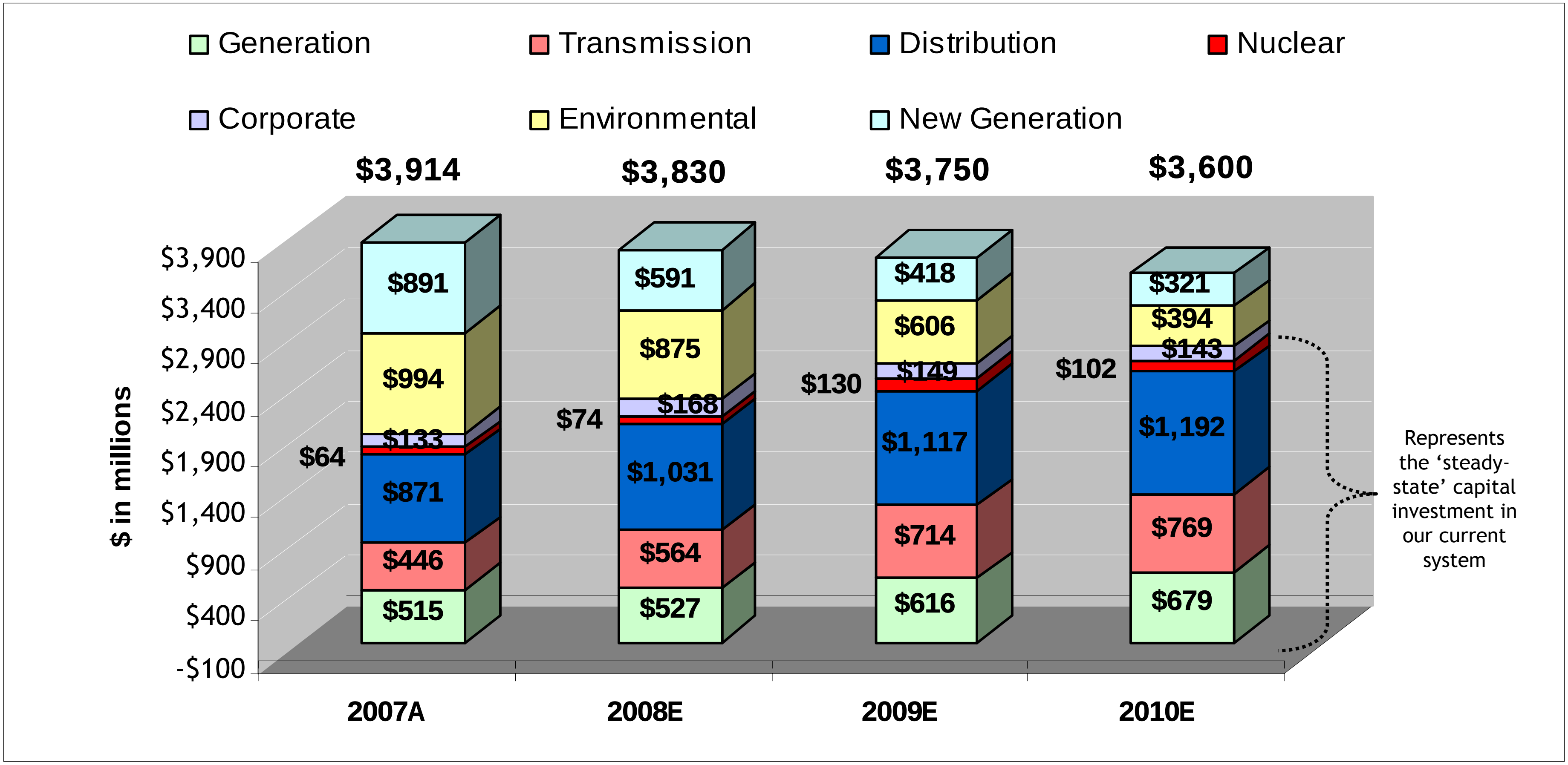
Annual Capital Investment Cycle



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects.

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Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

AEP®

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

AEP®

Capital investment is funded from cash from operations and debt issuances.

Distribution - gridSMART℠

•gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology		2008	2009	2010
Metering & Communications		$83	$138	$146
Distribution Technology Enhancements		$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

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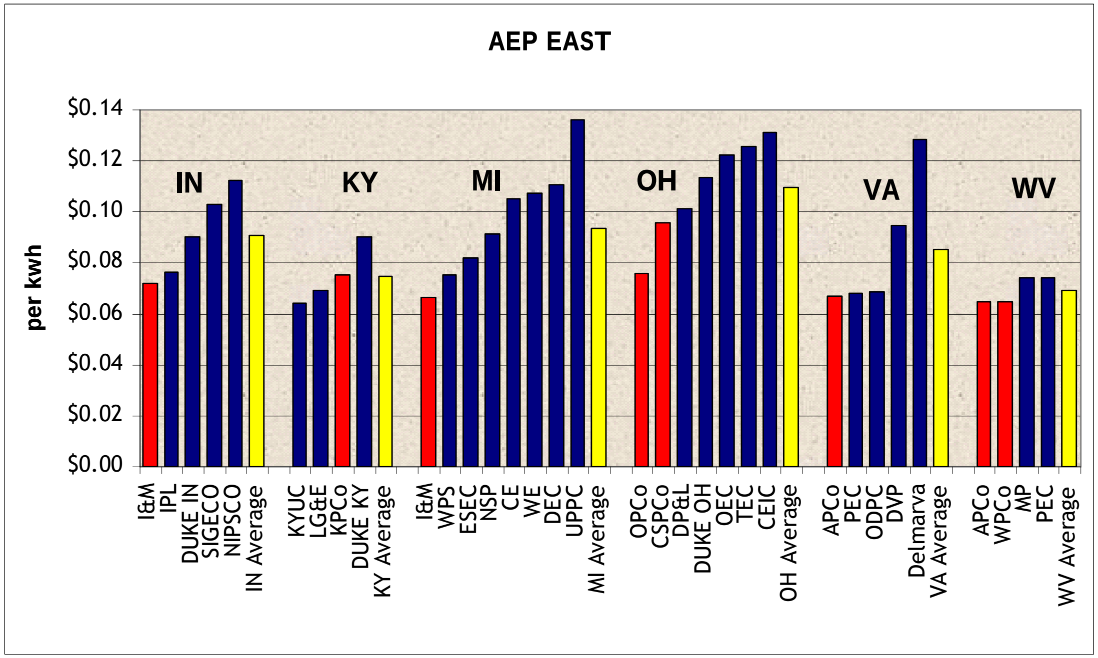
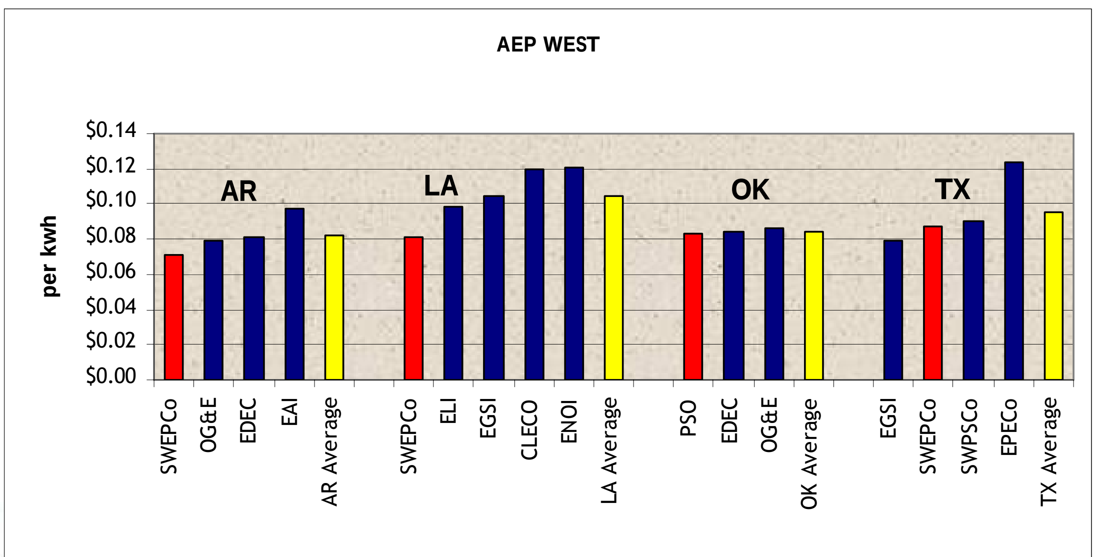
AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

Our low cost provider status in most of our jurisdictions, coupled with our scale and scope, allows us the flexibility to navigate current and future macro-economic issues.

- AEP Company
- Other Company within state
- State Average

AEP

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	\$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	\$305 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	\$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	\$1.5 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	\$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	\$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about \$1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

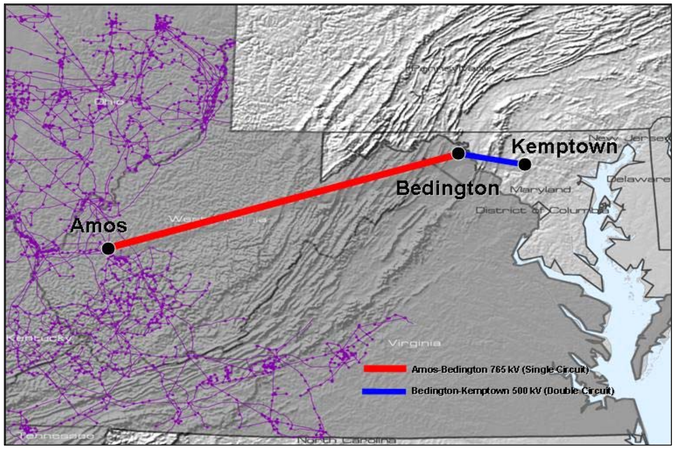
(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

AEP®

I-765™ Transmission: Investment Opportunities

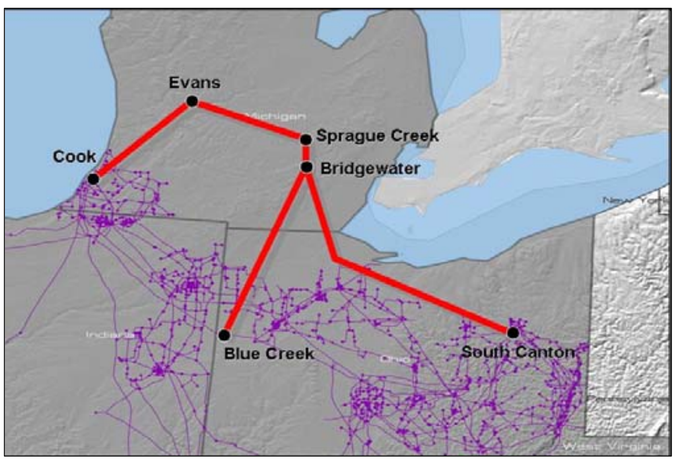
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)

Electric Transmission Texas

ETT (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

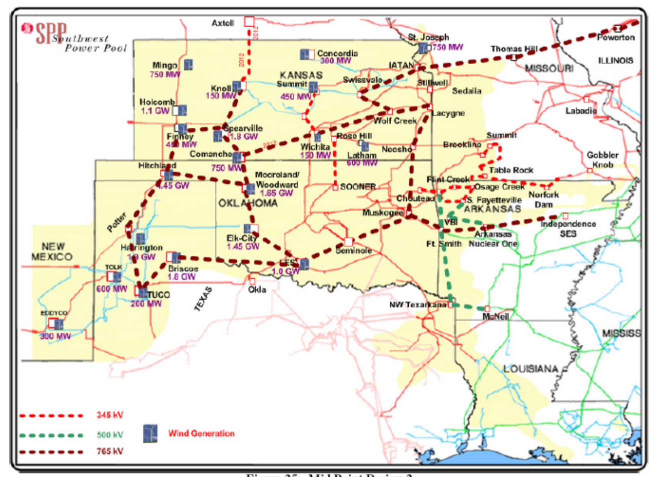


Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

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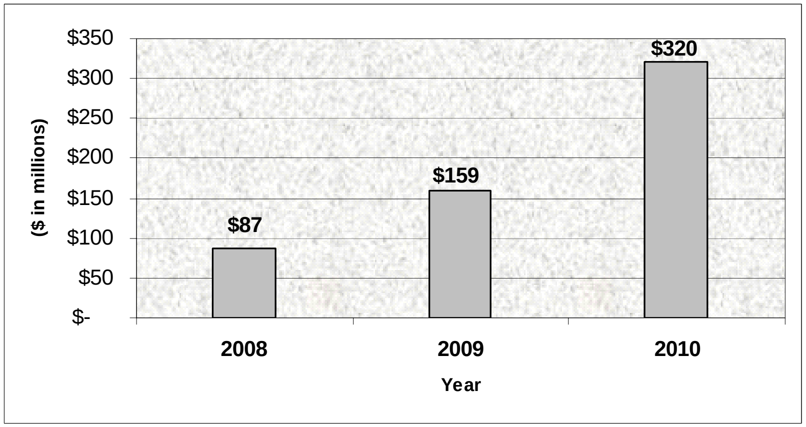
Transmission – Investments and Earnings Contributions

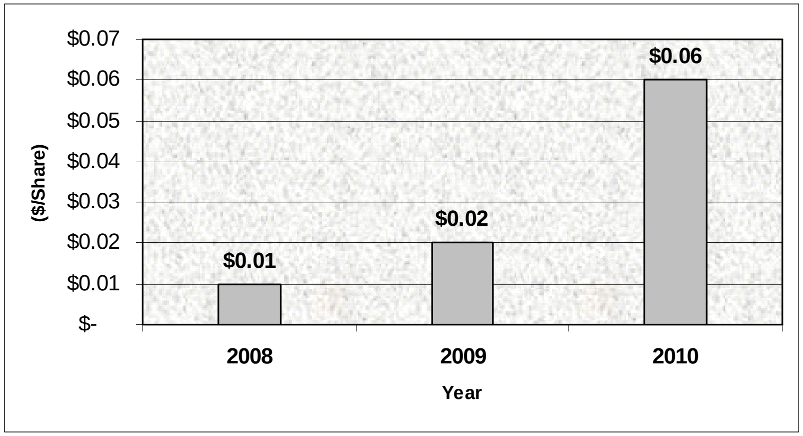
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PATH
Potomac-Appalachian Transmission Highline

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Transmission will provide a near and long term catalyst for growth.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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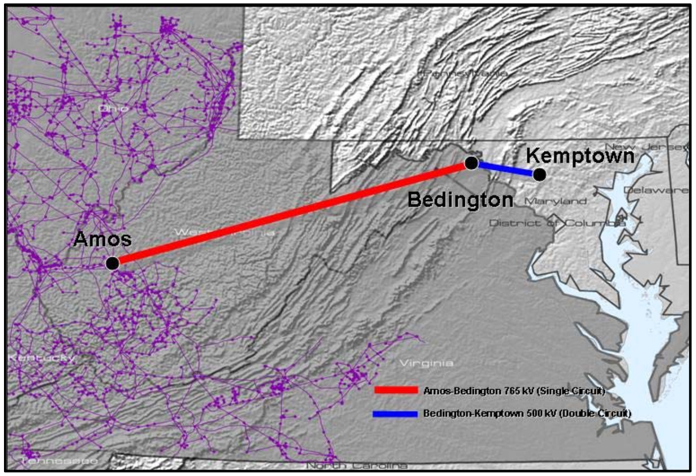
I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012

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Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
- To that end, ETA recently signed an agreement with Westar forming Prairie Wind Transmission, LLC proposing to build the first segment of the 765-kv Overlay Plan in SPP

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I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

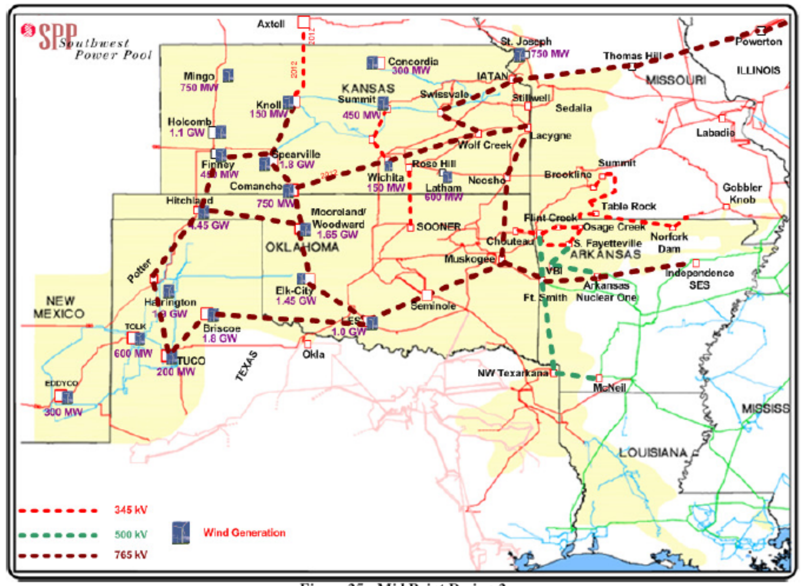


Figure 25: Mid Point Design 2

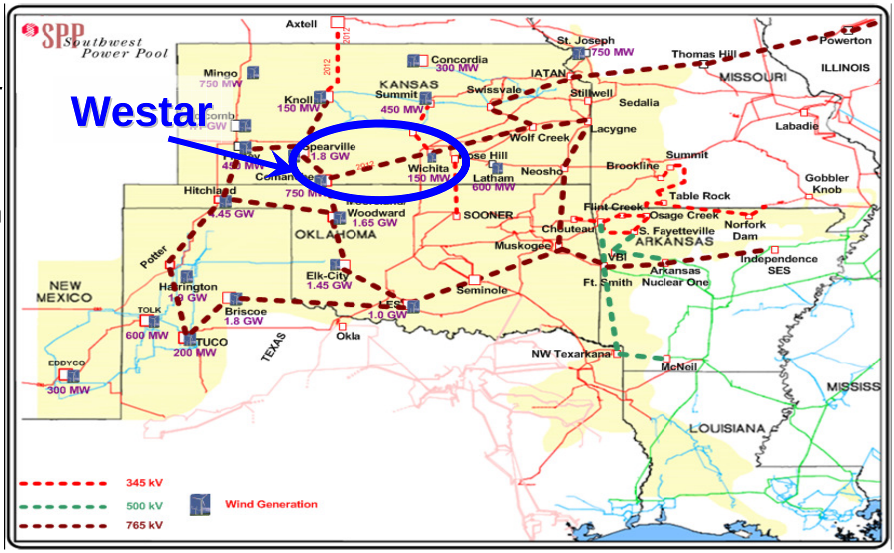
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765 kV Engineering, 765 kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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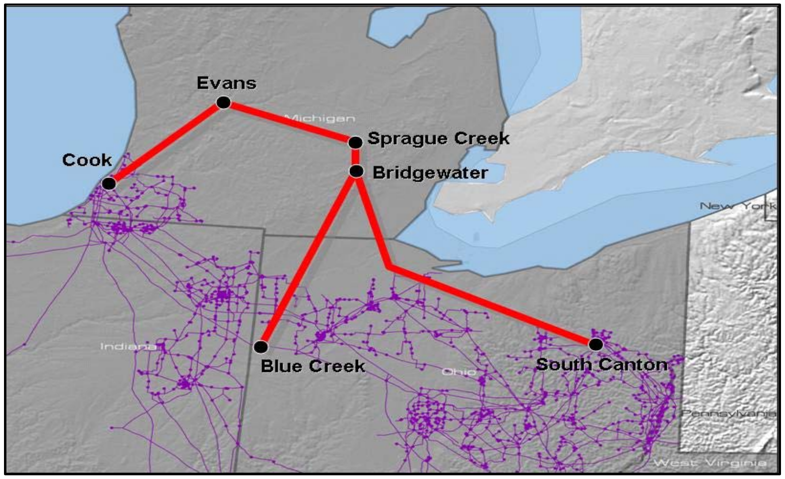
I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- SPP OATT Formula Rate Filing
- New Generation:
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas
  - IGCC

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure – Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief – Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

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Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on April 29, 2008, and the SCC issued an order granting reconsideration on April 30, 2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as resolution of pending rulemaking related to SB221 in Ohio.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearing is scheduled for May 29-30, 2008.

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Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

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Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

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Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

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AEP AMERICAN® ELECTRIC POWER

Deutsche Bank & Client Office Visit
March 30, 2010

765-kV Transmission Line (Wyoming-Jacksons Ferry)

General JM Gavin Coal Plant (OH)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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AEP AMERICAN ELECTRIC POWER®

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A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- Existing Plant Efficiency Gains
- Renewable Energy
  - 1400 MW wind
  - 300+ MW hydro
- Domestic Offsets
  - Over 63MM trees planted = 1.2MM tons of CO_2 uptake
- International Offsets
  - 1MM tons of forest carbon sequestered through 2009
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
– **2003-2010: 50 MMT+ Total**

New Additions (by 2012)

- 2000 MW Wind PPAs
- Domestic Offsets
  - Methane, Forestry
- Fleet Vehicle/Aviation Offsets
- Energy Efficiency & DSM
- Biomass Co-firing
- New Technology
  - New Generation: Ultra Super Critical Coal
  - Carbon Capture and Storage (CCS) for existing fleet
    - Chilled Ammonia

AEP's reductions/offsets of CO_2:
– **2011+: 5 MMT/yr**

AEP AMERICAN ELECTRIC POWER®

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service		
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	In-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

Captured CO_2 first time on 09/01/09; Injected CO_2 first time on 10/1/2009

Mountaineer Plant (WV) → **Chilled Ammonia 20MWe scale (Alstom)**

CO_2 Storage (Battelle)

2 injection wells & 3 monitoring wells

Captures and Stores ~100,000 metric tons of CO_2 /yr.

Phase 2

Awarded $334MM DOE Funding; Expected Commercial Operation: 2015

Mountaineer Plant (WV) → **Chilled Ammonia ~235MWe scale (Alstom)**

CO_2 Storage

Captures and Stores 1.5 Million metric tons of CO_2/yr, 1.5 miles below the surface

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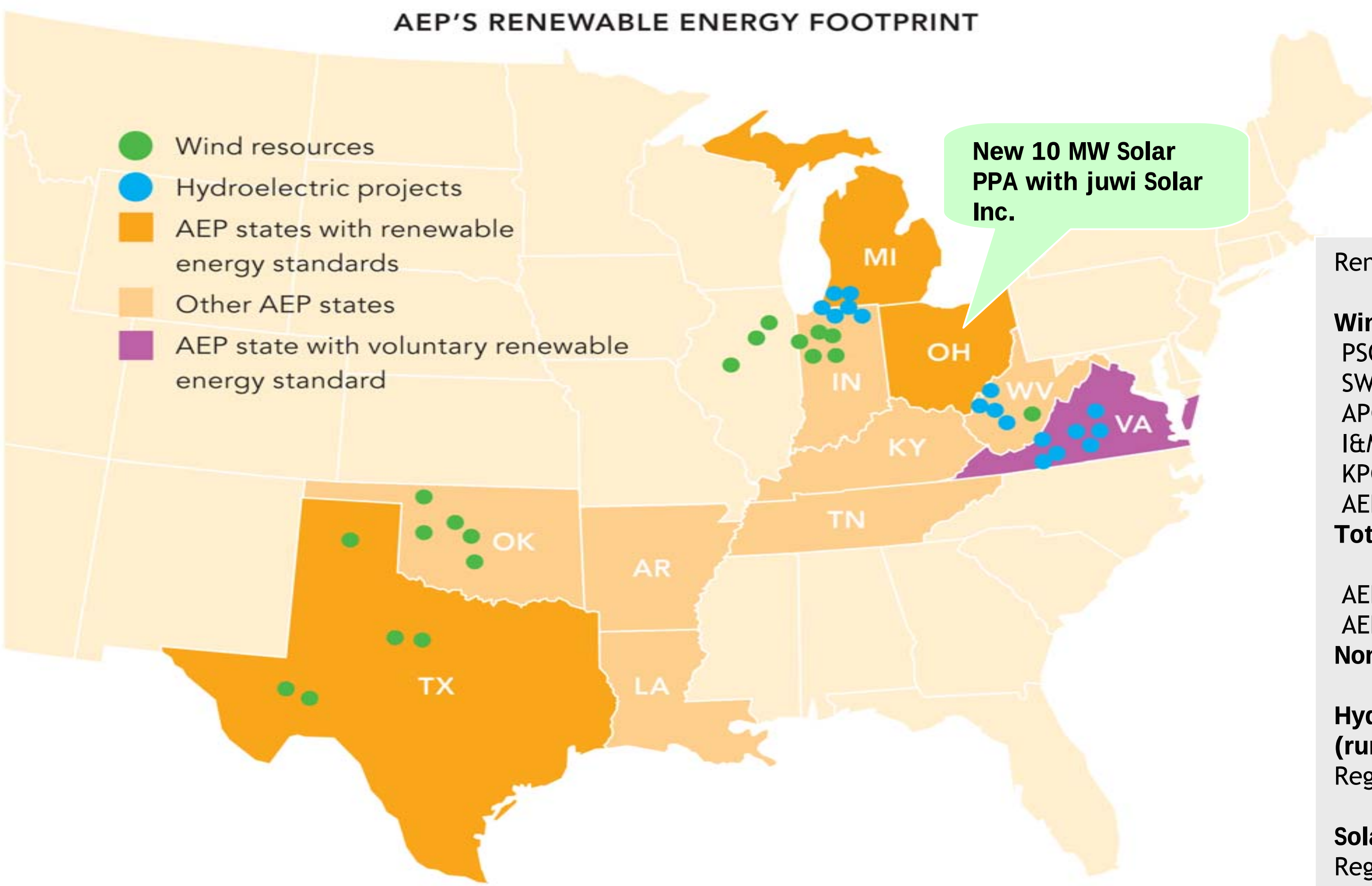
AEP Renewable Footprint



Renewables Portfolio*

Wind		
PSO - 5 PPAs		591MW
SWEPCo - 1 PPA		79MW
APCo - 4 PPAs		376MW
I&M - 2 PPAs		150MW
KPCo - 1 PPA		100MW
AEP Ohio - 2 PPAs		110MW
Total Regulated		**1406MW**
AEPEP -	owned	311MW
AEPEP -	2 PPAs	177MW
Non-regulated		**487 MW**
Hydro (run-of-river)		
Regulated - owned / PPA		**364MW**
Solar		
Regulated - PPA		**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

AEP AMERICAN ELECTRIC POWER®

New Generation Projects

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

John W. Turk Jr. Ultra-Supercritical Coal Plant

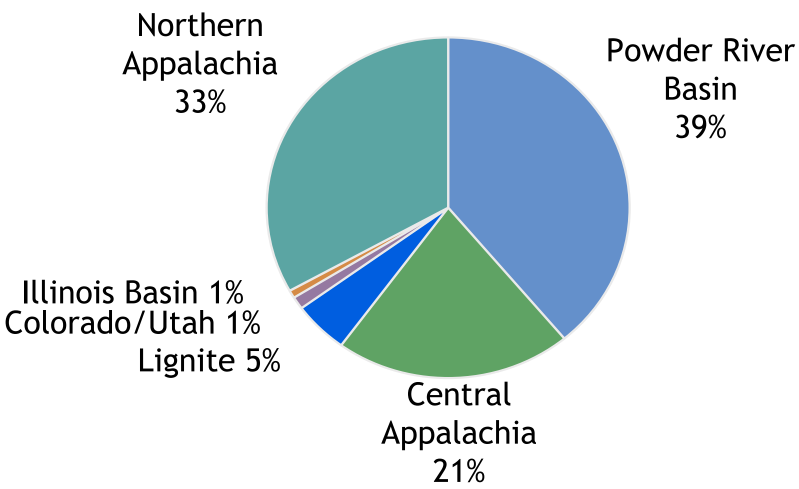
J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $378 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

AEP AMERICAN® ELECTRIC POWER

Coal Procurement – 2010 Projected

Total AEP System



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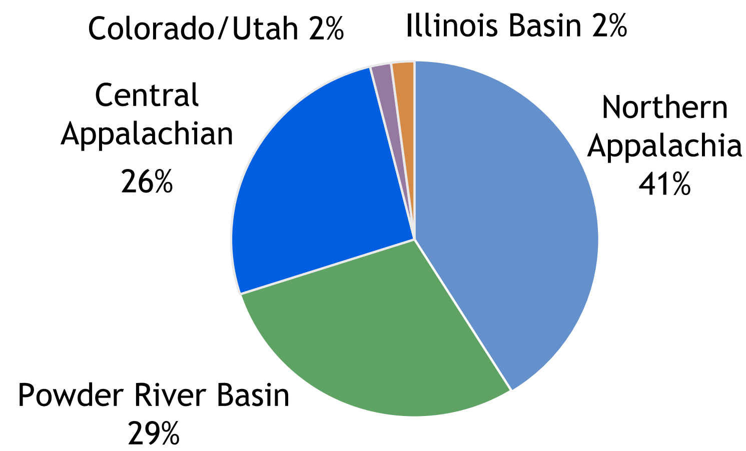
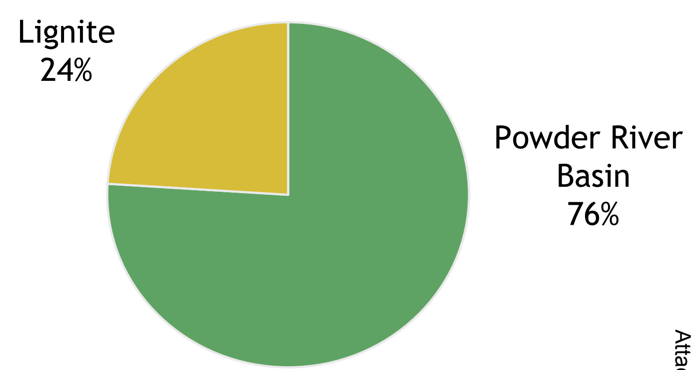


AEP West



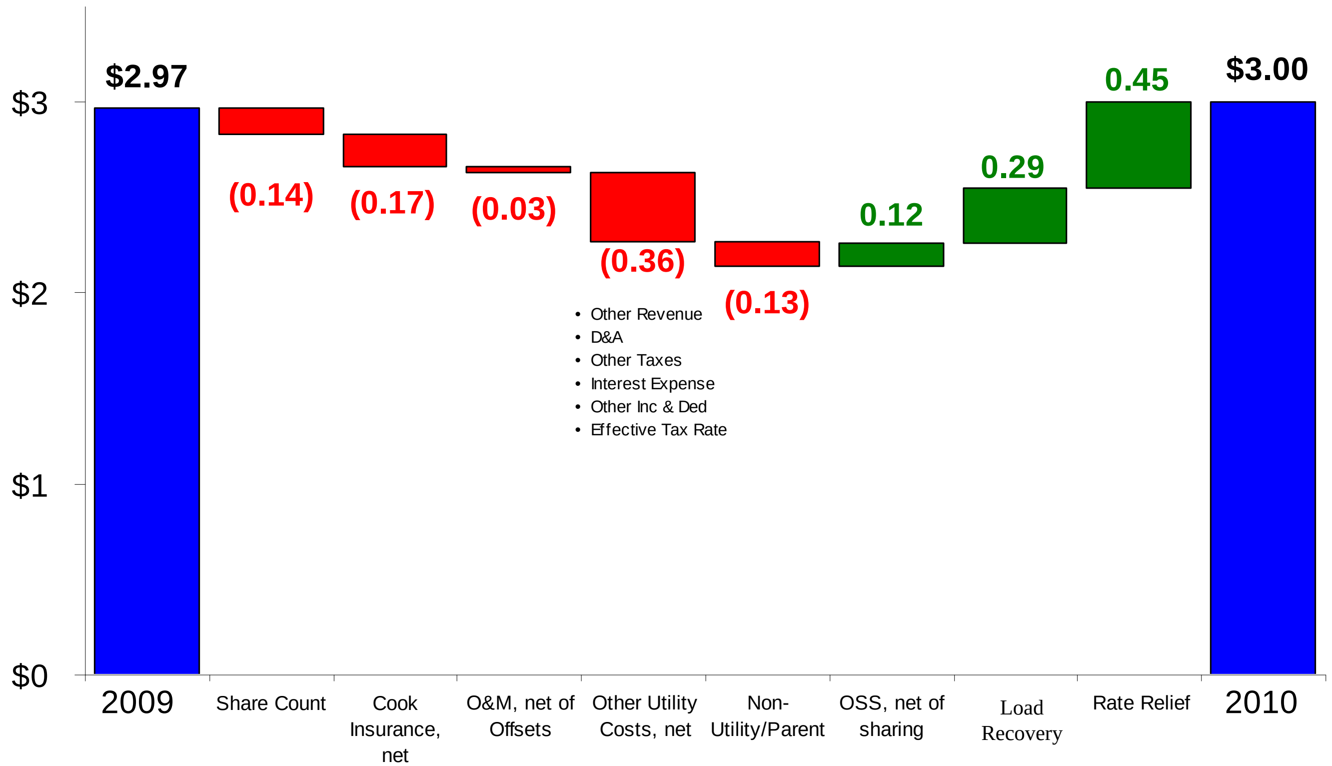
Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

AEP AMERICAN® ELECTRIC POWER

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



AMERICAN® ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

AEP AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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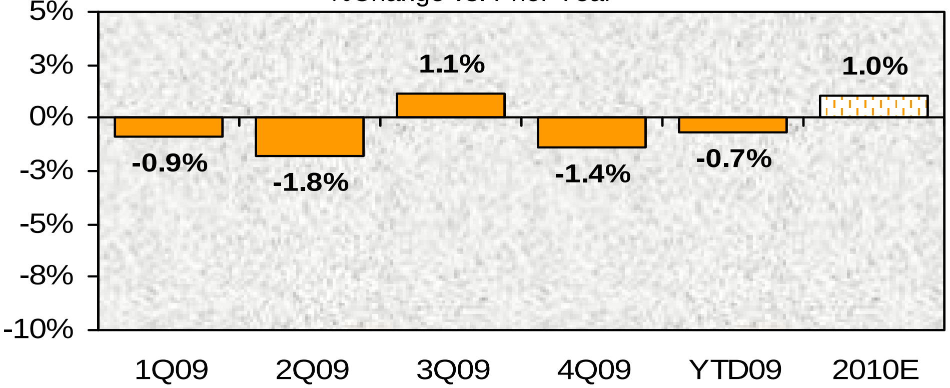
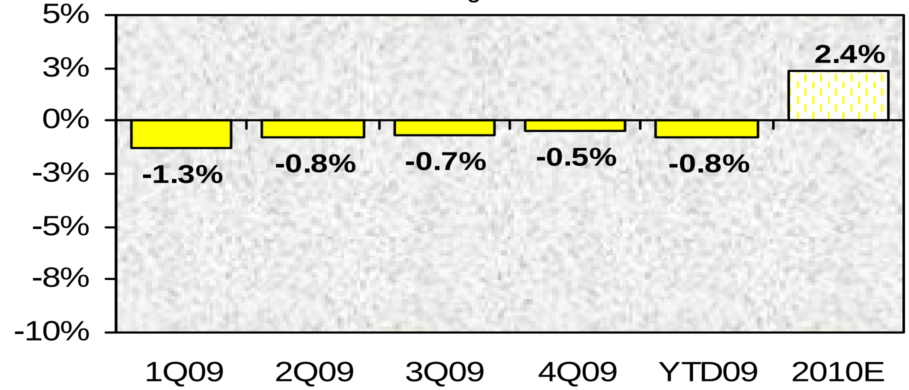
Normalized Load Trends

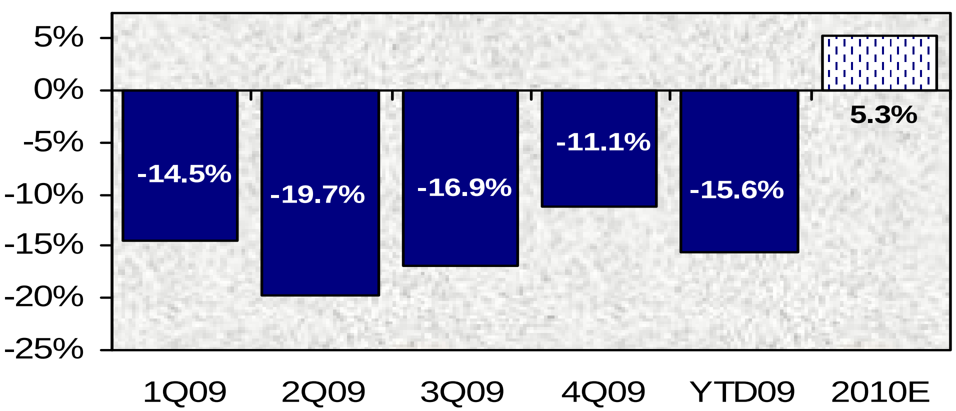
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



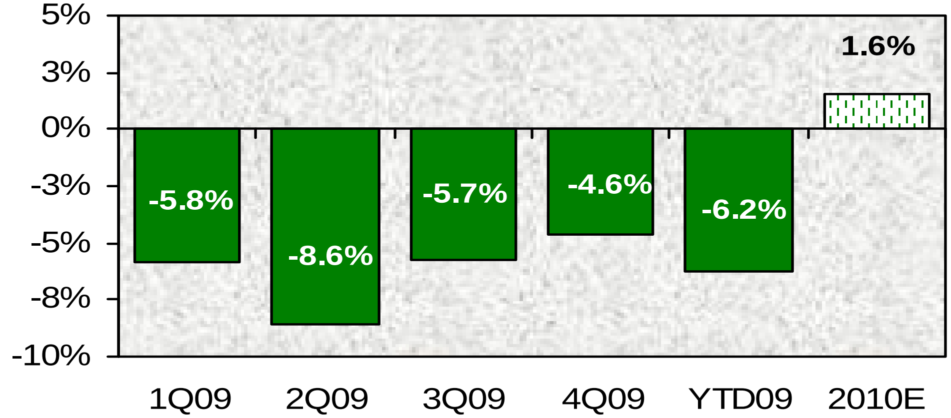
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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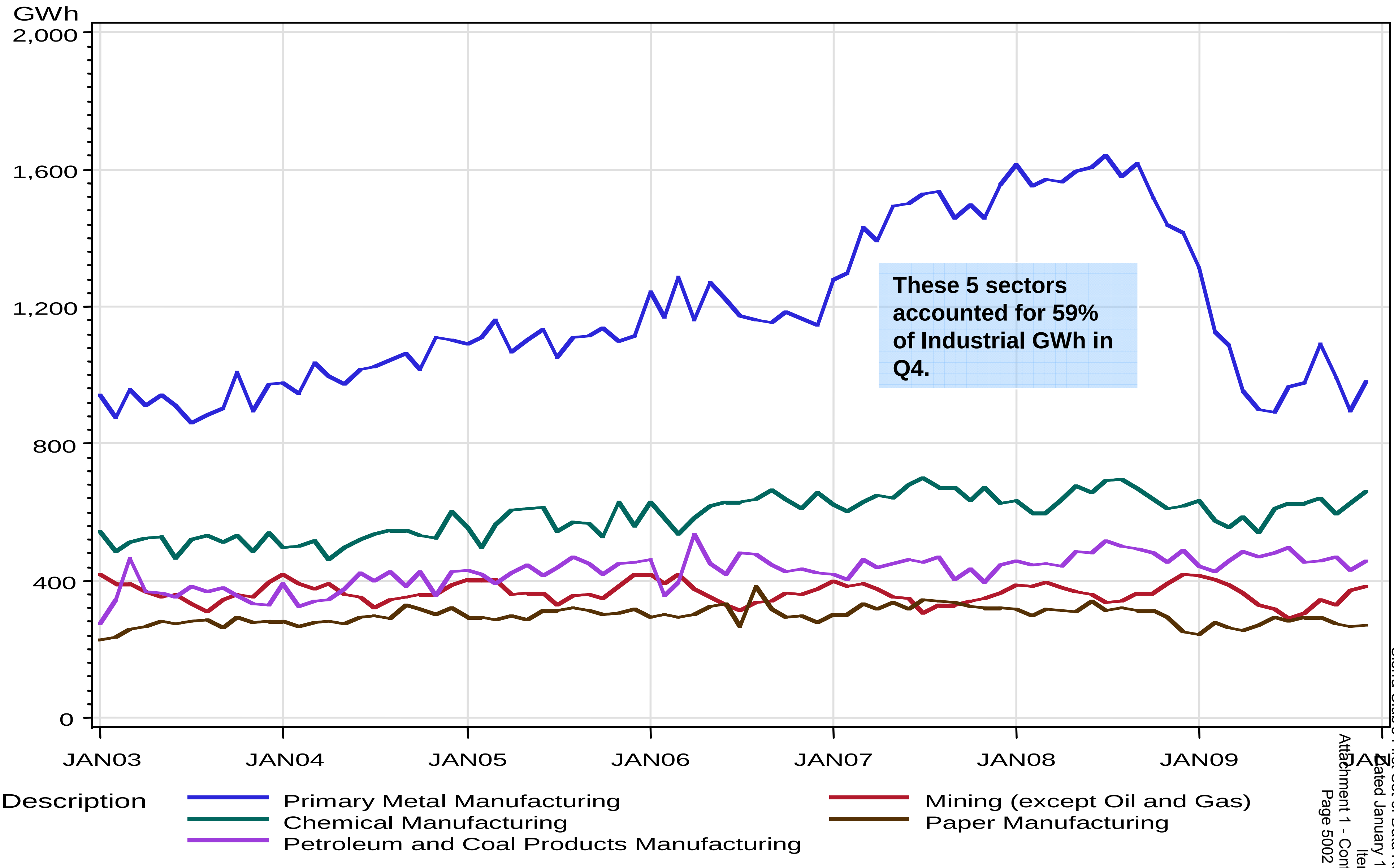
Industrial Sales Volumes



Additional 2010 Earnings Drivers

O&M Assumptions

- **$23MM increase over 2009, net of revenue offsets**
- **Includes $80MM increase in employee and operational expenses**

Rate Relief Assumptions

- **$320MM, net of trackers**
- **$167MM secured**
  - **AR, OH, OK, VA, WV**
- **Active or pending rate cases include KY, MI, TX, VA, WV and others**

AEP AMERICAN® ELECTRIC POWER

KPSC Case No. 2011-00401
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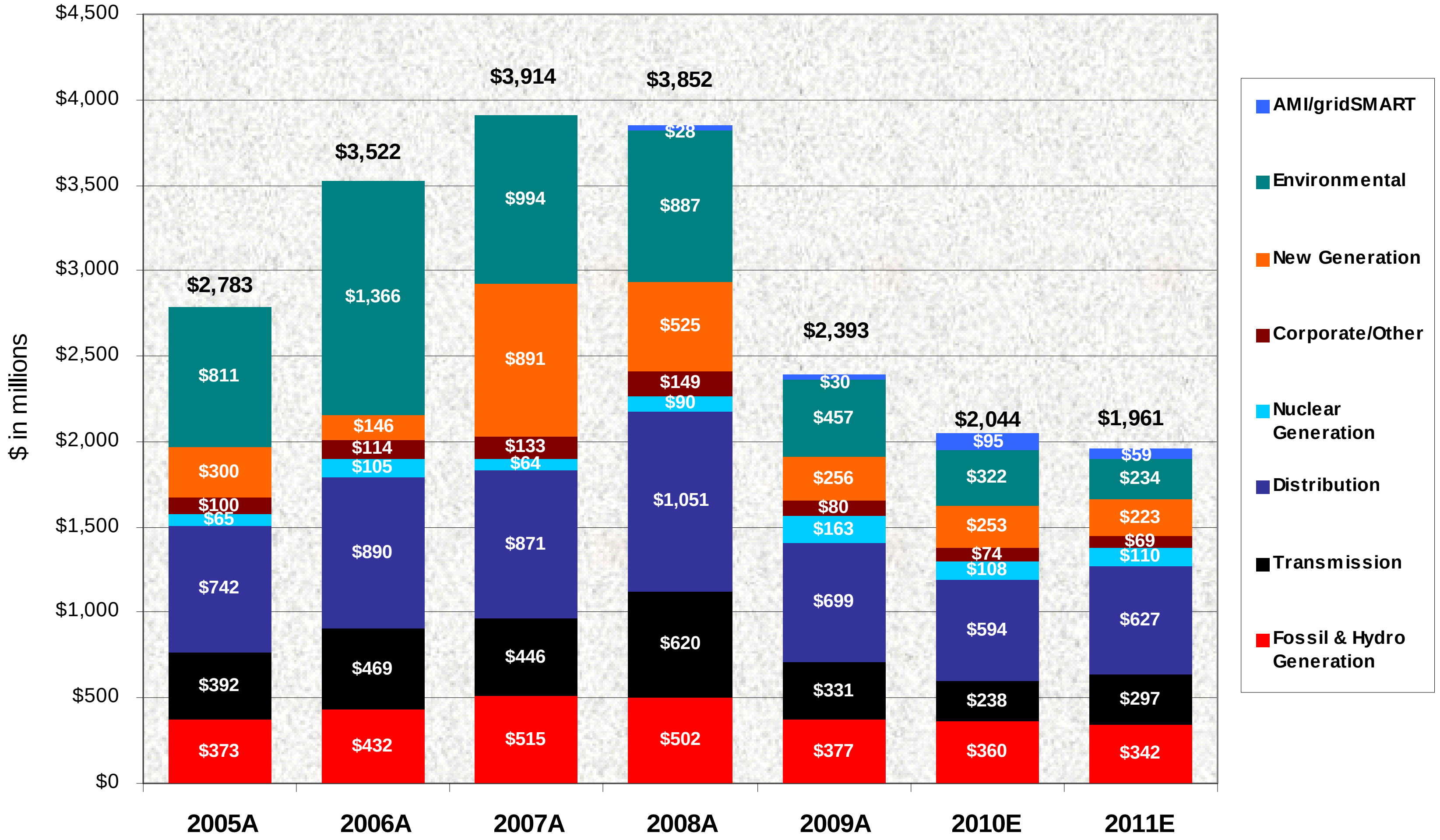
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

AEP AMERICAN ELECTRIC POWER®

Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

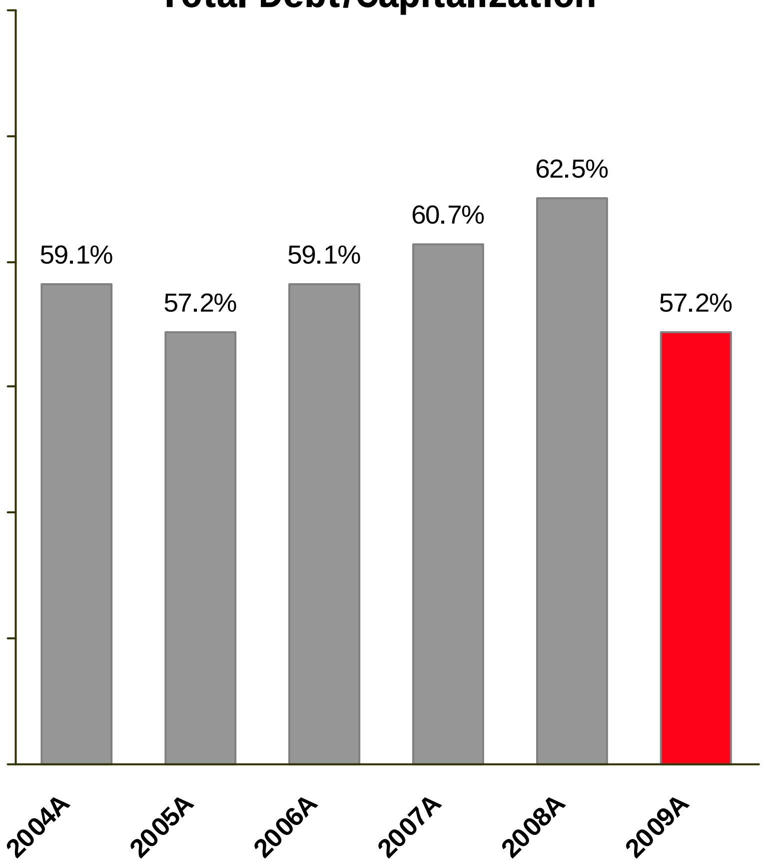
AEP AMERICAN ELECTRIC POWER®

Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Capitalization & Liquidity

Total Debt/Capitalization



Note: *Total Debt is calculated according to GAAP and includes securitized debt*

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AEP AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

Year		2010		2011		2012
AEP, Inc.	$	-	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	195
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	680	$	-	$	-
Public Service of Oklahoma	$	-	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company[(1)]	$	-	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,030	$	623	$	565

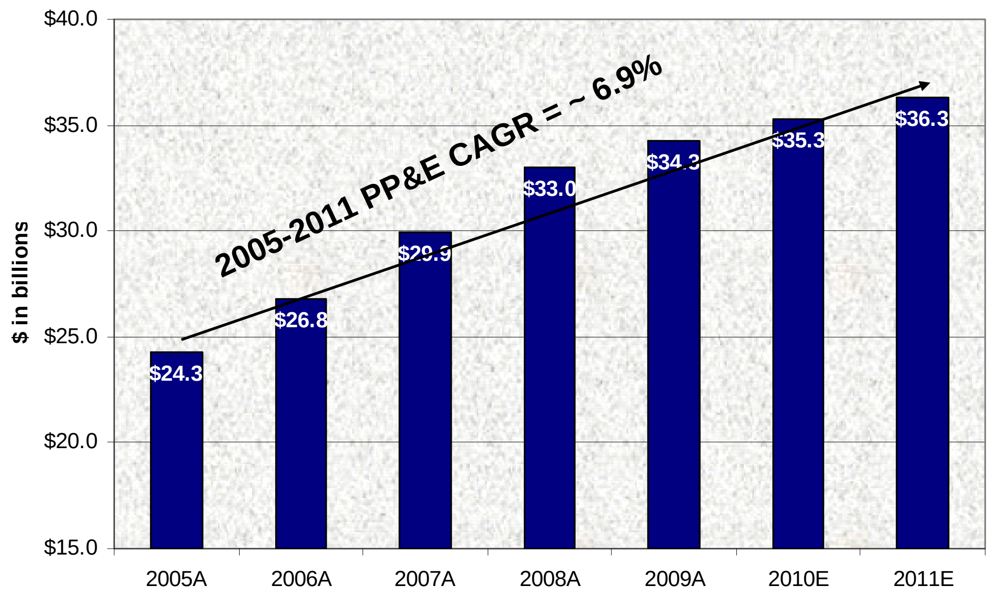
(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)

Data as of March 30, 2010

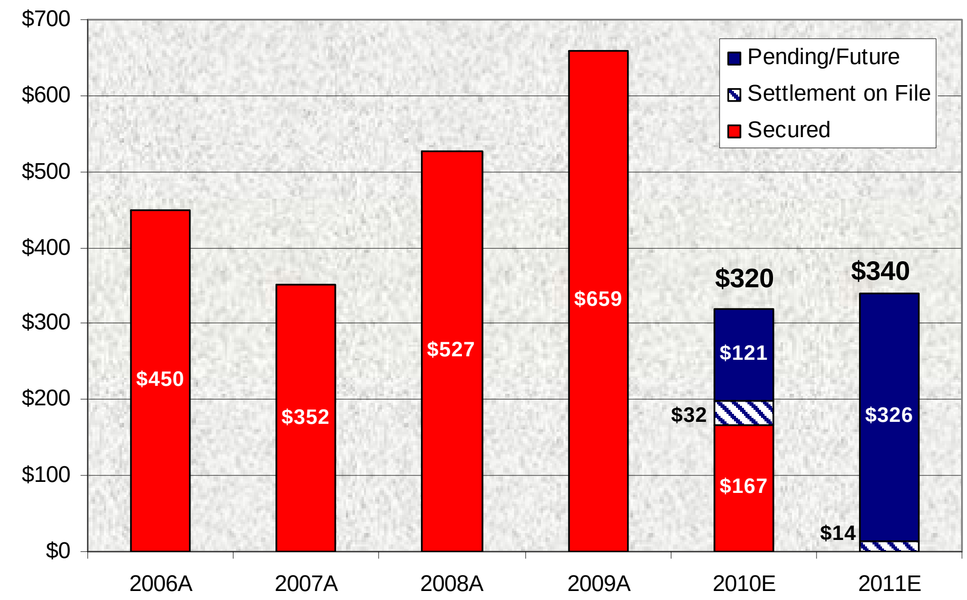
AMERICAN ELECTRIC POWER

Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Settlement on file relates to SWEPCO Texas rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

AMERICAN ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

AEP AMERICAN® ELECTRIC POWER

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company: AEP Appalachian Transmission Company Inc., AEP West Virginia Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company inc., AEP Oklahoma Transmission Company Inc., and AEP Southwestern Transmission Company Inc.
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filing made in Ohio
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

AEP AMERICAN ELECTRIC POWER®

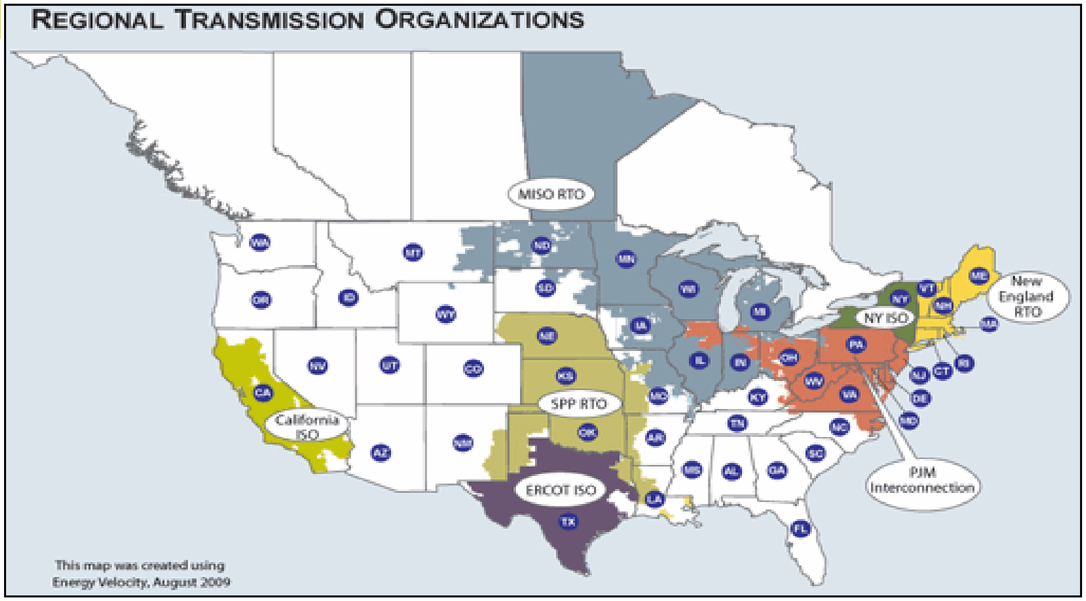
JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2017	**PATH-WV** COD: 2014	**Pioneer** COD: 2015
110 miles of 765 kV *Partners: Westar (50%) & Electric Transmission America (50%)* *Estimated Cost: $400 million* *ROE: 12.8%*	*345 kV ERCOT Expansion* *Partner: MidAmerican Energy (50%)* *Estimated Cost: $1.4 billion* *ROE: 9.96%*	*275 miles of 765 kV* *Partner: Allegheny Energy (50%)* *Estimated Cost: $1.2 billion* *ROE: 14.3%*	*240 miles of 765 kV* *Partner: Duke Energy (50%)* *Estimated Cost: $1 billion* *ROE: 12.54%*

Tallgrass COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
Regional Expansion of 765 kV Backbone	*Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	*Regional Expansion of 765 kV, 500 kV and 345 kV systems*	*700 miles of Proposed 765 kV*

AEP AMERICAN® ELECTRIC POWER

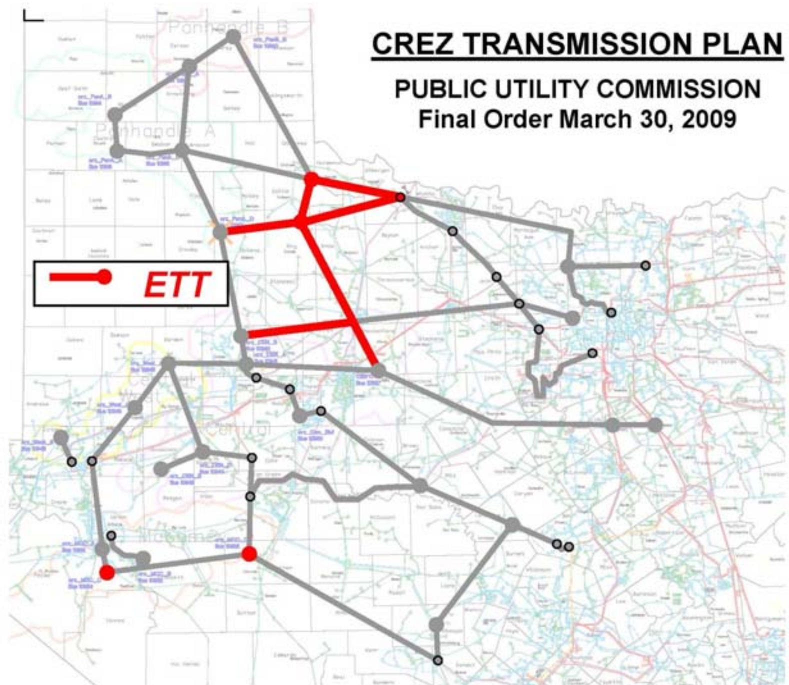
Electric Transmission Texas, LLC

Overview:

- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

- **Opportunities:**
  - Projects in service 2010-2017: $1.4 billion
  - CREZ projects in service 2012-2013: $1.1 billion
  - Other projects pending transfer in service 2010-2013: $600 million

- **Next Steps:**
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT
Electric Transmission Texas

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EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

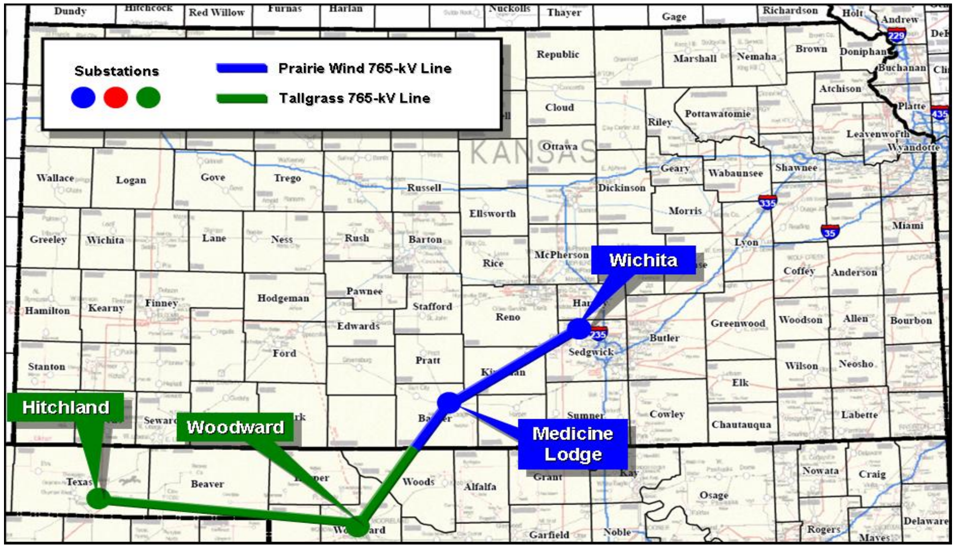
PATH
Potomac-Appalachian Transmission Highline

AEP AMERICAN® ELECTRIC POWER

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP’s ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

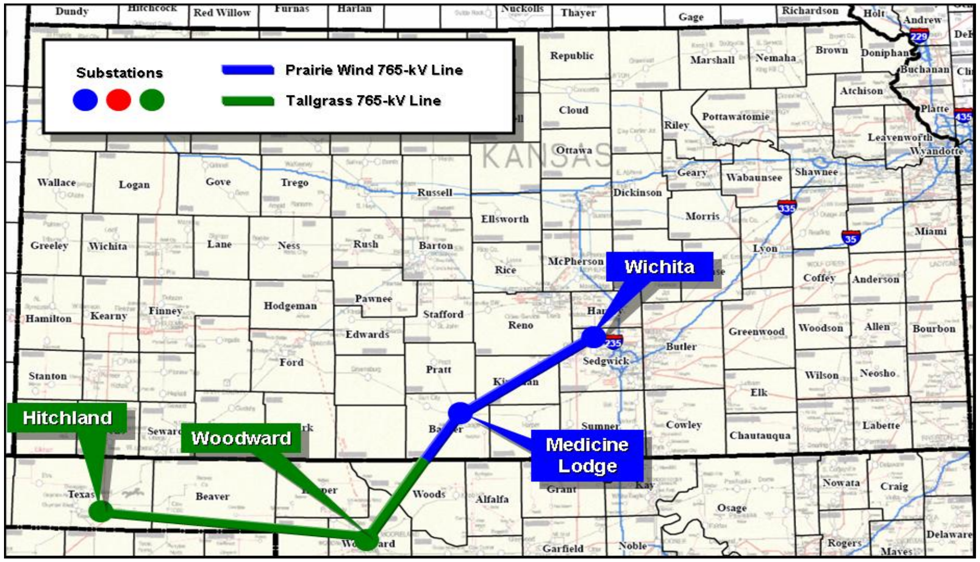
- RTO Approval
- Siting

AEP AMERICAN ELECTRIC POWER

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

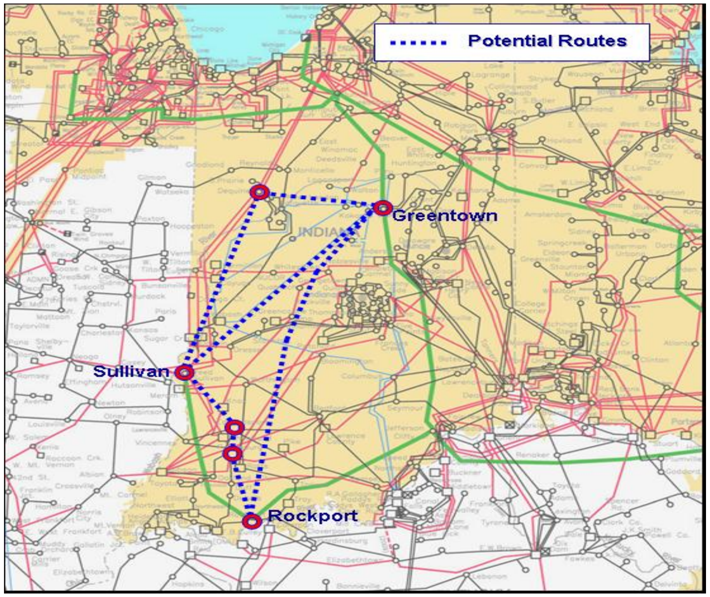
- RTO Approval
- Siting

AEP AMERICAN® ELECTRIC POWER

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

AMERICAN ELECTRIC POWER

Upper Midwest EHV Development—SMART Study

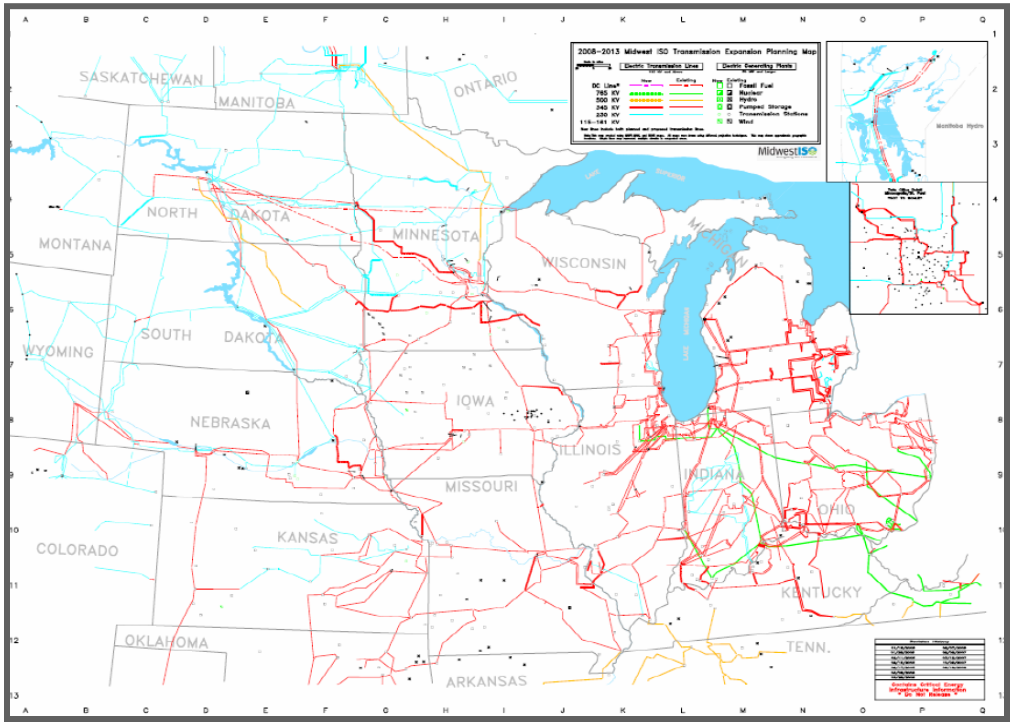
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2Q2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

AEP AMERICAN ELECTRIC POWER

Deutsche Bank
2005 Electric Power Conference

June 14, 2005
The Pierre Hotel
New York, NY

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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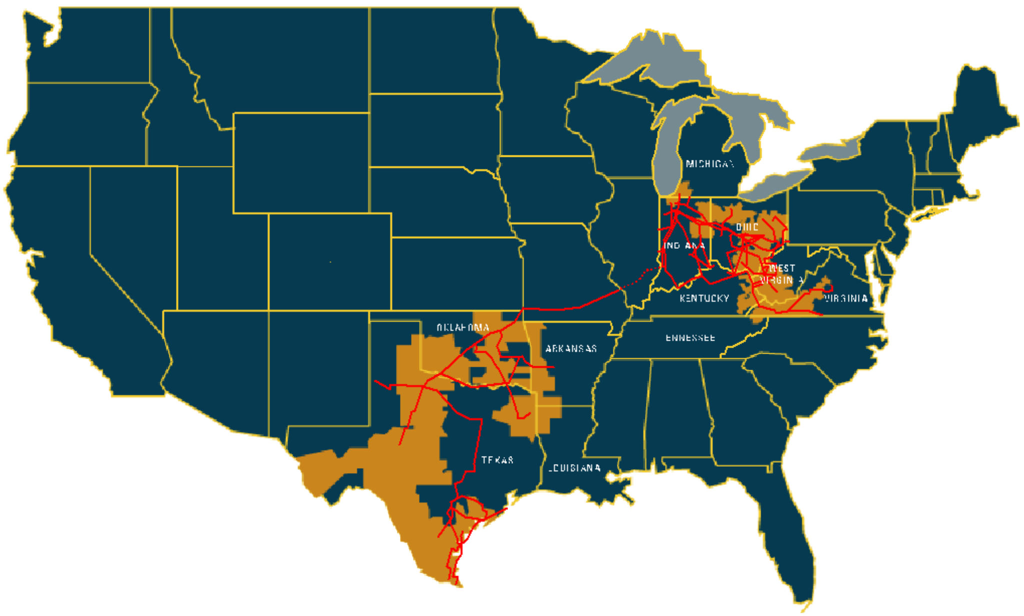
3

Asset Portfolio

Strength & Scale in Assets & Operations



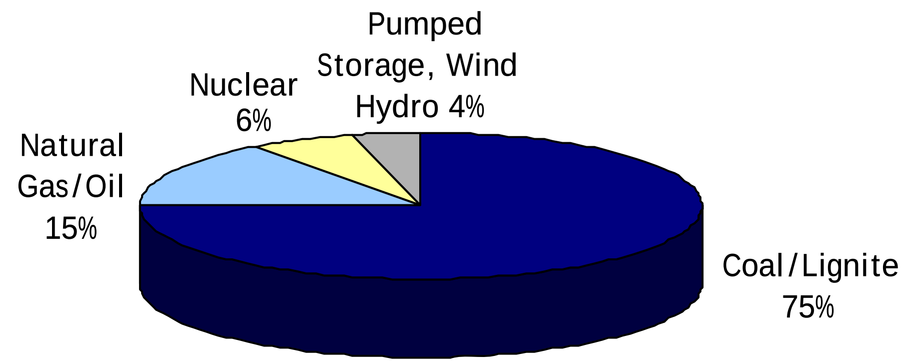
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

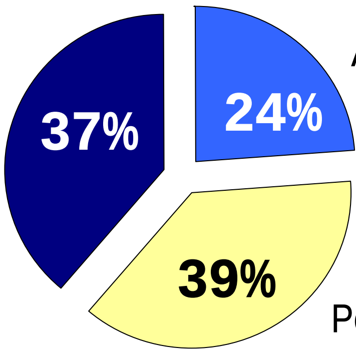
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Coal Procurement

AEP SYSTEM

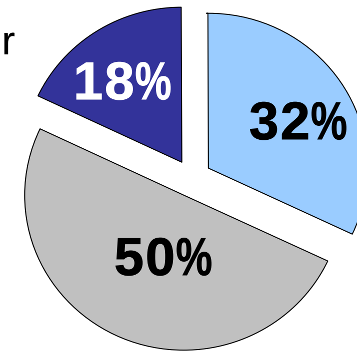


Coal Supply

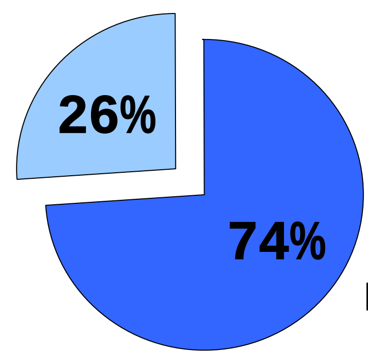
(on average)

- ➢Purchase 75 MM tons per year
- ➢Avg. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM

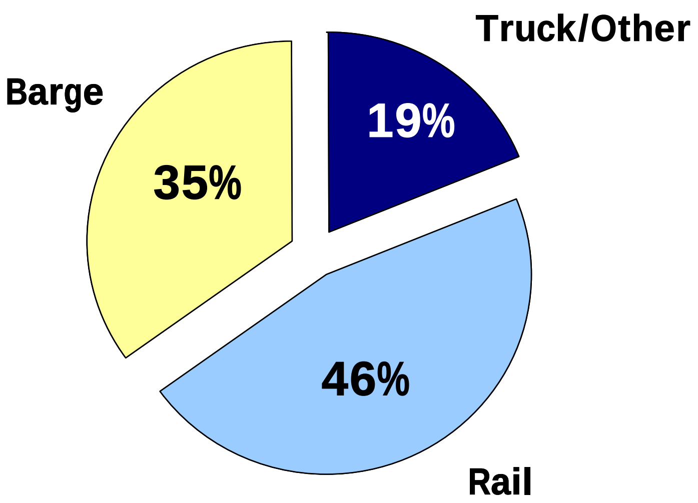


WESTERN SYSTEM



Coal Delivery Mix

DELIVERY MODE DIVERSITY
25 GW coal capacity



AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

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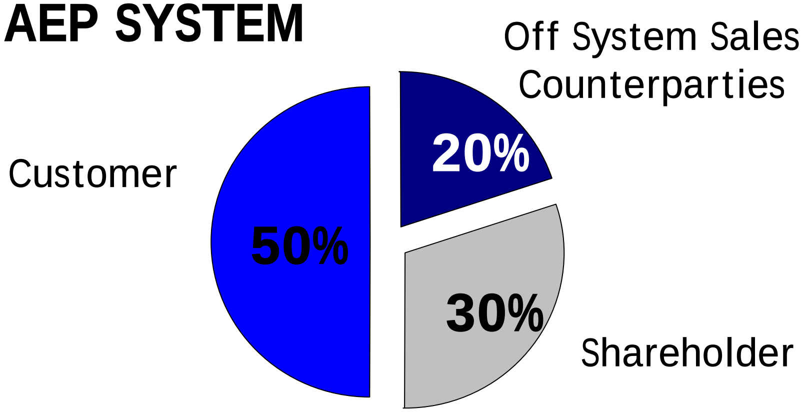
Fuel Recovery

AEP SYSTEM

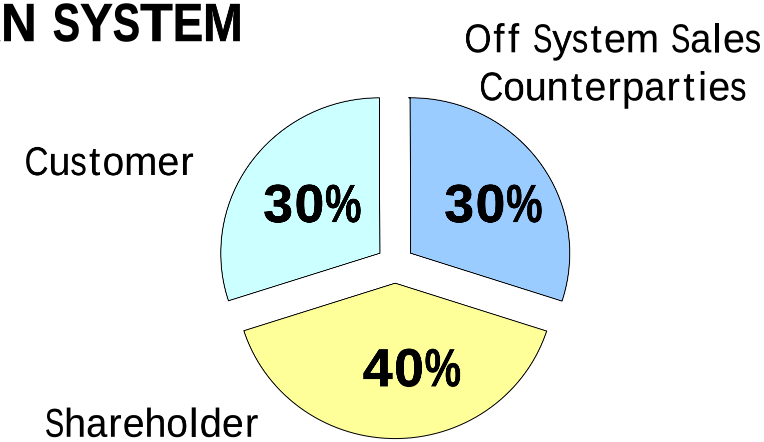


Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



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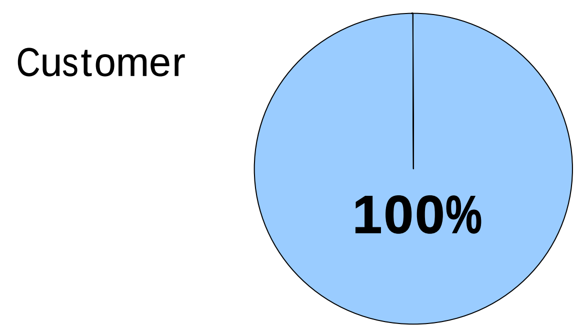
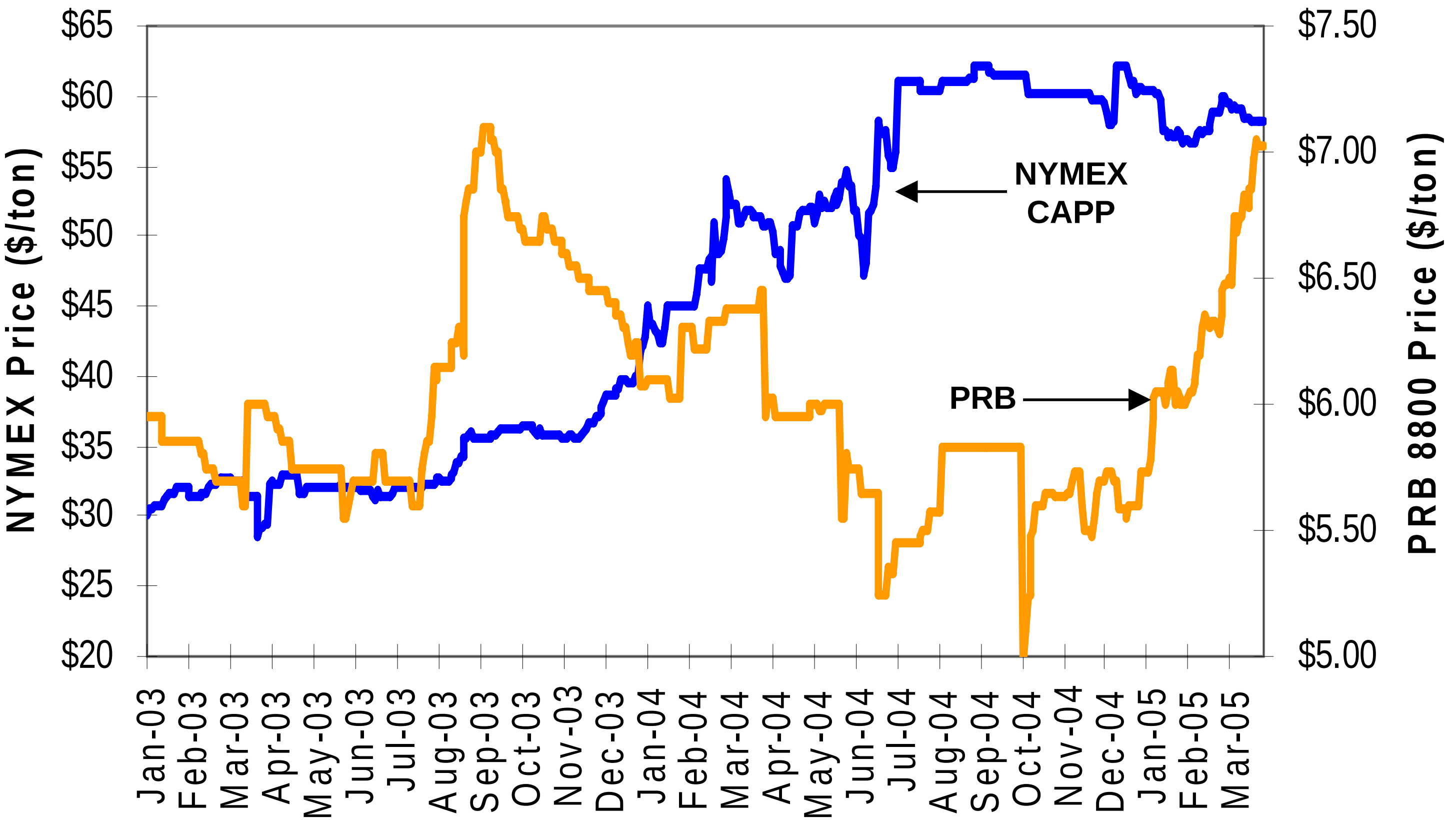


Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



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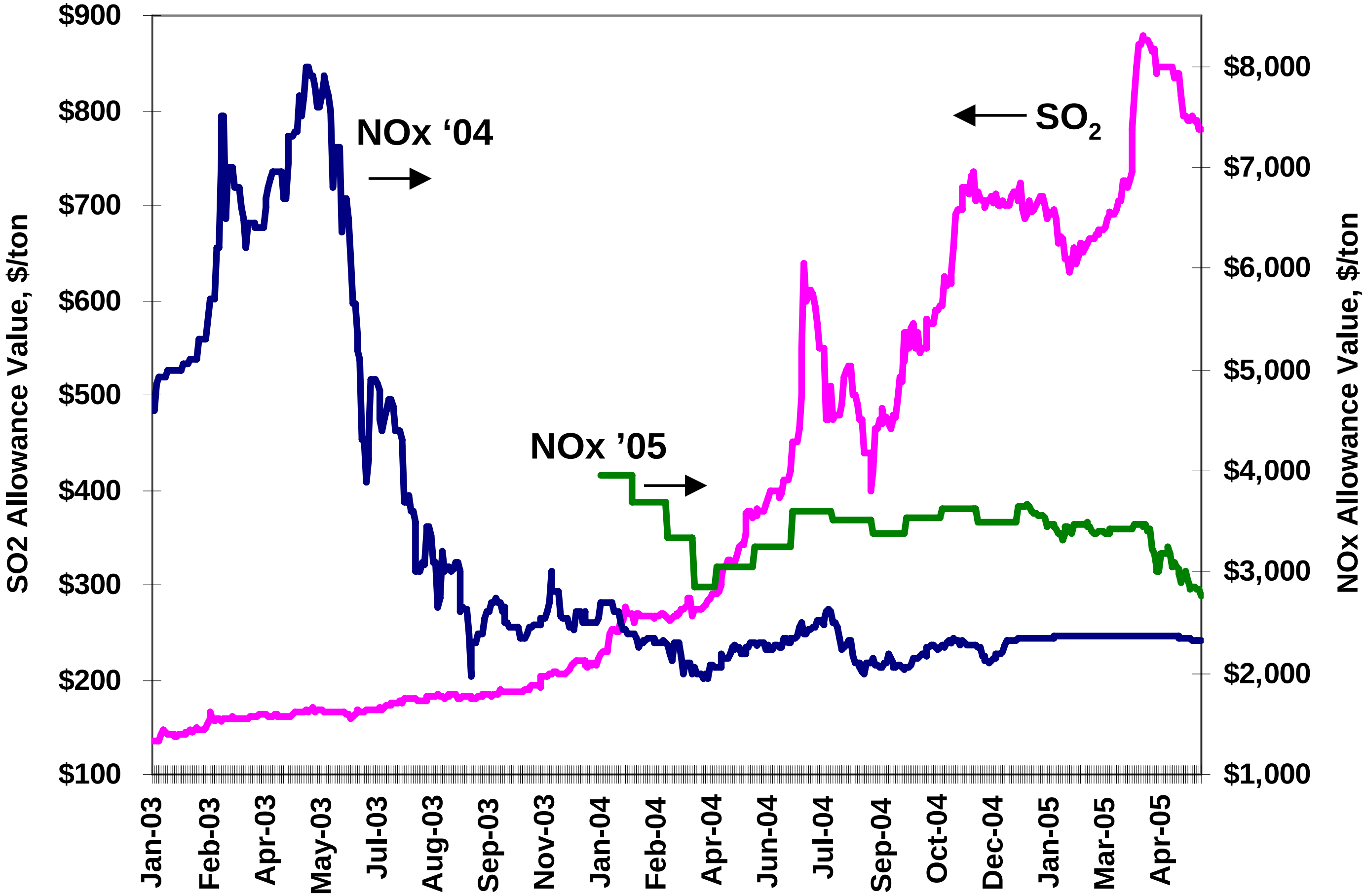
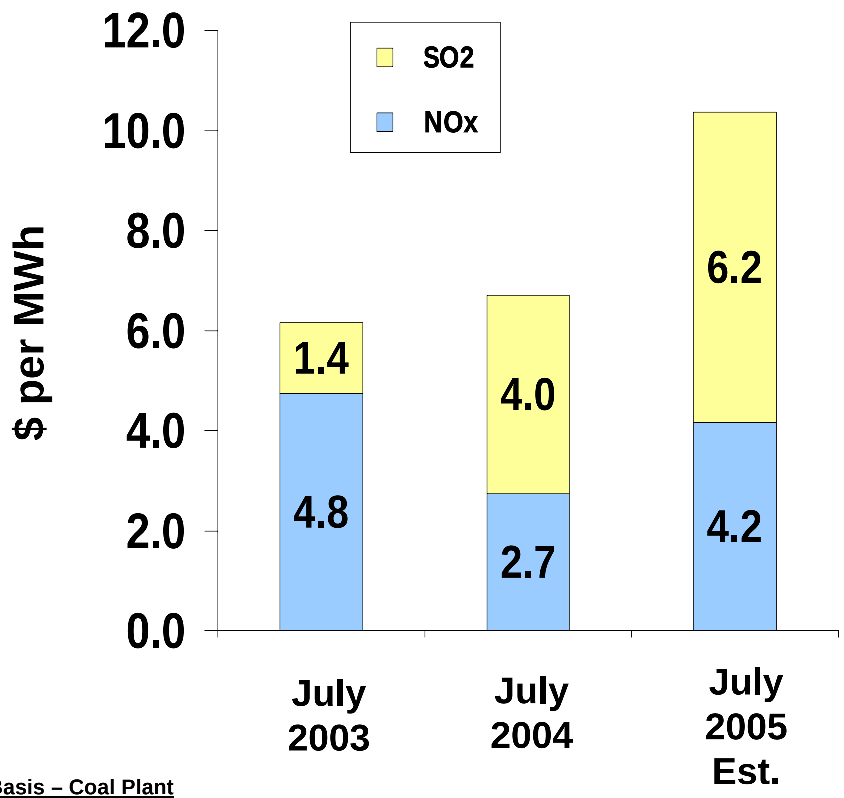
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



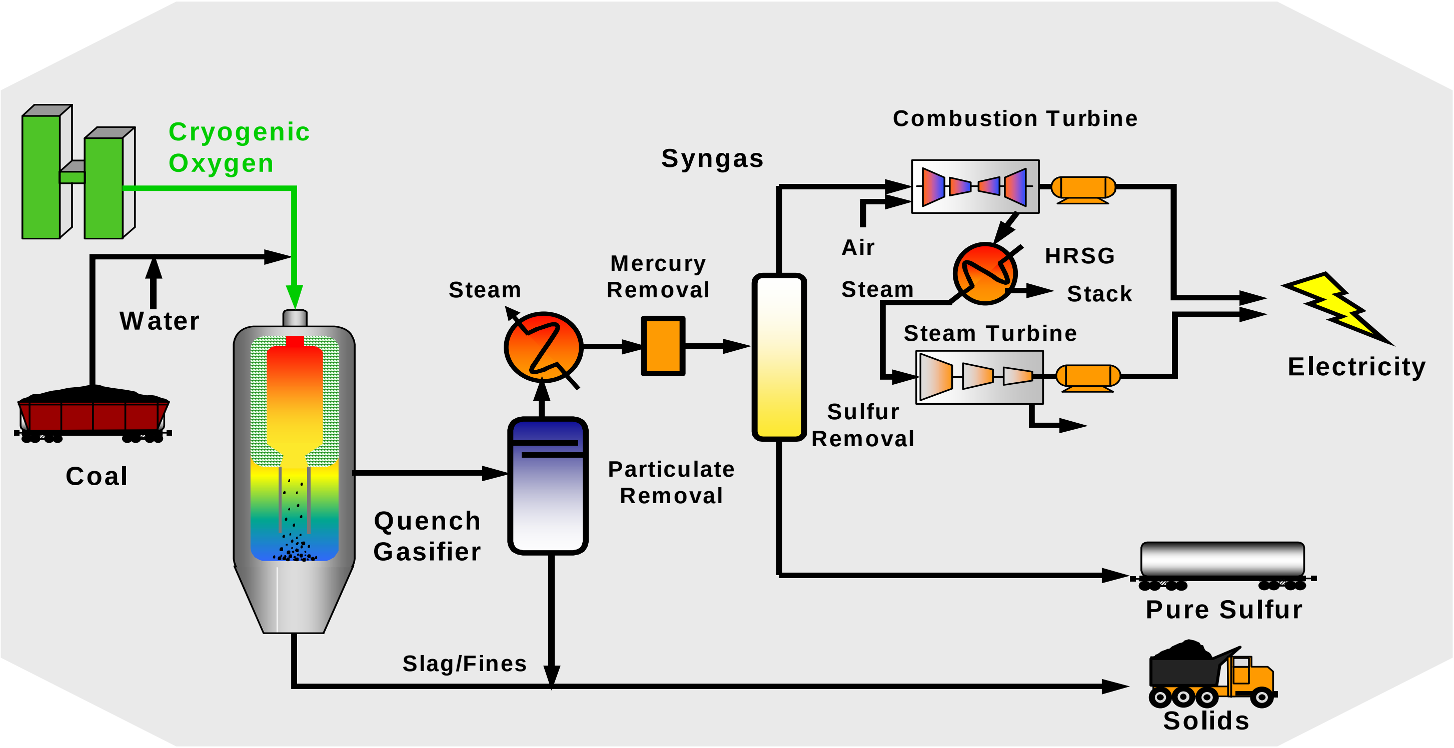
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B as of YE 2004)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

AEP®

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**530**
Heat Rate (BTU/kWh)	**8700**	**8600**	**7200**
EPC cost* ($/kW)	**1290**	**1350**	**440**
Total Plant cost ($/kW)**	**1490**	**1610**	**475**
Variable Production cost* ($/MWh)**	**15**	**14**	**38**
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	**47**	**50**	**57**
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	**76**	**70**	**91**

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- **Air** – to evaluate best available control technology (BACT)
- **Wastewater** – to understand wastewater streams
- **US COE** (Corp of Engineers) – to obtain permits for construction of river facilities
- **NEPA Process** – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

<u>2005</u>

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

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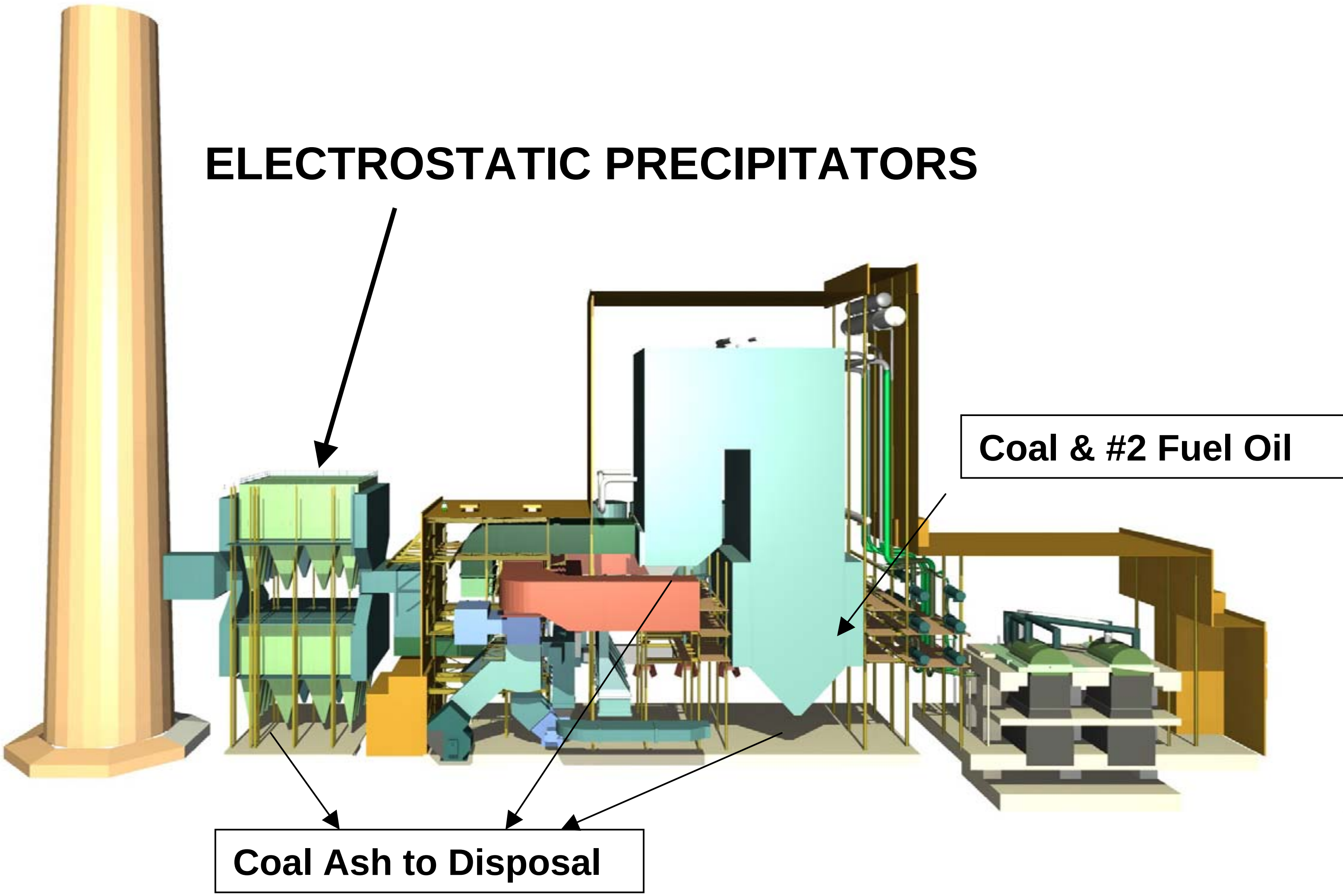
Mercury Rule

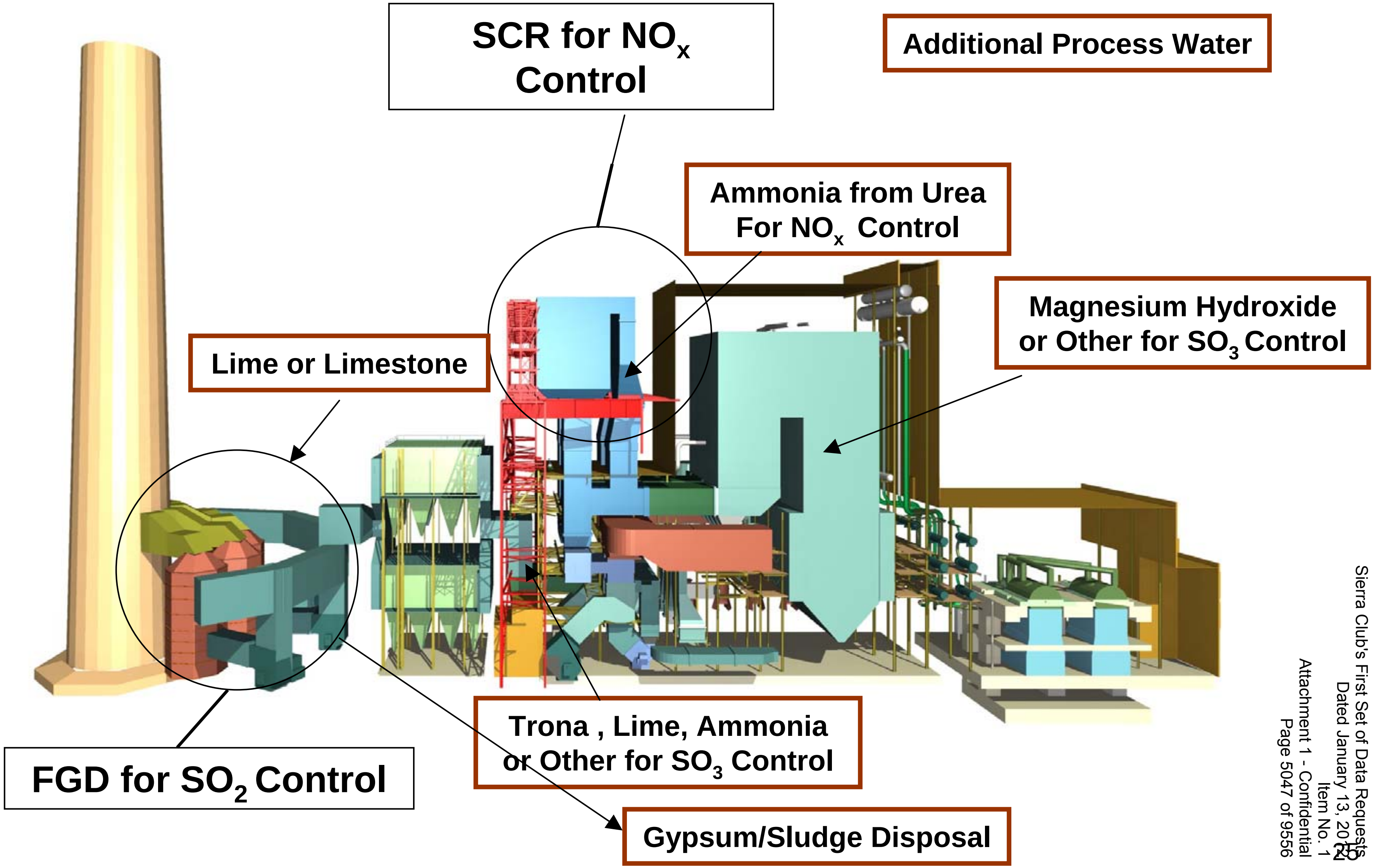
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

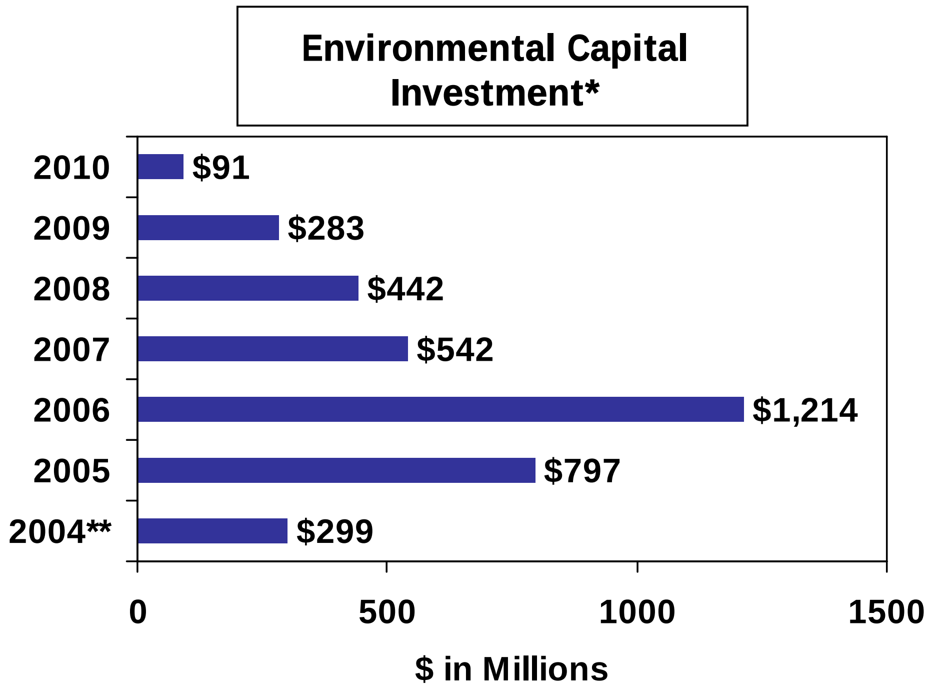
Pulverized Coal Unit as Built in 1970s



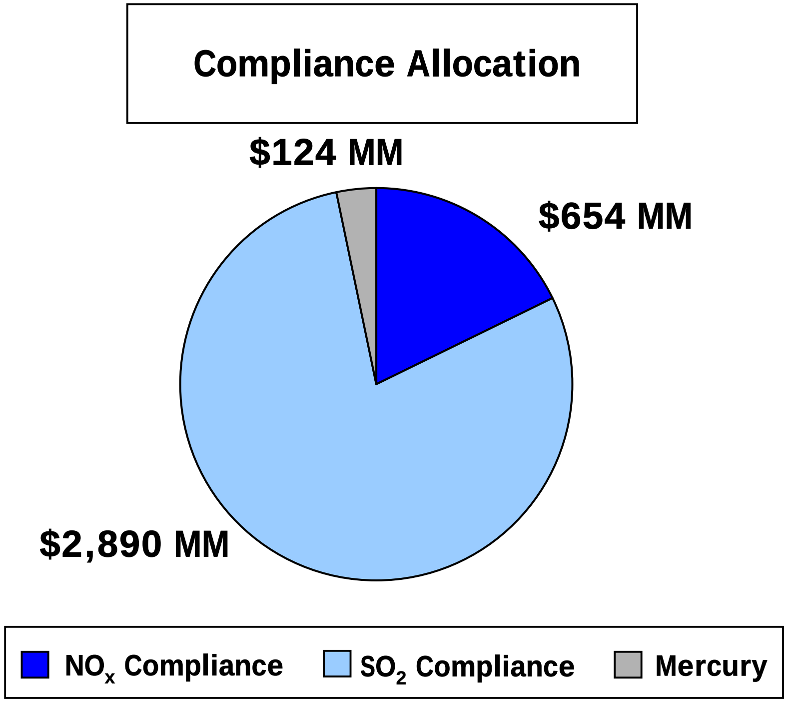
Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



Environmental Investment: $3.7 Billion Through 2010



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004



Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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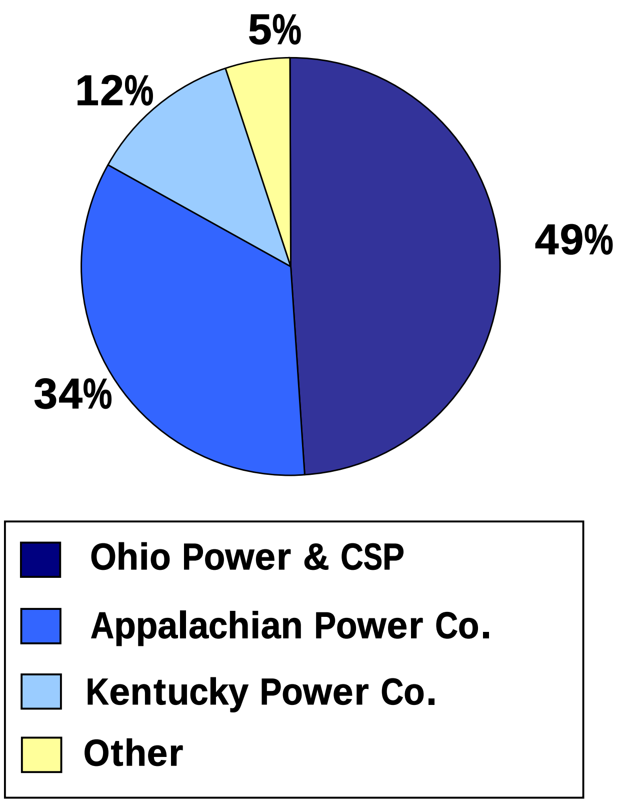
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD

SCR

Completed

FGD:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD: **2006 - 2010**

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

SCR: **2005 - 2007**

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, Hearings scheduled to begin 8-8-05.

West Virginia (Regulated)
- Base rates not frozen
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- No active fuel clause

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated) • SWEPCO-Texas retail competition delayed until at least 2007 • Bi-annual fuel clause adjustment opportunity **Texas (Restructured)** • TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) • TCC wires rate case order expected in June 2005. Settlement filed addressing final issue (affiliate transactions) will result in slight rate decrease with a positive earnings impact. • TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing issued in June 2005 updating rate case expenses. TCC will appeal decision. • TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC. • TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.	**Oklahoma (Regulated)** • On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval. • General rate case filed Oct. 31, 2003 On 5-2-05 the OCC issued an order approving a settlement agreement which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider. • 2001 Fuel review case Hearings scheduled for Sept. 2005. Scope expanded to cover 2002-2004 margin allocation issue. • 2003 Fuel review case Likely to include motions to expand scope to include prudence review
Louisiana (Regulated) • Base rates capped through June 15, 2005 • Currently under a merger required financial review • Fuel clause, adjusted monthly	**Arkansas (Regulated)** • Base rates not frozen • Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

Rate Stabilization Plan	Revenues 2005	Revenues 2006	Revenues 2007	Revenues 2008	Incremental Cash 2005	Incremental Cash 2006	Incremental Cash 2007	Incremental Cash 2008
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

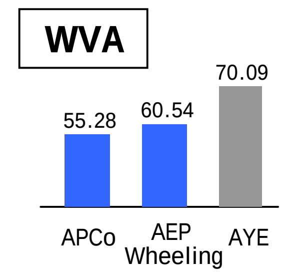
* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

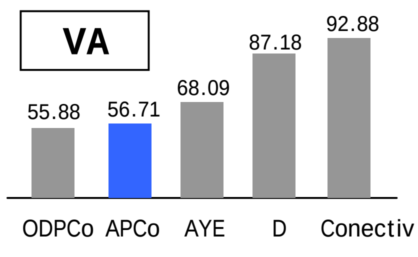
** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

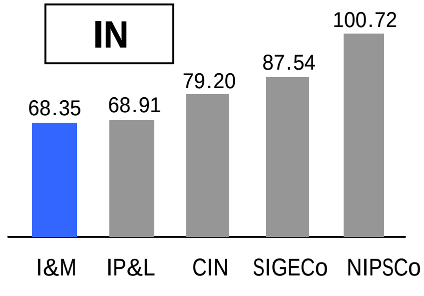
AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

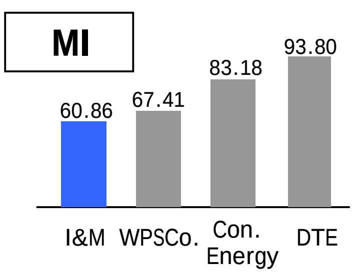
AEP: The Low Cost Provider

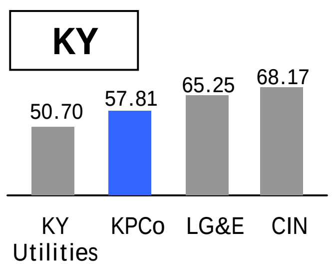
Regulated Rates

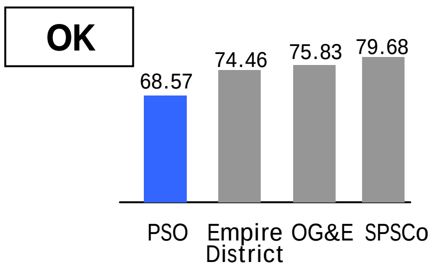


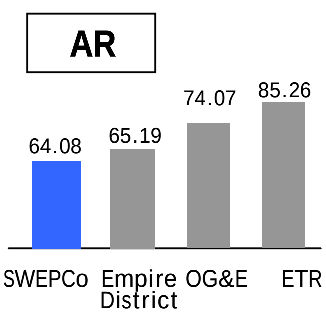


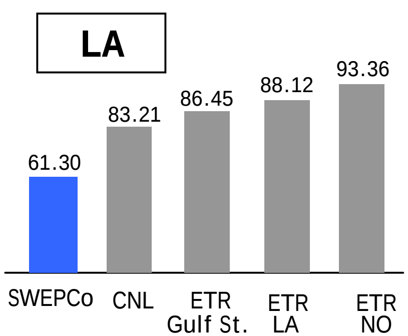


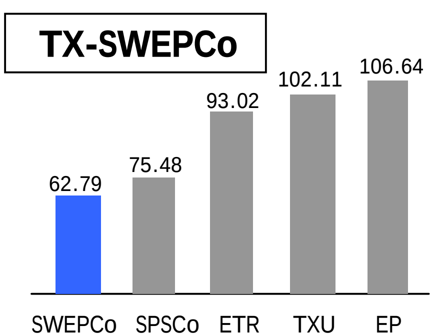




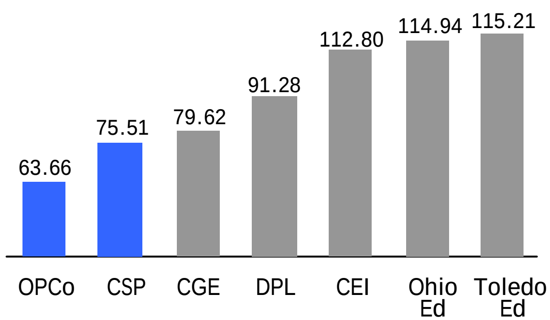








Unregulated Rates



OH (POLR bundled residential rates)

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

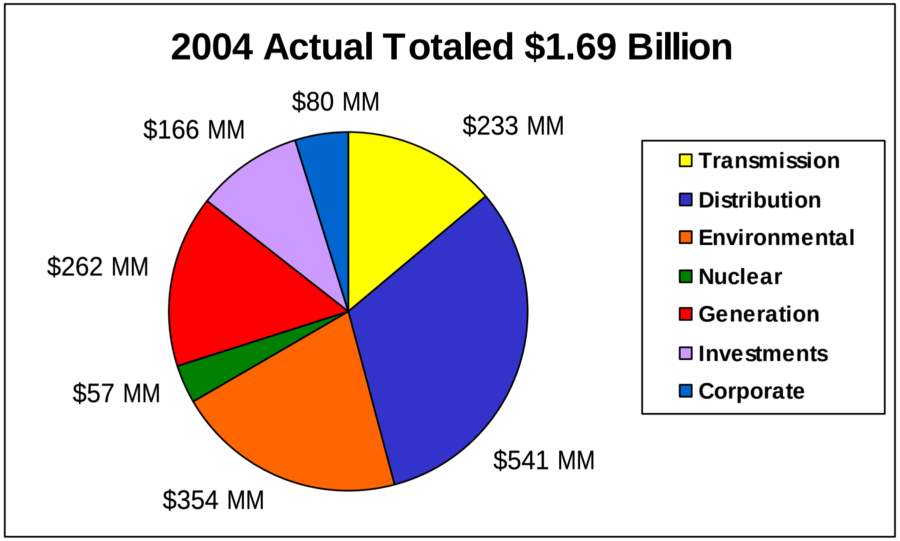
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

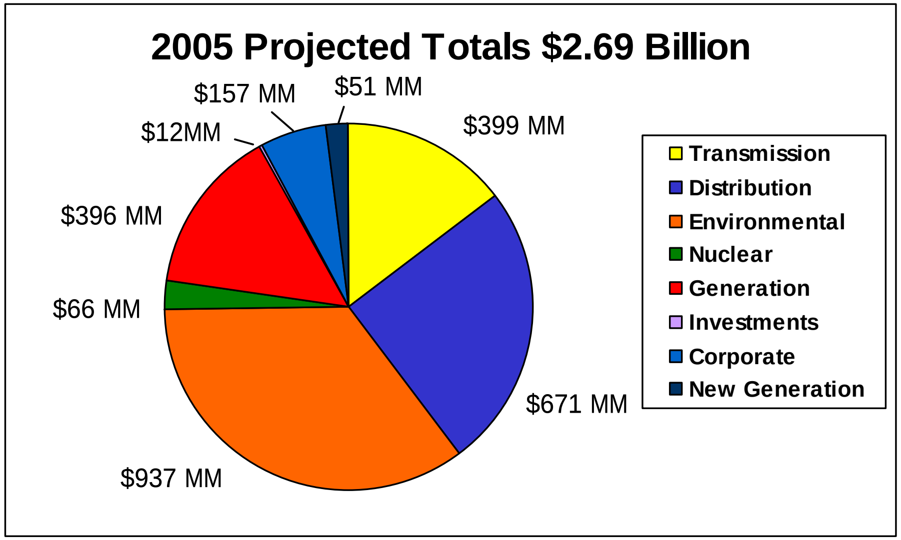
***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex



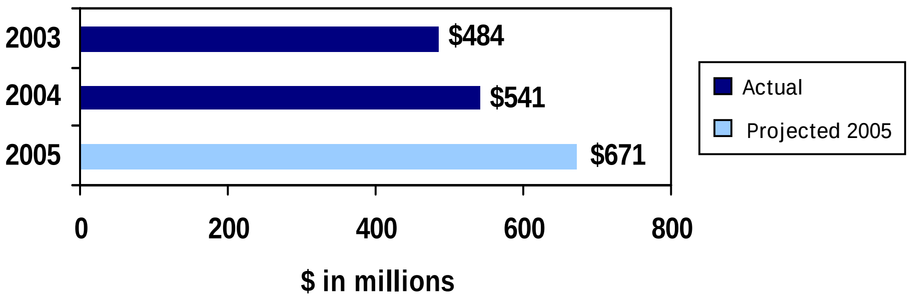
2004 Actual Totaled $1.69 Billion
$80 MM
$233 MM
$166 MM
$262 MM
$57 MM
$354 MM
$541 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate



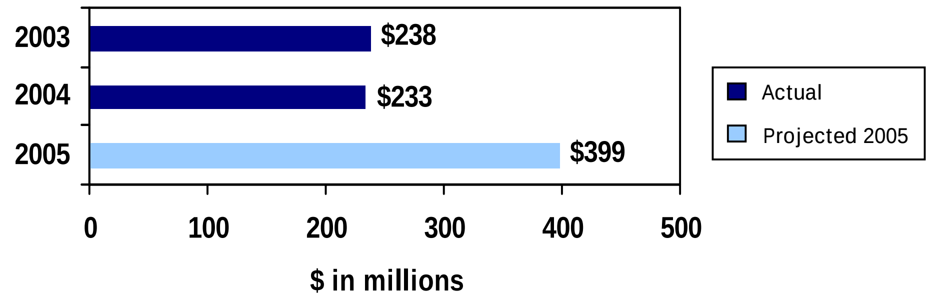
2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$12MM
$399 MM
$396 MM
$66 MM
$937 MM
$671 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



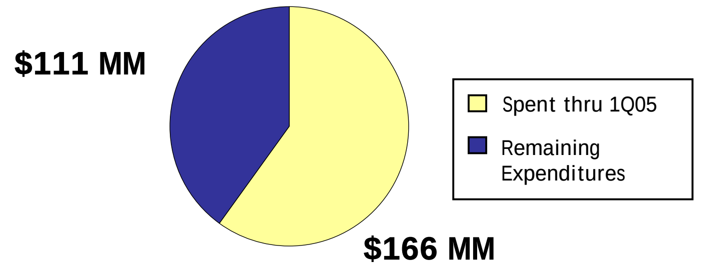
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**875,376,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Excludes $65.8 million of mortgage bonds due in 2005 that were defeased

(4) Excludes TCC securitization bonds

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Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

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Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

<u>2005</u>

- *Outcome of pending regulatory proceedings*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Earnings Guidance

No.		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.40
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AMERICAN ELECTRIC POWER

Deutsche Bank Energy, Utilities & Power Conference

May 27, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

Holly Koeppel, EVP & CFO

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier regulated utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

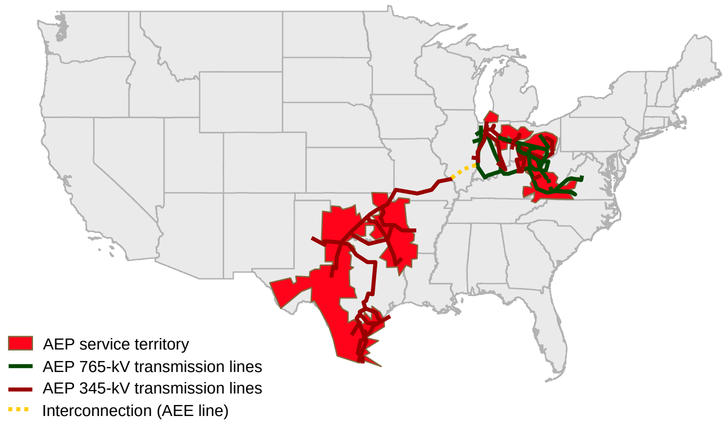
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

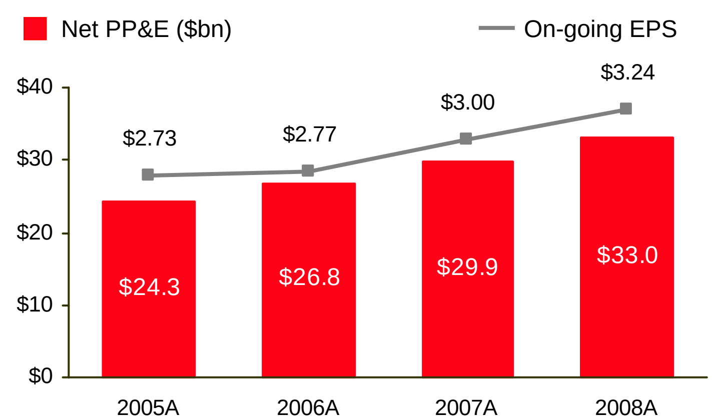


AEP's Leadership Position

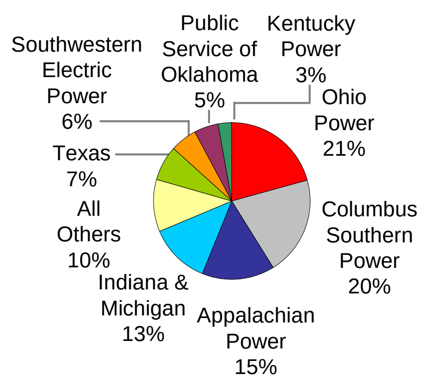
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
DUK	20.9	AEP	40.6 *	AEP	5.2
PCG	18.7	DUK	39.1	PCG	5.1
MidA	17.9	FPL	35.5	FPL	4.5
ITC	15.1	ETR	30.0	FE	4.5
FE	15.1	D	27.1	SO	4.4
Oncor	14.9	EXC	24.8	DUK	4.0
EIX	12.0	CPN	24.2	ED	3.6
PGN	11.0	NRG	24.0	XEL	3.4
AEE	7.4	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

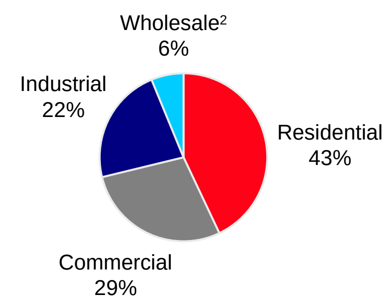
Regulated Operations



- Net PP&E CAGR of 10.7% since 2005
- Earnings CAGR of 5.9% since 2005



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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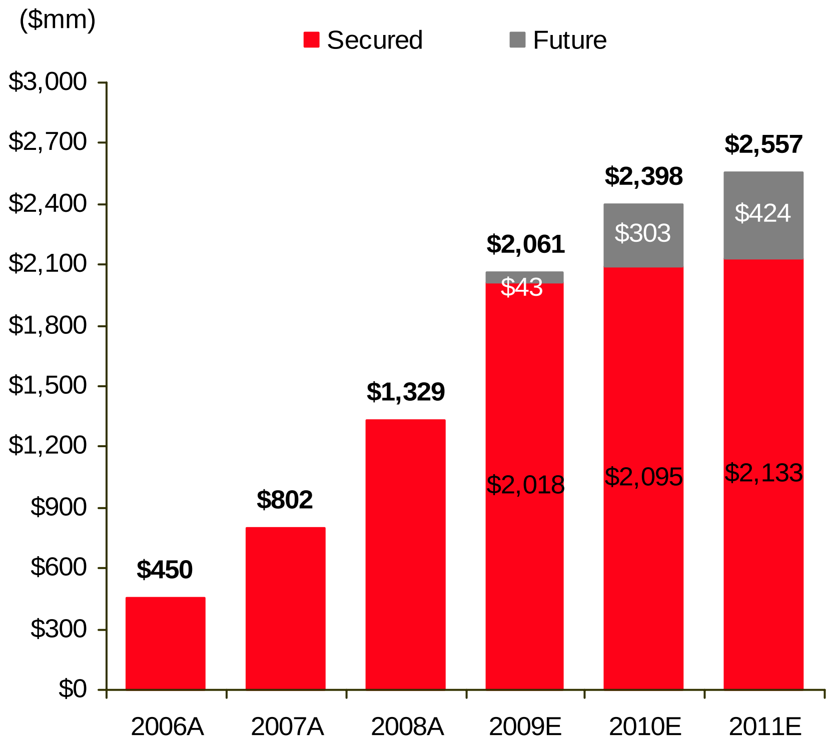
Effective Regulatory Relationships Provide Successful Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] *$77mm and $38mm was secured for 2010 and 2011, respectively, as of May 15, 2009*

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

High Growth Transmission Business

Active Projects:

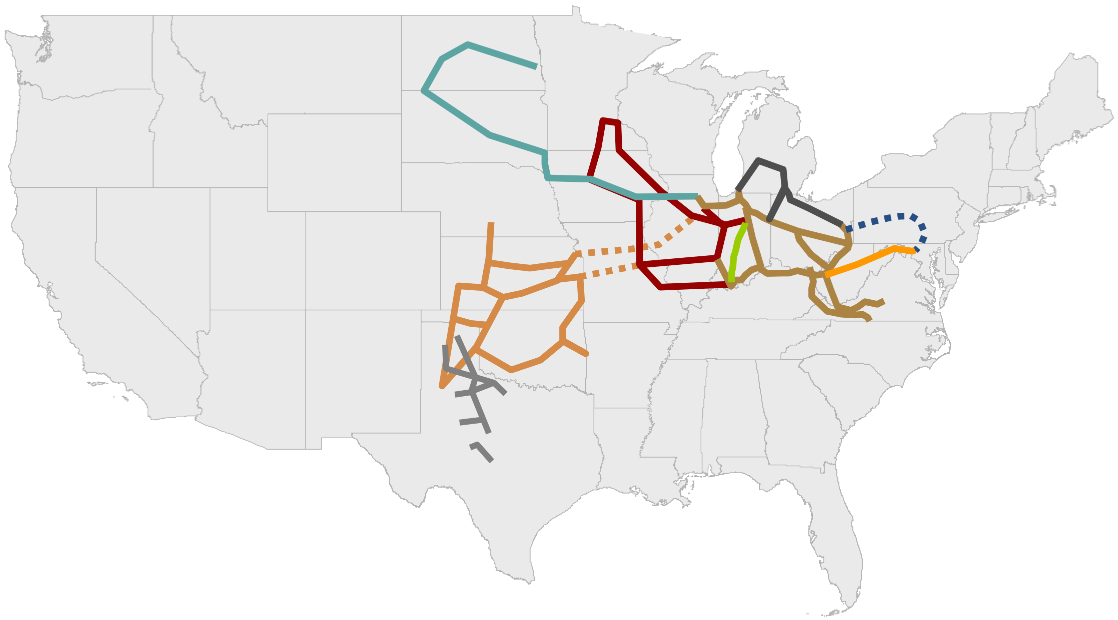
Pioneer — **COD: 2015**
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**
- *244 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013-14**
- *230 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $600 million*
- *ROE: 12.8%*

ETT — **COD: 2013**
- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**
- *700 miles of 765 kV*
- *Partner: ITC*

PJM Projects
- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**
- *1000+ miles of 765 kV*
- *Partner: Hartland Wind LLC*

MISO Vision Plan
- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**
- *765 kV Backbone*

ETT — **COD: ~2018**
- *345 kV in ERCOT*

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

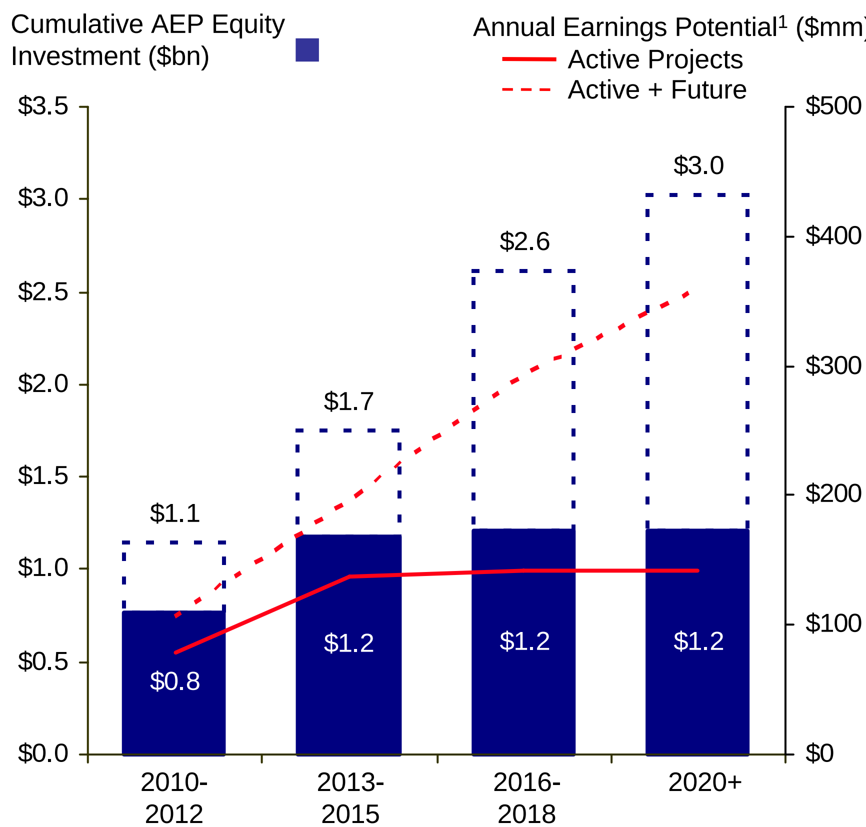
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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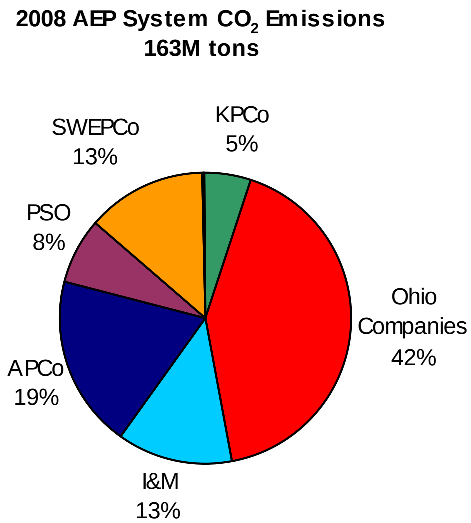
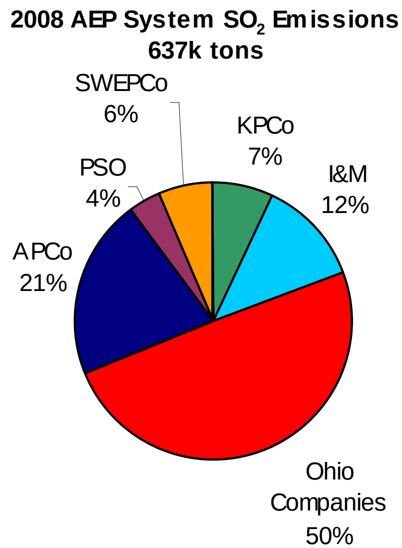
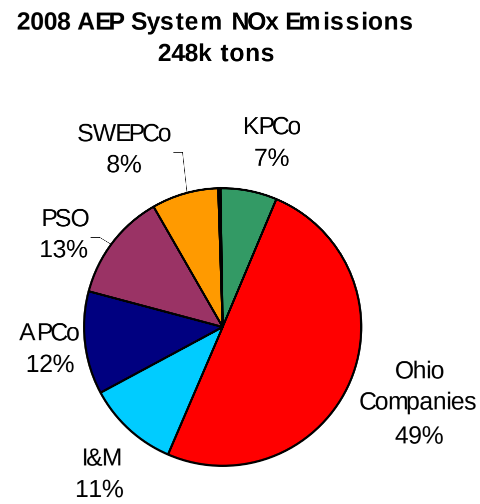
CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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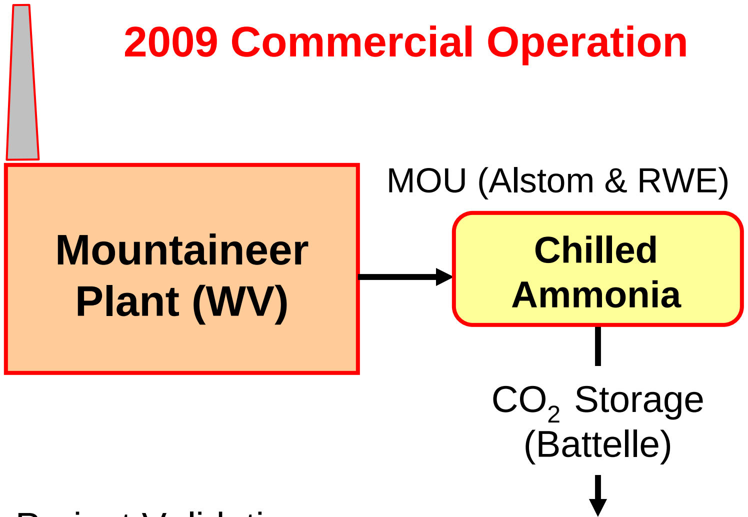
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**
- **Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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Each operating company should be self-sustaining

Strategy:

- ❑ Each operating company is evaluated on a stand-alone basis ensuring that each company becomes self-sustaining
- ❑ Due to the patchwork nature of regulation, each operating company has its own strategies and financial implications
- ❑ Over time, each operating company should be self-sustaining. Rate relief should be increased or capital and O&M realigned to achieve our targets

Operating Company Forecast

Targets

- **Returns, Earnings & Cash Flow (ROIC, ROE, EPS, FFO, Dividend)**
- **Credit Metrics Consistent with Credit Rating**
- **Customer Bill Impact (may be a limiting factor)**
- **Meet Prudent Utility Operator Practices**

Pass

Implement Plans

Fail

Action Required
❑ Cut capital and O&M
❑ Increase cash rate relief thru new mechanisms

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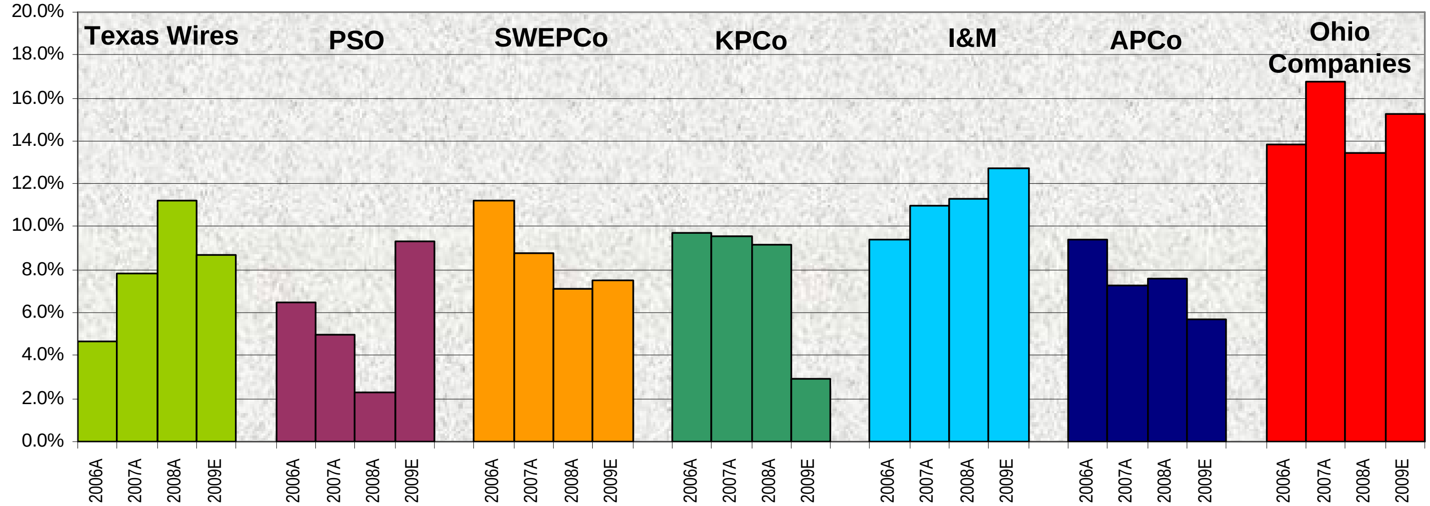
Pro-Forma Earned ROE & Net Income by Operating Company

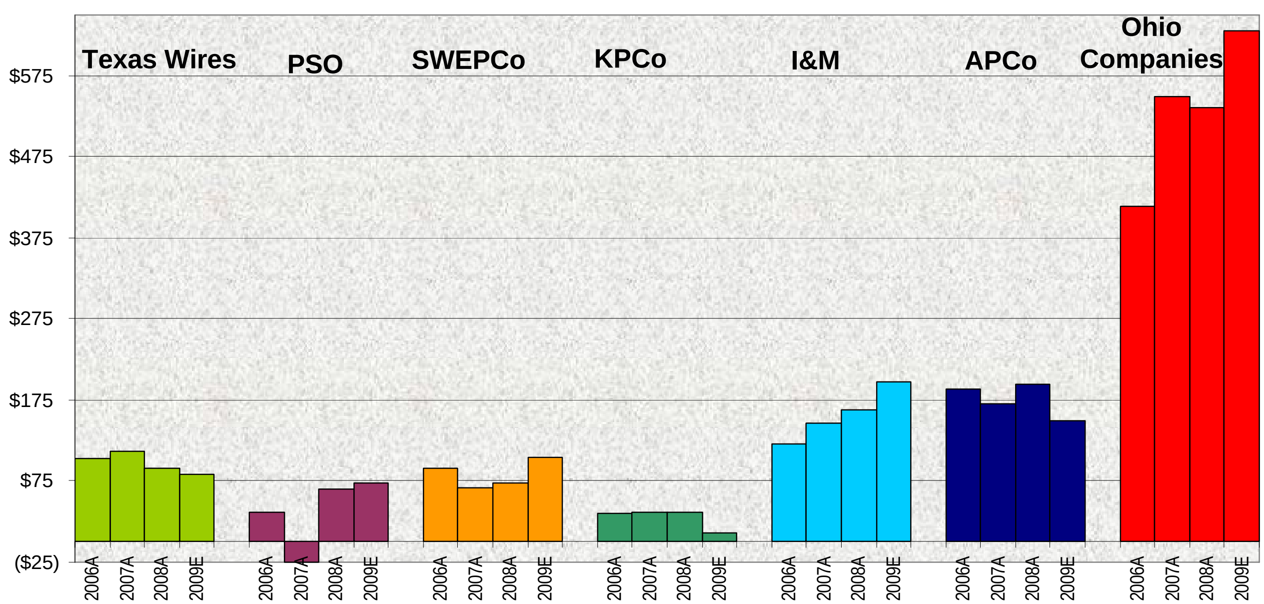


Pro-Forma Earned ROEs

Earned ROEs represent 12 months ended December 31. Regulatory Lag ranges from 3-15 months by jurisdiction.

Net Income by Operating Company

($ in millions)



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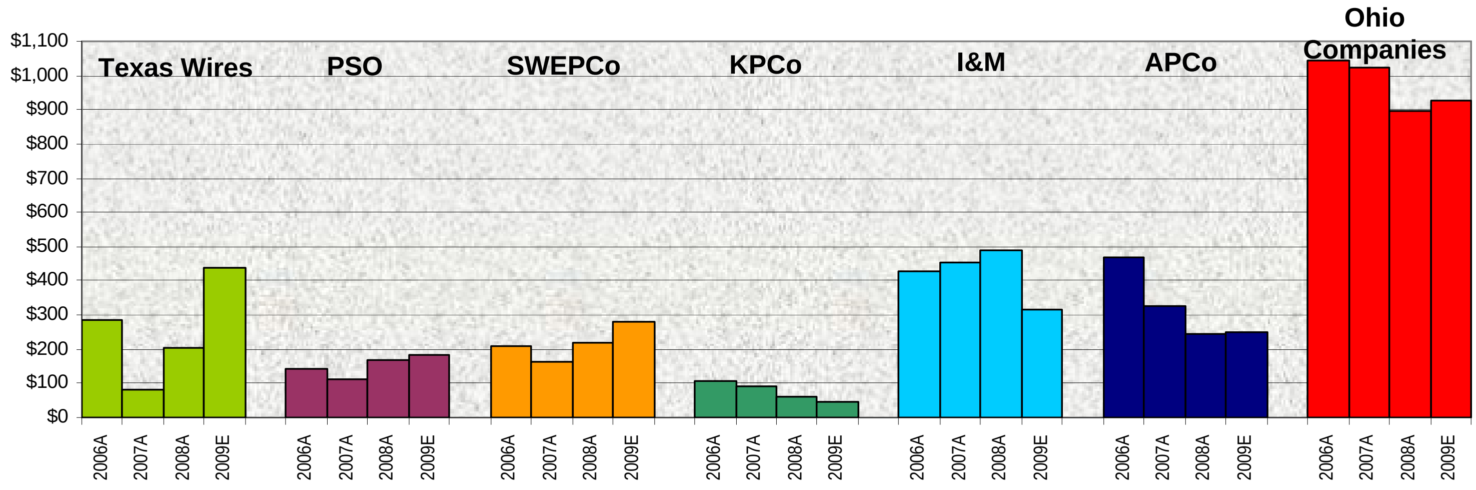
Cash Flow and Capex by Operating Company

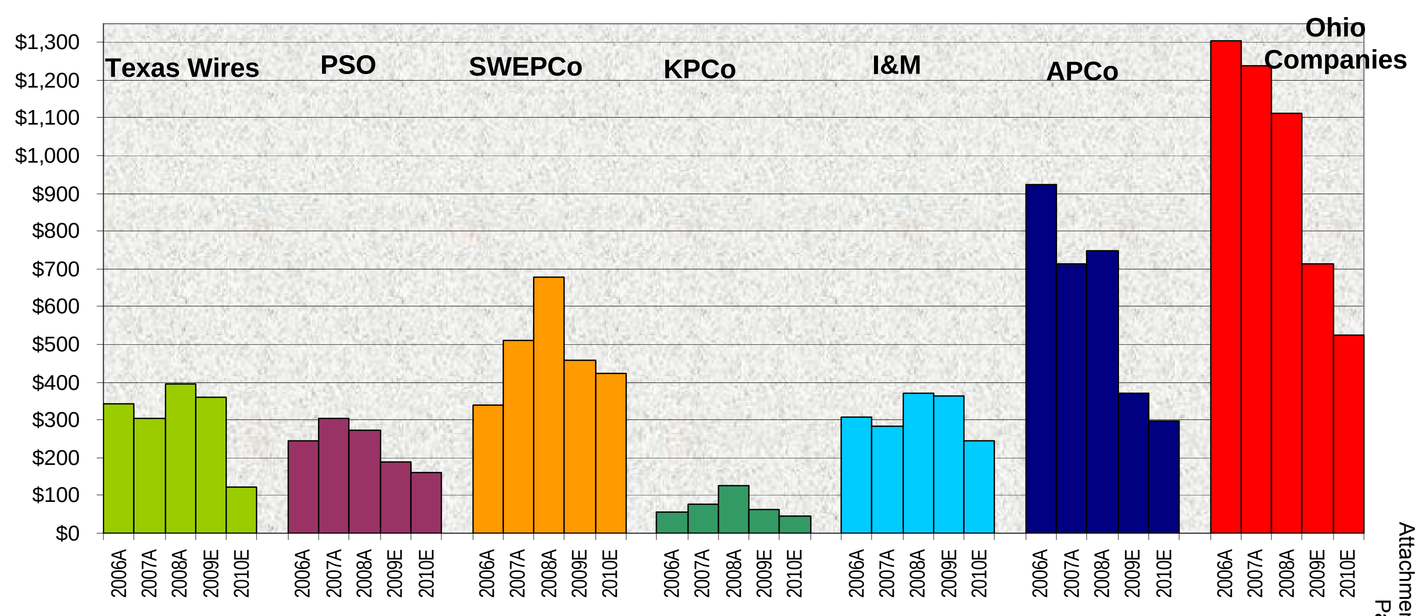


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



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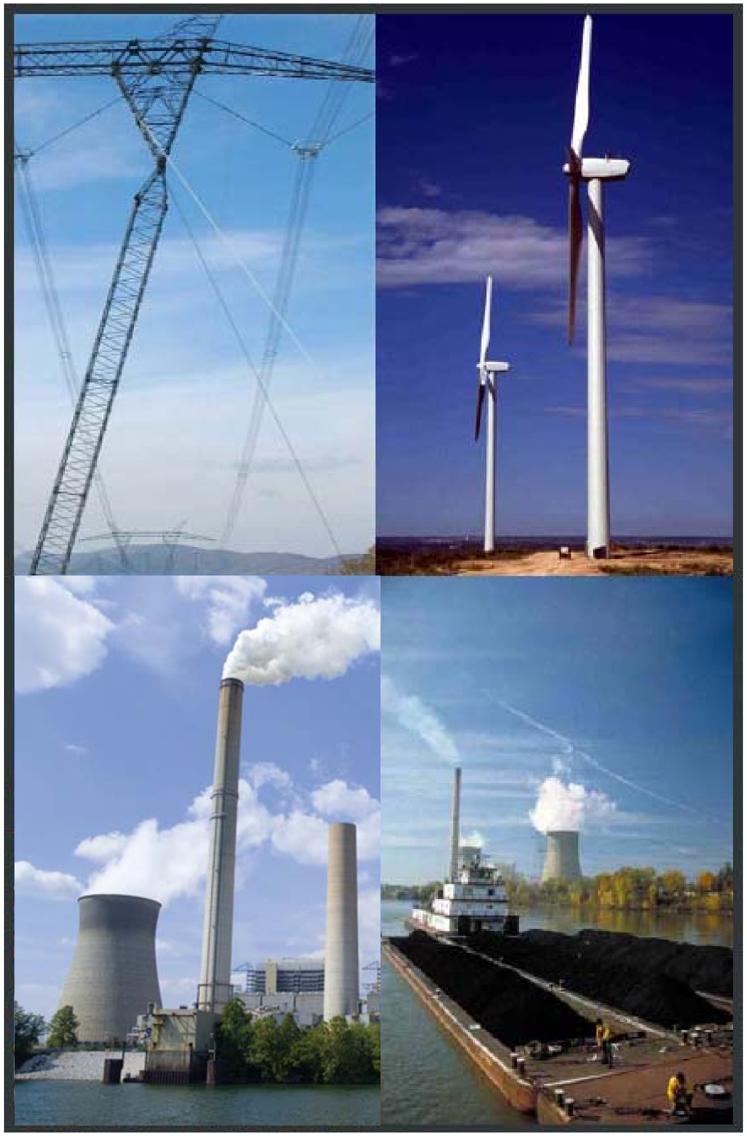
AEP is a Compelling Investment

- Market leading assets and operations
- Attractive pipeline of growth capital opportunities
- Successful regulatory management supports earnings continuity
- Strengthened balance sheet, liquidity and credit profile
- Diversified earnings growth and attractive dividend



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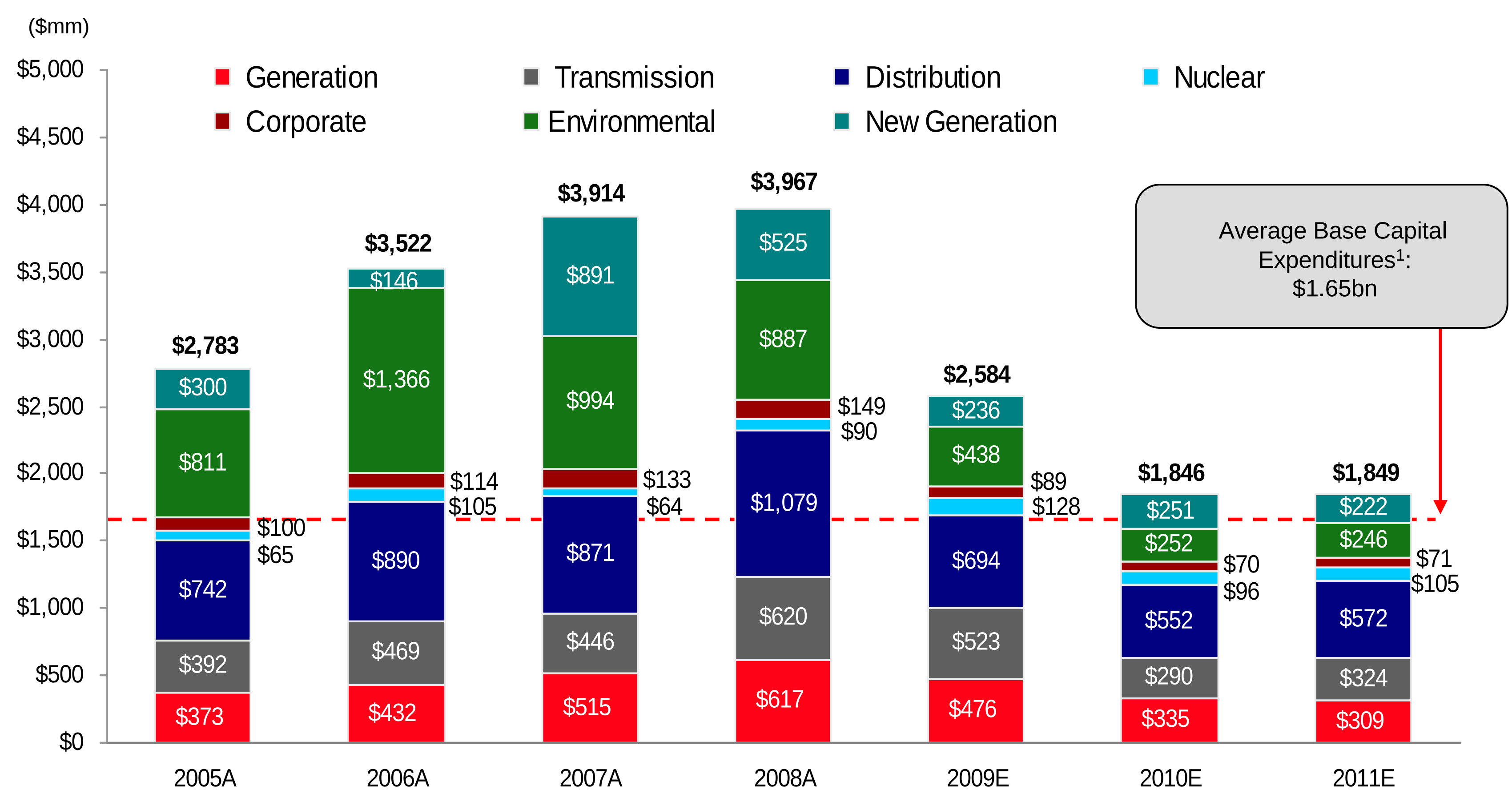
Appendix

Utility Capital Expenditures Support Growth of 2 - 4%



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC

[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion

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Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

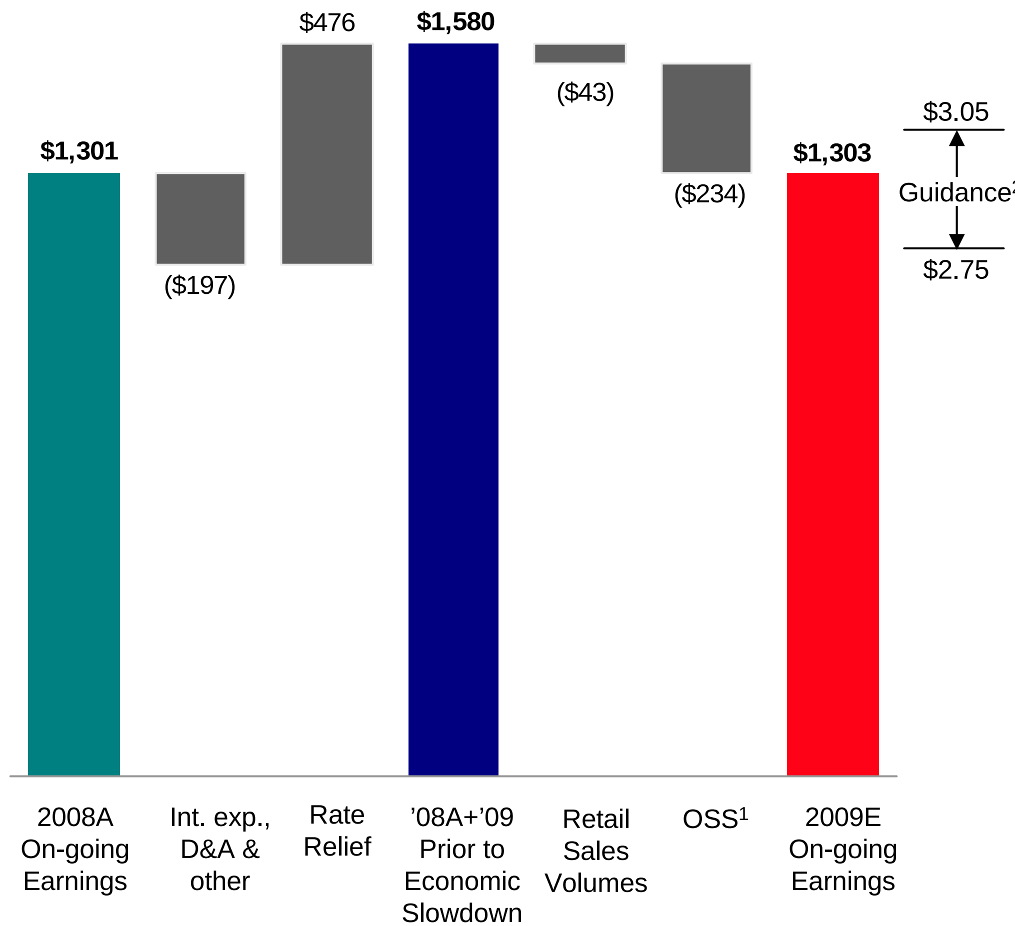
2009 Earnings Drivers:

- ⬆ Positive Ohio outcome
- ⬆ Rate relief - $732mm
- ⬇ Economic slowdown
  - — Lower OSS revenues
  - — Lower loads

Long-term Earnings Drivers:

- ⬆ Rate base investments
- ⬆ Additional rate relief
- ⬆ OSS/Retail load
- ⬆ Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
¹ Net of sharing
² Assumes 2009 average shares outstanding ~ 450 million

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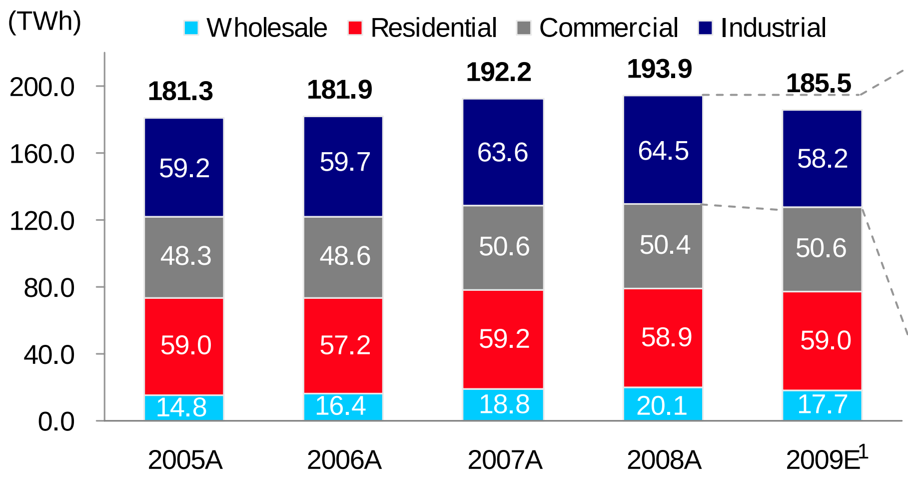
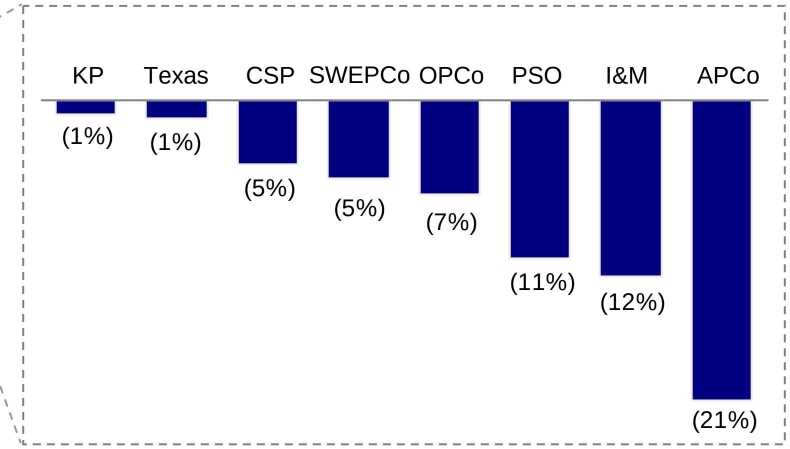
Key Drivers of Revised 2009 Guidance: Retail Sales

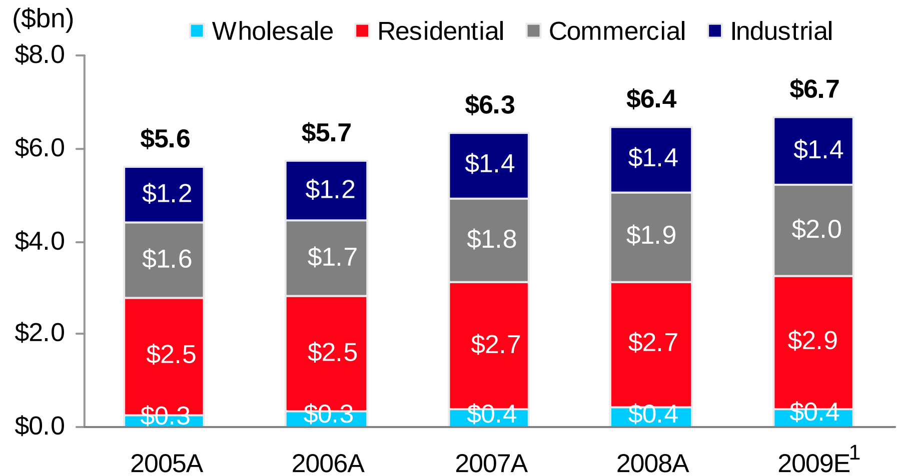
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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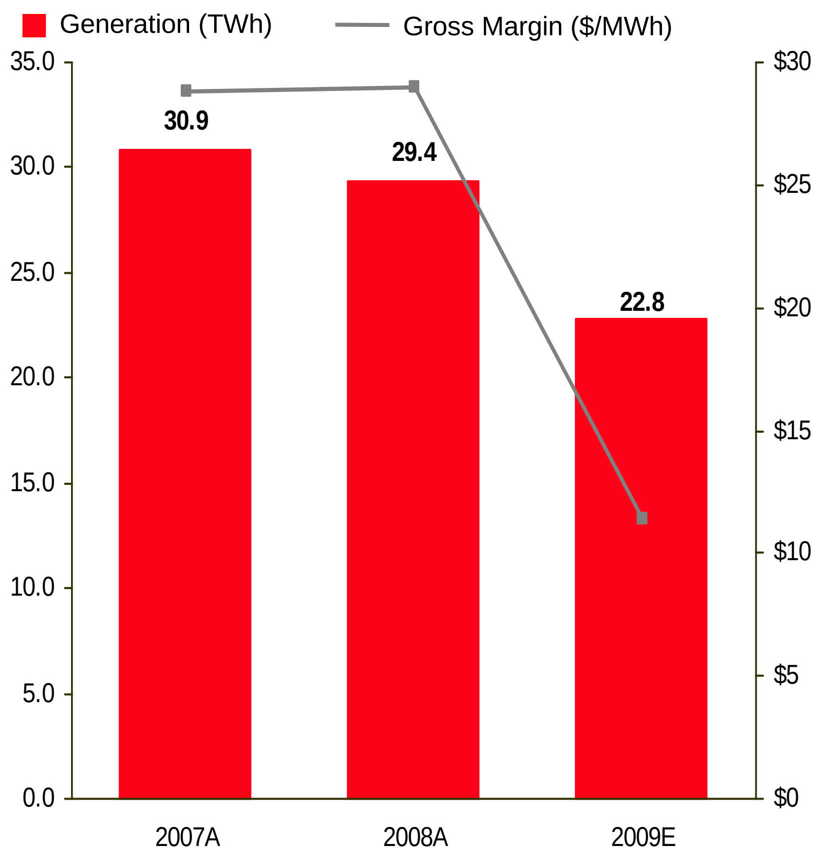
[1] *2009E assumes normalized weather*

[2] *Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables*

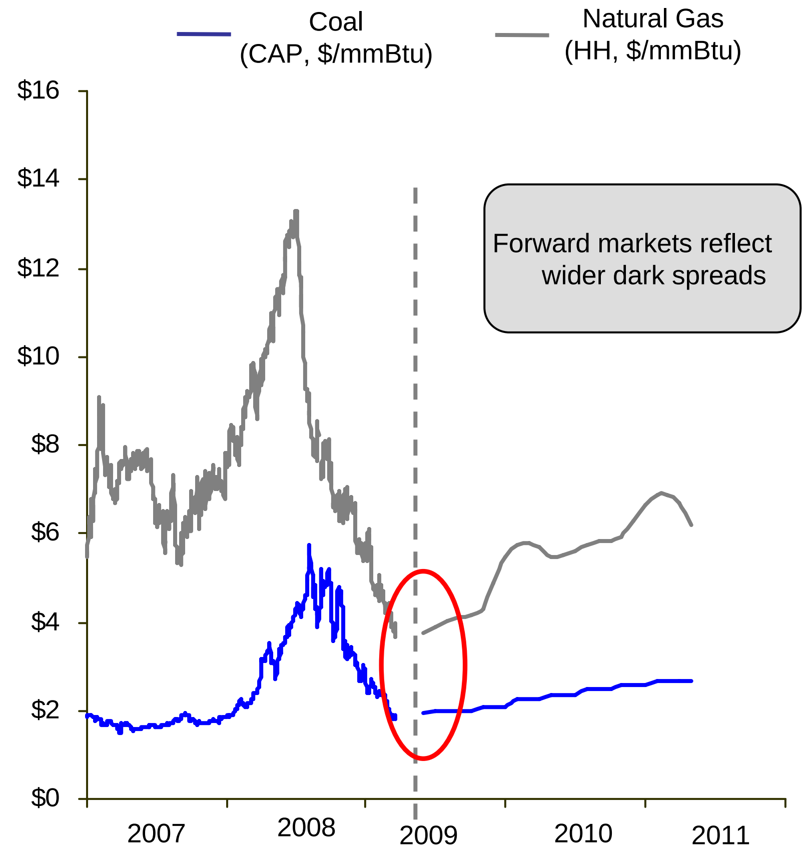
Key Drivers of Revised 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 15, 2009, Appalachian Power filed the fourth and final tranche of E&R surcharge filings with the Virginia SCC, requesting a $41.6 MM increase for environmental and reliability costs incurred during the period January 1, 2008 through December 31, 2008, with a proposed one year recovery period commencing January 1, 2010. A procedural schedule has not yet been published by the SCC.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	07/01/2004 thru 09/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/01/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008- 00045	10/01/2006 thru 12/31/2007	01/01/2009 thru 12/31/2009	$60.6 million
IV	PUE-2009-00039	01/01/2008 thru 12/31/2008	Proposed 01/01/2010 thru 12/31/2010	$41.6 million

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Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

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Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: "A blade-rotor system design that failed to provide adequate stress margin"
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

AEP AMERICAN ELECTRIC POWER

Deutsche Bank 2010
Alternative Energy, Utilities & Power Conference
Washington, D.C.
May 11,2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Thoughts about the Energy Policy Debate

To make significant advancement in developing clean, domestic energy and reducing emissions, we as a nation need a national energy policy with specific goals and guidelines, particularly as it relates to renewables, transmission and greenhouse gas emissions.

- **Cap and trade**
- **Incentives to develop and deploy new technologies**
- **Create timelines for emission reductions that match available technology**
- **Mandates to develop reasonable cost allocation methodologies to support EHV transmission**
- **Support for the siting of the national-interest transmission lines**

Trent Mesa Wind turbines in west Texas

AEP's Long-Term Platform

Energy policy initiatives around greenhouse gas emission reductions and energy efficiency, security and reliability create technology deployment and investment opportunity in our utility platform

Plans in Place

- 2,000 additional MW Wind PPAs by 2012
- Energy Efficiency & DSM
- Biomass Co-firing at coal-fired power plants
- New Technology Efforts
  - New Generation: ultra-supercritical coal generation in Arkansas
  - Development: carbon capture and storage (CCS) for existing fleet
- Transmission Initiatives
- Smart Grid Initiatives

A rendering of the John W. Turk, Jr. ultra-supercritical coal power plant now under construction in Arkansas

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation
Captured CO_2 – September 2009
Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

Transmission Investment Opportunities

- **AEP Transmission Company (Transco): Within our existing footprint**
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually
  - Enhance access to capital
  - First year investment opportunity--$121MM
- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B within this decade
- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RES will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
  - Robust pipeline of projects up to $15B

765-kV Tower

2010 Ongoing Earnings Guidance

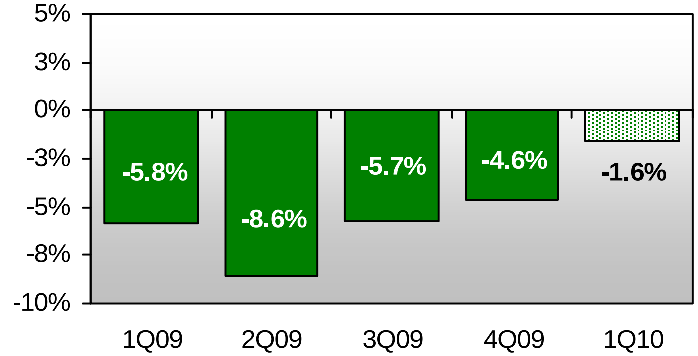
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**

AEP Total Normalized GWh Sales
Quarter %Change vs. Prior Year

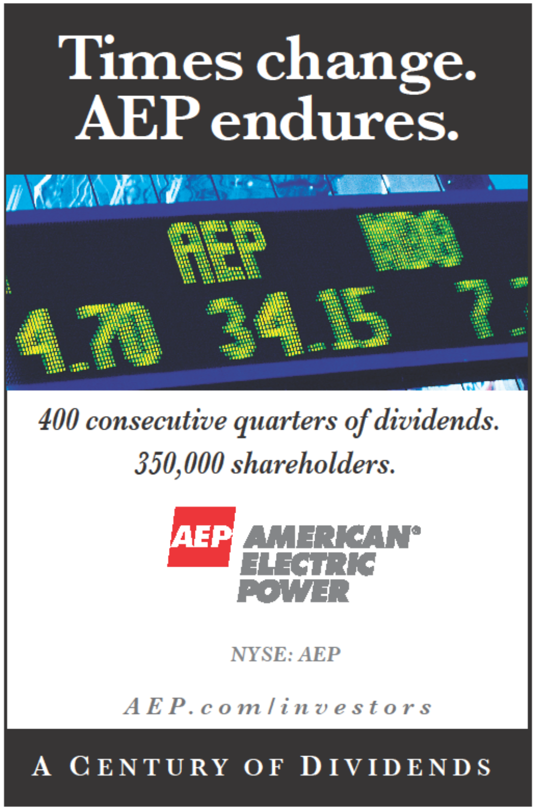


<u>Quarter over Quarter change by segment:</u>
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Value Proposition

❑ Current Yield Opportunity of 5.0%[1]

- June 10th - 400th consecutive quarterly dividend will be paid to shareholders
- 50-60% payout ratio targeted
- Dividend increased 2.44% on April 27th



❑ Earnings Growth Prospects

- Investment in utility platform greater than depreciation level (2 - 4%)
- With transmission opportunities (4 - 8%)

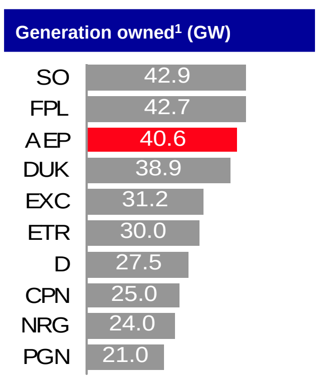
Attractive total return potential

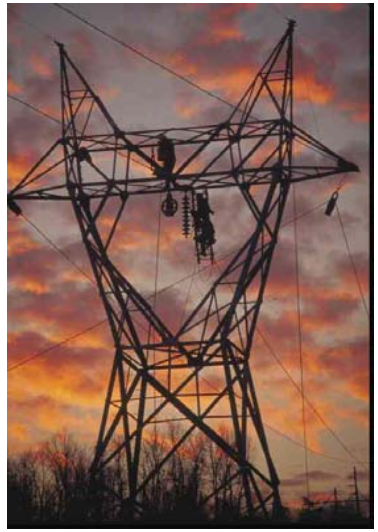
[1] yield percentage based on AEP closing price of $33.37 on 05/05/2010

Appendix

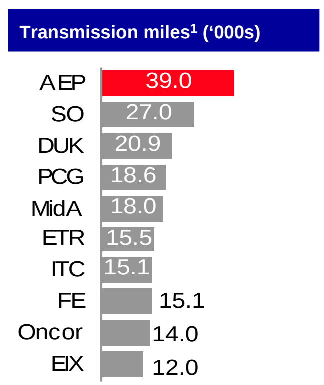
Industry Leadership

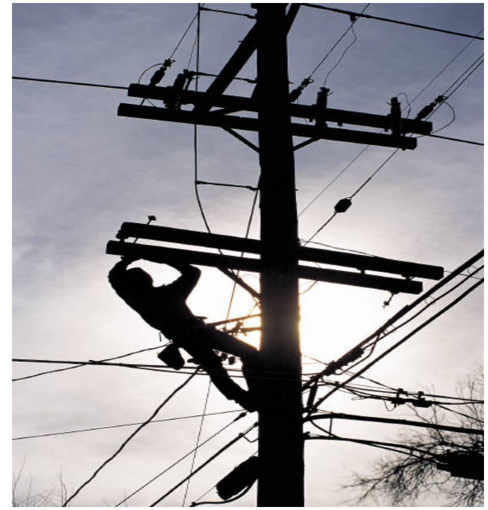
One of the largest U.S. electricity generators



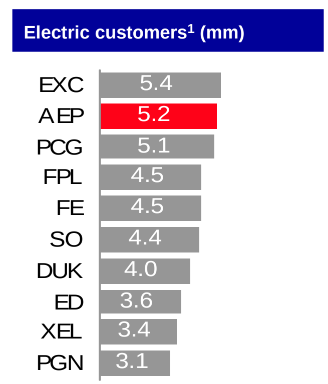


The largest U.S. electricity transmitter





One of the largest U.S. electricity distributors serving 5.2MM customers



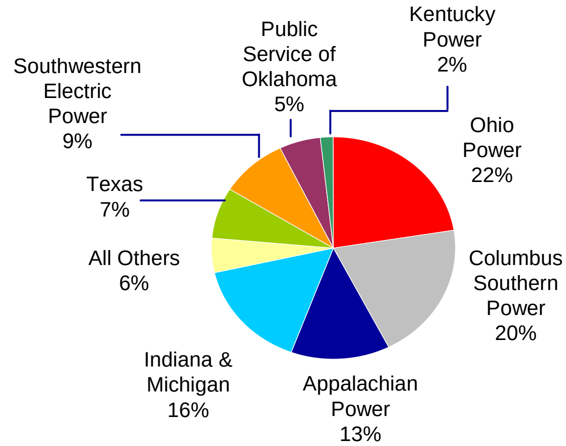
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

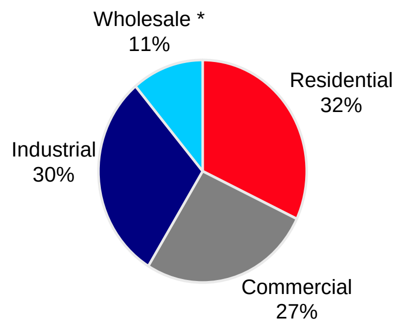
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

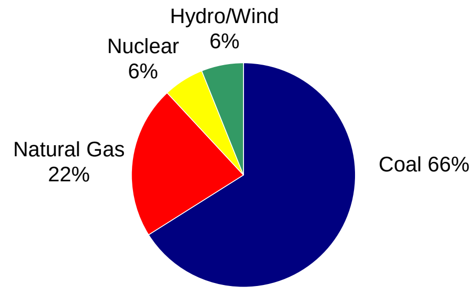


2009 Retail Load



Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

Fuel Mix



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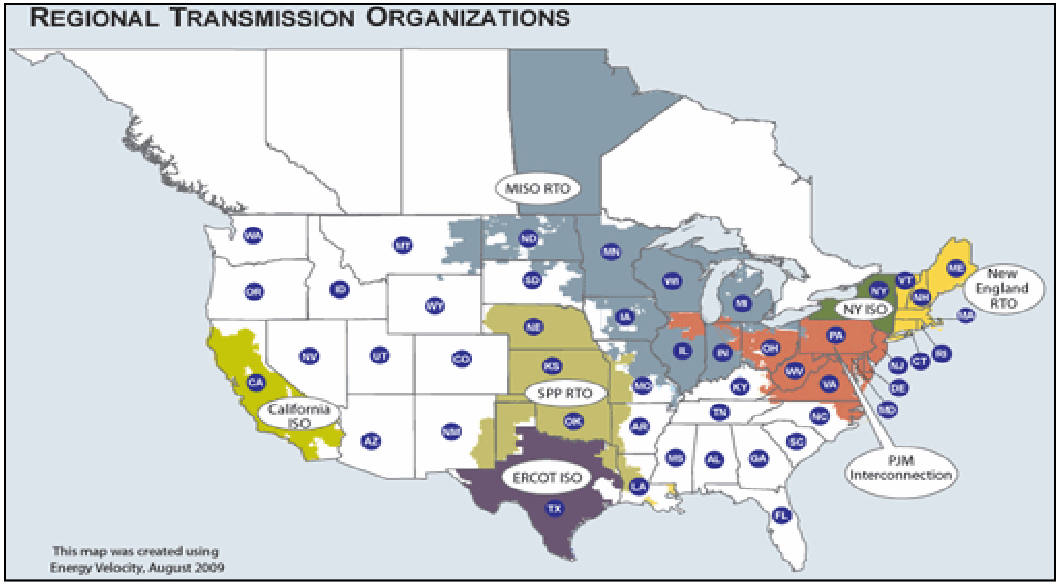
JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2017	**PATH-WV** COD: 2014	**Pioneer** COD: 2015
❑ *110 miles of 765 kV* ❑ *Partners: Westar (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $400 million* ❑ *ROE: 12.8%*	❑ *345 kV ERCOT Expansion* ❑ *Partner: MidAmerican Energy (50%)* ❑ *Estimated Cost: $1.4 billion* ❑ *ROE: 9.96%*	❑ *275 miles of 765 kV* ❑ *Partner: Allegheny Energy (50%)* ❑ *Estimated Cost: $1.2 billion* ❑ *ROE: 14.3%*	❑ *240 miles of 765 kV* ❑ *Partner: Duke Energy (50%)* ❑ *Estimated Cost: $1 billion* ❑ *ROE: 12.54%*
Tallgrass COD: 2013-14			
❑ *170 miles of 765 kV* ❑ *Partners: OG&E (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $500 million* ❑ *ROE: 12.8%*			



FUTURE DEVELOPMENT

SMARTransmission Study

- ❑ *Interregional EHV & Wind Integration Study*
- ❑ *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
❑ *Regional Expansion of 765 kV Backbone*	❑ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ❑ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	❑ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	❑ *700 miles of Proposed 765 kV*

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filings made in OH, VA, WV & AR
    - Filings later in 2010 for IN, KY & LA
- FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
- Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

Electric Transmission Texas, LLC

Overview:

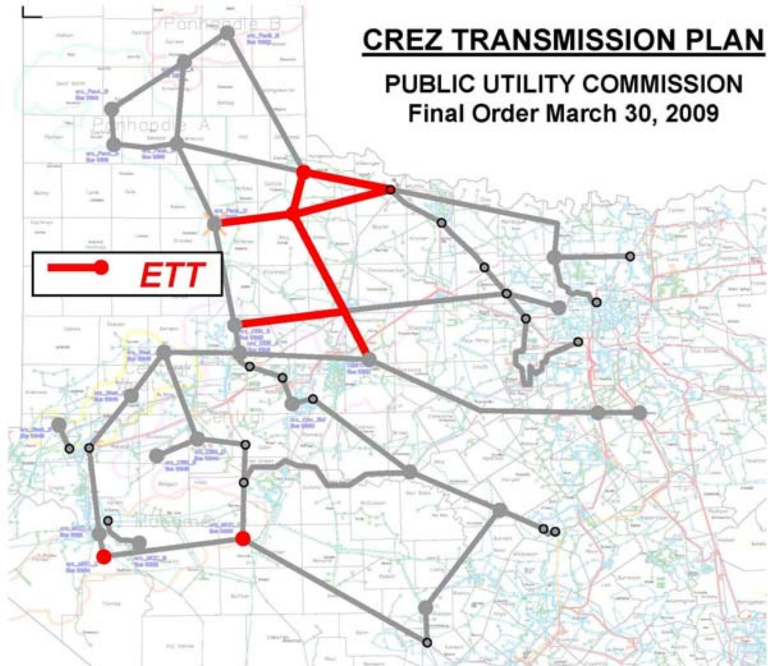
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2017: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects pending transfer in service 2010-2013: $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

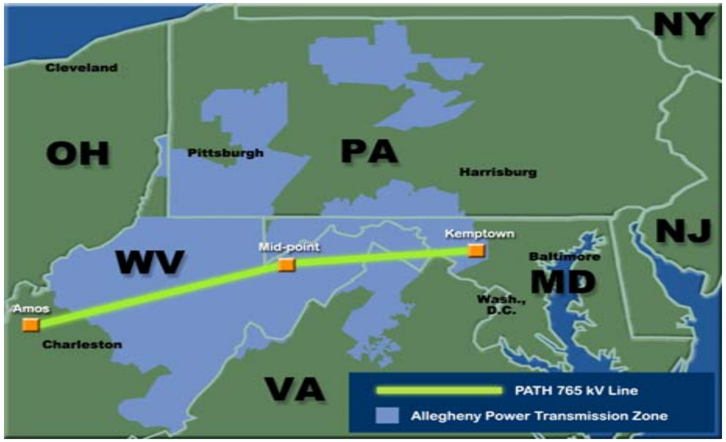
ETT
Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

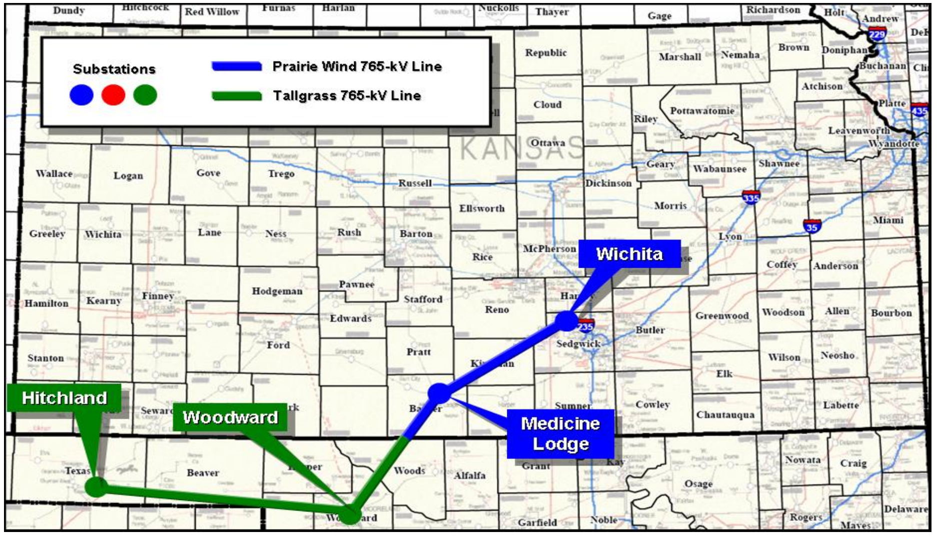
Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP’s ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

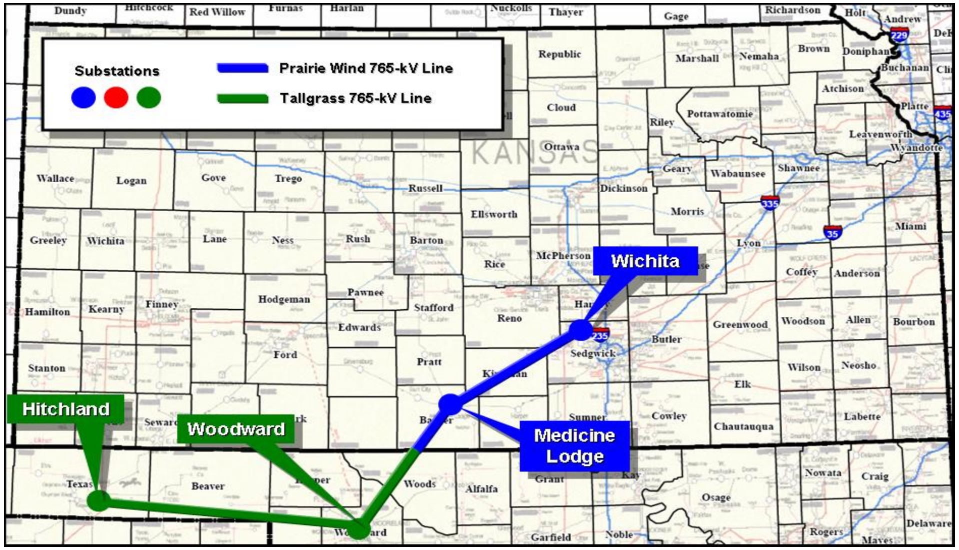
Key Challenges:

- RTO Approval
- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

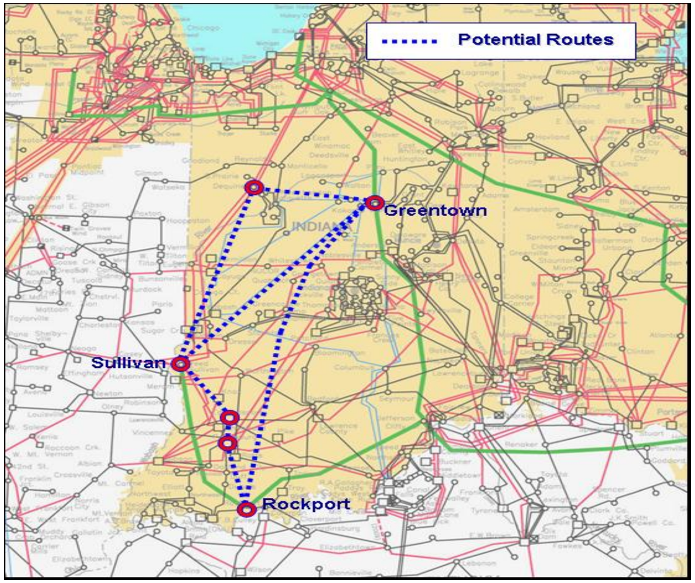
Key Challenges:

- RTO Approval
- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		42
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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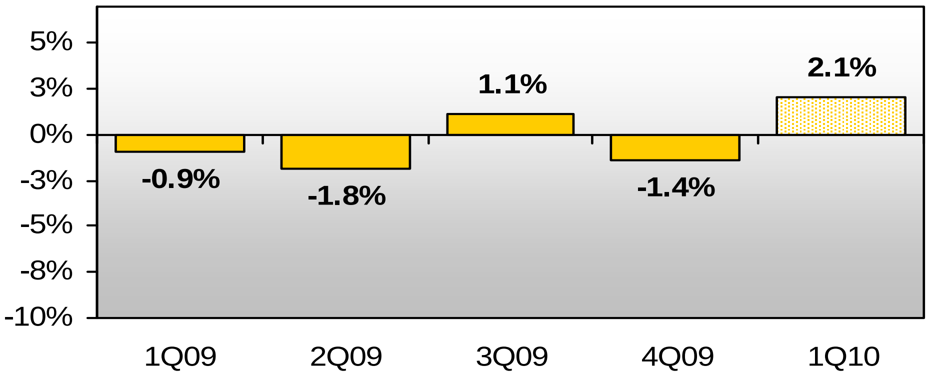
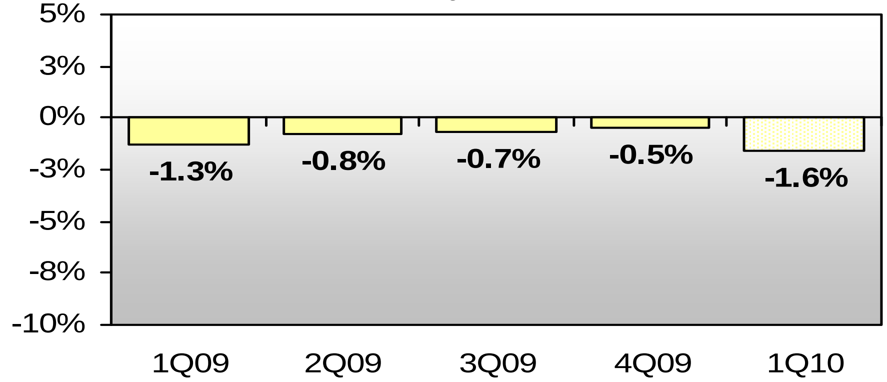
Normalized Load Trends

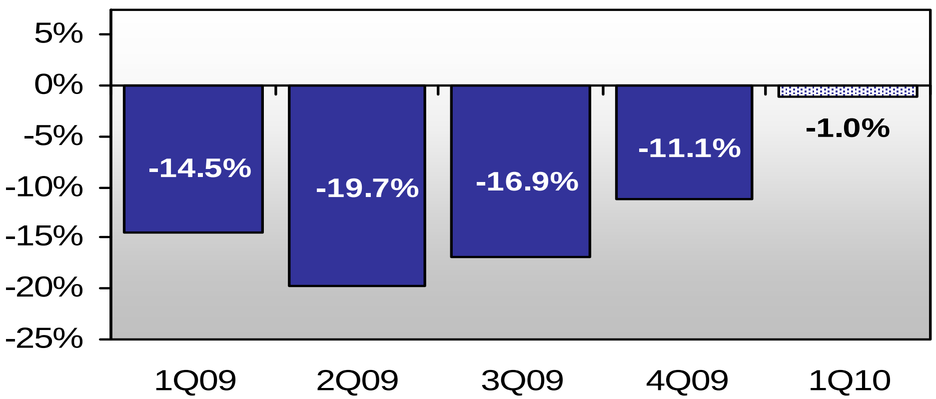
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



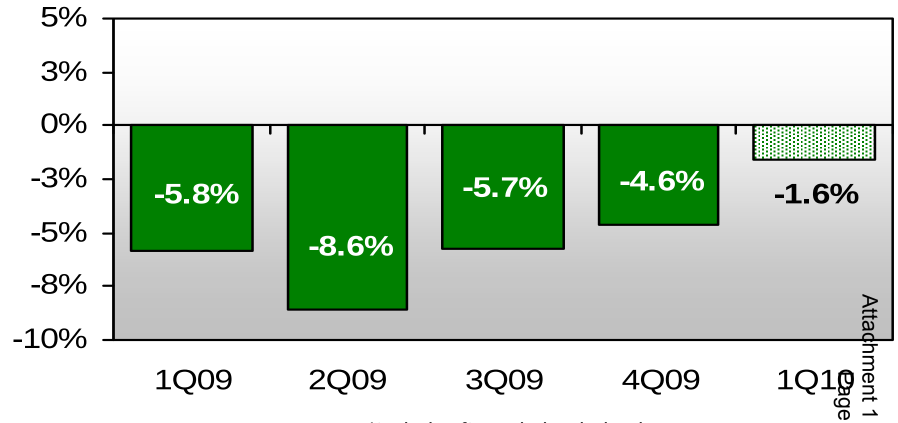
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year

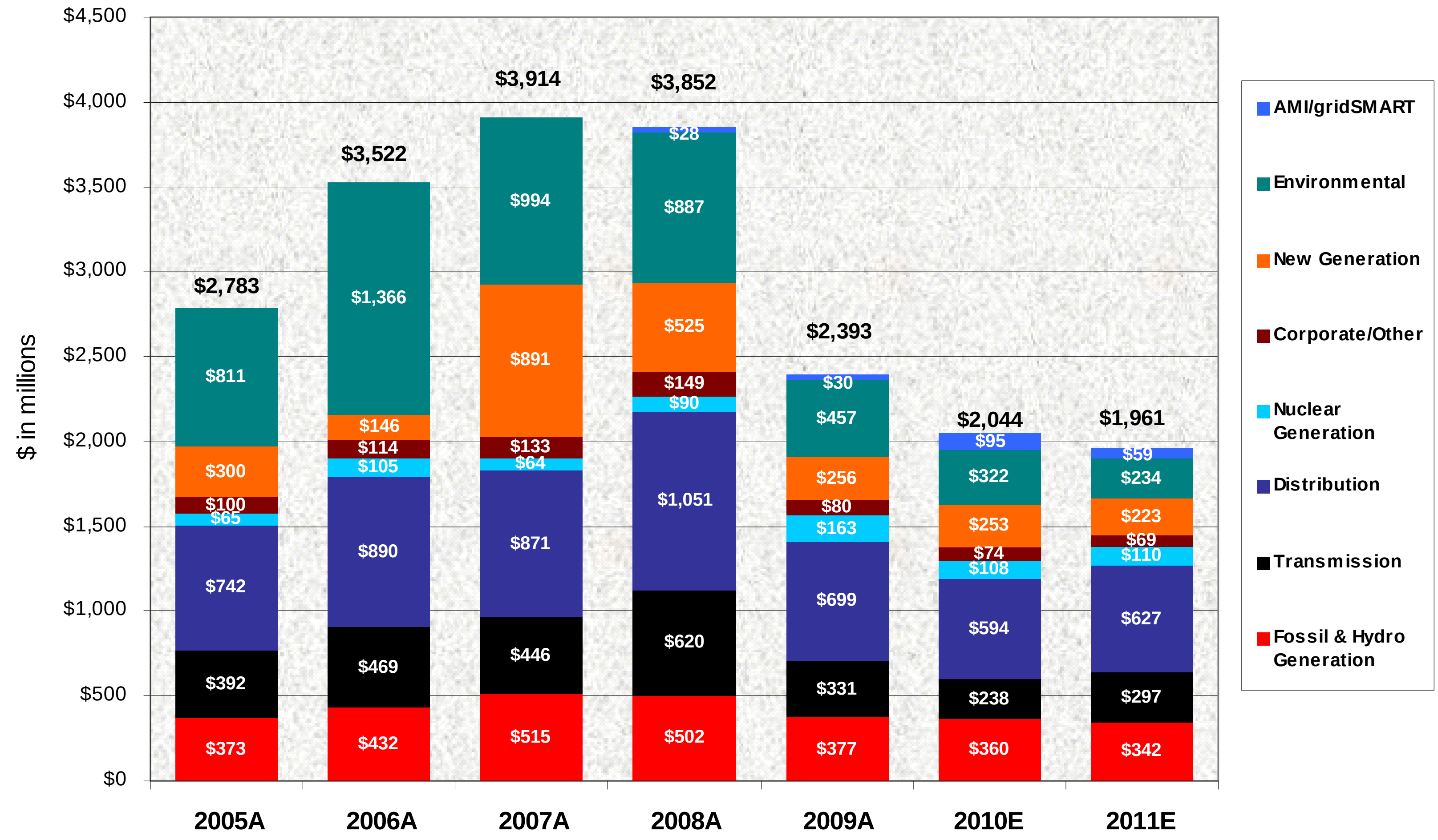


AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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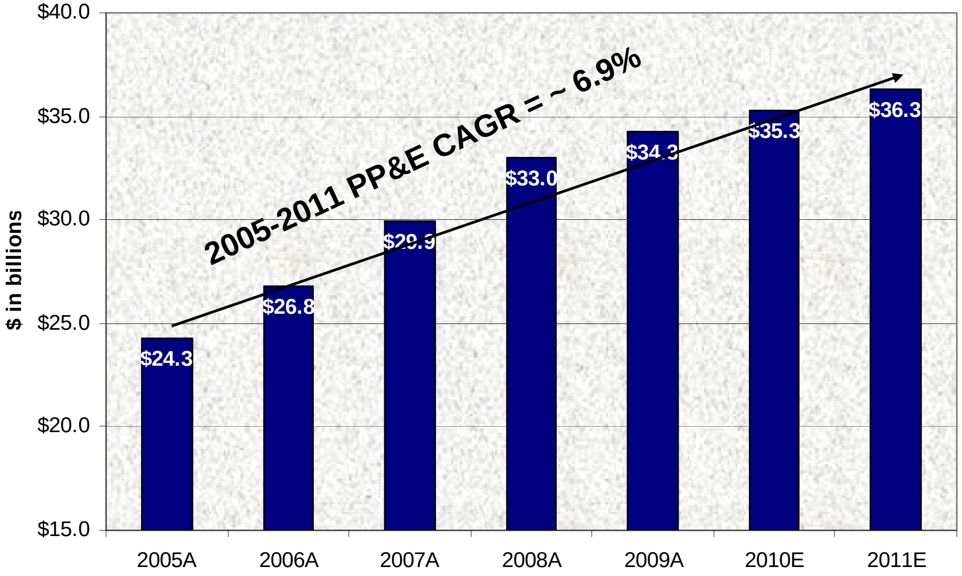
Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

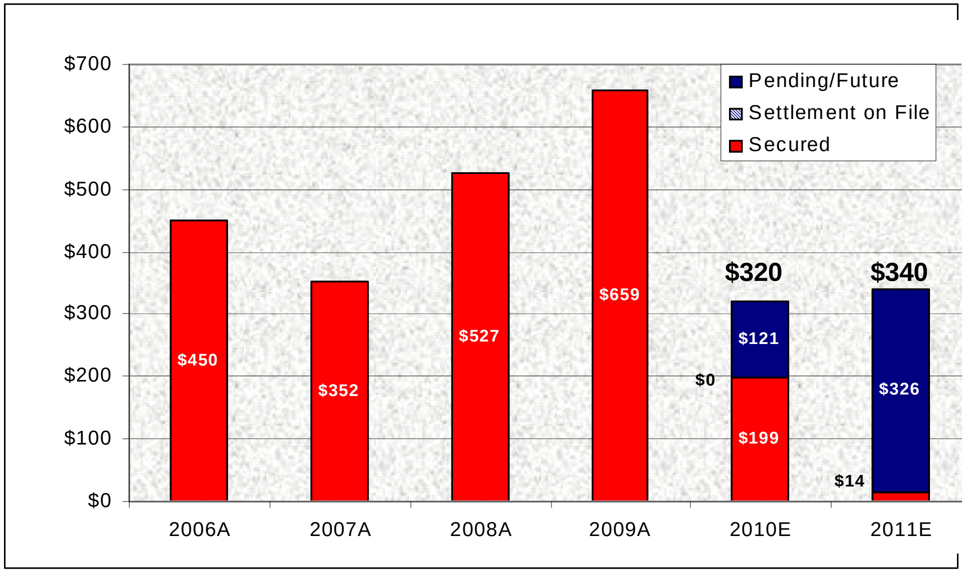
Traditional Rate Making Environment

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
May 25, 2010	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

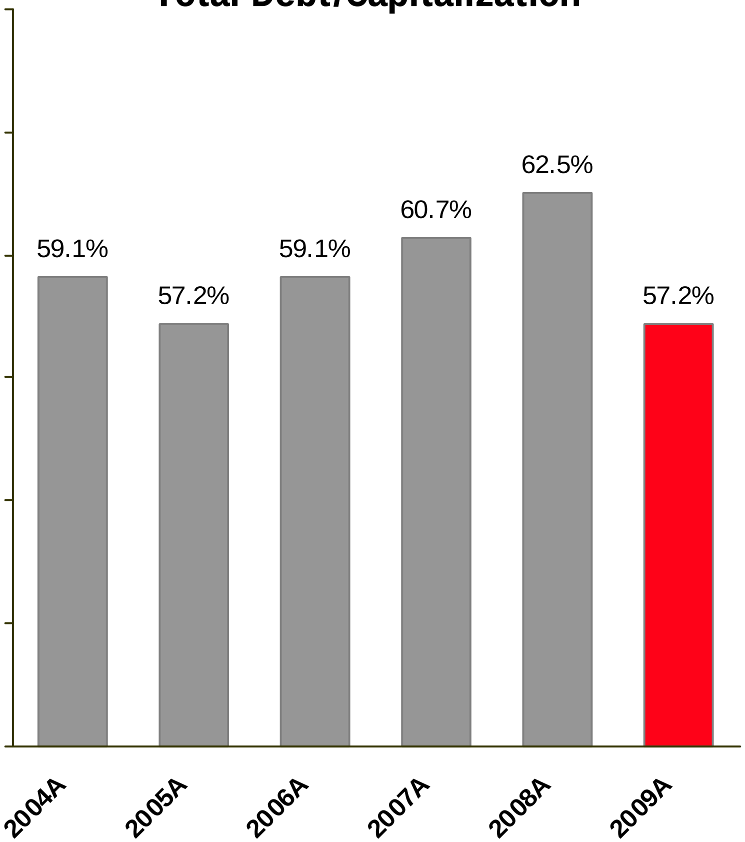
Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

March 31, 2010

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,454	April 2012
Revolving Credit Facility	627	April 2011
Total	3,581	
Cash and Cash Equivalents	818	
Total Liquidity Sources	4,399	
Less: AEP Commercial Paper Outstanding	399	
Letters of Credit Issued	652	
Net Available Liquidity	$ 3,348	

AEP Credit Ratings

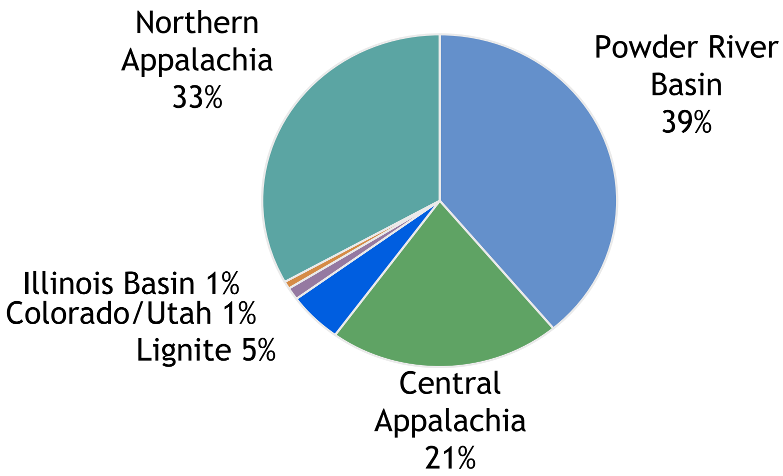
Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

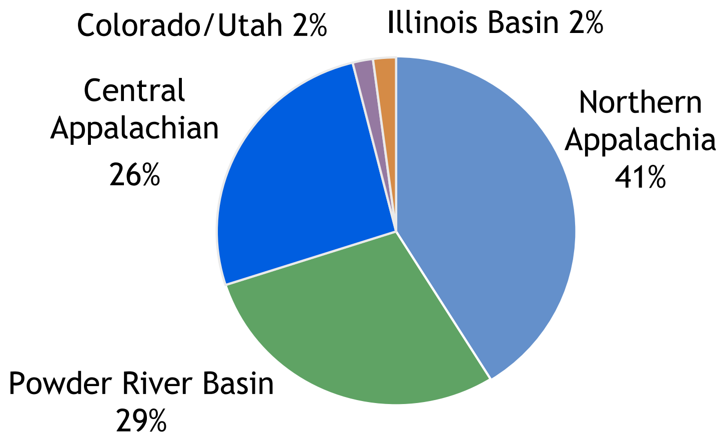
S=Stable, N=Negative Outlook

Coal Procurement - 2010 Projected

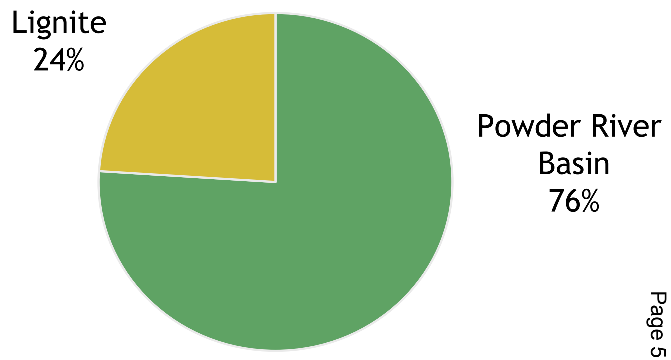
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

AEP AMERICAN® ELECTRIC POWER

Deutsche Bank Alternative Energy, Utilities & Power Conference

New York, NY
May 12, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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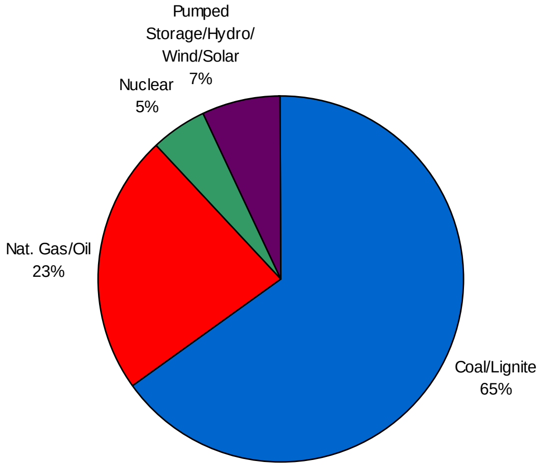
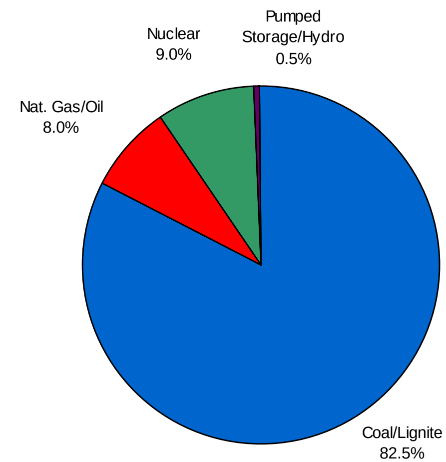
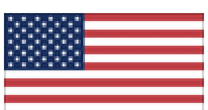
Domestic Generation Fleet

Generation Capacity by Fuel Type
Based on 39,910 MW

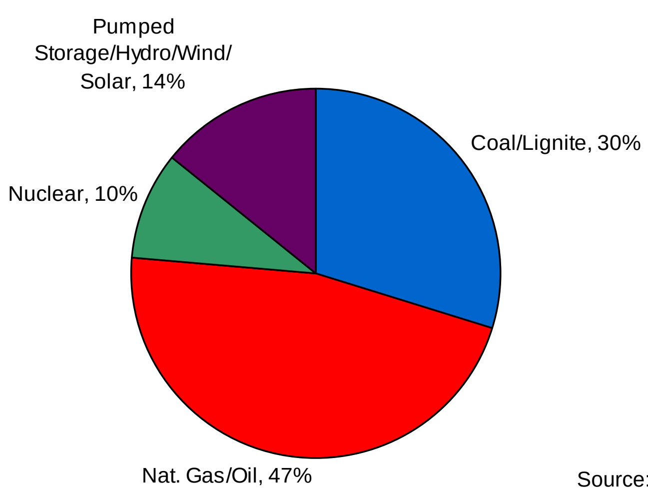


2010 Generation Production by Fuel Type
Based on 173.2 TWh

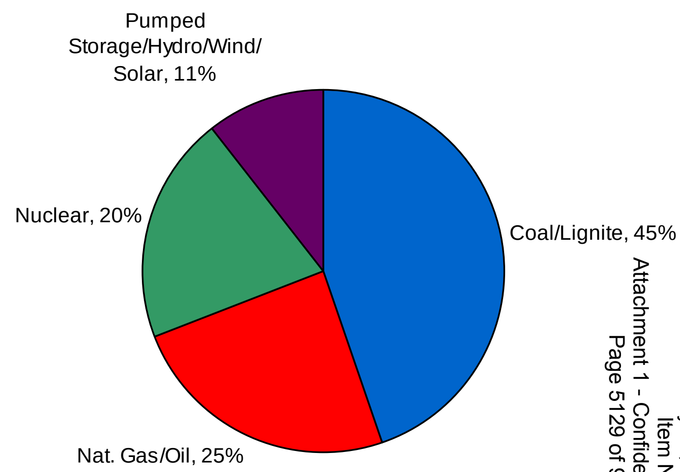




Generation Capacity by Fuel Type
Based on 1,063,848 MW



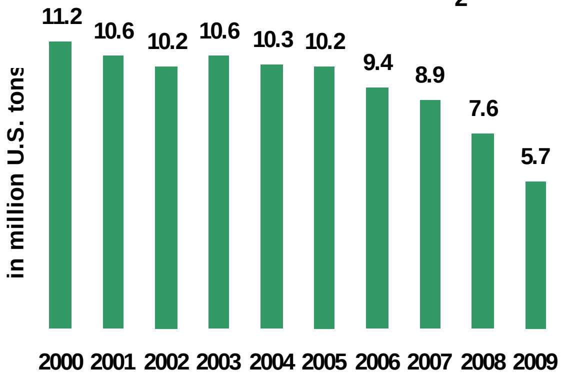
2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

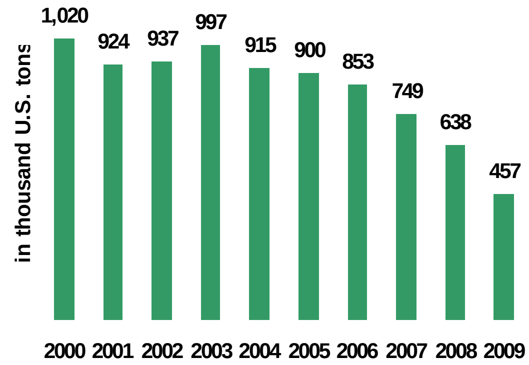
Emissions Reductions since 2000

U.S. Power Plant SO_2 Emissions



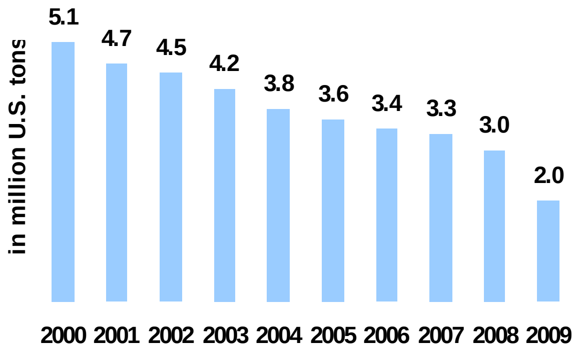
49% reduction since 2000

AEP SO_2 Emissions



55% reduction since 2000

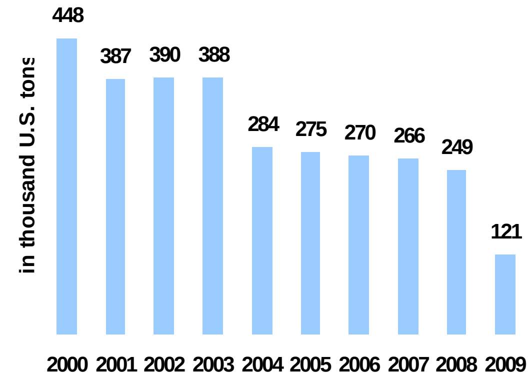
U.S. Power Plant NOx Emissions



61% reduction since 2000

Source: EPA, 2010; Acid Rain Program

AEP NOx Emissions



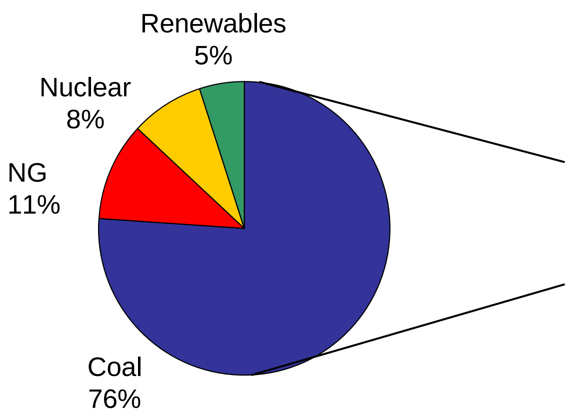
73% reduction since 2000

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

AEP Generation Capacity

East Capacity – 27,253 MW

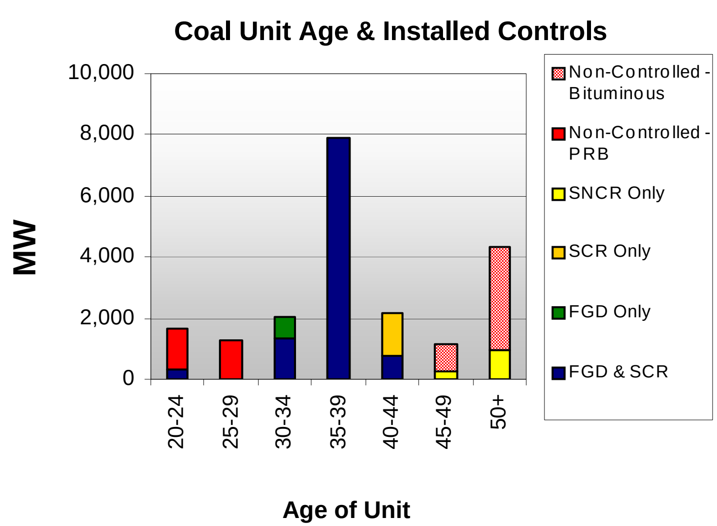
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



Coal Source

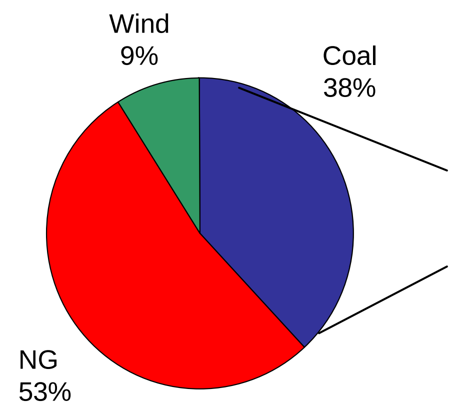
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

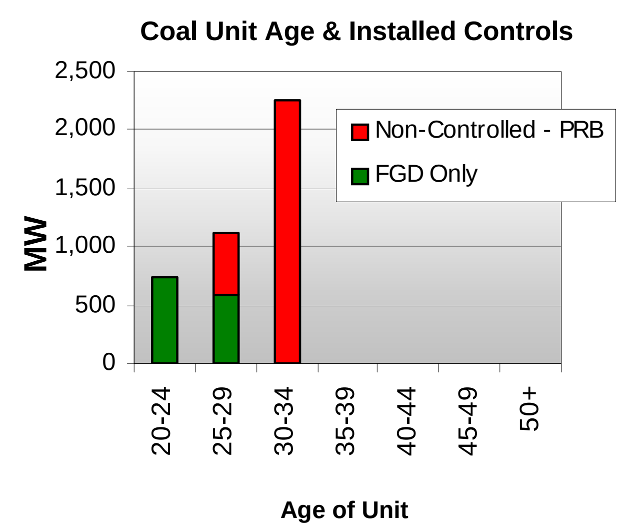
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Pending EPA Regulations

AEP®

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

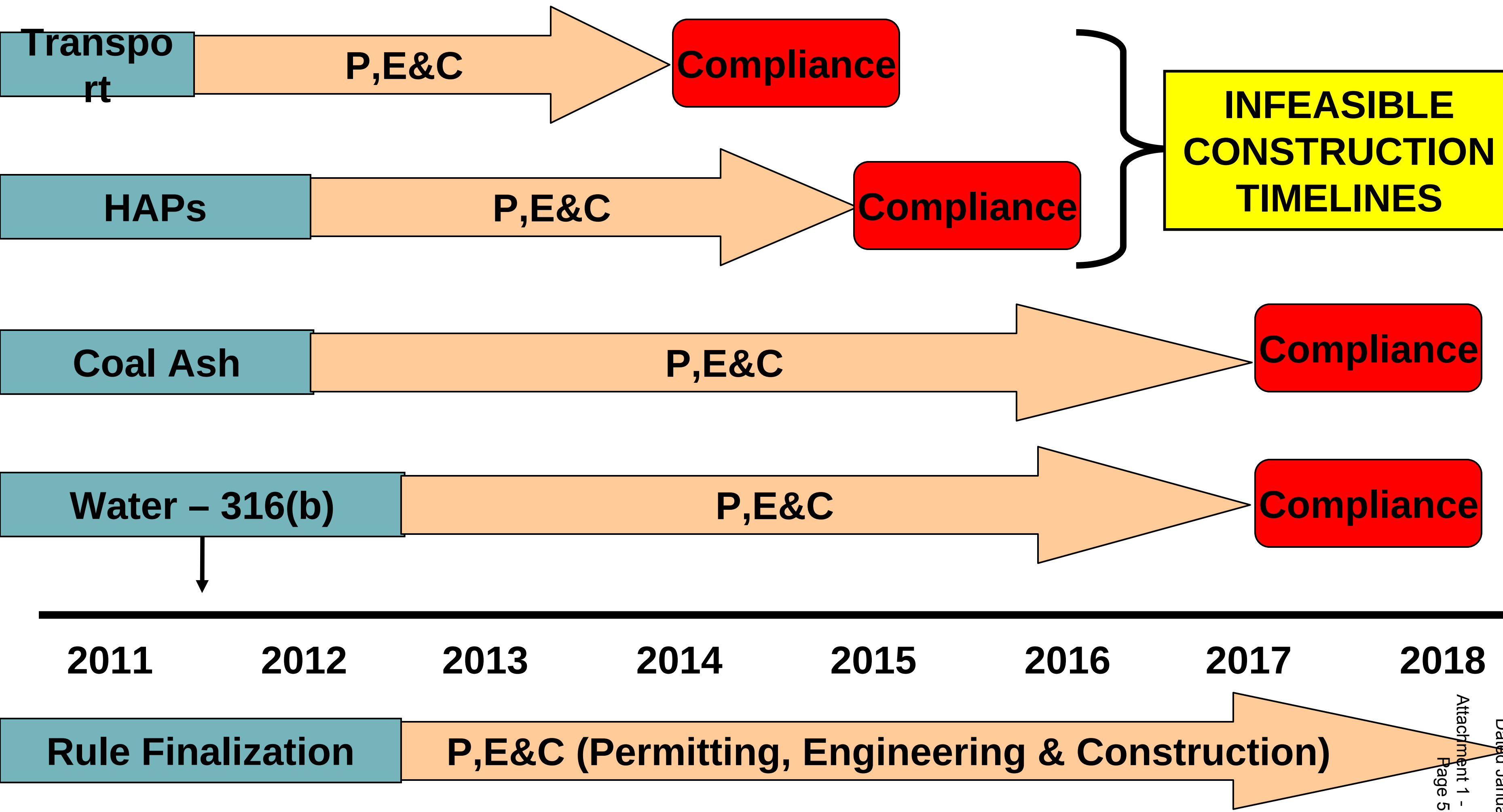
- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - "Non-hazardous", solid waste - action required by ~2017
  - "Special" hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- "Hazardous" option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

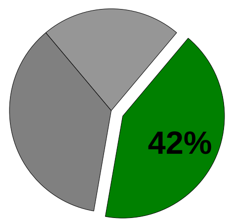
Anticipated EPA Timeline for Retrofits or Replacement



AEP Coal Fleet Assessment

AEP®

Least Exposed



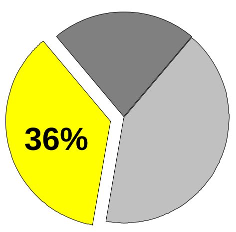
Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

2012 – 2020

Range of Capital ($Millions) (1)

Proposed Rules		Low		High
Water Rules (2)	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules (3)	$	766	$	1,046

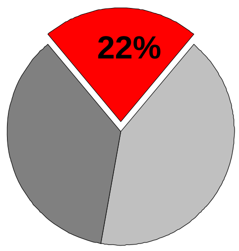
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High (4)
Water Rules (2)	$	26	$	46
CCR Rules	$	357	$	726
Air Rules (3) (5)	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

Key Takeaways

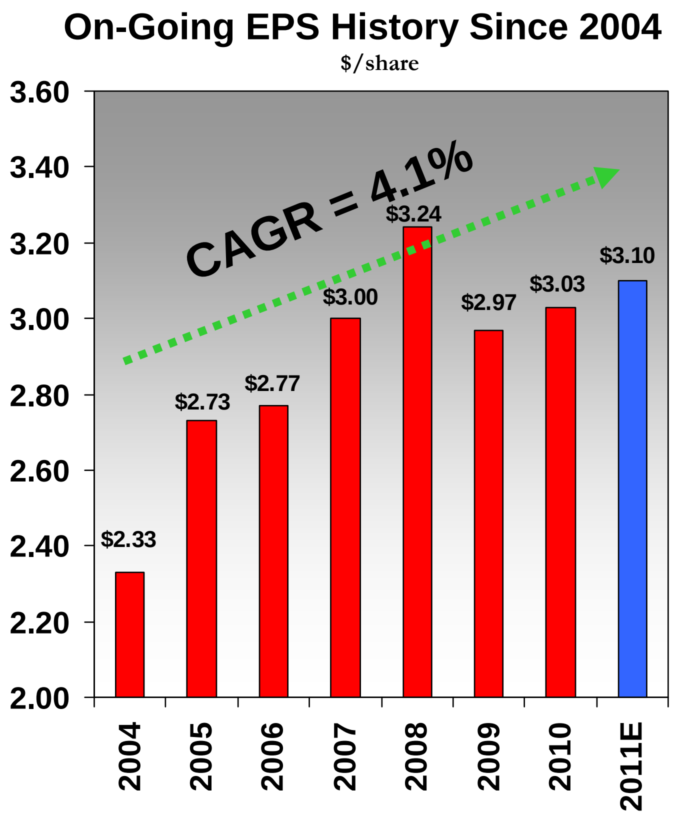
- Established track record of constructing state of the art pollution control equipment
  - 9 scrubbers on 7,900 MW's between 2003-2011(12,000+ scrubbed in total)
  - 12 SCR's on 11,000+ MW's between 2001-2011

- We are supportive of Clean Air Act, but it must be under a feasible timetable
  - Grid reliability concerns
  - Resource availability concerns

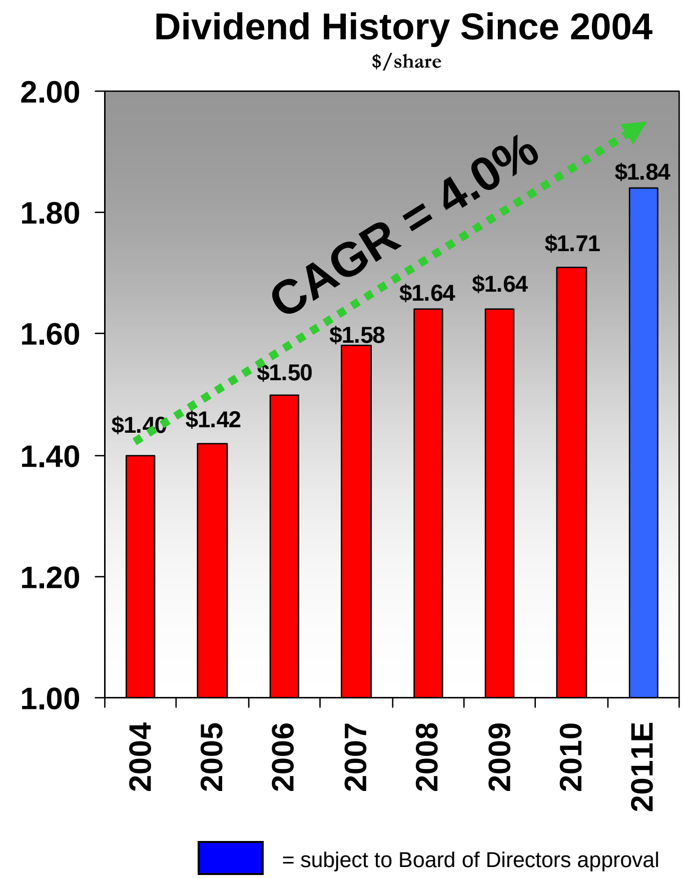
- We are analyzing all the rules together to determine most efficient compliance with the rules
  - Nearly 11,000 MW's will comply without major additions

Appendix

Earnings and Dividends

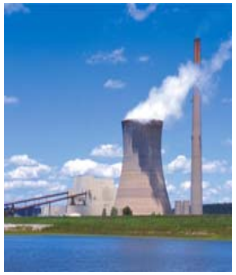


- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

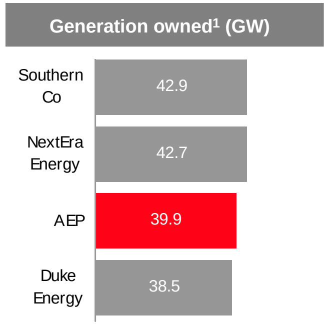


- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend will be paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

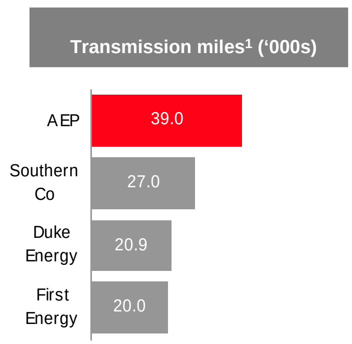
American Electric Power

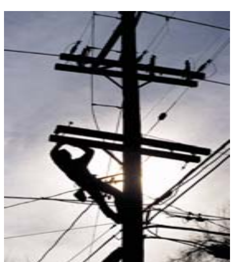


One of the largest U.S. electricity generators

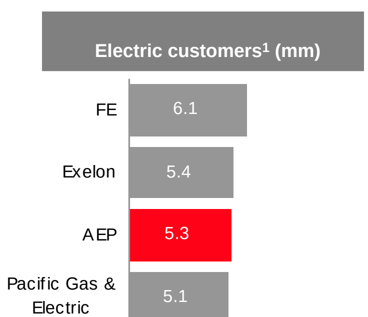


The largest U.S. electricity transmitter



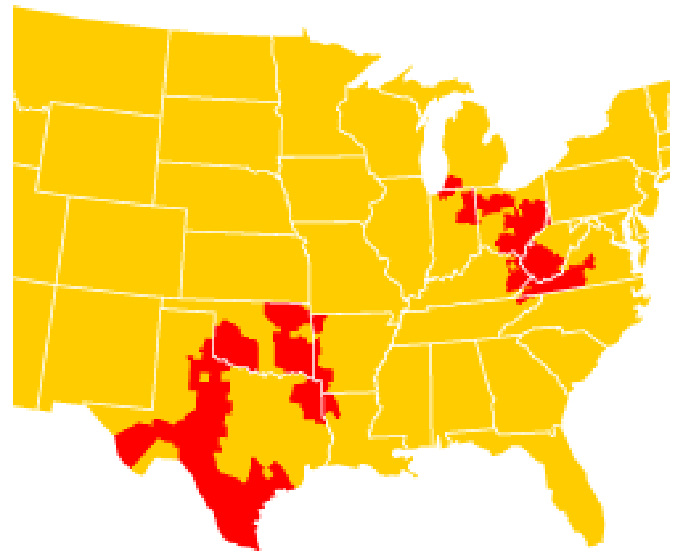


One of the largest U.S. electricity distributors



1 : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

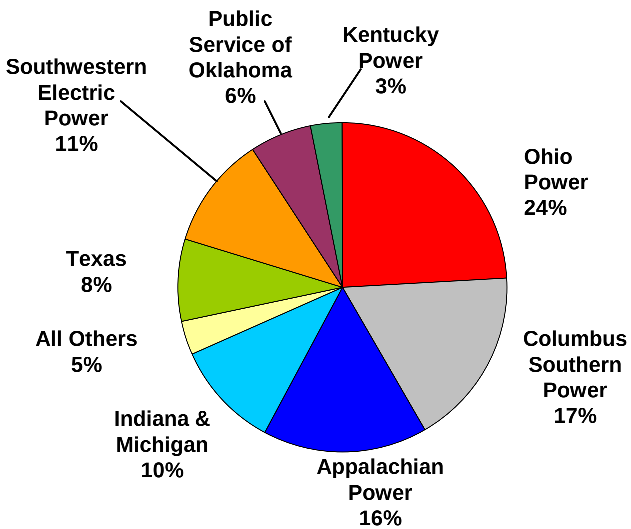
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17B Market Capitalization
BBB/Baa2/BBB credit rating

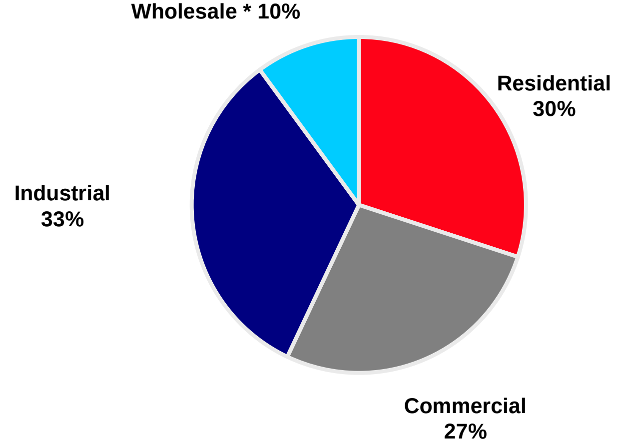
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

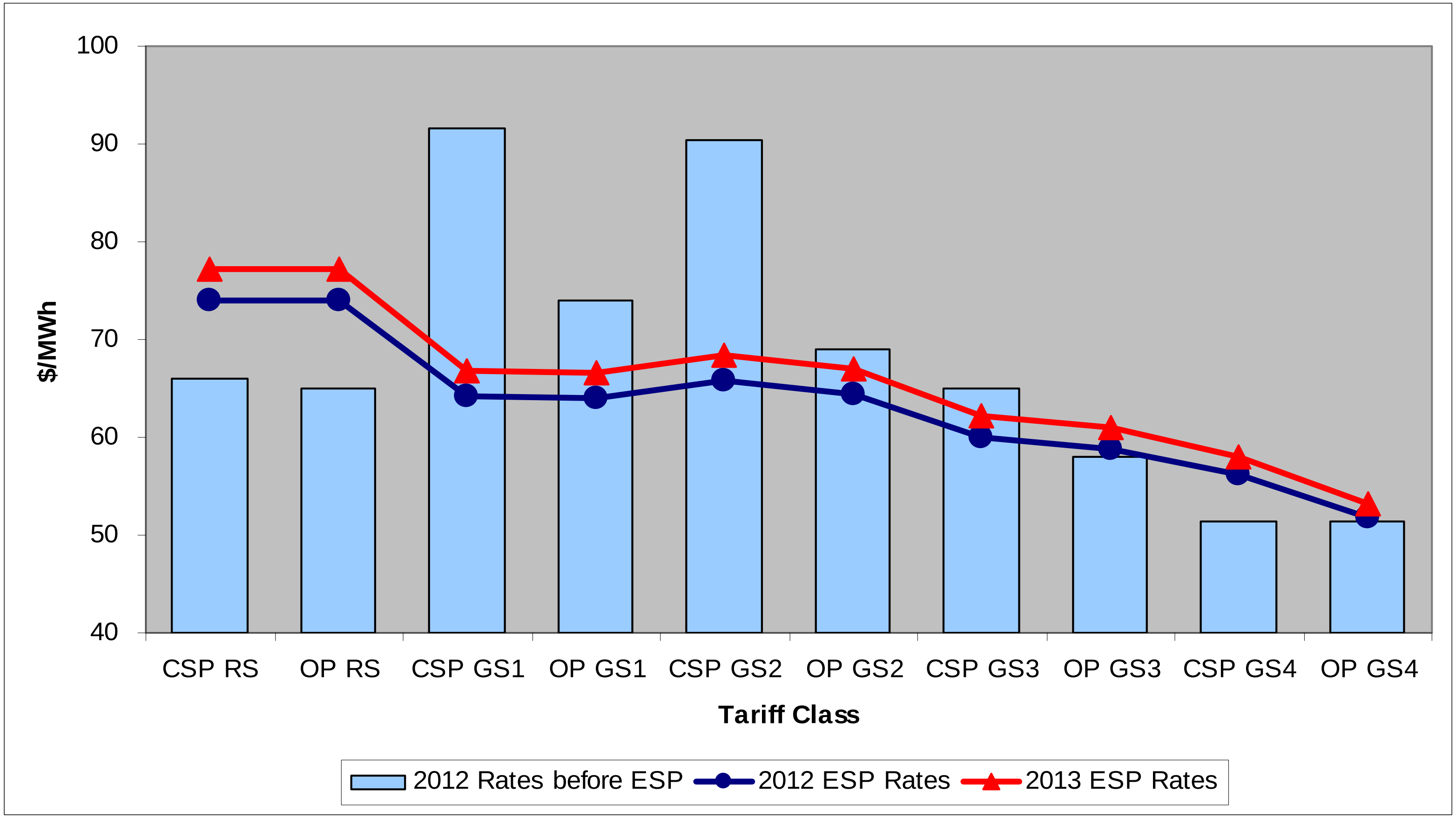
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

AEP®

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Summary Rate Case Information

AEP

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a .50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Detailed Ongoing Earnings Guidance

2010A: $3.03

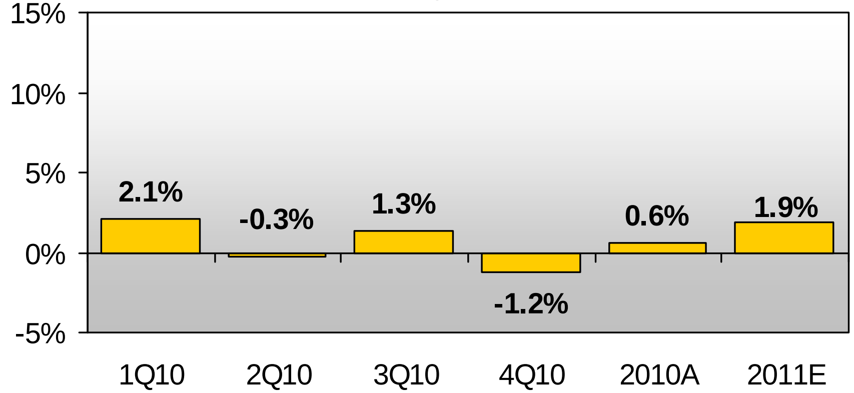
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

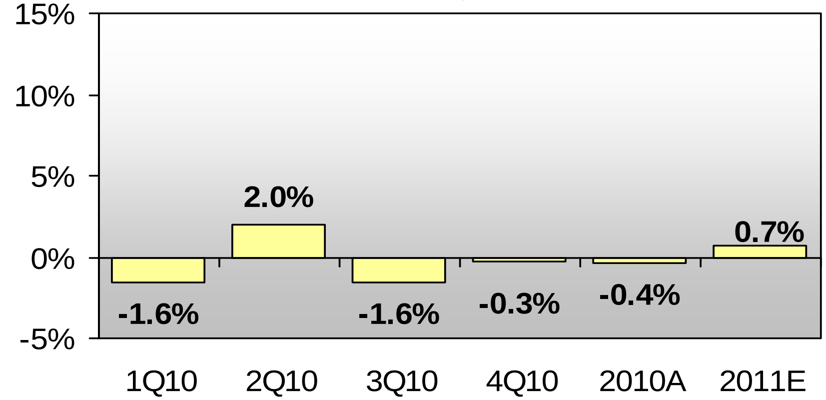
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

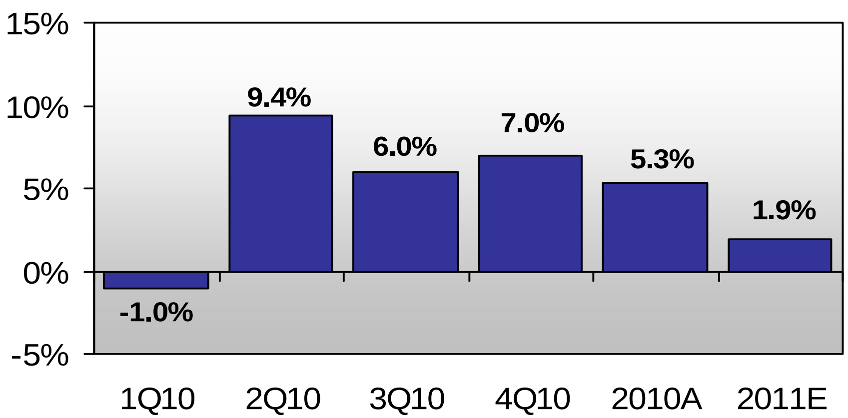
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



AEP Commercial Normalized GWh Sales
%Change vs. Prior Year

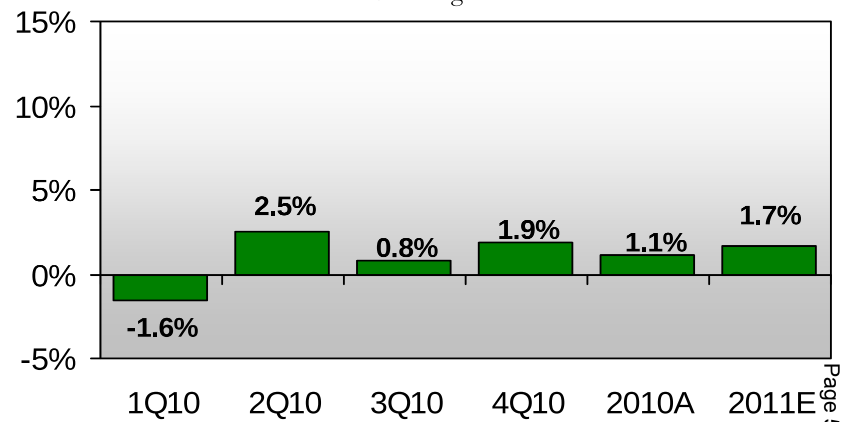


AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



Note: Chart represents connected load

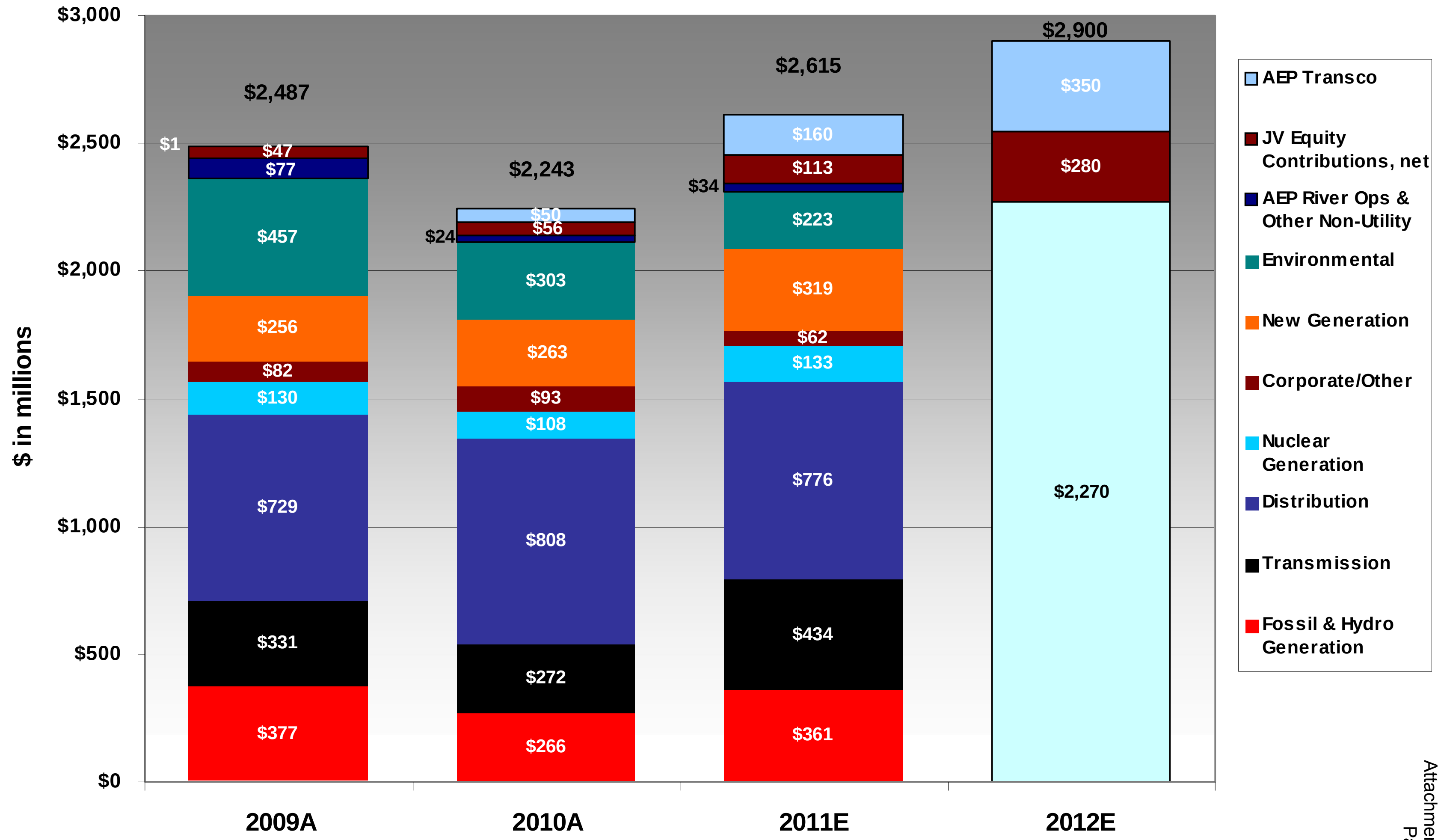
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

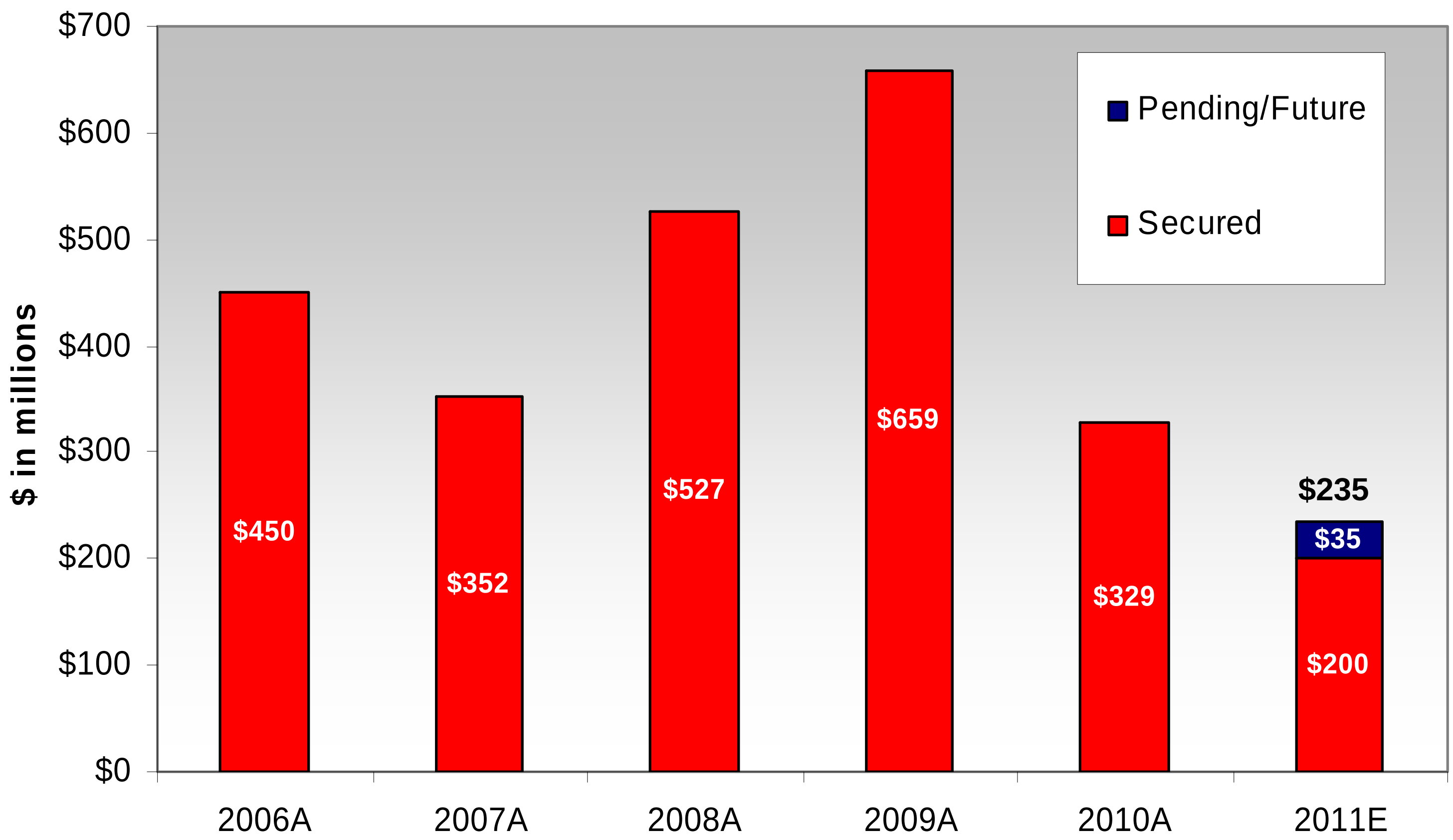
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

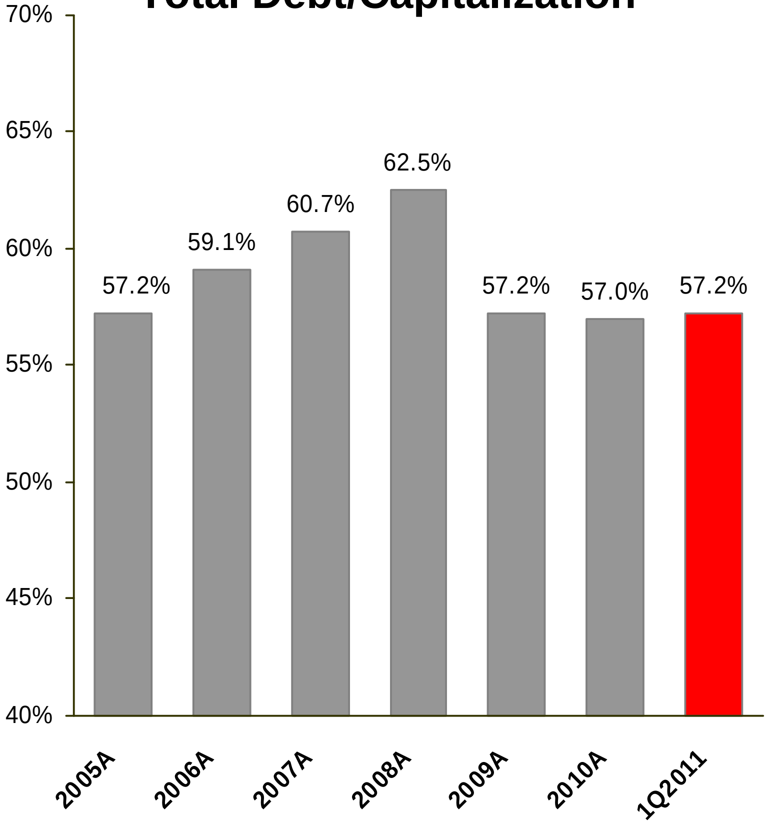
Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 04/25/11**	
($ in millions)	**Amount**	**Maturity**
5-Year Revolving Credit Facility	$1,500	Jun-13
5-Year Revolving Credit Facility	$1,454	Apr-12
Total Credit Facilities	**$2,954**	
Plus		
AEP, Inc. cash and investments	**$368**	
Less		
Commercial Paper Outstanding	$727	
Letters of Credit Issued	$124	
Total Borrowings	**$851**	
Net Available Liquidity	**$2,471**	

Long-term Debt Maturity Profile

AEP®

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[1]	$120	-	$535
Texas North Company	-	-	$225
Total	$616	$630	$1,888

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final

Includes mandatory tenders (put bonds)

Data as of April 26, 2011

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

AEP®

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

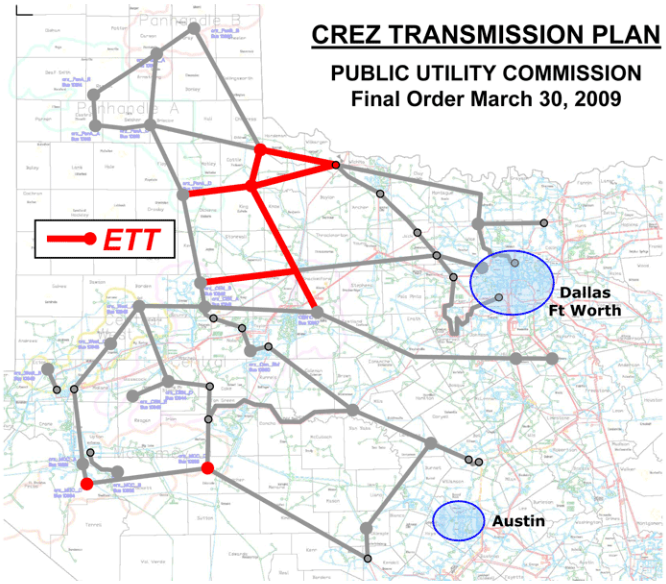
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **<u>Additional Projects in the Pipeline ~$1.6 B:</u>**
  – Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **<u>Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:</u>**
  – Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  – PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transco's is 11.49%
  - ROE order for West Transco's is 11.20%

State Filing Status Update:

- **Ohio** (filed and approved) – PUCO approved the Ohio Transco December 29, 2010
- **West Virginia** (filed) – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- **Arkansas and Louisiana** – Filing date in Arkansas likely early 2011
- **Texas-SPP** – Expecting TX filing in mid 2011
- **Kentucky** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- **Indiana** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- **Virginia** (withdrawn) – Filing withdrawn to give additional time to resolve issues with Staff
- **Michigan and Oklahoma** – Do not require state filing

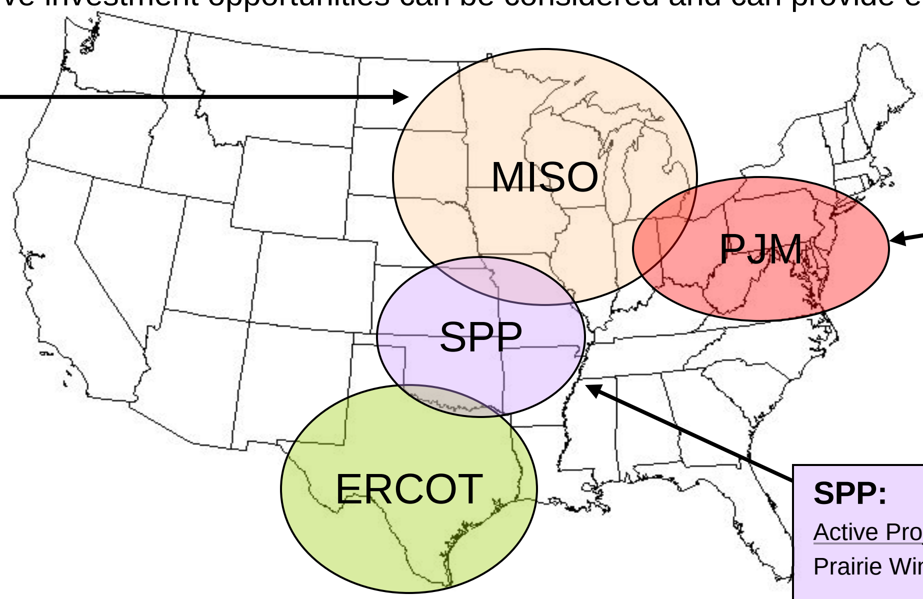
$160M capital spend forecasted for 2011; $350MM for 2012

Joint Venture Strategy: Long-term

- **Strategy:** JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Deutsche Bank Dinner Meeting

Columbus, OH
January 31, 2008

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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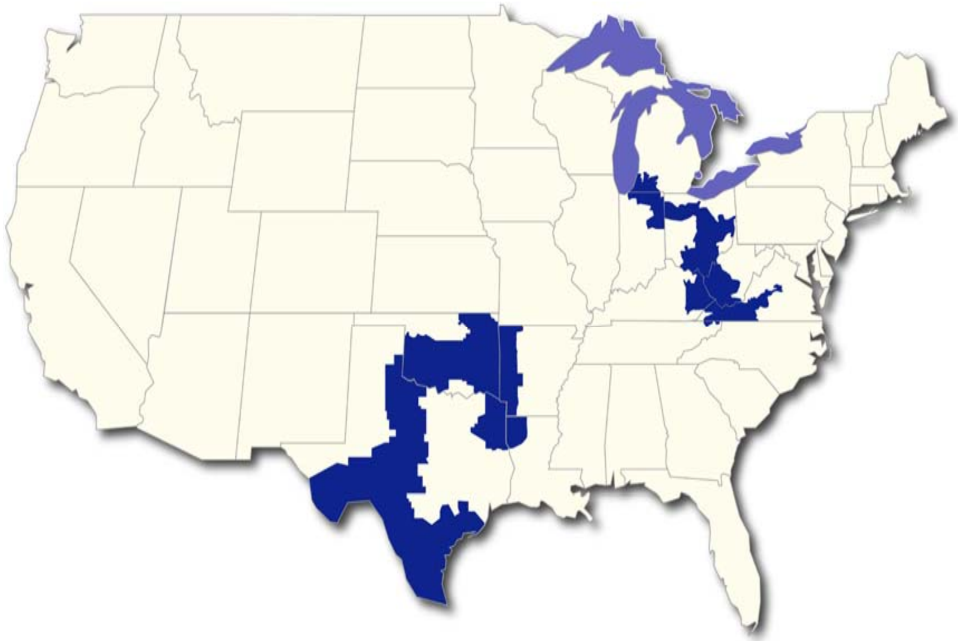
Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~212,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

Vision for Sustainability

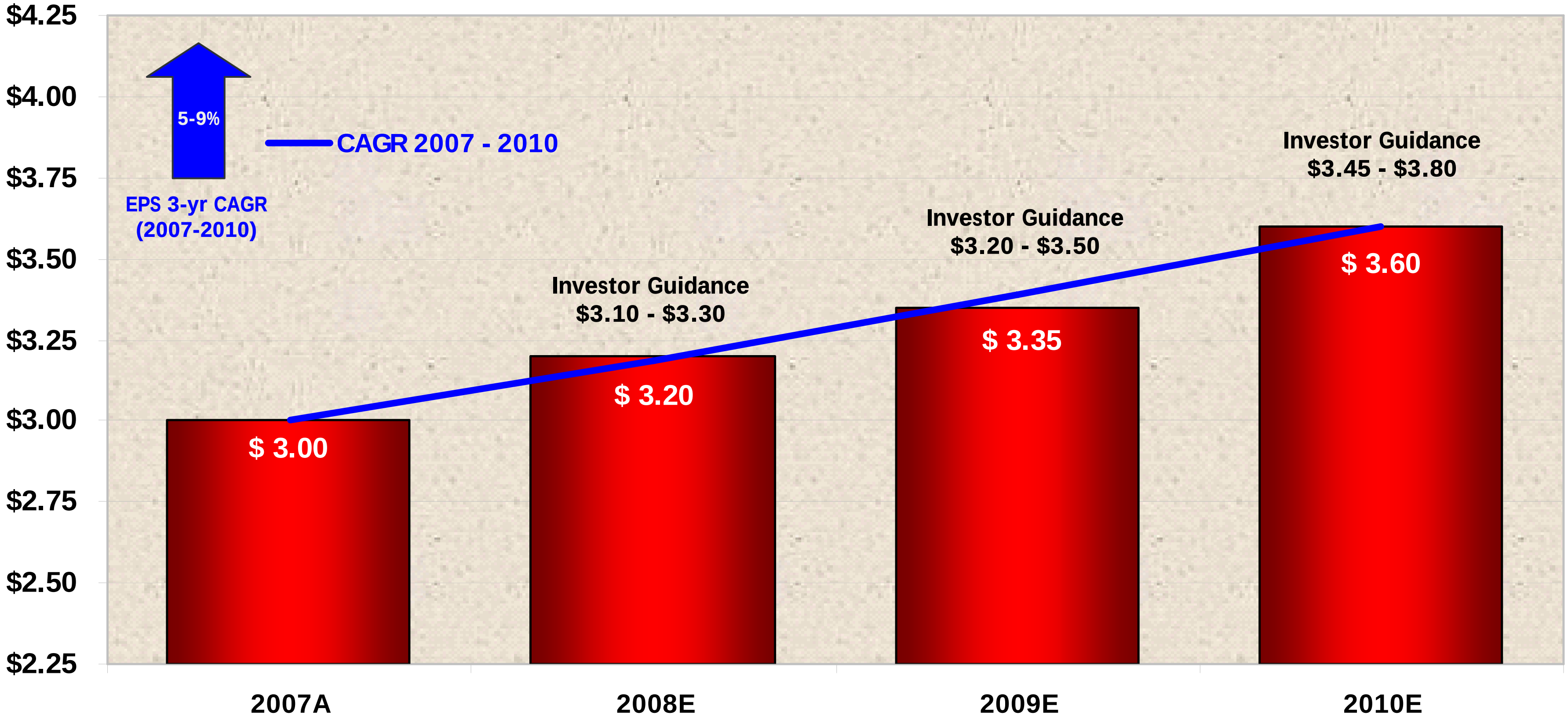
Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

Existing generation and transmission control systems	**GridSMART**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

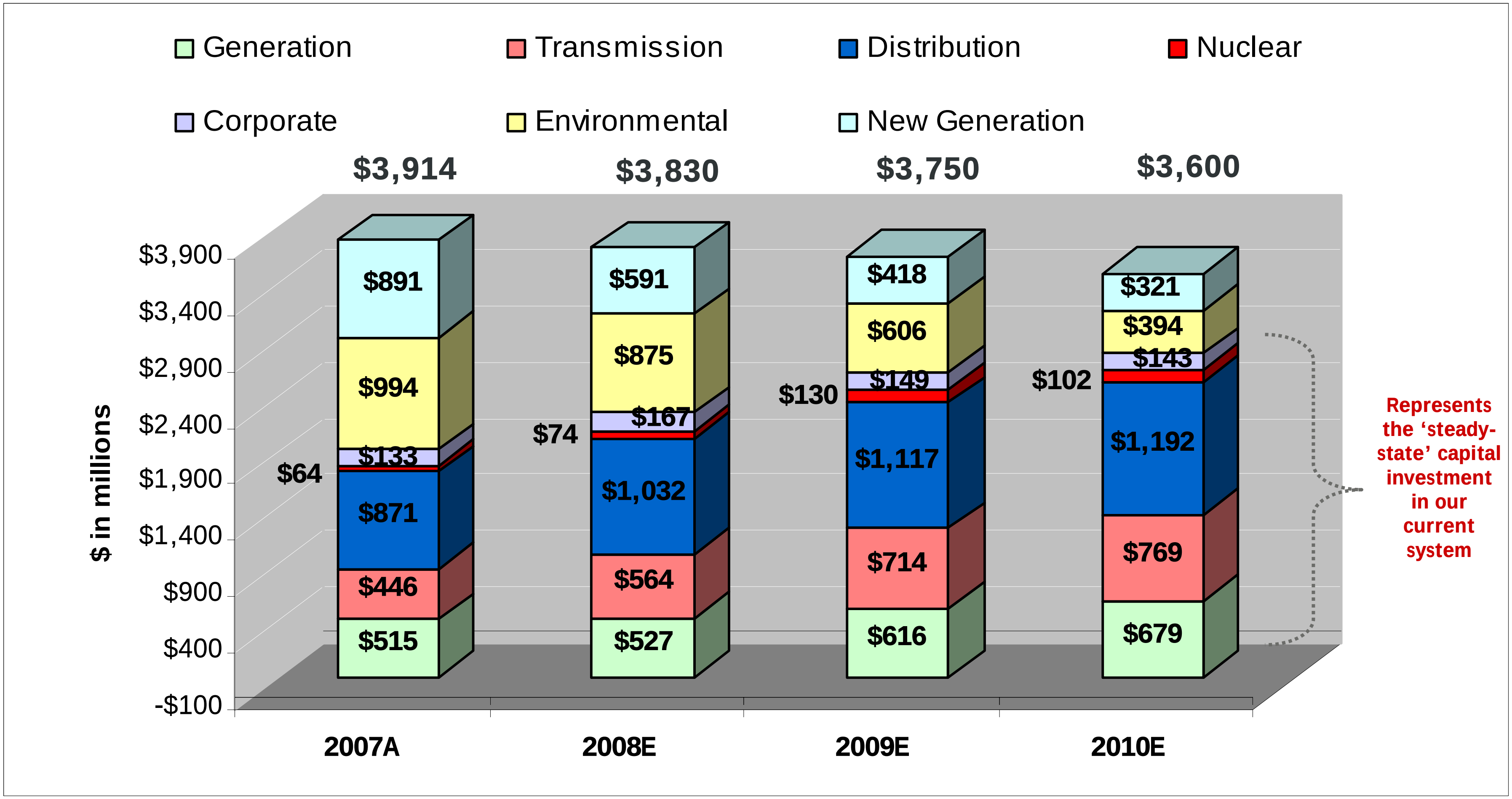
AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

4-Year Earnings Range Forecast



5% to 9% earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$265 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$375 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (2)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	TBD
CSP/OP	Great Bend	Ohio	Under Review (2)	Coal	IGCC	630	TBD

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the current appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- Enables customers to better manage energy
- Improves service to our customers by enhancing customer choice and customer control
- Improves efficiency
- Integrates distributed energy resources into our grid
- Transforms the way we do business

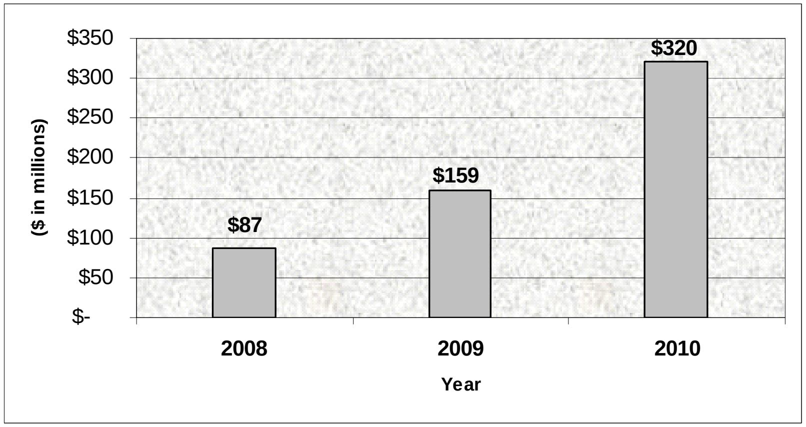
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

Contribution of Transmission Investments

Projected Transmission Capital Spending*

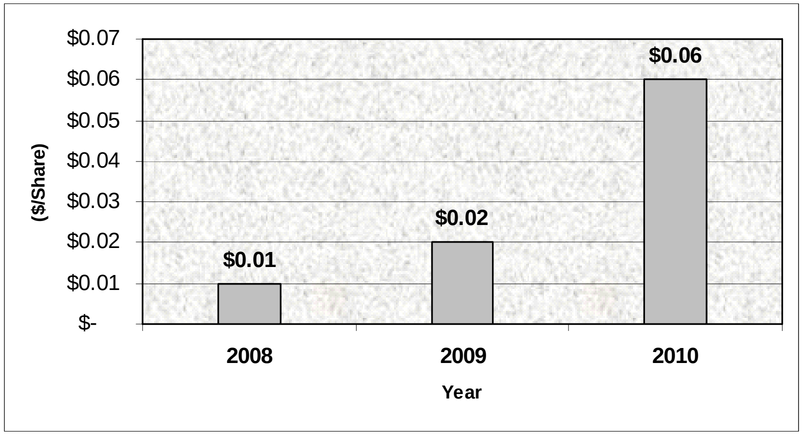


* ETT and PATH projects included in above projection.

Electric Transmission Texas

Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



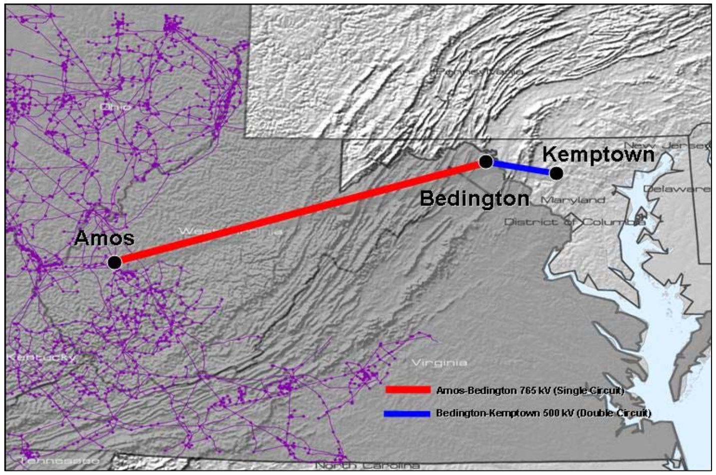
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Note: Transmission Joint Ventures are excluded from AEP's base forecast as shown on slide 8 because they are not consolidated for financial reporting. AEP will be responsible for funding 40-50% of our 50% share with our own capital, and the remainder will be financed with off-balance sheet debt.

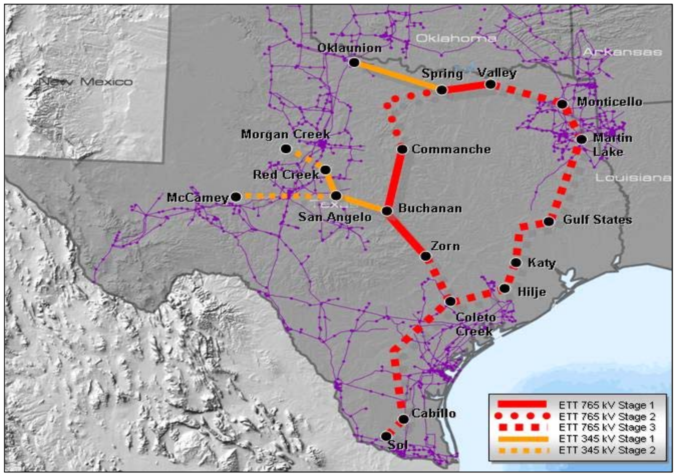
Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission: Investment Opportunities

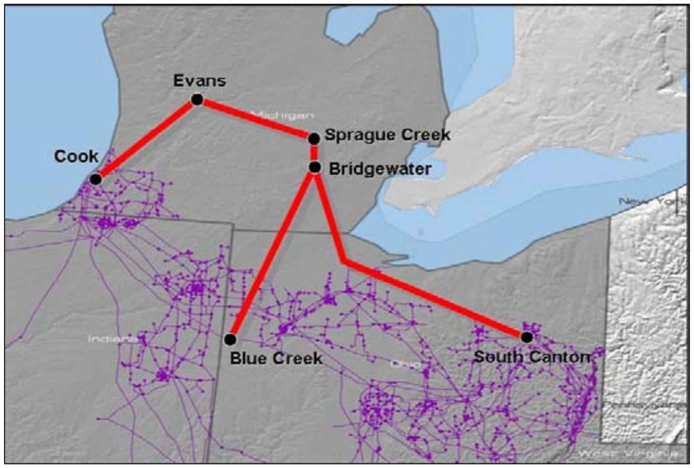
AEP is Advancing the Development of a National Interstate Today



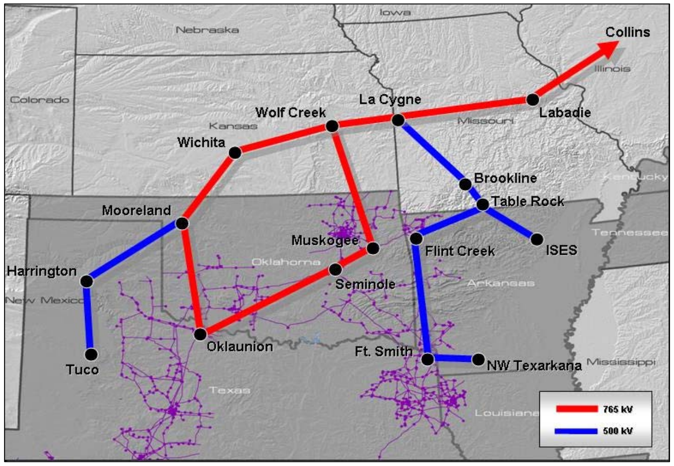
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

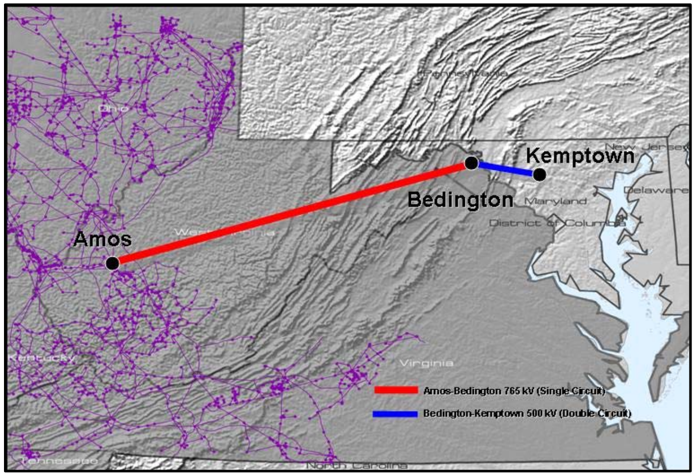


SPP Overlay Study

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, 14.3% ROE, recovery of all costs incurred prior to the time rates go into effect, and recovery of all prudently incurred development and construction costs if the project is abandoned.*
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



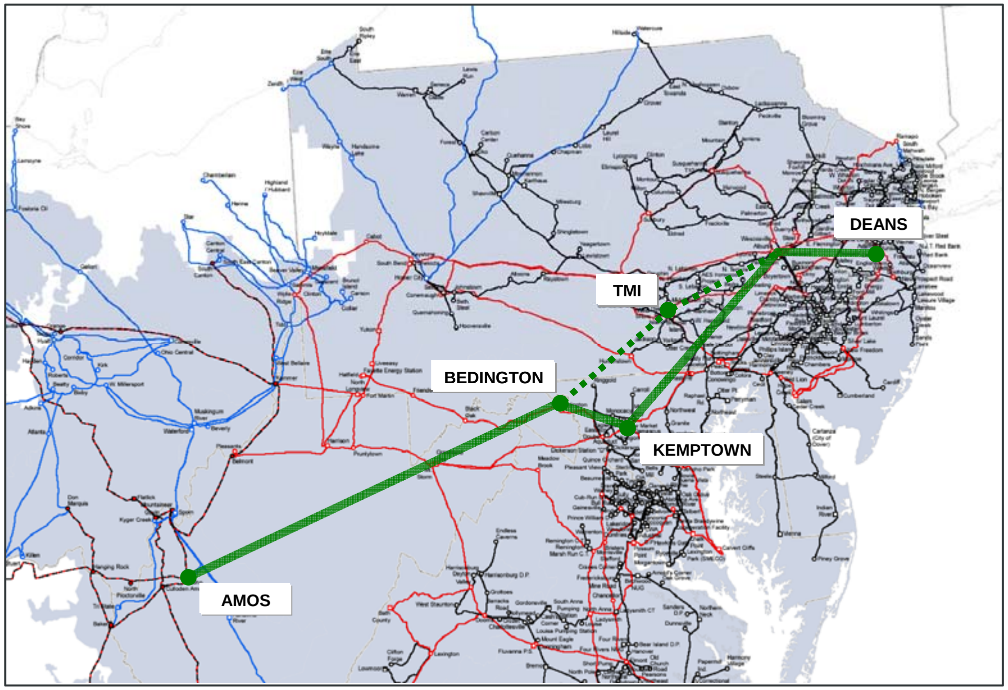
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

I-765TM Transmission in PJM East

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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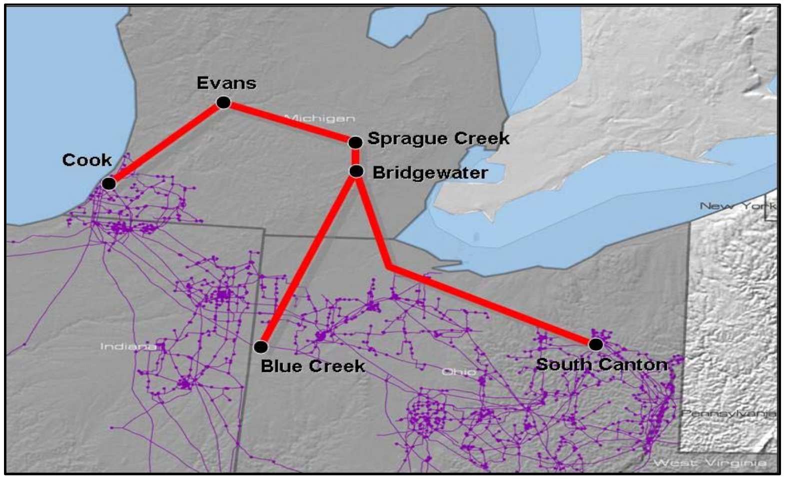
I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015



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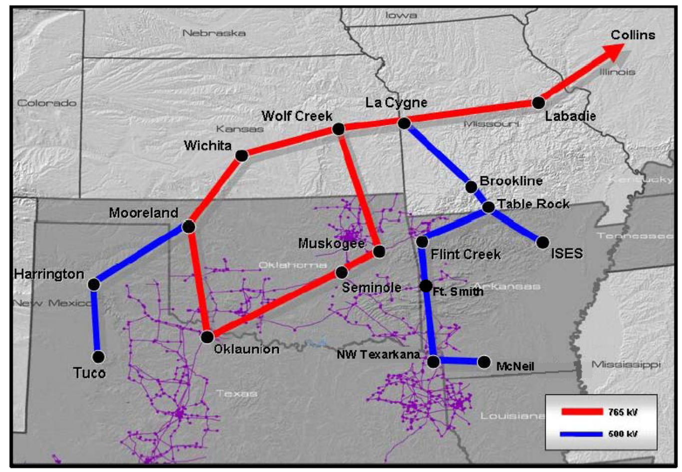
I-765TM Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity
  - Services provided by AEP
  - Investment opportunities can be offered by either partner

- *Transaction Status*
  - PUCT Approved in 2007:
    - ROE of 9.96%
    - Establishment of Transmission Utility Status
    - Transfer of $70 million assets from AEP Texas Central to ETT
  - FERC approval for asset transfer received April 20, 2007
  - Closed JV with Mid-American Energy Holdings Company on December 21, 2007

- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

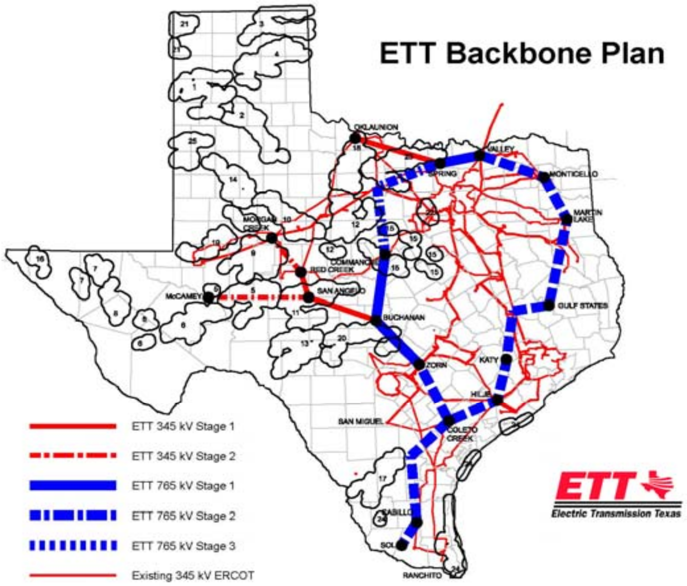
Electric Transmission Texas

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to harvest up to 10GW wind generation
  - Build a robust transmission system for ERCOT Texas
  - $1.5 billion investment Phase 1 – 2012*
  - $1.5 billion investment Phase 2 – 2015*

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



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* Before ownership division.

Advanced Generation & CO_2

Near Term:

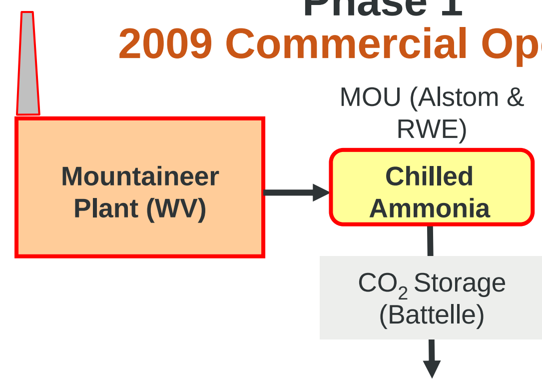
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

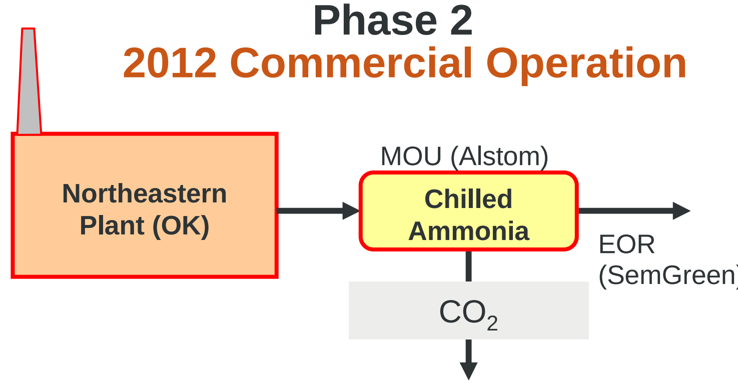
Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

Regulatory Strategy: Reduce Lag

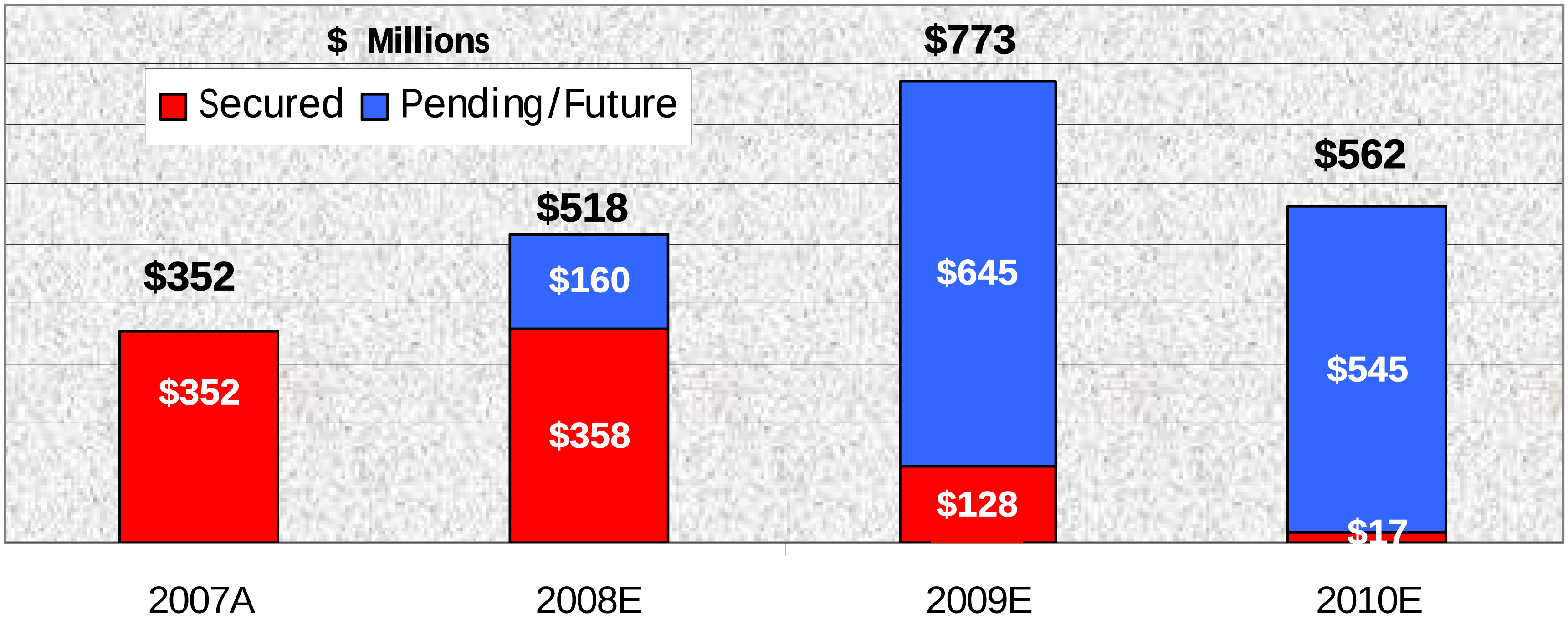
The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

2008 Credit Suisse Energy Summit

Incremental Rate Relief Assumptions



- 2008 Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery.
- 2008 Pending: APCo - Virginia Fuel Factor, PSO January 2007 Ice Storm Recovery, SWEPCo - LA Financial Review, other cases yet to be filed.

69% of the required 2008 rate relief already secured.

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Regulatory Activity Underway

- Ohio Post 2008
- APCo-VA Fuel Factor Adjustment Filing
- I&M - Indiana Base Rate Case
- PSO Storm Cost Recovery Filing
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO’s authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Appendix

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Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual		Projection	
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

2008 Projected Cash Flow

	2007 Actual	2008 Estimate
Beginning Cash Balance	$ 301	$ 178
Cash from Operations:		
Income from Continuing Operations	1,065	1,284
Depreciation and Amortization	1,513	1,484
Other	(190)	(196)
Total from Operations	2,388	2,572
Cash used for Investing:		
Construction Expenditures	(3,556)	(3,916)
Asset Sales	222	-
Distressed Generation Purchases	(512)	-
Other	(62)	(39)
Total used for Investing	(3,908)	(3,955)
Cash from Financing:		
Issuance of Common Stock, Net	143	150
Long-Term Debt Issued/(Retired), Net	1,260	1,883
Short-Term Debt Change, Net	642	(87)
Common Dividends	(630)	(659)
Other Financing Activities	(18)	44
Total from Financing	1,397	1,331
Net Change in Cash	$ (123)	$ (52)
Ending Cash Balance	$ 178	$ 126

Note: For analysis purposes, construction expenditures include AFUDC.

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$489	$206	$120	$90	**$905**
Total Capex	**$3,915**	**$3,830**	**$3,750**	**$3,600**	**$15,095**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

2008 Regulatory Activity Completed

AEP Ohio Application For 4% Provision On Generation Rate

- On January 30, 2008, a settlement agreement was approved by the PUCO allowing the generation rider to be increased to recover in 2008 an additional $28.5 million for CSPCo and $4.9 million for OPCo.
- The approved settlement also authorized the inclusion of $78 million of estimated net costs of marginal losses ($38.9 million for CSPCo and $39.2 million for OPCo) in the existing Transmission Cost Recovery Rider, with any over/under recovery of the actually incurred costs from June 2007 through December 2008 to be reflected in the 2009 TCRR recovery mechanism, including carrying charges on any such over/under recovery.

Regulatory Activity Underway

Ohio Post-2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearing schedule extends to the end of January 2008 and we anticipate a signed bill in March or April of 2008.

APCo (Virginia) Fuel Factor Adjustment

- On July 16, 2007, a filing was made with the VA SCC requesting the termination of the OSS base credit and reflected 75% of OSS margins as a credit to fuel expense, consistent with new Virginia legislation. Implementation of the fuel factor was approved effective September 1, 2007, subject to review/refund.
- Intervenor testimony was filed on October 5, 2007, staff testimony filed on October 15, 2007 and rebuttal testimony filed on October 22, 2007. APCo's rebuttal testimony included adding $18.8 million to the fuel factor request related to the recovery of PJM marginal losses incurred.
- Public hearings were held on December 19, 2007. We await an order in this proceeding.

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Regulatory Activity Underway

I&M Indiana Base Rate Case

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.
- Hearings are expected in May 2008, and an order in the first quarter of 2009.

Regulatory Activity Underway

PSO Storm Cost Recovery Filing

- On October 24, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of sulfur dioxide (SO_2) emission allowances.
- Staff and intervenor testimony was filed January 17, 2008, a settlement conference is scheduled for February 25, 2008 and hearings are scheduled for February 27 and 28, 2008.
- Staff and AG testimony was supportive of PSO's requested treatment for cost recovery.

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- PSO requests the Commission make a determination that the costs incurred on the Red Rock project were prudent and direct it to establish a regulatory asset of approximately $21 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of SO_2 emission allowances.
- A procedural schedule in the case has not yet been established.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Technical conferences and settlement meetings were held in October – December 2007. Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. An order is due by March 6, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings are scheduled for February 12, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected in the first quarter of 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony is due February 15, 2008, rebuttal testimony is due February 29, 2008 and hearings will commence on April 7, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

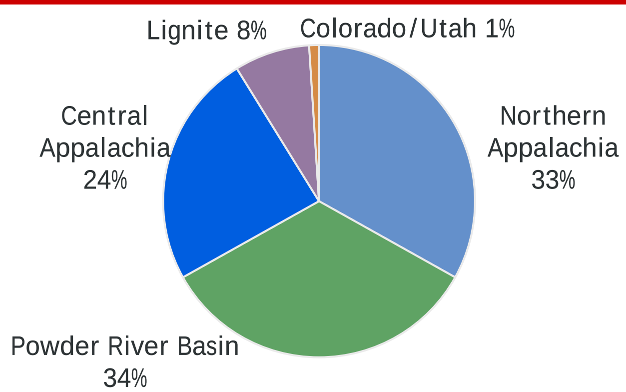
Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	7.29%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	23.86%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	13.01%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo-LA	$434MM	11.10%	12/29/1999	8.74%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	11.33%
Texas-TNC	$530MM	9.96%	6/1/2007	9.93%

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

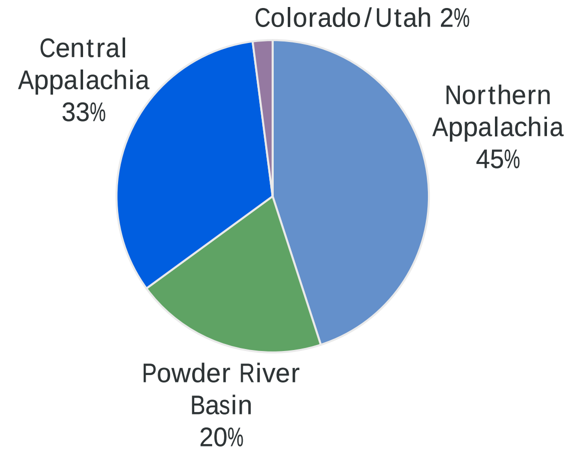
Total AEP System



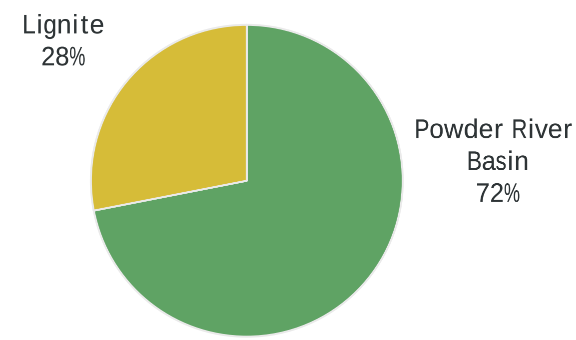
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

AEP East



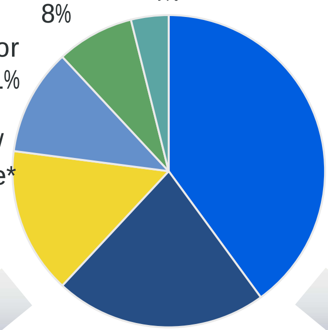
AEP West



Coal Delivery

Total AEP System

2007 Actual



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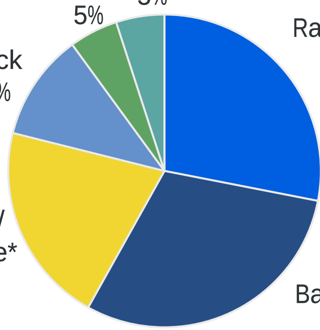

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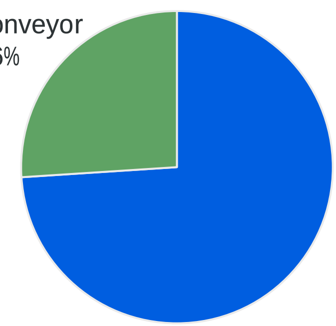

* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Deutsche Bank Securities Investor Meeting

"Ohio Utility Field Trip"

August 13, 2008

Columbus, Oh

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Julie Sherwood – Director, IR
Jana Croom – Investor Relations Analyst

Table of Contents

Highlights of AEP Ohio's ESP Filing

		2009		2010		2011		
		CSP	OPCo	CSP	OPCo	CSP	OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		**Other Components**		**Other Components**		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested a phase-in of proposed incremental FAC expenses during the three-year ESP period.Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 & PJN-10 provides calculation of the environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: We requested an annual 7% & 6.5% per year increase in Distribution for CSP and OPCo, respectively. Exhibit DMR-4 shows both expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response and energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009 CSP	2009 OPCo	2011 CSP	2011 OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	**-$80.7M**	**-$27.1M**	**$22.8M**	**$15.2M**

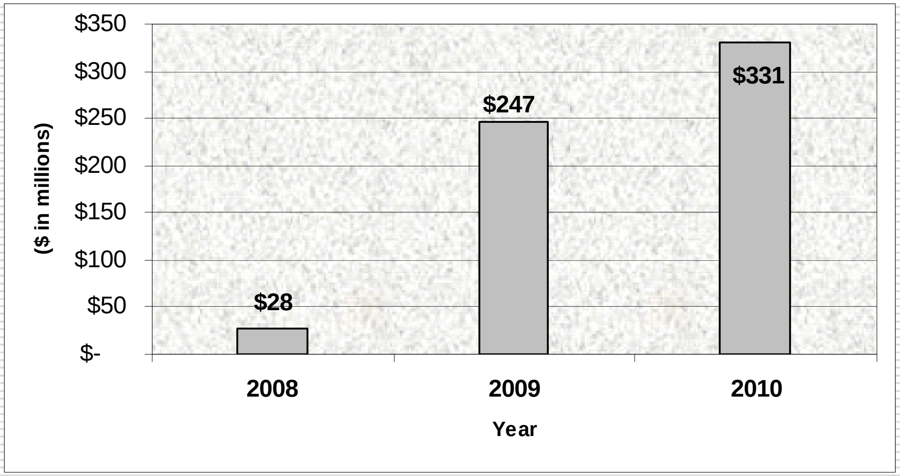
A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

In 2011 we have requested the authority to start amortizing deferrals previously approved by the PUCO, including customer choice (ETP and RSP cases), among others.

Note 8: $25 million will be provided annually by AEP Ohio to a "Partnership with Ohio" fund created by AEP Ohio for low-income assistance and economic development.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

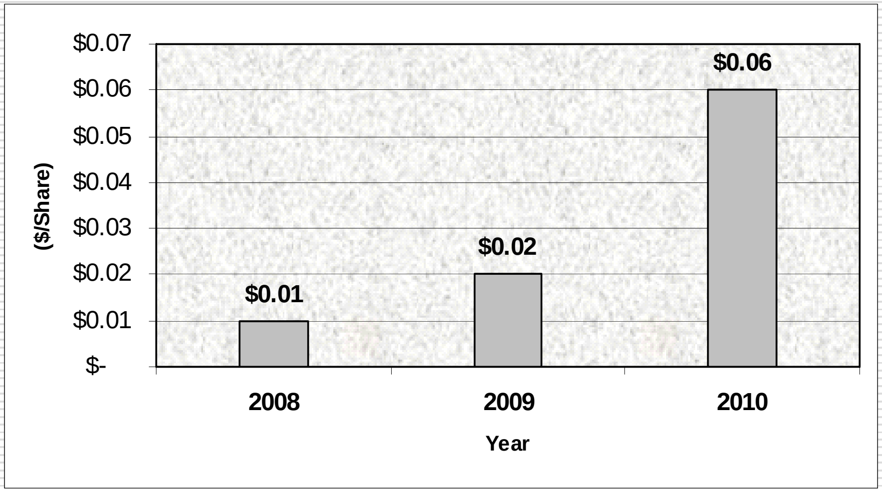


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

PATH
Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



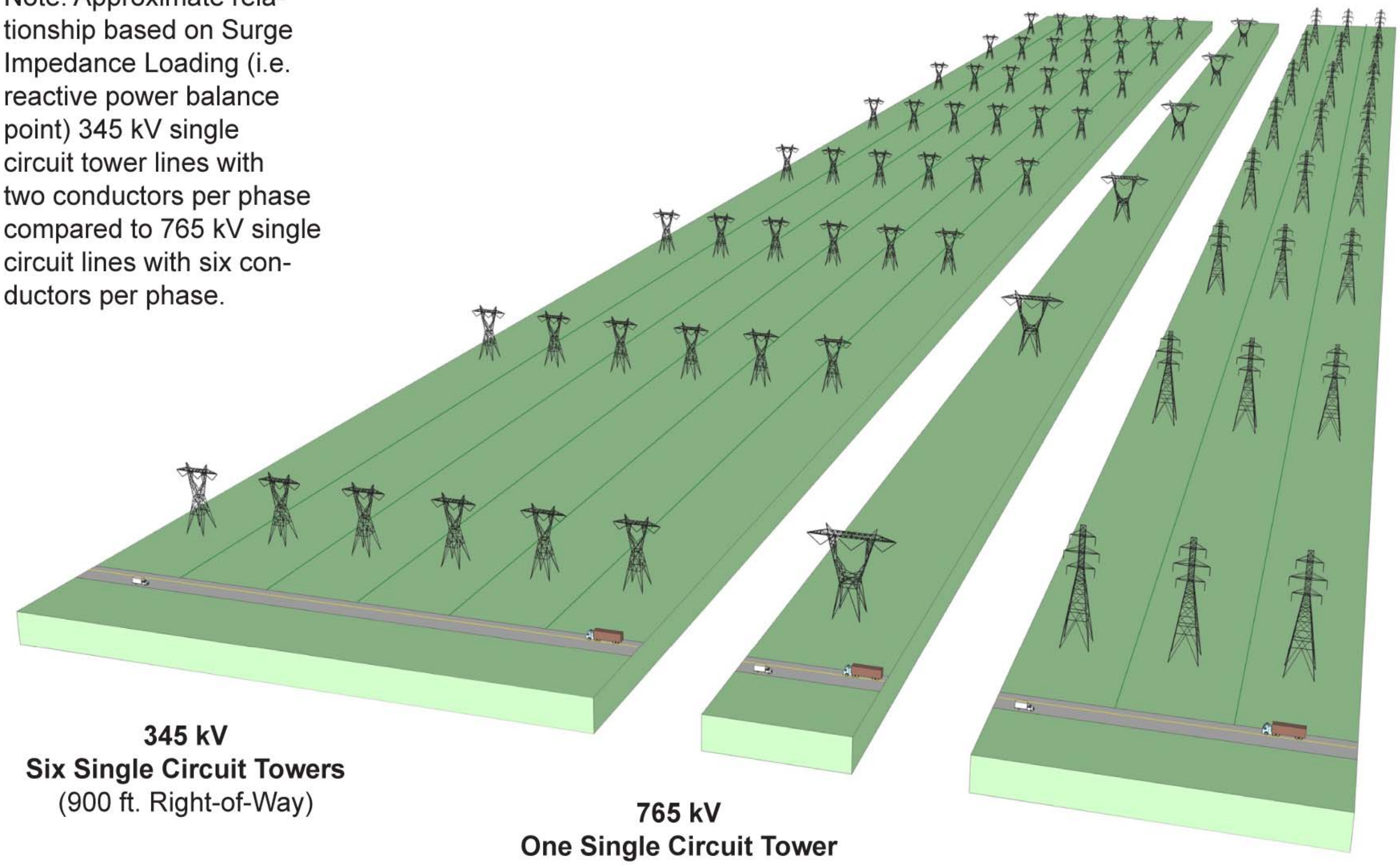
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

AEP®

Transmission will provide a near and long term catalyst for growth.

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

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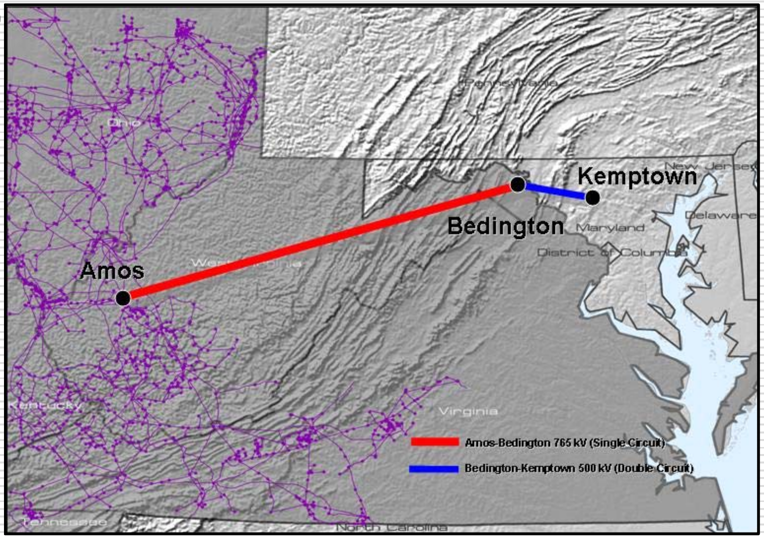
I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures

- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

Potomac-Appalachian Transmission Highline

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Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

AEP®

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ***Next Steps***
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

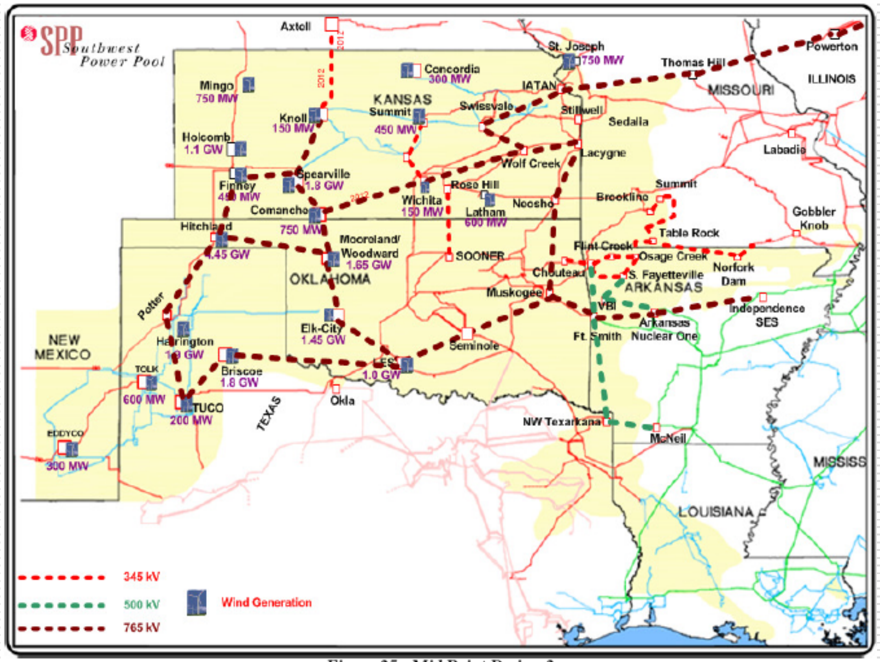

Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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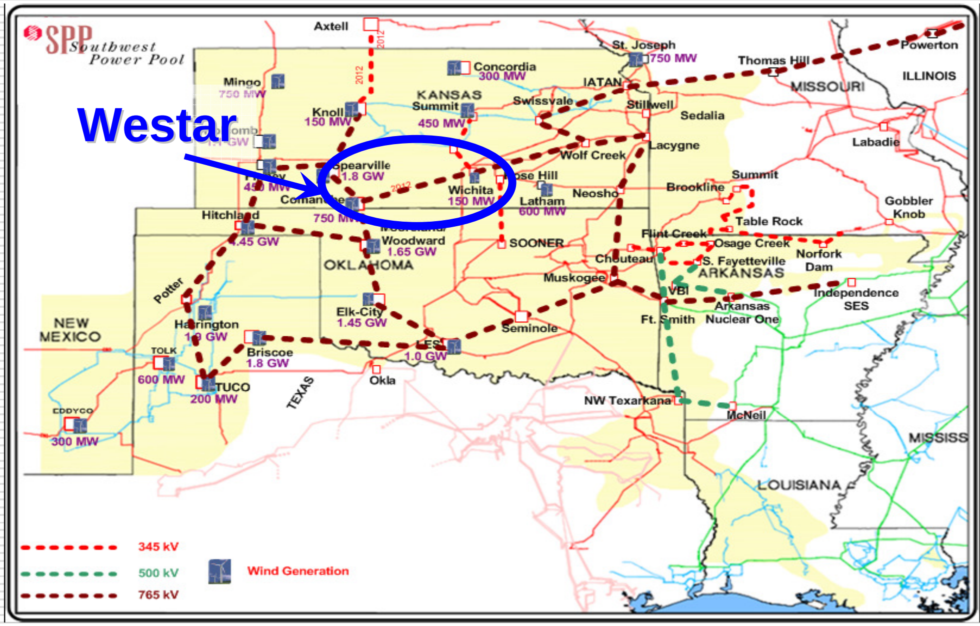
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – 2009
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



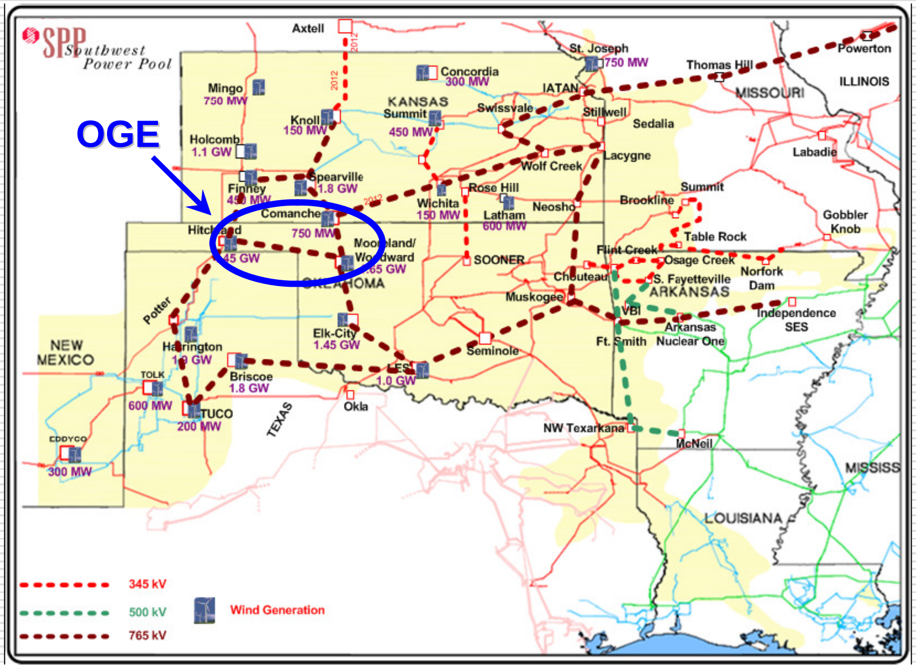
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- *Overview*
  - On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

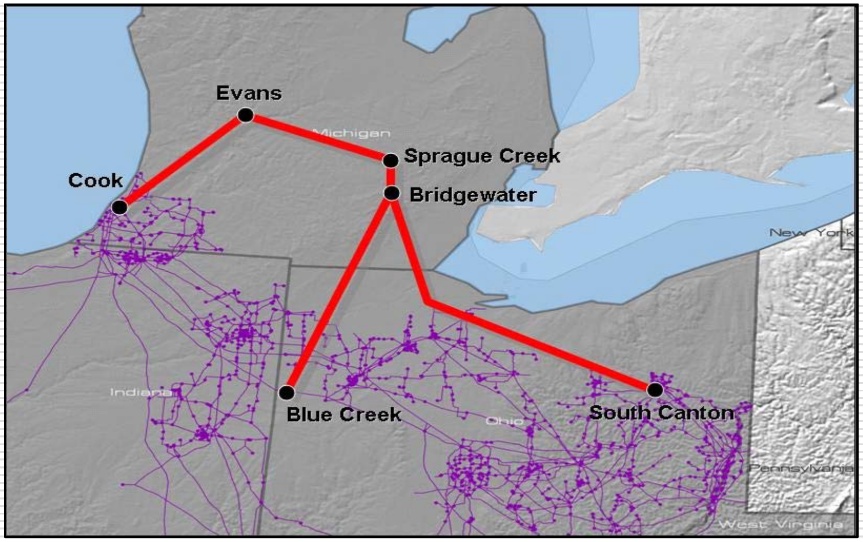
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate - 2009
  - SPP Cost Allocation Filing – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013

AEP®

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

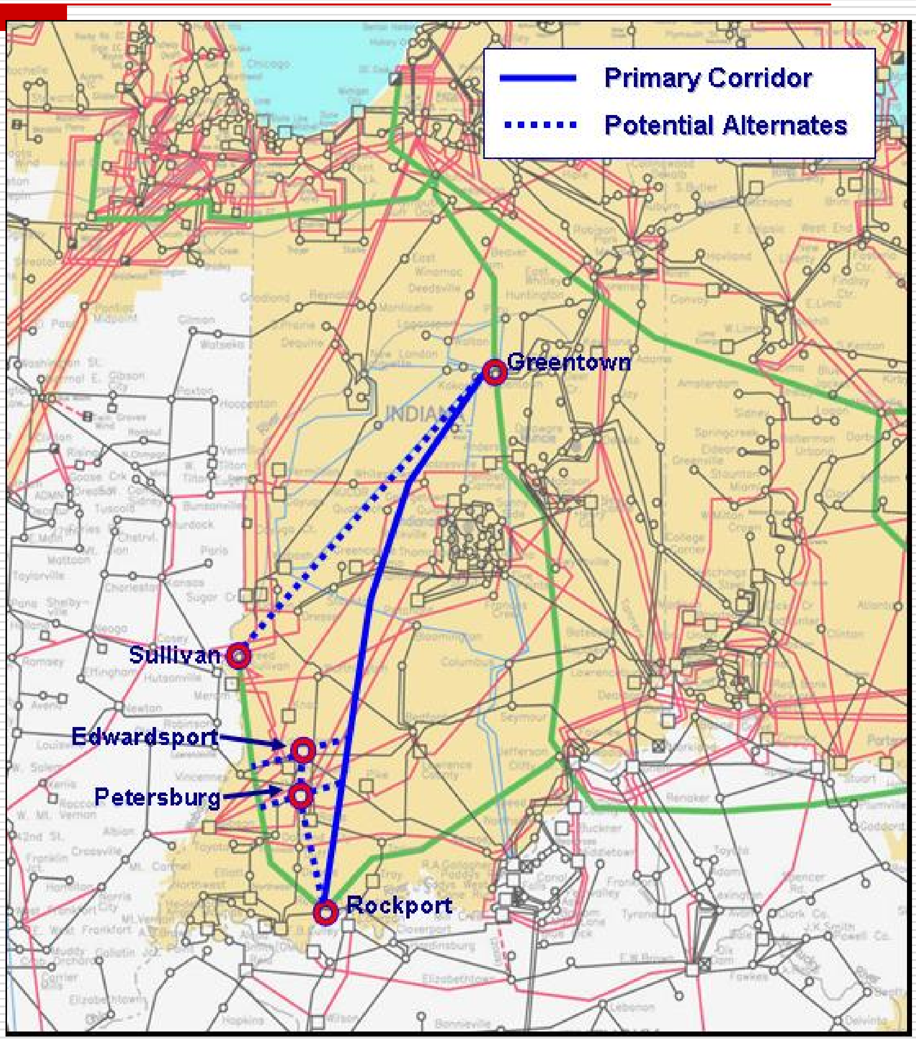
- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate & Cost Allocation Filing - 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on th routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.

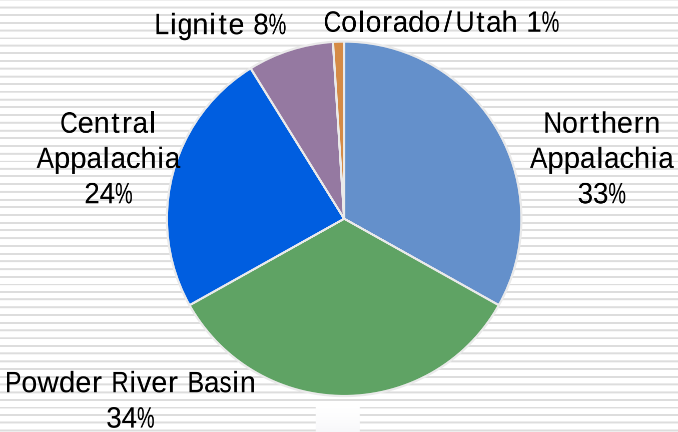


- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

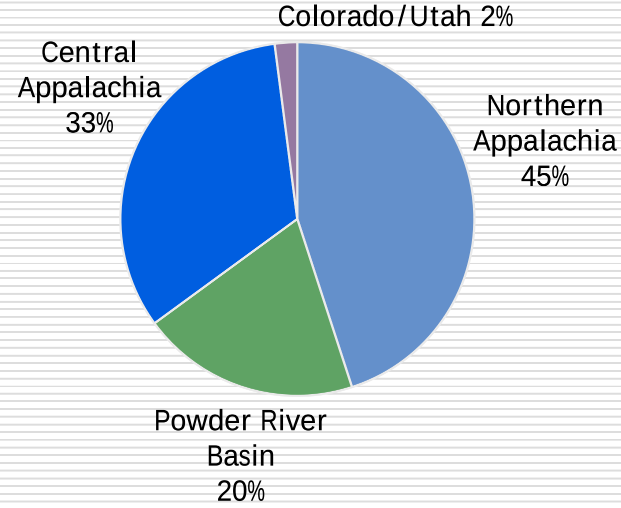
Total AEP System



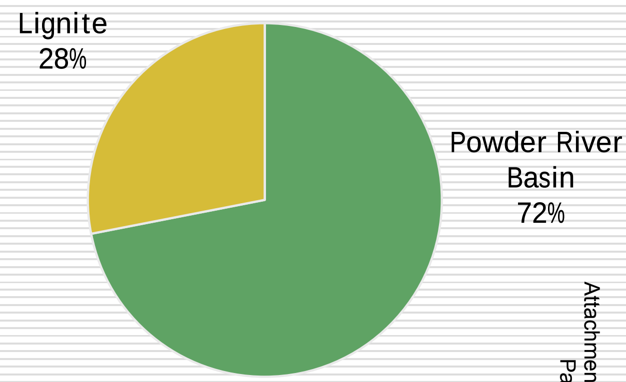
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East



AEP West

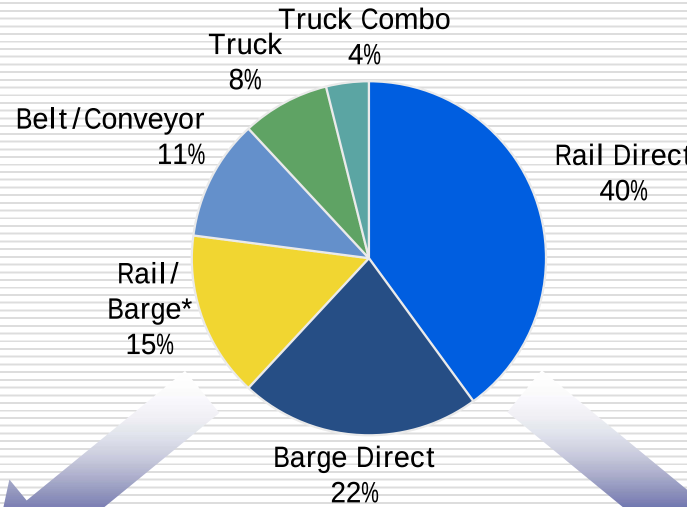


AEP®

Coal Delivery

Total AEP System

2007 Actual



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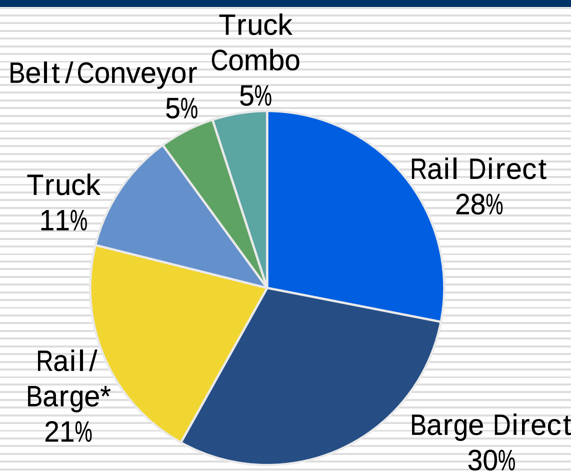

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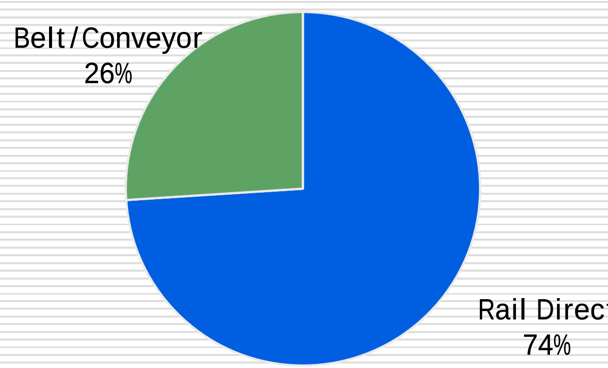

* Reflects coal delivered to AEP plants transported through a combination of rail and barge

American Electric Power

Company Update / Overview

Oslo & Dublin
October 2007

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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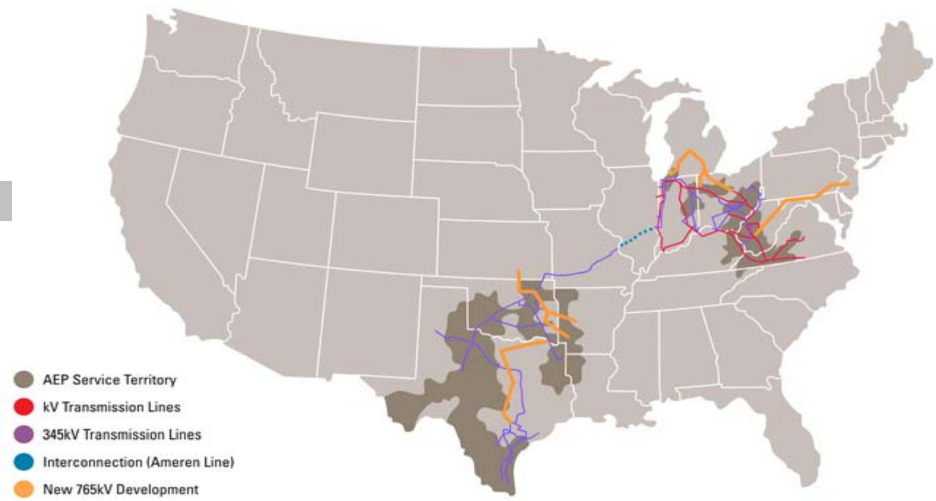
The AEP Footprint

Strength & Scale in Assets & Operations

- **5.1 million customers in 11 states**
- **Industry-leading size and scale of assets:**

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	#2
Transmission	~39,000 miles	#1
Distribution	~208,000 miles	#1

- **Coal & transportation assets:**
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity



AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
67%	24%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

- Prepare for transition to market in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to bring economic savings to our customers while continuing to enhance shareholder value through regulatory-supported investment and operational excellence

Sustained capital investment opportunities support earnings growth.

2007 Delivered Results

Accomplishments:

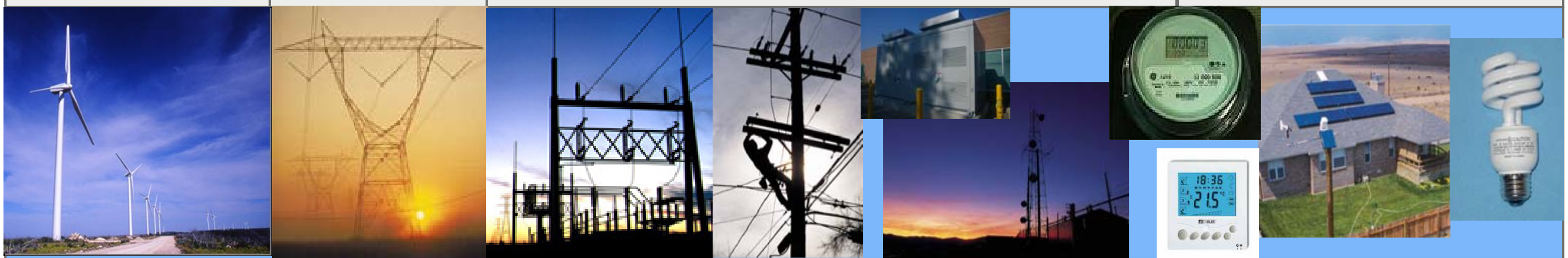
- ✓ **Acquisition of low-cost generation to meet capacity demand**
  - Darby—480MW simple cycle ($227/kW)
  - Lawrenceburg—1,140MW combined cycle ($295/kW)
  - Dresden—580MW combined cycle (currently under construction); anticipated all-in cost $600-$700/kW
- ✓ **Brought SWEPCo's Mattison Units 3&4 (150MW) on-line July 2007 (~$380/kW)**
- ✓ **Completed installation of scrubbers at Mitchell & Mountaineer**
- ✓ **Continued progress on transmission opportunities**
  - Obtained PJM approval of Potomac-Appalachian Transmission Highline
  - Formed joint venture with Allegheny Energy to construct the PATH
  - Formed joint ventures with MidAmerican Energy for ETT & ETA
  - Completed technical study with ITC for 765-kV in Michigan and continue to investigate the feasibility of forming a joint venture to develop the project
- ✓ **Secured to-date $325MM of $338MM of 2007 rate relief projections**
- ✓ **On track to deliver 5%-7% growth rate in 2007**

AEP continues track record of capital investment, regulatory approvals and earnings growth.

Vision for Sustainability

Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage



Existing generation and transmission control systems

GridSMART: bridging the gap to provide integrated two-way communications & control across the electricity value chain

Home energy automation

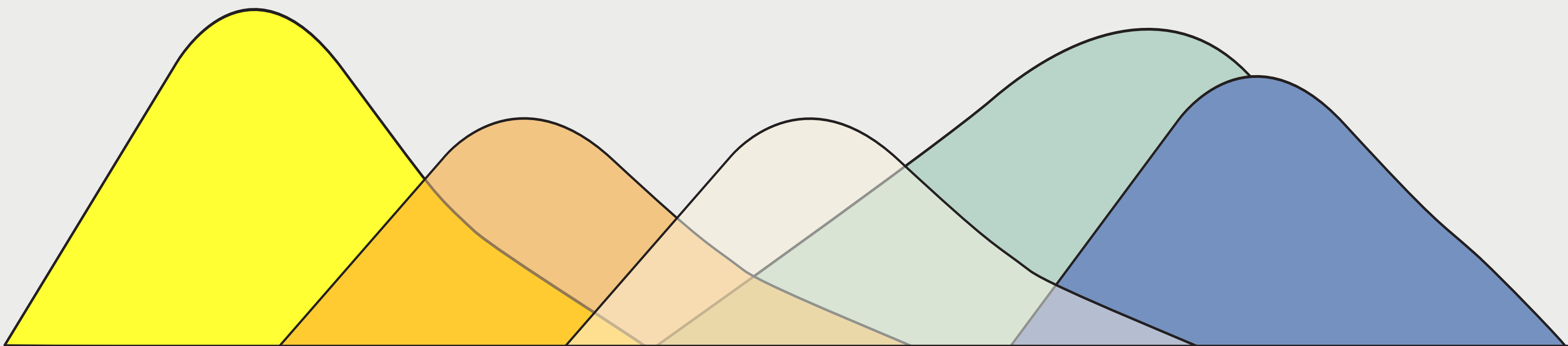
AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



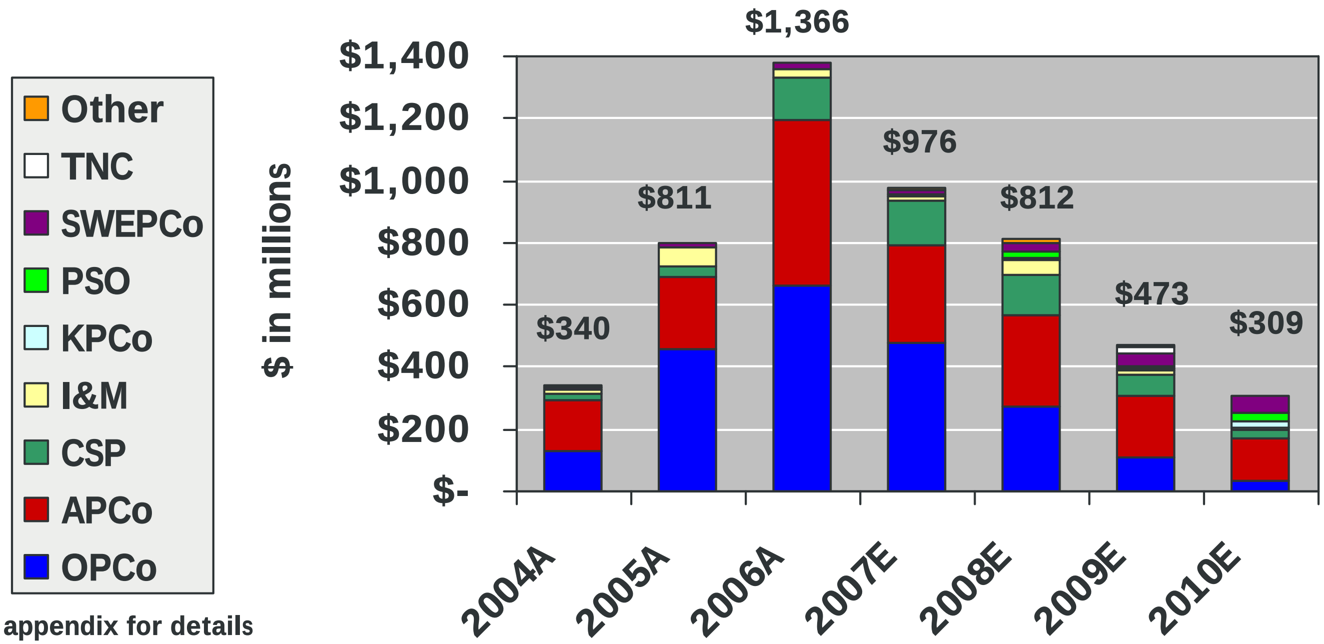
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

Environmental Investments Receive Timely Rate Recovery



See page 40 in appendix for details

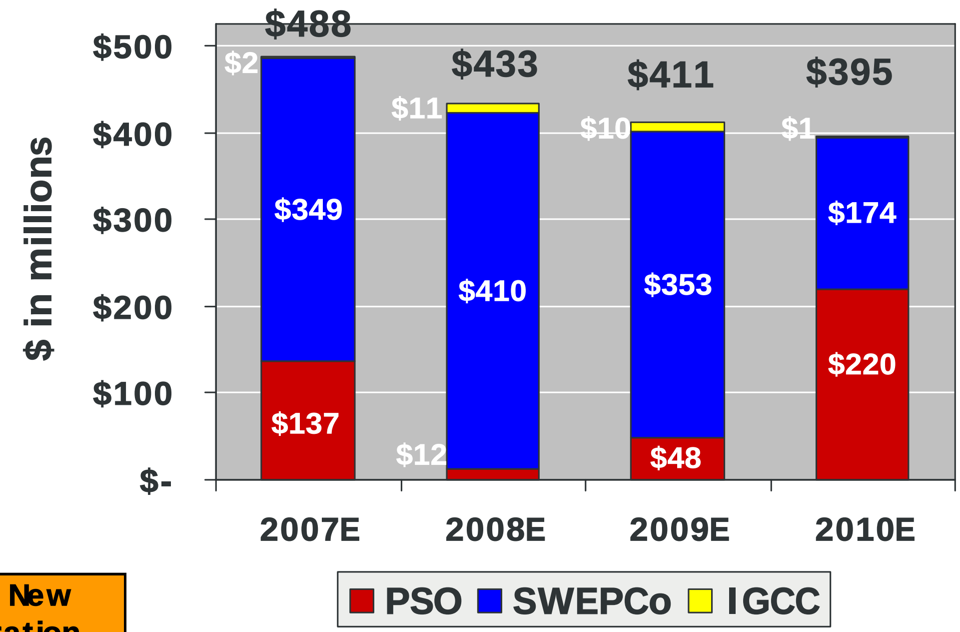
($ in millions)	Completed (2004-2006)	Rate Recovery
AEG	$9	partial/pending
APCo	$923	yes
I&M	$98	pending
KPCo	$3	yes
SWEPCo	$37	pending
CSP	$194	yes
OPCo	$1,253	yes
Total Capex	$2,517	

($ in millions)	Remaining (2007-2010)	Rate Recovery
AEG	$27	partial/pending
APCo	$944	yes
I&M	$77	pending
KPCo	$33	yes
PSO	$67	pending
SWEPCo	$135	pending
TNC	$22	through mkt. rates
CSP	$374	partial/pending
OPCo	$891	partial/pending
Total Capex	$2,570	

New Generation Investments and Related Recovery

Secured Recovery Mechanism

- PSO Peaking Facilities Rider



($ in millions)	Projected Construction Completion	Total New Generation Investment (2007-10)
PSO - Peaking Facilities	2008	$102
PSO - Combined Cycle *	2012	$315
SWEPCo - Mattison	2007	$66
SWEPCo - Stall	2010	$422
SWEPCo - Turk	2011	$798
APCo - IGCC	tbd	$12
CSP/OPCo - IGCC	tbd	$12
Total Capex	Total Capex	$1,727

* - intended to source requirements to be met by Red Rock Plant prior to cancellation.

Additional Recovery Mechanisms Under Consideration:

- Formula based rates
- Requests for return on CWIP
- Current and future rate cases

GridSMART

AEP Vision

- AEP is moving technology out of the laboratory and into real-world applications
- Aggressive goals:
  - 25 MW NaS battery installations by 2010
  - 1,000 MW demand reduction by 2012
  - 5 million smart meters by 2015

AEP Leadership

- **Environmental:** AEP's fleet includes hybrids
- **Efficiency and Conservation:** DOE Transformer Efficiency Initiative and participation in the Clinton Global Initiative
- **Education:** AEP Foundation's support of the National Energy Education Development (NEED) Project and Change-a-Light Program
- **Technology:** High temperature superconductors, micro grid test bed and extra-high voltage transmission advances

AEP's Collaboration with Others

- NGK (NaS battery) & Rolls Royce (fuel cells)
- Collaboration with GE to demonstrate the distribution/customer service business of the future

Modernization of our distribution infrastructure will change how we manage the flows of information and electricity across the energy value chain to optimize overall performance and prepare for the future.

AEP-GE Initiative

We will deploy smart meters, distribution automation and the associated enhanced technology resulting from the collaboration with GE in two regions by the end of 2008 -- representing approximately 200,000 customers.

By integrating customers and their end use technologies into the daily operation of the grid, we can collaborate to optimize supply and demand and improve energy efficiency and environmental sustainability.

Our agreement with GE is a winner for our customers, our shareholders and for the environment.

AEP AMERICAN ELECTRIC POWER

Working Together for a Brighter Future

imagination at work

AEP and GE will collaborate to address the full energy pathway from the power plant to the home.

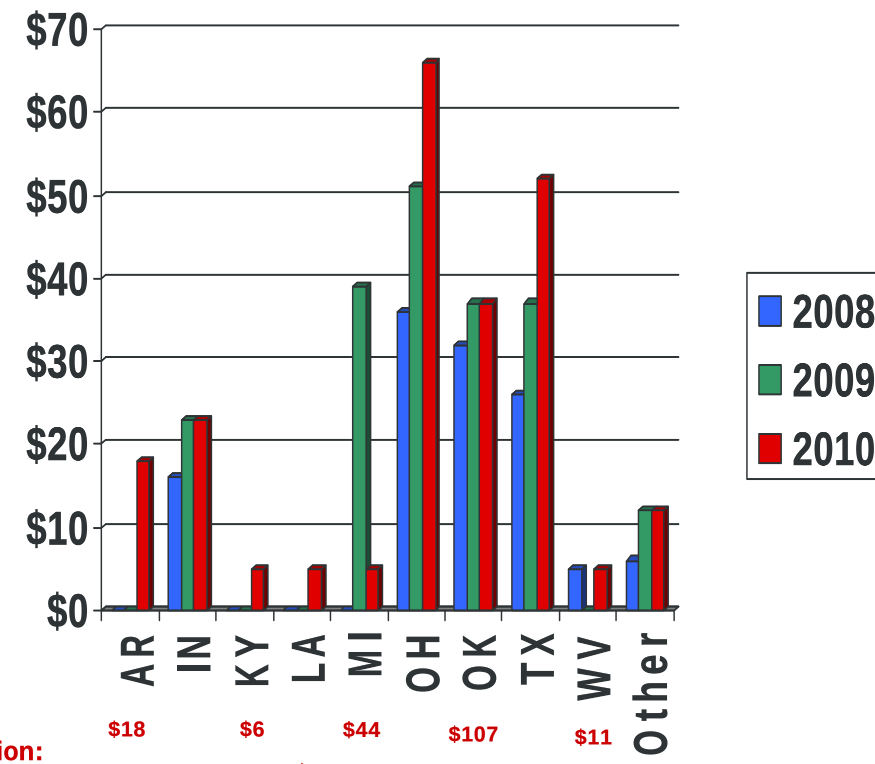
GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology	**2007**	**2008**	**2009**	**2010**
Metering & Communications	**$0**	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$2**	**$40**	**$ 63**	**$ 82**

*$452MM of the $554MM not in current forecast; spending contingent upon regulatory approval

$ in millions



3-Year Total by Jurisdiction: $18 $62 $6 $5 $44 $153 $107 $115 $11 $31

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Contribution of Transmission Investments

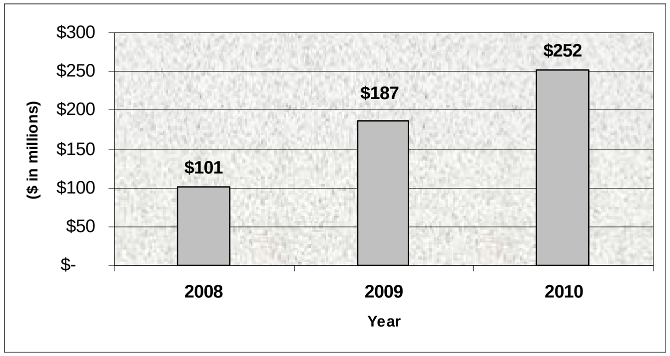
Potential Transmission Opportunities

- ~ $3 Billion I765™ Project in PJM
- ~ $2.6 Billion 765-kV study in Michigan w/ ITC
- ~ $3 Billion Project filed with SPP
- ~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions

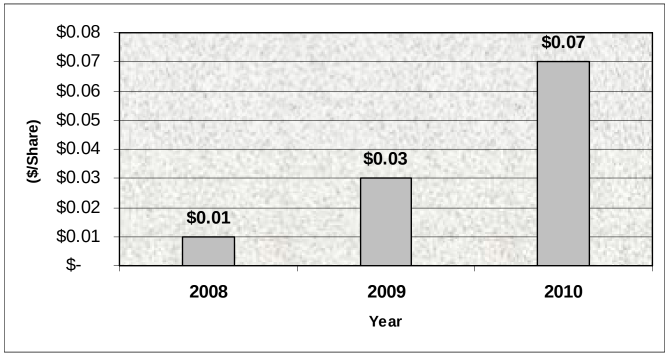
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 402 MM shares)	$0.60 - $1.00+

Projected Transmission Capital Spending*



* ~$9-$15 billion investment opportunity not included in current capital guidance forecasts, since it will be put into a JV. ETT base case and PATH projects included in above projection.

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

AEP®

Advanced Generation & CO_2

Near Term:

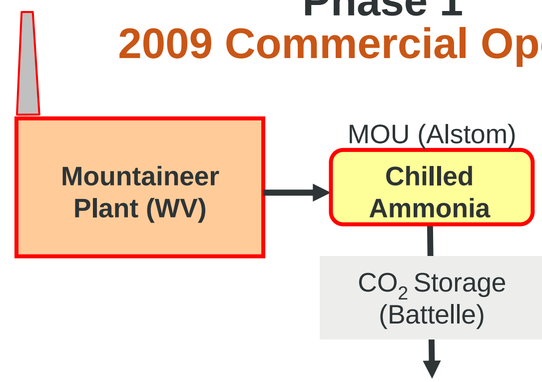
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
	2007	2008	2009	2010
Mountaineer Chilled Ammonia Project	$4	$56	$11	$0

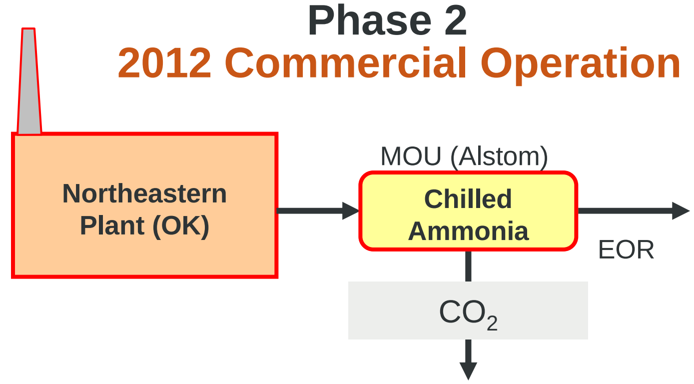
Long Term Strategy (Post 2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5231 of 9556

Regulatory Strategy: Reduce Lag

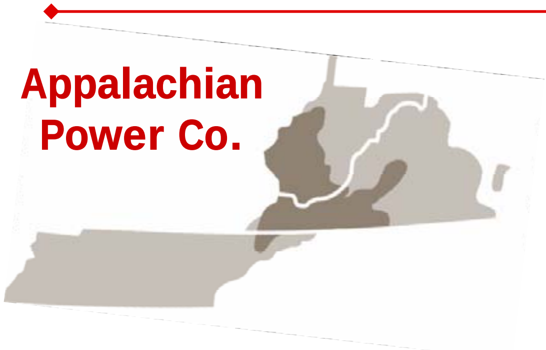
The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Lag Reduction: East Regulated Utilities

Appalachian Power Co.



Customers: 949,000
Estimated Rate Base: $3.7B *
Estimated 2007 Earnings: $183MM

Indiana Michigan Power Co.

Customers: 582,000
Est. Rate Base: $2.1B *
Est. 2007 Earnings: $130MM

Kentucky Power Co.

Customers: 176,000
Estimated Rate Base: $.9B *
Estimated 2007 Earnings: $27MM

* See Appendix, page 43 for rate base details

Virginia
- Opportunity for one rate case exists before 12/31/08
- E&R rider
- Post 2008 rider for DSM, renewable programs & new generation
- Fuel clause
- OSS margin sharing

West Virginia
- Special construction surcharge permitted
- Fuel clause (ENEC)

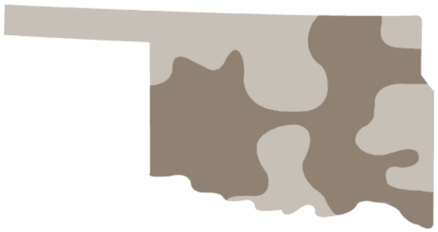
Indiana
- Riders to be requested for DSM, Environmental and RTOs
- CWIP may be approved for clean coal technology projects utilizing Indiana coal or qualified pollution control property via surcharge
- Fuel clause

Michigan
- Return on CWIP can be included in rate base
- Fuel clause

Kentucky
- Environmental surcharge
- Monthly adjustment clauses in place for DSM & fuel
- OSS margin sharing

Regulatory Lag Reduction: West Regulated Utilities

Public Service of Oklahoma

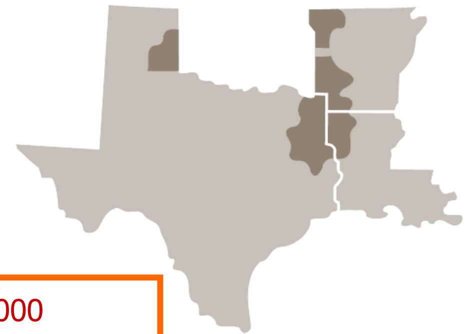


Customers: 520,000
Estimated Rate Base: $1.2B *
Estimated 2007 earnings: $35MM

* See Appendix, page 43 for rate base details

Oklahoma
- Rider mechanisms authorized for vegetation, Lawton Cogen & new peaking facilities after December 2007 in-service date
- Fuel clause
- OSS margin sharing

Southwestern Electric Power Co



Customers: 456,000
Est. Rate Base: $1.3B *
Est. 2007 earnings: $66MM

Arkansas
- CWIP permitted in rate base for plant that is placed in service within 6 months after the test year
- Fuel clause
- OSS margin sharing

Louisiana
- Formula rate plans permitted
- Fuel clause
- Seeking partial CWIP return on new generation projects
- OSS margin sharing

Texas
- CWIP allowed in rate base in some cases
- Fuel clause
- OSS margin sharing

Regulatory Lag Reduction: Texas Wires Business

AEP Texas Central Co & AEP Texas North Co

Customers: 927,000
Estimated Rate Base: $2.1B *
Estimated 2007 earnings: $73MM

* See Appendix, page 43 for rate base details

Texas

- Transmission rider provides annual recovery dependent on the level of transmission investment and ERCOT load growth rates
- AFUDC is permitted in limited circumstances

AEP Texas will synchronize general rate requests with significant rate base changes and benefit from the flexibility of periodic transmission filings.

The AEP Ohio Post-2008 Action Plan

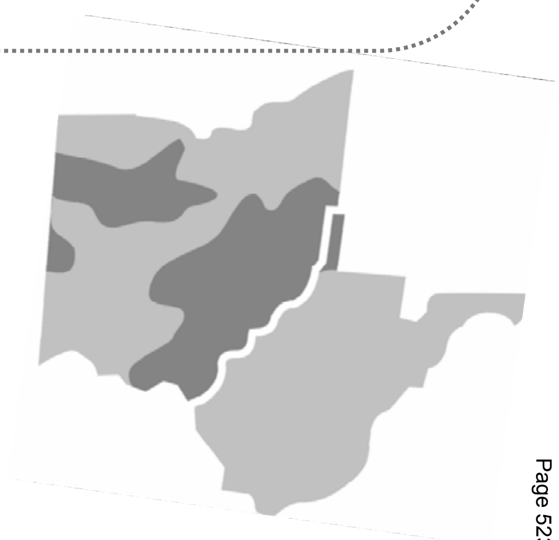
Concurrent pursuit of regulatory and legislative options

- Work for a legislative outcome that:
  - Allows for market pricing or
  - Allows for new Rate Stabilization Plans that reflect a value for generation consistent with market
- If legislation is not forthcoming, work with the PUCO Staff to develop new Rate Stabilization Plans that reflect the market value of generation

Essential elements of Post-2008 Plan

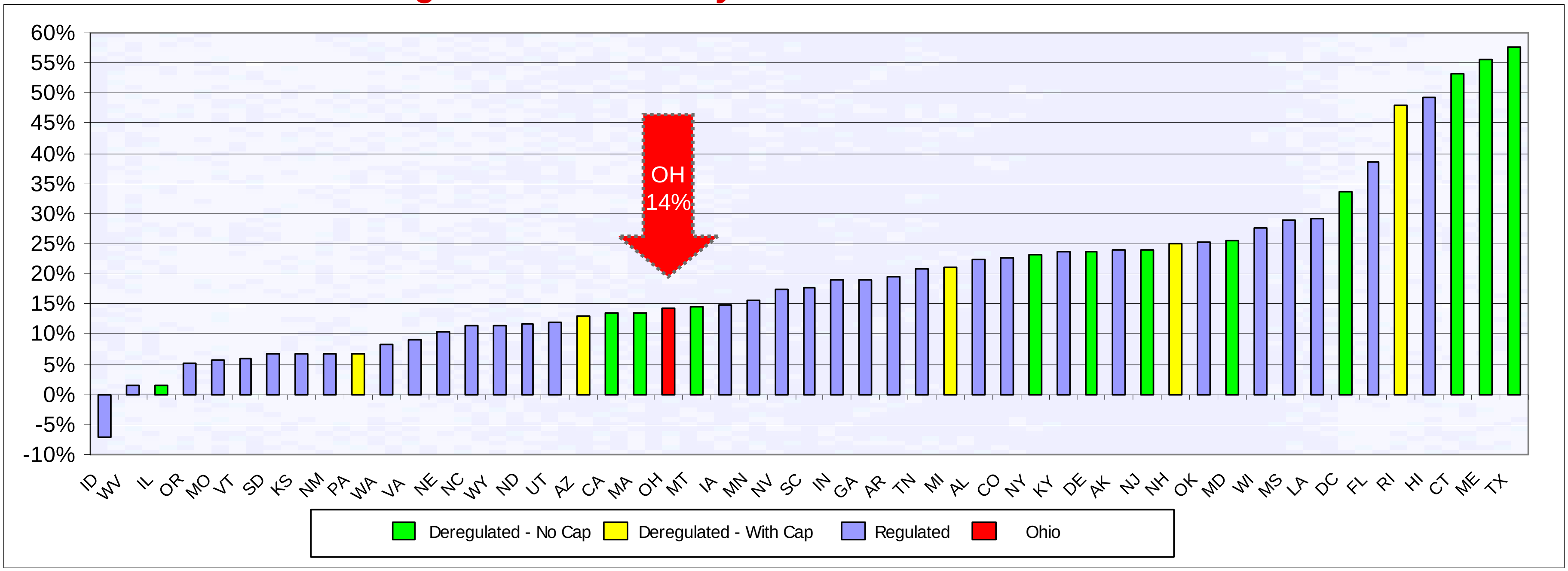
- Market-based generation pricing option
- Recovery mechanisms for new plants, fuel clause, environmental investments, GridSMART initiatives, energy efficiency projects and renewable energy investments
- Well-defined parameters for PUCO authority

Achieve a sustainable balance between shareholders and the Ohio economy.



Electricity Costs Have Increased in Both Regulated and Deregulated States

2002-2006 % Change in Electricity Prices

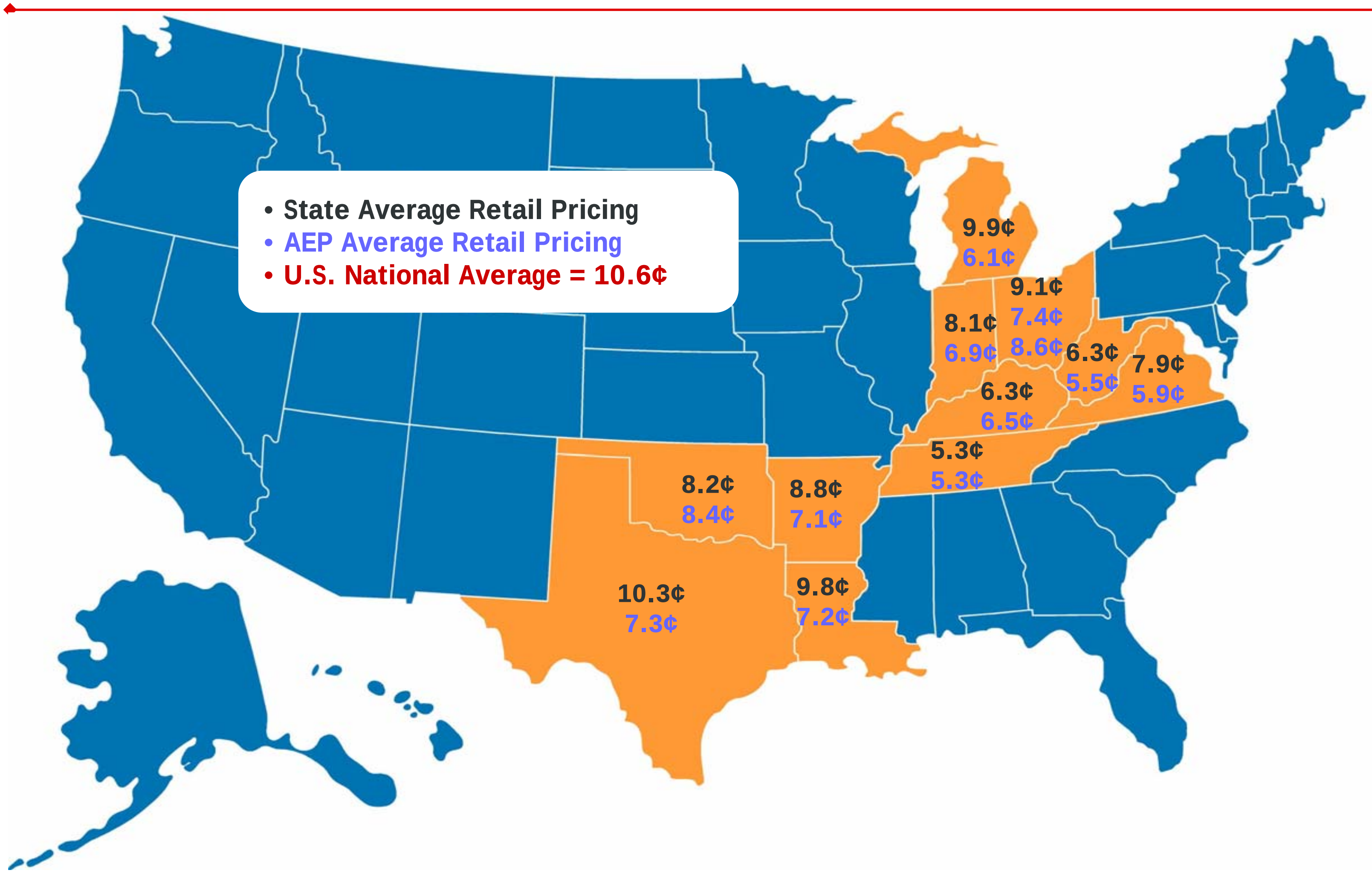


Source: USA Today, Aug. 10, 2007

- **Deregulated states median increase: 25%**
- **Regulated states average increase: 23%**
- **Ohio average increase: 14%**

Ohio increased less than the average of both regulated & deregulated states. Under any scenario, rates in Ohio will likely increase.

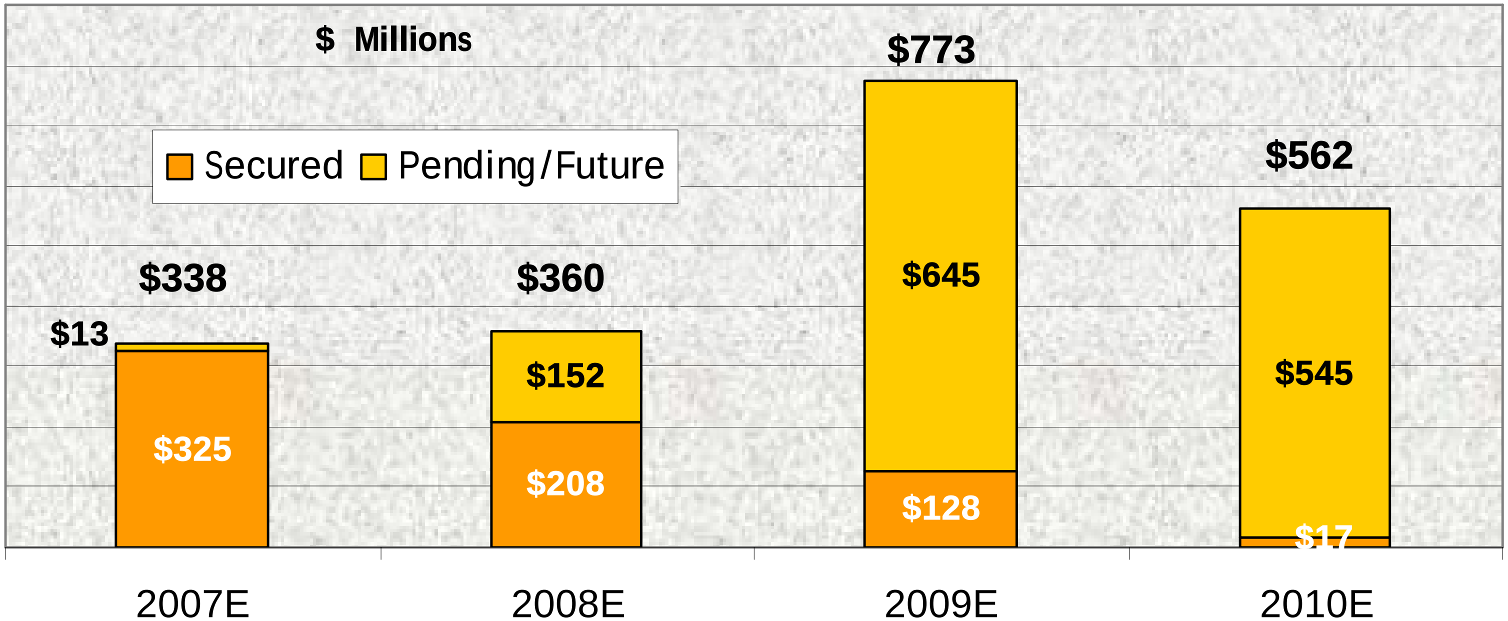
Average Retail Price of Electricity



AEP's pricing will remain competitive following anticipated rate increases.

Data source: EEI Summary of Average Realizations for the twelve months ended December 31, 2006
Ohio: OPCo = 7.4¢ / CSP = 8.6¢

Incremental Rate Relief Assumptions



2007 Pending: PSO Rate Case
TCC Rate Case
Ohio 4%

2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation

2007 - 2010 projected annual rate increases of 5.5%

Financial Forecast Highlights

- **Updated 2008 & 2009 earnings guidance ranges and introduction of 2010**

2007 Range $2.90 to $3.00	**2008 Range $3.05 to $3.25**
2009 Range $3.20 to $3.50	**2010 Range $3.45 to $3.80**

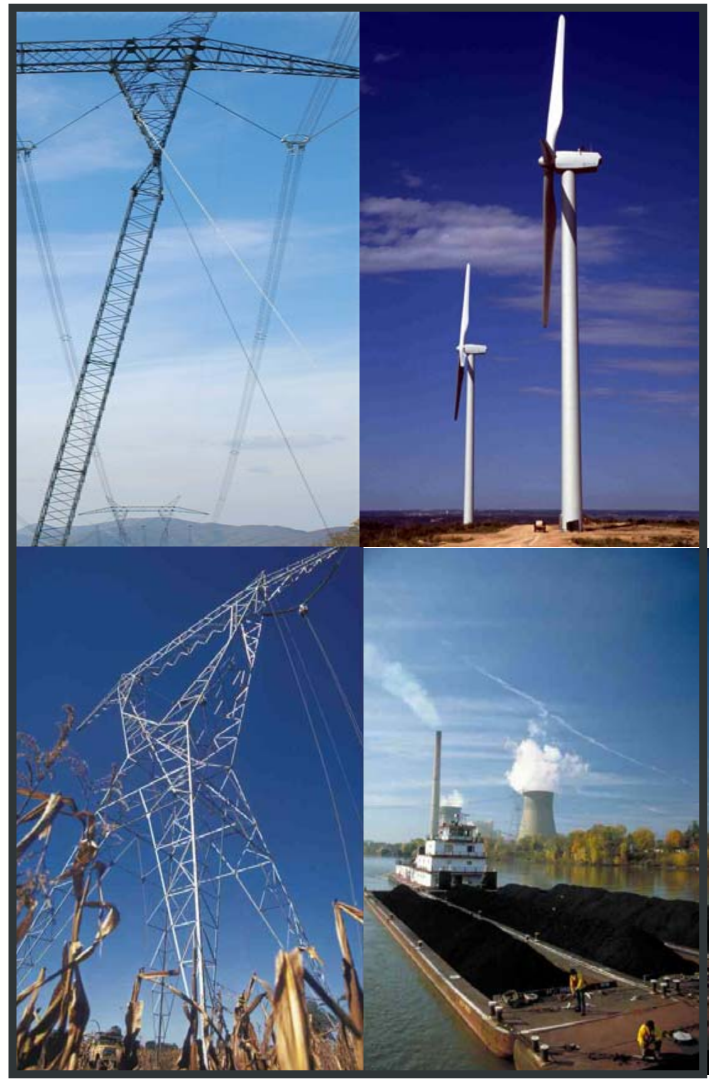
- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Ohio: Continue momentum toward market
  - Cost management
- Commitment to recommend an 8-cent/share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Refined capital investment forecast and introduction of 2010 level

2007E: $3,962 MM	**2008E: $3,770 MM**
2009E: $3,600 MM	**2010E: $3,401 MM**

- Maintain credit ratings: BBB/Baa2/BBB

Value Proposition

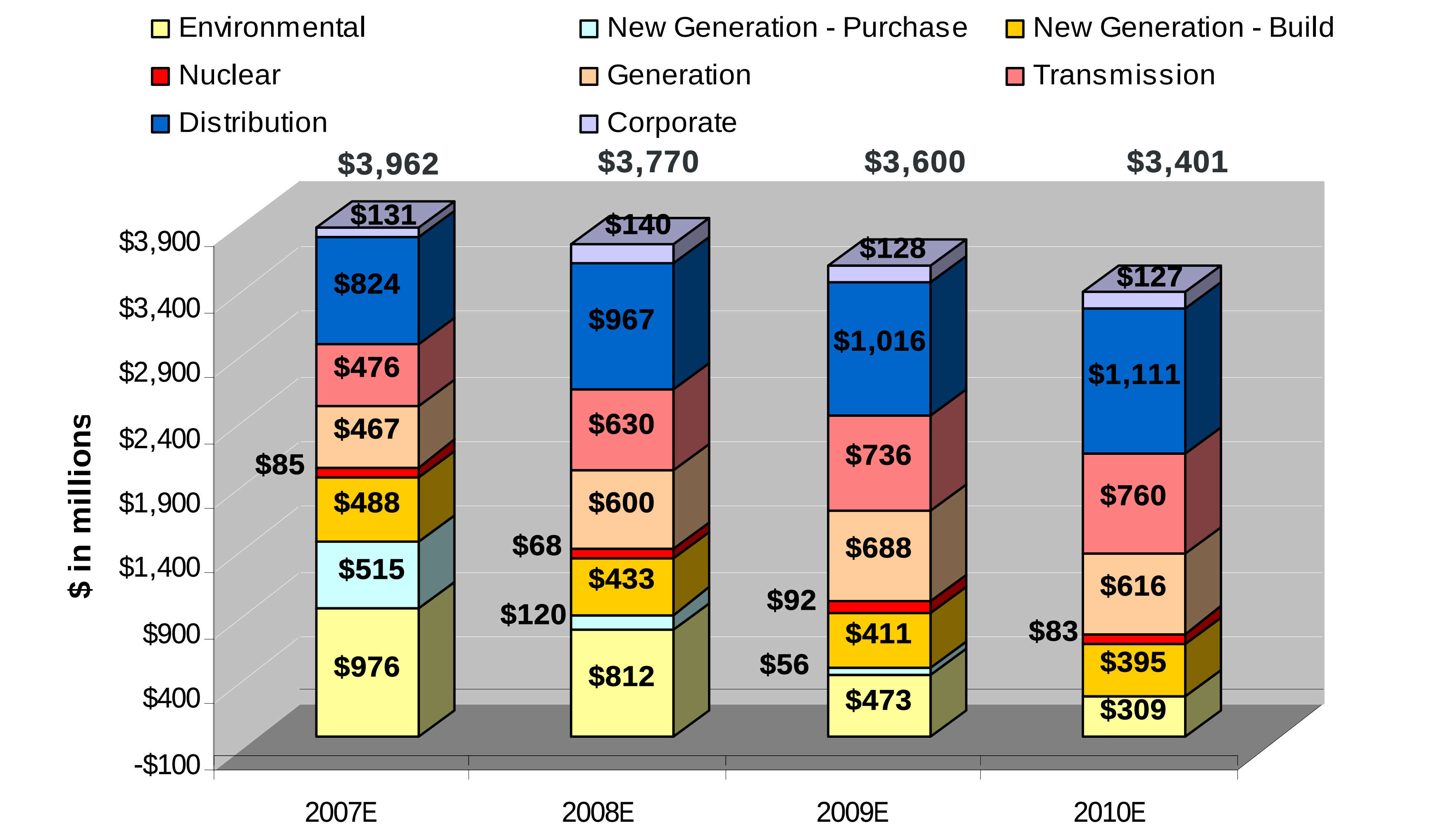
- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*



Sustainable Business Model

Appendix

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Capital investment is funded from cash from operations and debt issuances

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Credit Quality Parameters

Forecast Parameters:

- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCO	42-44%
CSP	45-47%
I&M	40-42%
KPCO	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings
  - FFO to Interest range of 3.7x to 4.2x
  - FFO/Total Debt range of 16% to 19%

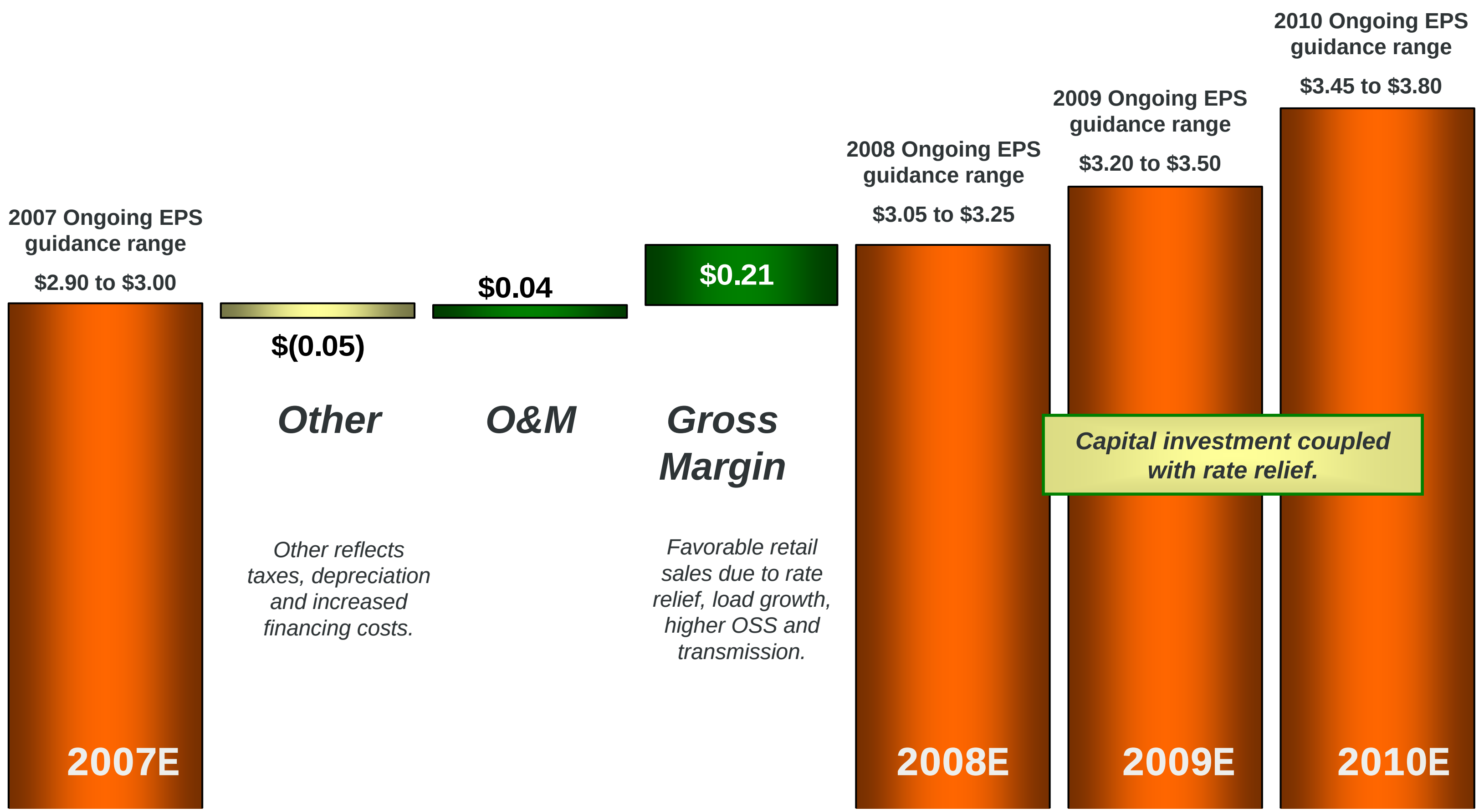
2008 Projected Cash Flow

	2007 Estimate	2008 Estimate
Beginning Cash Balance	$ 301	$ 102
Cash from Operations:		
Income from Continuing Operations	1,173	1,269
Depreciation and Amortization	1,535	1,511
Other	(655)	45
Total from Operations	2,053	2,825
Cash from Investing:		
Construction Expenditures	(3,604)	(3,860)
Asset Sales	228	-
Distressed Generation Purchases	(515)	-
Investment in Non-Consolidating Subsidiaries	(13)	(34)
Other	138	(69)
Total from Investing	(3,766)	(3,963)
Cash from Financing:		
Common Equity	150	150
Long-Term Debt Issued/(Retired)	1,334	1,789
Short-Term Debt Change, Net	529	(111)
Common Dividends	(631)	(659)
Other Financing Activities	132	(28)
Total from Financing	1,514	1,141
Net Change in Cash	$ (199)	$ 3
Ending Cash Balance	$ 102	$ 105

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation. In addition, construction expenditures include AFUDC.

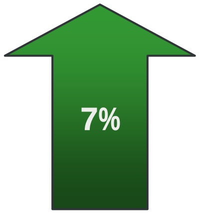
Long-Range Earnings Drivers

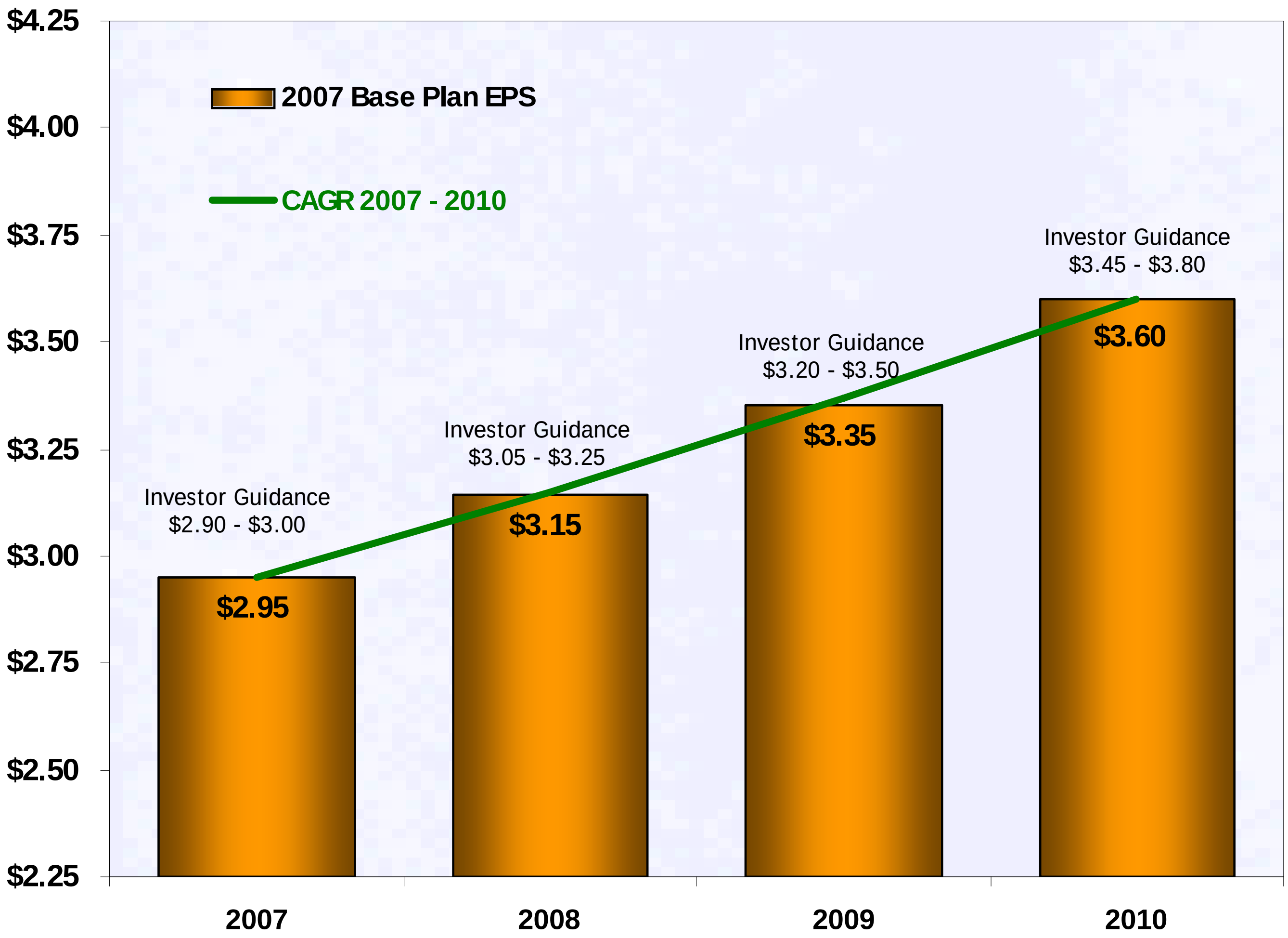
STRATEGIC DIRECTION & FINANCIAL OUTLOOK



Traditional utility factors will drive earnings

4-Year Earnings Range Forecast





5% to 9% earnings growth and recommendation of a 4Q07 dividend increase.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Transmission Revenue - 3rd Party		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		**96**		**78**
20	**Parent Company & Other On-Going Earnings**		**(40)**		**(51)**
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

2008 Earnings Guidance

		2007 Guidance ($ millions)	2008 Guidance ($ millions)
	UTILITY OPERATIONS:		
	Gross Margin:		
1	East Regulated Integrated Utilities	2,440	2,425
2	Ohio Companies	2,433	2,497
3	West Regulated Integrated Utilities	1,046	1,111
4	Texas Wires	520	536
5	Off-System Sales	617	642
6	Transmission Revenue - 3rd Party	276	331
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13	Other Income & Deductions	101	191
14	Income Taxes	(566)	(582)
15	Utility Operations On-Going Earnings	1,117	1,237

Performance Drivers

Retail Sales (lines 1-4):

- Positive load growth - $132MM
- Continued rate relief - $228MM
- Offset by fuel and PJM costs - $(186)MM

Off-System Sales (line 5):

- Increase due to slightly higher margins

Transmission Revenue (line 6):

- Higher rates in ERCOT, PJM and SPP

Other Operating Revenue (line 7):

- Lower revenues from third party work, primarily offset in line 9 - O&M

Operations & Maintenance (line 9):

- Continued emphasis on cost control

Interest Expense (line 12):

- Increased long term debt outstanding

Other Income & Deductions (line 13):

- Additional 2008 APCo E&R carrying charges & AFUDC, offset by elimination of Centrica earnings sharing mechanism in 2008

Income Taxes (line 14):

- Higher pre-tax income, offset by change in effective tax rate. Effective tax rate for utility operations is 33.6% in 2007 and 32.0% in 2008.

2008 Earnings Guidance

	2007 Guidance ($ millions)	2008 Guidance ($ millions)
TRANSMISSION OPERATIONS	-	5
NON-UTILITY OPERATIONS:		
MEMCO	67	57
Generation & Marketing	29	21
Non-Utility Operations On-Going Earnings	96	78
Parent and Other On-Going Earnings	(40)	(51)

Performance Drivers

Transmission Operations:

- Equity earnings contribution from Electric Transmission Texas LLC

MEMCO:

- Decrease due to increasing costs and reduced import/northbound river traffic

Generation & Marketing:

- Decrease due to divestiture of Sweeny in 4Q07

Parent & Other:

- Increase loss due primarily to interest expense related to hybrid securities issued at the parent

Performance Sensitivities

Driver	Change	Effect
EPS Sensitivities		
Load Growth (MWh)	1%	$0.10 EPS
Utility O&M	1%	$0.05 EPS
Capital Spending	$250M	$0.03 EPS
Unit Availability	1%	$0.04 EPS
ECAR Power Price	$1/MWh	$0.04 EPS
Fuel and Purchased Power	1%	$0.03 EPS
Henry Hub Gas Price	5%	$0.07 EPS
Interest Rate (20% floating debt)	100 BPs	$0.05 EPS
Authorized ROE	**1%**	**$0.24 EPS**

Longer term performance can be substantially enhanced by achieving a higher authorized return.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Pace of our GridSMART Implementation Determined by Regulators

- **Arkansas** – The Arkansas commission approved our 'quick-start' programs in September 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-performance pilot that results in a payment to customers who curtail load upon request. The commission's order allows implementation on or after October 1, 2007. We will now file a revised tariff, which will seek to recover costs beginning with the first billing cycle of November 2007.

- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and will administer a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.

- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.

- **Ohio**
  - Recent Governor remarks and draft legislation indicates modernization of Ohio's infrastructure is a high priority.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.

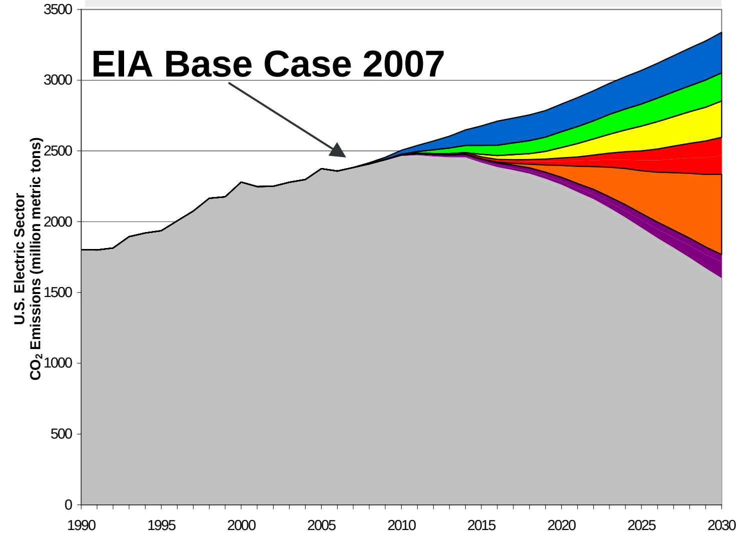
- **Texas**
  - Successful demand side management and energy efficiency programs have been in place in Texas since the 1990s.
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.

Distribution technologies and DSM/energy efficiency programs are an investment, which should be treated by regulators in the same manner as investments in generation and T&D

AEP is Pursuing a Portfolio of Options to Address Carbon

Technology	EIA 2007 Reference	Industry Target	AEP Plan
Efficiency	Load Growth ~ +1.5% / yr	Load Growth ~ +1.1% / yr	DSM: 1000MW reduction in demand by 2012
Renewables	30 GWe by 2030	70 GWe by 2030	Wind PPAs through 2015: 1610MW nameplate or 232MW capacity for planning purposes. Also, voluntary green energy tariffs (Ohio program starting 2007)
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030	Evaluation of Nuclear COL
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030	1,246MW IGCC by 2017 447MW USC Turk plant by 2011
Carbon Capture and Storage	None	Widely Deployed After 2020	Chilled Ammonia: Mountaineer 2009 & Northeastern 2012 Oxy-coal by 2020
Plug-in Hybrid Electric Vehicles	None	10% of New Vehicle Sales by 2017; +2% / yr Thereafter	Joined Electric Drive Transportation Association (EDTA) in May 2007
Distributed Energy Resources	< 0.1% of Base Load in 2030	5% of Base Load in 2030	Pursuit of NaS® Energy Storage – 25MW of storage by 2010 and 1000MW of other storage / fuel cells by 2020

Technical Potential for CO_2 Reductions - *Achieving all targets is very aggressive, but potentially feasible.*



Technology advancement is required beyond present "state of the art" to achieve 1990 CO_2 levels by 2030. AEP is investing in a portfolio of GHG reduction initiatives. Allocation of funds will shift over time depending on technology, legislation, etc.

Source for graphic, EIA 2007 reference and industry target data: EPRI

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
<u>East Plants</u>					
Amos 1	800	☑	In-service	☑	Projected 2009
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☐	Delayed
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5 & 6	750		N/A	☑	Unit 5 upgrade in-service; Unit 6 upgrade projected 2008
Gavin 1 & 2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☐	Delayed
<u>CCD Plants</u>					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
<u>West Plants</u>					
Dolet Hills	262		N/A	☑	In-service
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR 24,630 MW COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD).

AEP®

Investing in IGCC

Generation Technology Comparative Statistics

US2012$	Eastern Bituminous		
	USC	IGCC	NGCC
Nominal Capacity (MW)	**618**	**629**	**530**
Capacity Factor (%)	**85%**	**85%**	**25%**
Total Plant Cost (2012$, including: EPC+Owner's Cost+AFUDC+Transmission) **($/kW)**	**$2,876**	**$3,709**	**$754**
Production Cost ($/MWh)	**$23**	**$23**	**$57**
Cost of Electricity, Without CO_2 Capture ($/MWh)	**$86**	**$98**	**$111**
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	**$137**	**$124**	**$169**

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost includes cost to engineer, procure and construct plus owners direct costs, AFUDC, overheads and transmission lines.
- Assumes Northern Appalachian coal price of $2.28/mmBtu (2012$) for USC & IGCC and natural gas price of $7.73/mmBtu (2012$) for NGCC.
- Production cost includes fuel plus variable operations and maintenance costs.
- Cost of electricity represents first year estimates in 2012$ and are based on total plant cost plus fuel costs, operation and maintenance costs, and emission allowance costs.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ I&M Indiana Rate Petition
- ✓ Virginia Filings – Fuel Factor and E&R
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Rate Base by Jurisdiction

Jurisdiction	Rate Base	Approved ROE	Date	6/30/07 GAAP Earned ROE
APCo VA	$2.022MM	10.00%	5/15/2007	8.44%
APCo WV	$1.656MM	10.50%	7/26/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.89%
I&M-Indiana	$1.805MM	12.00%	11/12/1993	7.18%
I&M-Michigan	$268MM	13.00%	2/12/1991	
Ohio-CSP	$1.558MM	12.46%	5/12/1992	21.22%
Ohio-OPCo	$2.183MM	12.81%	3/23/1995	12.79%
PSO-Oklahoma (1)	$1,064MM	10.75%	5/2/2005	2.25%
SWEPCo-LA	$434MM	11.10%	12/29/1999	6.77%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1984	
Texas-TCC (2)	$862MM	10.13%	8/15/2005	6.22%
Texas-TNC (3)	$530MM	TBD	5/24/2007	8.63%

(1) PSO rate case under review. Company position is a new rate base of $1,189,422,564. Awaiting final order.

(2) TCC rate case under review. Company position is a new rate base of $1,600,487,376. Awaiting final order.

(3) PUCT approved a settlement agreement, and indicated ROE will be determined as part of TCC's rate case.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

KPSC Case No. 2011-00401
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Electric Transmission Texas (ETT)

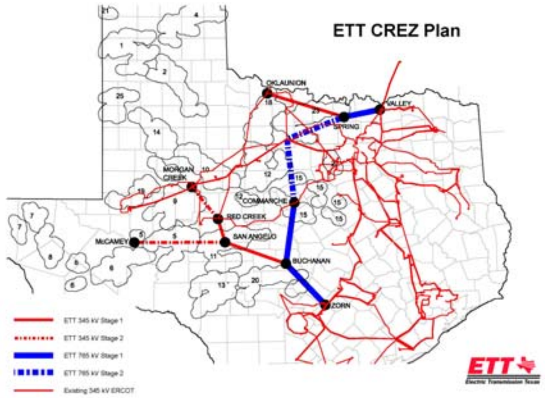
- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in the fall of 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

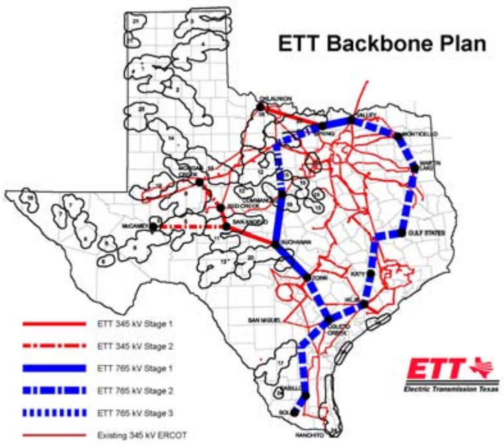
- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

- **Traditional ratemaking process through the PUCT will be utilized for investment cost recovery.**

ETT CREZ



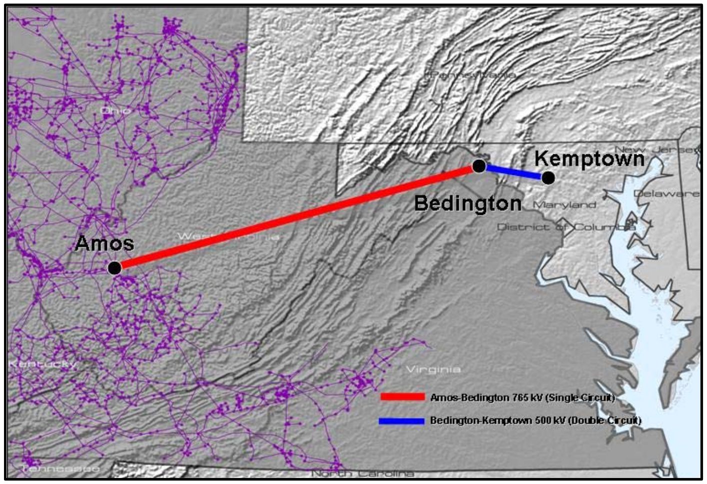
ETT Backbone



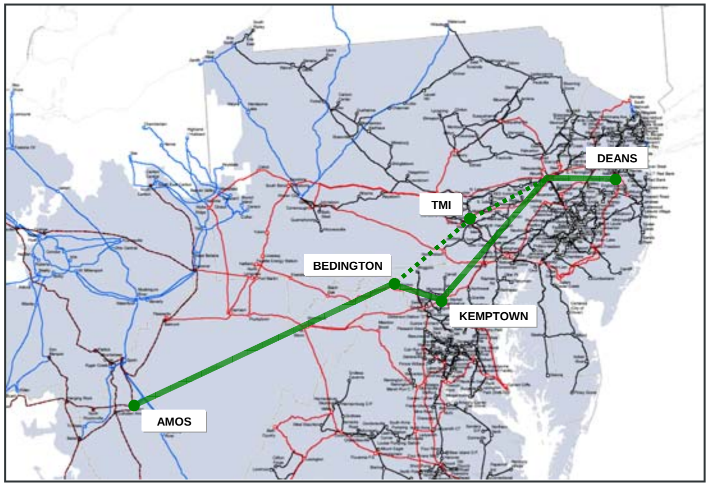
Transmission Project Updates

- ***I-765 ™ in PJM Phase I Progress to Date***
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012
- ***Key Next Steps***
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012
- ***PJM I-765 ™ Phase II Update***
  - Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
  - Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
  - Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.
- ***Regional Rate Design will be utilized for investment cost recovery.***

PJM Phase I



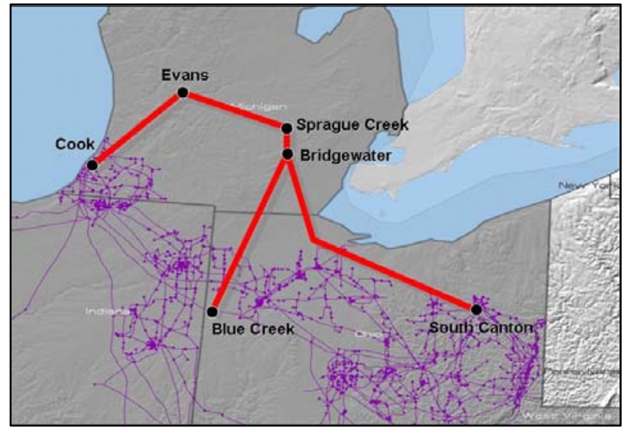
PJM Phase II



Transmission Project Updates – cont'd

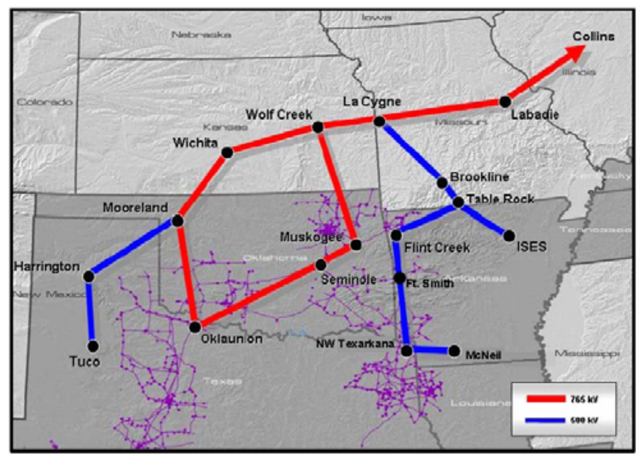
- *765 – kV in Michigan – Key Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2015

Michigan



- *765-kV in SPP – Key Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

Southwest Power Pool



- *Regional Rate Design will be utilized for investment cost recovery.*

Electric Transmission America (ETA)

- *Electric Transmission America (ETA)*
  - AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
  - Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
  - Projects taken on by the Joint Venture would entail transmission facilities:
    - 345 kV and above
    - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
    - Greater than $100 million
  - ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
  - ETA will look to collaborate with qualified partners in each particular region.

This JV reflects a natural progression and expansion of our partnership with MidAmerican.

Duquesne Capital Management
Office Visit-Jeff Coviello

Columbus, OH

September 17, 2008

AEP AMERICAN® ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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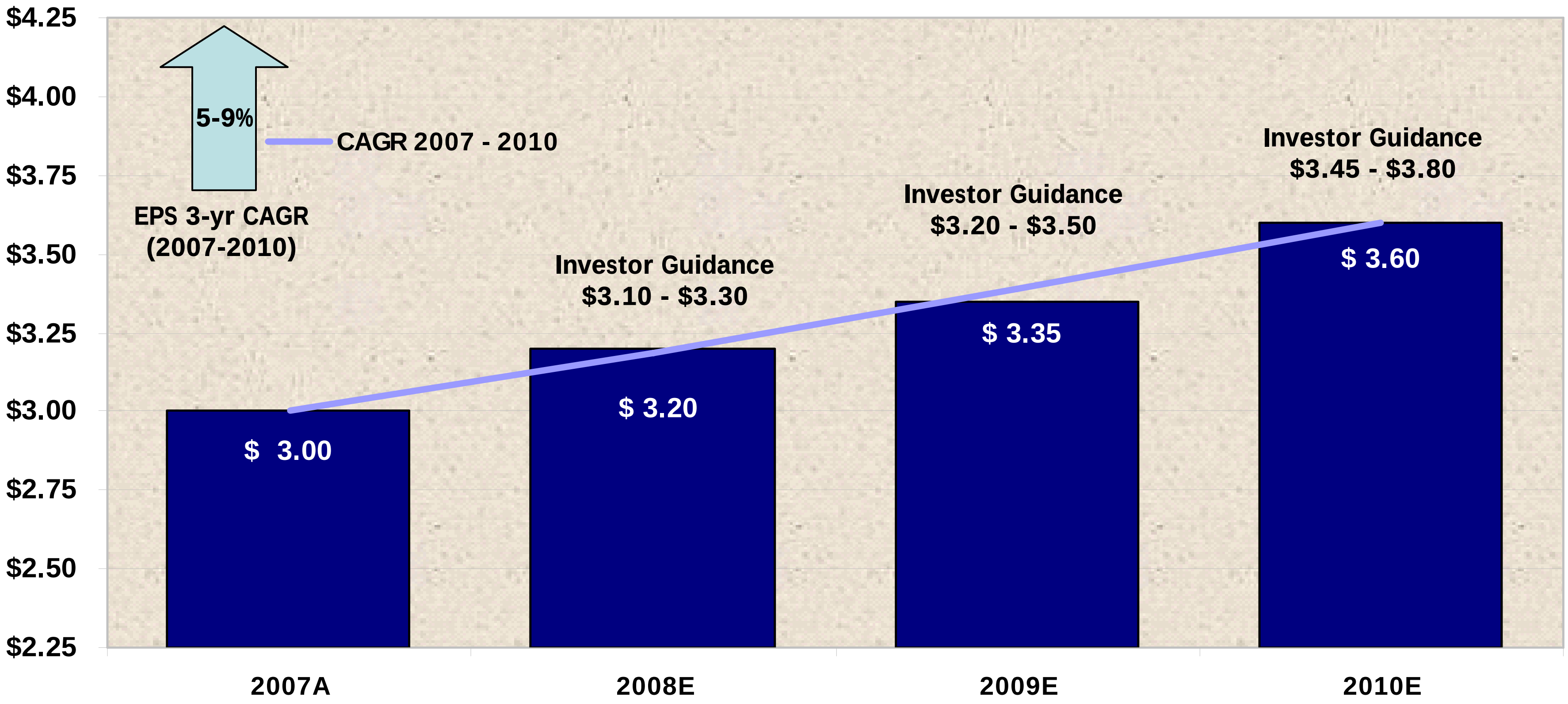
The AEP Value Proposition

Leveraging our vast energy platform with low-risk investments in infrastructure to enable sustainable growth.



AEP's ability to ensure a disciplined approach to capital investment allows us to sustainably grow earnings and shareholder value.

Detailed Ongoing Earnings Guidance

2007A: $3.00

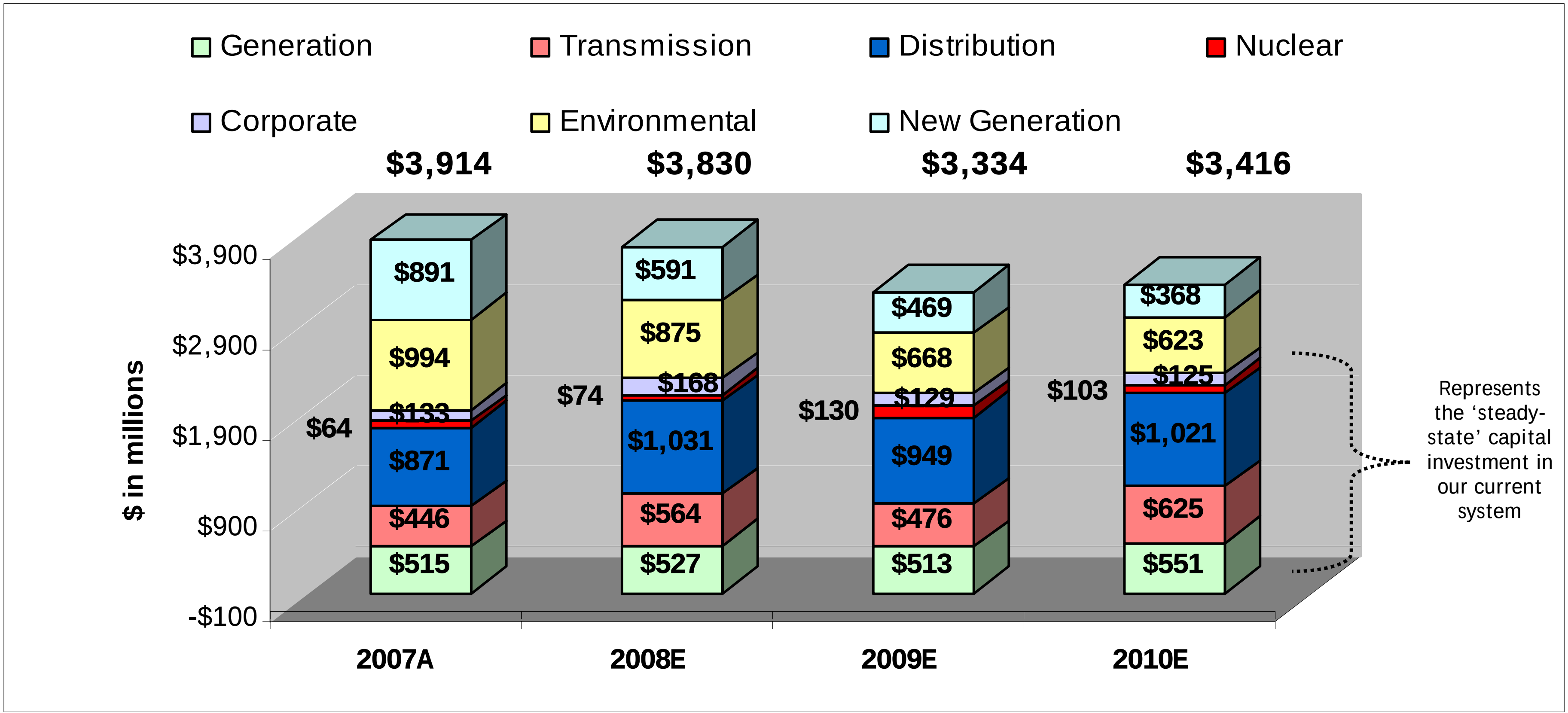
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4-Year Capital Investment Forecast



Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$583	$474	**$2,495**
I&M	$282	$386	$458	$497	**$1,623**
KPCo	$76	$127	$89	$106	**$398**
TCC	$212	$208	$186	$282	**$888**
TNC	$93	$120	$87	$91	**$391**
PSO	$303	$277	$257	$419	**$1,256**
SWEPCo	$511	$741	$710	$681	**$2,643**
CSP	$432	$404	$312	$308	**$1,456**
OPCo	$805	$635	$441	$411	**$2,292**
Other Companies	$488	$206	$211	$147	**$1,052**
Total Capex	**$3,914**	**$3,830**	**$3,334**	**$3,416**	**$14,494**

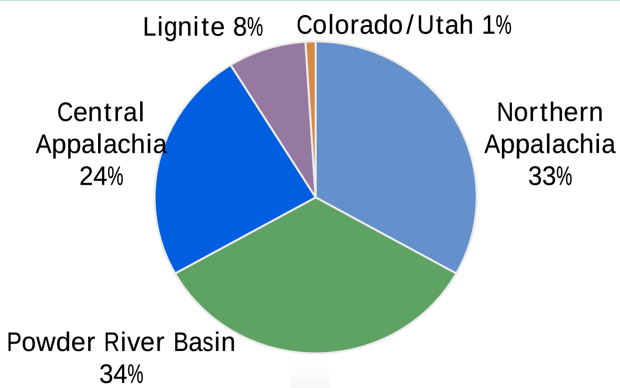
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

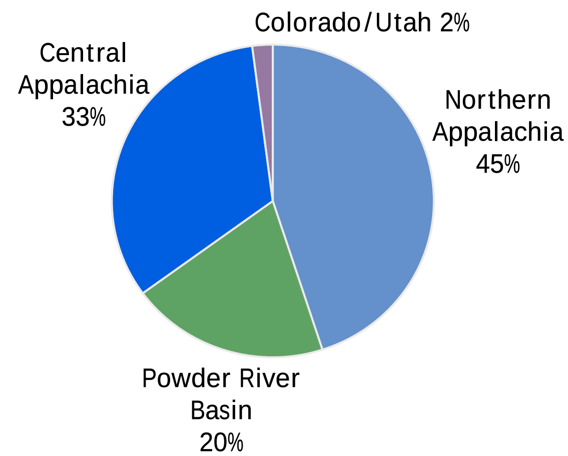
Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

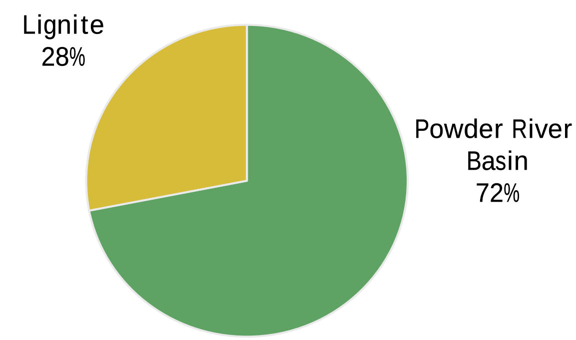
Total AEP System



AEP East



AEP West



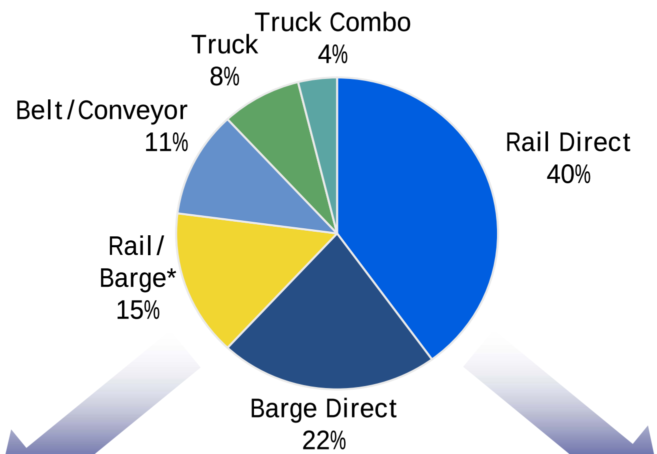
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

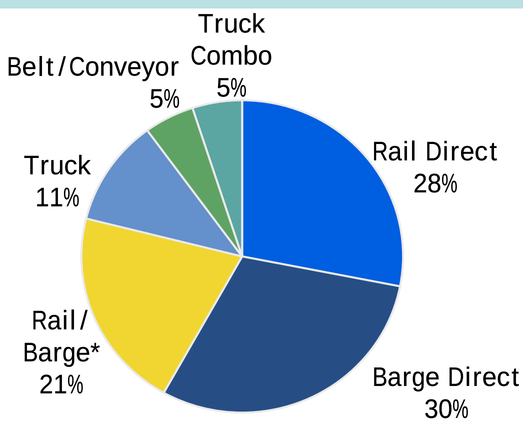
Coal Delivery

2007 Actual

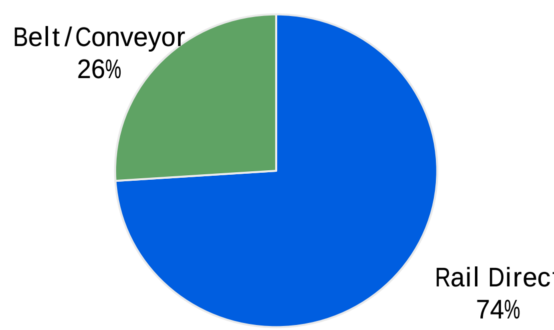
Total AEP System



AEP East

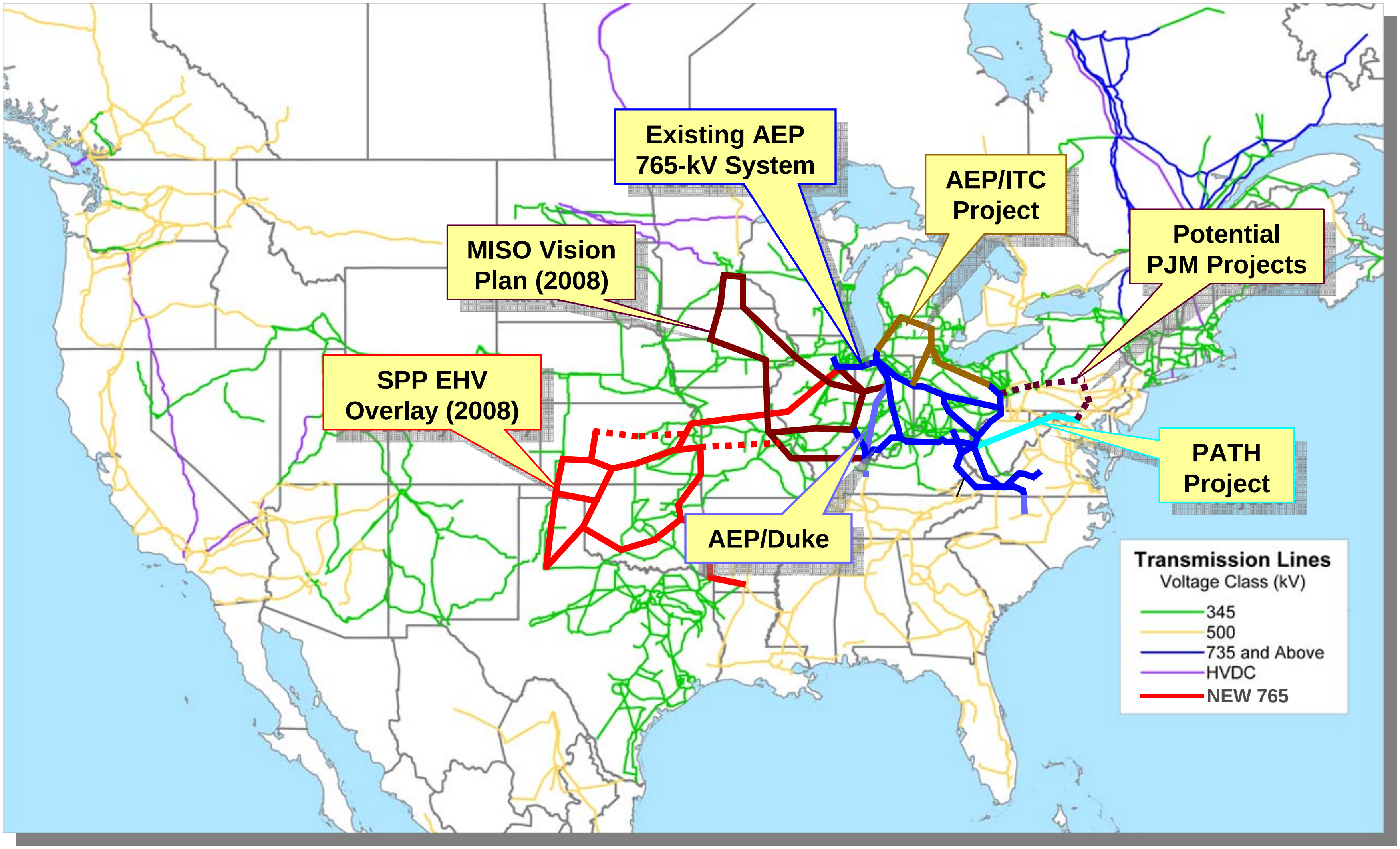


AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

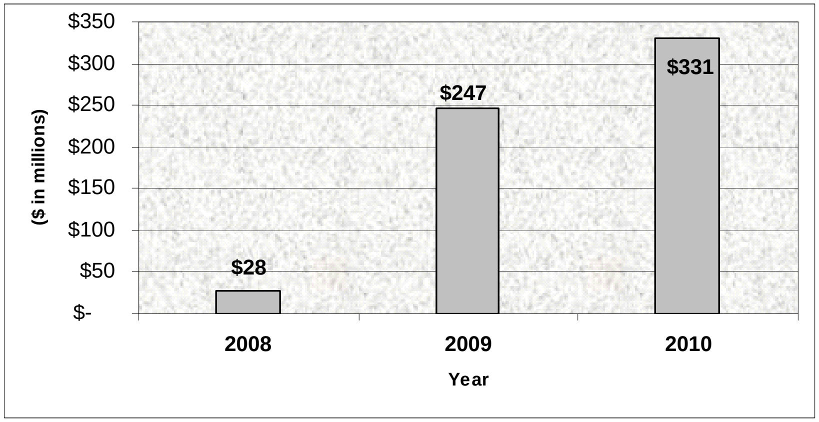
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

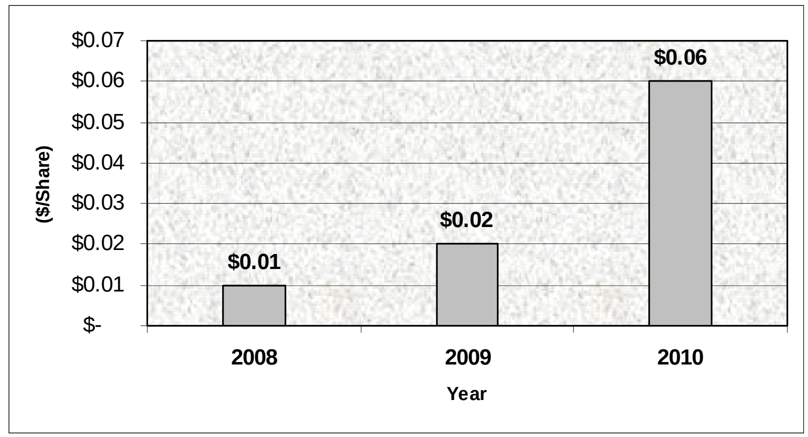


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

PATH
Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

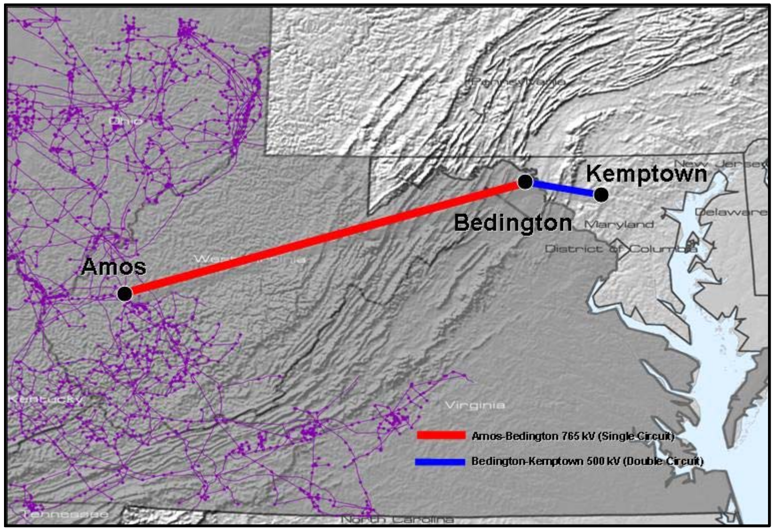
Transmission will provide a near and long-term catalyst for earnings growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

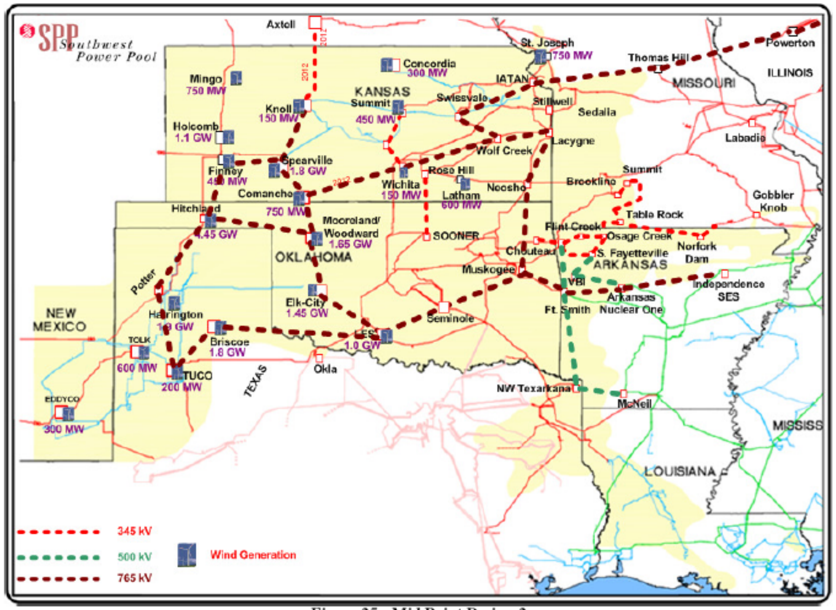


Figure 25: Mid Point Design 2

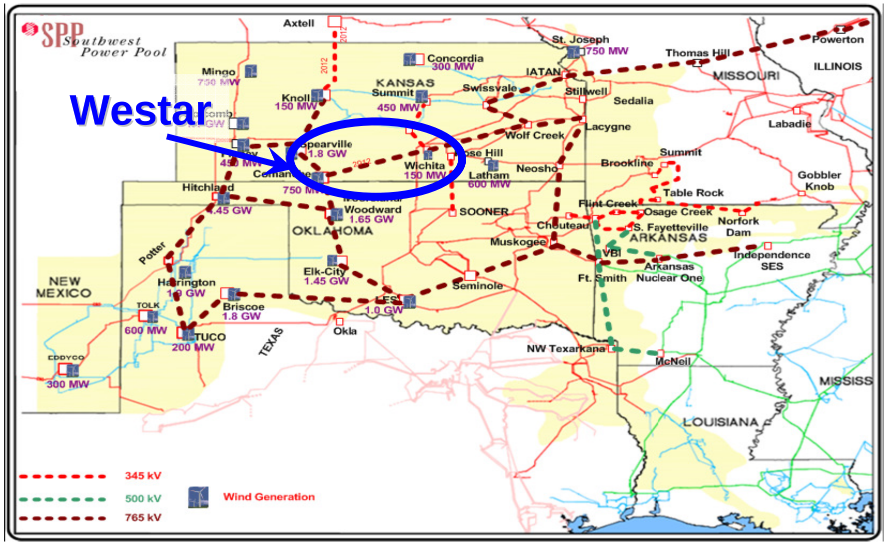
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - Filed CPCN – 2Q2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – Fall 2008
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



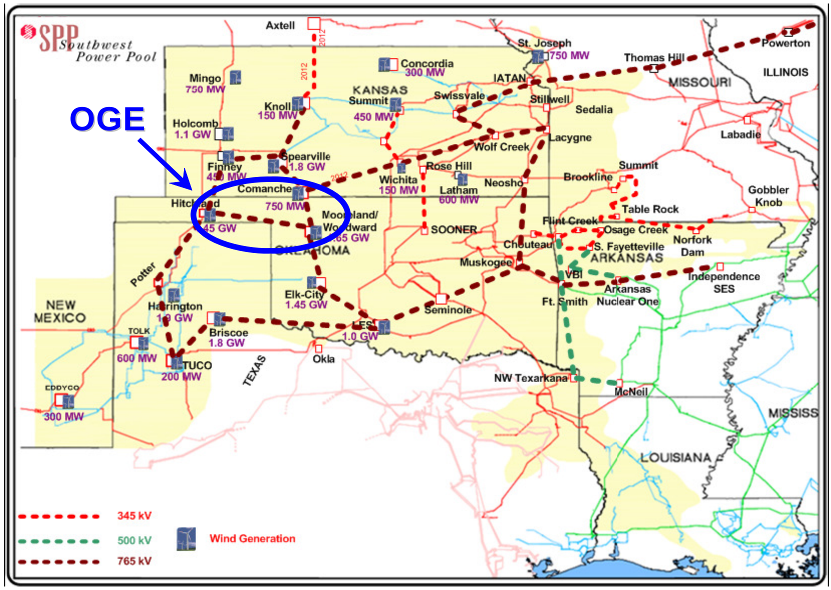
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- **Overview**
  - On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced



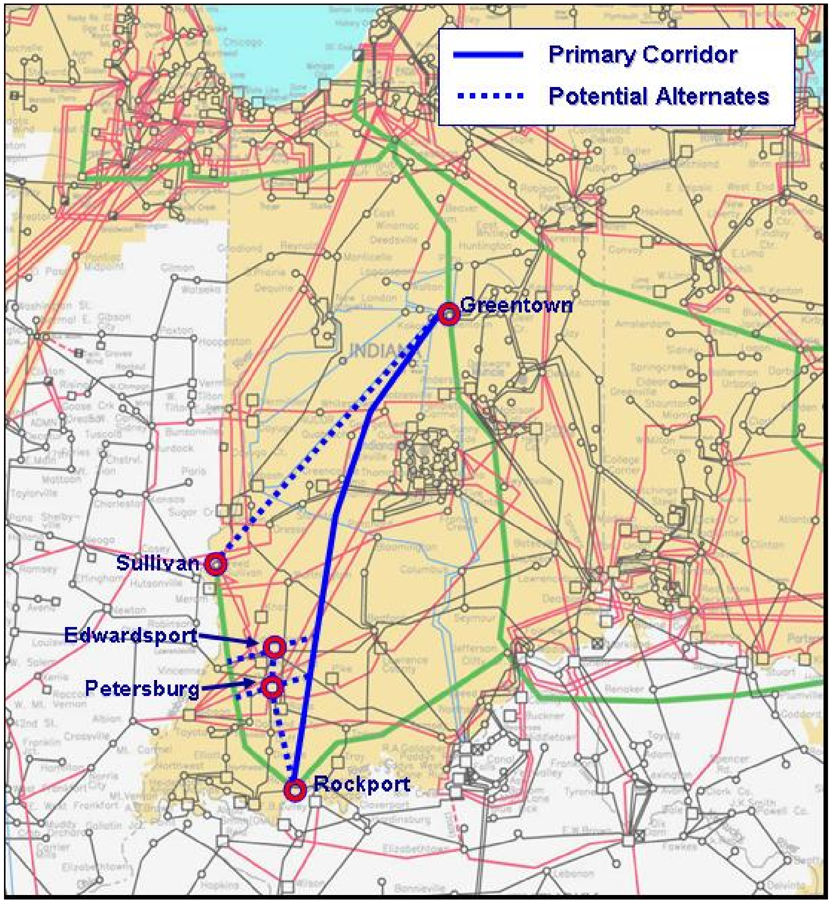
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- **Next Steps**
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate – Fall 2008
  - SPP Cost Allocation Filing – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on the routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.
- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015



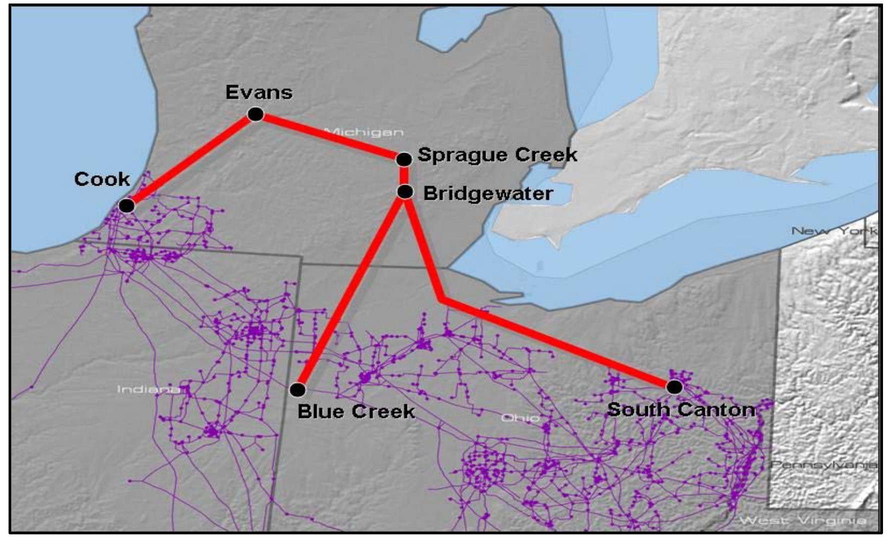
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

Overview

- ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
- Study was released Q3 2007
- 700 miles of 765-kV line in Ohio and Michigan
- $2.6 billion investment (before ownership division)
- AEP and ITC are in discussions to form a Joint Venture



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

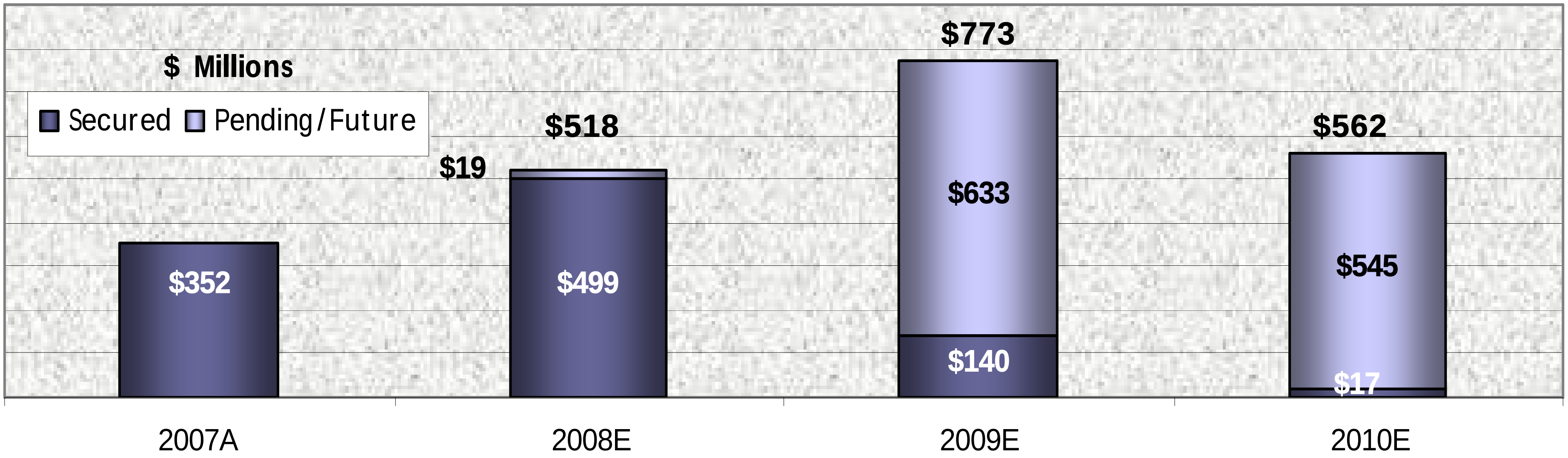
Benefits

- Up to 5,000 MW improved transfer capability
- Reduces network line losses by 250 MW

Next Steps

- Agreement on JV (AEP/ITC) - Summer 2008
- JV Formation - 2008
- MISO and PJM Review/Approval - 2009
- FERC Formula Rate & Cost Allocation Filing - 2009
- Siting Approval – 2011-2012
- Estimated Completion – 2015-2021

Incremental Rate Relief



- 96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Construction Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.

- 2008 Pending: Virginia base case rates subject to refund ($208MM requested).

- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM requested), Ohio ESP, other cases yet to be filed.

Secured $499MM of $518MM for 2008

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order						Expected Order						

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing Begins						12/1/08						
Expected Order												Expected Order
Ohio - ESP Filing												
Company Testimony Filed	07/31/08											
Intervenor Testimony				10/31/08								
Staff Testimony				11/07/08								
Hearing Begins					11/17/08							
Expected Order						Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Staff/Intervenor Testimony				10/29/08								
Rebuttal Testimony					11/19/08							
Settlement Conference						12/01/08						
Hearing Begins						12/08/08						
Rates Effective *							01/08/09					

* Subject to refund, with interest

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval
- SWEPCo Stall Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- SWEPCo Stall Plant Filing in Arkansas

AEP Ohio Electric Security Plan

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART^{SM} Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony is due October 31, Staff testimony is due November 7 and the public hearing commences on November 17, 2008. We anticipate an order at the end of 2008.

Highlights of AEP Ohio's ESP Filing

		2009		2010		2011		
		CSP	OPCo	CSP	OPCo	CSP	OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		**Other Components**		**Other Components**		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested phase-in of proposed incremental FAC expenses during the three-year ESP period. Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 &PJN-10 provides calculation of environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows the capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: Requested an annual 7% & 6.5% per year increase in Distribution for CSP & OPCo, respectively. Exhibit DMR-4 shows expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response & energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009		2011	
	CSP	OPCo	CSP	OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	-$80.7M	-$27.1M	$22.8M	$15.2M

A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

Summary Rate Case Information

AEP®

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1 *
Rate of Return		8.52%
Operating Income Requirement	$	205.7
Adjusted Operating Income	$	79.2
Difference	$	126.5
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	207.9

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony was received August 13, Staff testimony was received August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008. A draft air permit approval was released for public comment on August 11, 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued a written order approving construction of the plant on August 12, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding was suspended pending outcome in Louisiana. Now that Louisiana approval has been received, we will seek an expedited ruling from Arkansas.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- The Louisiana PSC approved the plant on September 10, 2008.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Commitment to Credit Quality

- ❑ Maintain adequate liquidity
- ❑ $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- ❑ Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- ❑ Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- ❑ Target long term dividend payout ratio range of 55-60%
- ❑ Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

AEP AMERICAN® ELECTRIC POWER

Edward Jones/Wells Fargo
Analyst Visit
St. Louis, MO
December 17, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Jana Croom – Analyst Investor Relations

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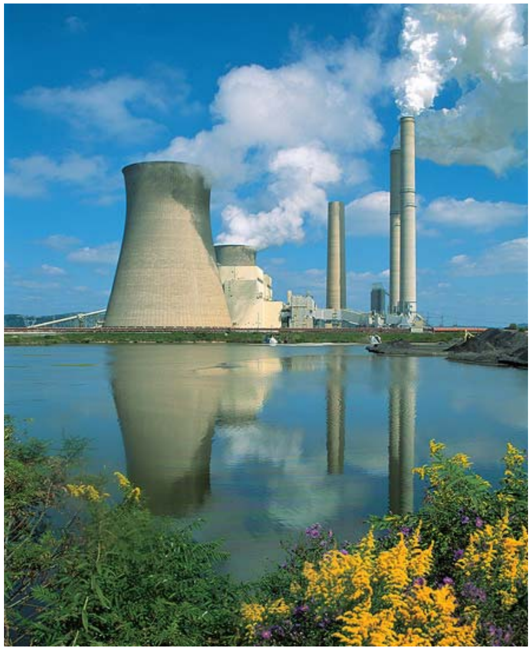
AEP AMERICAN® ELECTRIC POWER

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment

- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders

- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



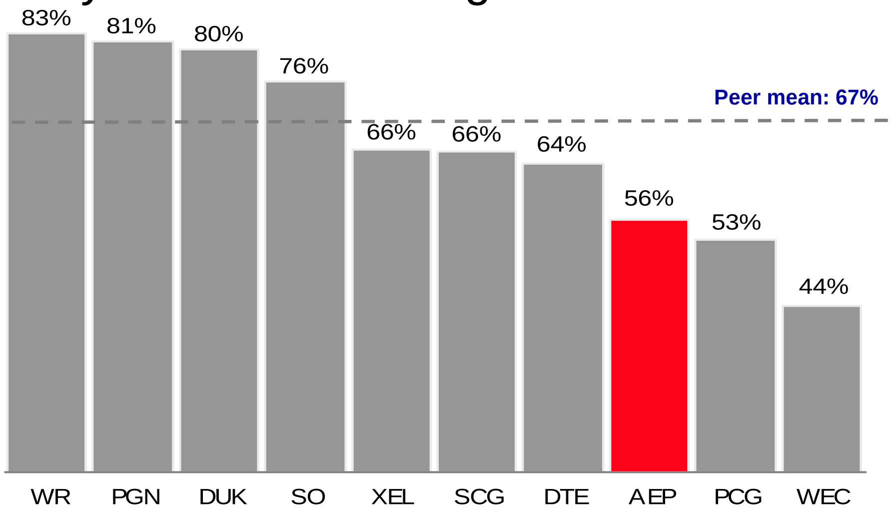
General JM Gavin Plant (OH)

AEP AMERICAN® ELECTRIC POWER

Dividend Overview

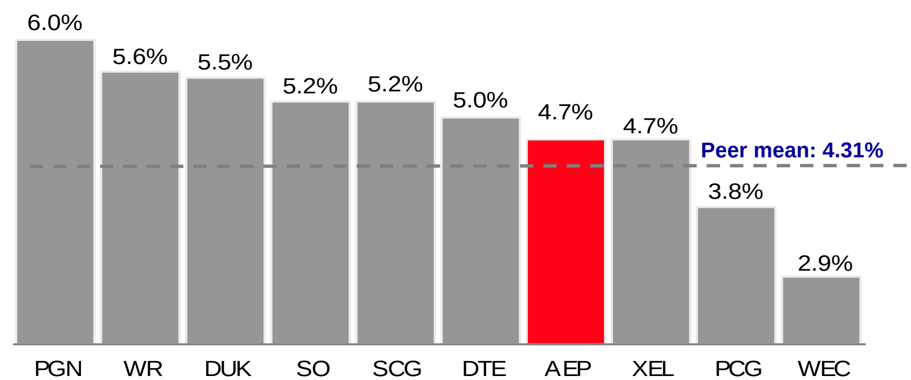
- We have paid 398 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 12/9/09

Dividend Yield vs. Integrated Electric Peers

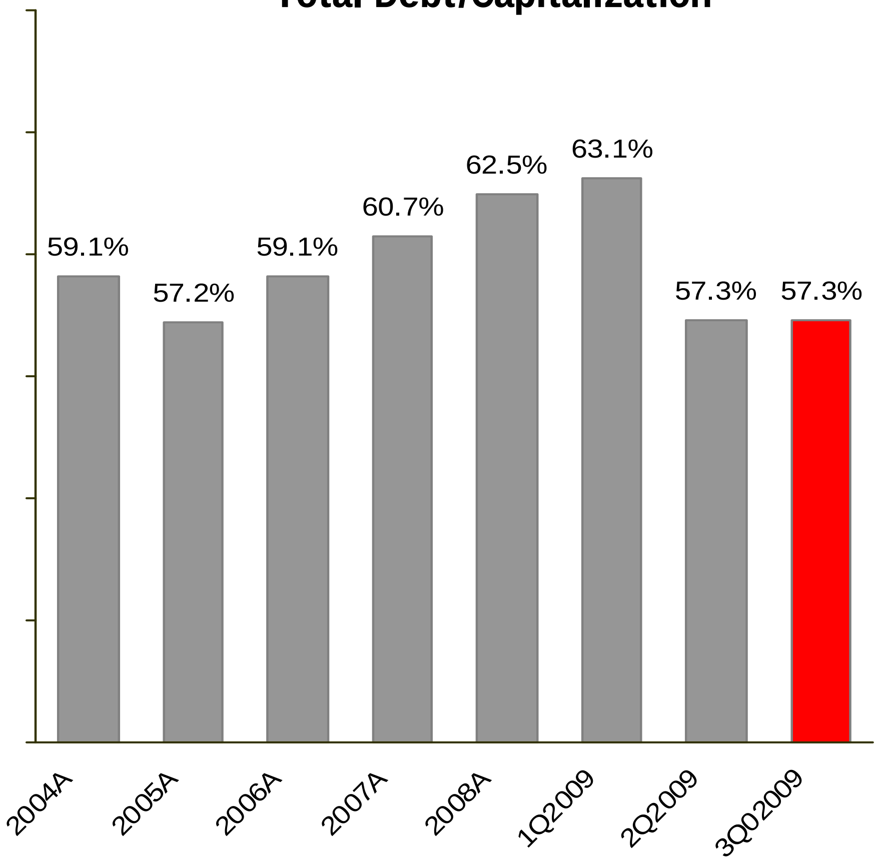


Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 12/9/09

AEP AMERICAN® ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

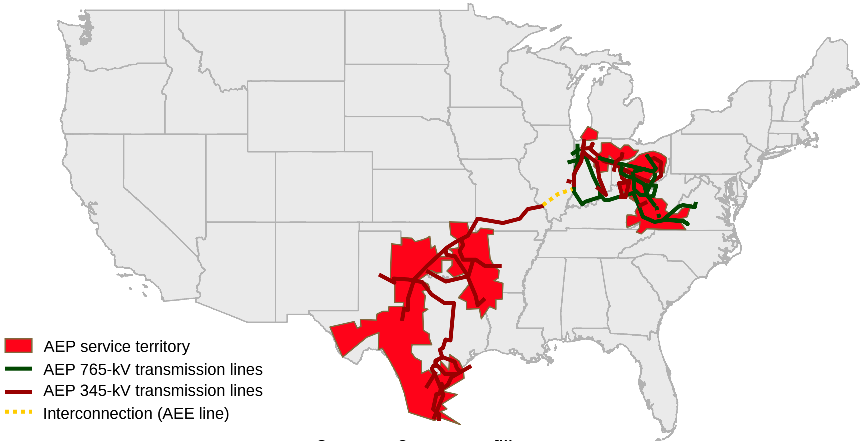
Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	877	
Less		
Commercial Paper Outstanding	(347)	
Letters of credit issued	(470)	
Net Available Liquidity	**$3,641**	

AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview



[1] *Source: Company filings*

AEP's Leadership Position

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

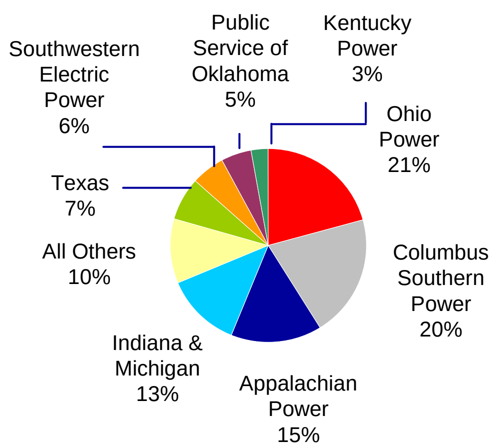
Generation owned[1] (GW)	
SO	42.6
AEP	40.6*
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

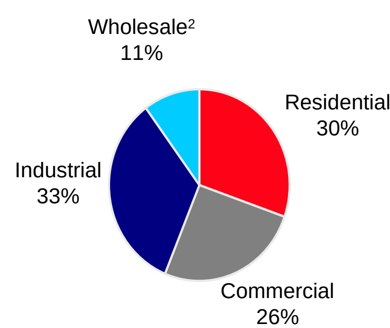
* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations

2008 On-going Earnings = $1.3bn



2008 Retail Load = 193.9 TWh



[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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2010 Ongoing Earnings Guidance

	2009E: $2.90-$3.05	2010E: $2.80-$3.20
Utility Operations	$ 2.92	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.18	$ 0.09
Parent & Other	$(0.14)	$(0.12)

EARNINGS DRIVERS

- ↑ $317MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

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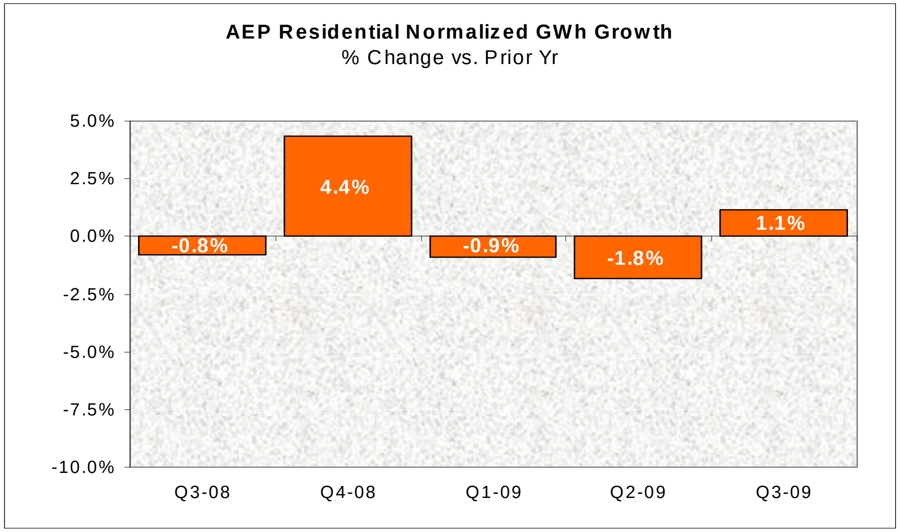
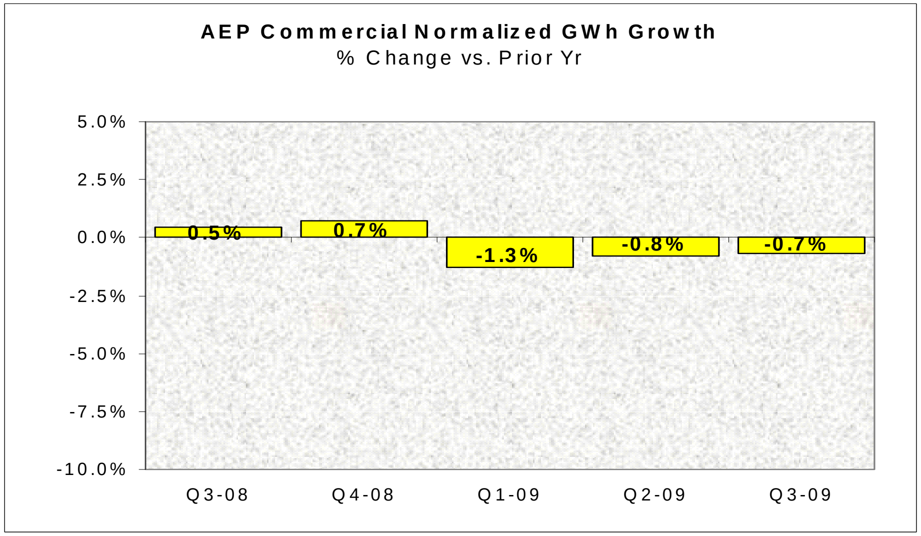
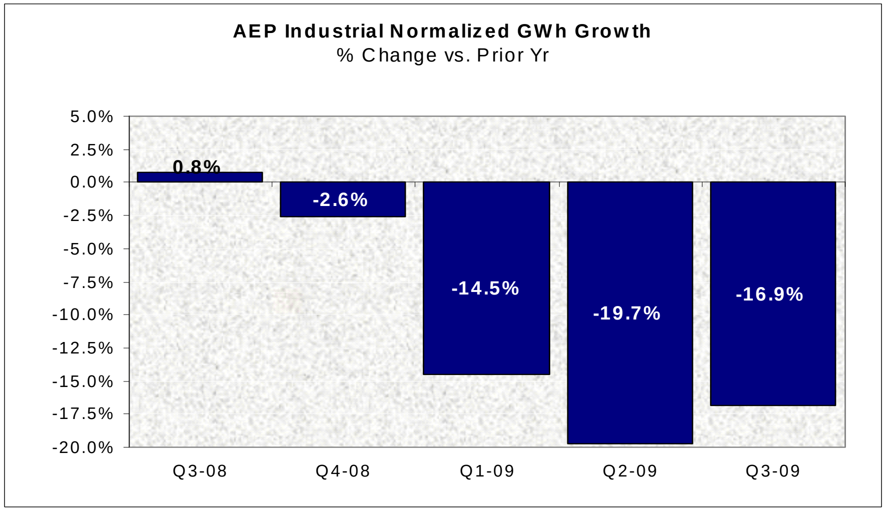
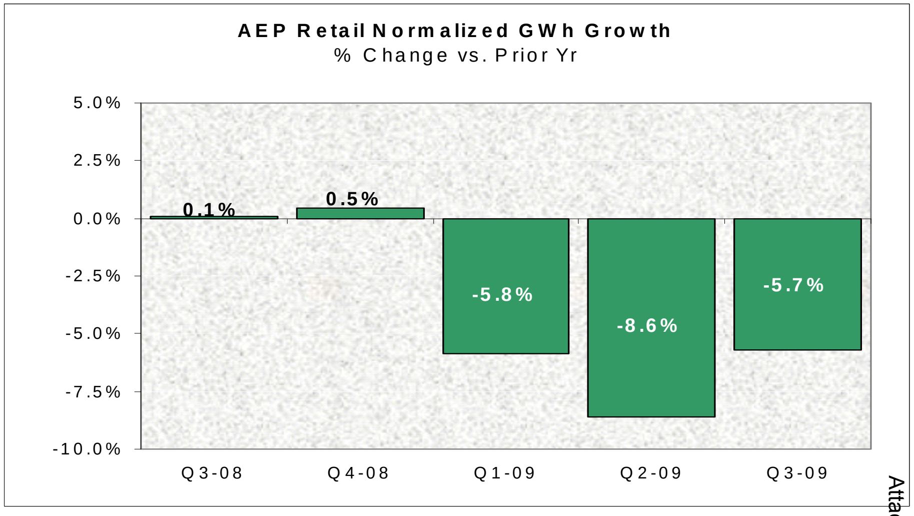
12-Month Normalized Retail Load Trends









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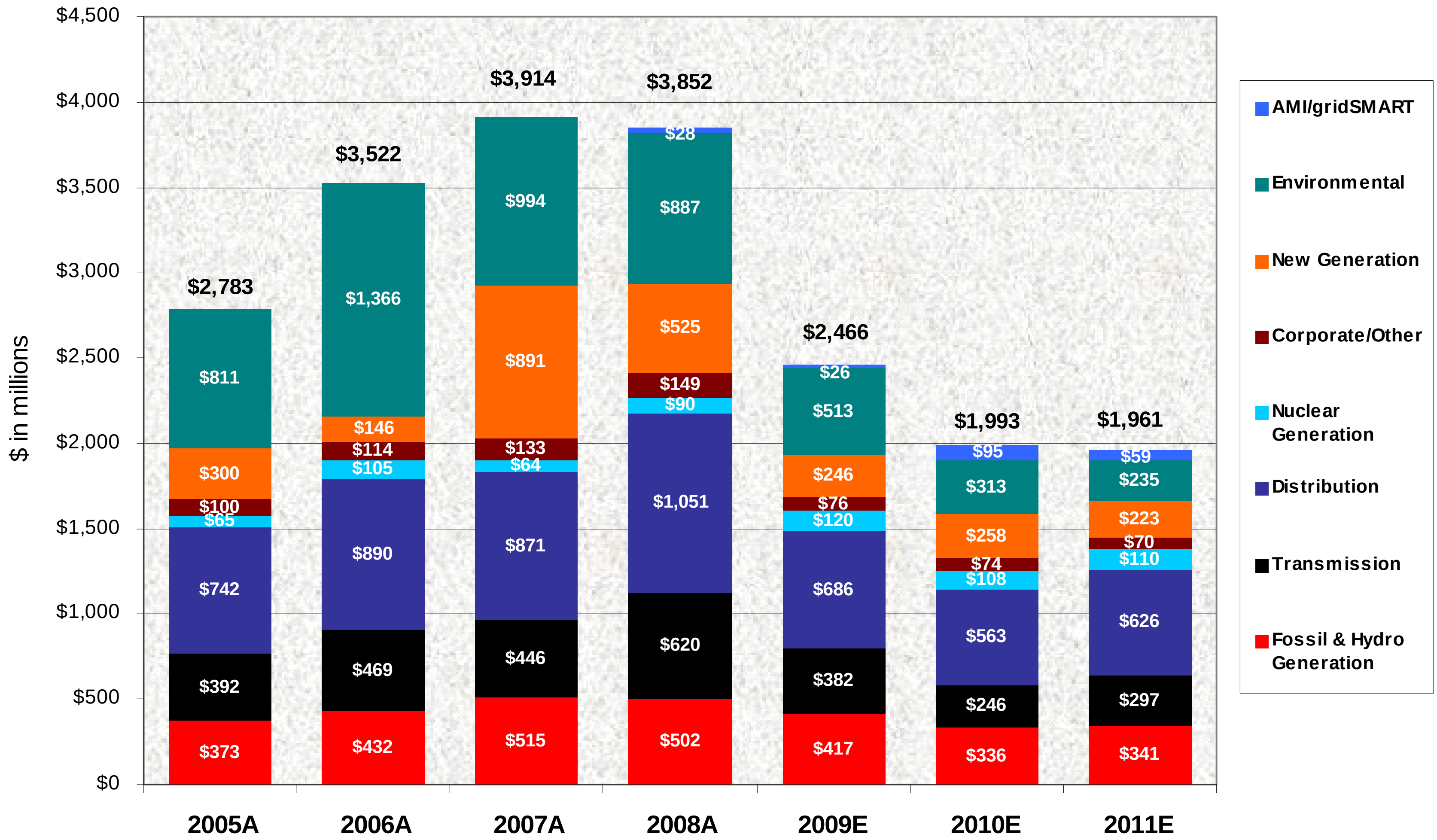
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

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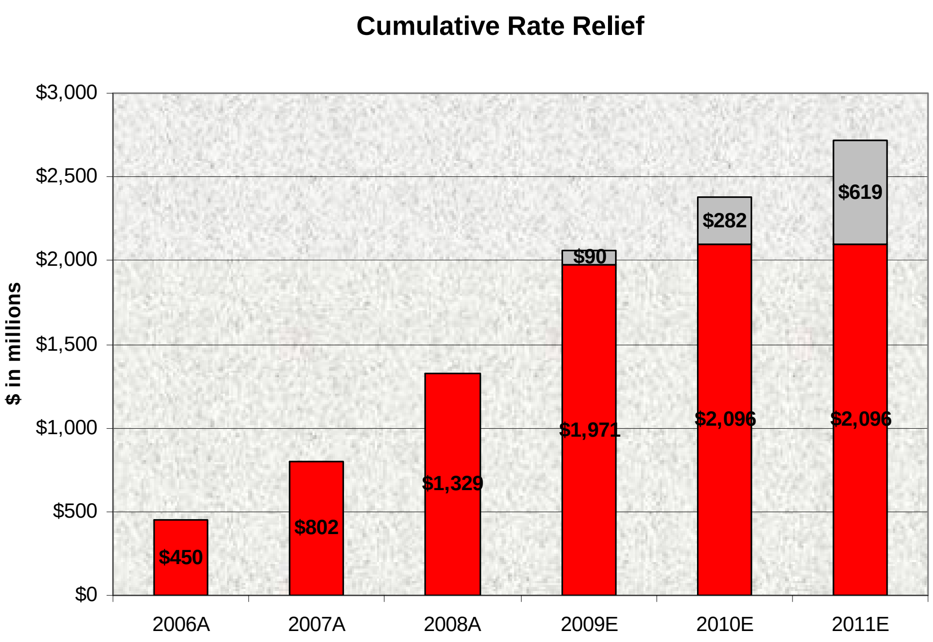
Investment in Utility Platform

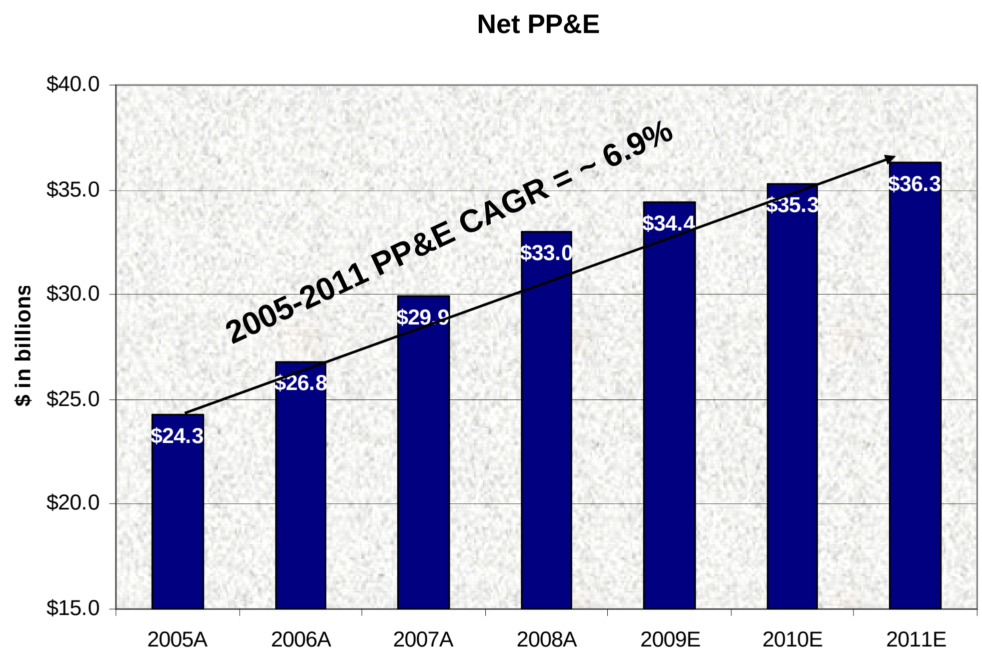
Track Record of Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$317[1]	$337

[1] *$125mm was secured for 2010 as of November 30, 2009*

Growth in Net PP&E



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Transmission Investment Opportunities

- **<u>ETT</u>: Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B in the next decade

- **<u>Transco</u>: Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM

- **<u>Joint Ventures</u>: Outside of our footprint, with ETA or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

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Accomplishments and Priorities

2004 – 2009

- ✓ Returned to the operating company model to enhance our constructive local relationships
- ✓ Secured over $2B in rate relief across the AEP system with solid regulatory relationships in all eleven jurisdictions
- ✓ Designed and implemented a $5.2 billion environmental retrofit program
- ✓ Effectively managed our credit and liquidity
- ✓ Paid over $3 billion in dividends
- ✓ Safe, diverse and motivated employee culture

2010 +

- Navigate through ongoing economic conditions
- Maintain capital spending and balance sheet discipline
- Continue delivering successful regulatory outcomes
- Participate in policy making at both the federal and state levels, particularly related to environmental/climate and transmission issues
- Invest in the next generation of energy infrastructure: high-voltage transmission, CCS, gridSMART℠

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Appendix

Transco

- **Transco will be used to develop significant new on-system, AEP-owned investment**
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- **Next steps:**
  - Obtain state utility status where required and join PJM and SPP as a transmission owner
  - FERC tariff for Transco filed December 1, 2009, with rates effective and first projects in service in 2010
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

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JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2013

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $600 million+*
- *ROE: 9.96%*

PJM

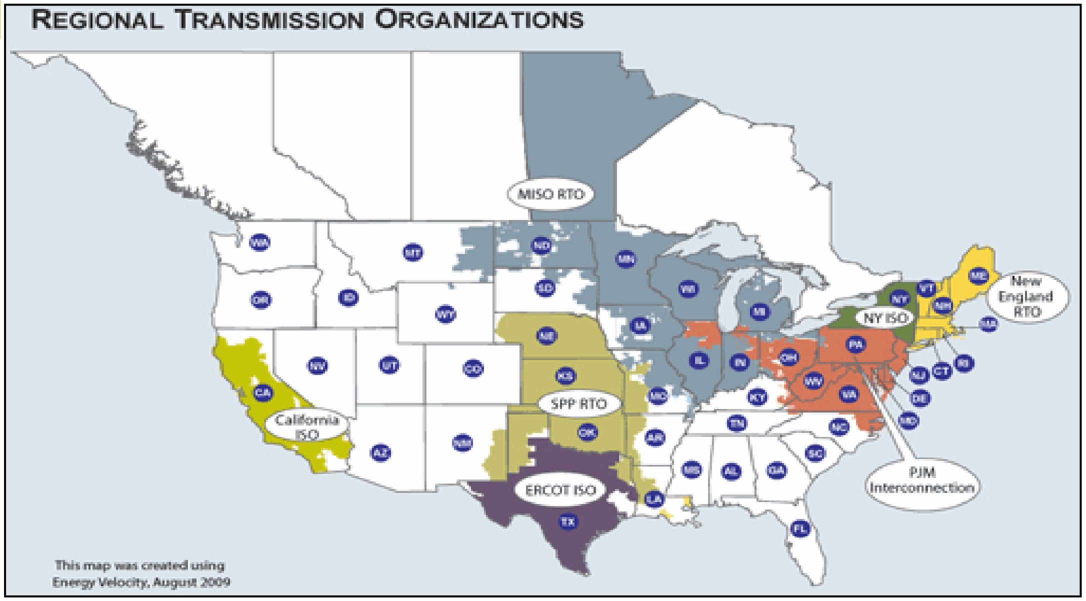
PATH-WV — COD: 2014

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — COD: various

- *Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)*

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP **ERCOT** **PJM** **PJM/MISO**

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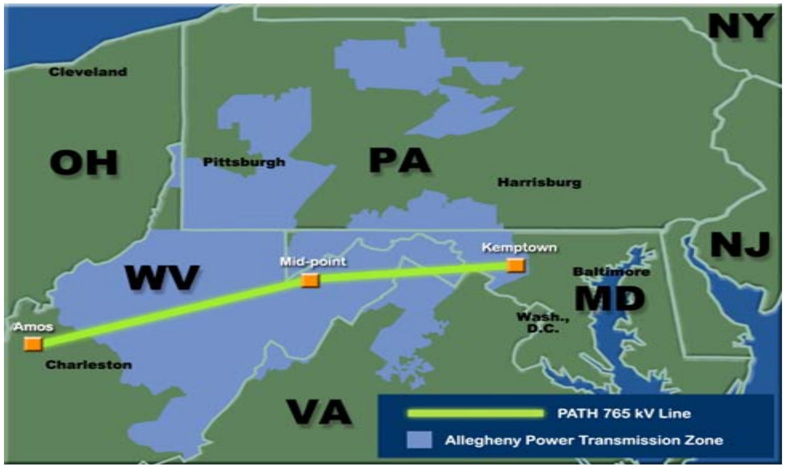
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009 with a decision expected February, 2011.
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
- Estimated completion date: 2014

PATH
Potomac-Appalachian Transmission Highline

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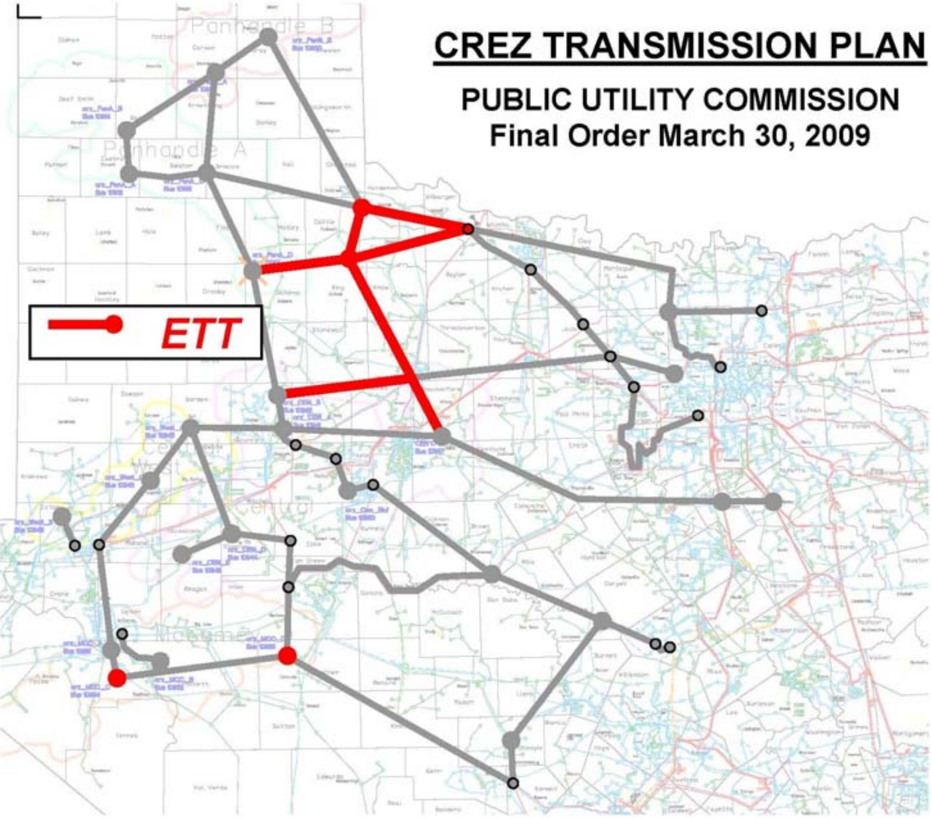
Texas CREZ Project

Overview

- On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
- Staging to occur in separate docket and consider timing of wind projects and congestion.
- PUCT established 2 categories based on priorities. ETT has no first priority lines.
- PUCT issued a final order assigning transmission service providers on March 30, 2009.
- ETT's share of CREZ investment is approx. $840MM of $4.9B total of which AEP's ownership is 50%.
- The filing calls for completion of the plan by 2013.

Next Steps

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT
Electric Transmission Texas

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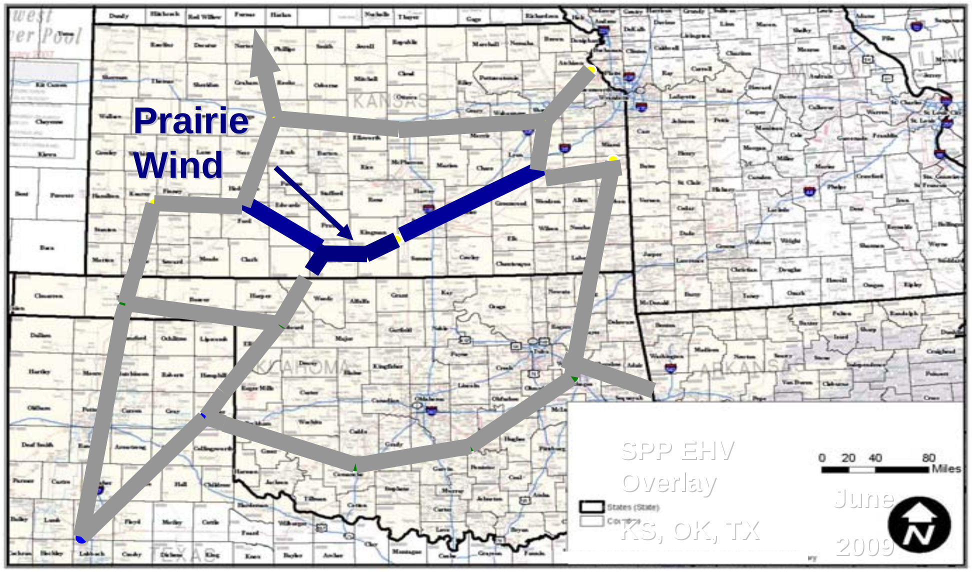
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5314 of 9556

Prairie Wind Transmission, LLC

Overview

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- Following a settlement agreement with ITC both entities agreed to split the mileage and costs of building the 765-kV transmission superhighway. The newly revised project is expected to cost approximately $400 million and be in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- RTO Approval

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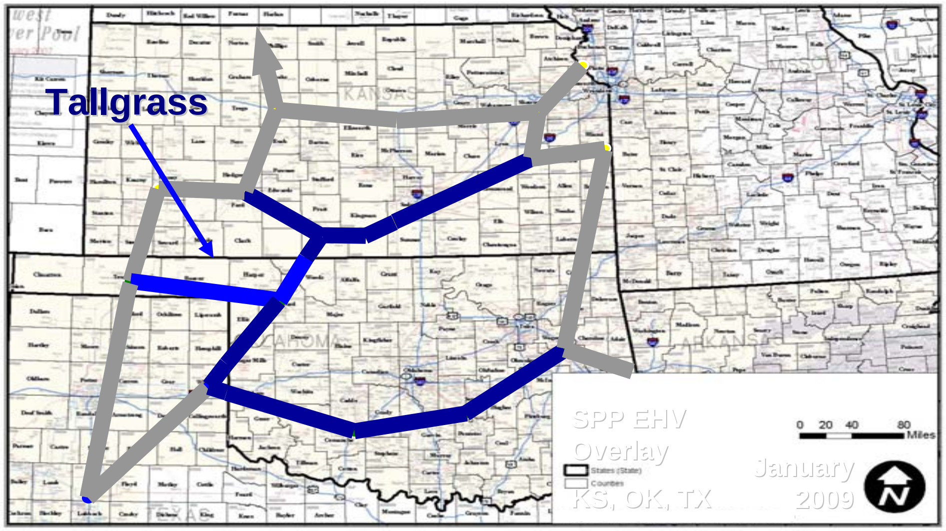
Tallgrass Transmission, LLC

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- RTO Approval

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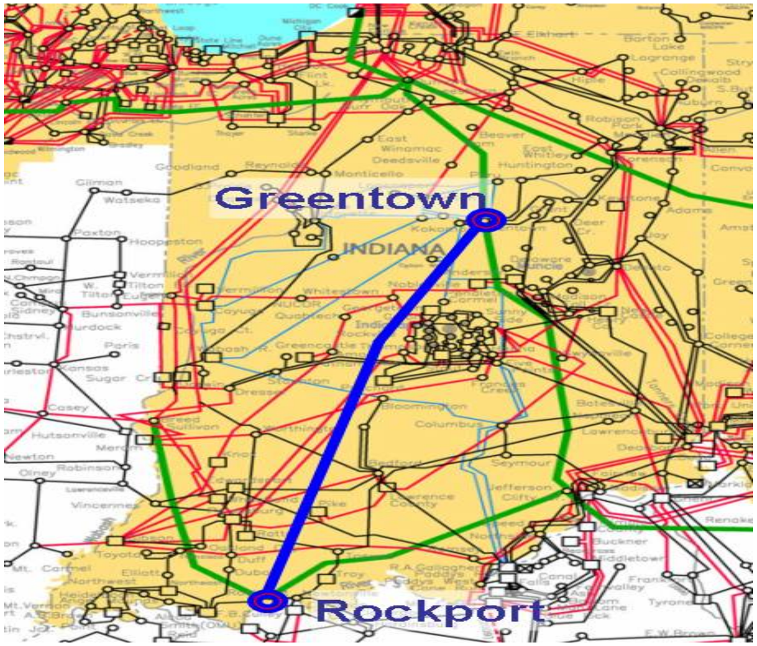
Pioneer Transmission, LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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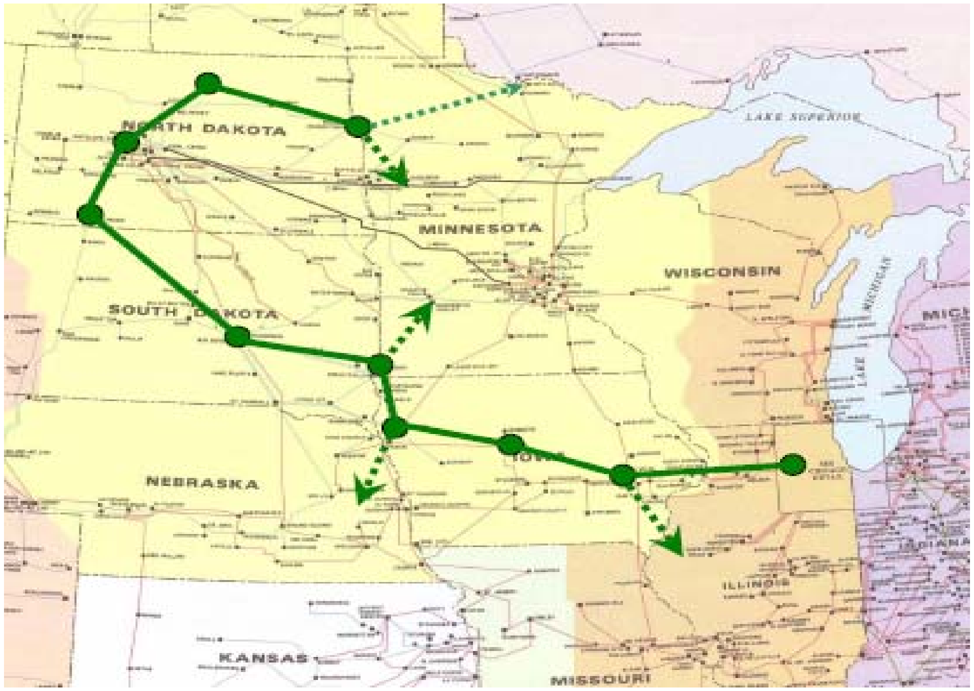
Upper Midwest EHV Development—SMART Study

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Announced SMARTransmission Study in August 2009.**
  - Participants include ETA, Exelon, ATC, Northwestern, MidAmerican and Xcel
  - Study due to be completed in early 2010 and will include “overlay” options and quantification of economic benefits.
- **Near Term Risks**
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including incentives
- **Mitigation**
  - Collaborative approach involving impacted utilities, RTOs, commissions and others



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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AEP Supports Climate Legislation

Key Design Elements:

- **Reductions and Timing -** Moderate with adequate lead times
- **Scope of Program -** Economy-wide w/ preemption of EPA authority to regulate CO_2 under existing Clean Air Act
- **Flexibility of the Program -** Market-based system w/ credit trading, banking, unrestricted offset use & early action credits
- **Allowance Allocation And Other Cost Issues -** Full, free allocation to electric sector and “Low” auctions
- **Technology Development/Deployment -** Bonus allowances or other support for carbon capture and storage (CCS)
- **International Linkage -** e.g. AEP-IBEW proposal on international competitiveness

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AEP's Near-Term CO_2 Reduction Commitment

Existing Programs

- Existing plant efficiency improvements
- Renewable Energy
  - 1785 MWs of Wind
  - 722 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr
  - Over 63MM trees planted through 2008
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
2003-2010: 48 MMT Total

New Program Additions (by 2011)

- 1000 additional MWs of Renewable through PPAs
- Domestic Offsets (methane, forestry): About 2MM tons/yr
- Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr
- Additional actions: Energy efficiency and biomass: 0.3MM tons/yr

New Technology Additions

- New Generation – Ultra Super Critical
- Carbon Capture and Storage (CCS) for existing fleet
  - Chilled Ammonia

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/Year
Longer Term - New Technology

Mountaineer CCS Update

PROJECT STATUS

- September 2 – successfully captured CO_2
- October 1 - began underground injection and storage
- October 30 – facility dedicated

NEXT STEPS

- Monitor the CO_2 behavior once underground
- Assess the parasitic load impact of the equipment on the plant
- DOE funding received for 50% of commercial phase of project ($334MM); project expected to be operational between 2012 and 2015

PROJECT DESCRIPTION

- Alstom's chilled ammonia process captures CO_2 from a 20 MWe slipstream of flue gas at AEP's Mountaineer plant located in New Haven, WV
- Captured CO_2, transformed to a semi-liquid state, is pumped into sandstone or dolomite layers approximately 1.5 miles underground. Caprock will hold the CO_2 in place permanently.

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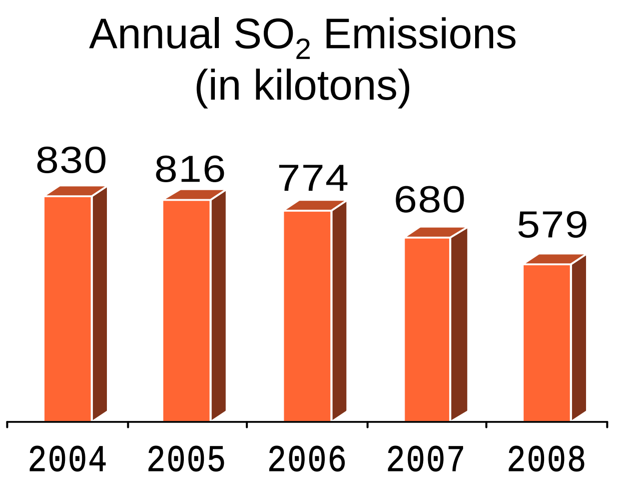
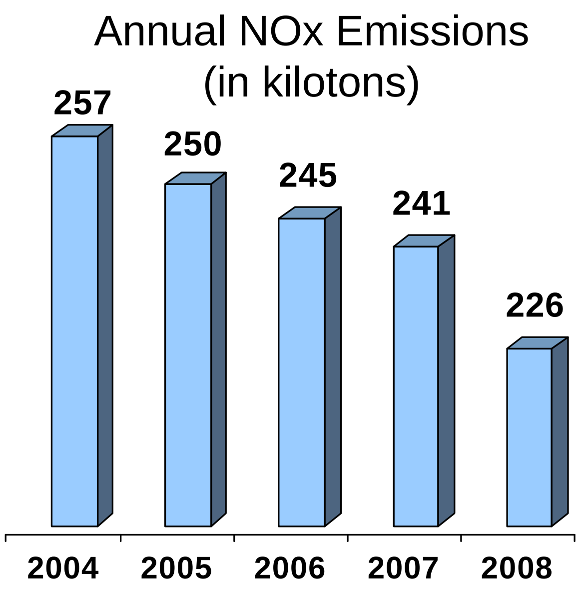
Environmental Program

- Environmental retrofits keep coal plants viable in order to take advantage of vast domestic fuel resources
- Scrubbers and SCRs reduce emissions of SO_2, NOx and Mercury
- Environmental technology installed on existing plants delays the premature retirement of those plants, thereby keeping low cost generation assets available to the market
- Since 2004, we have invested $4.4 billion in environmental retrofits to meet obligations required by environmental regulations





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New Generation Projects

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

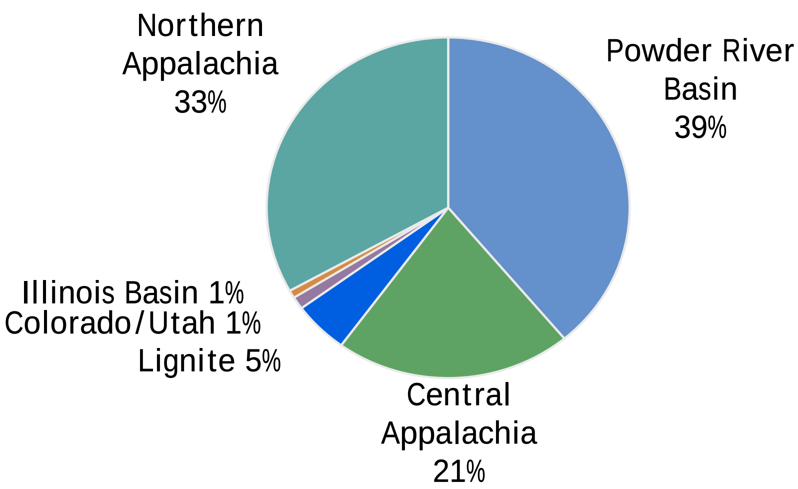
John W. Turk Jr. Ultra-Supercritical Coal Plant

J. Lamar Stall Combined-Cycle Gas Plant

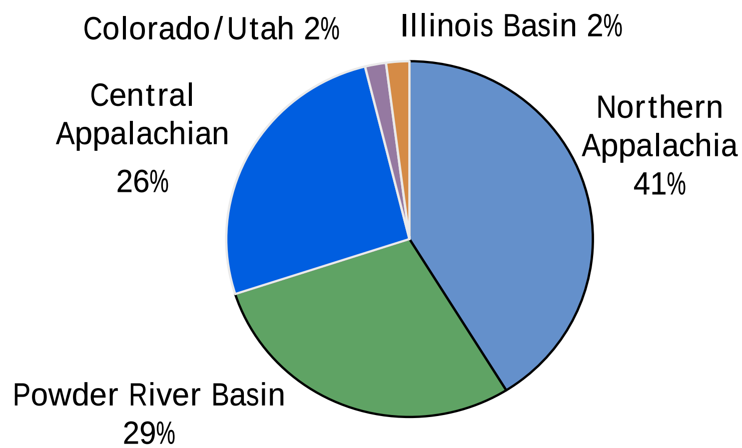
- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $386 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

Coal Procurement - 2010 Projected

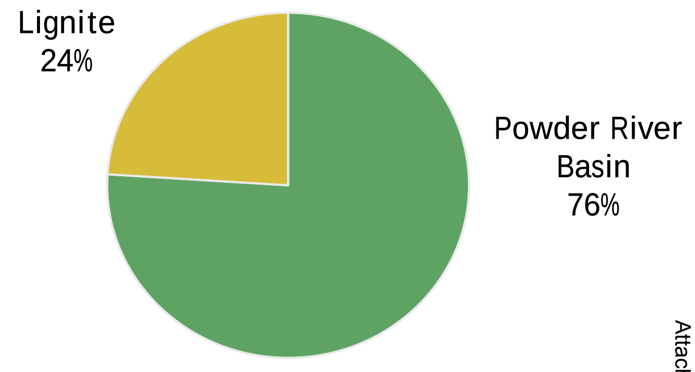
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009 and 98% for 2010
- Avg. delivered price ~ $47/ton in 2008
- Approximate 10% price increase in 2009 ~ $51/ton
- Approximate 10% price decrease in 2010 ~$46/ton

AEP River Operations

- Full-service Inland Waterways carrier
  - 2,978 hopper barges
  - 58+ towboats/25 tugs
- Tonnage & Commodity:
  - Captive: (for AEP)-37MM tons of coal;
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

River Operations barge

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030)

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

12/12/2009	Rates effective, subject to refund
12/28/2009	Intervenor testimony due
1/27/2010	Staff testimony due
2/17/2010	Rebuttal testimony due
3/16/2010	Evidentiary hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

Represents Generation and Distribution Rate Base Only

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case

On August 28, 2009 SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. (Docket# 37364) An order is expected in July, 2010.

Projected Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

2/8/2010	Intervenor testimony due
2/15/2010	Staff testimony due
3/1/2010	SWEPCO rebuttal testimony due
3/15/2010	Evidentiary hearing commences
4/30/2010	Rates in Effect Subject to Refund

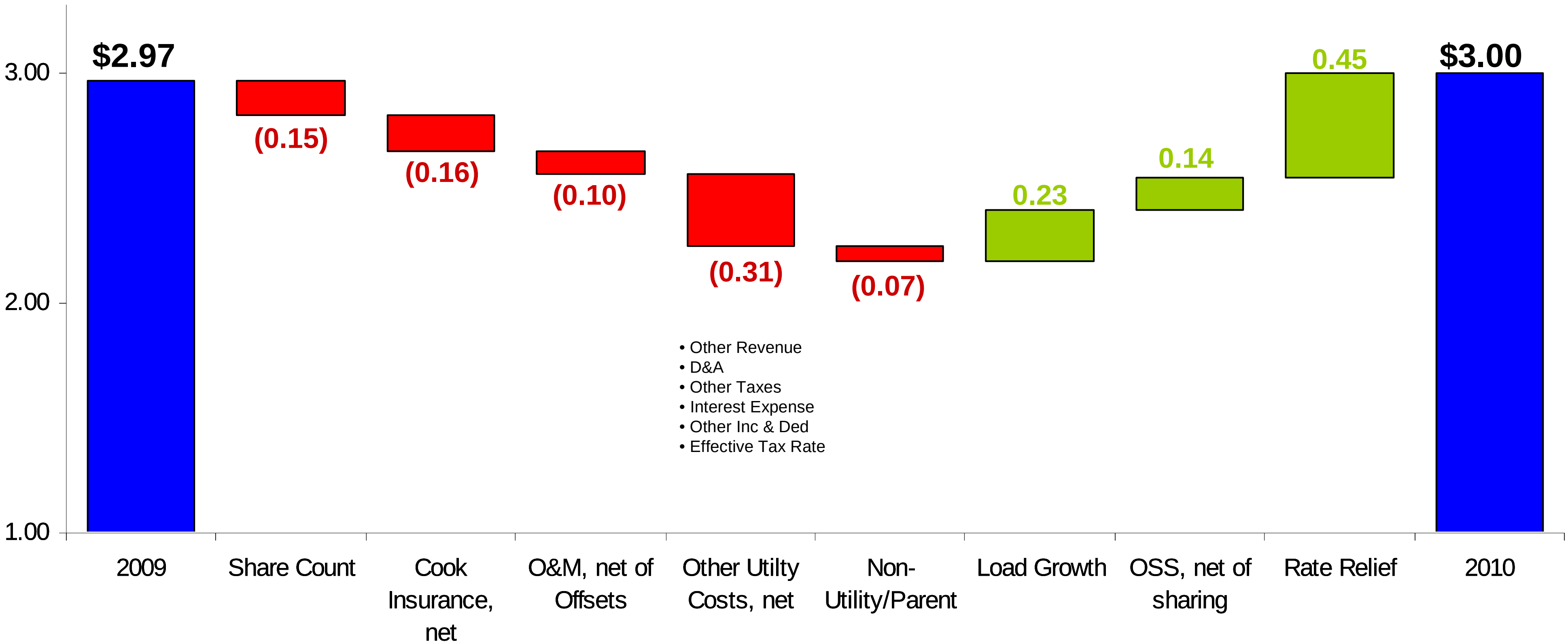
Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

AEP AMERICAN® ELECTRIC POWER

2010 Earnings Drivers



AMERICAN ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2009E: $2.90 - $3.05

American Electric Power
2009 Guidance vs. 2010 Guidance

2010E: $2.80 - $3.20

		Performance Driver	2009 Guidance ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,754 GWh @ $ 38.4 /MWhr =	2,562	68,249 GWh @ $ 42.1 /MWhr =	2,873
2	Ohio Companies	47,284 GWh @ $ 57.8 /MWhr =	2,733	47,922 GWh @ $ 61.9 /MWhr =	2,968
3	West Regulated Integrated Utilities	39,112 GWh @ $ 29.8 /MWhr =	1,166	41,495 GWh @ $ 31.3 /MWhr =	1,298
4	Texas Wires	27,208 GWh @ $ 21.1 /MWhr =	575	27,510 GWh @ $ 21.9 /MWhr =	602
5	Off-System Sales (Net of Sharing)	13,525 GWh @ $ 16.7 /MWhr =	226	23,992 GWh @ $ 13.4 /MWhr =	322
6	Transmission Revenue - 3rd Party		356		353
7	Other Operating Revenue		779		554
8	Utility Gross Margin		8,397		8,970
9	Operations & Maintenance		(3,309)		(3,546)
10	Depreciation & Amortization		(1,582)		(1,625)
11	Taxes Other than Income Taxes		(768)		(791)
12	Interest Exp & Preferred Dividend		(924)		(986)
13	Other Income & Deductions		124		168
14	Income Taxes		(597)		(742)
15	Utility Operations On-Going Earnings		1,341		1,448
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		36		2
	Non-Utility Operations On-Going Earnings		83		45
19	Parent & Other On-Going Earnings		(64)		(58)
20	ON-GOING EARNINGS		1,364		1,444

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN ELECTRIC POWER®

Multi-Year Capital Investment Funding Plan

	Actual 2008	Projection 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (3,967)	$ (2,885) *	$ (2,127)
Transmission Initiatives (JV Equity Contributions)	0	(49)	(93)
Dividend on Common Stock	(660)	(759)	(790)
Cash Sources (Uses)			
Cash from Operations	2,576	2,263	3,259
Proceeds from Sale of Assets	90	258	-
Common Stock Issued	159	1,744	150
Change in Debt, Net	2,266	(346)	(127)
Other	(231)	(436)	(274)
Change in Cash	233	(210)	(2)
Ending Cash Balance	$ 411	$ 201	$ 199

* - 2009 capital expenditure projection includes $340MM of construction-related accounts payable at 12/31

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Ratings current as of September 30, 2009

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

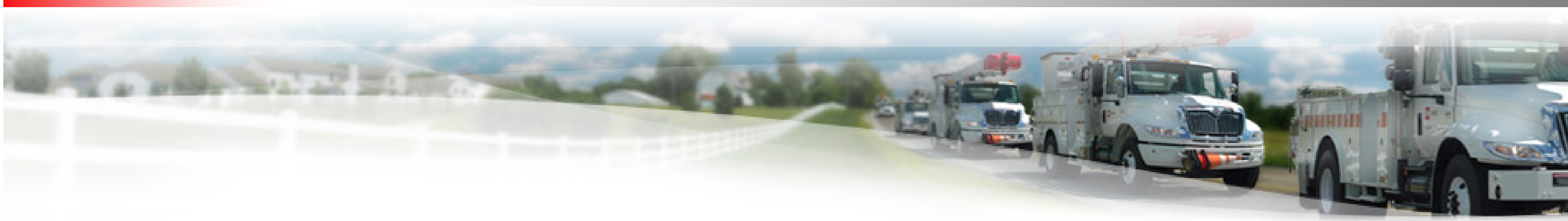
Year		2010		2011		2012
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	680	$	-	$	-
Public Service of Oklahoma	$	150	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company[(1)]	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,735	$	623	$	415

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)
Data as of September, 30 2009

AEP AMERICAN® ELECTRIC POWER

Edward Jones Call
Columbus, OH

May 2, 2011



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 5.1%[1]**
  - 50-60% payout ratio targeted
  - Quarterly dividend increased 12% in 2010
  - 403 consecutive quarters of dividend payments to our shareholders
- **Earnings Growth Prospects**
  - 4 – 6% in the 2012 to 2014 time frame
  - 5 – 7% beyond 2014

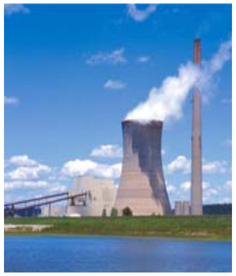
Current Wall Street Analyst Coverage:

- **20 analysts**
- **9 Buy Ratings**
- **11 Hold Ratings**

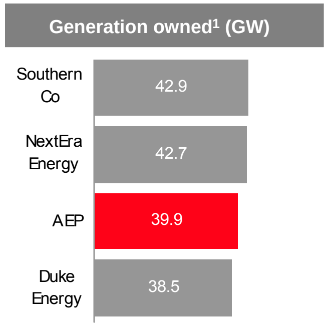
Attractive total return potential

[1] yield percentage based on AEP closing price of $36.38 on 04/28/2011

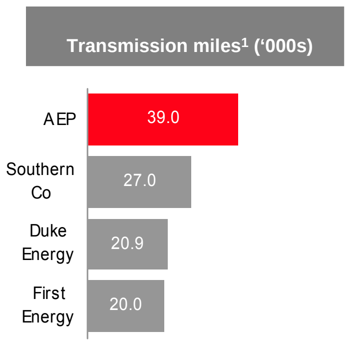
American Electric Power



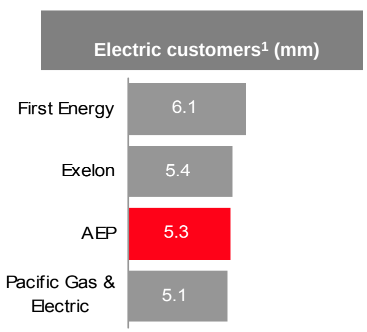
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

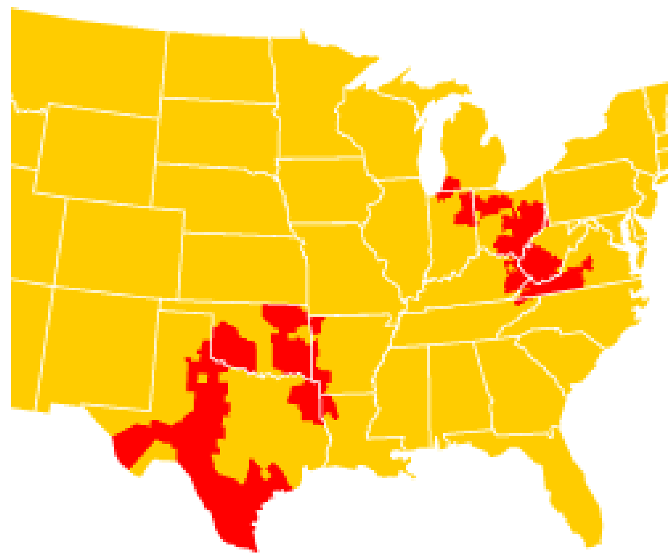


One of the largest U.S. electricity distributors



¹ : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.4B Market Capitalization
BBB/Baa2/BBB credit rating

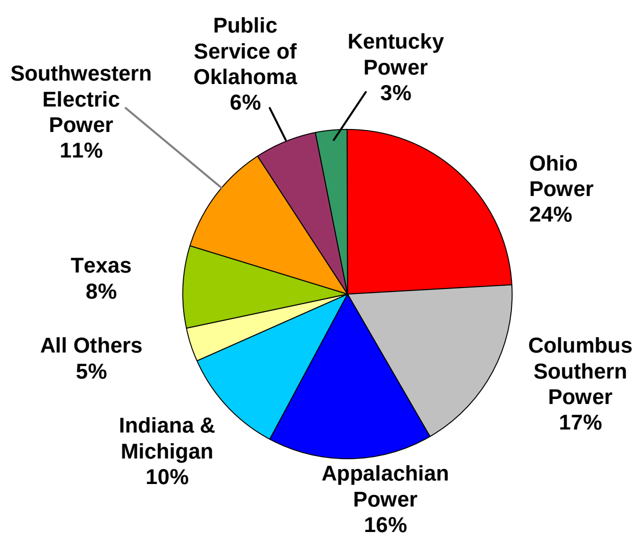
* - represents results for 2010

4

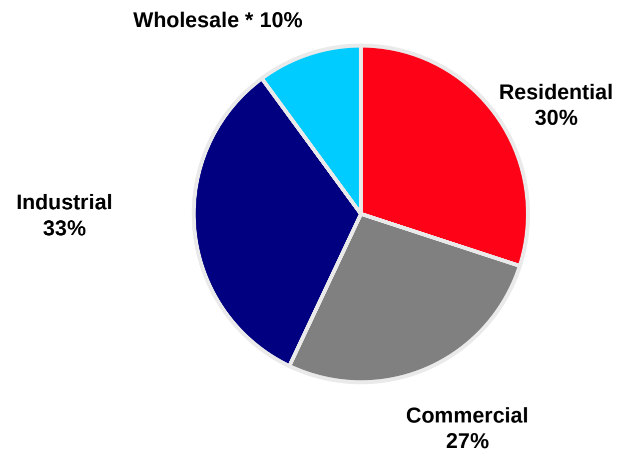
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



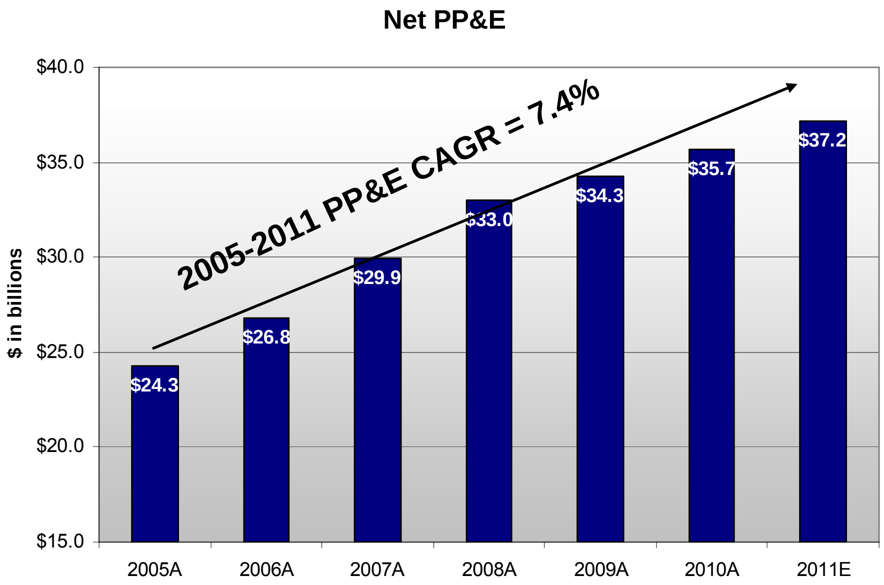
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Traditional Ratemaking Environment

AEP®

Growth in Net PP&E



Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

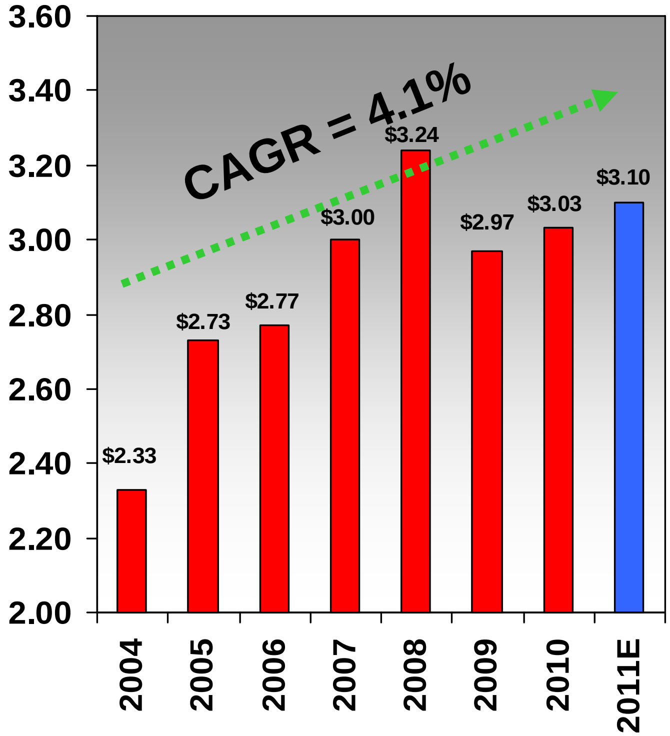
Regulatory Framework

- Base Rates
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- Recovery of Fuel Costs
  - Active fuel clauses in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)
  - Current generation rates set for 2009 – 2011
  - New filing currently with PUCO to set generation rates for 2012 - 2014

Earnings and Dividends

On-Going EPS History Since 2004

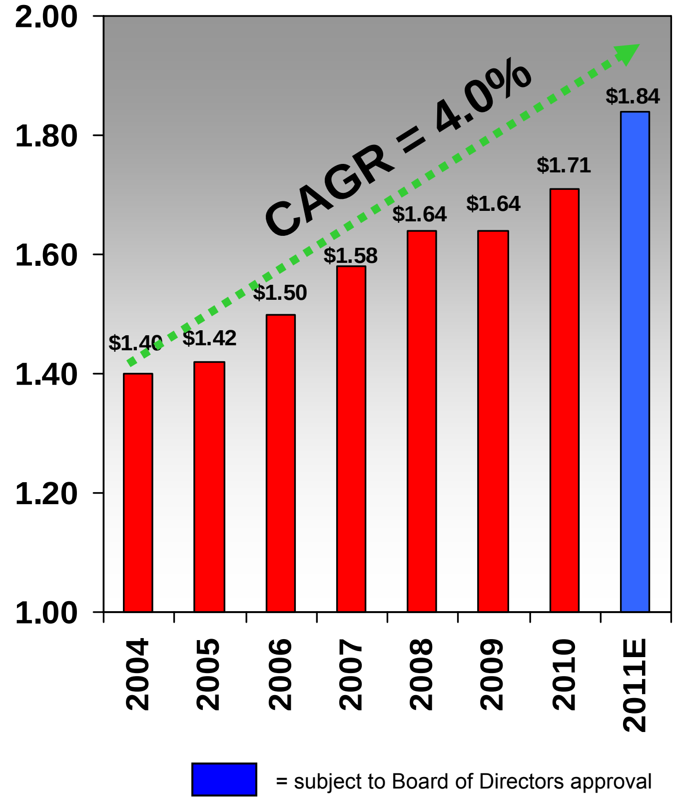
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

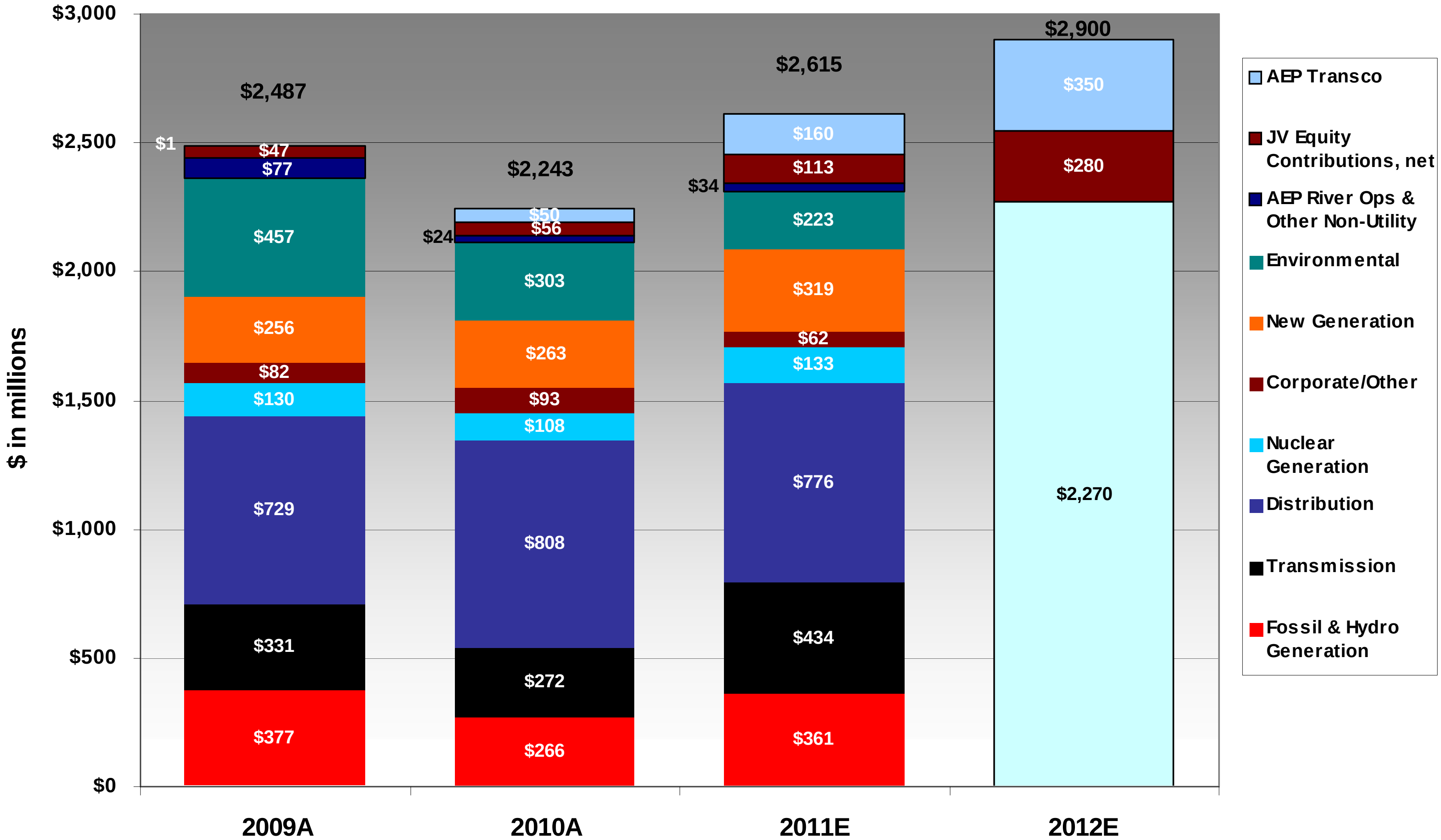
Dividend History Since 2004

$/share



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend declared in April 2011
- 50-60% payout ratio target
- Current yield over 5%

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

AEP Highlights

- **Regulated Electric Utility**
  - Regulatory and economic diversity
  - Operating Company Model
- **Focus on Capital Allocation**
  - Capital for Growth
  - Return of Capital to Shareholders
- **Strong Balance Sheet**
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- **Growth Opportunities**
  - Capital for utility platform
  - Transmission projects
- **Dividend yield over 5%**

Mountaineer Plant (WV)

AEP AMERICAN® ELECTRIC POWER

European Investor Roadshow
EEI International Utility Conference
March 9-16, 2010

DC Cook Nuclear Plant (Michigan)

345-kV Transmission Line

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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AEP Participants

Mike Morris – Chairman, President & CEO

Brian Tierney – EVP and CFO

Susan Tomasky – President, AEP Transmission

Chuck Zebula – Treasurer & SVP Investor Relations

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AEP Value Proposition

Regulated Utility Platform

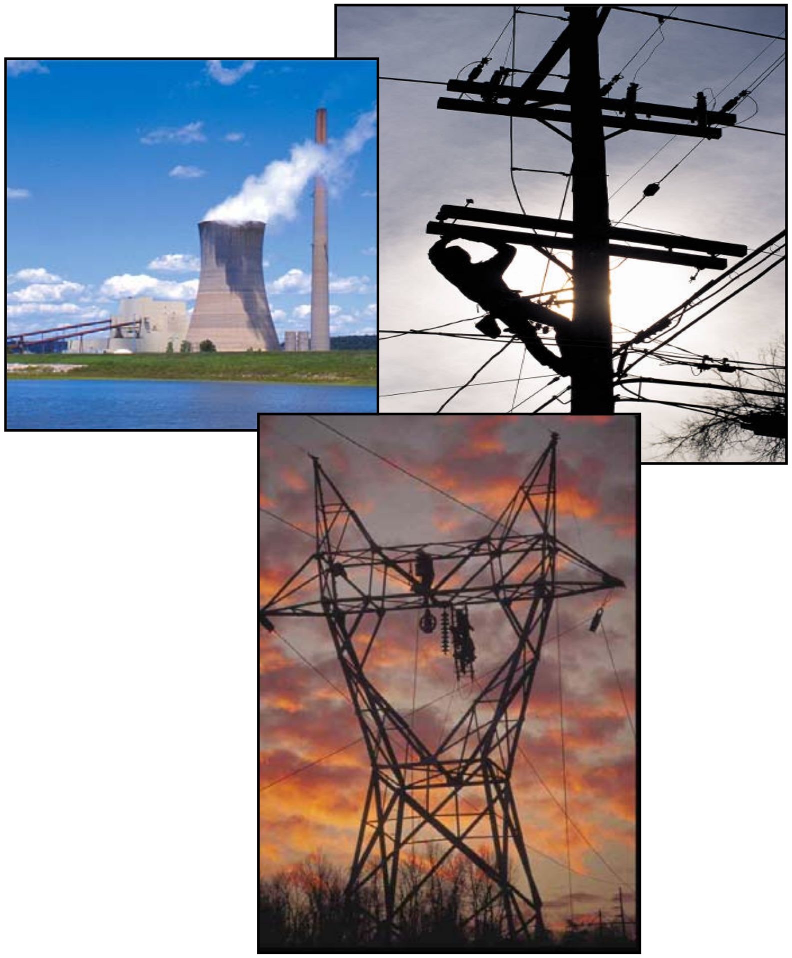
- Diversified service territory
- Successful regulatory track record
- Value compared to regulated peer group

Earnings Growth Prospects

- Investment in utility platform greater than depreciation level (2 - 4%)
- With transmission opportunities (4 - 8%)

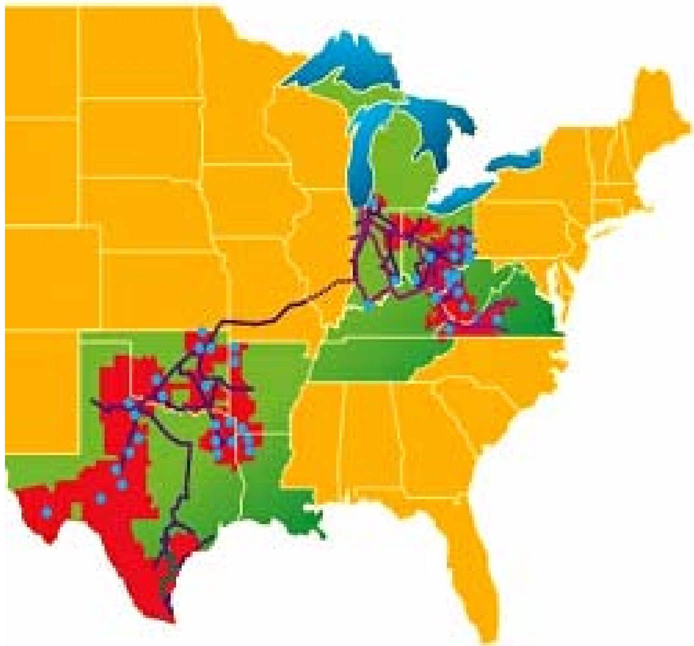
Attractive Yield Opportunity of 4.8%[1]

- 50-60% payout ratio targeted
- Nearly a century of dividend payments to shareholders



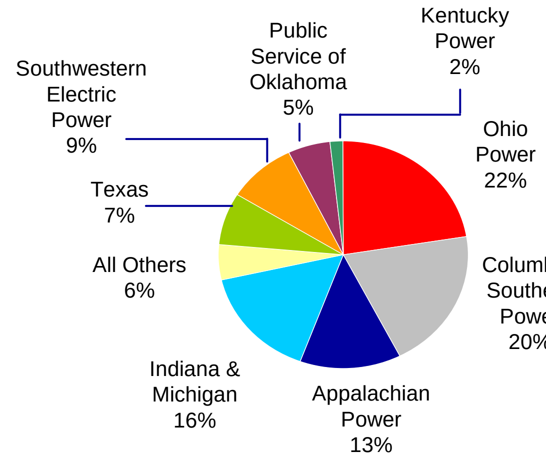
[1] yield percentage based on AEP closing price of $33.97 on 03/03/2010

Highly Diversified Regulated Utility Platform

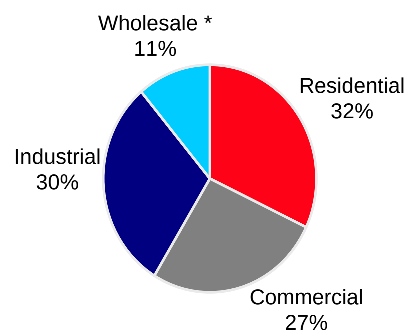


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

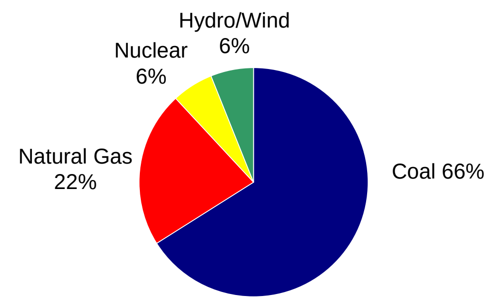


2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix**



** Based on Capacity

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5

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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

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JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

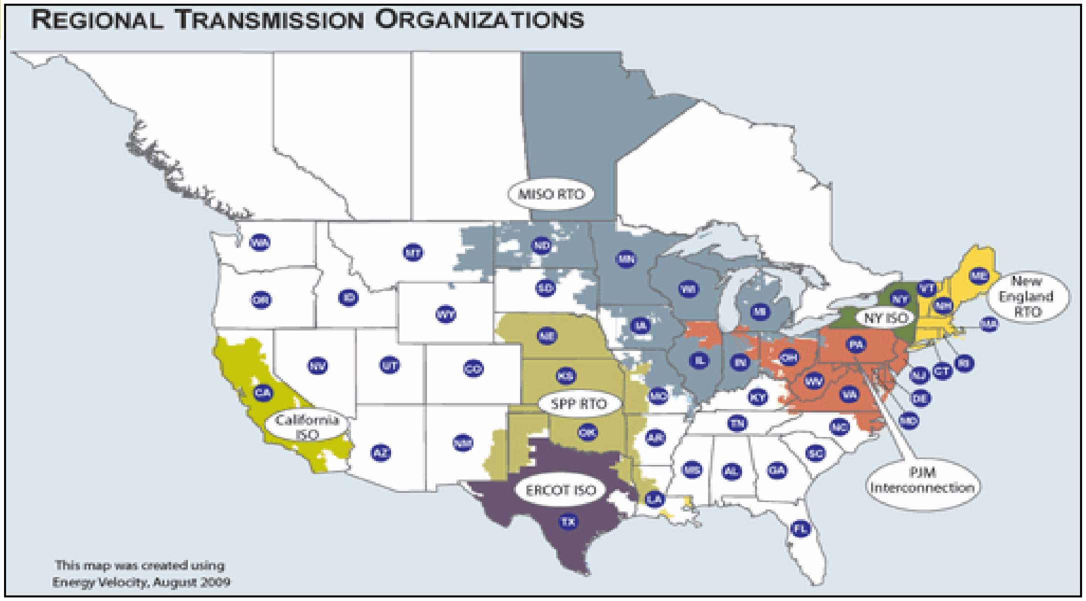
ETT — COD: 2010-2017
- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — COD: 2014
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



FUTURE DEVELOPMENT

SMARTransmission Study
- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP

SPP EHV Overlay
- *Regional Expansion of 765 kV Backbone*

ERCOT

ETT — COD: various
- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM

PJM Expansion
- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

PJM/MISO

EHV Michigan/Ohio
- *700 miles of Proposed 765 kV*

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A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- Existing Plant Efficiency Gains
- Renewable Energy
  - 1400 MW wind
  - 300+ MW hydro
- Domestic Offsets
  - Over 63MM trees planted = 1.2MM tons of CO_2 uptake
- International Offsets
  - 1MM tons of forest carbon sequestered through 2009
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:

– **2003-2010: 50 MMT+ Total**

New Additions (by 2012)

- 2000 MW Wind PPAs
- Domestic Offsets
  - Methane, Forestry
- Fleet Vehicle/Aviation Offsets
- Energy Efficiency & DSM
- Biomass Co-firing
- New Technology
  - New Generation: Ultra Super Critical Coal
  - Carbon Capture and Storage (CCS) for existing fleet
    - Chilled Ammonia

AEP's reductions/offsets of CO_2:

– **2011+: 5 MMT/yr**

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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

Captured CO_2 first time on 09/01/09; Injected CO_2 first time on 10/1/2009

Mountaineer Plant (WV)

Chilled Ammonia

20MWe scale

(Alstom)

CO_2 Storage

(Battelle)

2 injection wells & 3 monitoring wells

Captures and Stores ~100,000 metric tons of CO_2 /yr.

Phase 2

Awarded $334MM DOE Funding; Expected Commercial Operation: 2015

Mountaineer Plant (WV)

Chilled Ammonia

~235MWe scale

(Alstom)

CO_2 Storage

Captures and Stores 1.5 Million metric tons of CO_2/yr, 1.5 miles below the surface

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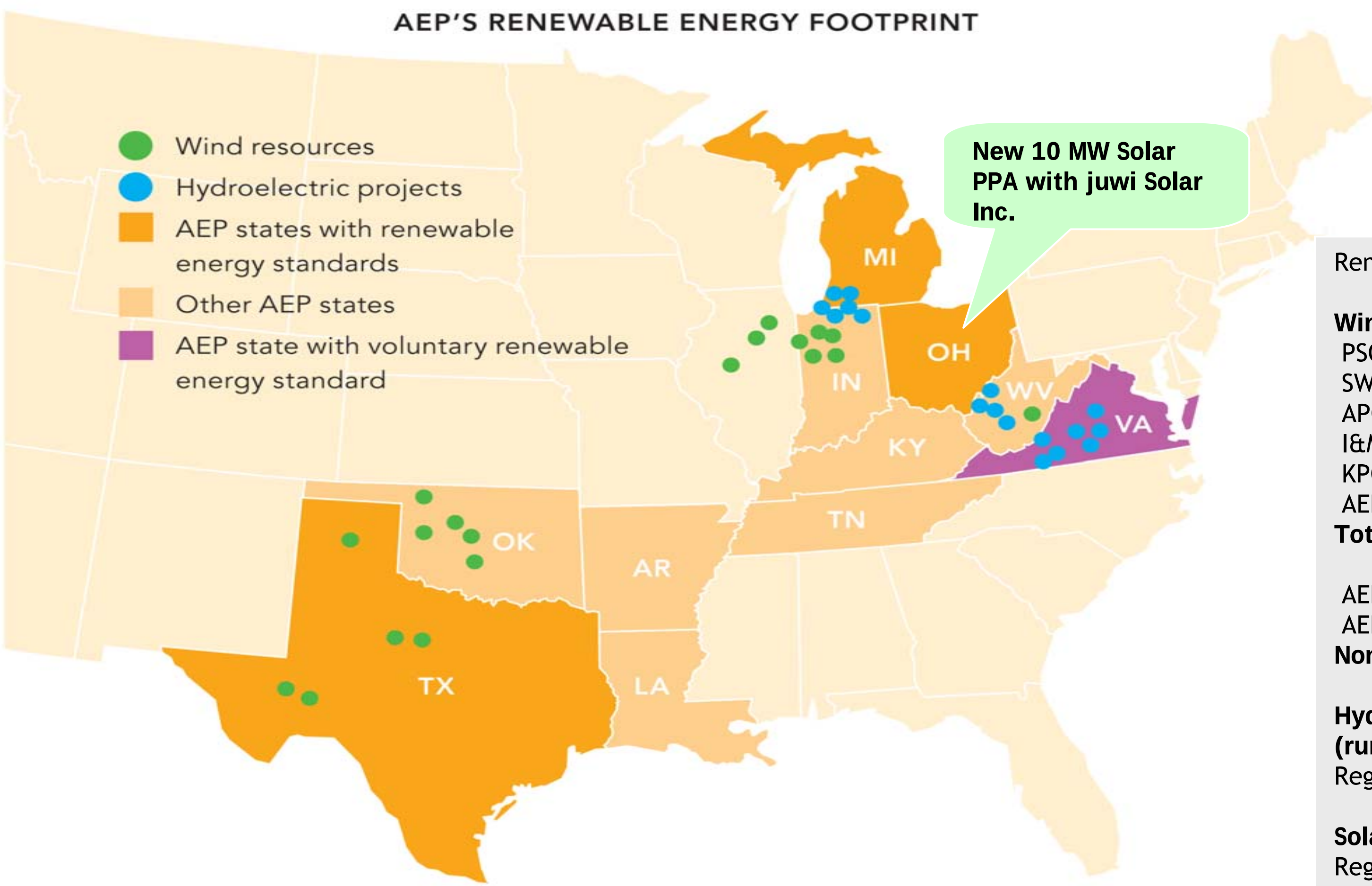
AEP Renewable Footprint



Renewables Portfolio*

Wind		
PSO - 5 PPAs		591MW
SWEPCo - 1 PPA		79MW
APCo - 4 PPAs		376MW
I&M - 2 PPAs		150MW
KPCo - 1 PPA		100MW
AEP Ohio - 2 PPAs		110MW
Total Regulated		**1406MW**
AEPEP -	owned	311MW
AEPEP -	2 PPAs	177MW
Non-regulated		**487 MW**
Hydro (run-of-river)		
Regulated - owned / PPA		**364MW**
Solar		
Regulated - PPA		**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

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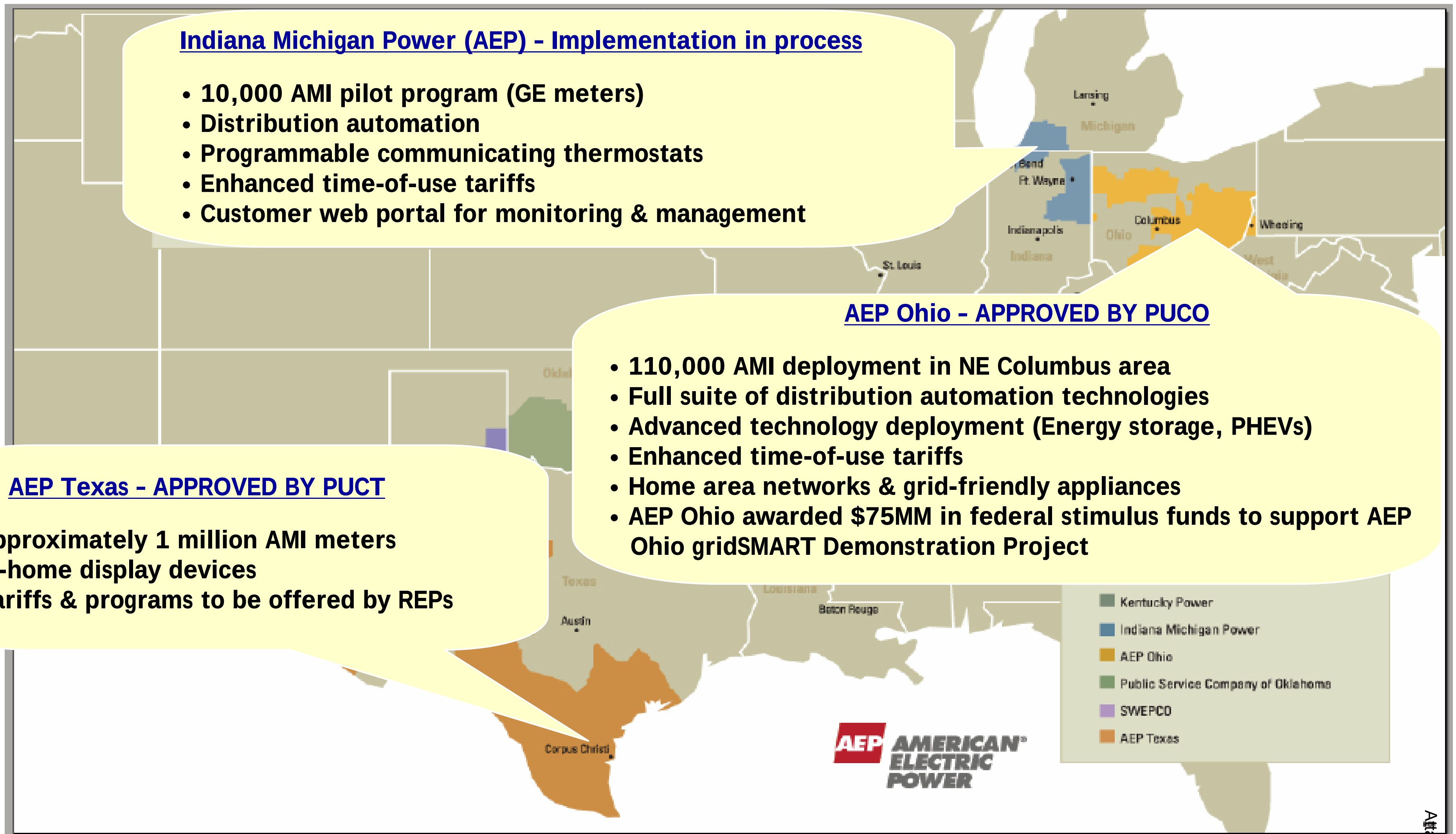
AEP gridSMART Deployment Status



Indiana Michigan Power (AEP) - Implementation in process

- 10,000 AMI pilot program (GE meters)
- Distribution automation
- Programmable communicating thermostats
- Enhanced time-of-use tariffs
- Customer web portal for monitoring & management

AEP Ohio - APPROVED BY PUCO

- 110,000 AMI deployment in NE Columbus area
- Full suite of distribution automation technologies
- Advanced technology deployment (Energy storage, PHEVs)
- Enhanced time-of-use tariffs
- Home area networks & grid-friendly appliances
- AEP Ohio awarded $75MM in federal stimulus funds to support AEP Ohio gridSMART Demonstration Project

AEP Texas - APPROVED BY PUCT

- Approximately 1 million AMI meters
- In-home display devices
- Tariffs & programs to be offered by REPs

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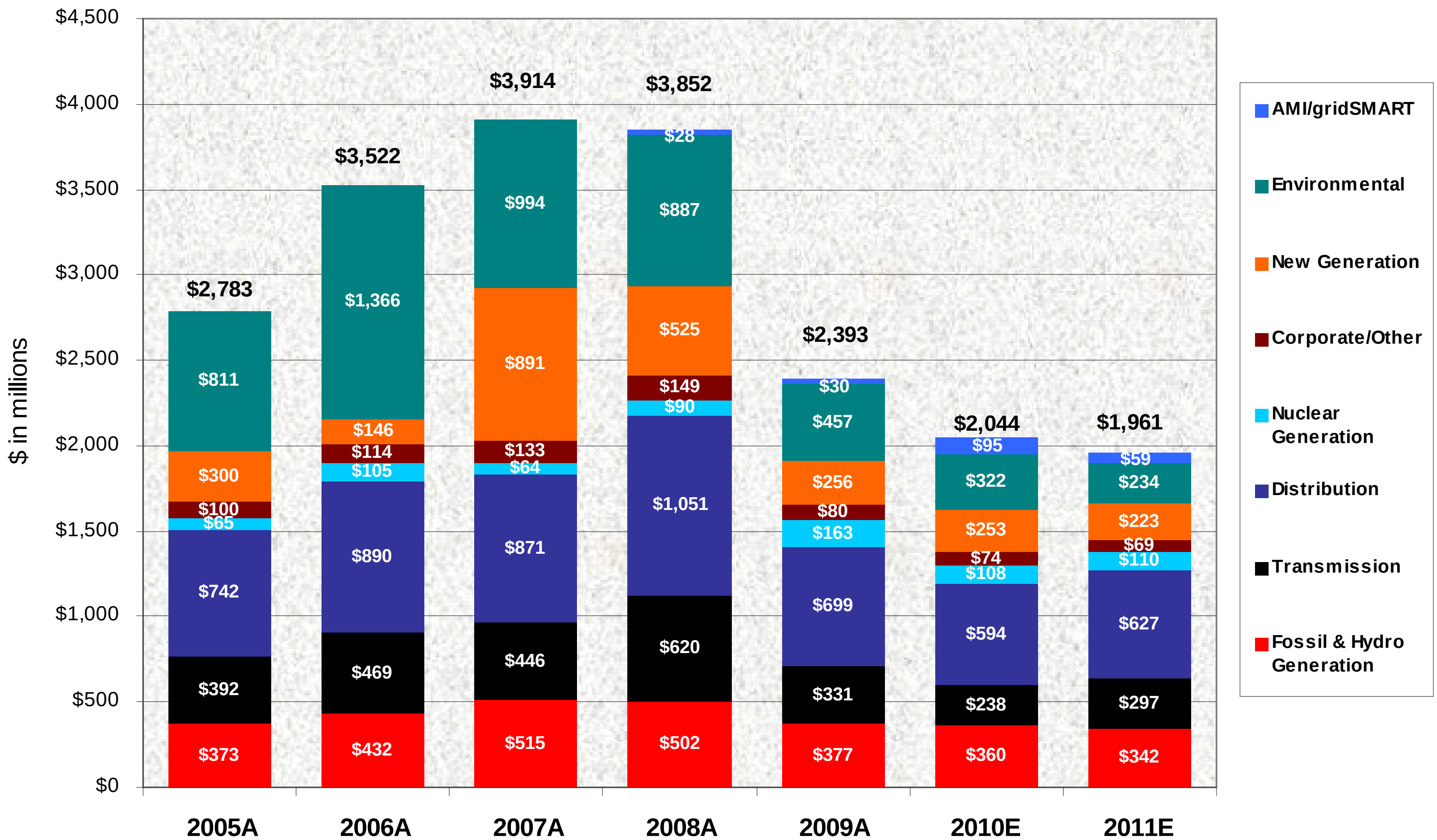
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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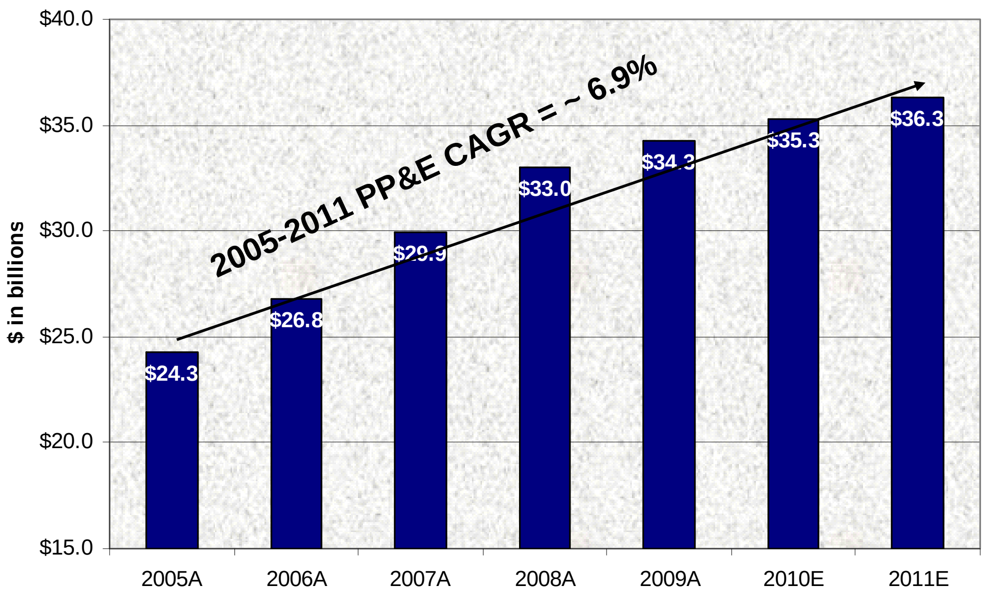
Multi-Year Capital Investment Funding Plan

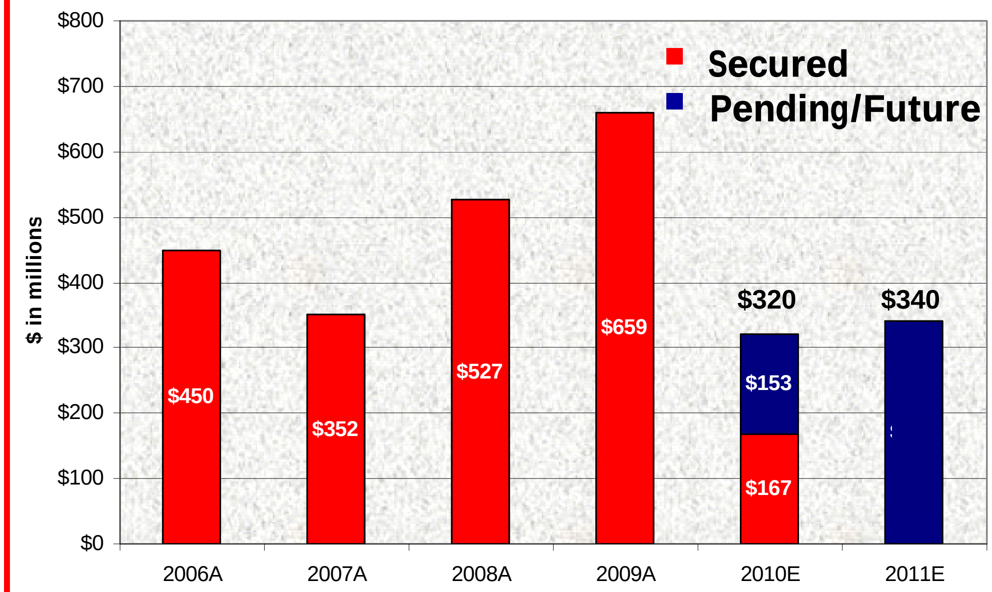
	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Texas, Virginia, West Virginia and others

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

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Appendix

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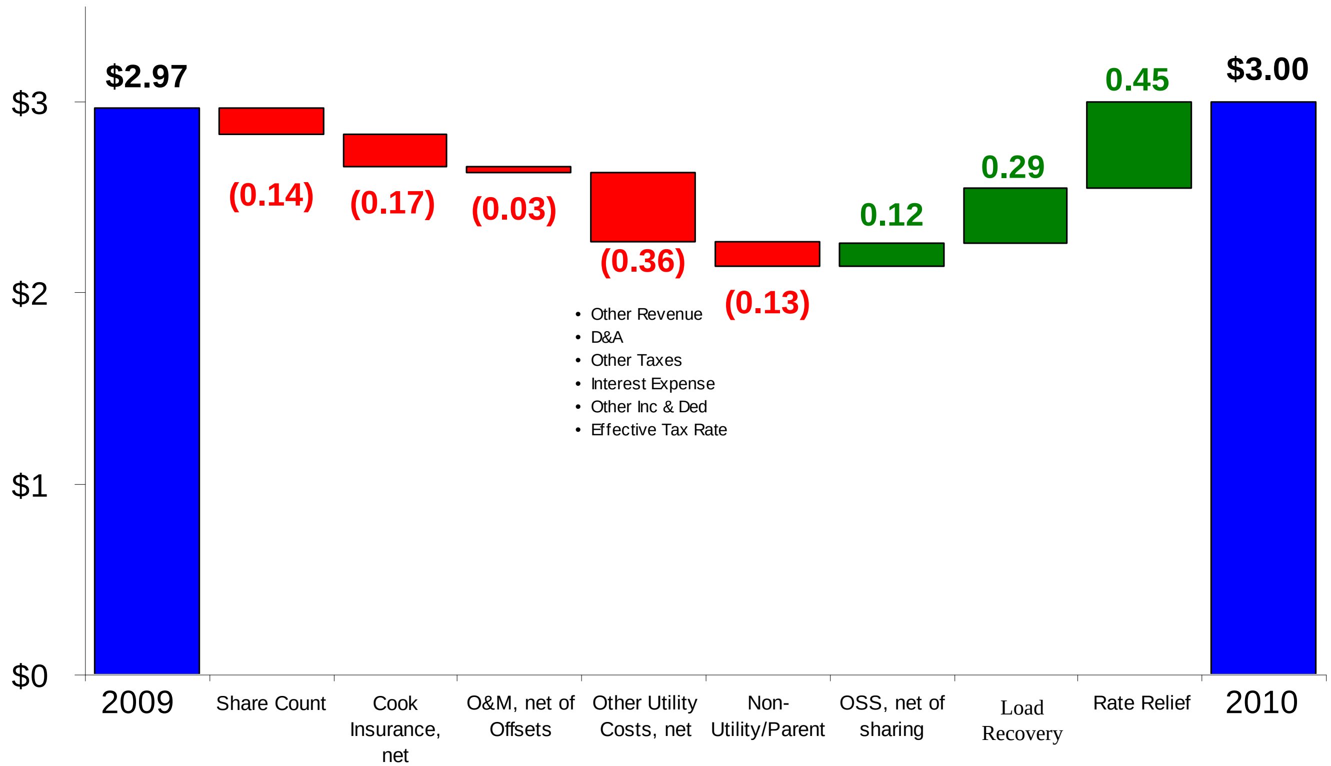
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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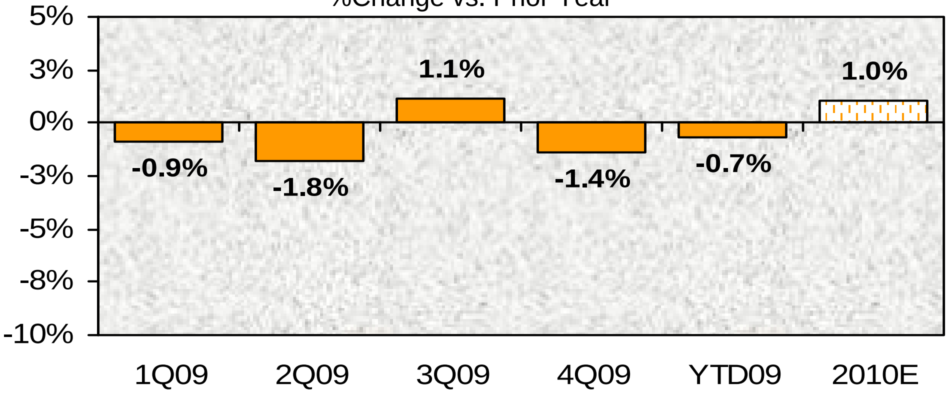
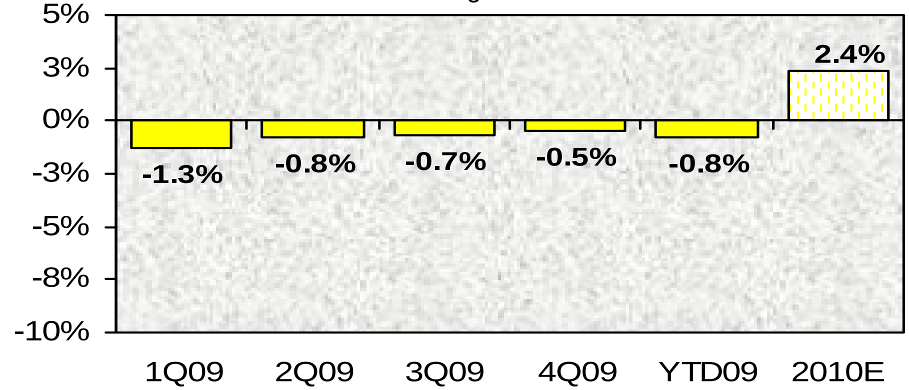
Normalized Load Trends

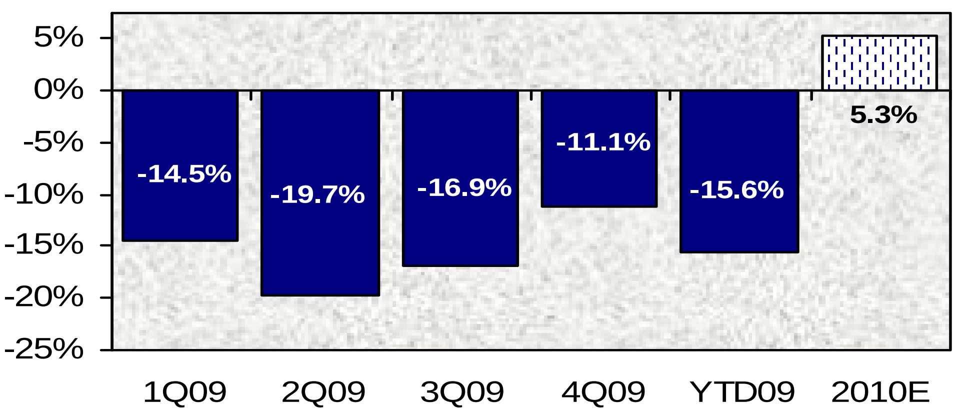
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



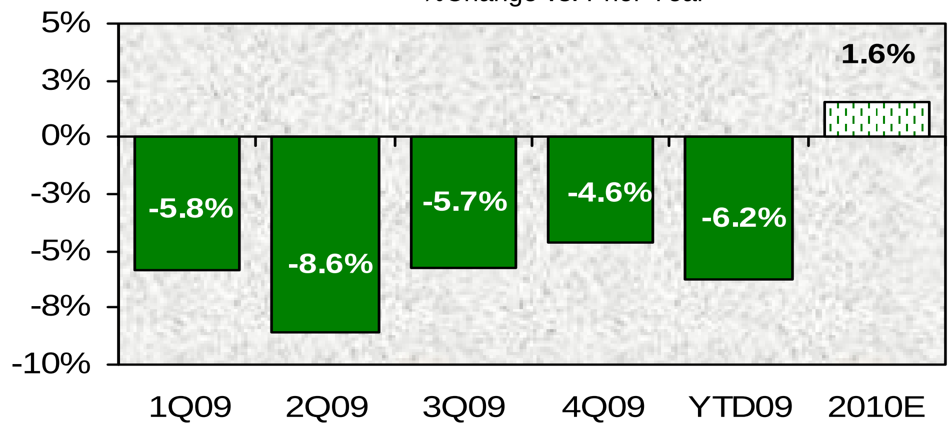
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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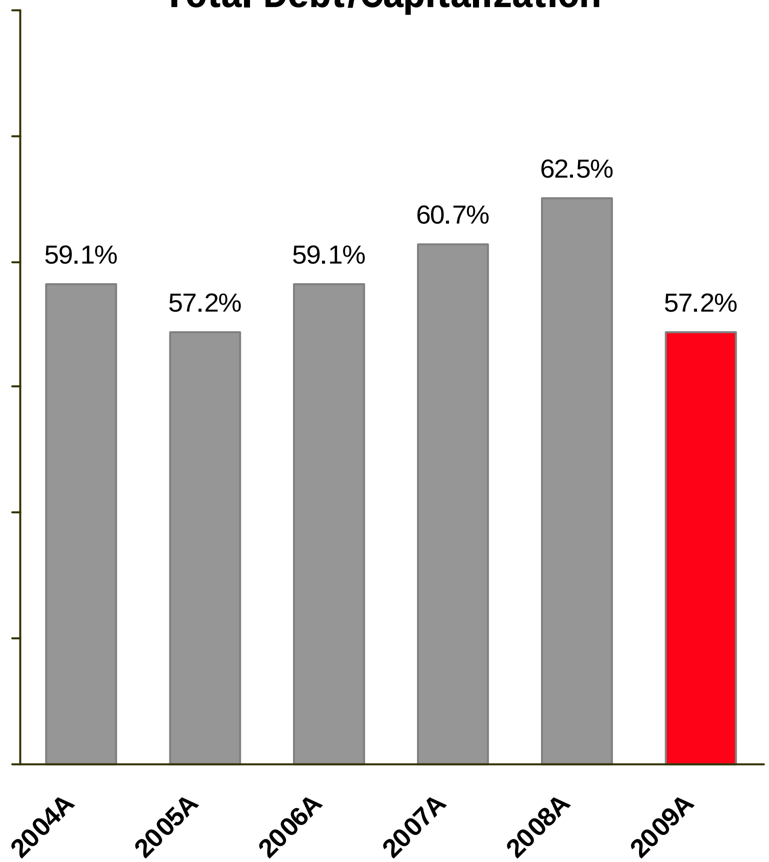
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 12/31/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

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AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

Long-term Debt Maturity Profile

($ in millions)

Year	2010		2011		2012	
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	679	$	-	$	-
Public Service of Oklahoma	$	-	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company[1]	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,585	$	623	$	415

(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

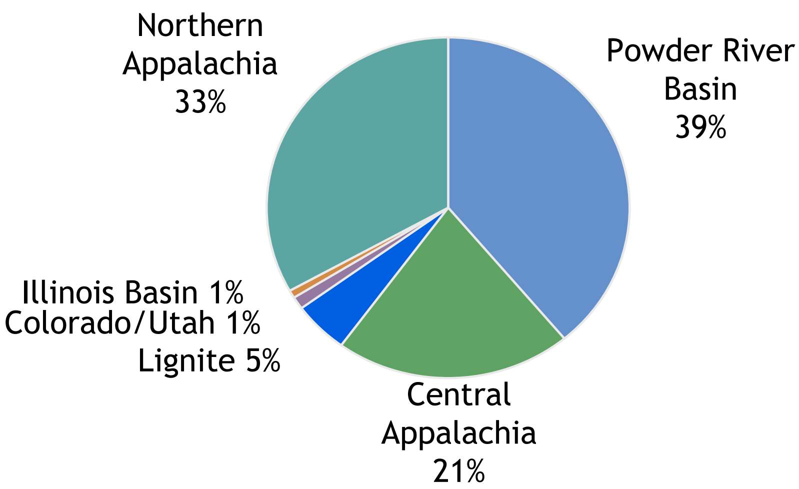
($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

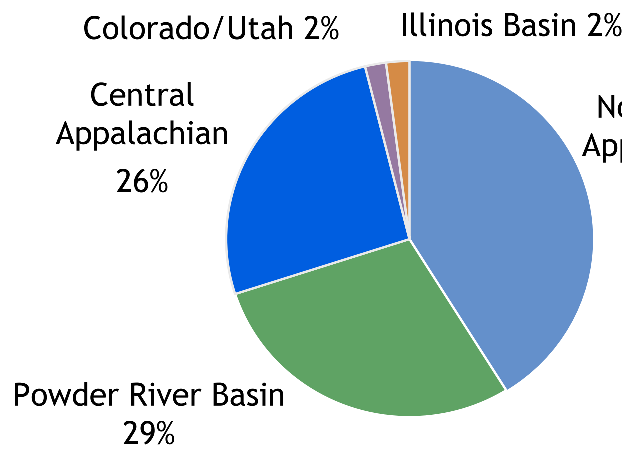
AEP AMERICAN ELECTRIC POWER

Coal Procurement - 2010 Projected

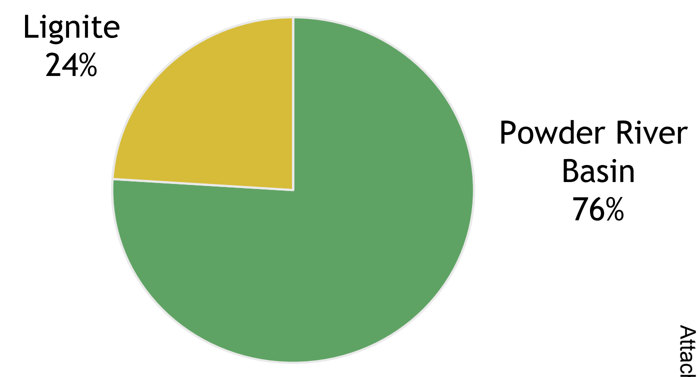
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

AEP AMERICAN ELECTRIC POWER

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AEP AMERICAN® ELECTRIC POWER

46th EEI Financial Conference Handout

Orlando, FL
November 7-8, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.07 - $3.17

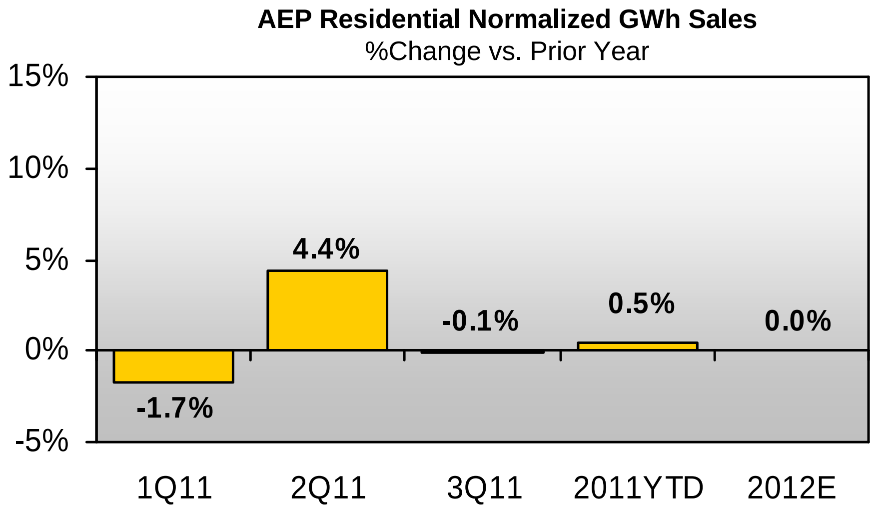
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

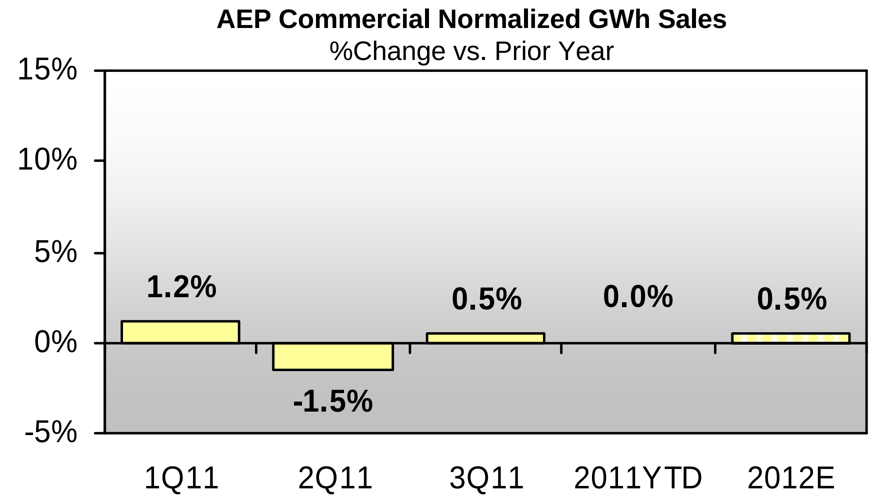
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

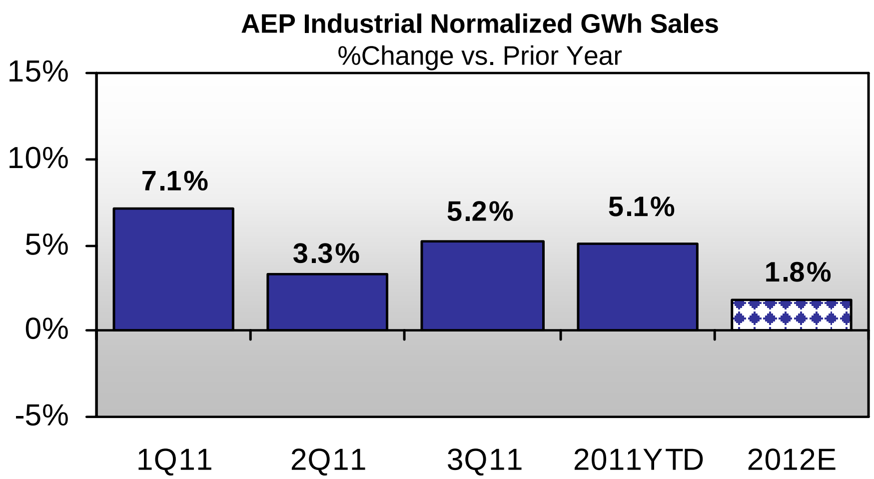
**original guidance given 01/28/2011*

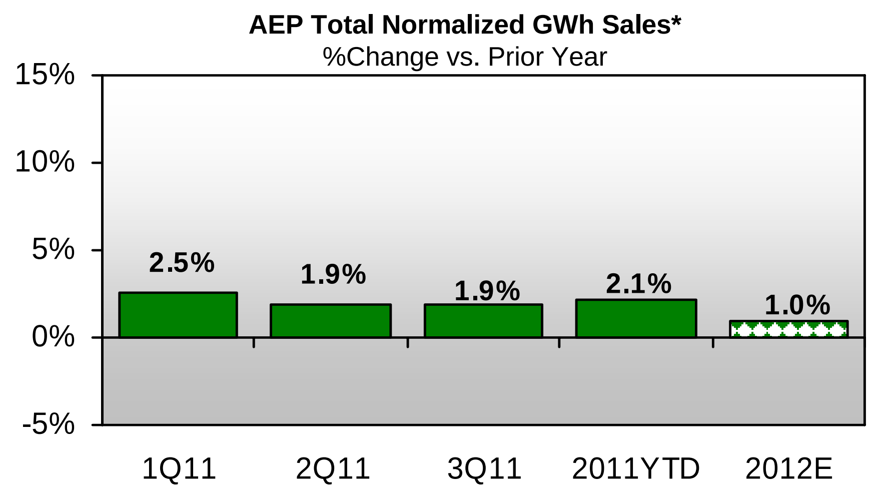
Normalized Load Trends

AEP









Note: Chart represents connected load

*includes firm wholesale load

KPSC Case No. 2011-00401
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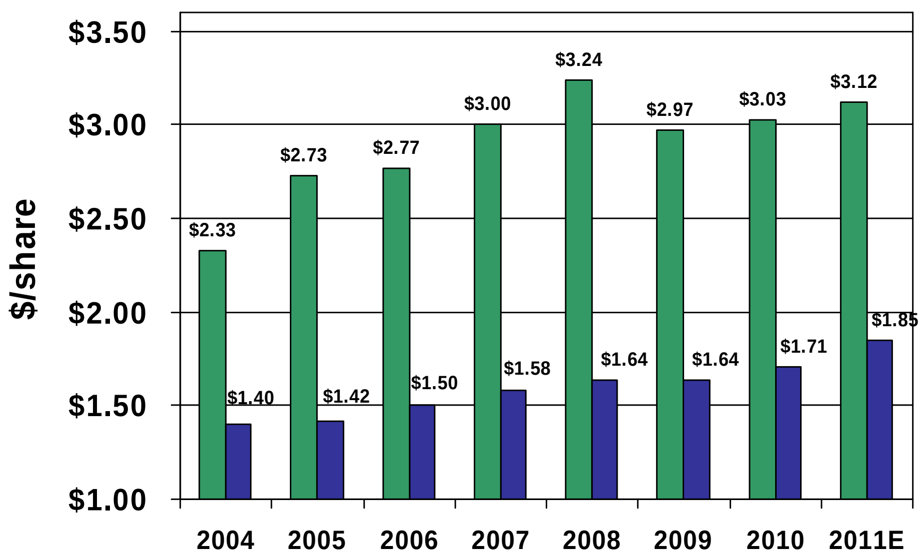
Earnings and Dividend Growth

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

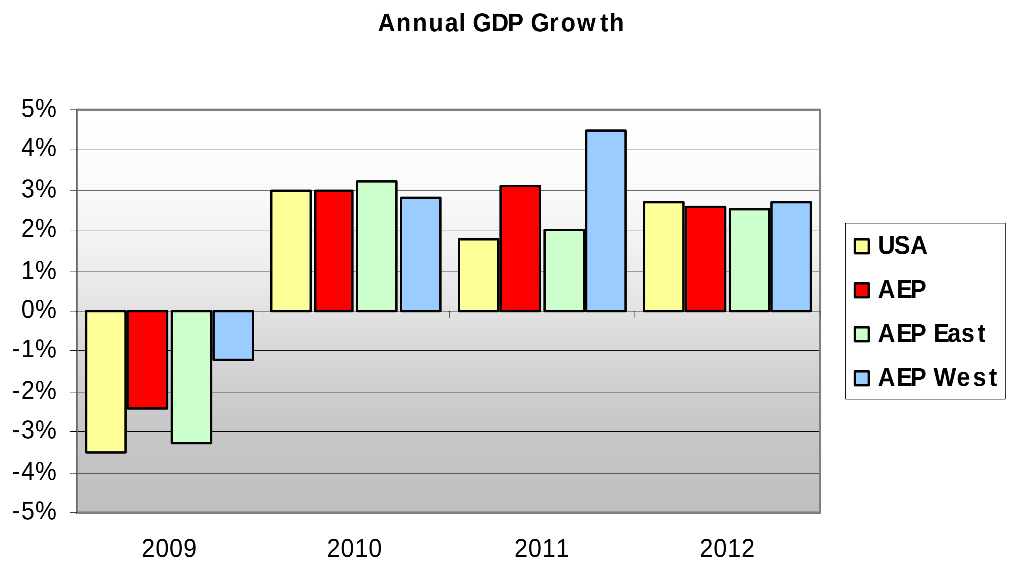
Dividend payout ratio target of 50–60%

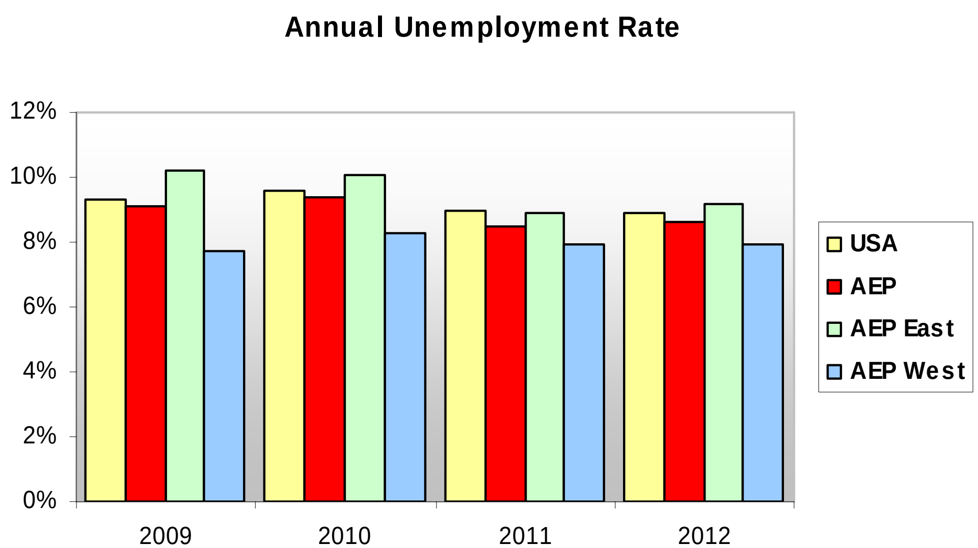
2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

Economic Conditions/Load

- AEP's GDP growth at 3.1% in 2011 has been better than the US at 1.8%
- AEP West region continues to experience stronger growth than AEP East





- AEP East unemployment remains higher than AEP West
- AEP Total unemployment has started to improve relative to the US

Sensitivities for 2012

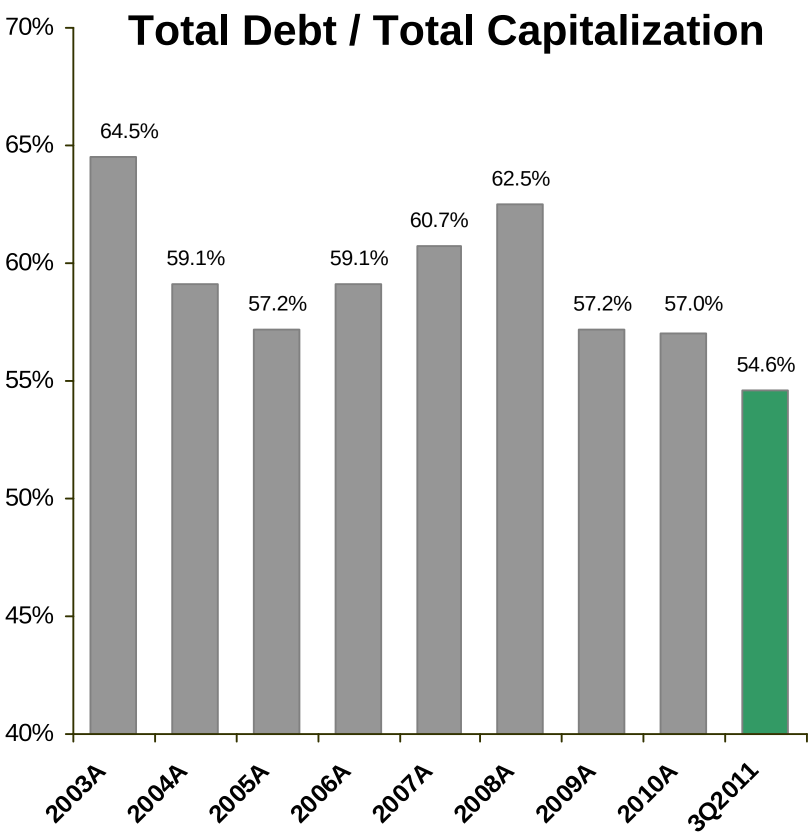
AEP®

EPS Sensitivities

Major Drivers		
Driver	**Driver Change**	**EPS Effect**
Average Load Growth	1%	$0.10
Off System Sales, net of sharing	10%	$0.05
Utility O&M	1%	$0.04
Capital Spending	$250M	$0.02

Operating Company Returns		
Company	**% Earnings Contribution**	**EPS Effect of 1% ROE Change**
AEP Ohio	42%	$0.10
APCo (incl WPCo)	16%	$0.06
SWEPCO	11%	$0.04
I&M	10%	$0.04
AEP Texas	8%	$0.02
PSO	6%	$0.02
KPCo	3%	$0.01
Other	4%	$0.02

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.50%	15%- 20%

Note: Credit statistics represent the 12 month trailing as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

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TCC Remand Case – PUCT Docket No. 39722

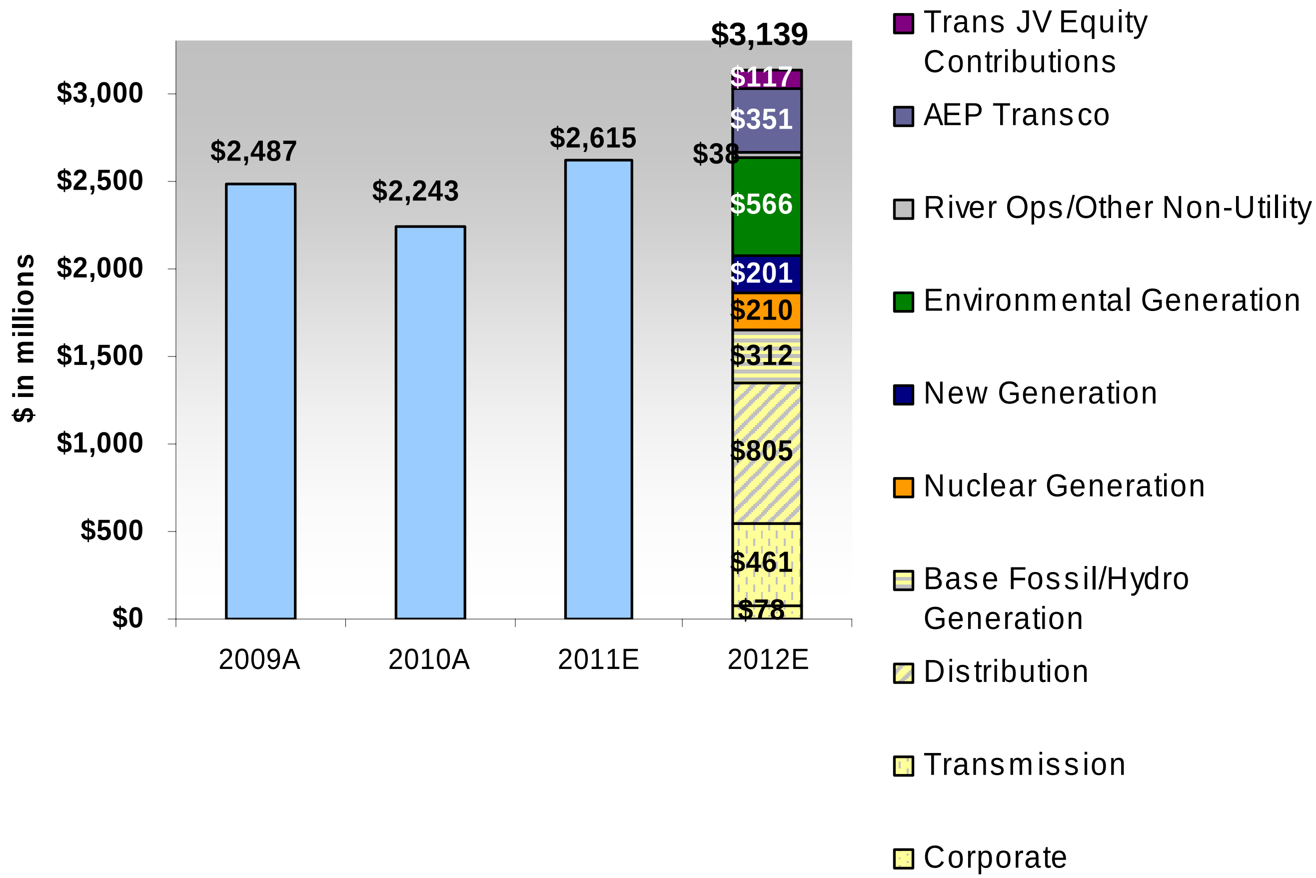
- In July 2011, the Supreme Court of Texas reversed the PUCT's decision of the disallowance of capacity auction costs. This opened the docket for TCC to file on October 10, 2011, an application to confirm the capacity auction true-up balance.
- TCC's filing requested a capacity auction true-up balance of $1.2B, which includes the capacity principal balance of $421M plus interest thru March 31, 2012. Interest is based on a carrying charge rate of 11.795%, which was the rate in effect at the time of the original PUC decision. Based on the Commission's Preliminary Order in the case, the capacity auction true-up balance would be approximately $817M inclusive of a carrying charge rate of 7.47%(based on ruling that modified the rate in 2007).
- The regulatory hearing is scheduled to take place November 29-30, 2011. A filing for a securitization order will occur soon after an order is issued on the remand case. TCC expects to issue the securitization bonds in the first quarter of 2012.
- TCC recorded a $425MM net-of-tax favorable special item related to this case in 3Q2011, ($421MM principal & $234MM interest, less related taxes). AEP also recorded $28MM on-going interest YTD in 3Q2011.
- Upon securitization, TCC will begin recognizing the equity component of the carrying cost prorated over the life of the securitization bonds (estimated to be $116MM, based on the PUCT preliminary order).
- Filing also seeks order to resolve tax normalization issues.

Pension and OPEB Estimate

- Investment returns for our pension plan remain slightly positive for the year despite volatility in the market, OPEB funds are slightly negative year to date.
- With very low short term interest rates, it is beneficial to pre-fund a portion of the required contributions to the plan.
- After making a discretionary contribution of $300 million by year end, cash contributions to the pension will total $450 million for 2011.
- We do not expect any required cash contributions to the pension for 2012, although we may make additional discretionary contributions.
- We expect combined pension and OPEB expense to increase $88M from 2011 to 2012 ($62MM O&M, pre-tax and $26MM capitalized).
- Discount rates are 5.05% for pension and 5.25% for OPEB for 2011, and are currently estimated to be 4.35% and 4.60% for 2012 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

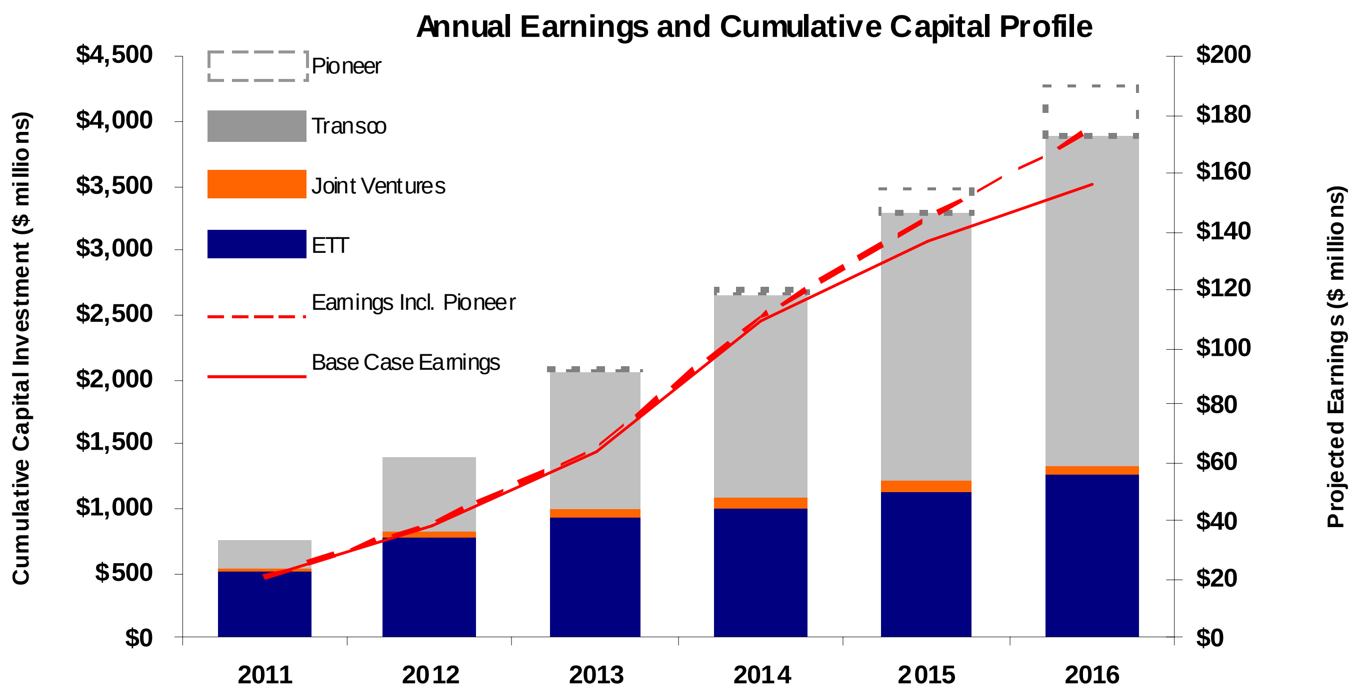
Capital Allocation

2012 AEP System Capital $3.1B



Major projects include: Turk Plant, Reliability upgrades, ETT contributions and Transco growth

Transmission Earnings & Capital Profile



[1] High Case includes AEP's share of Pioneer (50% ownership)

[2] Transco base case includes approximately $21MM in 2012 capital spend that is dependent upon state approval of Arkansas and Kentucky

[3] Joint Ventures include: PATH (50% ownership) assuming an ongoing suspension and Prairie Wind (25% ownership) assuming construction at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 11-13% for FERC projects; 60/40 debt/equity capitalization and 9.96% ROE (through 2013) and 55/45 debt/equity capitalization and 10% ROE (2014 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission Investment Opportunities

AEP

ETT
Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:** Current rate base is $482 million; expected to grow as follows:
  - 2011: $495 million
  - 2012: $750 million
  - 2013: $1,200 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $210 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

ROE Optimization

ROE by Jurisdiction		
Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia APCO – West Virginia Wheeling	10.53% 10.00% 10.00%	6.88%
I&M – Indiana I&M – Michigan	10.50% 10.35%	8.24%
SWEPCO – Louisiana SWEPCO – Arkansas SWEPCO – Texas	10.57% 10.25% 10.33%	10.05%
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule

Intervenor Testimony Due	October 24, 2011
Prehearing Conference	November 2, 2011
Hearing Commences	November 14, 2011

Summary Rate Case Information

AEP®

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Historical Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

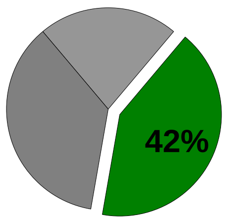
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).
- Various legal challenges are on-going related to the plant (see 10-Q).

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

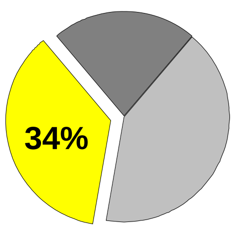
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

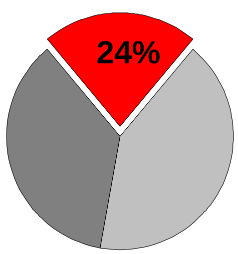
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	Has FGD
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Lawrenceburg **	1,186	2004	NG Combined Cycle
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	4,921		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**13,432**		

* May need FGD upgrades

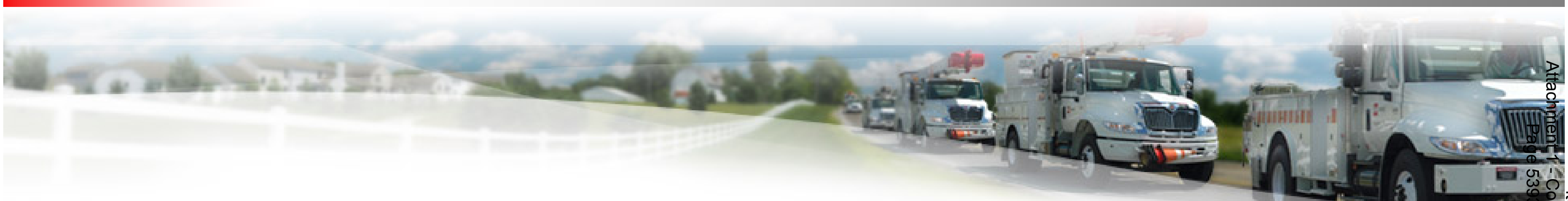
** CSP has a PPA with AEGCo for the Lawrenceburg Plant. The contract extends through 2017, with a two-year optional renewal.

Total Ohio Generation	13,432 MW
Less units slated for retirement	2,500 MW
Total remaining portfolio	10,932 MW
Remaining Portfolio:	
Coal	77%
Has FGD & SCR - 83%	
Has FGD; may require SCR - 10%	
May be replaced with gas - 7%	
Natural gas & hydro units	23%
	100%

45th EEI Financial Conference Handout

November 1-2, 2010

Palm Desert, CA



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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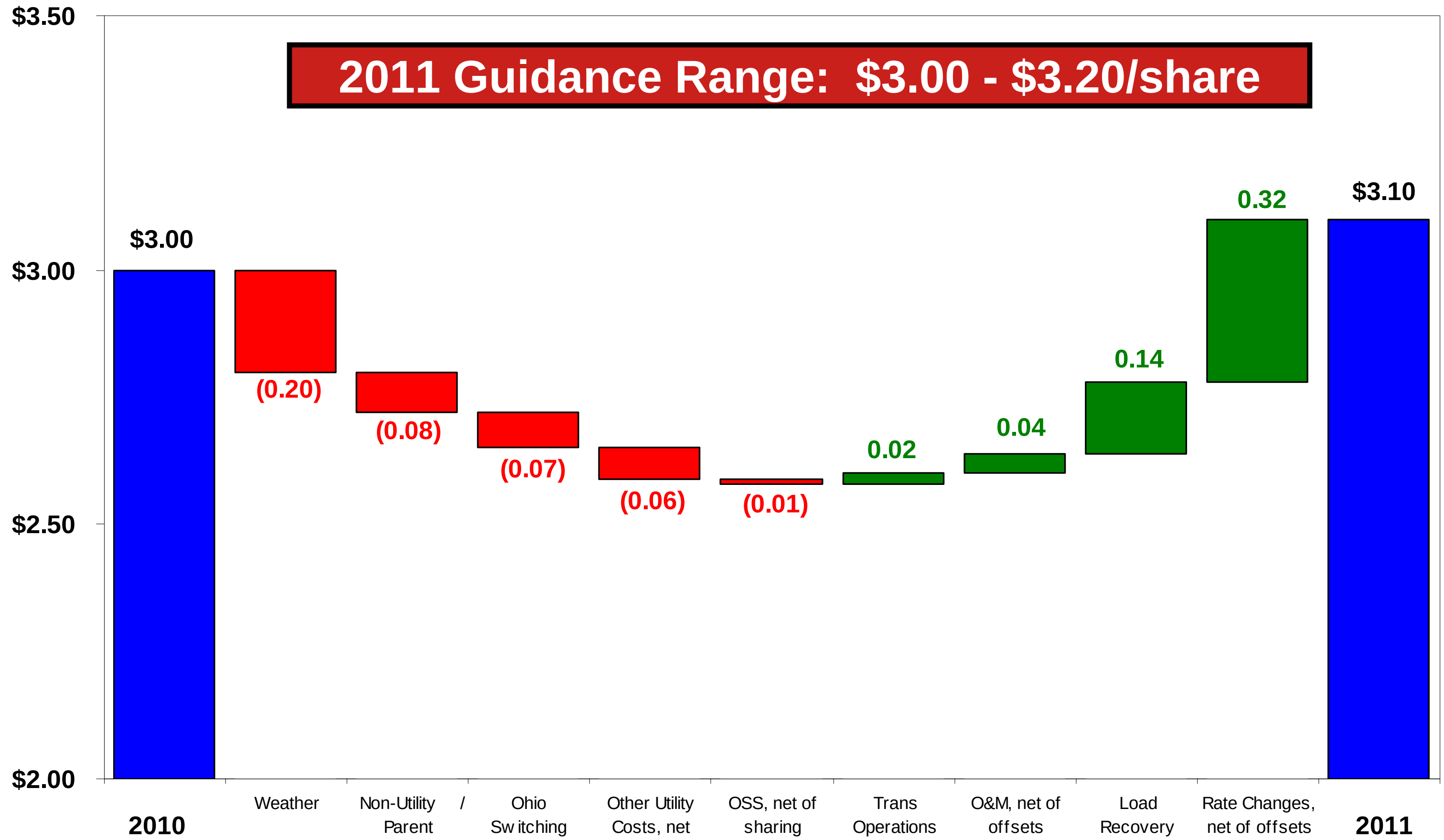
2011 Earnings Drivers



- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

2012 EPS Target: $3.25/share

Detailed Ongoing Earnings Guidance

2010E: $2.95 - $3.05

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Projection

		2010 Performance Driver	2010 Projection ($ millions)	2011 Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		51
18	Generation & Marketing		20		2
19	Parent & Other On-Going Earnings		(22)		(53)
20	ON-GOING EARNINGS		1,439		1,496

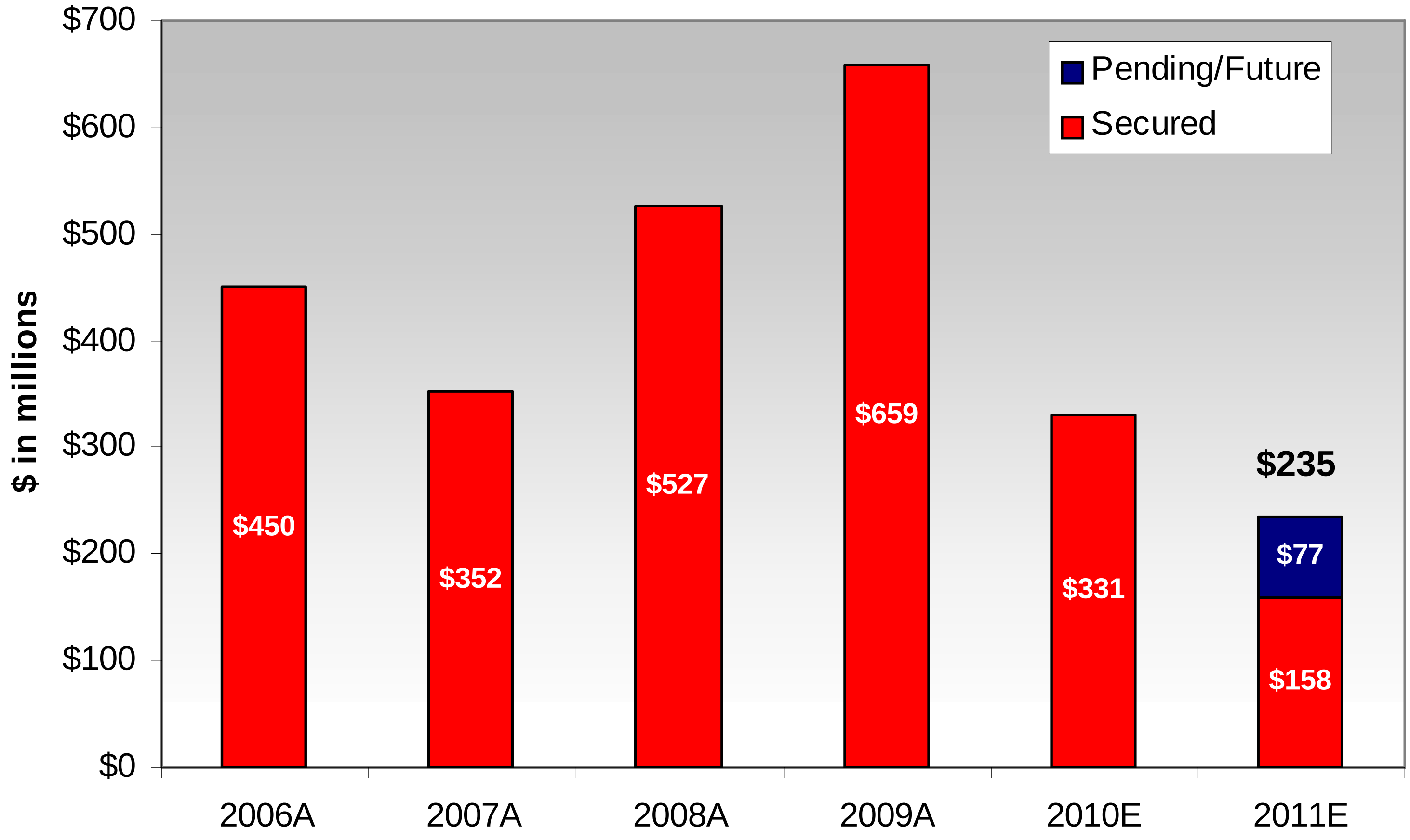
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Cash Flow Guidance

	$ in millions	
	2010E	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,205	$ 1,499
Depreciation & Amortization	1,654	1,588
Pension Funding	(500)	(150)
Other Cash Flow Items	653	234
Working Capital[1]	(218)	424
Cash From Operations	$ 2,794	$ 3,595
Investing Activities		
Construction Expenditures	(2,217)	(2,635)
Other Investing Activity	(352)	(265)
Total Investing Activities	$ (2,569)	$ (2,900)
Financing Activities		
Dividends	(826)	(893)
Net Debt Issued/(Retired)[1]	190	48
Common Equity	121	150
Total from Financing Activities	$ (515)	$ (695)
Beginning Cash Balance	$ 490	$ 200
Ending Cash Balance	$ 200	$ 200

[1] 2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Rate Changes

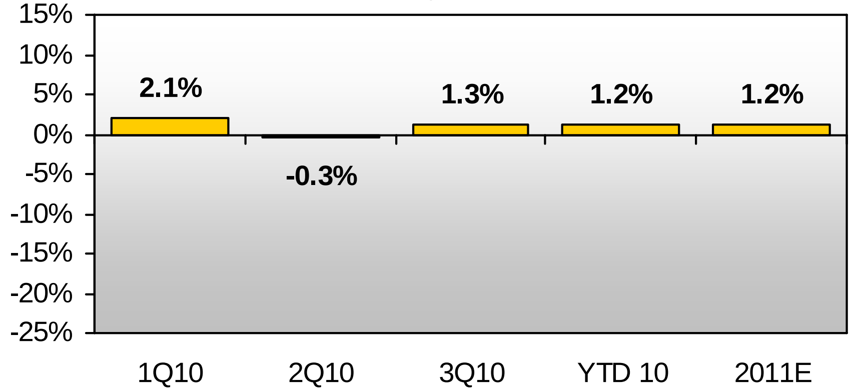


Note: Rate changes in this chart excludes revenues with offsetting costs

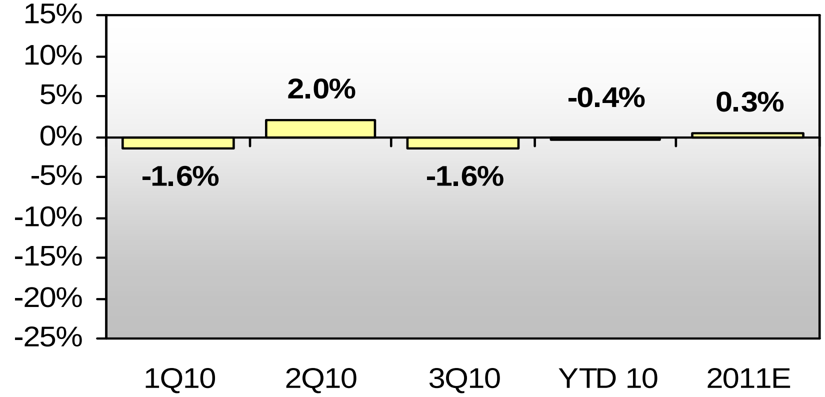
Active or pending rate cases include Oklahoma, West Virginia and others yet to be filed

Normalized Load Trends

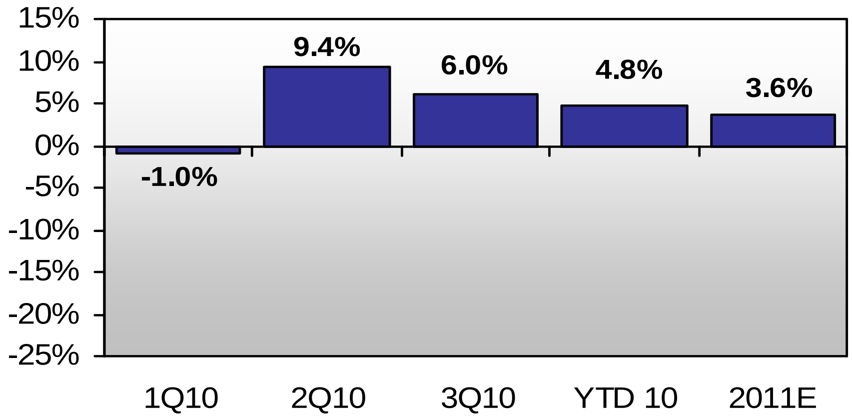
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



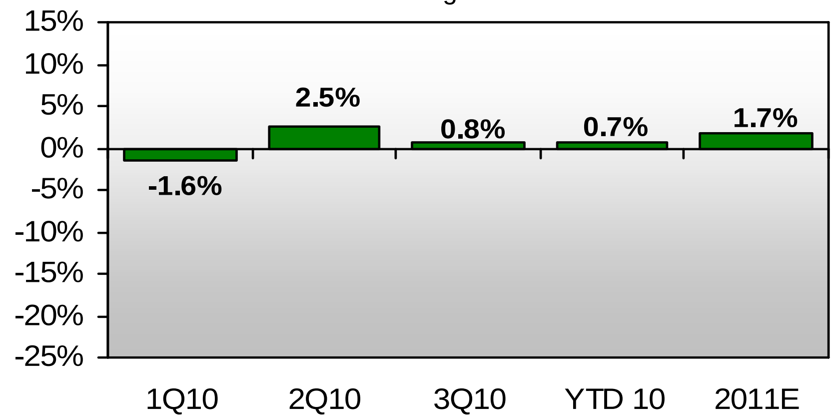
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



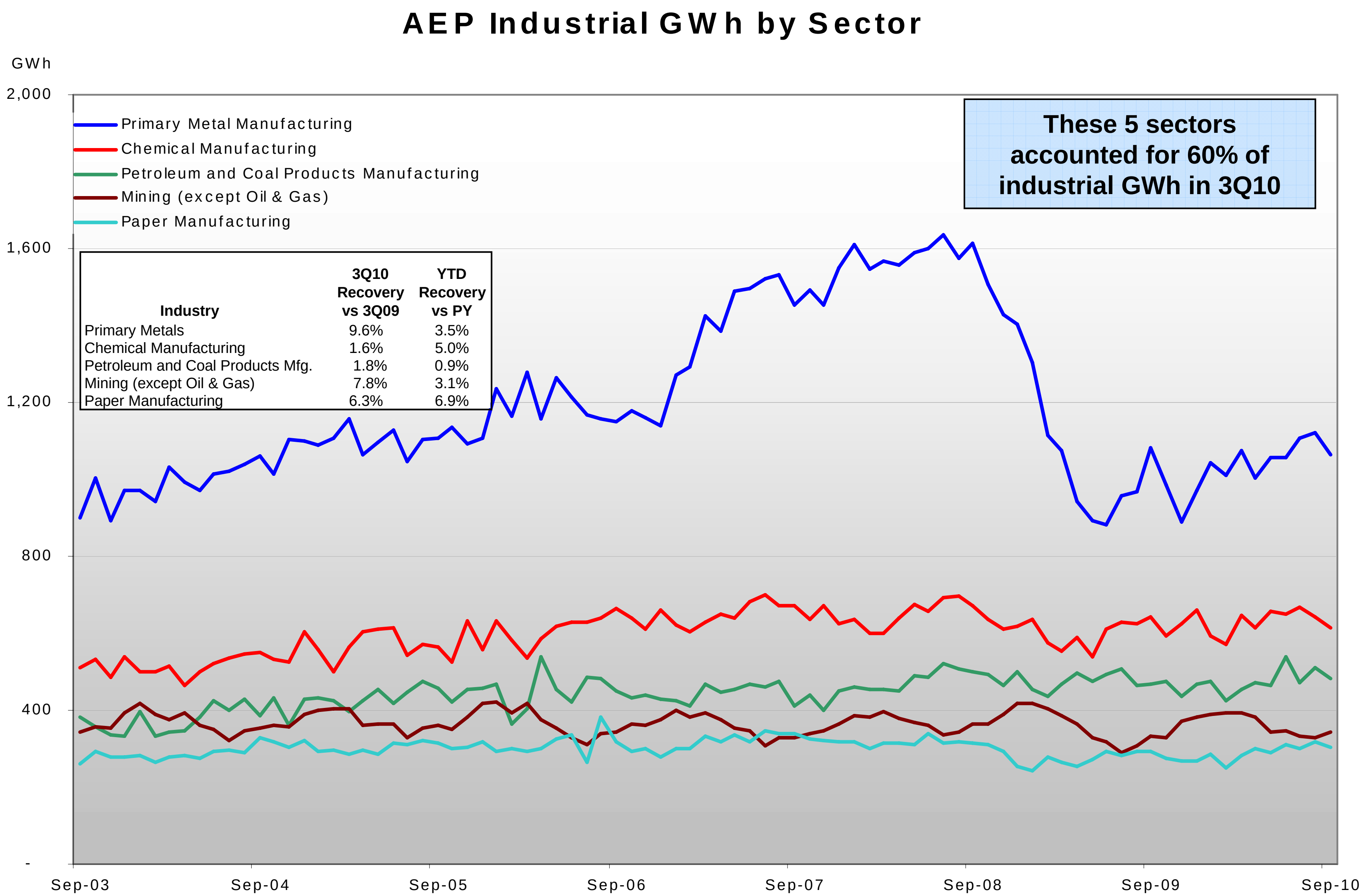
*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

7

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Industrial Sales



Industry	3Q10 Recovery vs 3Q09	YTD Recovery vs PY
Primary Metals	9.6%	3.5%
Chemical Manufacturing	1.6%	5.0%
Petroleum and Coal Products Mfg.	1.8%	0.9%
Mining (except Oil & Gas)	7.8%	3.1%
Paper Manufacturing	6.3%	6.9%

Liquidity and Financing

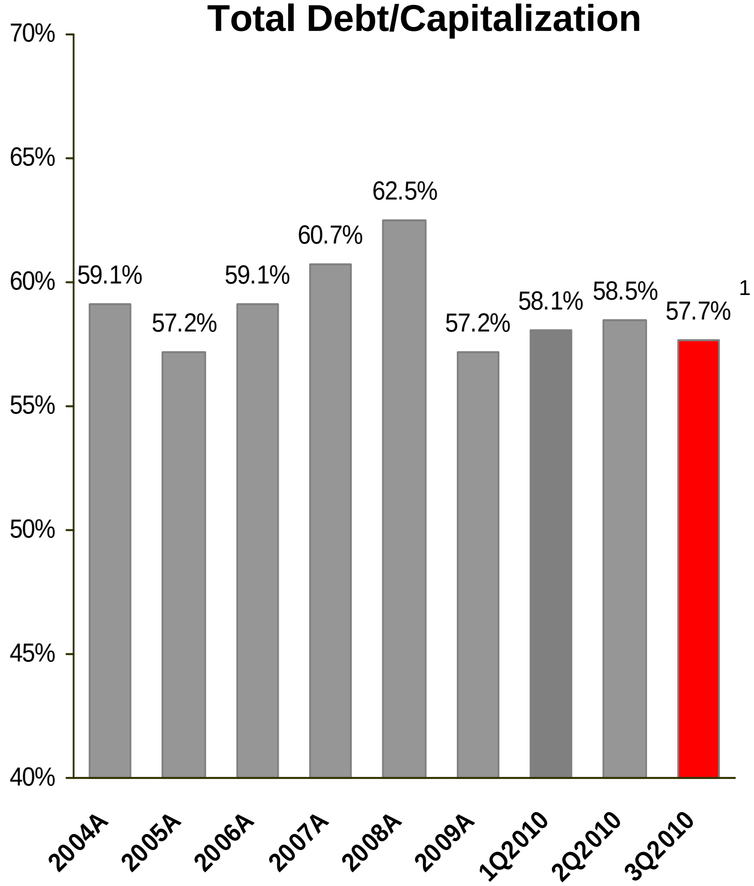
- Strong liquidity position supported by core Credit Facilities
  - Two $1.5B credit lines underpin liquidity position
    - Renewed 3-year $1.5B credit line in June 2010
    - Other $1.5B facility expires in April 2012, expect to address this renewal in 2011
  - Both facilities are undrawn

- Financing highlights
  - Cash flow and capital spending plan keep balance sheet stable
  - Committed to solid-investment grade credit metrics (BBB/Baa2)
    - Debt-to-Capital of 55-59%
    - FFO/Debt in the mid- to high teens
  - Debt Financing
    - Maturities total $620M in 2011
    - Net debt increases about $50M

Capitalization & Liquidity

AEP®

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

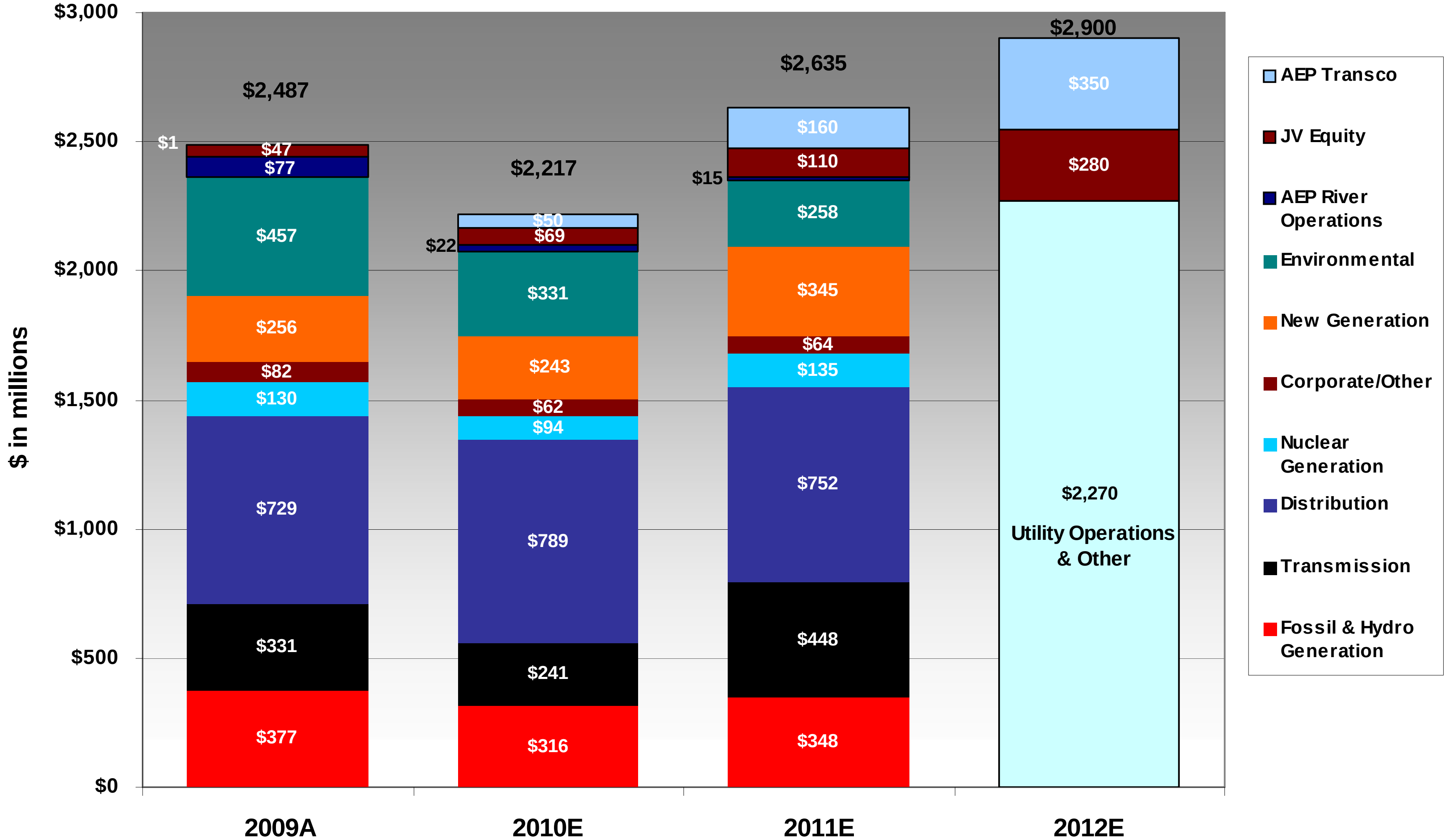
Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

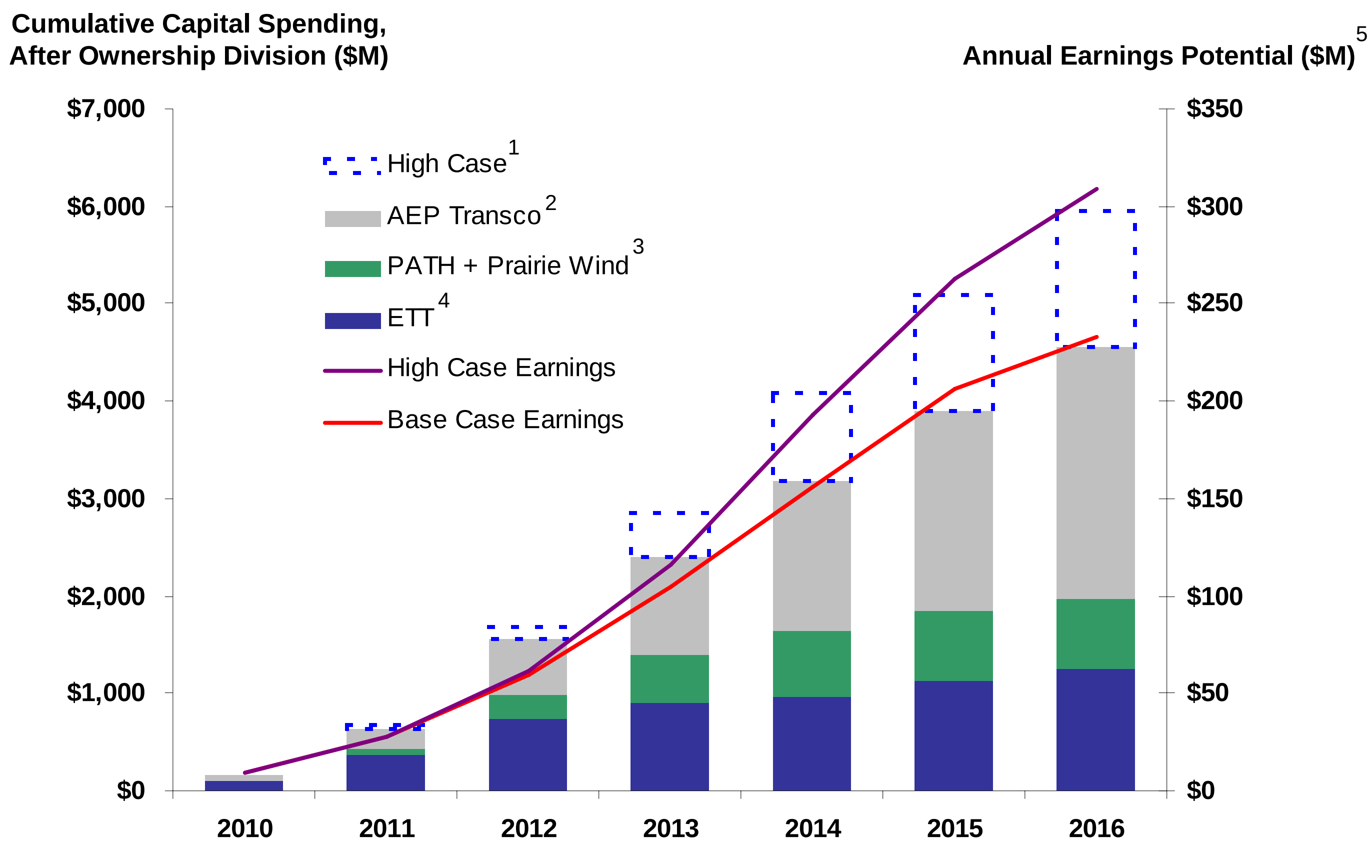
Pension and OPEB Estimate

- Investment returns for our pension plan and OPEB funds are solid so far this year. Year-to-date, the pension fund is up about 8% through September, with similar gains in the OPEB funds.
- After making a discretionary contribution of $350 million in September, cash contributions to the pension will total $500 million for 2010.
- We currently would have no required cash contributions to the pension for 2011 but are allocating a voluntary contribution up to $150 million.
- We expect combined pension and OPEB expense to decrease $34M from 2010 to 2011 (pre-tax and pre-capitalization).
- Discount rates are assumed to be 5.6% for pension and 5.85% for OPEB for 2010, and 4.75% and 5.0% for 2011 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

Capital Expenditures



Transmission – Capital/Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Two New Anchor Projects

ETA – AEP - Exelon: The RITE Line
Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

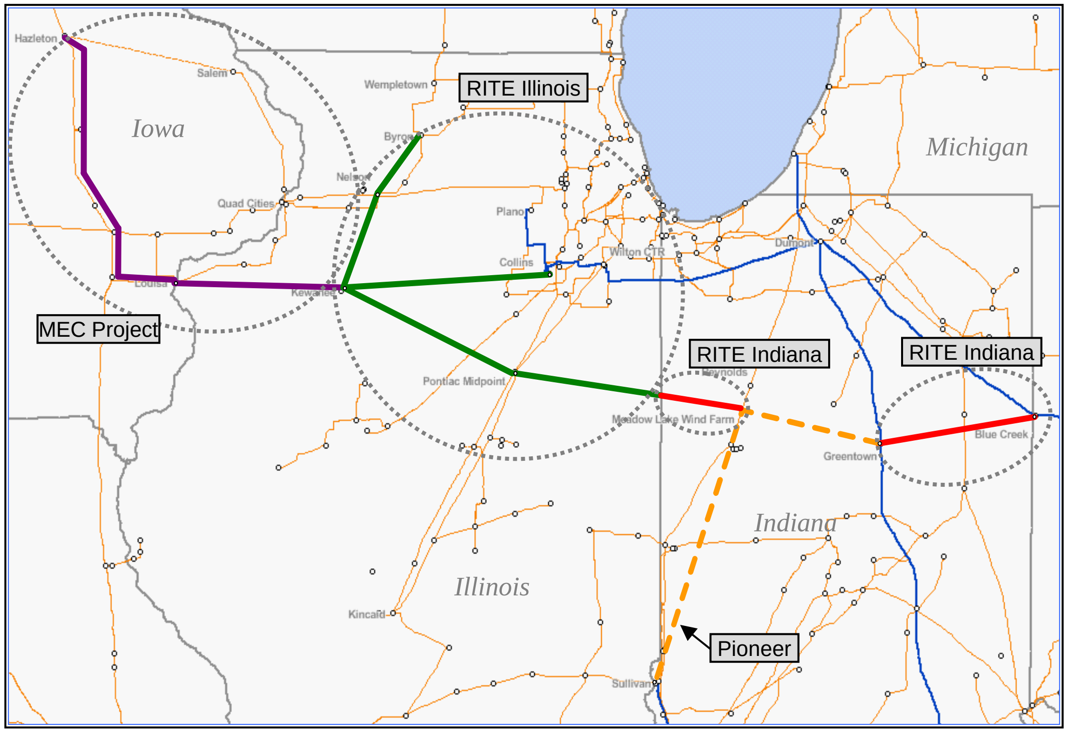
- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

ETA – MidAmerican Energy Co: MEC Project
Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

AEP Total Investment:

~$500M



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP Transco 2011 Capital Forecast

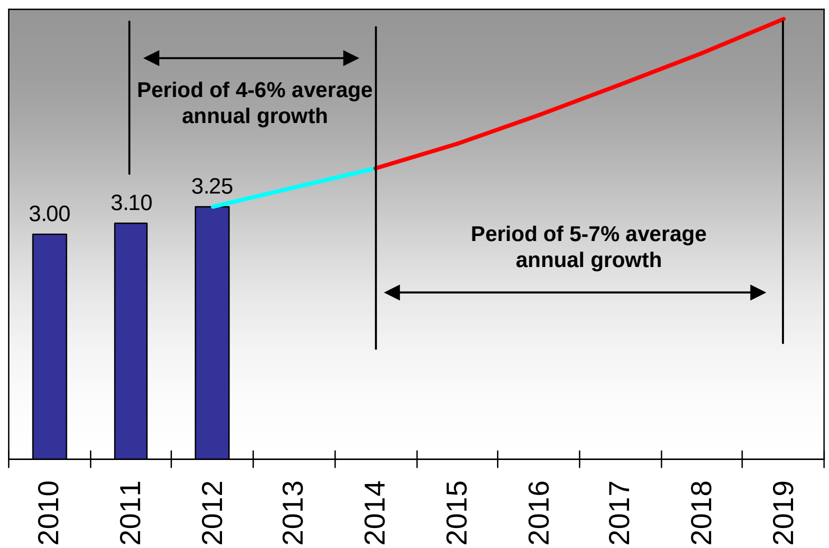
- Spending in 2011 will be focused in Ohio, Oklahoma and Michigan

2011 Transmission Company Capital Spending Forecast ($M)	2011E
AEP Ohio Transmission Company, Inc.	108
AEP Oklahoma Transmission Company, Inc.	42
AEP Indiana Michigan Transmission Company, inc.	10
Total AEP Transco	**160**

- Planned Transco projects include:
  - Replacement of 765 & 345 kV circuit breakers, autotransformers and shunt reactors
  - Ohio: Construction of a new 765/345/138 kV station (Vassell Station) near Galena, Ohio
  - Oklahoma: rebuild 30 miles of 138 kV line to provide transmission service to the City of Coffeyville, KS
  - Michigan: rebuild 6.5 mile Buchanan Hydro to Niles 69 kV transmission line in Southwestern Michigan

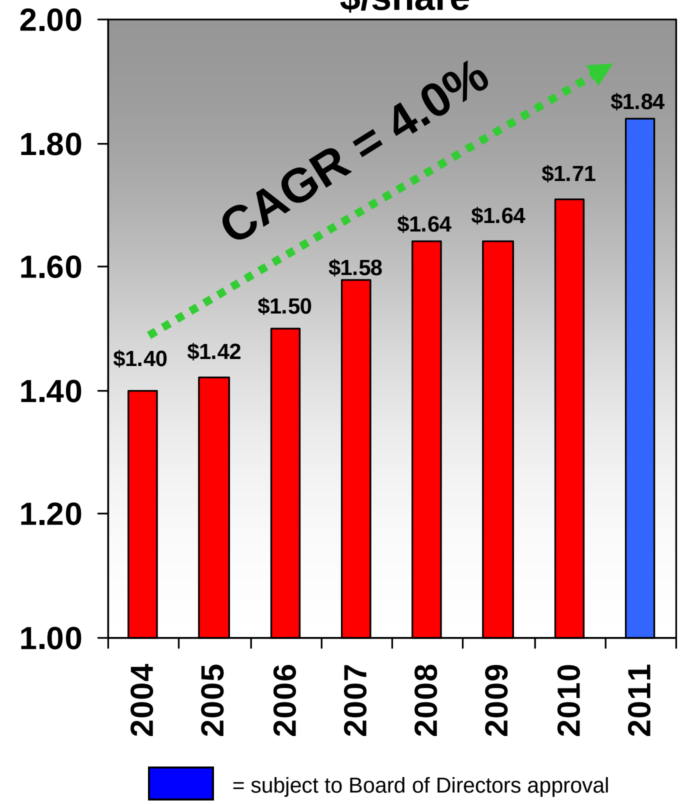
AEP – Income and Growth Opportunity

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004
$/share

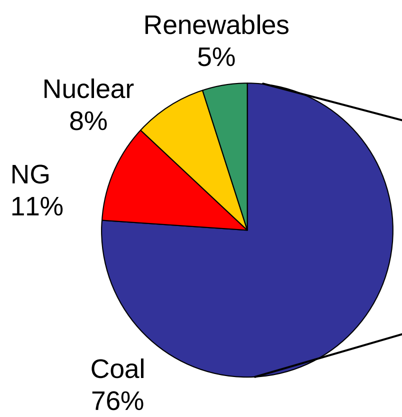


- 9.5% increase in quarterly dividend to $0.46/share declared on October 26th
- 401st consecutive quarterly dividend paid in September
- 50-60% payout ratio target
- Current yield about 5%

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



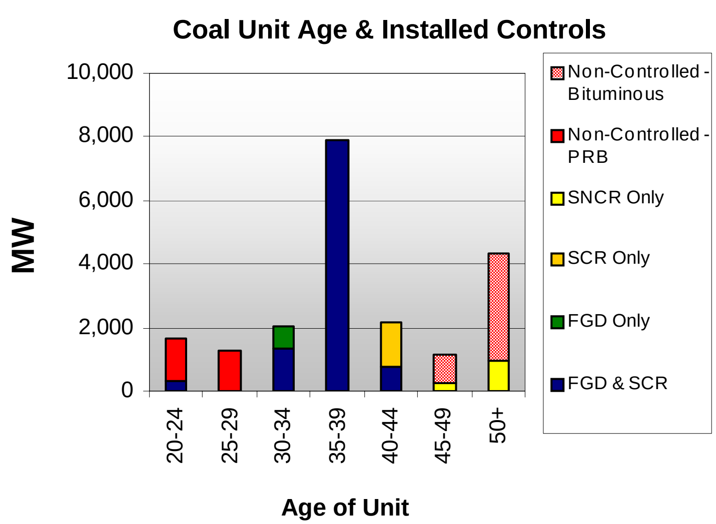
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost

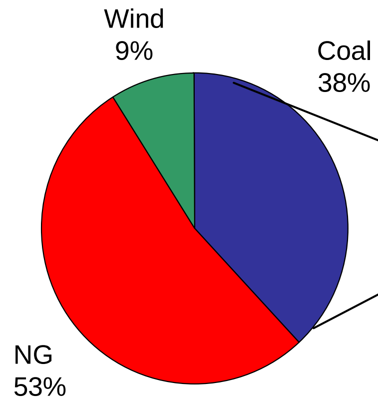
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind



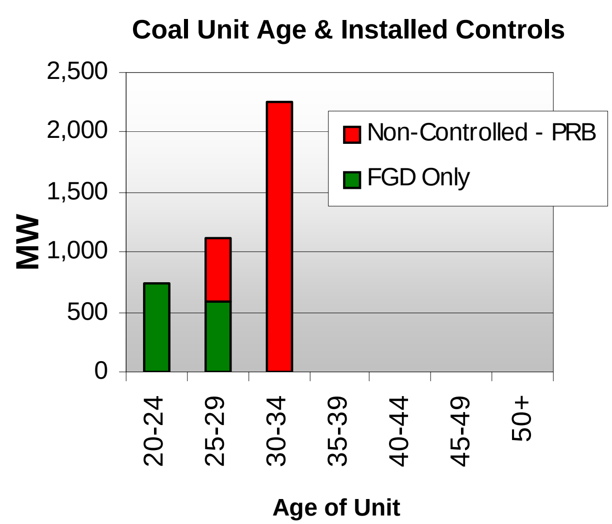
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

[1] Represents cost of committed position (90%)



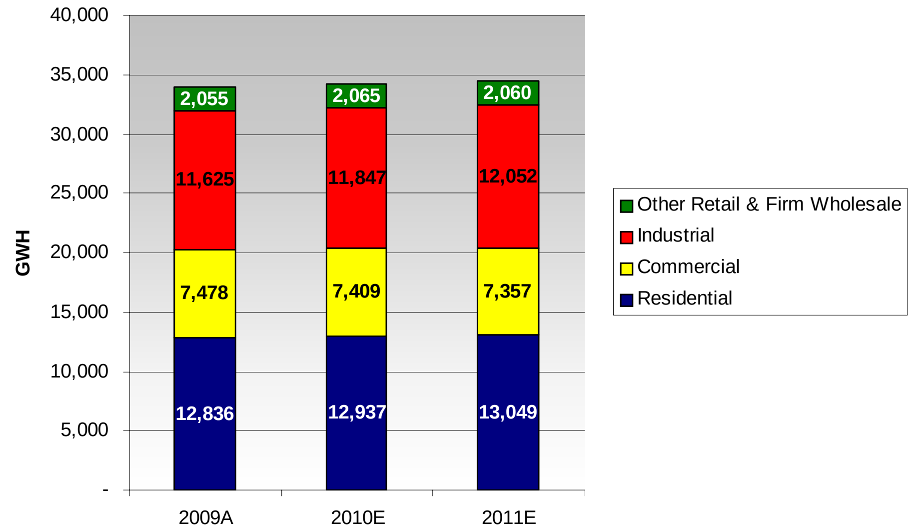
Overview of Appalachian Power

Total Customers at 12/31/09:

Residential	817,600	85%
Commercial	129,800	14%
Industrial	4,300	<1%
Other	7,100	1%
Total	958,800	

Generating Capacity 6,287 MW

Normalized Retail Load



Load represents Appalachian Power and Wheeling Power

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Coal Mining – 27%

Primary Metals – 14%

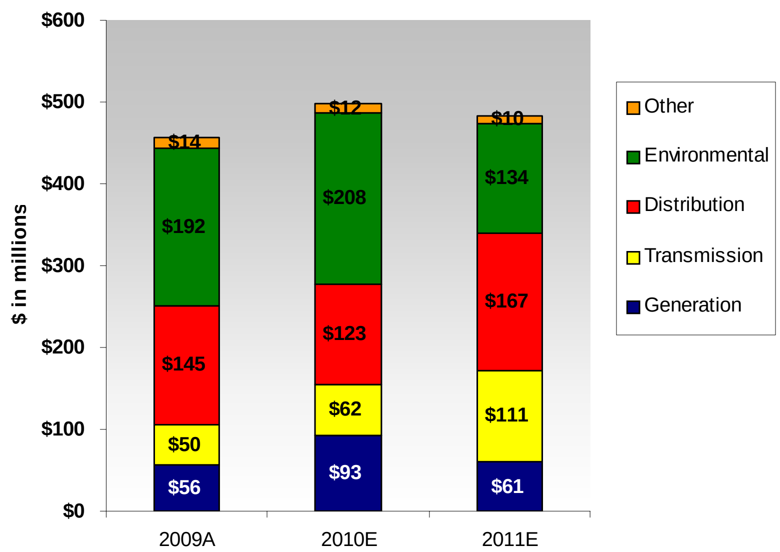
Electric/Gas/Sanitary Services – 9%

Chemical Products – 8%

Paper Products – 7%

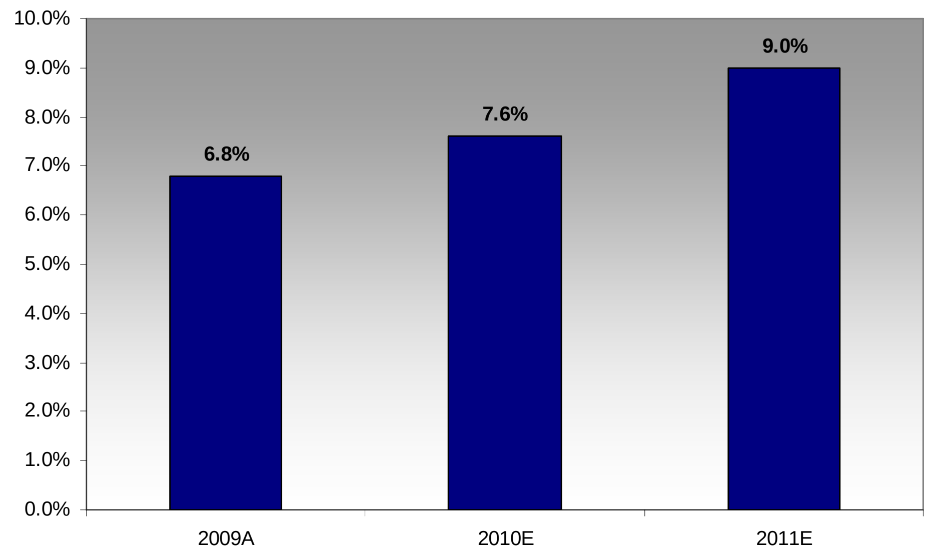
Overview of Appalachian Power

Capital Forecast



Capital represents Appalachian Power and Wheeling Power

Forecasted ROEs



ROEs represent Appalachian Power and Wheeling Power

Major Capital Project:
Amos Plant Unit 1 Scrubber

Current and Future Regulatory Activity:
WV Base Rate Case
VA Biennial Base Rate Case – March 31, 2011

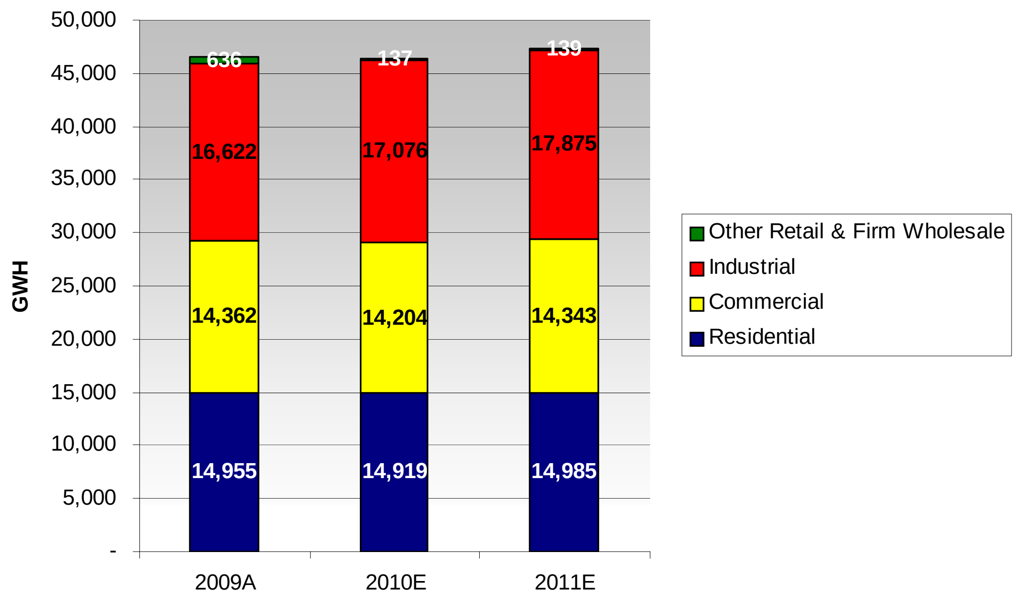
Overview of AEP Ohio

Total Customers at 12/31/09:

Residential	1,274,800	87%
Commercial	170,900	12%
Industrial	10,500	1%
Other	2,800	<1%
Total	1,459,000	

Generating Capacity 12,246 MW

Normalized Retail Load



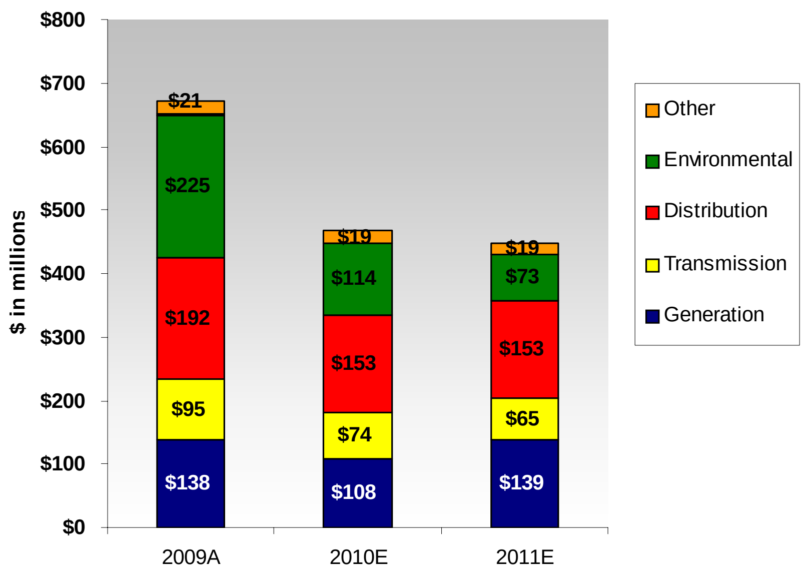
2010E and 2011E represent connected load

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Primary Metals – 42%
Chemical Products – 9%
Petroleum Refining – 8%
Rubber/Plastic Products – 6%
Stone/Clay/Glass Products – 4%

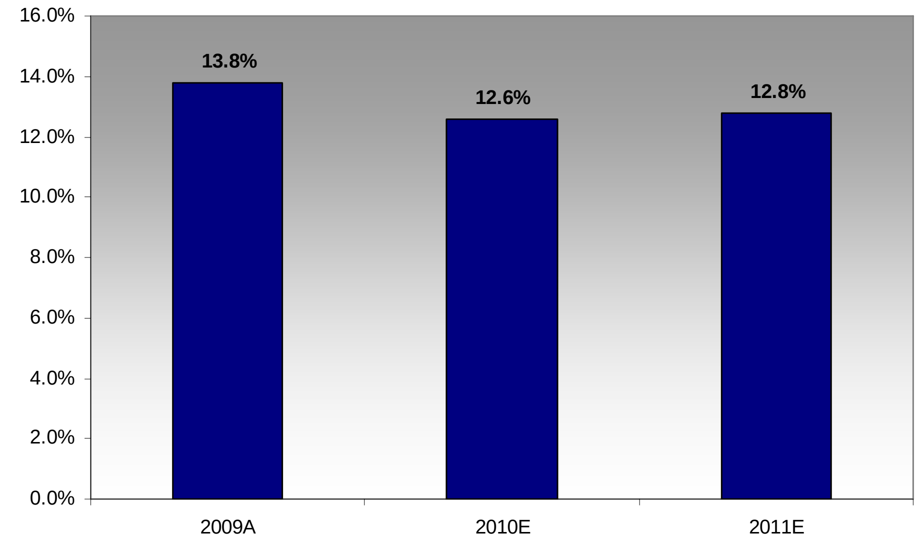
Overview of AEP Ohio

Capital Forecast



Major Capital Projects:
Conesville Plant Unit 4 Scrubber
Conesville Plant Mercury Mitigation

Forecasted ROEs

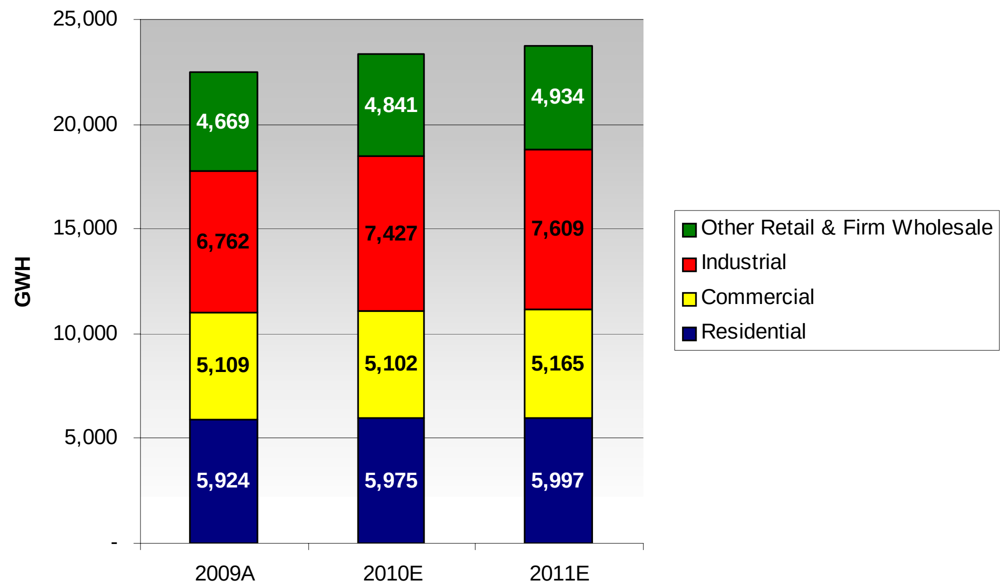


Current and Future Regulatory Activity:
2009 SEET
CSPCo/OPCo Merger
2010 SEET
2010 Environmental Rider
Electric Security Plan
Distribution Base Rate Case

Overview of Indiana Michigan Power

AEP®

Normalized Retail Load



Total Customers at 12/31/09:

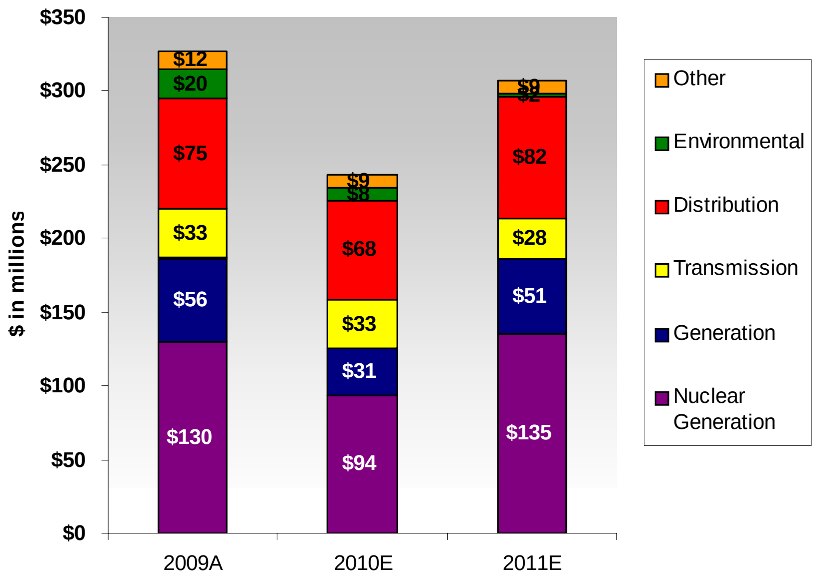
Residential	507,200	87%
Commercial	68,400	12%
Industrial	5,100	1%
Other	2,000	<1%
Total	582,700	
Generating Capacity	4,511 MW	

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

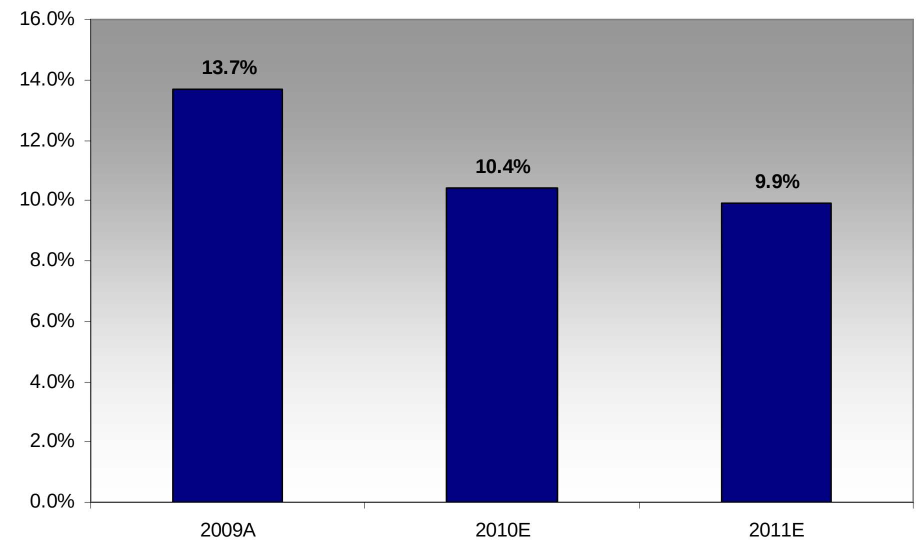
Primary Metals – 38%
Chemical Products – 11%
Transportation Equipment – 7%
Rubber/Plastic Products – 9%
Fabricated Metal Products – 6%

Overview of Indiana Michigan Power

Capital Forecast



Forecasted ROEs



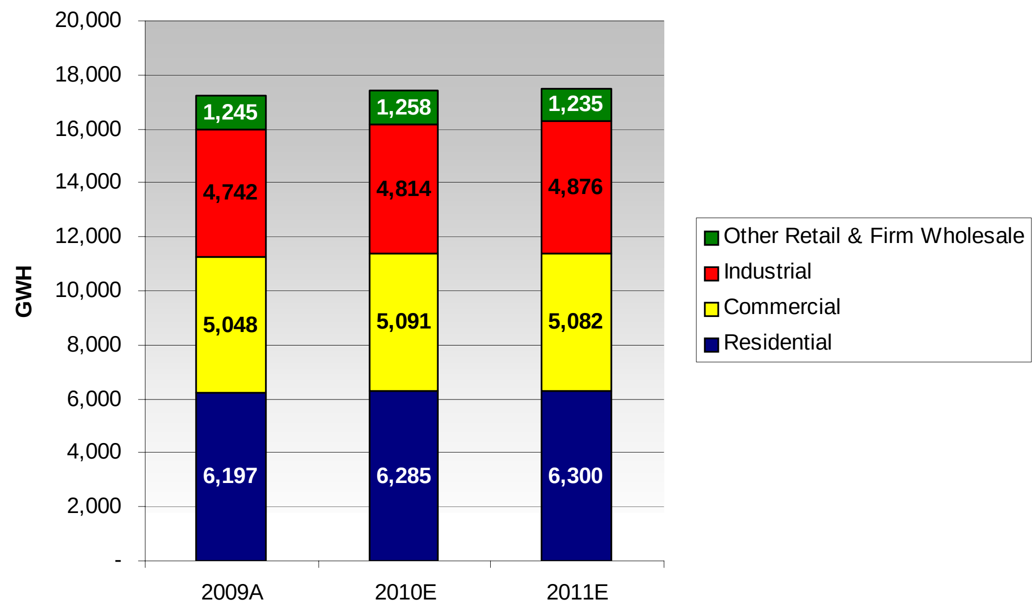
Major Capital Projects:
Cook Plant Life Cycle Management and Dry Cask Fuel Storage

Current and Future Regulatory Activity:
No major filings announced

Overview of PSO

Total Customers at 12/31/09:		
Residential	457,000	87%
Commercial	59,900	11%
Industrial	6,600	1%
Other	7,200	1%
Total	530,700	
Generating Capacity	4,408 MW	

Normalized Retail Load

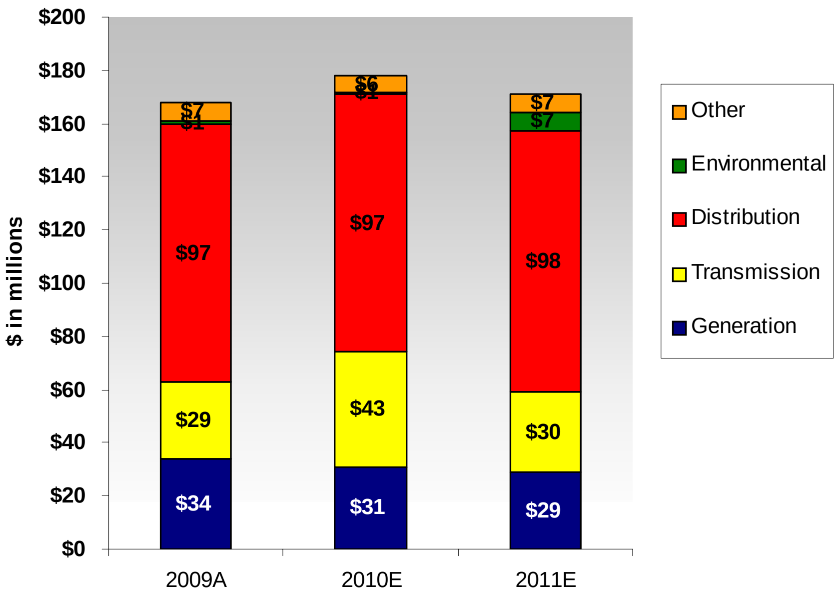


PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

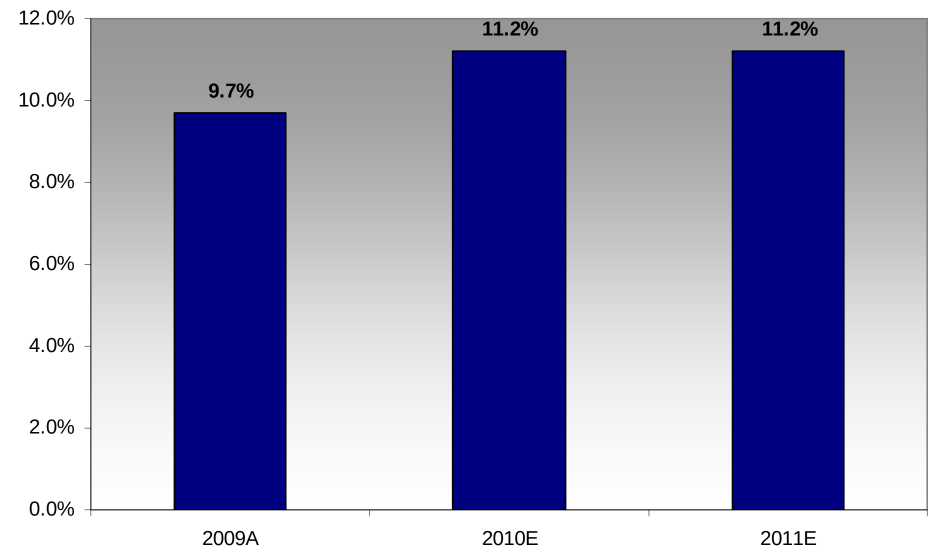
Paper Products – 17%
Oil & Gas Extraction – 13%
Transportation Equipment – 8%
Stone/Clay/Glass Products – 8%
Petroleum Refining – 8%

Overview of PSO

Capital Forecast



Forecasted ROEs



Major Capital Projects:
No major projects

Current and Future Regulatory Activity:
OK Base Rate Case

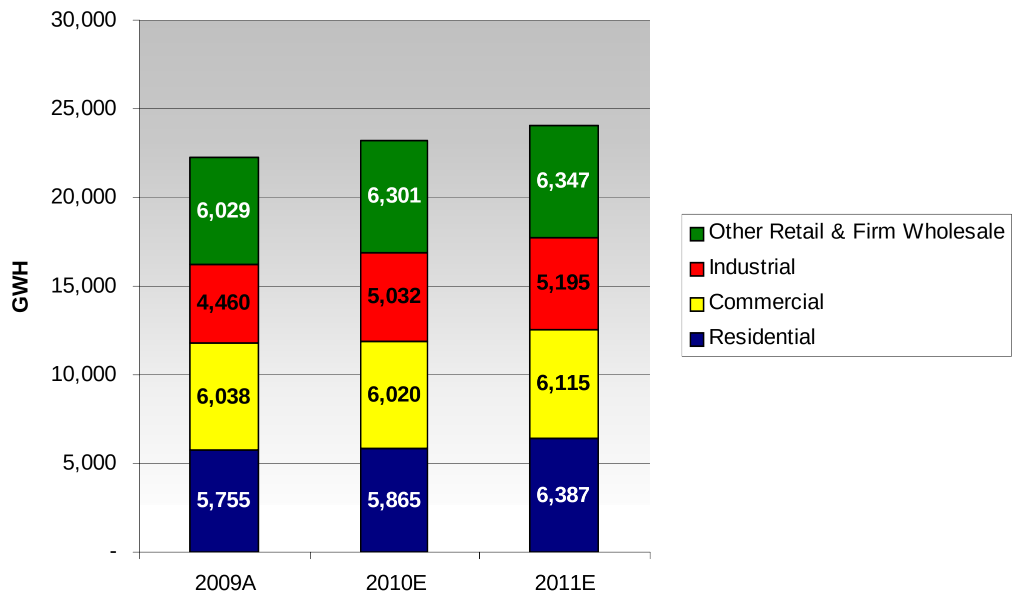
Overview of SWEPCO

Total Customers at 12/31/09:		
Residential	400,000	84%
Commercial	66,300	14%
Industrial	7,200	2%
Other	500	<1%
Total	474,000	

Generating Capacity 5,307 MW *

* - includes Stall Plant capacity (509MW) that came on line in June 2010

Normalized Retail Load



PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Food Products – 16%

Oil & Gas Extraction – 15%

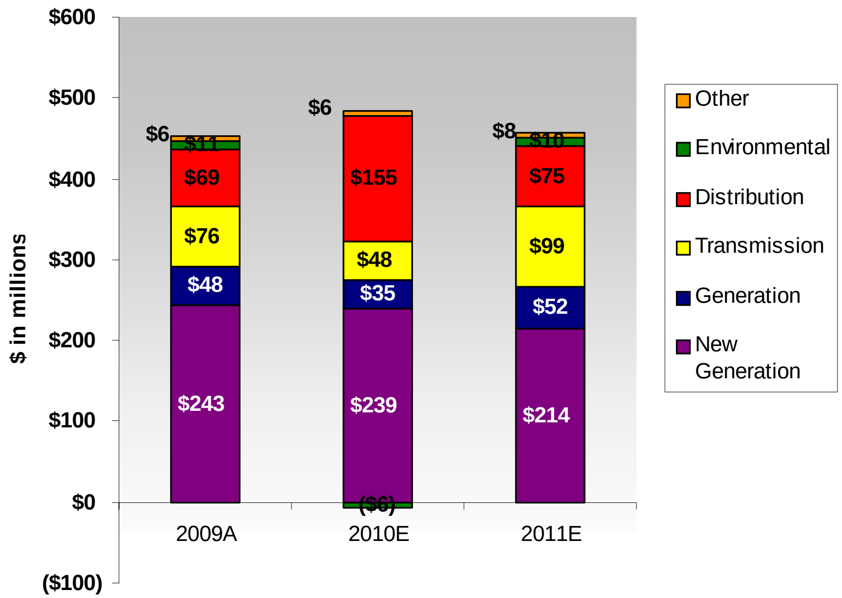
Paper Products – 14%

Petroleum Refining – 6%

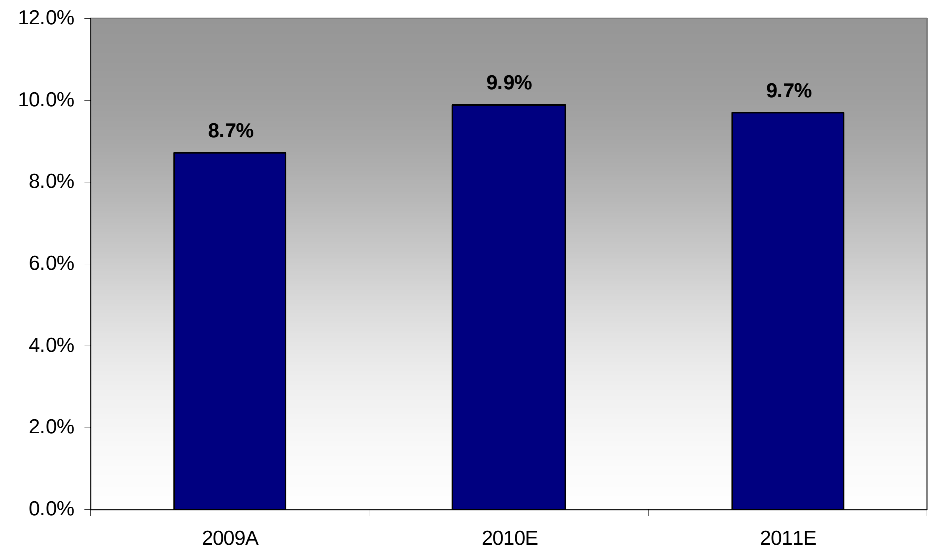
Chemical Products – 6%

Overview of SWEPCO

Capital Forecast



Forecasted ROEs

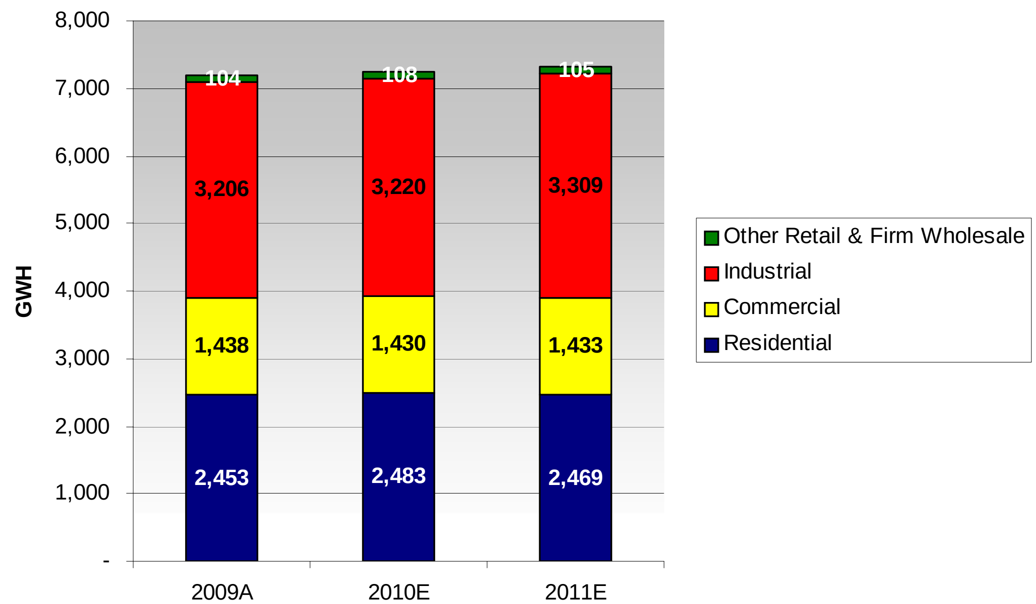


Major Capital Project: John W. Turk Plant

Current and Future Regulatory Activity: Turk Plant Recovery – LA and TX

Overview of Kentucky Power

Normalized Retail Load



Total Customers at 12/31/09:

Residential	143,600	82%
Commercial	29,600	17%
Industrial	1,400	1%
Other	400	<1%
Total	175,000	
Generating Capacity	1,078 MW	

PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Petroleum Refining – 36%
Coal Mining – 32%
Primary Metals – 11%
Chemical Products – 10%
Electric/Gas/Sanitary Services – 5%

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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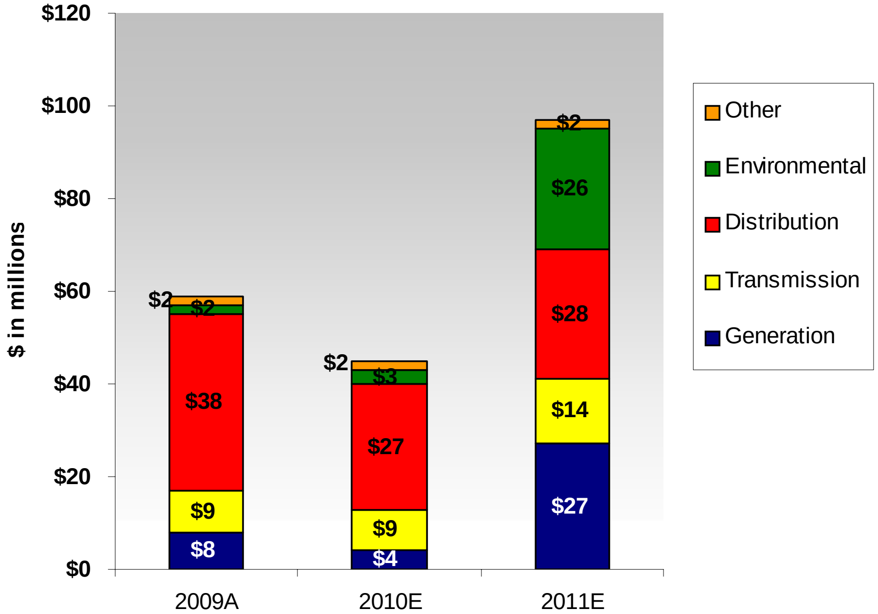
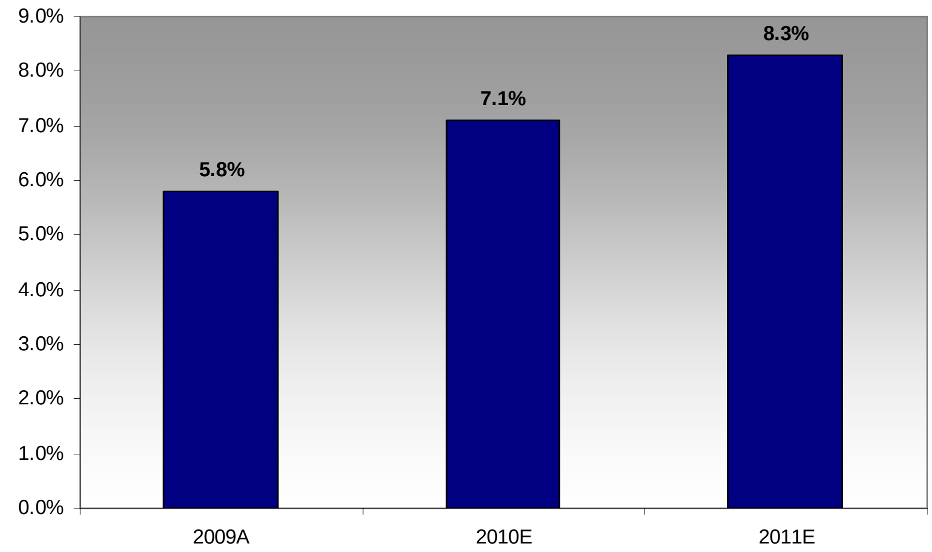
Overview of Kentucky Power

Capital Forecast



Forecasted ROEs



Major Capital Project:
No Major Projects

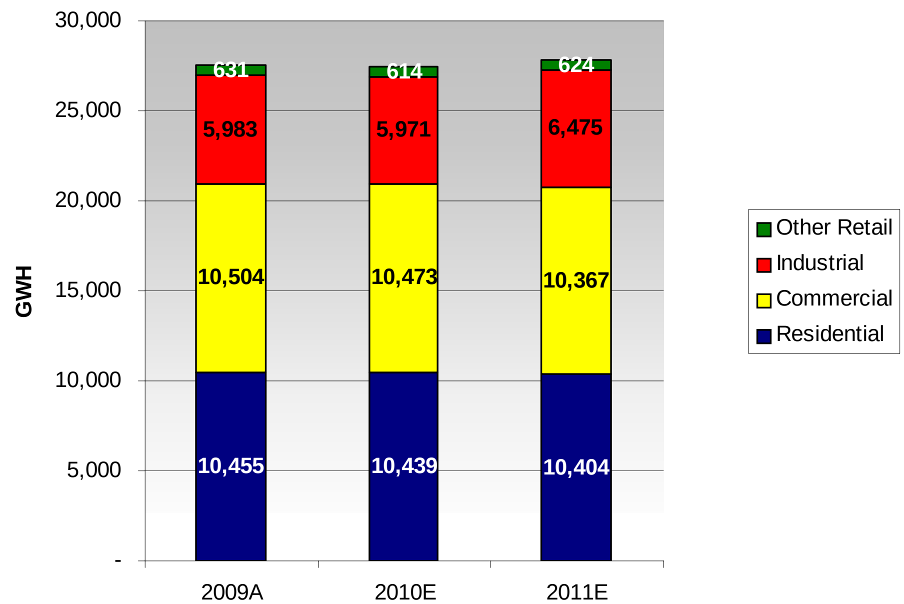
Future Regulatory Activity:
No major filings announced

Overview of AEP Texas

Total Customers at 12/31/09:

Residential	799,400	84%
Commercial	135,100	14%
Industrial	9,700	1%
Other	7,000	1%
Total	951,200	
Generating Capacity	377 MW	

Normalized Retail Load

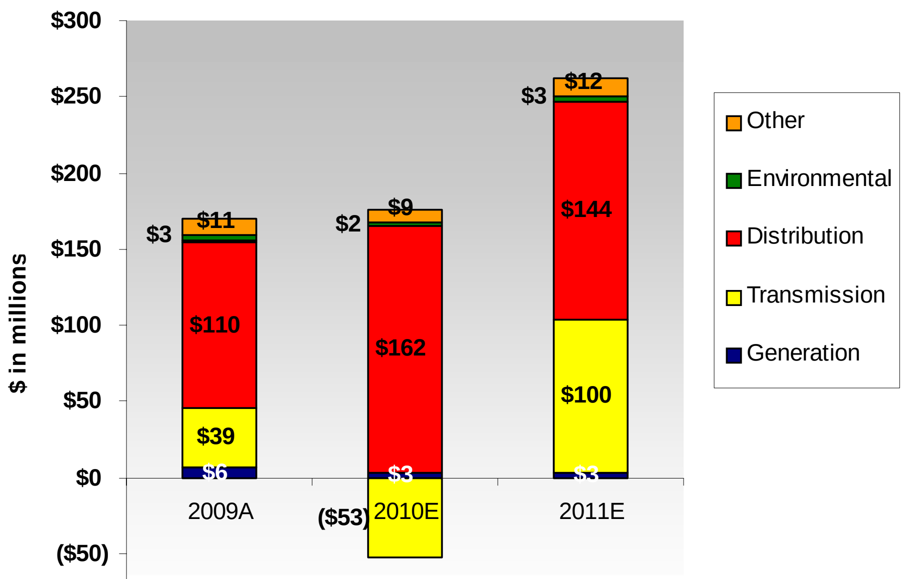


PRINCIPAL INDUSTRIES SERVED and % of 2009 INDUSTRIAL VOLUMES:

Petroleum Refining – 39%
Chemical Products – 29%
Oil & Gas Extraction – 12%
Food Products – 4%
Pipelines (excluding Nat Gas) – 1%

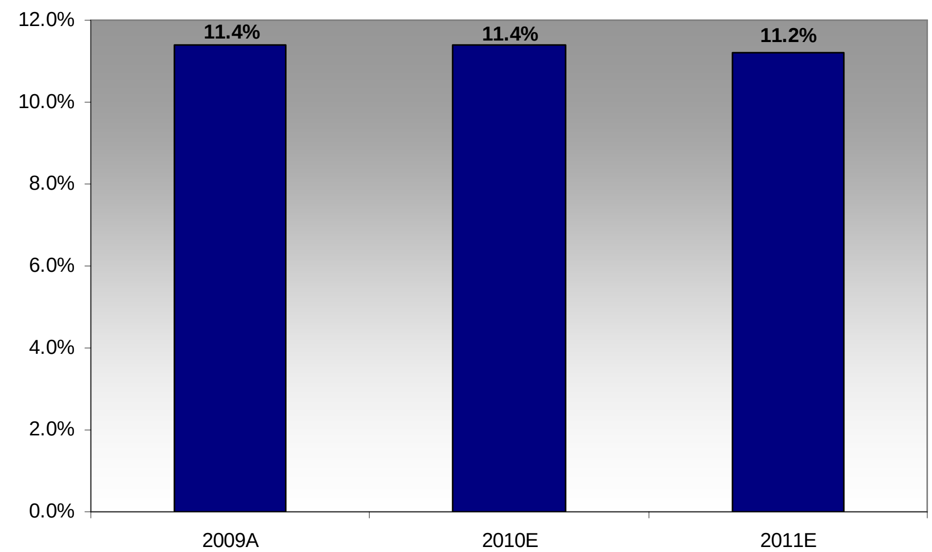
Overview of AEP Texas

Capital Forecast



Note: ($53) million in 2010E capital represents transfer of assets to Electric Transmission Texas

Forecasted ROEs



Major Capital Projects: AMI Deployment

Future Regulatory Activity: TCOS Filings

AEP AMERICAN® ELECTRIC POWER

EEI International Utility Conference
March 14-16, 2010

DC Cook Nuclear Plant (Michigan)

345-kV Transmission Line

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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AEP AMERICAN® ELECTRIC POWER

AEP Participants

Mike Morris – Chairman, President & CEO

Brian Tierney – EVP and CFO

Susan Tomasky – President, AEP Transmission

Chuck Zebula – Treasurer & SVP Investor Relations

AEP AMERICAN® ELECTRIC POWER

AEP Value Proposition

Regulated Utility Platform

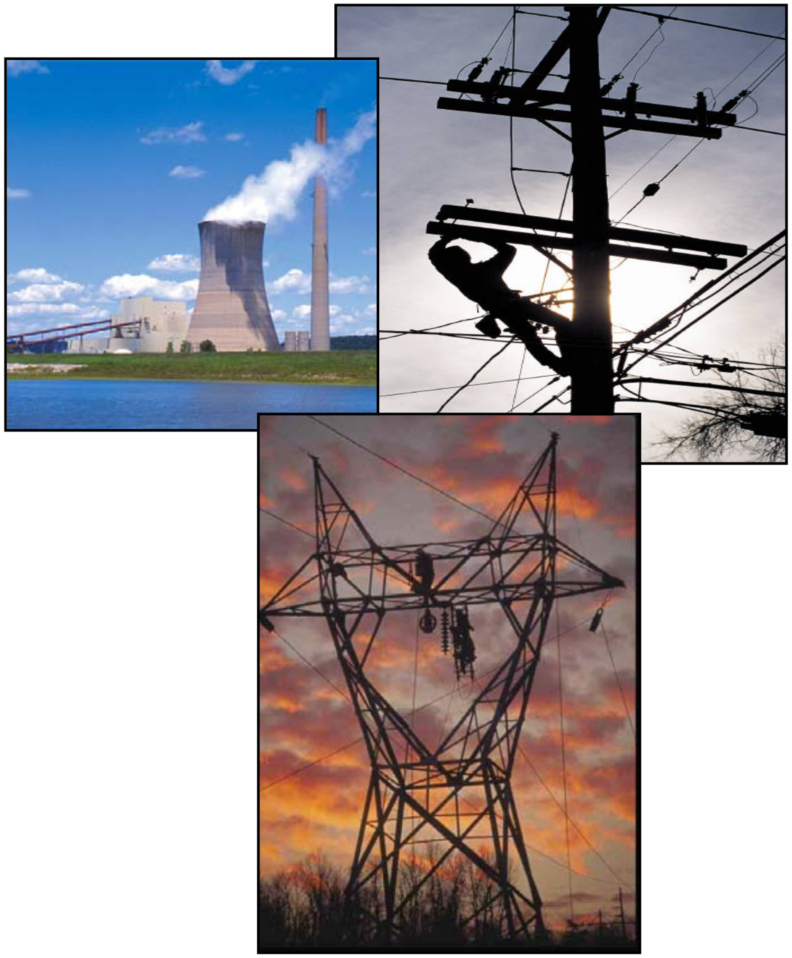
- Diversified service territory
- Successful regulatory track record
- Value compared to regulated peer group

Earnings Growth Prospects

- Investment in utility platform greater than depreciation level (2 - 4%)
- With transmission opportunities (4 - 8%)

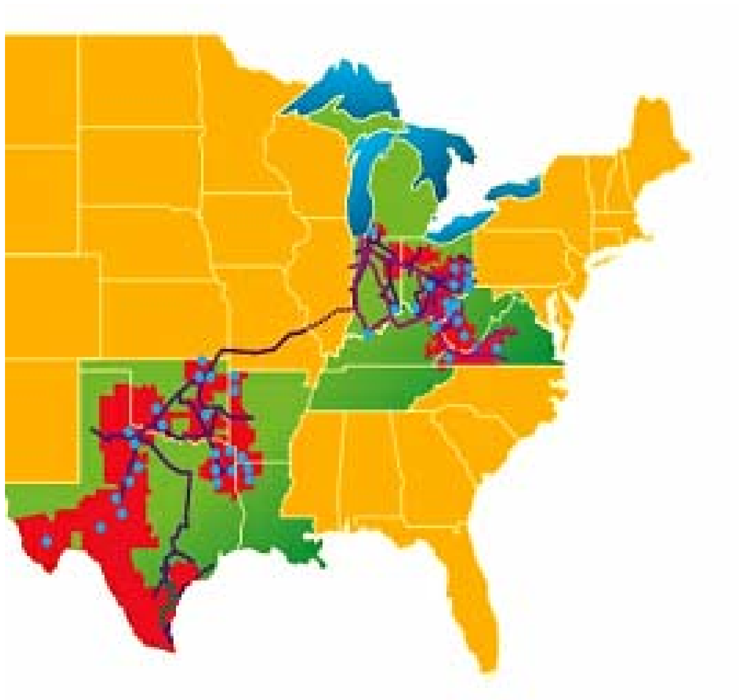
Attractive Yield Opportunity of 4.8%[1]

- 50-60% payout ratio targeted
- Nearly a century of dividend payments to shareholders



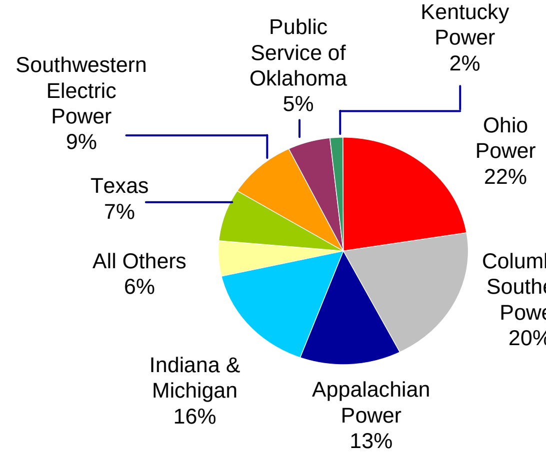
[1] yield percentage based on AEP closing price of $33.97 on 03/03/2010

Highly Diversified Regulated Utility Platform

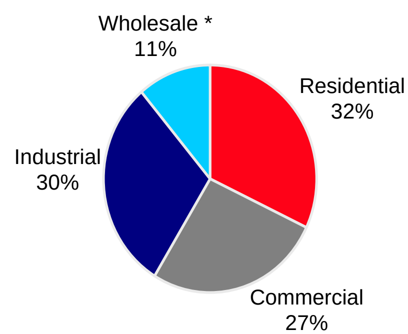


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

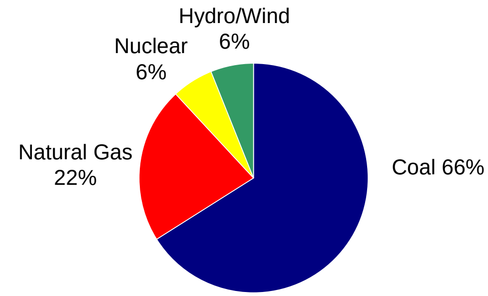


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix**



** Based on Capacity

AEP AMERICAN® ELECTRIC POWER

Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

AEP AMERICAN® ELECTRIC POWER

JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2017

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

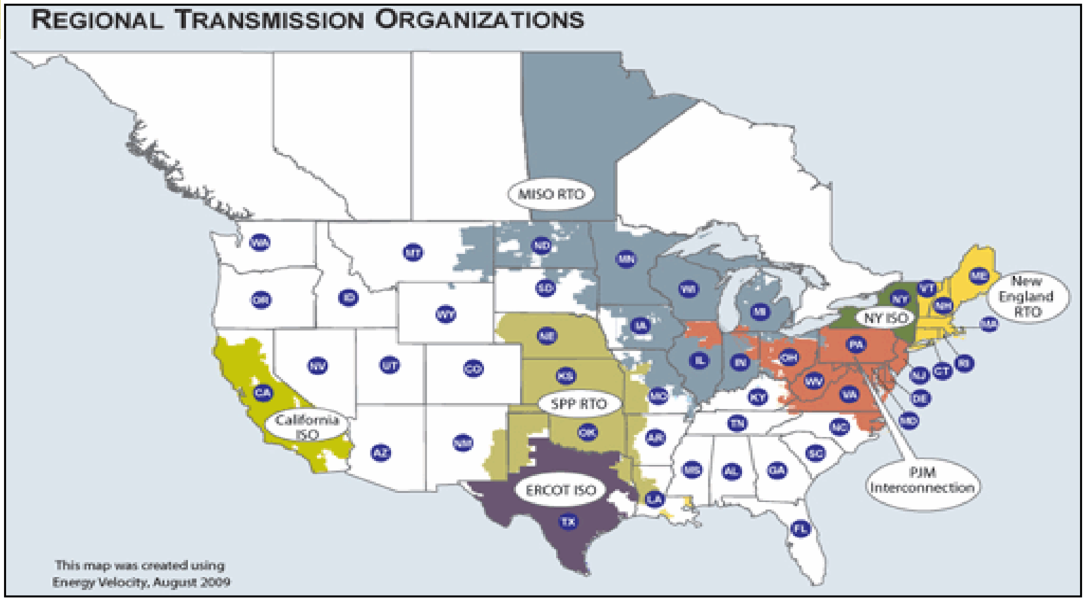
PATH-WV — COD: 2014

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — COD: various

- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP — ERCOT — PJM — PJM/MISO

AEP AMERICAN® ELECTRIC POWER

A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- Existing Plant Efficiency Gains
- Renewable Energy
  - 1400 MW wind
  - 300+ MW hydro
- Domestic Offsets
  - Over 63MM trees planted = 1.2MM tons of CO_2 uptake
- International Offsets
  - 1MM tons of forest carbon sequestered through 2009
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
– **2003-2010: 50 MMT+ Total**

New Additions (by 2012)

- 2000 MW Wind PPAs
- Domestic Offsets
  - Methane, Forestry
- Fleet Vehicle/Aviation Offsets
- Energy Efficiency & DSM
- Biomass Co-firing
- New Technology
  - New Generation: Ultra Super Critical Coal
  - Carbon Capture and Storage (CCS) for existing fleet
    - Chilled Ammonia

AEP's reductions/offsets of CO_2:
– **2011+: 5 MMT/yr**

AEP AMERICAN® ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

Captured CO_2 first time on 09/01/09; Injected CO_2 first time on 10/1/2009

Mountaineer Plant (WV)

Chilled Ammonia
20MWe scale
(Alstom)

CO_2 Storage
(Battelle)
2 injection wells & 3 monitoring wells

Captures and Stores
~100,000 metric tons of CO_2 /yr.

Phase 2

Awarded $334MM DOE Funding;
Expected Commercial Operation: 2015

Mountaineer Plant (WV)

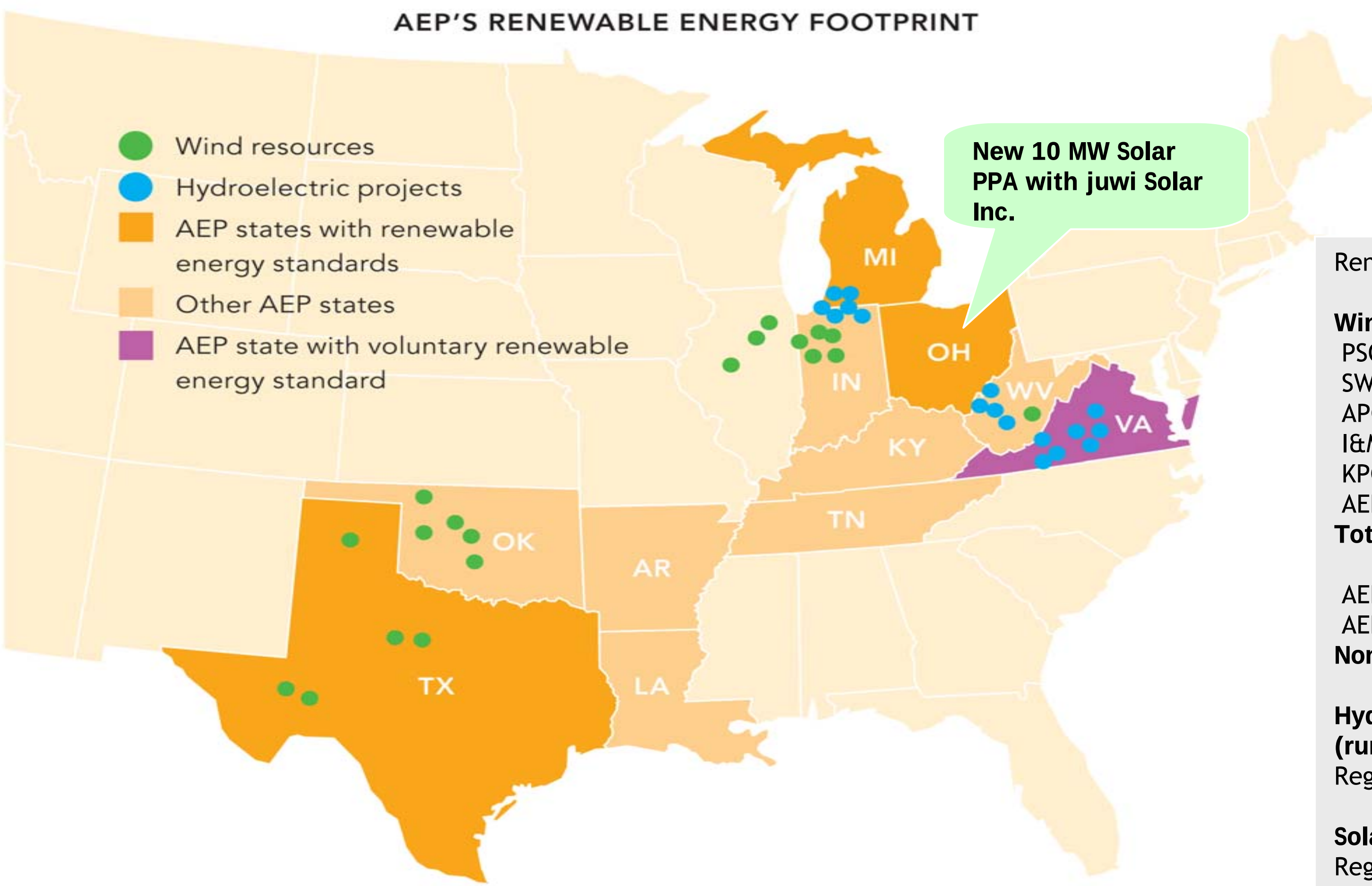
Chilled Ammonia
~235MWe scale
(Alstom)

CO_2 Storage

Captures and Stores
1.5 Million metric tons of CO_2/yr,
1.5 miles below the surface

AEP AMERICAN® ELECTRIC POWER

AEP Renewable Footprint



New 10 MW Solar PPA with juwi Solar Inc.

Renewables Portfolio*

Wind		
PSO - 5 PPAs		591MW
SWEPCo - 1 PPA		79MW
APCo - 4 PPAs		376MW
I&M - 2 PPAs		150MW
KPCo - 1 PPA		100MW
AEP Ohio - 2 PPAs		110MW
Total Regulated		**1406MW**
AEPEP -	owned	311MW
AEPEP -	2 PPAs	177MW
Non-regulated		**487 MW**
Hydro (run-of-river)		
Regulated - owned / PPA		**364MW**
Solar		
Regulated - PPA		**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

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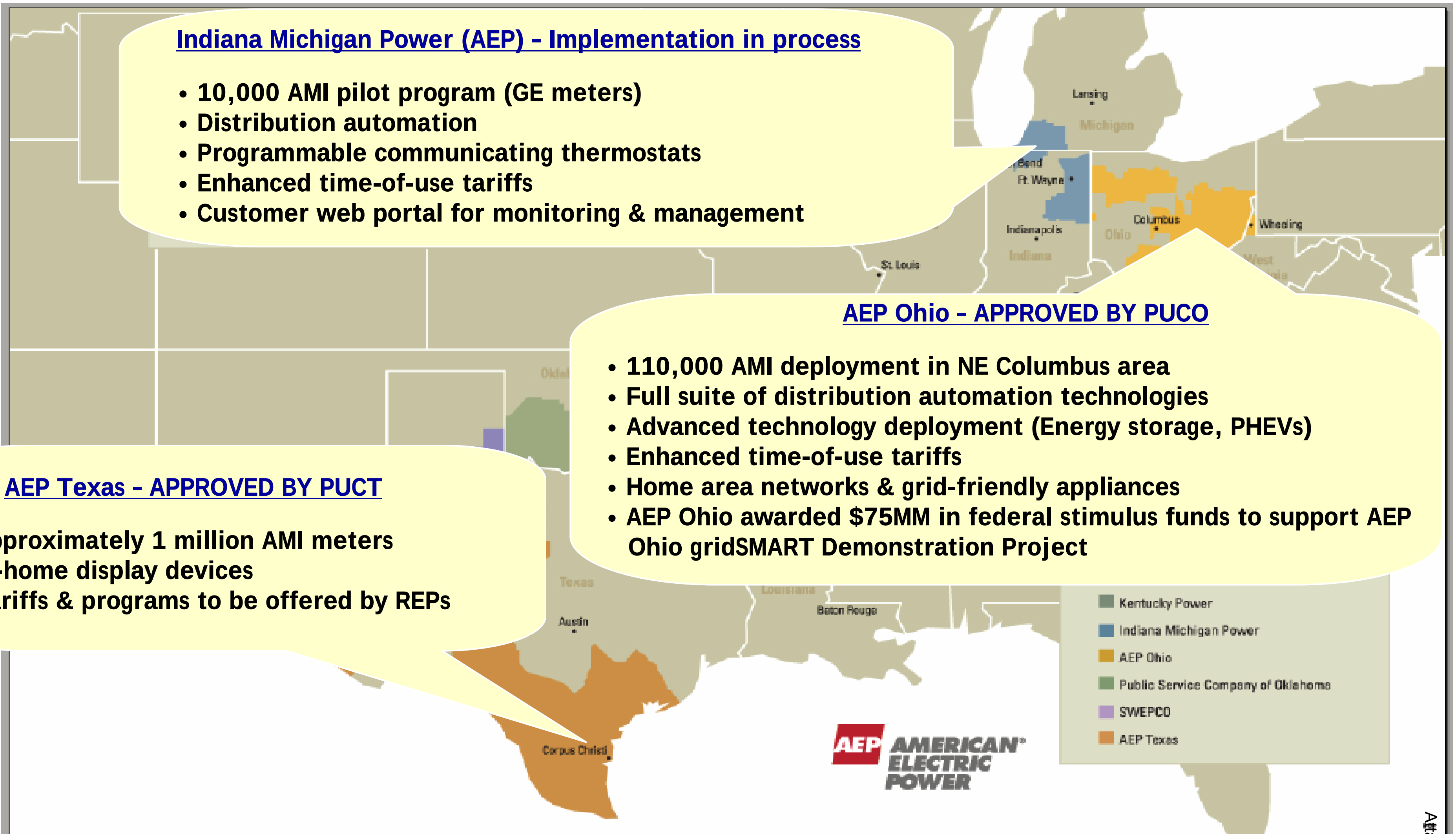
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

AEP gridSMART Deployment Status



Indiana Michigan Power (AEP) - Implementation in process

- 10,000 AMI pilot program (GE meters)
- Distribution automation
- Programmable communicating thermostats
- Enhanced time-of-use tariffs
- Customer web portal for monitoring & management

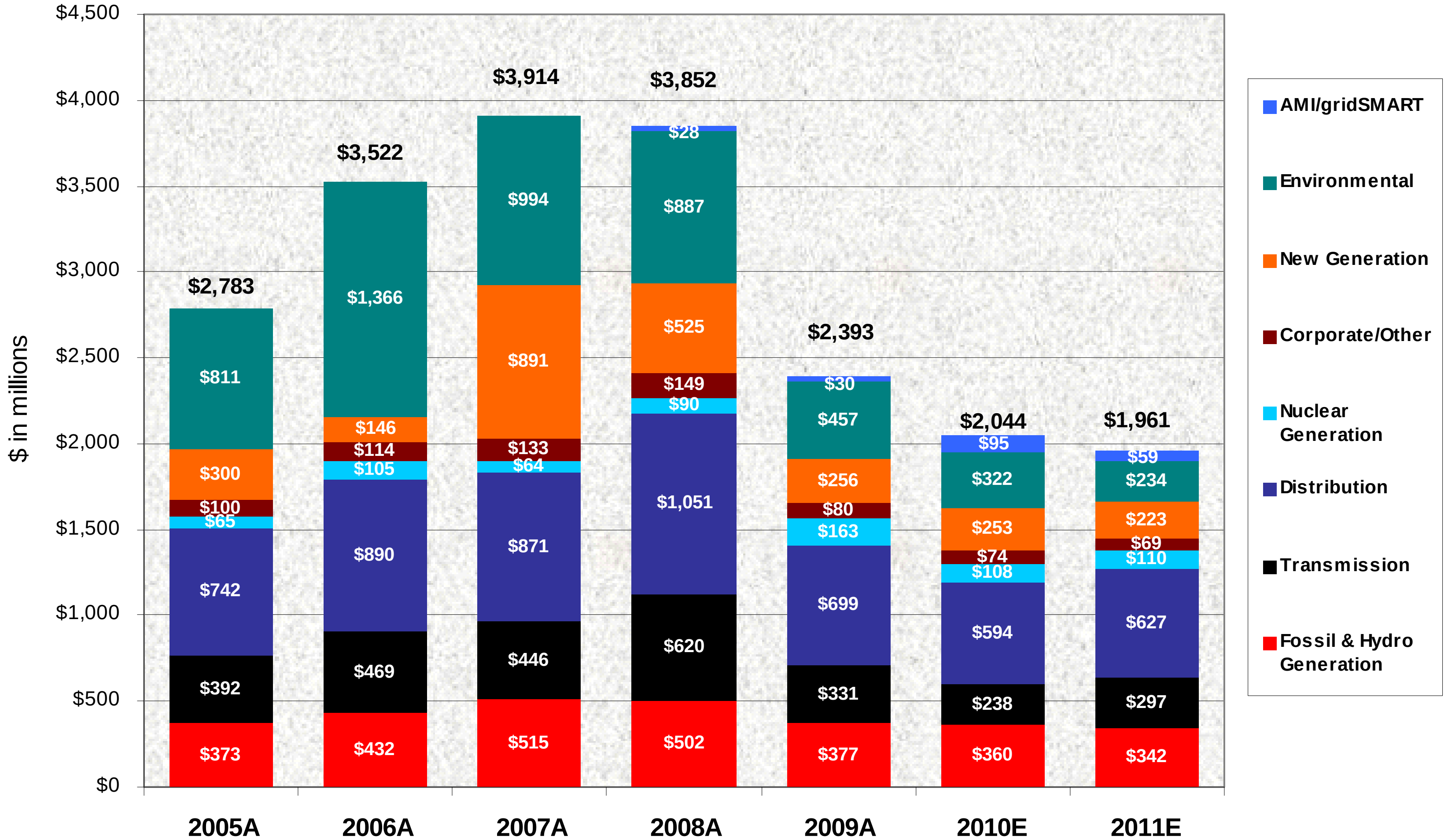
AEP Ohio - APPROVED BY PUCO

- 110,000 AMI deployment in NE Columbus area
- Full suite of distribution automation technologies
- Advanced technology deployment (Energy storage, PHEVs)
- Enhanced time-of-use tariffs
- Home area networks & grid-friendly appliances
- AEP Ohio awarded $75MM in federal stimulus funds to support AEP Ohio gridSMART Demonstration Project

AEP Texas - APPROVED BY PUCT

- Approximately 1 million AMI meters
- In-home display devices
- Tariffs & programs to be offered by REPs

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

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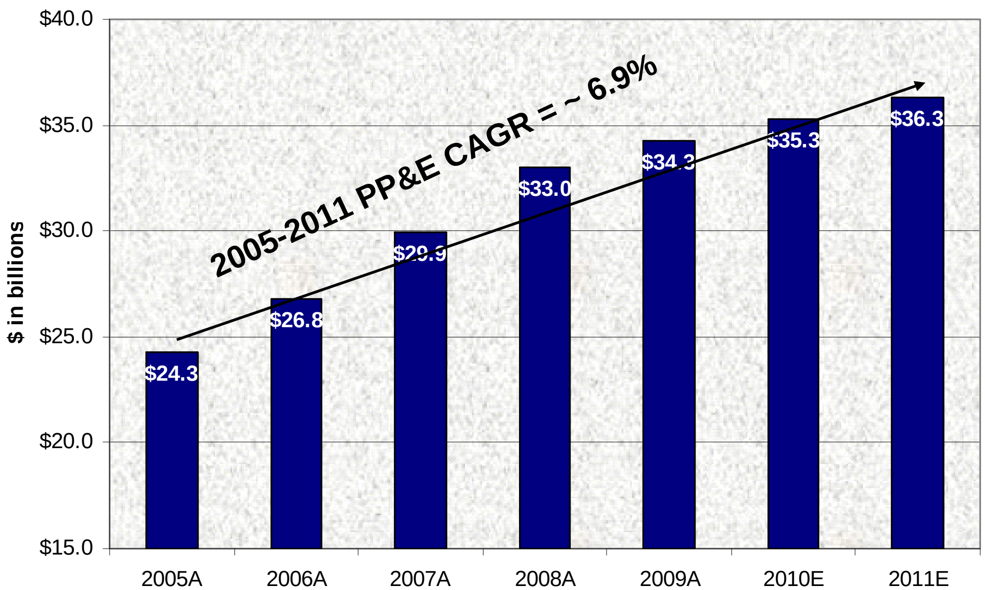
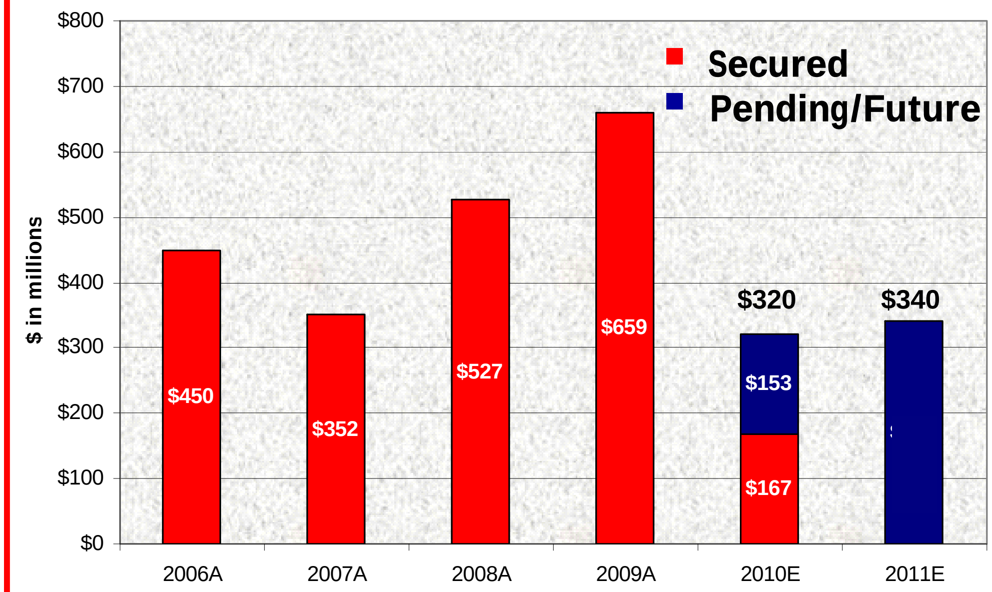
Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Texas, Virginia, West Virginia and others

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

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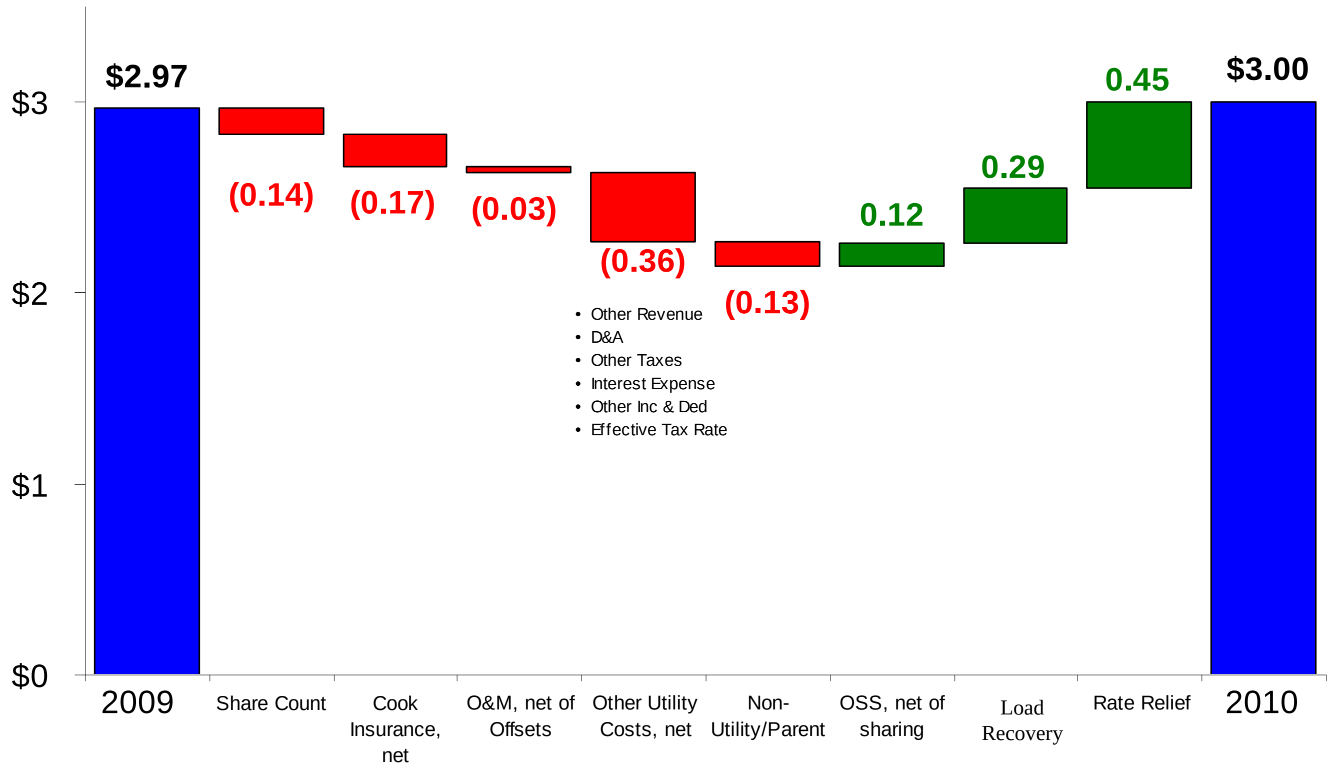
Appendix

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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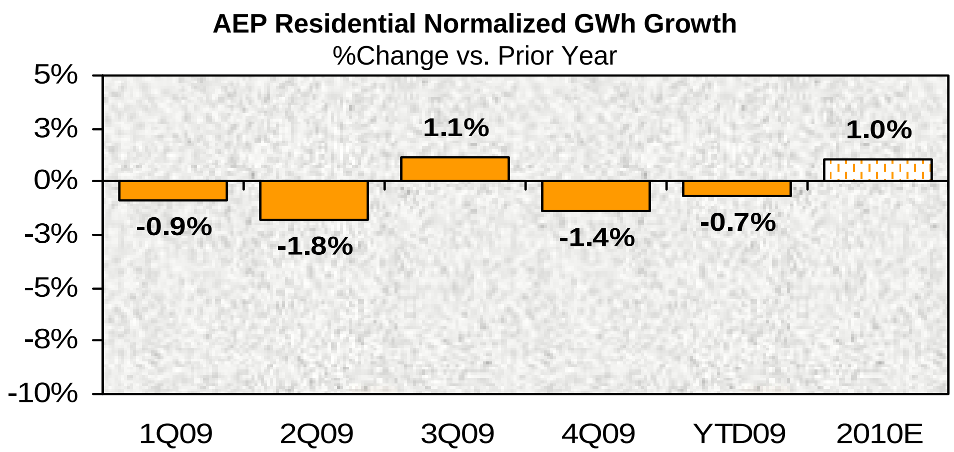
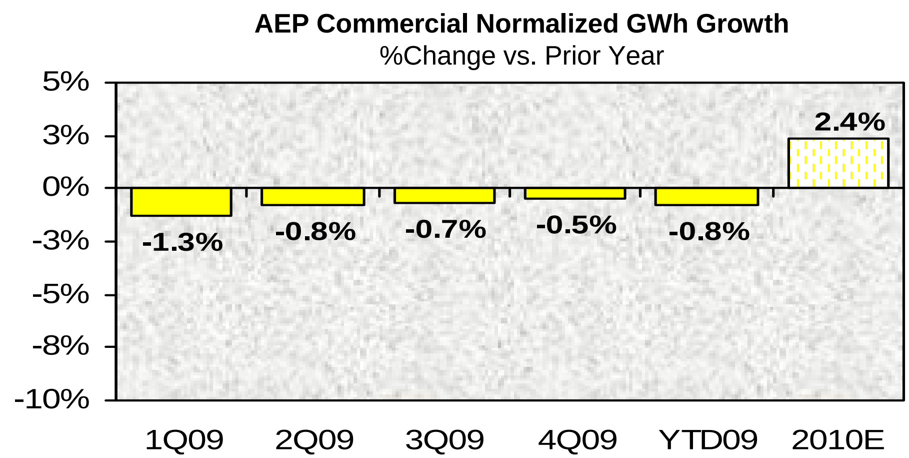
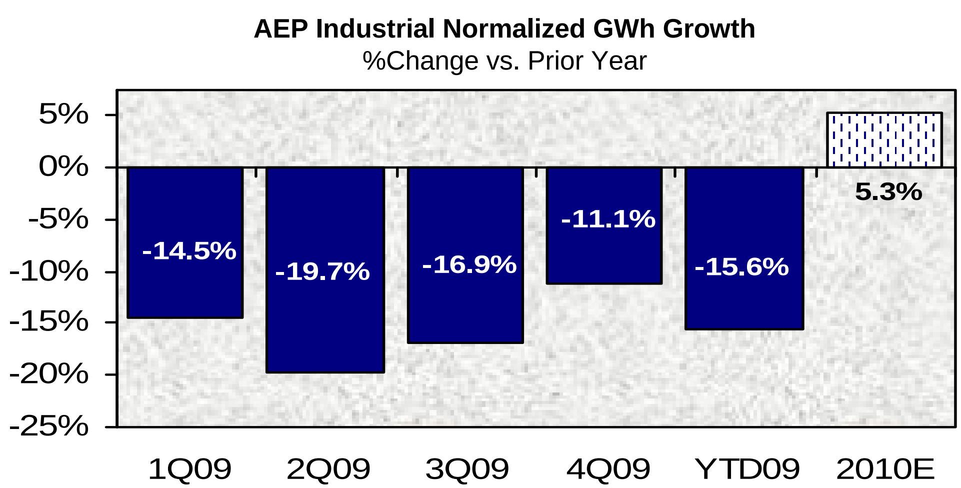
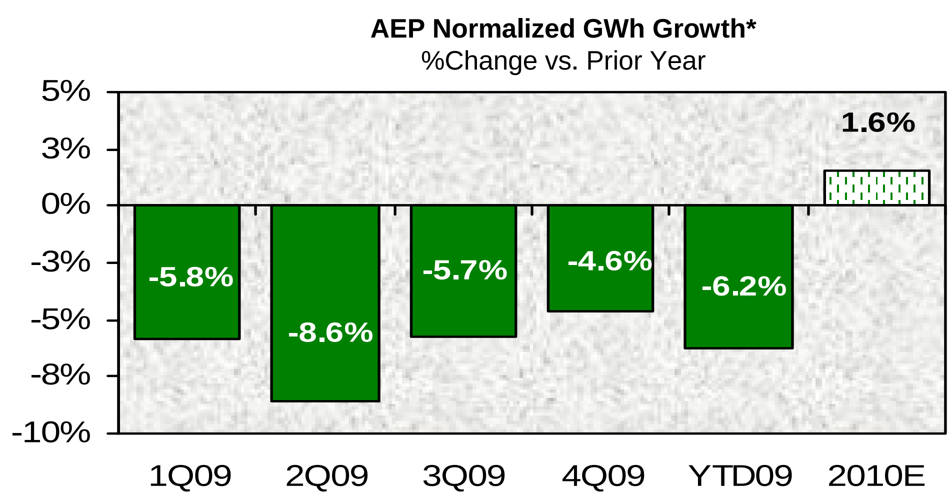
Normalized Load Trends









*includes firm wholesale load

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Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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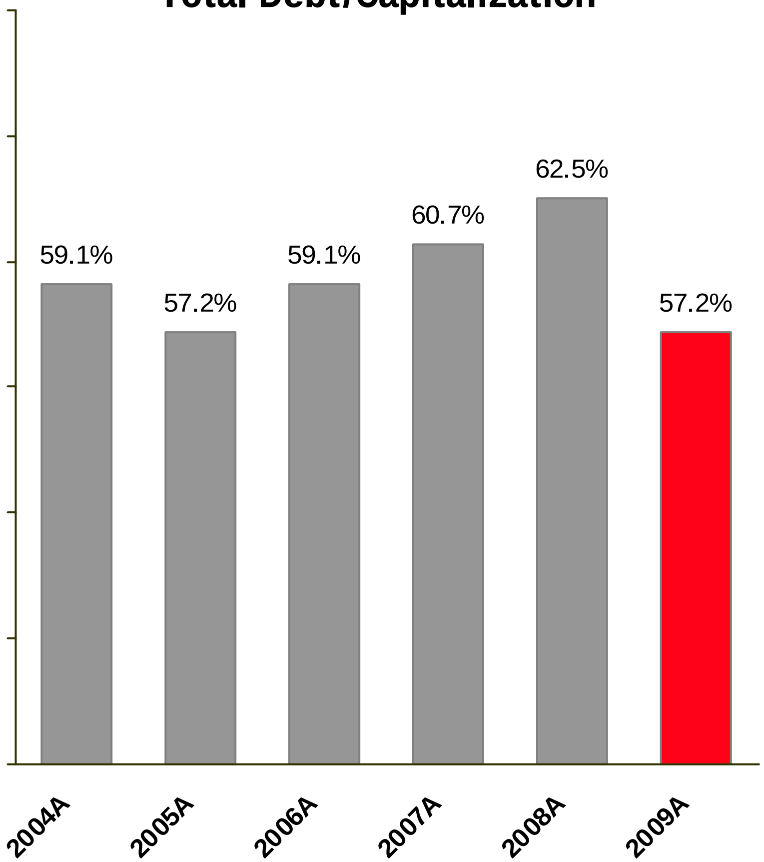
Capitalization & Liquidity

Total Debt/Capitalization



Note: *Total Debt is calculated according to GAAP and includes securitized debt*

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

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Long-term Debt Maturity Profile

($ in millions)

Year	2010		2011		2012	
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	679	$	-	$	-
Public Service of Oklahoma	$	-	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company(1)	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,585	$	623	$	415

(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

AMERICAN ELECTRIC POWER

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

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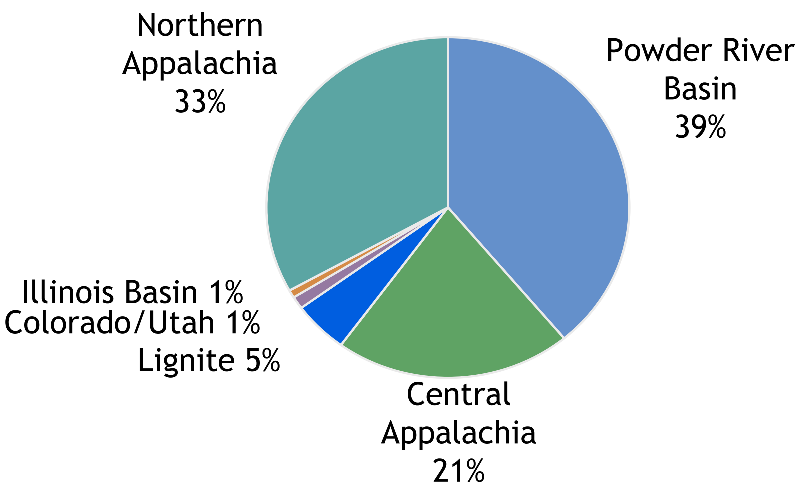
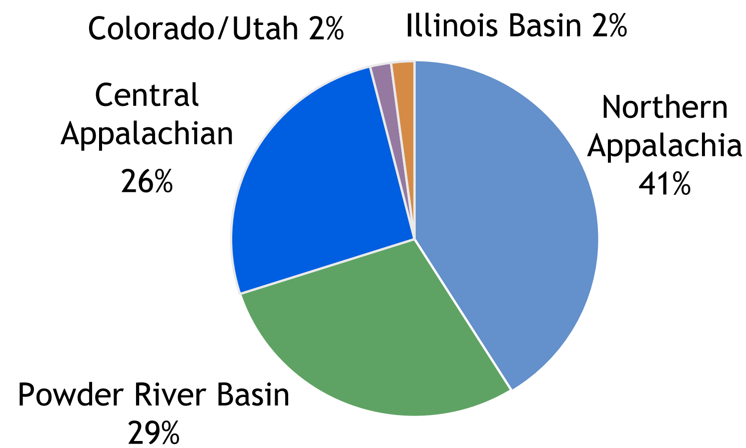
Coal Procurement - 2010 Projected

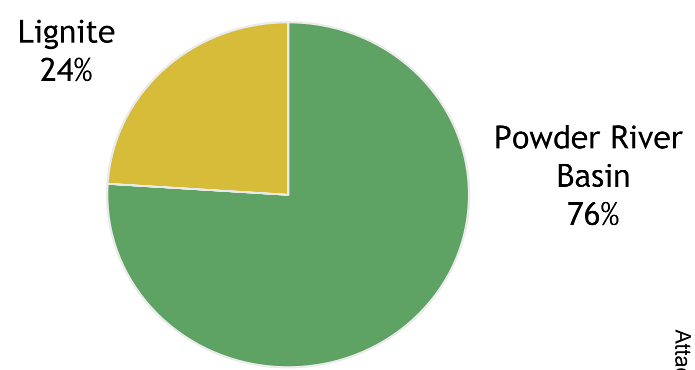
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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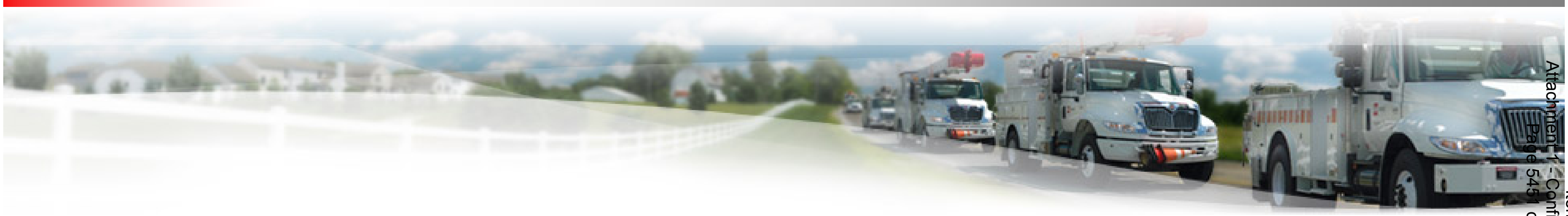
45th EEI Financial Conference

November 2, 2010
Palm Desert, CA



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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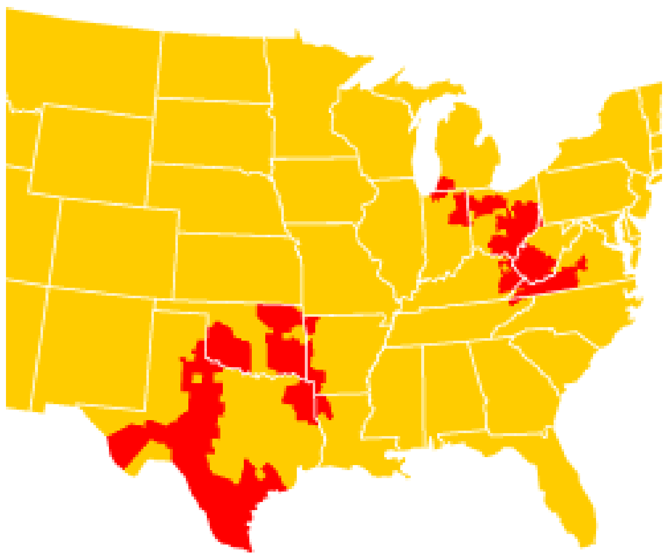
President
AEP Transmission

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield near 5%

Serving electric customers in 11 states



AEP Fast Facts

5.2 million customers
40 GW of generation capacity
39,000 miles of transmission lines

$17.5B Market Capitalization
BBB/Baa2/BBB credit rating

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

Capital for Growth

- Increased capital budget by $150M for 2011 to $2.6B
- Announced capital budget plan of $2.9B for 2012

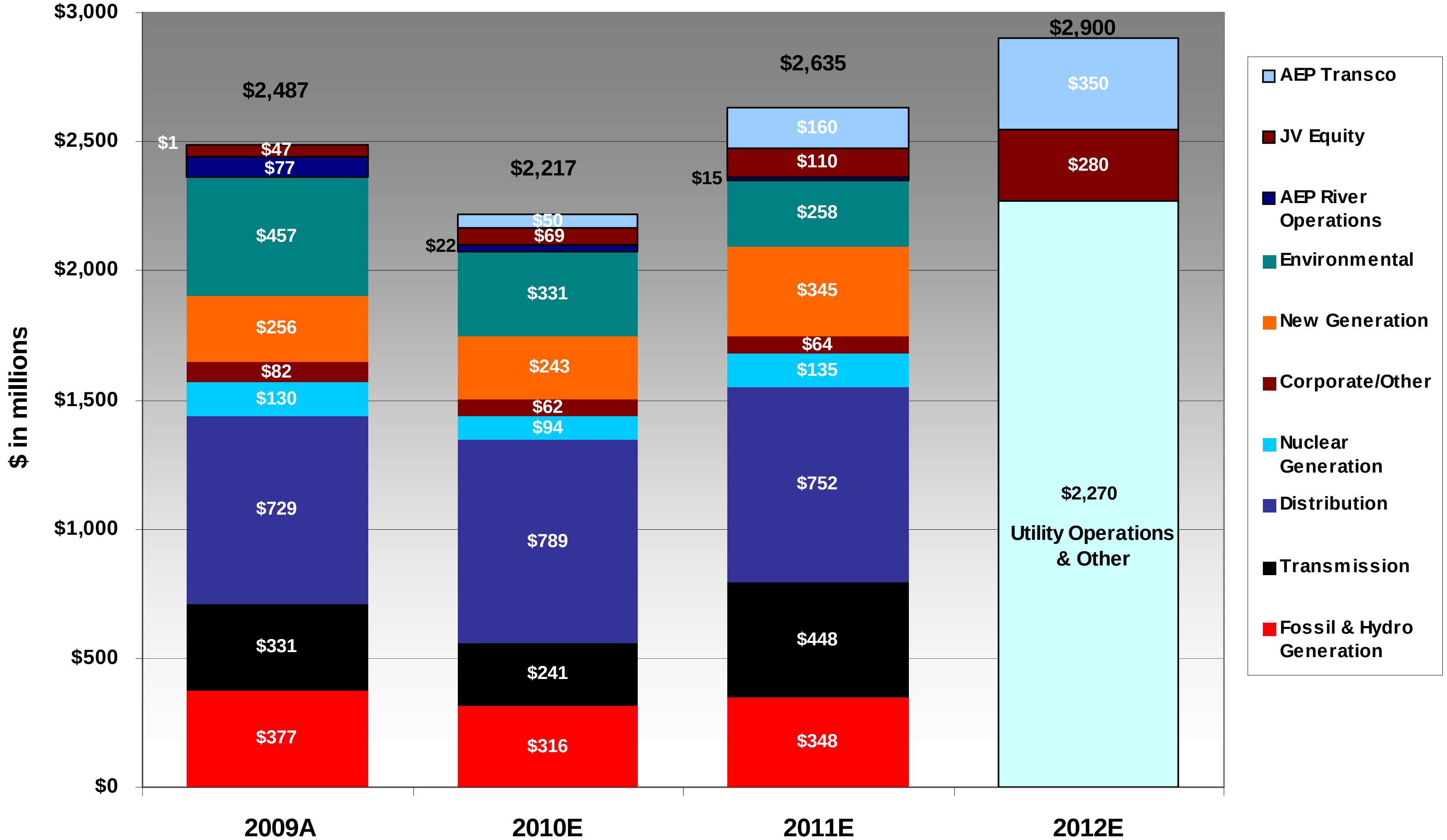
Return of Capital to Shareholders

- 9.5% increase in quarterly dividend to $0.46/share declared by the board of directors on October 26th
- Future dividend increases will grow with earnings

Capital to Reduce Risk

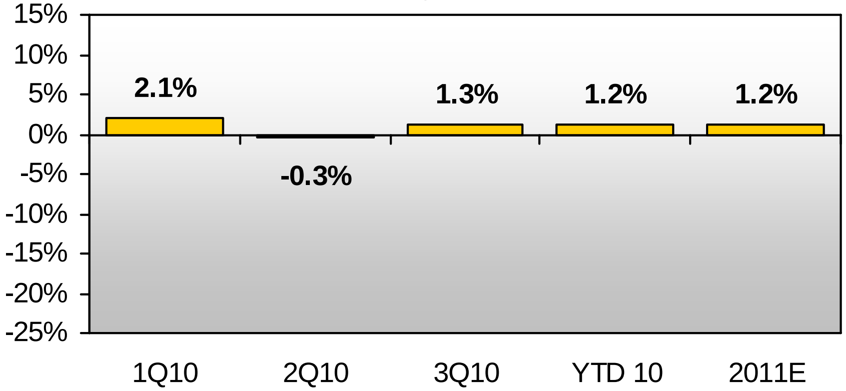
- Voluntarily funding pension $500M in 2010
- Allocating an additional $150M of funding for pension in 2011

Capital Expenditures

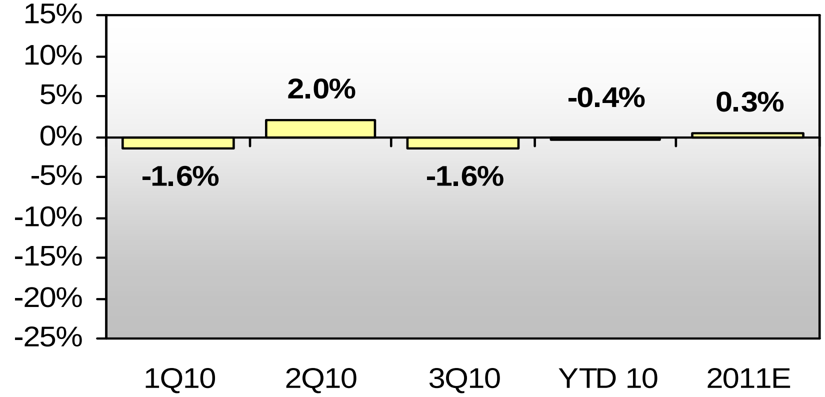


Normalized Load Trends

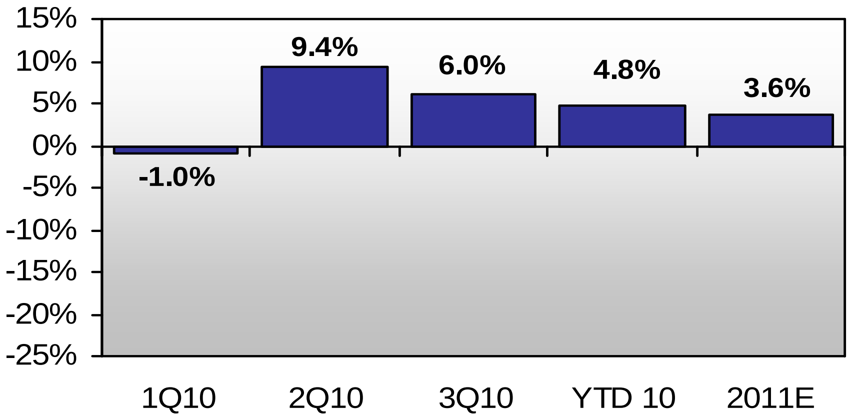
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



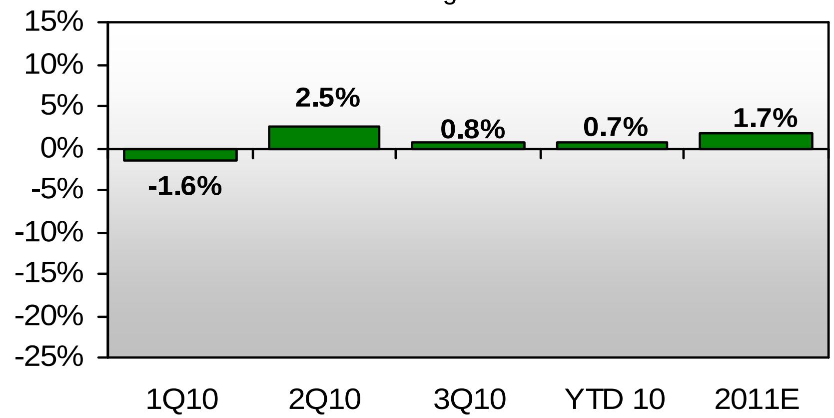
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



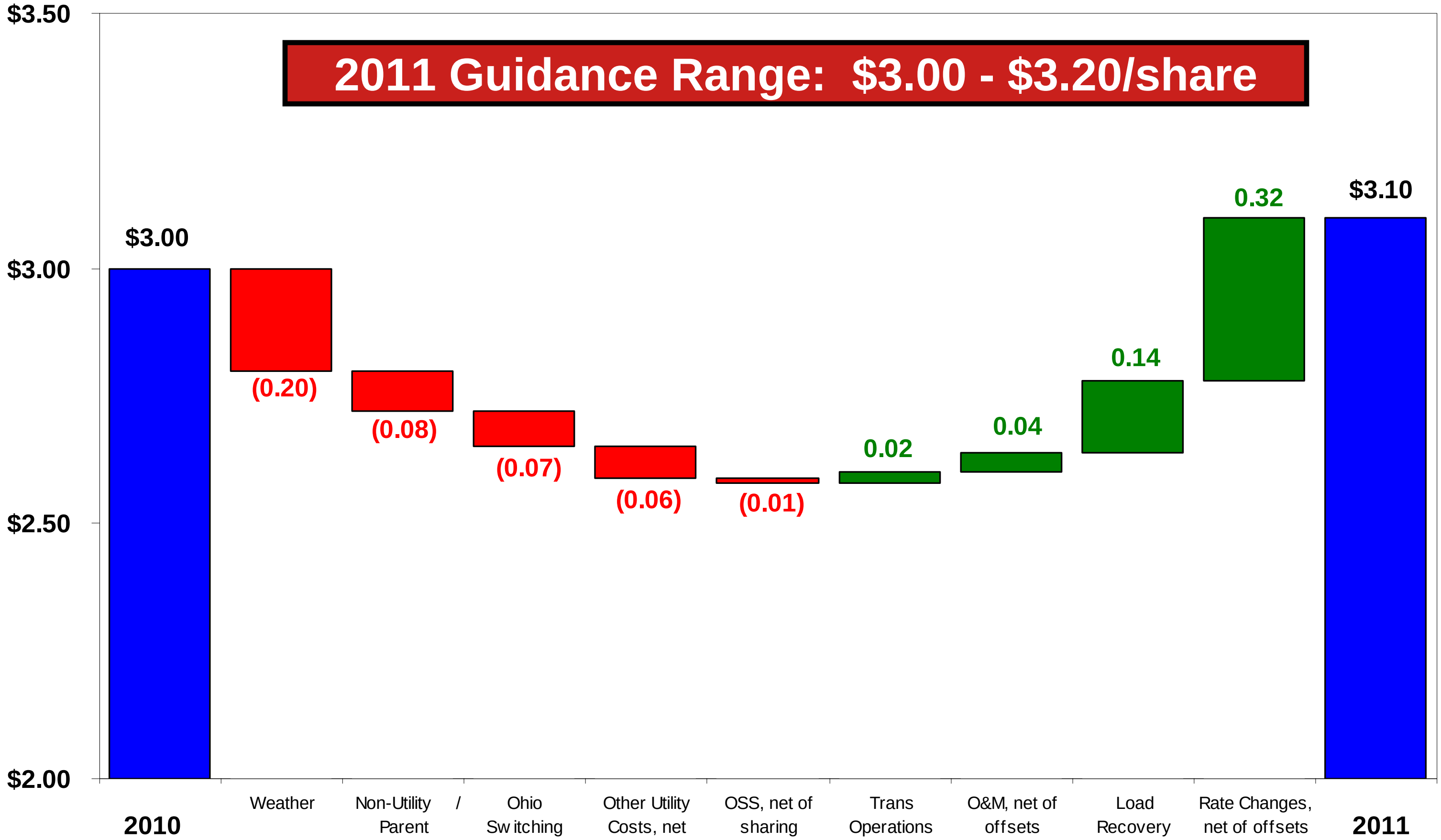
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

2011 Earnings Drivers



- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

2012 EPS Target: $3.25/share

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Transmission as a Growth Engine

- **Electric Transmission Texas (ETT)**
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- **AEP Transmission Company (AEP Transco)**
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- **Progress on Joint Ventures in 2010**
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

Two New Anchor Projects

ETA – AEP - Exelon: The RITE Line

Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

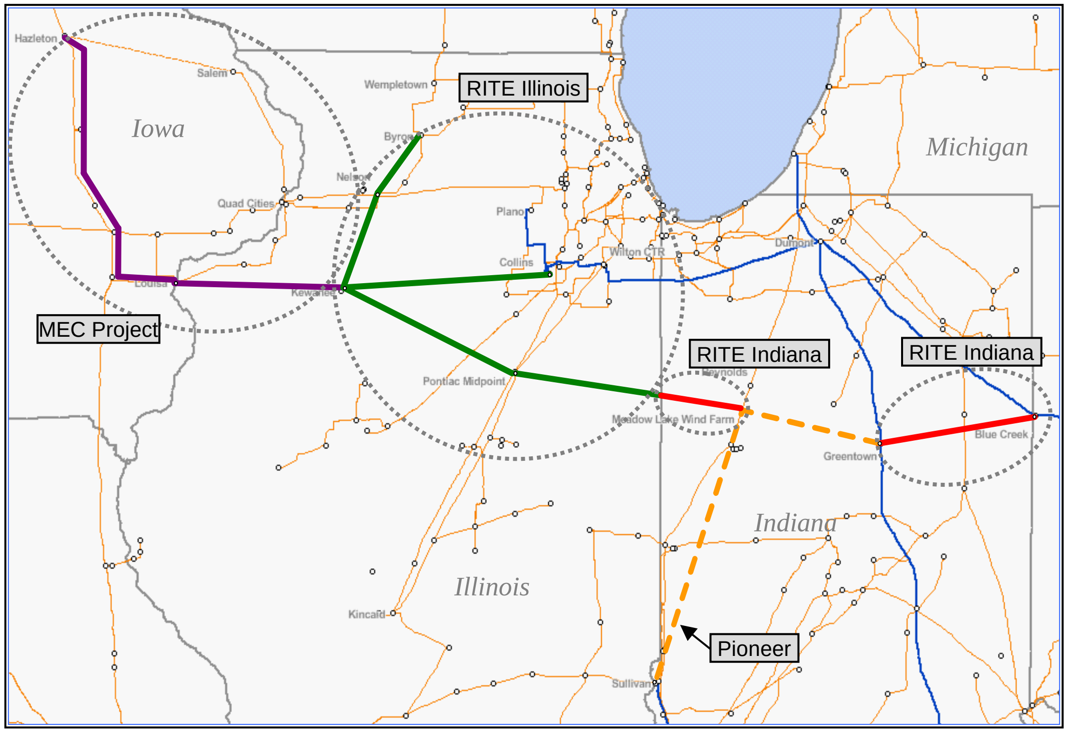
ETA – MidAmerican Energy Co: MEC Project

Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

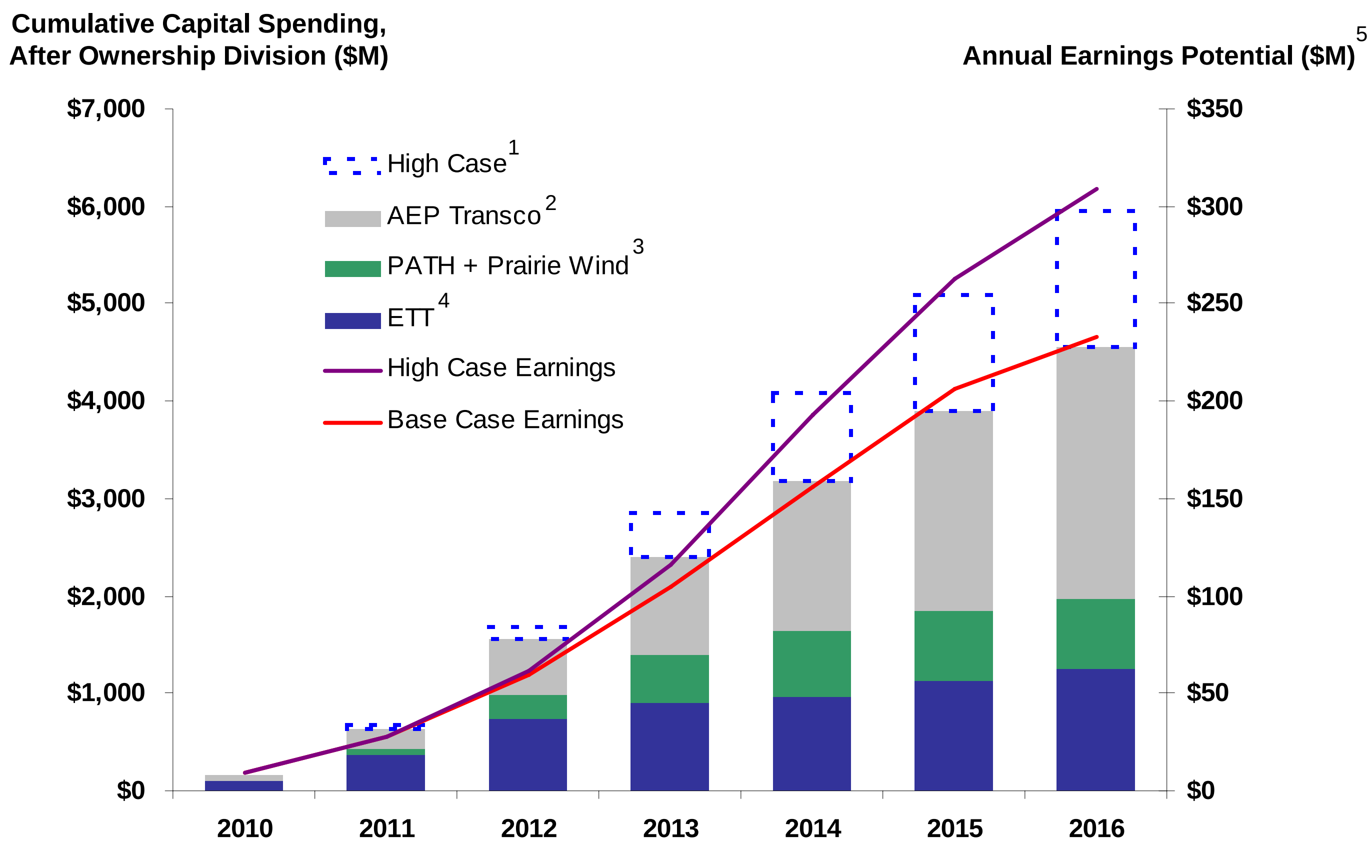
AEP Total Investment:

~$500M



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Transmission – Capital/Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

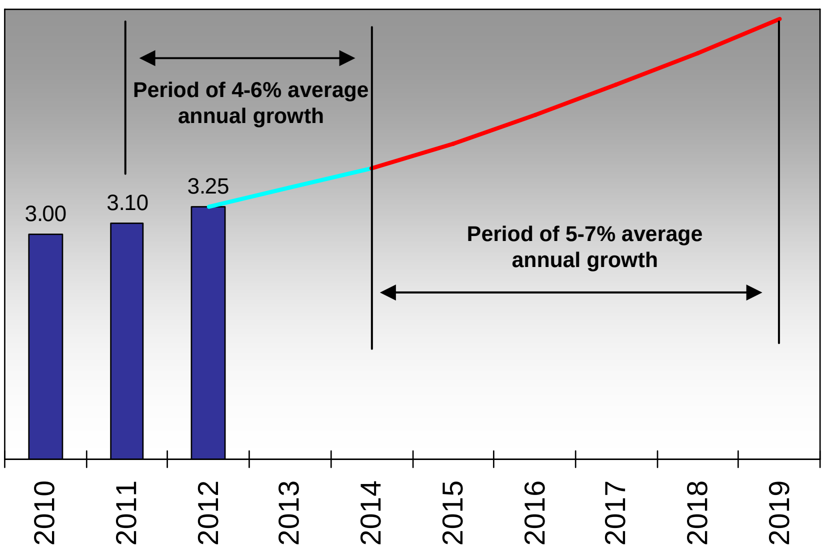
[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

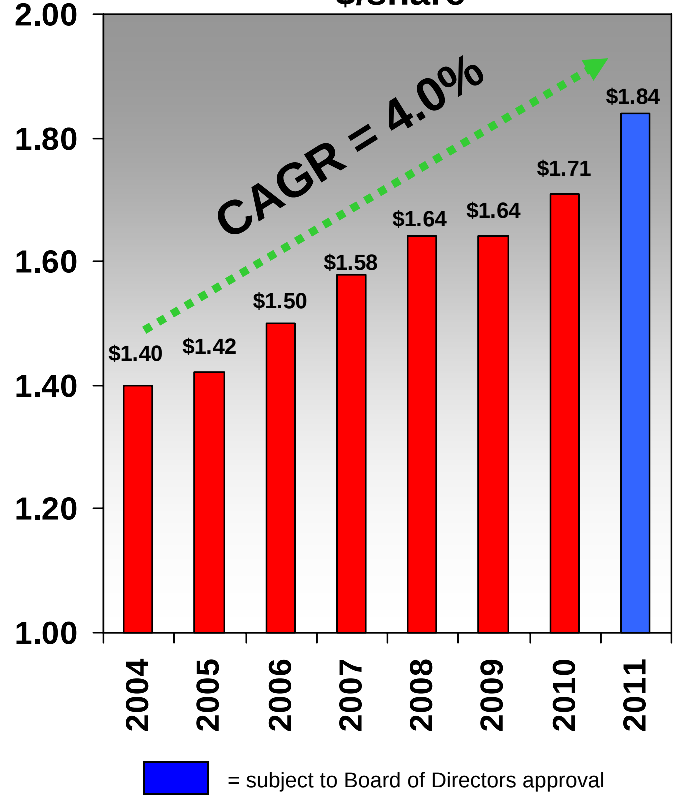
AEP – Income and Growth Opportunity

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004
$/share



- 9.5% increase in quarterly dividend to $0.46/share declared on October 26th
- 401st consecutive quarterly dividend paid in September
- 50-60% payout ratio target
- Current yield about 5%

Questions

13

AEP AMERICAN® ELECTRIC POWER

European Investor Road Show
March 9-12, 2010

DC Cook Nuclear Plant (Michigan)

345-kV Transmission Line

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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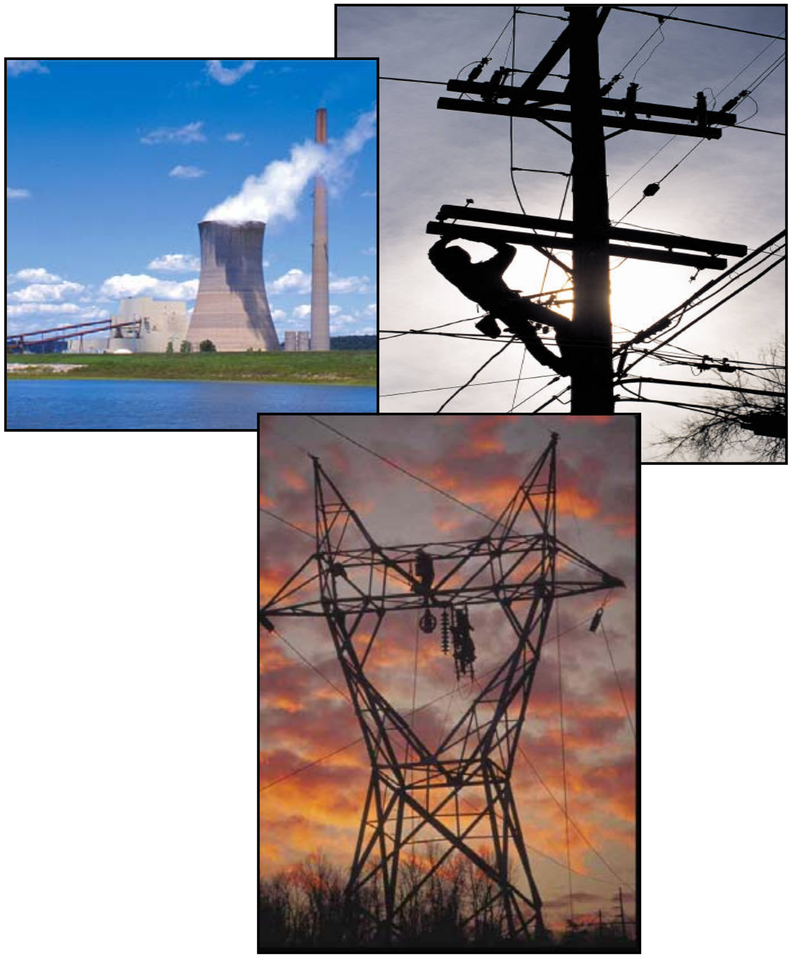
AEP Participants

Brian X. Tierney – EVP and CFO

Chuck Zebula – Treasurer & SVP Investor Relations

AEP Value Proposition

- **Regulated Utility Platform**
  - Diversified service territory
  - Successful regulatory track record
  - Value compared to regulated peer group
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
- **Attractive Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders



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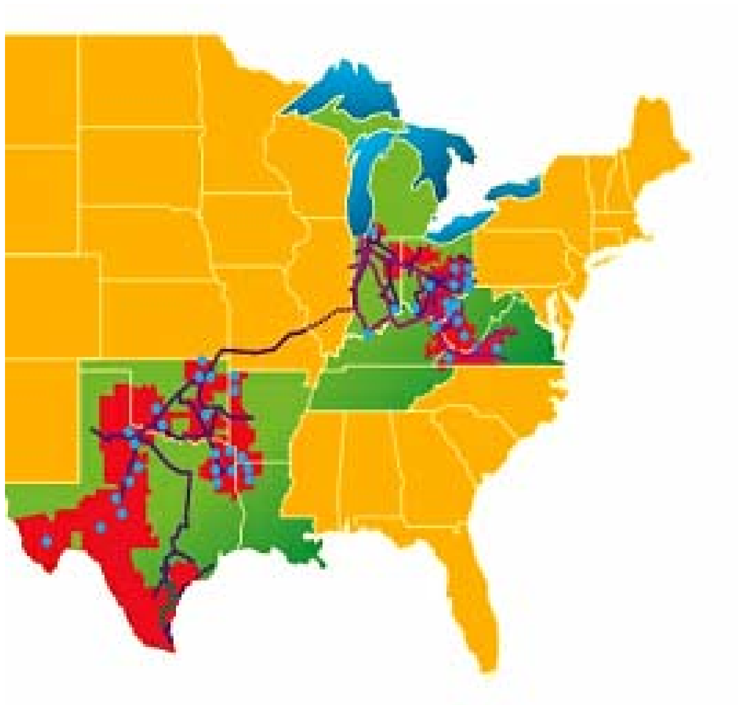
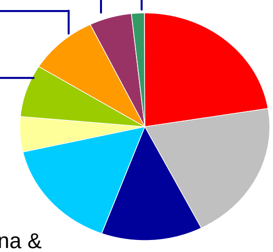
[1] yield percentage based on AEP closing price of $33.97 on 03/03/2010

Highly Diversified Regulated Utility Platform

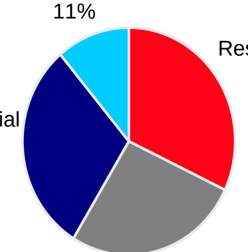


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

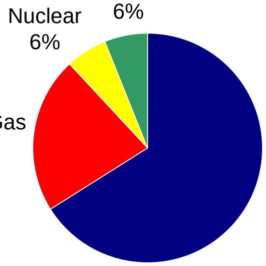


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix**



** Based on Capacity

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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

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JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 765 kV
- Partners: Westar (50%) & Electric Transmission America (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & Electric Transmission America (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

ETT — COD: 2010-2017
- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

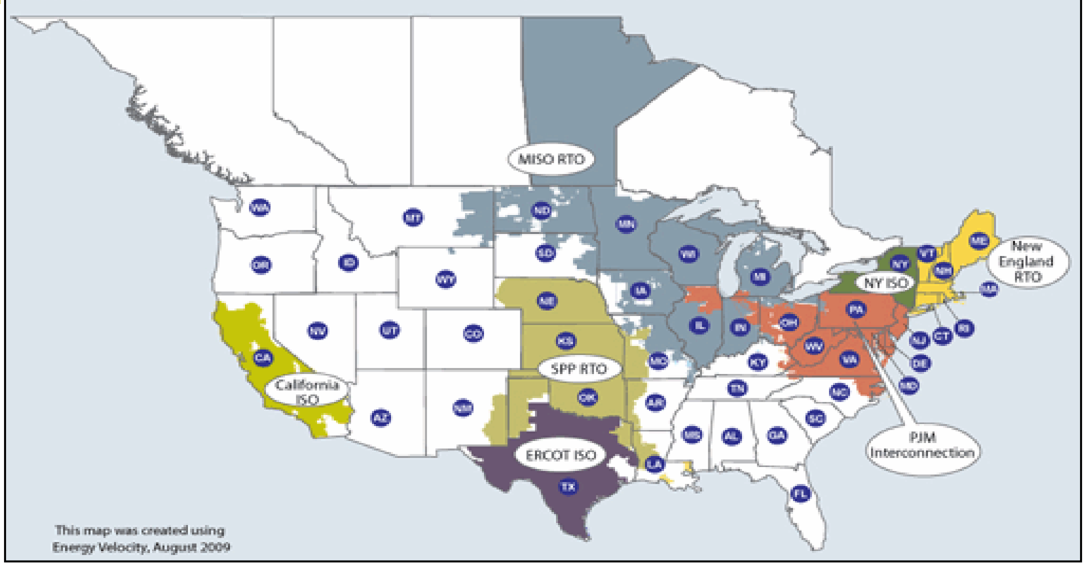
PJM

PATH-WV — COD: 2014
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

REGIONAL TRANSMISSION ORGANIZATIONS



FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay
- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various
- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM

PJM Expansion
- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio
- 700 miles of Proposed 765 kV

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A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- Existing Plant Efficiency Gains
- Renewable Energy
  - 1400 MW wind
  - 300+ MW hydro
- Domestic Offsets
  - Over 63MM trees planted = 1.2MM tons of CO_2 uptake
- International Offsets
  - 1MM tons of forest carbon sequestered through 2009
- Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
– **2003-2010: 50 MMT+ Total**

New Additions (by 2012)

- 2000 MW Wind PPAs
- Domestic Offsets
  - Methane, Forestry
- Fleet Vehicle/Aviation Offsets
- Energy Efficiency & DSM
- Biomass Co-firing
- New Technology
  - New Generation: Ultra Super Critical Coal
  - Carbon Capture and Storage (CCS) for existing fleet
    - Chilled Ammonia

AEP's reductions/offsets of CO_2:
– **2011+: 5 MMT/yr**

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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

Captured CO_2 first time on 09/01/09; Injected CO_2 first time on 10/1/2009

Mountaineer Plant (WV)

Chilled Ammonia

20MWe scale

(Alstom)

CO_2 Storage

(Battelle)

2 injection wells & 3 monitoring wells

Captures and Stores
~100,000 metric tons of CO_2 /yr.

Phase 2

Awarded $334MM DOE Funding;
Expected Commercial Operation: 2015

Mountaineer Plant (WV)

Chilled Ammonia

~235MWe scale

(Alstom)

CO_2 Storage

Captures and Stores
1.5 Million metric tons of CO_2/yr,
1.5 miles below the surface

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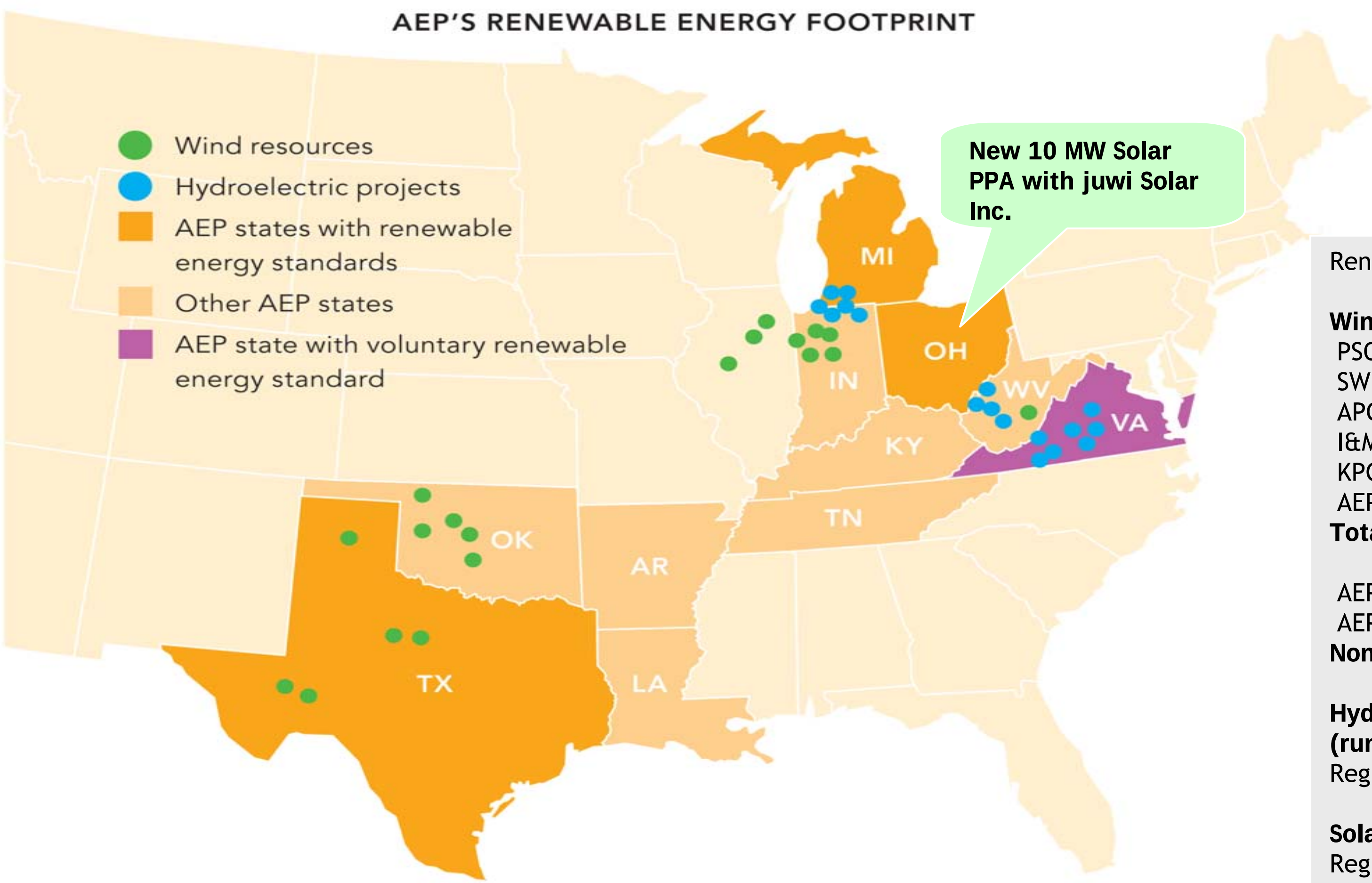
AEP Renewable Footprint



Renewables Portfolio*

Wind		
PSO - 5 PPAs		591MW
SWEPCo - 1 PPA		79MW
APCo - 4 PPAs		376MW
I&M - 2 PPAs		150MW
KPCo - 1 PPA		100MW
AEP Ohio - 2 PPAs		110MW
Total Regulated		**1406MW**
AEPEP -	owned	311MW
AEPEP -	2 PPAs	177MW
Non-regulated		**487 MW**
Hydro (run-of-river)		
Regulated - owned / PPA		**364MW**
Solar		
Regulated - PPA		**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

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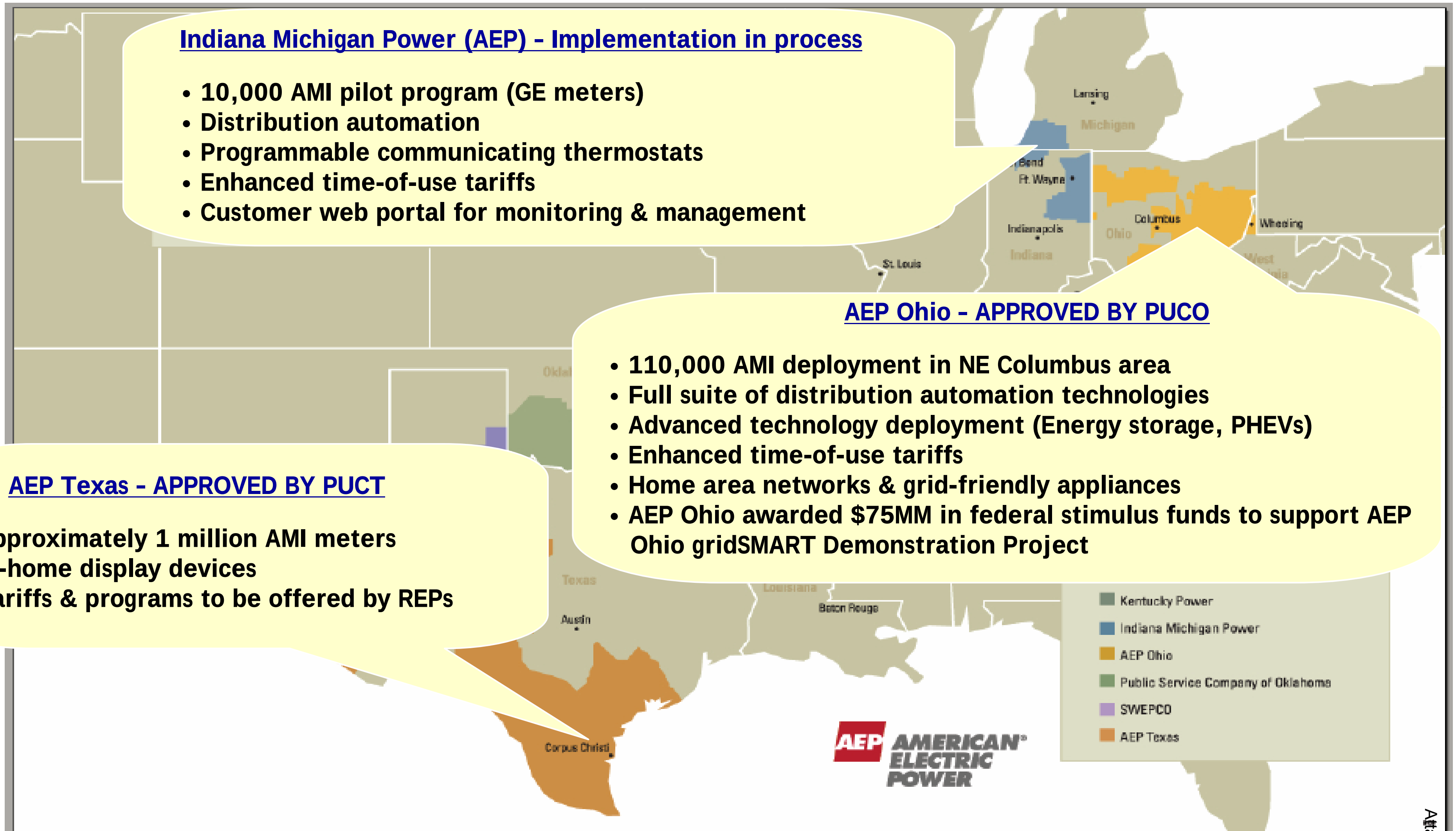
AEP gridSMART Deployment Status



Indiana Michigan Power (AEP) - Implementation in process

- **10,000 AMI pilot program (GE meters)**
- **Distribution automation**
- **Programmable communicating thermostats**
- **Enhanced time-of-use tariffs**
- **Customer web portal for monitoring & management**

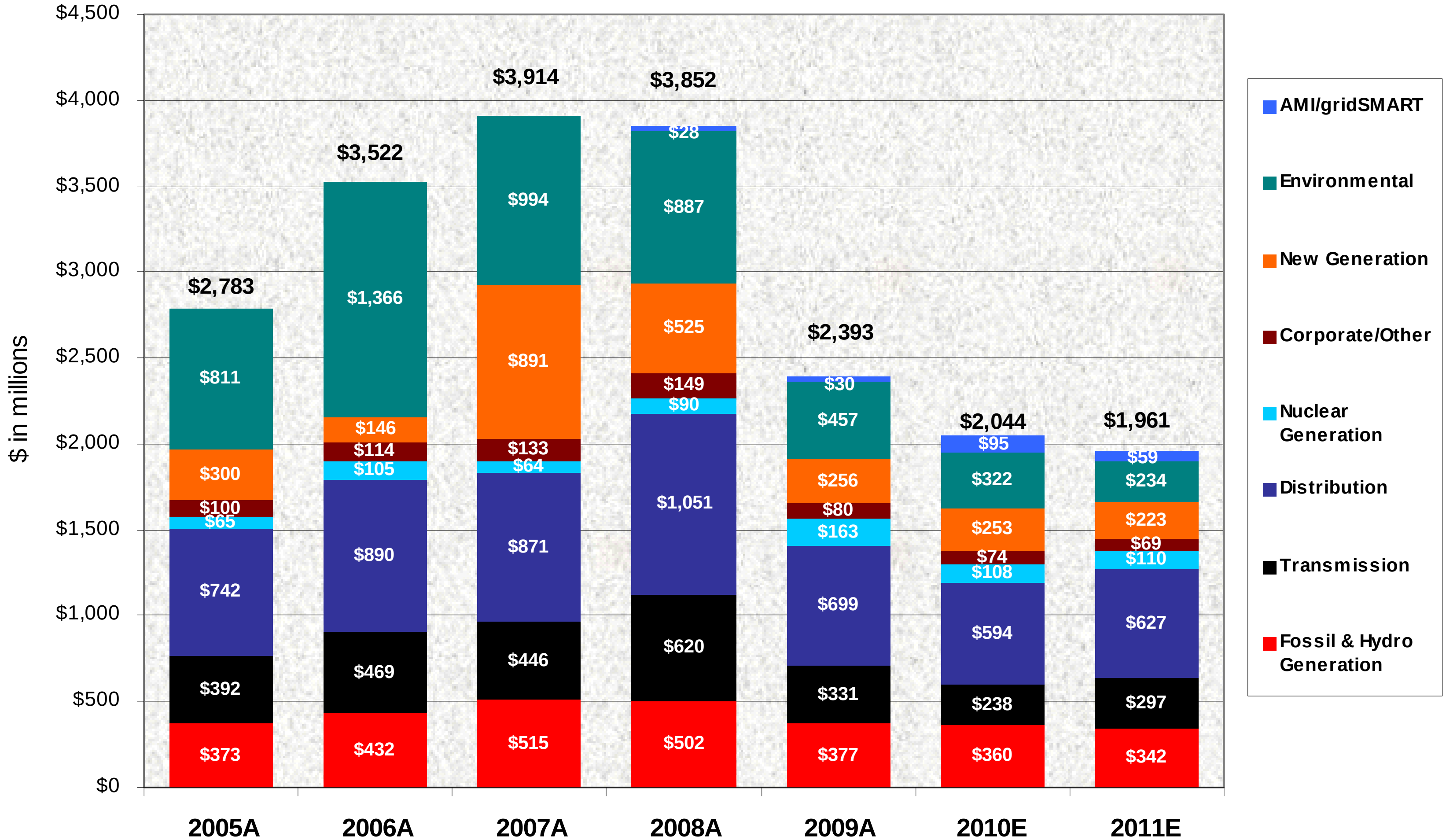
AEP Ohio - APPROVED BY PUCO

- **110,000 AMI deployment in NE Columbus area**
- **Full suite of distribution automation technologies**
- **Advanced technology deployment (Energy storage, PHEVs)**
- **Enhanced time-of-use tariffs**
- **Home area networks & grid-friendly appliances**
- **AEP Ohio awarded $75MM in federal stimulus funds to support AEP Ohio gridSMART Demonstration Project**

AEP Texas - APPROVED BY PUCT

- **Approximately 1 million AMI meters**
- **In-home display devices**
- **Tariffs & programs to be offered by REPs**

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

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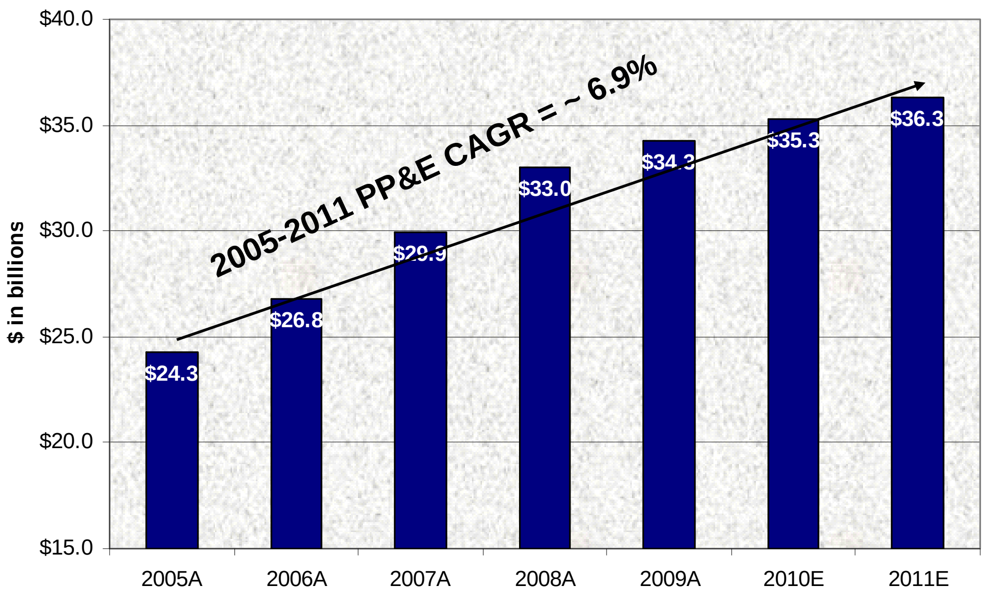
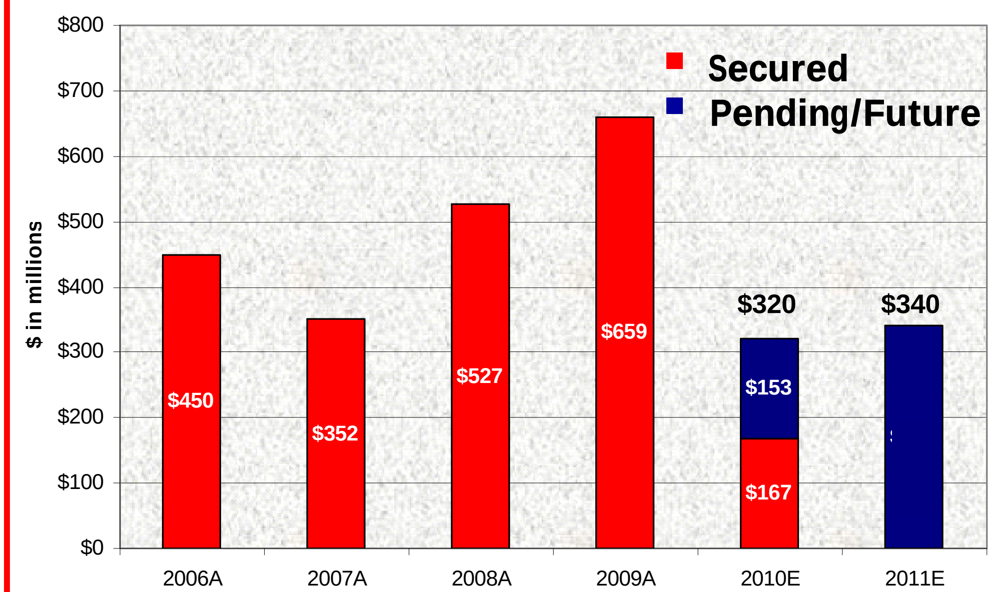
Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Texas, Virginia, West Virginia and others

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

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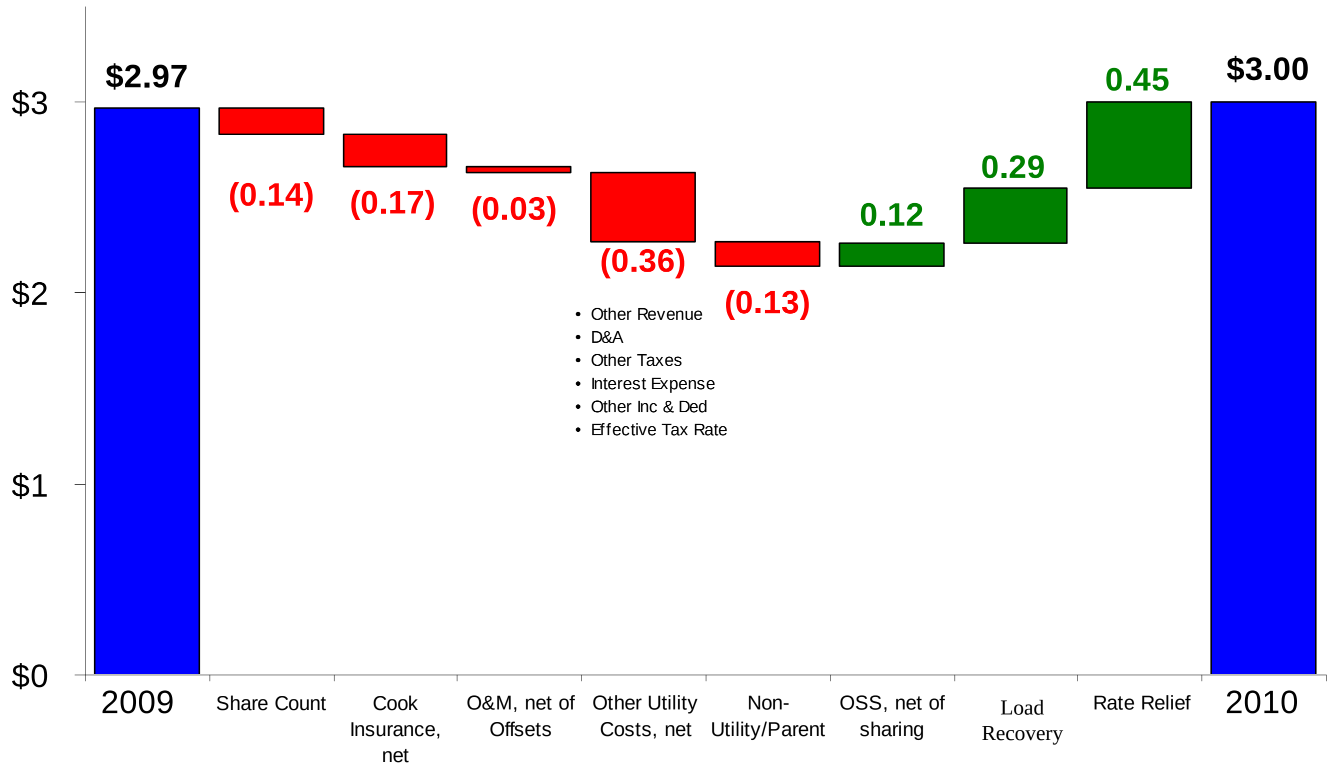
Appendix

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



Detailed Ongoing Earnings Guidance

2009A: $2.97

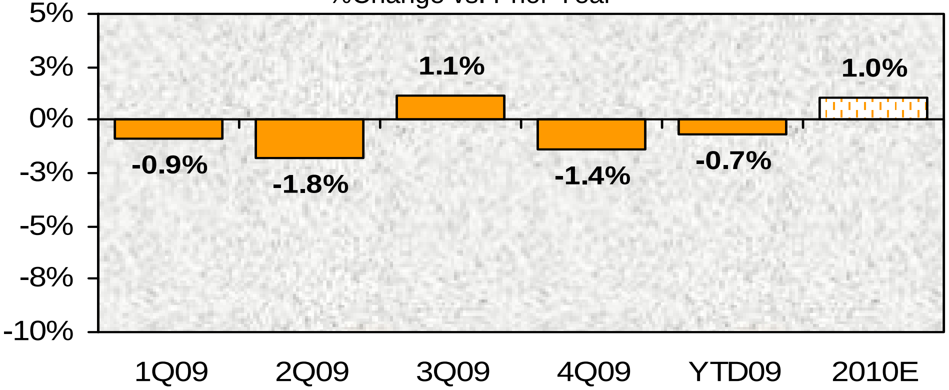
2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

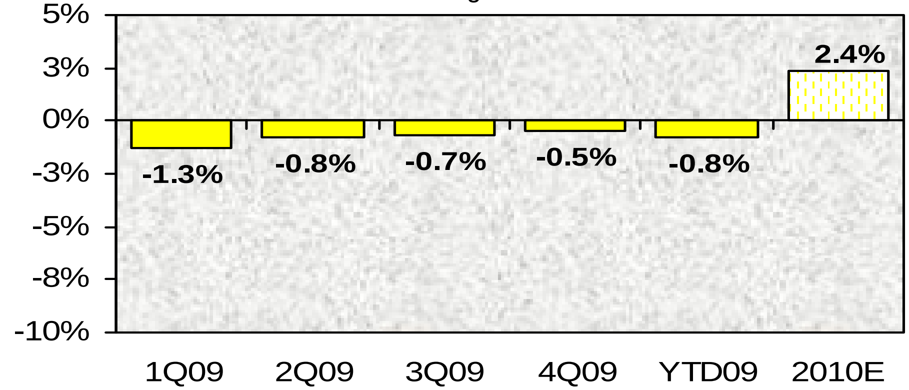
		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Normalized Load Trends

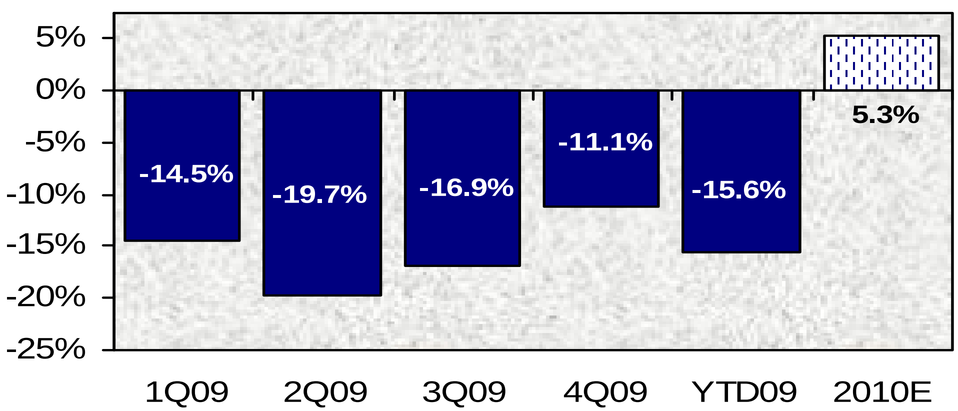
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



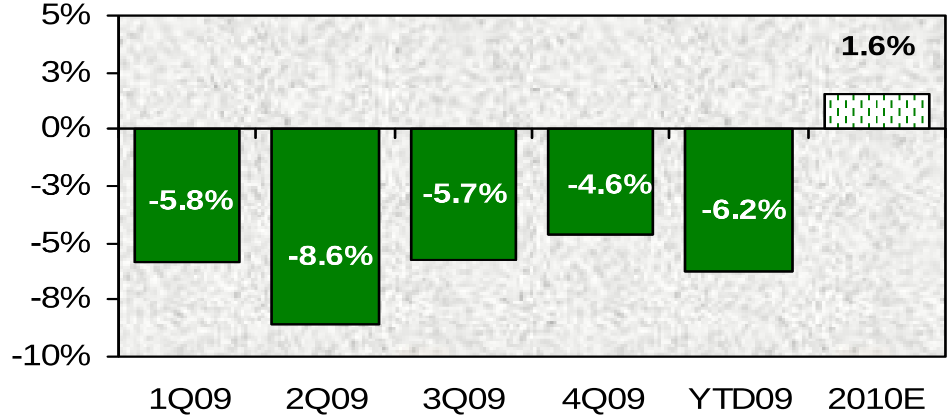
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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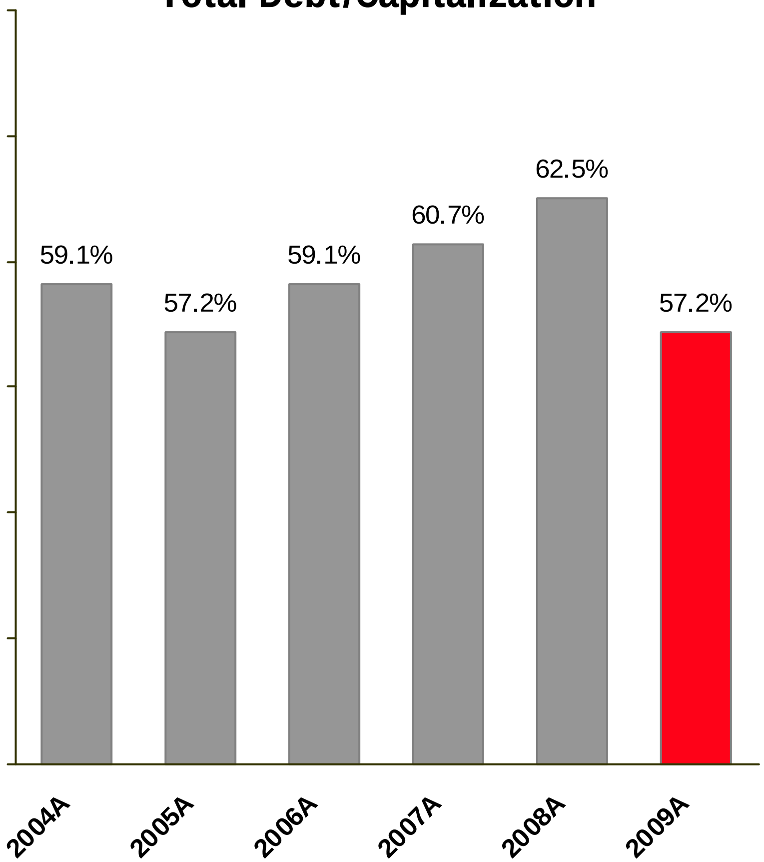
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AEP AMERICAN ELECTRIC POWER®

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ 490	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 45
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 679	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company(1)	$ 66	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,585	$ 623	$ 415

(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$ 2,057.4 *
Rate of Return	9.03%
Operating Income Requirement	$ 185.7
Adjusted Operating Income	$ 92.0
Difference	$ 93.7
Revenue Conversion Factor	1.64
Total Required Rate Relief	$ 154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

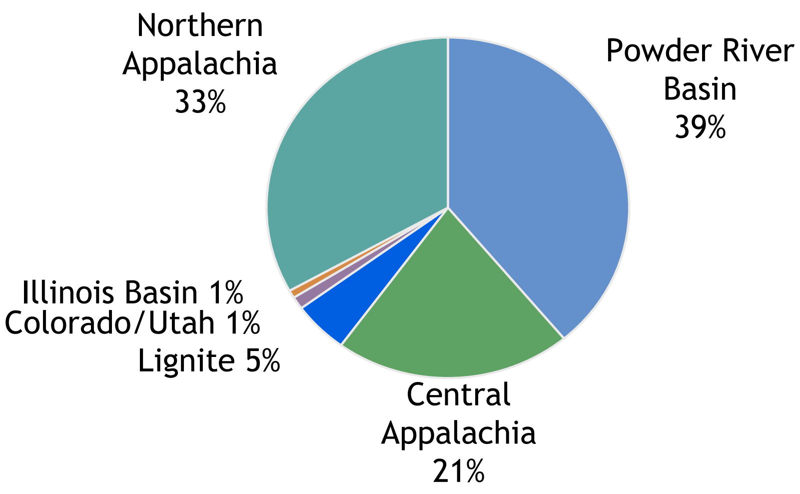
($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

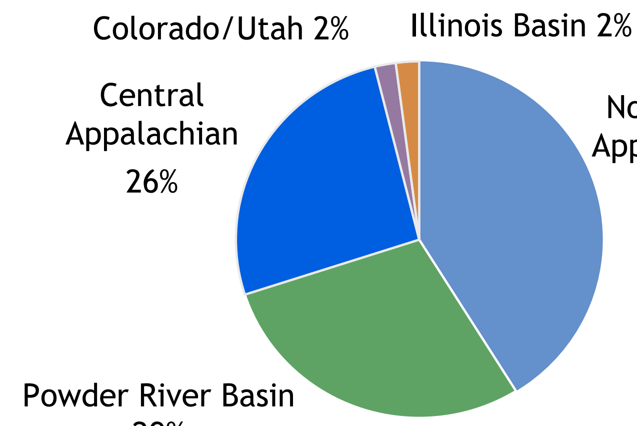
AEP AMERICAN® ELECTRIC POWER

Coal Procurement - 2010 Projected

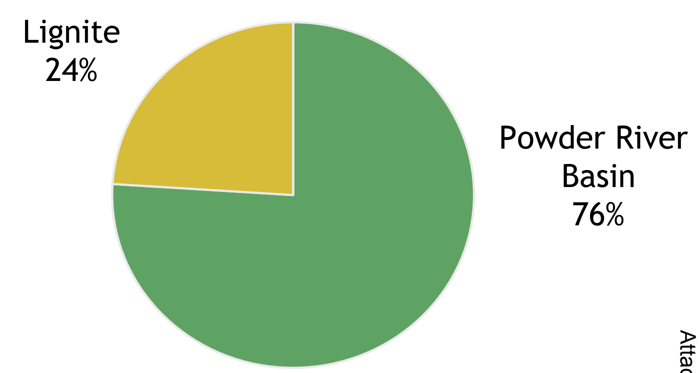
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

American Electric Power

European Investor Road Show

June 24 - 27, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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EVP & Chief Financial Officer

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5493 of 9556

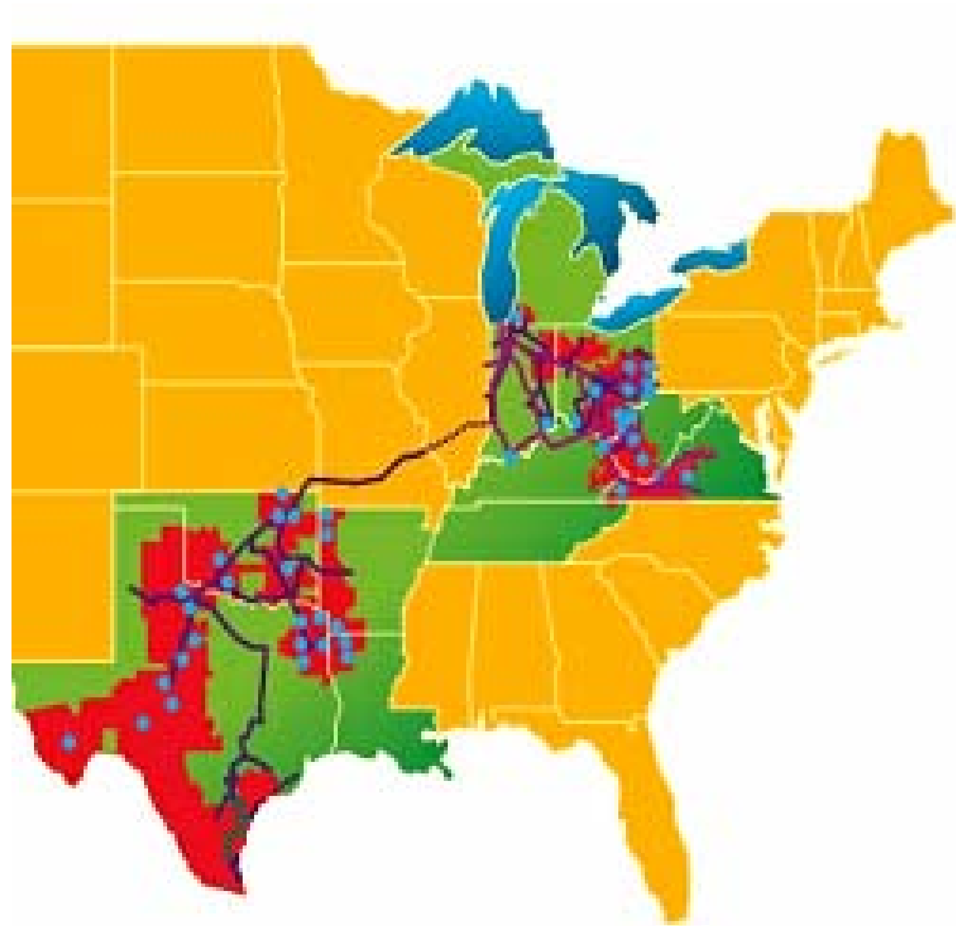
Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- 2007 financial statistics:
  - GAAP Net Income: $1.1B
    - 87% Regulated/13% Nonregulated
  - Assets: $40.3B
  - Adjusted Equity Ratio: 41.5%
- Current dividend - $1.64 per share annualized



AEP enjoys significant presence throughout the energy value chain.

AEP®

AEP Strategy

Strategy: grow our core utility business at a consistent 5-9% long-term rate through major regulated investment using disciplined capital allocation methods.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest $3.8 billion in our infrastructure
- Enhance cash flow & earnings through rate recovery mechanisms

Disciplined capital investment opportunities support earnings growth.

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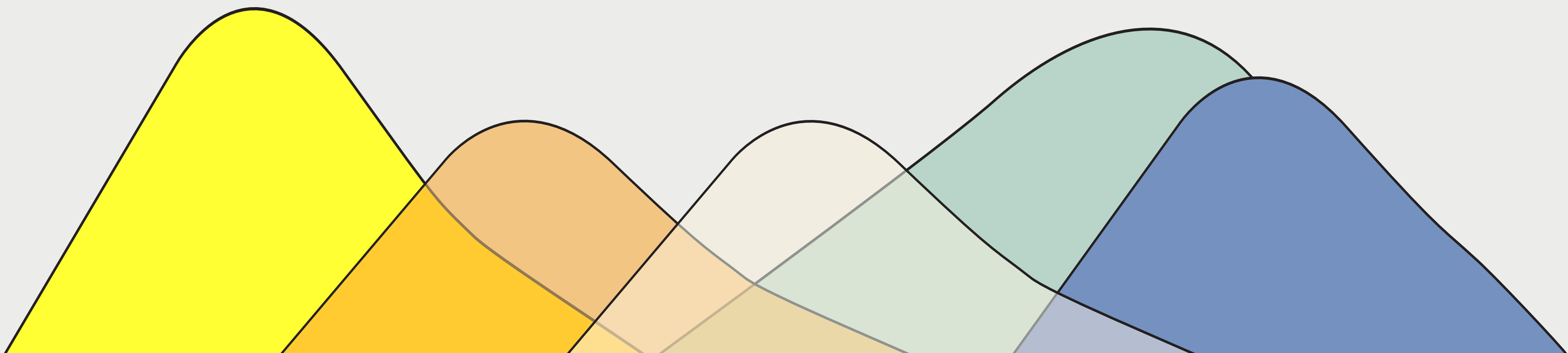
Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$2.8B	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.0B-$3.0B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 16. * The transmission opportunity is shown utilizing anticipated JV ownership structure.

Assuming timely regulatory recovery, baseline capital investment of $2.0B to $3.0B adds $0.09 to $0.20 annually to EPS based on a 10.5% target ROE and a 60/40 debt to capital structure

Disciplined capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

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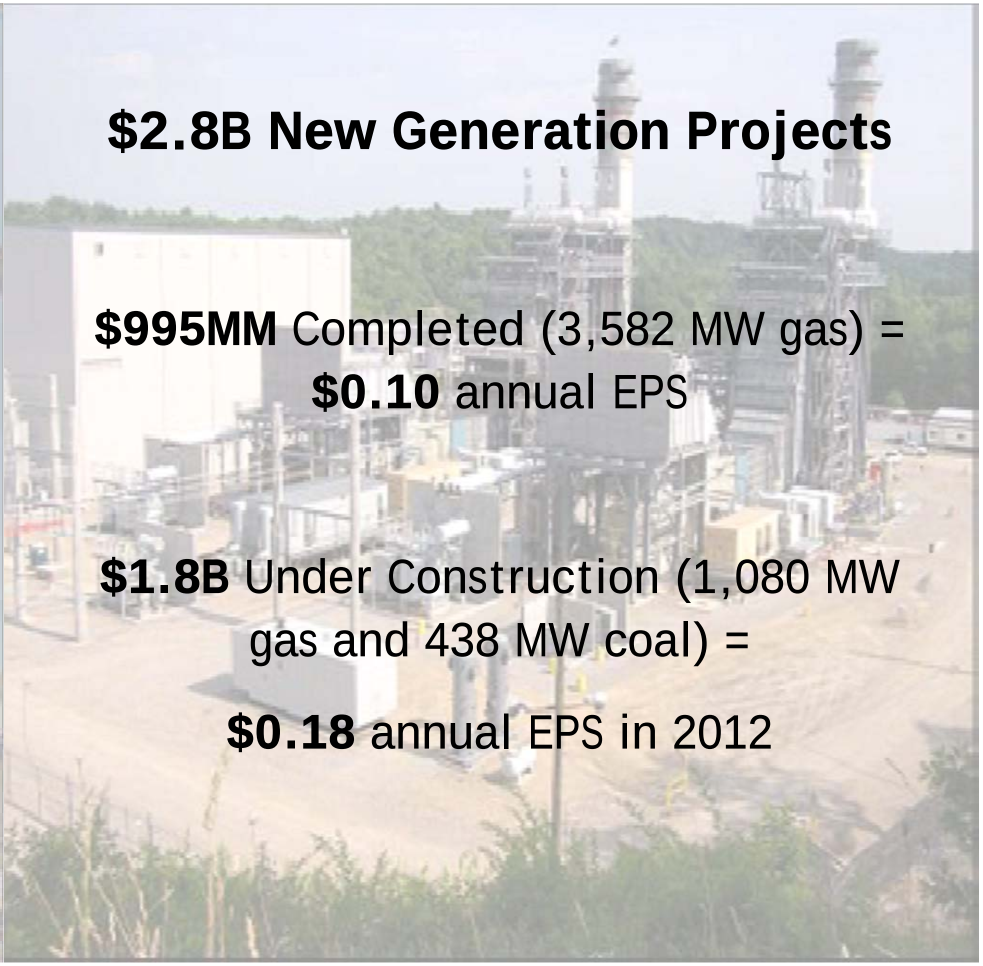
Environmental Retrofits & New Generation Projects

$5.4B Environmental Retrofits

$3.5B Completed = **$0.37** annual EPS

$1.9B Under Construction =

$0.20 annual EPS in 2011



$2.8B New Generation Projects

$995MM Completed (3,582 MW gas) = **$0.10** annual EPS

$1.8B Under Construction (1,080 MW gas and 438 MW coal) =

$0.18 annual EPS in 2012

Note: EPS calculations assume timely regulatory recovery with a 10.5% ROE and a 60/40 debt to capital ratio

2008-2010 Projected Capital Expenditures

	2008	2009	2010
Environmental	$875MM	$606MM	$394MM
New Generation - gas	$362MM	$126MM	$37MM
New Generation – coal *	$210MM	$244MM	$174MM

* $22MM relates to IGCC; the remaining capital is attributable to the ultra-supercritical Turk plant

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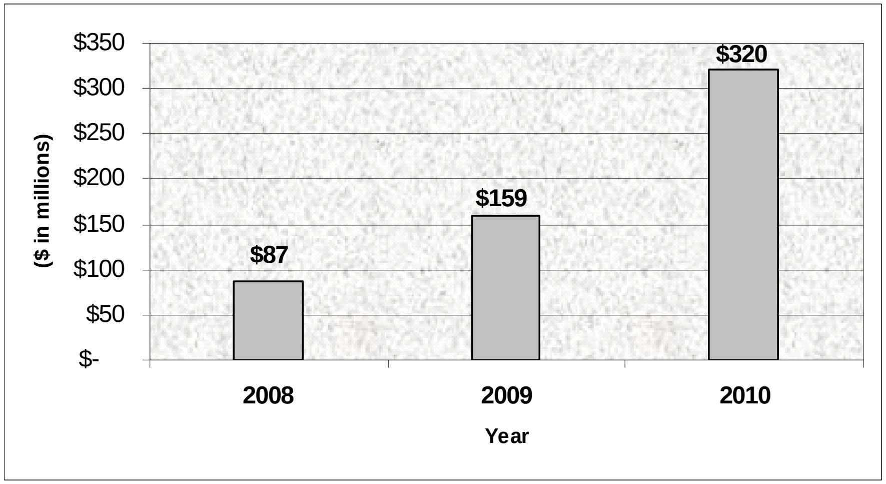
Transmission – Investments and Earnings Contributions

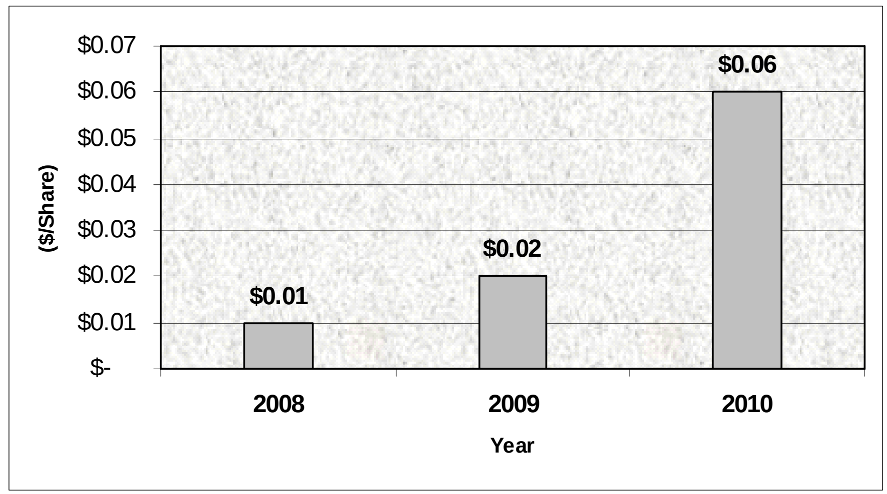
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PATH Potomac-Appalachian Transmission Highline

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Transmission will provide a near and long term catalyst for growth.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* Baseline capital investment averages $2.5B over the three year period 2008-2010.

Capital investment is funded from cash from operations and debt issuances.

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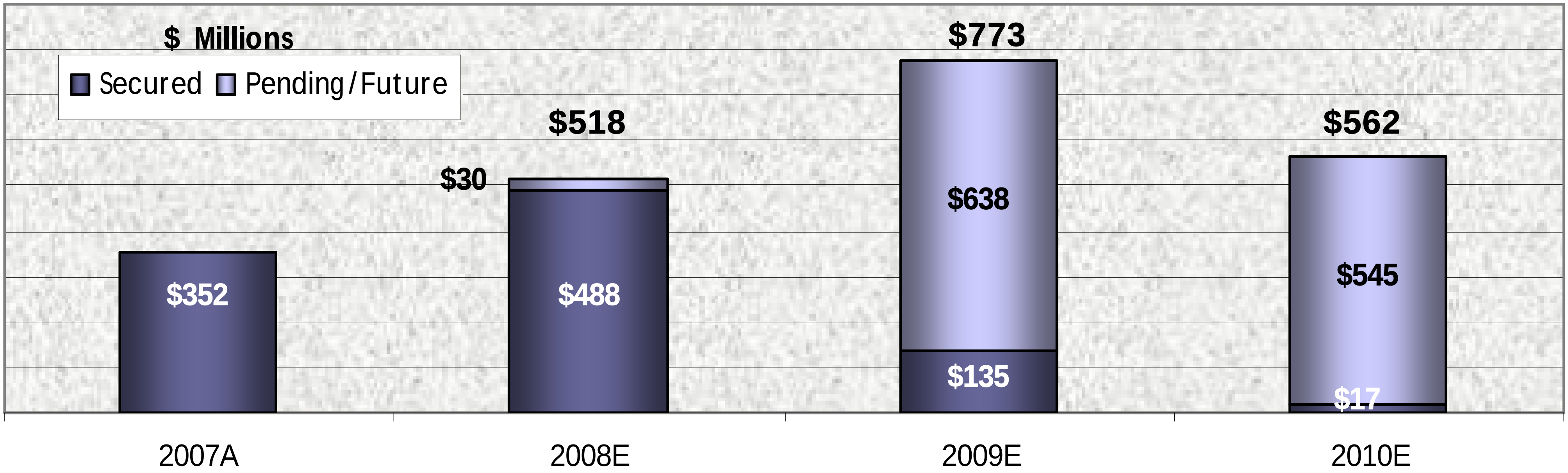
Incremental Rate Relief



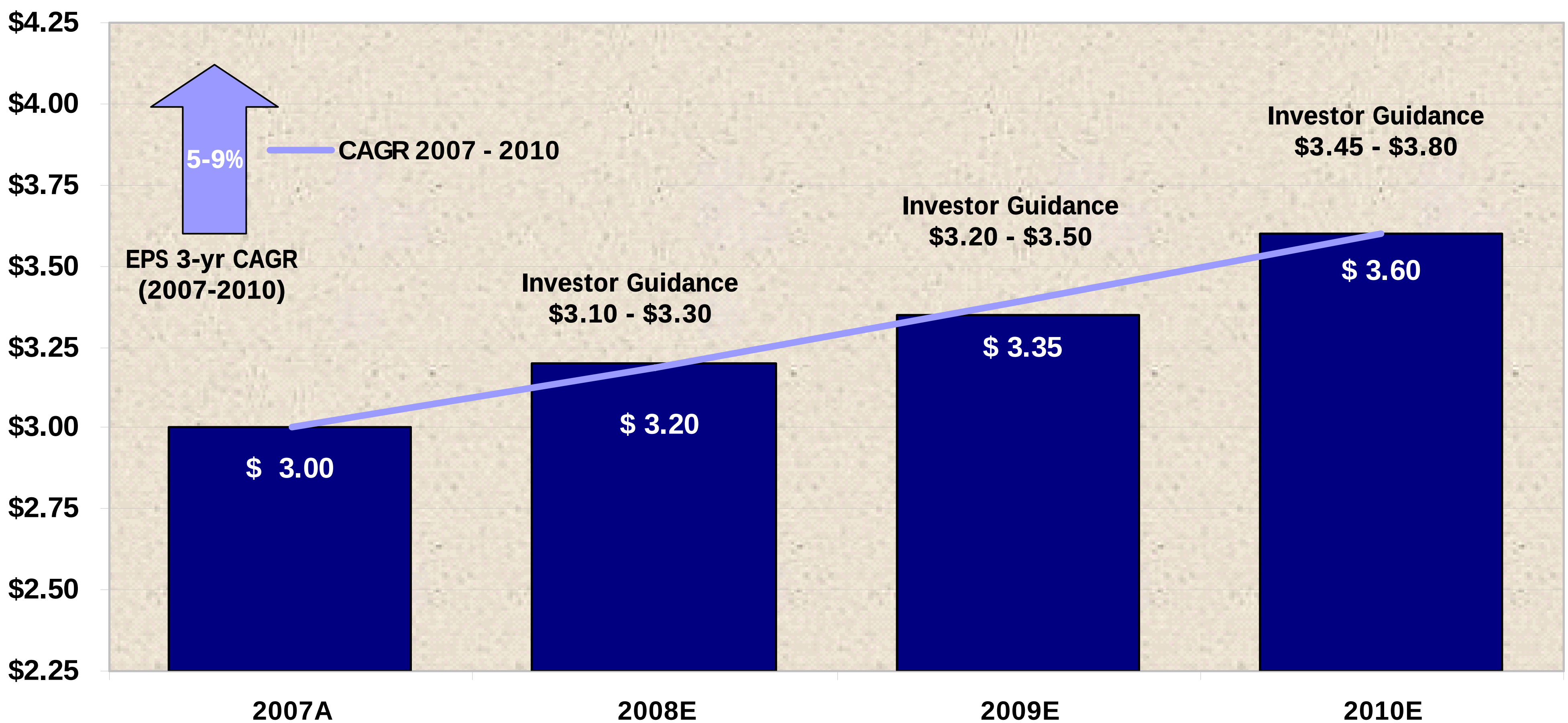
- 94% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery.

- 2008 Pending: 2008 TCC/TNC TCRF filings, Virginia base case rates subject to refund ($208MM requested), other cases yet to be filed.

- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case, Ohio ESP, other cases yet to be filed.

Secured $488MM of $518MM for 2008

4-Year Earnings Range Forecast



Utility Operations	$2.72
Non-Utility Operations	$0.24
Parent & Other	$0.04
Total EPS	$3.00

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5% to 9% earnings growth

2008 EPS Performance Sensitivities

Driver	Change	Effect
Load Growth (MWh)	1%	+/- $0.10 EPS
Utility O&M	1%	+/- $0.05 EPS
Capital Spending	$250M	+/- $0.03 EPS
Interest Rate (20% floating debt)	100 BPs	+/- $0.05 EPS
Unit Availability *	1%	+/- $0.04 EPS
ECAR Power Price *	$1/MWh	+/- $0.04 EPS
Fuel and Purchased Power *	1%	+/- $0.03 EPS
Henry Hub Gas Price *	5%	+/- $0.07 EPS
Authorized ROE	**1%**	**+/- $0.24 EPS**

* This driver's effect on EPS could change in 2009 and beyond based upon the reestablishment of a fuel clause and pending regulatory activity regarding post-2008 in Ohio

Longer term performance can be substantially enhanced by achieving a higher authorized return.

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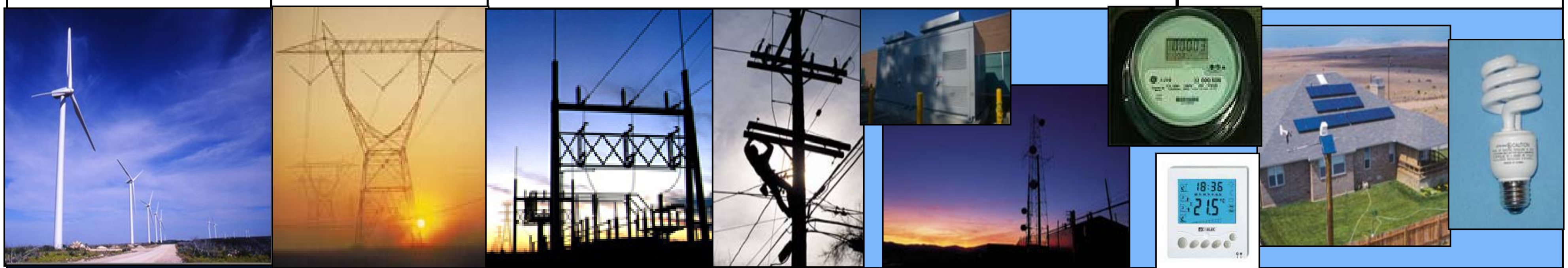
Vision for Sustainability



Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

Existing generation and transmission control systems	**gridSMART℠**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP®

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Appendix

Detailed Ongoing Earnings Guidance

2007A: $3.00

American Electric Power
2007 Actual vs 2008 Guidance

2008E: $3.10 - $3.30

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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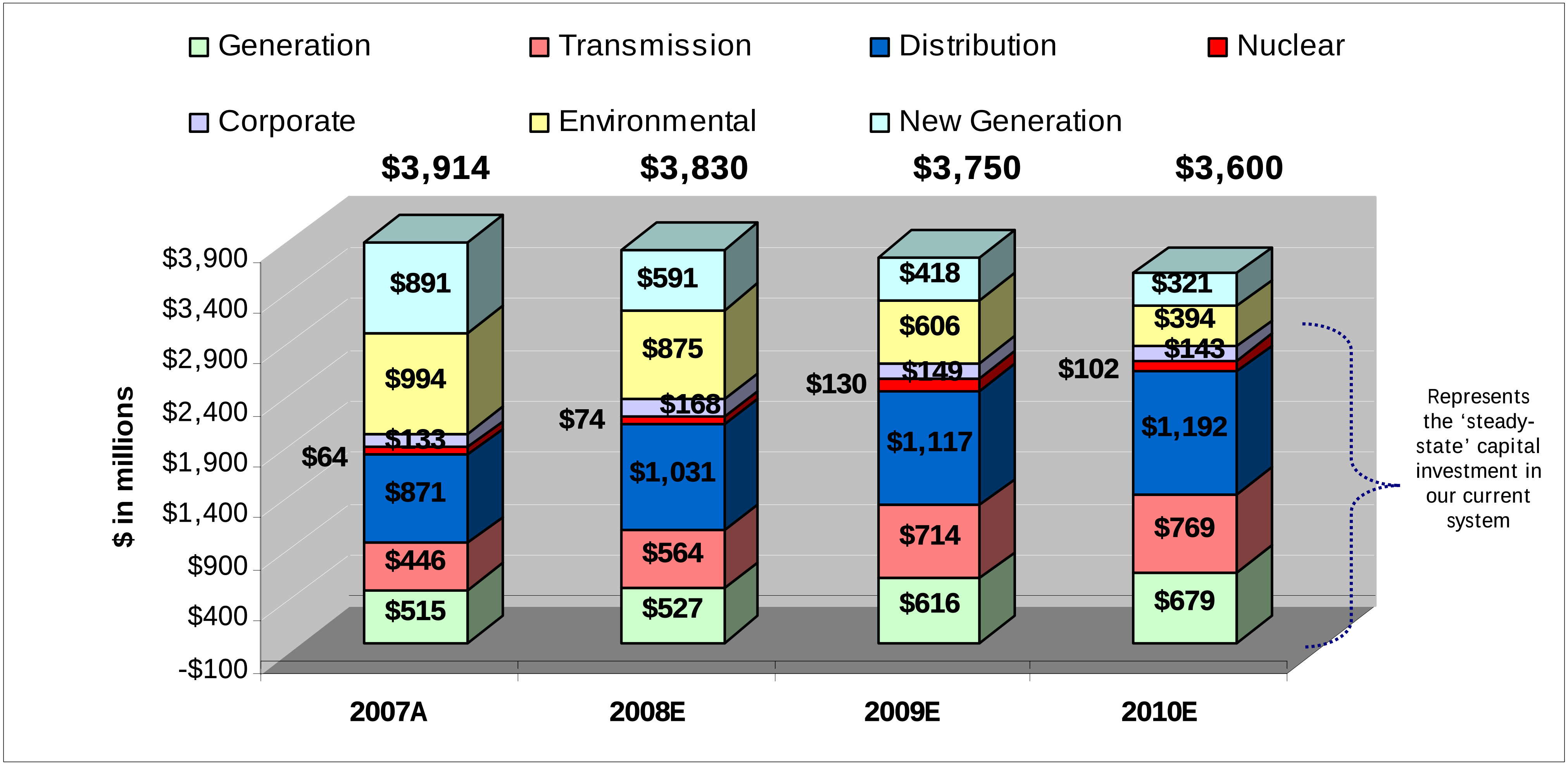
4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

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Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

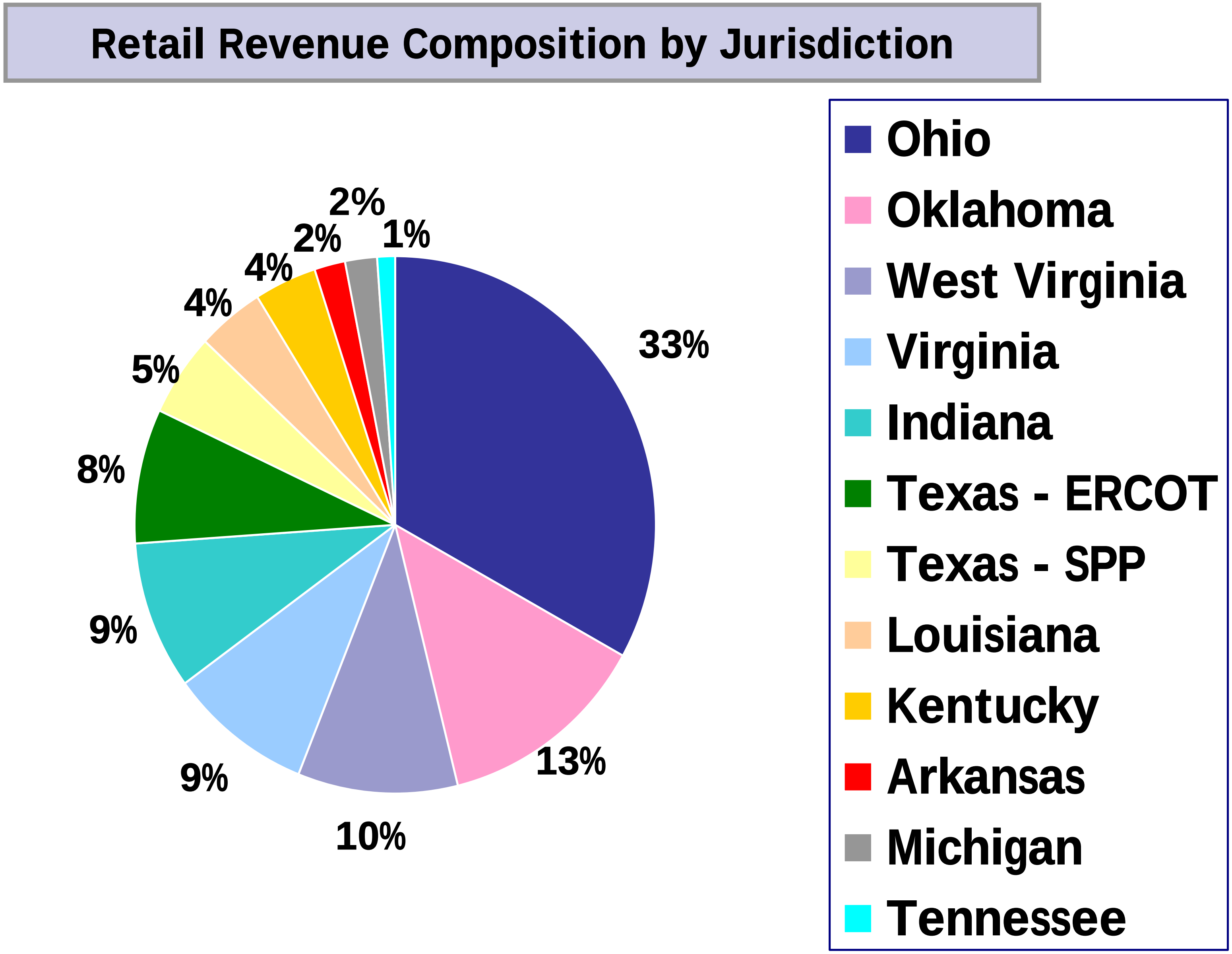
($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

AEP®

Capital Investment + Rate Relief = Earnings Growth

2007 Retail Revenue

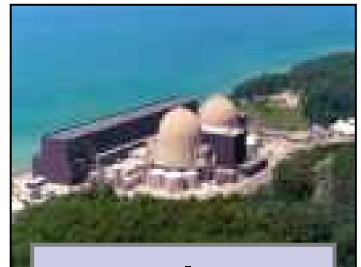


Jurisdictional diversity allows us to successfully manage regulatory risk.

Domestic Generation Fleet

Nat. Gas/Oil

23%

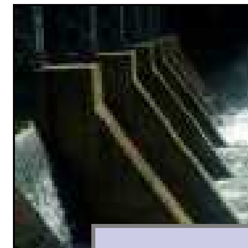


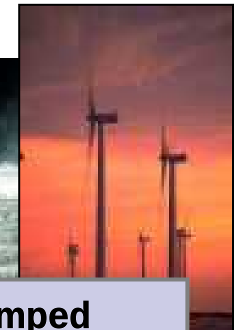
Nuclear

6%

Coal/Lignite

68%





Pumped Storage/ Hydro/Wind

3%

AEP's Generation Fleet

37,736 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

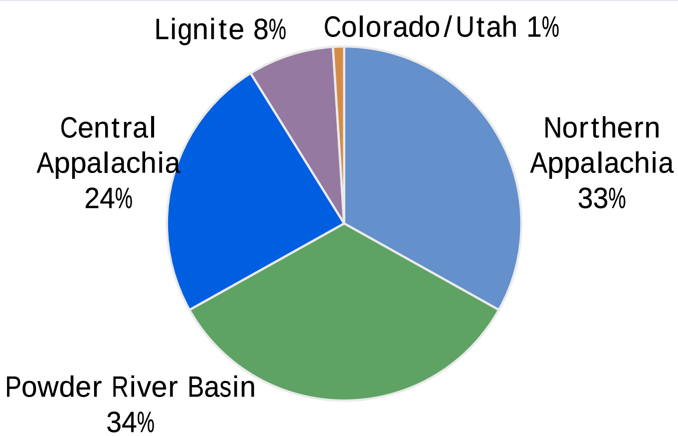
RFC	72%
SPP	23%
ERCOT	5%

AEP®

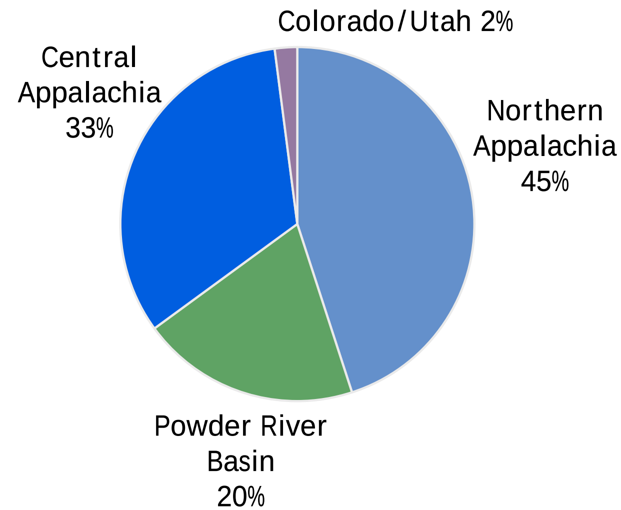
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

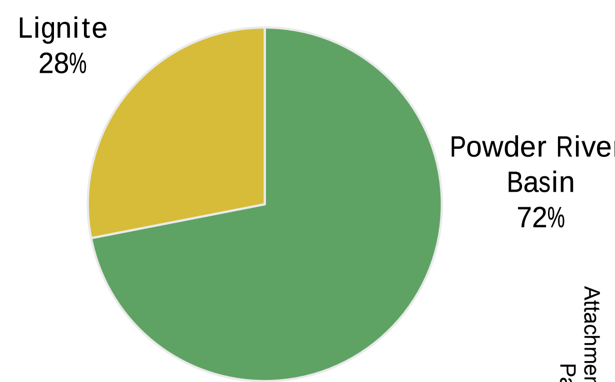
Total AEP System



AEP East



AEP West



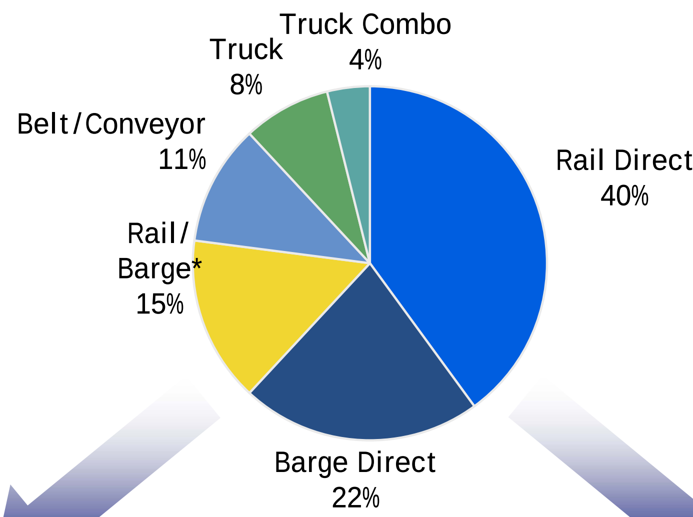
Coal Stats:

- Approximately 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 14%-18% price increase in 2008 based on 2007 actual results.

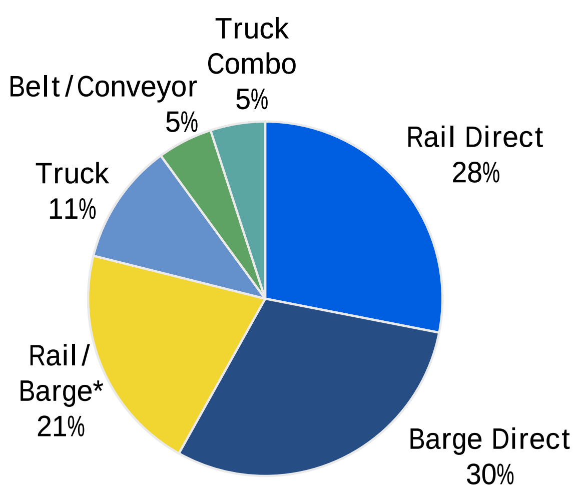
Coal Delivery

2007 Actual

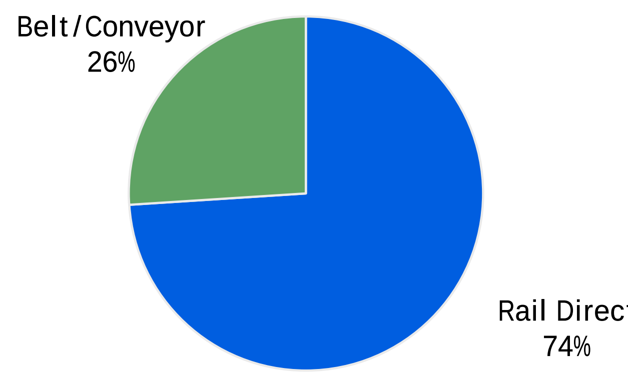
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade

USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100°F) coal plant in U.S. (Arkansas)

gridSMART℠

- gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

AEP®

I-765™ Transmission: Investment Opportunities

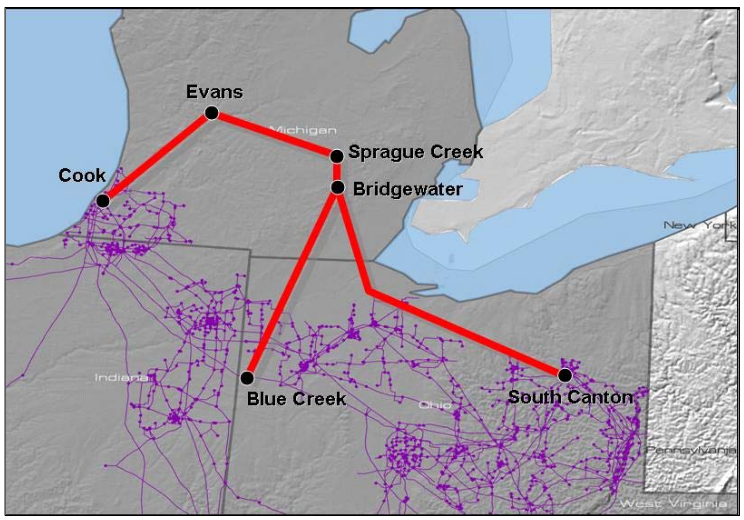
AEP is Advancing the Development of a National Interstate Today

Potomac-Appalachian Transmission Highline

PATH Project (PJM)

Electric Transmission Texas

ETT (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

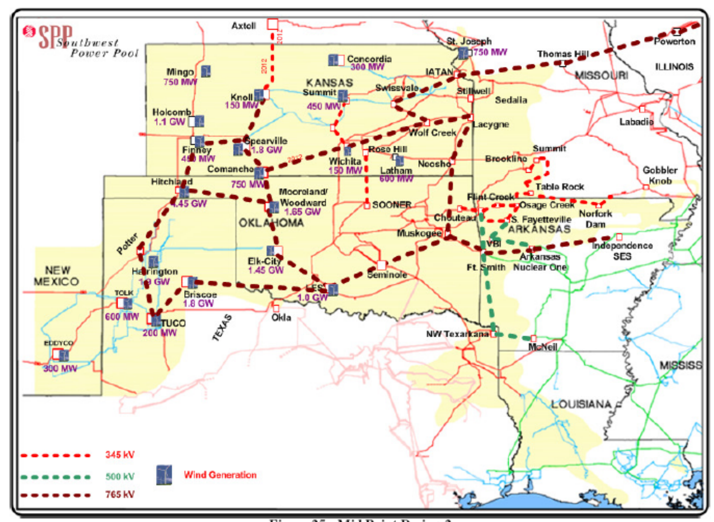


Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

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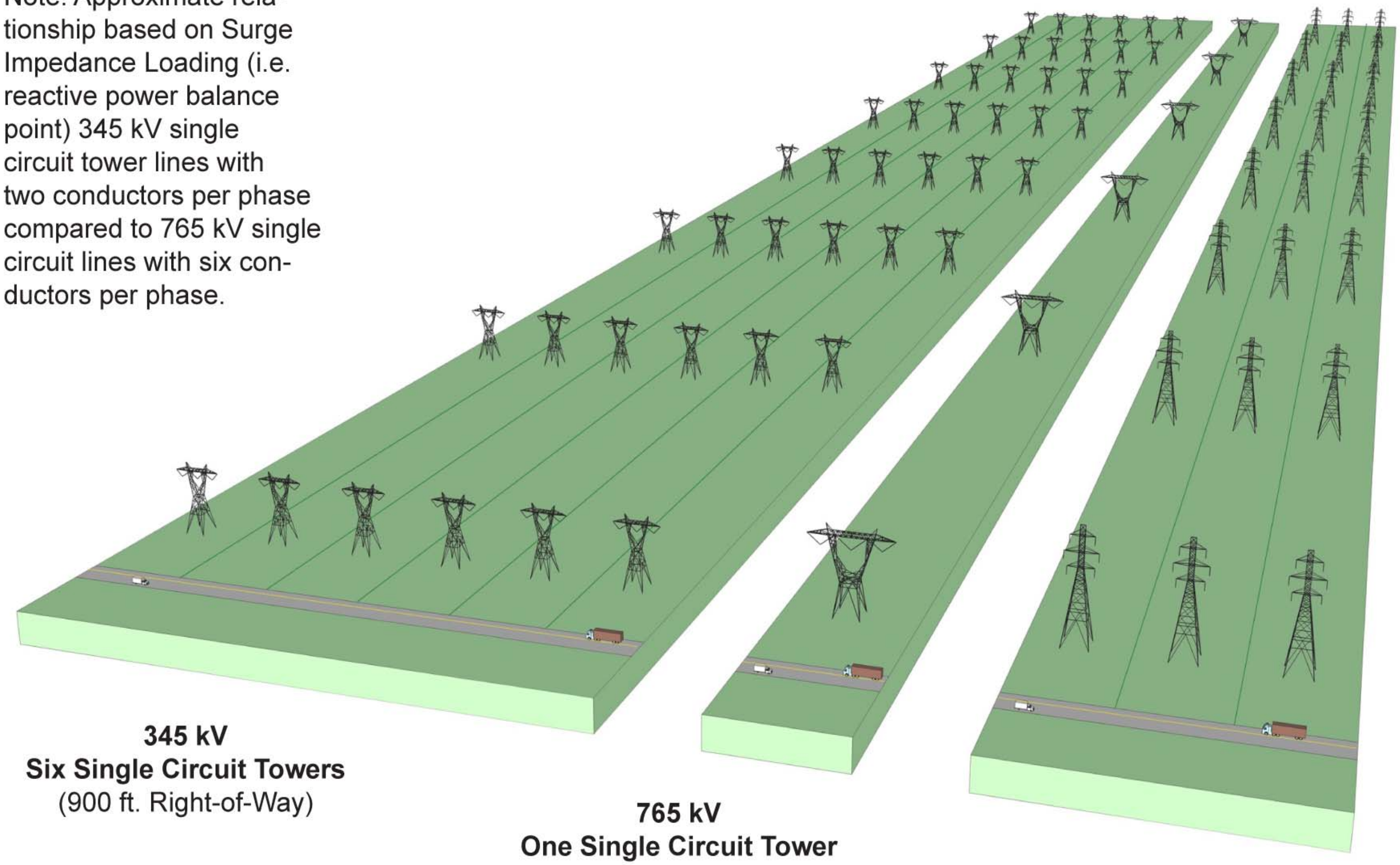
765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

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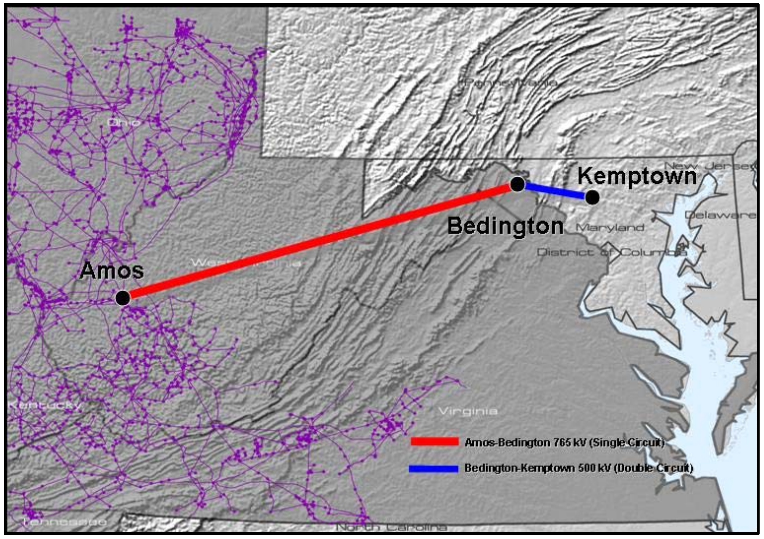
From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012

PATH
Potomac-Appalachian Transmission Highline

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Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed an agreement with Westar Energy forming Prairie Wind Transmission, LLC proposing to build the first segment of the 765-kV Overlay Plan in SPP

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I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

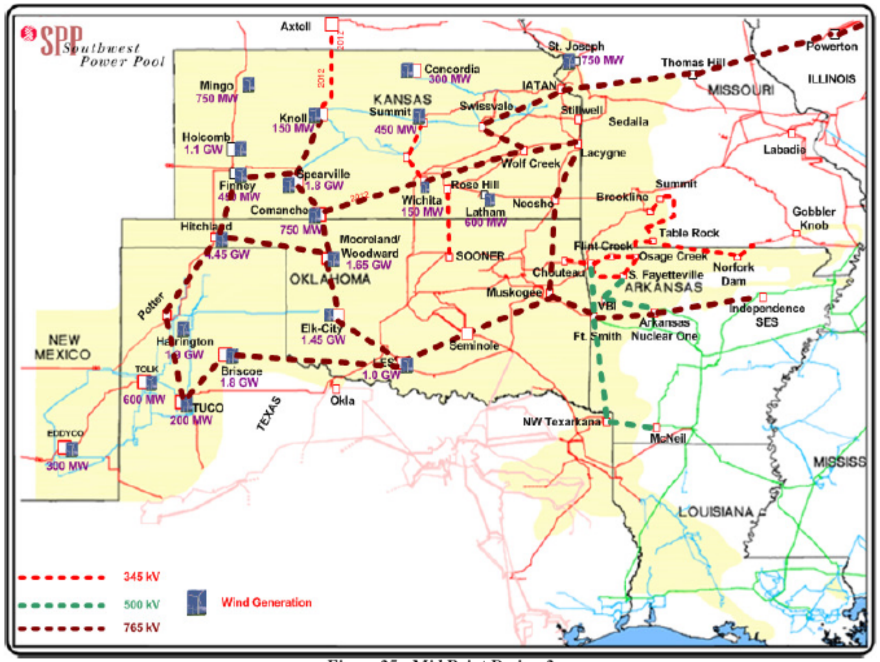


Figure 25: Mid Point Design 2

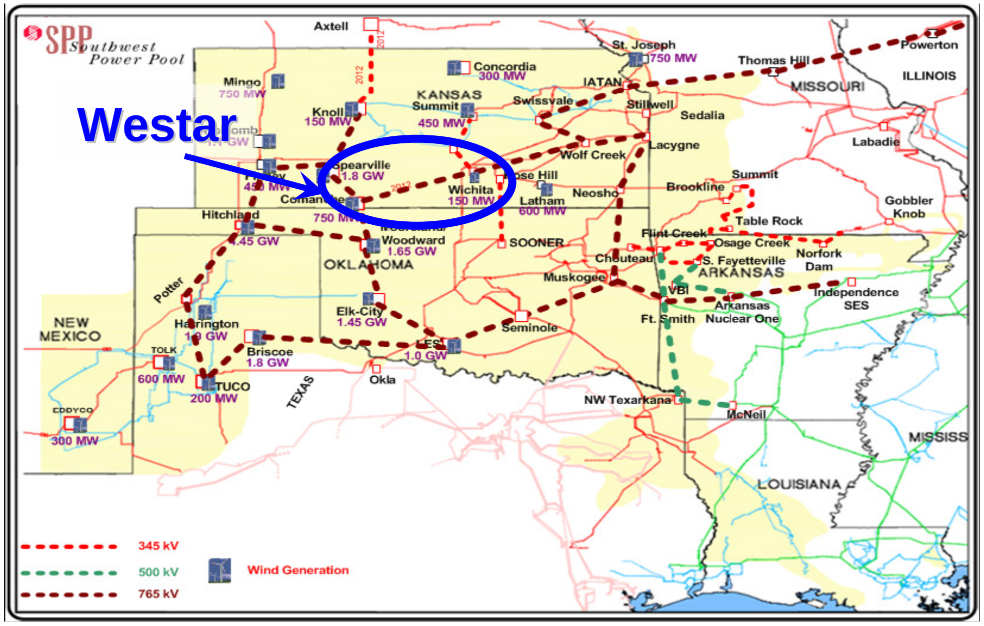
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



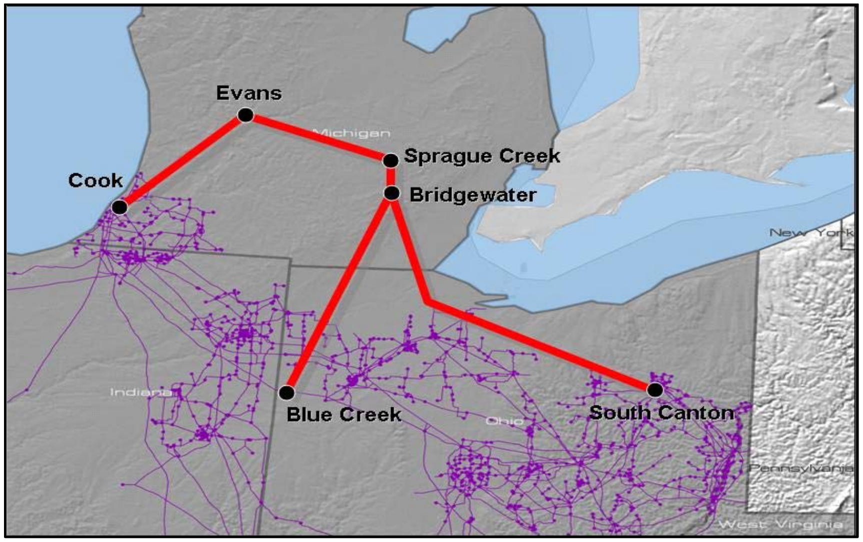
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP®

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

AEP's Long-Term GHG Reduction Portfolio

Renewables (Wind Purchases)

Supply and Demand Side Efficiency – gridSMART[SM]

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP®

AEP is investing in a portfolio of GHG reduction alternatives.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions			
	2008	**2009**	**2010**
Mountaineer Chilled Ammonia Project	**$30**	**$39**	**$0**

Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

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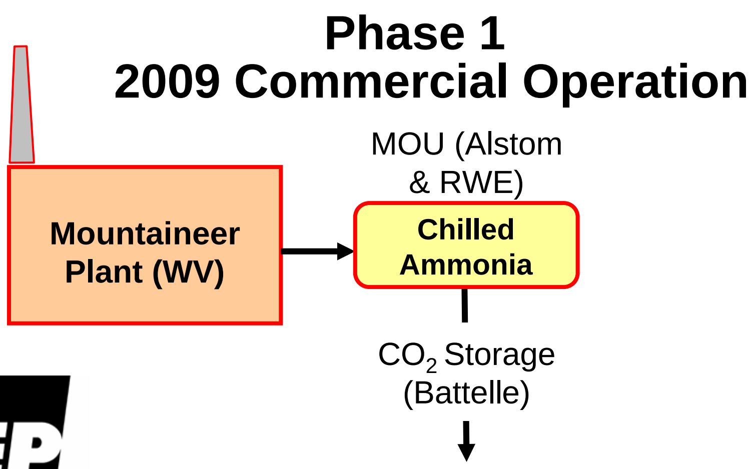
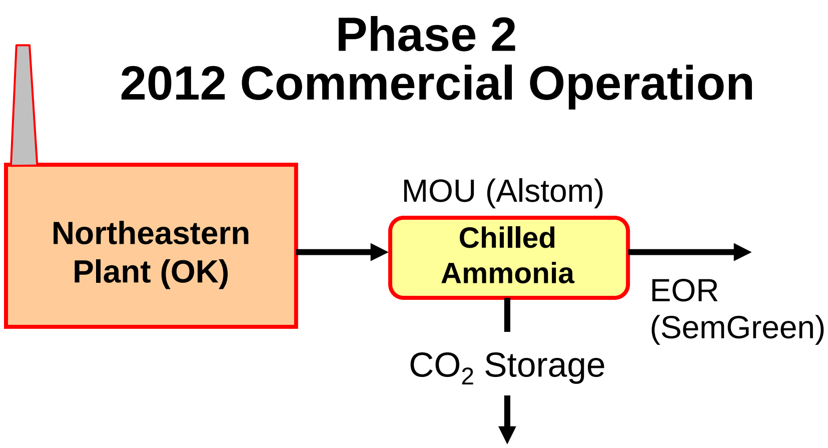
AEP's Carbon Capture & Storage Initiative

- In March 2007, AEP announced a major new carbon capture and storage initiative:
- Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.
  - The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.
  - The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.





CO_2 Capture Techniques

- **Post-Combustion Capture**
  - Conventional or Advanced Amines, Chilled Ammonia
    - Amine technologies commercially available in other industrial applications
    - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
    - High parasitic demand
      - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
    - Amines require **<u>very</u>** clean flue gas

- **Modified-Combustion Capture**
  - Oxy-Coal
    - Technology not yet proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - High parasitic demand, >25%

- **Pre-Combustion Capture**
  - IGCC with Water-Gas Shift
    - Most of the processes commercially available in other industrial applications have never been integrated together
    - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

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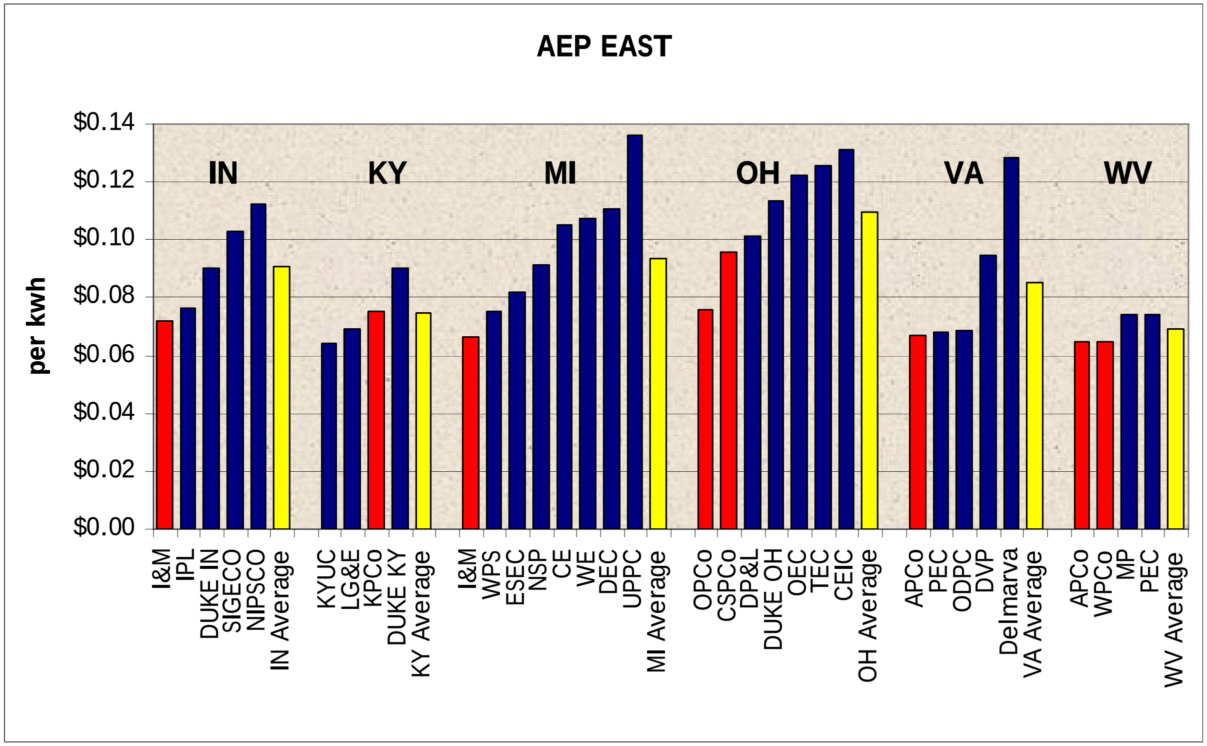
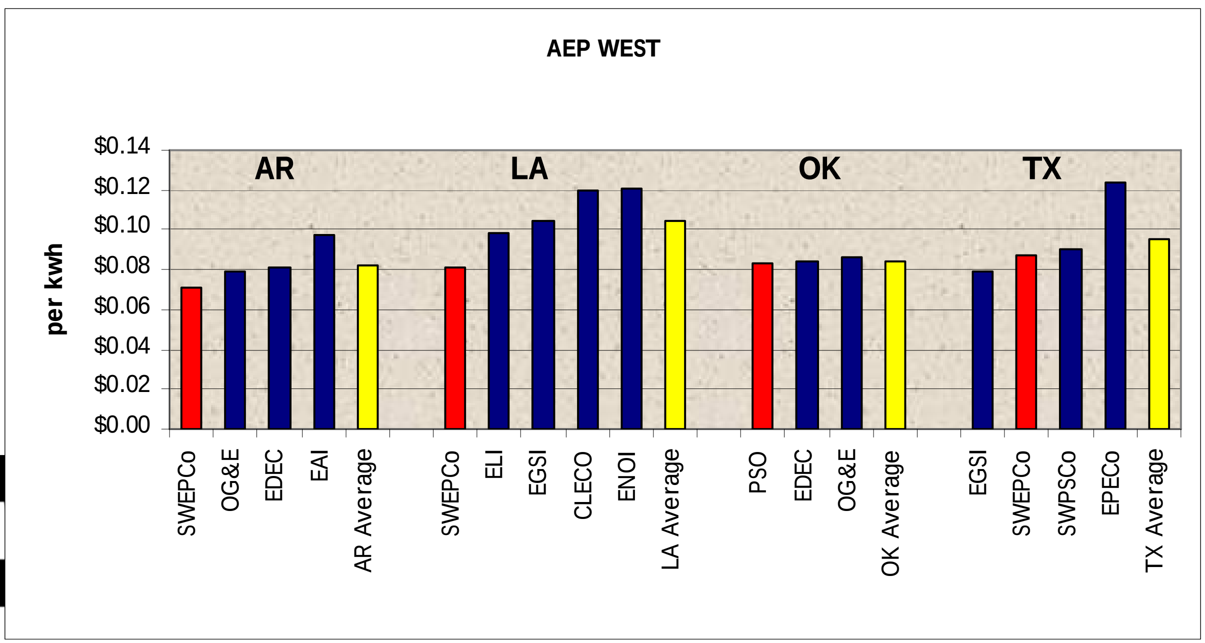
AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

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Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- APCo - Virginia Base Rate Case
- PSO - Base Rate Case to be filed mid-summer
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

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Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony		08/01/08										
Rebuttal Testimony			09/15/08									
Hearing				10/21/08								
Expected Order						Expected Order						
Louisiana - Stall Plant	Expected Order											
Ohio - ESP Filing	07/31/08					Order						
Oklahoma - Base Rate Case												
Company Testimony	Jul - 08											
Texas – Turk Plant	Expected Order											
Virginia – Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order						Expected Order						
Virginia – E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						

* Subject to refund, with interest

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Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1	*
Rate of Return		8.52%	
Operating Income Requirement	$	205.7	
Adjusted Operating Income	$	79.2	
Difference	$	126.5	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	207.9	

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

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Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony is due August 13, Staff testimony is due August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

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Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on April 29, 2008, and on May 29, 2008 the SCC denied our request to reconsider the previous rejection. We are now reviewing various options.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as resolution of pending rulemaking related to SB221 in Ohio.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners requested another hearing to directly cross examine some of the witnesses. The additional hearing was held May 29, 2008.

AEP®

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

AEP®

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

AEP®

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

AEP®

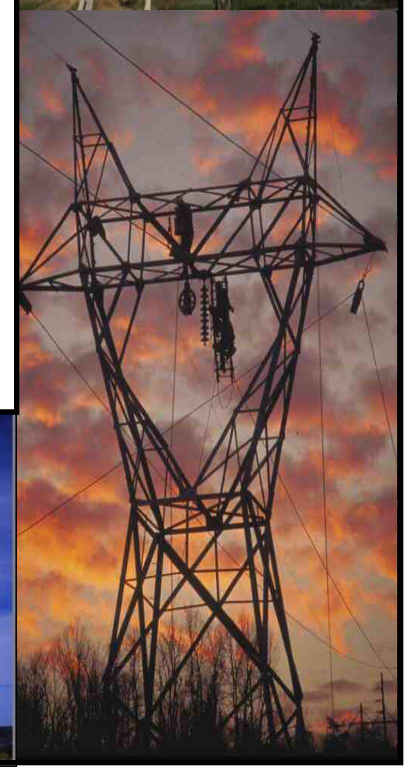
We are committed to maintaining our current credit ratings.

Goldman Sachs

8th Annual Power & Utility Conference

New York

May 13 & 14, 2008



AEP AMERICAN ELECTRIC POWER®

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Table of Contents

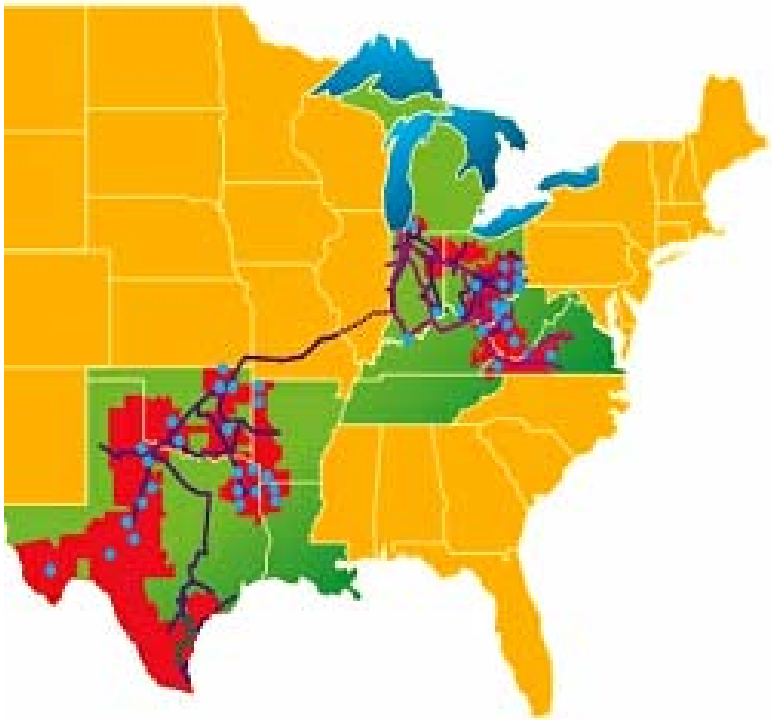
Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research



- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

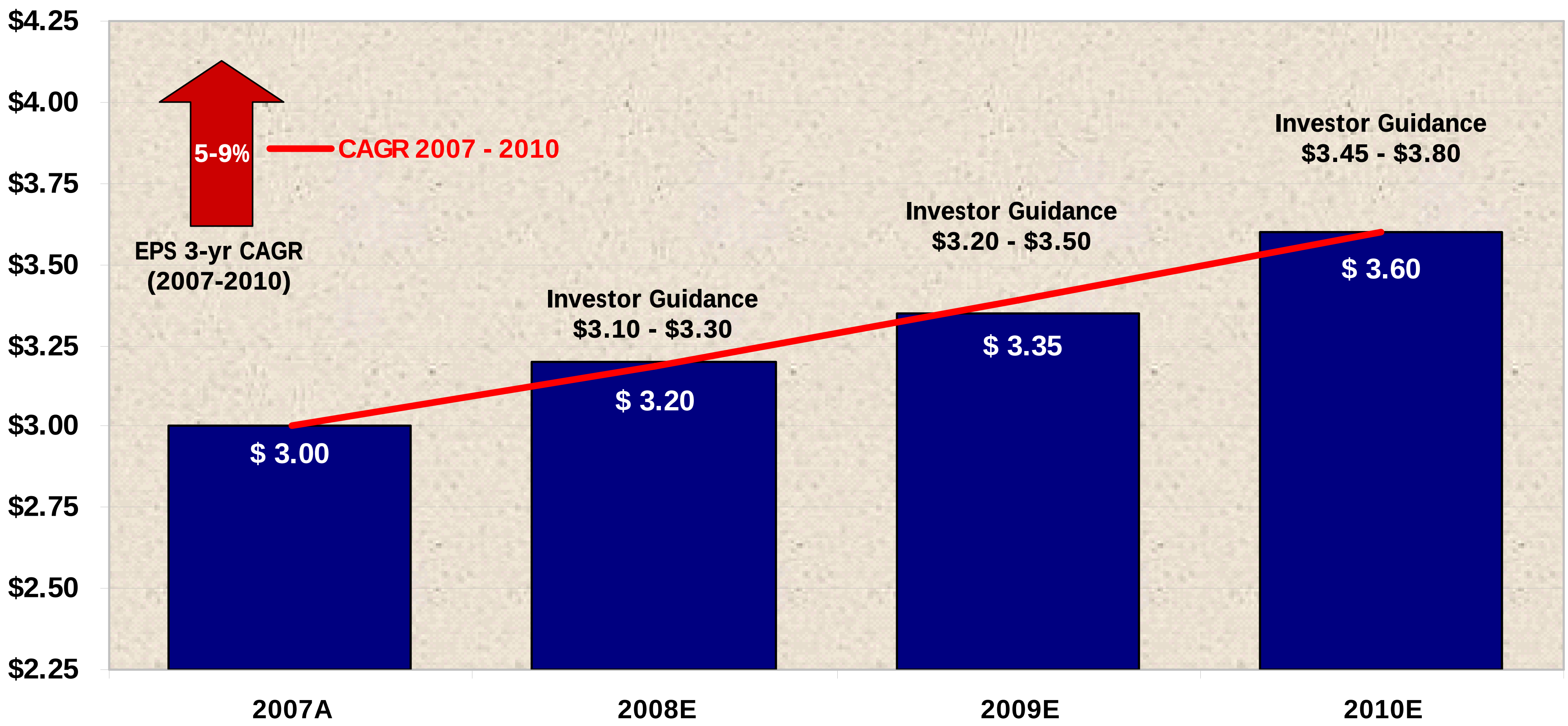
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast

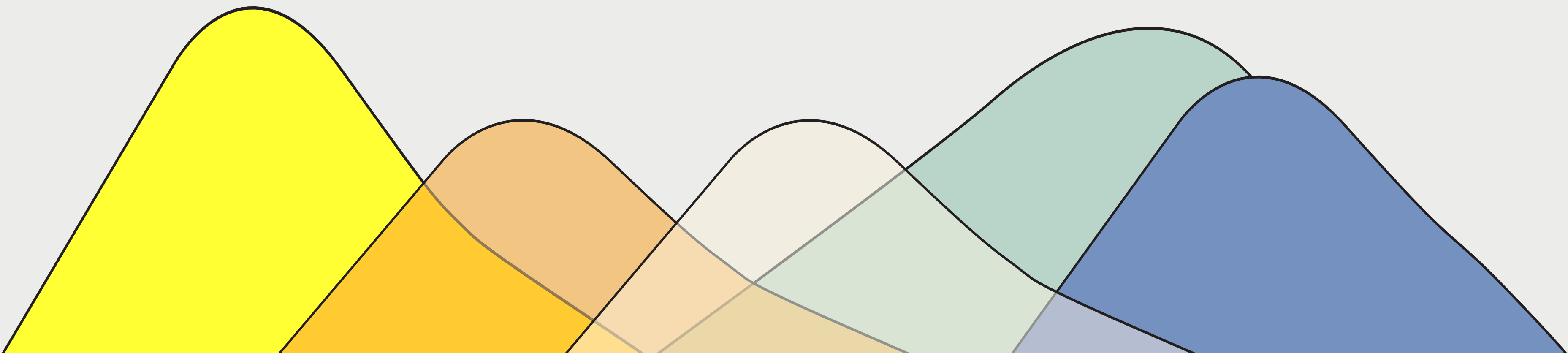


5% to 9% earnings growth

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1-2B	$2.25B - $3.75B*	$2.0B+



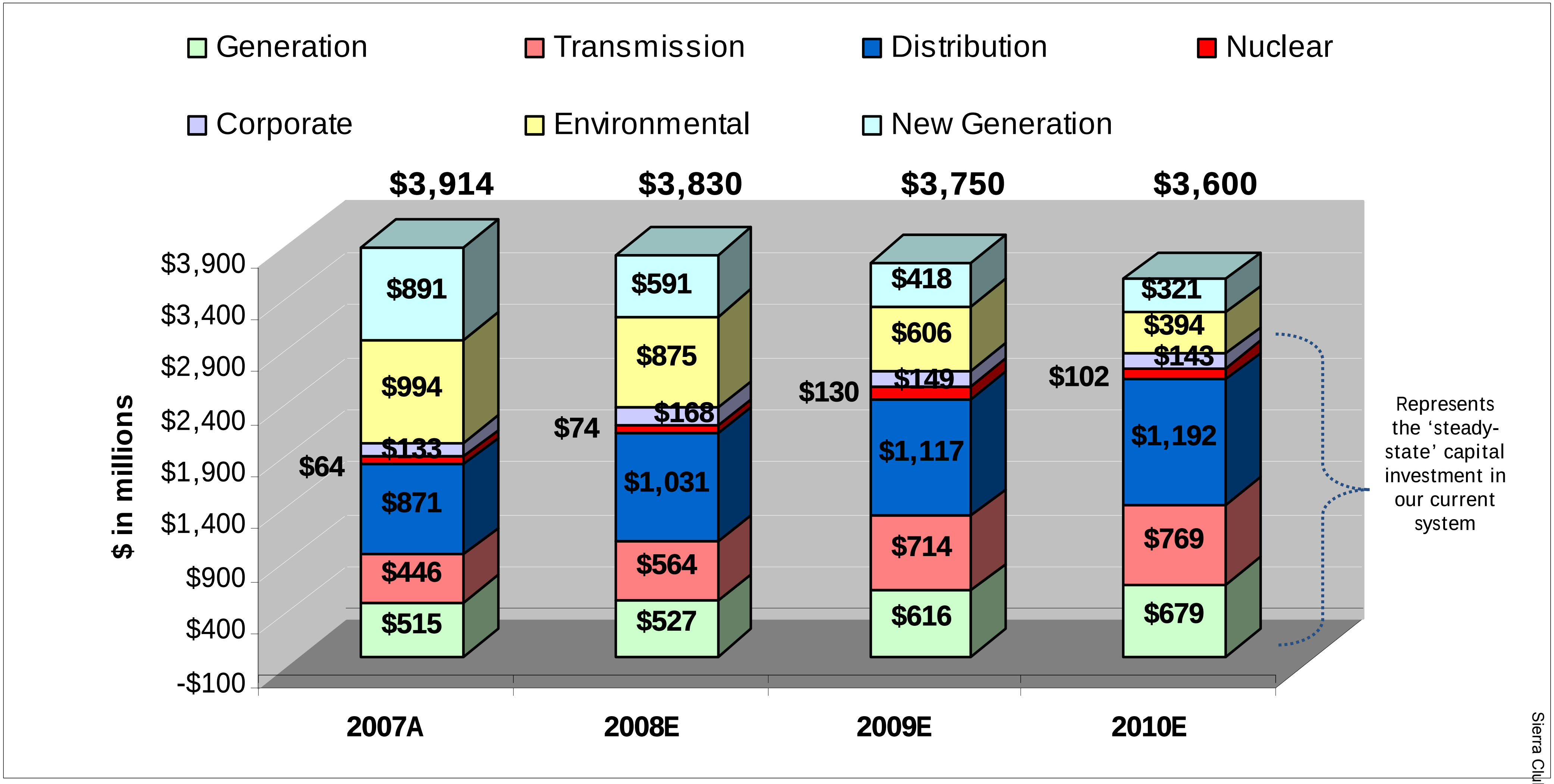
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

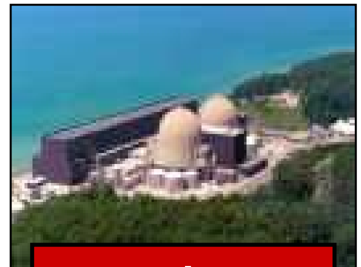
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

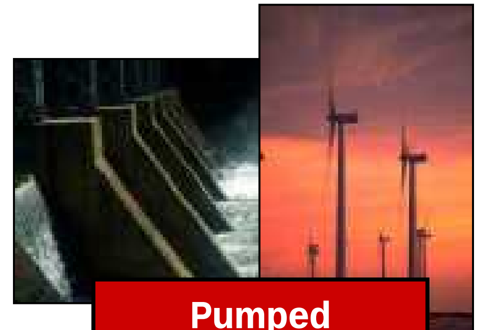
Domestic Generation Fleet

Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

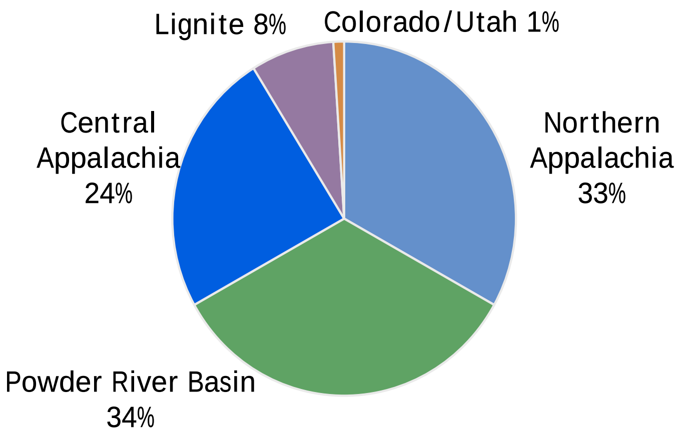
NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

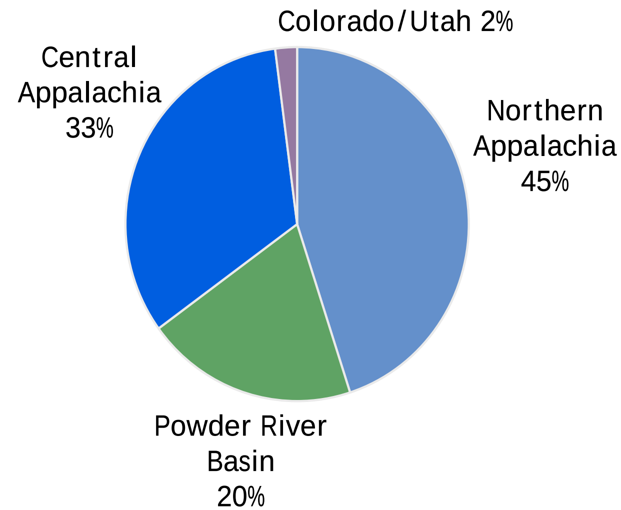
Total AEP System



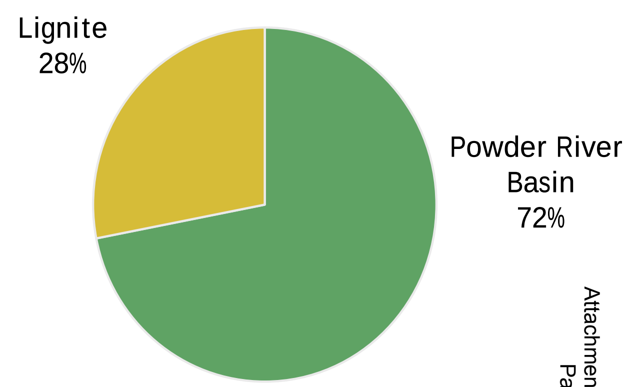
Coal Stats:

- Approximately 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 14%-18% price increase in 2008 based on 2007 actual results.

AEP East



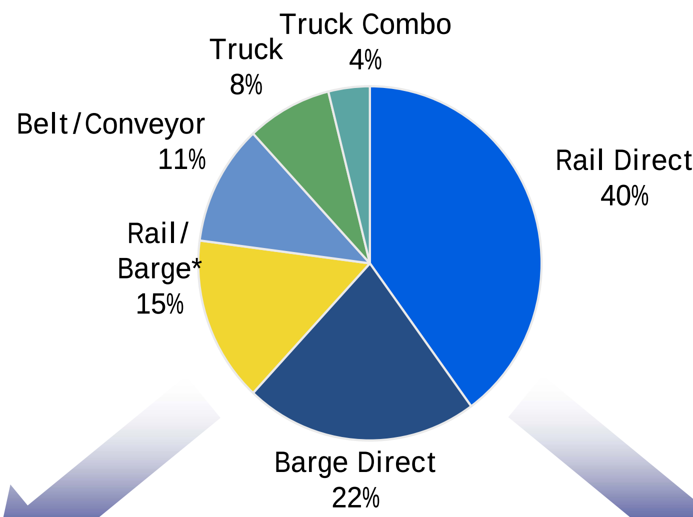
AEP West



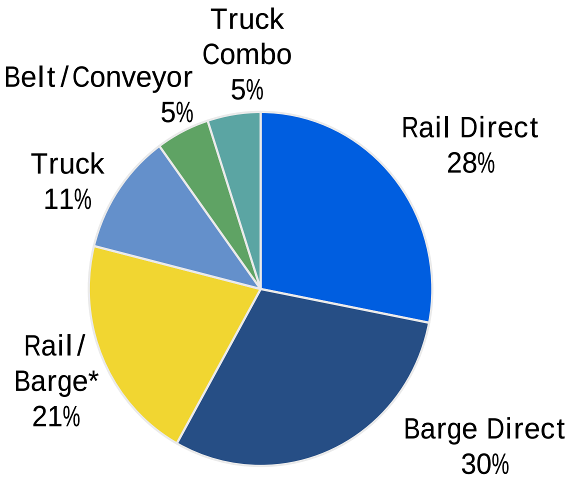
Coal Delivery

Total AEP System

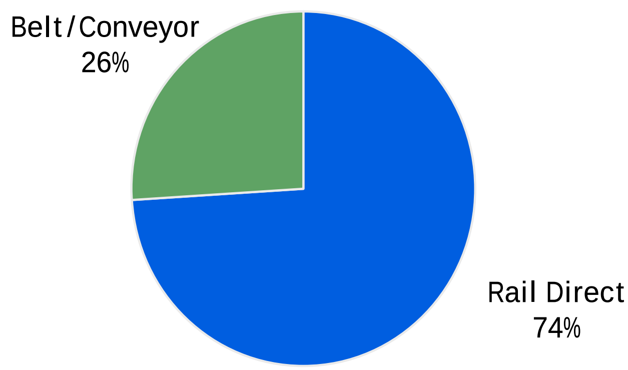
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$305 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART℠

gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

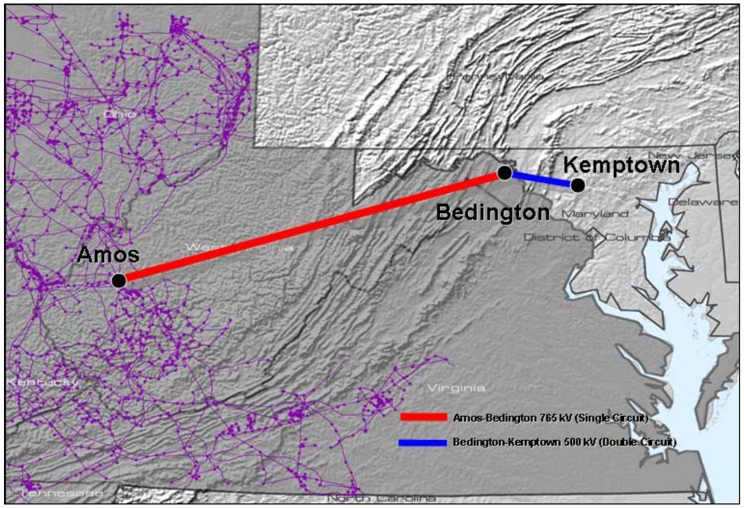
Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

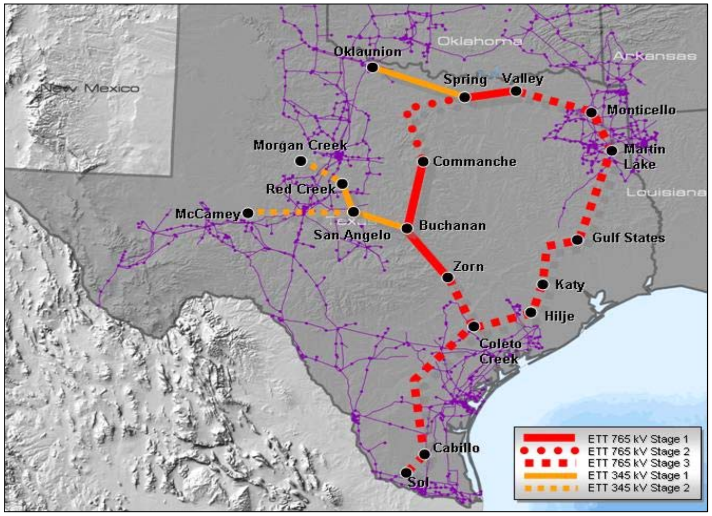
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

I-765™ Transmission: Investment Opportunities

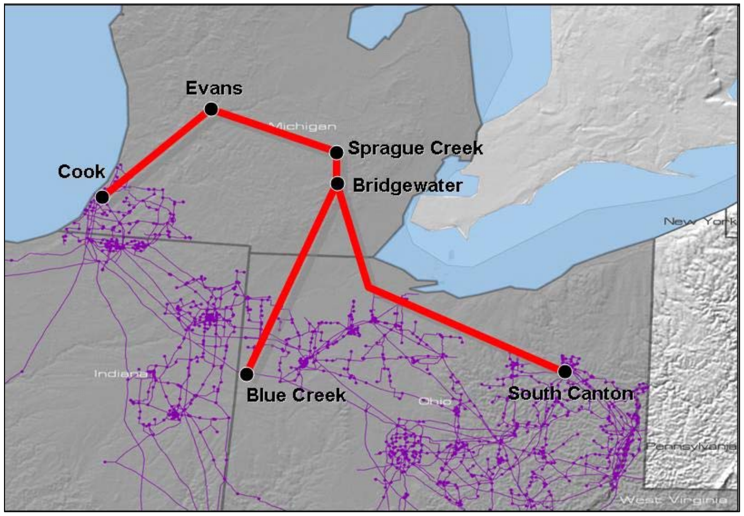
AEP is Advancing the Development of a National Interstate Today



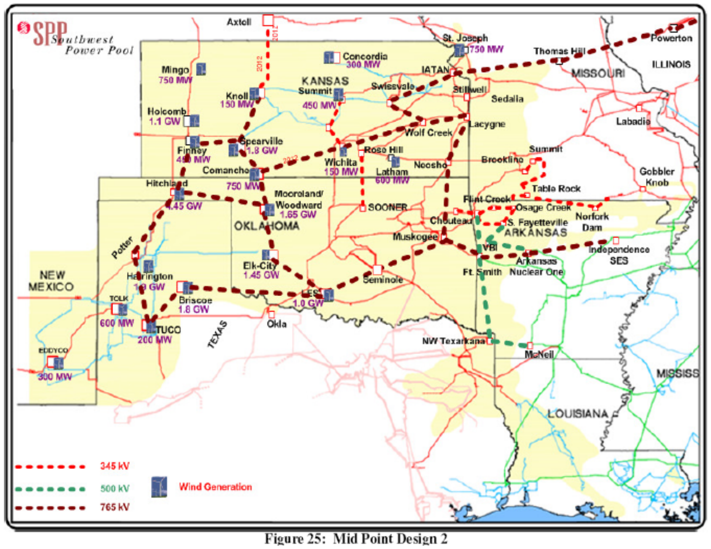
PATH Project (PJM)



ETT Proposal (ERCOT)



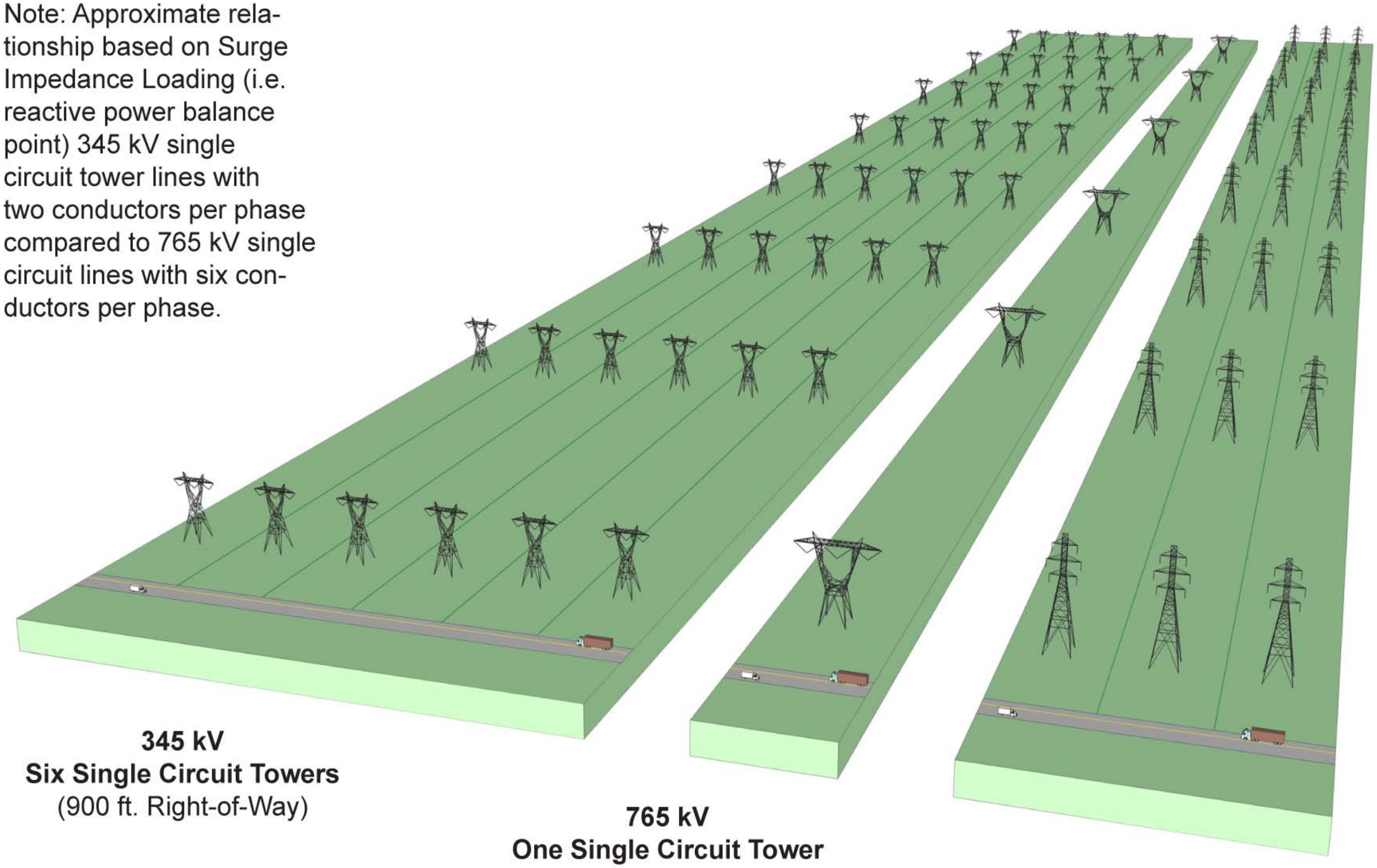
AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study – Mid Design 2

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

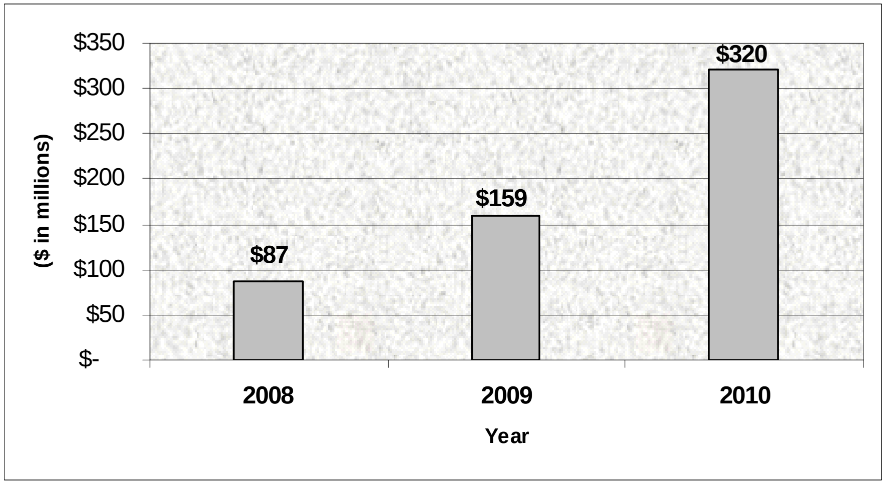
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission - Investments and Earnings Contributions

Projected Transmission Capital Spending*

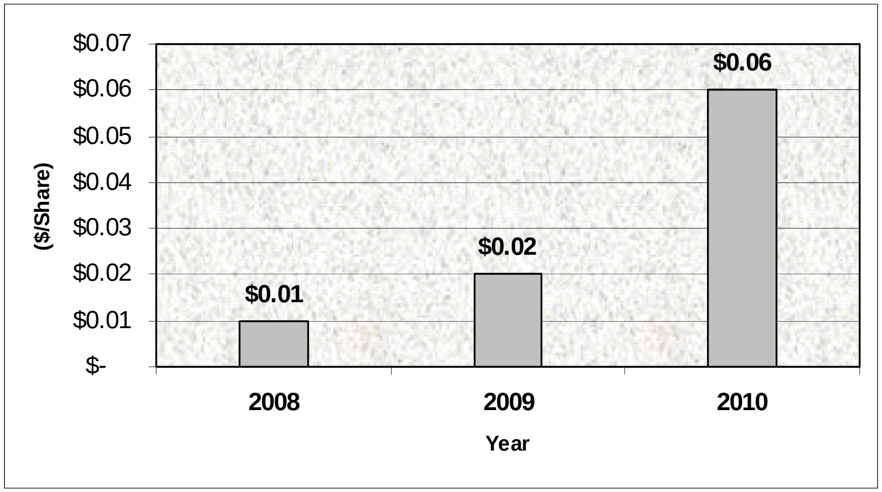


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

PATH
Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



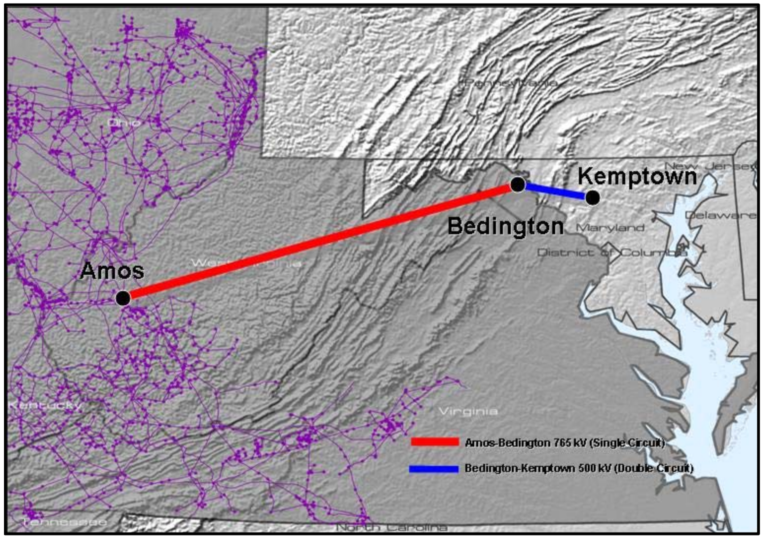
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765[TM] Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America (ETA)

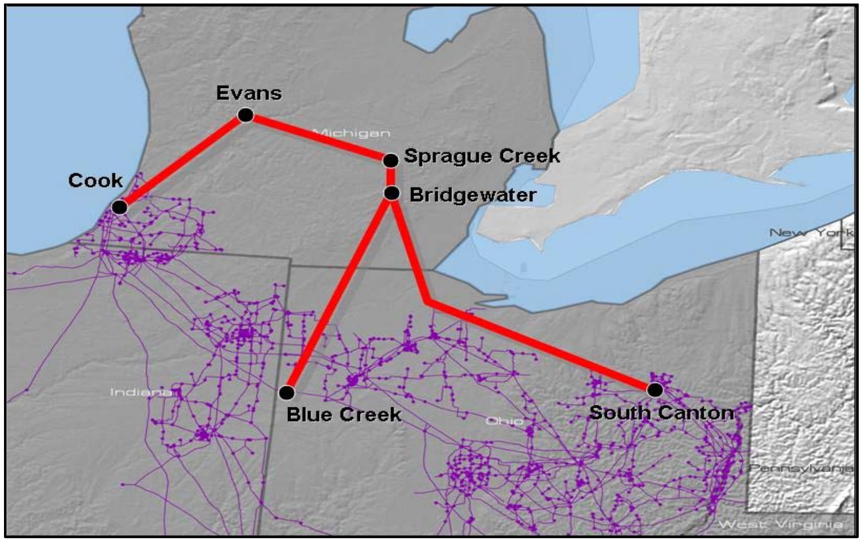
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765[TM] Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ### *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ### *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

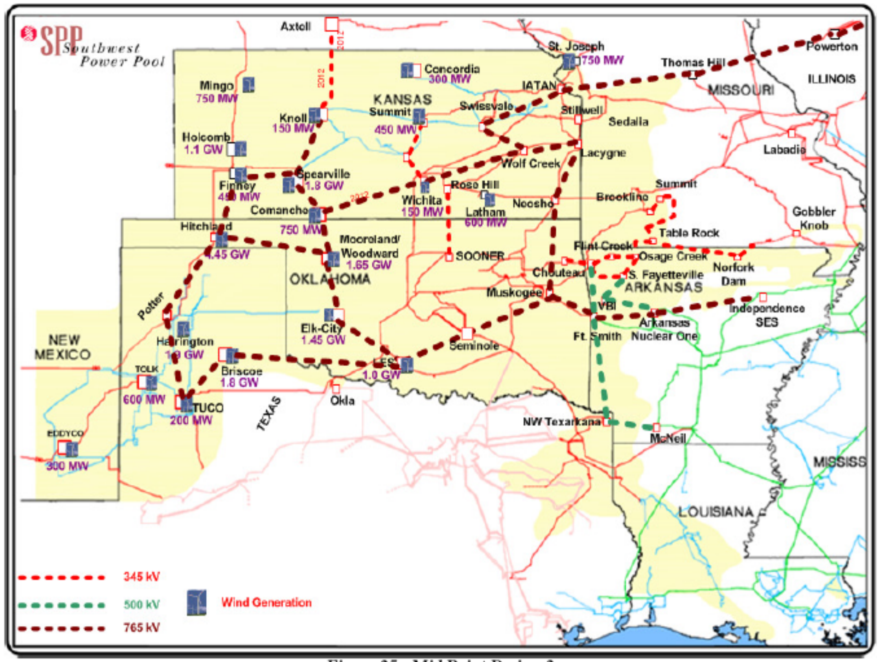


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

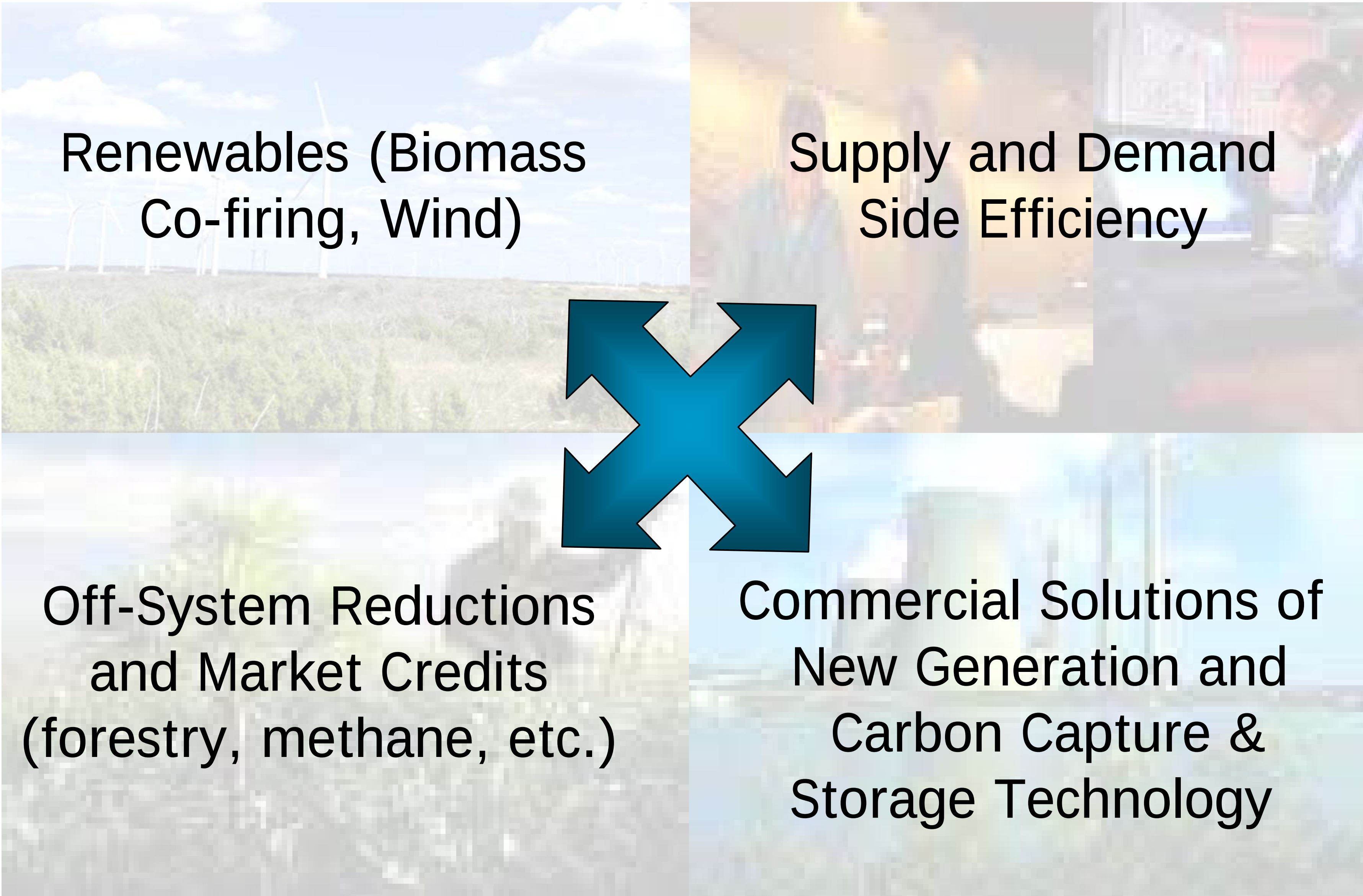
“Low Carbon Economy Act of 2007”

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Carbon Capture Technology Support—Bonus Allowances
- International action (AEP-IBEW trade proposal)

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives

A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- **Existing plant efficiency improvements**
- **Renewable Energy**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - **Forestry - 0.35MM tons/yr**
  - **Over 63MM trees planted through 2006**
  - **1.2MM tons of carbon sequestered**
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

AEP's reductions/offsets of CO_2:

- **2003-2007: 39 MM Tons**

New Program Additions (by 2011)

- **1000 MWs of Wind PPAs: 2 MM tons/yr**
- **Domestic Offsets (methane/forestry): 2.5 MM tons/yr**
- **Fleet Vehicle/Aviation Offsets: 0.2 MM tons/yr**
- **Additional actions—energy efficiency and biomass: 0.3MM tons/yr**

New Technology Additions

- **New Generation - IGCC and USC**
- **Retrofit solutions for existing fleet**
  - Chilled Ammonia
  - Oxy-Coal

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/YEAR
Longer Term—New Technology

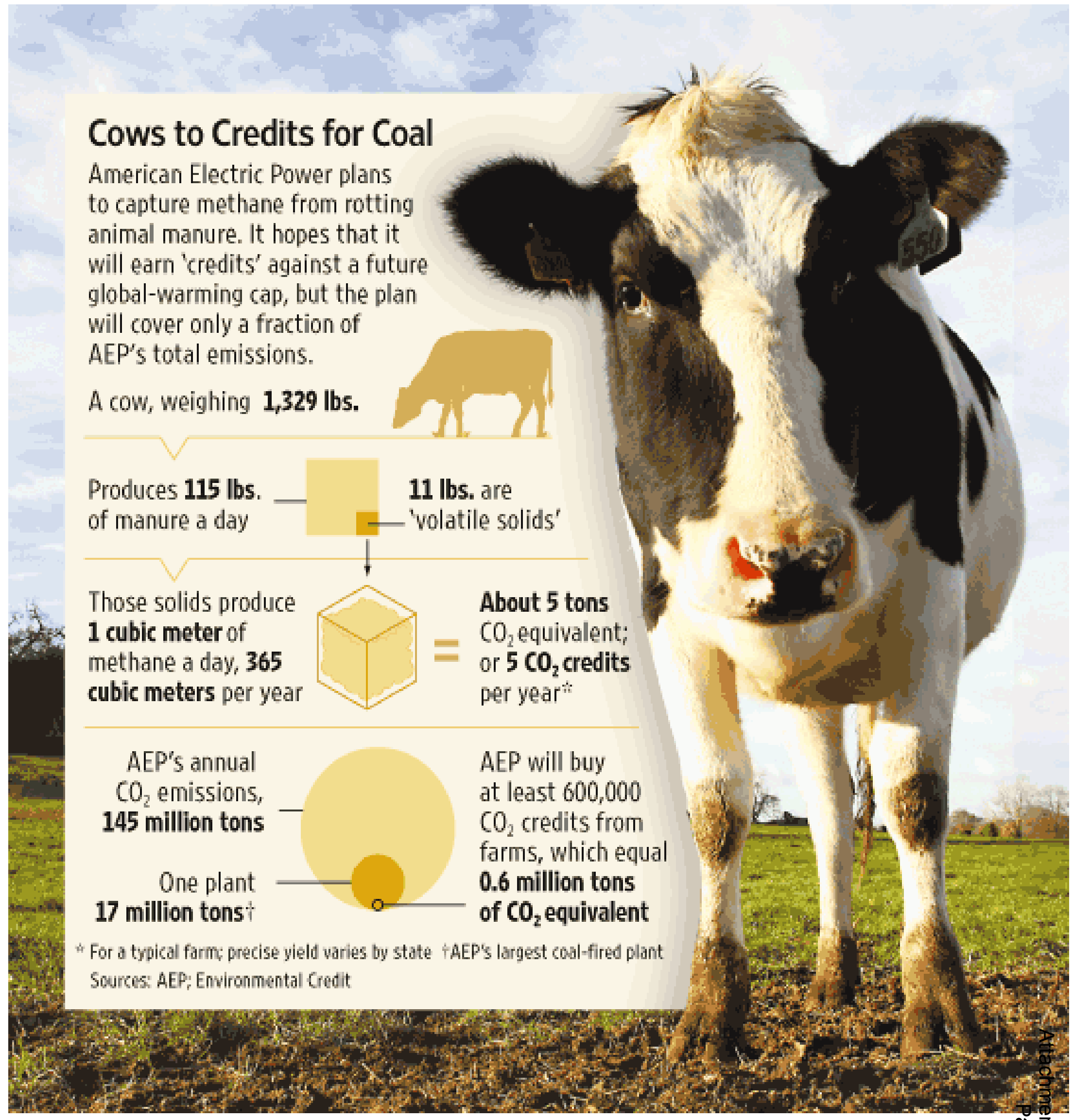
Off-System Reductions

New AEP Offset Commitment by 2011:

• 2.5 MM tons/year additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 0.6 MM Tons CO2e per year
  - 2010 through 2017
  - 51% of credits sourced from "AEP States"



Source: Wall Street Journal June 14, 2007

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

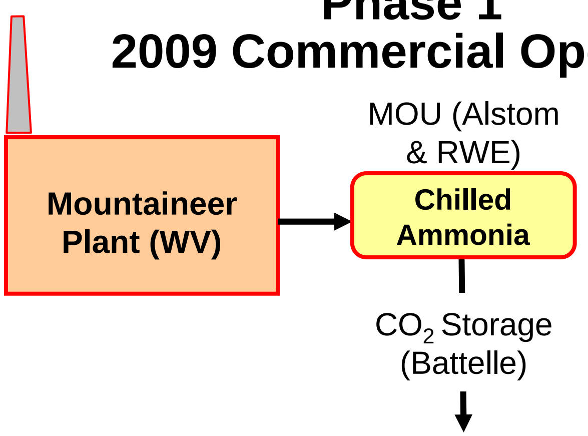
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

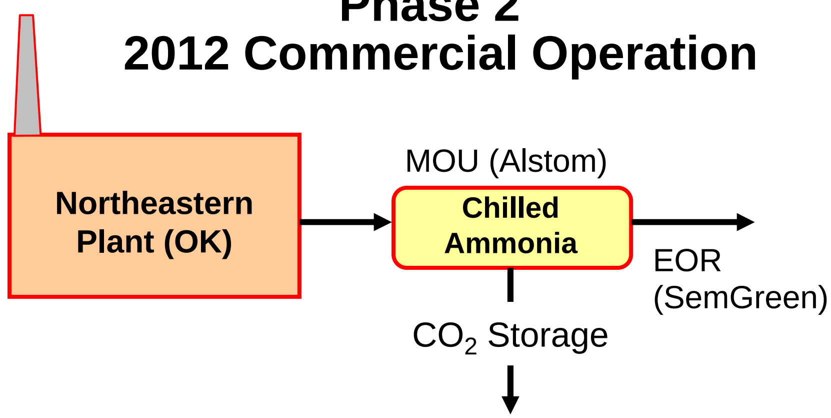
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

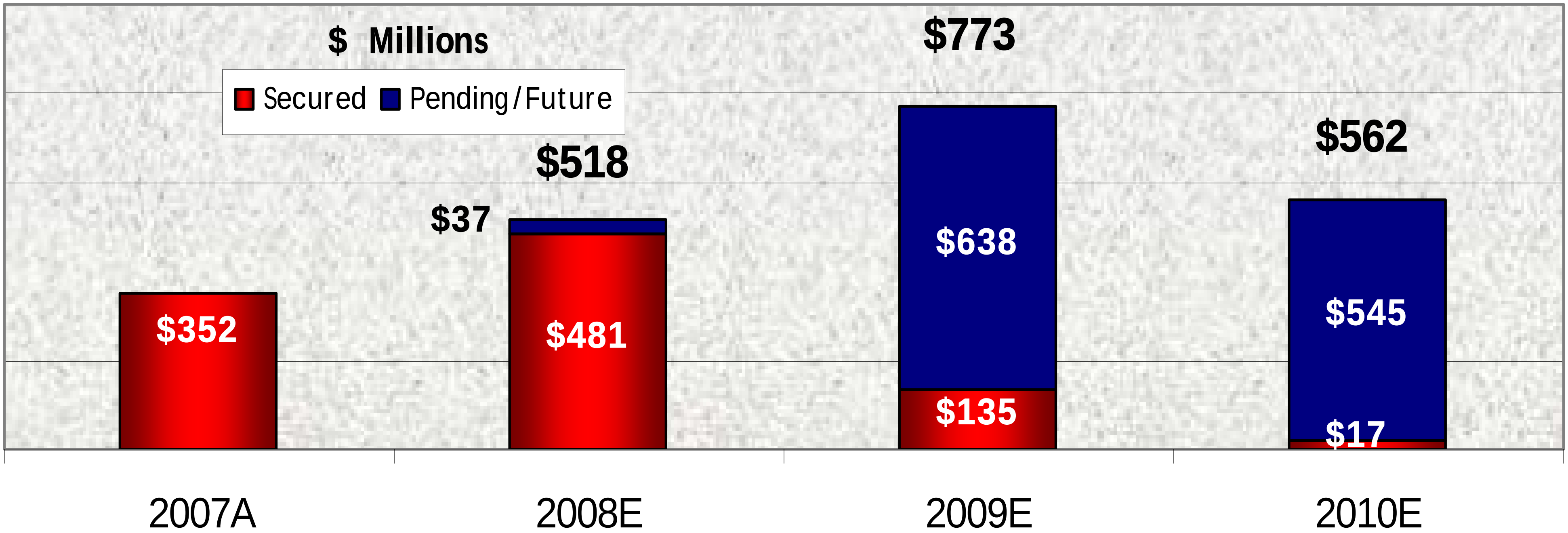
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Incremental Rate Relief

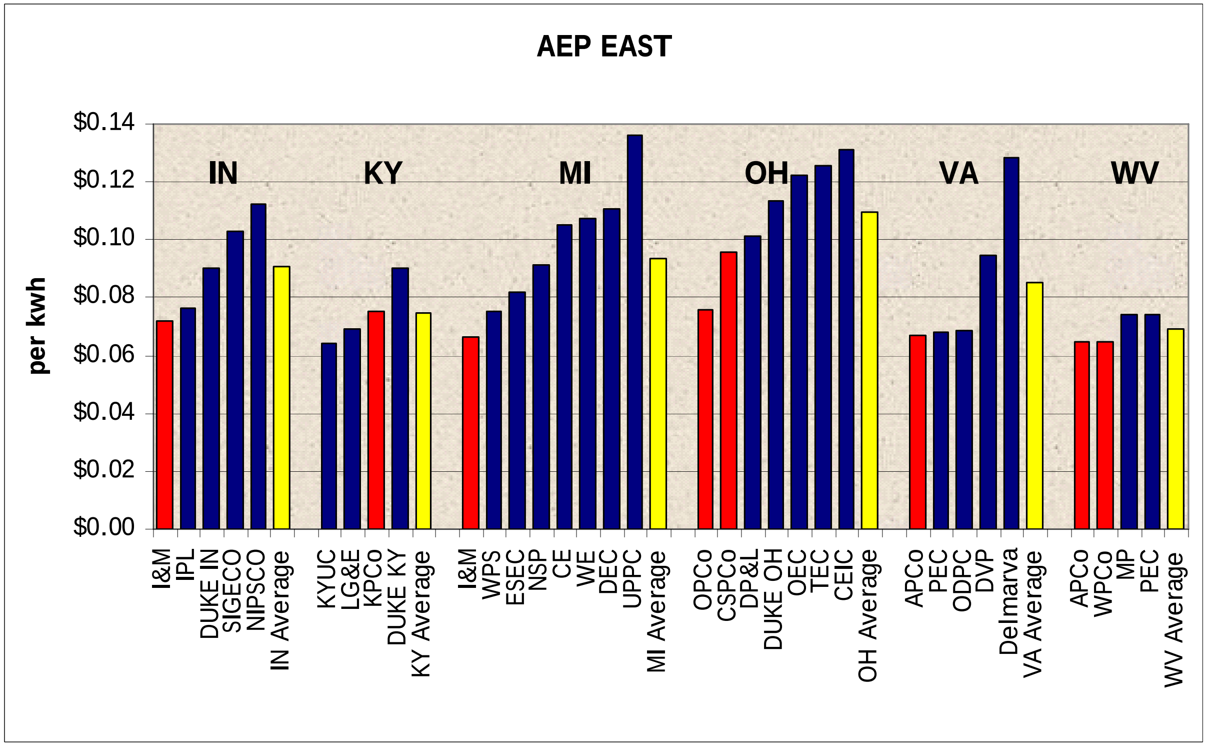


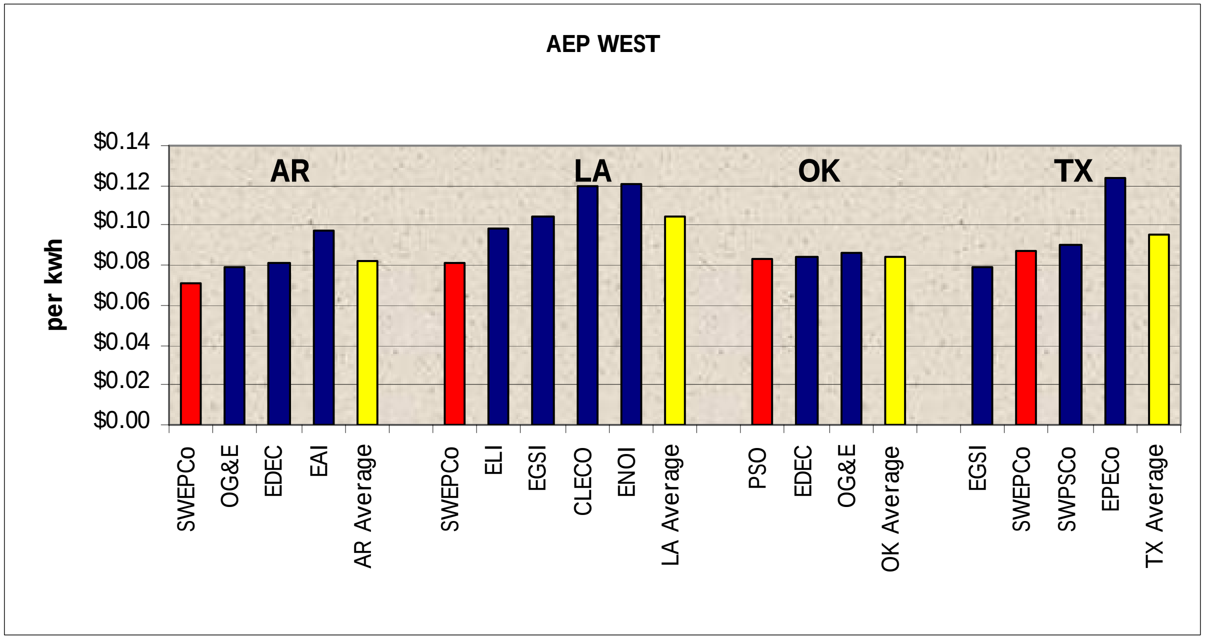
- **93% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan.**

- **2008 Pending: 2008 TCC/TNC TCRF filings, other cases yet to be filed including Virginia base case.**

Secured $481MM of $518MM for 2008

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

AEP Company

Other Company within state

State Average

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2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas
  - IGCC

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC. Hearings held May 12, 2008.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on 4/29/2008, and the SCC issued an order granting reconsideration on 4/30/2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearing is scheduled for May 29-30, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

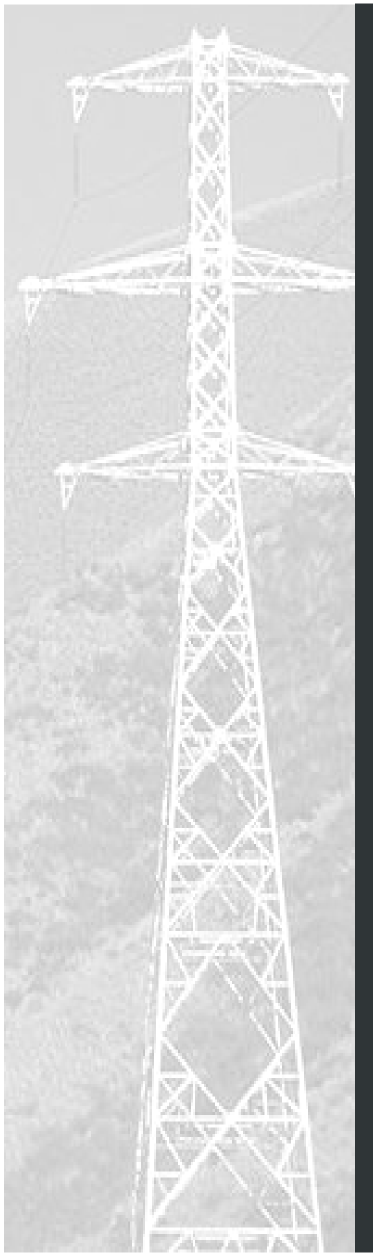
Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*



1Q09 Earnings Release Presentation

April 24, 2009

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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1Q09 Earnings

	$ millions			Earnings Per Share		
	1st Qtr 2008	1st Qtr 2009	Change	1st Qtr 2008	1st Qtr 2009	Change
Utility Operations	409	343	(66)	1.02	0.84	(0.18)
Transmission Operations	1	0	(1)	0.00	0.00	0.00
Non-Utility Operations	8	35	27	0.02	0.09	0.07
Parent & Other	(8)	(18)	(10)	(0.02)	(0.04)	(0.02)
AEP On-Going Earnings	410	360	(50)	1.02	0.89	(0.13)
Special Items	163	0	(163)	0.41	0.00	(0.41)
Reported Earnings (GAAP)	573	360	(213)	1.43	0.89	(0.54)

1Q09 Performance

American Electric Power
Financial Results for 1st Quarter 2009 Actual vs 1st Quarter 2008 Actual

		2008 Actual ($ millions)	2008 Actual EPS	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	594		691	
2	Ohio Companies	696		639	
3	West Regulated Integrated Utilities	223		239	
4	Texas Wires	122		127	
5	Off-System Sales	221		85	
6	Transmission Revenue - 3rd Party	80		84	
7	Other Operating Revenue	145		206	
8	Utility Gross Margin	2,081		2,071	
9	Operations & Maintenance	(747)		(803)	
10	Depreciation & Amortization	(355)		(373)	
11	Taxes Other than Income Taxes	(194)		(194)	
12	Interest Exp & Preferred Dividend	(210)		(221)	
13	Other Income & Deductions	41		31	
14	Income Taxes	(207)		(168)	
15	**Utility Operations On-Going Earnings**	409	1.02	343	0.84
16	**Transmission Operations On-Going Earnings**	1	-	-	-
17	AEP River Operations	7	0.02	11	0.03
18	Generation & Marketing	1	-	24	0.06
19	**Parent & Other On-Going Earnings**	(8)	(0.02)	(18)	(0.04)
20	ON-GOING EARNINGS	410	1.02	360	0.89

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q09 Performance Drivers:

- *Retail Sales (lines 1-4):*
  - *Rate relief of $101MM (Primarily APCo and PSO)*
  - *Lower OSS sharing of $54MM*
  - *Offset by:*
    - *$58MM favorable variance in the prior year related to a coal contract amendment*
    - *$20MM credit for fuel to I&M customers from a portion of Cook Unit 1 accidental outage policy proceeds*
    - *Load contraction of $6MM, primarily from industrial customers in I&M and the Ohio companies*
  - *Weather had no EPS impact vs. prior year or normal*
- *Off-System Sales (line 5):*
  - *Off System Sales were lower primarily due to lower volumes and market prices which reflect weak market demand and a significant drop in natural gas prices*
- *Other Operating Revenue (line 7):*
  - *Increase due to accidental outage insurance payments related to the DC Cook Unit 1 outage ($54MM)*
- *Operations & Maintenance (line 9):*
  - *Higher O&M costs related to the 1Q08 PSO storm deferral of $72MM, 2009 storms ($38MM) and an accrual of$15MM for the Partnership with Ohio Fund, offset by the Red Rock write-off in 1Q08($10MM) and a decrease in employee-related expenses ($34MM).*
- *Interest Expense & Preferred Dividend (line 12):*
  - *Higher due to increased long-term debt outstanding and higher interest rates*
- *Income Taxes (line 14):*
  - *Effective tax rate for utility operations was 32.9% in 2009 and 33.6% in 2008*
- *River Operations increased due to gains on the sale of two older towboats.*
- *Generation & Marketing increased as a result of higher gross margin from marketing activities in ERCOT.*
- *Parent and Other decreased primarily due to higher interest expense at the Parent.*

1Q2009 Cash Flow

($ millions)	2008	2009
Operating Activities		
Net Income -- Reported	$ 573	$ 360
Discontinued Operations	-	-
Continuing Earnings	573	360
Depreciation, Amortization & Deferred Taxes	427	543
Changes in Components of Working Capital	(74)	(468)
Other Assets & Liabilities	(298)	(117)
Cash Flows From Operating Activities	628	318
Investing Activities		
Capital Expenditures	(778)	(897)
Proceeds on Sale of Assets	18	172
Change in Other Temporary Cash Investments, net	(17)	90
Acquisition of Nuclear Fuel	(98)	(76)
Other Investing, net	(19)	(16)
Cash Flows Used for Investing Activities	(894)	(727)
Financing Activities		
Common Shares Issued, net	45	47
Long-term Debt Issuances, net	627	854
Short-term Debt Decrease, net	(251)	(1)
Other Financing	(14)	(25)
Dividends Paid	(164)	(167)
Cash Flows From Financing Activities	243	708
Cash From Continuing Operations	$ (23)	$ 299
Beginning Cash & Cash Equivalent Balances	178	411
Ending Cash & Cash Equivalent Balances	$ 155	$ 710

1Q2009 Cash Flow Drivers:

Operating Activities

- Changes in working capital largely driven by fuel (coal) stock increase and G&A type items
- Changes in other assets and liabilities largely driven by changes in un-recovered fuel

Investing Activities

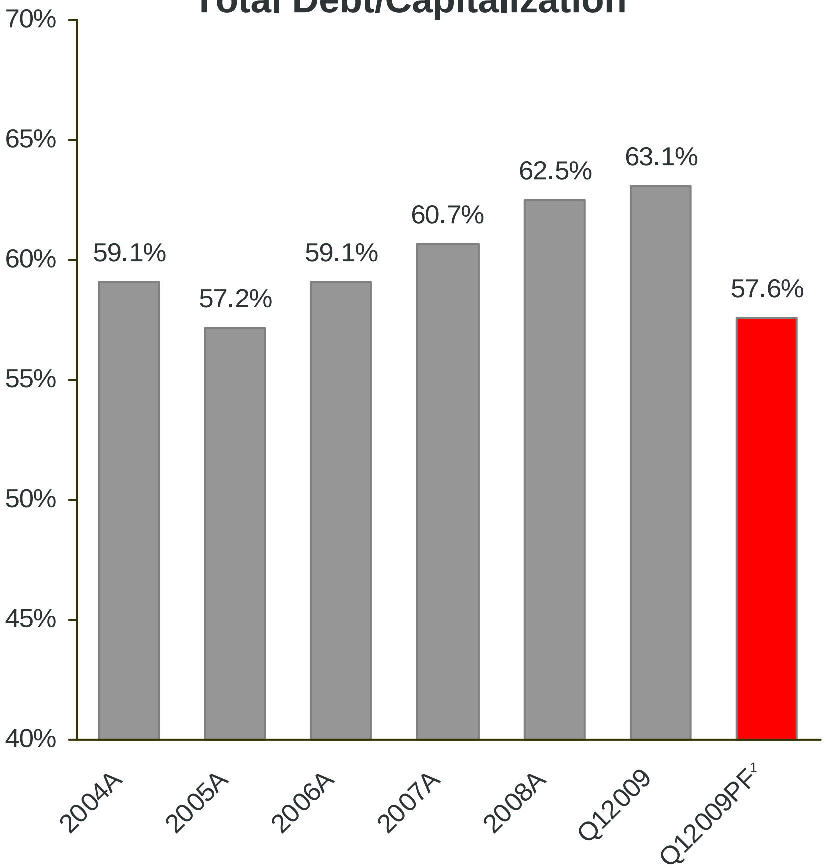
- Cash outlay of $897MM for 2009 YTD capital investment.
- 2009 asset sale proceeds primarily relate to the transfer of assets from TCC to ETT ($60MM) and the payments from the third-party owners of the Turk Plant ($104MM)

Financing Activities

- Long-term debt issuances of $854MM primarily related to I&M and APCo senior notes.

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	04/20/2009	Maturity
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2009 Actual vs 1st Quarter 2008 Actual

		2008 Performance Driver	2008 Actual ($ millions)	2008 Actual EPS	2009 Performance Driver	2009 Actual ($ millions)	2009 Actual EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	19,542 GWh @ $ 30.4 /MWhr =	594		18,661 GWh @ $ 37.0 /MWhr =	691	
2	Ohio Companies	13,901 GWh @ $ 50.0 /MWhr =	696		13,134 GWh @ $ 48.7 /MWhr =	639	
3	West Regulated Integrated Utilities	9,869 GWh @ $ 22.6 /MWhr =	223		9,063 GWh @ $ 26.4 /MWhr =	239	
4	Texas Wires	5,823 GWh @ $ 21.0 /MWhr =	122		5,738 GWh @ $ 22.1 /MWhr =	127	
5	Off-System Sales	8,236 GWh @ $ 26.8 /MWhr =	221		2,595 GWh @ $ 32.7 /MWhr =	85	
6	Transmission Revenue - 3rd Party		80			84	
7	Other Operating Revenue		145			206	
8	Utility Gross Margin		2,081			2,071	
9	Operations & Maintenance		(747)			(803)	
10	Depreciation & Amortization		(355)			(373)	
11	Taxes Other than Income Taxes		(194)			(194)	
12	Interest Exp & Preferred Dividend		(210)			(221)	
13	Other Income & Deductions		41			31	
14	Income Taxes		(207)			(168)	
15	**Utility Operations On-Going Earnings**		409	1.02		343	0.84
16	**Transmission Operations On-Going Earnings**		1	-		-	-
	NON-UTILITY OPERATIONS:						
17	AEP River Operations		7	0.02		11	0.03
18	Generation & Marketing		1	-		24	0.06
19	**Parent & Other On-Going Earnings**		(8)	(0.02)		(18)	(0.04)
20	ON-GOING EARNINGS		410	1.02		360	0.89

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q09 Earnings Release

Detailed Ongoing Earnings Guidance

2008 Actual: $3.24

2009E: $2.75-$3.05

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

1Q09 Retail Performance

	Load Growth (weather normalized) 1Q09 vs. 1Q08
East Regulated Integrated Utilities	-5.0%
Ohio Companies	-5.6%
West Regulated Integrated Utilities	-7.8%
Texas Wires	0%
Impact on EPS	$0.01

	Weather Impact 1Q09 vs. 1Q08
East Regulated Integrated Utilities	$0.00
Ohio Companies	($0.00)
West Regulated Integrated Utilities	($0.00)
Texas Wires	($0.00)
Impact on EPS	$0.00

Retail Performance – con’t

	Rate Relief (in millions)
	1Q09 vs. 1Q08
East Regulated Integrated Utilities	$73
Ohio Companies	$13*
West Regulated Integrated Utilities	$20
Texas Wires	($5)
AEP System Total	$101
Impact on EPS	$0.16

* - excludes activation of revised fuel recovery mechanism of $6MM

Off System Sales Gross Margin Detail

	1Q08			1Q09		
	GWh	Realization	($ millions)	GWh	Realization	($ millions)
OSS Physical Sales	8,236	$ 21.49	$ 177	2,595	$ 11.18	$ 29
Oklaunion Payment	-		$ 13	-		$ 15
Marketing/ Trading	-		$ 31	-		$ 41
Pre-Sharing Gross Margin	8,236		$ 221	2,595		$ 85

- Reduction in Pre-Sharing OSS Physical Sales primarily due to lower demand and significantly lower realized prices as a result of natural gas price contraction

AEP and Climate Legislation

Mountaineer Plant - New Haven, WV

AMERICAN ELECTRIC POWER

Northeastern Plant - Oologah, OK

Bruce Braine

Vice President - Strategic Policy Analysis

October 9, 2007

Sanford C. Bernstein 2007 Carbon Symposium

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Presentation Topics

- **AEP Climate Strategy:**
  - How is AEP preparing for ultimate climate legislation?
  - What specific voluntary actions and proactive investments is the company undertaking?

- **Federal Legislation:**
  - What type of climate legislation is likely?
  - When will it become effective?
  - How will climate legislation affect operations, capital investment, choice of generation, operations and earnings?
  - What constitutes “reasonable” climate legislation?

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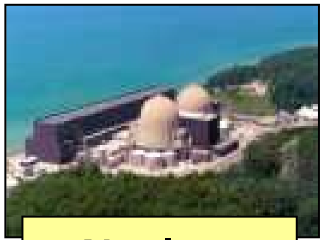
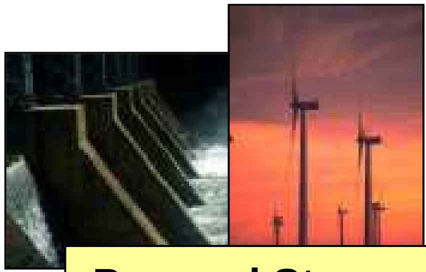
Company Overview





Coal/Lignite
67%

Nat.
Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

5.1 million customers in 11 states
Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

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AEP Climate Strategy

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, making real reductions and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders and SF-6 Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Investing in longer term technology solutions--new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical PC)**

AEP must be a leader in addressing climate change

AEP's Long-Term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

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AEP is investing in a portfolio of GHG reduction alternatives

A Portfolio Approach: AEP Long-Term CO_2 Reduction Commitment

Existing Programs

- **Existing plant efficiency improvements**
- **Renewable Energy**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - **1.2MM tons of carbon sequestered**
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

AEP's reductions/offsets of CO_2:
- **2003-2005: 31 MMT**
- **2006-2010 (proj.): Additional 15 MMT**

New Program Additions (by 2011)

- **1000 MWs of Wind PPAs: 2MM tons/yr**
- **Domestic Offsets (methane): 2MM tons/yr**
- **Forestry: Tripling annual investment to increase to 0.5MM tons/yr by 2015**
- **Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr**
- **Additional actions--end use and supply efficiency and biomass: 0.2MM tons/yr**

New Technology Additions

- **New Technology Generation – IGCC and USC**
- **Commercial solutions for existing fleet**
  - Chilled Ammonia
  - Oxy-Coal

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/YEAR
Longer Term—New Technology

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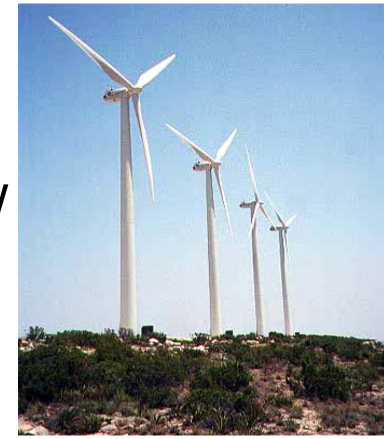
AEP Wind Operations/Purchases

Trent Mesa (2001)

- **150 MW** (100 - 1.5 MW turbines)
- Abilene/Sweetwater, TX

Southwest Mesa (1999)

- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser



Desert Sky (2002)

- **160 MW** (107 - 1.5 MW turbines)
- Bakersfield, TX

Summary

- Owned/Operated 385 MW
- Wind Purchases 392 MW
- Total Existing Wind at end of 2006: 777 MW
- **New Wind Purchases in 2007: 275 MW**

Will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011

AEP Has 10 Years of Wind Experience

- 5 MW Ft. Davis Wind Farm: Early AEP R&D Project (1996 - 2004) Decommissioned
- 75 MW Southwest Mesa PPA: Project built on AEP owned land (1998) SWEPCo
- 150 MW Trent Wind Farm: AEP owned / developed IPP wind farm (2001) AEPEP
- 160 MW Desert Sky Wind Farm: AEP owned IPP wind farm (2001) AEPEP
- 147 MW Weatherford PPA: (2005) PSO
- 151 MW Blue Canyon II PPA: (2005) PSO
- 94.5 MW Sleeping Bear PPA: Completion in Summer 2007 PSO
- **200 MW Fowler Ridge PPA: Completion in late Q4 – 2008** **I&M / APCo**
- **75 MW Camp Grove PPA: Completion in early – 2008** **APCo**

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Off-System Reductions

Existing AEP Programs:

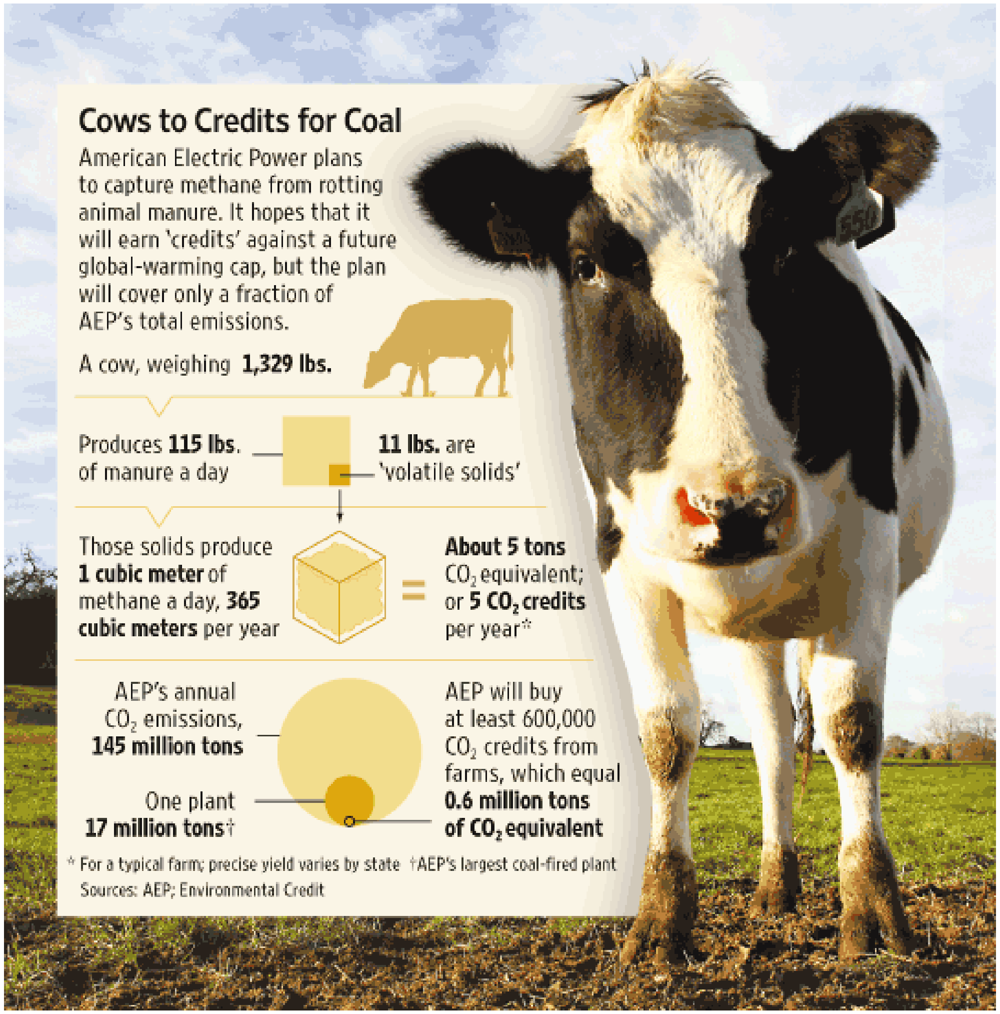
- Forestry - Domestic
  - 350,000 tons / yr
  - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 600,000 CCX carbon credits per year
  - Begins 2010
  - Runs through 2017
  - 51% of credits sourced from "AEP States"



Source: Wall Street Journal June 14, 2007

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AEP Leadership in Technology: IGCC/USC and Future Gen

NEW ADVANCED GENERATION

- **IGCC---AEP plans to build first two 600+ MW IGCC commercial-scale facilities in the US in OH and WV by the end of the next decade**

- **USC--AEP plans to build a new generation ultra-supercritical (steam temperatures greater than 1100°F) coal plant in Arkansas**

FUTUREGEN- First Near Zero Emissions Hydrogen/ Electric (coal-fueled IGCC with CCS)- AEP and Alliance members

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AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

- **Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.**
  - **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009**
  - **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**
- **Oxy-Coal--AEP will also demonstrate (10MWe) and then install oxy-coal CO_2 capture & storage at a commercial sized coal unit (about 200 MWe)—feasibility study to be completed in 2008.**

AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

2009 Commercial Validation

1300 MW Mountaineer Plant (WV) → MOU (Alstom) **Chilled Ammonia 20MWe scale**

CO_2 Storage (Battelle)

Captures and sequesters 100,000 metric tons of CO_2 /yr.

Phase 2

2012 Commercial Operation

450 MW Northeastern Plant (OK) → MOU (Alstom) **Chilled Ammonia 200MWe scale** → EOR

CO_2 Storage

Captures and sequesters 1.5 Million metric tons of CO_2 /yr.

Examples of Relative GHG Mitigation Costs for Power Sector

$40+

$/ton CO_2e

$0

- Carbon Capture w/ Geologic Sequestration
- Other renewable, advanced geothermal and/or solar
- Carbon Capture for Enhanced Oil Recovery
- New Biomass Generation
- Dispatch of additional gas vs. inefficient coal
- Biomass Co-firing
- Biological Sequestration (e.g. Forestry)
- New Wind
- Energy Efficiency
- Methane Offsets

Nuclear?

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Key Issues for CCS Development in U.S.

- Overcoming the "Economic" Hurdle
- High Up-Front Capital Investment—Getting Adequate Financing and Recovery in Rates
- Commercial Demonstrations of CCS at Large Coal-Fired Power Plants
- National Standards for Permitting of Storage Reservoirs
- Potential Institutional, Legal and Regulatory Barriers to Carbon Storage

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Federal Legislation and AEP Position

Prospects for US Federal Legislation— The Crystal Ball

- With Democratic majorities in the House and Senate, prospects during the 110th Congress for mandatory climate legislation have increased.
- Nonetheless, the Senate and House have just begun introducing/developing legislation and there are many contentious issues, particularly allocation.
- In the 2009 and after period, passage of legislation is more likely, with a new President in office.
- A general timeline for passage of Clean Air Legislation has typically been 5-8 years after the initial "serious" proposals.

We are at the "end of the beginning" NOT the "beginning of the end."

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Potential for Federal Climate Legislation

- Legislation could pass as early as 2009-10 with limits taking effect as early as 2015. Any earlier reduction requirements are unlikely.
- Moderate approach probably has best chance of passage, which means offsetting emissions growth initially (during next decade) with significant reductions thereafter.
- Impacts in terms of utility operations, capital and earnings won't be until the 2015-20 period. With more substantial impacts probably not beginning until 2020 and after.

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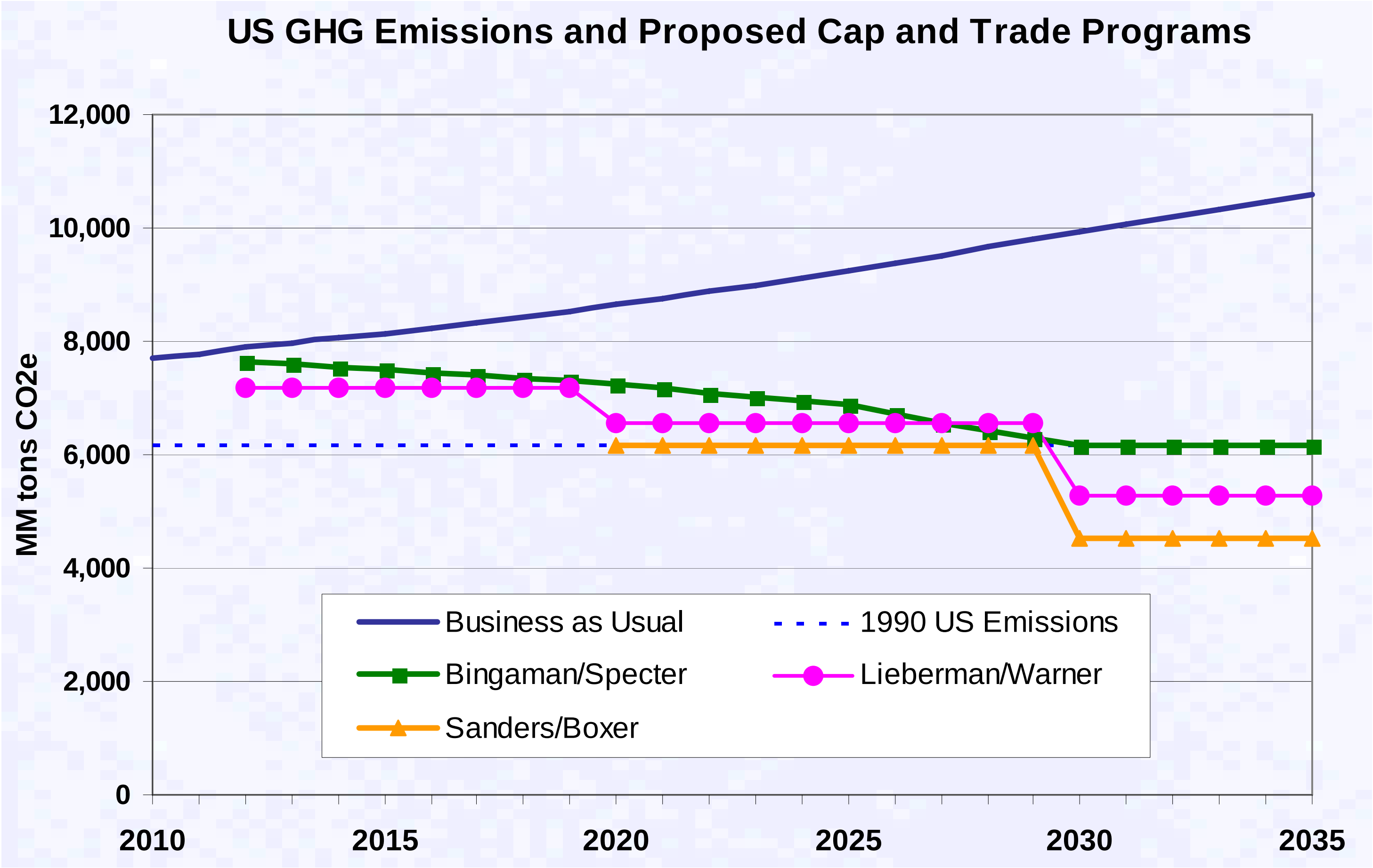
Emission Reductions Under Selected Bills



AEP's Climate Position

- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment

- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable & reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

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AEP Position: A "Reasonable" Approach to Climate Legislation

- Reductions and Timing--Moderate with Adequate Lead Times
- Scope of Program-- Economy Wide
- Point of Regulation (e.g. Upstream or Downstream)--Hybrid Approach
- Flexibility of the Program—Trading, Banking, Unrestricted Offsets, Early Action Credits
- Allowance Allocation And Other Cost Issues—Low auctions and safety valve
- International Linkage—AEP-IBEW Proposal: emission requirements to foreign imports from non-participating countries

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AEP Supports Bingaman-Specter Bill

"Low Carbon Economy Act of 2007"

- Economy wide cap-and-trade program to limit Greenhouse Gas Emissions
  - Caps and Dates
    - 2006 Levels by 2020
    - 1990 levels by 2030
  - Industry Sectors "Regulated" under bill
    - Natural Gas and Petroleum regulated "upstream"
    - Coal regulated "downstream" at the power plant level
  - Allocations to Electricity Generators
    - Only fossil-fired electric generators receive allowances
  - Safety Valve (TAP)
  - Bonus Allowances for Carbon Capture and Sequestration
  - Early Reduction Credits and Offsets Included
  - Congressional Review of International Action (e.g. AEP-IBEW Proposal)

AEP Supports Reasonable Legislation on GHG

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Background on Allowance Allocations and Auctions

- **"Allowance" = Right to emit a ton of emissions.** Each year allowances are surrendered to cover annual emissions.
- **Most programs (e.g. EPA's SO_2 and NOx, CAIR and CAMR) allocate allowances (at "no cost") to generators (primarily based on historic emissions) with little or no auction.** The EPA SO_2 program has been hailed as a success because of its AFFORDABILITY due in part to a small (2.8%) auction.
- **Allowance allocation to emitters does NOT result in a "windfall." CO_2 cap means ALLOWANCES <EMISSIONS. So reductions must be made at a NET COST.**
- **Importantly, whether allowances are allocated at "no cost" or auctioned has NO environmental impact, it is the overall CO_2 cap that determines the amount of reductions.**

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"Free" Allocation To Emitters Does Not Increase Profits

- **Example: Company Emits 100 Tons, Receives 80 "No-Cost" Allowances (i.e. 20 % Reduction).**

Beginning of Year

Allowances 80 Tons

Allocated

CO_2 100 Tons

Year End

Surrendered/ Returned to EPA

Allowances 80 Tons

Net Emission Reduction/Liability 20 Tons

- **Full Allocation to Emitters Does NOT Create a "Net Asset" or Windfall because of the Liability of Complying with the CO_2 Cap. In fact, it is a NET LIABILITY.**

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Electricity Deregulated vs. Cost Regulated States

- It is the CO_2 cap that increases electricity costs and prices. The key distinction is whether a generator is subject to:
  1. Cost-of-Service Regulation
  2. Deregulated Generation Markets
- Most states and the vast majority of coal fired generation are subject to cost-based regulation. There are NO WINDFALLS or PROFIT GAINS for these generators because they are regulated and can ONLY pass-thru their costs to customers.
- For the US power industry, allocation/auction is predominantly about electricity costs and rates:

Higher Auctions = Higher Electricity Rates

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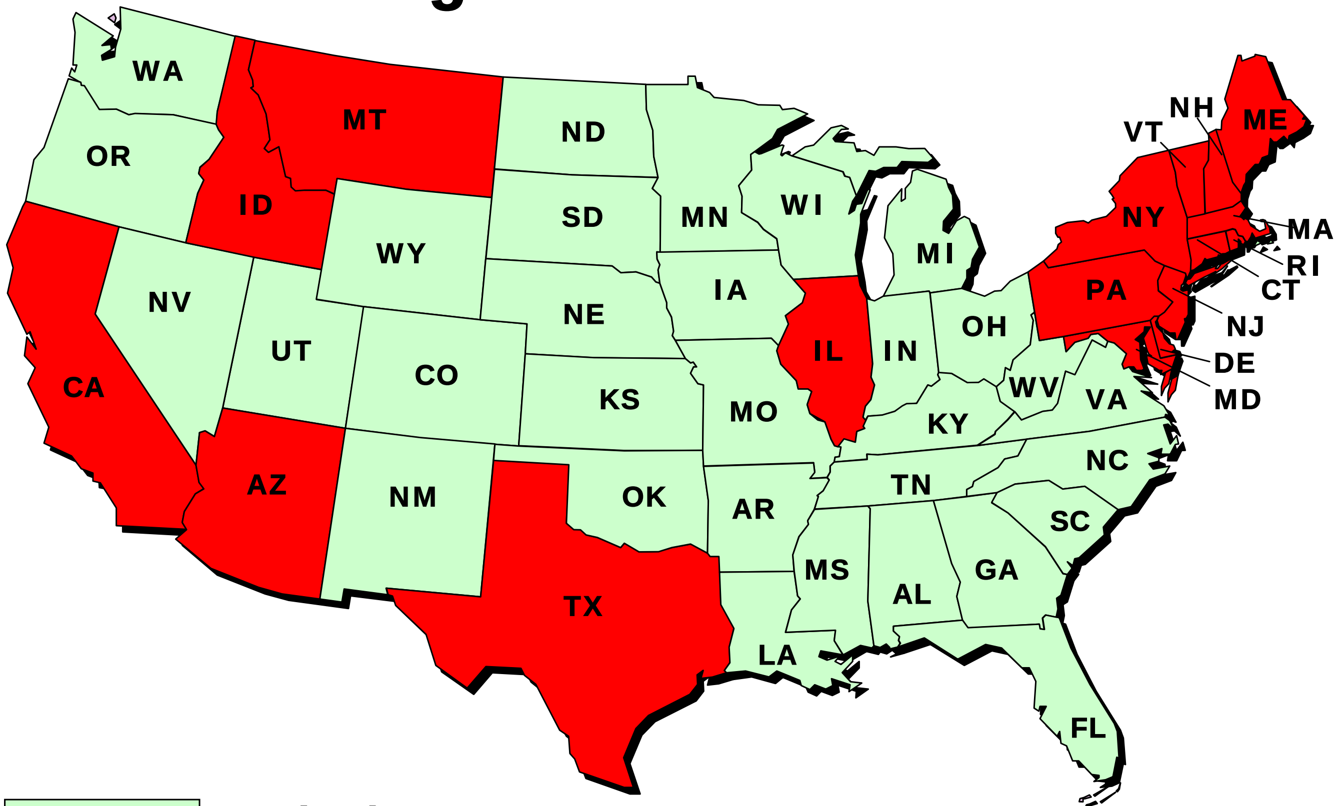
Most Coal Generation is Cost-Regulated

- Most states are "cost-regulated" today with 80 % of US coal fired generation in these states.



Regulated

Unbundled/
Deregulated

Note: Based on "current" state status of regulation/deregulation. States that have continued cost-based POLR rates or transition rates are considered to have kept generation "regulated".

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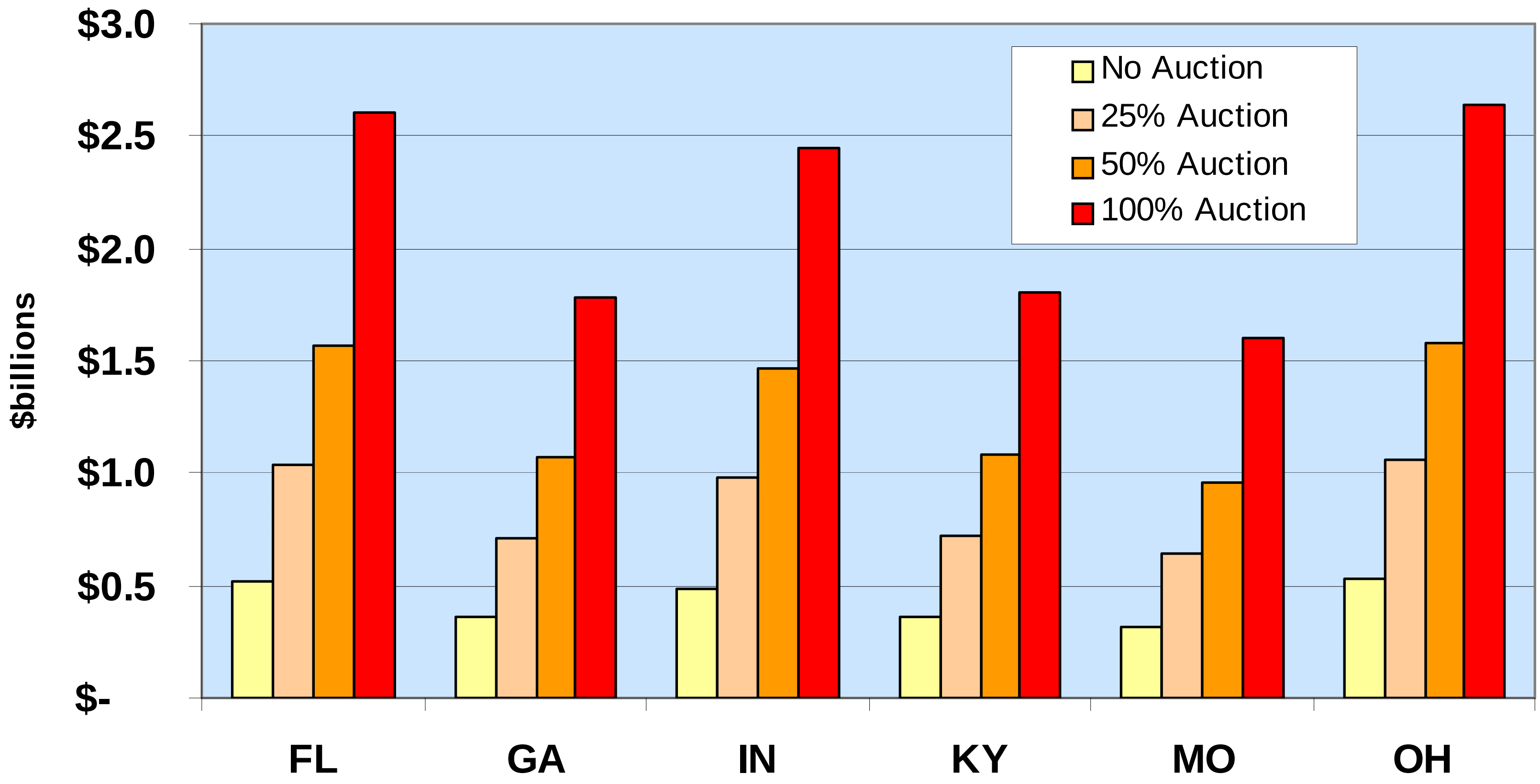
Increase in Customer Electricity Costs/Rates due to Auctions

Annual Increase in Electricity Costs (in Billions of Dollars)



Approximate Calculation based on a 20% reduction in electric sector GHG emissions with CO_{2e} reductions/allowances costing $20/ton

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Allocations and Auctions—Price Deregulated States

- **The CO_2 cap (not allowance allocation) will increase electricity prices and, for some participants, increase profits. BUT ONLY in states (primarily in the Northeast and West), where generation is "unbundled" and retail prices deregulated.**
- **In these states, SOME generators will have higher profits IF their revenues increase more than their costs:**
  - The majority of the profit increase will go to non-fossil generation (e.g. nuclear, hydro and renewables) because they have no emissions and because almost half of the generation is projected to come from non-fossil sources in these states.
  - Natural gas units will also see profit increases because their CO_2 reduction costs are small.
- **Thus, auctions do little to "tax away" higher profits since most profits come from non-emitting or low emitting units that don't need allowances. In fact, the main impact of auctions is to penalize ratepayers or coal-fired generators.**

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Allowance Allocation Within the Electric Sector

- **Emissions-Based Allocations Are More Equitable---**Allowances should be allocated based on historic/current emissions to existing generators required to make reductions. **Allocation principle is all emitters make their "fair" pro-rata share of reductions**.
- **Output or Total KWh based Allocations Create Large Windfalls for Some Generators and Major Losses for Coal ----**
  - Allowances should NOT be allocated to sources that do not have emissions such as hydro and nuclear. Gas fired plants should not receive "excess" allocations.
  - Nuclear, hydro and gas plants will already benefit (to the extent they are in "deregulated" states) due to higher power prices.
  - Output based allocations increase costs to ratepayers of largely regulated, coal dependent states (e.g. the Midwest and Southeast) and provide large windfalls to deregulated gas and nuclear plants. For example, output-based allocation would increase costs to AEP and its customers by about $1 billion/year with no CO_2 benefit.

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Technical Appendix

Carbon Capture and Storage

CO_2 Capture Techniques

- **Post-Combustion Capture**
  - Conventional or Advanced Amines, Chilled Ammonia
  - *Key Points*
    - Amine technologies commercially available in other industrial applications
    - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
    - High parasitic demand
      - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
    - Amines require **very** clean flue gas
- **Modified-Combustion Capture**
  - Oxy-Coal
  - *Key Points*
    - Technology not yet proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - High parasitic demand, >25%
- **Pre-Combustion Capture**
  - IGCC with Water-Gas Shift – FutureGen
  - *Key Points*
    - Most of the processes commercially available in other industrial applications
      - Have never been integrated together
    - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

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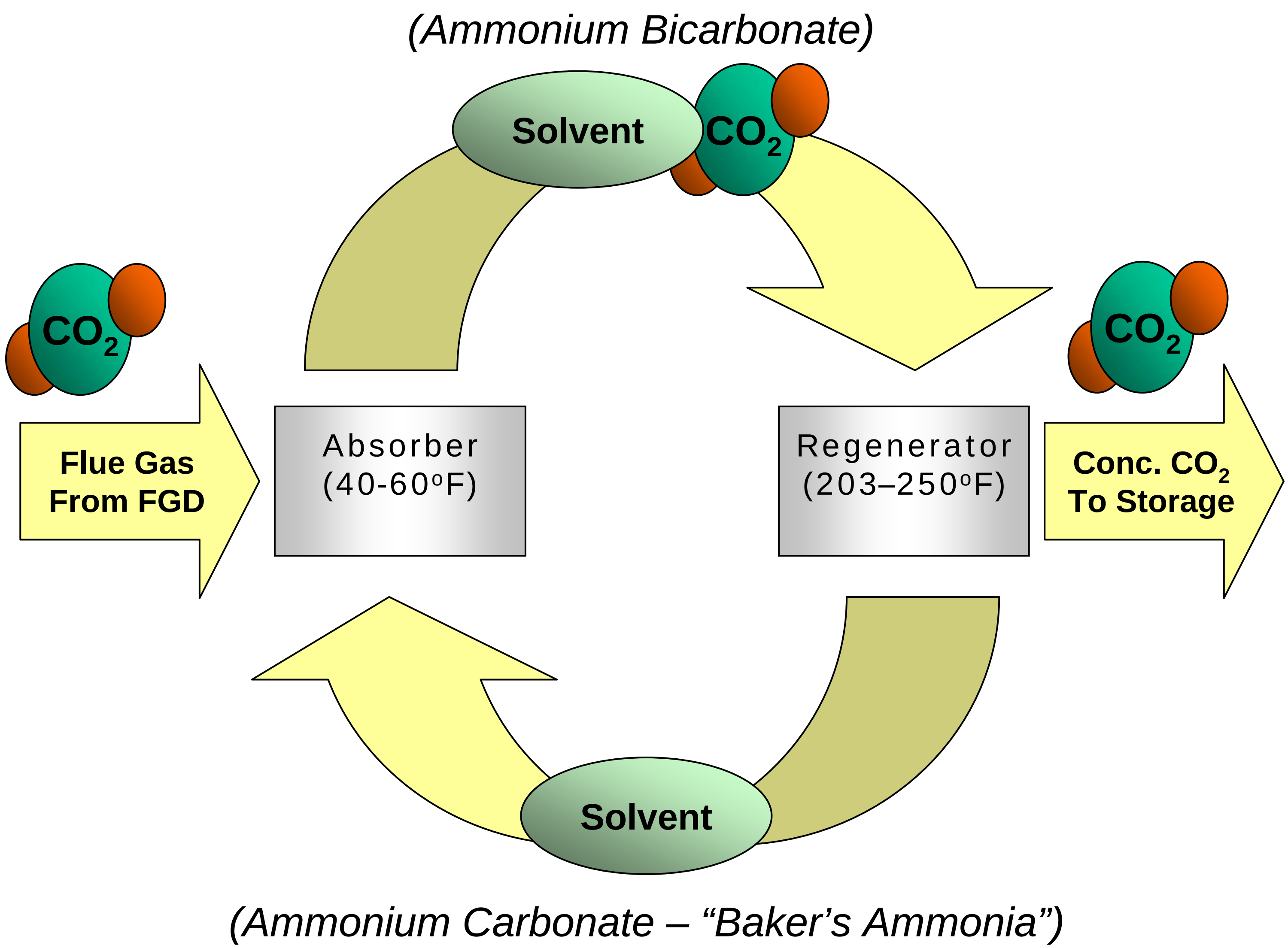
Alstom Chilled Ammonia Process
Post-Combustion Capture



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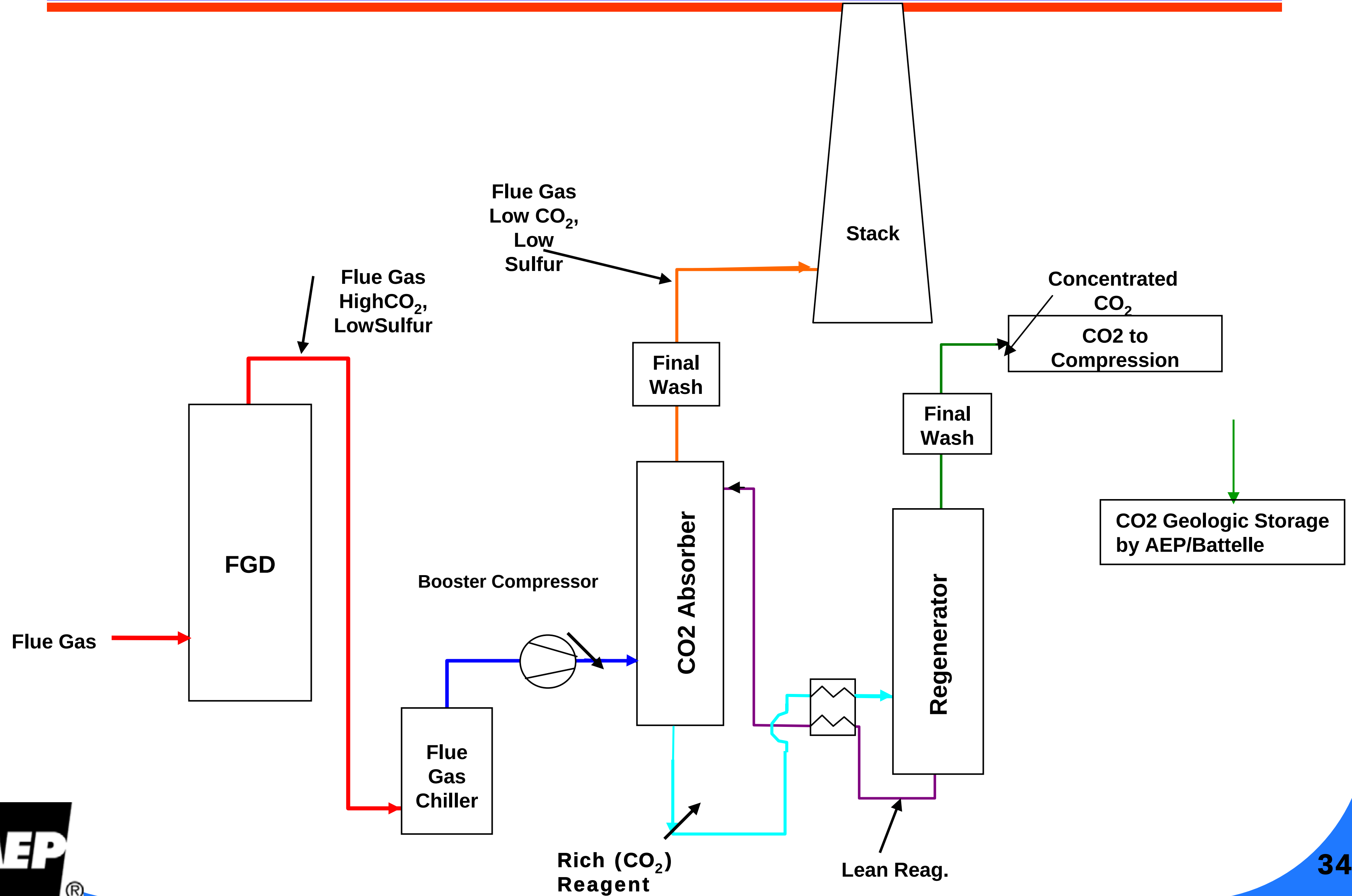

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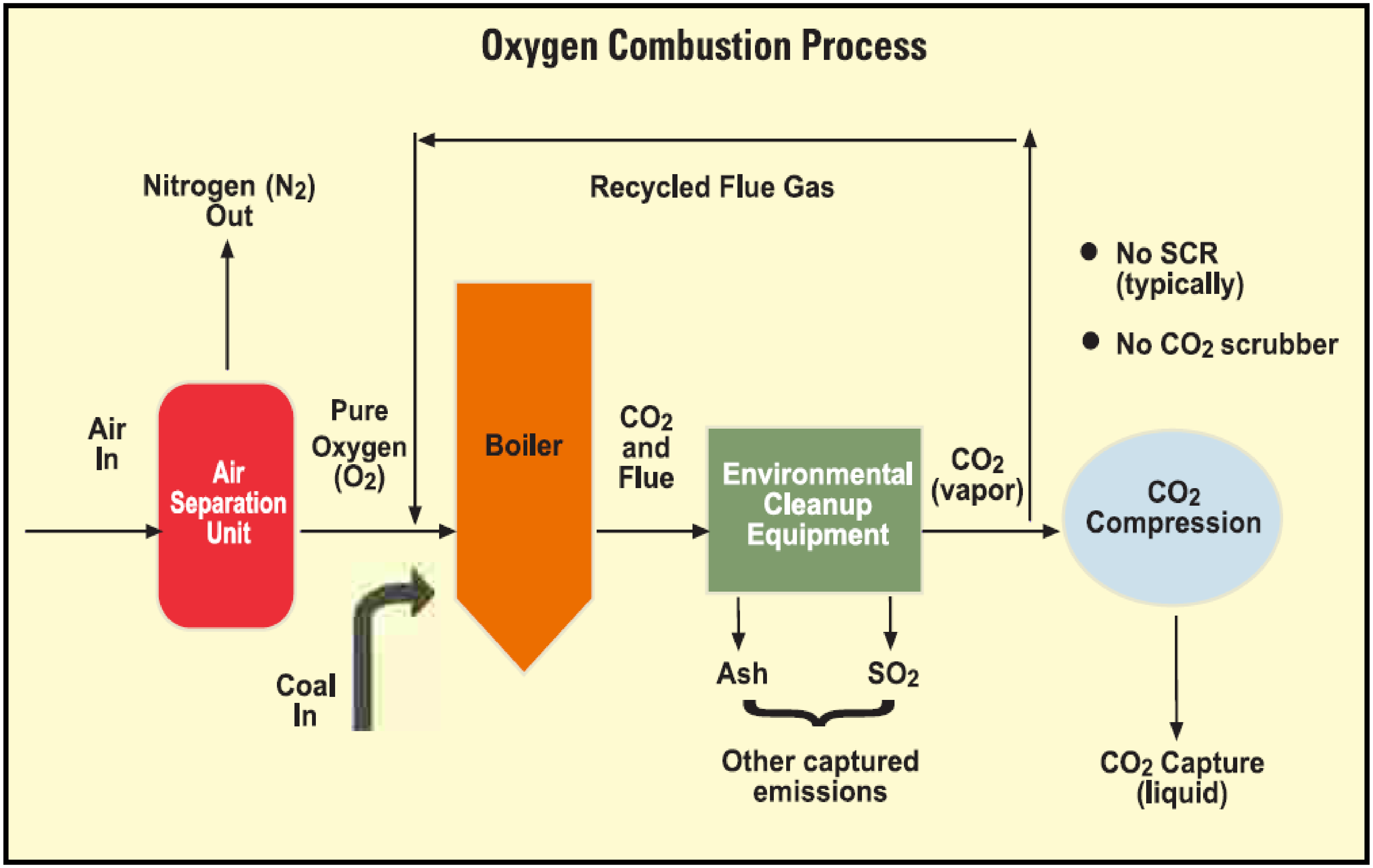
Babcock & Wilcox Oxy-Coal Process

Modified Combustion Capture



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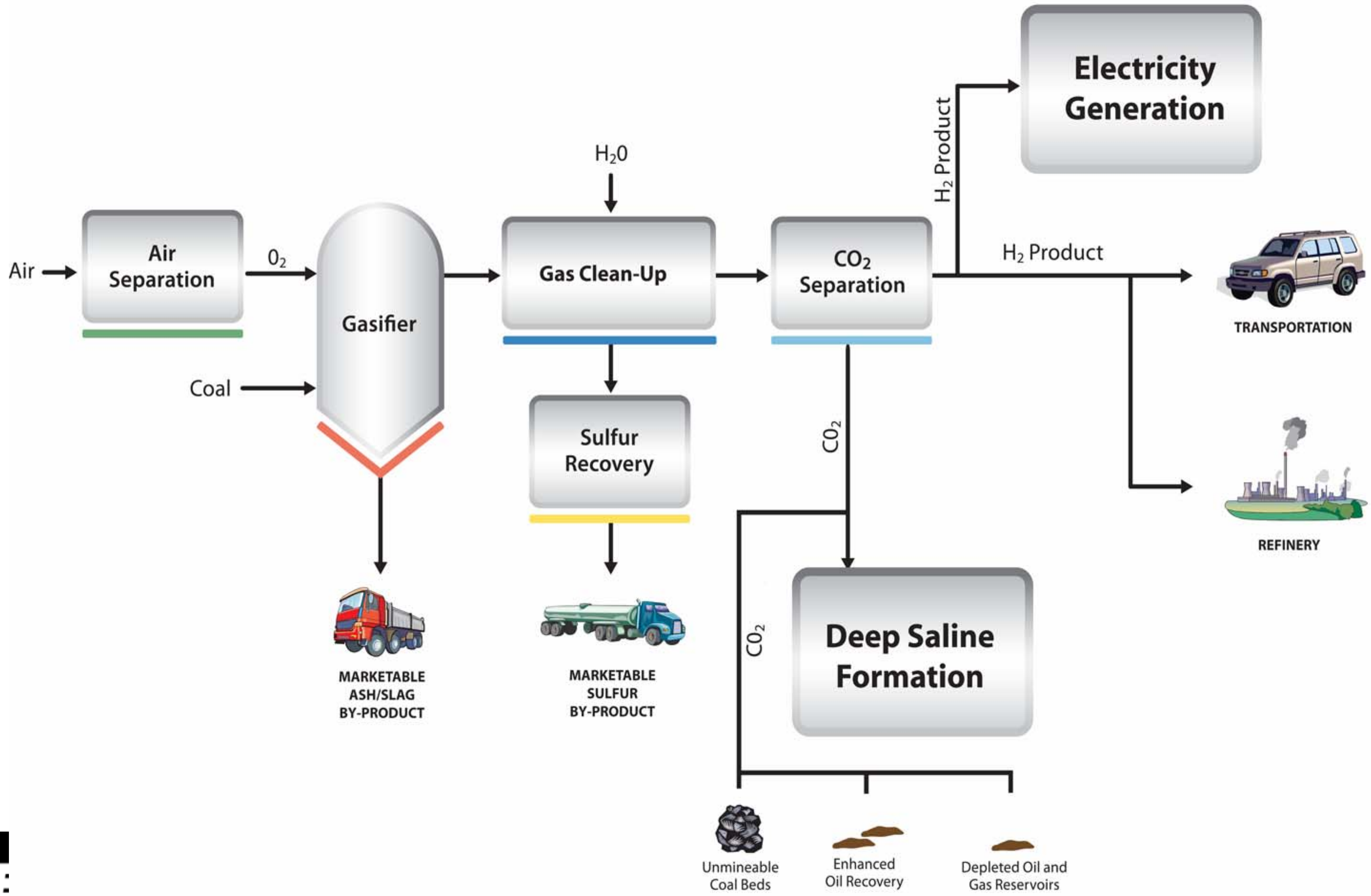
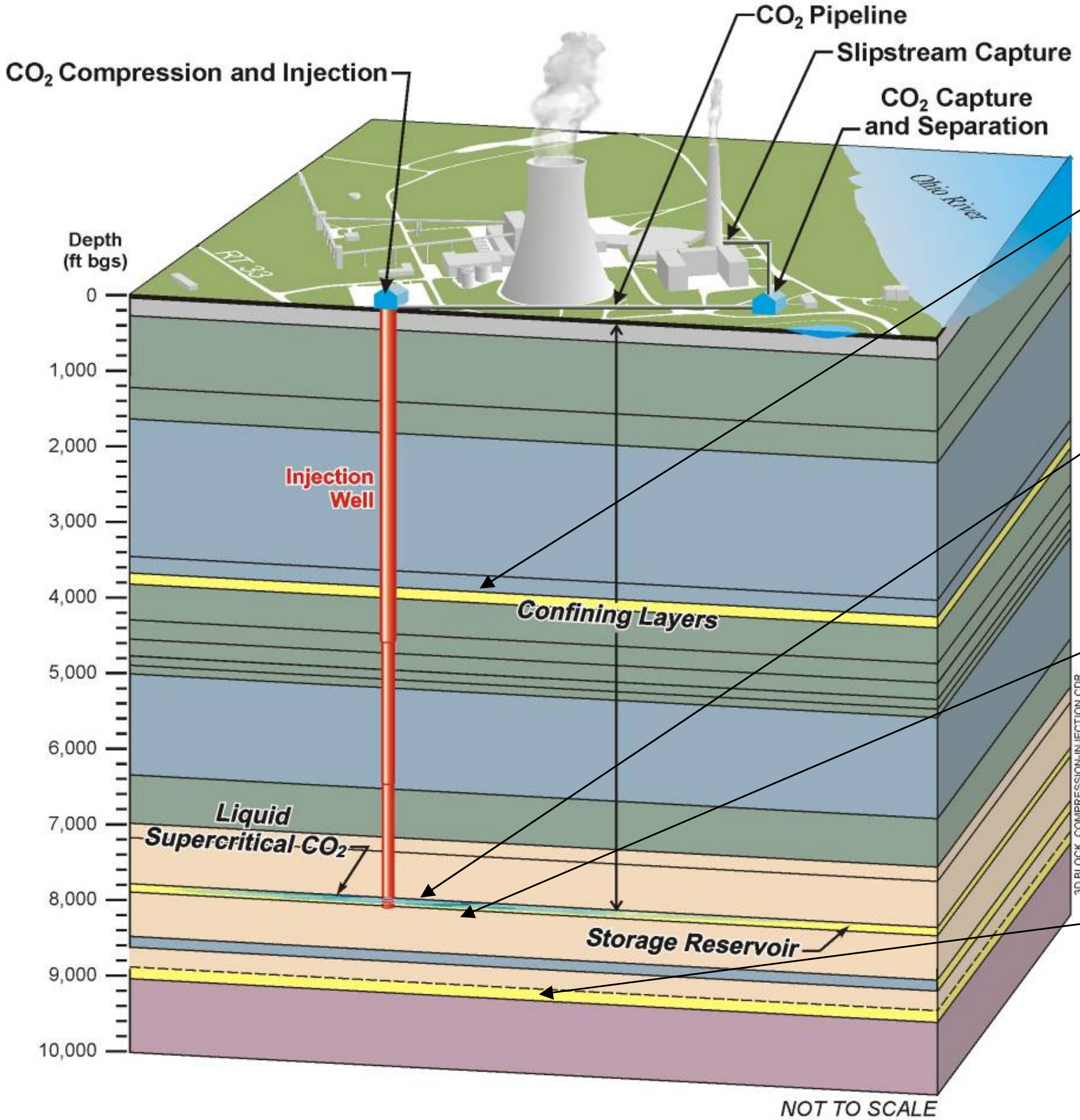
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5631 of 9556

FutureGen Water-Gas Shift Process

Pre-Combustion Capture



CO_2 Injectivity in the Mountaineer Area



CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the “B zone” within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

BMO Capital Markets Investor Meeting

"Focus on Ohio" Tour

March 18, 2008

Columbus, Oh

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Bette Jo Rozsa - Managing Director, IR
Julie Sherwood – Director, IR

Table of Contents

Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,600 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

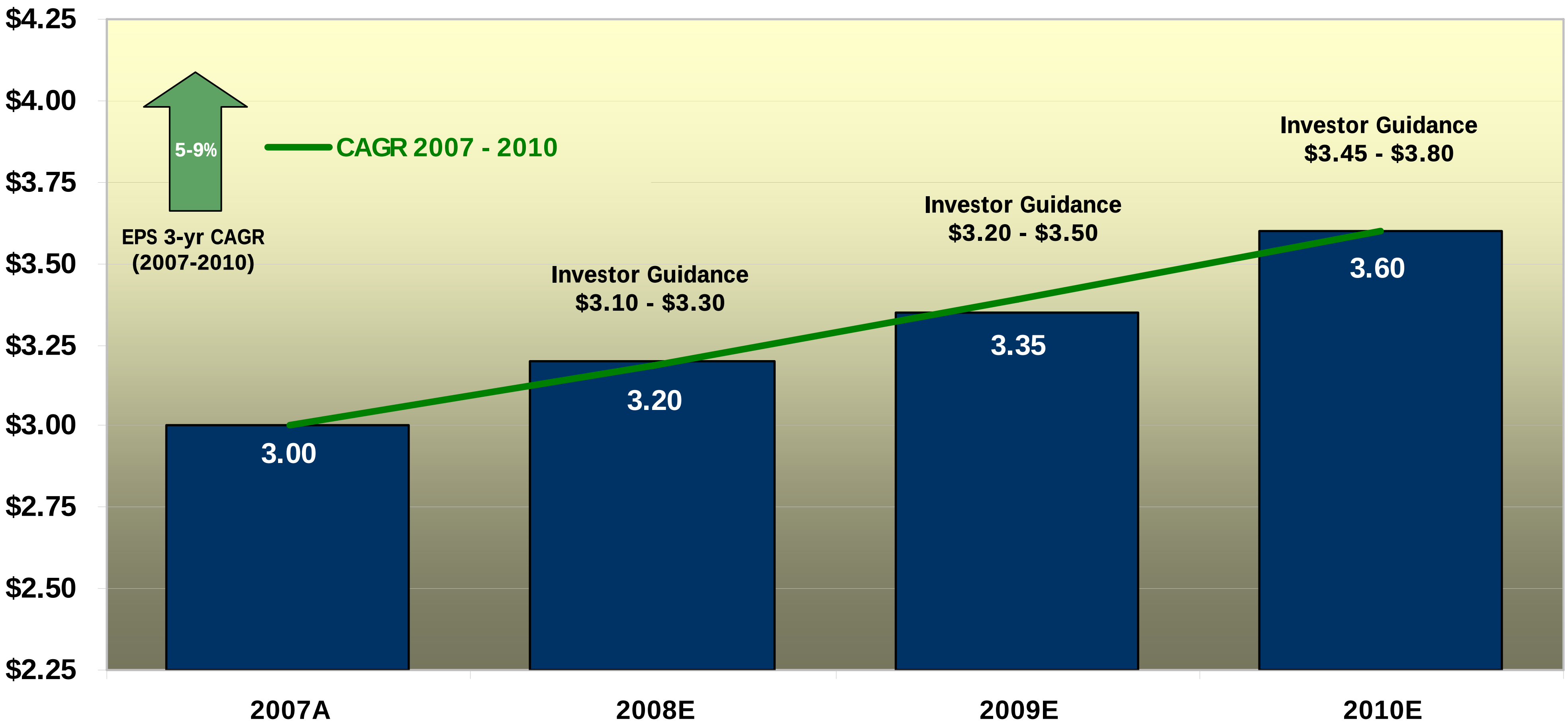
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast



5% to 9% earnings growth, largely predicated on outcome in Ohio

Vision for Sustainability

Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

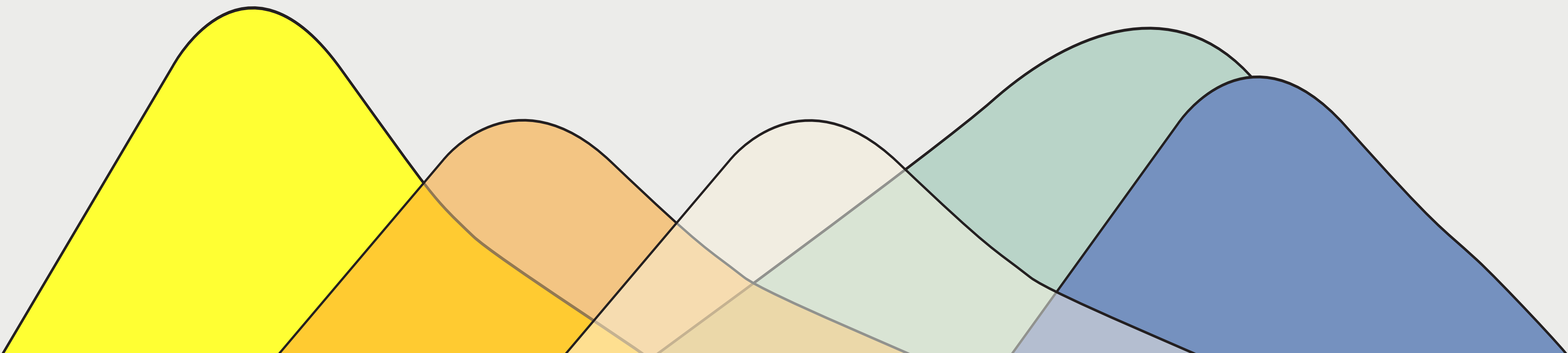
Existing generation and transmission control systems	**gridSMART℠**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



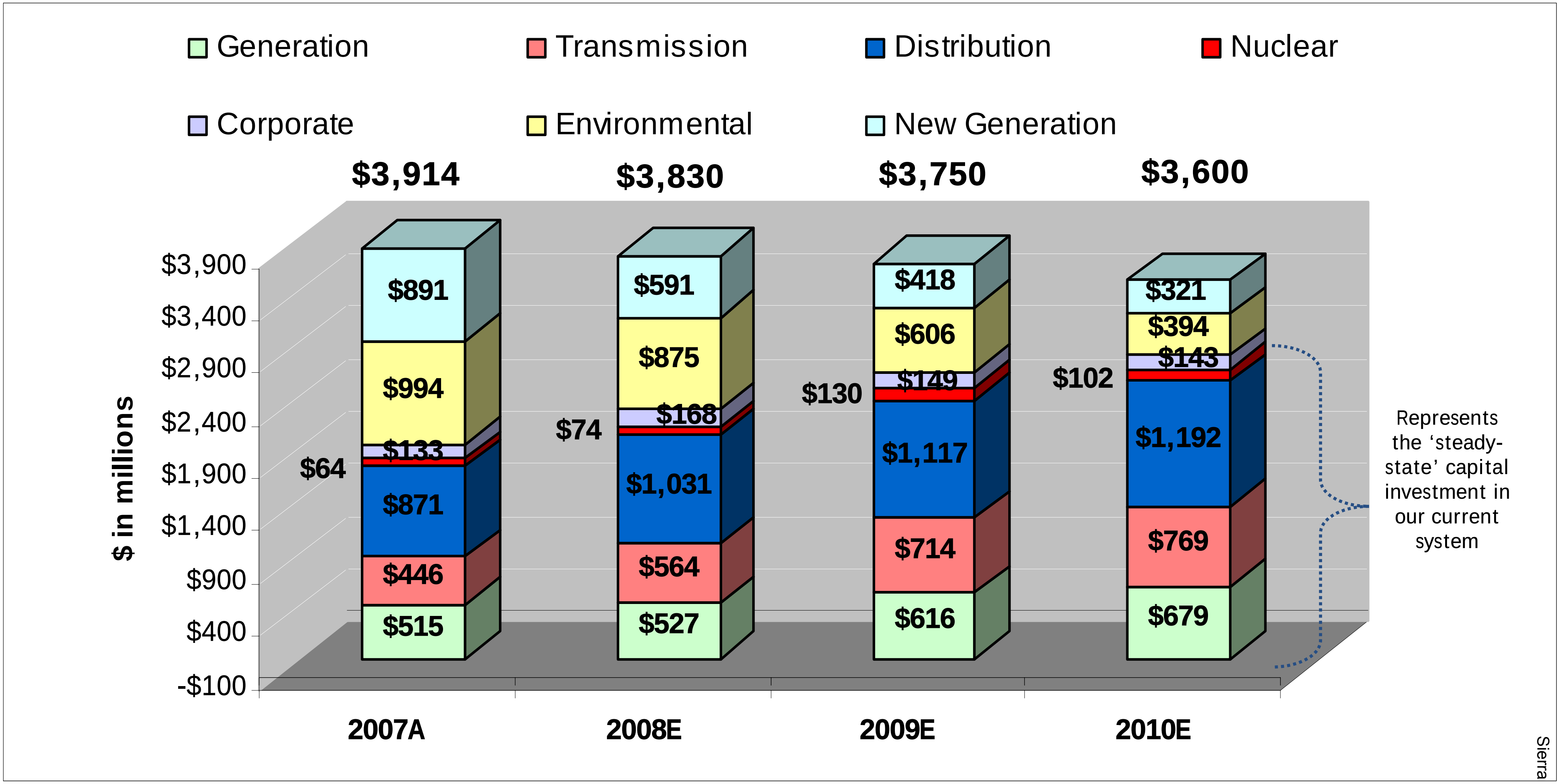
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual		Projection					
	2007		2008		2009		2010	
Planned Capital Investment (Excluding AFUDC) *	$	(3,914)	$	(3,830)	$	(3,750)	$	(3,600)
Planned Transmission Initiatives	$	-	$	(75)	$	(57)	$	(194)
Dividend on Common Stock		(630)		(659)		(664)		(669)
Cash Sources								
Cash from Operations		2,388		2,572		2,691		3,324
Proceeds from Sale of Assets		222		-		-		-
Common Stock Issued (Dividend Reinvestment Plan)		143		150		150		150
Change in Debt, Net		1,902		1,796		2,119		1,180
Other		(234)		(6)		(458)		(247)
Change in Cash		(123)		(52)		31		(56)
Ending Cash Balance	$	178	$	126	$	157	$	101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

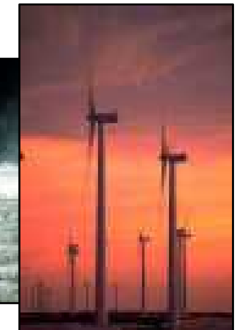
Capital investment is funded from cash from operations and debt issuances.

Domestic Generation Fleet

Coal/Lignite
68%

Nat. Gas/Oil
23%

Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,566 * MW Capacity

*** Includes 270MW of retired/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B(2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO pending remand from the Supreme Court of Ohio back to the PUCO.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

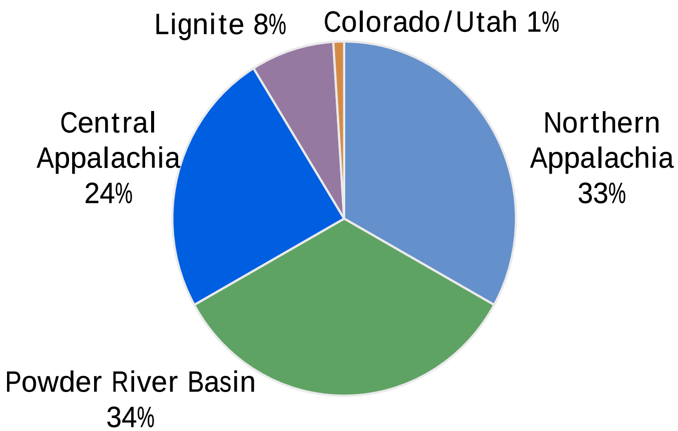
Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

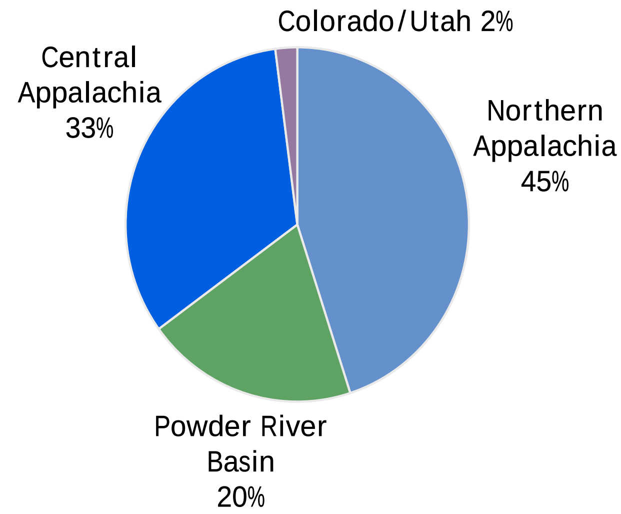
Total AEP System



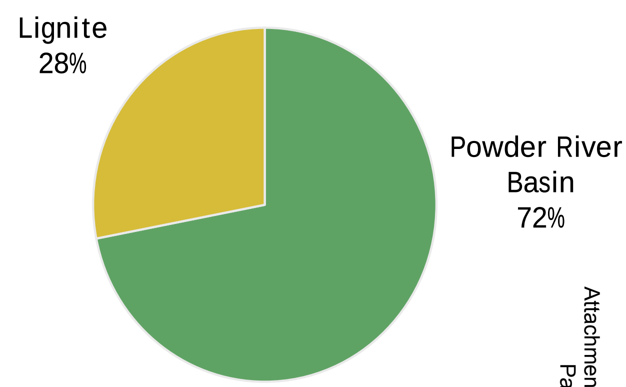
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

AEP East



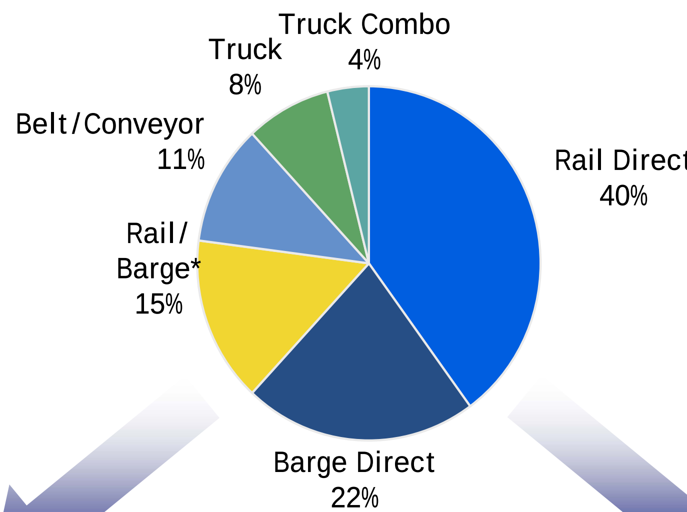
AEP West



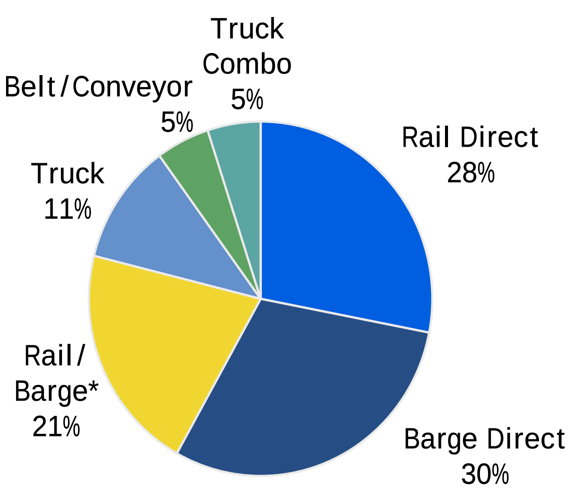
Coal Delivery

Total AEP System

2007 Actual



AEP East



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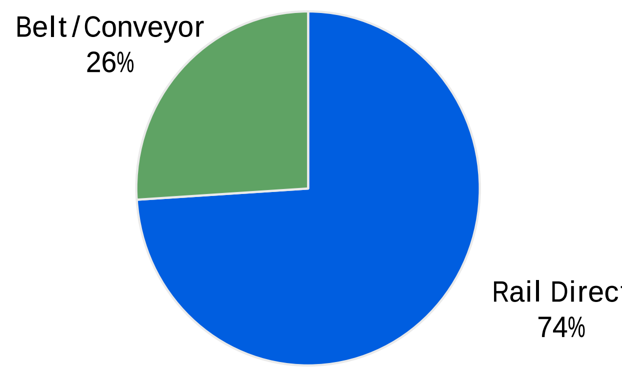


* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

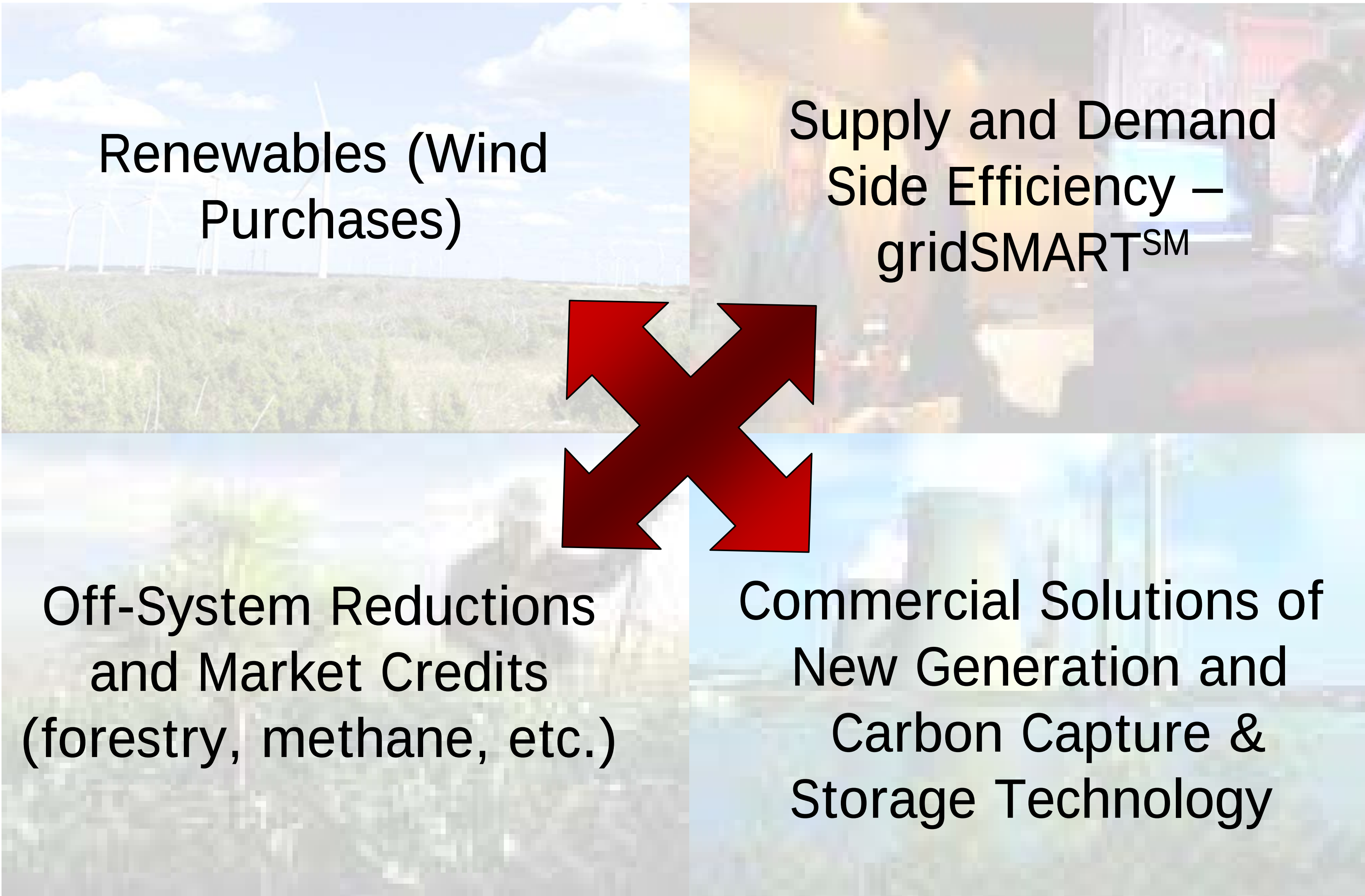
“Low Carbon Economy Act of 2007”

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives.

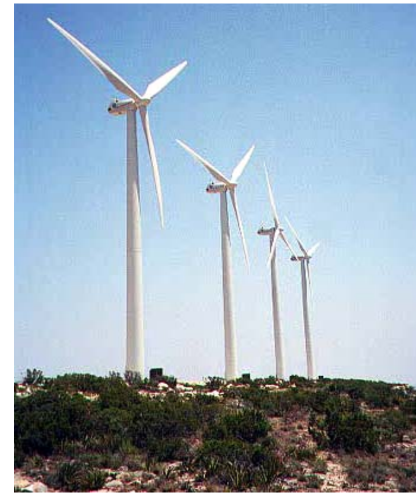
AEP Wind Operations/Purchases

Trent Mesa (2001)

150 MW (100 - 1.5 MW turbines)
Abilene/Sweetwater, TX

Southwest Mesa (1999)

- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser



Desert Sky (2002)

160 MW (107 - 1.5 MW turbines)
Bakersfield, TX

Summary

- Owned/Operated 385 MW
- Wind Purchases 392 MW
- Total Existing Wind at end of 2006: 777 MW
- **New Wind Purchases in 2007: 275 MW**

AEP will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011.

Off-System Reductions

Existing AEP Programs:

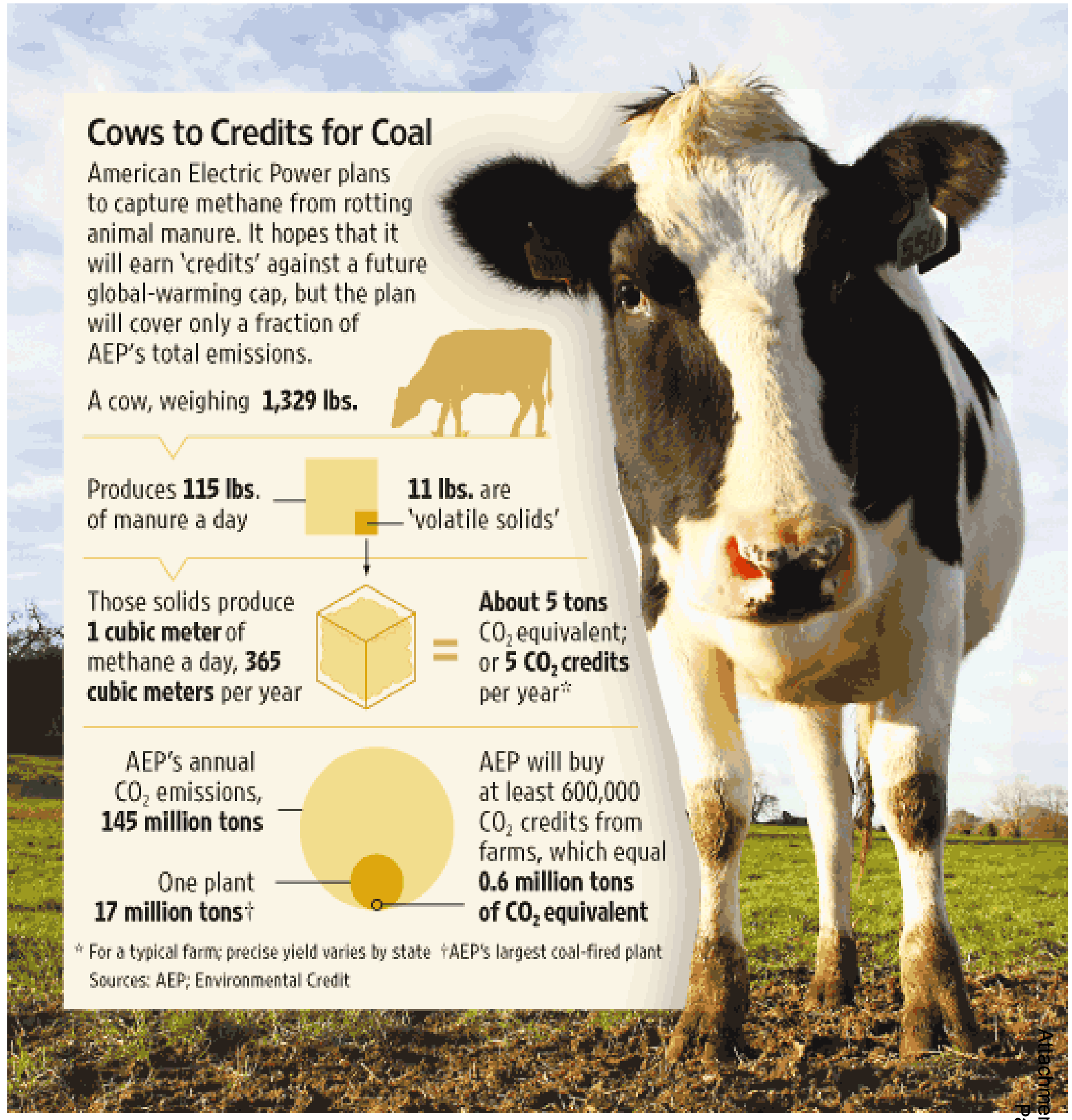
- Forestry - Domestic
  - 350,000 tons / yr
  - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 600,000 CCX carbon credits per year
  - Begins 2010
  - Runs through 2017
  - 51% of credits sourced from "AEP States"



Source: Wall Street Journal June 14, 2007

Advanced Generation & CO_2

Near Term:

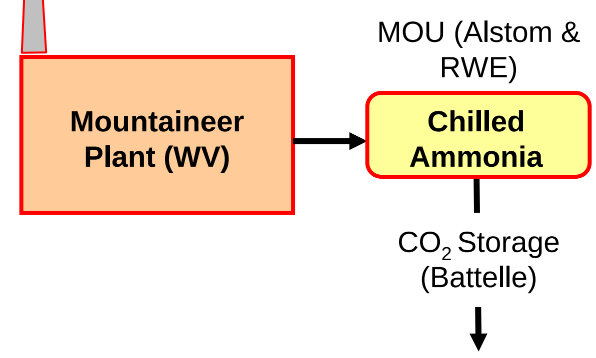
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

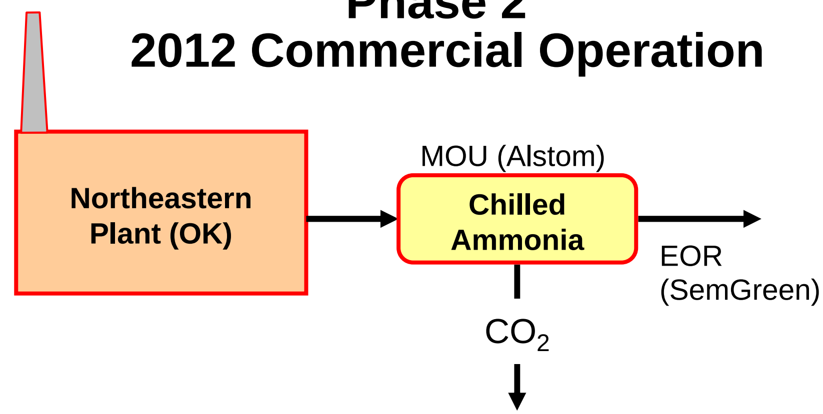
Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade

USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100^{o}F) coal plant in U.S (AR)

AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Oxy-Coal--AEP will also demonstrate (10MWe) and then install oxy-coal CO_2 capture & storage at a commercial sized coal unit (about 200 MWe)—feasibility study to be completed in 2008.

CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require <u>**very**</u> clean flue gas

Modified-Combustion Capture

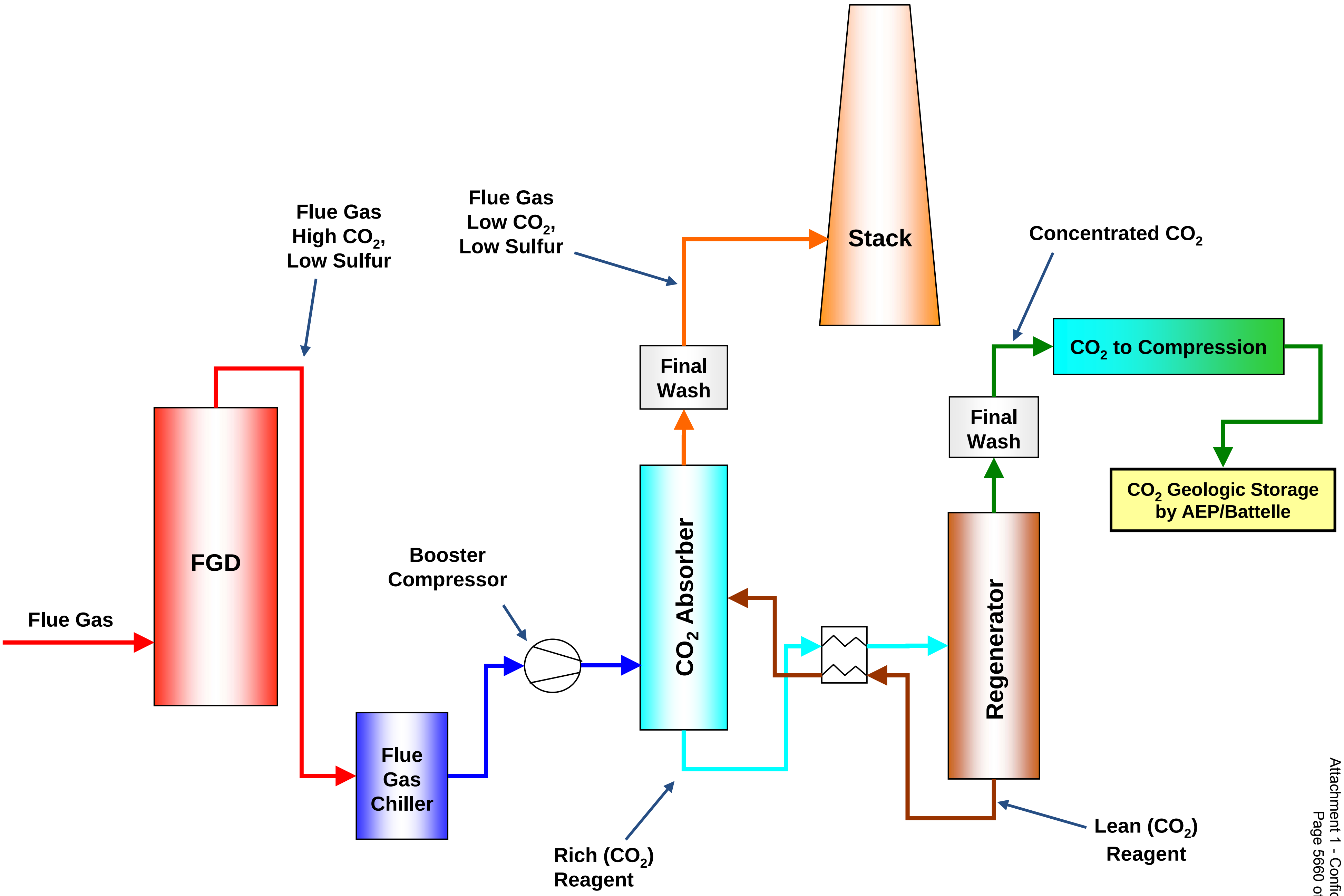
- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

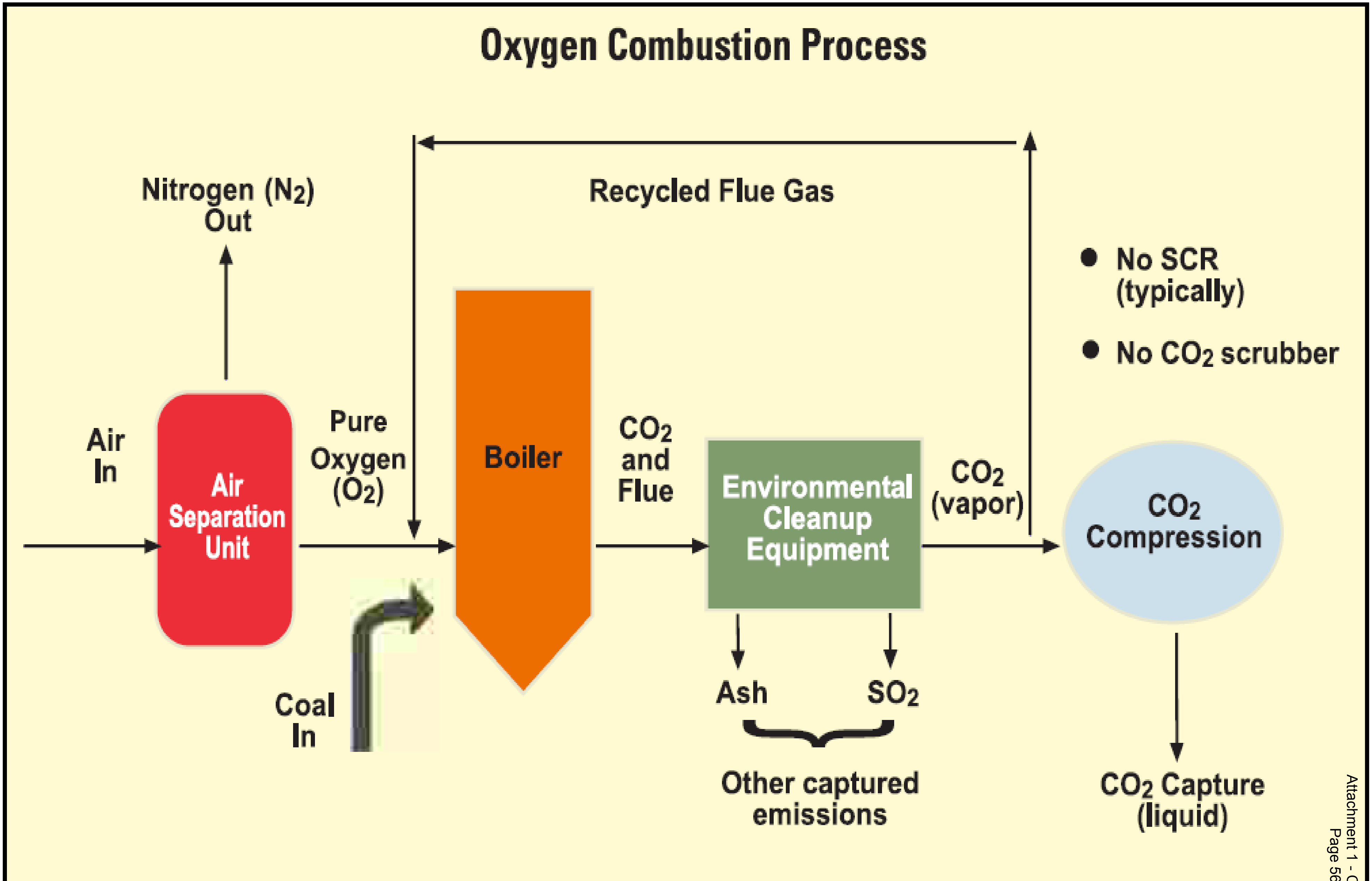
Alstom's Chilled Ammonia Process

Post-Combustion Capture



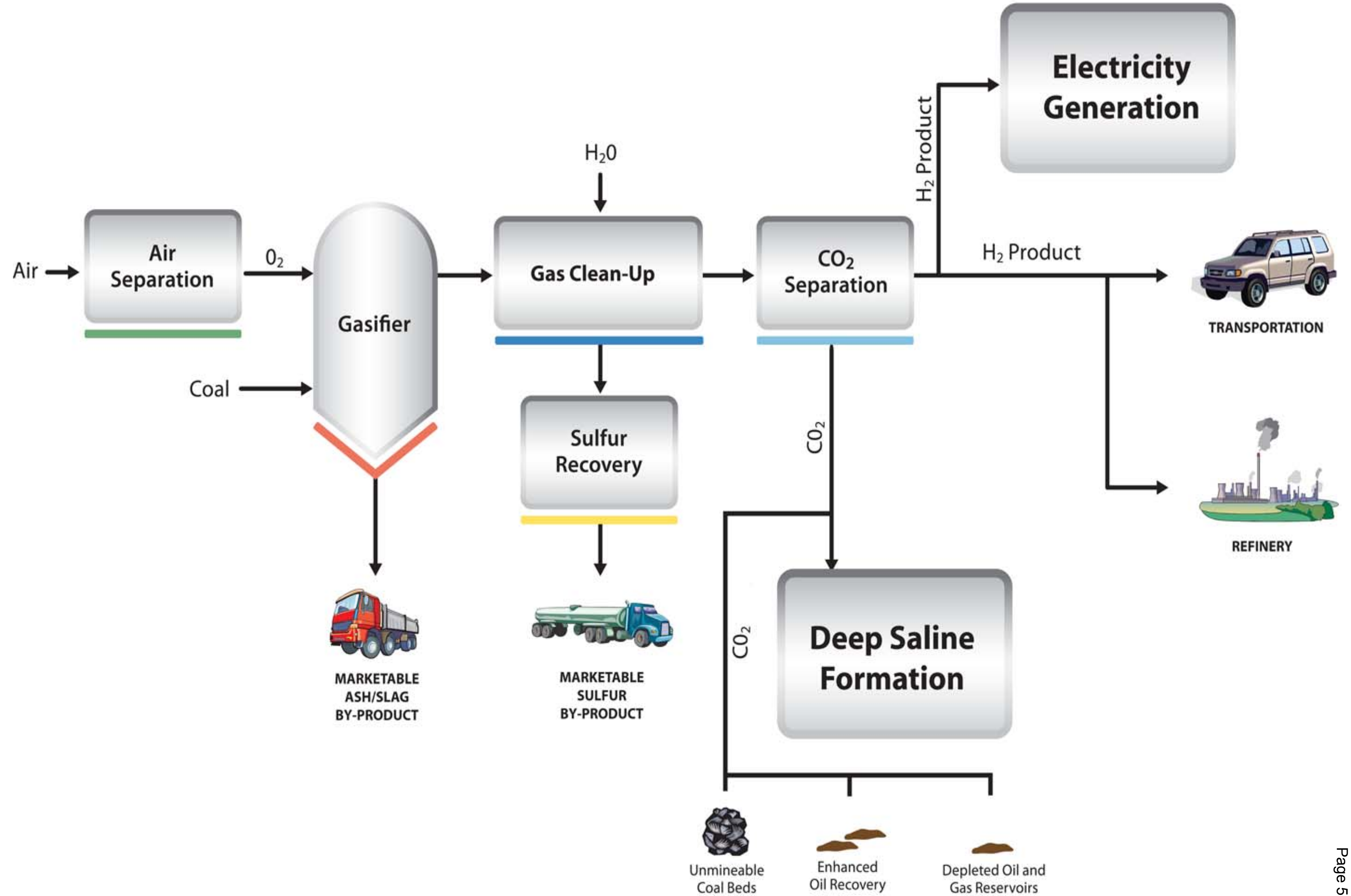
Babcock & Wilcox Oxy-Coal Process

Modified Combustion Capture

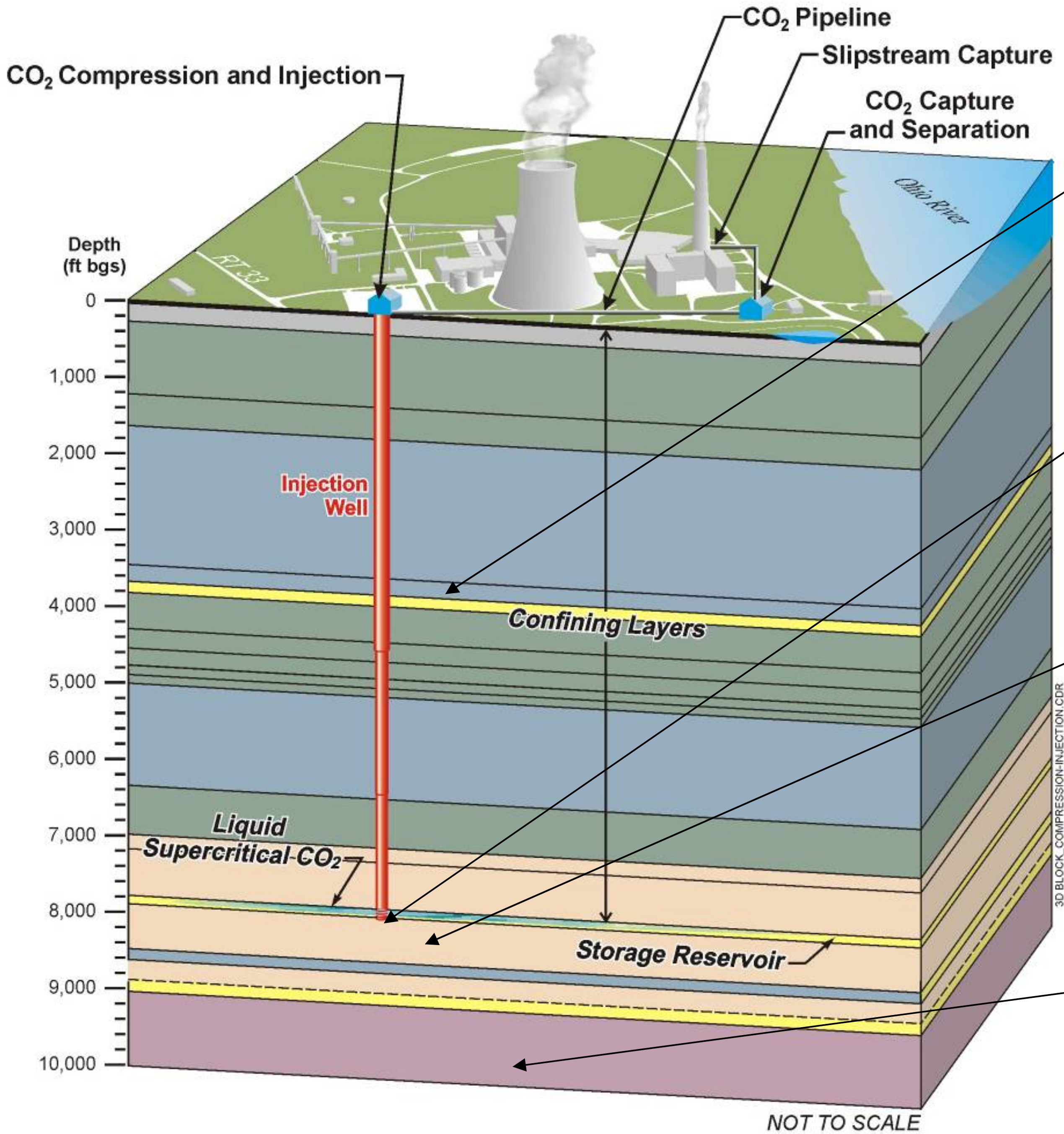


IGCC with Water-Gas Shift Process

Pre-Combustion Capture



CO_2 Injectivity in the Mountaineer Area



CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the “B zone” within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

Distribution - gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

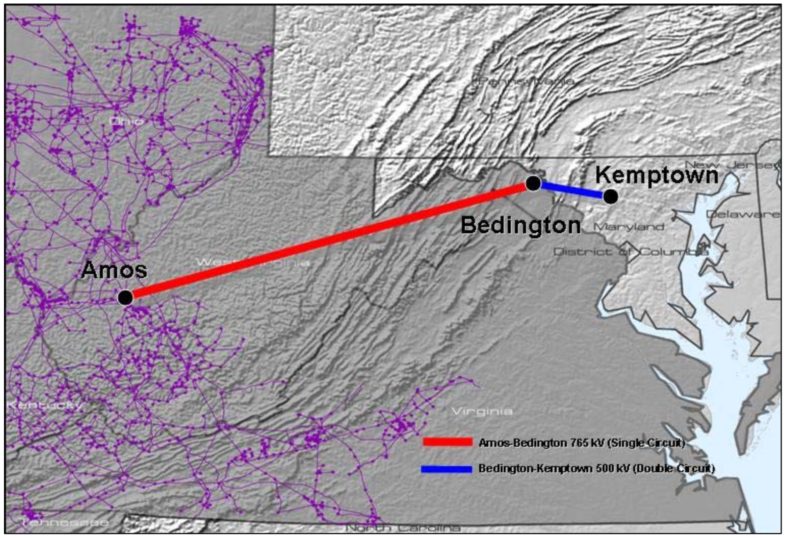
Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

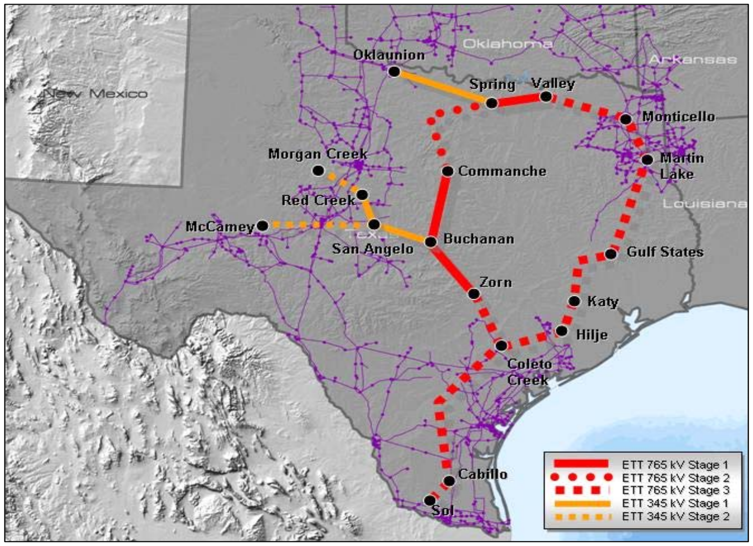
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

I-765TM Transmission: Investment Opportunities

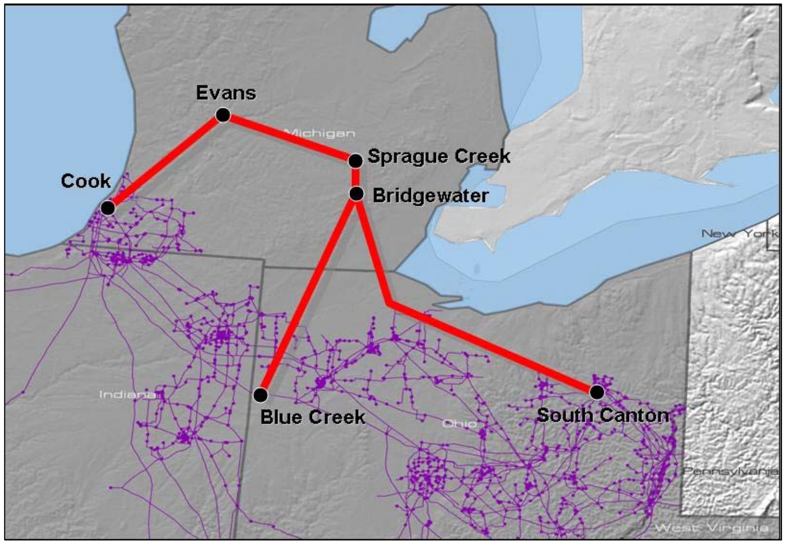
AEP is Advancing the Development of a National Interstate Today



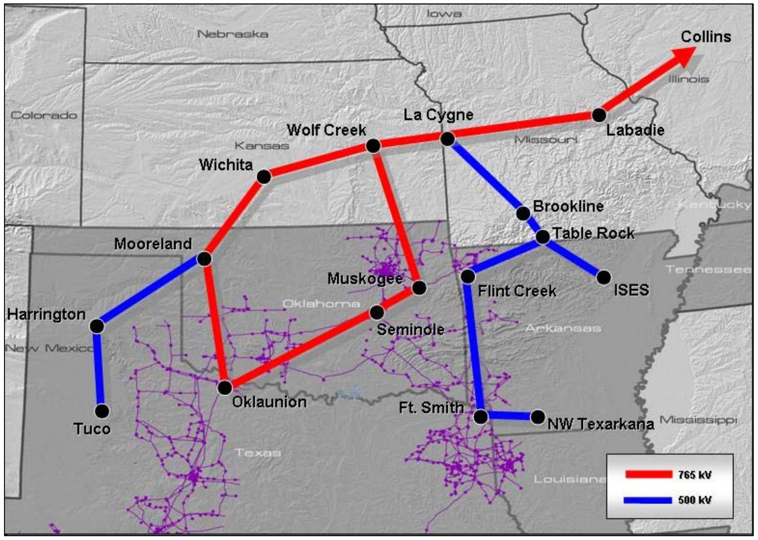
PATH Project (PJM)



ETT Proposal (ERCOT)



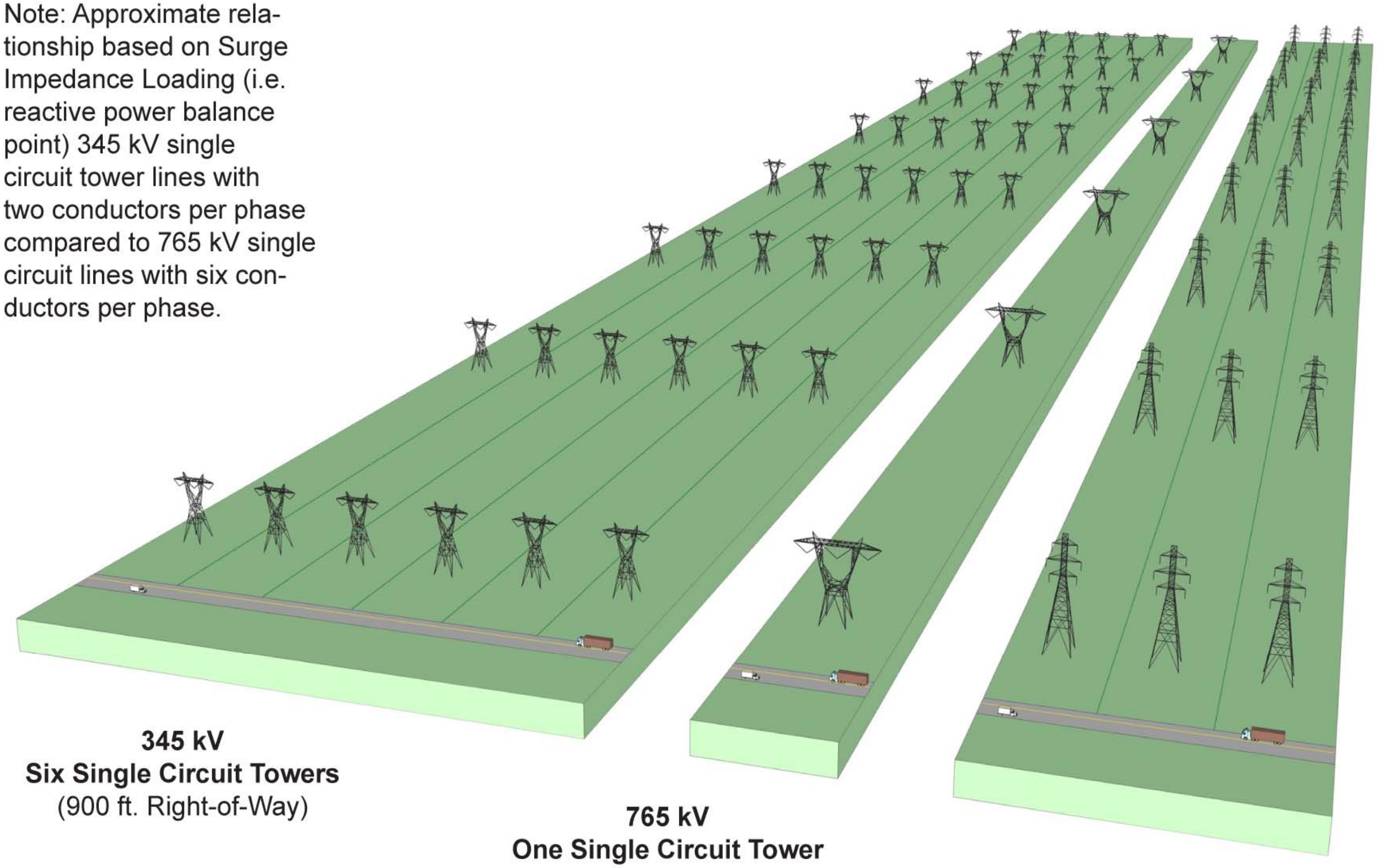
AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

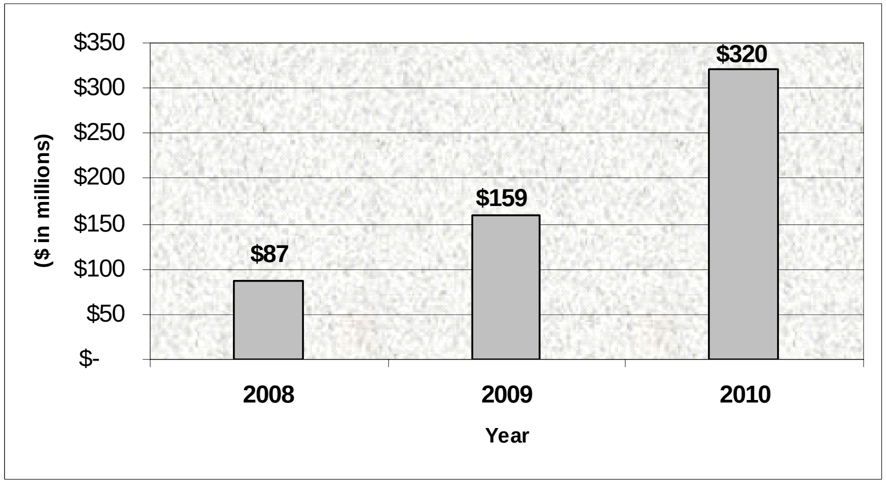
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

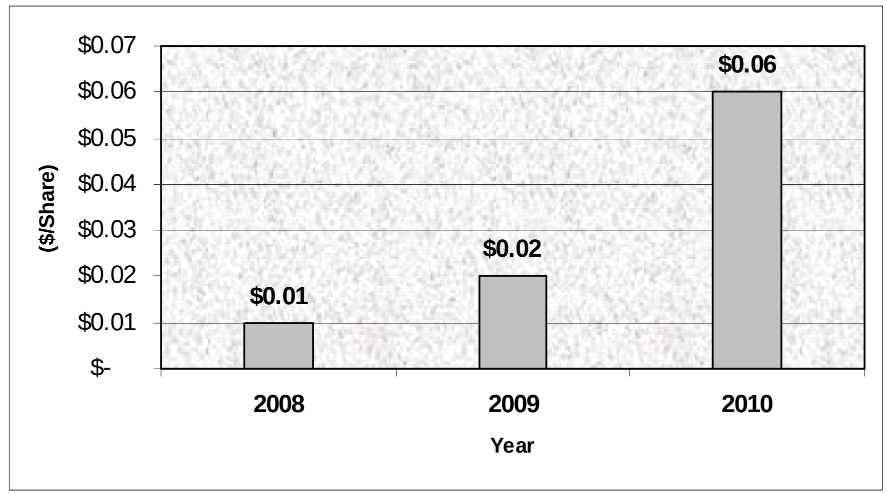


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

PATH Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



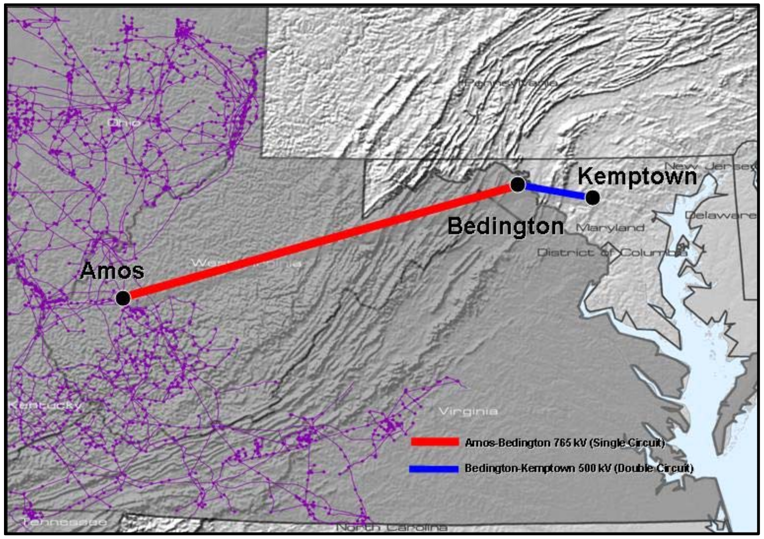
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- ## *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007; FERC order issued on February 29, 2008 approving:
    - *cash return on CWIP*
    - *14.3% ROE*
    - *recovery of all costs incurred prior to the time rates go into effect, and*
    - *recovery of all prudently incurred development and construction costs if the project is abandoned.*
  - FERC ordered the formula rate issue be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ## *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- ## *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012

PATH
Potomac-Appalachian Transmission Highline

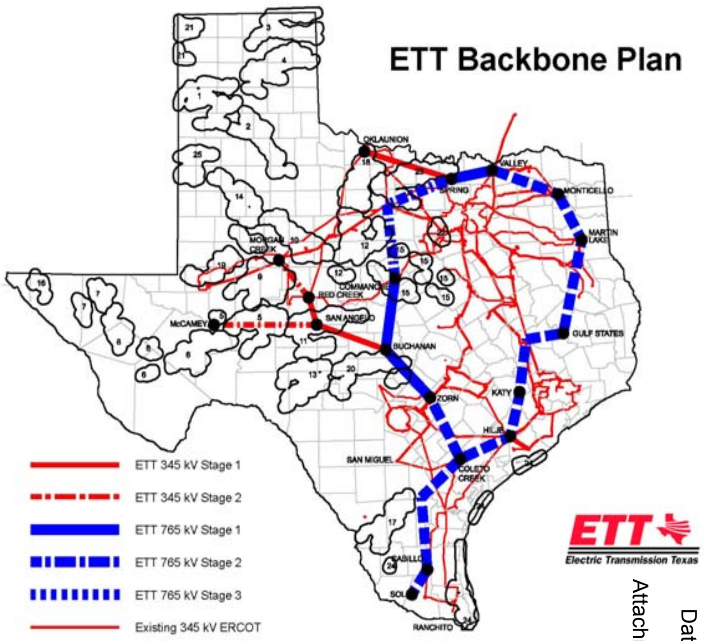
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- ***Transaction Structure***
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- ***Next Steps***
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- ***ETT ERCOT Backbone Proposal***
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5669 of 9556

Electric Transmission America (ETA)

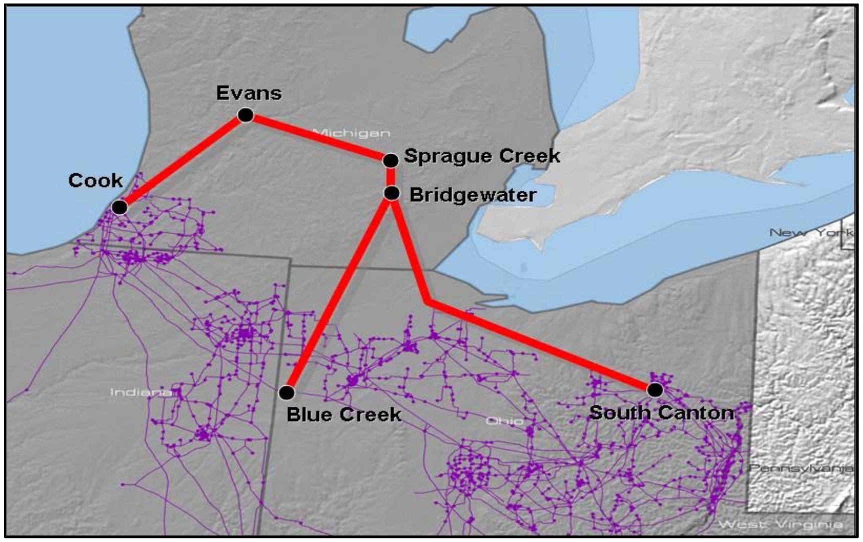
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015

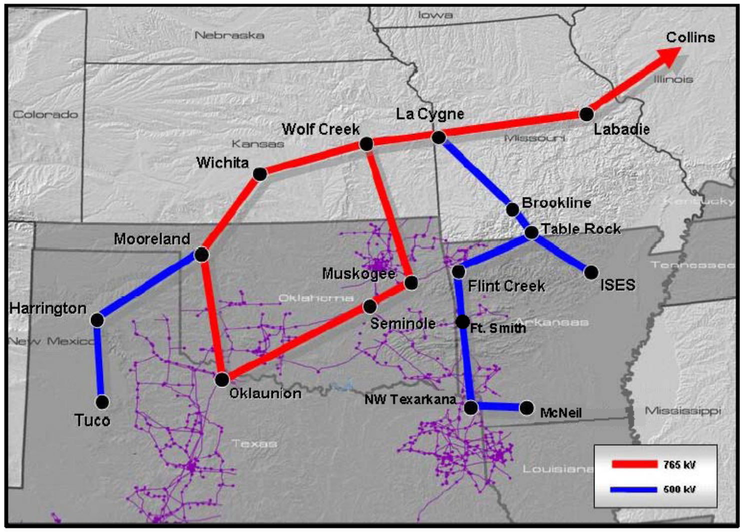


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Regulatory Activity Underway

- Ohio Post 2008
- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia for approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway/Completed

PSO Storm Cost Recovery Filing

- On October 24, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of sulfur dioxide (SO_2) emission allowances.
- Staff and intervenor testimony was filed January 17, 2008 and a settlement agreement has been signed and filed with the OCC. The settlement allows for the deferral of approximately $83 million related to both the January and December 2007 ice storms. A portion of the deferral would be amortized against gains on sales of allowances with the remainder collected from customers over a five-year period beginning in October 2008. An ALJ approved the settlement in February 2008 and the OCC approved it on March 13, 2008.

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008 PSO signed a settlement agreement to recover 50% of the costs ($10.5MM). This agreement has not yet been approved by the OCC.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10.5MM of the increase relates to 3rd party and the rest, if approved would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate. We proposed an 11.5% ROE.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going. Intervenors and AEP will meet on March 20, 2008 to review any additional issues and report back to the settlement judge on the status of the settlement discussions.

Regulatory Activity Underway/Completed

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 629MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony included a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. On March 6, 2008 the WV PSC granted the Certificate of Public Convenience and Necessity, and approved the use of a surcharge during construction.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order on April 16, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. On March 13, 2008, the Ohio Supreme Court issued an order remanding the Ohio IGCC proceeding back to the PUCO.

Regulatory Activity Underway/Completed

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. A positive ALJ report was issued on February 8, 2008 recommending approval of the plant. An order is expected in March 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. A final order is expected on March 27, 2008.

Regulatory Activity Underway/Completed

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was filed February 29, 2008 and hearings will commence on April 7, 2008. Staff testimony was favorable.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	8.15%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	23.86%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	13.01%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo-LA	$434MM	11.10%	12/29/1999	8.74%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	11.33%
Texas-TNC	$530MM	9.96%	6/1/2007	8.32%

Detailed Ongoing Earnings Guidance

2007A: $3.00

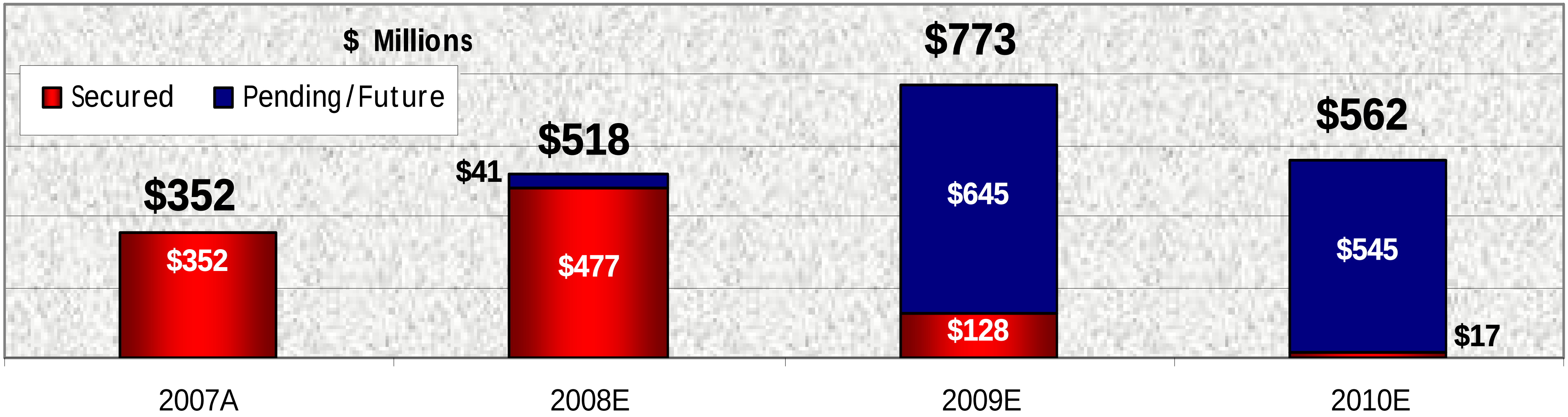
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Incremental Rate Relief Assumptions



- **92% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings & PSO ice storm recovery.**

- **2008 Pending: SWEPCo - LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Commitment to Credit Quality

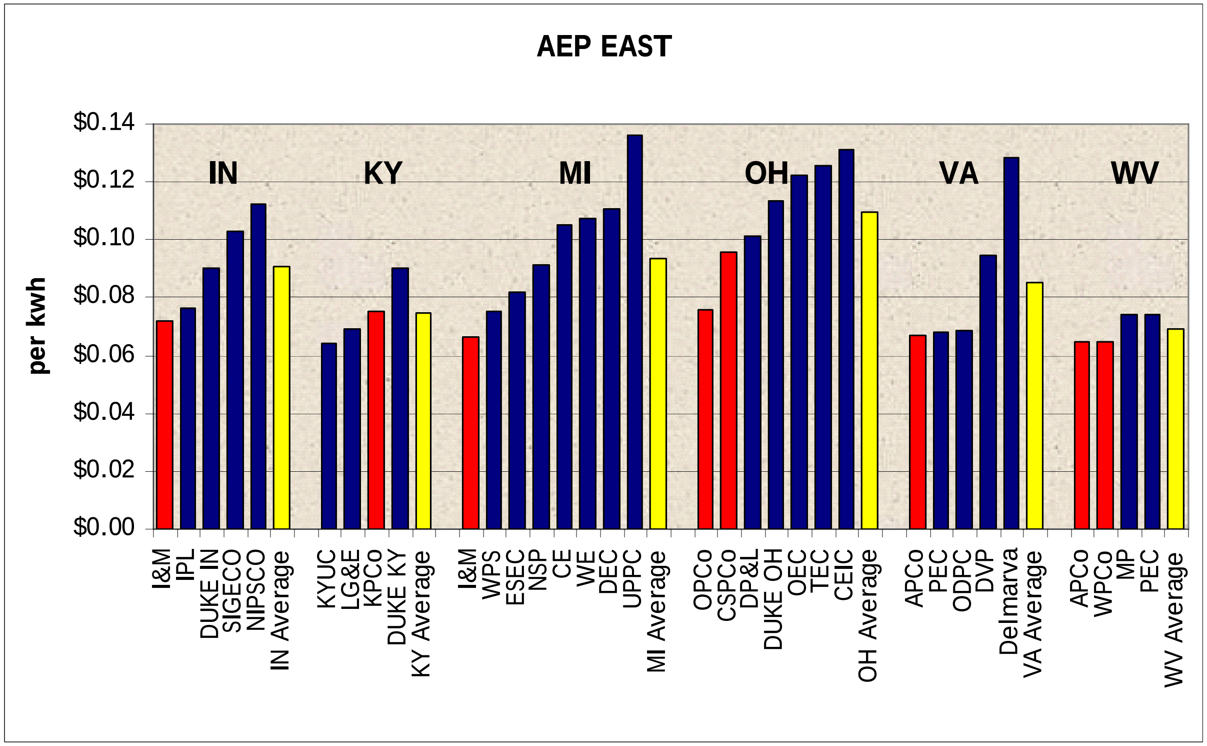
- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

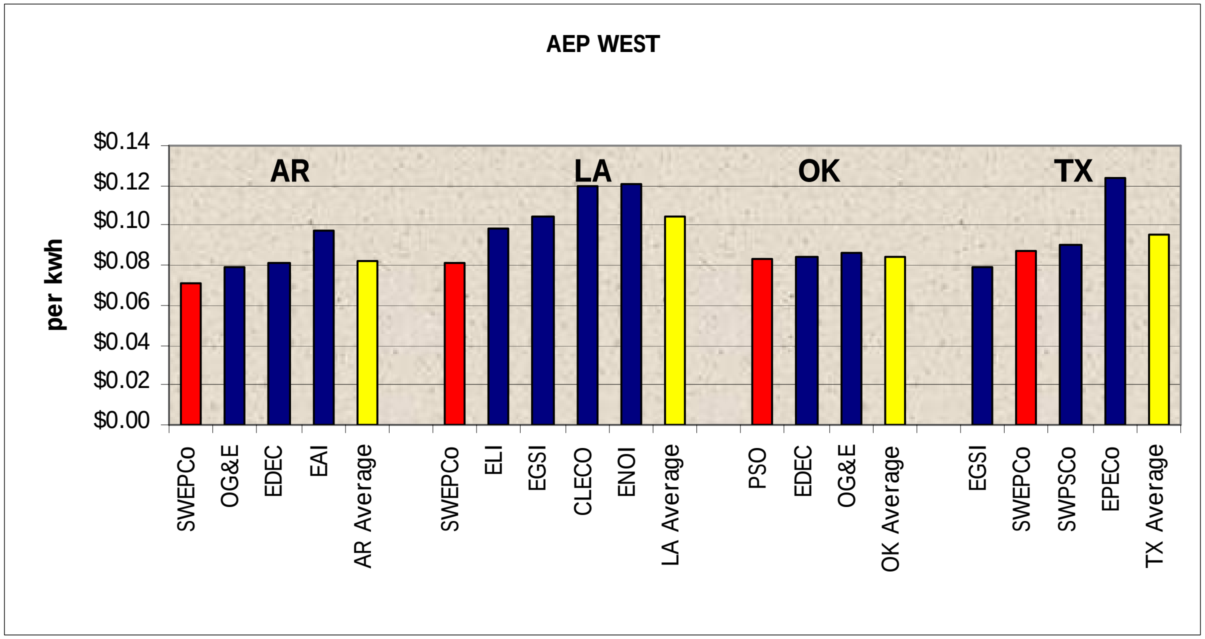
Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

American Electric Power, Inc.

Boston Road Show

Hosted by JP Morgan

July 10, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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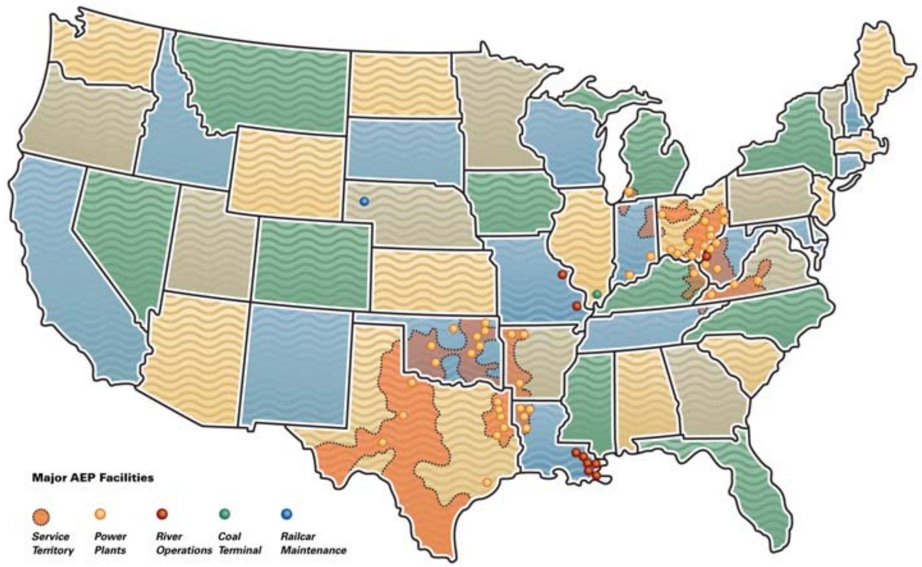
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

- 20,000 employees

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

AEP®

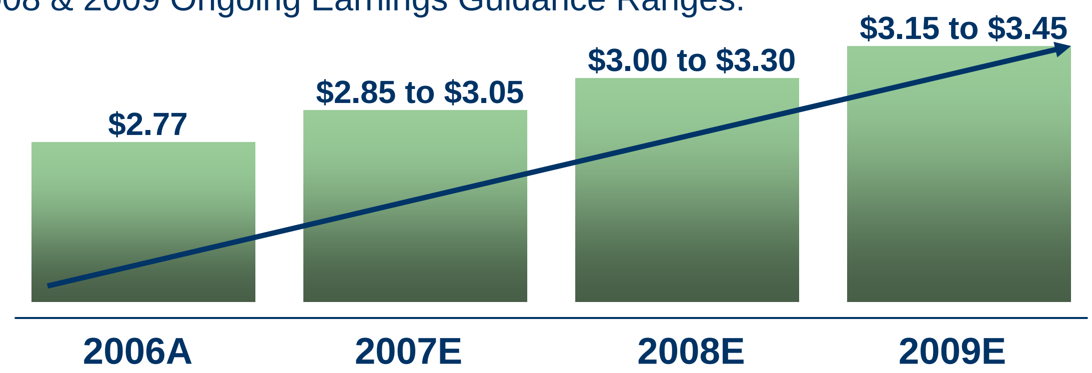
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

Utility Investment Drives Growth

AEP®

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

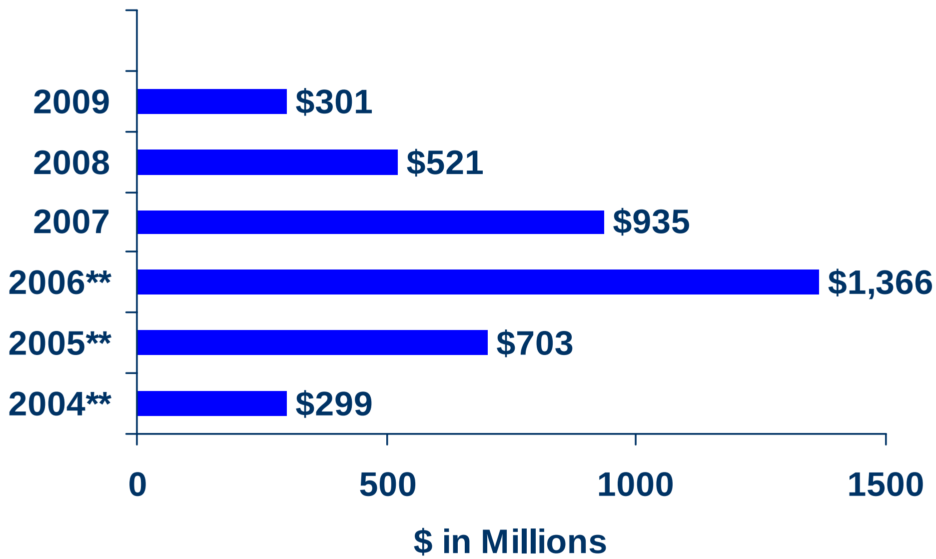
Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash
From Operations Via Rate Relief And Debt Issuances

$4.1 Billion Environmental Investment

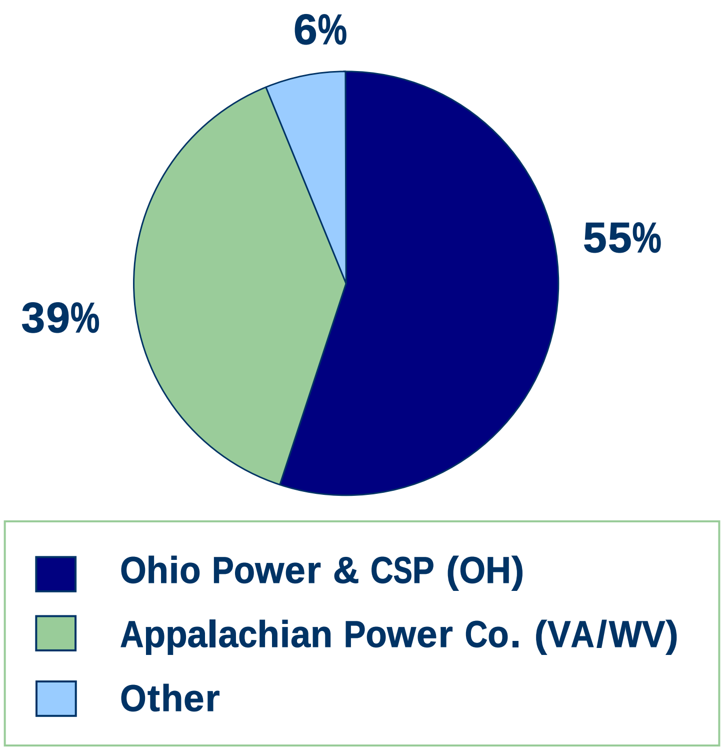
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



Majority Of 2006 & 2007 Dollars Will Be Invested In Ohio & APCo

Purchased Generation

AEP®

Waterford

–821 MW combined-cycle gas plant
–$220MM purchase price
–Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

–505 MW simple-cycle gas plant
–$100MM purchase price
–APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

–480 MW simple-cycle gas plant
–$102MM purchase price
–Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

–1140 MW combined-cycle gas plant
–$325MM purchase price
–AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B(1)	Coal	Ultra-supercritical	600(3)	2011
PSO	Red Rock	Oklahoma	$1.8 B(2)	Coal	Ultra-supercritical	950(4)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	600	2012
CSP/OP	Great Bend	Ohio	Under Review(3)	Coal	IGCC	600	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(2) PSO will own 50%, or 475 megawatts, totaling approximately $900MM in capital investment
(3) The FEED (front-end engineering and design) study with GE and Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit filed and approved in February 2007
  - Units 3 and 4 online by summer peaking-season 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes costs for Southwestern and Riverside peakers to be recovered through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
- Air permit approval expected in August 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

- Used and useful determination filed in February 2006 – Hearings commenced July 9, 2007 and approval is expected by September 2007
- Air permit approval expected in August 2007
- Regulatory Recovery
  - Order expected in PSO rate filing in July 2007 – filing included request for CWIP treatment for new projects
- Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- Regulatory Recovery Filing
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO2 capture provides pressurized CO2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC Technology Is Strategic To Keeping Coal In The Money

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

Incremental Rate Relief Composition

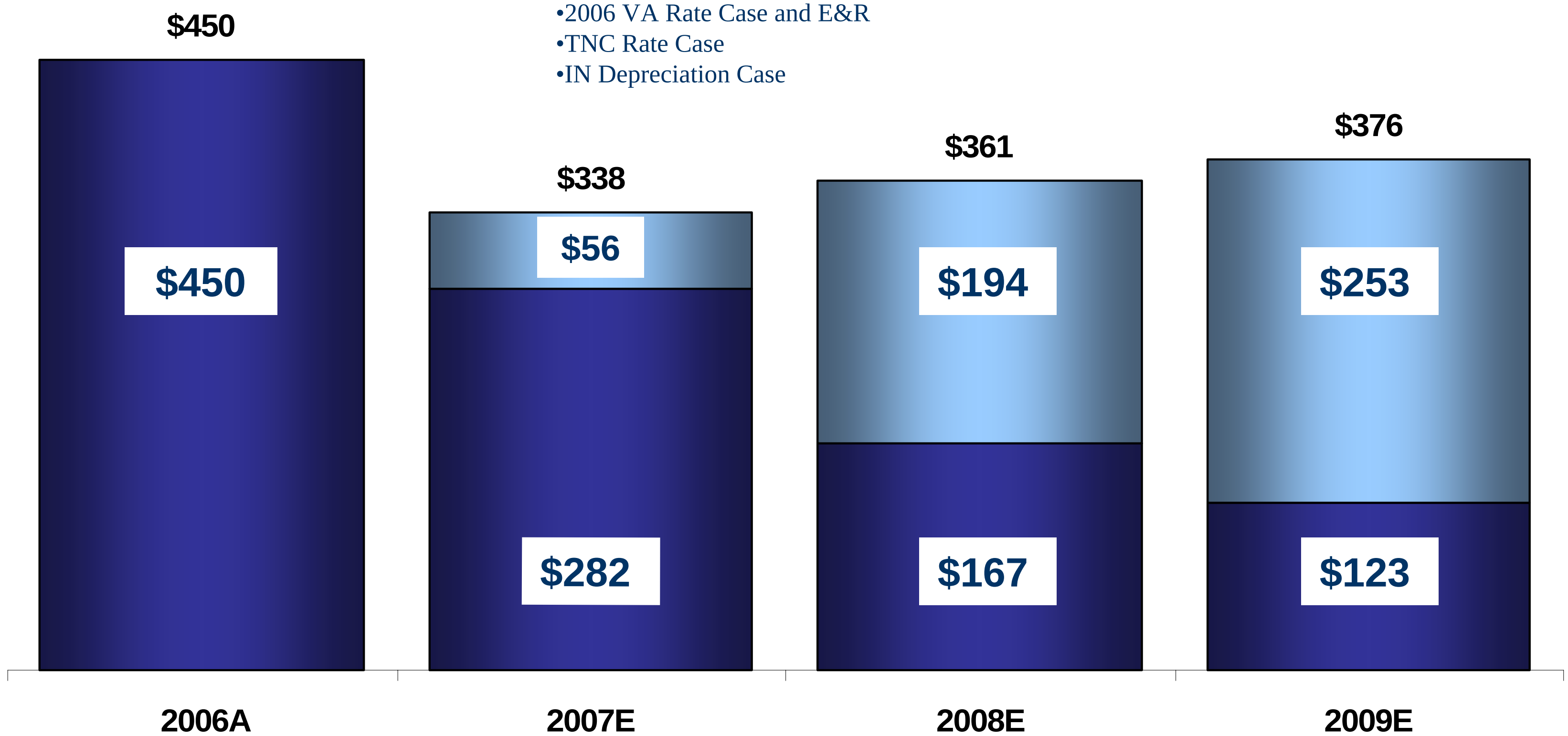
$ Millions

Secured

- OH RSP
- 2006 WV Rate Case, including ENEC
- 2006 Kentucky Rate Case
- FERC & OH OATT
- 2006 VA Rate Case and E&R
- TNC Rate Case
- IN Depreciation Case

Pending/Future

- PSO Rate Case - $49.6 increase requested
- TCC Rate Case - $69.9 increase requested
- SWEPCo proceedings
- Cases yet to be filed



Rate Relief Is A Critical Element To AEP's Financial Success

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - ✓ SWEPCo Turk Plant Filings in Arkansas and Louisiana for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP®

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
July 2007	Final order expected

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- I&M requested a test year of the twelve months ended September 30, 2007 but it is up to the IURC to determine the test year to be used.
- I&M will file its revenue requirement in approximately 2-3 months after the end of the stipulated test year.

Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings are scheduled for July 16-19, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

Regulatory Activity Underway

West Virginia Mountaineer IGCC Filing

- Testimony filed on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for September 10-14, 2007 with an order on or before December 2, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for the Used and Useful Determination commenced July 9, 2007.
- Hearings for OG&E's cost recovery commence July 19, 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Depending on contested issues, public hearings will begin either July 19, 2007 or August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

✓ Results in $24 Million annual increase in base rates

✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)

✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

✓ Results in $85.5 million net increase in revenues effective July 1, 2007

- ✓$54.8 million covers increased costs related to coal and purchased power
- ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
- ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year

✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding

✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

In Hand to Date - $282MM of the $338MM Rate Recovery in 2007 Guidance

Summary of 5-7% Long-Range Growth Components

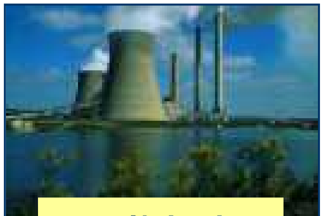
AEP®

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - – Generation plant purchases & build
  - – Transmission – interstate & intrastate
  - – Distribution
  - – Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - – Achieve timely returns
  - – Seek cash returns on investment during construction
  - – Create & secure innovative rate plans
    - – Pursue post-2008 solution in Ohio
    - – Expand use of trackers
    - – Formula rates

New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

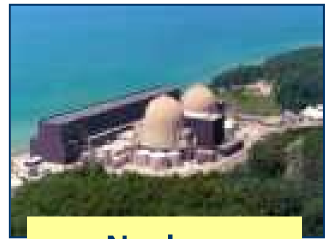
Appendix

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

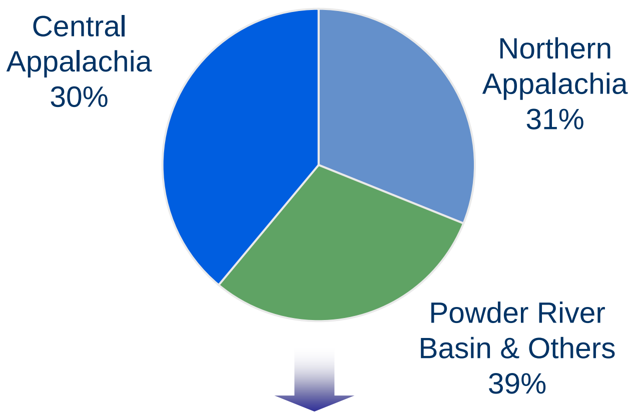
NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

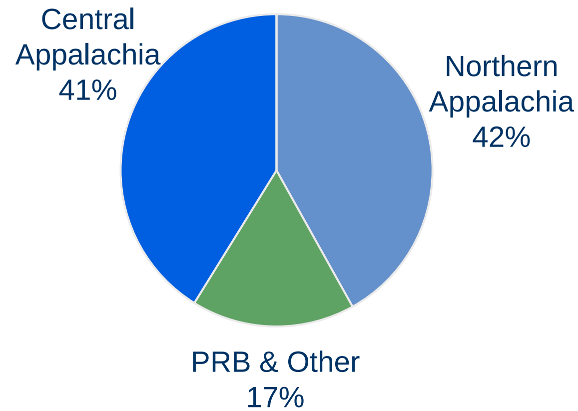
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

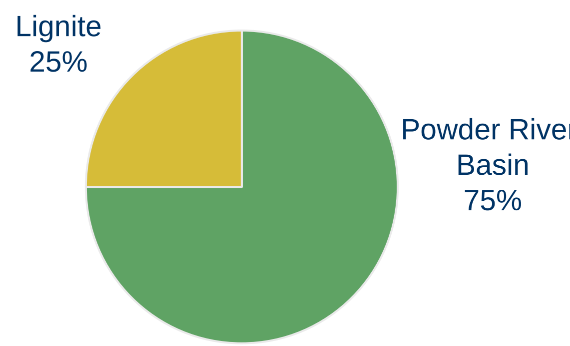
Total AEP System



AEP East



AEP West



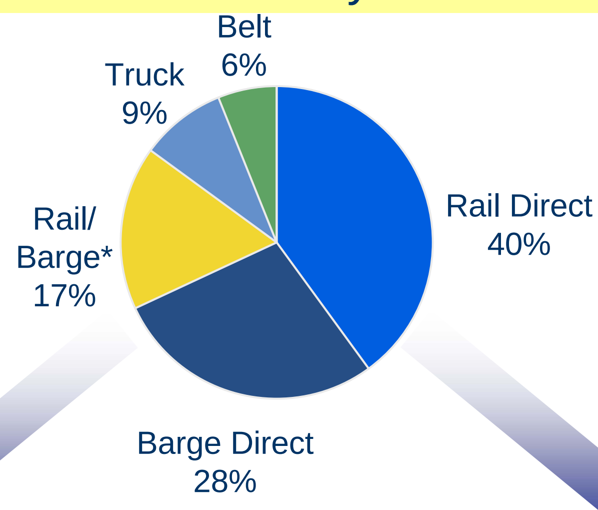
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

Coal Delivery

2006 Actual

Total AEP System



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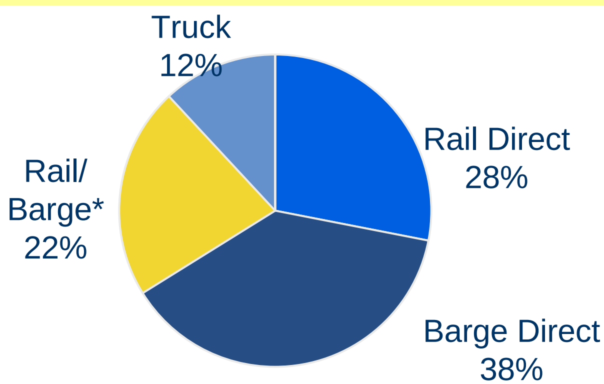

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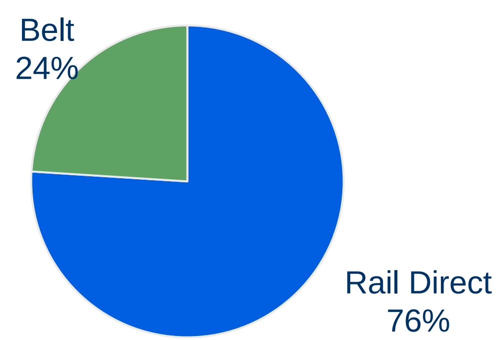

* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Environmental Investment

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AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008 -10
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	In-service	✓	In-service
Mitchell 2	800	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	✓	Upgrade In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
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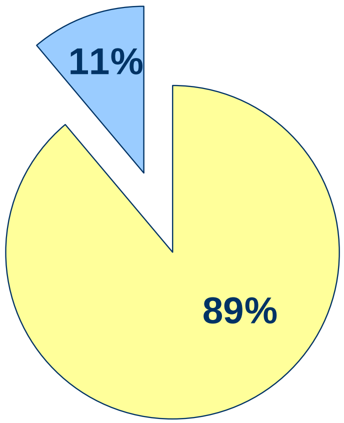
Muskingum River 5	585	✓	In-service	☐	Delayed
Pirkey	580	☐	N/A	✓	Upgrade In-service
Oklaunion	485	☐	N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262	☐	N/A	✓	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

AEP®

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

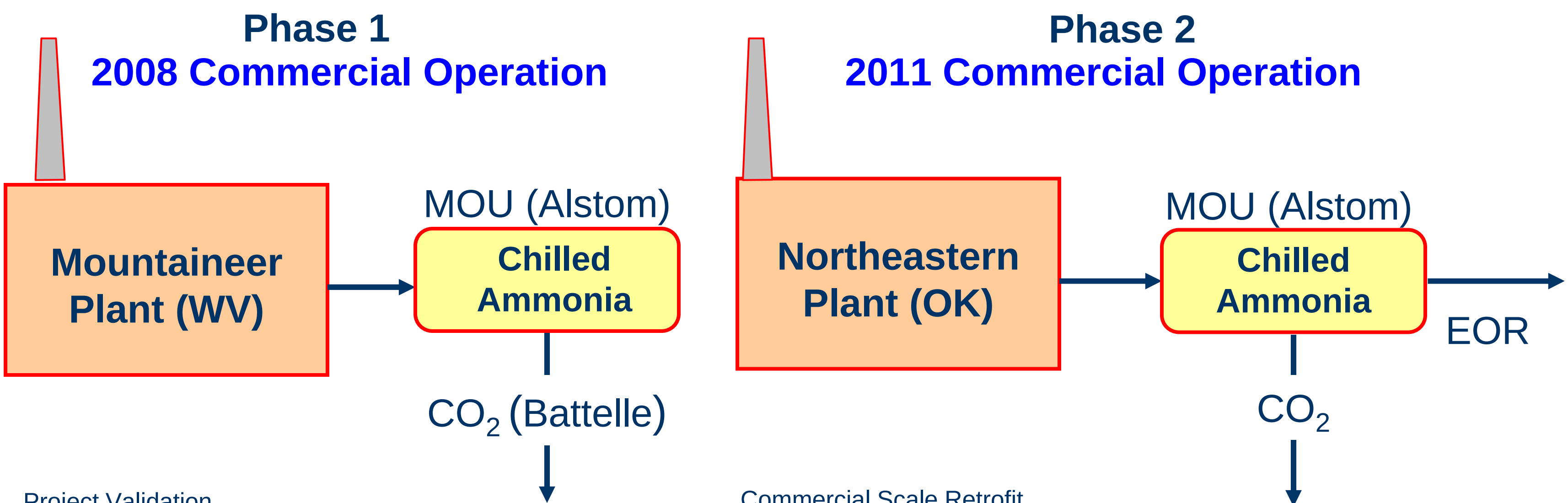
- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Process Plant Footprint

AEP®

Chilled Ammonia Technology Program



Project Validation

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Fuel Technology Initiative

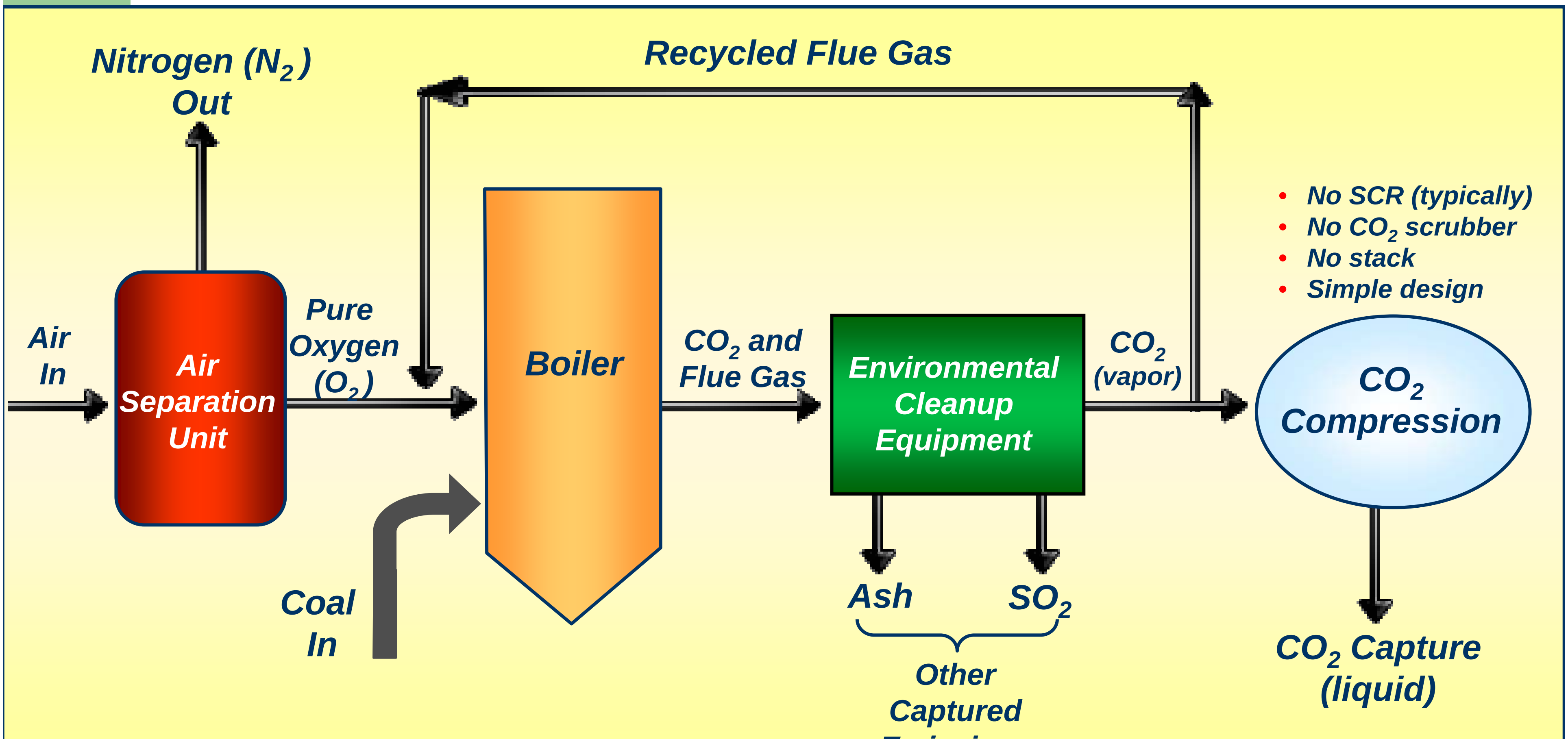


Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-zero Emissions Using Oxy-fuel Combustion Technology

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5723 of 9556

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

AEP®

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital Investment Is Funded By Cash From Operations And Debt Issuances

American Electric Power, Inc.

Chicago Fixed Income Road Show

Hosted by Banc of America

August 30, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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SVP & Treasurer

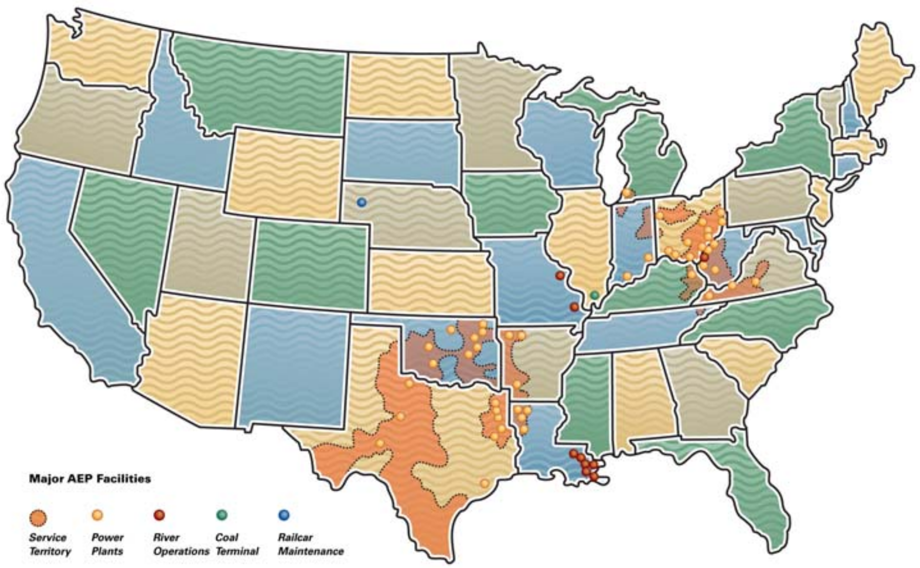
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

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AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

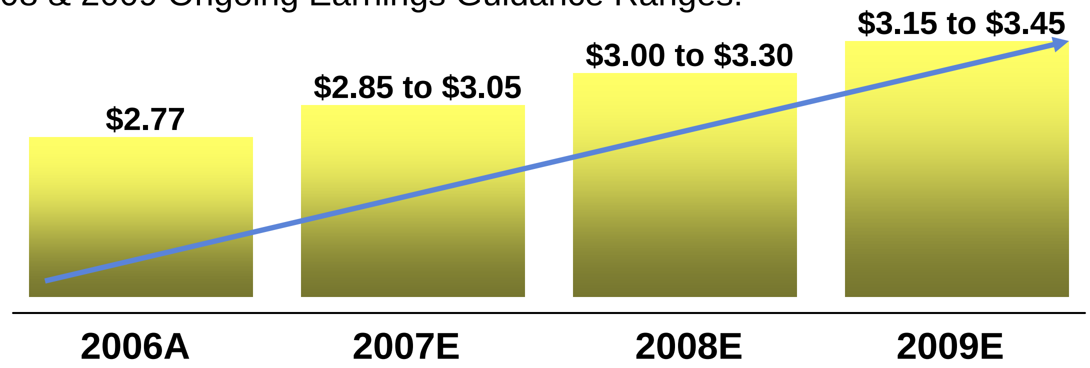
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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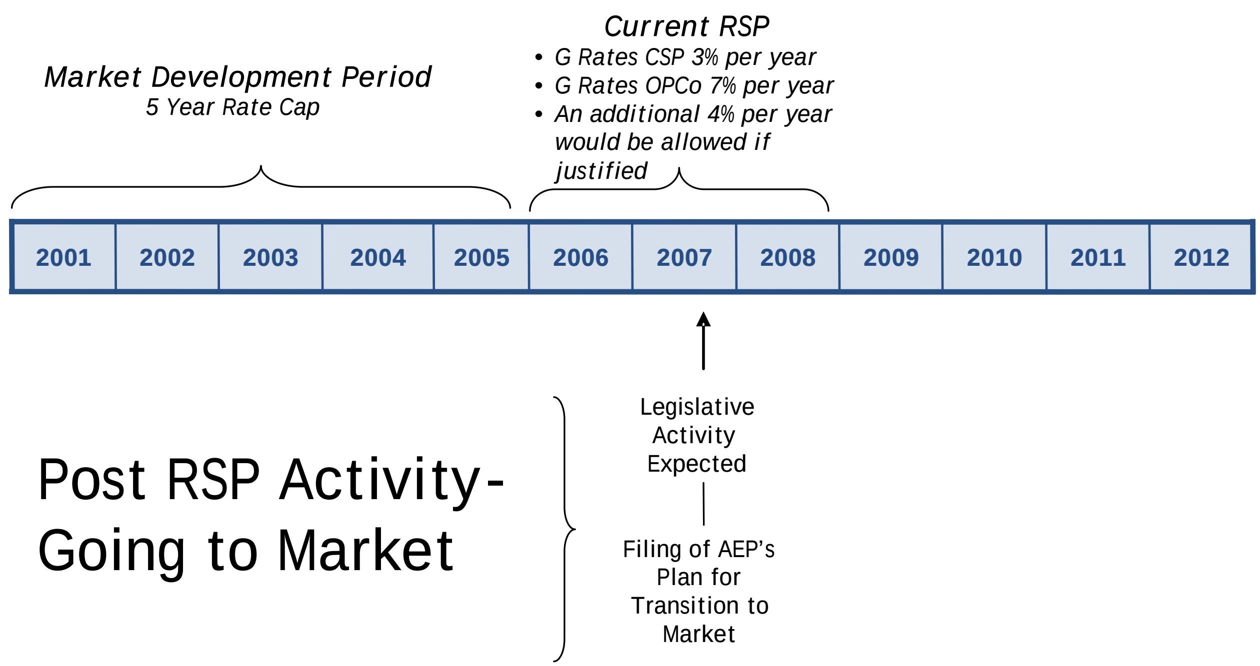
New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

Ohio Background

- The Ohio market was restructured beginning 1/1/2001 with a five year market development period during which time total rates were capped.
- The company was scheduled to go to market on 1/1/2006; however, rate shock to customers was a significant Commission concern (the region lacked competitive suppliers).
- The Ohio Rate Stabilization Plan (RSP) extended the market development period an additional three years with the customers going to market on 1/1/2009.



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AEP Ohio Next Steps

- AEP has filed as an intervenor in support of competitive generation.
- The plan, proposed on July 10, 2007 by First Energy includes bidding processes for providing competitively priced generation.
- AEP's Ohio customers who do not choose another electricity supplier would, beginning Jan 1, 2009 pay generation rates as determined through an auction process.
- Not clear that a new statutory framework will be in place before Jan. 1, 2009.
- Joining the current case before PUCO is the best way to ensure we have certainty regarding electricity generation before the end of 2008.
- We will continue to work with the utility coalition that has proposed legislation to address alternative approaches post-2008.

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden	$85
2007 Including Lawrenceburg	**$3,952**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

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Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
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Oklaunion	485		N/A	✓	In-service
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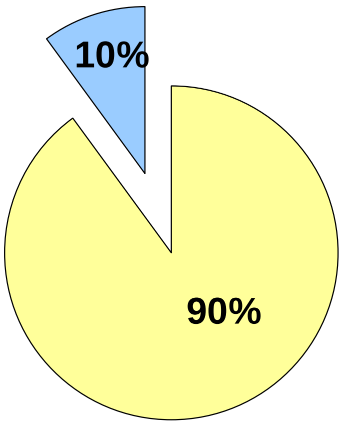

Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

•B&W/Alstom – FGD Spray Tower
•B&V/Chyioda – FGD Jet Bubbling Reactor
•Pullman Power – Stack Supplier
•Babcock Power – SCR
•Black & Veatch – Architect/Engineering
•Sargent & Lundy – Architect/Engineering

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- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

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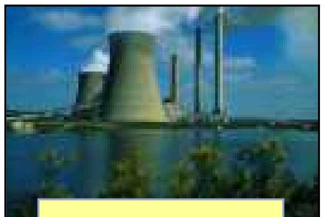
FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP®

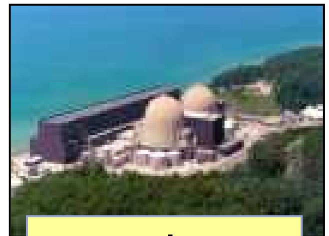
AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

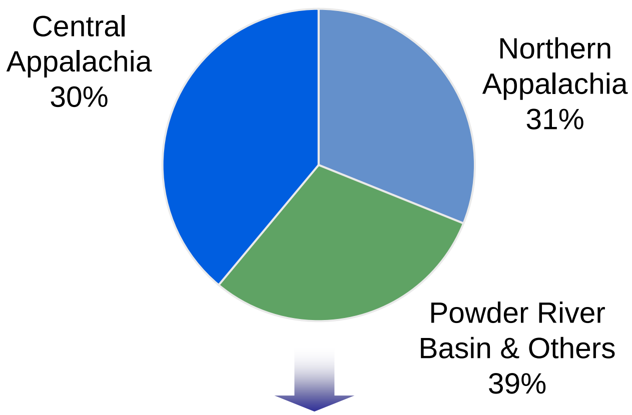
RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

AEP®

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

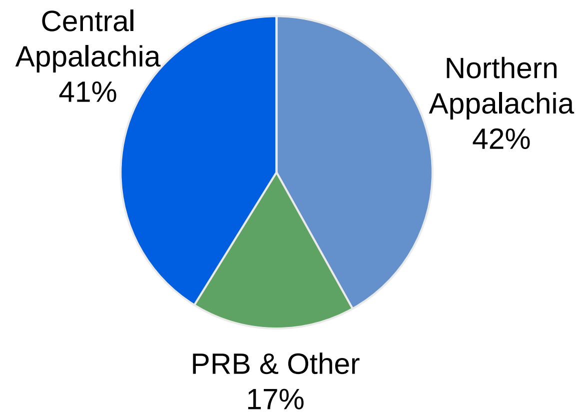
Total AEP System



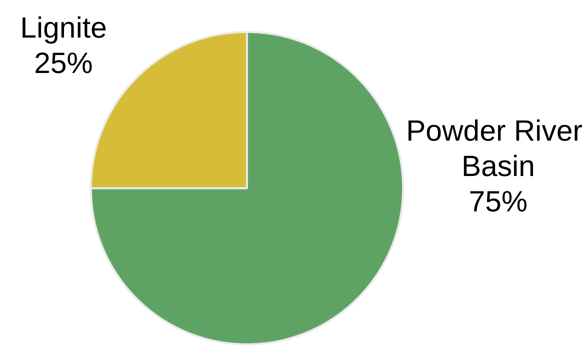
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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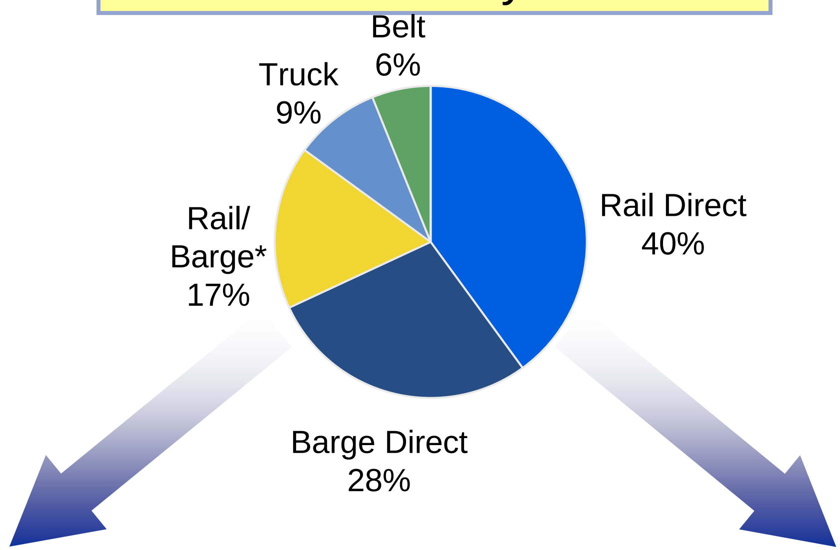
Coal Delivery

2006 Actual

Total AEP System



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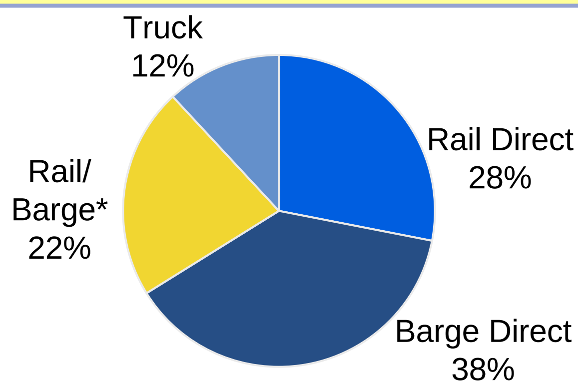
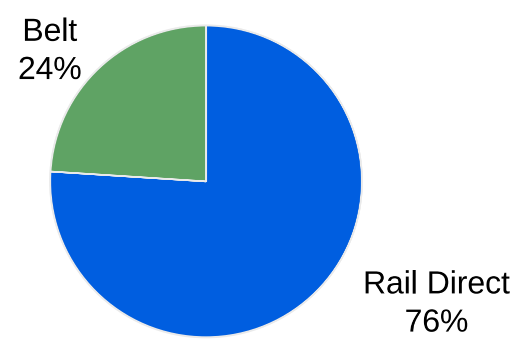


AEP West



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* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007

AEP®

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	900 (4)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	630	2017

(1) 150MW were declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(5) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

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New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
- Air permit approval expected in Fall 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

- Used and Useful Determination filed in February 2006 – Hearings concluded July 31, 2007 and order is expected in September 2007
- Favorable ALJ report received August 21, 2007
- Air permit approval expected in October 2007
- Regulatory Recovery
  - Order expected in PSO rate case filing in July 2007 – filing included request for CWIP treatment for new projects
- Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

AEP®

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

AEP®

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	IGCC	NGCC
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

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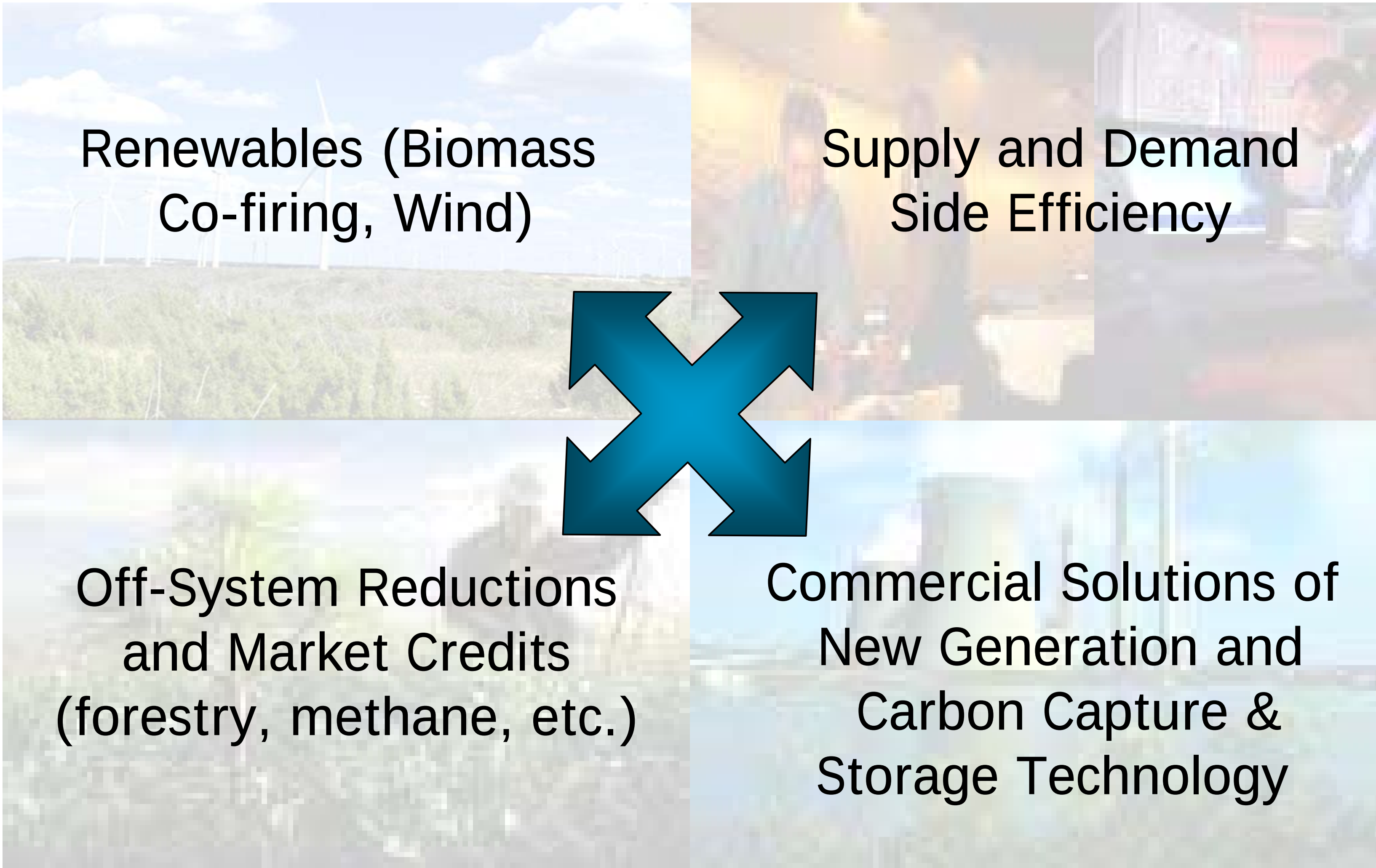
AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio



AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

15

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

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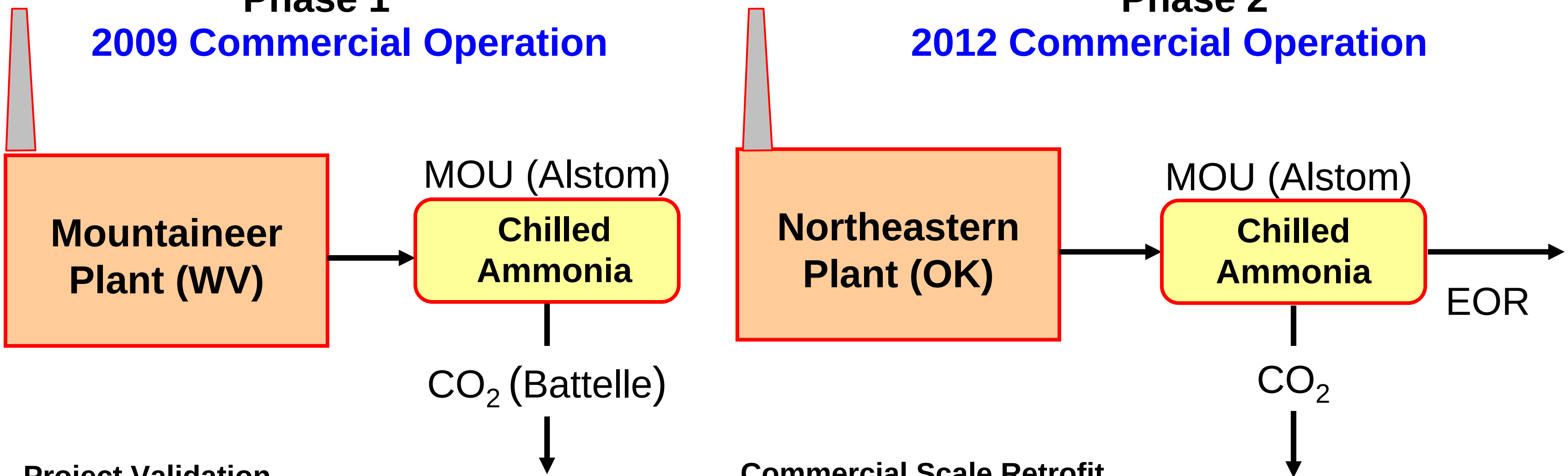
Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost $50 – $80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~$225 – $300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

AEP®

Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

AEP ®

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities
~ $3 Billion I765$_{TM}$ Project in PJM
~ $2 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

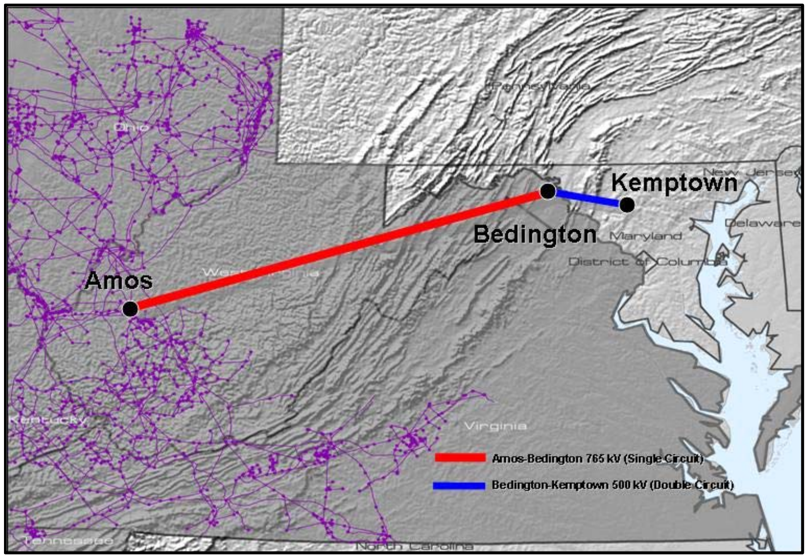
Assumptions	
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PJM I-765$_{TM}$

- *Overview*
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM approved)
- *Benefits*
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation
- *Phase I Progress to Date*
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012



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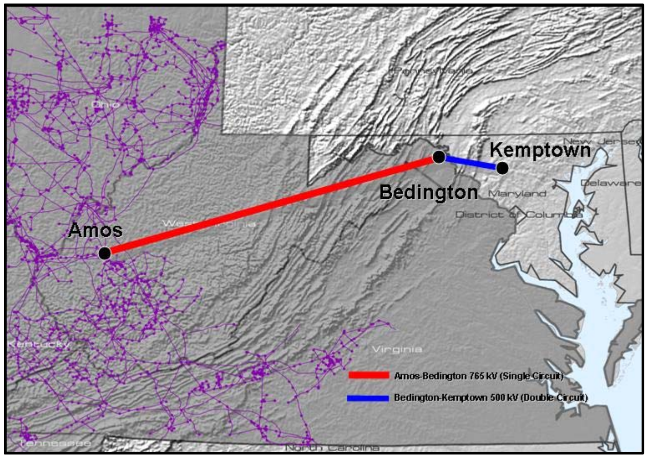
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5756 of 9556

PJM I-765$_{TM}$ Phase I cont'd

Execution in Action

- *Funding Plans/Transaction Structure*
  - Formed a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
  - JV portion of the I-765$_{TM}$ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - I-765$_{TM}$ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007



- *Key Regulatory Activity Completed*
  - FERC declaratory order approved July 2006
  - PJM approved plan June 2007

- *Key Next Steps*
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012

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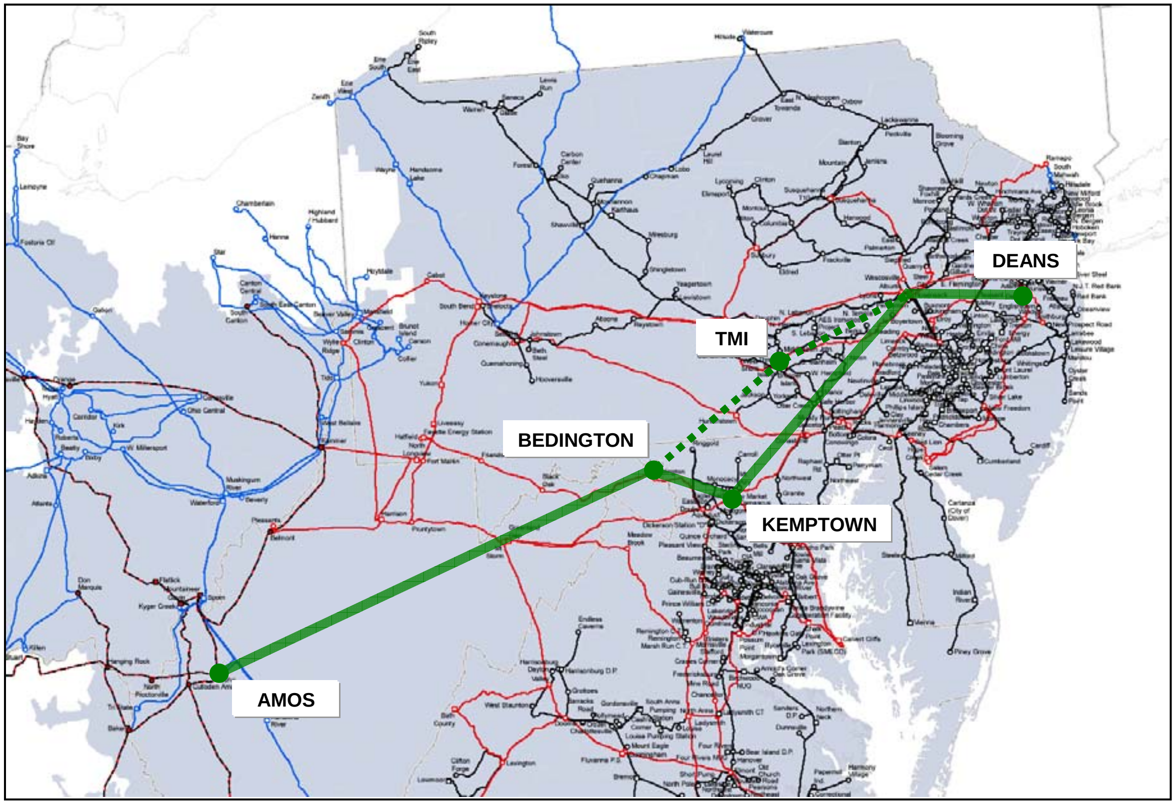
PJM I-765™ Phase II (Bedington-Deans)

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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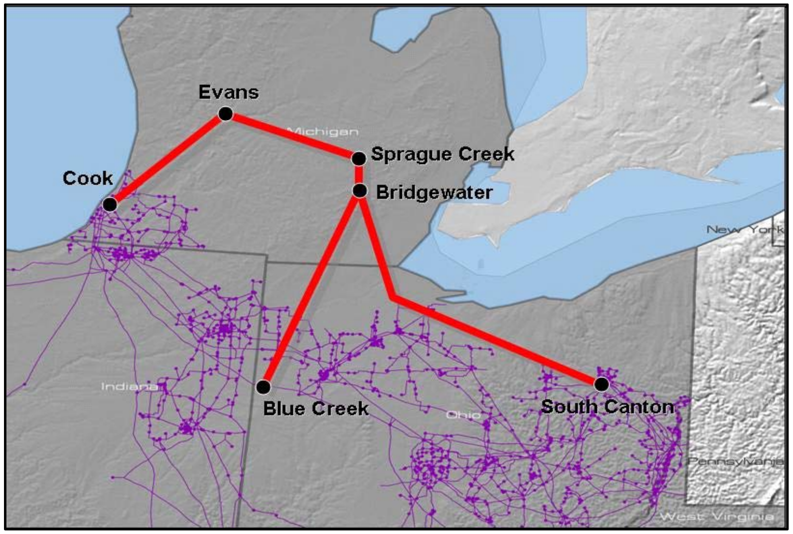
765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.0 billion investment (before ownership division)



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Benefits*
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW

- *Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013

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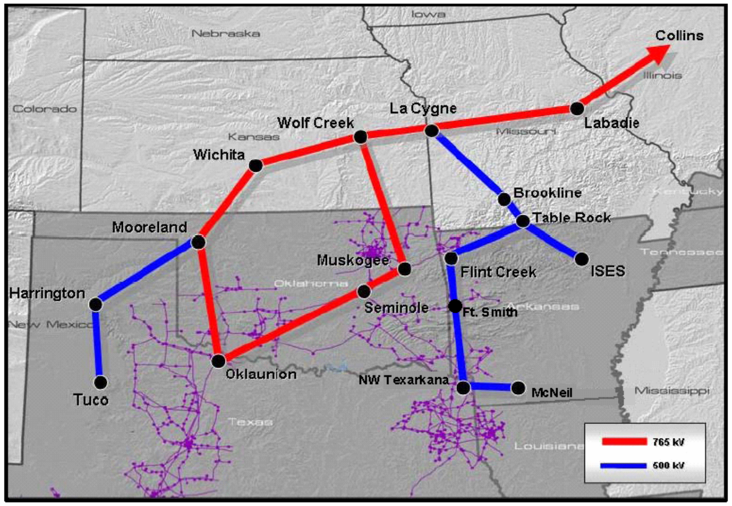
765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri

- *Benefits*
  - 4,000 MVA capability

- *Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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ETT Status Update

ETT: Delivering Power for Texas' Future

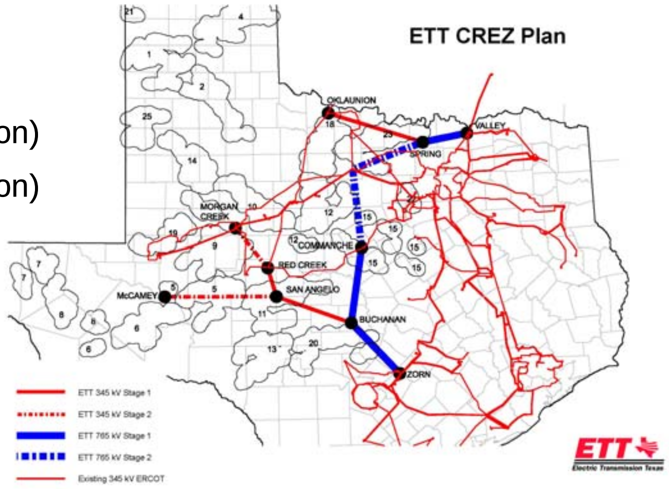
- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP; business manager provided by MidAmerican.
  - Investment opportunities can be offered by either partner and accepted or rejected by ETT.

- *Transaction Status*
  - Formation documents finalized and Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in September 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - \$1.5 billion investment Phase 1 – 2012 (before ownership division)
  - \$1.5 billion investment Phase 2 – 2015 (before ownership division)

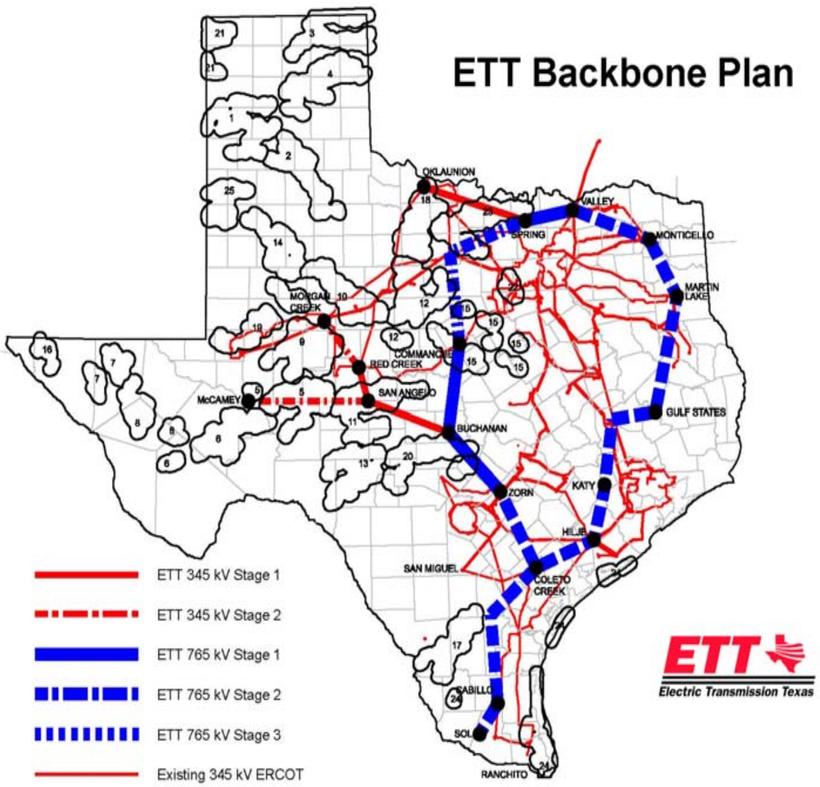


- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).



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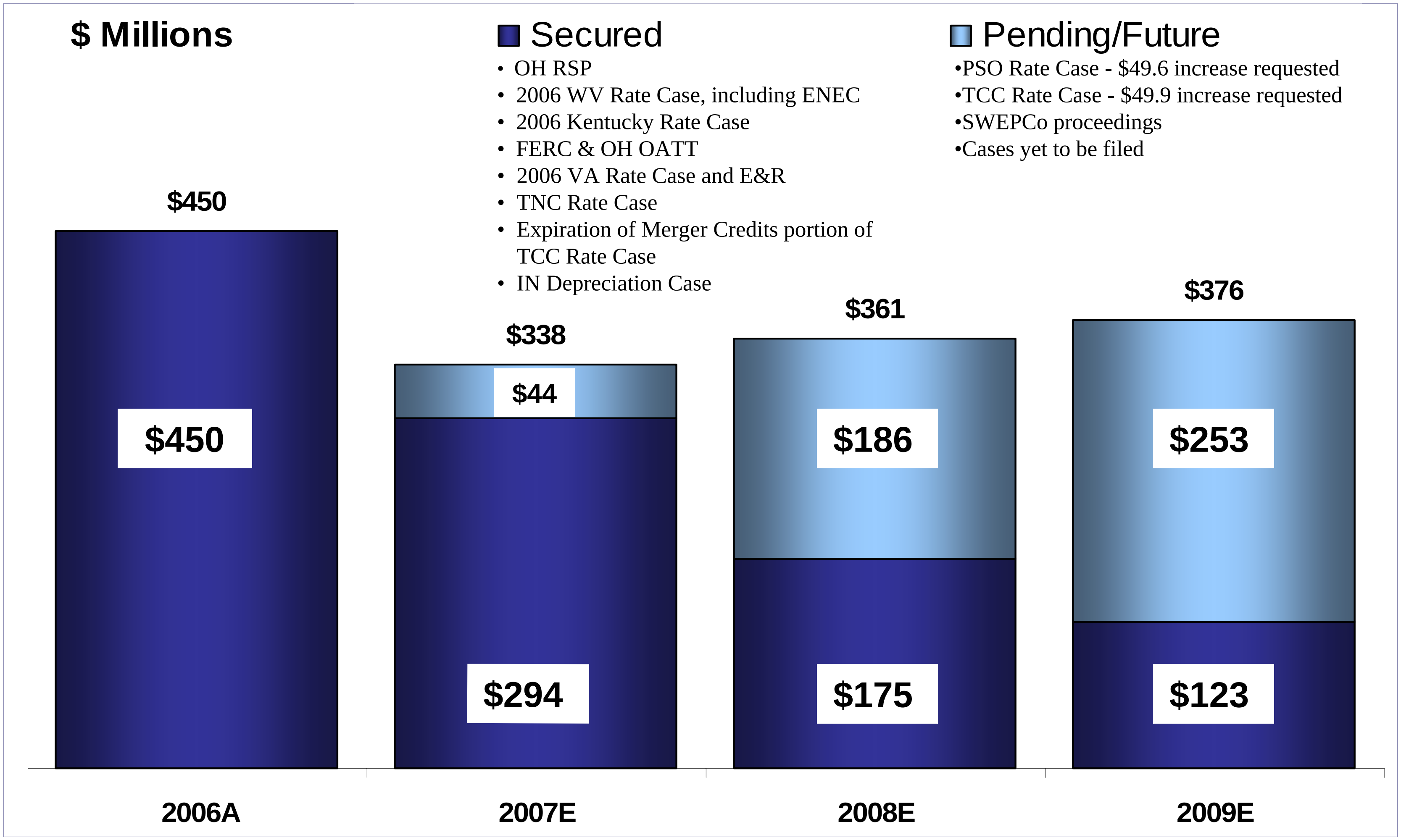
Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

✓ Results in $24 Million annual increase in base rates

✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)

✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

✓ Results in $85.5 million net increase in revenues effective July 1, 2007

- ✓$54.8 million covers increased costs related to coal and purchased power
- ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
- ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year

✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding

✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

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In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings – Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recover investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
September 2007	Final order expected

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Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule is subject to IURC approval.

Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for PSO's Used and Useful Determination and OG&E's cost recovery were held July 9-31, 2007.
- We received a positive ALJ report on August 21, 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings began August 20, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for September 27-28, 2007.

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Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

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We Are Committed To Maintaining Our Current Credit Ratings

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5775 of 9556

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital Investment Is Funded By Cash From Operations And Debt Issuances

American Electric Power, Inc. Operating Company Detail

Chicago Fixed Income Road Show

Hosted by Banc of America

August 30, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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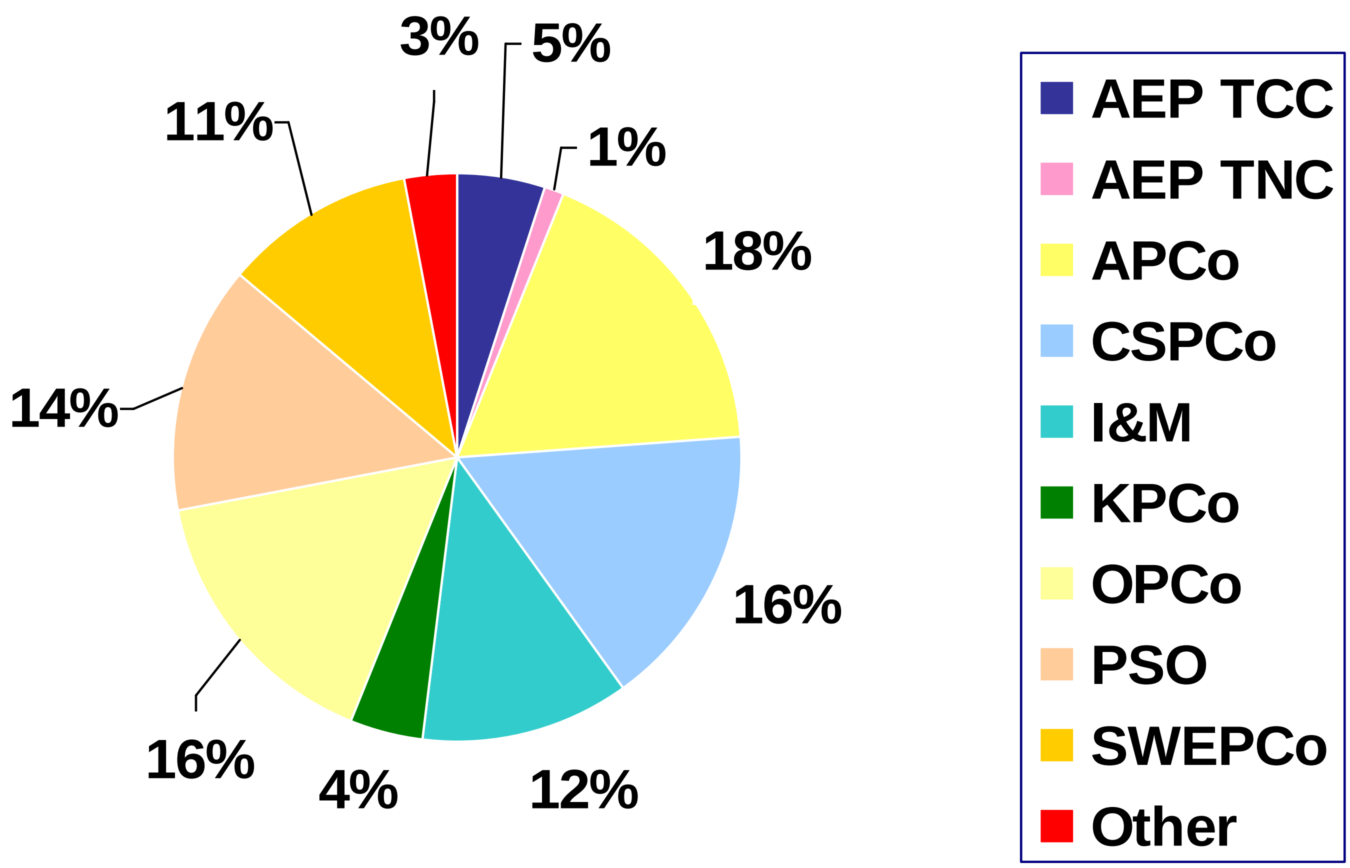
2006 Retail Revenue

Retail Revenue Composition by Operating Company



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Earned ROEs

Company	6/30/07 Earned ROE
AEP Texas Central Company	**6.22%**
AEP Texas North Company	**8.63%**
Appalachian Power Company	**4.56%**
Columbus Southern Power Company	**21.22%**
Indiana Michigan Power Company	**7.18%**
Kentucky Power Company	**9.89%**
Ohio Power Company	**12.79%**
Public Service Company of Oklahoma	**2.25%**
Southwestern Electric Power Company	**6.77%**

ROEs Calculated on a GAAP Basis

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Semi-annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate. Effective 7/1/07, legislation was enacted to allow company retention of at least 25% of OSS margins. We have a filing pending before the VA SCC to initiate this sharing.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Issuances (a)	Target Adjusted Equity Ratio
AEG	$343	$220	40%
APCo	$664	$600-$700	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$0	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

*Approx. $1B of issuances remaining in 2007 assuming appropriate market conditions

Maintain Financial Strength Of Utility Companies By Retaining And/Or Infusing Equity Capital Depending On Their Credit Ratios And Free Cash Flow

AEP®

Managing Subsidiary Cash Flows

- We monitor:
  - AEP consolidated cash requirements
  - Utility expected rates of return and potential regulatory lags
  - Amount of capital spending and internal cash needs
  - Free cash flow – cash available after construction
  - Credit ratios

- Dividends and equity:
  - We pay dividends based on free cash flow and credit metrics
  - When additional equity/cash is needed at the subsidiary level, the first option is dividend reductions, then capital infusions
  - We are currently evaluating hybrid securities as a source of equity

Our Objective Is To Maintain The Financial Strength And Capital Markets Access Of The AEP Operating Companies

AEP®

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Long-Term Debt Maturity Profile

($ in millions)

Year	2007	2008	2009
AEP, Inc.	$ 345	$ -	$ -
Appalachian Power	$ 200	$ 200	$ 150
Columbus Southern Power	$ -	$ 112	$ -
Kentucky Power	$ 323	$ 30	$ -
Indiana Michigan	$ -	$ 50	$ 45
Ohio Power Company	$ -	$ 42	$ 100
Public Service of Oklahoma	$ -	$ -	$ 50
Southwestern Electric Power	$ 90	$ 116	$ -
Texas Central Company *	$ -	$ 68	$ -
Total	$ 958	$ 618	$ 345

Note: Maturities remaining as of June 30, 2007

* - 2008 maturities include $19 million in first mortgage bonds that were defeased in May 2004

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Debt Schedules – as of 6/30/07

American Electric Power, Inc.

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.102%		$1,077,775,000

American Electric Power Service Corp.

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

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Debt Schedules – as of 6/30/07

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond *	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Preferred Stock	4.000%	N/A	$4,191,200
Preferred Stock	4.200%	N/A	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.898%		$695,017,300
Securitization Bond	5.010%	1/15/2008 **	$49,523,804
Securitization Bond	5.560%	1/15/2010 **	$107,094,258
Securitization Bond	5.960%	7/15/2013 **	$214,926,738
Securitization Bond	6.250%	1/15/2016 **	$191,856,858
Securitization Bond	4.980%	1/1/2010 **	$217,000,000
Securitization Bond	4.980%	7/1/2013 **	$341,000,000
Securitization Bond	5.090%	7/1/2015 **	$250,000,000
Securitization Bond	5.170%	1/1/2018 **	$437,000,000
Securitization Bond	5.306%	7/1/2020 **	$494,700,000
Weighted Average or Total	5.323%		$2,303,101,658

* TCC's First Mortgage Bond was defeased in May 2004

** represents scheduled final payment date, no ultimate maturity date

AEP Texas North

Series	Interest	Maturity	Amount
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Preferred Stock	4.400%	N/A	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.420%		$315,968,600

AEP®

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Debt Schedules – as of 6/30/07

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	05/01/2037	$75,000,000
Preferred Stock	4.500%	N/A	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.294%		$2,480,038,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	12/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Debt Schedules – as of 6/30/07

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	N/A	$5,533,500
Preferred Stock	4.120%	N/A	$1,105,500
Preferred Stock	4.560%	N/A	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.811%		$1,320,080,200

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

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Debt Schedules – as of 6/30/07

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Notes Payable	6.810%	03/31/2008	$4,390,244
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	N/A	$1,459,500
Preferred Stock	4.200%	N/A	$2,282,400
Preferred Stock	4.400%	N/A	$3,148,200
Preferred Stock	4.500%	N/A	$9,737,300

Ohio Power Company (continued)

Series	Interest	Maturity	Amount
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	Floating	04/05/2010	$400,000,000
Weighted Average or Total	5.841%		$2,680,372,644

AEP®

Debt Schedules – as of 6/30/07

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Preferred Stock	4.000%	N/A	$4,454,800
Preferred Stock	4.240%	N/A	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Weighted Average or Total	5.489%		$689,281,700

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$16,888,366
Notes Payable	Floating	06/30/2008	$3,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	N/A	$3,767,300
Preferred Stock	4.650%	N/A	$190,700
Preferred Stock	4.280%	N/A	$738,600
Senior Notes	5.380%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.541%		$924,322,966

AEP®

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**630,000**
• **Commercial**	**102,000**
• **Industrial**	**5,000**
• **Other**	**1,000**
Total	**738,000**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data (in thousands)

Revenue	$	665,000
% of AEP Retail		5%
Net Income (Loss)	$	42,000
Capital Expenditure	$	270,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,324,000
Net Plant Assets	$	2,240,000

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 241,000	$ 247,000	$ 222,100

AEP®

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:
Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

PRINCIPAL INDUSTRIES SERVED:
Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**6,000**
Total	**189,000**

Generating Capacity	**377 MW**

Oklaunion Plant – Vernon, TX
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,500**
Distribution Miles	**14,000**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data (in thousands)

Revenue	$	329,000
% of AEP Retail		1%
Net Income	$	15,000
Capital Expenditure	$	70,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	968,000
Net Plant Assets	$	842,000
Cash	$	84

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$143,000	$188,000	$149,000

AEP®

Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers:

• **Residential**	**810,000**
• **Commercial**	**128,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**949,000**

Generating Capacity	**6,282 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**80.8%**
• **Hydro/Pump:**	**10.8%**
• **Nat Gas**	**8.4%**

Transmission Miles	**6,750**
Distribution Miles	**49,000**

AEP®

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 7,016,000
Net Plant Assets	$ 5,524,000
Cash	$ 2,318

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 664,000	$ 531,000	$ 461,000

AEP®

Appalachian Power

APCo Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	5	Hydro
Byllesby #1, 2, 3, 4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	528	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	28	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lyn #1, 2	Glen Lyn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	9	Hydro
Niagara #1, 2	Roanoke, Virginia	1	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2 *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	12	Hydro
Marmet #1, 2, 3	Marmet, West Virginia	11	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES *

West Virginia	Customers
APCo	**434,504**
Allegheny	492,354

Virginia	Customers
APCo	**503,525**
Dominion Virginia	2,171,253
Allegheny	95,665
Kentucky Utilities	29,900
Conectiv	21,930

Tennessee	Customers
APCo	**45,960**

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

West Virginia	
APCo	**58.87**
AEP – Wheeling	**58.87**
Allegheny	70.46

Virginia	
ODPCo	64.69
APCo	**66.72 *****
Dominion Virginia	85.28
Conectiv	126.82

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

*** APCo Virginia rate adjusted for effect of rate case order received in May 2007.

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
CONSOL Energy (VA)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Dickenson-Russell Coal Co, LLC (VA)
Steel of WV, Inc. (WV)
Toyota Motor Manufacturing (WV)

- **Top 10 Customers = 49% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

AEP®

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers:

• **Residential**	**662,000**
• **Commercial**	**76,000**
• **Industrial**	**4,000**
Total	**742,000**

Generating Cap	**3,708 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **63.2%**
- **Natural Gas** **36.1%**
- **Hydro:** **0.7%**

Transmission Miles	**2,400**
Distribution Miles	**17,200**

AEP®

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data (in thousands)

Revenue	$ 1,807,000
% of AEP Retail	16%
Net Income	$ 185,000
Capital Expenditure	$ 307,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,521,000
Net Plant Assets	$ 2,725,000
Cash	$ 1,319

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 439,000	$ 354,000	$ 233,000

AEP®

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,254	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	26	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	857	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	480	Nat Gas

Columbus Southern Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

AEP®

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5808 of 9556

Indiana Michigan Power

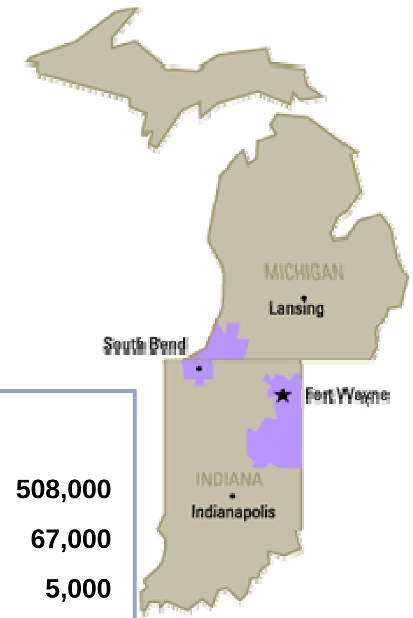
President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products



Total Customers:	
• **Residential**	**508,000**
• **Commercial**	**67,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**582,000**
Generating Capacity	**5,753 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.2%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data (in thousands)

Revenue	$	1,977,000
% of AEP Retail		12%
Net Income	$	121,000
Capital Expenditure	$	325,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,546,000
Net Plant Assets	$	3,313,000
Cash	$	1,369

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 252,000	$ 264,000	$ 294,000

Indiana Michigan Power

I&M Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1 , 2 , 3	Berrien Springs, Michigan	5	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	2	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	2	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	1	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I & M	**453,788**
IP & L	462,831
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECo	144,632

Michigan	Customers
I & M	**125,588**
Consumers Energy	1,779,184
Detroit Edison	2,156,214

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	
I & M	**69.64**
IP & L	76.00
Duke Indiana (PSI)	78.82
SIGECo	94.62

Michigan	
I & M	**66.65**
Consumers Energy	101.43
Detroit Edison	111.93

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**

Generating Capacity	**1,060 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**1,200**
Distribution Miles	**9,700**

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

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Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data (in thousands)

Revenue	$	586,000
% of AEP Retail		4%
Net Income	$	35,000
Capital Expenditure	$	78,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	1,311,000
Net Plant Assets	$	1,002,000
Cash	$	702

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 70,000	$ 114,000	$ 100,000

AEP®

Kentucky Power

Kentucky Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY UTILITIES *

Kentucky	**Customers**
KPCo	**175,255**
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	58.57
LG&E	65.40
KPCo	**69.40**
Duke Kentucky	76.70

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Total Customers:

• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**

Generating Capacity	**8,498 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.9%**
- **Hydro:** **0.1%**

Transmission Miles	**6,500**
Distribution Miles	**26,200**

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

AEP®

40

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data (in thousands)

Revenue	$ 2,725,000
% of AEP Retail	16%
Net Income	$ 229,000
Capital Expenditure	$ 1,000,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 6,819,000
Net Plant Assets	$ 5,569,000
Cash	$ 1,625

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 832,000	$ 368,000	$ 389,000

AEP®

Ohio Power

Ohio Power Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak – August 2nd	5,260 MW

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	26	Hydro

Ohio Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers:	
• **Residential**	**447,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**8,000**
Total	**520,000**

Generating Capacity	**4,219 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**25%**
• **Natural Gas:**	**75%**
Transmission Miles	**3,600**
Distribution Miles	**21,200**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data (in thousands)

Revenue	$	1,442,000
% of AEP Retail		14%
Net Income	$	37,000
Capital Expenditure	$	240,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	2,579,000
Net Plant Assets	$	1,999,000
Cash	$	1,651

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 319,000	$ 330,000	$ 466,000

AEP®

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	**511,924**
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	70.73
PSO	**73.67**
OG&E	74.60

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.

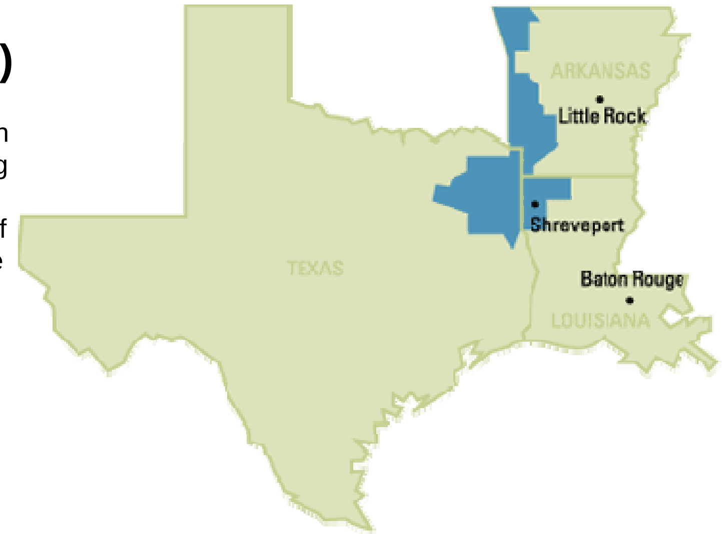
- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.



Total Customers:

• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**456,000**

Generating Capacity	**4,637 MW**
Generating Capacity by Fuel Mix:	
• **Coal/Lignite:**	**58%**
• **Natural Gas:**	**42%**
Transmission Miles	**3,500**
Distribution Miles	**19,300**

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data (in thousands)

Revenue	$ 1,432,000
% of AEP Retail	11%
Net Income	$ 92,000
Capital Expenditure	$ 323,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,191,000
Net Plant Assets	$ 2,494,000
Cash	$ 2,618

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 537,000	$ 605,000	$ 540,000

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas
Mattison #3, 4	Tontitown, Arkansas	150	Gas

Southwestern Electric Power

SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	**109,760**
Entergy AR	672,890

Louisiana	Customers
SWEPCo	**171,564**
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	**166,906**
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	**74.63**
OG&E	77.70
Empire District	86.30
ETR	102.43

Louisiana	
SWEPCo	**63.91**
Entergy LA	99.63
Entergy Gulf St	100.81
Entergy NO	104.20
CLECO	110.19

Texas	
SWEPCo	**60.80**
SPSCo	80.91
ETR	114.79
EP	128.32
TXU	144.11

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

AEP®

Citigroup Power, Gas & Utilities Conference

March 1 – 3, 2006
The Mandarin Oriental Hotel,
Miami, FL

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

A Century of Firsts

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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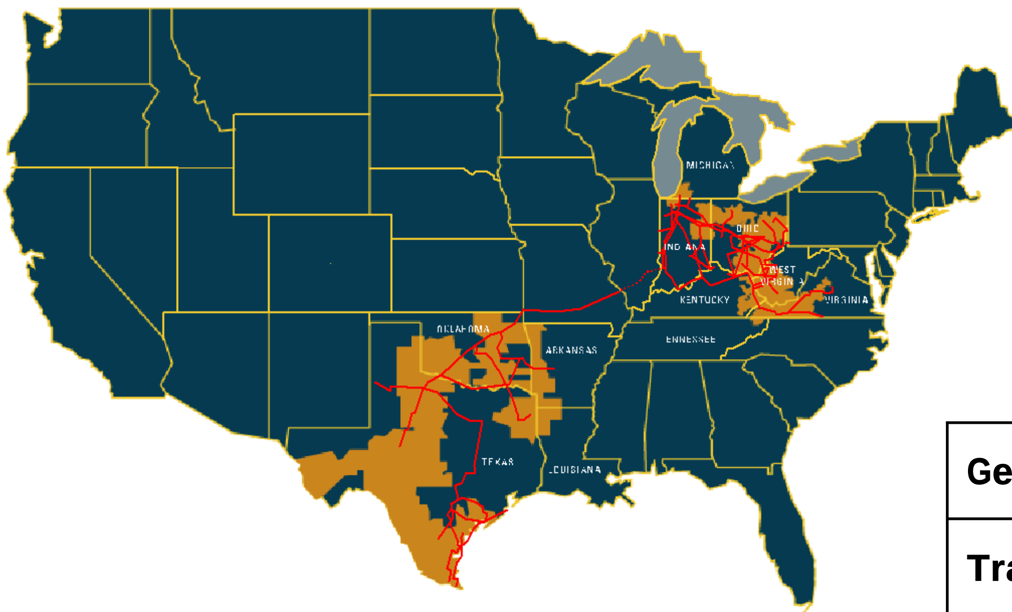
Asset Portfolio

Strength & Scale in Assets & Operations



Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

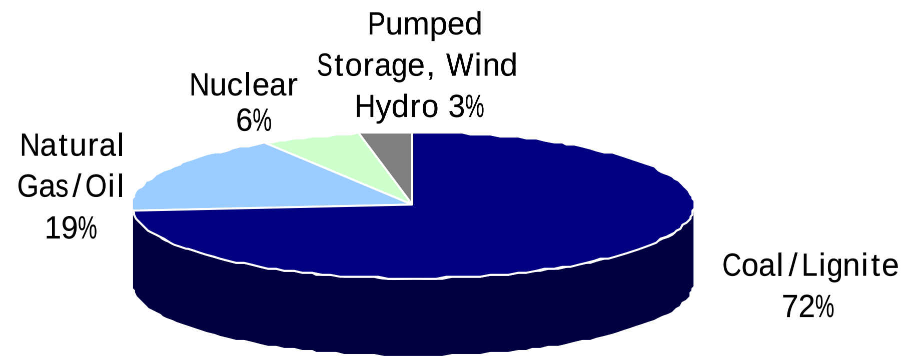
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Asset Portfolio: Generation Fleet Composition

- 35,600 MW Domestic Capacity
- 85% System Availability Factor YE 2005
- 63% System Capacity Factor YE 2005

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	23,985	0	1,954
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**29,902**	**3,516**	**2,142**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Financial Projections

Framework for 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

2006 Earnings Guidance Range: $2.50 - $2.70

A Century of Firsts

		2005 Actual			2006 Forecast	
	Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
UTILITY OPERATIONS:						
Gross Margin:						
1 Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2 Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3 Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4 Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5 Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6 Transmission Revenue - 3rd Party		394			285	
7 Other Operating Revenue		485			515	
8 Total Gross Margin		7,106			7,283	
9 Operations & Maintenance		(3,142)			(3,045)	
10 Depreciation & Amortization		(1,285)			(1,332)	
11 Taxes Other than Income Taxes		(743)			(761)	
12 Interest Exp & Preferred Dividend		(595)			(688)	
13 Other Income & Deductions		264			153	
14 Income Taxes		(514)			(563)	
15 Net Earnings Utility Operations		1,091	2.80		1,047	2.66
INVESTMENTS:						
21 Total Investments		24	0.06		(7)	(0.02)
22 Parent Company		(52)	(0.13)		(17)	(0.04)
23 ON-GOING EARNINGS		1,063	2.73		1,023	2.60
Shares Outstanding (in millions)			390			

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

Summary of Major 2006 Earnings Drivers

- ✓ **Load growth of 2.5%**
- ✓ **$500MM rate recovery assured or in progress**
- ✓ **Rising fuel costs of 11-13%**
- ✓ **Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales**
- ✓ **Decline in utility operations O&M**
- ✓ **Parent Company improvement**

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

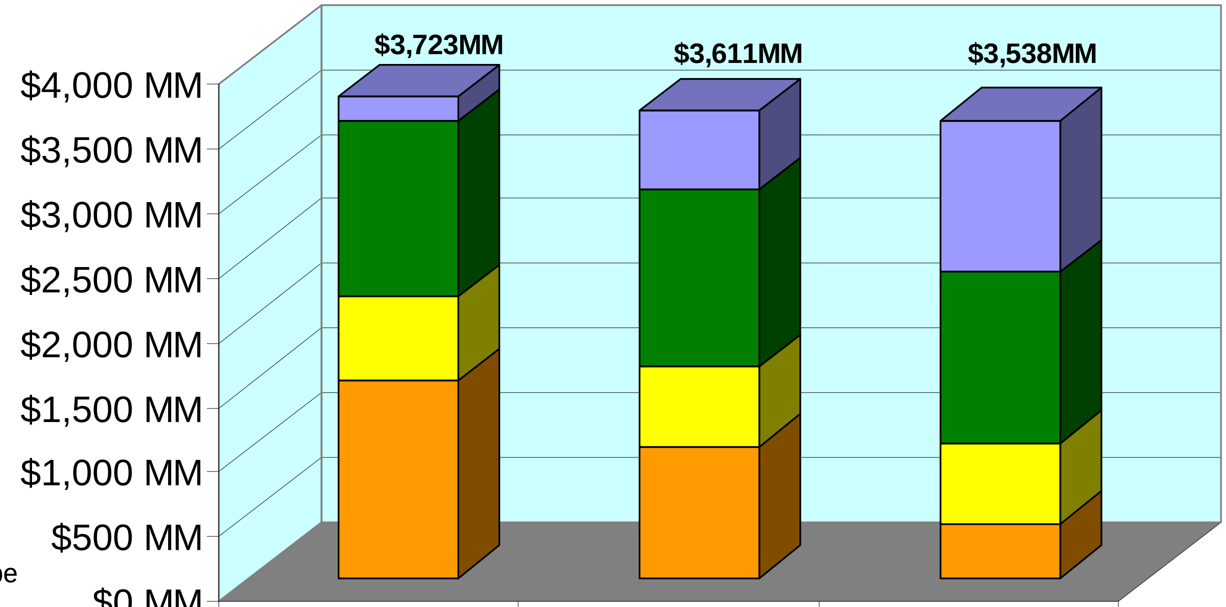
- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana, Kentucky, FERC*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Capital Investment Funding

A Century of Firsts

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (554)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,795	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,314	$ 1,294	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (24)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 2,434	$ 1,661	$ 1,623
Other	$ 43	$ 160	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.402B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

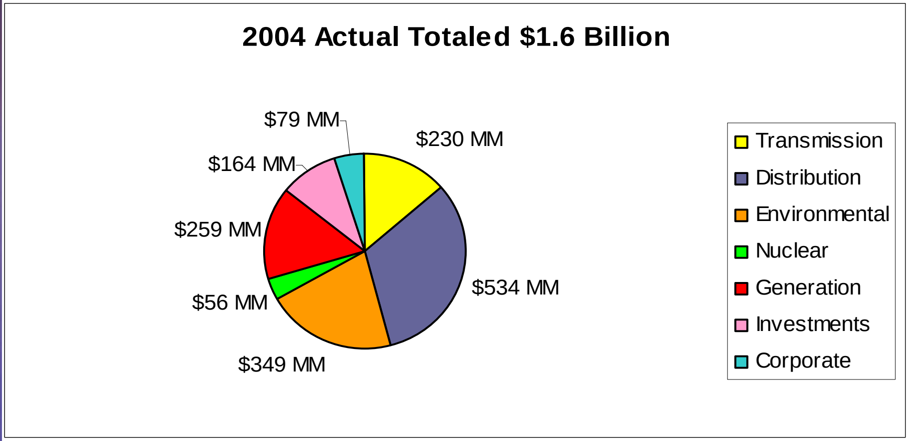
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

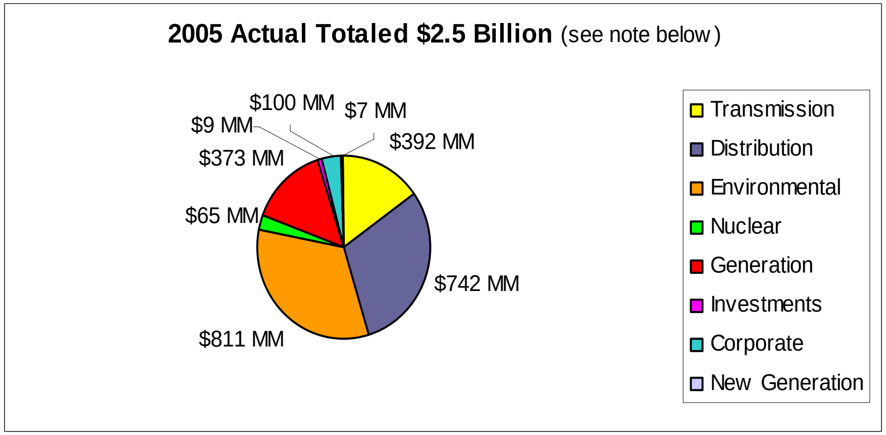
Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

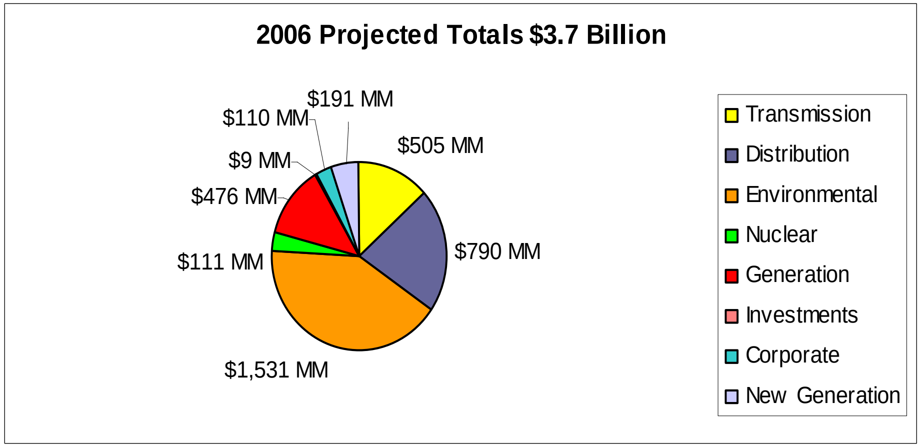
REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Capital Investment 2004 - 2006

Figures exclude AFUDC







Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5841 of 9556

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	91	(315)
Total from Operations	**$ 1,795**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,402)	(3,723)
Asset Sales	1,294	28
Other	179	(163)
Total from Investing	**$ (929)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(24)	-
Net Long Term Debt Issued/(Retired)	(78)	2,434 *
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(554)	(582)
Other Financing Activities	(50)	(3)
Total from Financing	**$ (785)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes $1.2 billion of securitization bonds issued in 4Q06

CASH ON HAND OF $326 MILLION AT YEAR END 2006

Capitalization

Capital Structure	Actual 12/31/04			Actual 12/31/2005		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,226	-	12,226
Short-term Debt	23	-	23	10	-	10
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	(66)	66	-	30	(30)	-
Defeased First Mortgage Bonds	(84)	-	(84)	(30)	-	(30)
Off-balance Sheet Leases	1,241	-	1,241	1,213	-	1,213
Securitization Bonds	(698)	-	(698)	(648)	-	(648)
Spent Nuclear Fuel Trust	(229)	-	(229)	(228)	-	(228)
Total Adjusted Capitalization	**12,540**	**8,642**	**21,182**	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***59.2%***	***40.8%***	***100.0%***	***58.0%***	***42.0%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 58.0% AT 12/31/05

Regulatory Activity

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ Kentucky Base Rate Filing – Settlement Pending
- ✓ Indiana Depreciation Petition
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

<u>TCC Stranded Cost Recovery Case</u>

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- Mar 2006 - Request for securitization
  - 4Q06 - Issuance of securitization bonds if no appeal
- Apr 2006 – Request approval for CTC to collect other true-up items
  - Jan 2007 – CTC charge to be implemented

<u>Ohio Companies Pass through of FERC OATT Changes</u>

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Regulatory Activity Underway

Appalachian Power – Virginia E & R Cost Recovery Factor

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- ✓ Public hearings began February 27, 2006

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ March 16, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

Regulatory Activity Underway

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Parties to the case reached a settlement on Feb 6, 2006
  - ✓ $41 million annual increase in base rates
  - ✓ To be effective March 30, 2006
- ✓ Settlement was presented to the Commission at a public hearing on Feb 7, 2006
- ✓ Final order expected in March 2006

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1
- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2
- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3
- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:
- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006—2007:
- ✓ Obtain permits and finalize engineering and procurement

2007—2010:
- ✓ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

Summary Rate Case Information

A Century of Firsts

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

March 8, 2006	Staff & Intervenor Testimony
March 29, 2006	Company Rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order issued

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

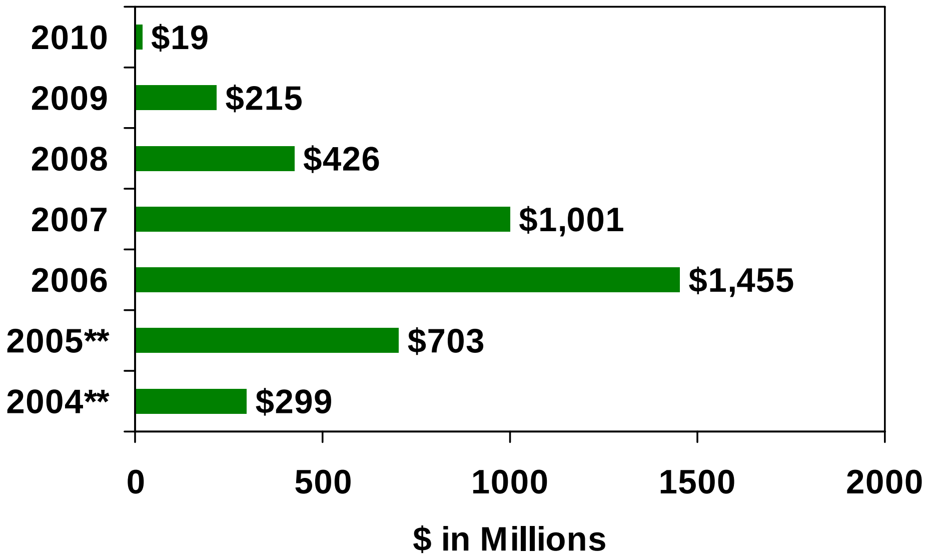
* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Environmental Investment

$4.1 Billion Environmental Investment

A Century of Firsts

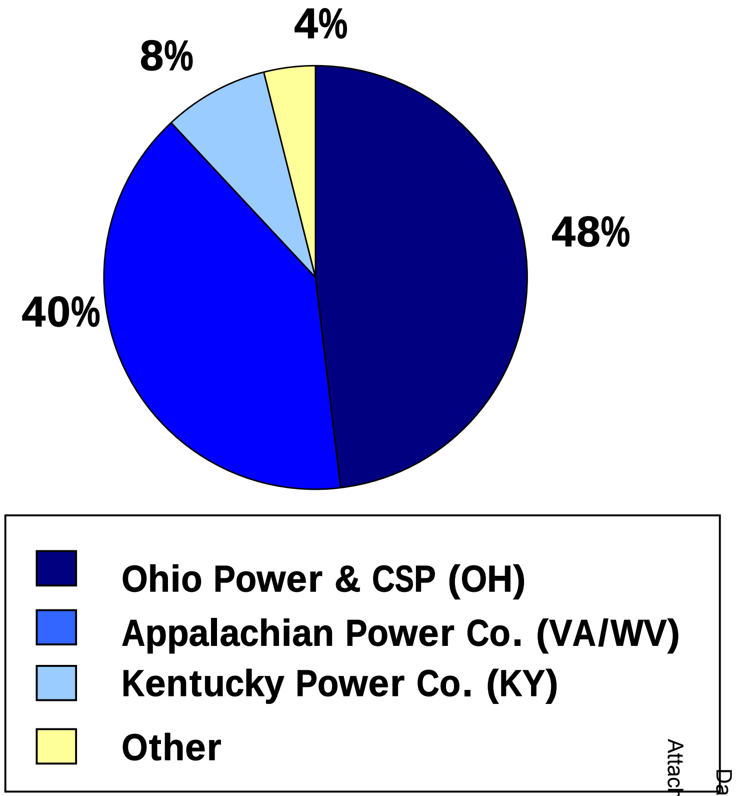
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

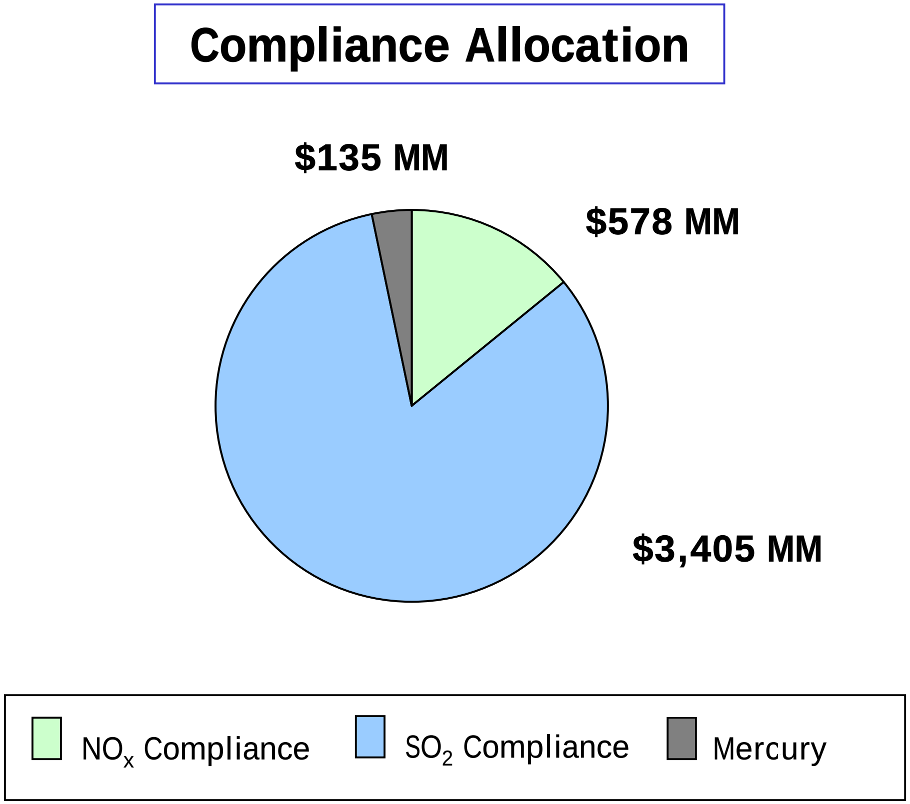
** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation



MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment



Current Programs

\$2.0 Billion:

\$0.5 Billion for NOx

\$1.5 Billion for SO_2

Future Programs

\$2.1 Billion:

\$1.9 Billion for SO_2

\$0.2 Billion for Other

Note: Figures Include AFUDC

\$4.1 BILLION ENVIRONMENTAL INVESTMENT

PROJECTED 2004 THROUGH 2010

Environmental Installations

A Century of Firsts

FGD - Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD: 2006 - 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR: 2006 - 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

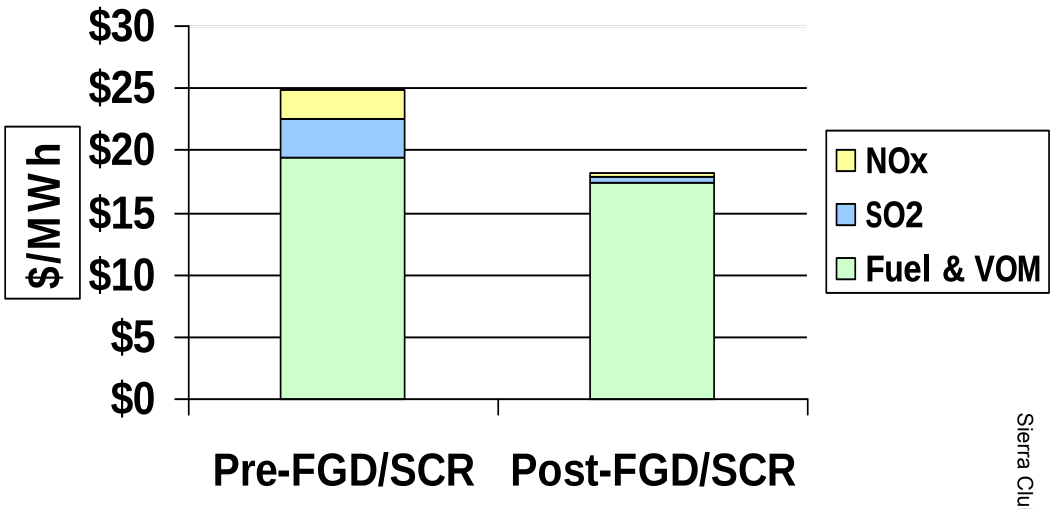
Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- **Lowers exposure to high cost emission allowances**
- **Creates opportunity to burn wider variety of lower cost fuels**
- **Improves baseload operation (higher capacity factor, higher margin)**
- **All-in cost of electricity, including FGD/SCR investment, remains low**

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



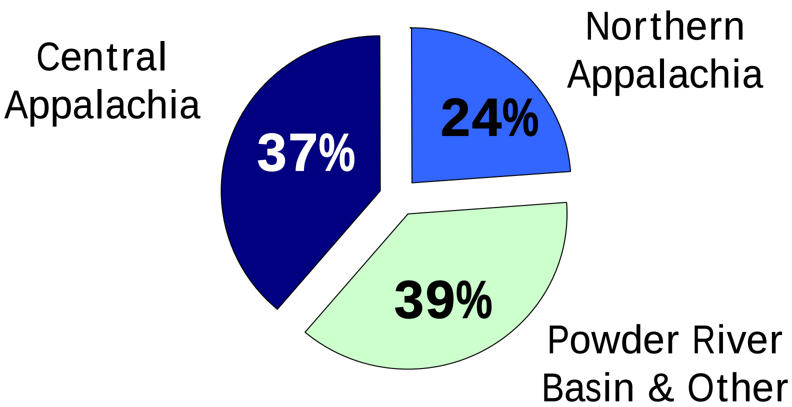
* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Fuel Procurement

Coal Procurement

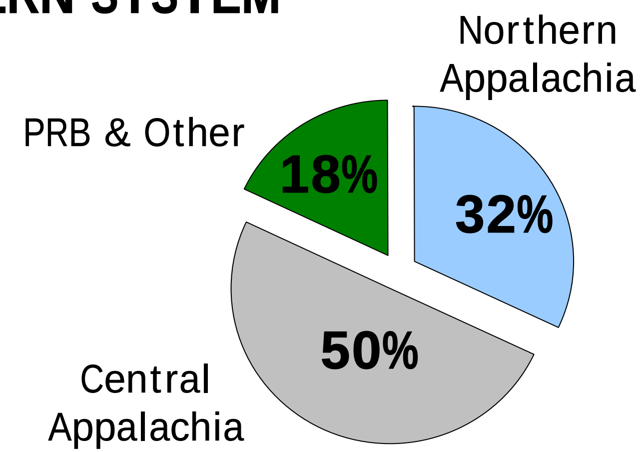
AEP SYSTEM



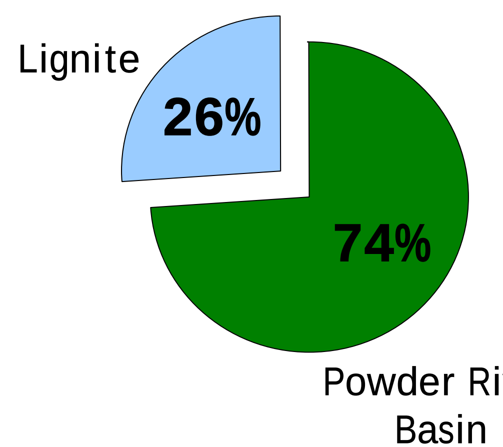
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Essentially >95% purchased for 2006
- Approximately 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM

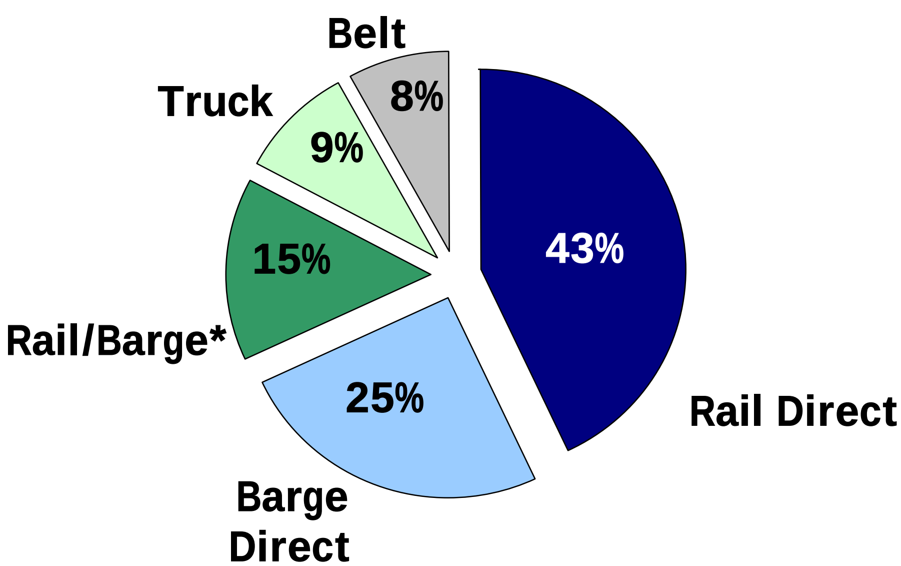


WESTERN SYSTEM

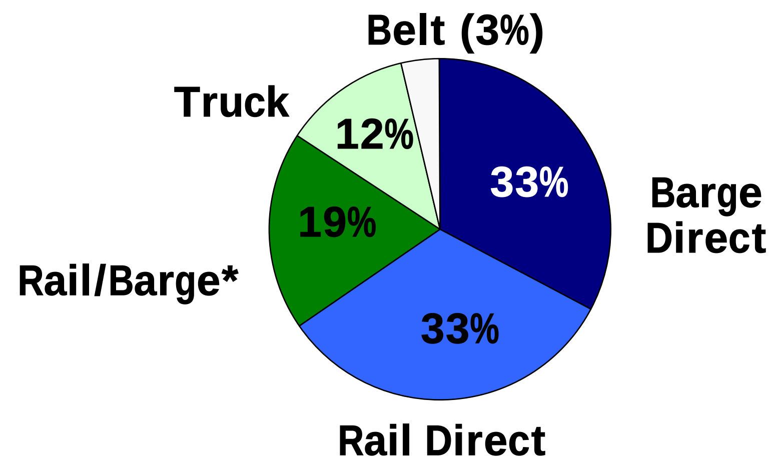


Coal Delivery

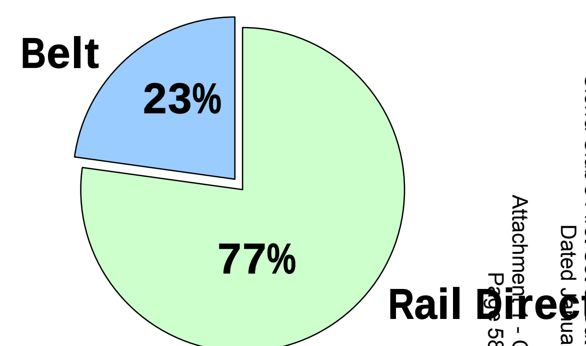
AEP SYSTEM
DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



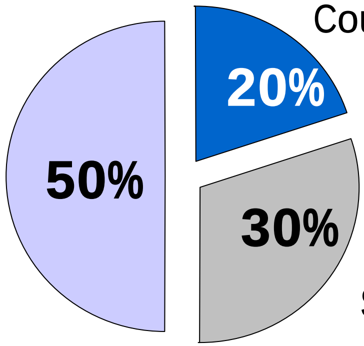
WESTERN SYSTEM
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

Fuel Recovery

AEP SYSTEM

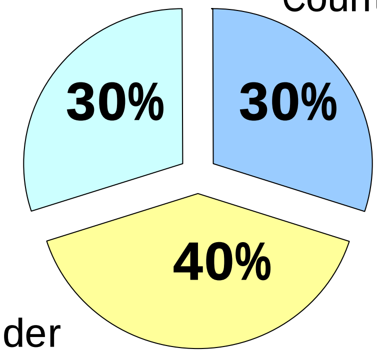


Fuel Cost Recovery

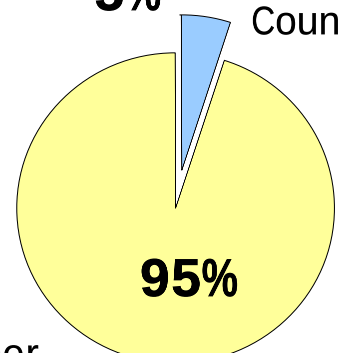
(on average)

- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KGP, KPCo
  - AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



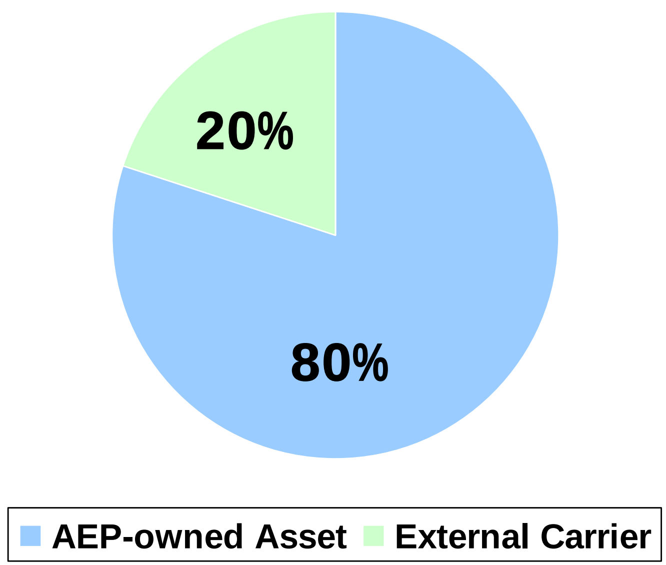
WESTERN SYSTEM



Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
2005 Actual



AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

* Represents close approximations

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

IGCC

Integration Gasification Combined Cycle

A Century of Firsts

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

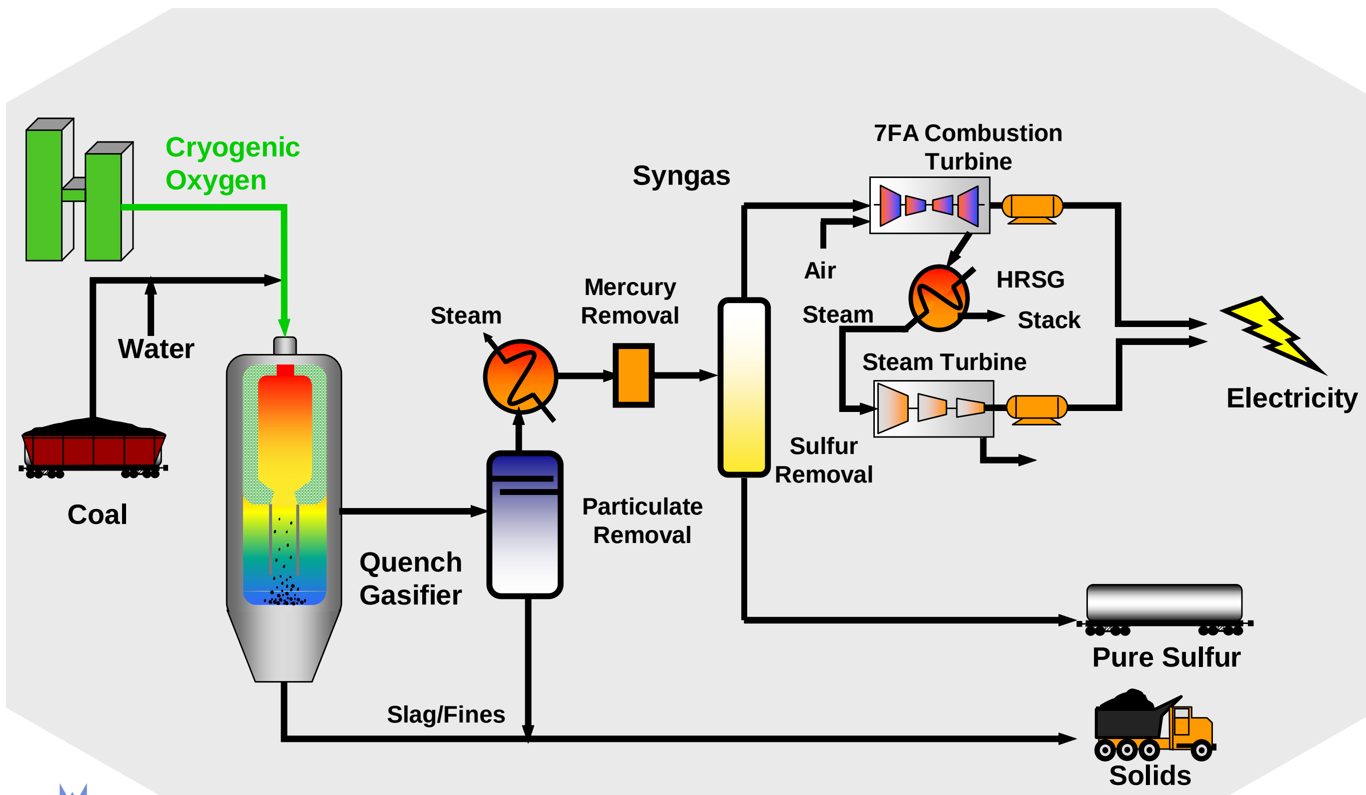
Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 5864 of 9556

Looking to the Future - IGCC



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AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing in IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Credit Suisse 2008 Energy Summit

Vail, Colorado
February 5, 2008

AEP AMERICAN® ELECTRIC POWER



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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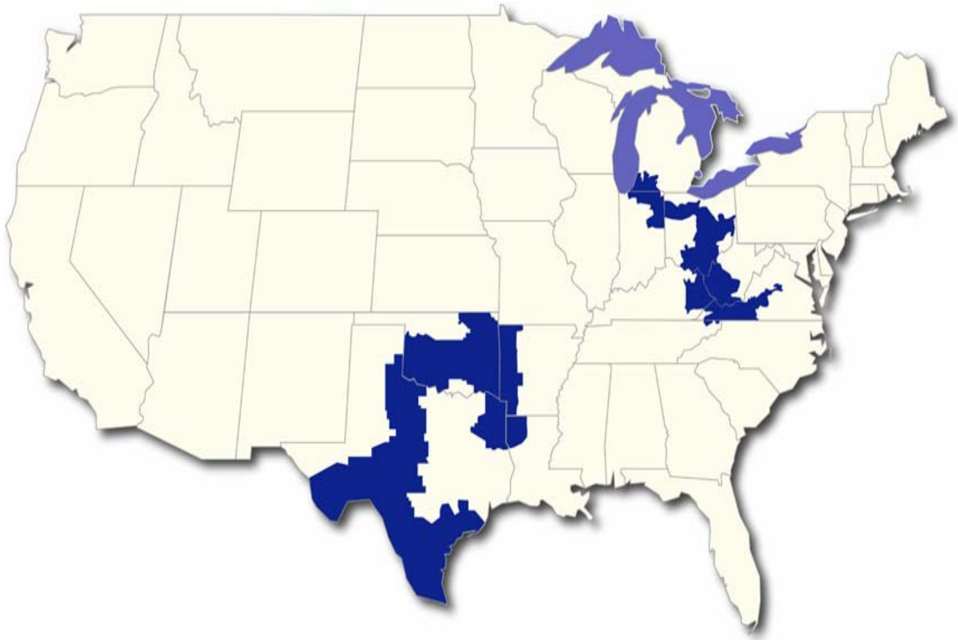
Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~212,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees



AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
67%	**24%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

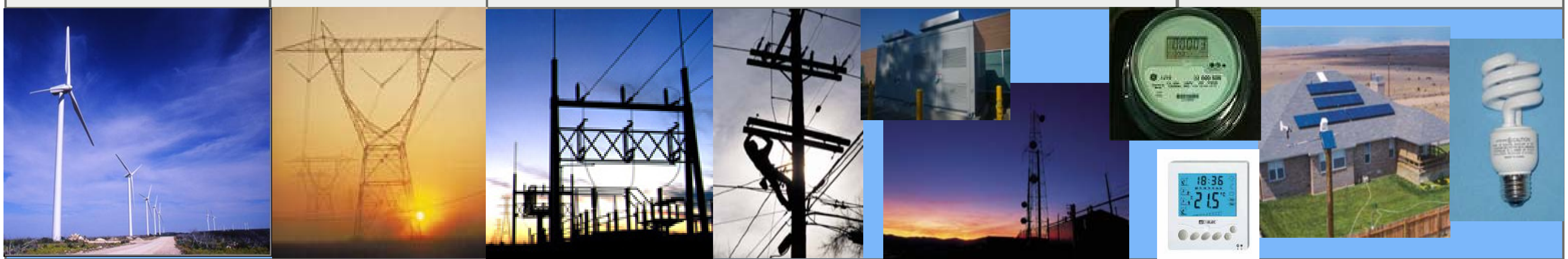
- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

Vision for Sustainability

Generation	Transmission	Distribution	Customers

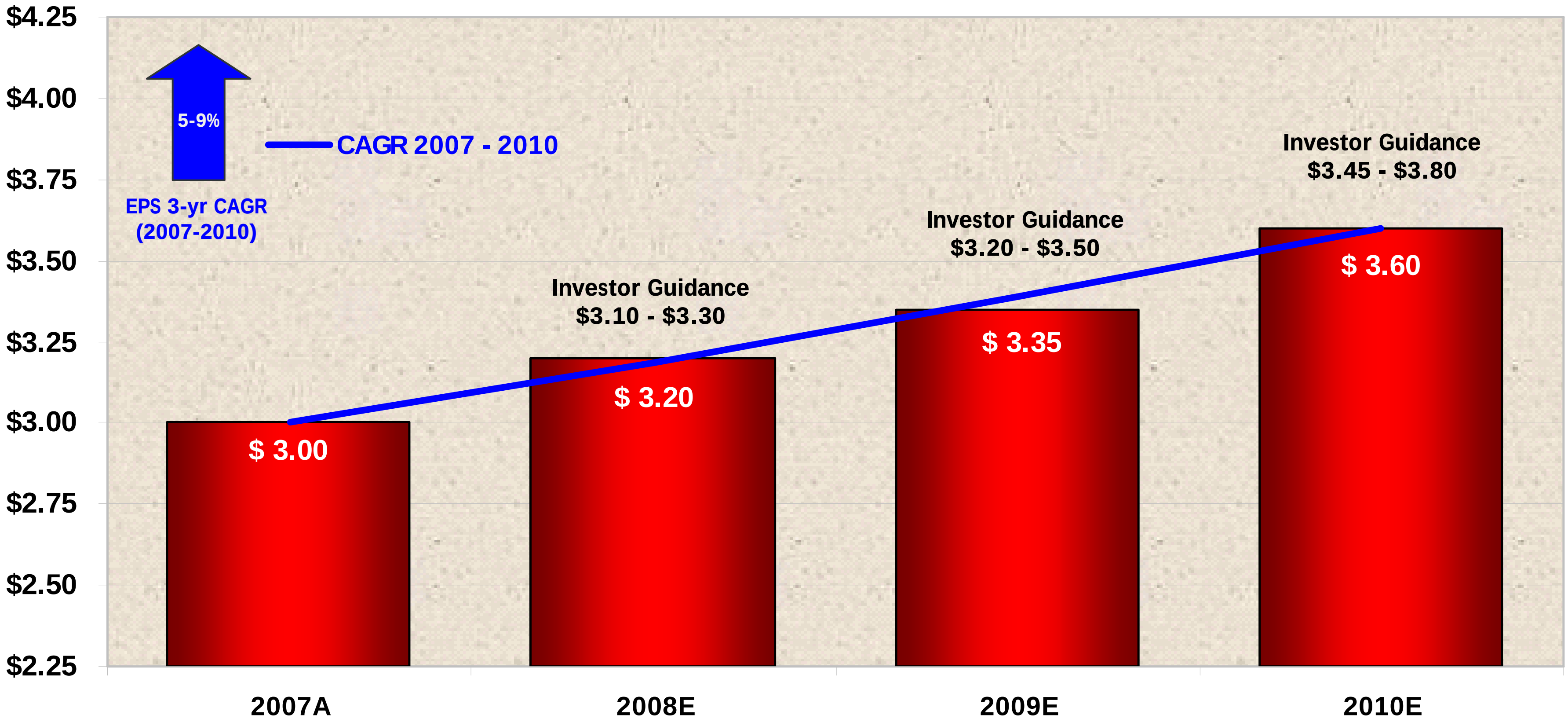
• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage



Existing generation and transmission control systems	**gridSMART℠**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

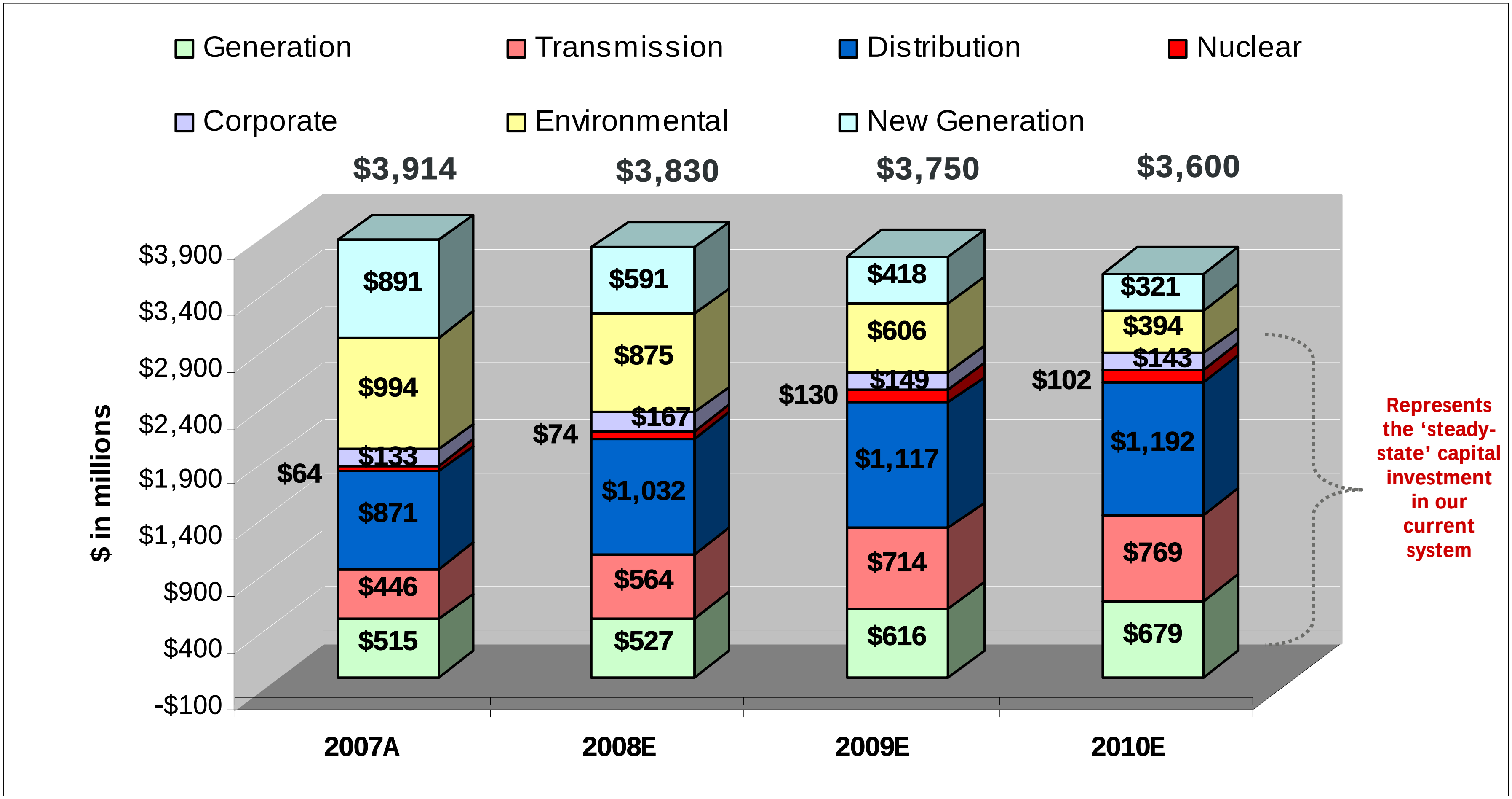
AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

4-Year Earnings Range Forecast



5% to 9% earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$265 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$375 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B [1]	Coal	Ultra-supercritical	600 [2]	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	TBD
CSP/OP	Great Bend	Ohio	Under Review [2]	Coal	IGCC	630	TBD

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the current appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

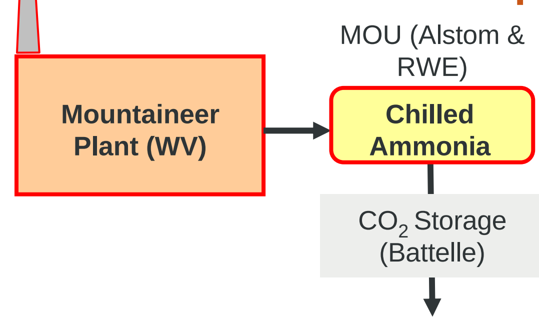
$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

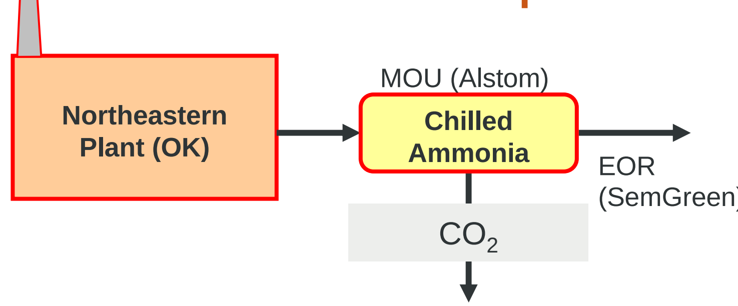
Phase 1

2009 Commercial Operation



Phase 2

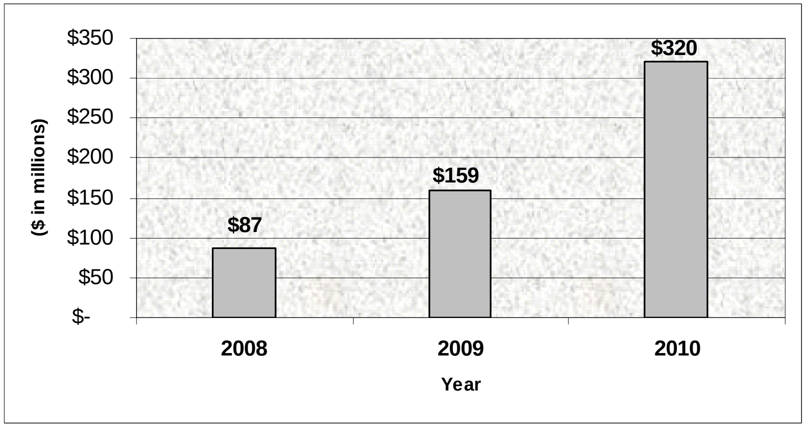
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

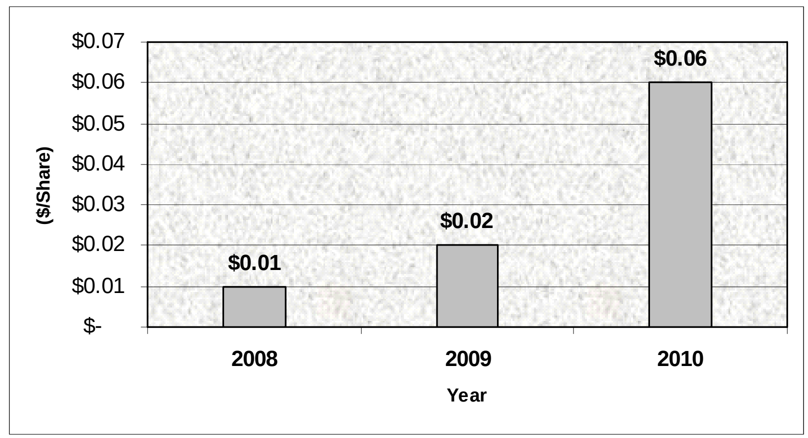


* ETT and PATH projects included in above projection.

ETT Electric Transmission Texas

PATH Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

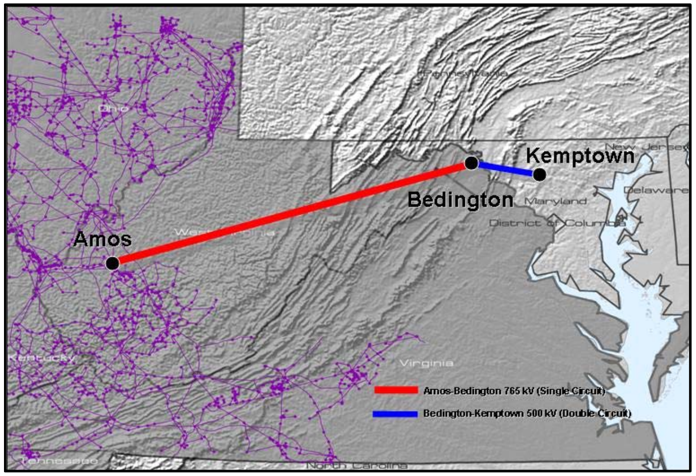
Note: Transmission Joint Ventures are excluded from AEP's base forecast as shown on slide 8 because they are not consolidated for financial reporting. AEP will be responsible for funding 40-50% of our 50% share with our own capital, and the remainder will be financed with off-balance sheet debt.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, 14.3% ROE, recovery of all costs incurred prior to the time rates go into effect, and recovery of all prudently incurred development and construction costs if the project is abandoned.*
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

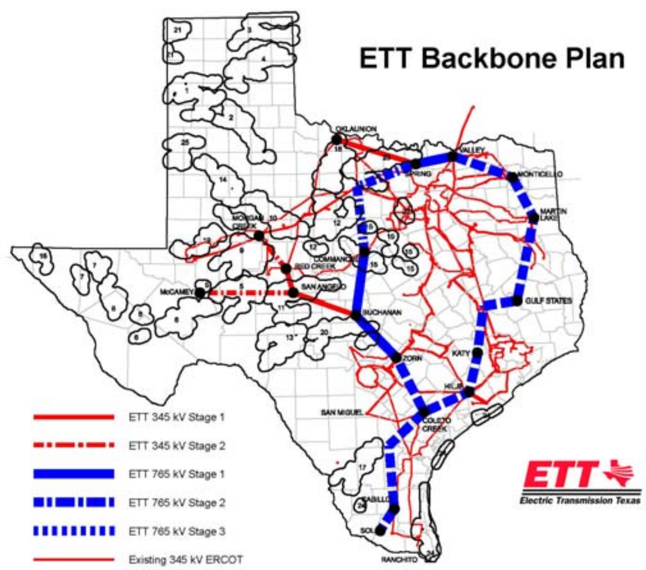
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- **Transaction Structure**
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- **Next Steps**
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*

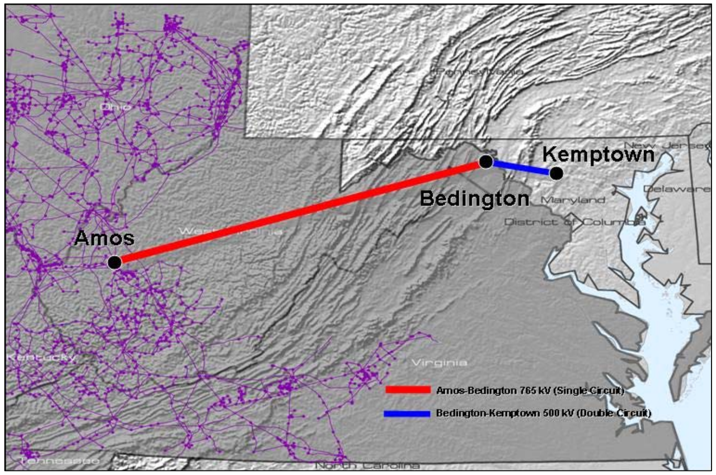


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

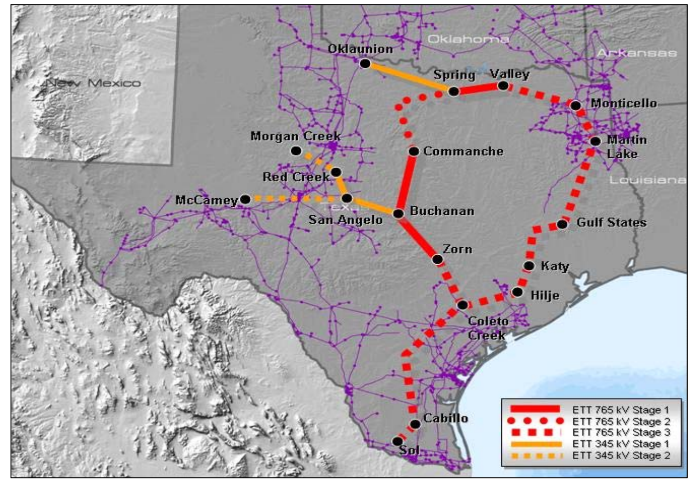
* Before ownership division.

I-765™ Transmission: Investment Opportunities

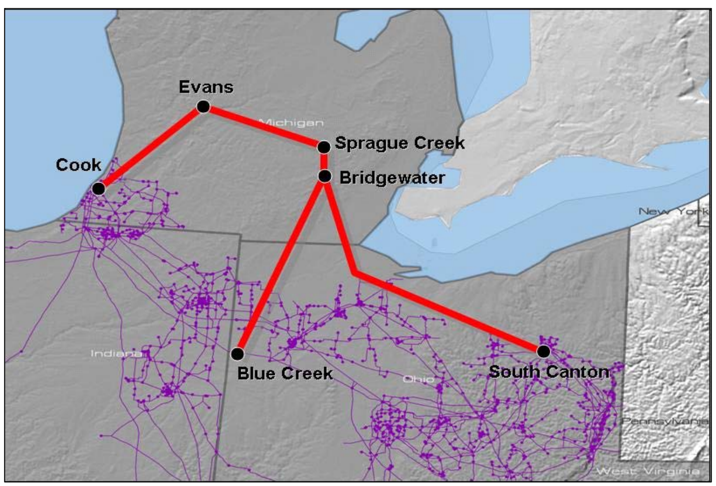
AEP is Advancing the Development of a National Interstate Today



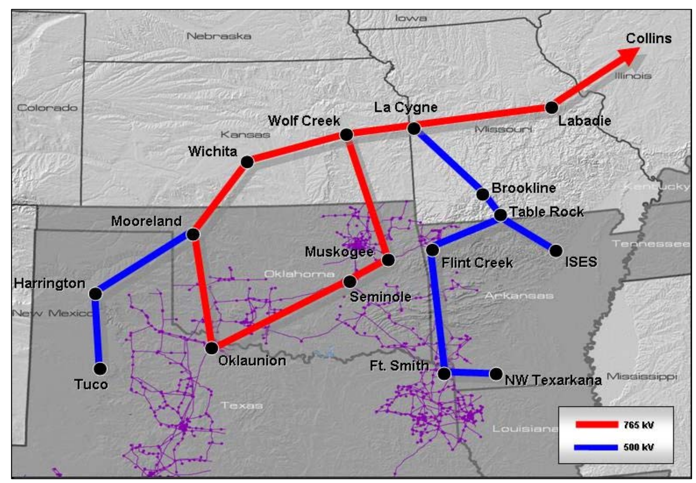
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

Credit Suisse 2008 Energy Summit

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Distribution - gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

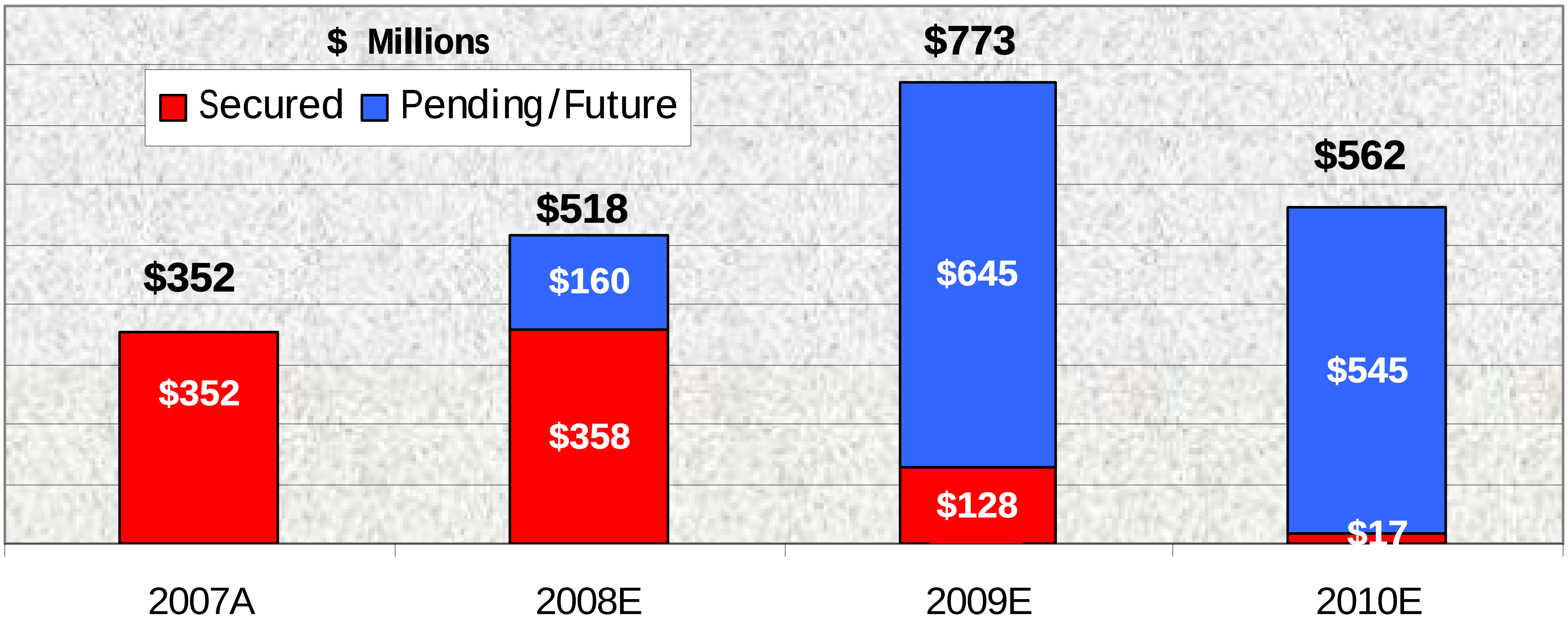
- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$40**	**$ 63**	**$ 82**

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

Incremental Rate Relief Assumptions



- 69% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery.
- 2008 Pending: APCo - Virginia Fuel Factor, PSO January 2007 Ice Storm Recovery, SWEPCo - LA Financial Review, other cases yet to be filed.

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

KPSC Case No. 2011-00401
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Regulatory Activity Underway

- Ohio Post 2008
- APCo-VA Fuel Factor Adjustment Filing
- I&M - Indiana Base Rate Case
- PSO Storm Cost Recovery Filing
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Questions?

Appendix

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

2008 Projected Cash Flow

	2007 Actual	2008 Estimate
Beginning Cash Balance	$ 301	$ 178
Cash from Operations:		
Income from Continuing Operations	1,065	1,284
Depreciation and Amortization	1,513	1,484
Other	(190)	(196)
Total from Operations	2,388	2,572
Cash used for Investing:		
Construction Expenditures	(3,556)	(3,916)
Asset Sales	222	-
Distressed Generation Purchases	(512)	-
Other	(62)	(39)
Total used for Investing	(3,908)	(3,955)
Cash from Financing:		
Issuance of Common Stock, Net	143	150
Long-Term Debt Issued/(Retired), Net	1,260	1,883
Short-Term Debt Change, Net	642	(87)
Common Dividends	(630)	(659)
Other Financing Activities	(18)	44
Total from Financing	1,397	1,331
Net Change in Cash	$ (123)	$ (52)
Ending Cash Balance	$ 178	$ 126

Note: For analysis purposes, construction expenditures include AFUDC.

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$489	$206	$120	$90	**$905**
Total Capex	**$3,915**	**$3,830**	**$3,750**	**$3,600**	**$15,095**

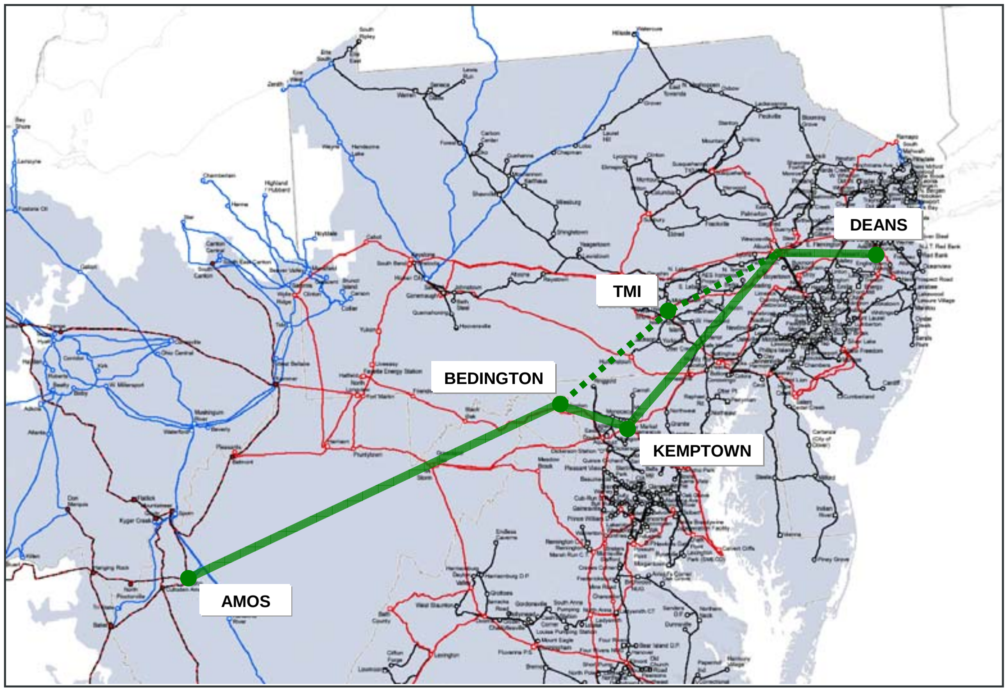
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

I-765™ Transmission in PJM East

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.

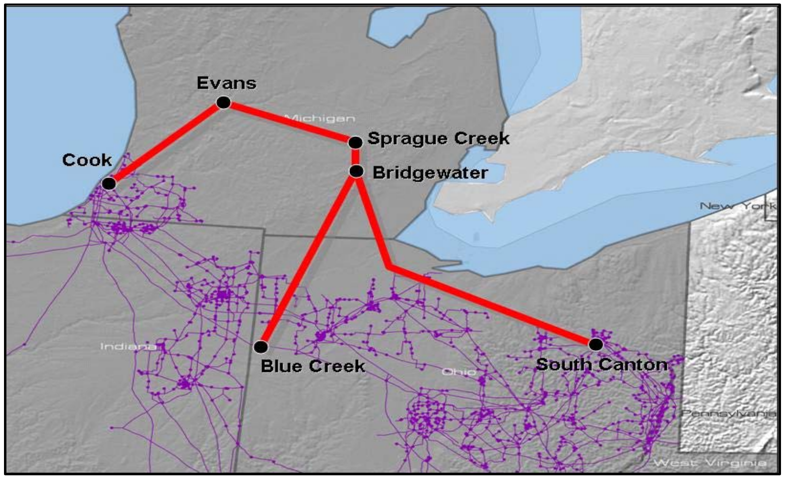


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765^{TM} Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015

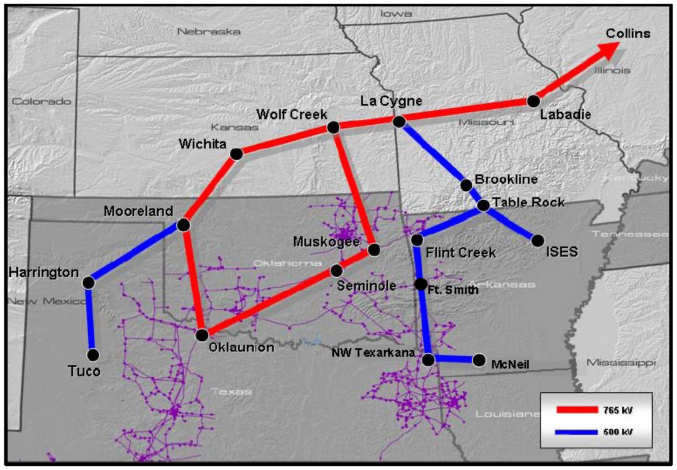


The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765TM Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- ***Benefits***
  - 4,000 MW improved transfer capability
- ***Next Steps***
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

2008 Regulatory Activity Completed

AEP Ohio Application For 4% Provision On Generation Rate

- On January 30, 2008, a settlement agreement was approved by the PUCO allowing the generation rider to be increased to recover in 2008 an additional $28.5 million for CSPCo and $4.9 million for OPCo.
- The approved settlement also authorized the inclusion of $78 million of estimated net costs of marginal losses ($38.9 million for CSPCo and $39.2 million for OPCo) in the existing Transmission Cost Recovery Rider, with any over/under recovery of the actually incurred costs from June 2007 through December 2008 to be reflected in the 2009 TCRR recovery mechanism, including carrying charges on any such over/under recovery.

Regulatory Activity Underway

Ohio Post-2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearing schedule extends to the end of January 2008 and we anticipate a signed bill in March or April of 2008.

APCo (Virginia) Fuel Factor Adjustment

- On July 16, 2007, a filing was made with the VA SCC requesting the termination of the OSS base credit and reflected 75% of OSS margins as a credit to fuel expense, consistent with new Virginia legislation. Implementation of the fuel factor was approved effective September 1, 2007, subject to review/refund.
- Intervenor testimony was filed on October 5, 2007, staff testimony filed on October 15, 2007 and rebuttal testimony filed on October 22, 2007. APCo's rebuttal testimony included adding $18.8 million to the fuel factor request related to the recovery of PJM marginal losses incurred.
- Public hearings were held on December 19, 2007. We await an order in this proceeding.

Regulatory Activity Underway

I&M Indiana Base Rate Case

- On January 31, 2008, I&M filed a base rate case with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties agreed to a historic test year ended September 30, 2007, with adjustments allowed for fixed, known and measurable items that will occur within 12 months following the end of the test year.
- The case includes the following:
  - Required Rate Relief/Revenue Requirement - $128.5 million
  - Rate Base (original cost less depreciation) – approximately $2 billion
  - Requested ROE – 11.50%
  - Required ROR – 8.10%
- Hearings are expected in May 2008 and an order in the first quarter of 2009.

Regulatory Activity Underway

PSO Storm Cost Recovery Filing

- On October 24, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of sulfur dioxide (SO_2) emission allowances.
- Staff and intervenor testimony was filed January 17, 2008, a settlement conference is scheduled for February 25, 2008 and hearings are scheduled for February 27 and 28, 2008.
- Staff and AG testimony was supportive of PSO's requested treatment for cost recovery.

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- PSO requests the Commission make a determination that the costs incurred on the Red Rock project were prudent and direct it to establish a regulatory asset of approximately $21 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of SO_2 emission allowances.
- A procedural schedule in the case has not yet been established.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Technical conferences and settlement meetings were held in October – December 2007. Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. An order is due by March 6, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings are scheduled for February 12, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected in the first quarter of 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony is due February 15, 2008, rebuttal testimony is due February 29, 2008 and hearings will commence on April 7, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

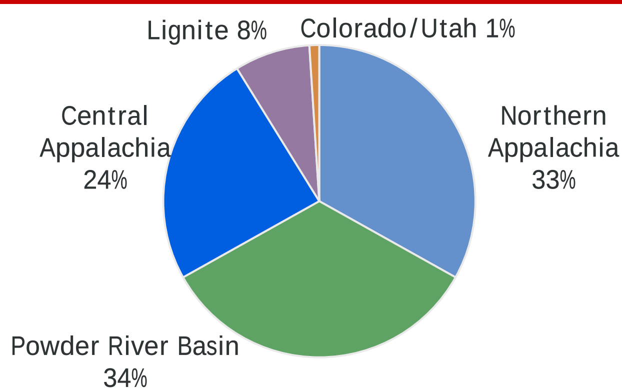
Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	7.29%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	23.86%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	13.01%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo-LA	$434MM	11.10%	12/29/1999	8.74%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	11.33%
Texas-TNC	$530MM	9.96%	6/1/2007	9.93%

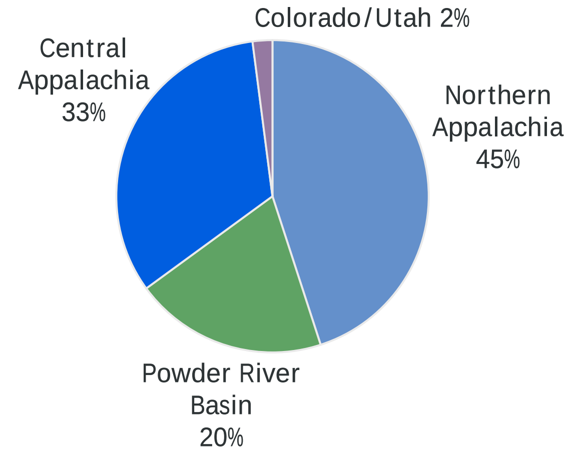
Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

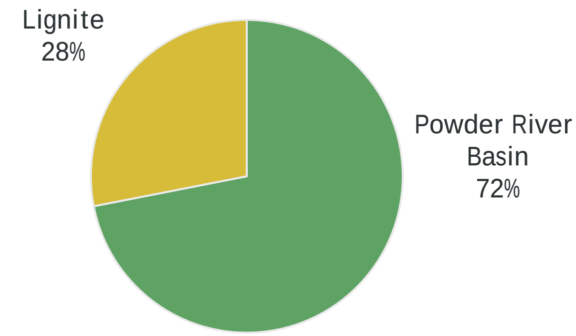
Total AEP System



AEP East



AEP West



Coal Stats:

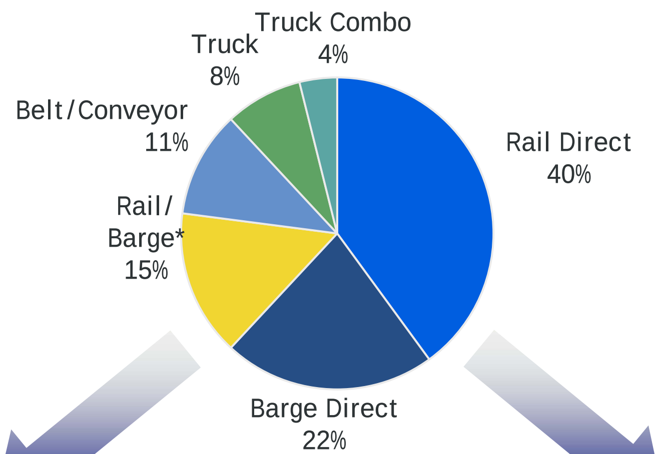
- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

Credit Suisse 2008 Energy Summit

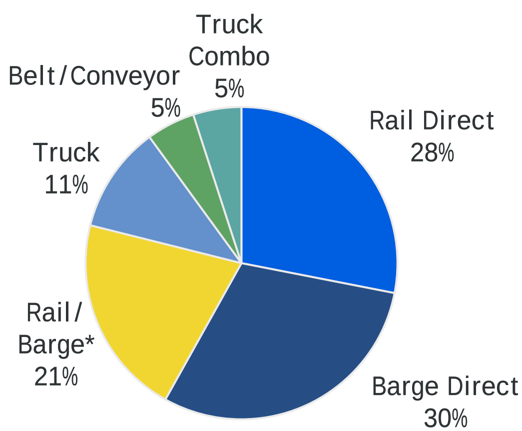
Coal Delivery

Total AEP System

2007 Actual



AEP East



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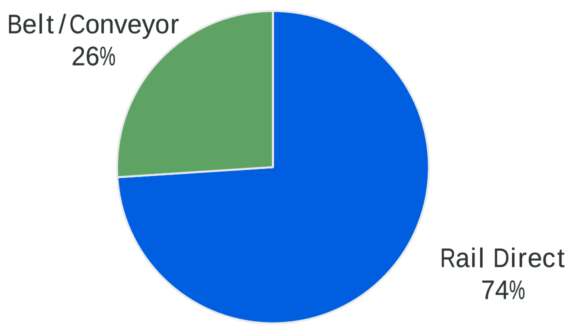

* Reflects coal delivered to AEP plants transported through a combination of rail and barge

American Electric Power

GridSMART Opportunities

42nd EEI Financial Conference
Walt Disney World Dolphin
Lake Buena Vista, Florida
November 6, 2007

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

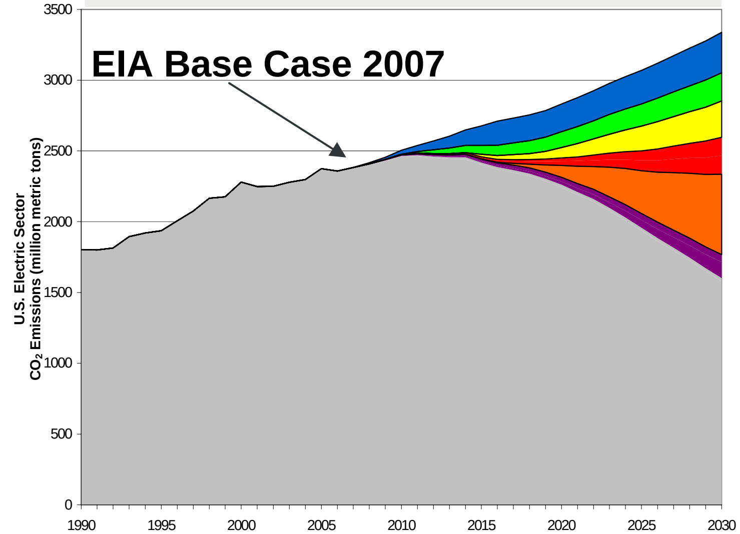
- Prepare for transition to market in Ohio
- **Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management**
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

AEP is Pursuing a Portfolio of Options to Address Sustainability

Technology	EIA 2007 Reference	Industry Target	AEP Plan
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr	DSM: 1000MW reduction in demand by 2012
Renewables	30 GWe by 2030	70 GWe by 2030	Wind PPAs through 2015: 1610MW nameplate or 232MW capacity for planning purposes. Also, voluntary green energy tariffs (Ohio program started 2007)
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030	Evaluation of COL
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030	1,246MW IGCC by 2017 447MW USC Turk plant by 2011
Carbon Capture and Storage	None	Widely Deployed After 2020	Chilled Ammonia: Mountaineer 2009 & Northeastern 2012 Oxy-coal by 2020
Plug-in Hybrid Electric Vehicles	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter	Joined Electric Drive Transportation Association (EDTA) in May 2007
Distributed Energy Resources	< 0.1% of Base Load in 2030	5% of Base Load in 2030	Pursuit of NaS® Energy Storage – 25MW of storage by 2010 and 1000MW of other storage/fuel cells by 2020

Technical Potential for CO_2 Reductions - *Achieving all targets is very aggressive, but potentially feasible.*



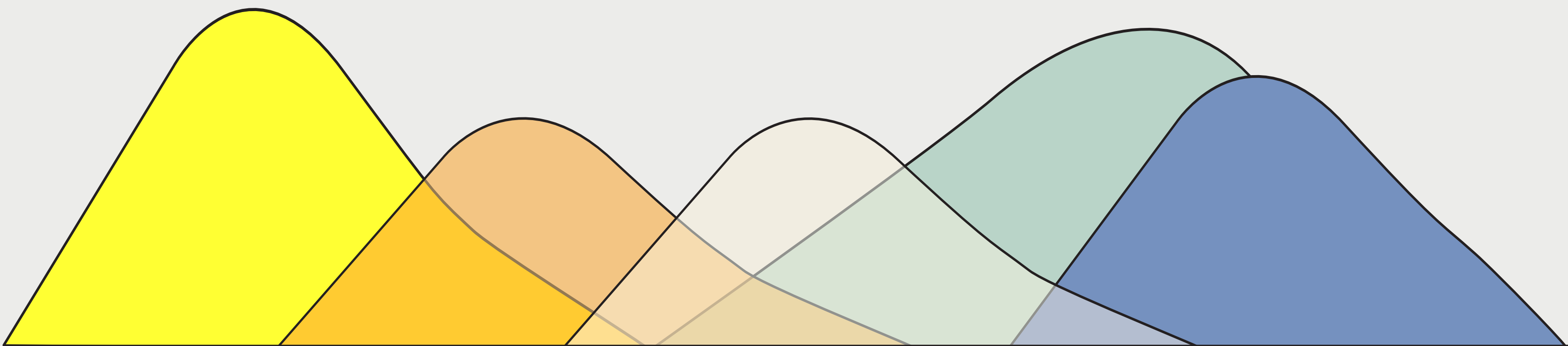
Technology advancement is required beyond present "state of the art" to achieve 1990 CO_2 levels by 2030. AEP is investing in a portfolio of GHG reduction initiatives. Allocation of funds will shift over time depending on technology, legislation, etc.

Source for graphic, EIA 2007 reference and industry target data: EPRI

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

Imagine . . .

- Enabling our customers to better manage energy
- Dramatically improving service to our customers
- Integrating distributed energy resources into our grid
- Transforming the way we do business

Our vision for GridSMART is ambitious and innovative.

What is GridSMART?

- **Addresses the full energy pathway from the power plant to the customer**
- **Improves efficiency and reduces both customer demand and energy losses**
- **Enhances Customer Choice, Customer Control and Customer Service through:**
  - Time of use rates
  - Real time pricing/critical peak pricing
  - Direct load control
  - New and improved self service options
    - Account maintenance
    - Start/Stop service
    - Remittance date selection with electronic bill presentment and payment
    - Outage reporting and restoration notification
    - Prepay metering
    - Energy usage analysis

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

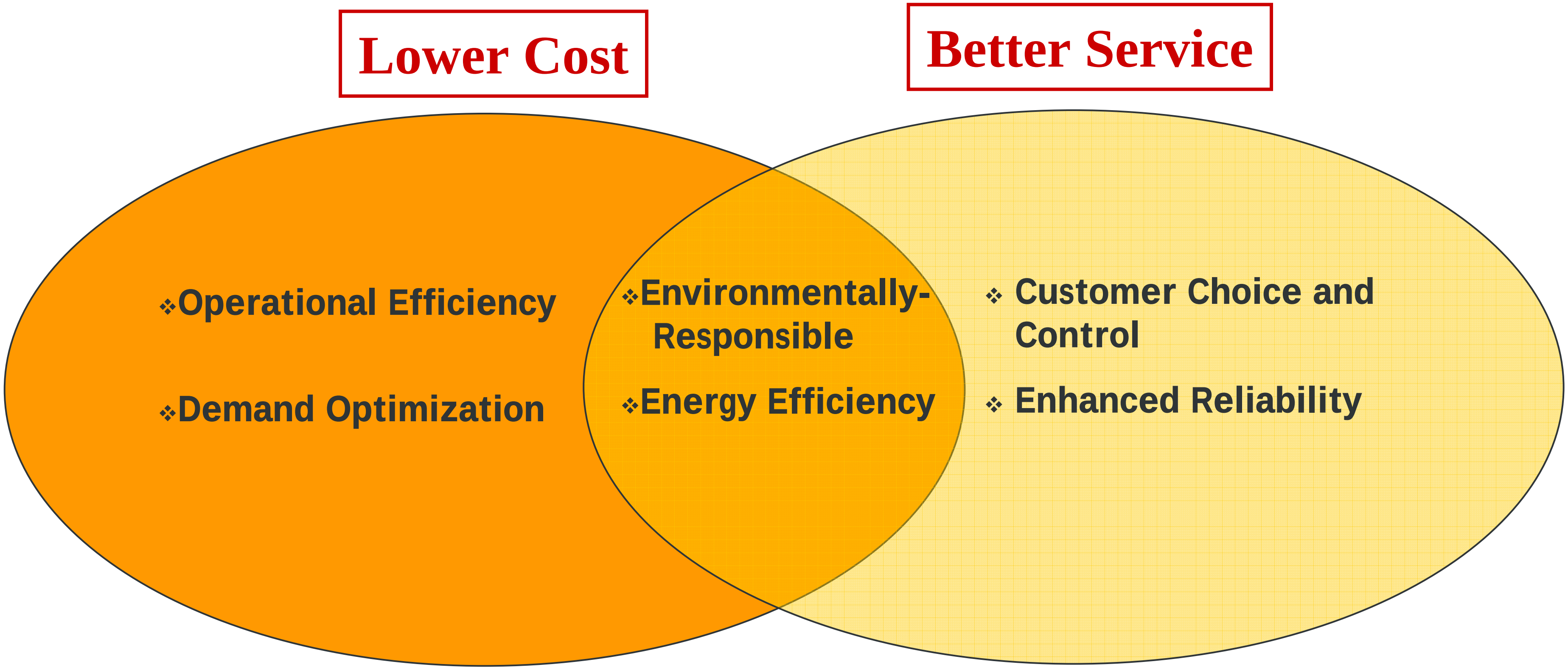
Why Now?

- The price of electricity is rising and demand is growing
- Costs of equipment/technology for consumers are decreasing
- Customers are increasingly technologically savvy
- T&D infrastructure is aging
- New generation is needed
- Increased focus on environmental issues, including carbon footprint

Customer programs + Advanced technologies = Customer, Shareholder and Company Value

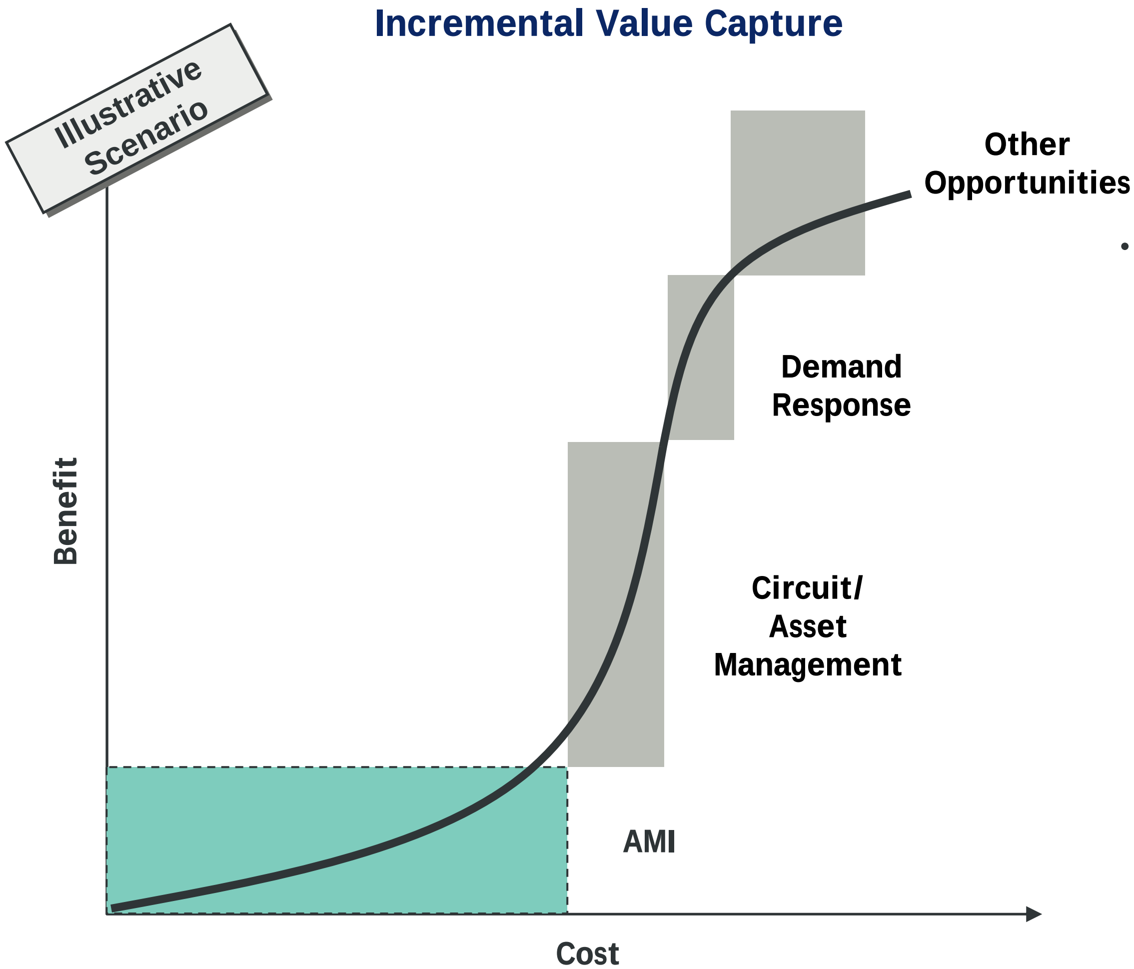
AEP's GridSMART Project

AEP's **GridSMART** project will develop a deployment plan for new customer programs and advanced technologies to support pursuit of the following value propositions:



Increased efficiency reduces cost and GHG emissions. It also delays the need for new generation.

Investment Opportunity Evaluation

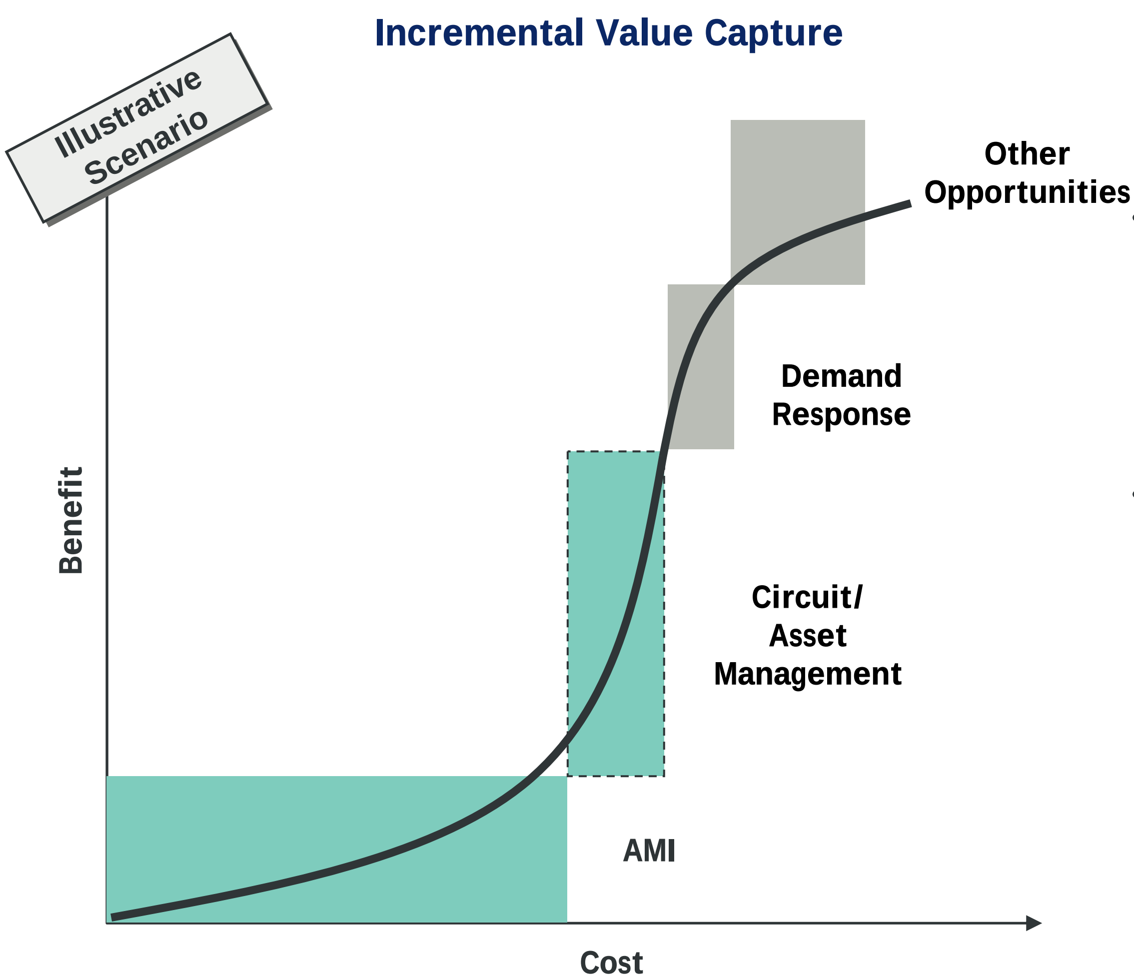


AMI

- **Represents the initial capital outlay**
  - Meter functionality
  - Communications infrastructure
  - Head-end and legacy systems modifications
  - Dependent upon regulatory approval

AMI is the first building block of the GridSMART initiative.

Investment Opportunity Evaluation

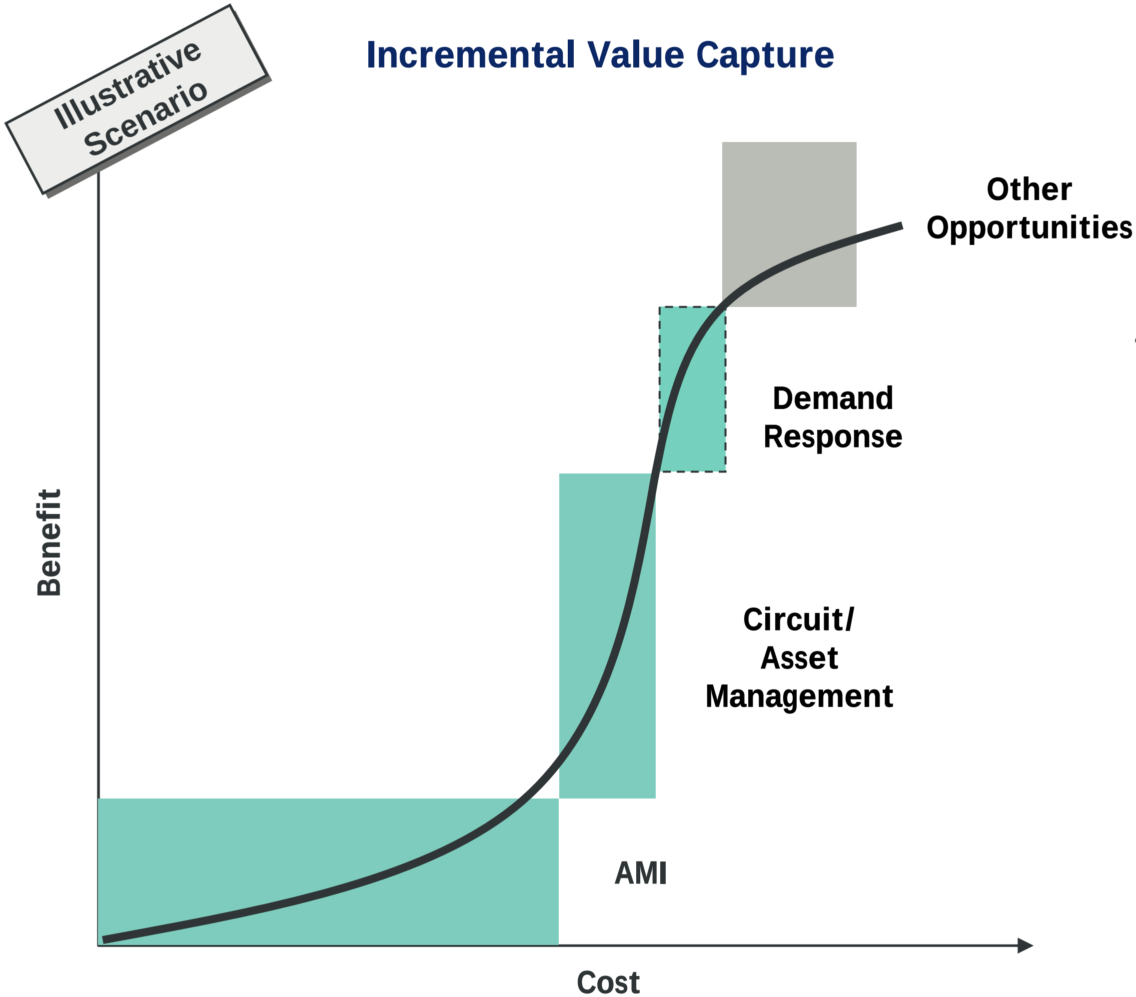


Circuit & Asset Management

- **Incremental field capital and knowledge-based applications**
  - Sensors & device controllers
  - Information management
- **Real-time information from our distribution assets enables advanced analysis and improved operations**
  - Outage and restoration reporting
  - Circuit reporting on exceptions
  - Voltage alerts on all feeders

Circuit & asset management will transform our distribution business.

Investment Opportunity Evaluation



Demand Response

- **Incremental utility-side capital**
  - Provides real-time pricing
  - Enables customer control
  - Results in reduced demand and energy consumption
  - Improves environmental performance

Demand response sends real-time signals to customers to enable decision making.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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The AEP-GE Initiative

We will deploy smart meters, distribution automation and the associated enhanced technology resulting from the collaboration with GE in two regions by the end of 2008 -- representing approximately 200,000 customers.

By integrating customers and their end use technologies into the daily operation of the grid, we can collaborate to optimize supply and demand and improve energy efficiency and environmental sustainability.

Our agreement with GE is a winner for our customers, our shareholders and for the environment.

AEP AMERICAN® ELECTRIC POWER

Working Together for a Brighter Future

imagination at work

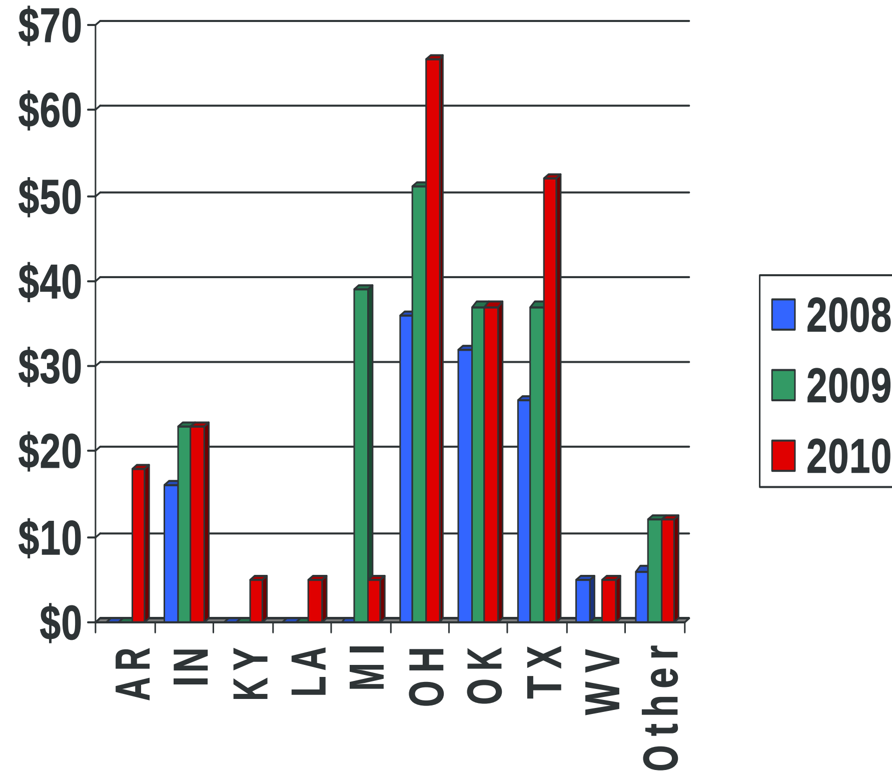
AEP and GE will collaborate to address the full energy pathway from the power plant to the home.

Pace of our GridSMART Implementation Determined by Regulators

- **Our GridSMART initiative results in a 'menu' of programs from which regulators can choose what they would like implemented in their jurisdiction**
- **Discussions and/or implementation underway in the following jurisdictions:**

EAST	**WEST**
- Indiana	**- Arkansas**
- Michigan	**- Oklahoma**
- Kentucky	**- Texas**
- Ohio	

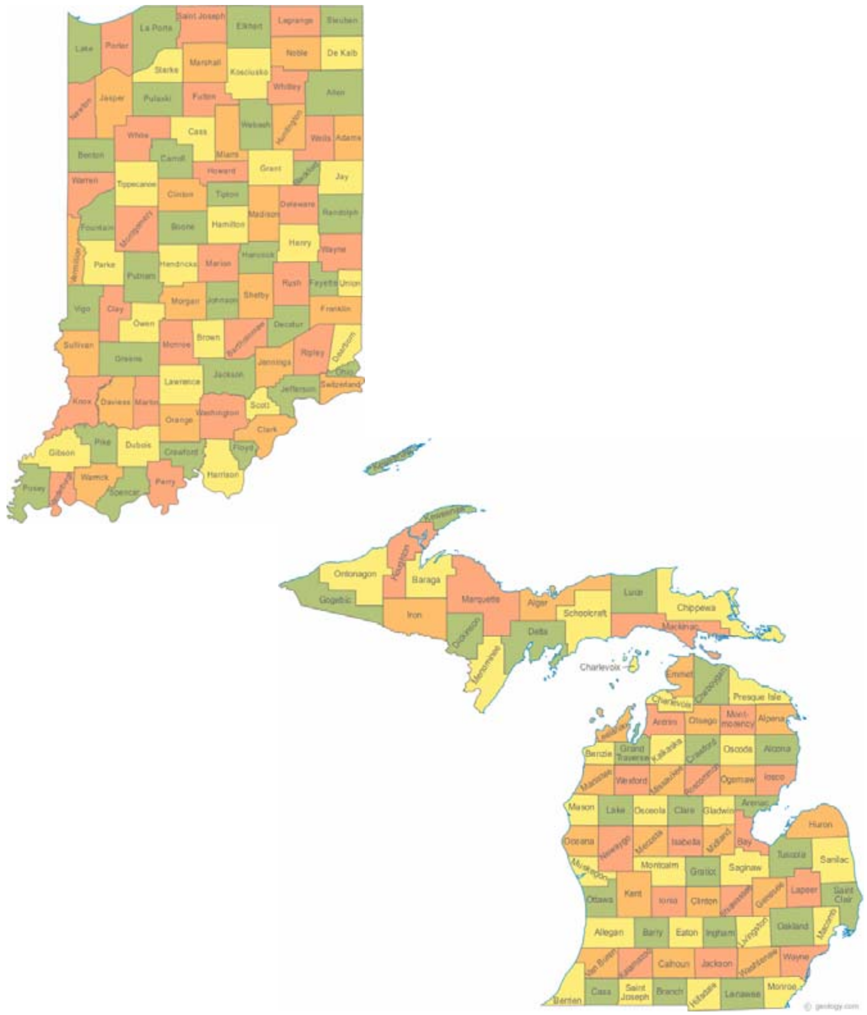
2008-2010 proposed capital investment by jurisdiction, subject to regulatory approval ($ in millions)



AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

Indiana/Michigan

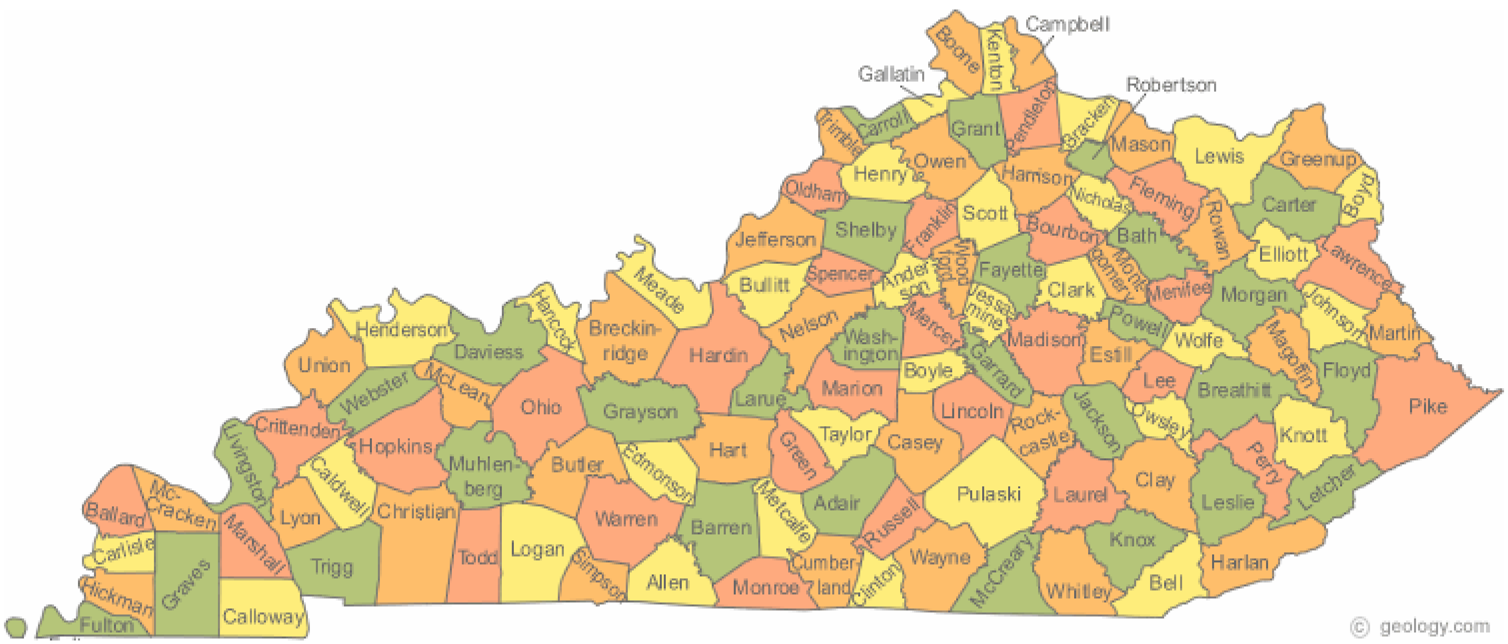
- Smart Metering Pilot Program (SMPP) for approximately 10,000 Indiana customers
- I&M proposed seven circuits in South Bend, Indiana with a total estimated capital cost of approximately $7 million and O&M costs of approximately $200,000 per year
- Initial meter installation occurring in 2008
- Beginning initial discussions with Michigan for a demand response/smart metering collaboration



I&M is pleased to be a leader in the exploration of smart metering as a part of AEP's GridSMART initiative. As smart metering expands beyond pilot projects, we can imagine even more of our customers benefiting, not just from being able to use our service more efficiently, but also from our service being more reliable and convenient to use.
- Helen Murray, I&M President and COO

Kentucky

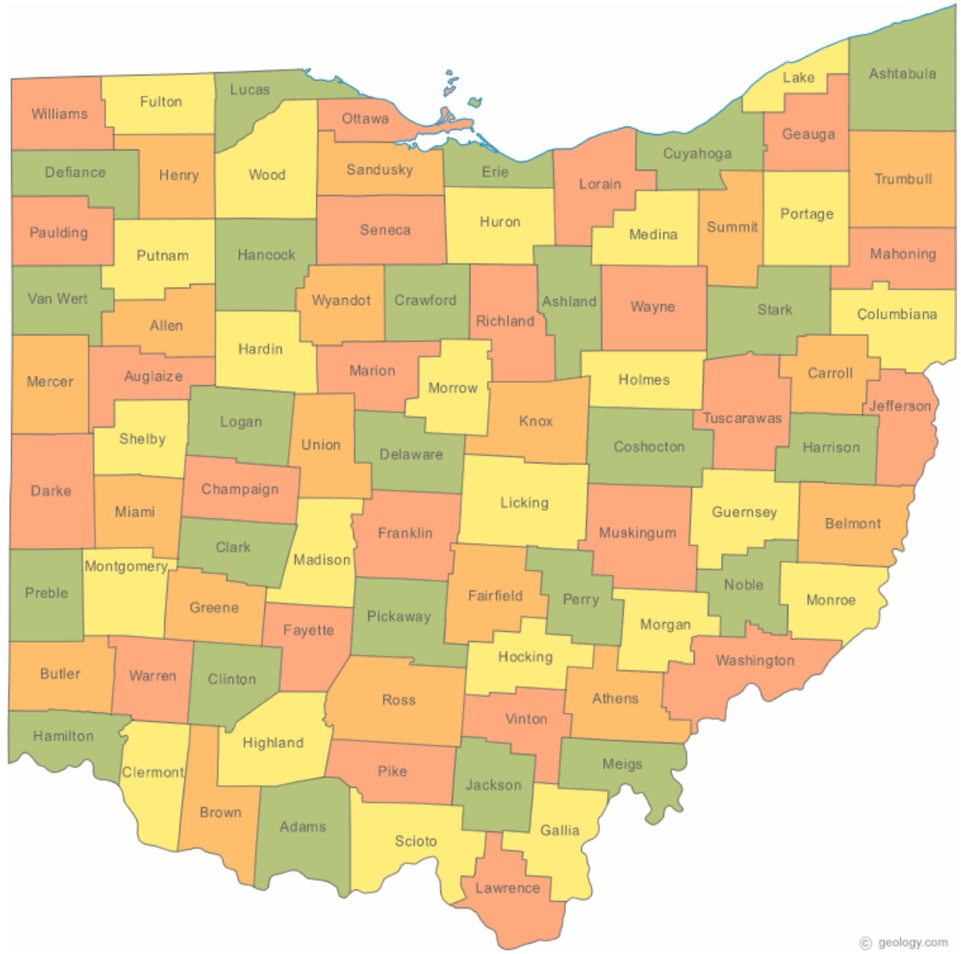
- Successful demand-side management programs have been in place since 1996
- Recent proposal filed for a real-time pricing pilot



Since the inception of our DSM program in Kentucky over a decade ago, 17,400 customers, nearly 10% of those we serve, have participated in various programs from weatherization to energy smart audits. Based on the success of these programs, we're looking forward to the new opportunities energy efficiency programming and real time pricing tariffs will offer. Our active DSM Collaborative has been anxiously awaiting new programs.
- Tim Mosher, KPCo President and COO

Ohio

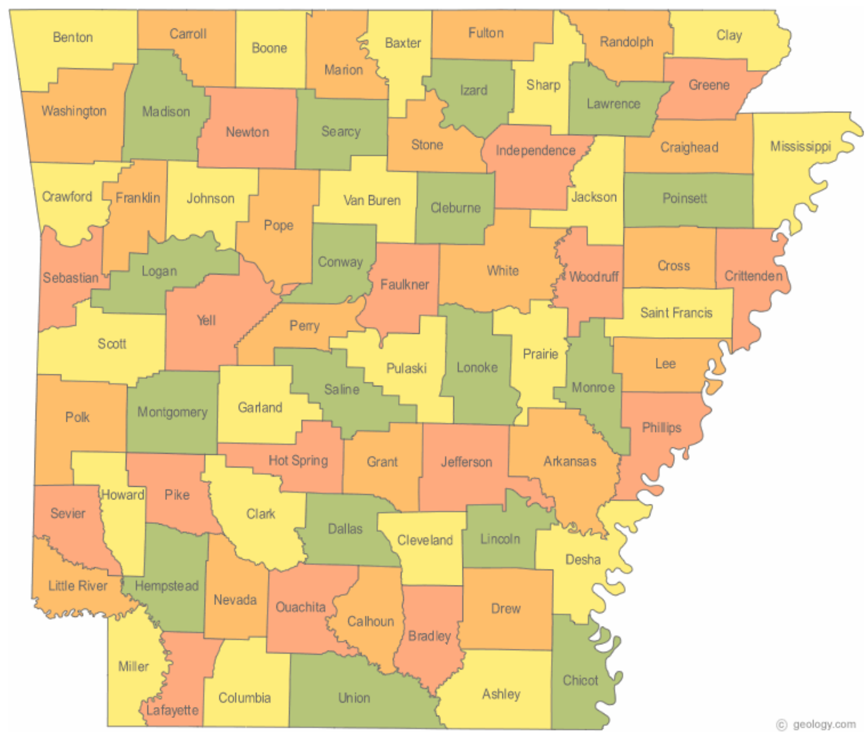
- Recent Governor remarks and draft legislation indicates modernization of Ohio's infrastructure is a high priority and includes demand and energy efficiency goals.
- PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.



As demand for electricity continues to grow, it is critical that we modernize Ohio's infrastructure. Through the GridSMART initiative, AEP Ohio is taking an active role working with our stakeholders to identify solutions that provide long-term benefits for our customers.
- Kevin Walker, AEP Ohio President and COO

Arkansas

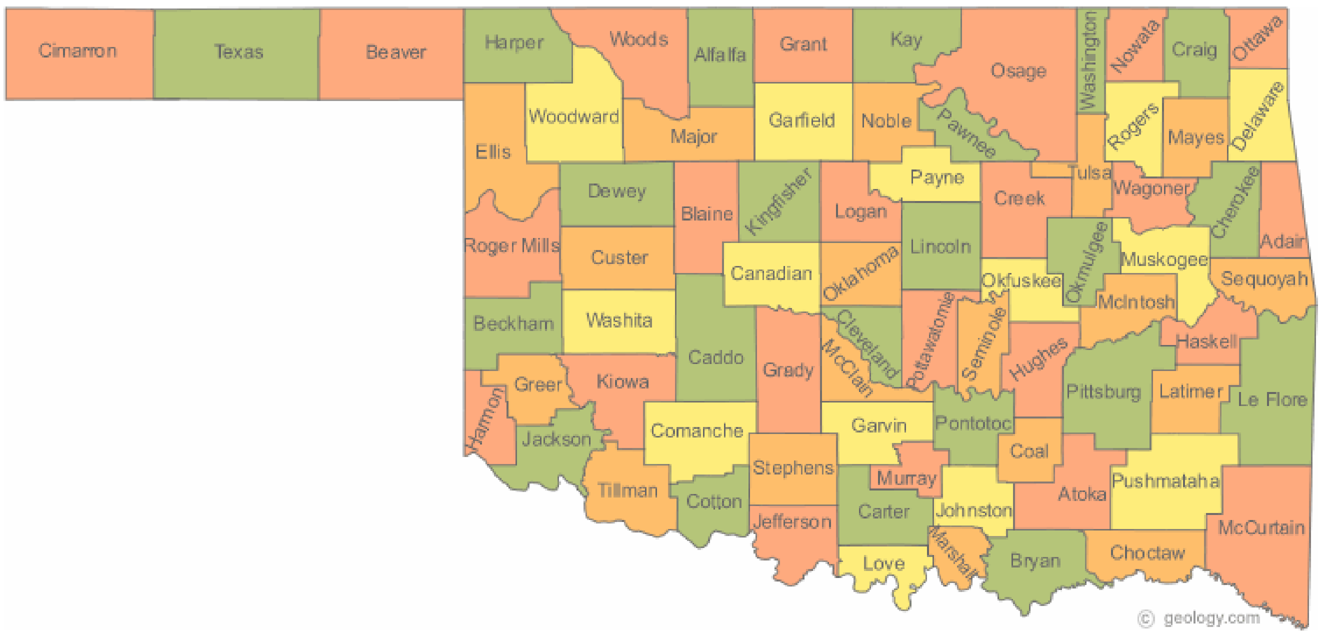
- Quick-Start Energy Efficiency Programs approved in September 2007
  - State-wide education
  - Incentive to encourage use of compact florescent lights and higher efficiency appliances
  - Weatherization for low-income housing
  - Cost recovery beginning with the first billing cycle of November 2007
- GridSMART discussions requested by the PSC
  - Potential solution to next incremental need for capacity



The growth in Northwest Arkansas makes it a perfect platform for GridSMART technology. SWEPCo is excited about exploring this solution with the PSC.
- Venita McCellon-Allen, SWEPCo President and COO

Oklahoma

- In October 2007, the OCC issued a Notice of Proposed Rulemaking to Establish Rules Promoting Energy Efficiency and Establishing Demand Program Requirements for Oklahoma Electric Utilities
- As part of PSO’s recent base rate case order, the OCC requested that PSO file a DSM/energy efficiency plan by December 8, 2007.



As demonstrated by its rulemaking and the recent PSO rate case order, the Oklahoma Corporation Commission is more focused on energy efficiency, conservation and demand programs than ever before.
- Stuart Solomon, PSO President and COO

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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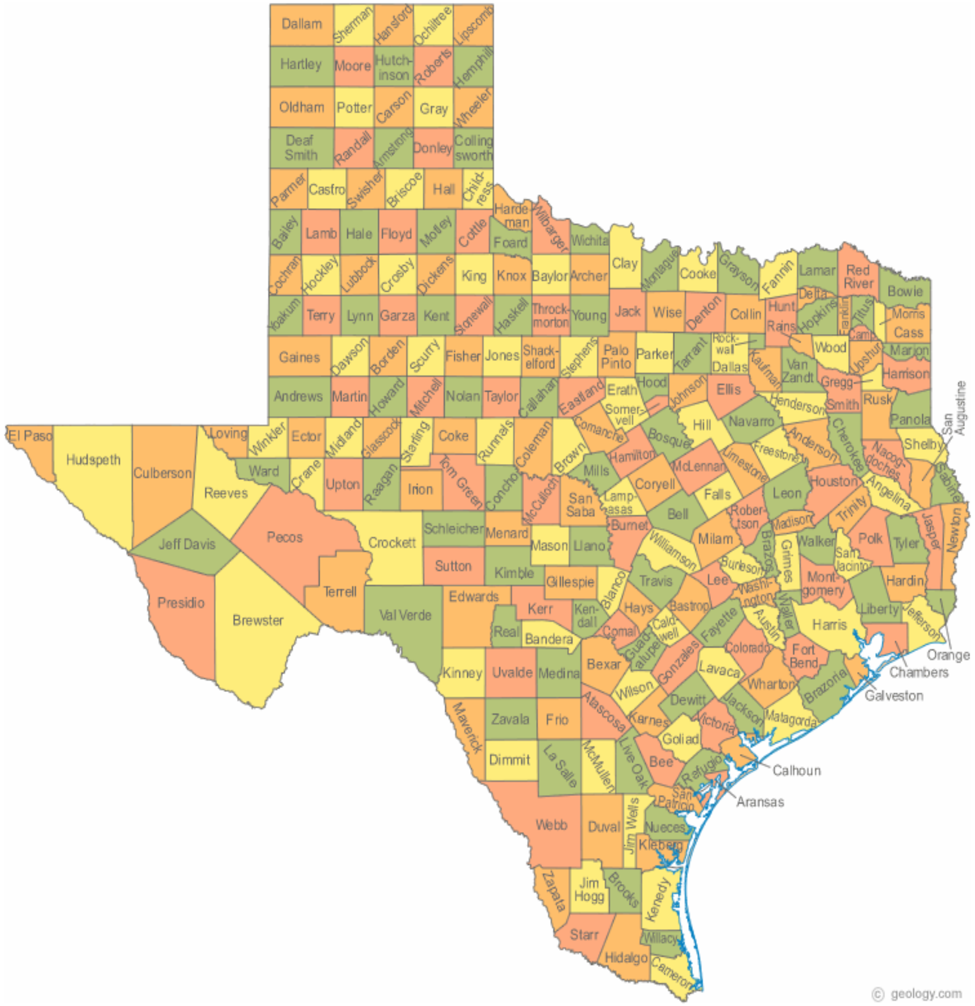
Texas

- Successful demand side management and energy efficiency programs have been in place since the 1990s
- PUCT recently opened an Energy Efficiency Rulemaking to expand energy efficiency goals and add a cost recovery rider
- AEP Texas Advanced Metering Project commenced July 31, 2007
- Goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008



Both the Texas Legislature and the Public Utility Commission of Texas have clearly demonstrated by law and rule their commitment to the deployment of advanced metering technologies in Texas. Deployment is not speculative nor tentative, it will occur and at a grand scale and place Texas at the forefront of implementing smart meter technologies.

- Charles Patton, AEP Texas President and COO

AEP's Continued Value Proposition

- Strength and scale in assets & operations
- Continued innovation and deployment of leading technology advancements
- Sustainable earnings growth through near and long term capital investment opportunities
- Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag
- Strong dividend yield with respect to peers
- Balance sheet and credit profile stability

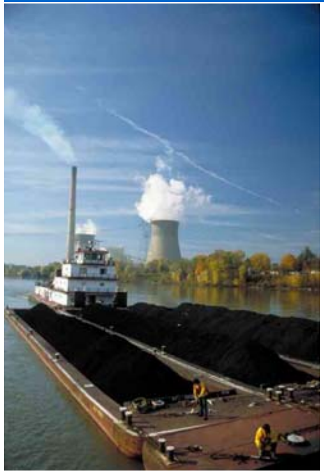
Sustainable Business Model

Questions

Goldman Sachs Seventh Annual Power & Utility Conference

New York, NY

May 11, 2007



AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP®

Holly Koeppel
EVP & Chief Financial Officer

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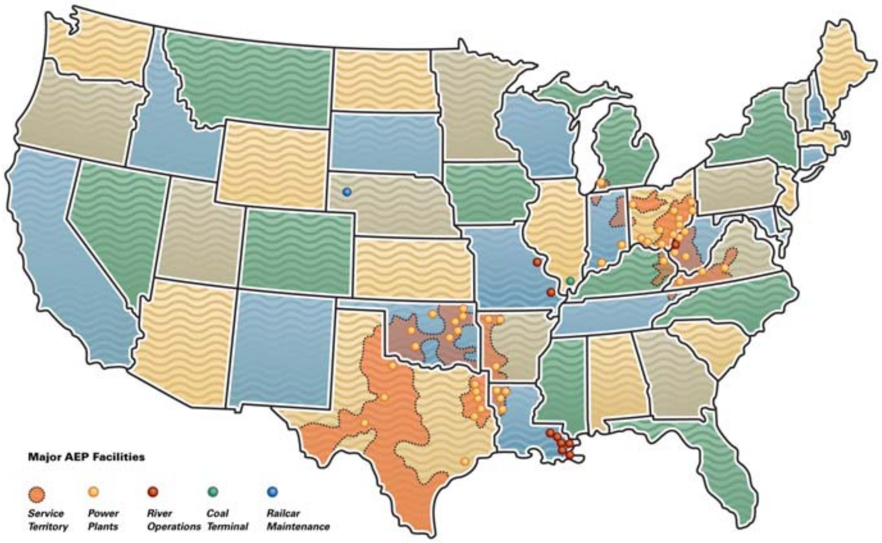
AEP®

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

Strategic Direction

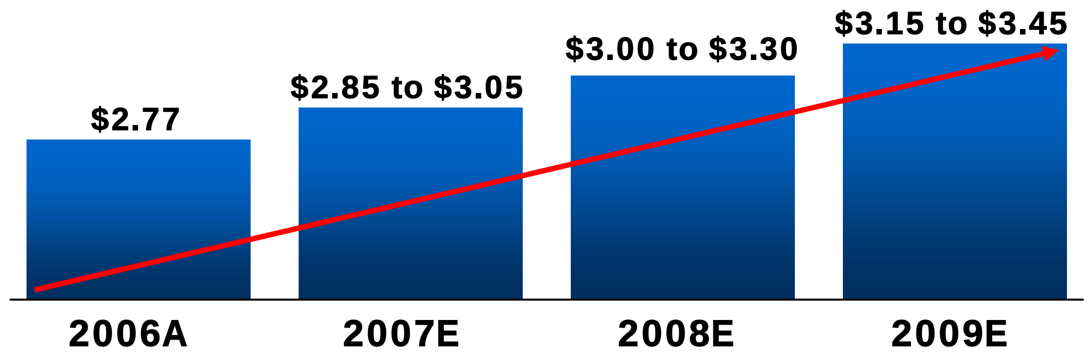
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:

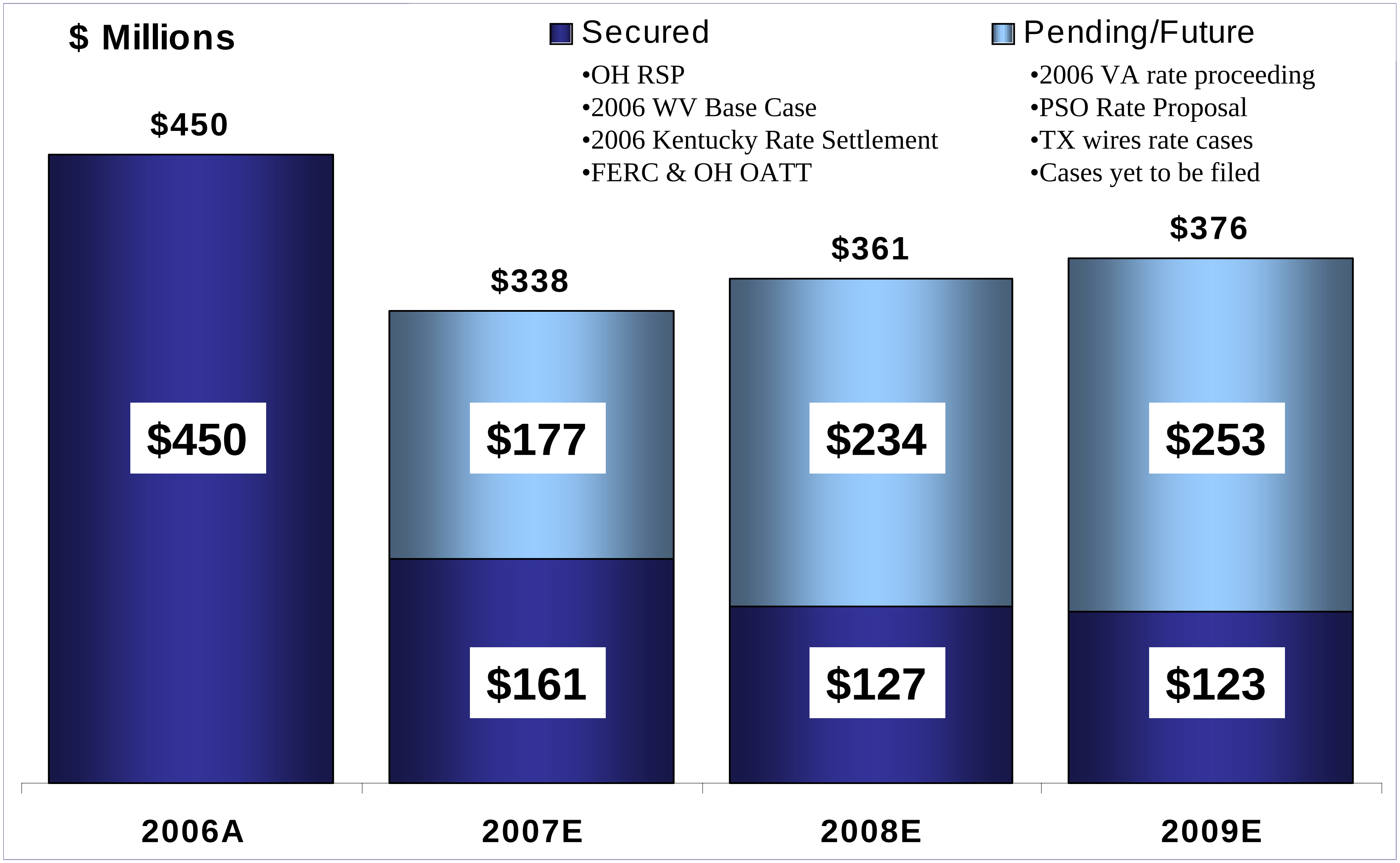


- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

AEP®

Our Strategy Remains Focused On Regulated Operations

Incremental Rate Relief Composition



RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

®

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07(1)
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07(2)
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B(3)	Coal	Ultra-supercritical	600(3)	2011
PSO	Red Rock	Oklahoma	$1.8 B(4)	Coal	Ultra-supercritical	950(4)	2012
CSP/OP	Great Bend	Ohio	Under Review(5)	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review(5)	Coal	IGCC	600	TBD

(1) Sale closed on April 25, 2007 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

AEP®

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

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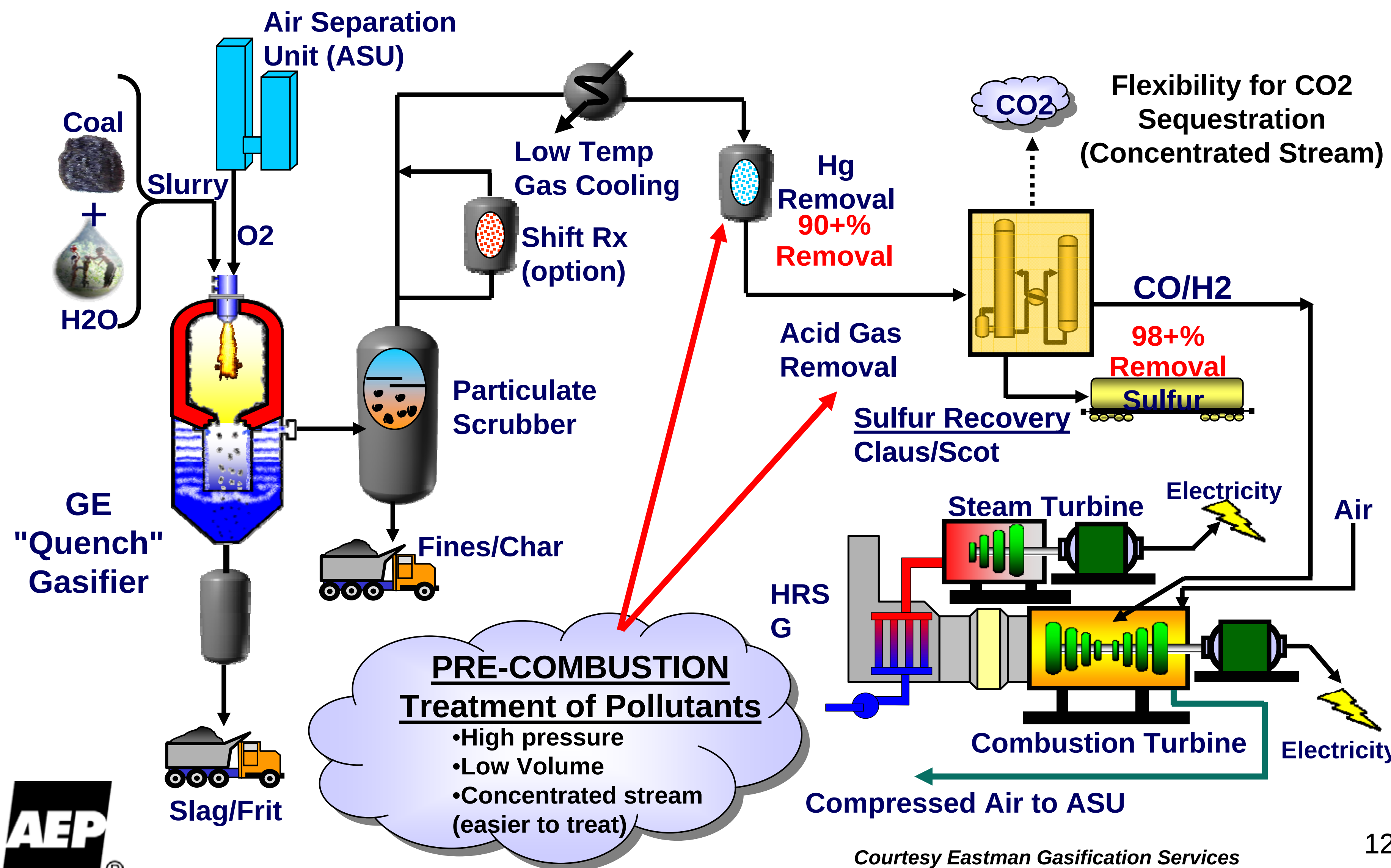
AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

IGCC Permitting Process

IGCC Permitting Issues

- **Air**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- **Wastewater**
  - ✓ understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- **US ACE (US Army Corp of Engineers)**
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

Permitting process takes 1 – 2 years and is well under way

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% Mid-American Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- AEP I-765 Interstate Project
  - Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- Other Transmission Projects
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

AEP®

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008-09
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	Projected 2007	✓	Projected 2007
Mitchell 2	800	✓	Projected 2007	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service		Delayed
Conesville 5 & 6	750		N/A	✓	In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2007
Muskingum River 5	585	✓	In-service		Delayed
Pirkey	580		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262		N/A	✓	In-service

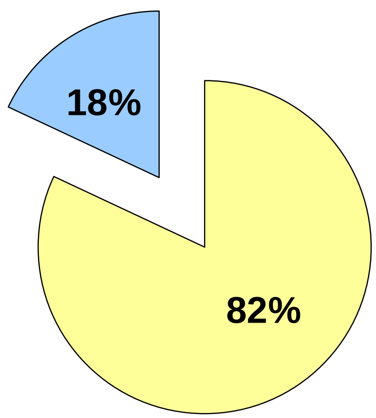
*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

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A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

FutureGen™ ALLIANCE
Clean Energy for a Secure Future

GLOBAL ROUNDTABLE ON CLIMATE CHANGE

CLIMATE LEADERS®
U.S. Environmental Protection Agency

CCX™ Chicago Climate Exchange

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

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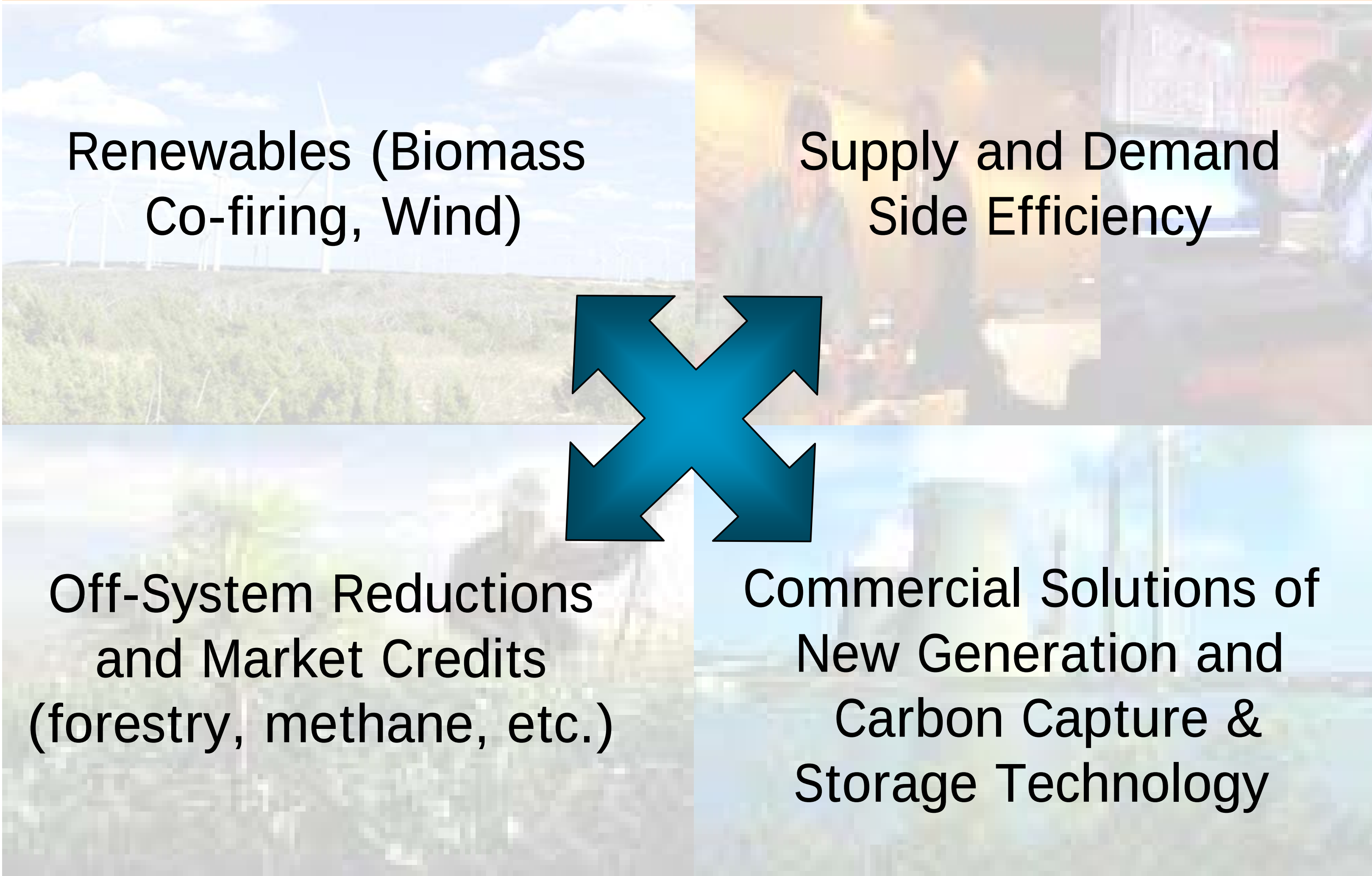
AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio



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AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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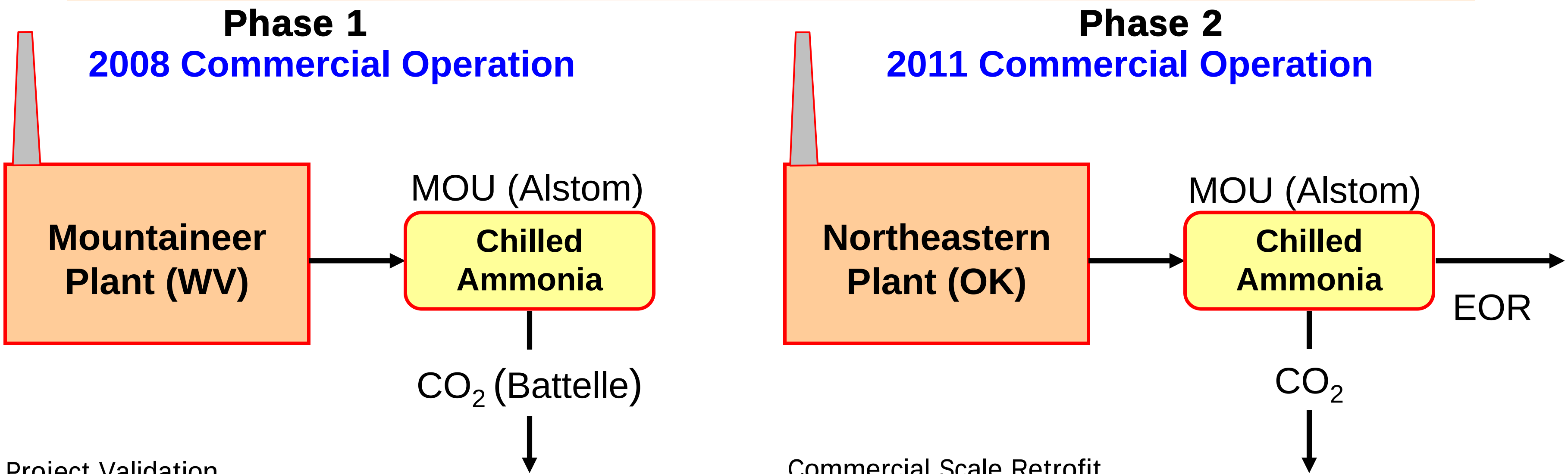
Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program



Project Validation

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

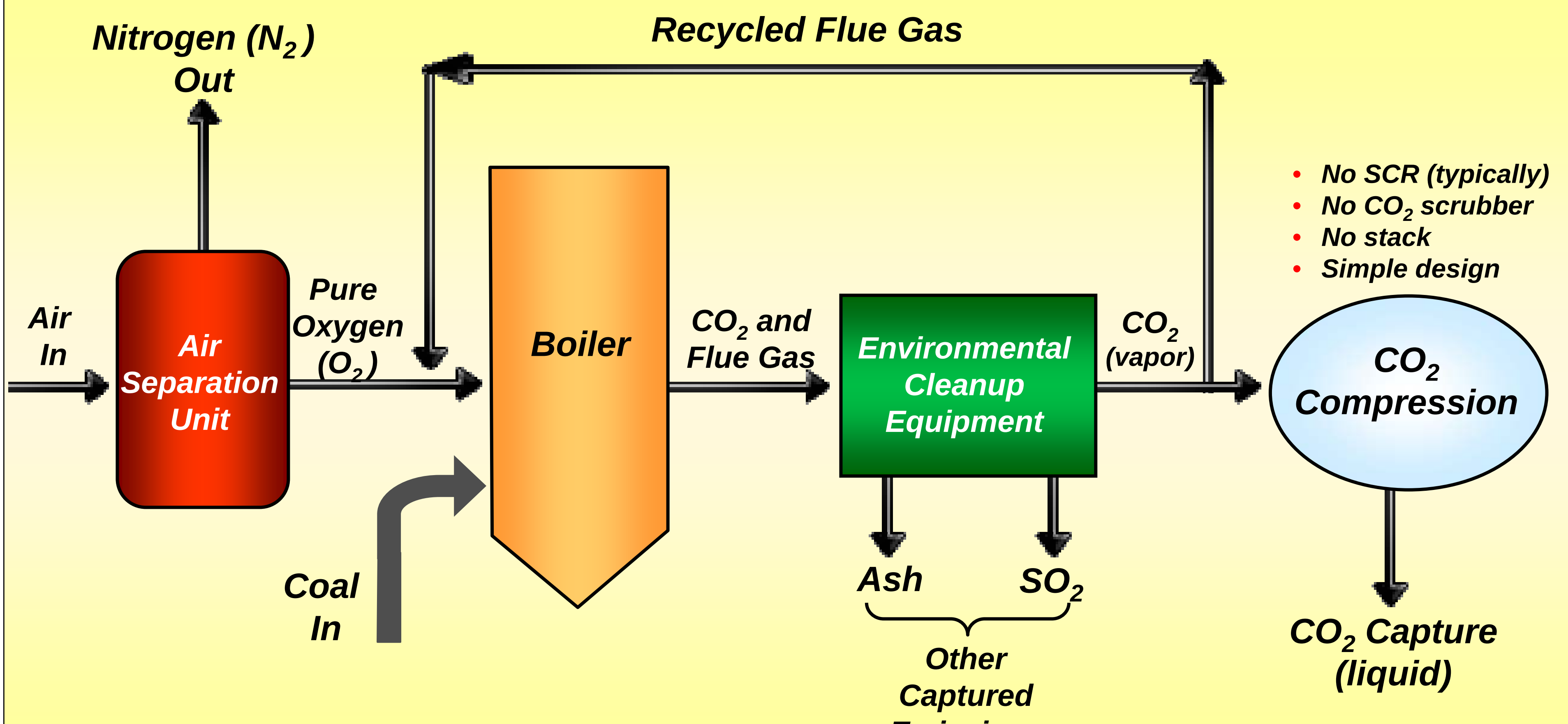


Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

<u>Pilot Scale Demonstration</u>

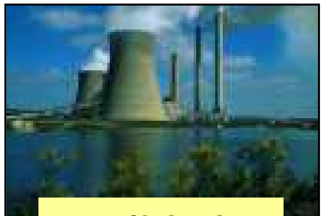
- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

<u>Commercial Scale Retrofit</u>

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

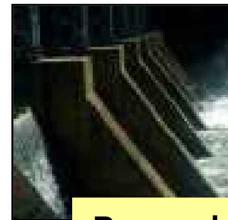
Domestic Generation Fleet

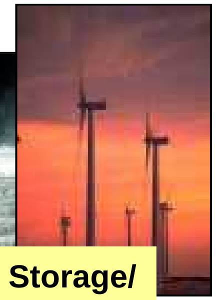


Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%





Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

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Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

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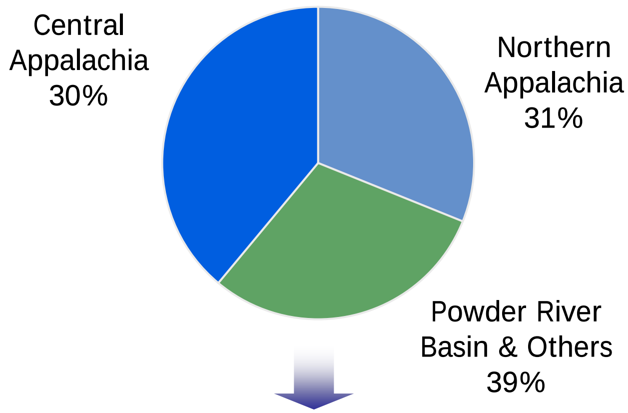
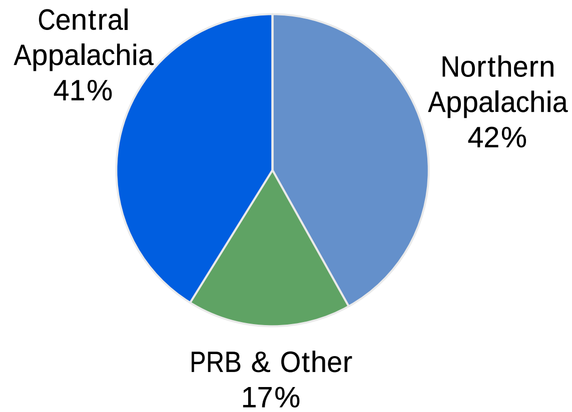
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

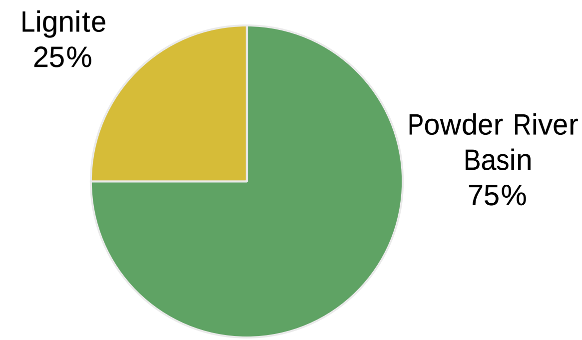
Total AEP System



AEP East



AEP West



Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

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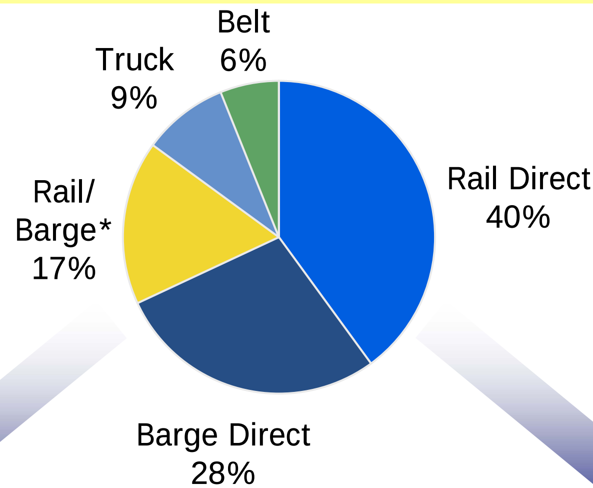
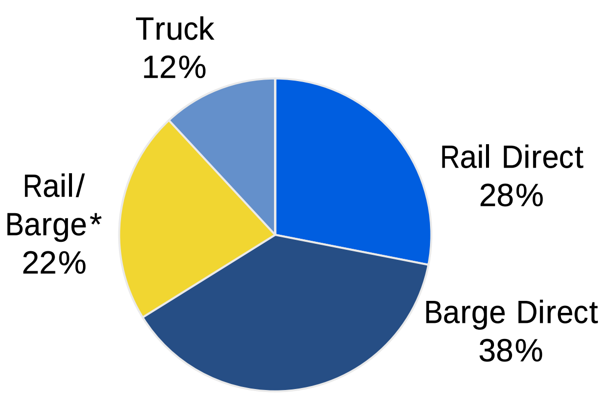
Coal Delivery

2006 Actual

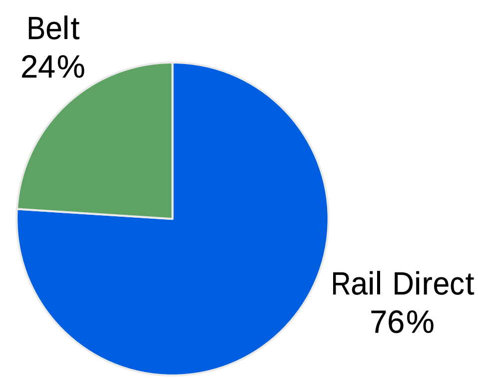
Total AEP System



AEP East

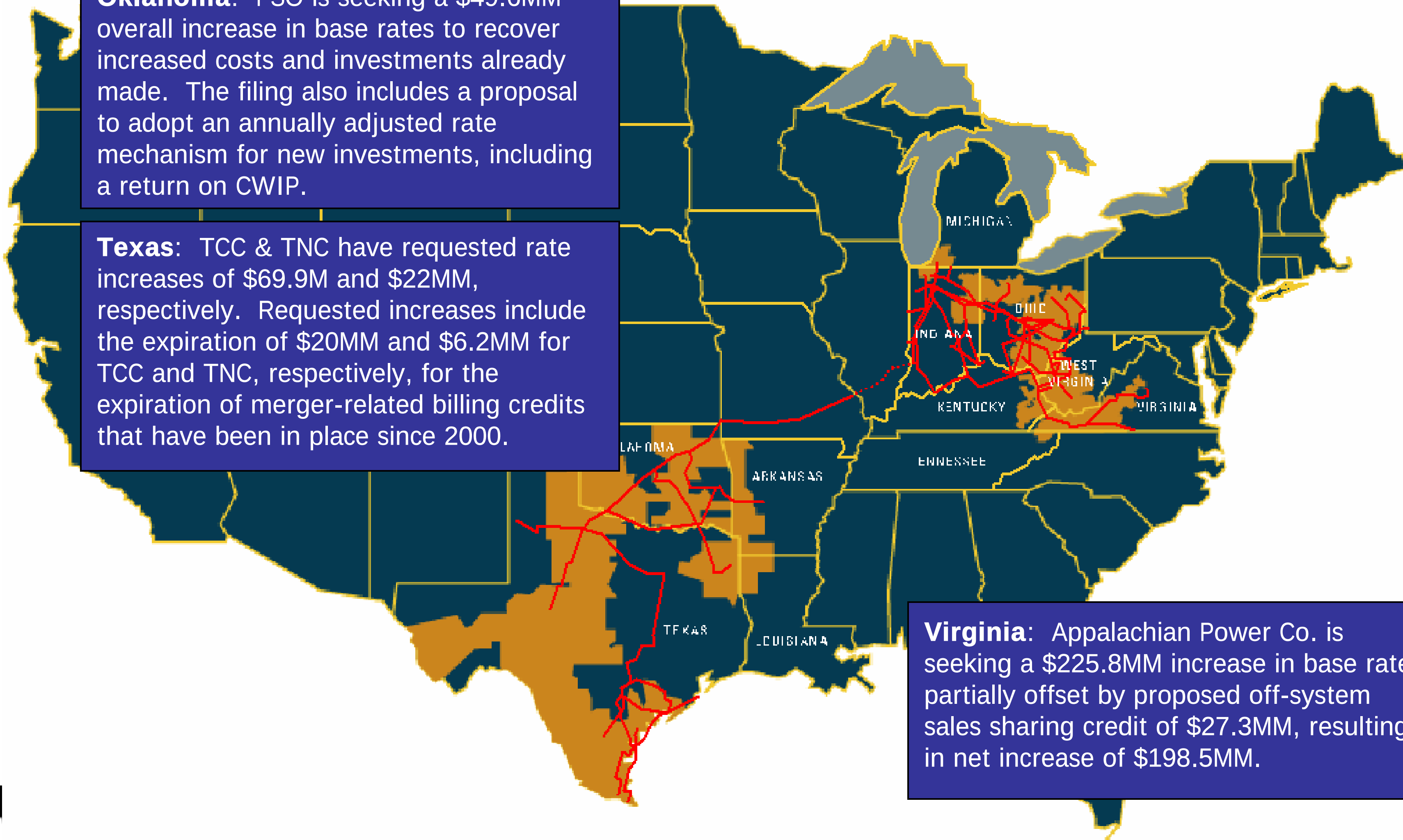


AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $69.9M and $22MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.

Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony were due May 11, 2007; Evidentiary hearing to commence May 22, 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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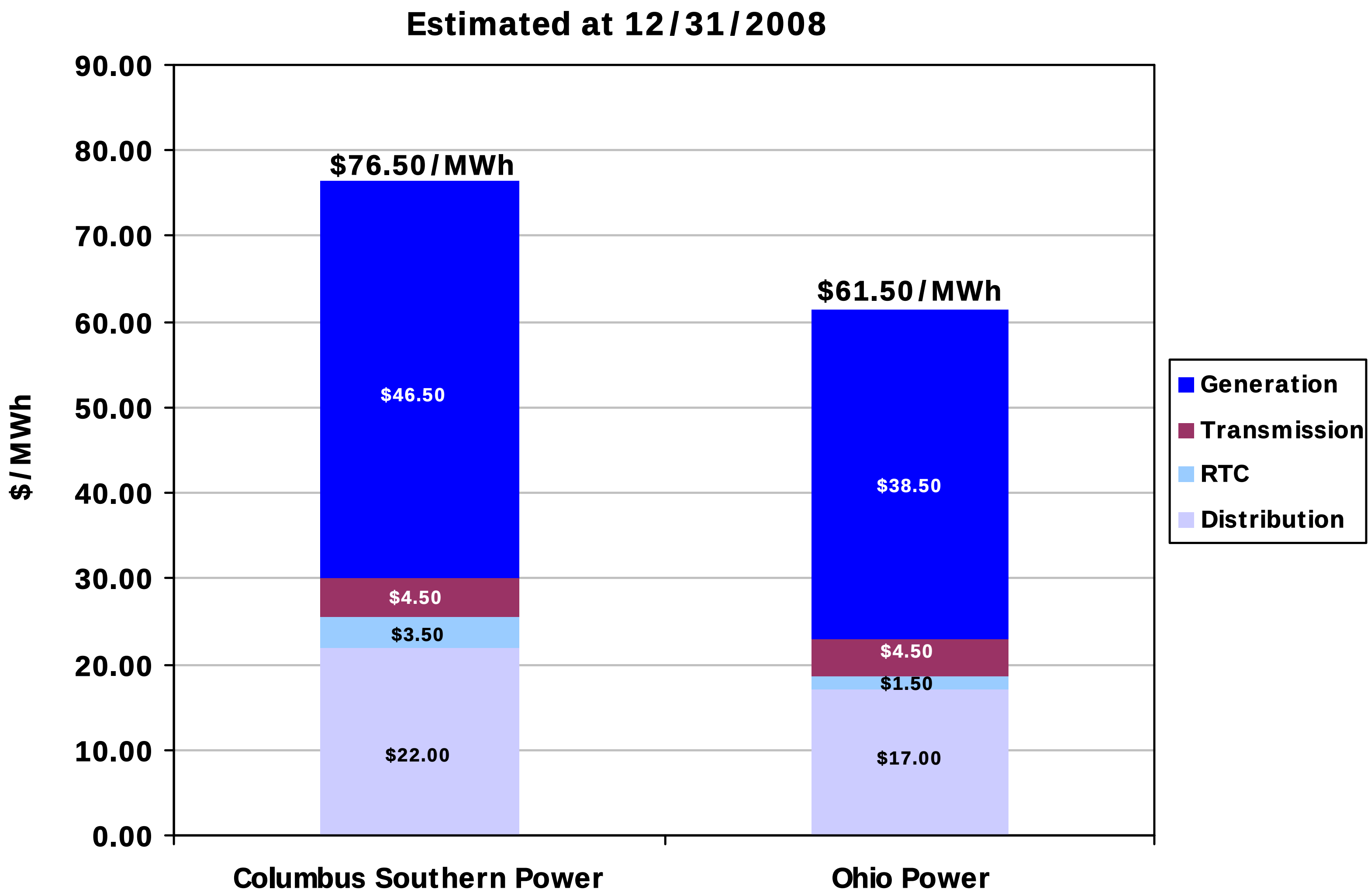
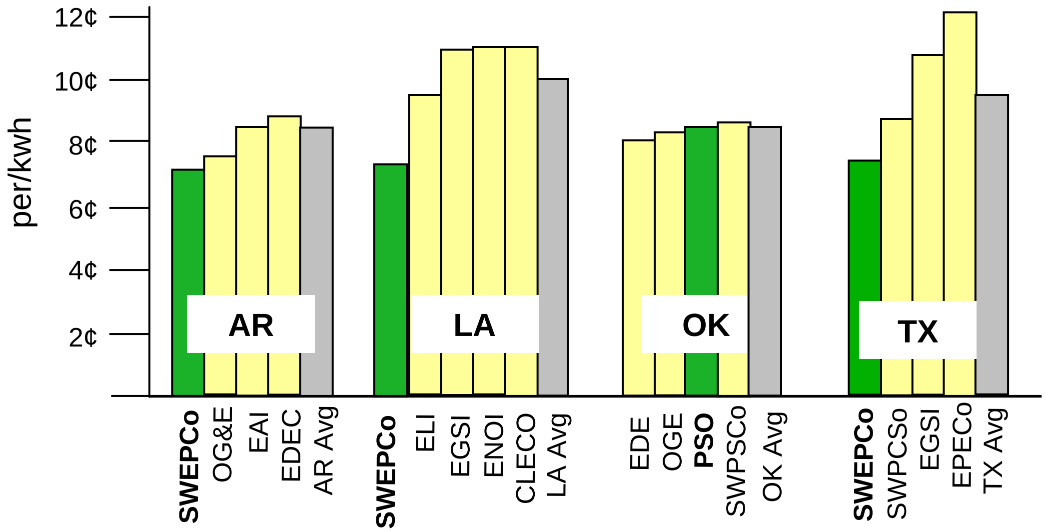
Average Unbundled AEP Ohio Rates



AEP Provides Low Cost Electric Service

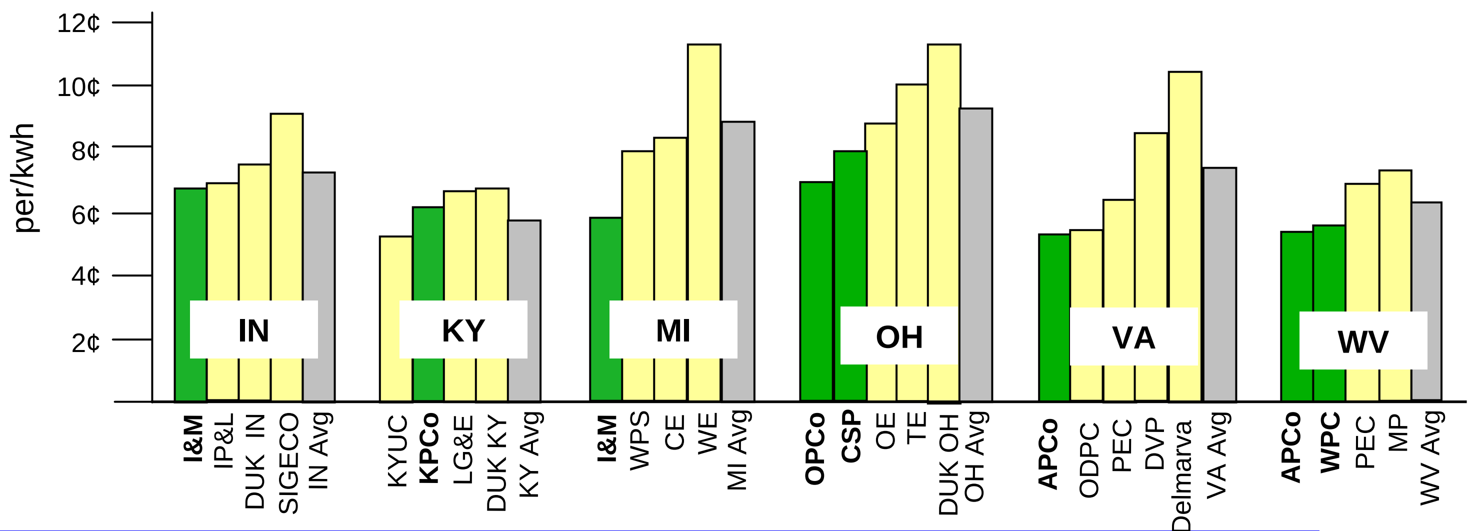
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



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2006-2009 Projected Annual Rate Increase Of 3.8%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power

Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Goldman Sachs

Investor Office Visit

February 19, 2008

Columbus, OH

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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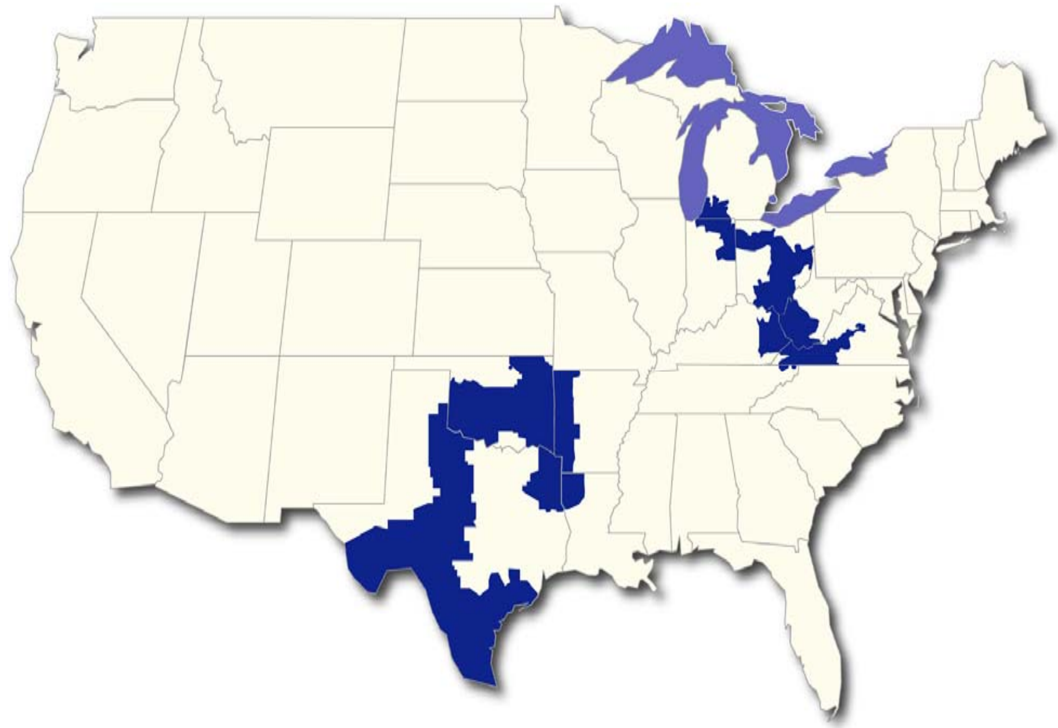
Company Overview



5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

Coal & transportation assets

- Control over 8,400 railcars
- Own/lease and operate over 2,650 barges & 52 towboats
- Coal handling terminal with 20 million tons of capacity

20,800 employees

AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
67%	**24%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate trough major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

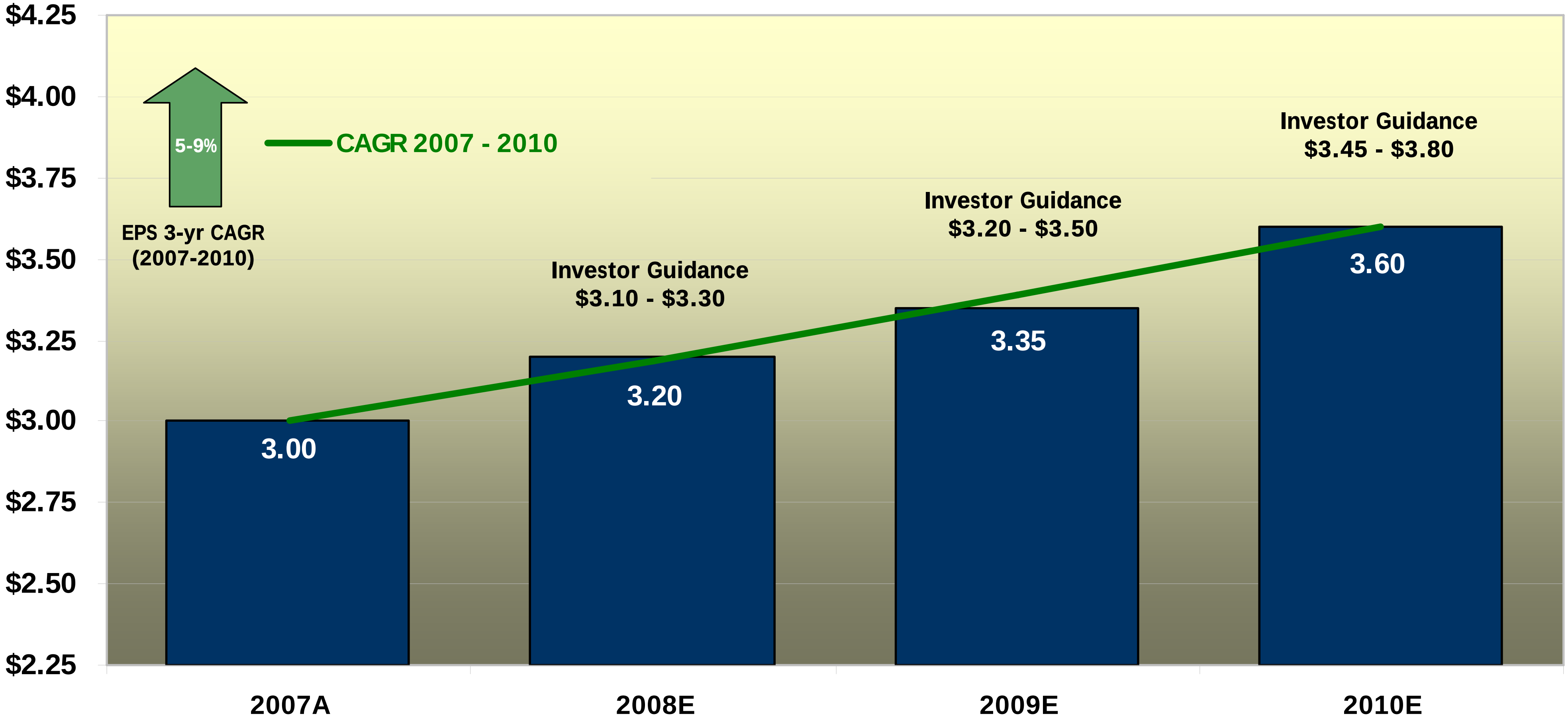
Vision for Sustainability

<table>
<tr><th>Generation</th><th>Transmission</th><th>Distribution</th><th>Customers</th></tr>
<tr><td colspan="4"></td></tr>
<tr>
<td>• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage</td>
<td>• I-765™
• Electric Transmission Texas JV
• Electric Transmission America JV
• AEP-ABB Alliance</td>
<td>• Distribution automation
• Self-healing distribution circuits
• Advanced metering
• Communications infrastructure
• Mobile workforce
• Internal energy efficiency
• Integration platform for advanced visualization and analytics
• Distributed generation and energy storage</td>
<td>• Customer programs and incentives
  • Energy efficiency
  • Direct load control
  • Peak demand reduction
• Energy storage</td>
</tr>
</table>

<table>
<tr><td>Existing generation and transmission control systems</td><td>gridSMART℠: bridging the gap to provide integrated two-way communications & control across the electricity value chain</td><td>Home energy automation</td></tr>
</table>

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

4-Year Earnings Range Forecast



5% to 9% earnings growth

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Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2009
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B(2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(2) Front-end engineering and design is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Advanced Generation & CO_2

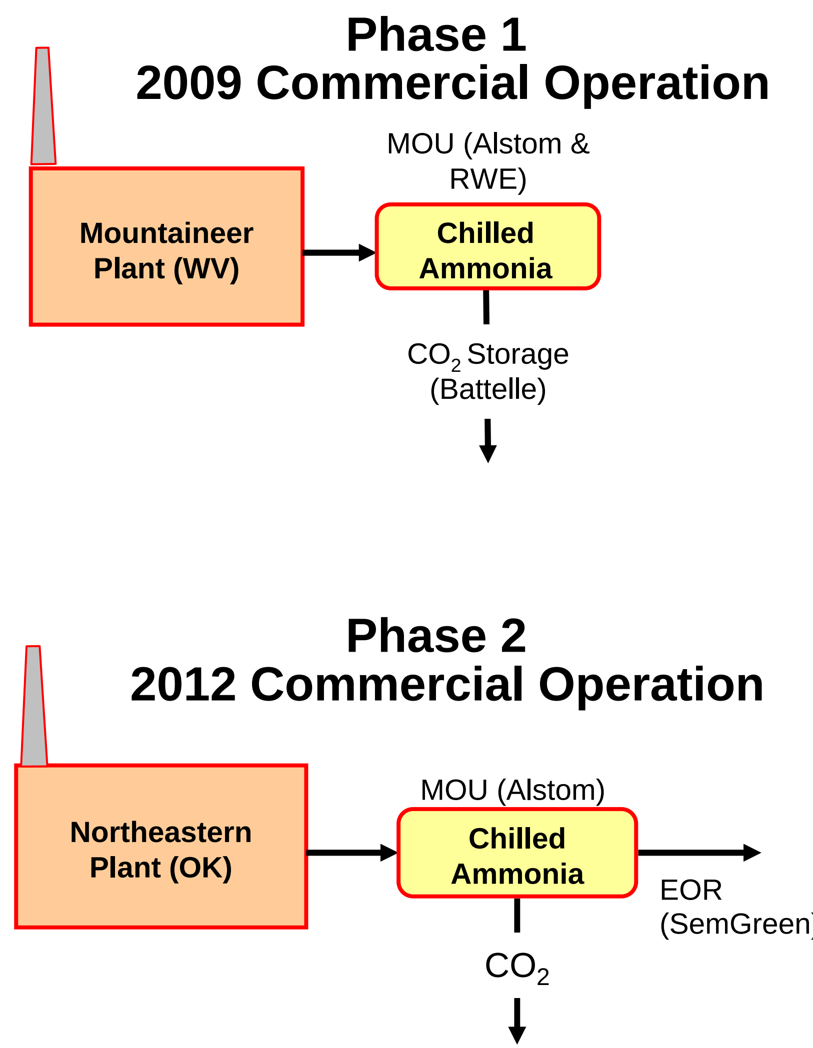
Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

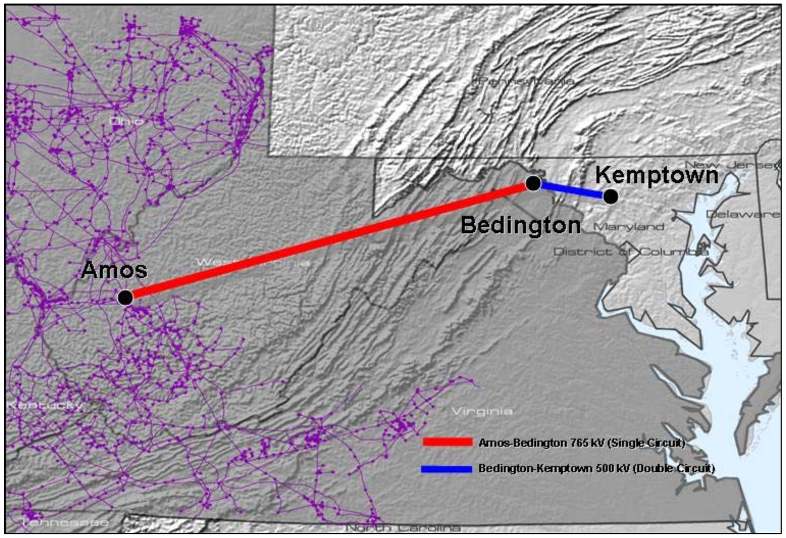
- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL



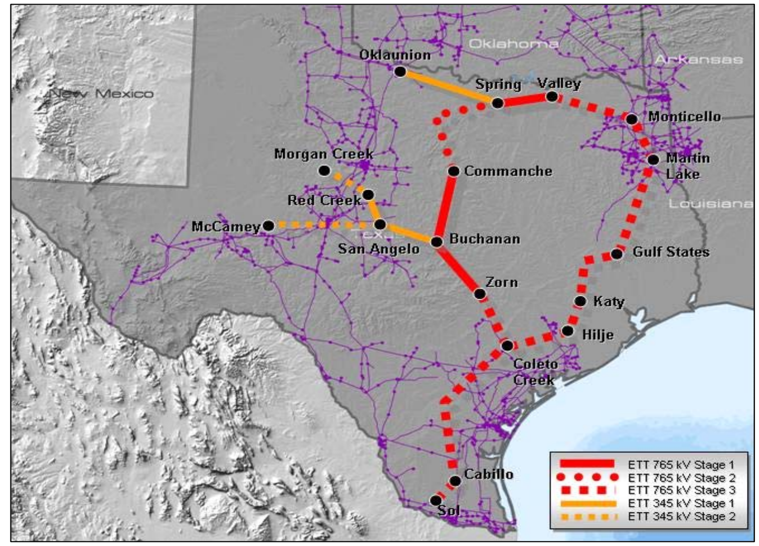
We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

I-765™ Transmission: Investment Opportunities

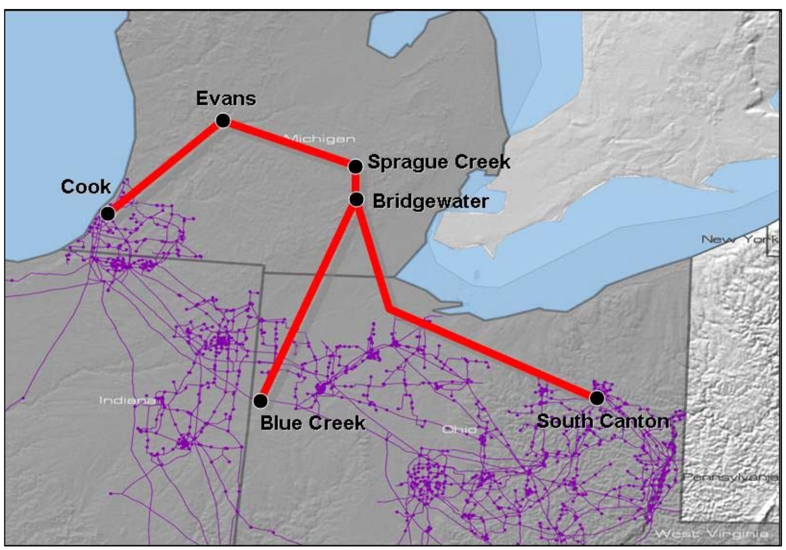
AEP is Advancing the Development of a National Interstate Today



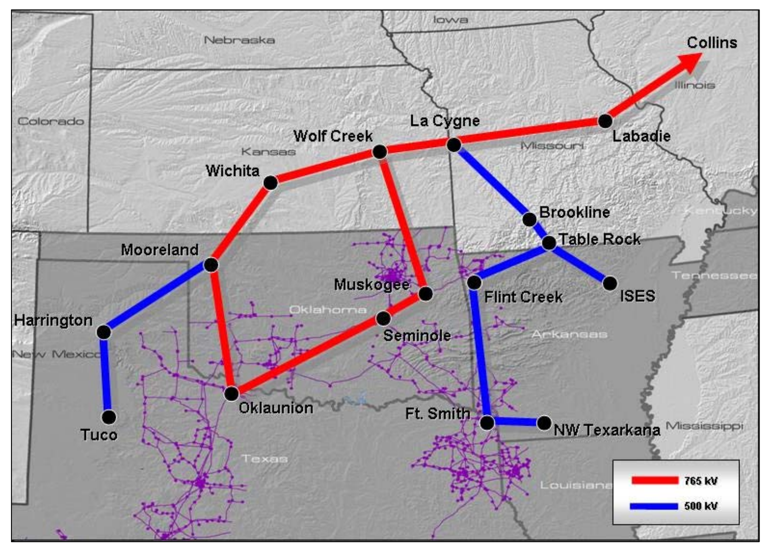
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

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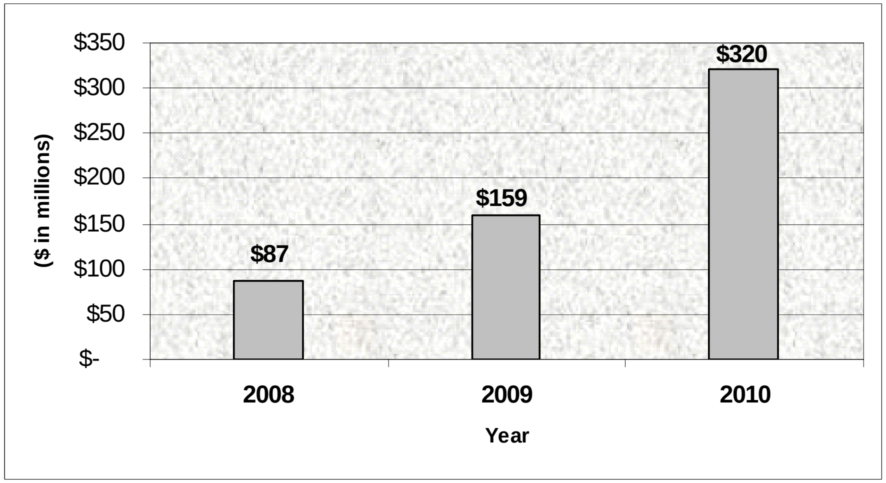
Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

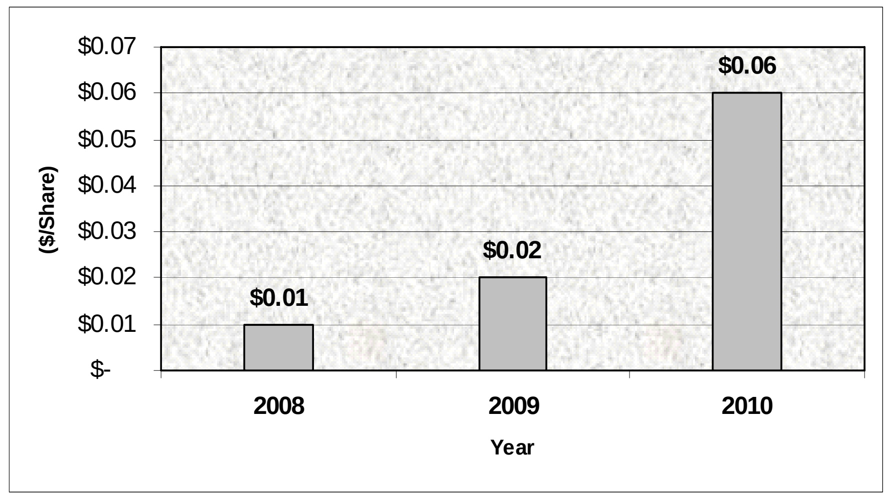


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

PATH
Potomac-Appalachian Transmission Highline

ETT
Electric Transmission Texas

Projected Transmission EPS Contributions*



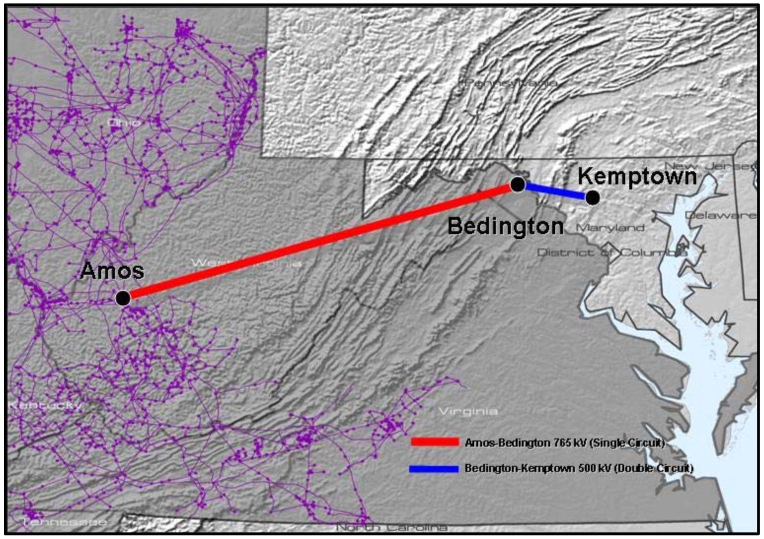
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, 14.3% ROE, recovery of all costs incurred prior to the time rates go into effect, and recovery of all prudently incurred development and construction costs if the project is abandoned.*
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP’s investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE’s National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012



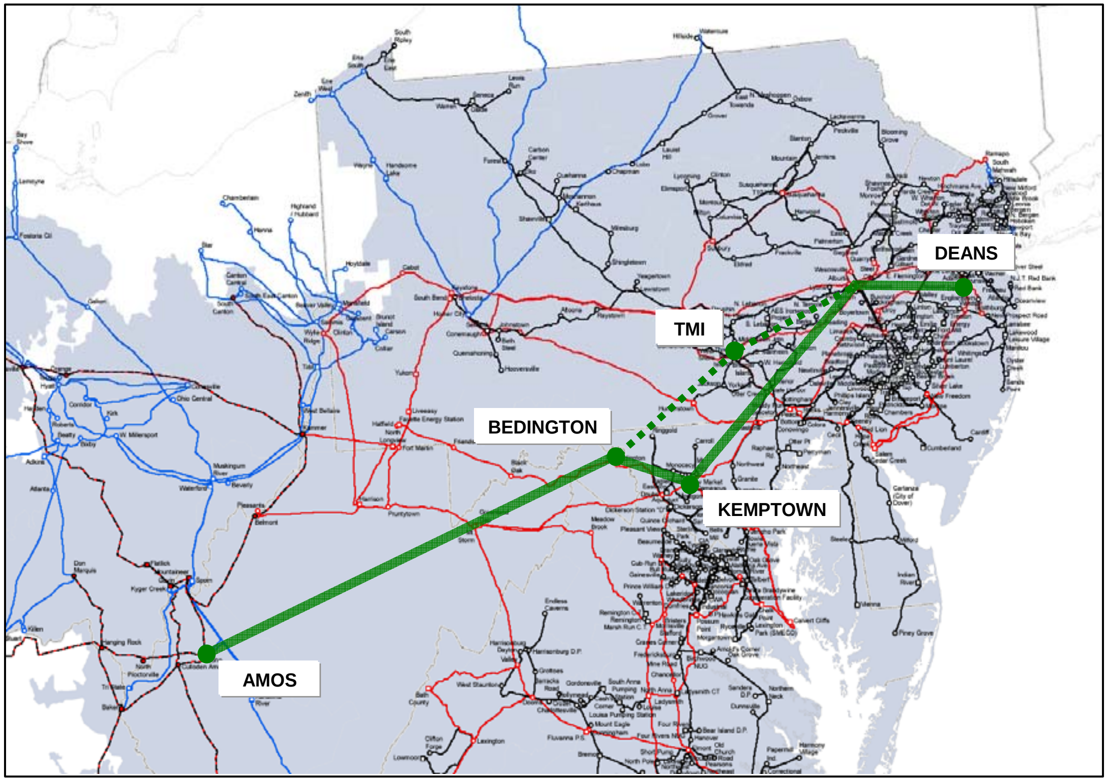
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

I-765™ Transmission in PJM East

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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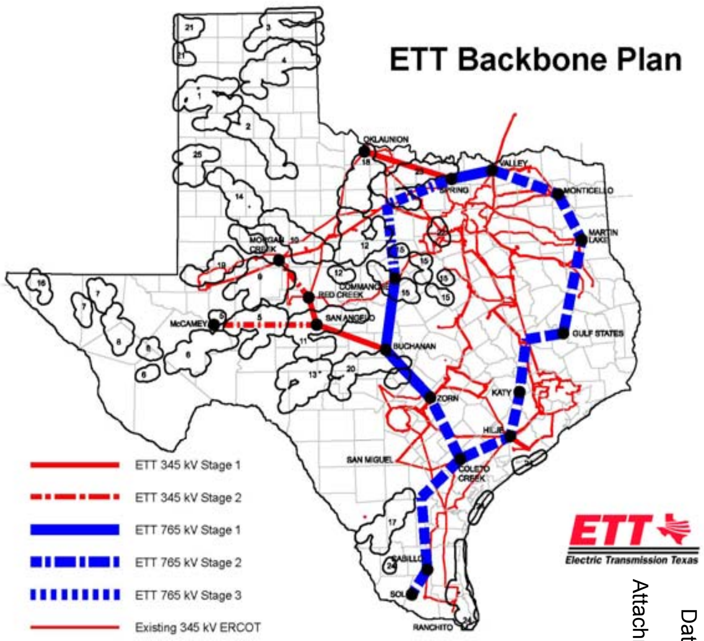
I-765TM Transmission in Texas (ETT)

Electric Transmission Texas Update

- **_Transaction Structure_**
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- **_Next Steps_**
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- **_ETT ERCOT Backbone Proposal_**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



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* Before ownership division.

Electric Transmission America (ETA)

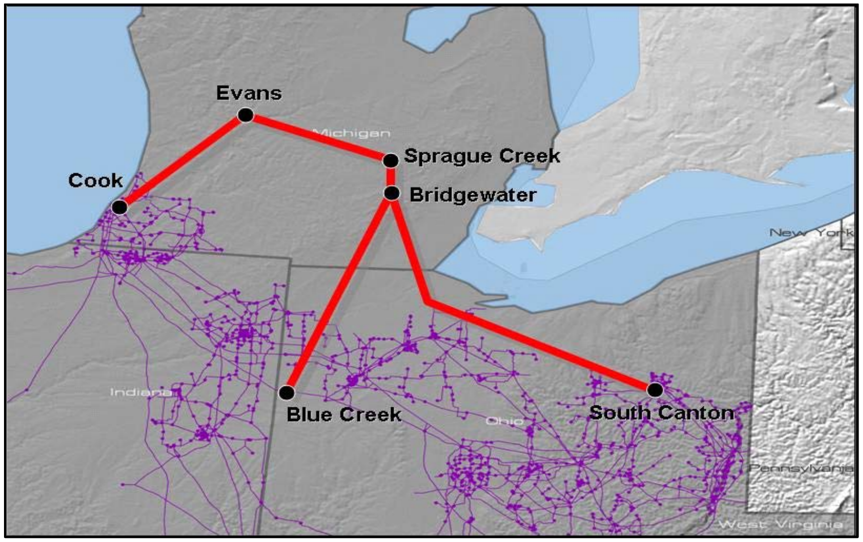
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015



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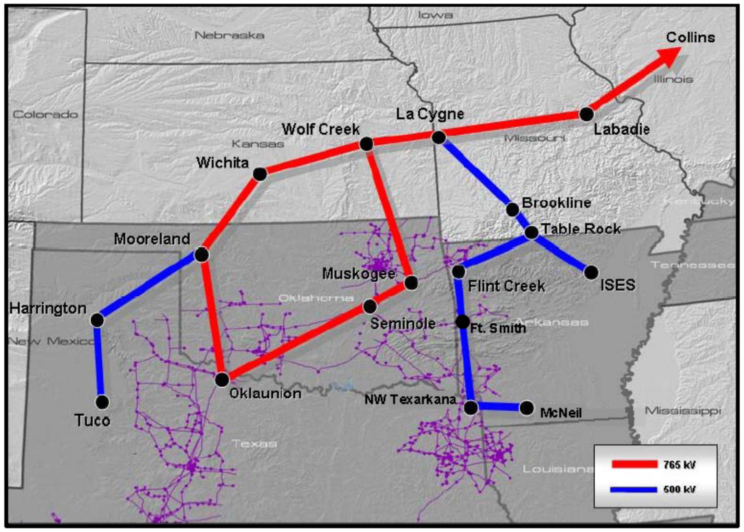
I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



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Distribution - gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

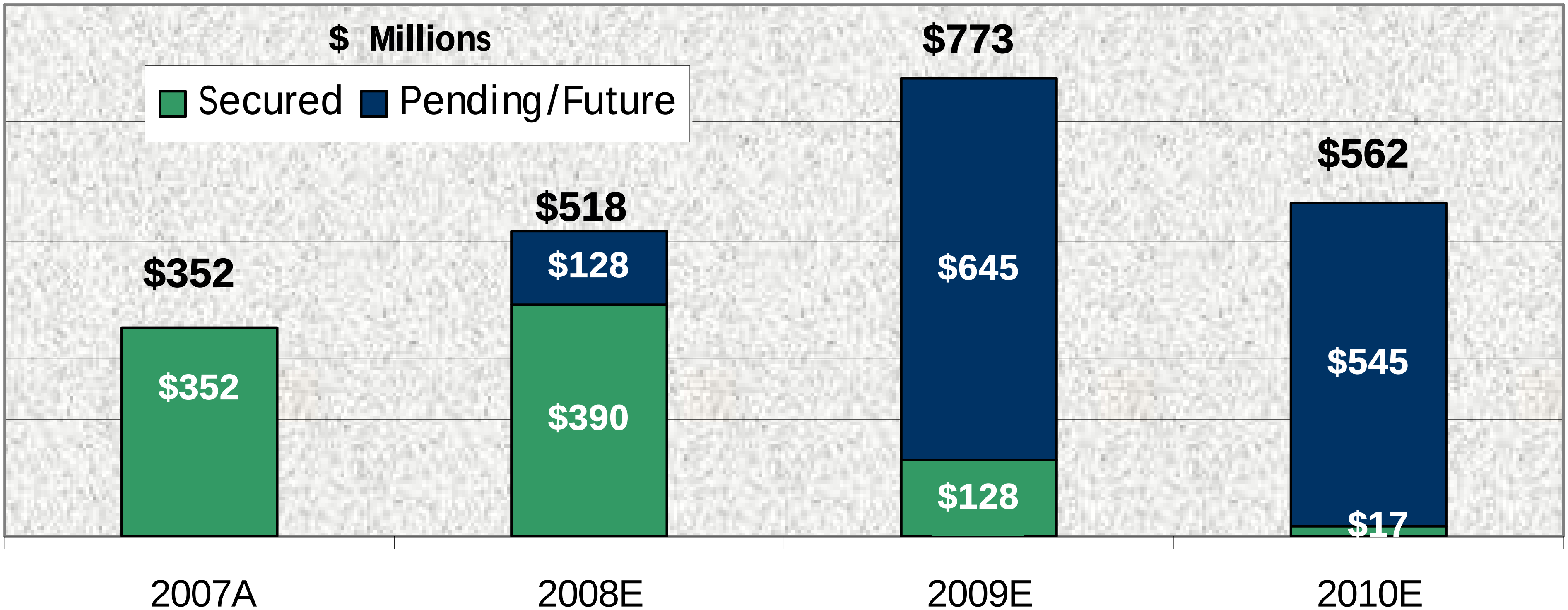
Capital Investment, Subject to Regulatory Approval *
$ in millions

Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

Incremental Rate Relief Assumptions



- **75% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings.**

- **2008 Pending: PSO January 2007 Ice Storm Recovery, SWEPCo - LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Activity Underway

- Ohio Post 2008
- I&M - Indiana Base Rate Case
- PSO Storm Cost Recovery Filing
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

2008 Regulatory Activity Completed

AEP Ohio Application For 4% Provision On Generation Rate

- On January 30, 2008, a settlement agreement was approved by the PUCO allowing the generation rider to be increased to recover in 2008 an additional $28.5 million for CSPCo and $4.9 million for OPCo.
- The approved settlement also authorized the inclusion of $78 million of estimated net costs of marginal losses ($38.9 million for CSPCo and $39.2 million for OPCo) in the existing Transmission Cost Recovery Rider, with any over/under recovery of the actually incurred costs from June 2007 through December 2008 to be reflected in the 2009 TCRR recovery mechanism, including carrying charges on any such over/under recovery.

APCo Virginia - Fuel Factor Adjustment

- On February 1, 2008 APCo Virginia received an order authorizing annual incremental earnings and cash increases of approximately $28MM and $6MM, respectively. The incremental earnings increase is attributed to recovery of marginal losses and the change in OSS sharing.

Regulatory Activity Underway

Ohio Post-2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearings continue and we anticipate a signed bill in March or April of 2008.

Regulatory Activity Underway

I&M Indiana Base Rate Case

- On January 31, 2008, I&M filed a base rate case with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties agreed to a historic test year ended September 30, 2007, with adjustments allowed for fixed, known and measurable items that will occur within 12 months following the end of the test year.
- The case includes the following:
  - Required Rate Relief/Revenue Requirement - $128.5 MM ($46MM trackers)
  - Rate Base – approximately $2 billion
  - Requested ROE – 11.50%
  - Required ROR – 8.10%
- Hearings are expected in May 2008 and an order in the first quarter of 2009.

Regulatory Activity Underway

PSO Storm Cost Recovery Filing

- On October 24, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of sulfur dioxide (SO_2) emission allowances.
- Staff and intervenor testimony was filed January 17, 2008, a settlement conference is scheduled for February 25, 2008 and hearings are scheduled for February 27 and 28, 2008.
- Staff and AG testimony was supportive of PSO's requested treatment for cost recovery.

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- PSO requests the Commission make a determination that the costs incurred on the Red Rock project were prudent and direct it to establish a regulatory asset of approximately $21 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of SO_2 emission allowances.
- A procedural schedule in the case has not yet been established.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Technical conferences and settlement meetings were held in October – December 2007. Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. An order is due by March 6, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected in the first quarter of 2008. A positive ALJ report was issued on February 8, 2008 recommending approval of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Intervenor testimony was completed on February 15, 2008, rebuttal testimony is due February 29, 2008 and hearings will commence on April 7, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Detailed Ongoing Earnings Guidance

2007A: $3.00

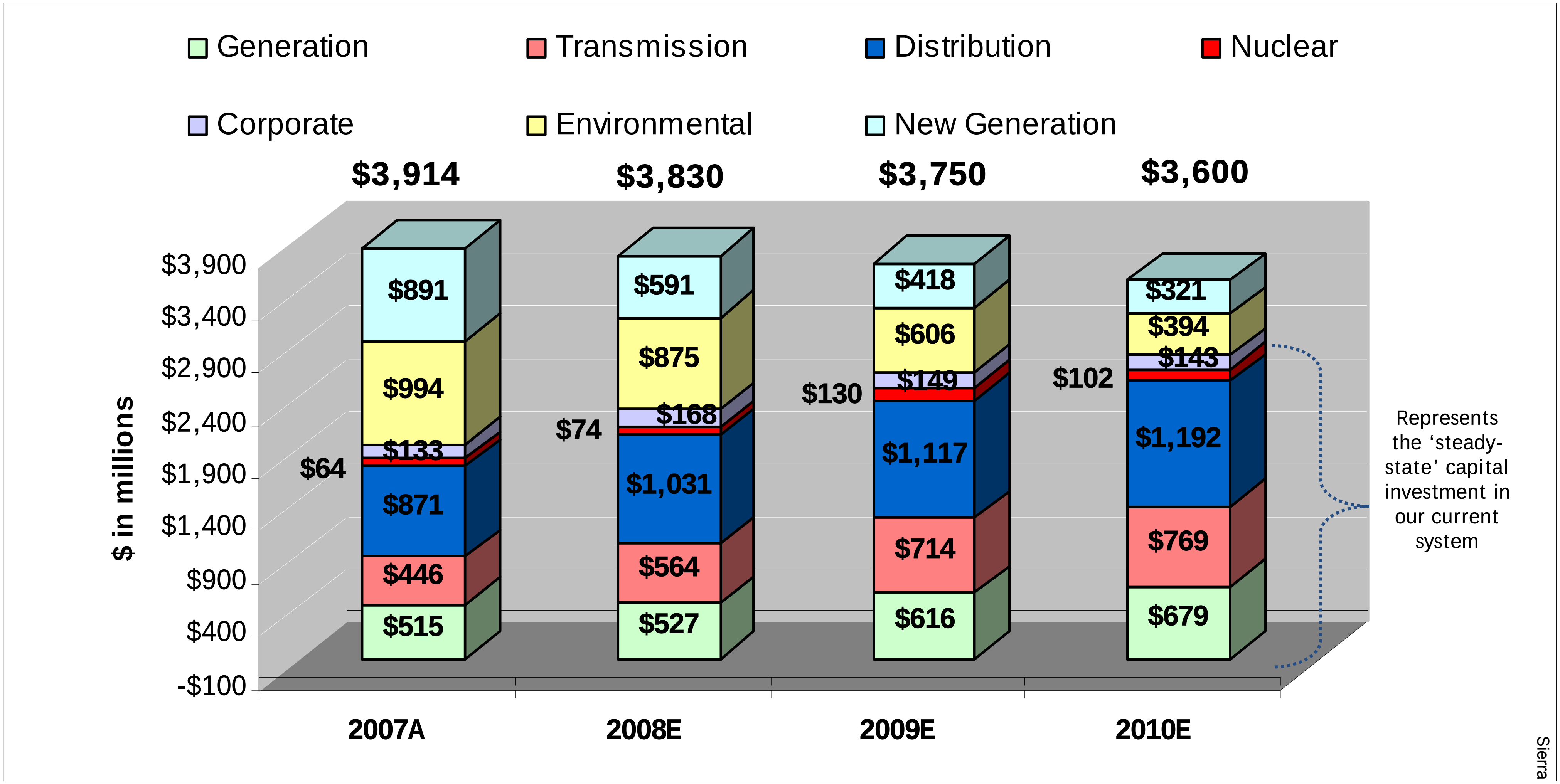
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$489	$206	$120	$90	**$905**
Total Capex	**$3,915**	**$3,830**	**$3,750**	**$3,600**	**$15,095**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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2008 Projected Cash Flow

	2007 Actual	2008 Estimate
Beginning Cash Balance	$ 301	$ 178
Cash from Operations:		
Income from Continuing Operations	1,065	1,284
Depreciation and Amortization	1,513	1,484
Other	(190)	(196)
Total from Operations	2,388	2,572
Cash used for Investing:		
Construction Expenditures	(3,556)	(3,916)
Asset Sales	222	-
Distressed Generation Purchases	(512)	-
Other	(62)	(39)
Total used for Investing	(3,908)	(3,955)
Cash from Financing:		
Issuance of Common Stock, Net	143	150
Long-Term Debt Issued/(Retired), Net	1,260	1,883
Short-Term Debt Change, Net	642	(87)
Common Dividends	(630)	(659)
Other Financing Activities	(18)	44
Total from Financing	1,397	1,331
Net Change in Cash	$ (123)	$ (52)
Ending Cash Balance	$ 178	$ 126

Note: For analysis purposes, construction expenditures include AFUDC.

Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	7.29%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	23.86%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	13.01%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo-LA	$434MM	11.10%	12/29/1999	8.74%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	11.33%
Texas-TNC	$530MM	9.96%	6/1/2007	9.93%

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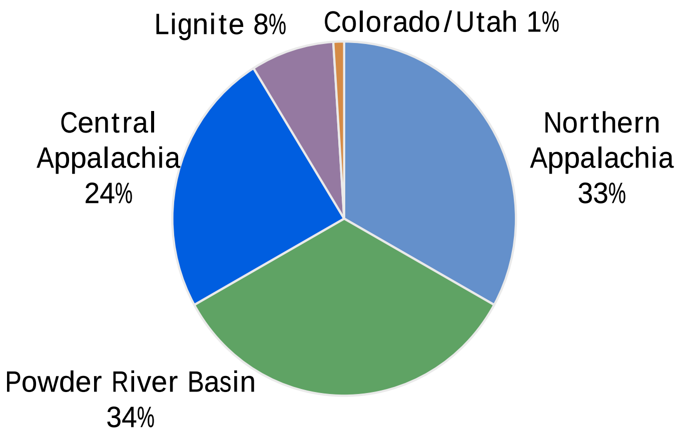
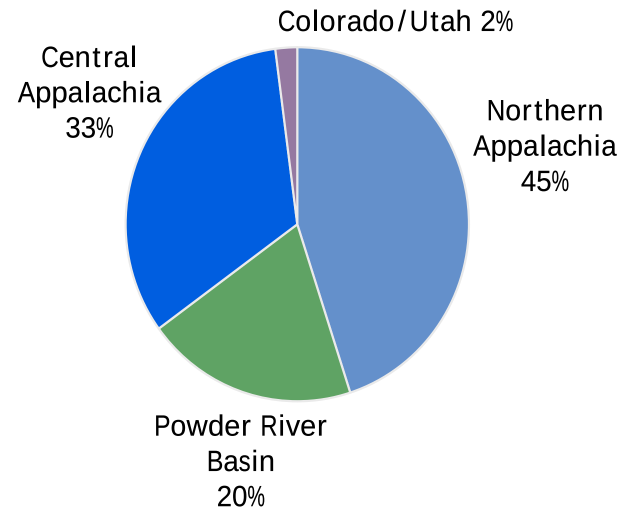
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

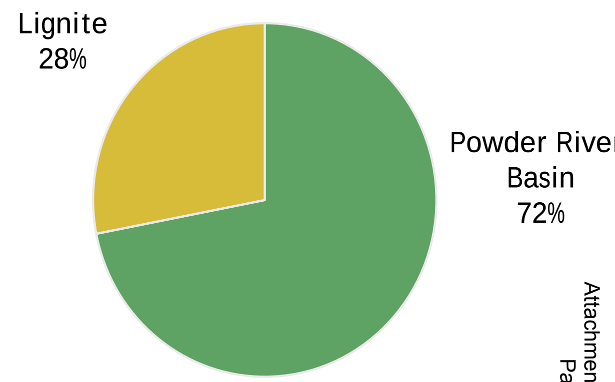
Total AEP System



AEP East



AEP West



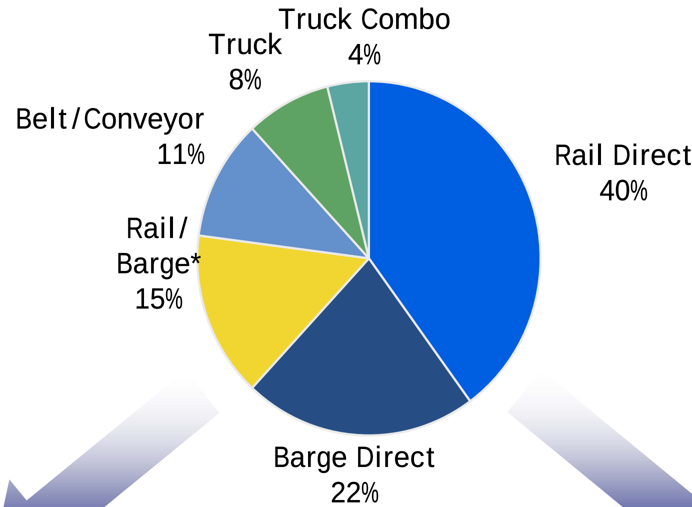
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

Coal Delivery

2007 Actual

Total AEP System



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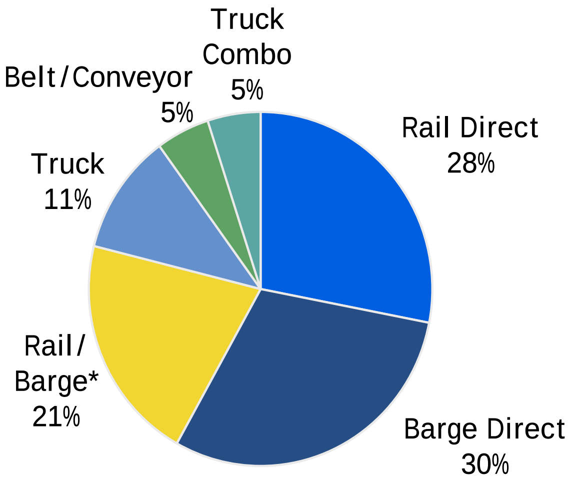

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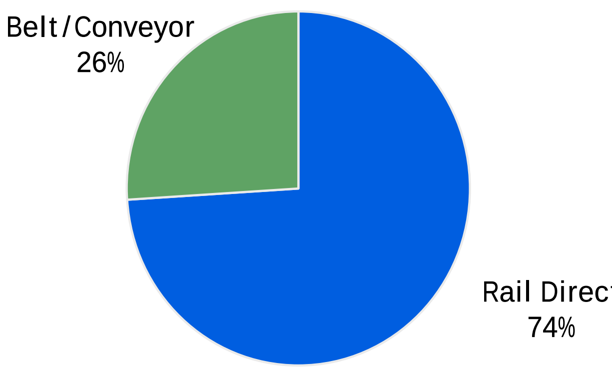
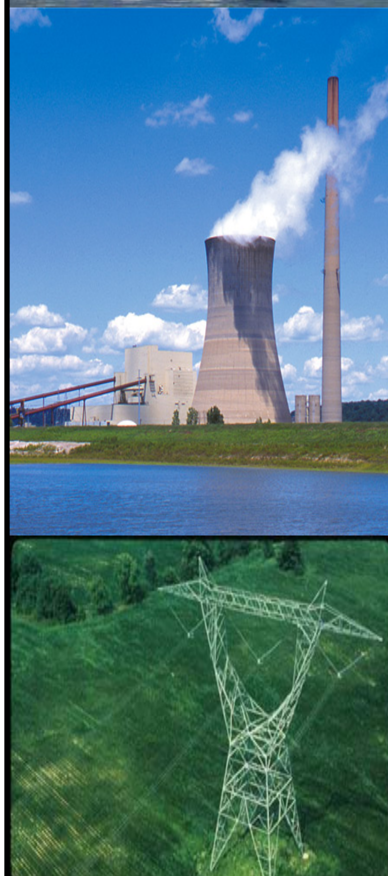


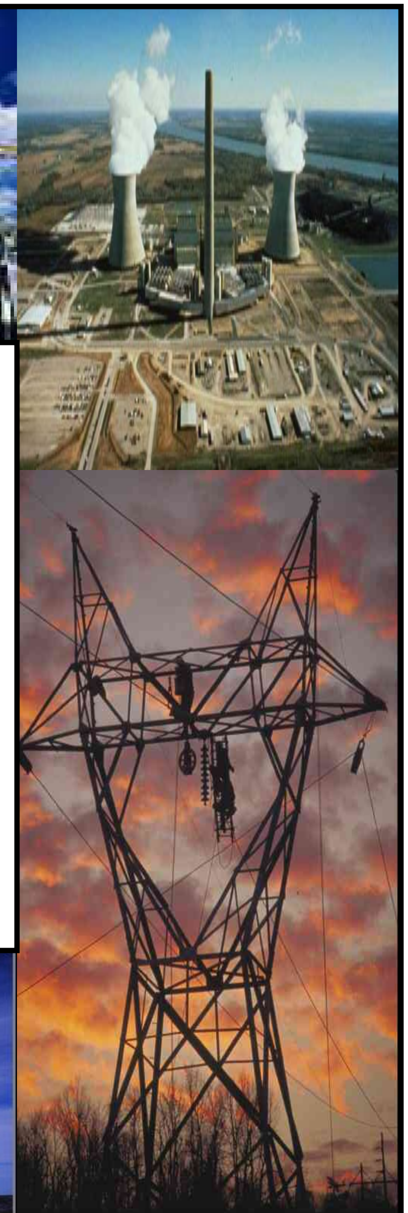
* Reflects coal delivered to AEP plants transported through a combination of rail and barge



EEI International Utility Conference and Road Show

March 10-12, 2008

United Kingdom



AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Holly Koeppel
EVP & Chief Financial Officer

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Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

Vision for Sustainability

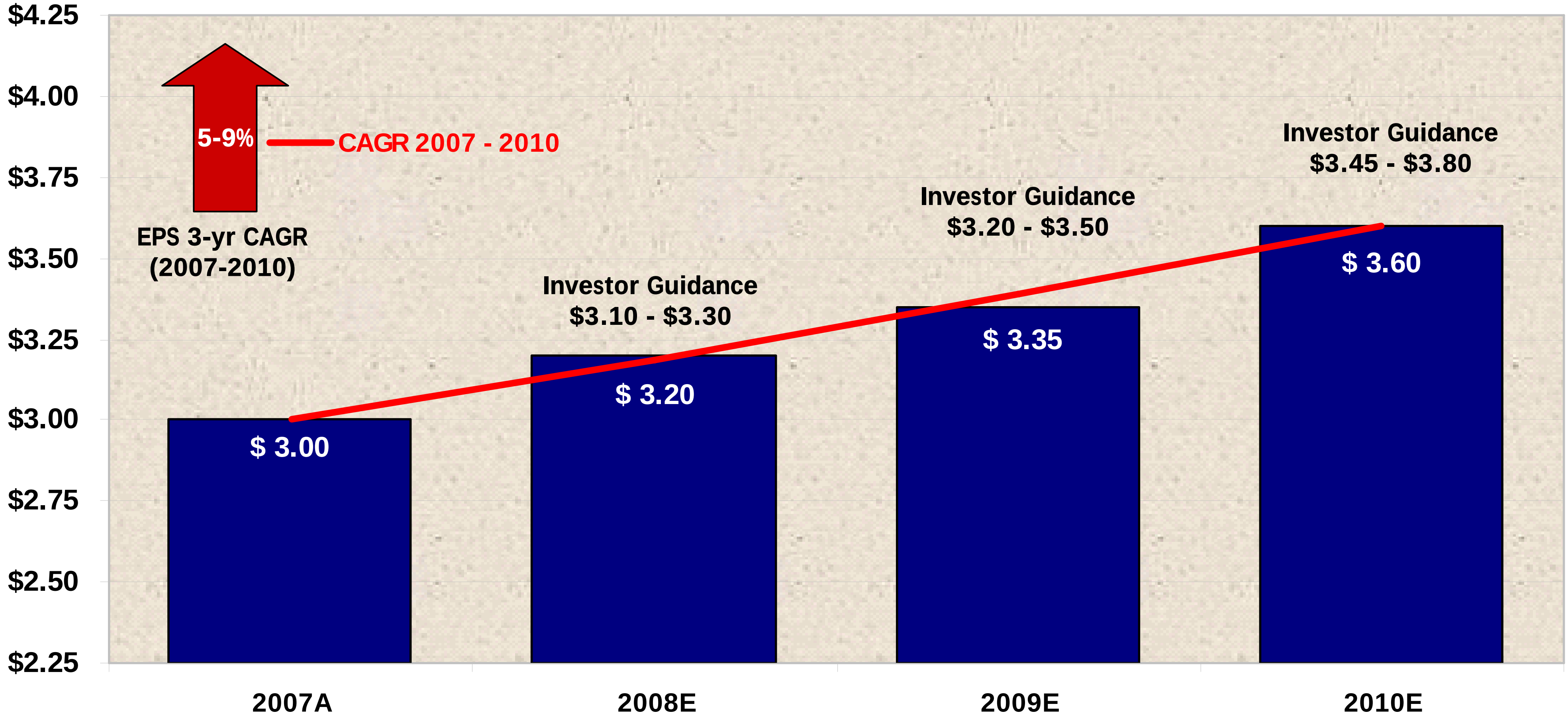
Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

Existing generation and transmission control systems	**gridSMART℠**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

4-Year Earnings Range Forecast

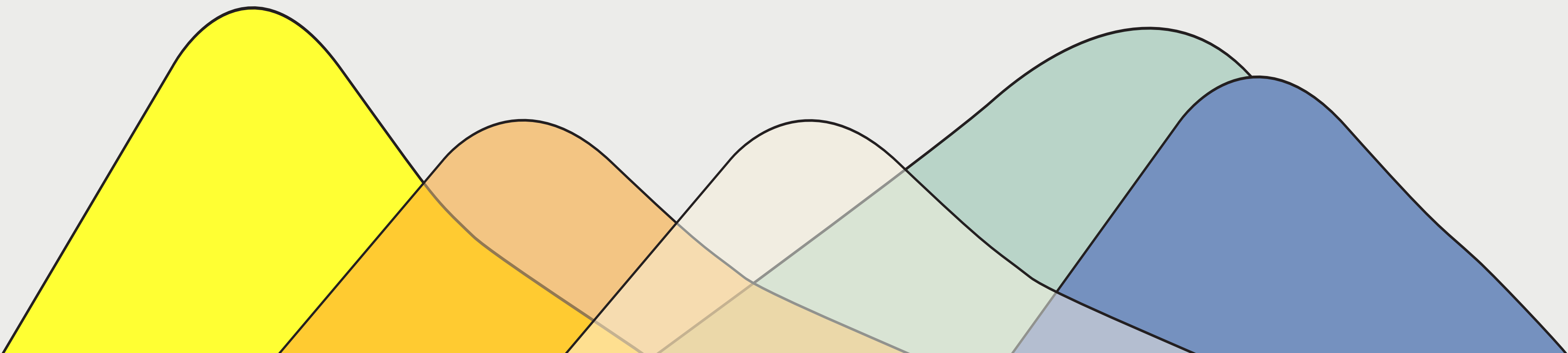


5% to 9% earnings growth

Capital Investment Earnings Catalysts

Capital Investment - Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



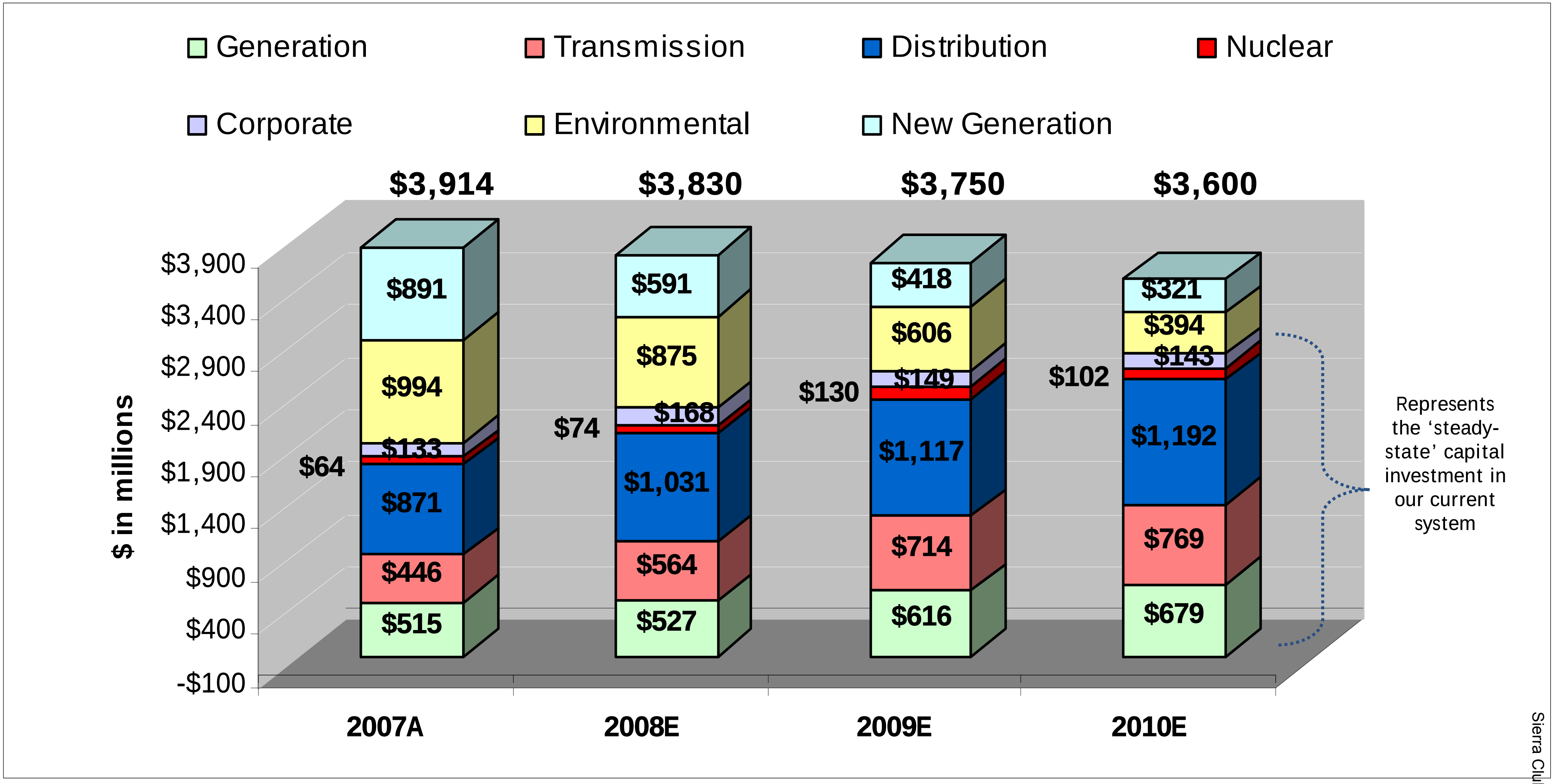
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

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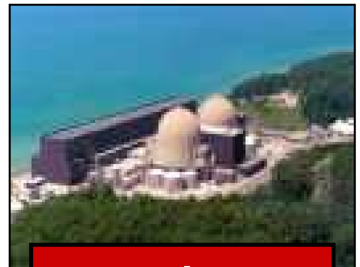
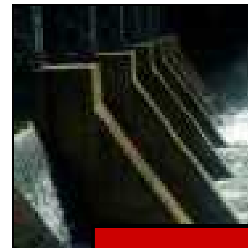
Domestic Generation Fleet

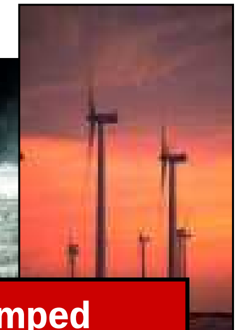
Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%





Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

*** Includes 270MW of retired/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

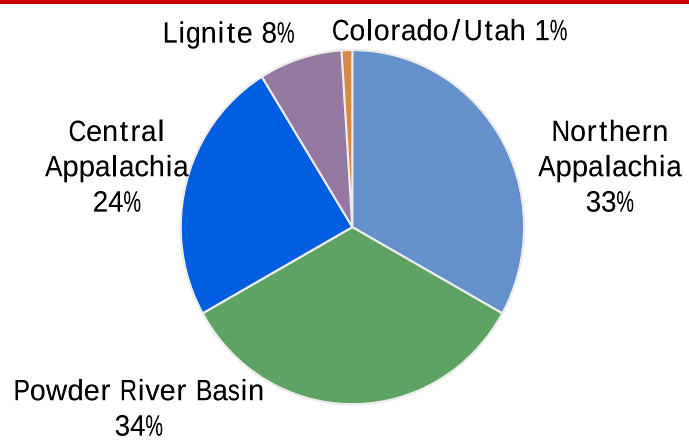
NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

Total AEP System



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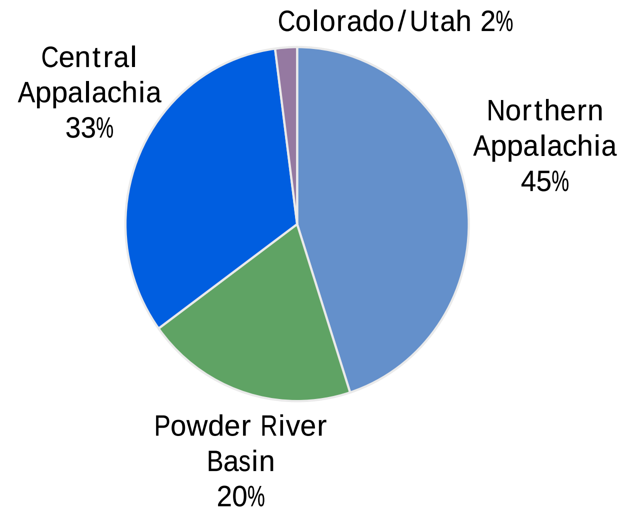
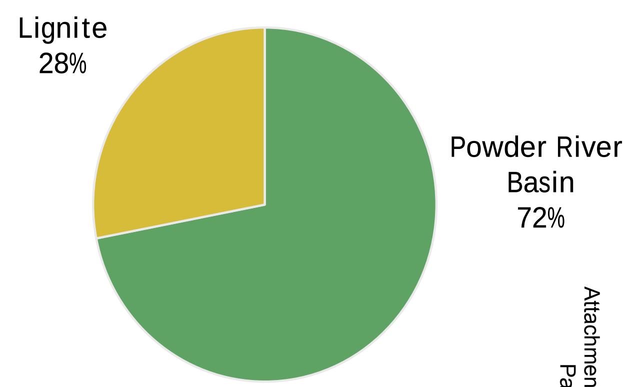


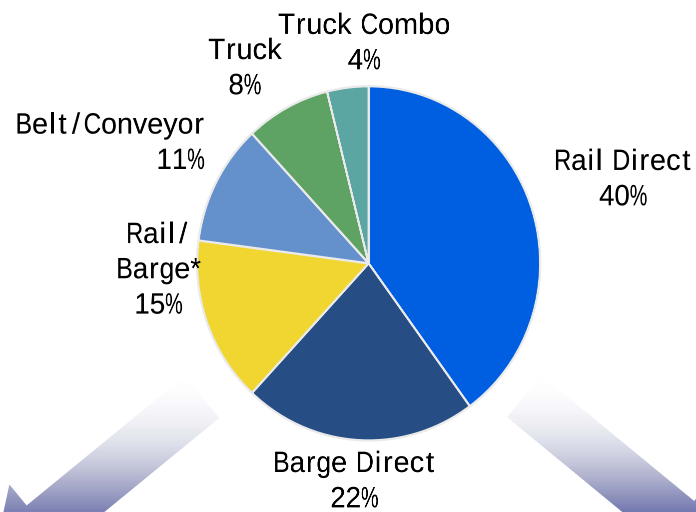
AEP West



Coal Delivery

Total AEP System

2007 Actual



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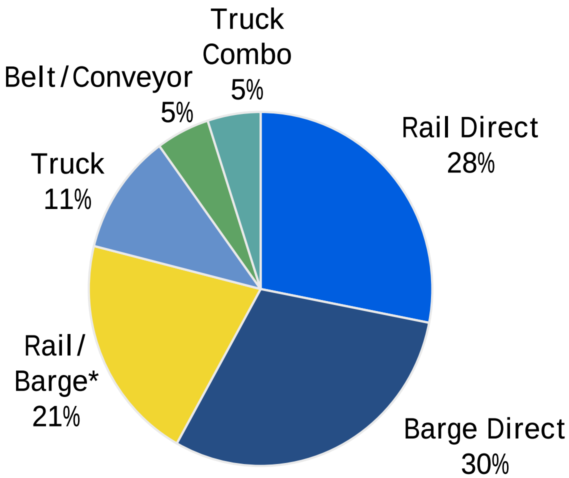

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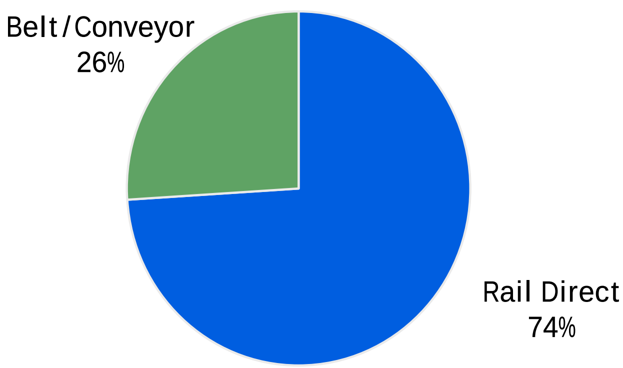

* Reflects coal delivered to AEP plants transported through a combination of rail and barge

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Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $950 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the current appeals before the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART[SM]

gridSMART[SM]: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

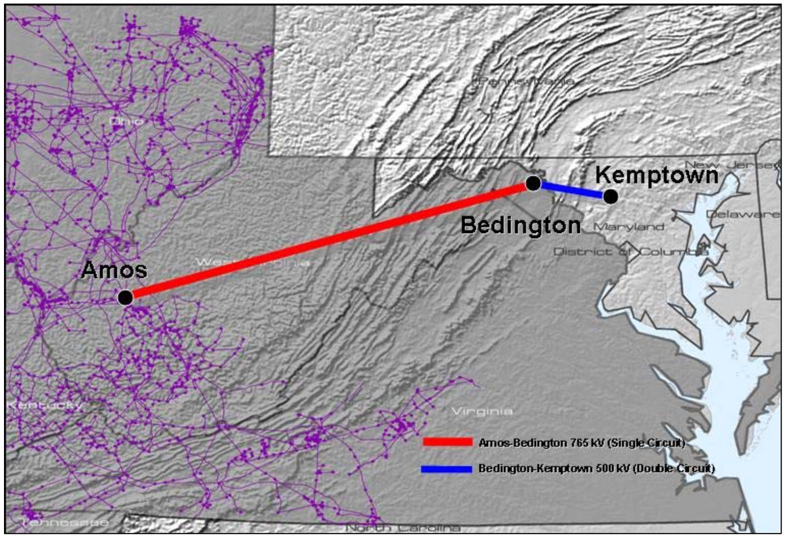
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

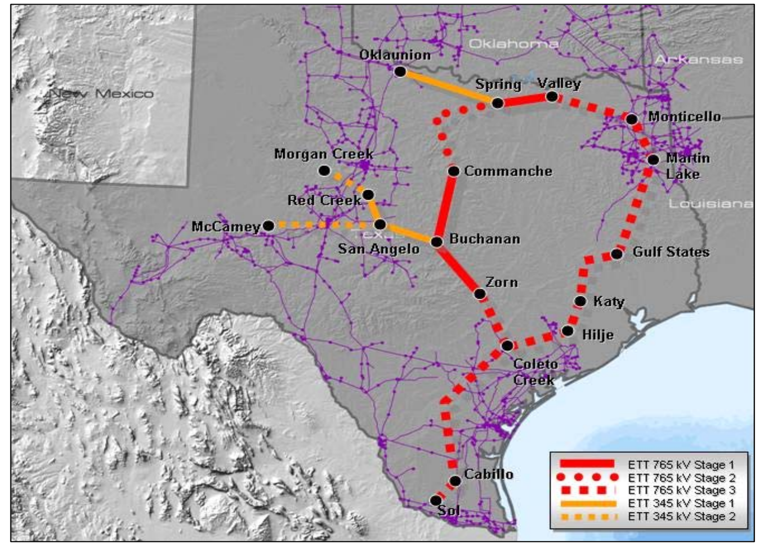
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

I-765™ Transmission: Investment Opportunities

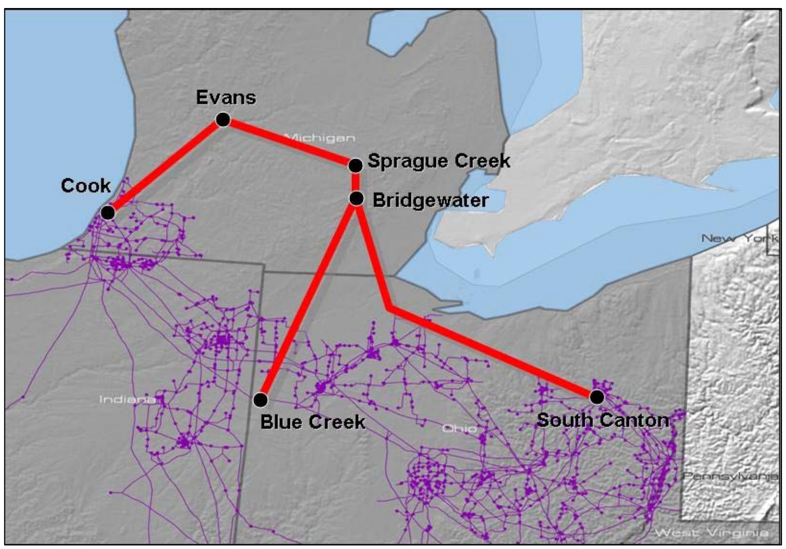
AEP is Advancing the Development of a National Interstate Today



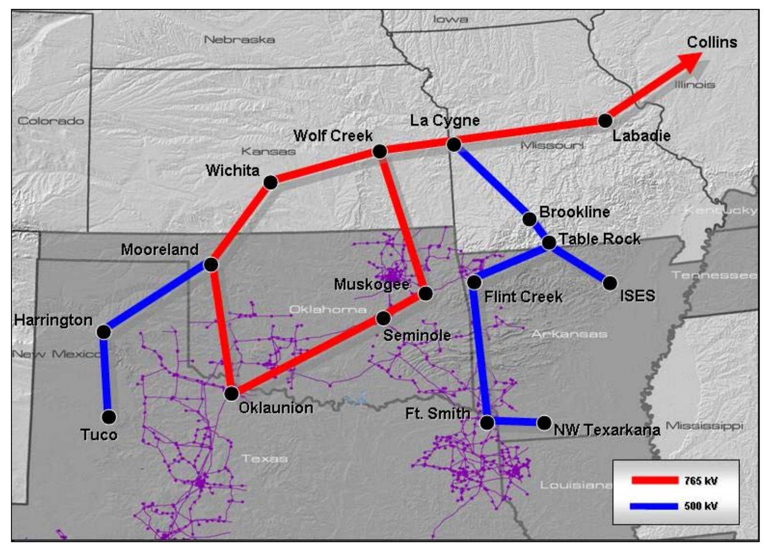
PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

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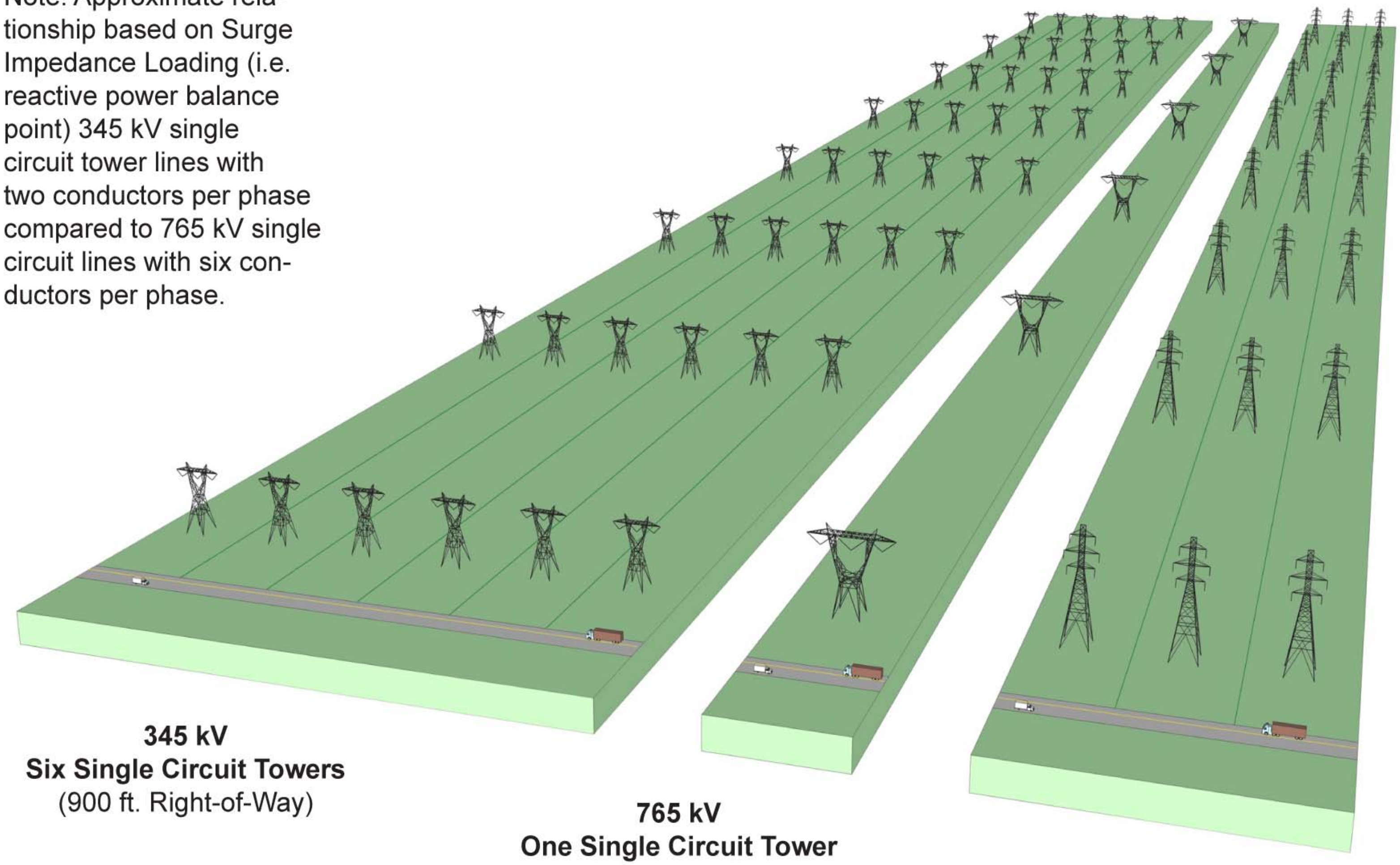
765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

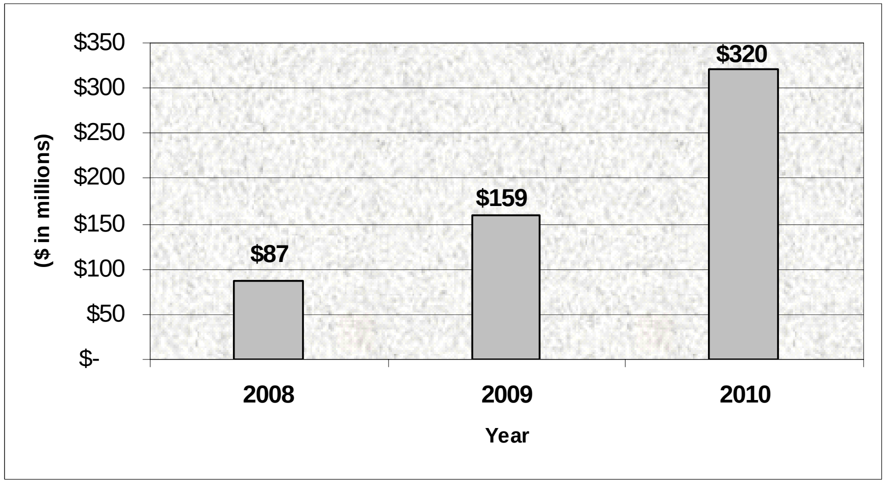
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

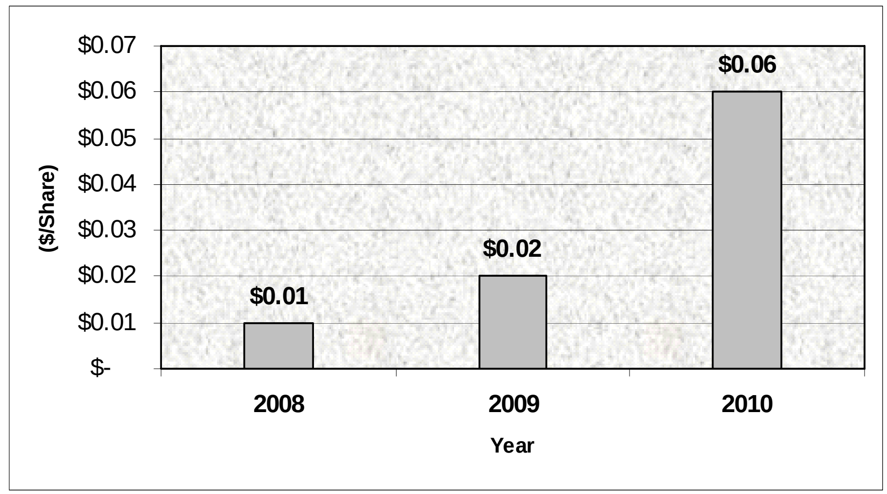


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

PATH Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



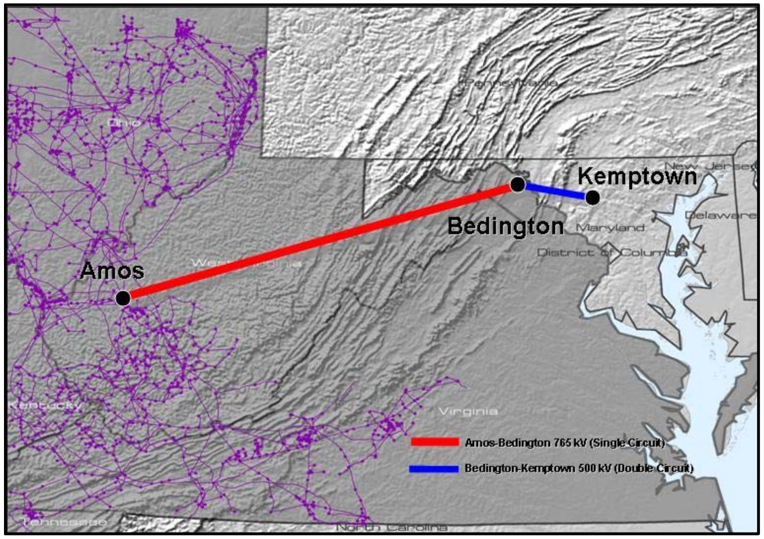
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765TM Transmission in PJM: PATH

Execution in Action

- ## *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - cash return on CWIP
    - 14.3% incentive ROE
    - recovery of all costs incurred prior to the time rates go into effect, and
    - recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate issue be set for hearing, pending settlement judge procedures
- ## *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- ## *Key Next Steps*
  - Siting Approval from WV and MD – Fall 2009
  - Targeted Completion – 2012



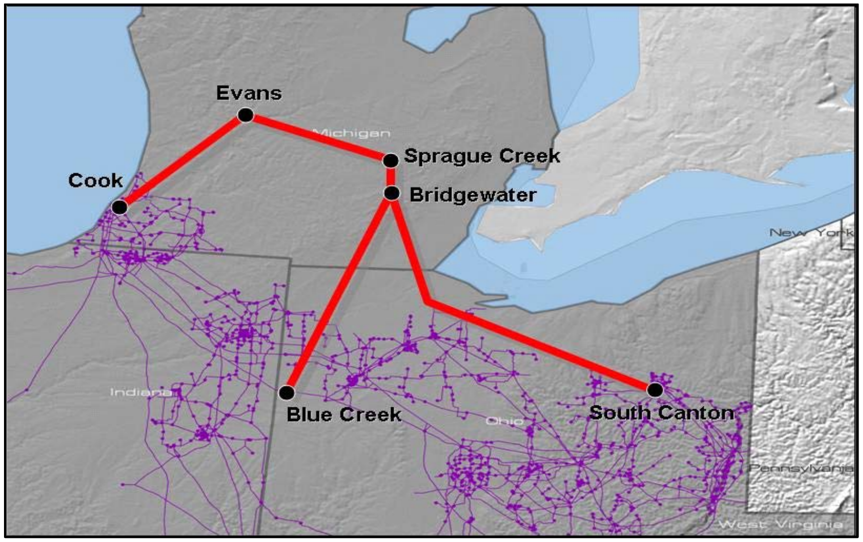
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

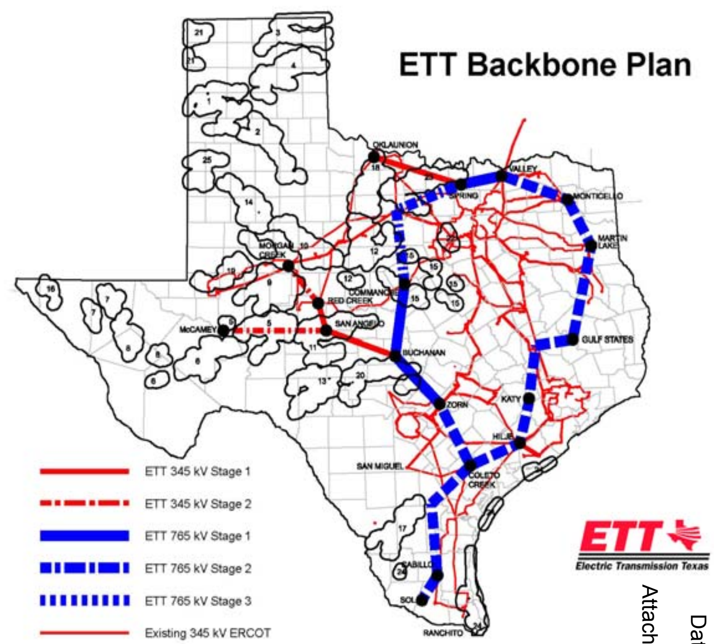
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- *ETT ERCOT Backbone Proposal*
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

Electric Transmission America (ETA)

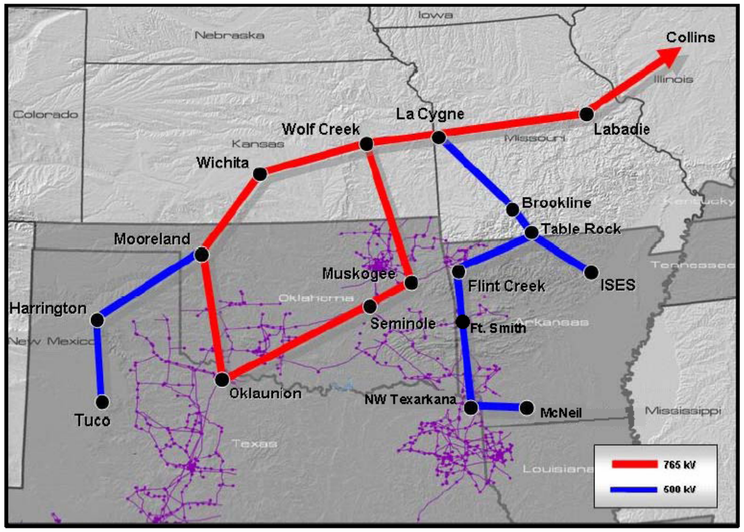
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- *Benefits*
  - 4,000 MW improved transfer capability
- *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

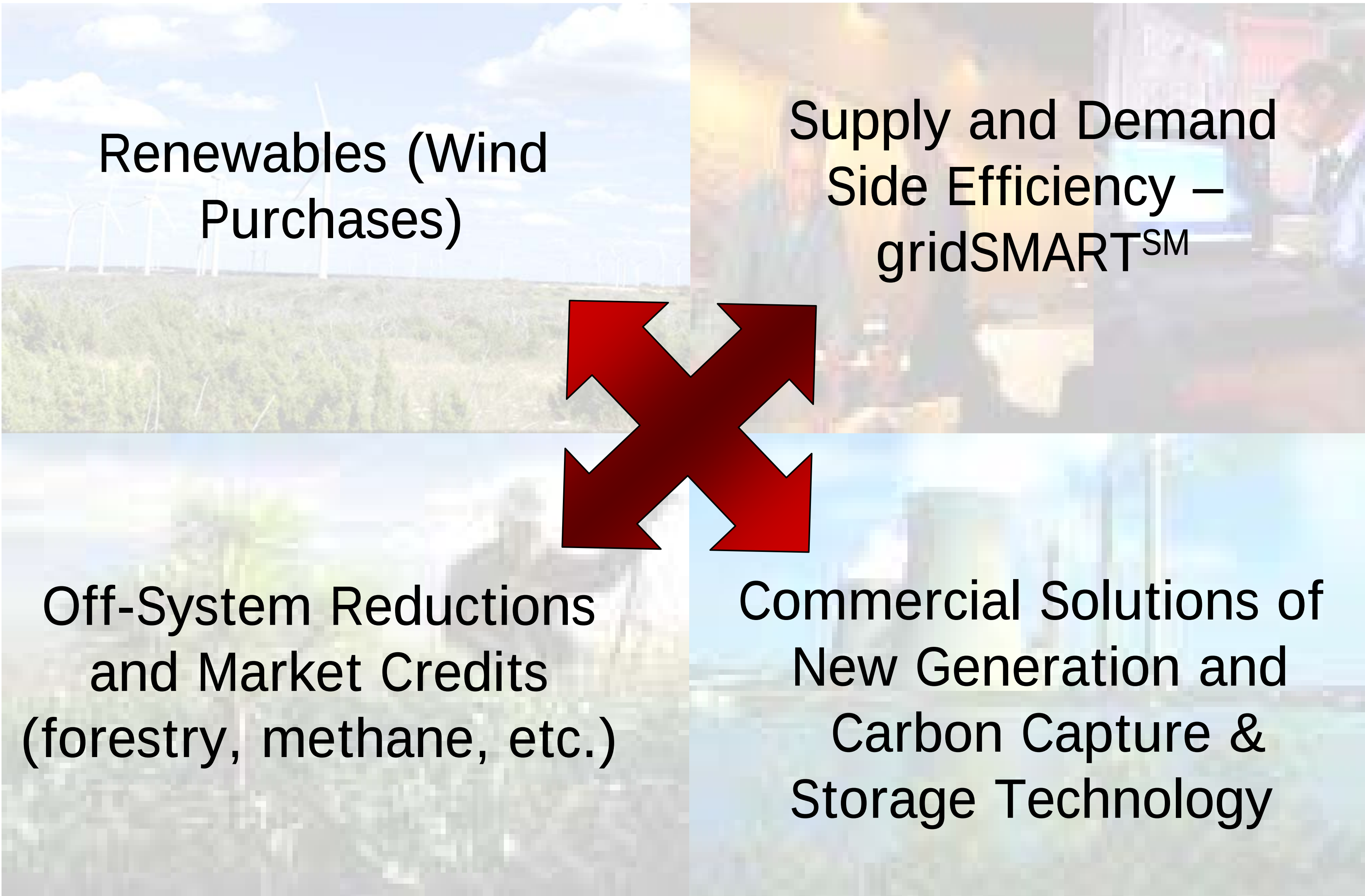
"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives.

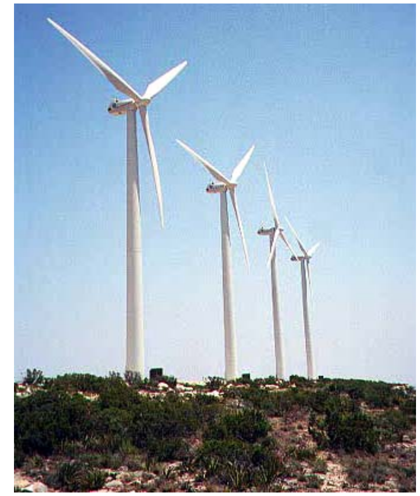
AEP Wind Operations/Purchases

Trent Mesa (2001)

150 MW (100 - 1.5 MW turbines)

Abilene/Sweetwater, TX

Southwest Mesa (1999)



- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser

Desert Sky (2002)

160 MW (107 - 1.5 MW turbines)

Bakersfield, TX

Summary

- Owned/Operated 385 MW
- Wind Purchases 392 MW
- Total Existing Wind at end of 2006: 777 MW
- **New Wind Purchases in 2007: 275 MW**

AEP will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011.

Off-System Reductions

Existing AEP Programs:

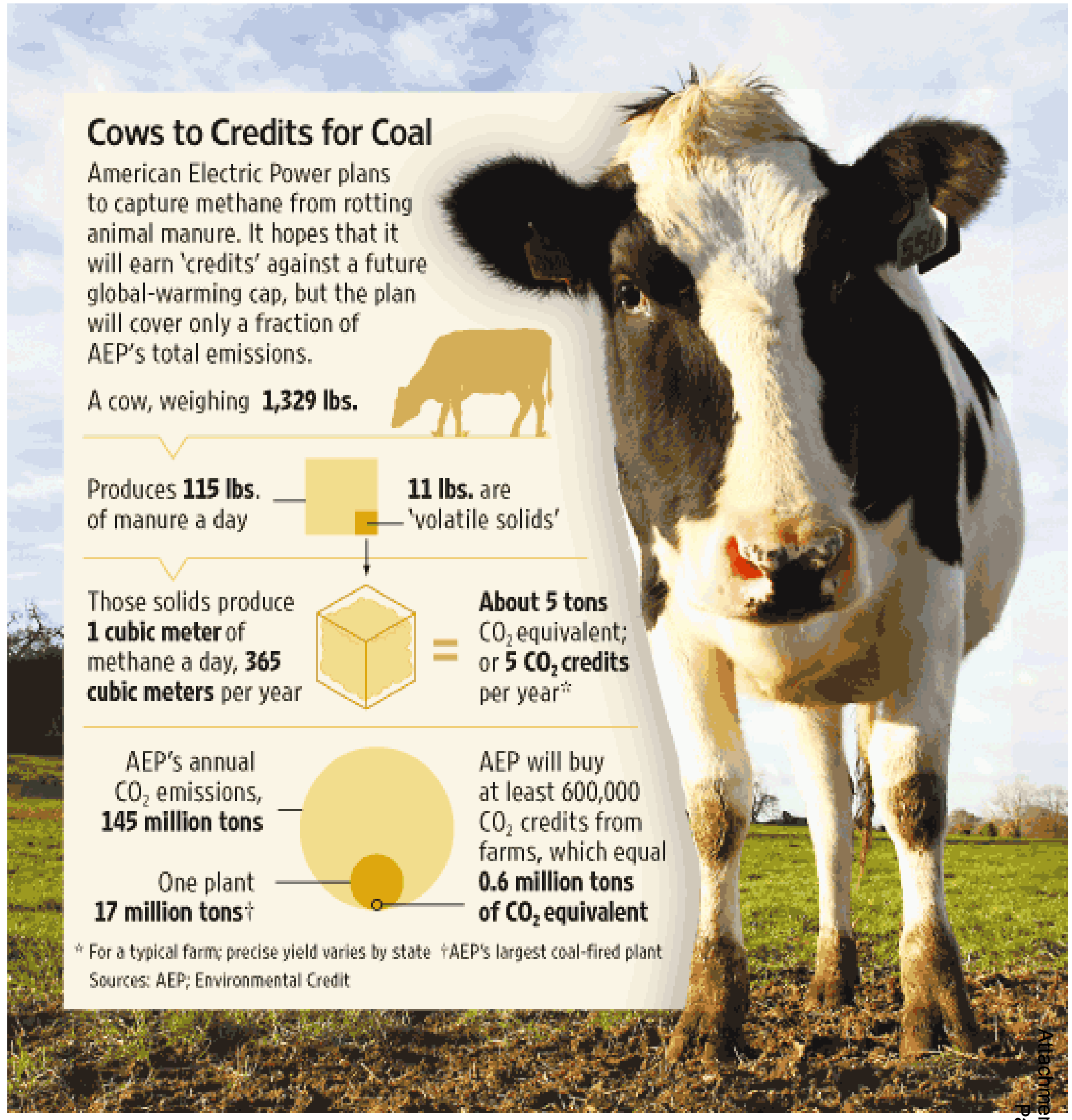
- Forestry - Domestic
  - 350,000 tons / yr
  - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 600,000 CCX carbon credits per year
  - Begins 2010
  - Runs through 2017
  - 51% of credits sourced from "AEP States"



Source: Wall Street Journal June 14, 2007

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade

USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100ºF) coal plant in U.S (AR)

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

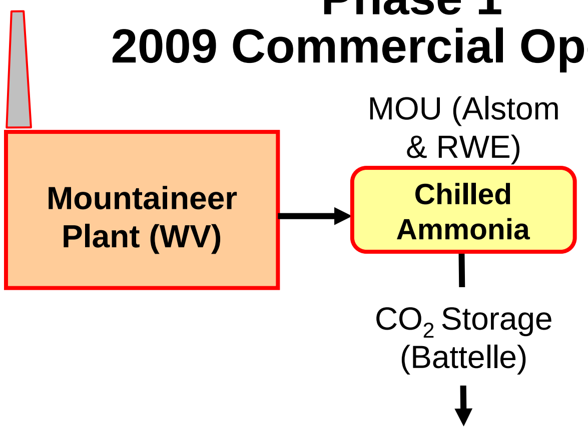
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

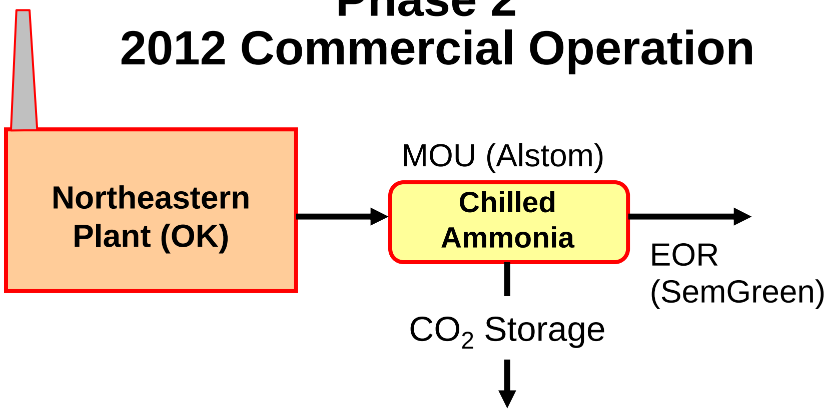
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

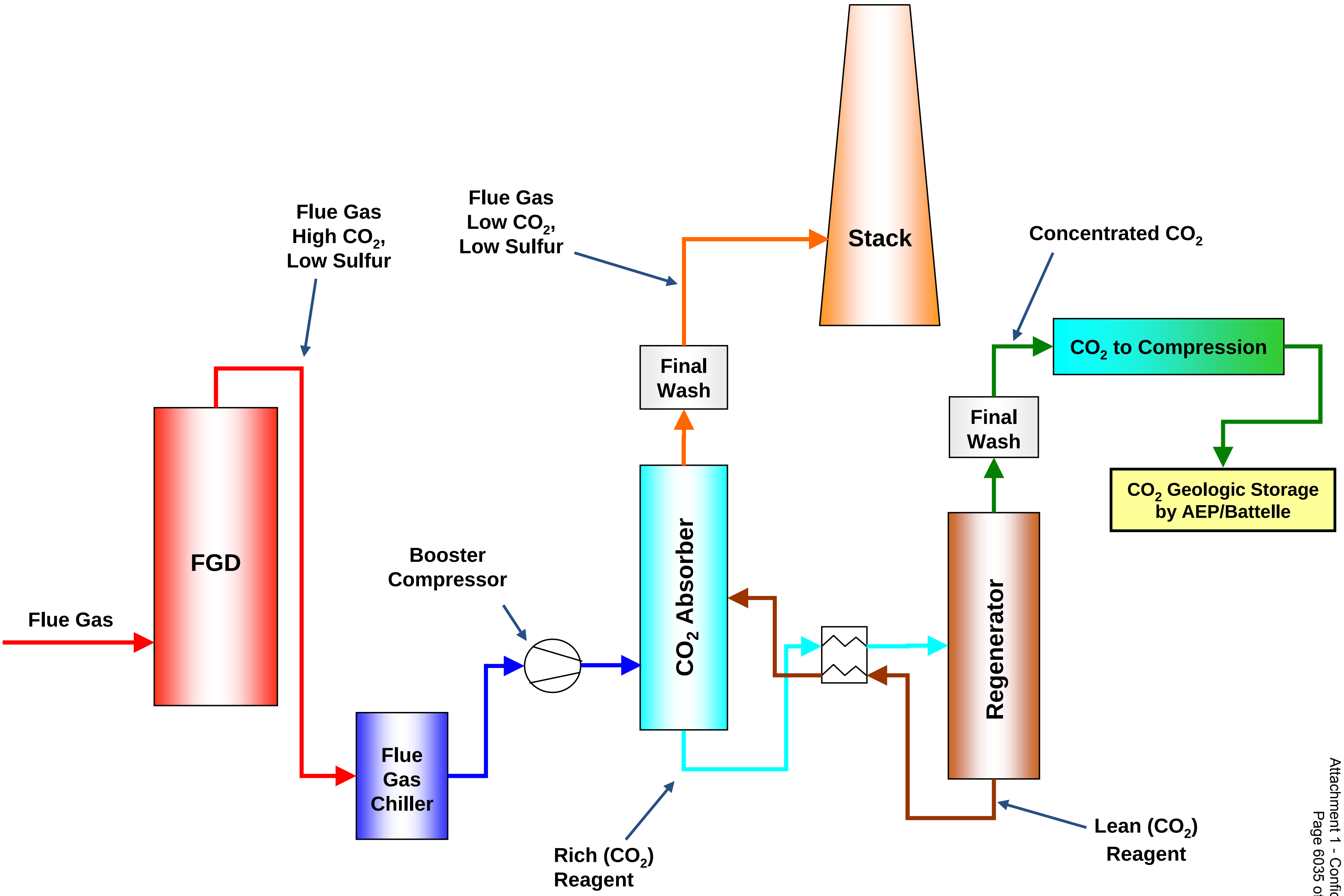
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Alstom's Chilled Ammonia Process
Post-Combustion Capture



Babcock & Wilcox Oxy-Coal Process
Modified Combustion Capture

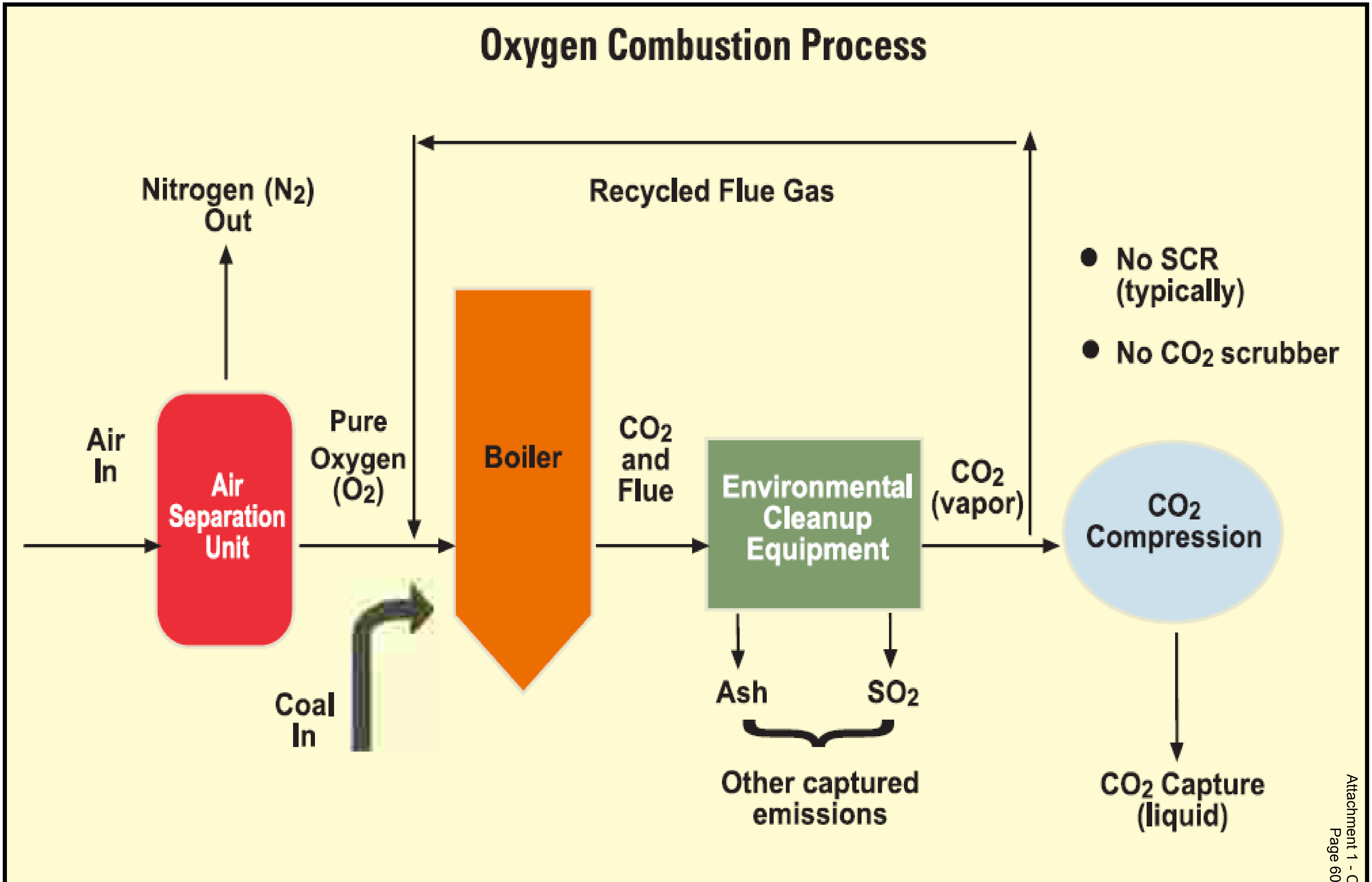
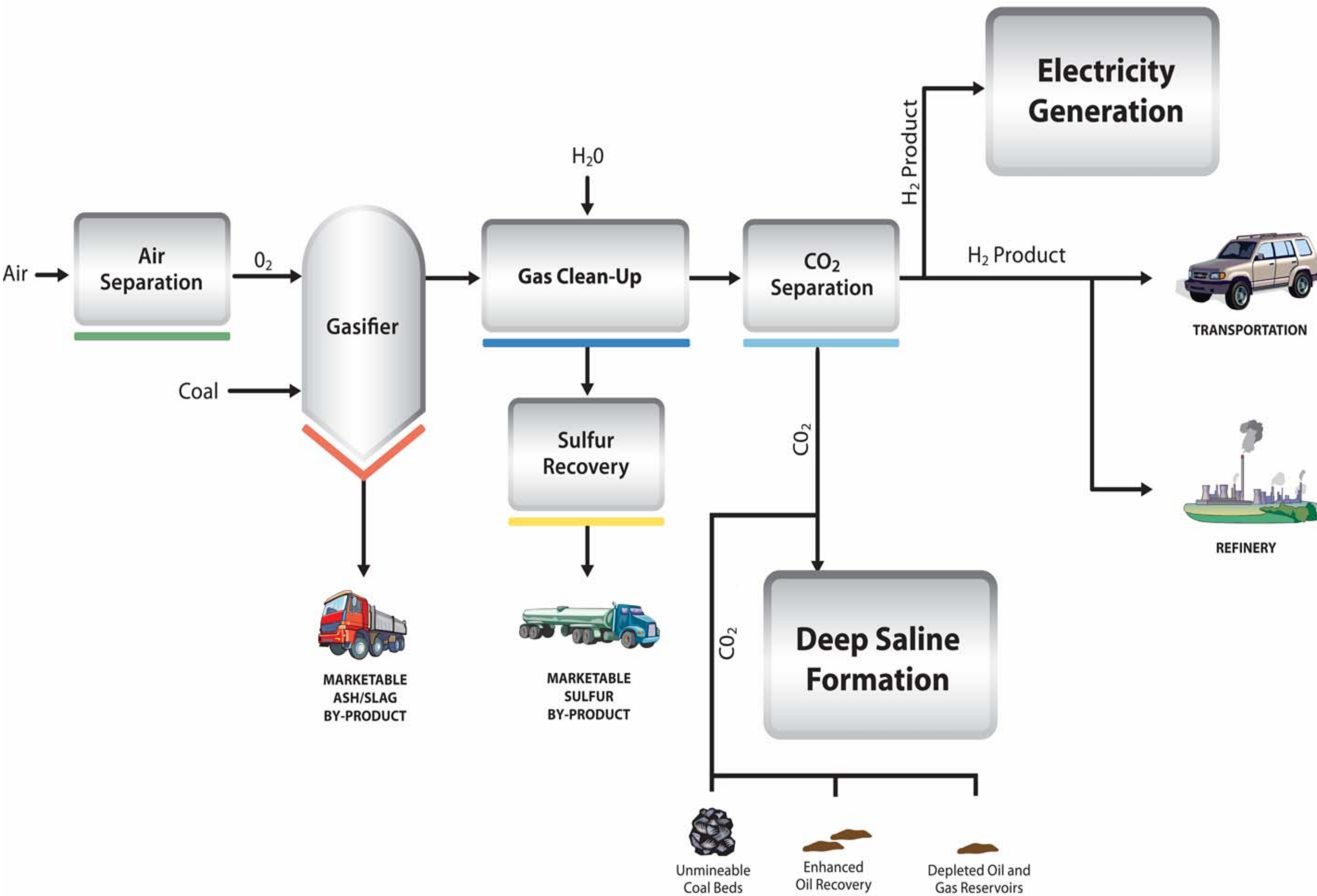
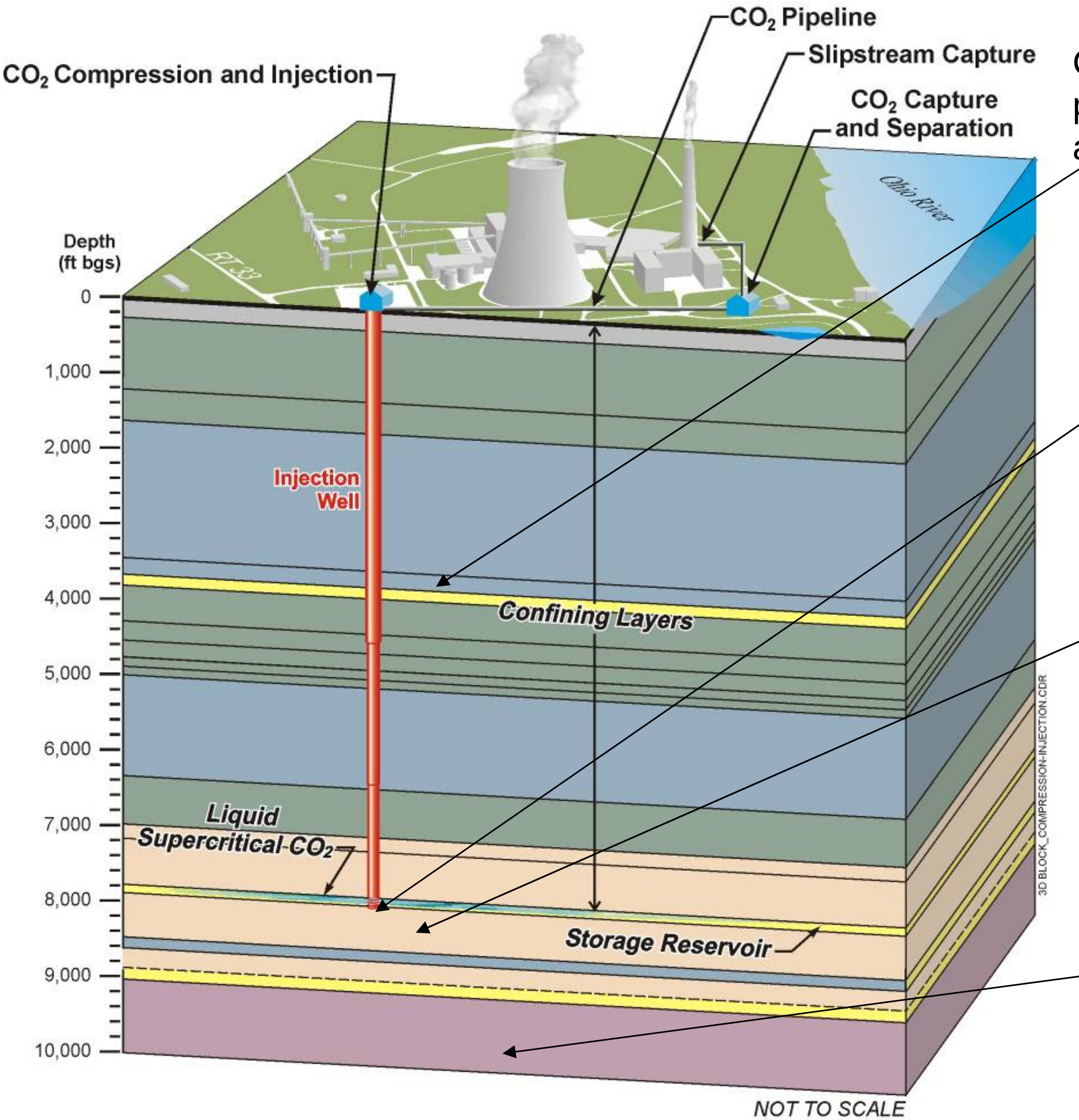


Illustration supplied courtesy of The Babcock & Wilcox Company

IGCC with Water-Gas Shift Process
Pre-Combustion Capture



CO_2 Injectivity in the Mountaineer Area



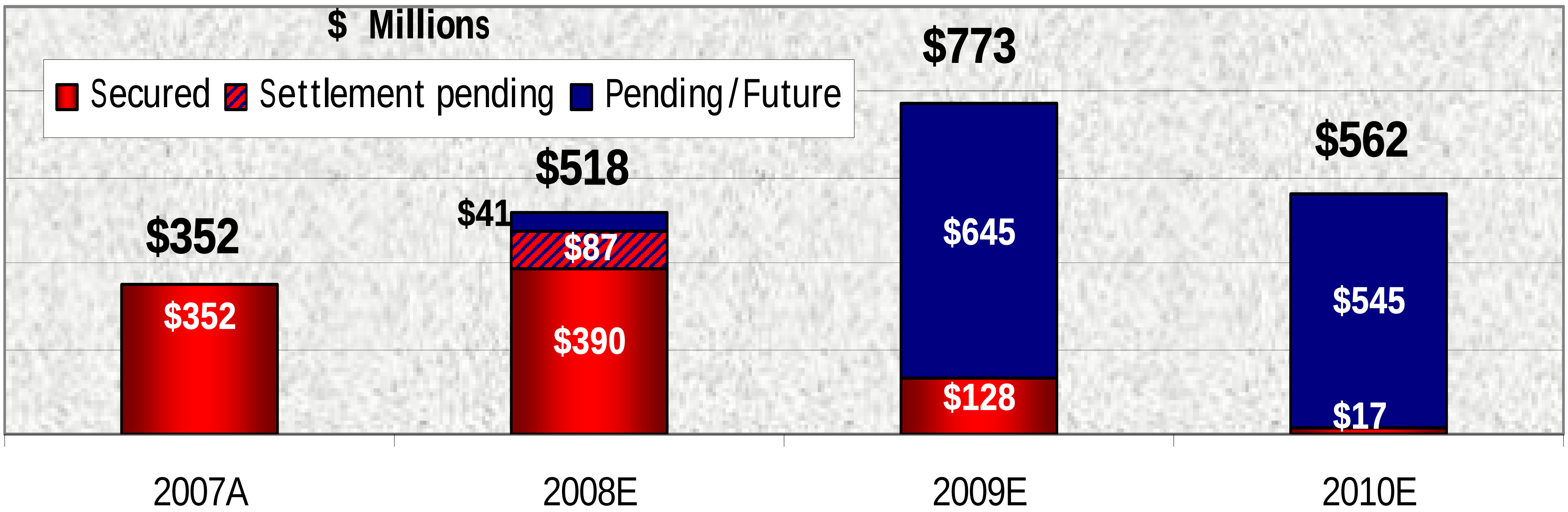
CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the “B zone” within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

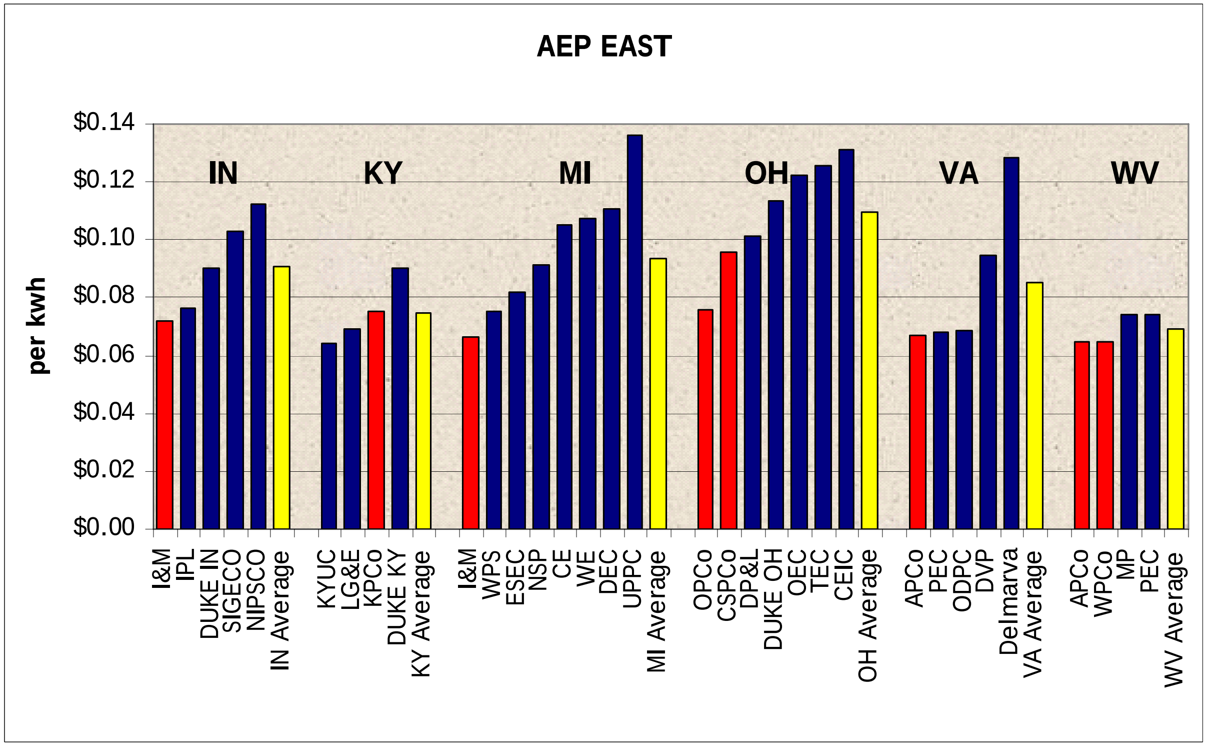
Incremental Rate Relief Assumptions

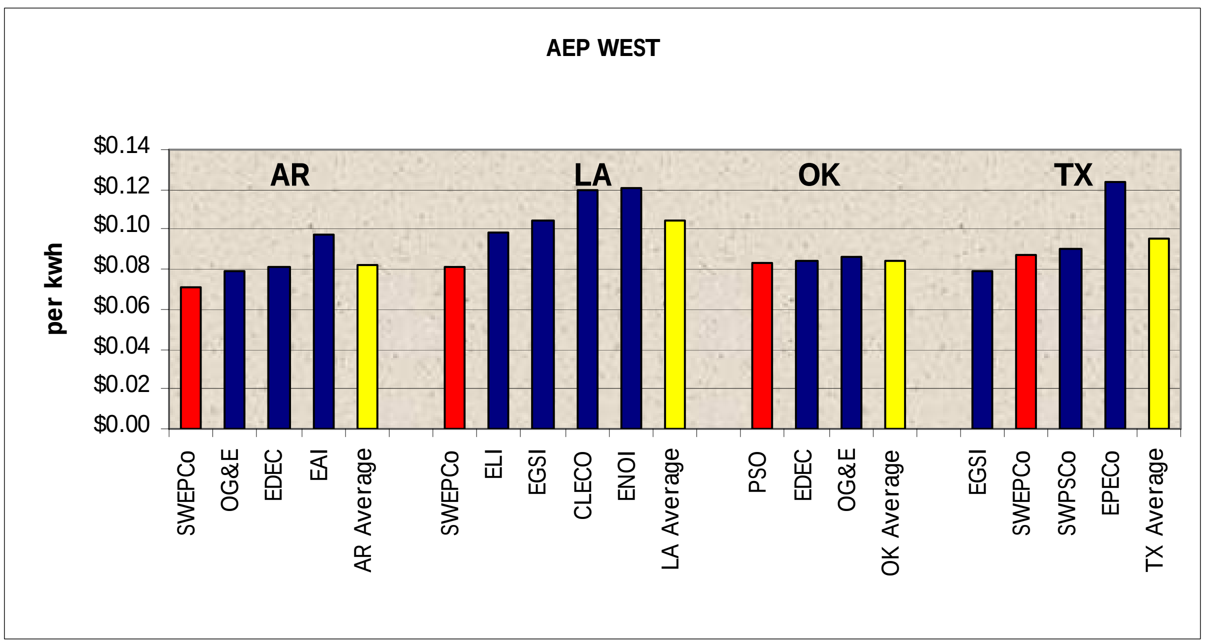


- **75% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings.**
- **17% of 2008 Rate Relief Settlement Pending: Uncontested settlement approved by an ALJ on February 29, 2008 for the PSO January and December 2007 Ice Storm Recovery; OCC approval pending**
- **2008 Pending: SWEPCo - LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

Regulatory Activity Underway

- Ohio Post 2008
- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Regulatory Activity Underway

Ohio Post-2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearings continue and we anticipate a signed bill in March or April of 2008.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- PSO requests the Commission make a determination that the costs incurred on the Red Rock project were prudent and direct it to establish a regulatory asset of approximately $21 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of SO_2 emission allowances.
- The procedural schedule in this case has been suspended pending the outcome of the storm cost recovery. Once an order in that case is issued, additional cost recovery testimony likely will be filed and a new procedural schedule established.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Technical conferences and settlement meetings were held in October – December 2007. Settlement discussions are currently on-going. Intervenors and AEP are scheduled to meet on March 11, 2008 to review any additional issues and report back to the settlement judge on the status of the settlement discussions.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 629MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. We expect an order in early March 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order in April 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. A positive ALJ report was issued on February 8, 2008 recommending approval of the plant. An order is expected in March 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. A final order is expected on March 27, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings will commence on April 7, 2008. Staff testimony was favorable.

Texas

- PUCT order approving plant was issued on March 8, 2007.

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Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Rate Base & December 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	12/31/07 GAAP Adjusted Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	8.15%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.56%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	10.98%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	23.86%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	13.01%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	4.96%
SWEPCo-LA	$434MM	11.10%	12/29/1999	8.74%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	11.33%
Texas-TNC	$530MM	9.96%	6/1/2007	8.32%

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

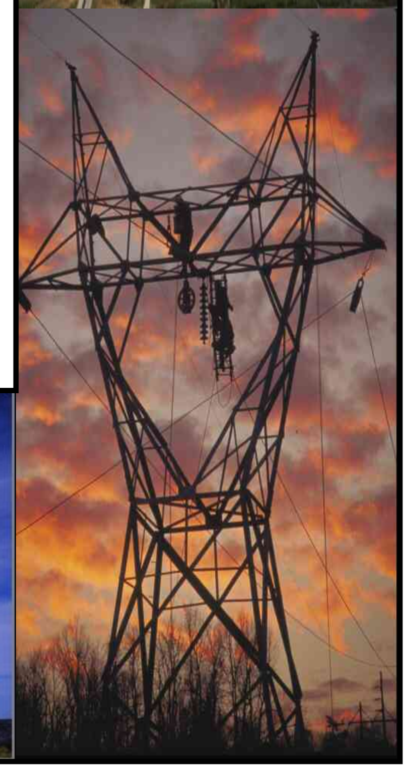
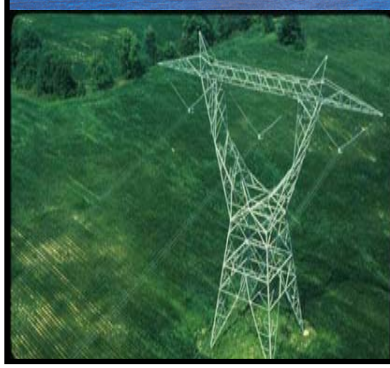





Merrill Lynch

"Buckeye Tour"
Columbus, OH

May 7, 2008

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Table of Contents

Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

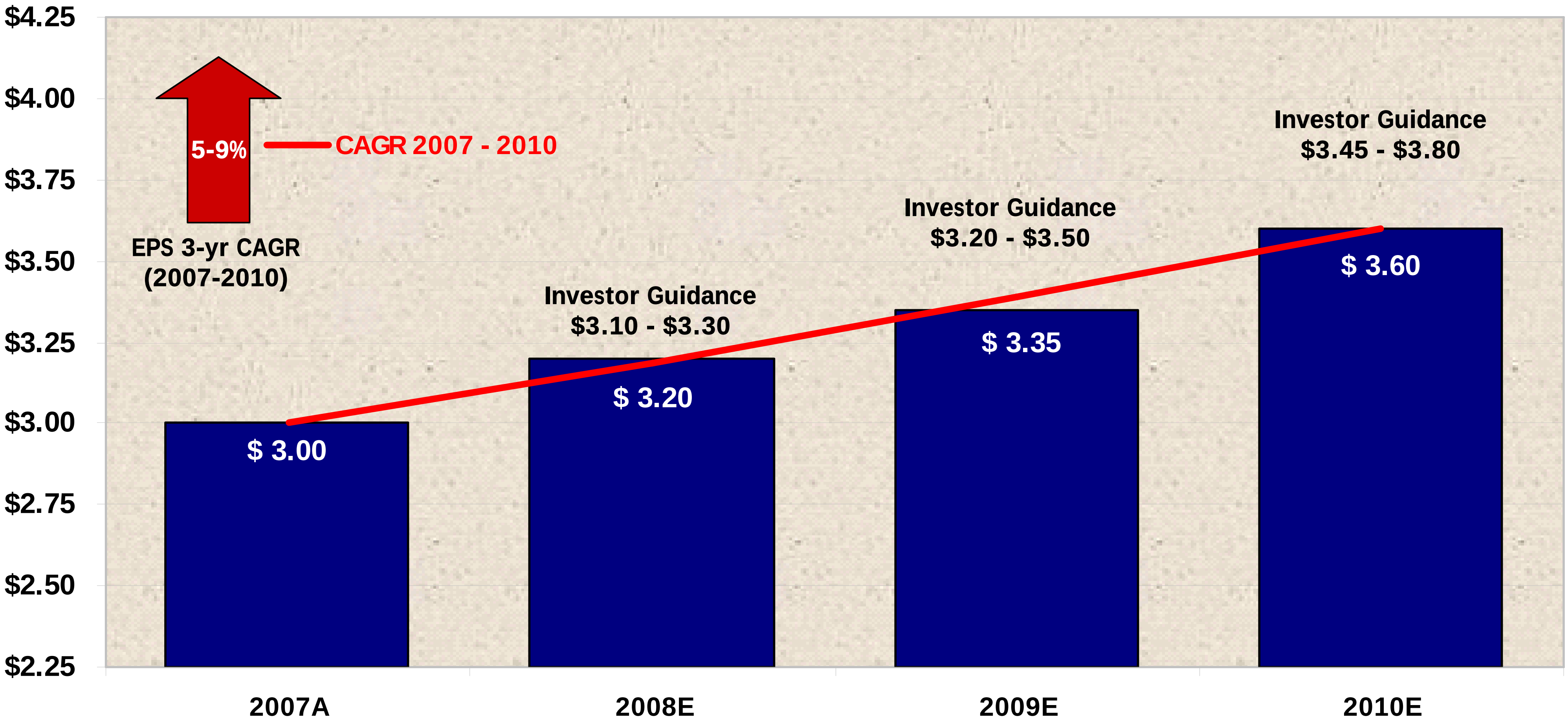
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast

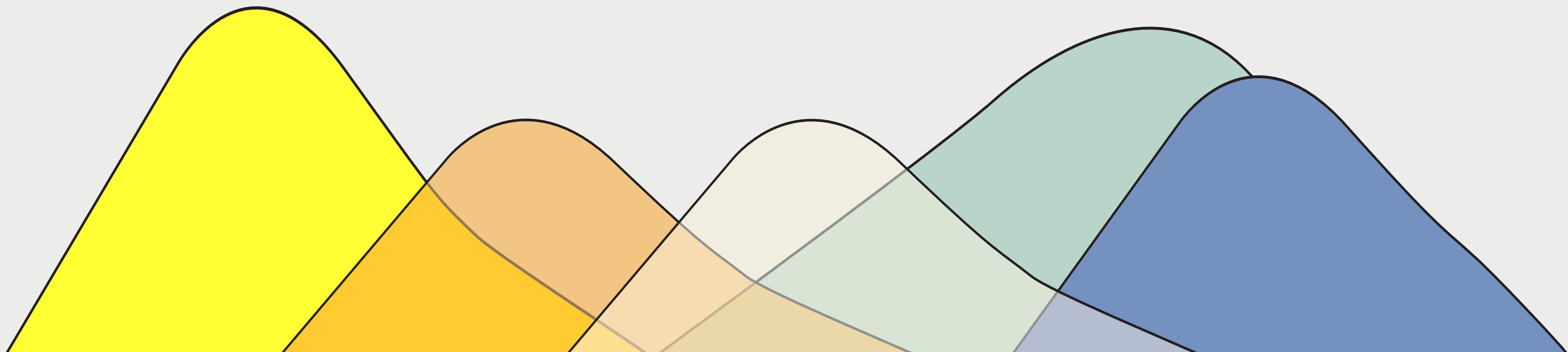


5% to 9% earnings growth

Capital Investment Earnings Catalysts

Capital Investment - Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1-2B	$2.25B - $3.75B*	$2.0B+



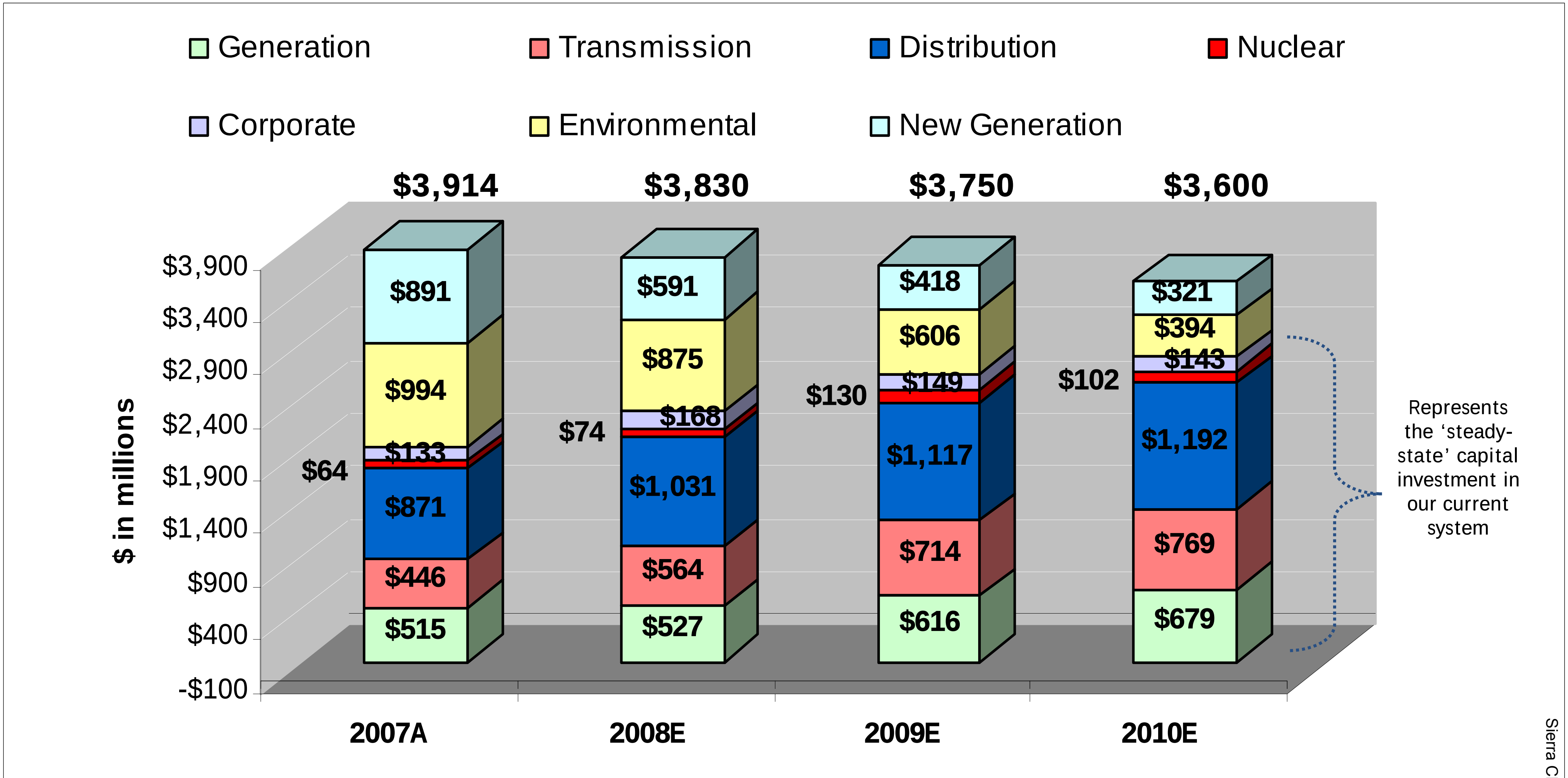
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

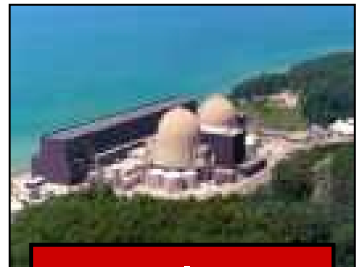
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

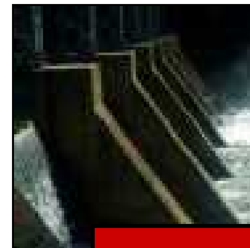
Domestic Generation Fleet

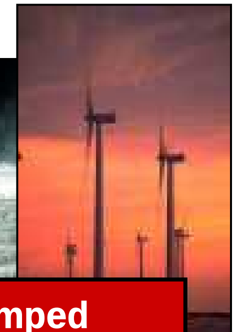
Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%





Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

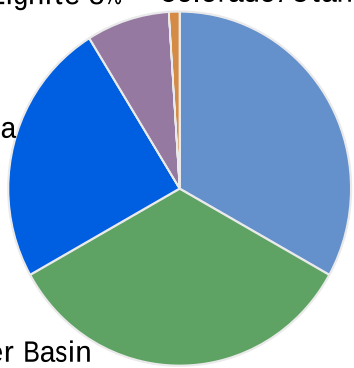
NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

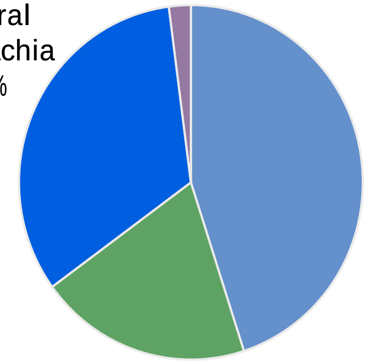
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

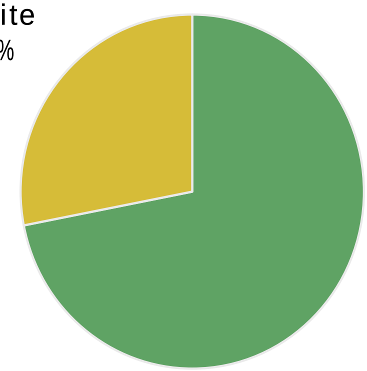
Total AEP System



AEP East



AEP West



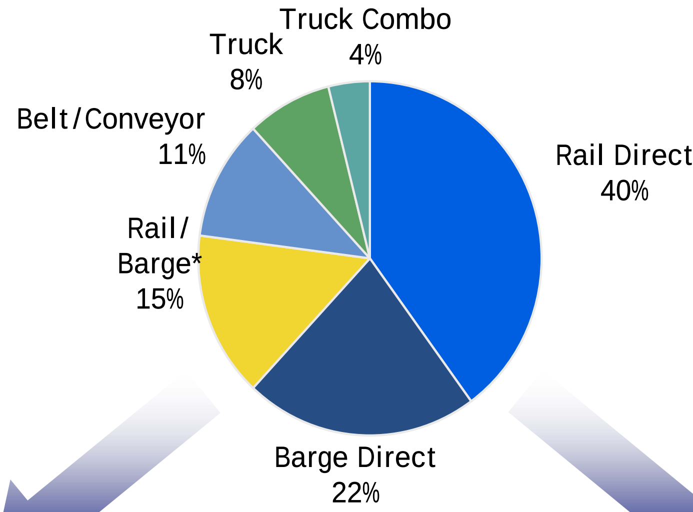
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 14%-18% price increase in 2008 based on 2007 actual results.

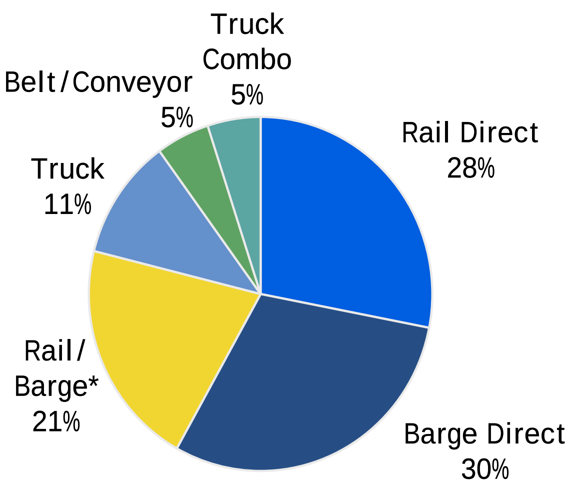
Coal Delivery

Total AEP System

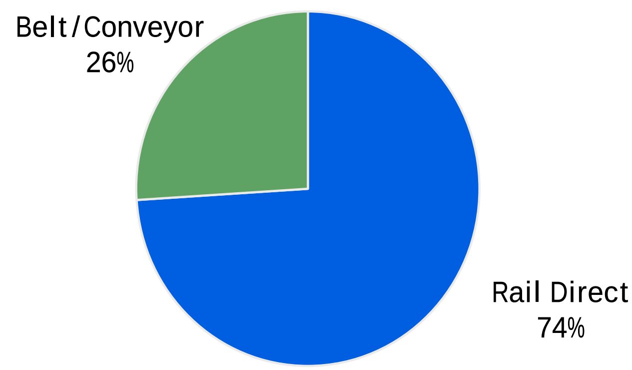
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

AEP®

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$305 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART℠

gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

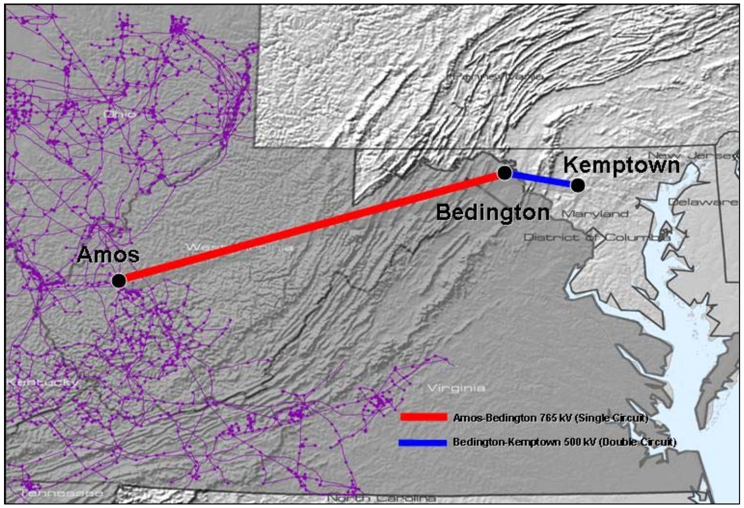
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

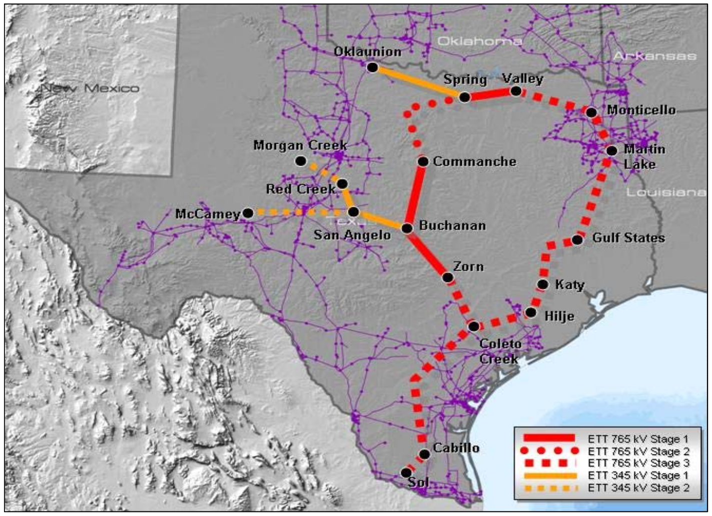
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

I-765™ Transmission: Investment Opportunities

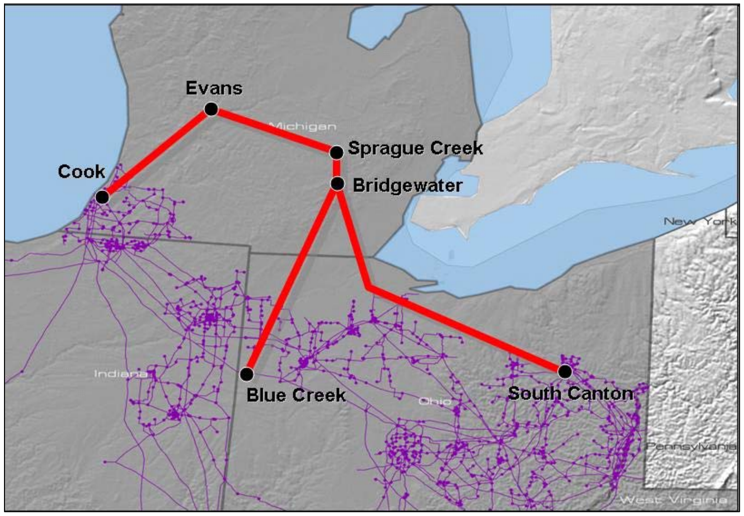
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

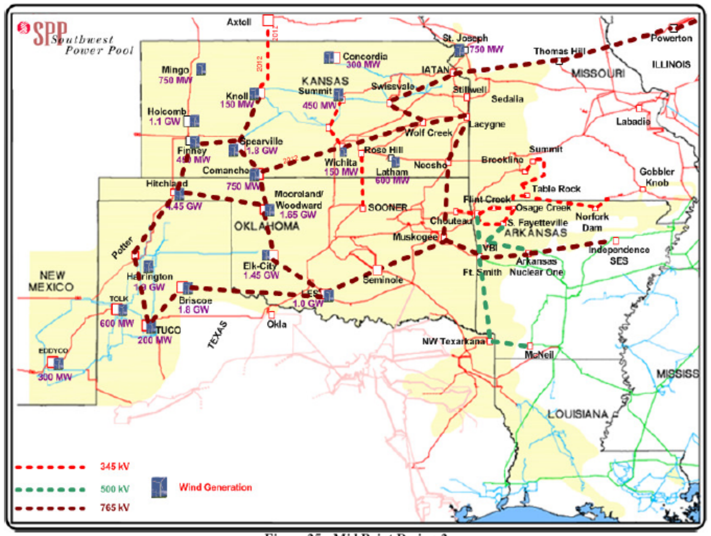


Figure 25: Mid Point Design 2

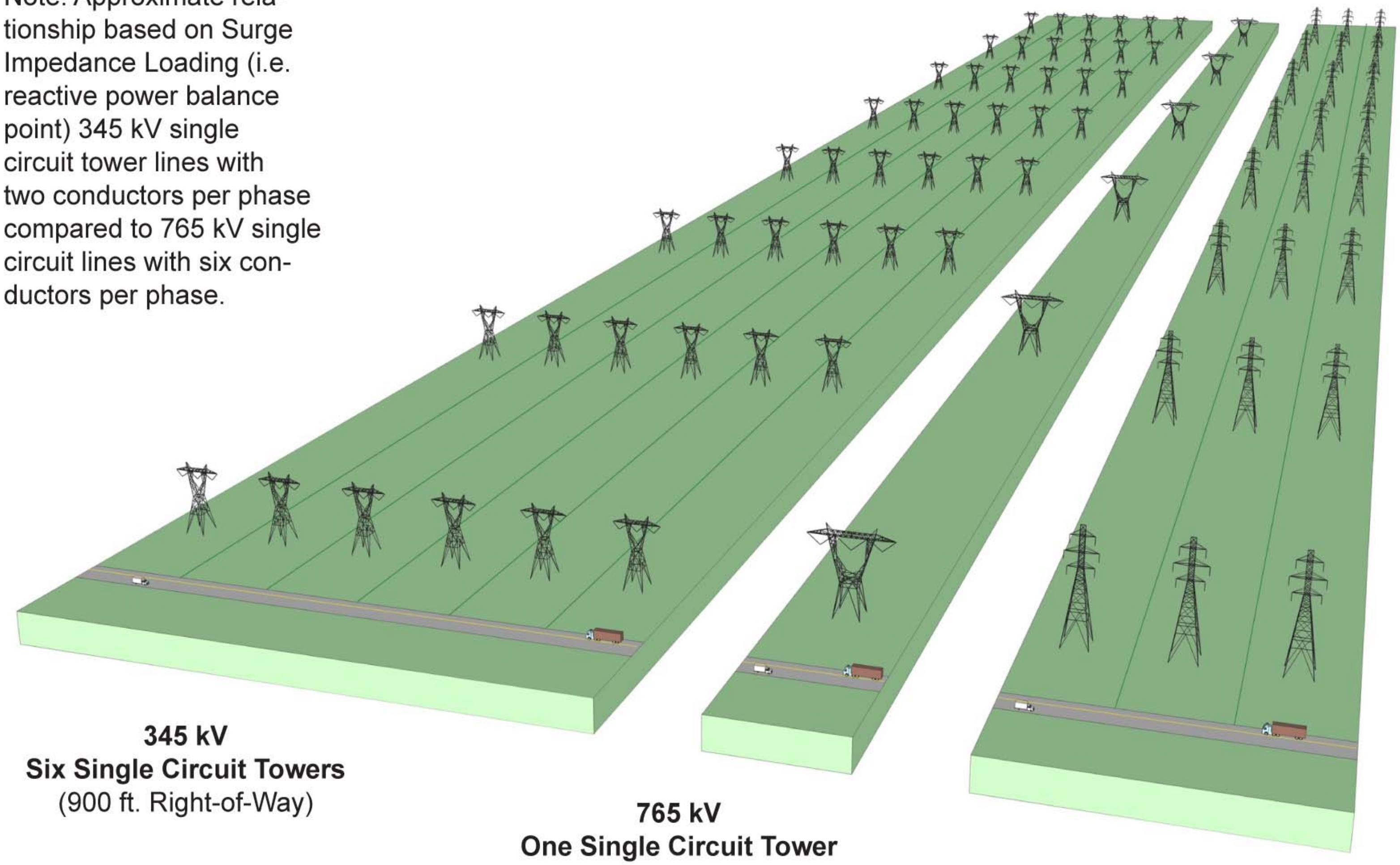
SPP Overlay Study – Mid Design 2

6

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6069 of 9556

765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

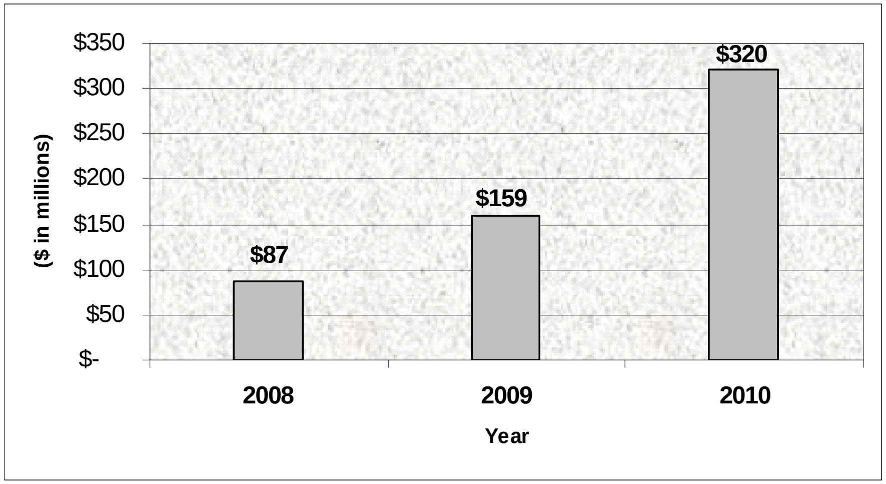
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission - Investments and Earnings Contributions

Projected Transmission Capital Spending*

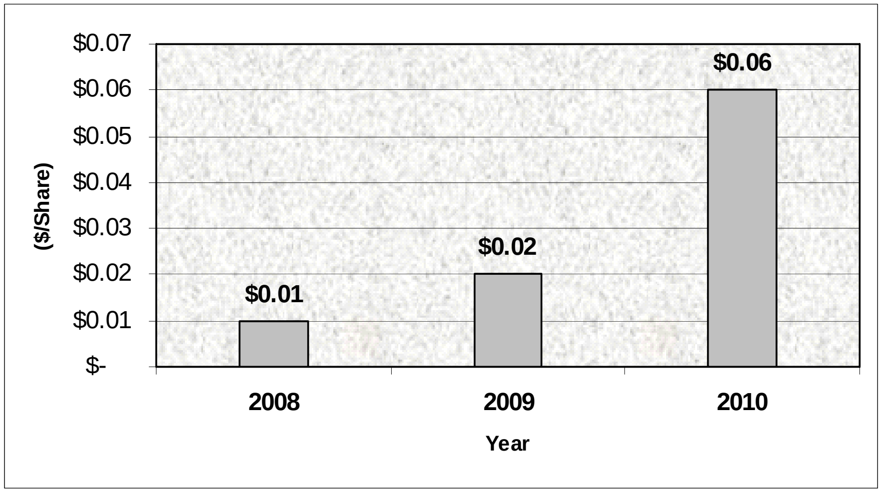


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT
Electric Transmission Texas

PATH
Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



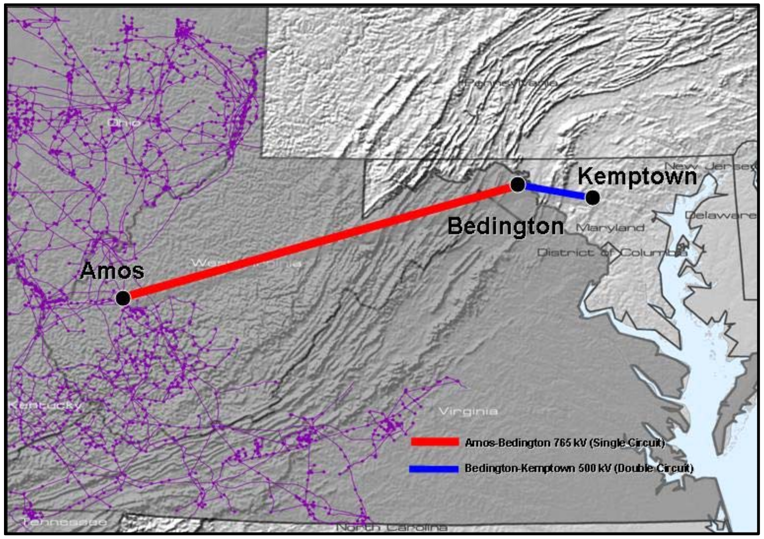
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America (ETA)

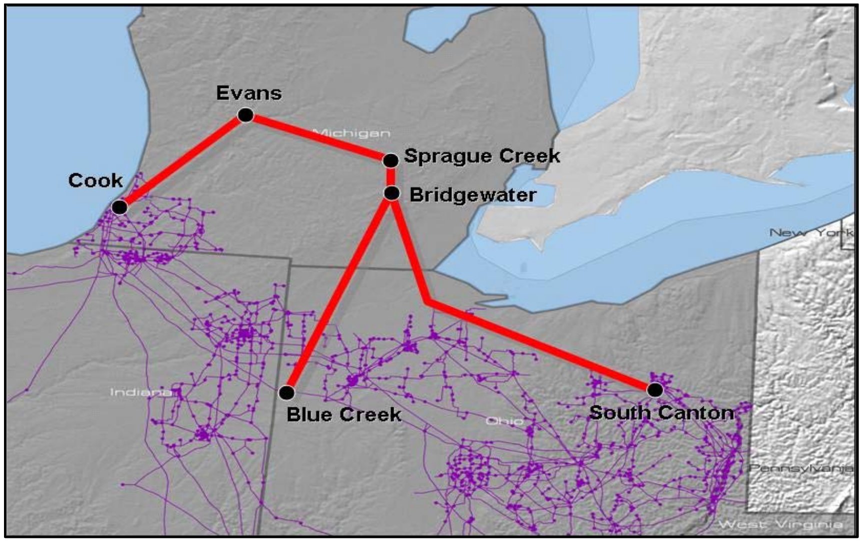
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ### *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ### *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

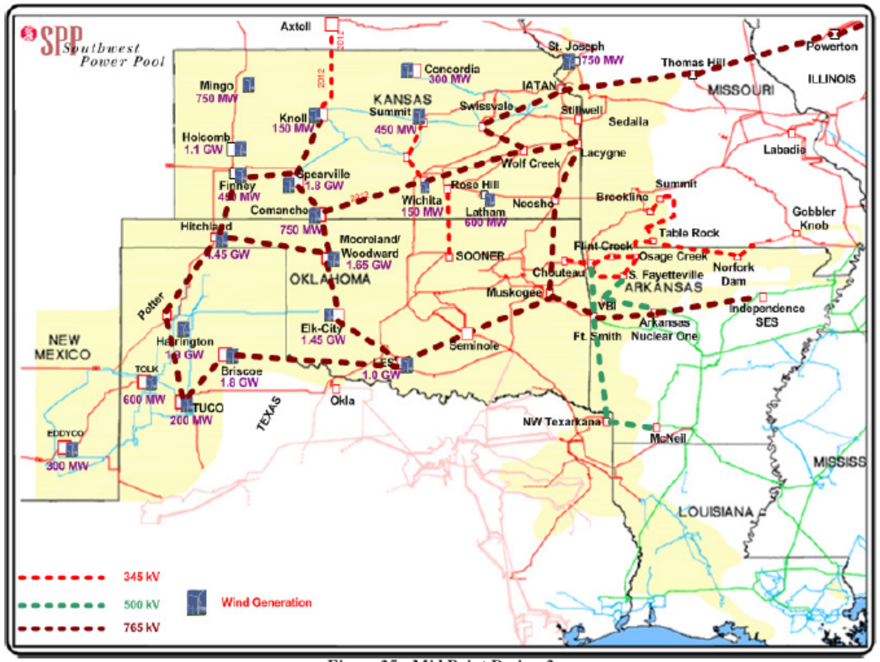


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Carbon Capture Technology Support—Bonus Allowances
- International action (AEP-IBEW trade proposal)

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP is investing in a portfolio of GHG reduction alternatives.

A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- **Existing plant efficiency improvements**
- **Renewable Energy**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - **Forestry - 0.35MM tons/yr**
  - **Over 63MM trees planted through 2006**
  - **1.2MM tons of carbon sequestered**
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

AEP's reductions/offsets of CO_2:
- **2003-2007: 39 MM Tons**

New Program Additions (by 2011)

- **1000 MWs of Wind PPAs: 2 MM tons/yr**
- **Domestic Offsets (methane/forestry): 2.5 MM tons/yr**
- **Fleet Vehicle/Aviation Offsets: 0.2 MM tons/yr**
- **Additional actions—energy efficiency and biomass: 0.3MM tons/yr**

New Technology Additions

- **New Generation - IGCC and USC**
- **Retrofit solutions for existing fleet**
  - Chilled Ammonia
  - Oxy-Coal

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/YEAR
Longer Term—New Technology

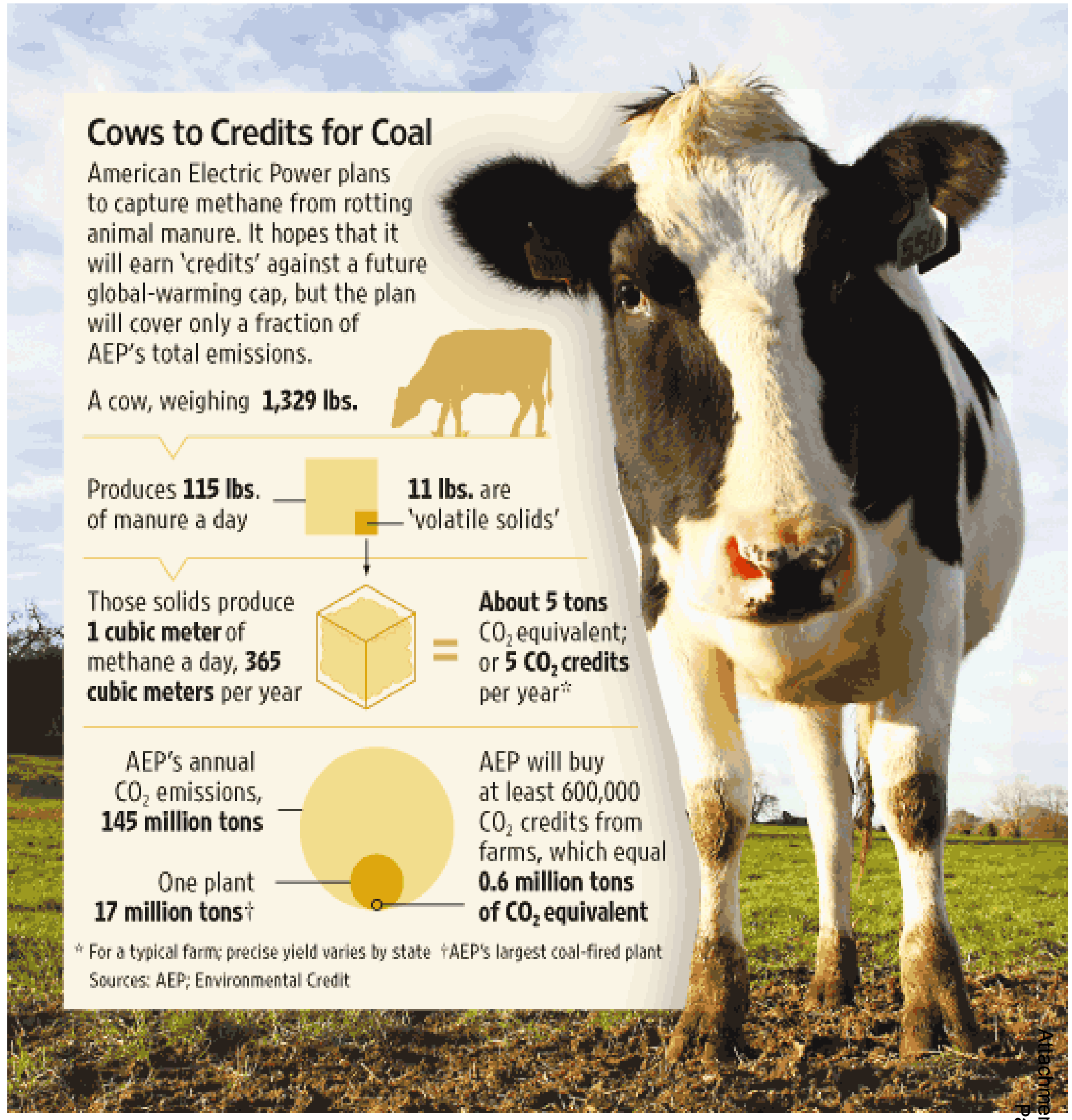
Off-System Reductions

New AEP Offset Commitment by 2011:

• 2.5 MM tons/year additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 0.6 MM Tons CO2e per year
  - 2010 through 2017
  - 51% of credits sourced from "AEP States"



Source: Wall Street Journal June 14, 2007

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

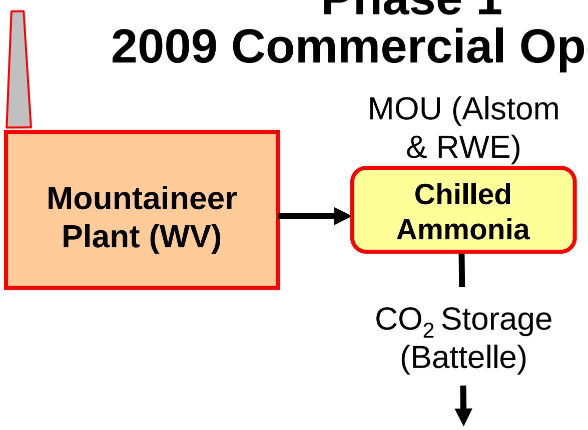
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

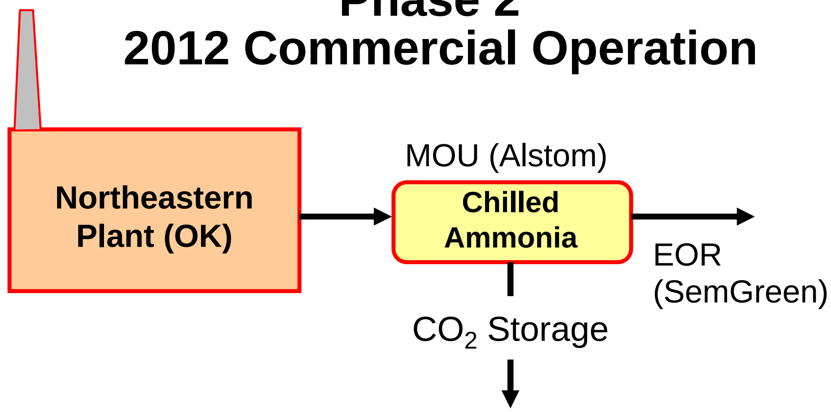
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **very** clean flue gas

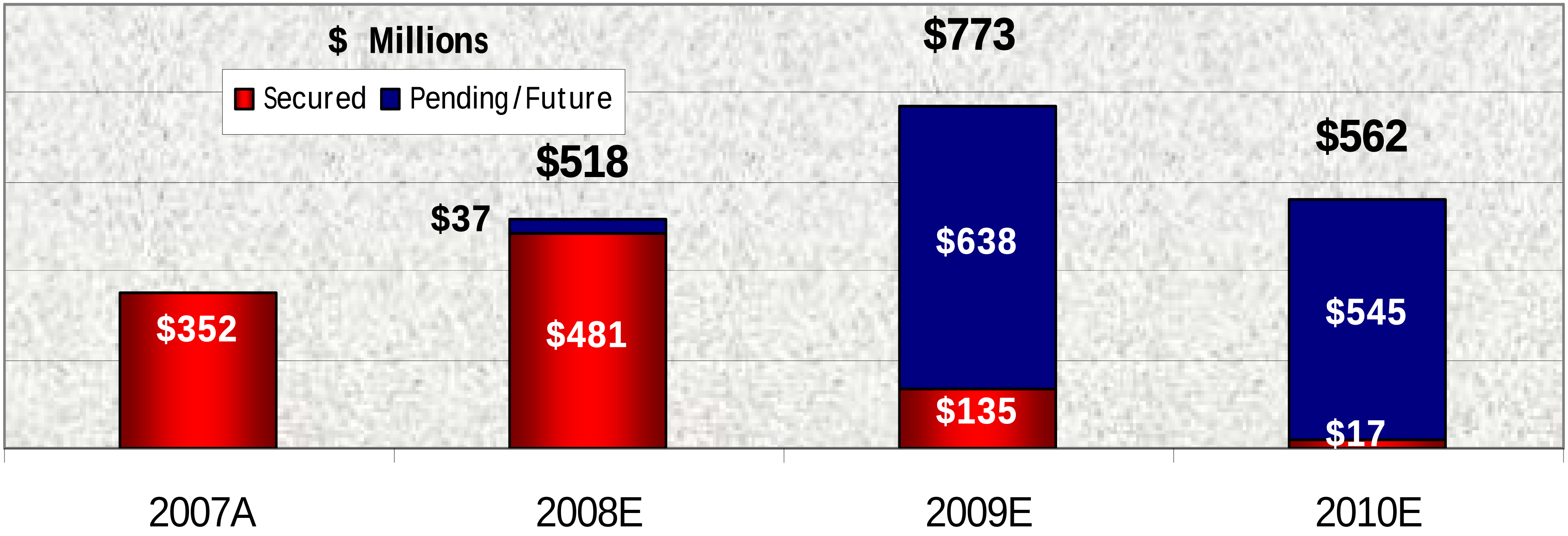
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Incremental Rate Relief

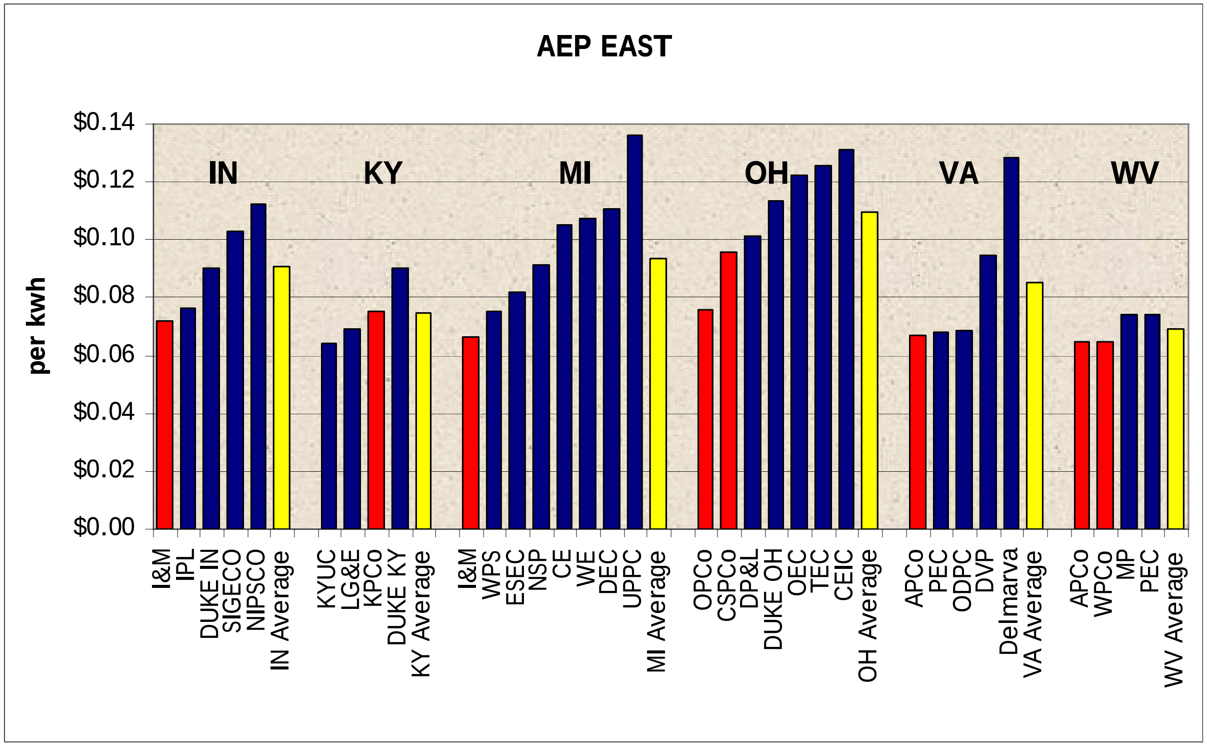


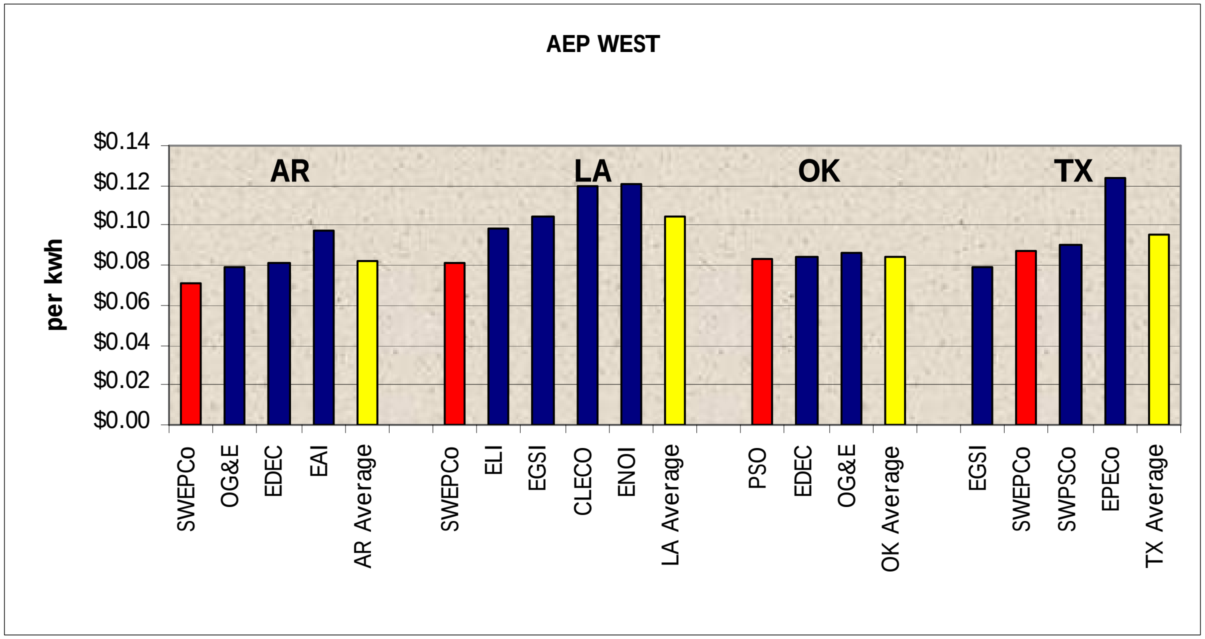
- **93% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan.**

- **2008 Pending: 2008 TCC/TNC TCRF filings, other cases yet to be filed including Virginia base case.**

Secured $481MM of $518MM for 2008

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas
  - IGCC

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC. A hearing is scheduled for May 12, 2008.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on 4/29/2008, and the SCC issued an order granting reconsideration on 4/30/2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearing is scheduled for May 29-30, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Operating Company Overview

AEP AMERICAN® ELECTRIC POWER

May 23, 2007
New York, NY

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$400-$500	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

MAINTAIN FINANCIAL STRENGTH OF UTILITY COMPANIES BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Figures exclude AFUDC.

Long-Term Debt Maturity Profile

($ in millions)

Year		2007		2008		2009
AEP Service Corp.	$	-	$	36	$	-
AEP, Inc.	$	345	$	-	$	-
AEG	$	-	$	-	$	-
APCo	$	325	$	200	$	150
CSPCo	$	-	$	112	$	-
KPCo	$	323	$	30	$	-
I&M	$	-	$	50	$	45
OPCo	$	-	$	45	$	106
PSO	$	-	$	-	$	50
SWEPCo	$	90	$	118	$	-
TCC	$	-	$	68	$	-
TNC *	$	8	$	-	$	-
Total	$	1,091	$	659	$	351

Note: Maturities remaining as of March 31, 2007

* - represents TNC first mortgage bonds that were defeased in December 2005

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS

Managing Subsidiary Cash Flows

- **We monitor:**
  - AEP consolidated cash requirements
  - Utility expected rates of return and potential regulatory lags
  - Amount of capital spending and internal cash needs
  - Free cash flow – cash available after construction
  - Credit ratios

- **Dividends and equity:**
  - We pay dividends based on free cash flow and credit metrics
  - When additional equity/cash is needed, the first option is dividend reductions, then capital infusions

OUR OBJECTIVE IS TO MAINTAIN THE FINANCIAL STRENGTH AND CAPITAL MARKETS ACCESS OF THE AEP OPERATING COMPANIES

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6107 of 9556

Debt Schedules – as of 3/31/07

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.102%		$1,077,775,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Pollution Control Bond	4.150%	07/01/2025	$22,500,000
Weighted Average or Total	4.150%		$45,000,000

Debt Schedules – as of 3/31/07

AEP®

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Preferred Stock	4.000%	N/A	$4,191,200
Preferred Stock	4.200%	N/A	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.895%		$688,687,300
Securitization Bond	5.010%	1/15/2008 **	$49,523,804
Securitization Bond	5.560%	1/15/2010 **	$107,094,258
Securitization Bond	5.960%	7/15/2013 **	$214,926,738
Securitization Bond	6.250%	1/15/2016 **	$191,856,858
Securitization Bond	4.980%	1/1/2010 **	$217,000,000
Securitization Bond	4.980%	7/1/2013 **	$341,000,000
Securitization Bond	5.090%	7/1/2015 **	$250,000,000
Securitization Bond	5.170%	1/1/2018 **	$437,000,000
Securitization Bond	5.306%	7/1/2020 **	$494,700,000
Weighted Average or Total	5.323%		$2,303,101,658

* TCC's First Mortgage Bond was defeased in May 2004

** represents scheduled final payment date, no ultimate maturity date

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond *	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	N/A	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

* TNC's First Mortgage Bond was defeased in December 2005

Debt Schedules – as of 3/31/07

AEP®

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	N/A	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	06/29/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.294%		$2,530,038,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Debt Schedules – as of 3/31/07

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	N/A	$5,535,700
Preferred Stock	4.120%	N/A	$1,105,500
Preferred Stock	4.560%	N/A	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.811%		$1,320,082,400

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Debt Schedules – as of 3/31/07

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$5,853,659
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	N/A	$1,459,500
Preferred Stock	4.200%	N/A	$2,282,400
Preferred Stock	4.400%	N/A	$3,148,200
Preferred Stock	4.500%	N/A	$9,737,300
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	5.863%		$2,216,836,059

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.000%	N/A	$4,454,800
Preferred Stock	4.240%	N/A	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Weighted Average or Total	5.498%		$676,621,700

Debt Schedules – as of 3/31/07

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$18,352,372
Notes Payable	Floating	06/30/2008	$3,750,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	N/A	$3,767,300
Preferred Stock	4.650%	N/A	$190,700
Preferred Stock	4.280%	N/A	$738,600
Senior Notes	5.380%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.535%		$926,536,972

AEP Texas Central Company

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

President and Chief Operating Officer: Charles Patton

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**630,000**
• **Commercial**	**102,000**
• **Industrial**	**5,000**
• **Other**	**1,000**
Total	**738,000**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

AEP Texas Central Company

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data (in thousands)

Revenue	$	665,000
% of AEP Retail		5%
Net Income (Loss)	$	42,000
Capital Expenditure	$	270,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,324,000
Net Plant Assets	$	2,240,000

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 241,000	$ 247,000	$ 222,100

AEP Texas North Company

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

President and Chief Operating Officer: Charles Patton

MAJOR CUSTOMERS:

Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

PRINCIPAL INDUSTRIES SERVED:

Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Total Customers: (Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**6,000**
Total	**189,000**

Generating Capacity	**377 MW**

Oklaunion Plant – Vernon, TX
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles	**4,500**
Distribution Miles	**14,000**

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data (in thousands)

Revenue	$	329,000
% of AEP Retail		1%
Net Income	$	15,000
Capital Expenditure	$	70,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	968,000
Net Plant Assets	$	842,000
Cash	$	84

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$143,000	$188,000	$149,000

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers:

• **Residential**	**810,000**
• **Commercial**	**128,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**949,000**

Generating Capacity **6,282 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **80.8%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas** **8.4%**

Transmission Miles **6,750**

Distribution Miles **49,000**

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Appalachian Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 7,016,000
Net Plant Assets	$ 5,524,000
Cash	$ 2,318

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 664,000	$ 531,000	$ 461,000

Appalachian Power

AEP®

APCo Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants

Name	Location	Megawatt Capacity	Fuel
Buck #1, 2, 3	Ivanhoe, Virginia	5	Hydro
Byllesby #1, 2, 3, 4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	528	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	28	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lyn #1, 2	Glen Lyn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	9	Hydro
Niagara #1, 2	Roanoke, Virginia	1	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2 *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	12	Hydro
Marmet #1, 2, 3	Marmet, West Virginia	11	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers:

• **Residential**	**662,000**
• **Commercial**	**76,000**
• **Industrial**	**4,000**
Total	**742,000**

Generating Cap	**3,708 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**63.2%**
• **Natural Gas**	**36.1%**
• **Hydro:**	**0.7%**

Transmission Miles	**2,400**
Distribution Miles	**17,200**

Columbus Southern Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data (in thousands)

Revenue	$ 1,807,000
% of AEP Retail	16%
Net Income	$ 185,000
Capital Expenditure	$ 307,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,521,000
Net Plant Assets	$ 2,725,000
Cash	$ 1,319

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 439,000	$ 354,000	$ 233,000

Columbus Southern Power

AEP®

Columbus Southern Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,254	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	26	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	857	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	480	Nat Gas

Columbus Southern Power

AEP

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**72.87**
AEP (CSP)	**92.05**
DP&L	97.79
Duke Ohio (CG&E)	98.10
FE (Ohio Edison)	121.67
FE (Toledo Edison)	124.38
FE (CEI)	129.86

**** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

Indiana Michigan Power

President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

Total Customers:	
• **Residential**	**508,000**
• **Commercial**	**67,000**
• **Industrial**	**5,000**
• **Other**	**<u>2,000</u>**
Total	**582,000**
Generating Capacity	**5,753 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.2%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana Michigan Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data (in thousands)

Revenue	$	1,977,000
% of AEP Retail		12%
Net Income	$	121,000
Capital Expenditure	$	325,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	5,546,000
Net Plant Assets	$	3,313,000
Cash	$	1,369

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 252,000	$ 264,000	$ 294,000

Indiana Michigan Power

AEP®

I&M Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	5	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	2	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	2	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	1	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

AEP®

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I&M	**453,788**
IP & L	462,837
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECO	144,632

Michigan	Customers
I&M	**125,588**
Consumers Energy	1,779,184
Detroit Edison	2,156,214

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Indiana	
I & M	**69.27**
IP & L	78.91
Duke Indiana (PSI)	89.99
SIGECo	88.67

Michigan	
I & M	**65.02**
Consumers Energy	102.36
Detroit Edison	112.19

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**

Generating Capacity	**1,060 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**1,200**
Distribution Miles	**9,700**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data (in thousands)

Revenue	$	586,000
% of AEP Retail		4%
Net Income	$	35,000
Capital Expenditure	$	78,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	1,311,000
Net Plant Assets	$	1,002,000
Cash	$	702

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 70,000	$ 114,000	$ 100,000

Kentucky Power

AEP®

Kentucky Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

AEP®

KENTUCKY UTILITIES *

Kentucky	Customers
KPCo	175,255
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	59.91
LG&E	65.43
Duke Kentucky	65.89
KPCo	75.63

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Total Customers:

• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**
Generating Capacity	**8,498 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**99.9%**
• **Hydro:**	**0.1%**
Transmission Miles	**6,500**
Distribution Miles	**26,200**

Ohio Power

AEP®

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data (in thousands)

Revenue	$	2,725,000
% of AEP Retail		16%
Net Income	$	229,000
Capital Expenditure	$	1,000,000

2006 Asset Data (in thousands)

	As of 12/31/06	
Total Assets	$	6,819,000
Net Plant Assets	$	5,569,000
Cash	$	1,625

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 832,000	$ 368,000	$ 389,000

Ohio Power

Ohio Power Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak – August 2^{nd}	5,260 MW

Ohio Power Plants

Name	Location	Megawatt Capacity	Fuel
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	26	Hydro

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Ohio Power

AEP®

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**72.87**
AEP (CSP)	**92.05**
DP&L	97.79
Duke Ohio (CG&E)	98.10
FE (Ohio Edison)	121.67
FE (Toledo Edison)	124.38
FE (CEI)	129.86

**** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers:

• **Residential**	**447,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**8,000**
Total	**520,000**

Generating Capacity	**4,219 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**25%**
• **Natural Gas:**	**75%**
Transmission Miles	**3,600**
Distribution Miles	**21,200**

Public Service Company of Oklahoma

AEP®

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data (in thousands)

Revenue	$ 1,442,000
% of AEP Retail	14%
Net Income	$ 37,000
Capital Expenditure	$ 240,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 2,579,000
Net Plant Assets	$ 1,999,000
Cash	$ 1,651

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 319,000	$ 330,000	$ 466,000

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants

Name	Location	Megawatt Capacity	Fuel
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

AEP®

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	511,924
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	79.04
SPSCo	82.19
PSO	83.24
OG&E	89.96

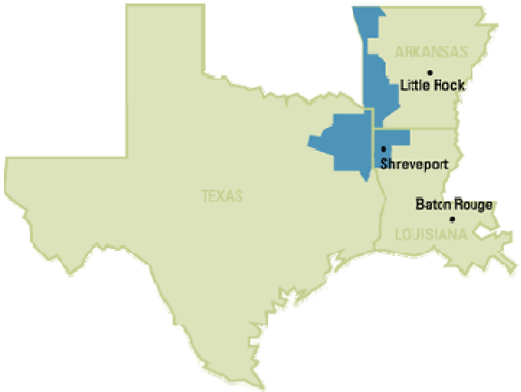
** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.

- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

Total Customers:

• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**<u>1,000</u>**
Total	**456,000**

Generating Capacity	**4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite: 60%**
- **Natural Gas: 40%**

Transmission Miles	**3,500**
Distribution Miles	**19,300**

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data (in thousands)

Revenue	$ 1,432,000
% of AEP Retail	11%
Net Income	$ 92,000
Capital Expenditure	$ 323,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,191,000
Net Plant Assets	$ 2,494,000
Cash	$ 2,618

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 537,000	$ 605,000	$ 540,000

Southwestern Electric Power

AEP®

Southwestern Electric Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

AEP®

SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	109,760
Entergy AR	672,890

Louisiana	Customers
SWEPCo	171,564
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	166,906
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	80.14
Empire District	91.66
OG&E	92.72
ETR	102.77

Louisiana	
SWEPCo	79.11
Entergy LA	92.17
Entergy Gulf St	104.81
Entergy NO	117.92
CLECO	121.25

Texas	
SPSCo	88.55
SWEPCo	93.56
ETR	120.27
EP	133.32
TXU	153.73

** Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2006 Typical Bills and Average Rates Report as of July 1, 2006.

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

AEP AMERICAN ELECTRIC POWER

Presentation to

PHILADELPHIA SECURITIES ASSOCIATION

established 1929

August 5, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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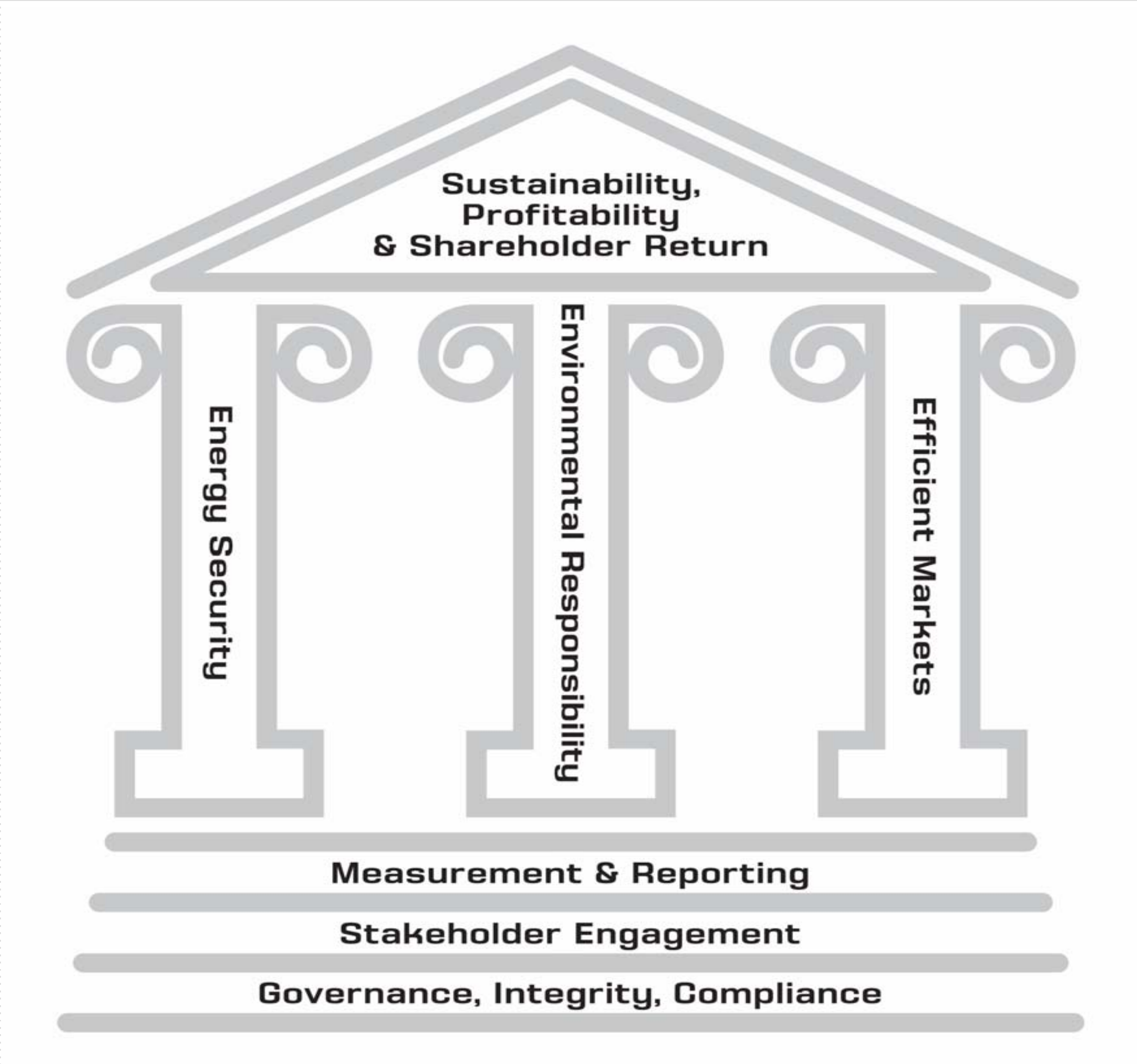
AEP's Vision for Sustainability



AEP's programs for Environmental, Advanced Generation, Carbon Capture and Storage, Transmission, Renewable Resources and gridSMART℠ underpin the three pillars supporting sustainability and profitability.

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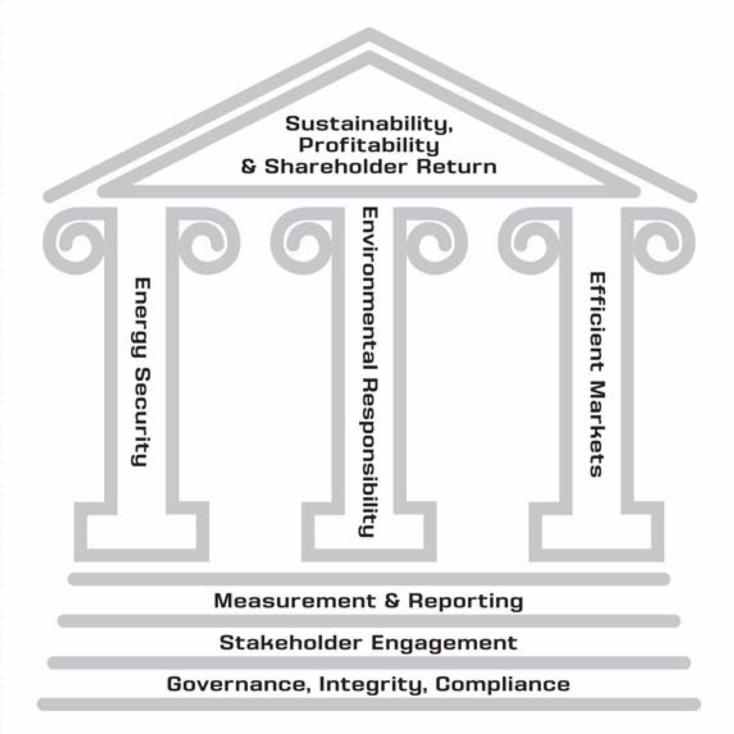
Environmental Program



Energy Security:

- Environmental retrofits keep coal plants viable in order to take advantage of vast domestic fuel resources

Environmental Responsibility:

- Scrubbers and SCRs reduce emissions of SO_2, NOx and Mercury

Efficient Markets:

- Environmental technology installed on existing plants delays the premature retirement of those plants, thereby keeping low cost generation assets available to the market

$5.4B Environmental Retrofits

$3.5B Completed = **$0.37** annual EPS

$1.9B Under Construction =

$0.20 annual EPS in 2011

Note: EPS calculations assume timely regulatory recovery with a 10.5% ROE and a 60/40 debt to capital ratio

Advanced Generation & Carbon Capture and Storage

Energy Security:

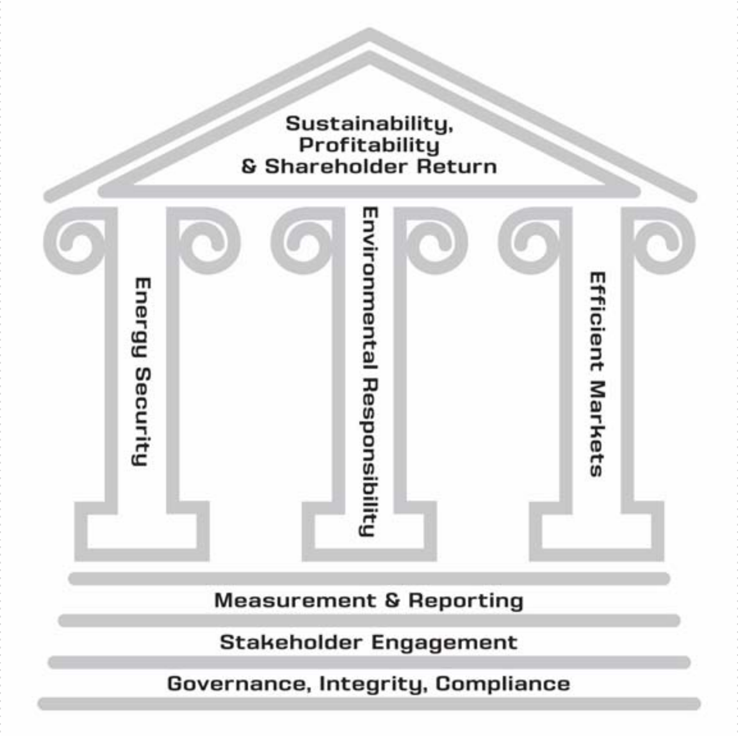
- New state-of-the-art coal plants and solutions for retrofitting current coal plants to capture and store CO_2 will ensure domestic fuel resources are utilized to the fullest potential

Environmental Responsibility:

- USC technology burns less fuel, thereby creating fewer emissions.
- Carbon capture and storage advancement will help find a solution to reduce carbon emissions in the future.

Efficient Markets:

- New baseload coal plants allow lower cost generation to enter the market
- Understanding the price of CCS will lead to a sensible solution that will ensure coal plants remain economically viable



NEW ADVANCED GENERATION

USC -- AEP will be the first company to employ a new generation ultra-supercritical (steam temperatures >1100ºF) coal plant in the U.S. (Arkansas)

Transmission and Renewable Resources

Energy Security:

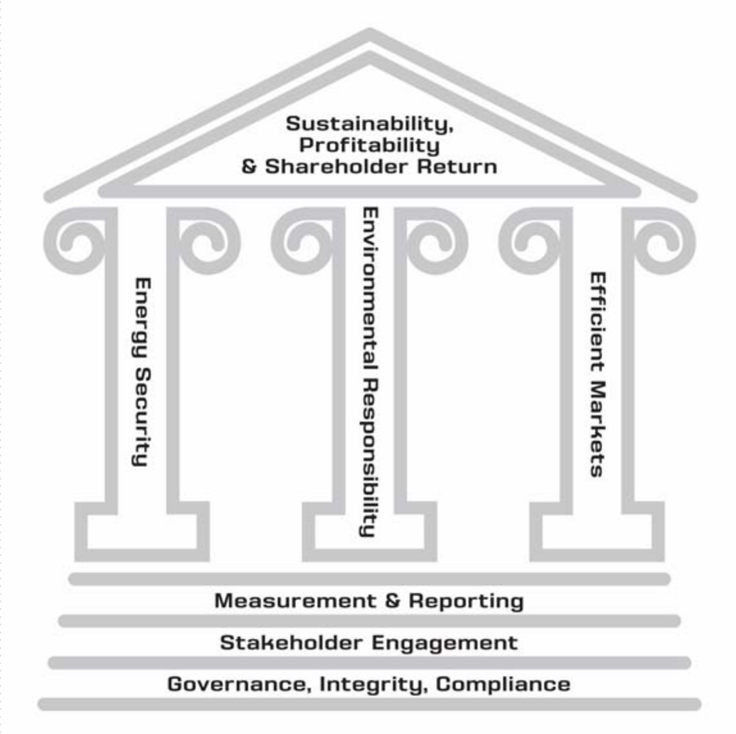
- Improved reliability, increased usage of renewable resources and enhanced fuel diversity allows the U.S. to strengthen its energy security

Environmental Responsibility:

- Availability of increased renewable generation resources through transmission investment acts as an alternative path to reduce emissions and could potentially offset the future need for polluting generation sources

Efficient Markets:

- Enhanced transmission infrastructure within RTOs allows energy markets to operate more efficiently by increasing reliability while at the same time reducing congestion
- New transmission ensures that the most economical generation serves as many people as possible



$2.0B Transmission Investment in Existing Assets and New Joint Ventures 2008 - 2010 =

$0.21 annual EPS in 2011

Note: EPS calculation assumes timely regulatory recovery with a 10.5% ROE and a 60/40 debt to capital ratio

By leveraging existing assets, expertise and leadership, AEP will enhance shareholder value by creating a significant new transmission investment opportunity.

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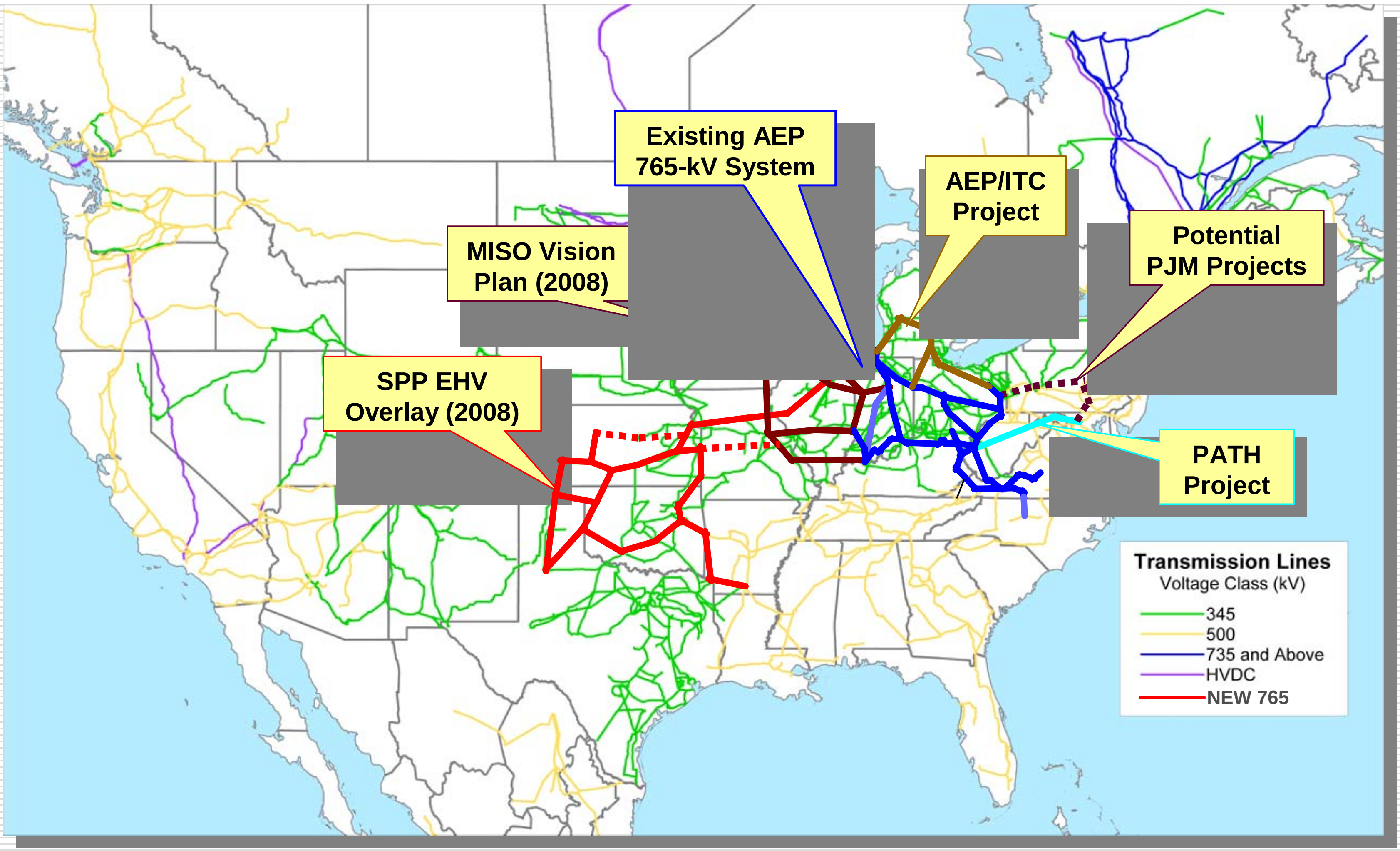
Transmission & Renewable Resources

Our Goal: Contribute sustainable shareholder growth by leveraging AEP's position as the nation's leading transmission provider to become the nation's leading developer and owner of interstate transmission investment.



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

AEP is advancing the development of a national transmission interstate.

gridSMART[SM]

Energy Security:

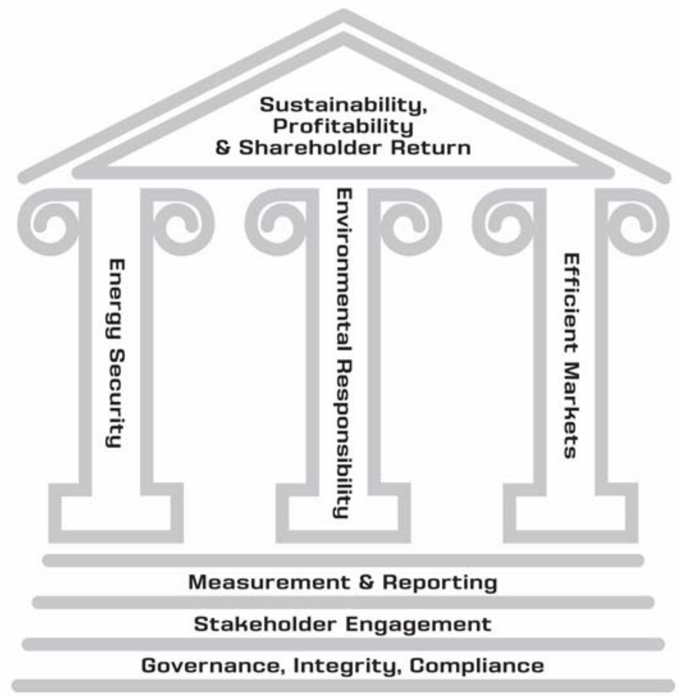
- More efficient operations mean reduced fuel consumption and reduced reliance on imported fuels

Environmental Responsibility:

- Efficiency improvements can help reduce the need for the fuels used to generate electricity, which translates directly into lower emissions and a cleaner environment
- Energy use reduction through energy efficiency and demand-side management options could ultimately delay the need for new or replacement power generating equipment

Efficient Markets:

- Peak demand adjustments (the maximum amount of energy used at any one time) allow AEP to make more efficient use of its existing facilities



$1.5B+ gridSMART technology

through 2015 =

$0.16 annual EPS in 2016

Pilot program underway in Indiana

Note: EPS calculation assumes timely regulatory recovery with a 10.5% ROE and a 60/40 debt to capital ratio

Increased efficiency reduces costs and emissions. It also delays the need for new generation sources.

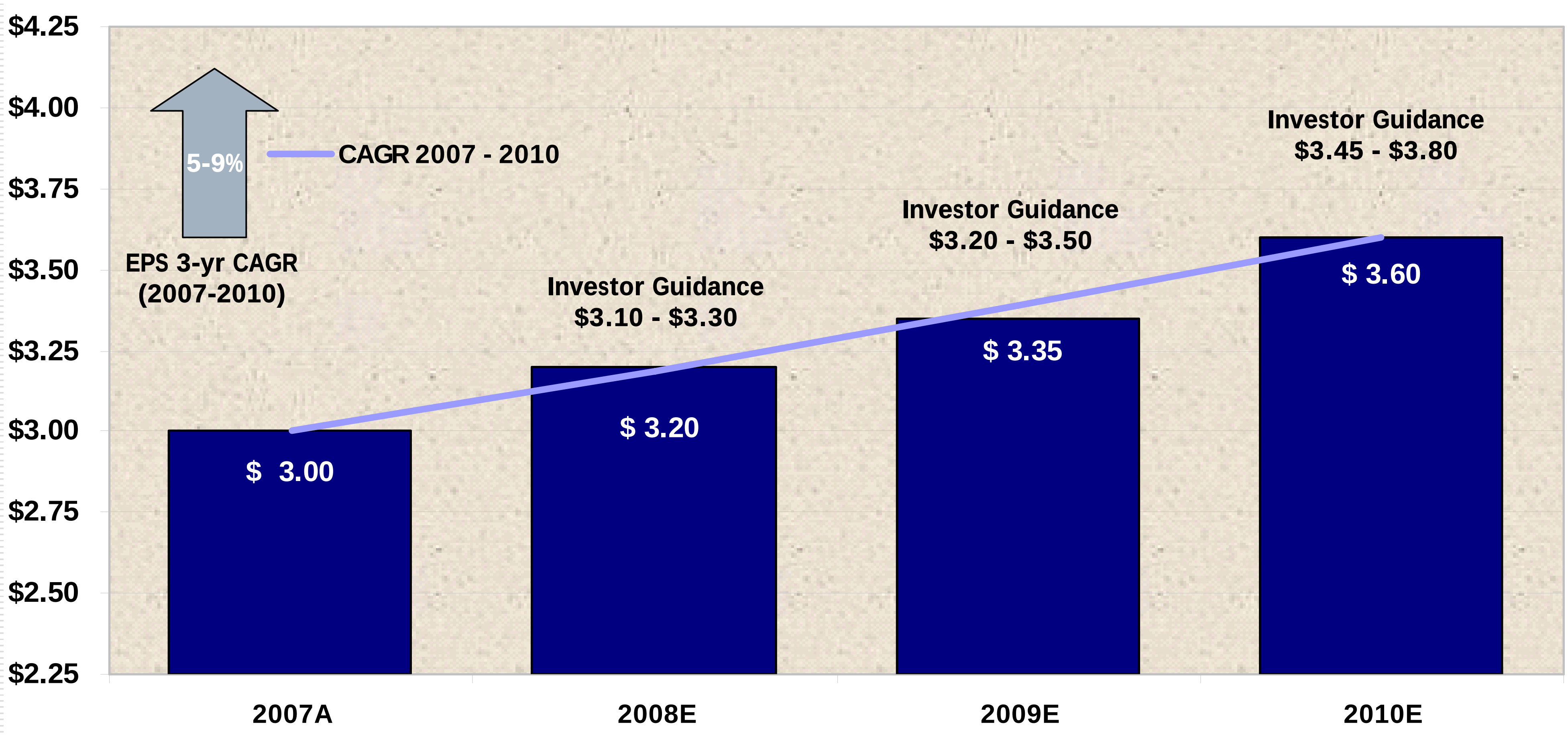
Policy Initiatives

AEP is heavily involved in shaping public policy, including:

- Federal Carbon Policy
    - The Low Carbon Economy Act of 2007
- Federal and state Carbon Capture and Storage Policies
    - The Carbon Capture and Storage Early Development Act
    - CCS framework development in WV and OK
- Federal and state Renewable Portfolio Standards
- Advanced Distribution Infrastructure and Demand-Reduction Programs in all jurisdictions (gridSMART)
- Federal and state Energy Policy

Through the shaping of federal and state public policy, AEP is balancing the need for energy security, environmental responsibility and efficient markets.

The AEP Value Proposition



AEP's leadership role in ensuring a balanced approach to energy security, environmental responsibility and efficient markets allows us to sustainably grow earnings and shareholder value.

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Questions

Appendix

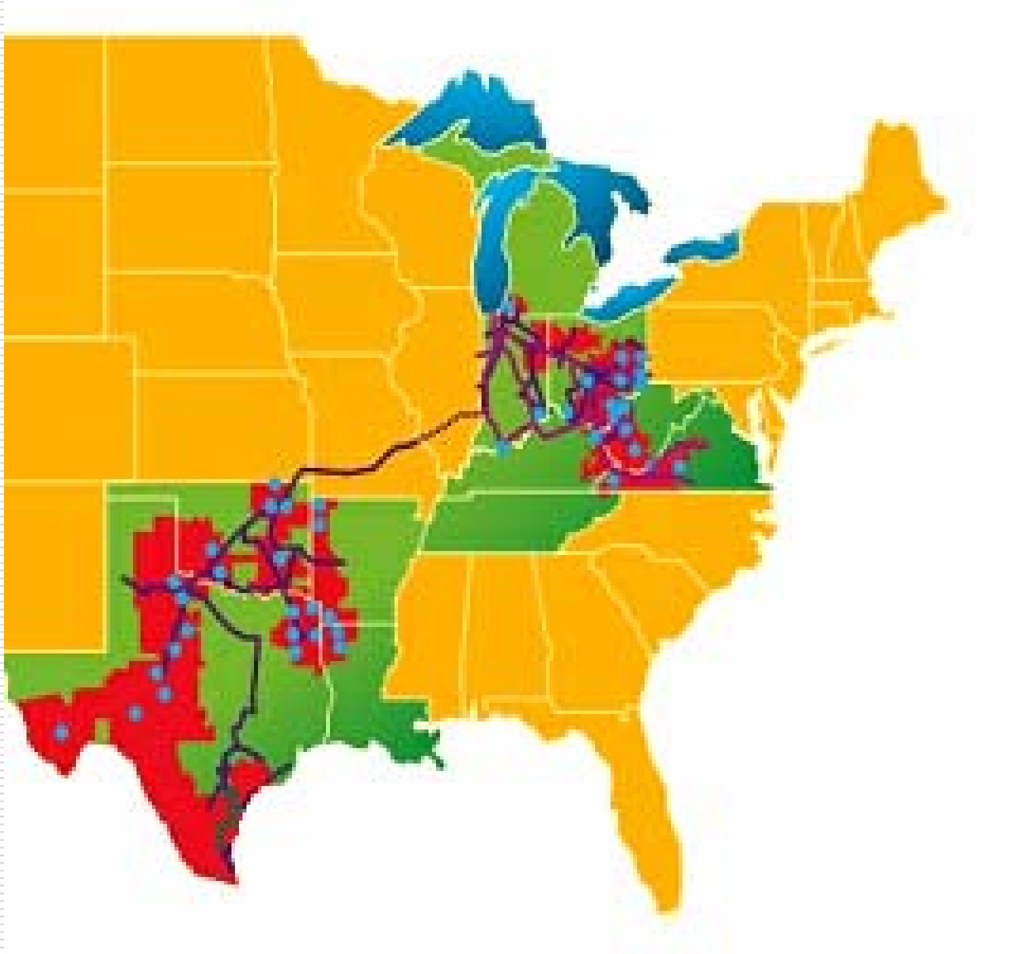
Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,900 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- 2007 financial statistics:
  - GAAP Net Income: $1.1B
    - 87% Regulated/13% Nonregulated
  - Assets: $40.3B
  - Adjusted Equity Ratio: 41.5%
- Current dividend - $1.64 per share annualized



AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent 6-8% long-term rate through major regulated investment using disciplined capital allocation methods.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest $3.8 billion in our infrastructure
- Enhance cash flow & earnings through rate recovery mechanisms

Disciplined capital investment opportunities support earnings growth.

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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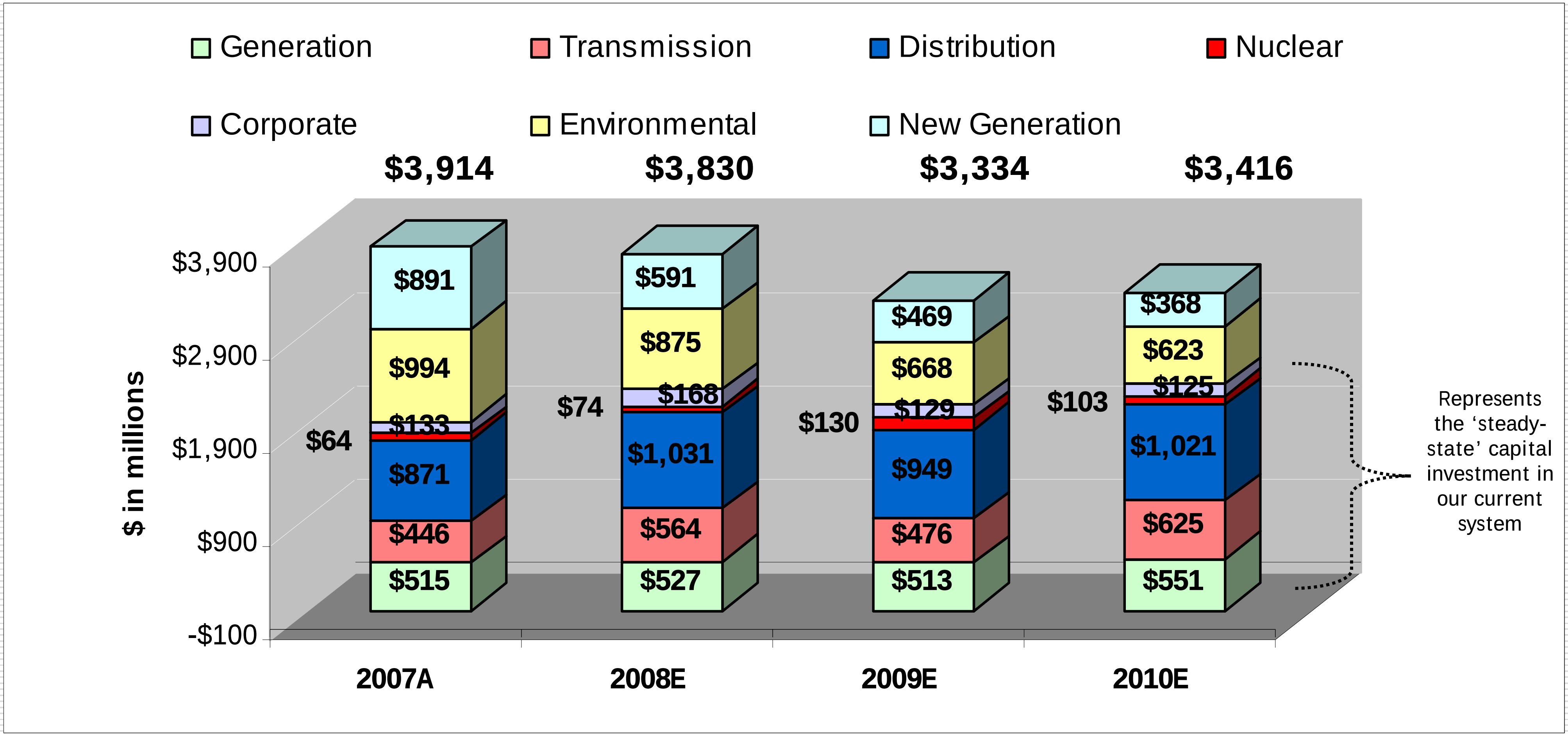
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6160 of 9556

4-Year Capital Investment Forecast



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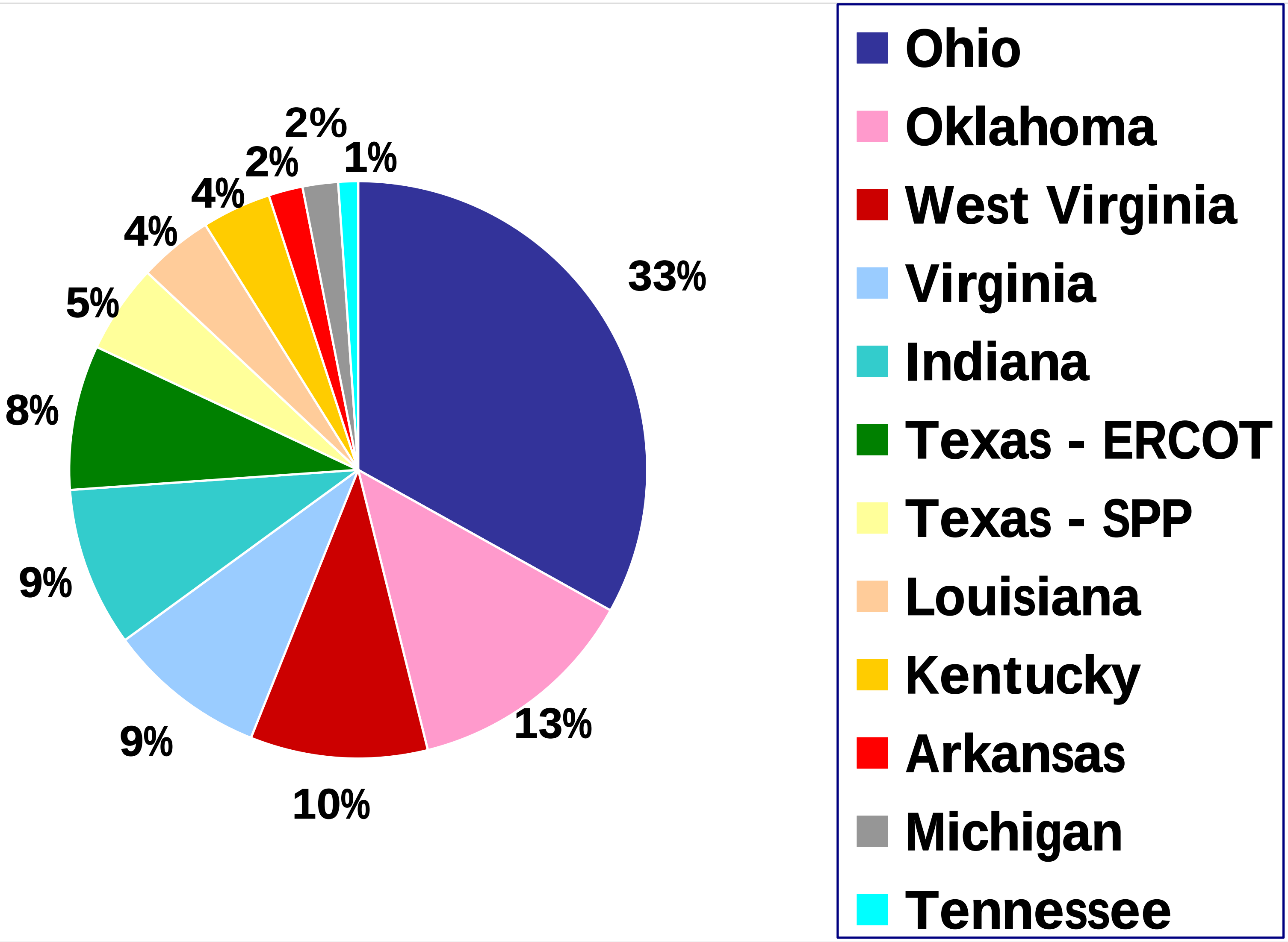
p.17

2007 Retail Revenue

Retail Revenue Composition by Jurisdiction



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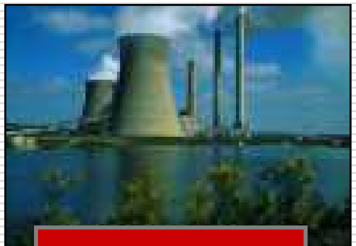
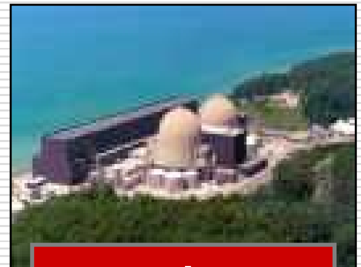
Jurisdictional diversity allows us to successfully manage regulatory risk.

Domestic Generation Fleet

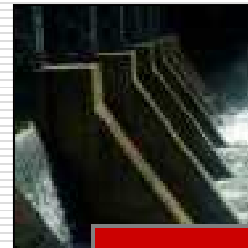


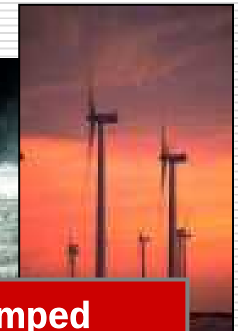
Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%





Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,866 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

NERC Regional Presence

RFC	72%
SPP	23%
ERCOT	5%

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2006	82.62%	60.06%
2007	81.84%	59.54%

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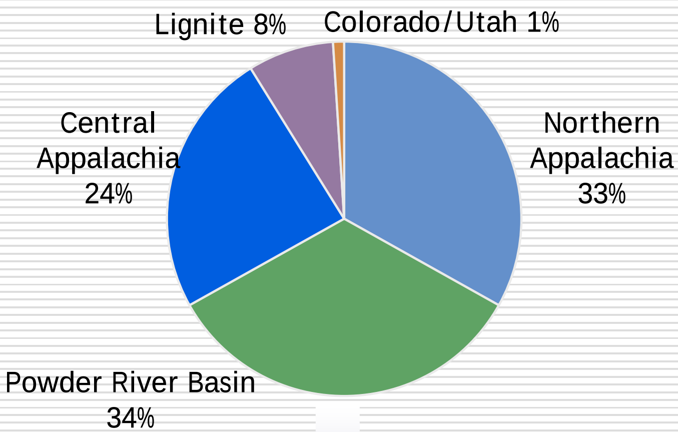
Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

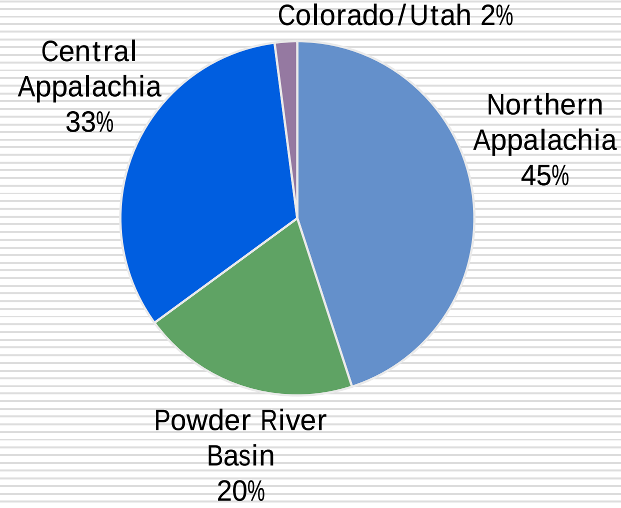
Total AEP System



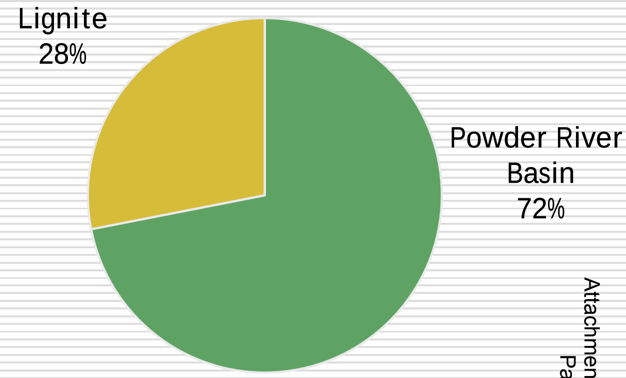
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East

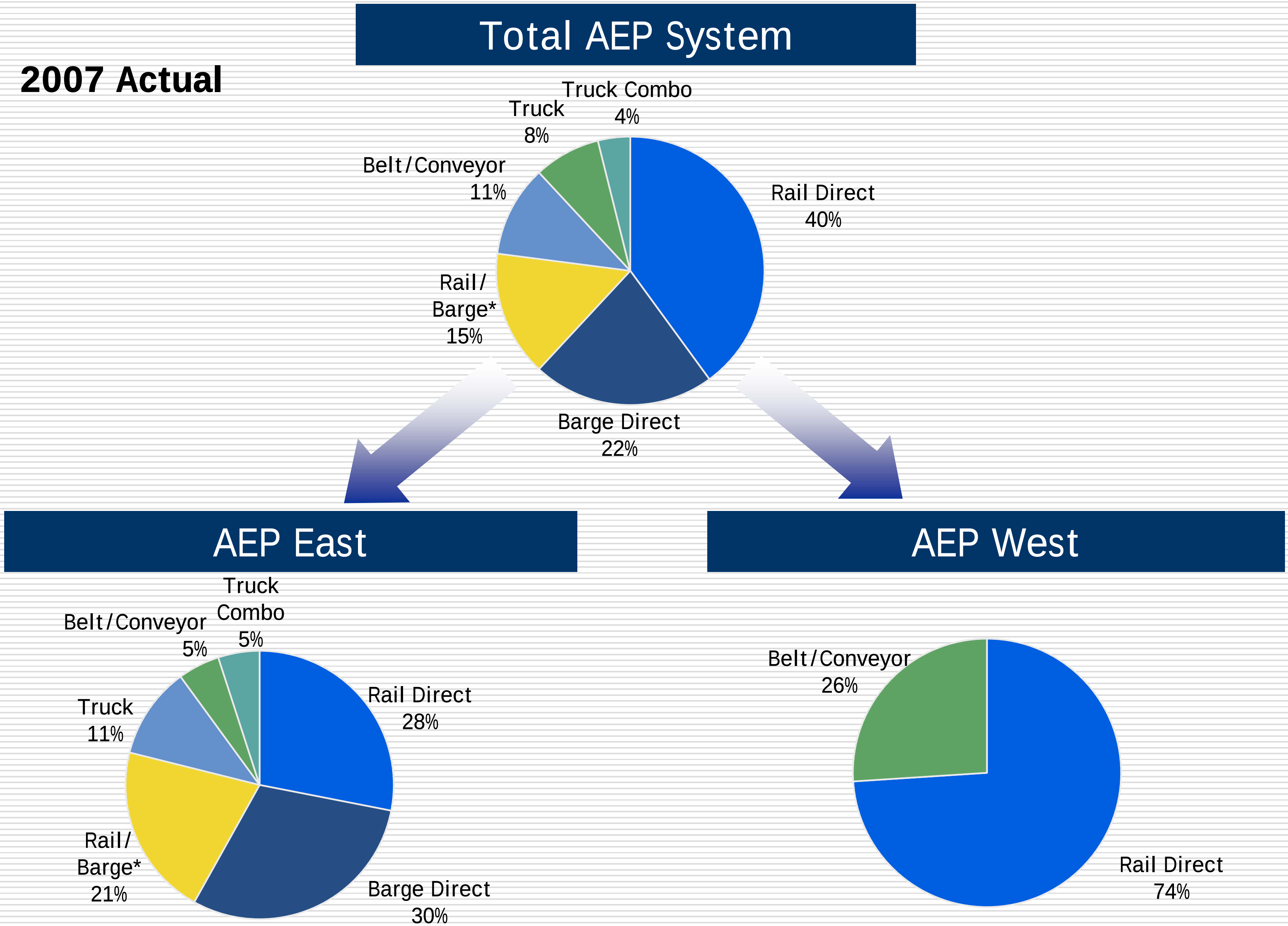


AEP West



Coal Delivery

2007 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

gridSMART^SM

gridSMART^SM: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

Technology	2008	2009	2010
Metering & Communications	$ 5	$ 65	$132
Distribution Technology Enhancements	$28	$117	$179

* $387MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $526MM capital investment by 2010, subject to regulatory approval.

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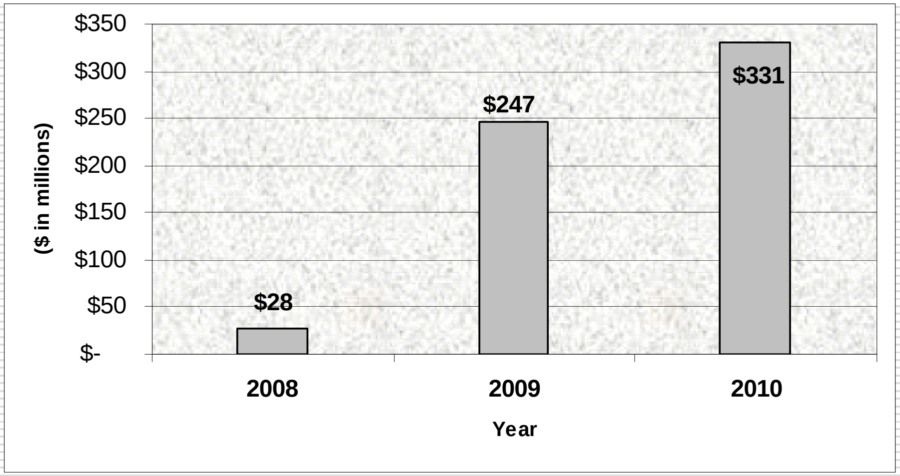
Transmission – Investments and Earnings Contributions

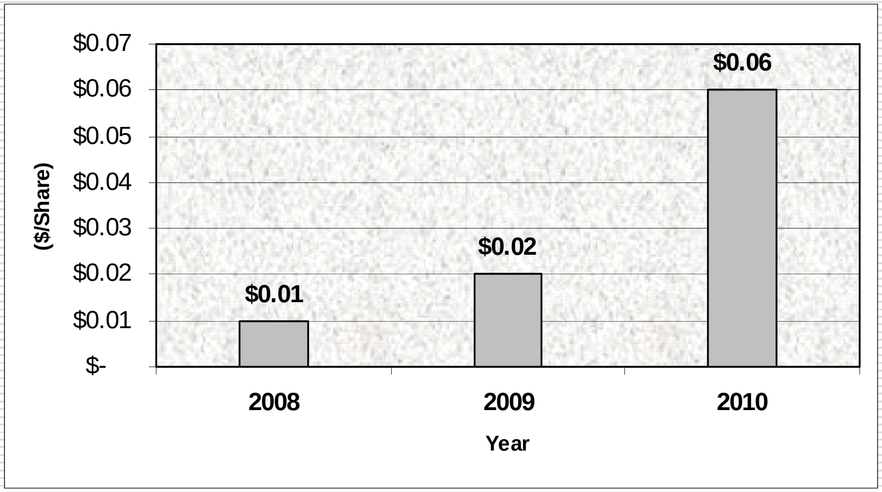
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



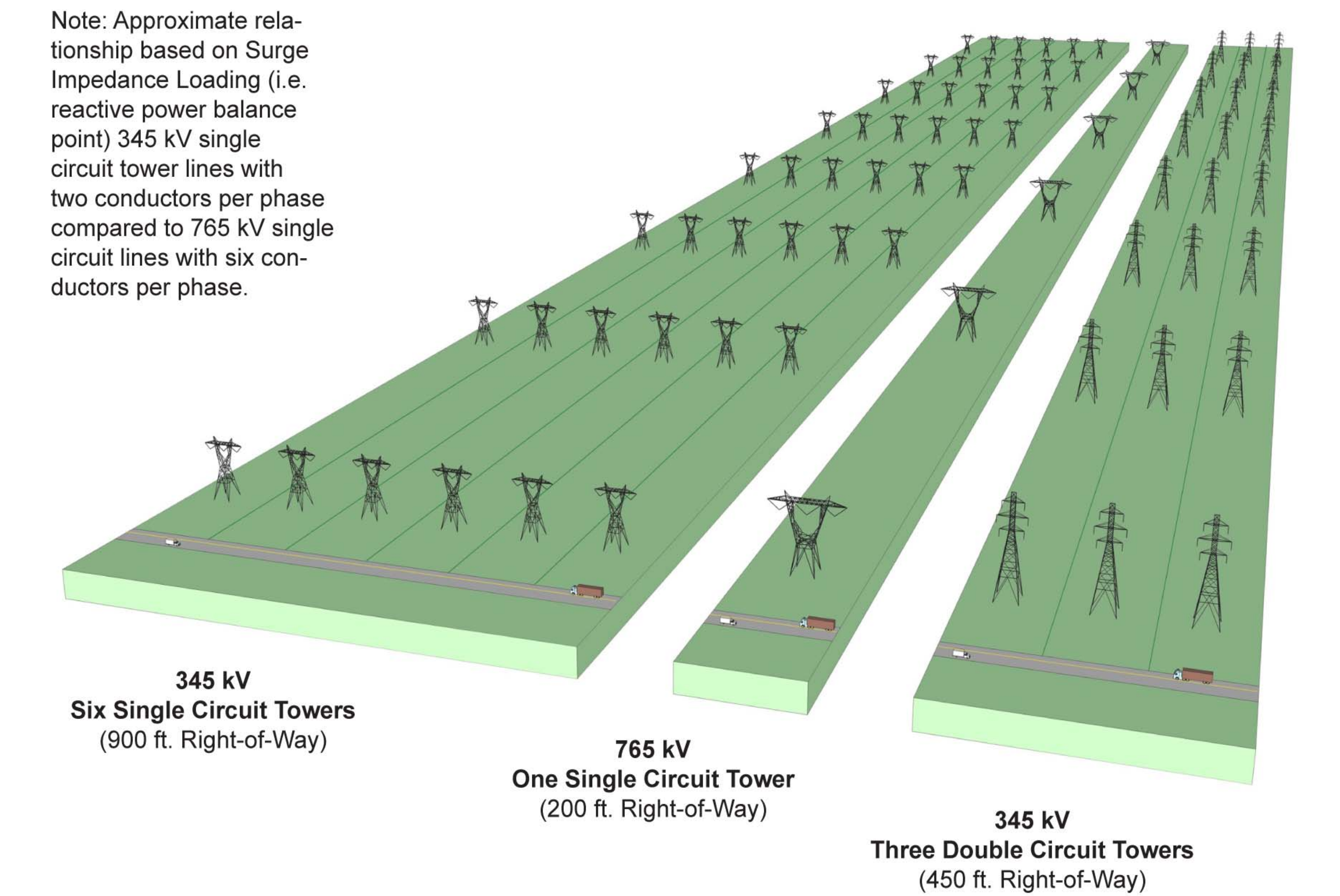
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PATH Potomac-Appalachian Transmission Highline

Transmission will provide a near and long term catalyst for growth.

AEP®

765 Right-of-Way Comparison



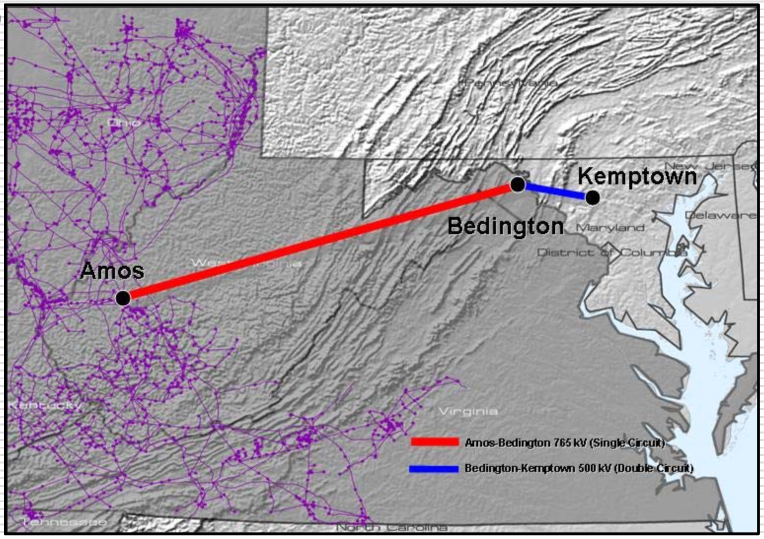
From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

AEP®

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

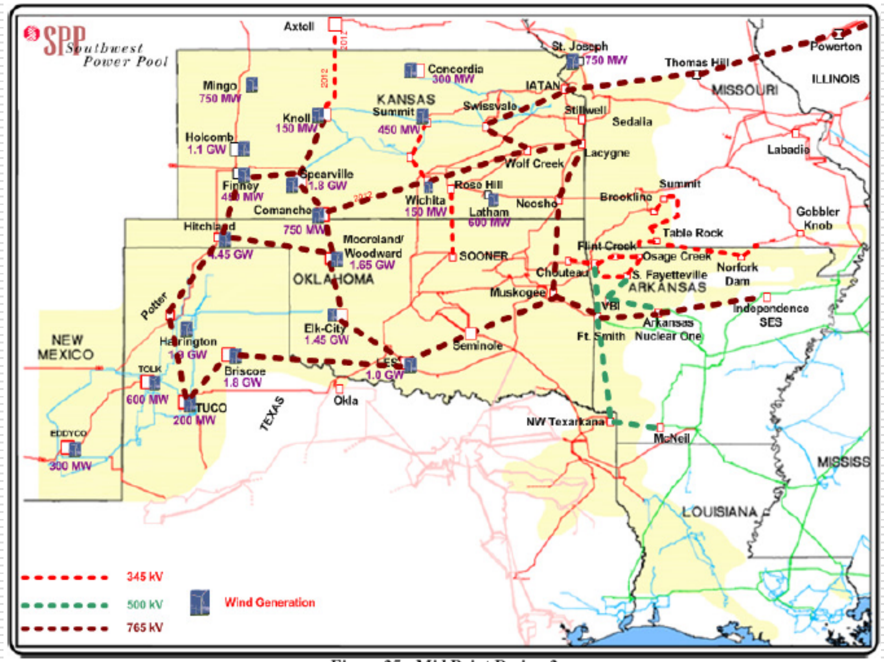


Figure 25: Mid Point Design 2

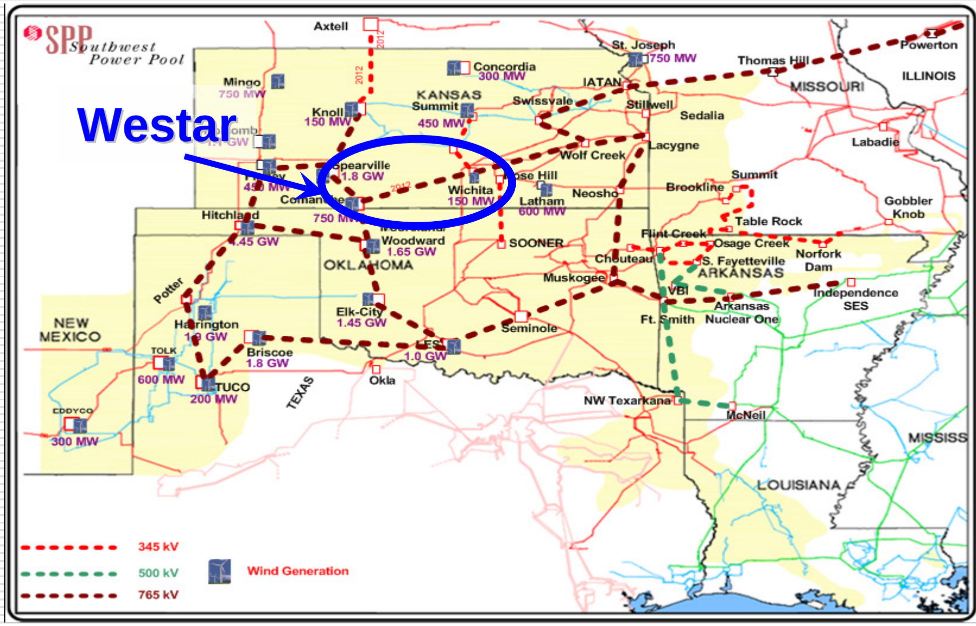
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



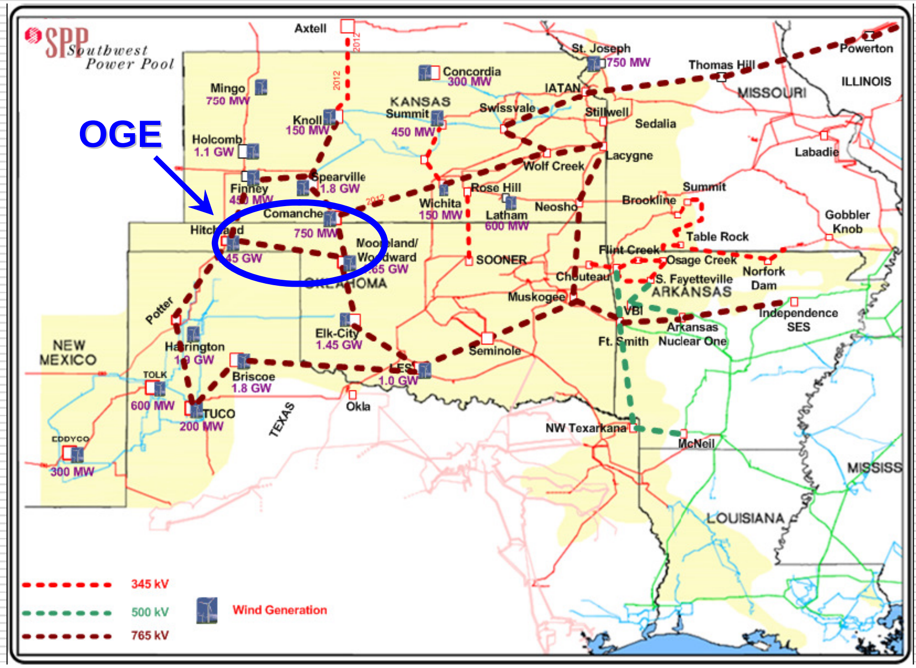
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Horizon Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- *Overview*
  - On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form Horizon Transmission, LLC (Horizon)
  - Horizon is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

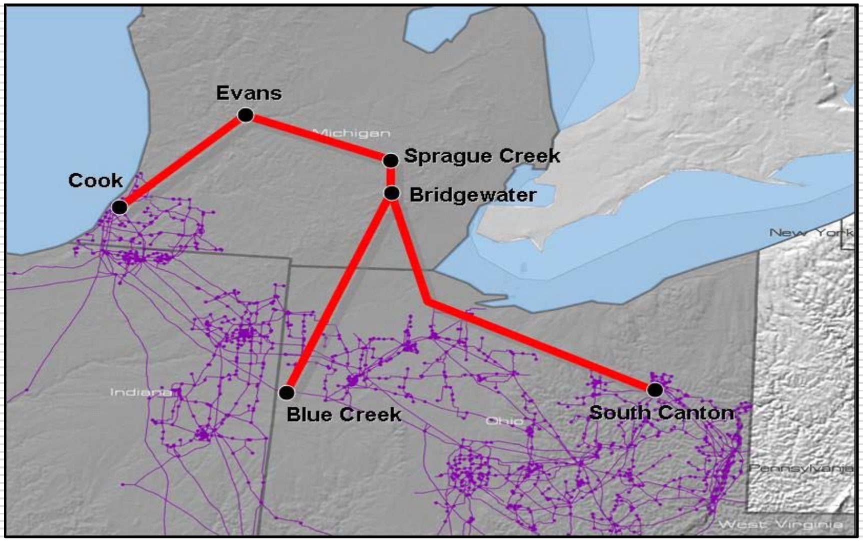
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP®

I-765TM Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer Plant in West Virginia

$ in millions			
	2008	**2009**	**2010**
Mountaineer Chilled Ammonia Project	**$33**	**$40**	**$0**

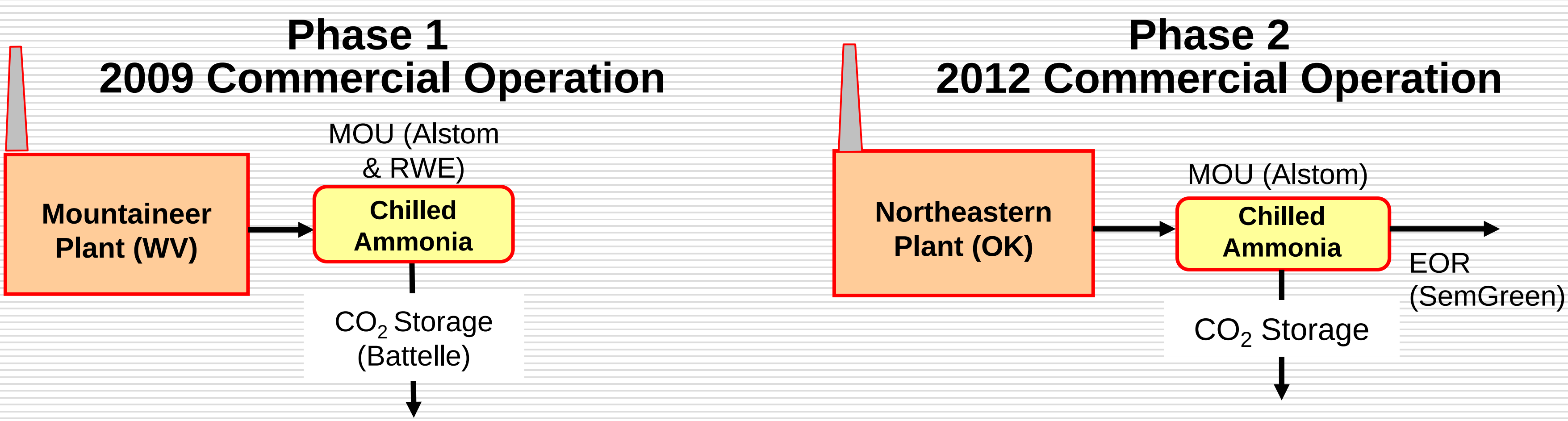
Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP's Carbon Capture & Storage Initiative

- **In March 2007, AEP announced a major new carbon capture and storage initiative**
- **Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.**
  - **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
  - **The second, at the Northeastern plant in Oklahoma *, will begin commercial operation in 2012.**



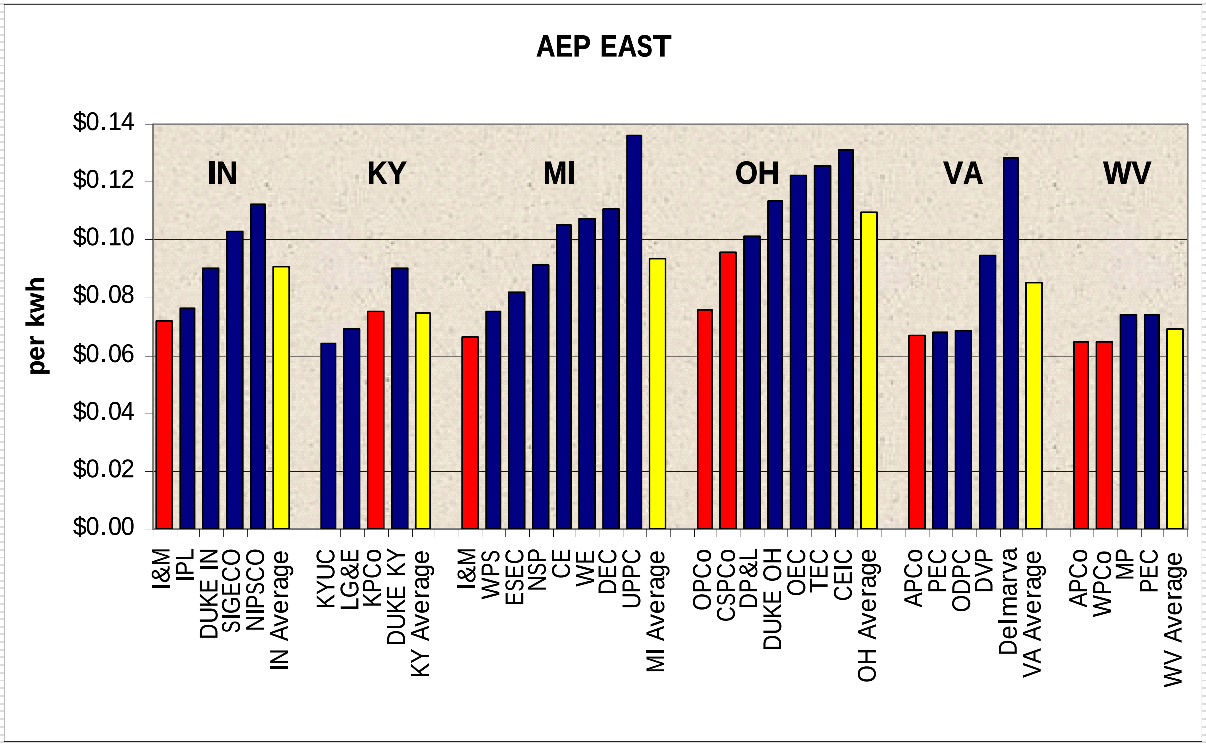
* - the second project is dependent upon the results of the validation phase at the Mountaineer plant as well as favorable regulatory treatment

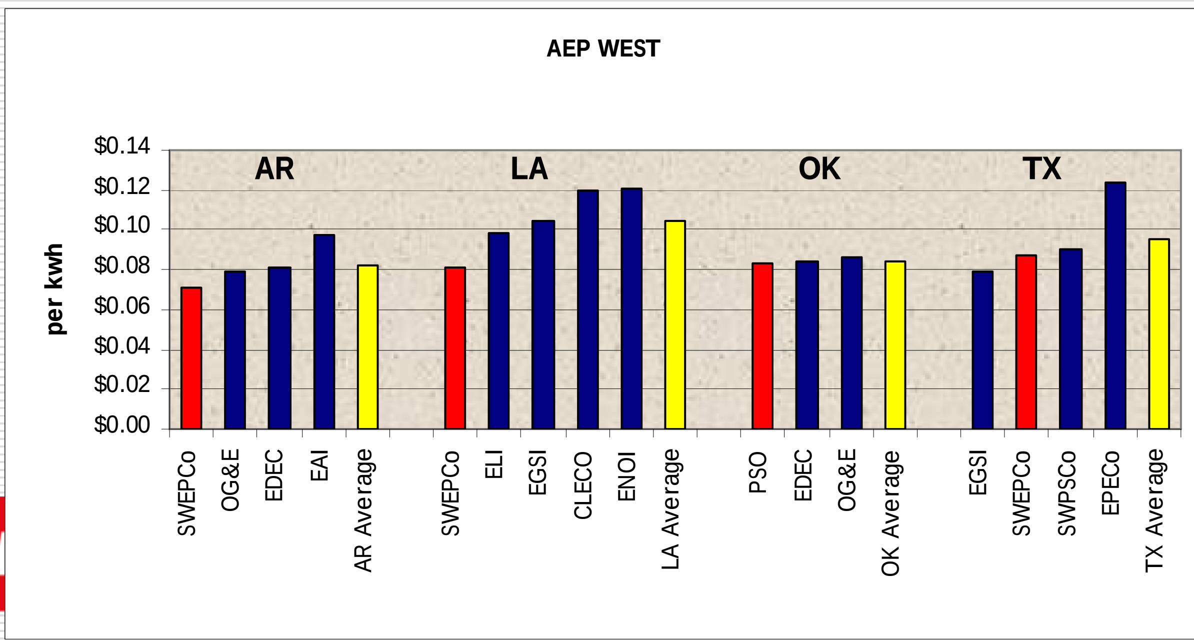
AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

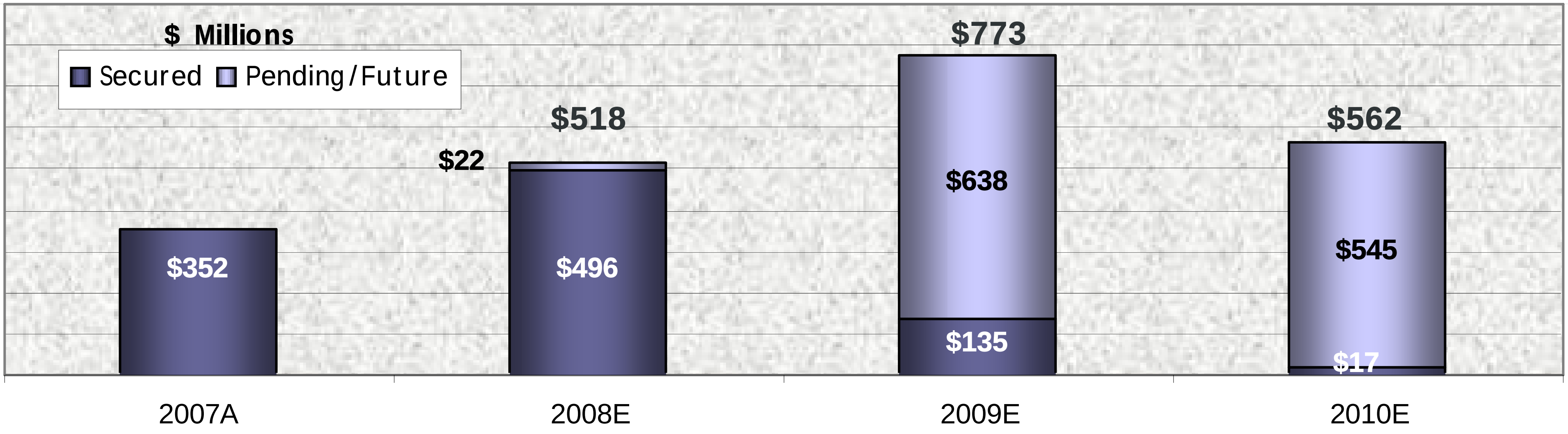
AEP Company

Other Company within state

State Average

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6179 of 9556

Incremental Rate Relief



- **96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Construction Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.**

- **2008 Pending: 2008 TCC/TNC TCRF filings, Virginia base case rates subject to refund ($208MM requested).**

- **2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM requested), Ohio ESP, other cases yet to be filed.**

Secured $496MM of $518MM for 2008

AEP®

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- New Generation:
  - SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval

AEP®

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- New Generation:
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order						Expected Order						

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing						12/1/08						
Expected Order												Expected Order
Louisiana - Stall Plant		Expected Order										
Ohio - ESP Filing	07/31/08					Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Rates Effective *							01/08/09					
Remaining Procedural Schedule Pending OCC Order												

* Subject to refund, with interest

Regulatory Activity Underway

AEP Ohio Electric Security Plan Filing

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates
- We anticipate an order at the end of 2008

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

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Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure – Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Required Rate Relief – Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Procedural Schedule

July 11, 2008	Case filed
November 3, 2008	Staff and intervenor testimony
November 24, 2008	PSO rebuttal testimony
December 8, 2008	Hearings commence
January 8, 2009	Interim rates effective, subject to refund
1st Quarter 2009	Final order

NOTE: THE ABOVE DATA IS AN ESTIMATE PREPARED BY PSO; NO PROCEDURAL SCHEDULE HAS BEEN ORDERED BY THE OCC YET

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure – Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Required Rate Relief – Company Position (12/31/07)

($ in millions)

Rate Base	$ 2,415.1	*
Rate of Return	8.52%	
Operating Income Requirement	$ 205.7	
Adjusted Operating Income	$ 79.2	
Difference	$ 126.5	
Revenue Conversion Factor	1.64	
Total Required Rate Relief	$ 207.9	

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony is due August 13, Staff testimony is due August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$507MM and the new revenue requirement requested is \$606MM. Approximately \$31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the second half of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT verbally approved construction of the plant on July 3, 2008. A written order is pending.

AEP®

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

AEP®

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

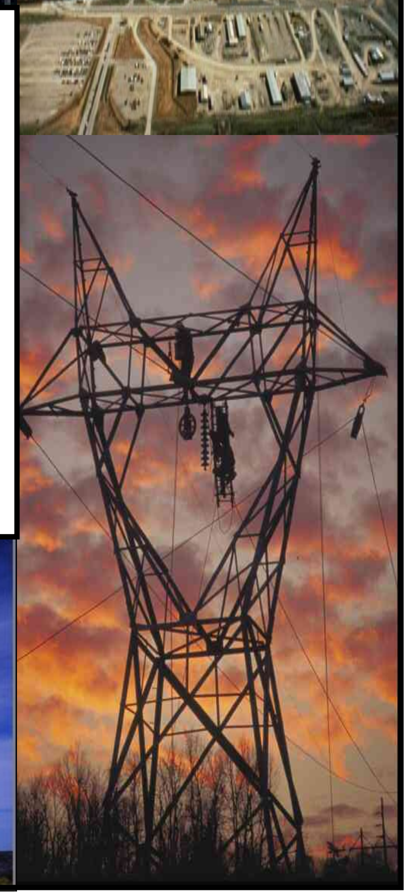
- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

EEI Annual Finance Meeting

New York, NY

May 21, 2008



AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Table of Contents

Company Overview

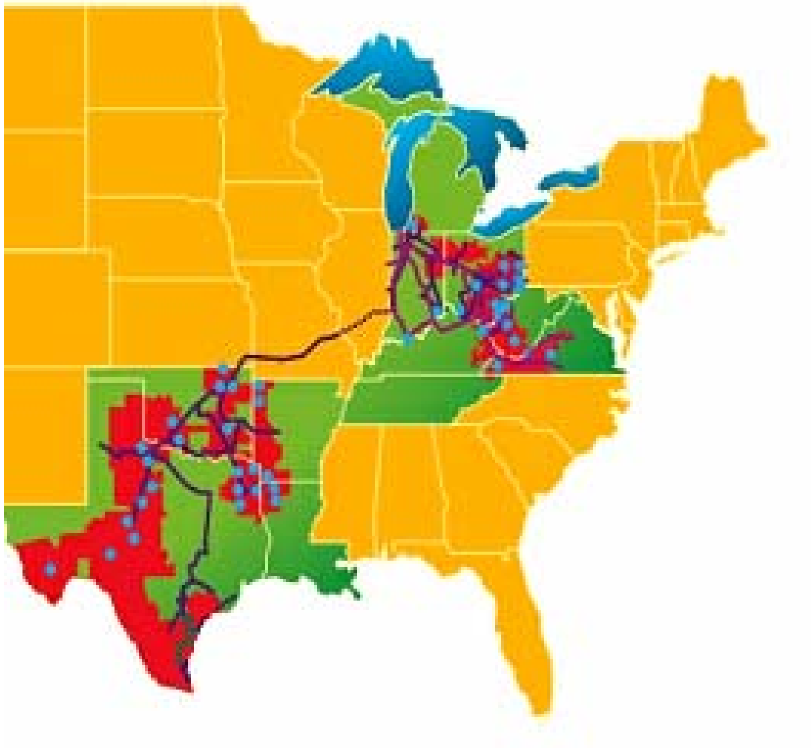
- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
68%	23%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

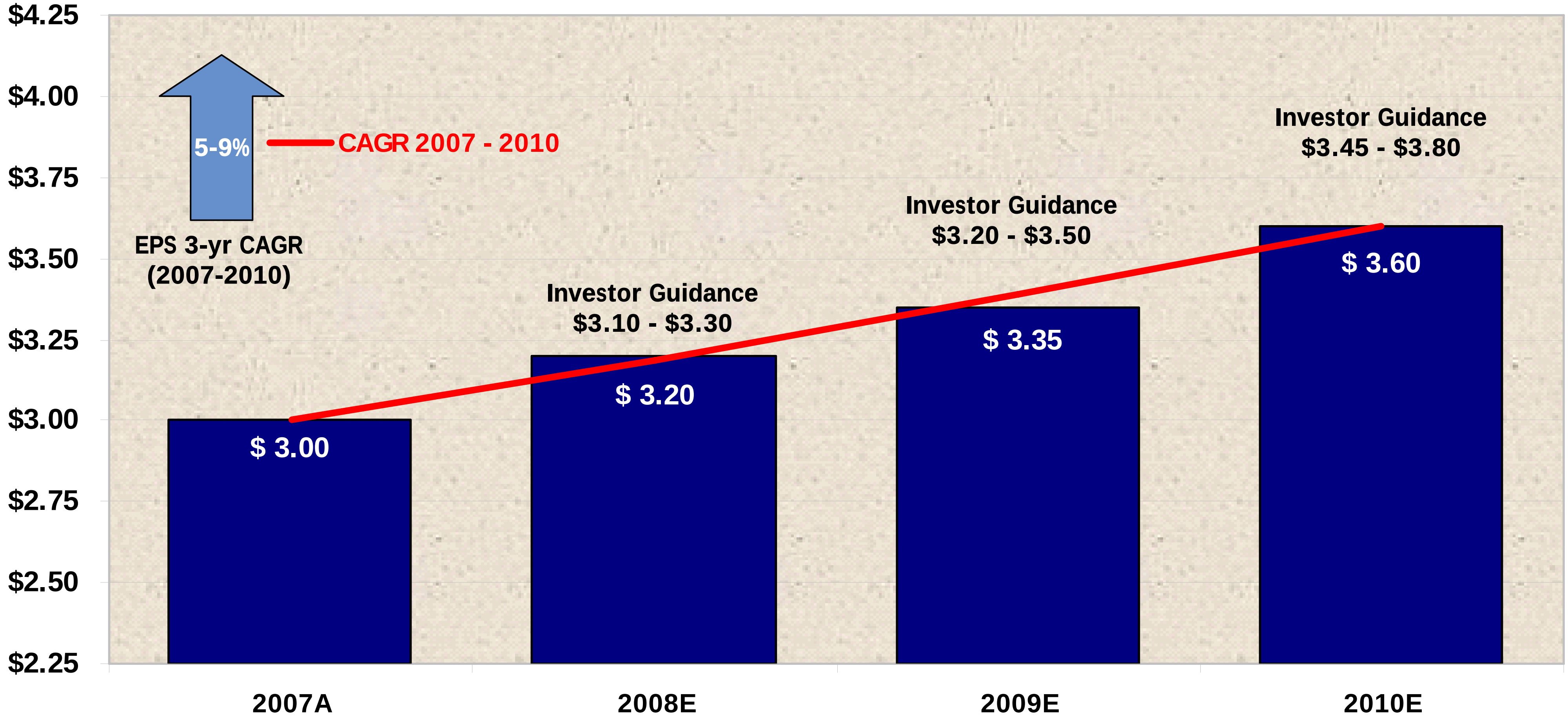
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

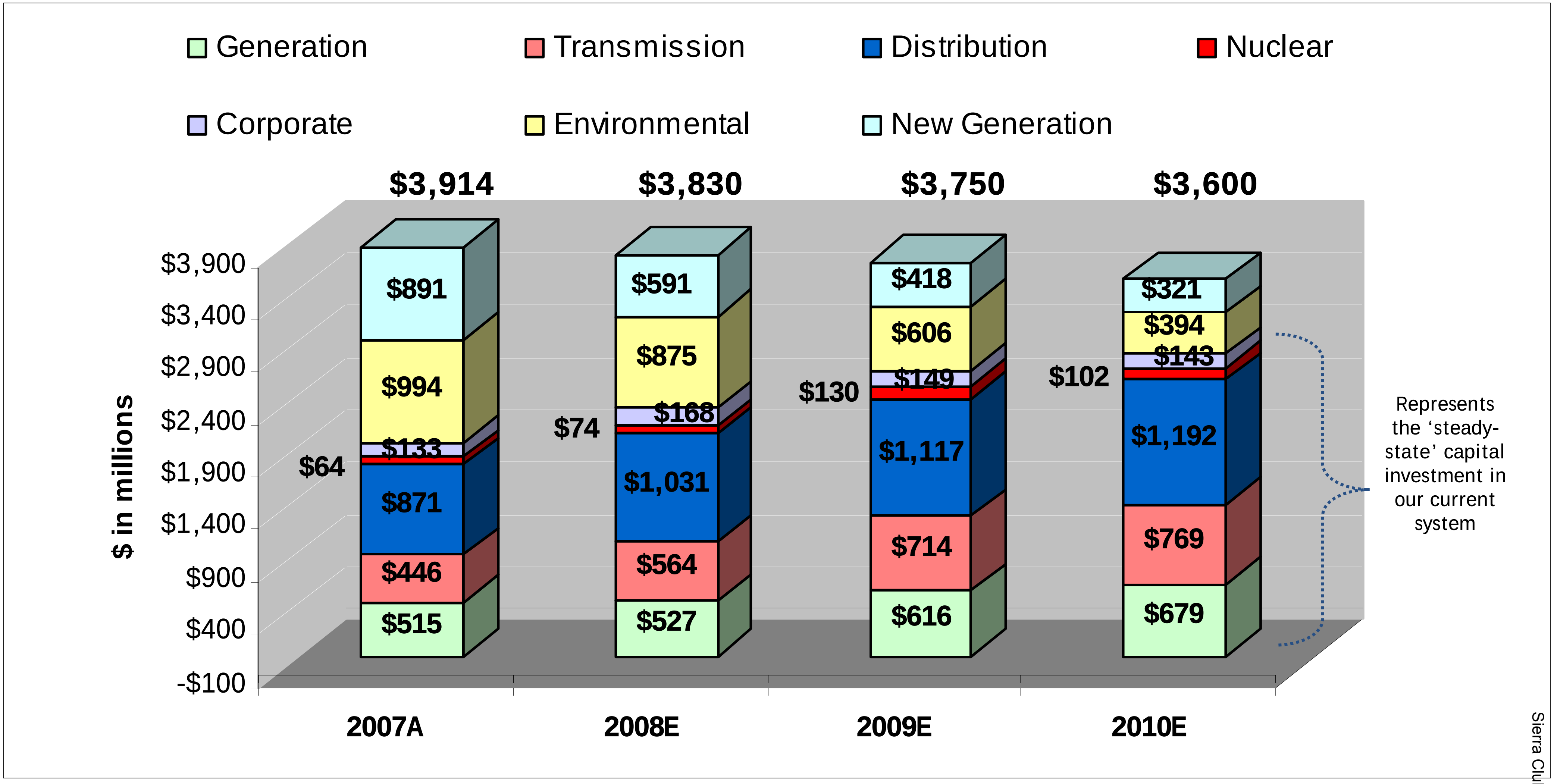
Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast



5% to 9% earnings growth

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

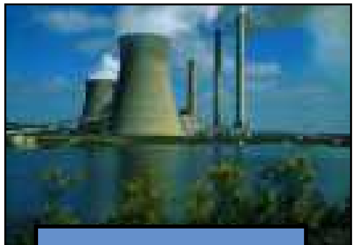
Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

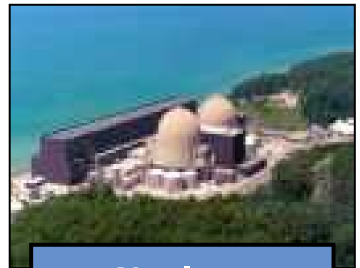
Capital Investment + Rate Relief = Earnings Growth

Domestic Generation Fleet

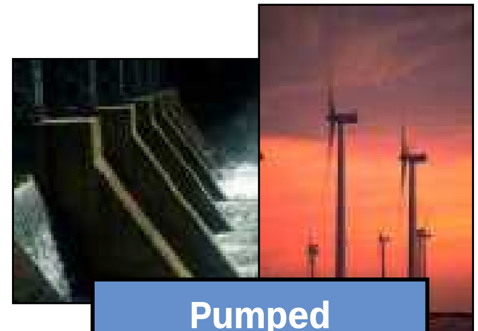


Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

*** Includes 270MW of retired/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

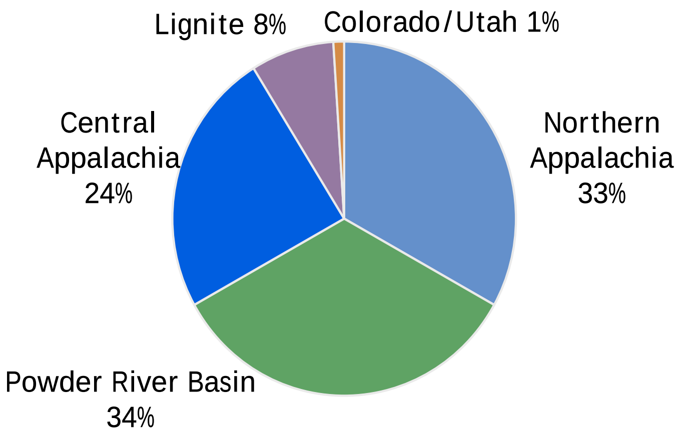
NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

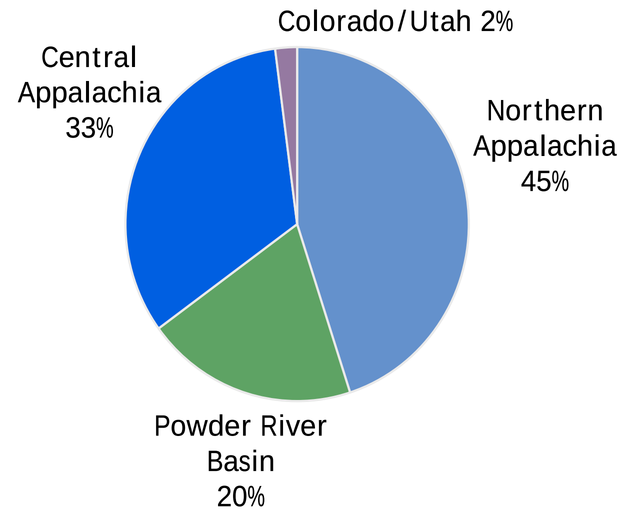
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

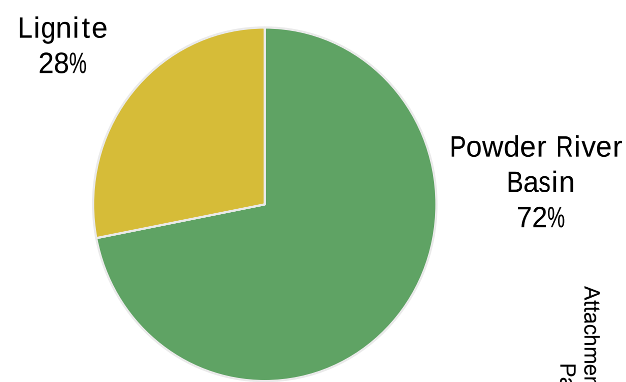
Total AEP System



AEP East



AEP West



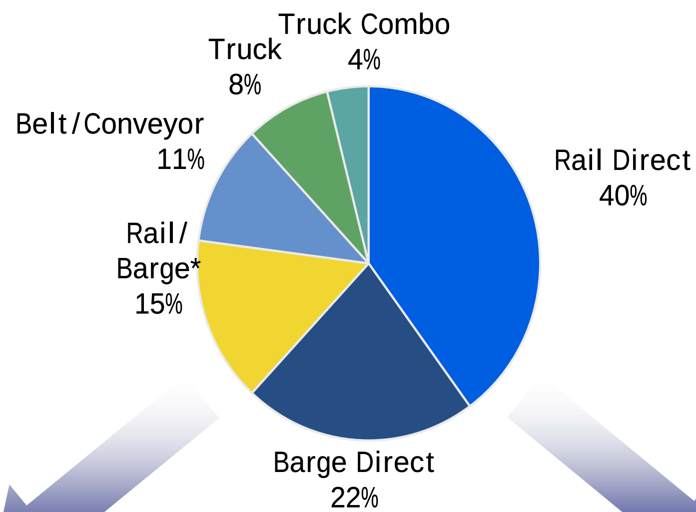
Coal Stats:

- Approximately 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 14%-18% price increase in 2008 based on 2007 actual results.

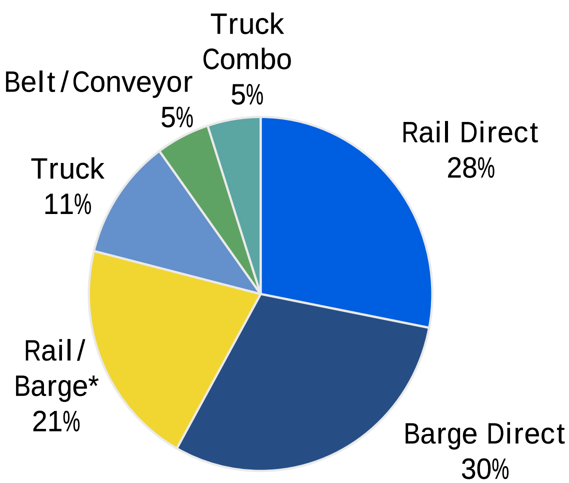
Coal Delivery

2007 Actual

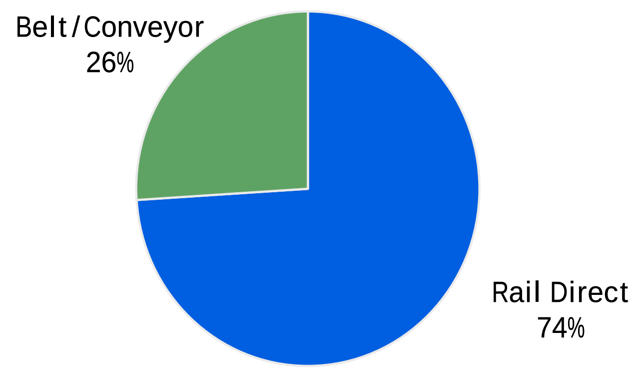
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$305 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.5 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1,110 million in capital investment. The increase in the cost estimate relates to cost escalations due to the delay in receipt of permits and approvals.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART℠

gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

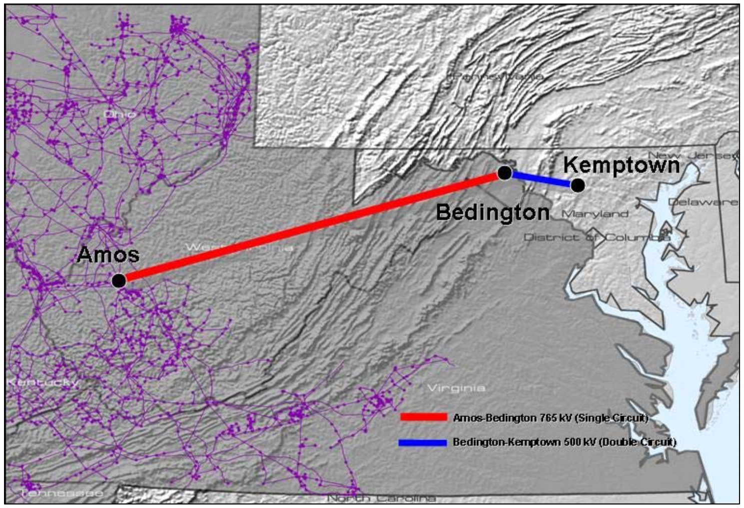
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$40**	**$ 63**	**$ 82**

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

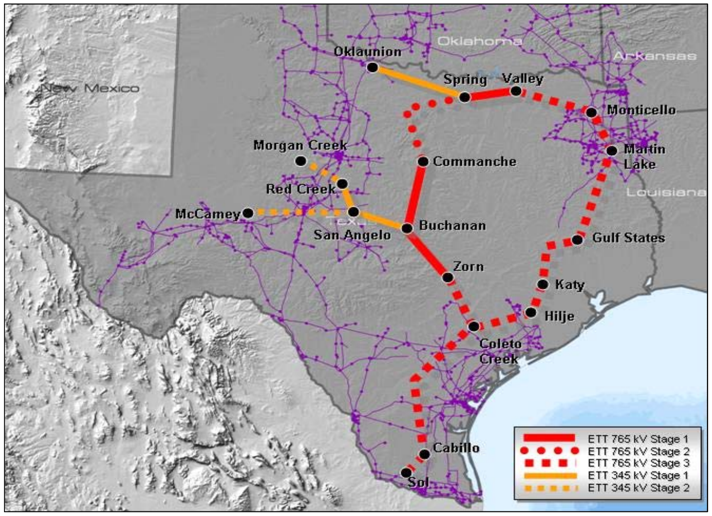
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

I-765™ Transmission: Investment Opportunities

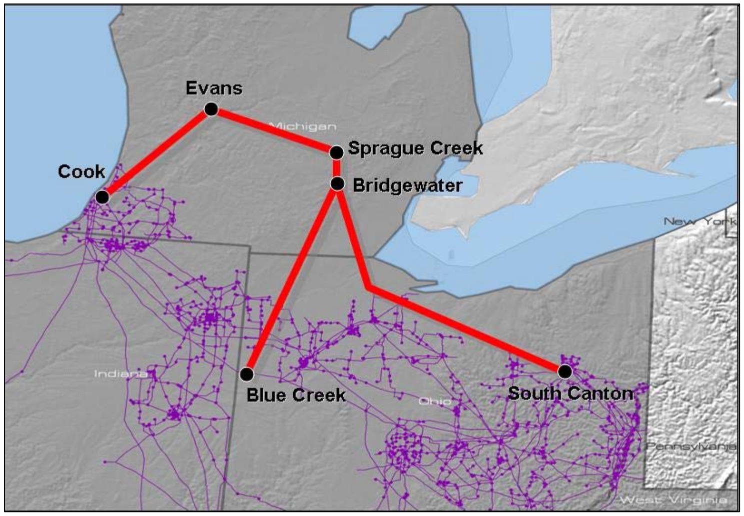
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

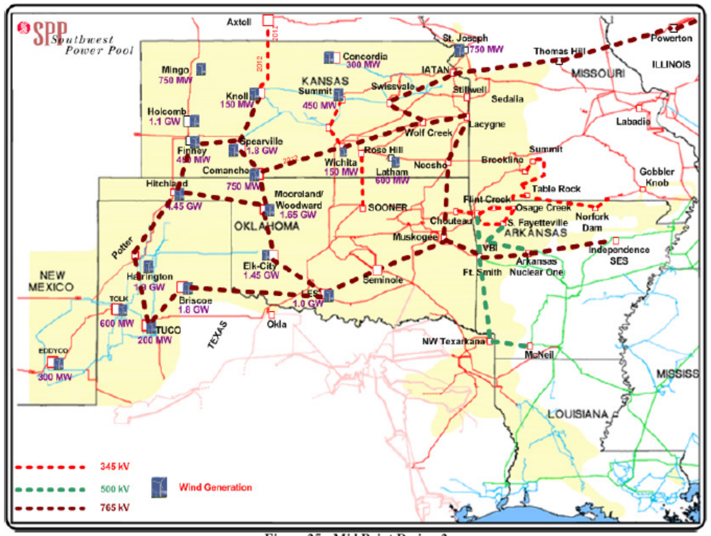
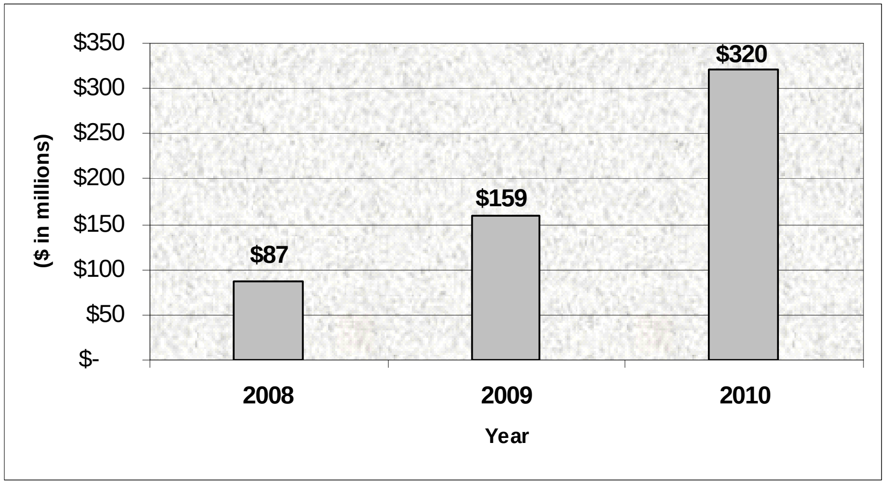


Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

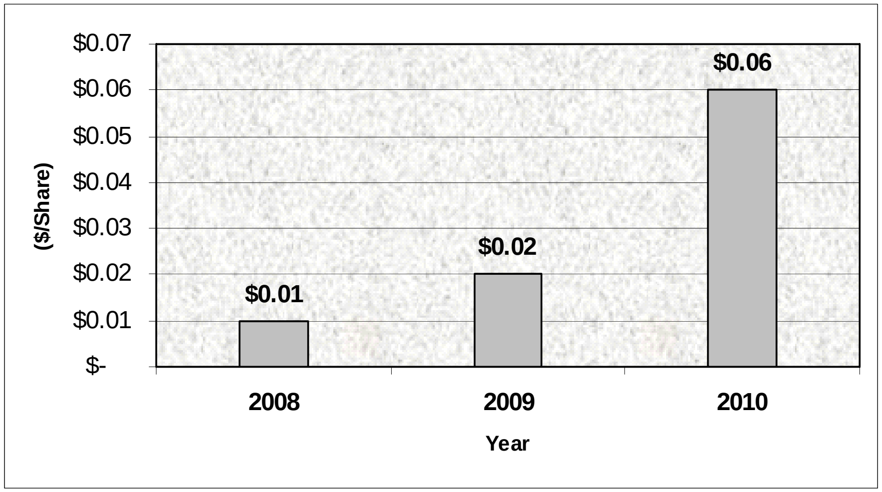


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

Electric Transmission Texas

Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*

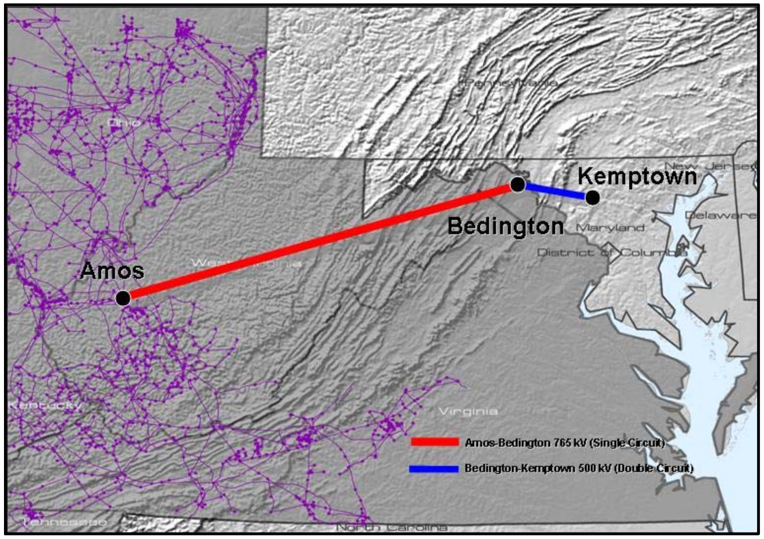


* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment is held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012

Joint Ventures with MEHC

Electric Transmission Texas Update	Electric Transmission America Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

I-765TM Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ### *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ### *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

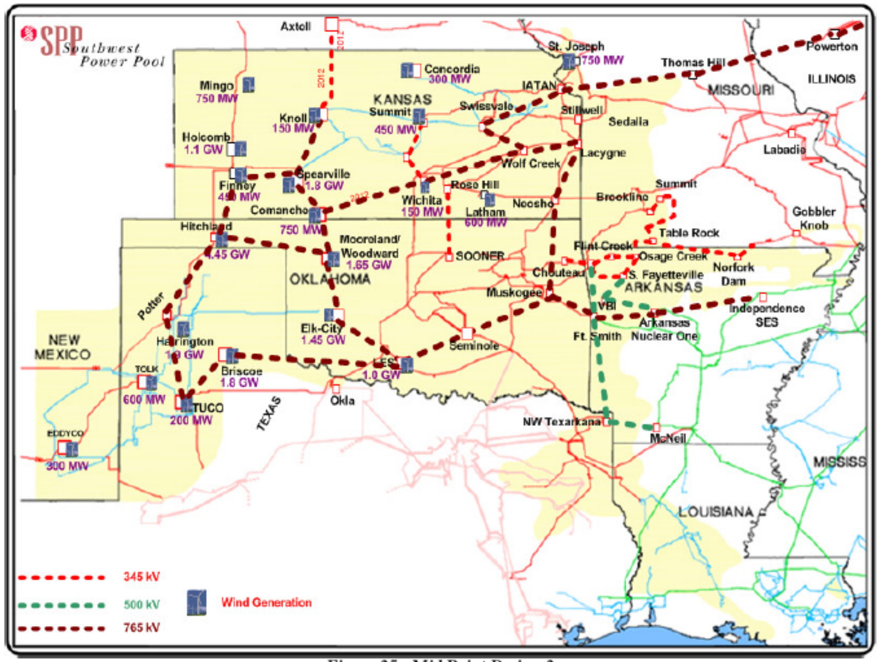


Figure 25: Mid Point Design 2

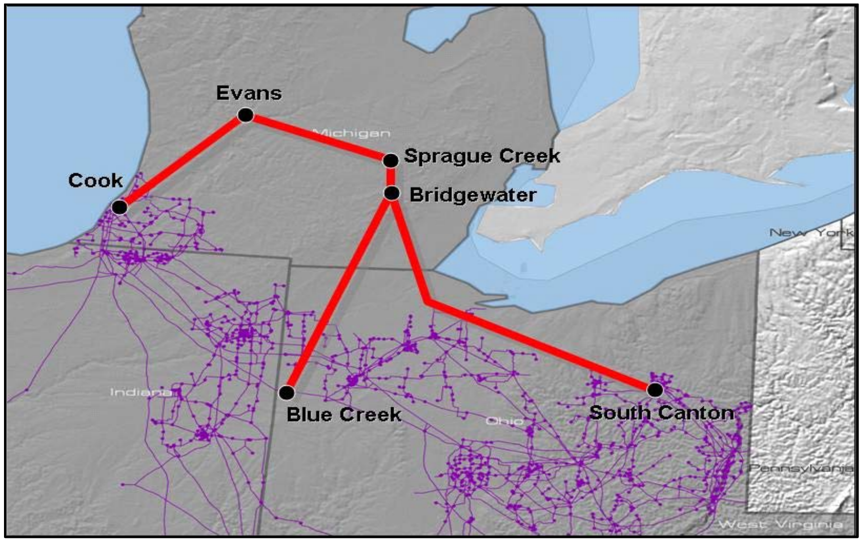
Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

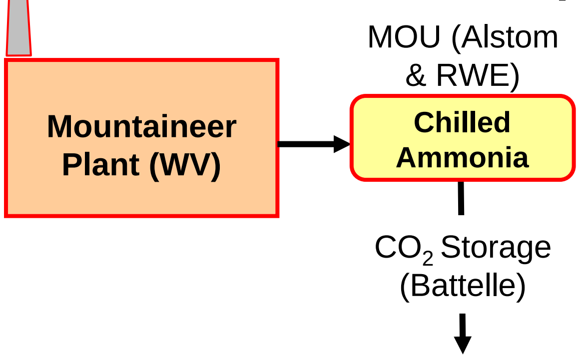
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

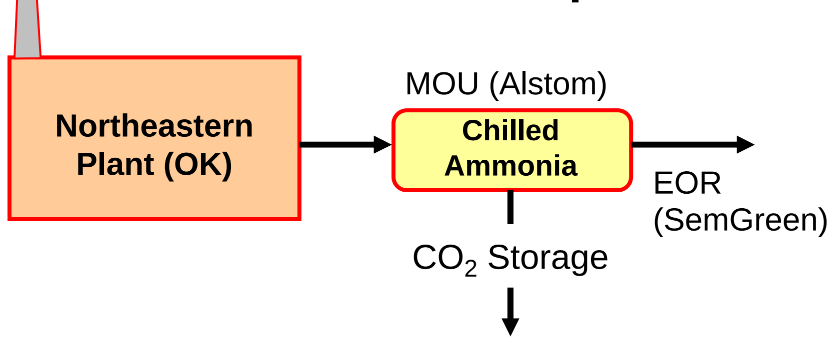
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

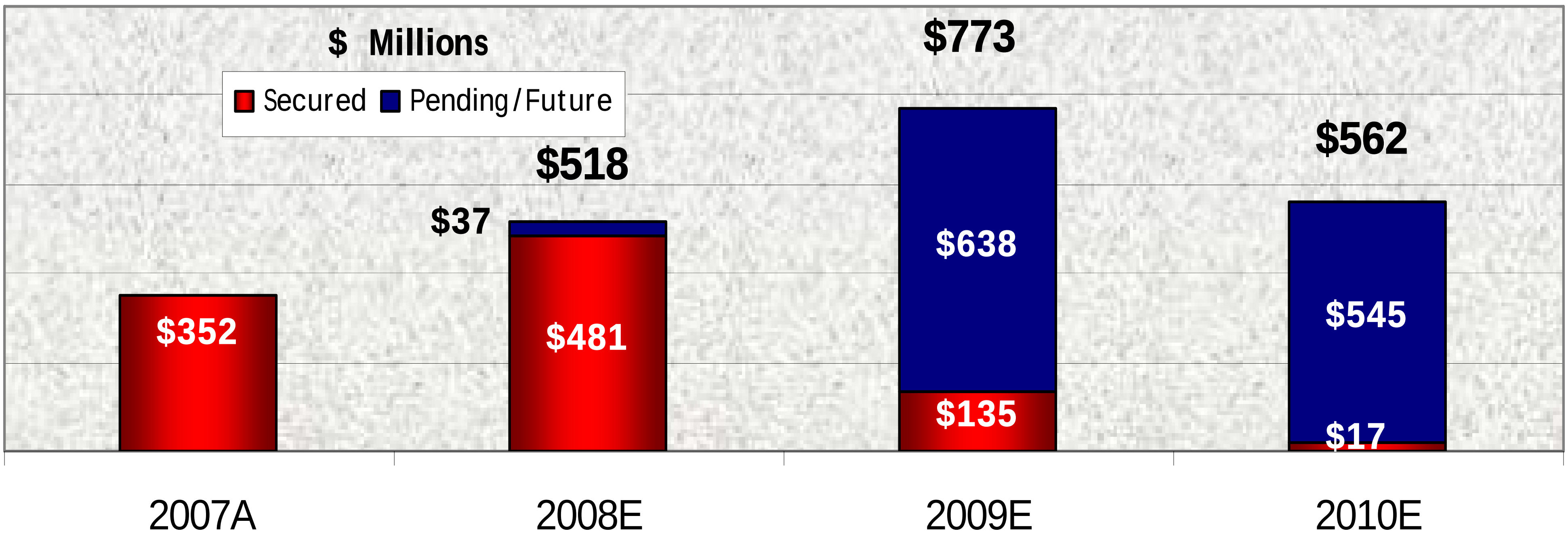
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Incremental Rate Relief

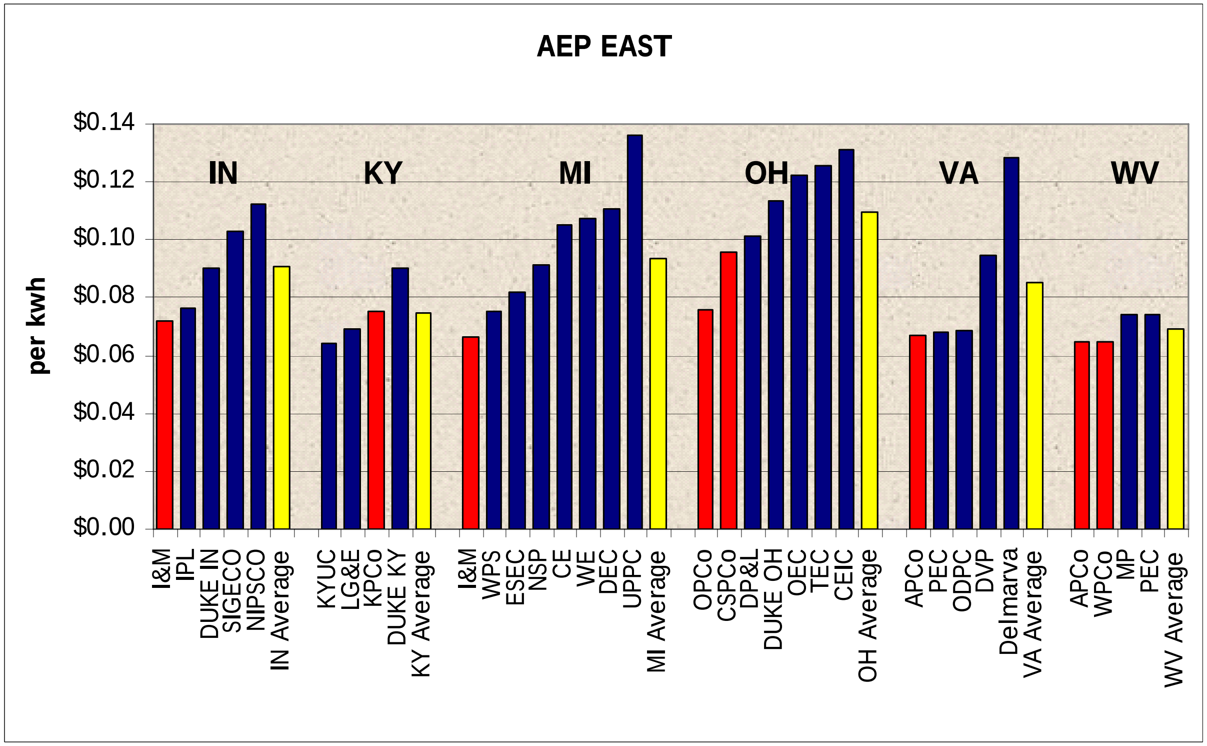


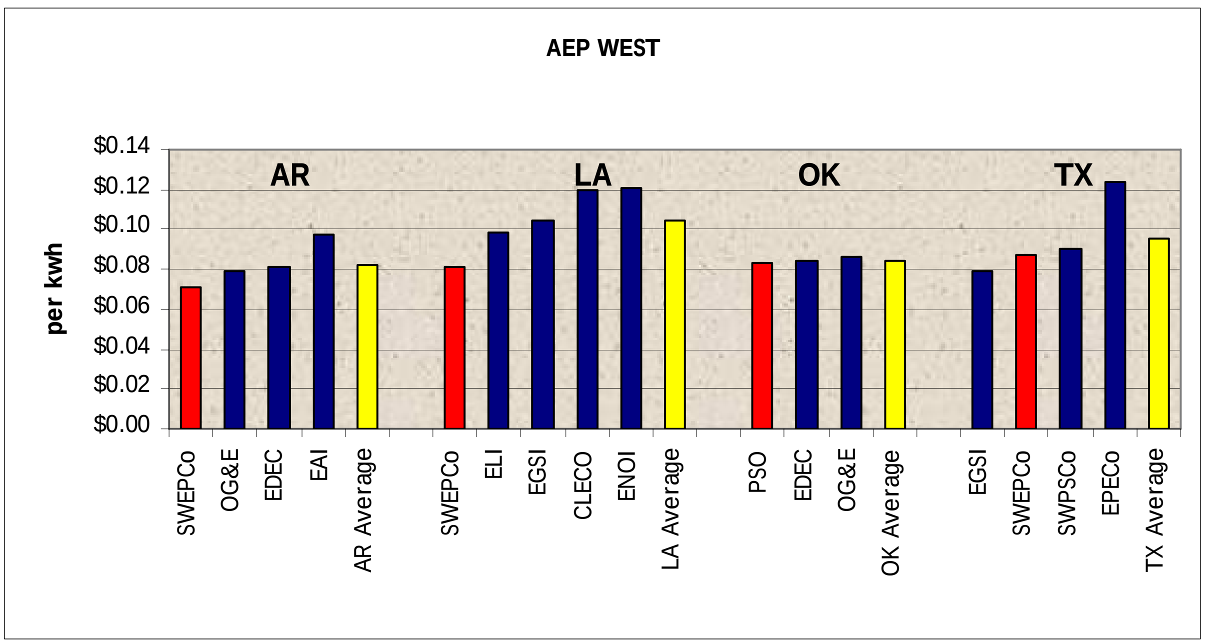
- 93% of 2008 Rate Relief Secured: I&M Depreciation, APCo - WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan.

- 2008 Pending: 2008 TCC/TNC TCRF filings, other cases yet to be filed including Virginia base case.

Secured $481MM of $518MM for 2008

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas
  - IGCC

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC. Hearing held May 12, 2008.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We petitioned for reconsideration on April 29, 2008, and the SCC issued an order granting reconsideration on April 30, 2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as resolution of pending rulemaking related to SB221 in Ohio.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearing is scheduled for May 29-30, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable. An order is expected in mid-summer.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	10.565%	8/1/2008
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual 2007	Projection 2008	Projection 2009	Projection 2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

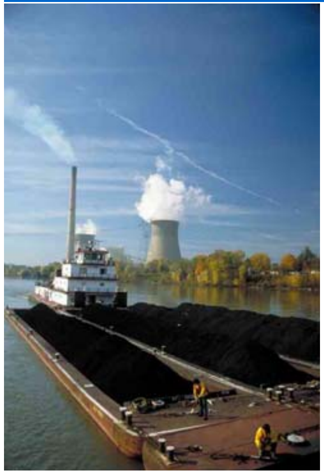
We are committed to maintaining our current credit ratings.

EEI Annual Spring Finance Meeting

Waldorf=Astoria

New York

May 23, 2007




AEP AMERICAN ELECTRIC POWER®


"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Table of Contents

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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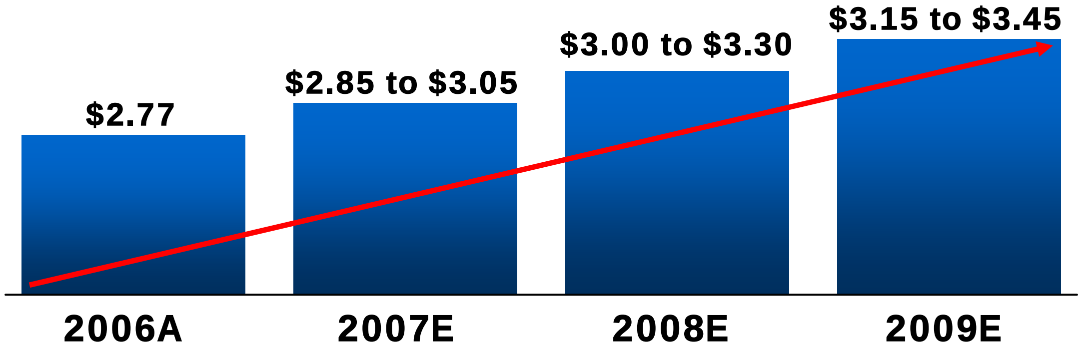
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

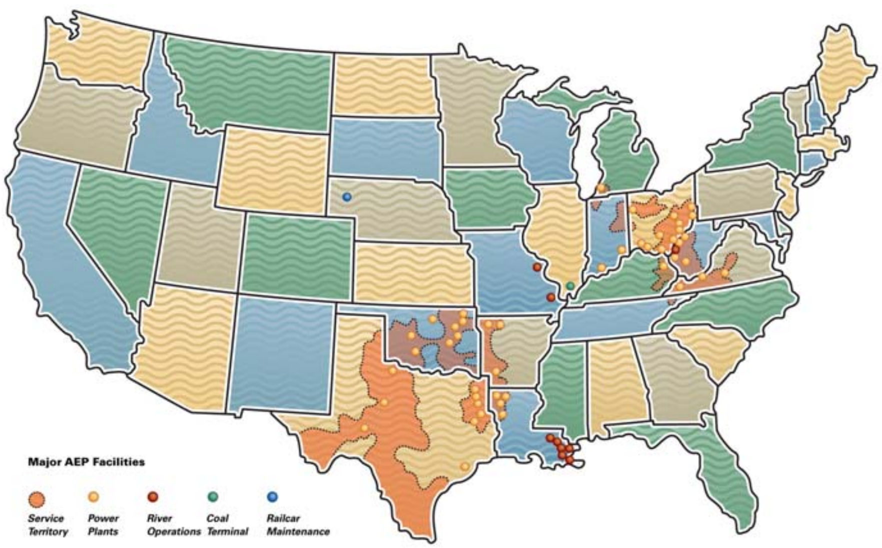
Our Strategy Remains Focused On Regulated Operations

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



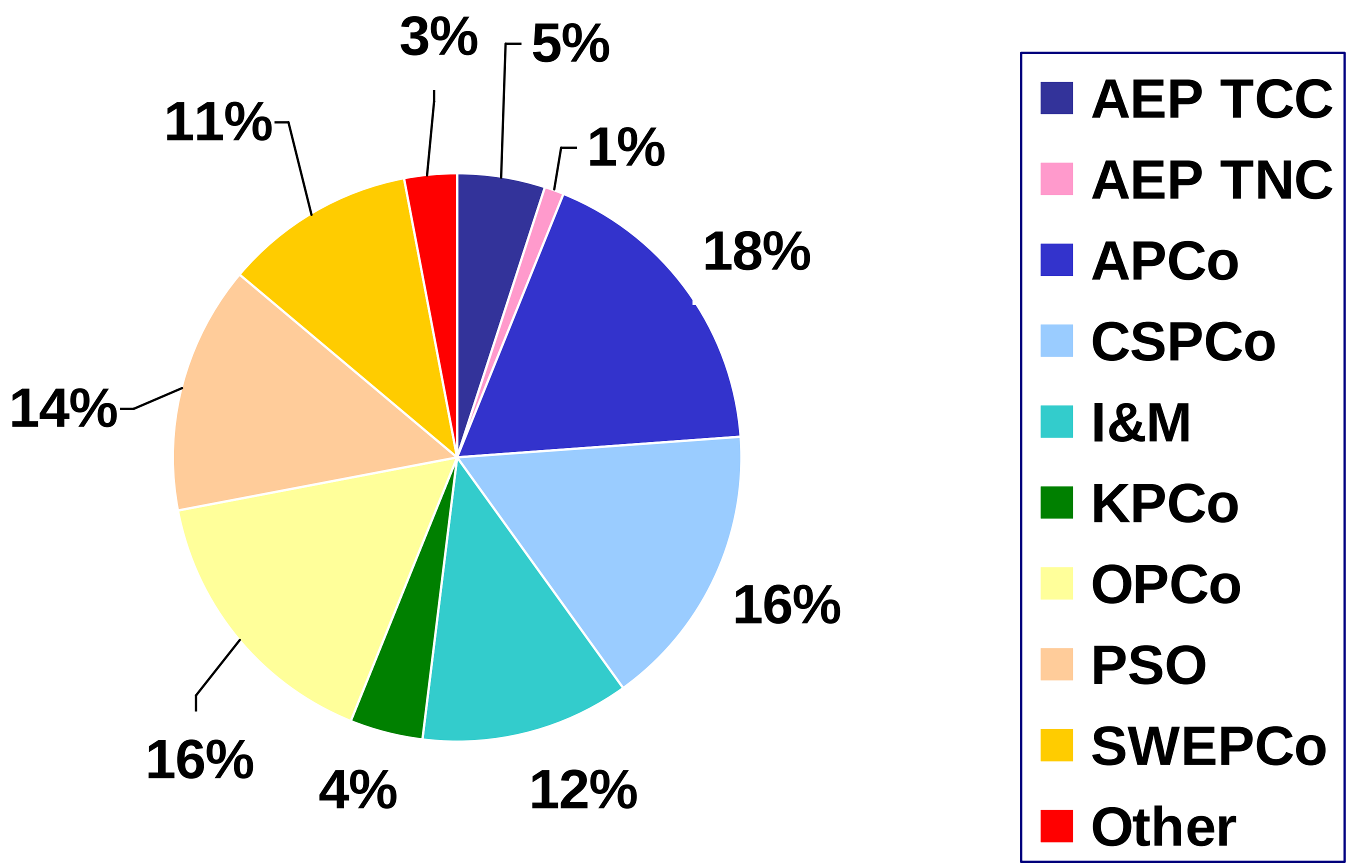
- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

2006 Retail Revenue

Retail Revenue Composition by Operating Company



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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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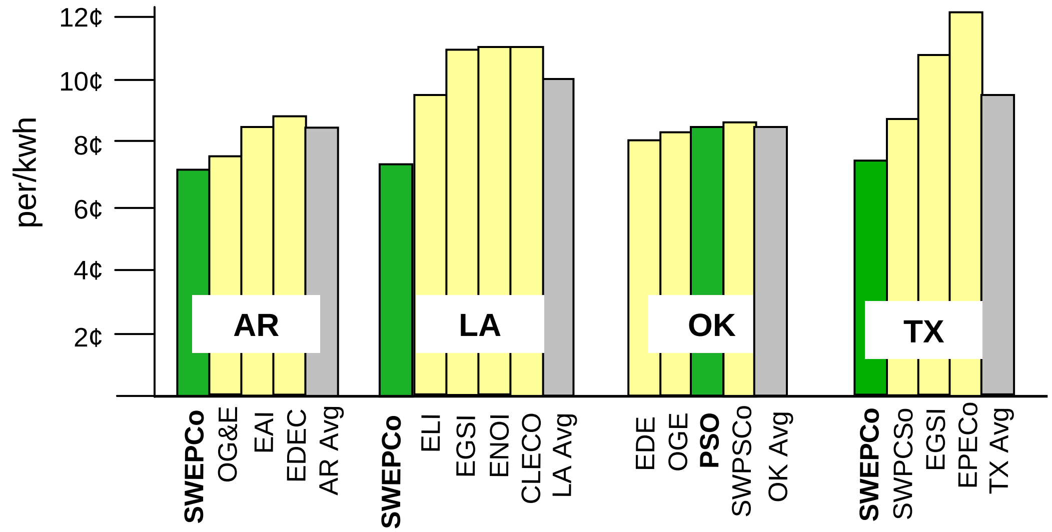
AEP Provides Low Cost Electric Service

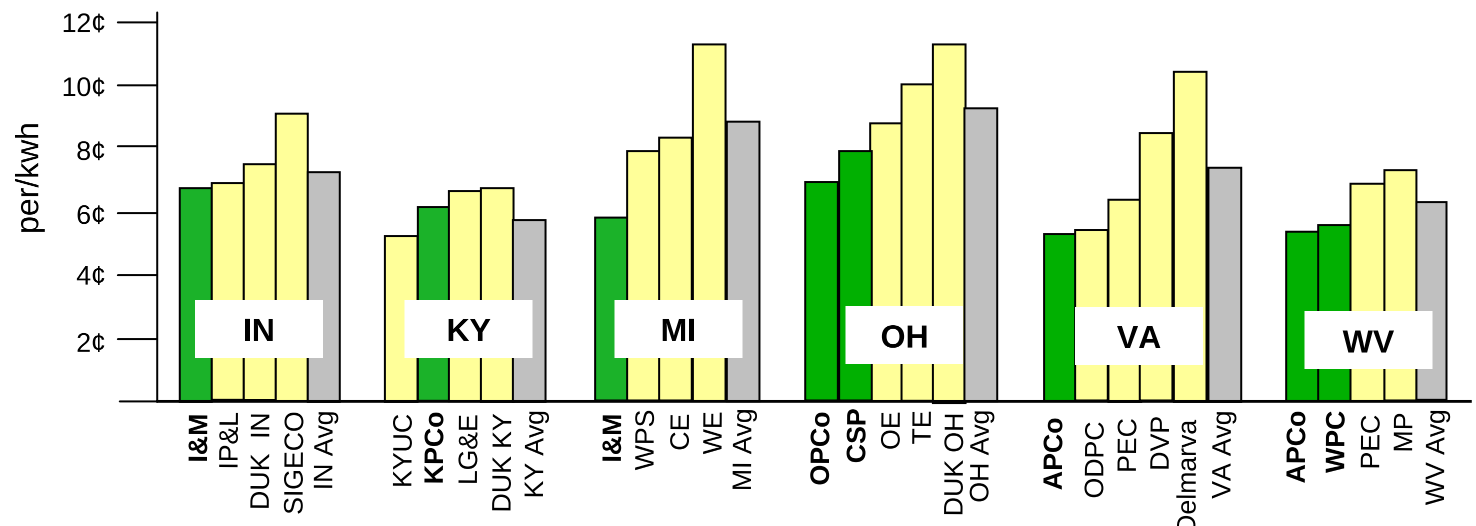
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2012
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale closed on April 25, 2007 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

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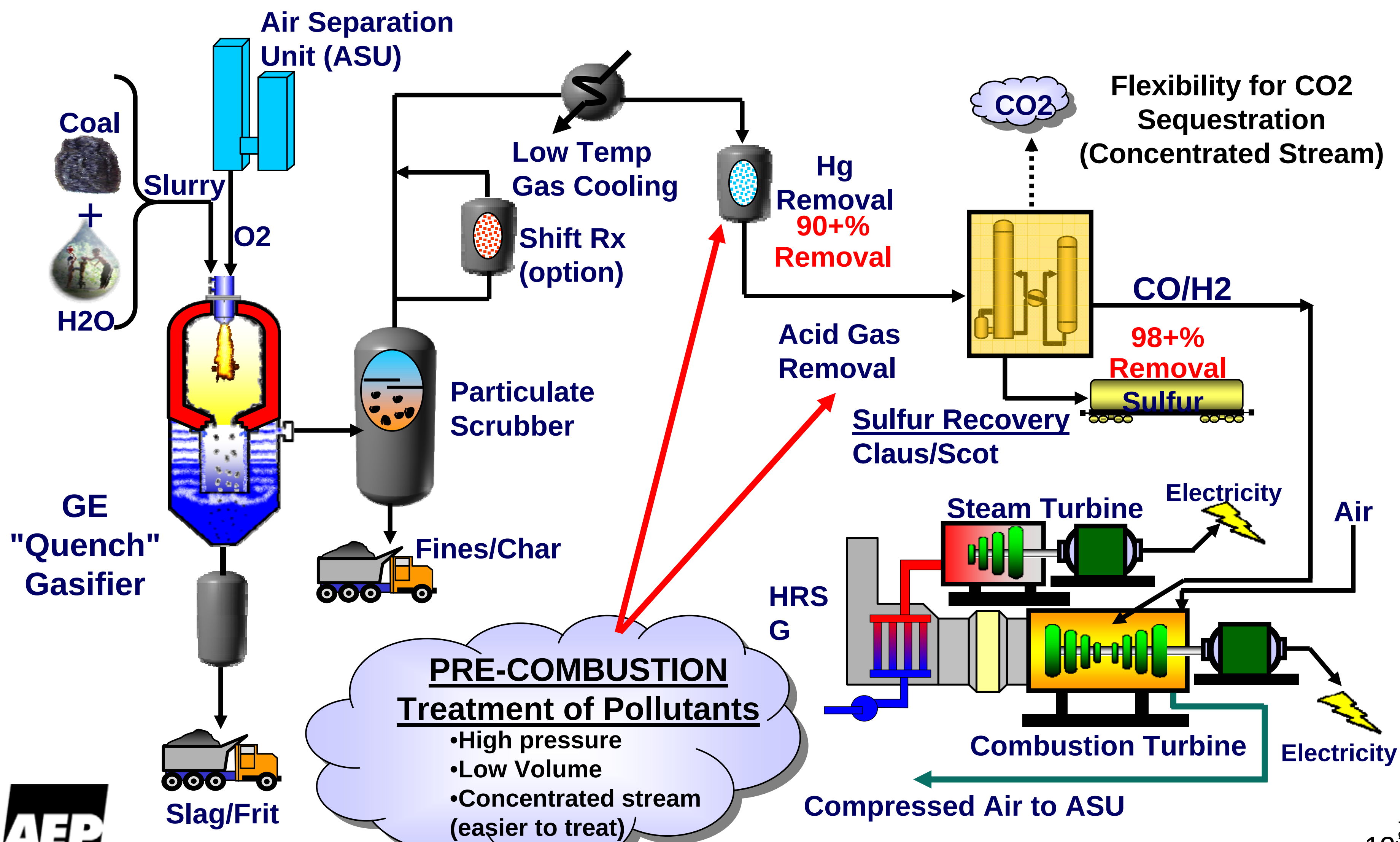
AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

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IGCC Permitting Process

IGCC Permitting Issues

- **Air**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- **Wastewater**
  - ✓ understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- **US ACE (US Army Corp of Engineers)**
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

Permitting process takes 1 – 2 years and is well under way

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% Mid-American Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- AEP I-765 Interstate Project
  - Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- Other Transmission Projects
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

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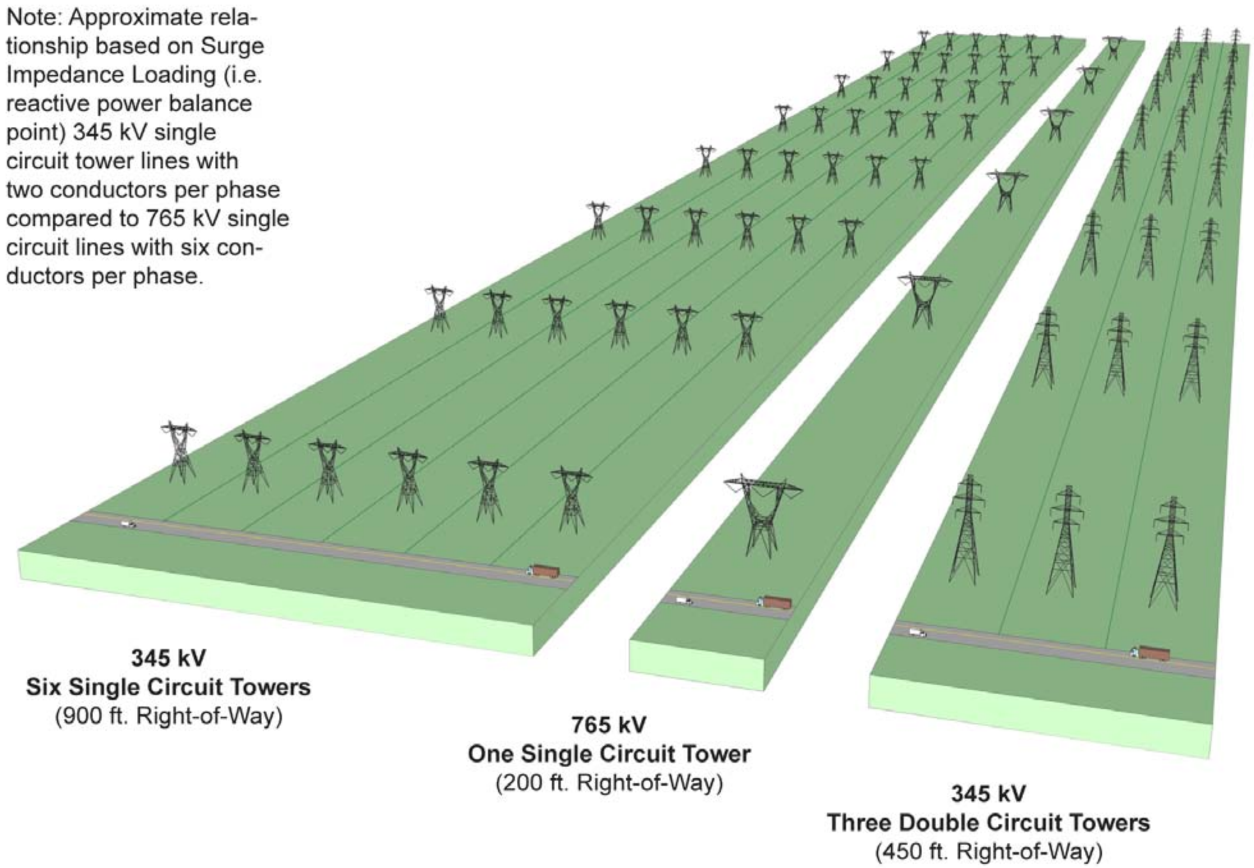
765 Right-of-Way Comparison



From a siting standpoint, 765 kV is much more efficient in terms of economies of scale and right-of-way than lower capacity lines

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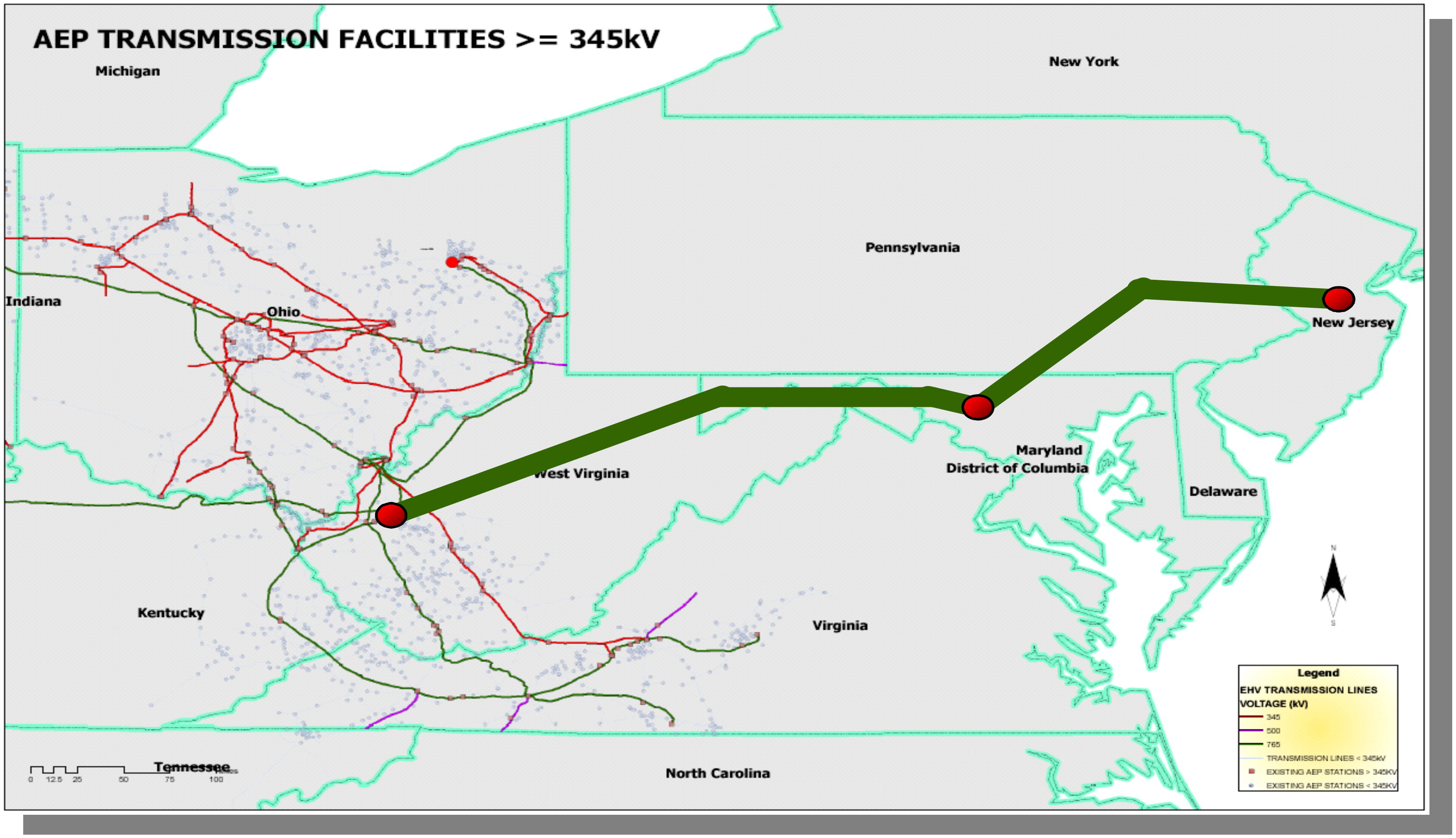
765 PJM



- **Jointly owned with Allegheny, will improve eastern grid reliability**
- **Enhance Midwest-Mid-Atlantic power transfer capability by 5000 MW**
- **Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.**

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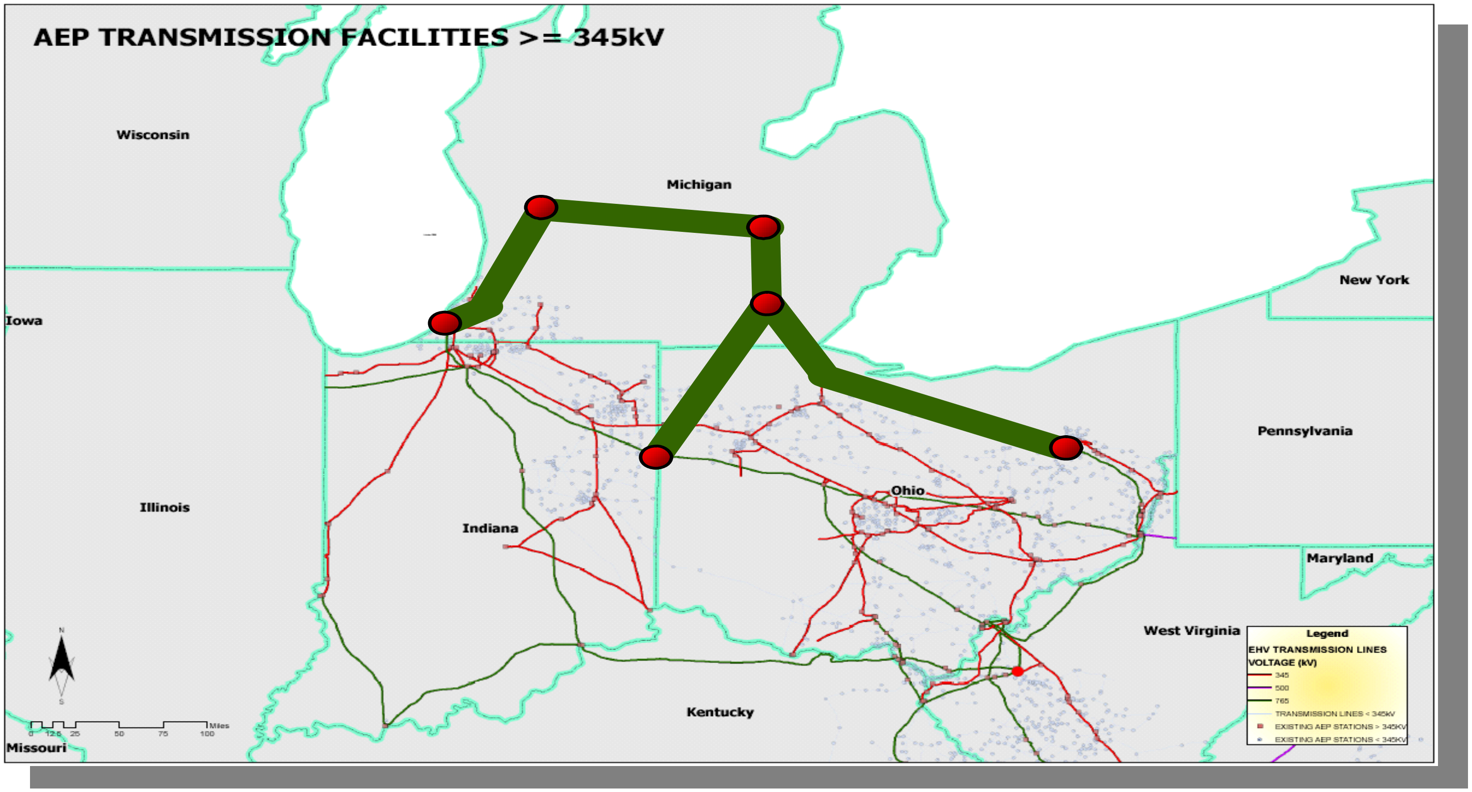
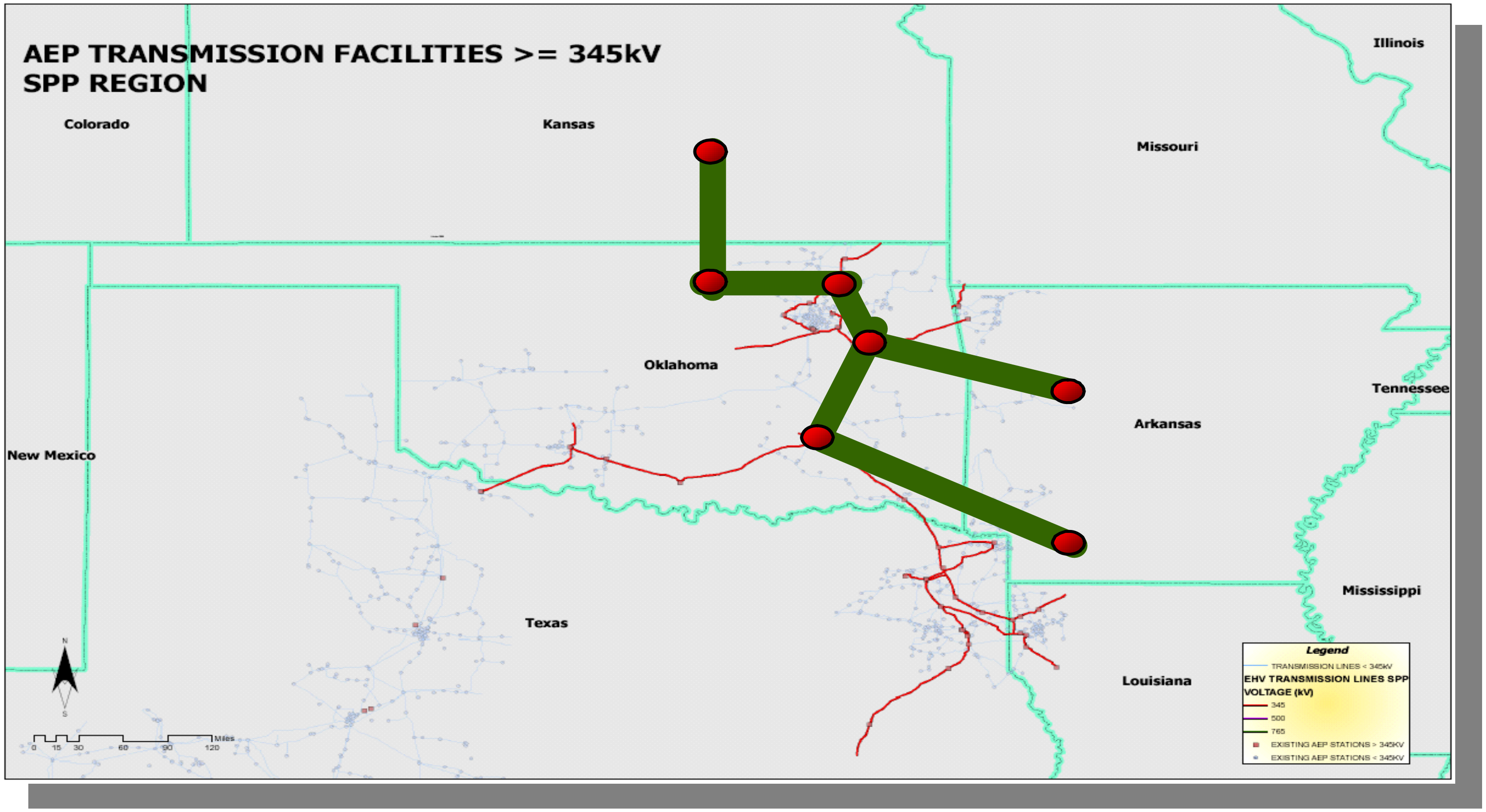
765-Michigan



- Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of a new line in MI.
  - 675 line miles
  - Over 4000MW improved transfer capability
  - 765-kV anticipated to alleviate constraints

765-SPP



➢July '06 AEP submitted conceptual project to SPP:

Six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, proposed construction period 2012-17

➢Next steps:

SPP issued EHV Overlay Study RFP to review 345 kV, 500 kV, and 765 kV potential projects in SPP with results expected in mid-2007

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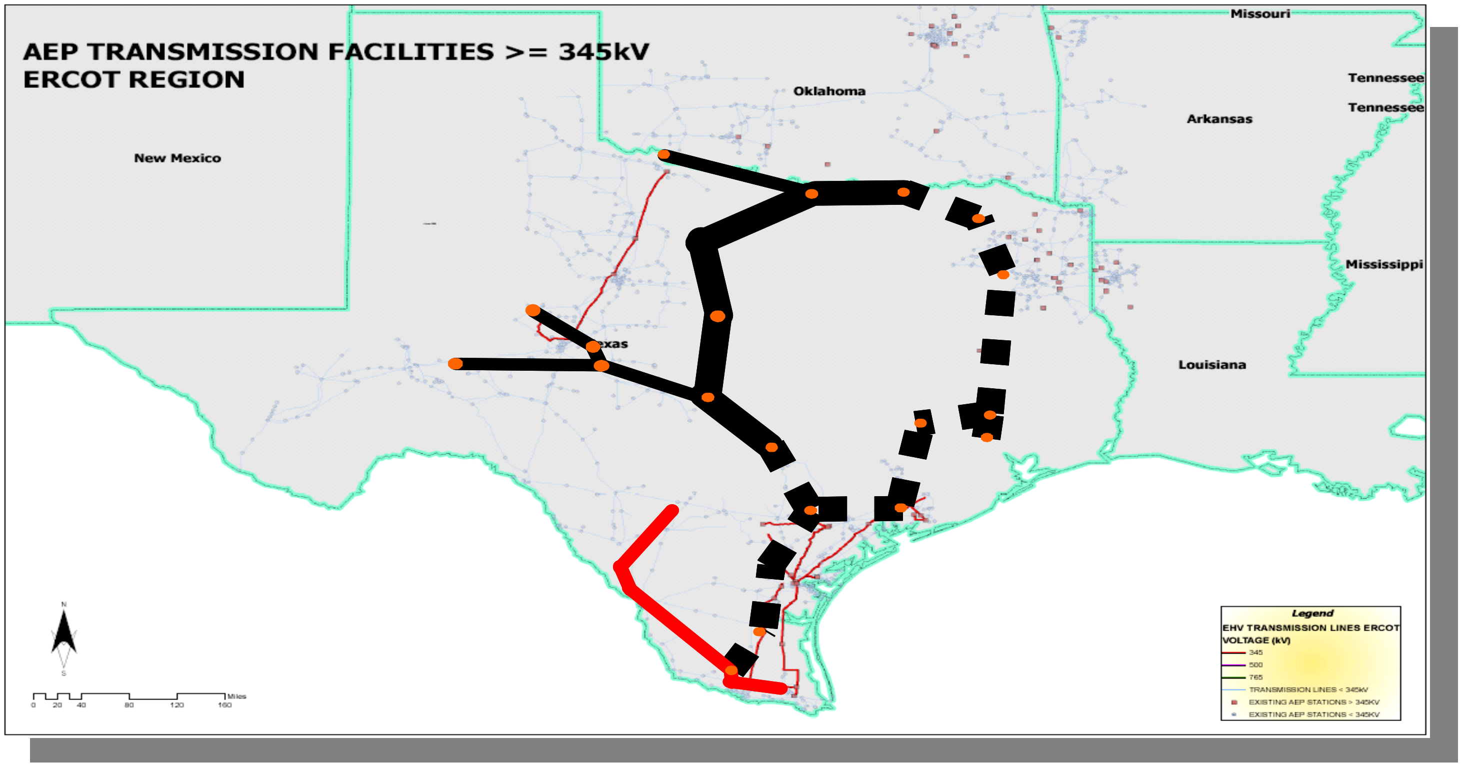
765-ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets
- AEP exploring 765-kV ERCOT transmission investment opportunity
- 420 line miles
- Up to 4000MW improved transfer capability

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Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	In-service	☑	In-service
Mitchell 2	800	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

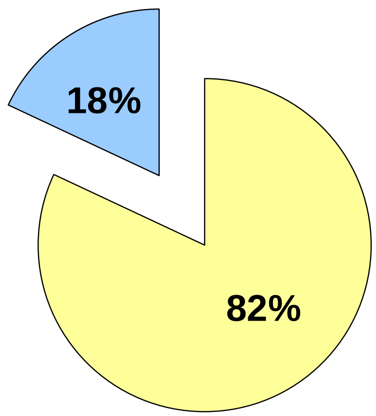
*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

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AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

FutureGen™ ALLIANCE
Clean Energy for a Secure Future

GLOBAL ROUNDTABLE ON CLIMATE CHANGE

CLIMATE LEADERS®
U.S. Environmental Protection Agency

CCX™ Chicago Climate Exchange

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

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AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

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AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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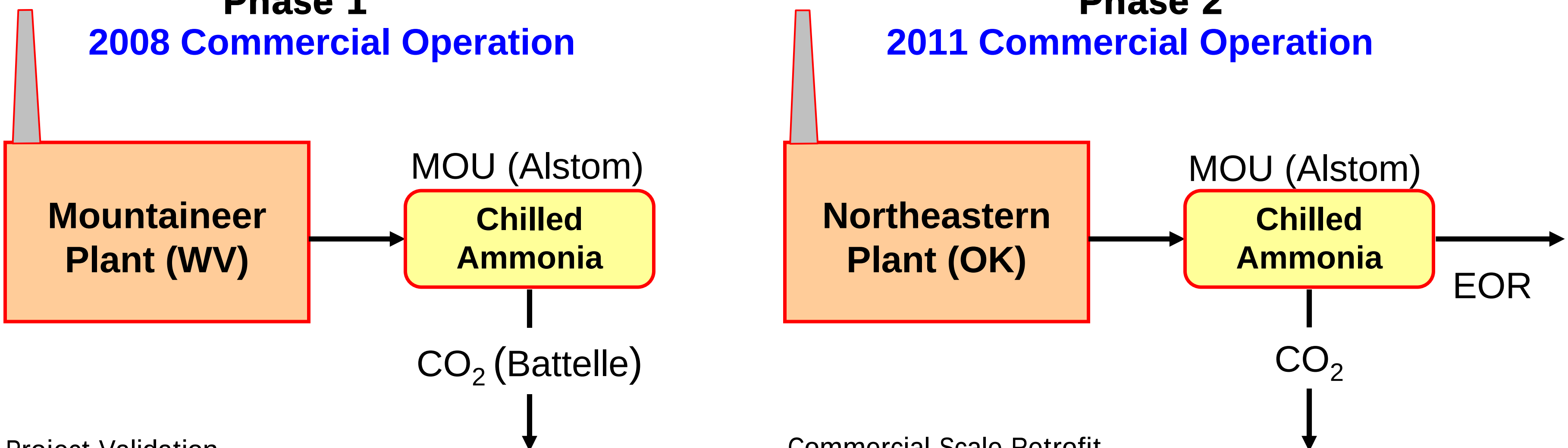
Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1 — **2008 Commercial Operation**

Phase 2 — **2011 Commercial Operation**



<u>Project Validation</u>

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost $50 – $80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

<u>Commercial Scale Retrofit</u>

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~$225 – $300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

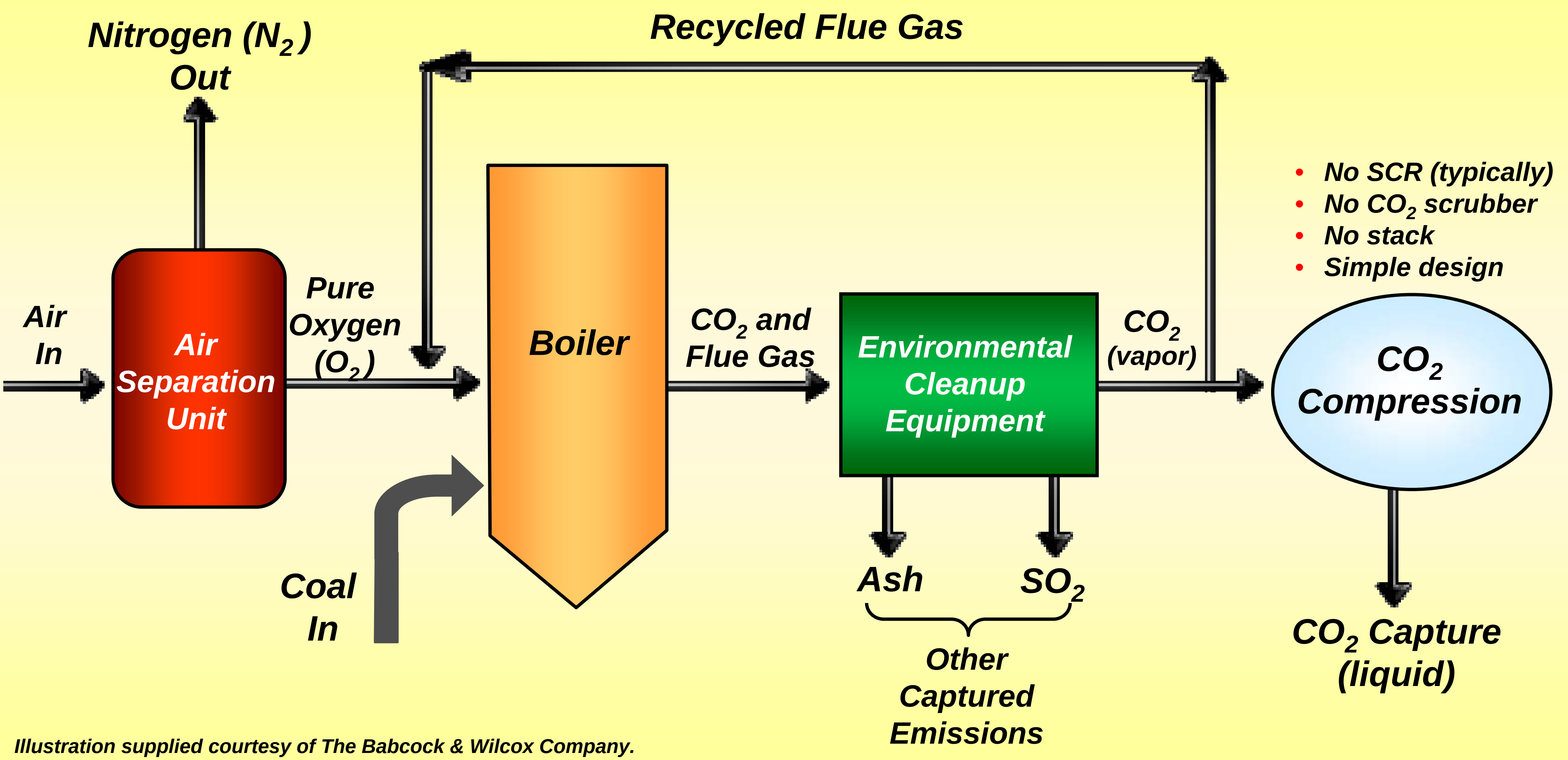

Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

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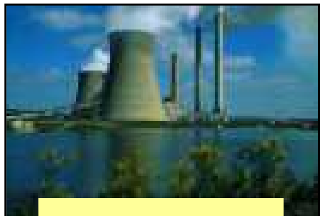
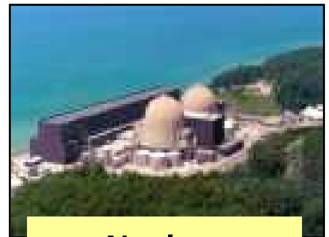
Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

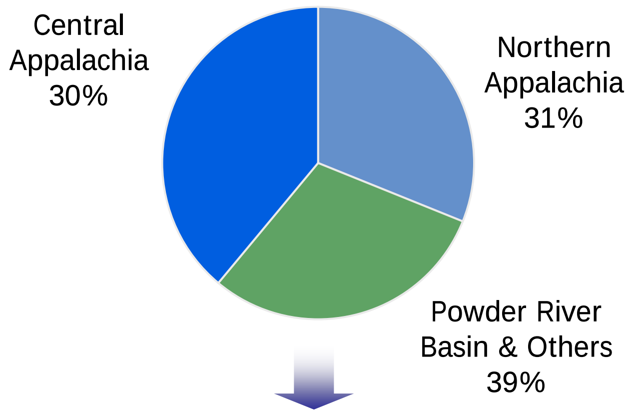
* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

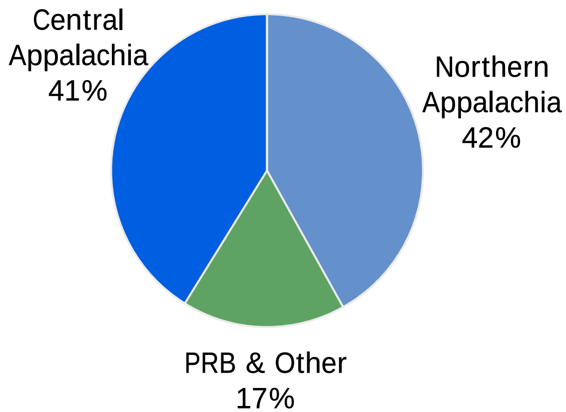
Total AEP System



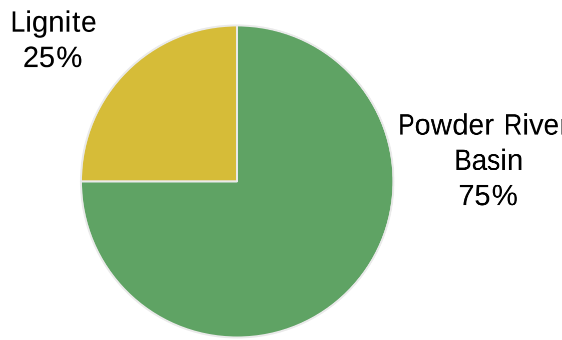
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



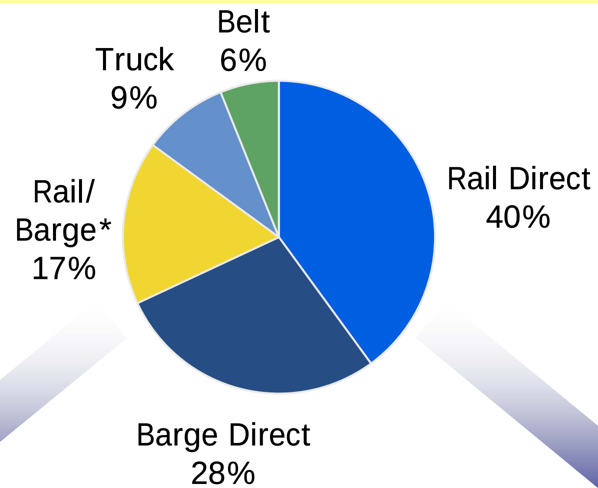
AEP West



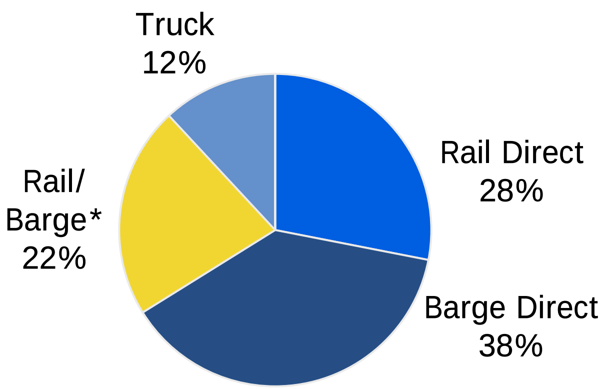
Coal Delivery

2006 Actual

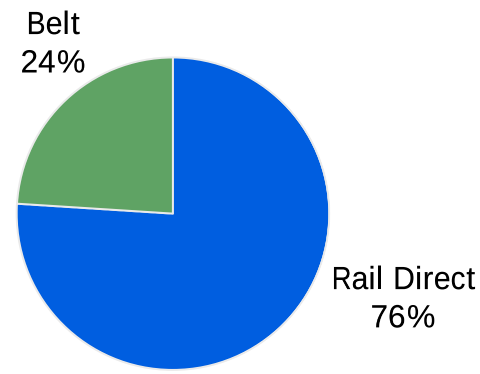
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065). An order was issued on May 15, 2007, authorizing $24MM, with E&R to be addressed in a separate filing.

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

May 4, 2006	Case filed
Oct. 2, 2006	Rates went into effect, subject to refund
Oct. 24, 2006	Staff testimony filed
Dec. 7, 2006	Hearings commenced
Feb. 5, 2007	Briefs filed
Mar. 28, 2007	Hearing Examiner Recommendation filed
Apr. 18, 2007	APCo filed comments to HE report
May 15, 2007	Commission order issued

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for $13.7MM

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

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Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 11, 2007; Evidentiary hearing to commence May 22, 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
- April 2007 Commission decision:
  - Reaffirmed PJM's current "license plate" rate design, reversing the finding of the ALJ; each utility pays for transmission service based on the costs of transmission facilities located in the same, sub-regional zone that the utility is located in
  - Directed PJM to develop a detailed methodology to be included in PJM's tariff for determining who benefits from and therefore, who pays for new facilities below 500 kV.
  - Determined that the costs of all new PJM-planned facilities that operate at or above 500 kV should be shared on a region-wide basis.

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Earned ROE's

Company	Earned ROE as of March 31, 2007
AEP Texas Central Company	**5.81%**
AEP Texas North Company	**5.24%**
Appalachian Power Company	**8.97%**
Columbus Southern Power Company	**17.14%**
Indiana Michigan Power Company	**7.12%**
Kentucky Power Company	**11.06%**
Ohio Power Company	**10.57%**
Public Service Company of Oklahoma	**3.75%**
Southwestern Electric Power Company	**10.11%**

These ROE's are based on GAAP, Not Rate Base

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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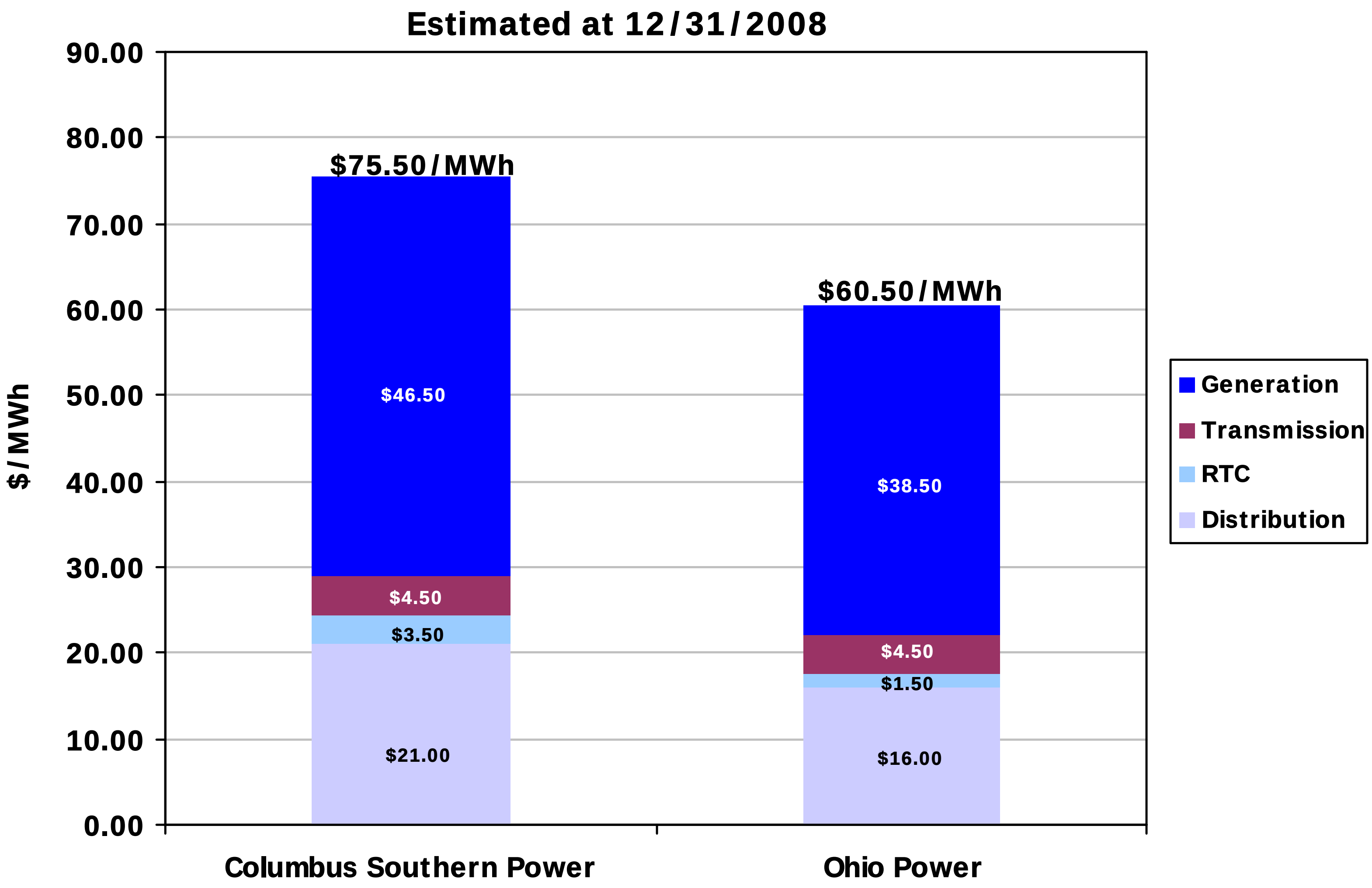
Average Unbundled AEP Ohio Rates



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2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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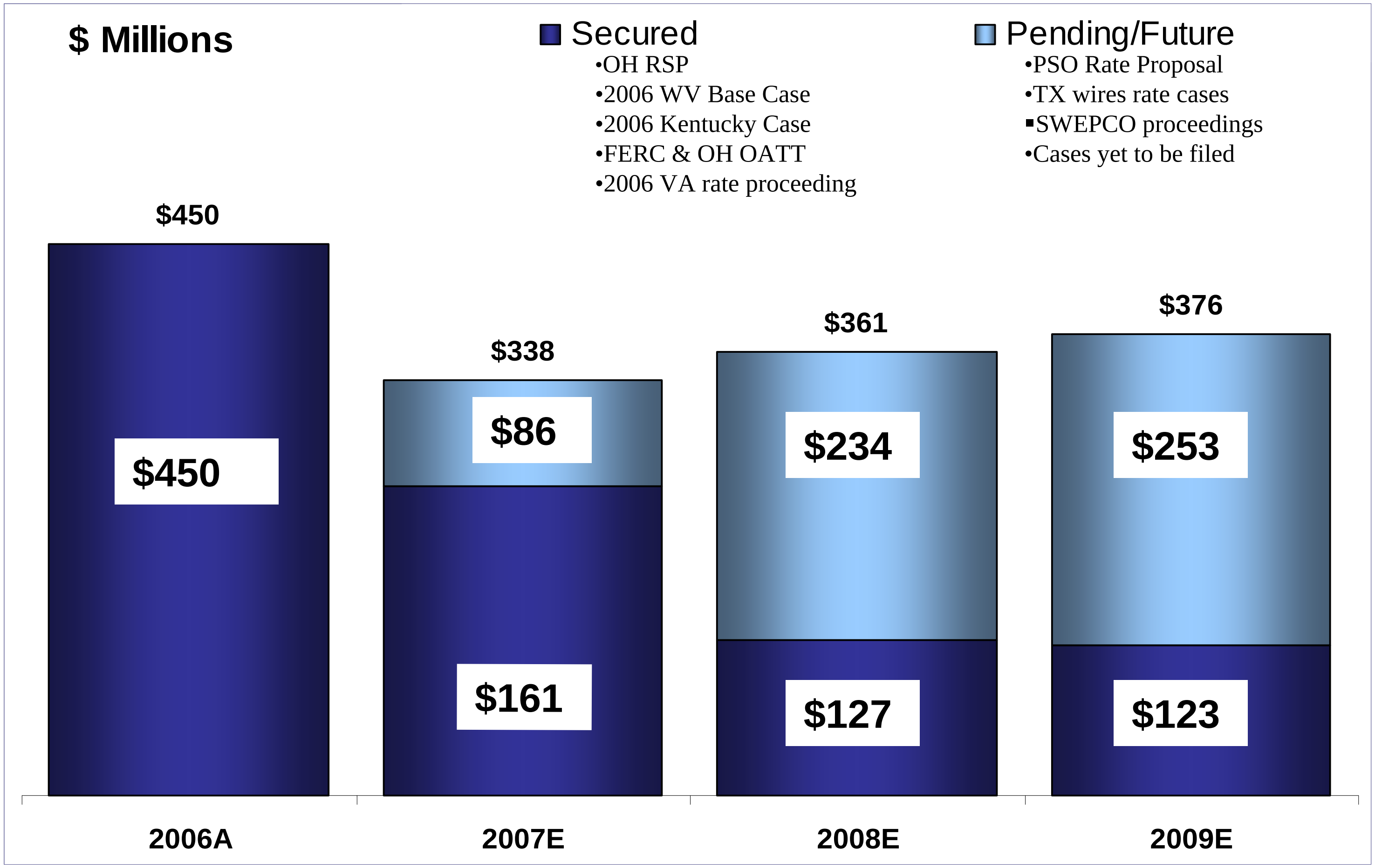
Incremental Rate Relief Composition



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RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

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CASH ON HAND EXPECTED TO BE $205 MILLION AT YEAR END 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ **43**	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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Capital Structure

Capital Structure	Actual 12/31/2006			Actual 3/31/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	13,902	-	13,902
Short-term Debt	18	-	18	175	-	175
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,540	9,540
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**14,077**	**9,601**	**23,678**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.5%***	***40.5%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(27)	-	(27)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(251)	-	(251)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**12,679**	**9,601**	**22,280**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***56.9%***	***43.1%***	***100.0%***

AEP®

ADJUSTED DEBT/CAPITALIZATION: 56.90%

Long-Term Debt Maturity Profile

($ in millions)

Year	2007		2008		2009	
AEP Service Corp.	$	-	$	36	$	-
AEP, Inc.	$	345	$	-	$	-
AEG	$	-	$	-	$	-
APCo	$	325	$	200	$	150
CSPCo	$	-	$	112	$	-
KPCo	$	323	$	30	$	-
I&M	$	-	$	50	$	45
OPCo	$	-	$	45	$	106
PSO	$	-	$	-	$	50
SWEPCo	$	90	$	118	$	-
TCC	$	-	$	68	$	-
TNC *	$	8	$	-	$	-
Total	$	1,091	$	659	$	351

Note: Maturities remaining as of March 31, 2007

* - represents TNC first mortgage bonds that were defeased in December 2005

AEP®

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS

AMERICAN ELECTRIC POWER, INC.

Tokyo Investor Meetings September 12, 2007

Hosted by Nikko Citigroup Limited

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

Holly K. Koeppel –
EVP & Chief Financial Officer

Near Term Investor Communication Activities

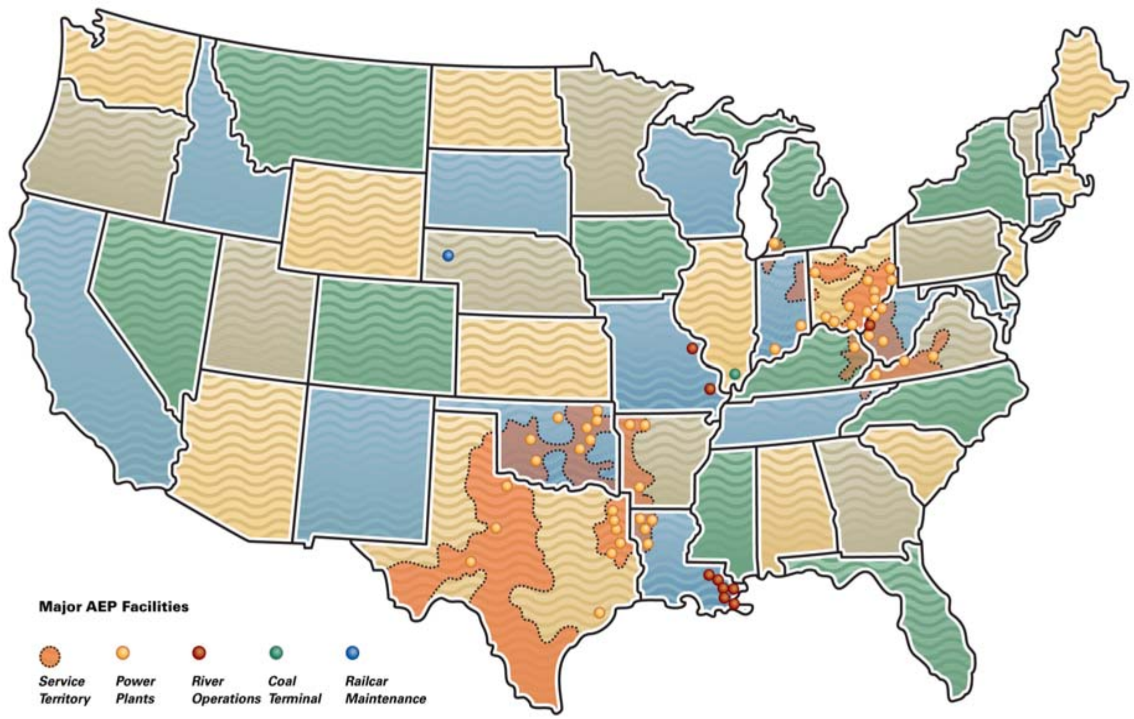
- September 26, 2007 – Merrill Lynch 2007 Power & Gas Leaders Conference, NYC
- October 4, 2007 – Strategic Direction: Financial Analyst/Investor Conference, NYC
- October 11, 2007 – Dublin Investor Meetings
- October 24, 2007 – 3Q07 Earnings Call

Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets:
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio

Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Strategic Direction

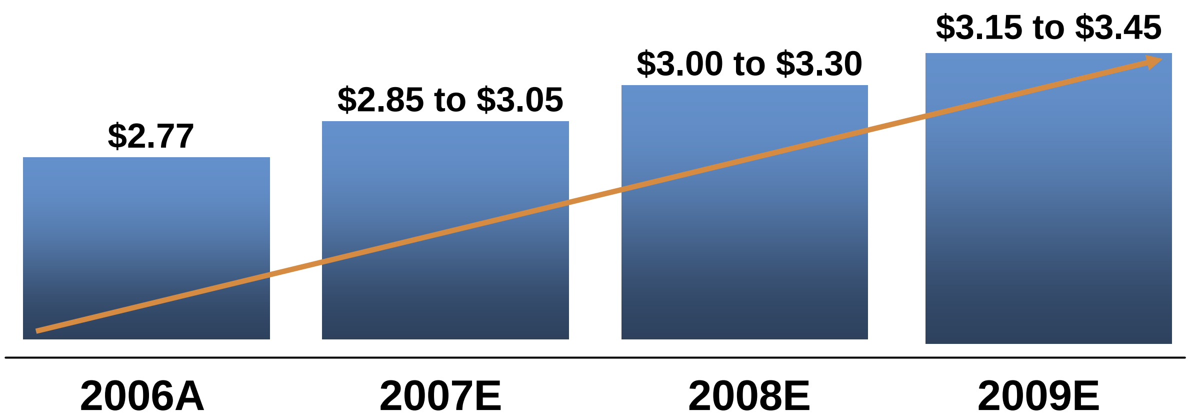
Delivering Value to Investors and Cost-Effective Service to our Customers

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Grow our transmission business
- Achieve adequate returns on all assets

Our core utility mission: Bring reasonably priced electric service to our customers, thereby strengthening our communities and rewarding our investors

Long Range Performance – Consistent and Predictable Growth

2007, 2008 & 2009 Ongoing Earnings Guidance Ranges: 5-7% Annual Growth



- Continued disciplined investment in existing utility operations:
  - Reliability
  - Environmental
  - New Generation & Distribution Infrastructure
- Investment in new transmission opportunities
- New investment coupled with rate recovery
- Continued cost control
- Timely Rate Relief
- Maintain Credit Ratings
  - BBB/Baa2/BBB

Future earnings growth driven by native load growth and substantial utility investment opportunity focused on regulated operations

Summary of 5-7% Long-Range Growth Components

Energy sales growth of 1.5%

Rate base investment

- Generation plant purchases & build
- Transmission – interstate & intrastate
- Distribution
- Reliability

Transmission company

Commercial operations

Regulatory strategy

- Achieve timely returns
- Seek cash returns on investment during construction
- Create & secure innovative rate plans
  - Pursue post-2008 solution in Ohio
  - Expand use of trackers
  - Formula rates

New baseload generation and transmission projects largely reflect upside to the long-range earnings growth targets of 5-7%

Capital Investment Focus

- Completion of our intensive environmental retrofit program, coupled with associated rate relief, allows us to redeploy capital into other areas
- Near-term
  - In our western footprint, our capital investment will focus on new generation
  - In our eastern footprint, our capital investment will focus on modernization of the distribution infrastructure, also known as the 'Modern Grid' program
  - In both the east and west, we will focus on successful demonstration and implementation of the chilled ammonia technology for carbon capture
- Long-term
  - Throughout our service territory, transmission and IGCC will be our long-term capital investment focus

9

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528** *
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

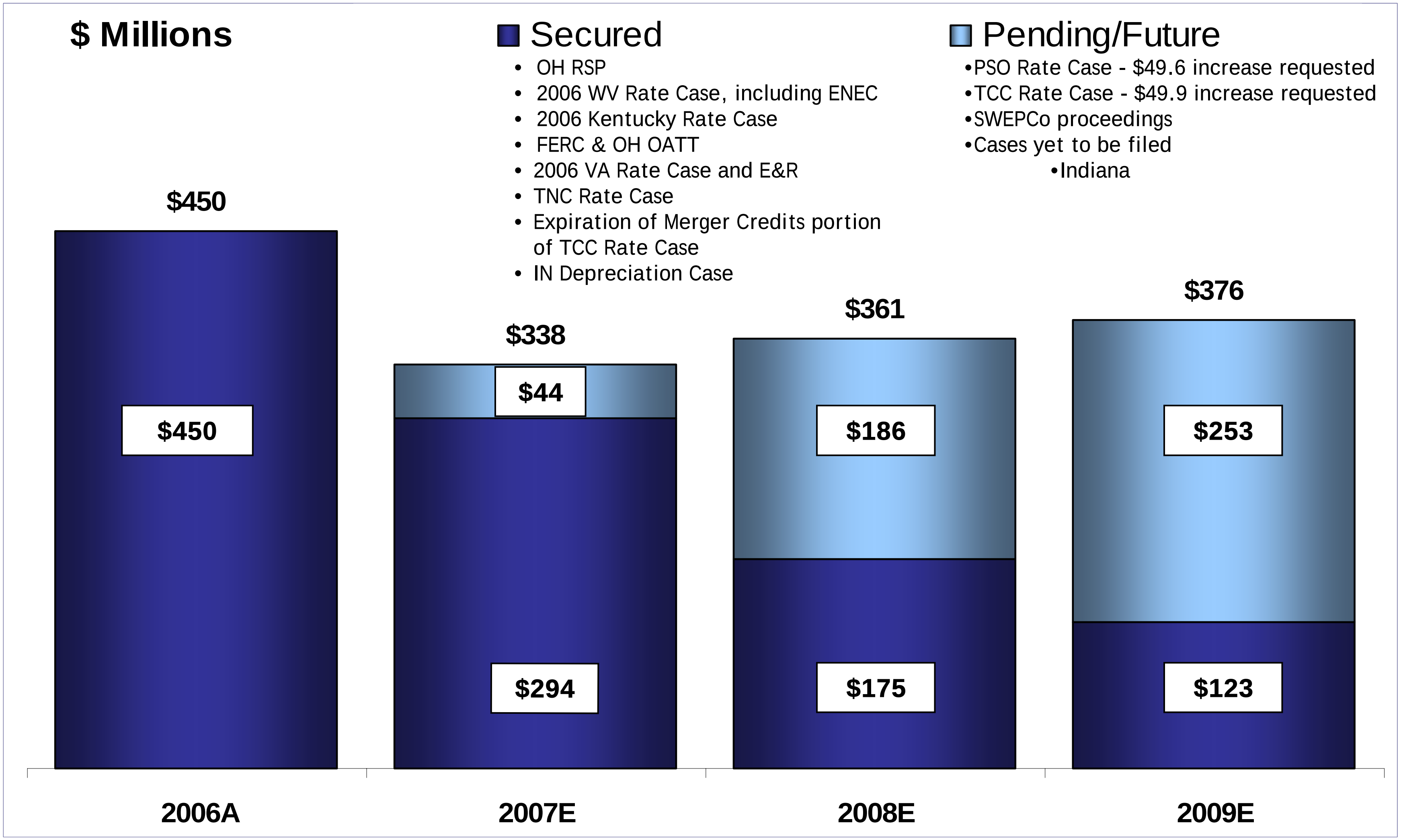
Add: Lawrenceburg Plant Purchase	$325
Add: Dresden Plant Purchase	$85
2007 Including Lawrenceburg & Dresden	**$3,952**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

* Includes Lawrenceburg purchase of $325MM and Dresden purchase of $85MM in 2007

Growth investment to be funded by cash from operations via rate relief and debt issuances

Incremental Rate Relief Composition



Rate relief is a critical element to AEP's financial success and allows us to pursue additional generation, transmission and infrastructure investment

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2007 Regulatory Activity Completed

Appalachian Power - Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power - West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓ $54.8 million covers increased costs related to coal and purchased power
  - ✓ $28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓ Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power - Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

In Hand to Date - $294MM of the $338MM
Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Virginia Filings – Fuel Factor and E&R
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - ✓ SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

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Generation Investment Forecast

Public Service Company of Oklahoma Rate Proposal

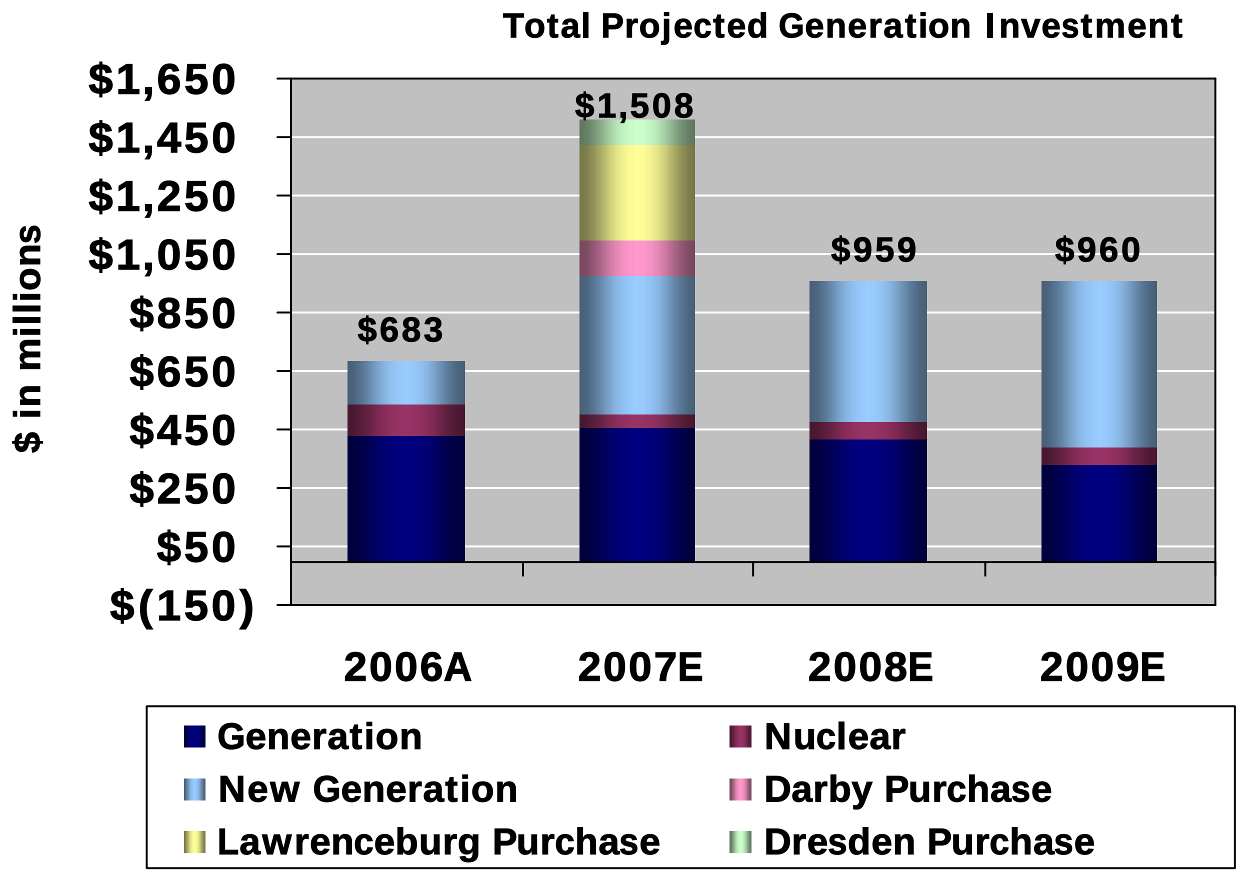
- Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP

Distressed Generation Initiative

- New generation resources required to meet growing electricity needs of our customers
- Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 and 1,620 MW in 2007

WV and VA IGCC Filings

- Filings made with both commissions requesting return on CWIP, including development design and planning costs



Investing in generation to meet the growing electricity demands of our customers at an attractive price

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005
- $268/kW

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007
- $295/kW

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007
- $227/kW

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005
- $198/kW

Addition of gas-fired generation allows us to meet the growing needs of our customers and provides the company with greater fuel flexibility

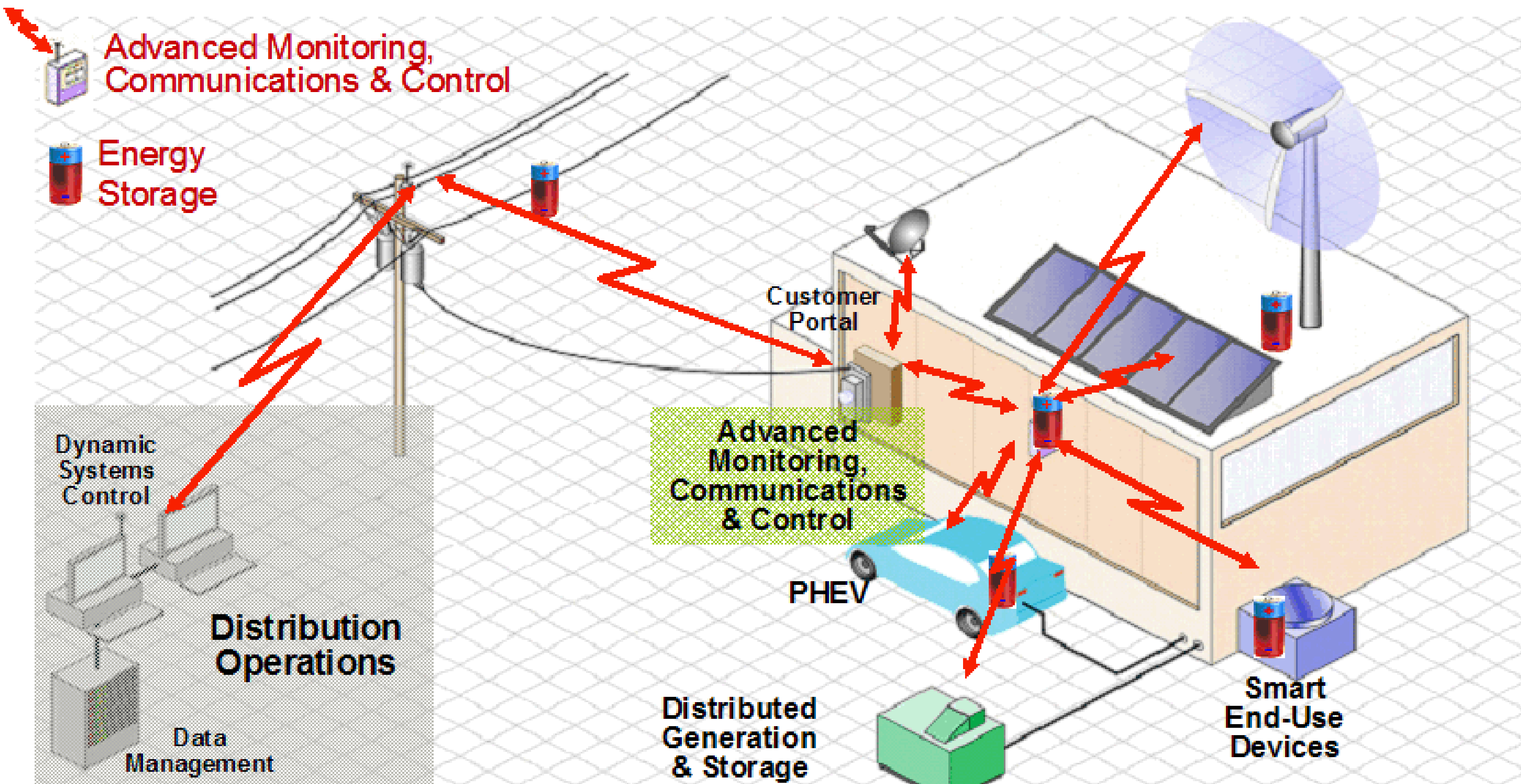
New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	900 (4)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	630	2017

(1) 150MW were declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(5) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

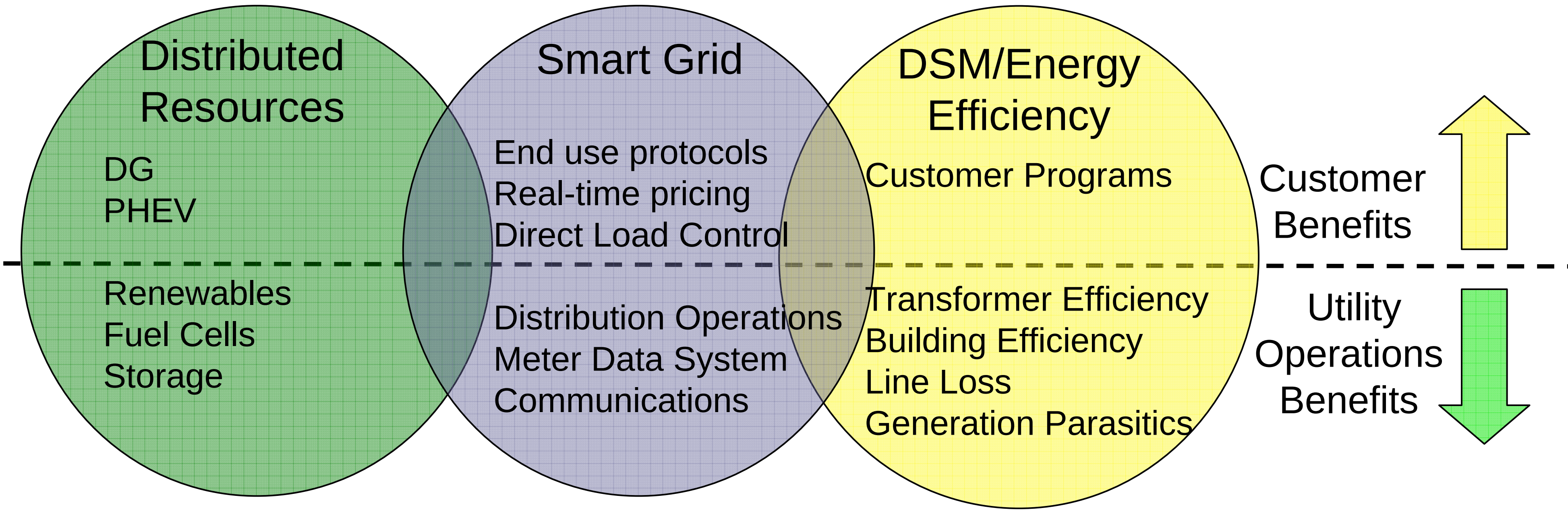
AEP is meeting the growing electricity needs of customers through the pursuit of new, economic generation facilities

Distribution Operations of the Future



Courtesy of EPRI for source image

The “Modern Grid” Initiative



AEP has initiated an internal project to help clarify these inter-relationships, and develop our strategy for deploying these programs and technologies

Modern Grid Initiative

- Project to develop a vision for AEP's distribution and customer services business in the future, including the development of new customer programs and a plan to deploy advanced technologies

- Focus on:
  - Enabling greater customer control over energy usage
  - Enhancing conservation activities and overall environmental performance
  - Optimizing the operation of AEP's distribution business

- AEP needs to pursue:
  - Providing customers with real-time pricing signals
  - Providing customers with program options that encourage reduced energy consumption and lower peak demand
  - Promoting the use of electric vehicles and distributed generation
  - Using real-time system intelligence on our distribution system to improve operations and customer service
  - Utilizing advanced electricity storage for peak usage and power outages
  - Enabling technologies such as biomass, solar and fuel cells
  - Modeling future customer behaviors as a consumer of our own products

- Examples include:
  - Customer Energy Efficiency and Demand-Side Management Programs
  - Advanced Metering Infrastructure (AMI) & Distribution Automation (DA)
  - Distributed Generation, Renewable Resources and Energy Storage

Pace of our Modern Grid Implementation Determined by Regulators

- **Arkansas** – SWEPCo filed 'quick-start' programs with the commission on July 1, 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-for-performance pilot that results in a payment to customers who curtail load upon request. We are awaiting commission approval.

- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and administering a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.

- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.

- **Ohio**
  - Recent Governor remarks indicate modernization of Ohio's infrastructure is a high priority and his plan would allow single-issue rate cases for these high-priority investments and system upgrades.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.

- **Texas**
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.

- **Virginia** – The Virginia commission has initiated a docket to address various aspects of demand-side management and energy efficiency.

Energy efficiency is an investment, which should be treated by regulators in the same manner as investments in generation, transmission and distribution

Environmental Investment Forecast

Ohio Rate Stabilization Plan

- Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
- Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related investments – activation of 4% rider

West Virginia Rate Settlement

- Mechanism in place to provide rate increases through 2009 for ongoing environmental investments

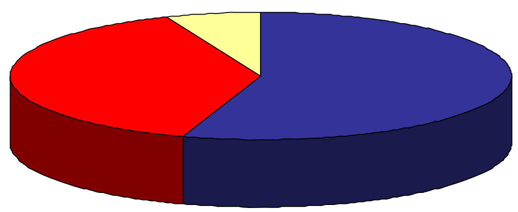
Virginia E&R Mechanism

- Allows APCo-VA to recover incremental environmental & reliability costs
- Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Additional filing made in July 2007 requesting recovery of $60MM of E&R costs

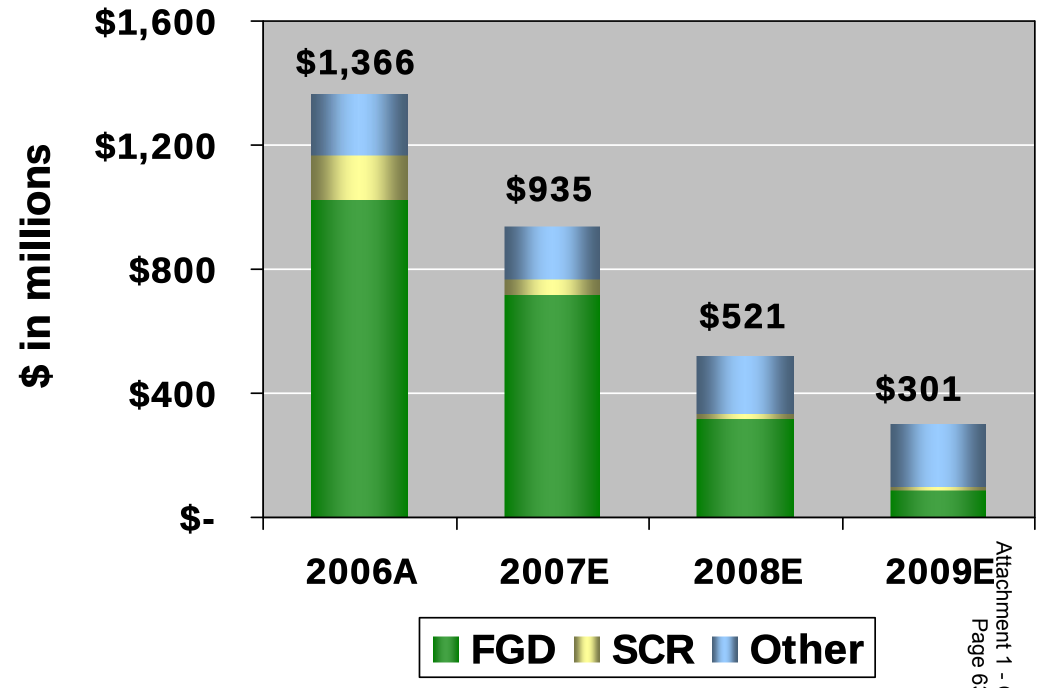
Kentucky Environmental Surcharge

- Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment



Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
West Plants					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

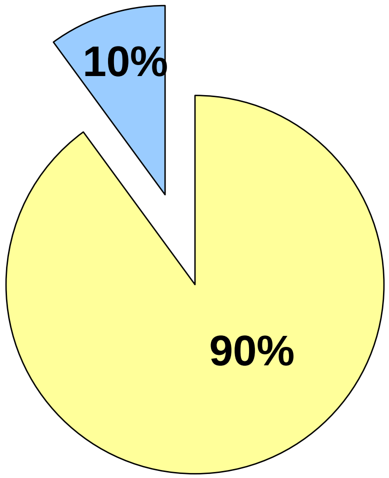
At the conclusion of our current environmental retrofit program, over 47% of our coal-fired generation fleet will be equipped with SCRs and over 50% will be scrubbed (FGD).
AEP's total coal fleet capacity = 24,630 megawatts *

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Materials and Vendors – AEP's Advantage

Environmental Program Costs:

Active/Firm Costs to Remaining Estimated Costs



- Actuals To Date & Firm Costs
- Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Babcock Power – SCR
- Pullman Power – Stack Supplier
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

First-Mover Advantage:

- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- AEP capital costs for a scrubber average approximately $250/kW
- We have since seen a 30-60% increase in material costs and a 15% increase in labor rates
- An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

AEP's customers and shareholders benefit from first-mover advantage through lower contracted pricing & reduced market escalation exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve

AEP AMERICAN ELECTRIC POWER

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

Incremental Reduction quantity: 5MM tons/yr

Timing: To take effect/receive credits by 2011

Methods

- +1000 MWs of Wind PPAs – 2MM tons/yr
- Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
- Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
- Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
- Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

IGCC and Ultra-supercritical coal plants

Commercial solutions for existing fleet

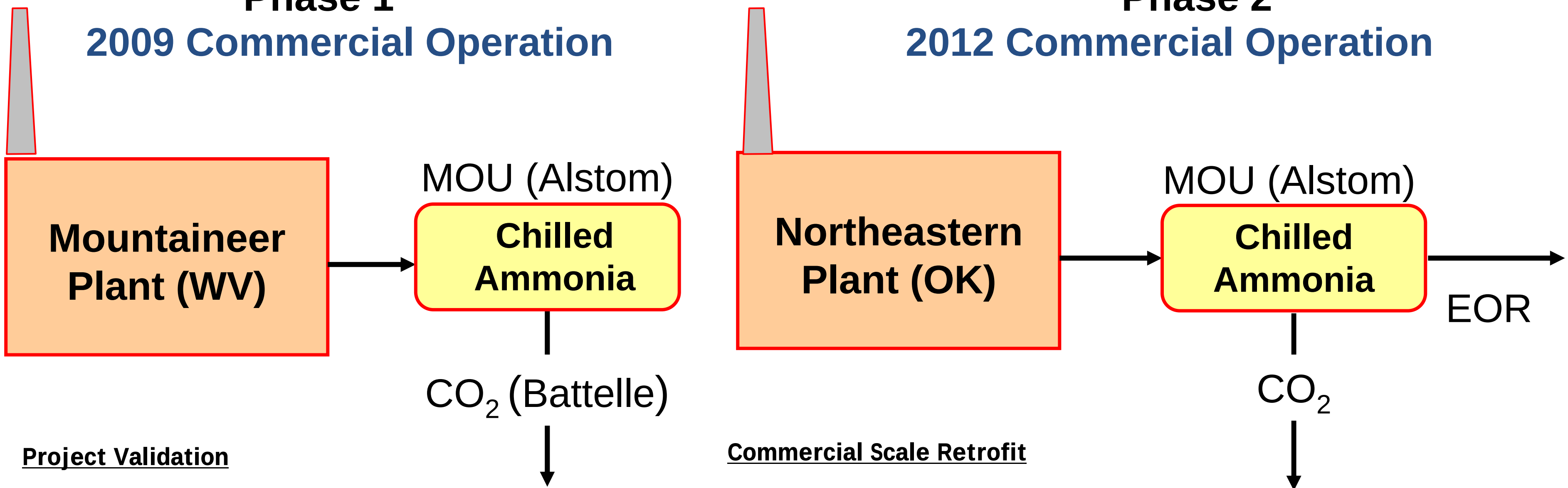
- Chilled Ammonia
- Oxy-Coal

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion carbon solution provides pure CO_2 stream for capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

10 MW_e scale

Teamed with B&W at its Alliance Research Center and 16 other utilities

Demo complete 3Q 2007

AEP funding of $50k

Commercial Scale Retrofit

Retrofit on existing AEP sub-critical unit (several available)

150 – 230 MW_e scale retrofit

4,000 – 5,000 tons CO_2 per day

Team with B&W

AEP funding of ~ $1.5M for feasibility study

Feasibility study to be completed in late 2007/early 2008

Combustion conversion technology for existing coal fleet – longer lead time with enhanced viability and long term potential

Significant Opportunity for Investment

The current U.S. transmission system cannot support the demand of tomorrow's energy supply needs

- Investment in transmission has lagged load growth
- Transmission congestion equates to increased costs to customers
- Large-scale wind generation in remote areas requires a high-capacity transmission system for efficient energy movement to load centers

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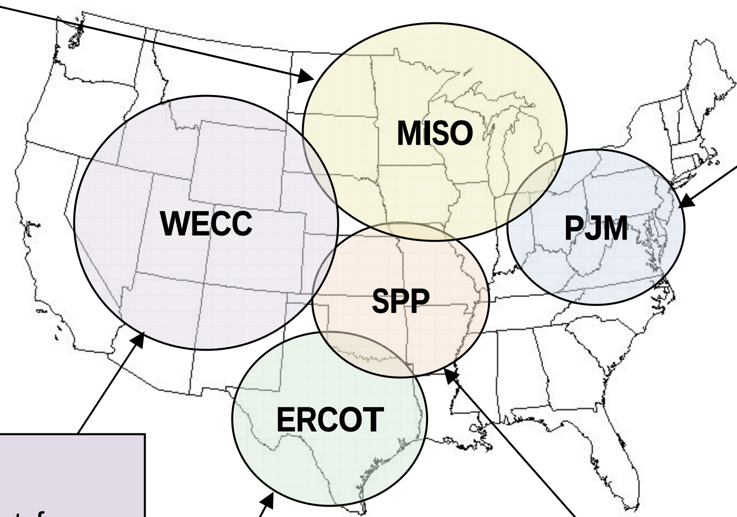
Transmission Investment Opportunities

Investigation of opportunities needs to be mindful of regional drivers

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues



PJM

Congestion will be reduced and reliability will be increased

WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

ERCOT

Load growth and access to wind resources driving transmission investment

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

~ $3 Billion I765$_{TM}$ Project in PJM
~ $2 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

Building the next US interstate system for enhanced reliability and market efficiency

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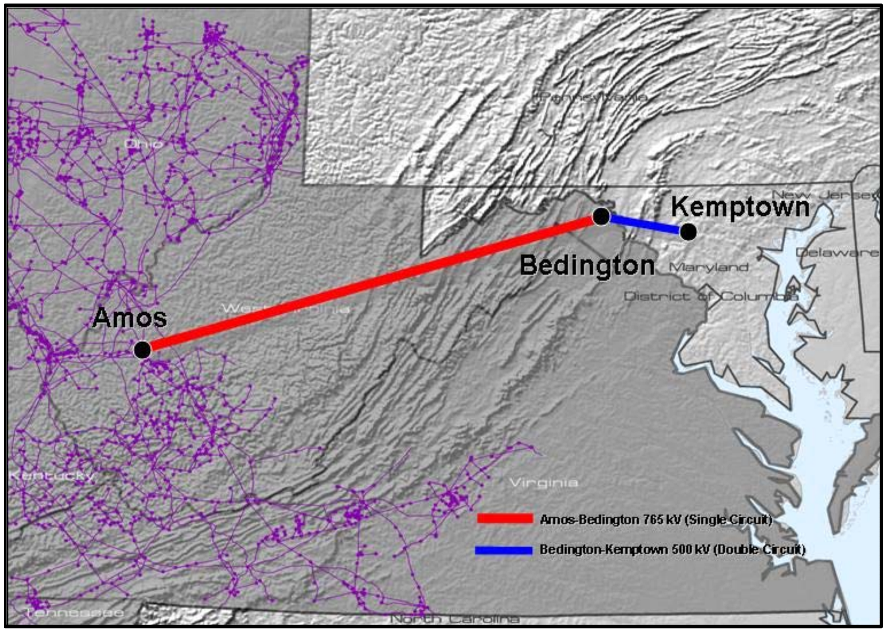
PJM I-765™

Execution in Action

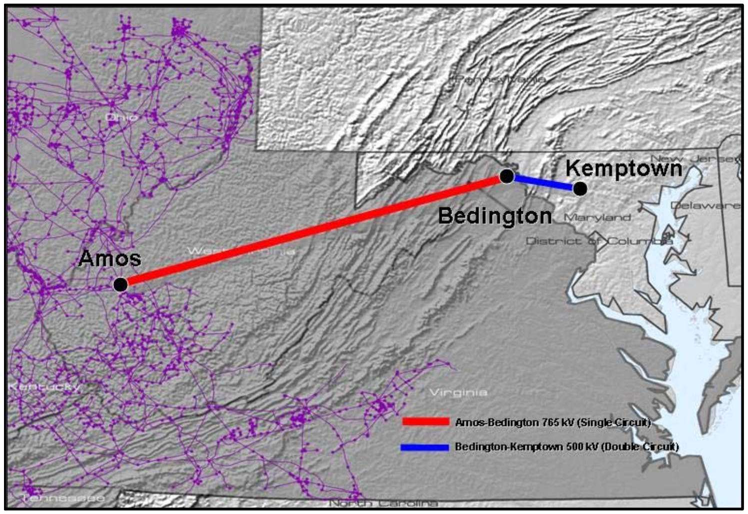
- ### *Overview*
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM approved)
- ### *Benefits*
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation
- ### *Phase I Progress to Date*
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012



PJM I-765™ Phase I cont'd

Execution in Action

- ### *Funding Plans/Transaction Structure*
  - Formed a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
  - JV portion of the I-765™ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - I-765™ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007



- ### *Key Regulatory Activity Completed*
  - FERC declaratory order approved July 2006
  - PJM approved plan June 2007

- ### *Key Next Steps*
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012

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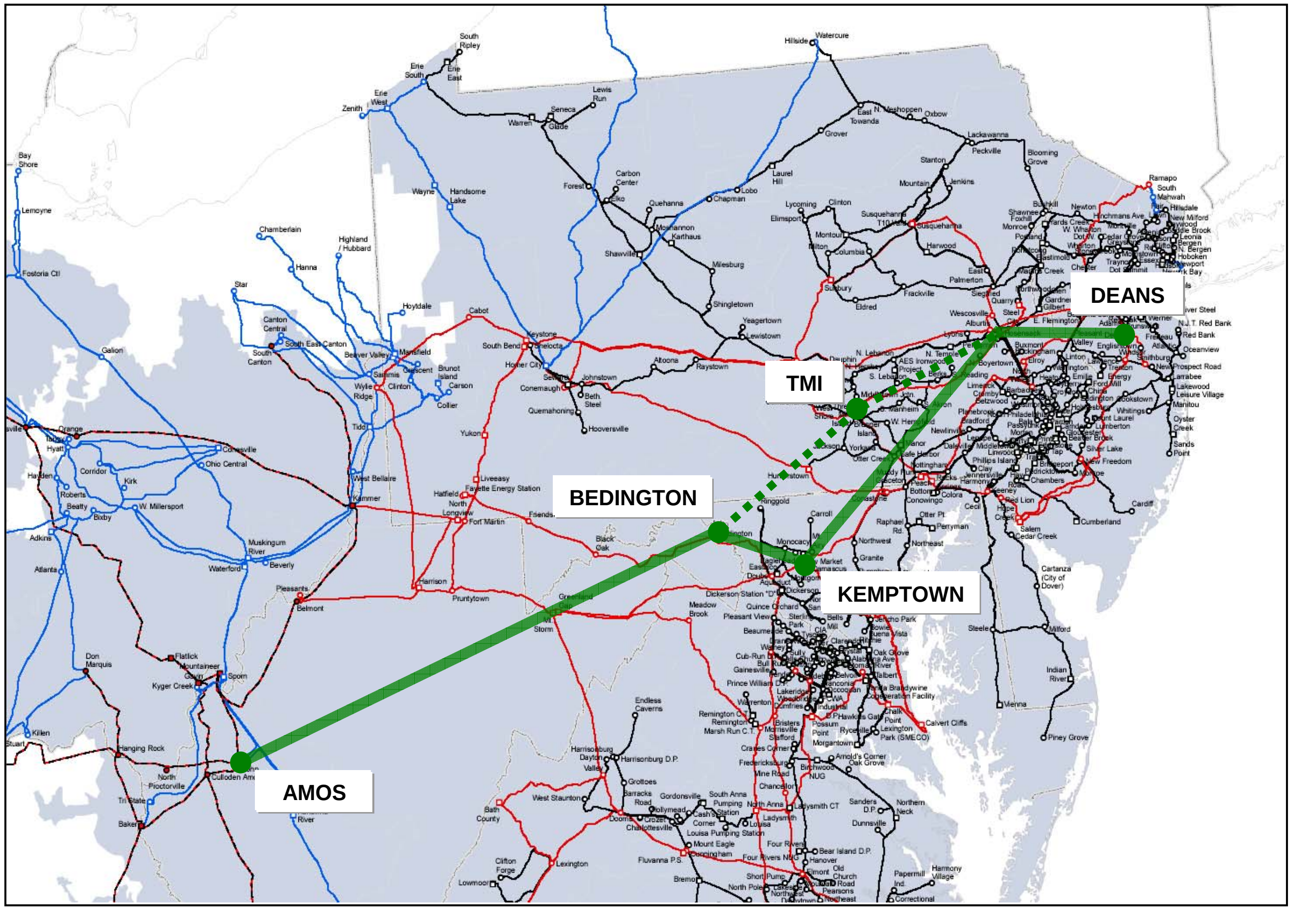
PJM I-765™ Phase II (Bedington-Deans)

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



AEP AMERICAN ELECTRIC POWER

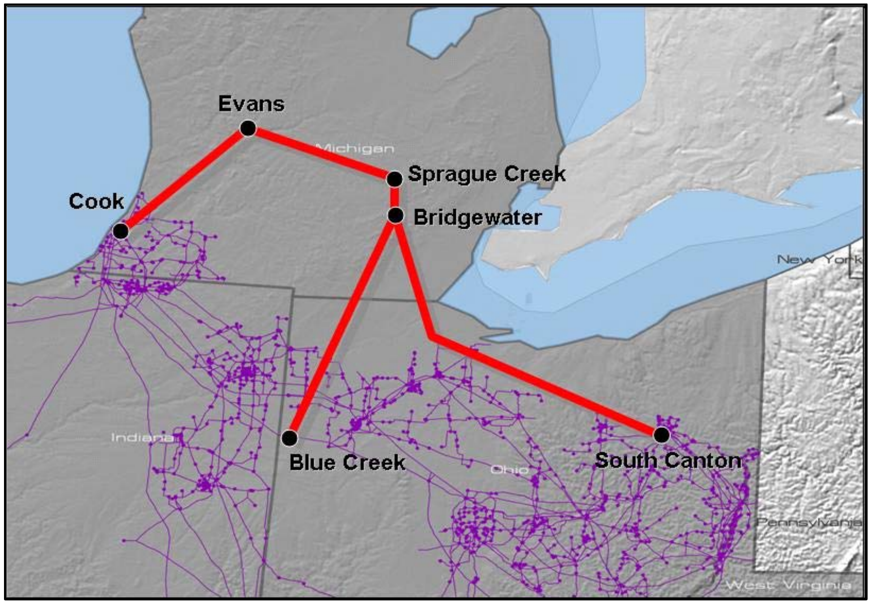
765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.0 billion investment (before ownership division)

- *Benefits*
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW

- *Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

Overview

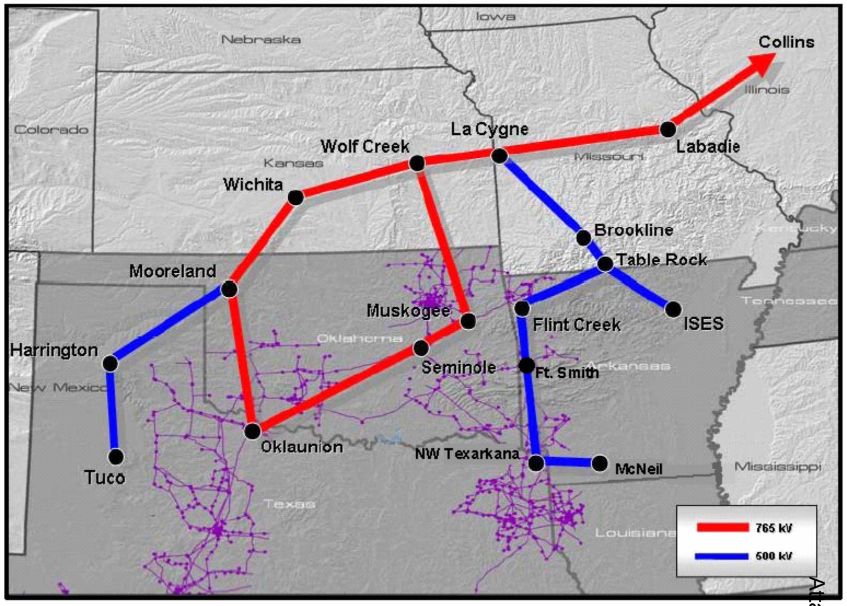
- July 2006 AEP submitted conceptual project for six 765-kV lines
- Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
- 610 miles from Kansas to Arkansas
- $3.0 billion investment (before ownership division)
- Proposed 2012-2017 construction period
- SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
- SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri

Benefits

- 4,000 MVA capability

Next Steps

- Study disclosure – Fall 2007
- JV formation (Partner-TBD) – Fall 2007
- SPP RTO/BOD EHV Overlay approval – Summer 2009
- SPP RTO FERC Filing – Fall 2009
- Siting approval – Fall 2011
- Estimated completion – Summer 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT Status Update

ETT: Delivering Power for Texas' Future

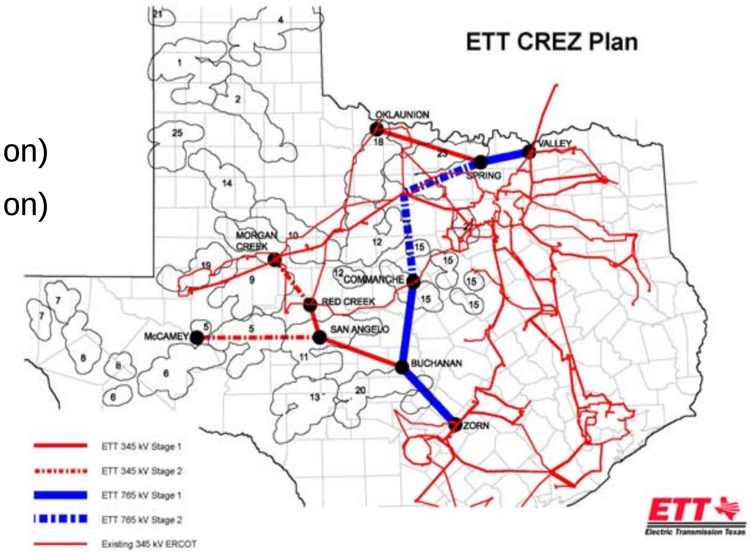
- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP; business manager provided by MidAmerican.
  - Investment opportunities can be offered by either partner and accepted or rejected by ETT.

- *Transaction Status*
  - Formation documents finalized and Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in September 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

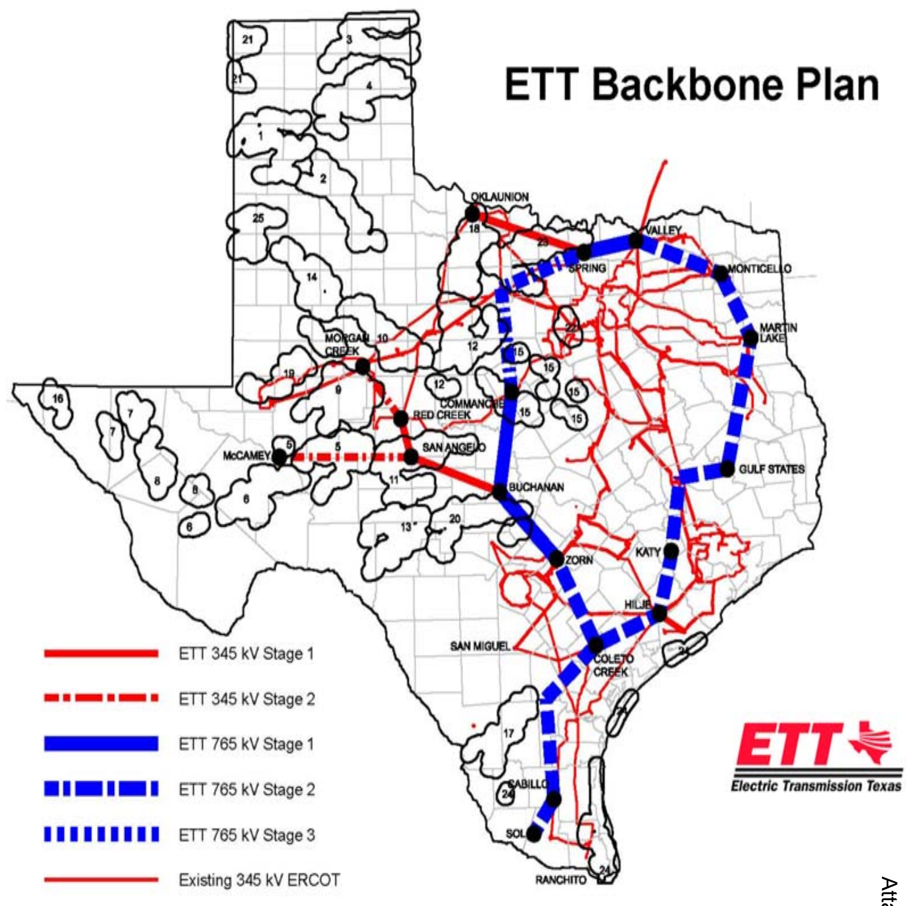


- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).



AMERICAN ELECTRIC POWER

2007 Ongoing Guidance: $2.85 to $3.05 per share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance *
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash on hand is expected to be $205 million by the end of 2007

AEP AMERICAN ELECTRIC POWER

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital investment is funded by cash from operations and debt issuances

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6327 of 9556

UBS 2008 Natural Gas, Electric Power & Coal Conference

March 6, 2008

Austin, Texas

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Table of Contents

Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,600 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
68%	**23%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

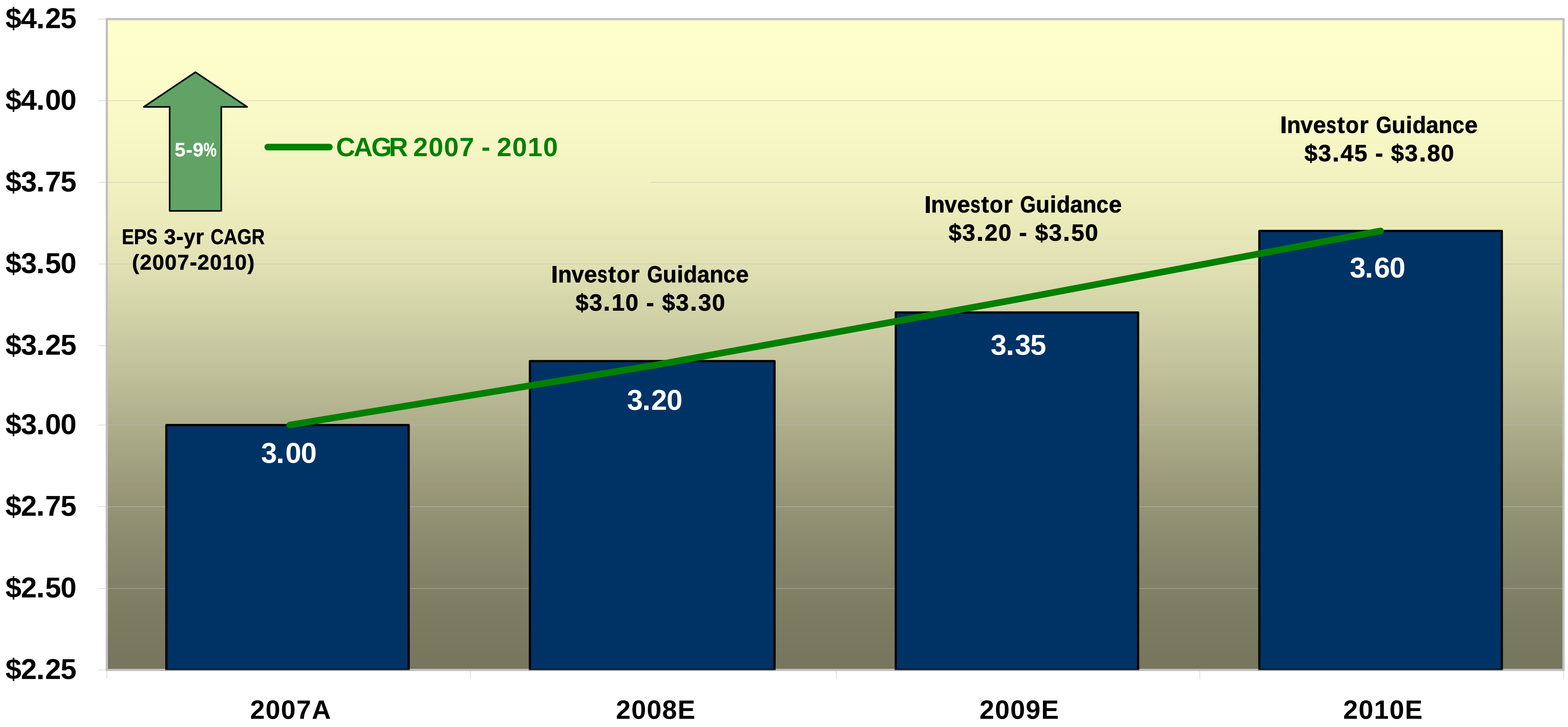
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

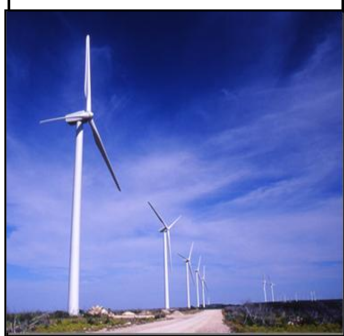
Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast



5% to 9% earnings growth, largely predicated on outcome in Ohio

Vision for Sustainability

Generation	Transmission	Distribution	Customers
			

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

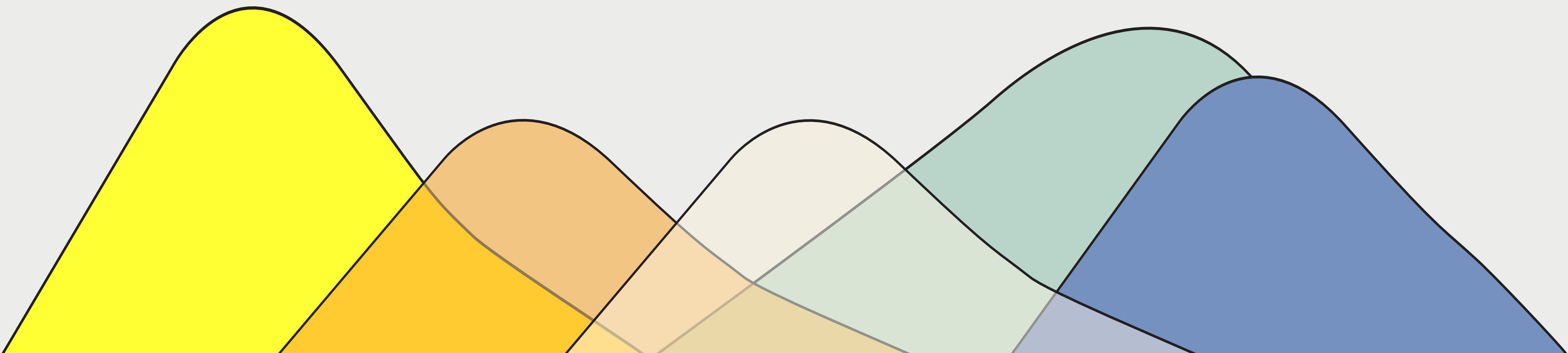
Existing generation and transmission control systems	**gridSMART℠**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Capital Investment Earnings Catalysts

Capital Investment - Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation / CO_2
$5.4B	$1.3B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



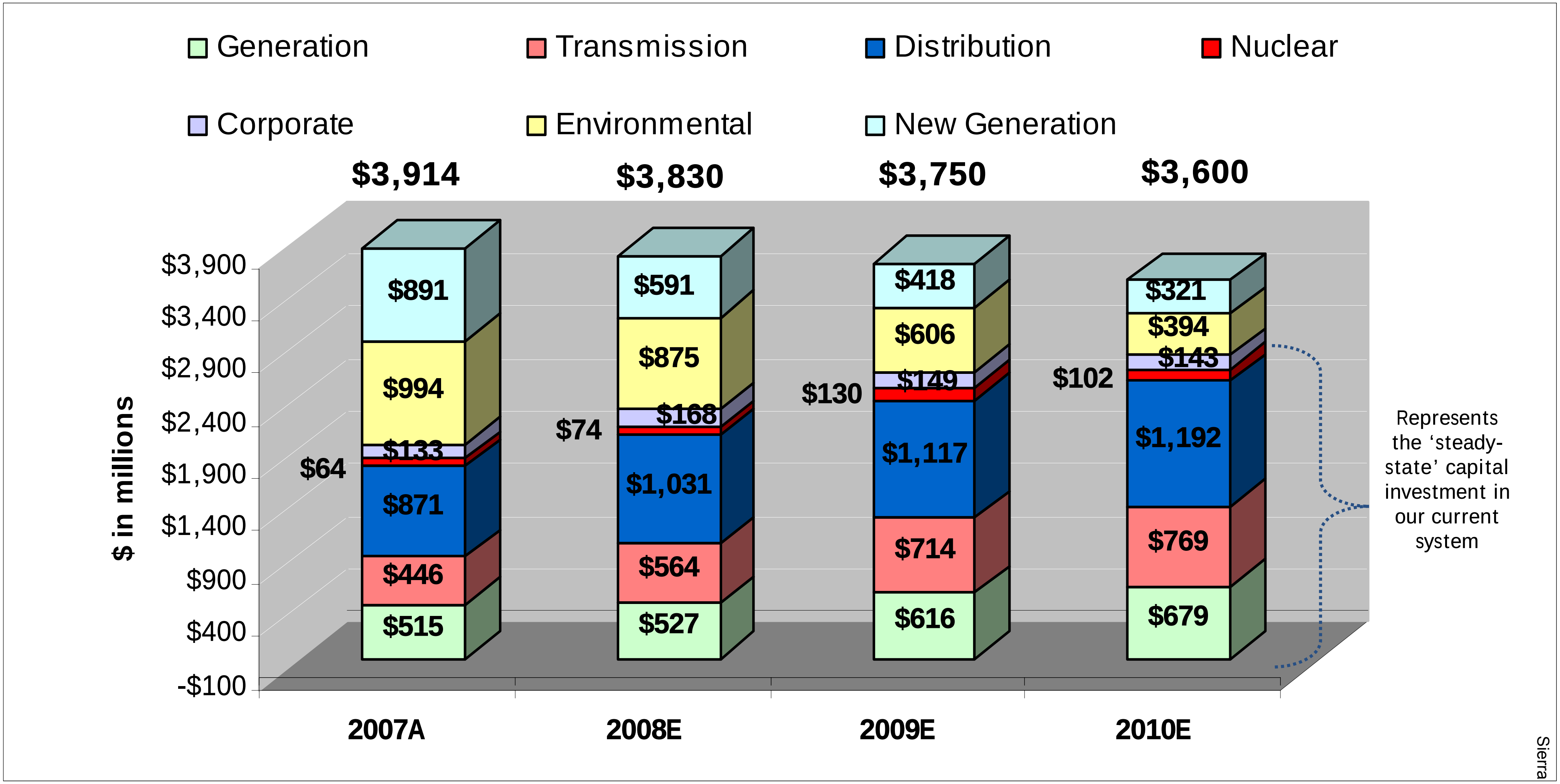
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

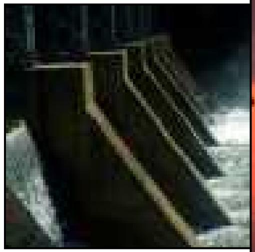
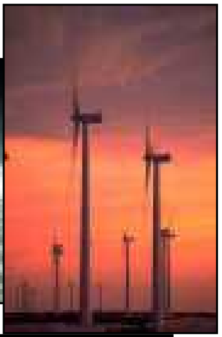
Capital investment is funded from cash from operations and debt issuances.

Domestic Generation Fleet

Coal/Lignite
68%

Nat. Gas/Oil
23%

Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,566 * MW Capacity

*** Includes 270MW of retired/decommissioned generating capacity.**

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B(2)	Coal	IGCC	629	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(2) Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order.

Secured Recovery Mechanism:

PSO Peaking Facilities Rider

Additional Recovery Mechanisms Under Consideration:

Formula based rates

Requests for return on CWIP

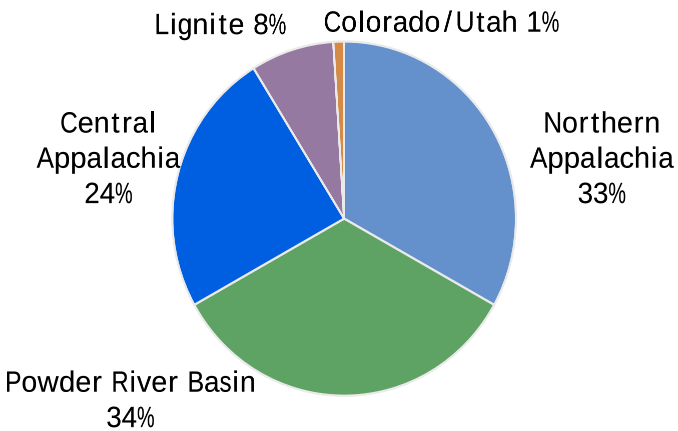
Current and future rate cases

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

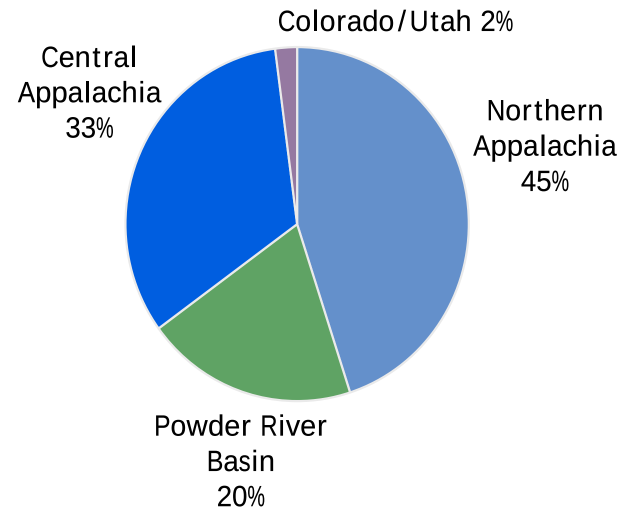
Total AEP System



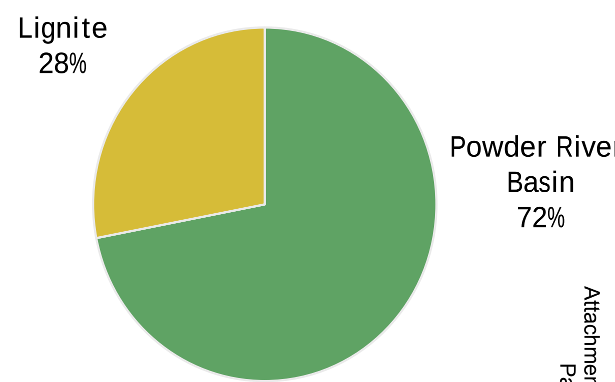
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

AEP East



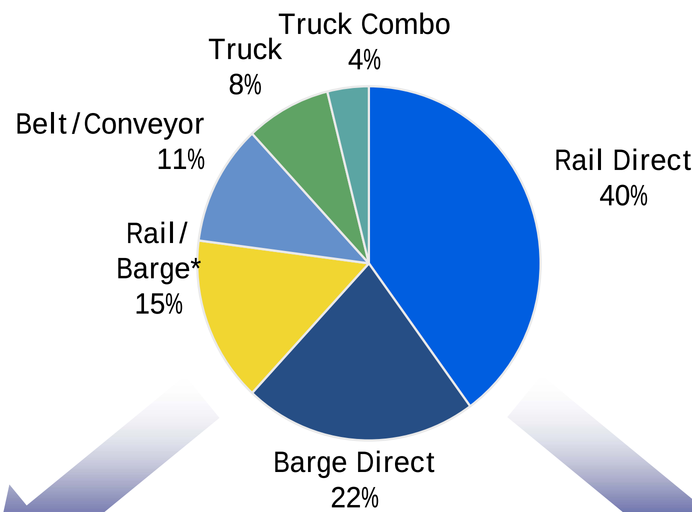
AEP West



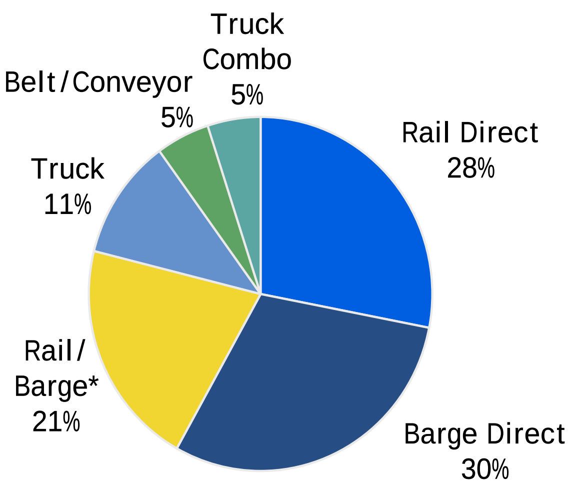
Coal Delivery

Total AEP System

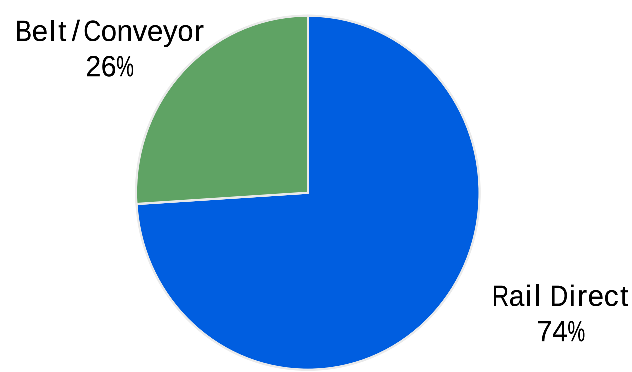
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

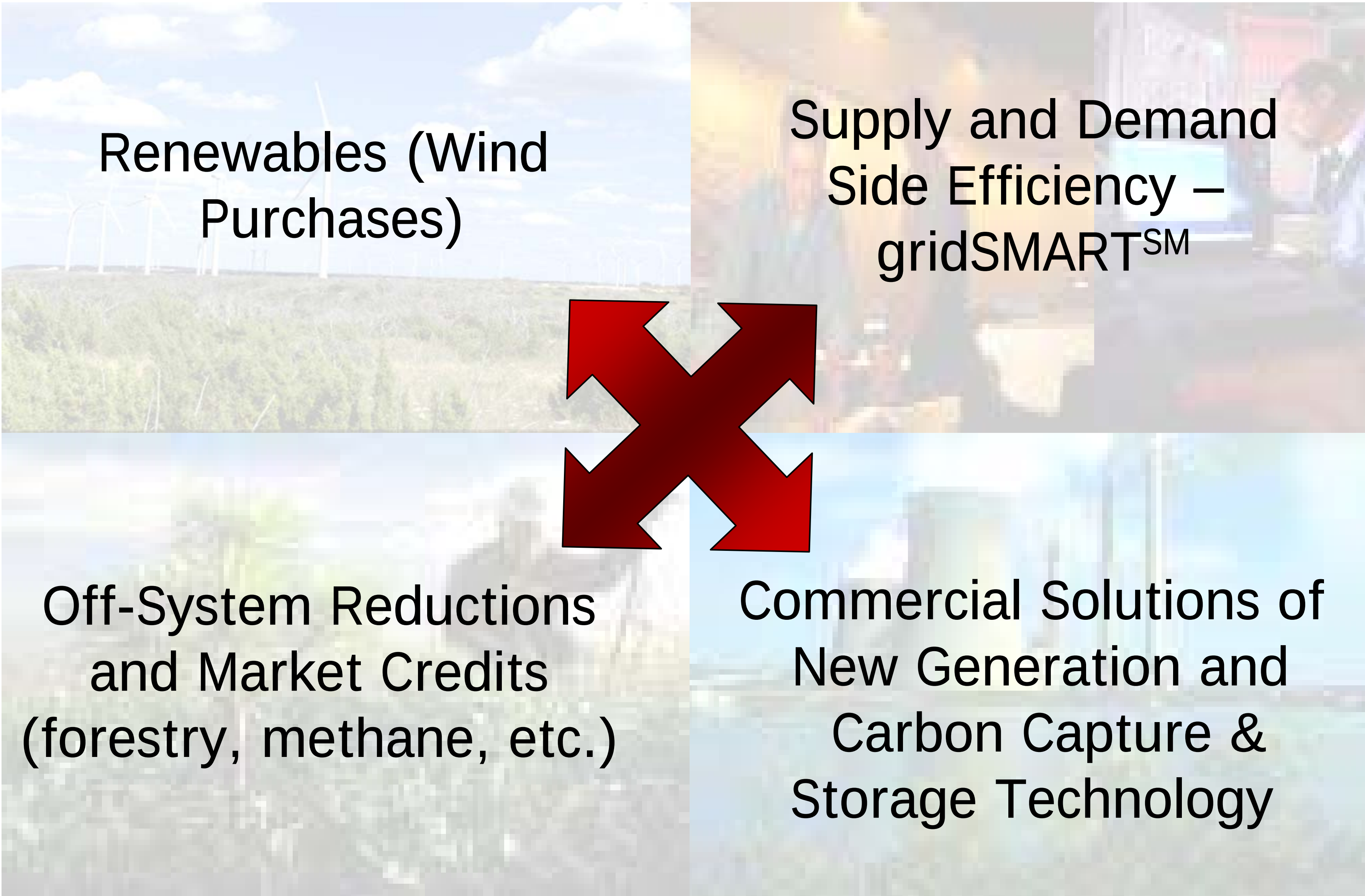
"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives.

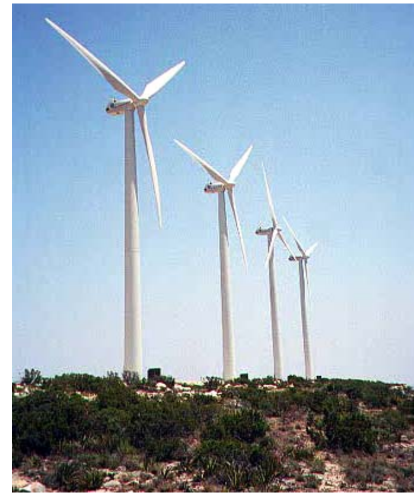
AEP Wind Operations/Purchases

Trent Mesa (2001)

150 MW (100 - 1.5 MW turbines)
Abilene/Sweetwater, TX

Southwest Mesa (1999)

- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser



Desert Sky (2002)

160 MW (107 - 1.5 MW turbines)
Bakersfield, TX

Summary

•Owned/Operated 385 MW

•Wind Purchases 392 MW

•Total Existing Wind at end of 2006: 777 MW

•**New Wind Purchases in 2007: 275 MW**

AEP will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011.

Off-System Reductions

Existing AEP Programs:

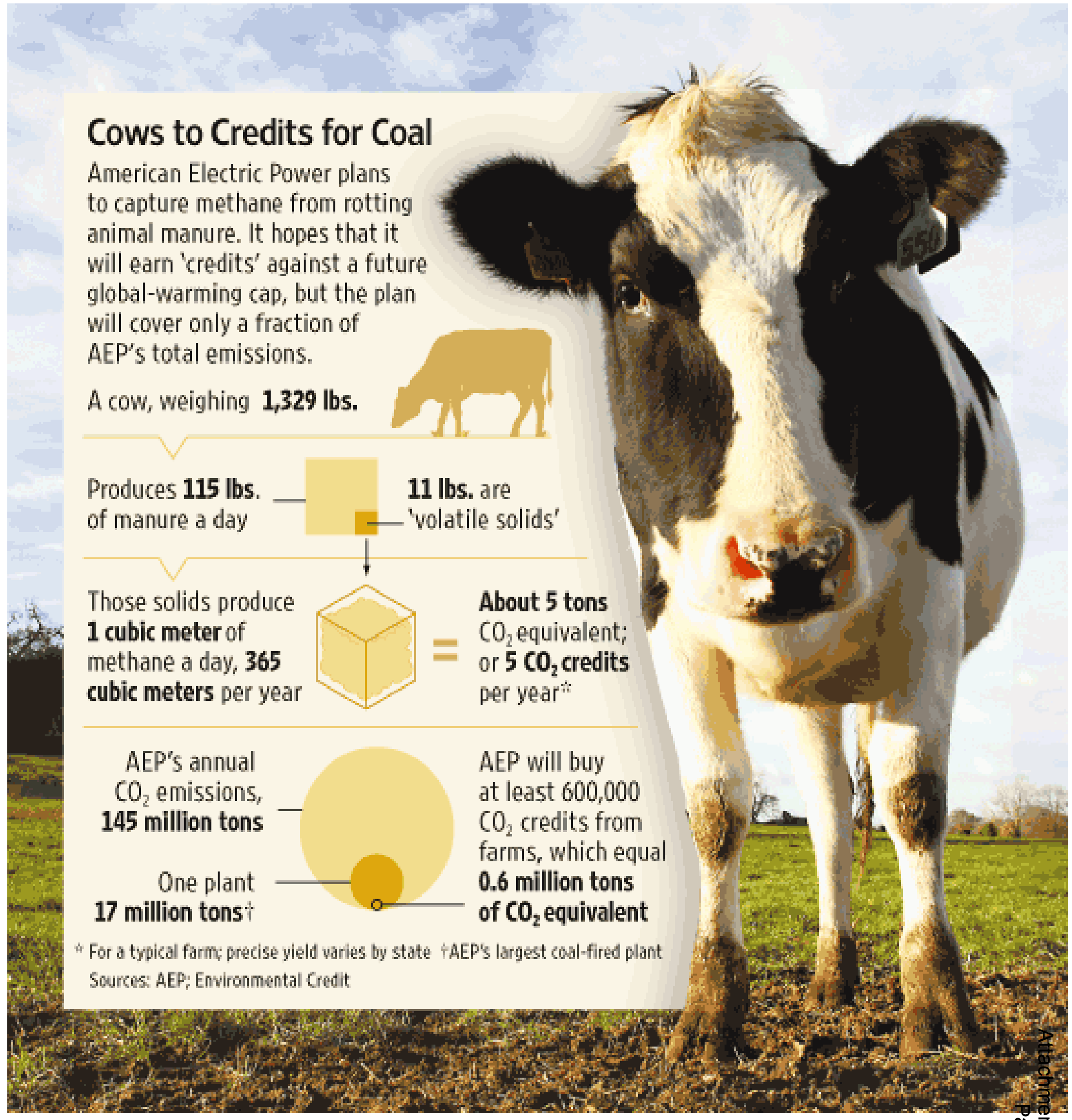
- Forestry - Domestic
    - 350,000 tons / yr
    - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
    - 600,000 CCX carbon credits per year
    - Begins 2010
    - Runs through 2017
    - 51% of credits sourced from “AEP States”



Source: Wall Street Journal June 14, 2007

Advanced Generation & CO_2

Near Term:

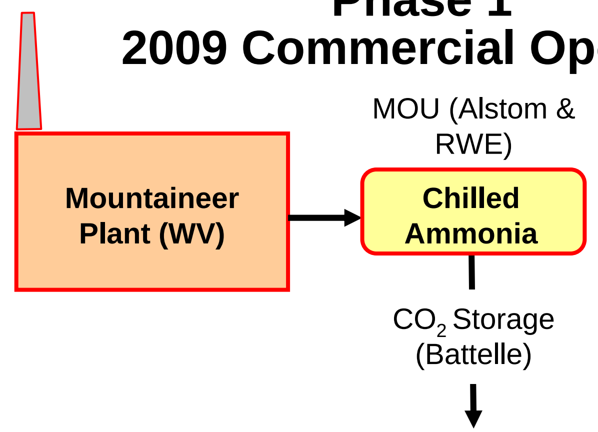
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

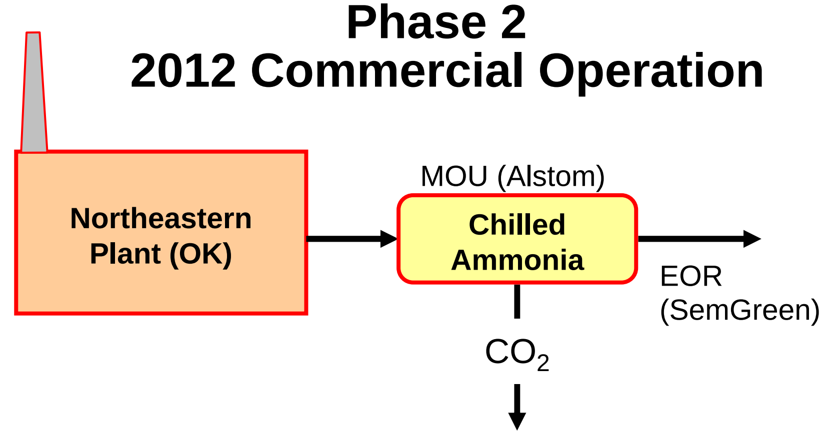
Long Term Strategy (Post-2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by next decade

USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100^{o}F) coal plant in U.S (AR)

AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Oxy-Coal--AEP will also demonstrate (10MWe) and then install oxy-coal CO_2 capture & storage at a commercial sized coal unit (about 200 MWe)—feasibility study to be completed in 2008.

CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

Modified-Combustion Capture

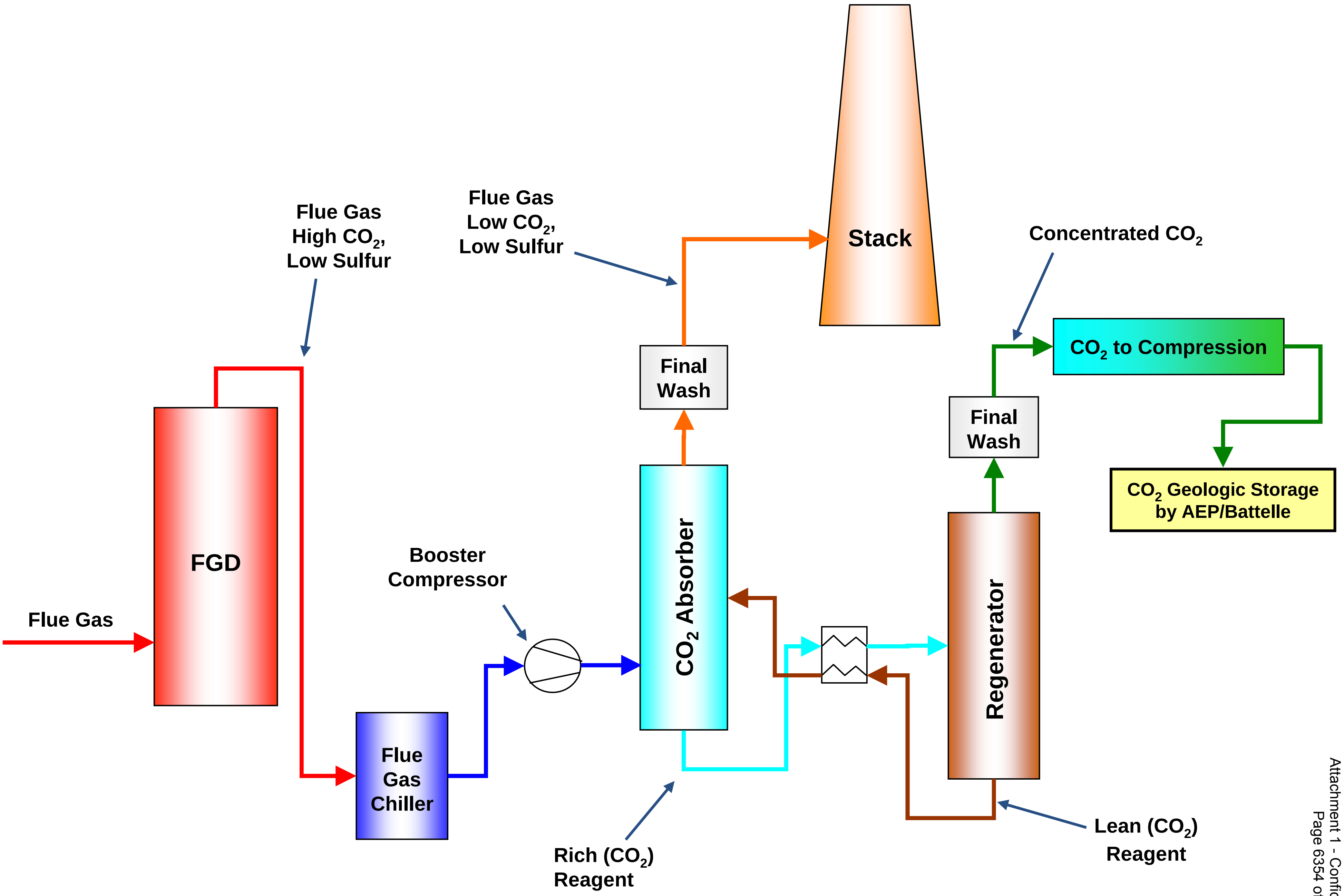
- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

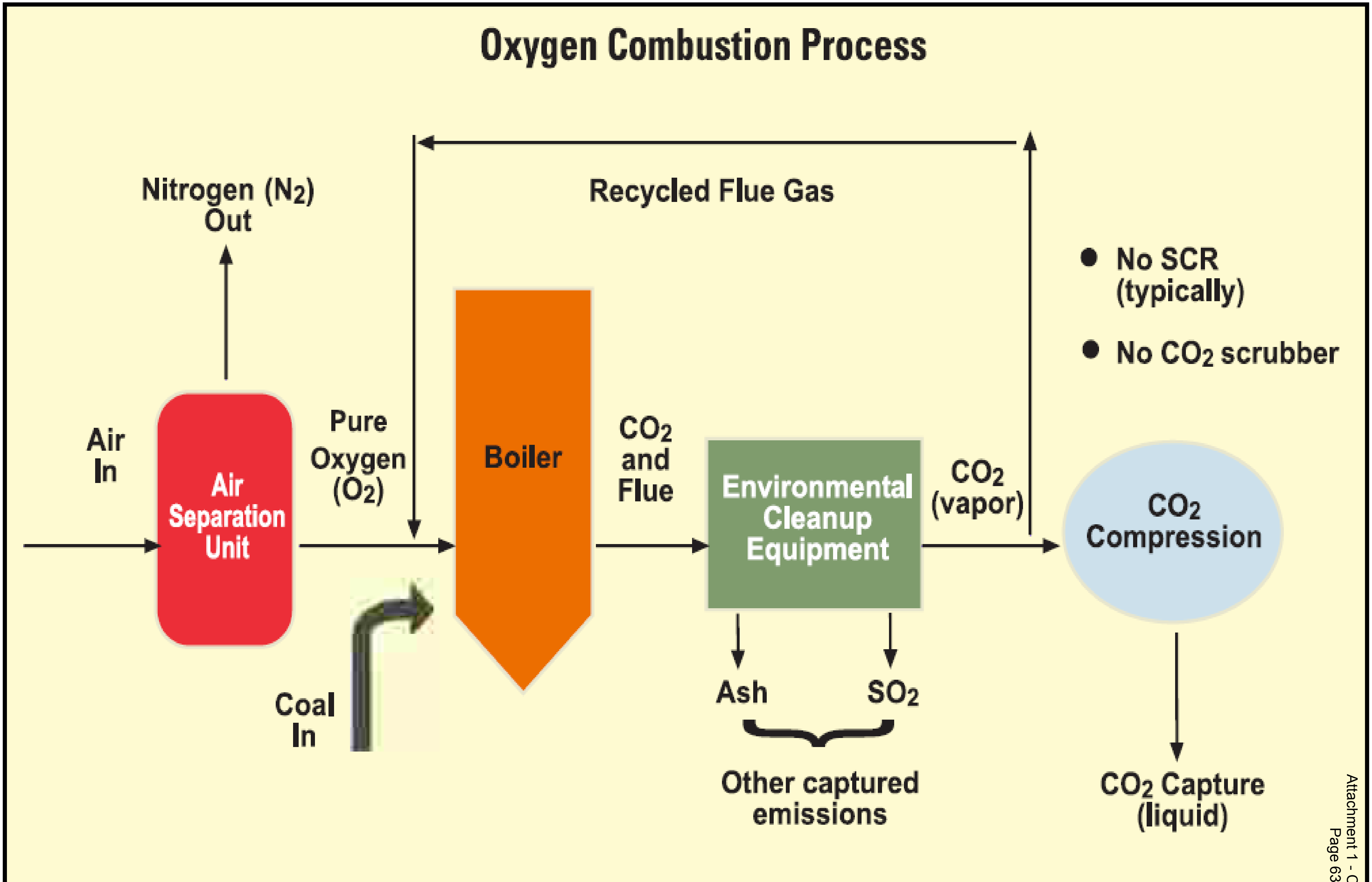
Alstom's Chilled Ammonia Process

Post-Combustion Capture



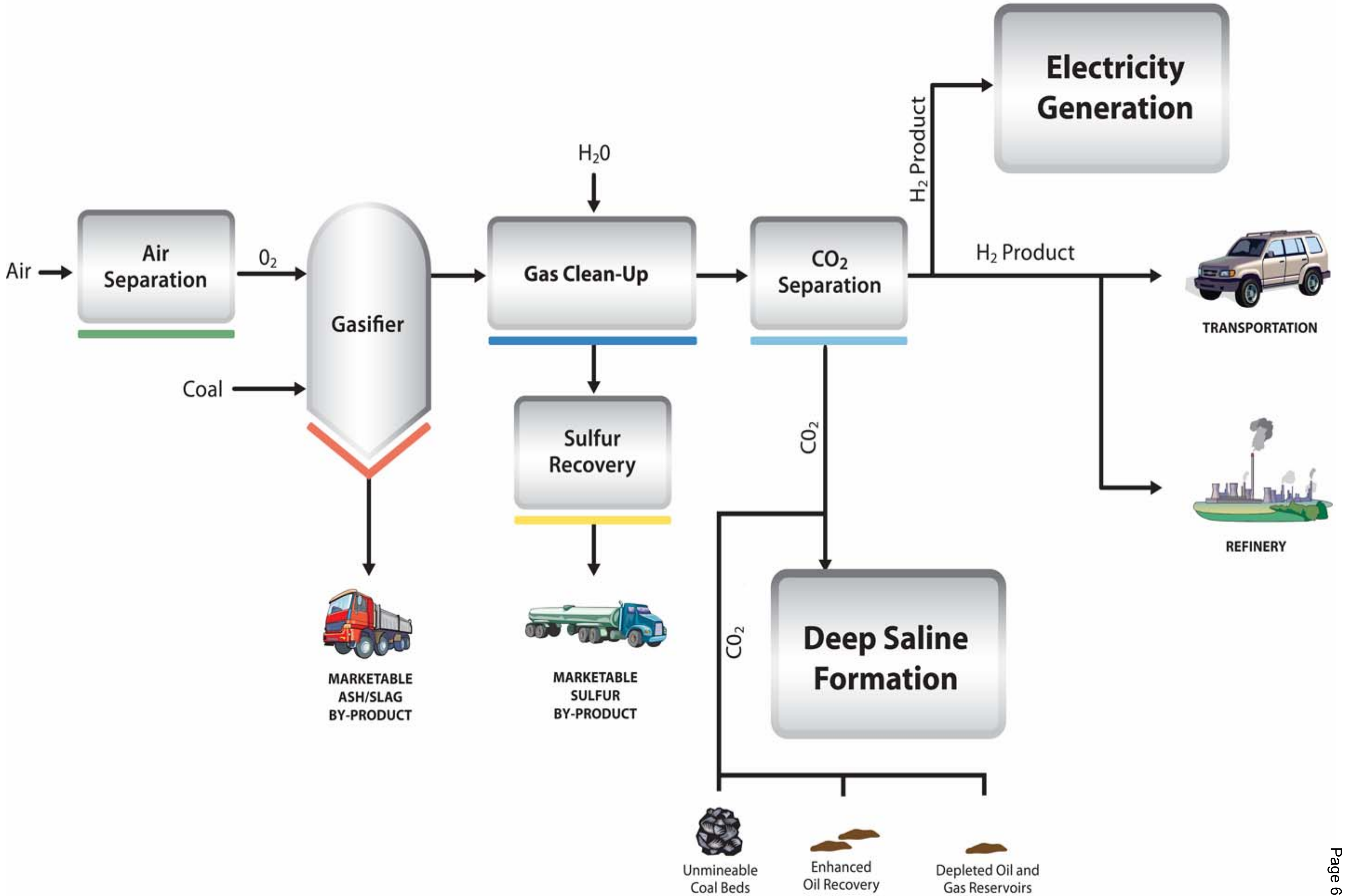
Babcock & Wilcox Oxy-Coal Process

Modified Combustion Capture

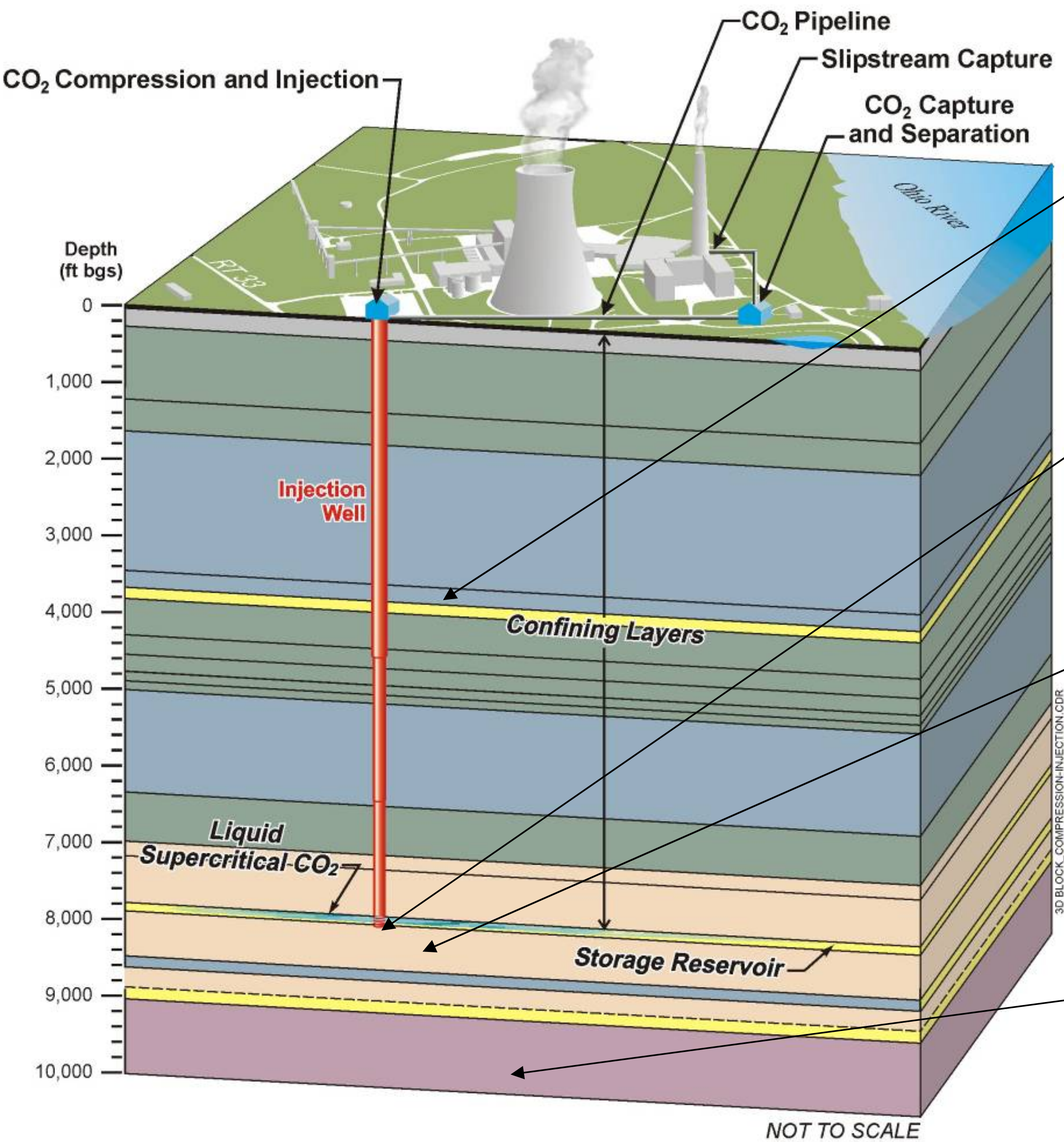


IGCC with Water-Gas Shift Process

Pre-Combustion Capture



CO_2 Injectivity in the Mountaineer Area



CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the “B zone” within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

Distribution - gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

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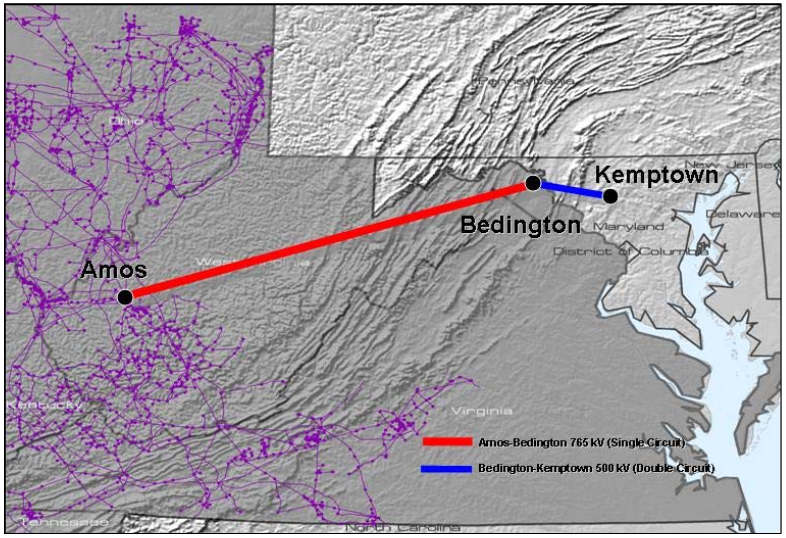
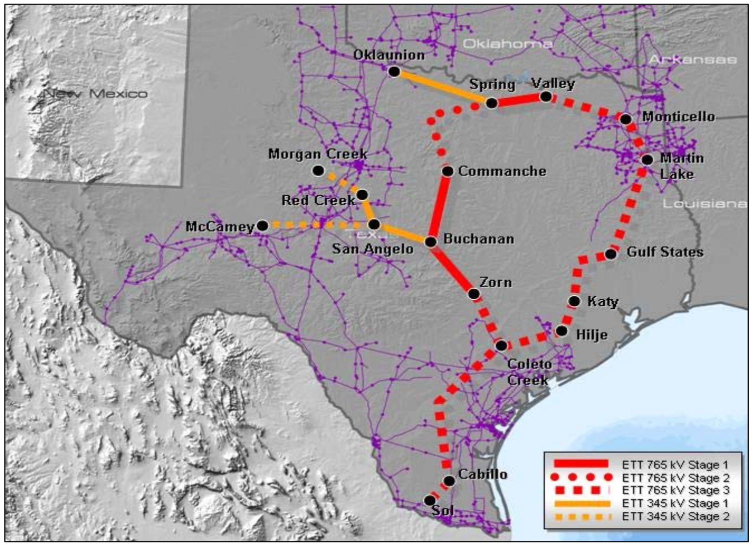
I-765™ Transmission: Investment Opportunities

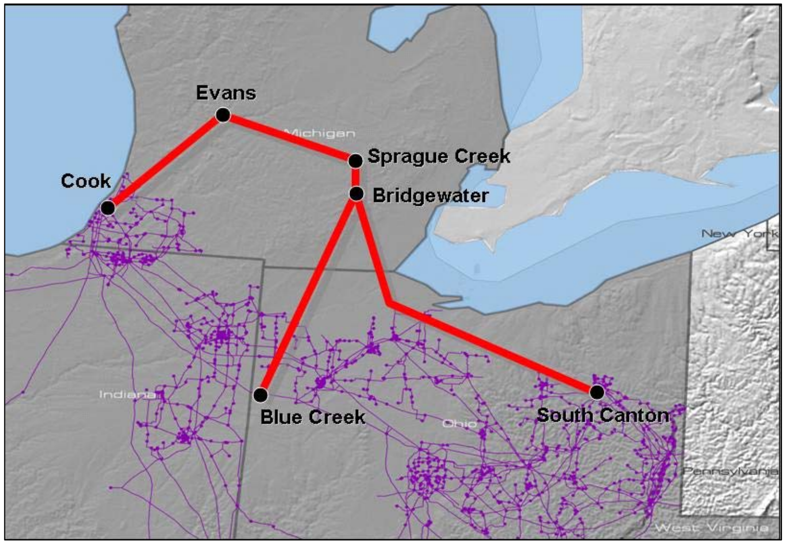
AEP is Advancing the Development of a National Interstate Today



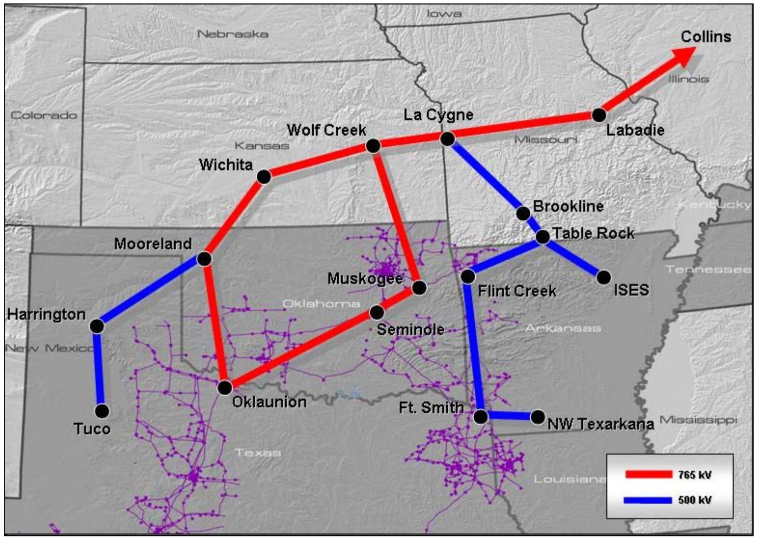
PATH Project (PJM)



ETT Proposal (ERCOT)



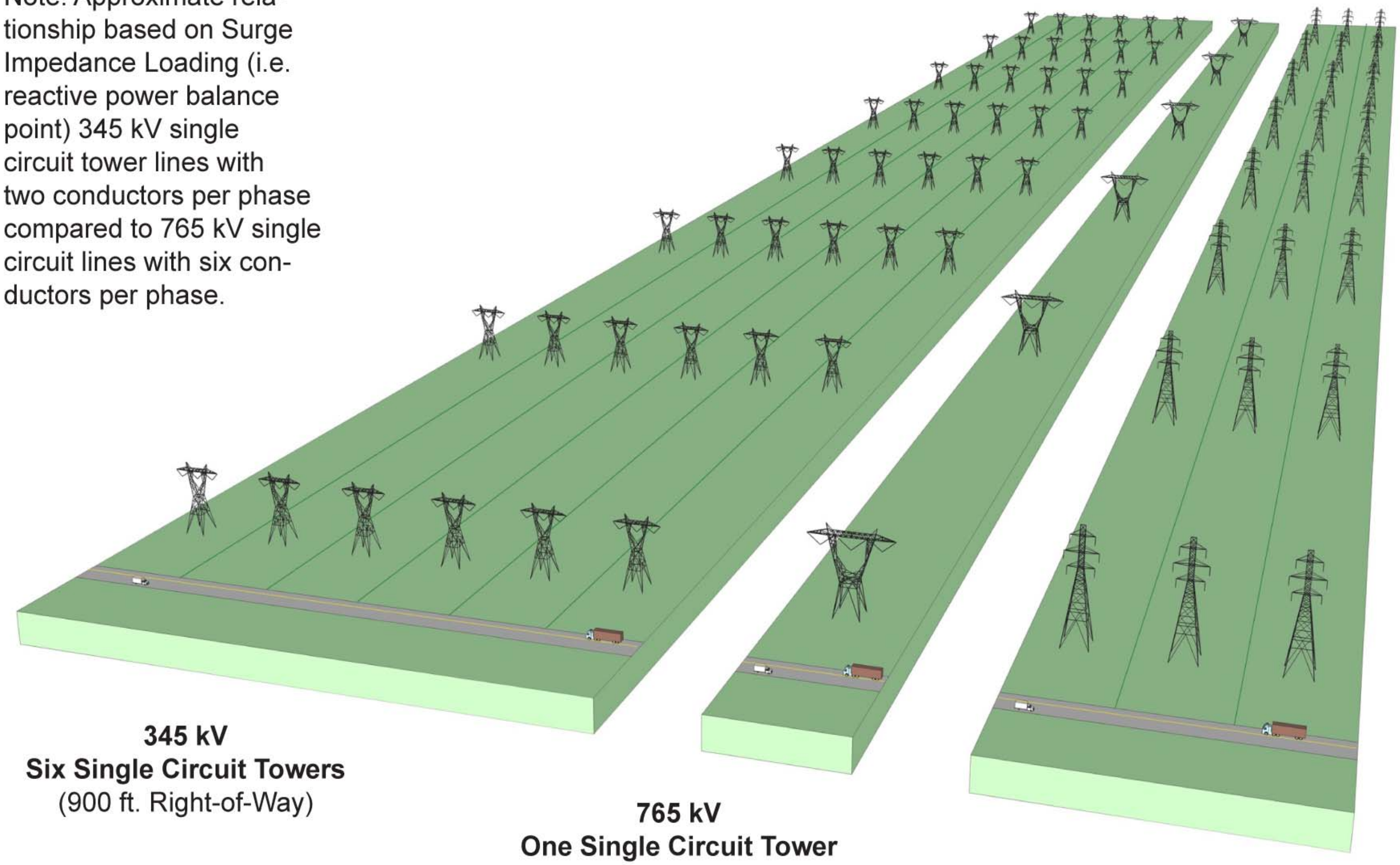
AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study

765 Right-of-Way Comparison

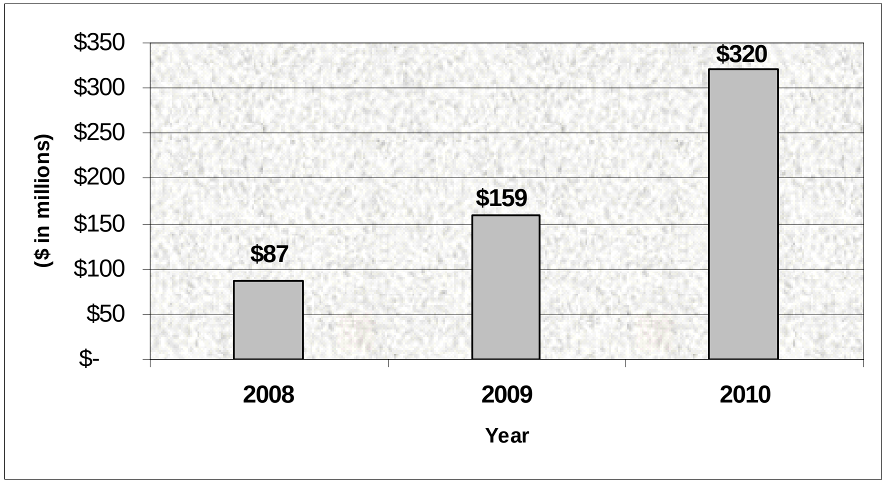
Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

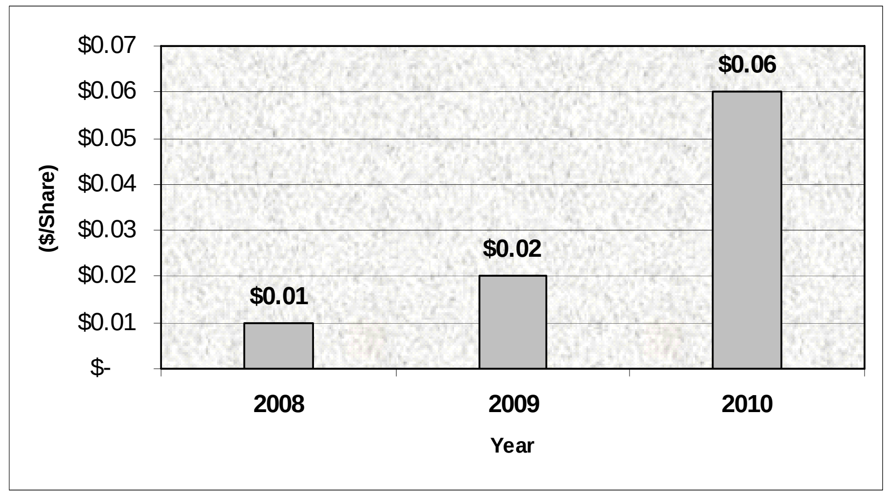


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

PATH Potomac-Appalachian Transmission Highline

Projected Transmission EPS Contributions*



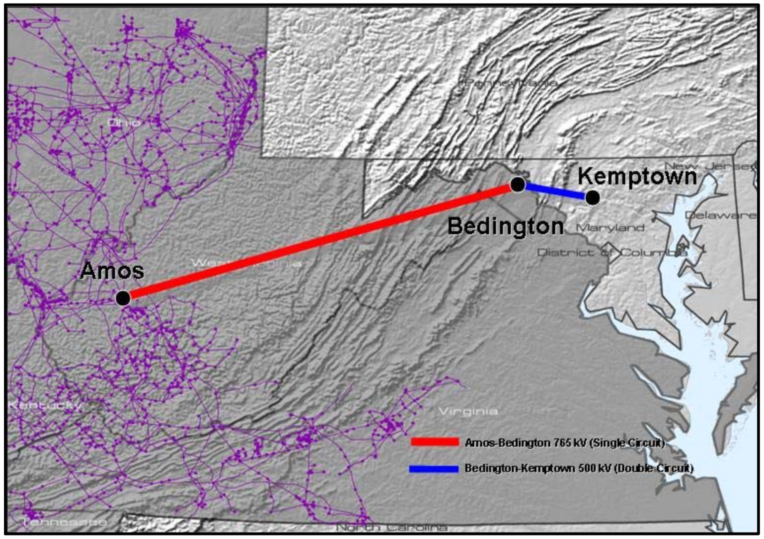
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - Completed FERC Filing – December 2007; FERC order issued on February 29, 2008 approving:
    - *cash return on CWIP*
    - *14.3% ROE*
    - *recovery of all costs incurred prior to the time rates go into effect, and*
    - *recovery of all prudently incurred development and construction costs if the project is abandoned.*
  - FERC ordered the formula rate issue be set for hearing, pending settlement judge procedures



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
  - Project corridor was included in the DOE's National Interest Electric Transmission Corridor
- *Key Next Steps*
  - Siting Approval – Fall 2009
  - Targeted Completion – 2012

PATH
Potomac-Appalachian Transmission Highline

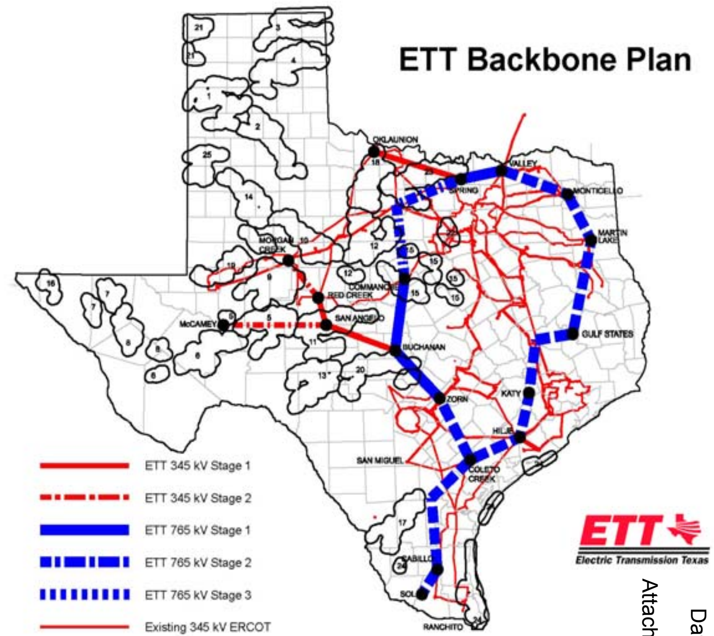
I-765^{TM} Transmission in Texas (ETT)

Electric Transmission Texas Update

- ***Transaction Structure***
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- ***Next Steps***
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- ***ETT ERCOT Backbone Proposal***
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



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* Before ownership division.

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Electric Transmission America (ETA)

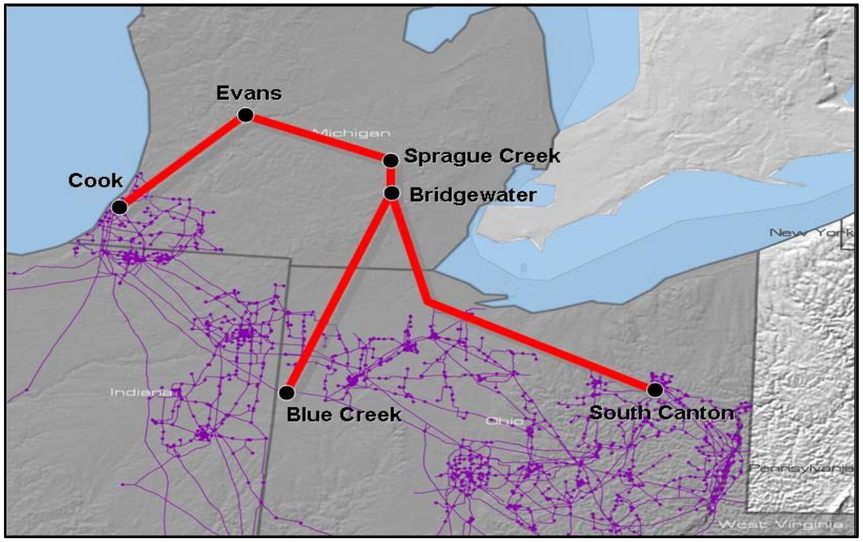
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) Q2 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2008
  - FERC Filing - Fall 2008
  - Siting Approval – Fall 2010
  - Estimated Completion – Fall 2015



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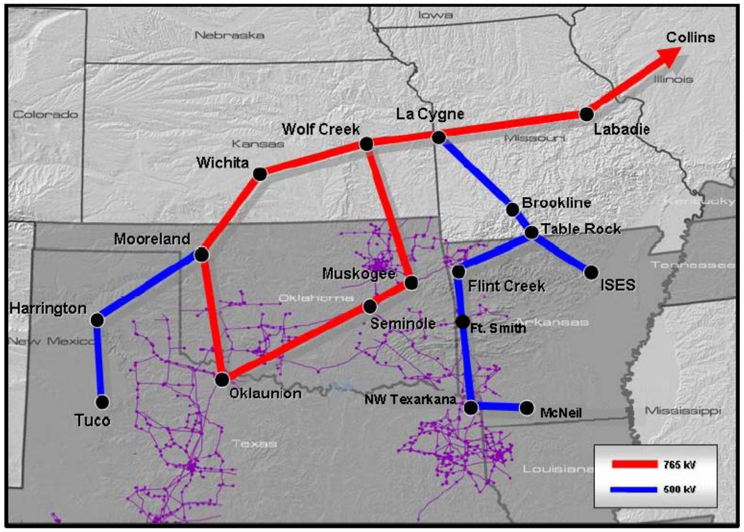
I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
- ### *Benefits*
  - 4,000 MW improved transfer capability
- ### *Next Steps*
  - Study Disclosure – Completed 2Q 2007
  - JV Formation (ETA) – Completed 3Q 2007
  - SPP 10-year Expansion Plan Issued – December 2007
  - SPP RTO/BOD EHV Overlay Approval – 2Q 2009
  - SPP RTO FERC Filing – 3Q 2009
  - Siting Approval – 3Q 2011
  - Estimated Completion – 3Q 2017



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Regulatory Activity Underway

- Ohio Post 2008
- I&M - Indiana Base Rate Case
- PSO Storm Cost Recovery Filing
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Louisiana and Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Regulatory Activity Underway

Ohio Post-2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearings continue and we anticipate a signed bill in March or April of 2008.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Storm Cost Recovery Filing

- On October 24, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of sulfur dioxide (SO_2) emission allowances.
- Staff and intervenor testimony was filed January 17, 2008 and a settlement agreement has been signed and filed with the OCC. The settlement allows for the deferral of approximately $83 million related to both the January and December 2007 ice storms. A portion of the deferral would be amortized against gains on sales of allowances with the remainder collected from customers over a five-year period beginning in October 2008. An ALJ approved the settlement in February 2008 and we anticipate an order in late March or early April 2008.

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- PSO requests the Commission make a determination that the costs incurred on the Red Rock project were prudent and direct it to establish a regulatory asset of approximately $21 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sales of SO_2 emission allowances.
- The procedural schedule in this case has been suspended pending the outcome of the storm cost recovery. Once an order in that case is issued, additional cost recovery testimony likely will be filed and a new procedural schedule established.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Technical conferences and settlement meetings were held in October – December 2007. Settlement discussions are currently on-going. Intervenors and AEP will meet on March 11, 2008 to review any additional issues and report back to the settlement judge on the status of the settlement discussions.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 629MW IGCC plant in WV at a cost of approximately $2.23 billion.
    - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
    - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony was filed November 19, 2007 and hearings were held December 10-12, 2007. An order is due by March 6, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order in April 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. A positive ALJ report was issued on February 8, 2008 recommending approval of the plant. An order is expected in March 2008.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. A final order is expected on March 27, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings will commence on April 7, 2008. Staff testimony was favorable.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Rate Base & Approved ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	11.10%	12/29/1999
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

Detailed Ongoing Earnings Guidance

2007A: $3.00

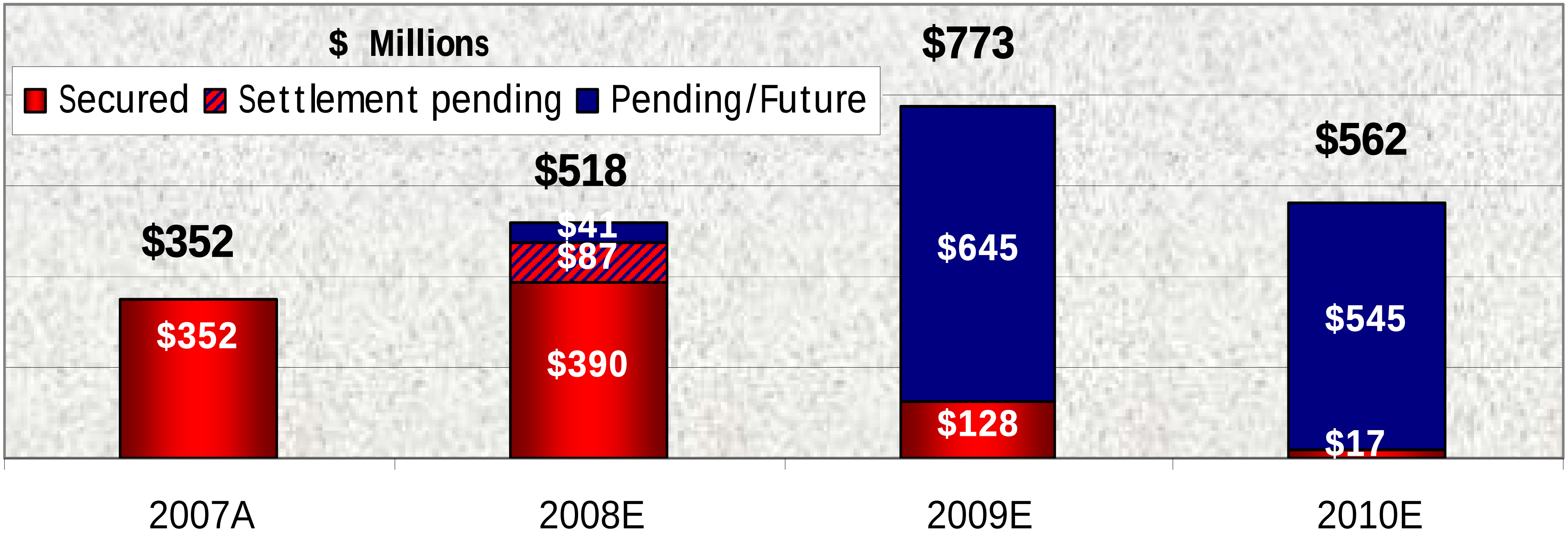
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		2007 Performance Driver	2007 Actual ($ millions)	2008 Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Incremental Rate Relief Assumptions



- **75% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings.**
- **17% of 2008 Rate Relief Settlement Pending: Uncontested settlement approved by an ALJ on February 29, 2008 for the PSO January and December 2007 Ice Storm Recovery; OCC approval pending**
- **2008 Pending: SWEPCo – LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Commitment to Credit Quality

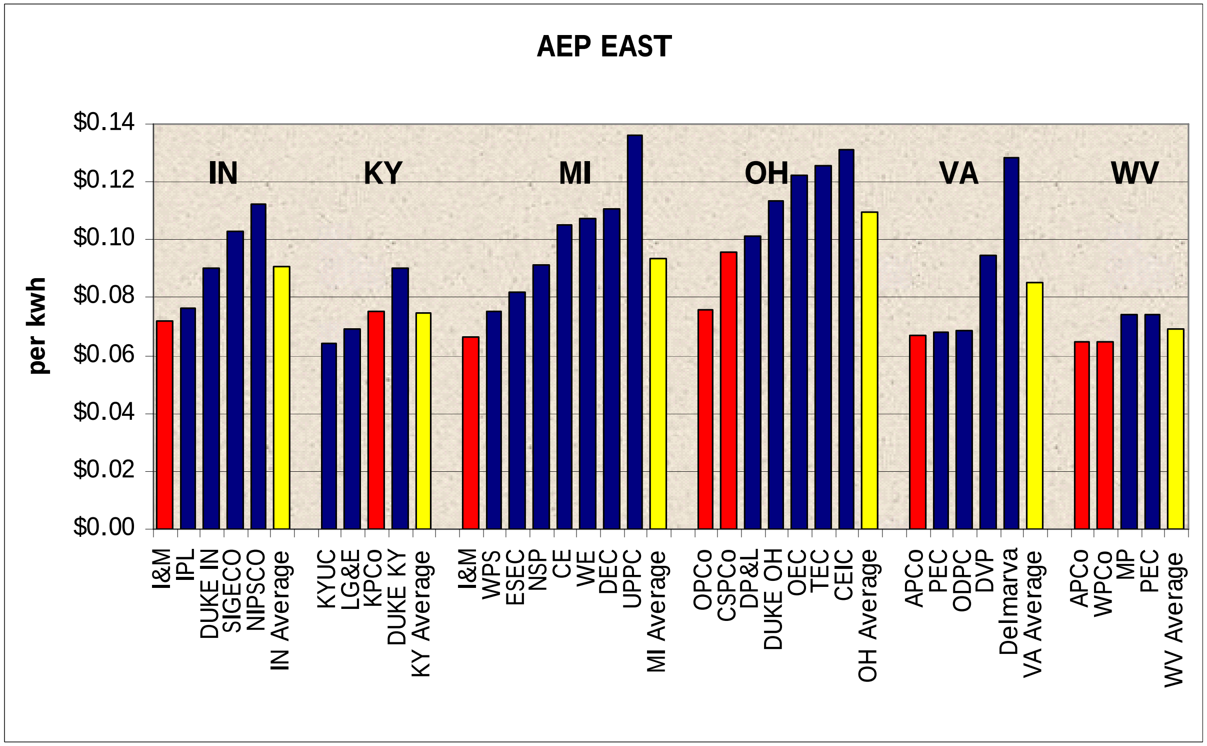
- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

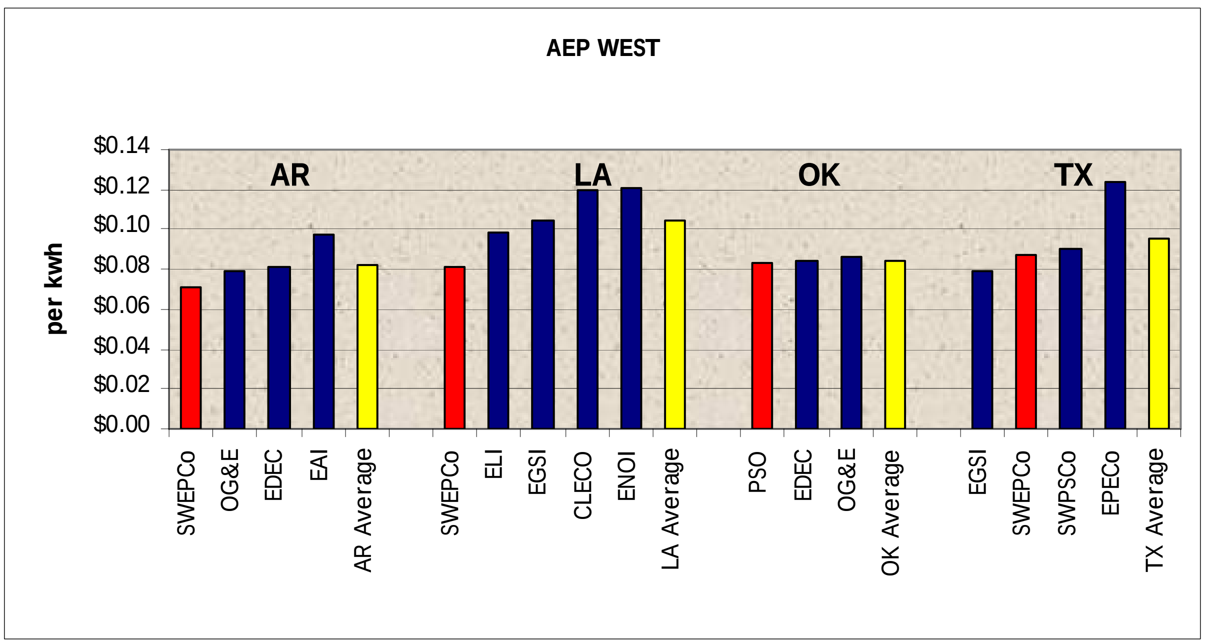
Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

AEP Company

Other Company within state

State Average

American Electric Power

Strategic Direction & Financial Outlook

W New York Union Square
October 4, 2007

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Michael G. Morris
Chairman, President & CEO

Agenda

- 2007 Delivered Results & Strategic Direction
- Sustainable Capital Investment Opportunities
  - Near-term: Environmental, New Generation & GridSMART
  - Long-term: Transmission, Advanced Generation & CO_2
- Capital Investment and Regulatory Strategy Inextricably Linked
  - AEP Regulatory Strategy: Reduce Lag
  - Ohio Post-2008
- 2007-2010 Financial Forecast
  - Increase growth rate target range to 5%-9%
- 2007–2010 Capital Investment Projections and Funding
- 2008 Earnings Guidance and Details
  - Includes proposed dividend increase

2007 Delivered Results

Accomplishments:

- ✓ **Acquisition of low-cost generation to meet capacity demand**
  - Darby—480MW simple cycle ($227/kW)
  - Lawrenceburg—1,140MW combined cycle ($295/kW)
  - Dresden—580MW combined cycle (currently under construction); anticipated all-in cost $600-$700/kW
- ✓ **Brought SWEPCo's Mattison Units 3&4 (150MW) on-line July 2007 (~$380/kW)**
- ✓ **Completed installation of scrubbers at Mitchell & Mountaineer**
- ✓ **Continued progress on transmission opportunities**
  - Obtained PJM approval of Potomac-Appalachian Transmission Highline
  - Formed joint venture with Allegheny Energy to construct the PATH
  - Formed joint ventures with MidAmerican Energy for ETT & ETA
  - Completed technical study with ITC for 765-kV in Michigan and continue to investigate the feasibility of forming a joint venture to develop the project
- ✓ **Secured to-date $302MM of $338MM of 2007 rate relief projections**
- ✓ **On track to deliver 5%-7% growth rate in 2007**

AEP continues track record of capital investment, regulatory approvals and earnings growth.

AEP Strategy

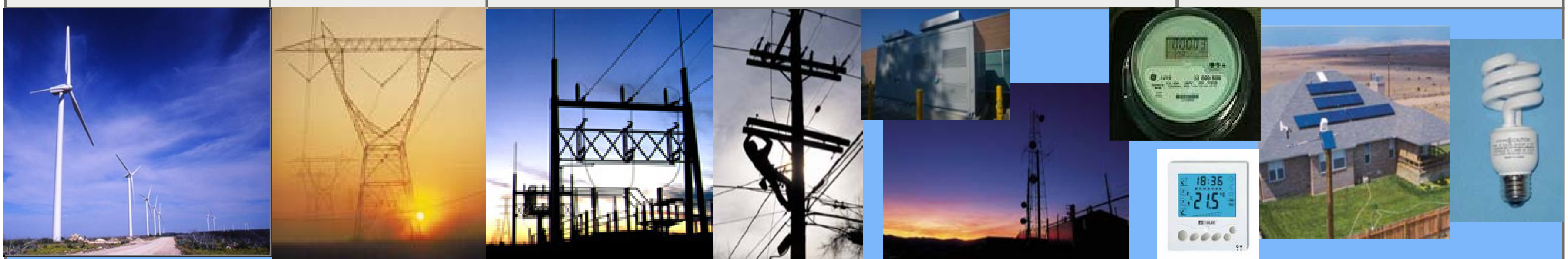
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

- Prepare for transition to market in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to bring economic savings to our customers while continuing to enhance shareholder value through regulatory-supported investment and operational excellence

Sustained capital investment opportunities support earnings growth.

Vision for Sustainability



Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

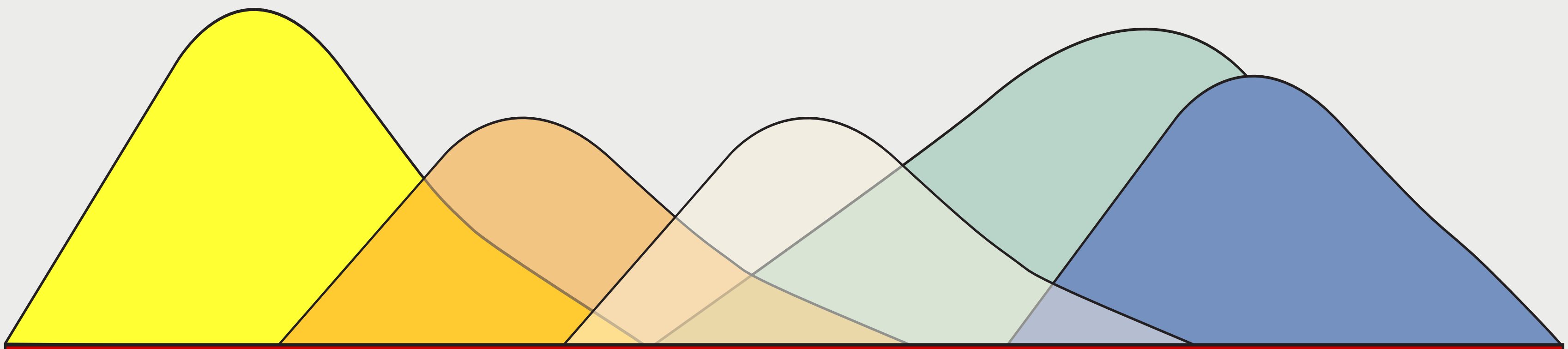
Existing generation and transmission control systems	**GridSMART**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

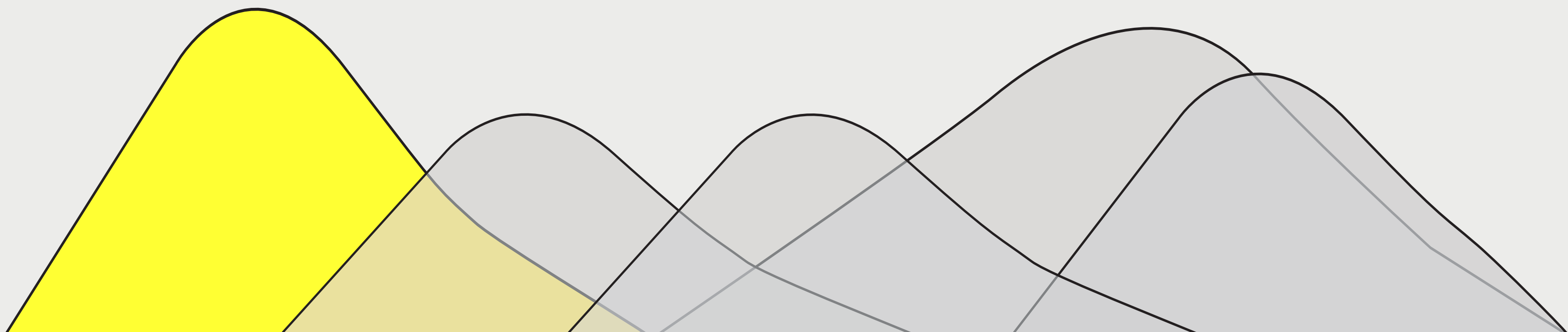
Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

AEP®

Investment Opportunity: Environmental

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



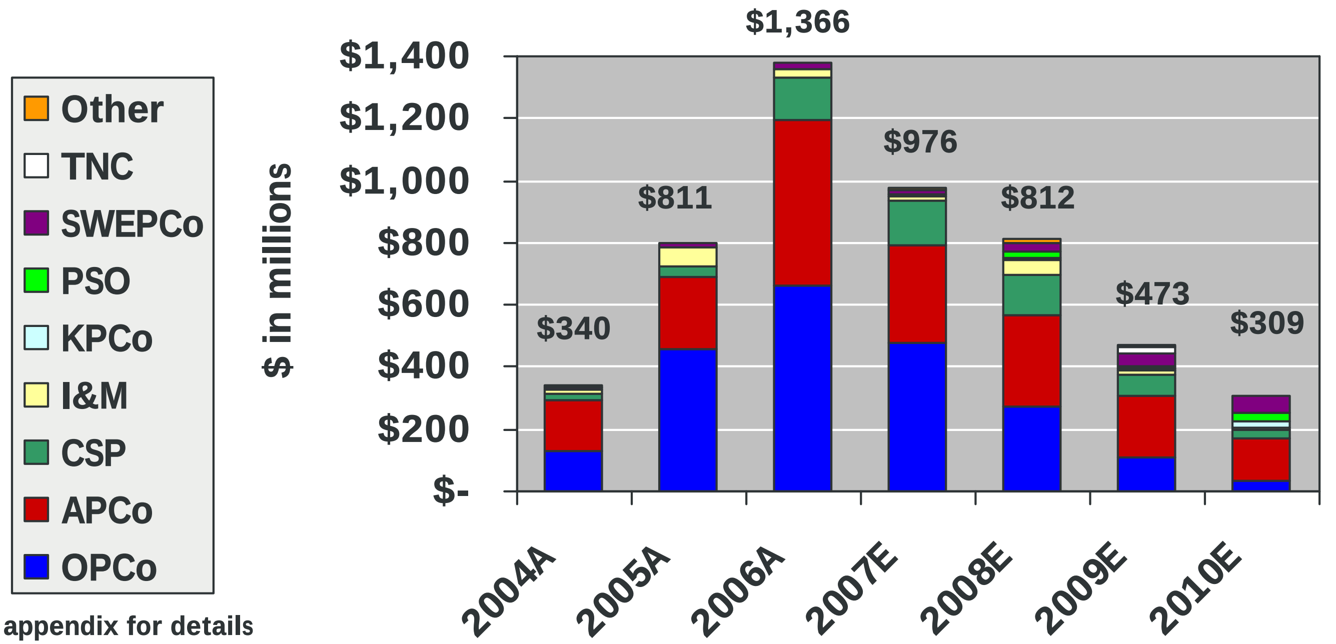
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

Environmental retrofits reduce our emissions profile and reduce risks to the environment and the health of communities.

Environmental Investments Receive Timely Rate Recovery



See page 47 in appendix for details

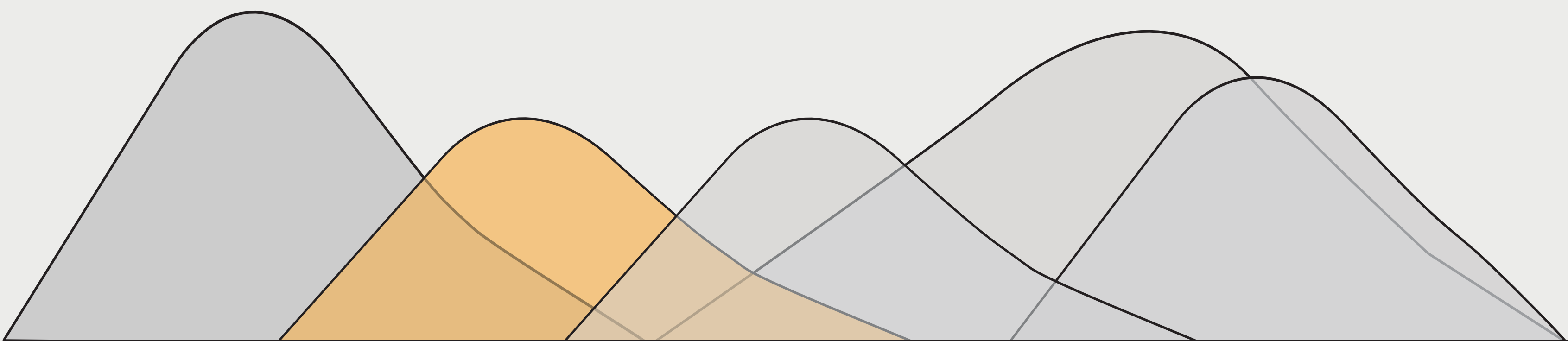
($ in millions)	Completed (2004-2006)	Rate Recovery
AEG	$9	partial/pending
APCo	$923	yes
I&M	$98	pending
KPCo	$3	yes
SWEPCo	$37	pending
CSP	$194	yes
OPCo	$1,253	yes
Total Capex	$2,517	

($ in millions)	Remaining (2007-2010)	Rate Recovery
AEG	$27	partial/pending
APCo	$944	yes
I&M	$77	pending
KPCo	$33	yes
PSO	$67	pending
SWEPCo	$135	pending
TNC	$22	through mkt. rates
CSP	$374	partial/pending
OPCo	$891	partial/pending
Total Capex	$2,570	

Investment Opportunity: New Generation

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

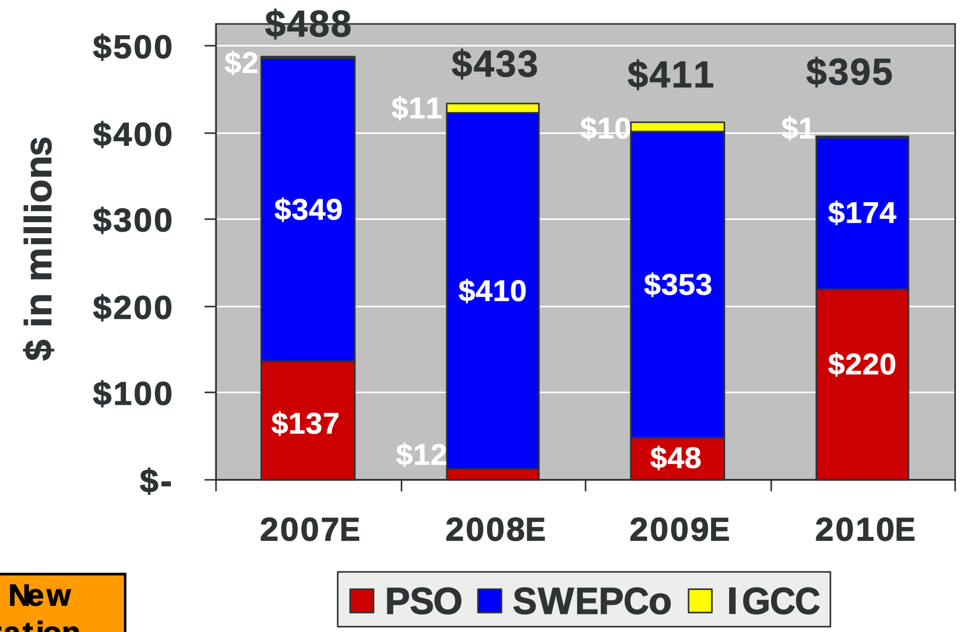
Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

New generation investments will yield higher operating efficiencies and lower emissions while meeting growing customer demand.

New Generation Investments and Related Recovery

Secured Recovery Mechanism

- PSO Peaking Facilities Rider



($ in millions)	Projected Construction Completion	Total New Generation Investment (2007-10)
PSO - Peaking Facilities	2008	$102
PSO - Combined Cycle *	2012	$315
SWEPCo - Mattison	2007	$66
SWEPCo - Stall	2010	$422
SWEPCo - Turk	2011	$798
APCo - IGCC	tbd	$12
CSP/OPCo - IGCC	tbd	$12
Total Capex	Total Capex	$1,727

* - intended to source requirements to be met by Red Rock Plant prior to cancellation.

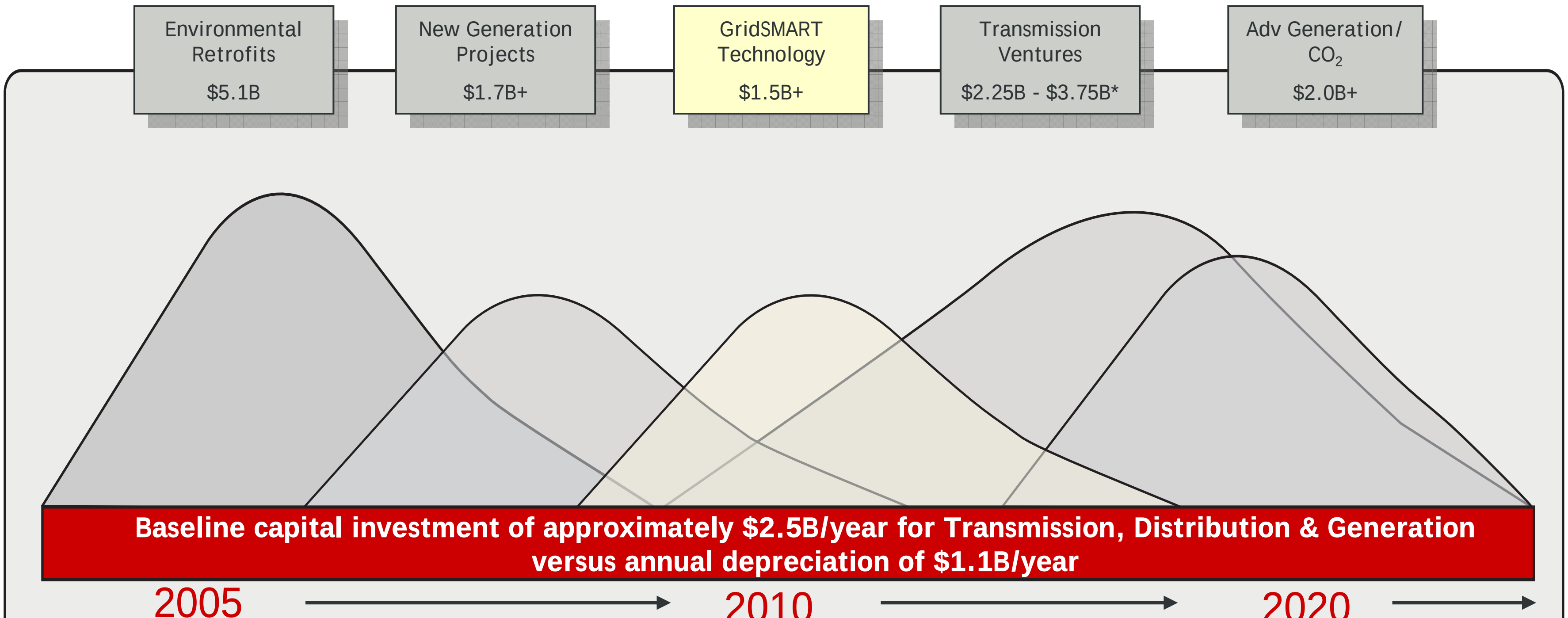
Additional Recovery Mechanisms Under Consideration:

- Formula based rates
- Requests for return on CWIP
- Current and future rate cases

AEP®

Investment Opportunity: GridSMART

Capital Investment – Consistent Waves of Opportunity



Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

Modernization of our transmission and distribution infrastructure will change how our customers use energy and how we manage demand to economically meet future electric energy needs.

GridSMART

AEP Vision

- AEP is moving technology out of the laboratory and into real-world applications
- Aggressive goals:
  - 25 MW NaS battery installations by 2010
  - 1,000 MW demand reduction by 2012
  - 5 million smart meters by 2015

AEP Leadership

- **Environmental:** AEP's fleet includes hybrids
- **Efficiency and Conservation:** DOE Transformer Efficiency Initiative and participation in the Clinton Global Initiative
- **Education:** AEP Foundation's support of the National Energy Education Development (NEED) Project and Change-a-Light Program
- **Technology:** High temperature superconductors, micro grid test bed and extra-high voltage transmission advances

AEP's Collaboration with Others

- NGK (NaS battery) & Rolls Royce (fuel cells)
- Collaboration with GE to demonstrate the distribution/customer service business of the future

Modernization of our distribution infrastructure will change how we manage the flows of information and electricity across the energy value chain to optimize overall performance and prepare for the future.

AEP-GE Initiative

We will deploy smart meters, distribution automation and the associated enhanced technology resulting from the collaboration with GE in two regions by the end of 2008 -- representing approximately 200,000 customers.

By integrating customers and their end use technologies into the daily operation of the grid, we can collaborate to optimize supply and demand and improve energy efficiency and environmental sustainability.

Our agreement with GE is a winner for our customers, our shareholders and for the environment.

Working Together for a Brighter Future

AEP and GE will collaborate to address the full energy pathway from the power plant to the home.

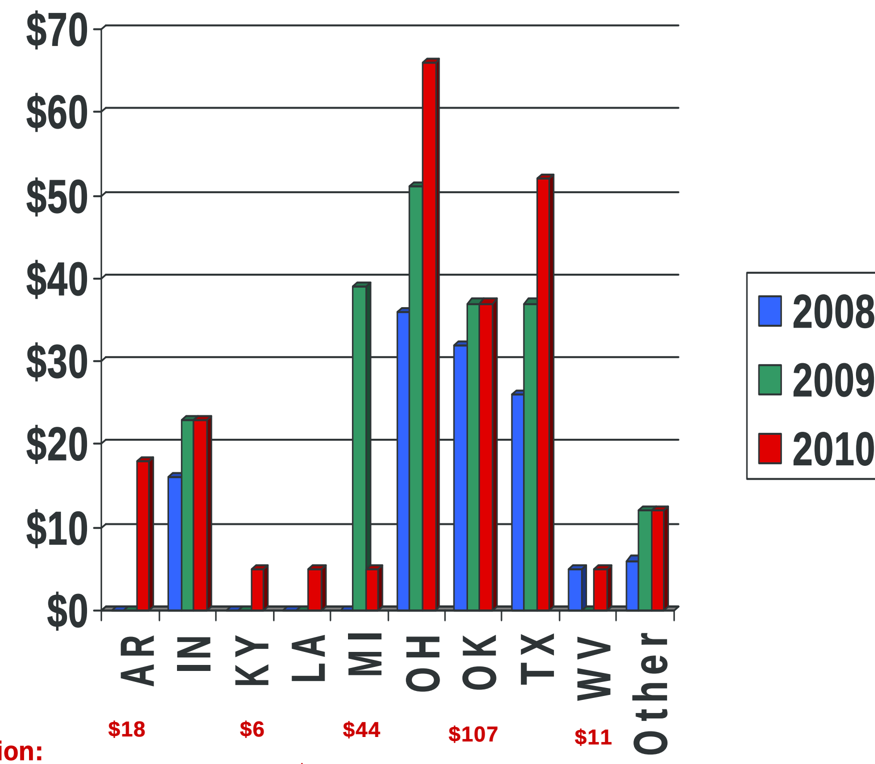
GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology	**2007**	**2008**	**2009**	**2010**
Metering & Communications	$0	$83	$138	$146
Distribution Technology Enhancements	$2	$40	$ 63	$ 82

*$452MM of the $554MM not in current forecast; spending contingent upon regulatory approval

$ in millions



3-Year Total by Jurisdiction: $18 $62 $6 $5 $44 $153 $107 $115 $11 $31

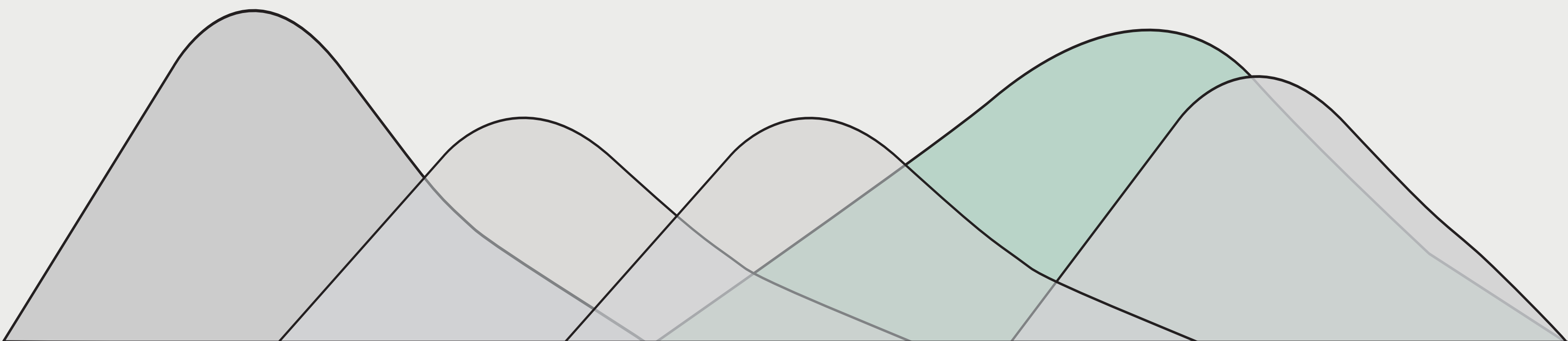
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Investment Opportunity: Transmission Ventures

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.5B/year for Transmission, Distributon & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

Today's state of the art high voltage transmission technology optimizes land use, minimizes environmental impacts, and provides the gateway to an interconnected system that is more sustainable, reliable and competitive.

Contribution of Transmission Investments

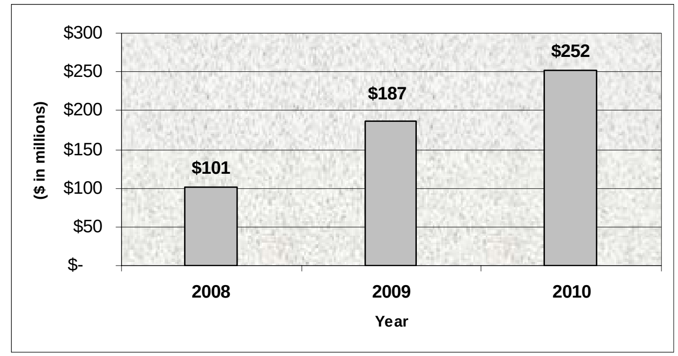
Potential Transmission Opportunities

~ $3 Billion I765™ Project in PJM
~ $2.6 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions

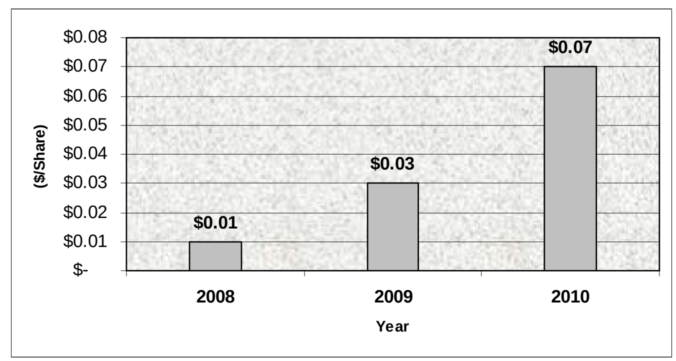
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 402 MM shares)	$0.60 - $1.00+

Projected Transmission Capital Spending*



* ~$9-$15 billion investment opportunity not included in current capital guidance forecasts, since it will be put into a JV. ETT base case and PATH projects included in above projection.

Projected Transmission EPS Contributions*



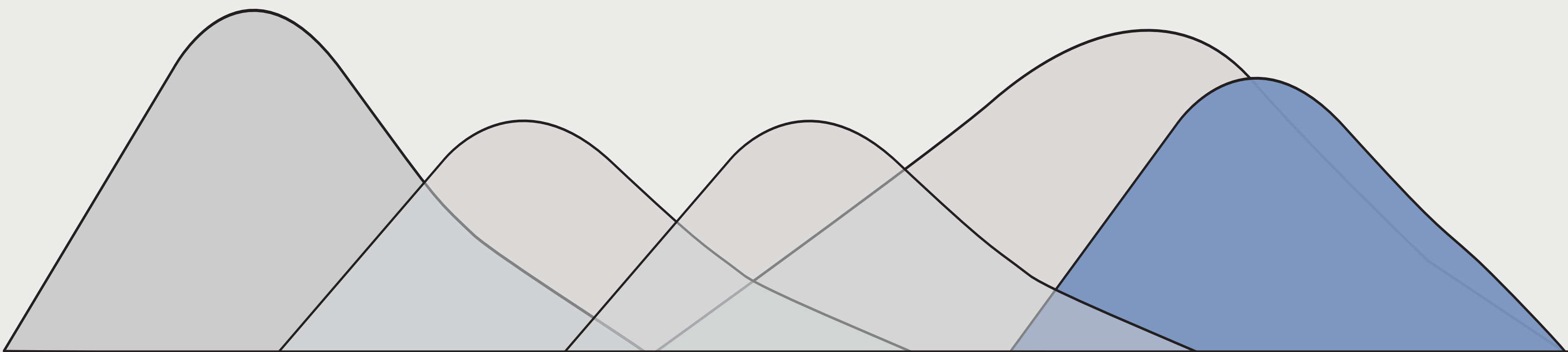
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

Investment Opportunity: Advanced Generation/CO_2

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

New technology keeps coal a sustainable domestic energy resource that is good for the economy, good for the environment, and good for society.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

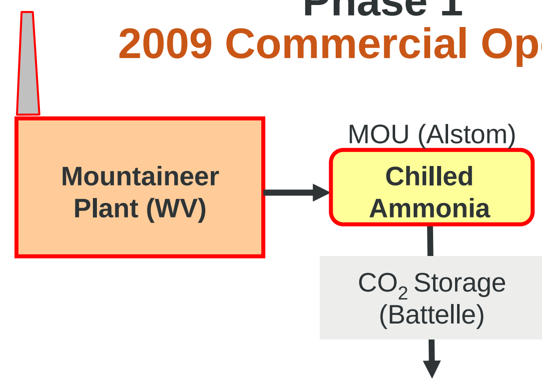
$ in millions				
	2007	2008	2009	2010
Mountaineer Chilled Ammonia Project	$4	$56	$11	$0

Long Term Strategy (Post 2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

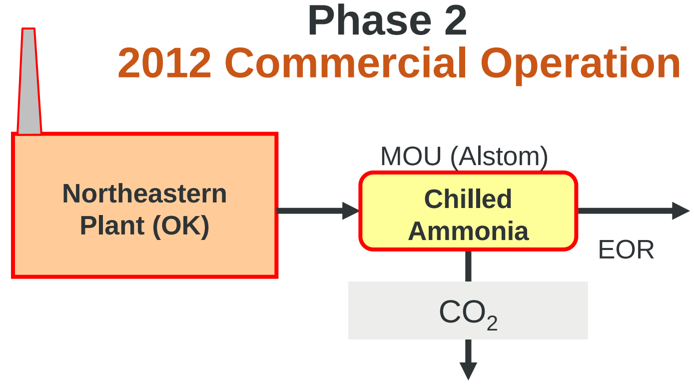
Phase 1

2009 Commercial Operation



Phase 2

2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Regulatory Strategy: Reduce Lag

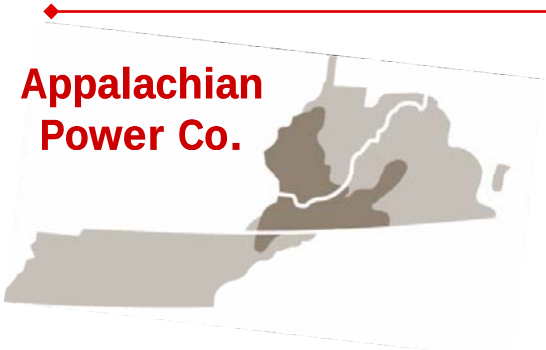
The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Lag Reduction: East Regulated Utilities

Appalachian Power Co.



Customers: 949,000
Estimated Rate Base: $3.7B *
Estimated 2007 Earnings: $183MM

Indiana Michigan Power Co.

Customers: 582,000
Est. Rate Base: $2.1B *
Est. 2007 Earnings: $130MM

Kentucky Power Co.

Customers: 176,000
Estimated Rate Base: $.9B *
Estimated 2007 Earnings: $27MM

* See Appendix, page 48 for rate base details

Virginia
- Opportunity for one rate case exists before 12/31/08
- E&R rider
- Post 2008 rider for DSM, renewable programs & new generation
- Fuel clause
- OSS margin sharing

West Virginia
- Special construction surcharge permitted
- Fuel clause (ENEC)

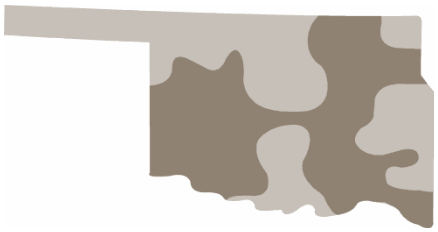
Indiana
- Riders to be requested for DSM, Environmental and RTOs
- CWIP may be approved for clean coal technology projects utilizing Indiana coal or qualified pollution control property via surcharge
- Fuel clause

Michigan
- Return on CWIP can be included in rate base
- Fuel clause

Kentucky
- Environmental surcharge
- Monthly adjustment clauses in place for DSM & fuel
- OSS margin sharing

Regulatory Lag Reduction: West Regulated Utilities

Public Service of Oklahoma

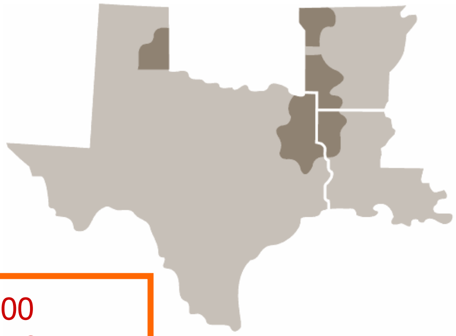


Customers: 520,000
Estimated Rate Base: $1.2B *
Estimated 2007 earnings: $35MM

* See Appendix, page 48 for rate base details

Oklahoma
- Rider mechanisms authorized for vegetation, Lawton Cogen & new peaking facilities after December 2007 in-service date
- Fuel clause
- OSS margin sharing

Southwestern Electric Power Co



Customers: 456,000
Est. Rate Base: $1.3B *
Est. 2007 earnings: $66MM

Arkansas
- CWIP permitted in rate base for plant that is placed in service within 6 months after the test year
- Fuel clause
- OSS margin sharing

Louisiana
- Formula rate plans permitted
- Fuel clause
- Seeking partial CWIP return on new generation projects
- OSS margin sharing

Texas
- CWIP allowed in rate base in some cases
- Fuel clause
- OSS margin sharing

Regulatory Lag Reduction: Texas Wires Business

AEP Texas Central Co & AEP Texas North Co

Customers: 927,000
Estimated Rate Base: $2.1B *
Estimated 2007 earnings: $73MM

* See Appendix, page 48 for rate base details

Texas
- Transmission rider provides annual recovery dependent on the level of transmission investment and ERCOT load growth rates
- AFUDC is permitted in limited circumstances

AEP Texas will synchronize general rate requests with significant rate base changes and benefit from the flexibility of periodic transmission filings.

The AEP Ohio Post-2008 Action Plan

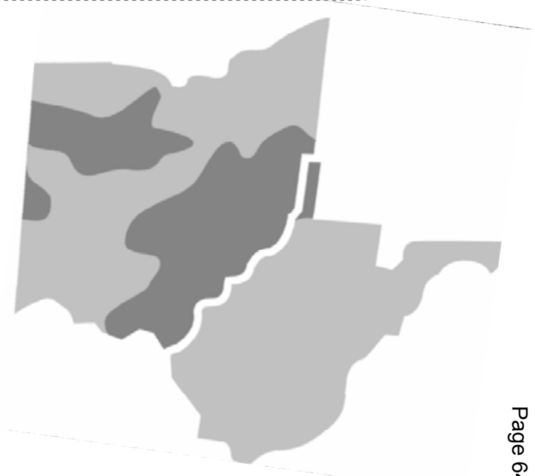
Concurrent pursuit of regulatory and legislative options

- Work for a legislative outcome that:
  - Allows for market pricing or
  - Allows for new Rate Stabilization Plans that reflect a value for generation consistent with market
- If legislation is not forthcoming, work with the PUCO Staff to develop new Rate Stabilization Plans that reflect the market value of generation

Essential elements of Post-2008 Plan

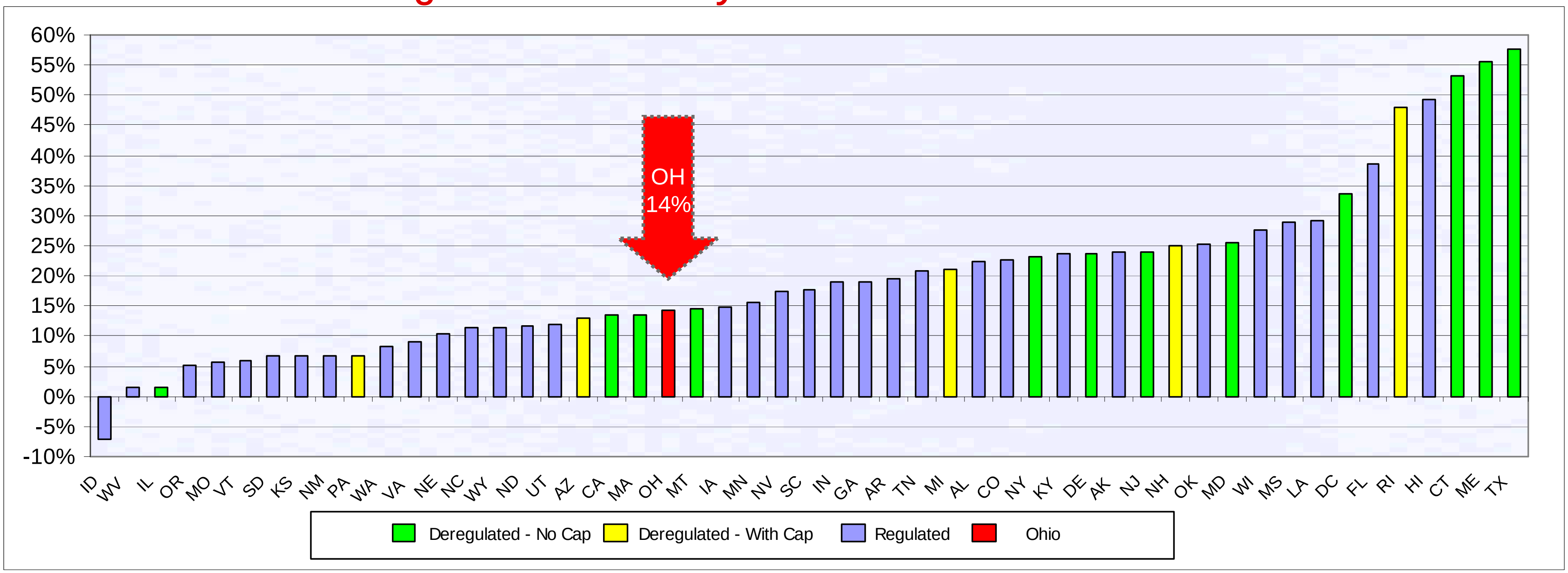
- Market-based generation pricing option
- Recovery mechanisms for new plants, fuel clause, environmental investments, GridSMART initiatives, energy efficiency projects and renewable energy investments
- Well-defined parameters for PUCO authority

Achieve a sustainable balance between shareholders and the Ohio economy.



Electricity Costs Have Increased in Both Regulated and Deregulated States

2002-2006 % Change in Electricity Prices

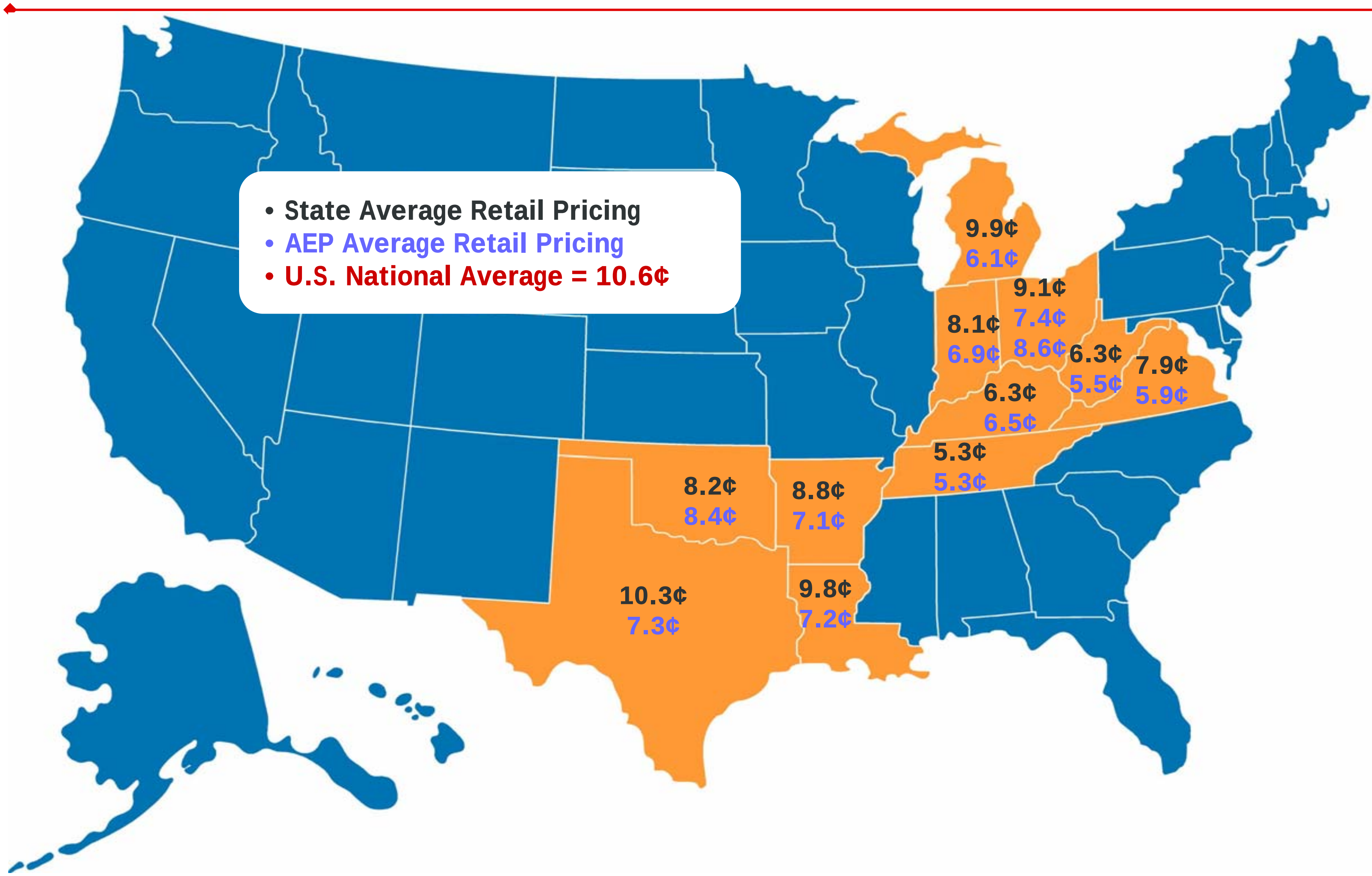


Source: USA Today, Aug. 10, 2007

- **Deregulated states median increase: 25%**
- **Regulated states average increase: 23%**
- **Ohio average increase: 14%**

Ohio increased less than the average of both regulated & deregulated states. Under any scenario, rates in Ohio will likely increase.

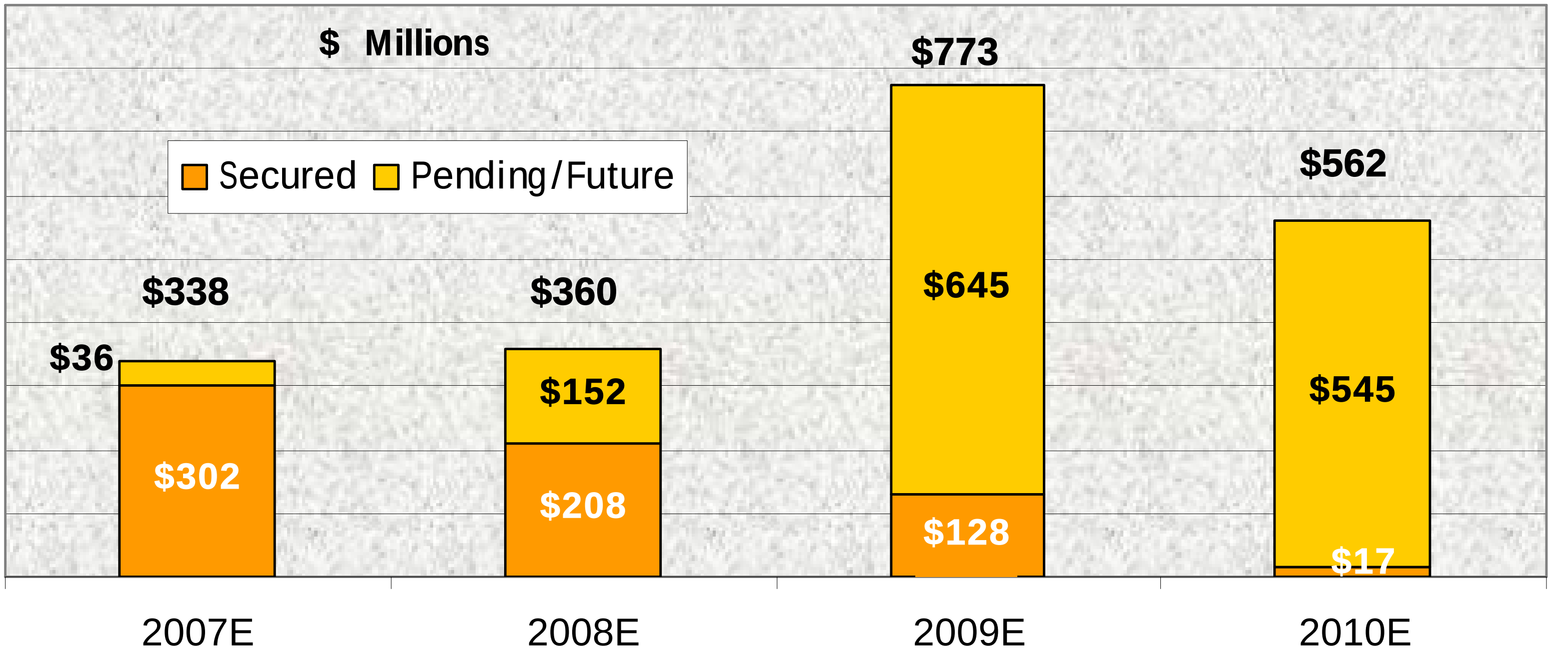
Average Retail Price of Electricity



AEP's pricing will remain competitive following anticipated rate increases.

Data source: EEI Summary of Average Realizations for the twelve months ended December 31, 2006
Ohio: OPCo = 7.4¢ / CSP = 8.6¢

Incremental Rate Relief Assumptions

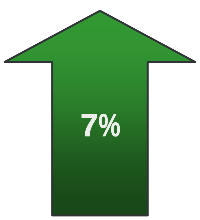


2007 Pending: PSO Rate Case
TCC Rate Case
Ohio 4%

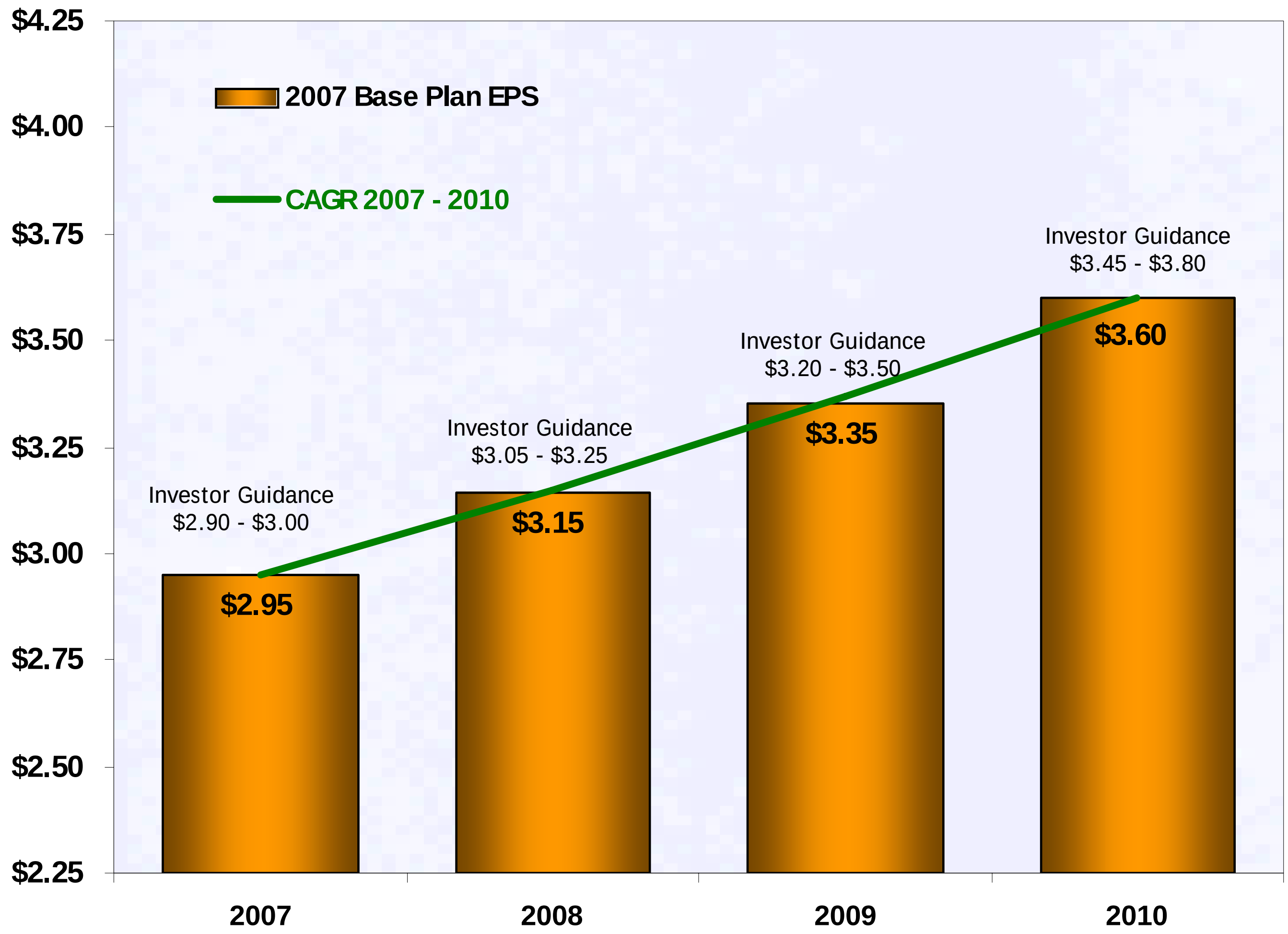
2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation

2007 - 2010 projected annual rate increases of 5.5%

4-Year Earnings Range Forecast



EPS 3-yr CAGR
(2007-2010)



5% to 9% earnings growth and recommendation of a 4Q07 dividend increase.

Value Proposition

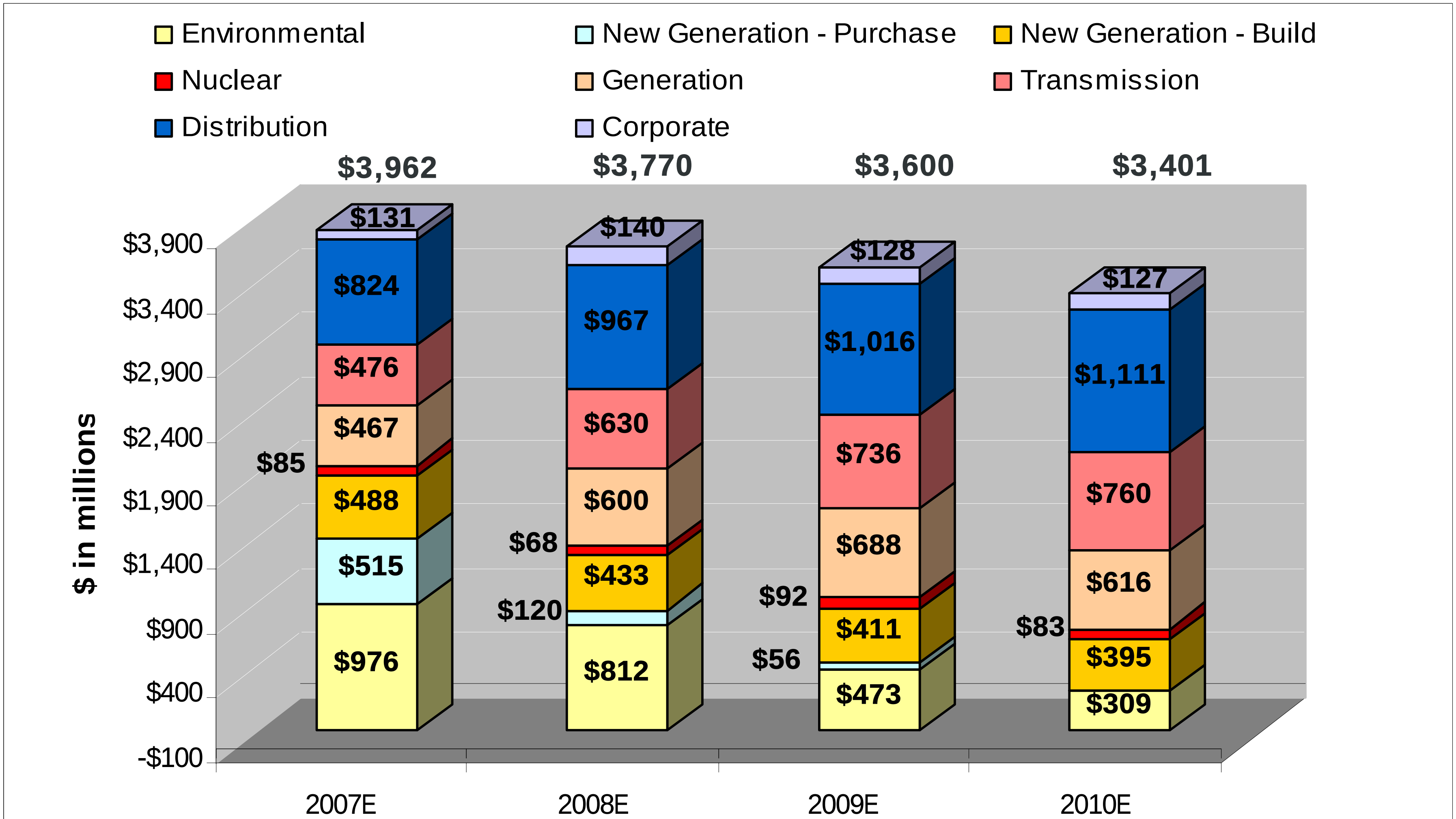
- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Sustainable Business Model

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Holly Koeppel
EVP & Chief Financial Officer

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

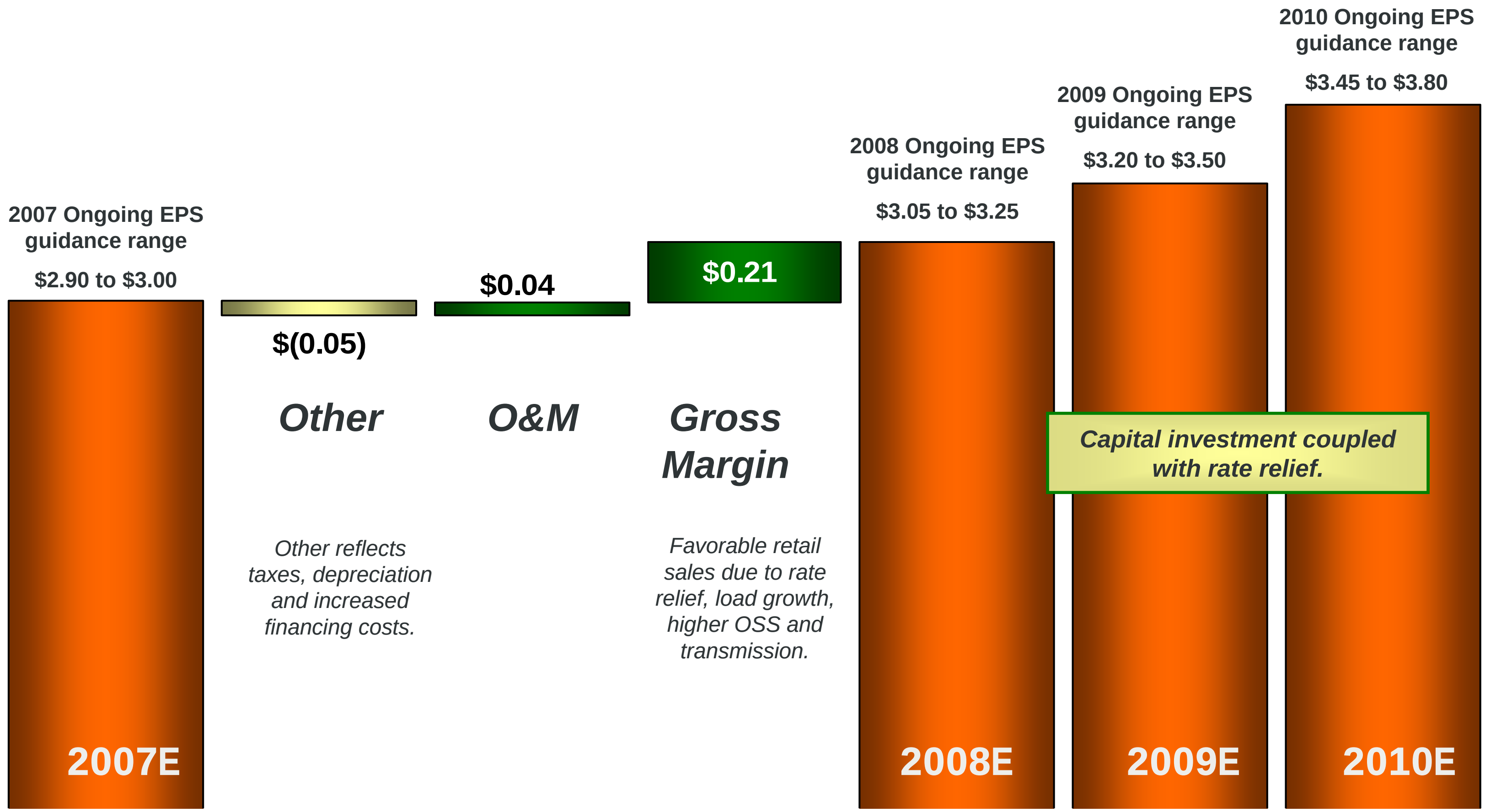
	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Capital investment is funded from cash from operations and debt issuances

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Long-Range Earnings Drivers



Traditional utility factors will drive earnings

AEP®

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Transmission Revenue - 3rd Party		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

2008 Earnings Guidance

#		2007 Guidance ($ millions)	2008 Guidance ($ millions)
	UTILITY OPERATIONS:		
	Gross Margin:		
1	East Regulated Integrated Utilities	2,440	2,425
2	Ohio Companies	2,433	2,497
3	West Regulated Integrated Utilities	1,046	1,111
4	Texas Wires	520	536
5	Off-System Sales	617	642
6	Transmission Revenue - 3rd Party	276	331
7	Other Operating Revenue	627	545
8	Utility Gross Margin	7,959	8,087
9	Operations & Maintenance	(3,353)	(3,328)
10	Depreciation & Amortization	(1,476)	(1,479)
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12	Interest Exp & Preferred Dividend	(773)	(864)
13	Other Income & Deductions	101	191
14	Income Taxes	(566)	(582)
15	Utility Operations On-Going Earnings	1,117	1,237

Performance Drivers

Retail Sales (lines 1-4):

- Positive load growth - $132MM
- Continued rate relief - $228MM
- Offset by fuel and PJM costs - $(186)MM

Off-System Sales (line 5):

- Increase due to slightly higher margins

Transmission Revenue (line 6):

- Higher rates in ERCOT, PJM and SPP

Other Operating Revenue (line 7):

- Lower revenues from third party work, primarily offset in line 9 - O&M

Operations & Maintenance (line 9):

- Continued emphasis on cost control

Interest Expense (line 12):

- Increased long term debt outstanding

Other Income & Deductions (line 13):

- Additional 2008 APCo E&R carrying charges & AFUDC, offset by elimination of Centrica earnings sharing mechanism in 2008

Income Taxes (line 14):

- Higher pre-tax income, offset by change in effective tax rate. Effective tax rate for utility operations is 33.6% in 2007 and 32.0% in 2008.

2008 Earnings Guidance

	2007 Guidance ($ millions)	2008 Guidance ($ millions)
TRANSMISSION OPERATIONS	-	5
NON-UTILITY OPERATIONS:		
MEMCO	67	57
Generation & Marketing	29	21
Non-Utility Operations On-Going Earnings	96	78
Parent and Other On-Going Earnings	(40)	(51)

Performance Drivers

Transmission Operations:

- Equity earnings contribution from Electric Transmission Texas LLC

MEMCO:

- Decrease due to increasing costs and reduced import/northbound river traffic

Generation & Marketing:

- Decrease due to divestiture of Sweeny in 4Q07

Parent & Other:

- Increase loss due primarily to interest expense related to hybrid securities issued at the parent

2008 Projected Cash Flow

	2007 Estimate	2008 Estimate
Beginning Cash Balance	$ 301	$ 102
Cash from Operations:		
Income from Continuing Operations	1,173	1,269
Depreciation and Amortization	1,535	1,511
Other	(655)	45
Total from Operations	2,053	2,825
Cash from Investing:		
Construction Expenditures	(3,604)	(3,860)
Asset Sales	228	-
Distressed Generation Purchases	(515)	-
Investment in Non-Consolidating Subsidiaries	(13)	(34)
Other	138	(69)
Total from Investing	(3,766)	(3,963)
Cash from Financing:		
Common Equity	150	150
Long-Term Debt Issued/(Retired)	1,334	1,789
Short-Term Debt Change, Net	529	(111)
Common Dividends	(631)	(659)
Other Financing Activities	132	(28)
Total from Financing	1,514	1,141
Net Change in Cash	$ (199)	$ 3
Ending Cash Balance	$ 102	$ 105

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation. In addition, construction expenditures include AFUDC.

Credit Quality Parameters

Forecast Parameters:

- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCO	42-44%
CSP	45-47%
I&M	40-42%
KPCO	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings
  - FFO to Interest range of 3.7x to 4.2x
  - FFO/Total Debt range of 16% to 19%

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Performance Sensitivities

Driver	Change	Effect
EPS Sensitivities		
Load Growth (MWh)	1%	$0.10 EPS
Utility O&M	1%	$0.05 EPS
Capital Spending	$250M	$0.03 EPS
Unit Availability	1%	$0.04 EPS
ECAR Power Price	$1/MWh	$0.04 EPS
Fuel and Purchased Power	1%	$0.03 EPS
Henry Hub Gas Price	5%	$0.07 EPS
Interest Rate (20% floating debt)	100 BPs	$0.05 EPS
Authorized ROE	**1%**	**$0.24 EPS**

Longer term performance can be substantially enhanced by achieving a higher authorized return.

Financial Forecast Highlights

- **Updated 2008 & 2009 earnings guidance ranges and introduction of 2010**

2007 Range $2.90 to $3.00	**2008 Range $3.05 to $3.25**
2009 Range $3.20 to $3.50	**2010 Range $3.45 to $3.80**

- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Ohio: Continue momentum toward market
  - Cost management
- Commitment to recommend an 8-cent/share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Refined capital investment forecast and introduction of 2010 level

2007E: $3,962 MM	**2008E: $3,770 MM**
2009E: $3,600 MM	**2010E: $3,401 MM**

- Maintain credit ratings: BBB/Baa2/BBB

Questions

Appendix

Pace of our GridSMART Implementation Determined by Regulators

- **Arkansas** – The Arkansas commission approved our 'quick-start' programs in September 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-performance pilot that results in a payment to customers who curtail load upon request. The commission's order allows implementation on or after October 1, 2007. We will now file a revised tariff, which will seek to recover costs beginning with the first billing cycle of November 2007.

- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and will administer a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.

- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.

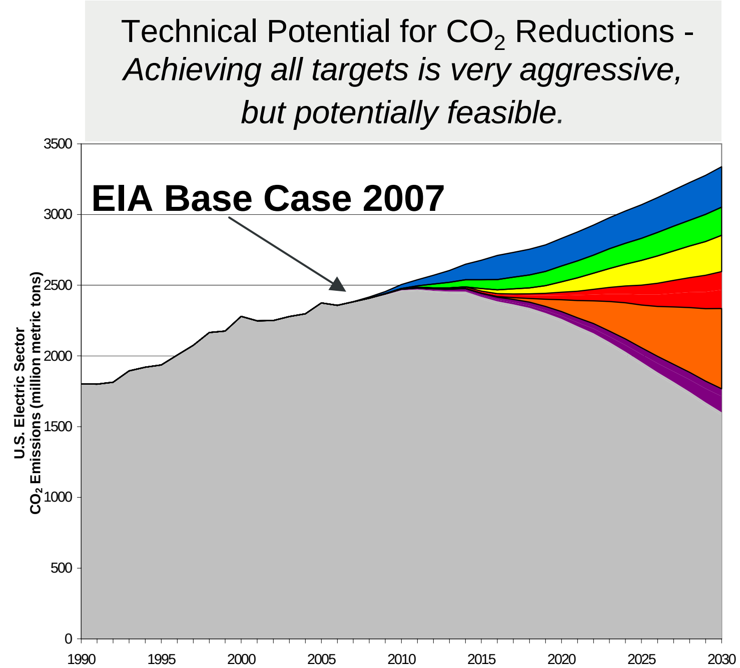
- **Ohio**
  - Recent Governor remarks and draft legislation indicates modernization of Ohio's infrastructure is a high priority.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.

- **Texas**
  - Successful demand side management and energy efficiency programs have been in place in Texas since the 1990s.
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.

Distribution technologies and DSM/energy efficiency programs are an investment, which should be treated by regulators in the same manner as investments in generation and T&D

AEP is Pursuing a Portfolio of Options to Address Carbon

Technology	EIA 2007 Reference	Industry Target	AEP Plan
Efficiency	Load Growth ~ +1.5% / yr	Load Growth ~ +1.1% / yr	DSM: 1000MW reduction in demand by 2012
Renewables	30 GWe by 2030	70 GWe by 2030	Wind PPAs through 2015: 1610MW nameplate or 232MW capacity for planning purposes. Also, voluntary green energy tariffs (Ohio program starting 2007)
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030	Evaluation of Nuclear COL
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030	1,246MW IGCC by 2017 447MW USC Turk plant by 2011
Carbon Capture and Storage	None	Widely Deployed After 2020	Chilled Ammonia: Mountaineer 2009 & Northeastern 2012 Oxy-coal by 2020
Plug-in Hybrid Electric Vehicles	None	10% of New Vehicle Sales by 2017; +2% / yr Thereafter	Joined Electric Drive Transportation Association (EDTA) in May 2007
Distributed Energy Resources	< 0.1% of Base Load in 2030	5% of Base Load in 2030	Pursuit of NaS® Energy Storage – 25MW of storage by 2010 and 1000MW of other storage / fuel cells by 2020



Technology advancement is required beyond present "state of the art" to achieve 1990 CO_2 levels by 2030. AEP is investing in a portfolio of GHG reduction initiatives. Allocation of funds will shift over time depending on technology, legislation, etc.

Source for graphic, EIA 2007 reference and industry target data: EPRI

Environmental Project Status Report

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 upgrade in-service; Unit 6 upgrade projected 2008
Gavin 1 & 2	2620	✓	In-service	✓	In-service; Upgrade projected 2010
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2008
Zimmer	330	✓	In-service	✓	In-service
West Plants					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR 24,630 MW COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD).

Rate Base by Jurisdiction

Jurisdiction	Rate Base	Approved ROE	Date	6/30/07 GAAP Earned ROE
APCo VA	$2.022MM	10.00%	5/15/2007	8.44%
APCo WV	$1.656MM	10.50%	7/26/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.89%
I&M-Indiana	$1.805MM	12.00%	11/12/1993	7.18%
I&M-Michigan	$268MM	13.00%	2/12/1991	
Ohio-CSP	$1.558MM	12.46%	5/12/1992	21.22%
Ohio-OPCo	$2.183MM	12.81%	3/23/1995	12.79%
PSO-Oklahoma (1)	$1,064MM	10.75%	5/2/2005	2.25%
SWEPCo-LA	$434MM	11.10%	12/29/1999	6.77%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1984	
Texas-TCC (2)	$862MM	10.13%	8/15/2005	6.22%
Texas-TNC (3)	$530MM	TBD	5/24/2007	8.63%

(1) PSO rate case under review. Company position is a new rate base of $1,189,422,564. Awaiting final order.

(2) TCC rate case under review. Company position is a new rate base of $1,600,487,376. Awaiting final order.

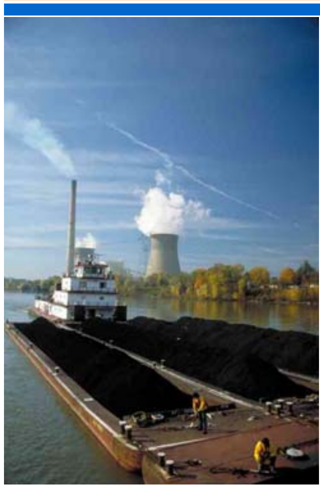
(3) PUCT approved a settlement agreement, and indicated ROE will be determined as part of TCC's rate case.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6427 of 9556

EEI International Utility Conference

London, United Kingdom

March 5-6, 2007




AEP AMERICAN ELECTRIC POWER®


“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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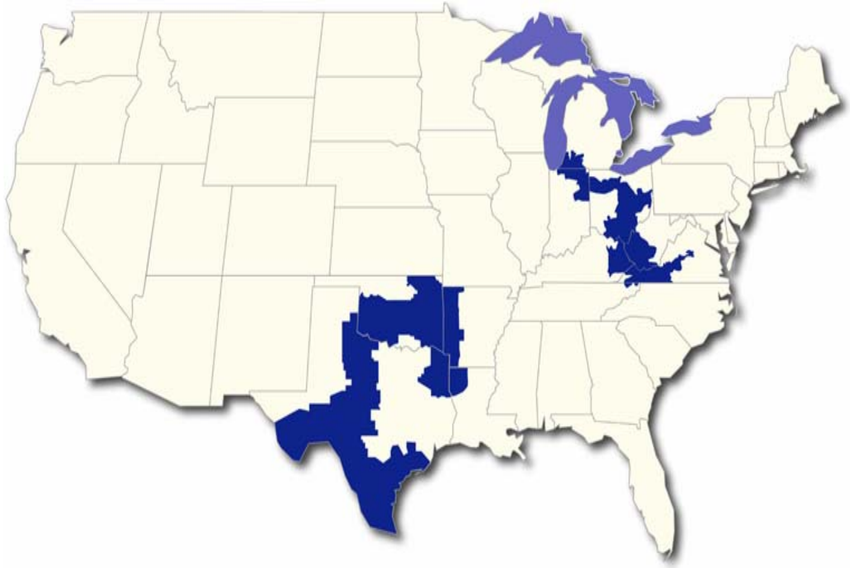
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,000 MW	# 3
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



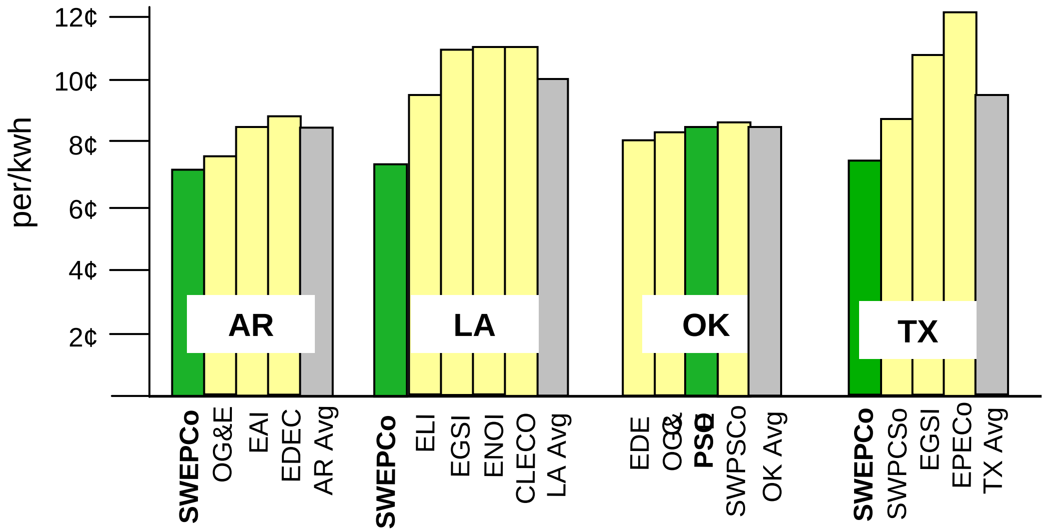
AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
70%	21%	6%	2%	1%

AEP®

AEP Enjoys Significant Presence Throughout the Energy Value Chain

AEP Provides Low Cost Electric Service

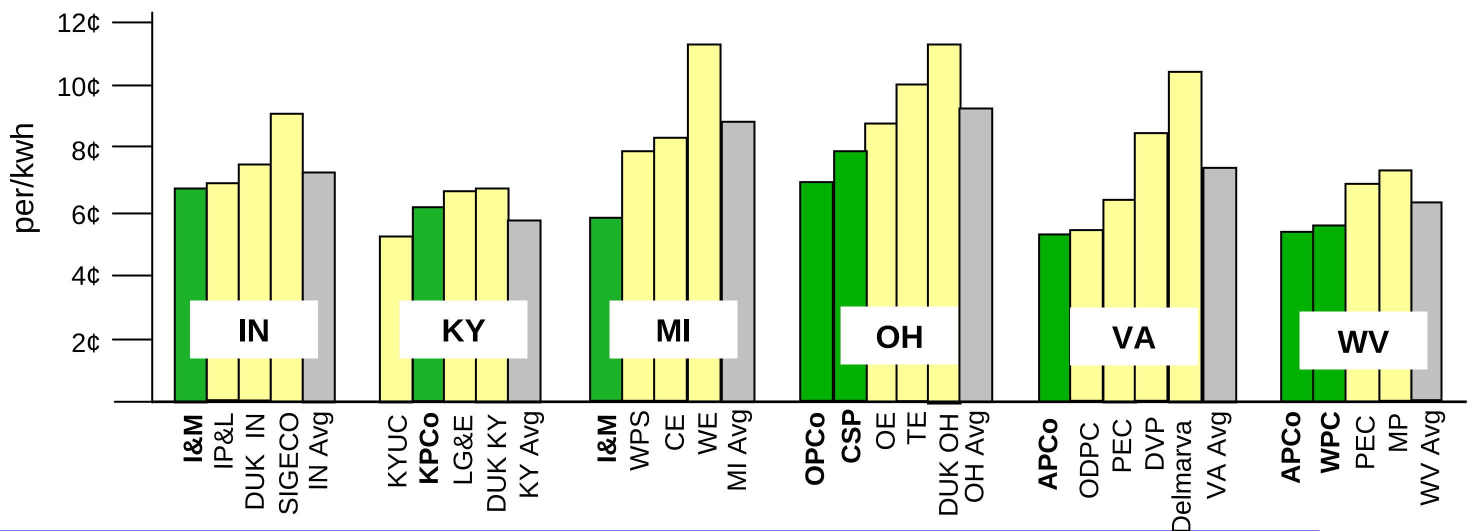
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

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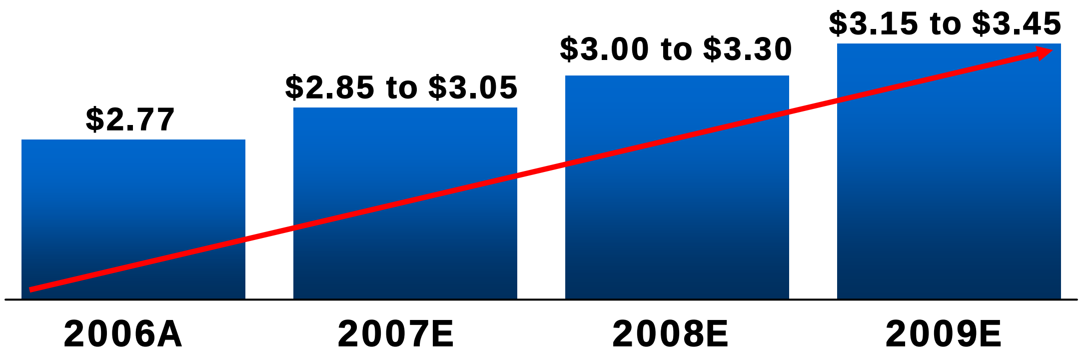
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash
From Operations via Rate Relief and Debt Issuances

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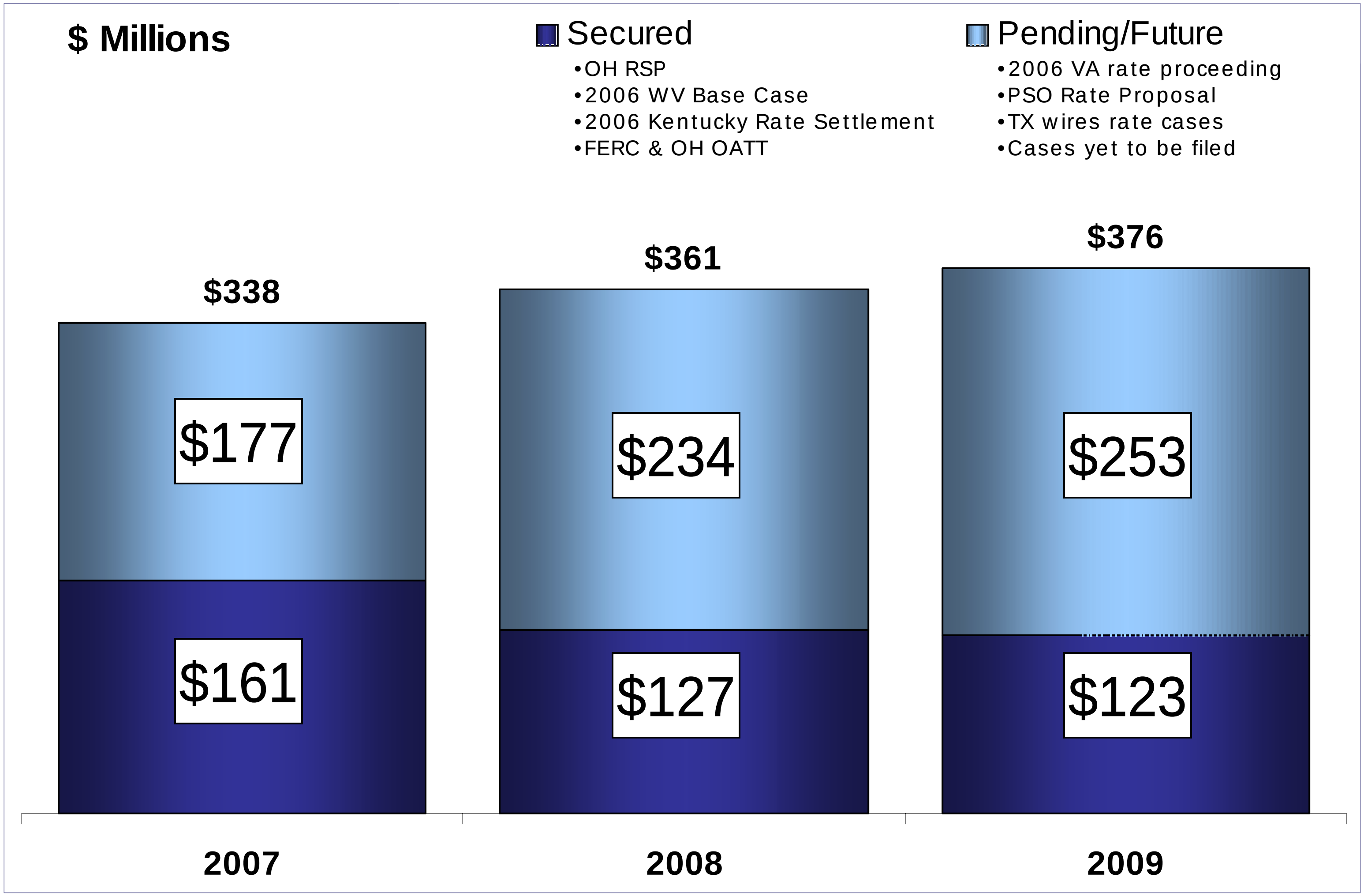
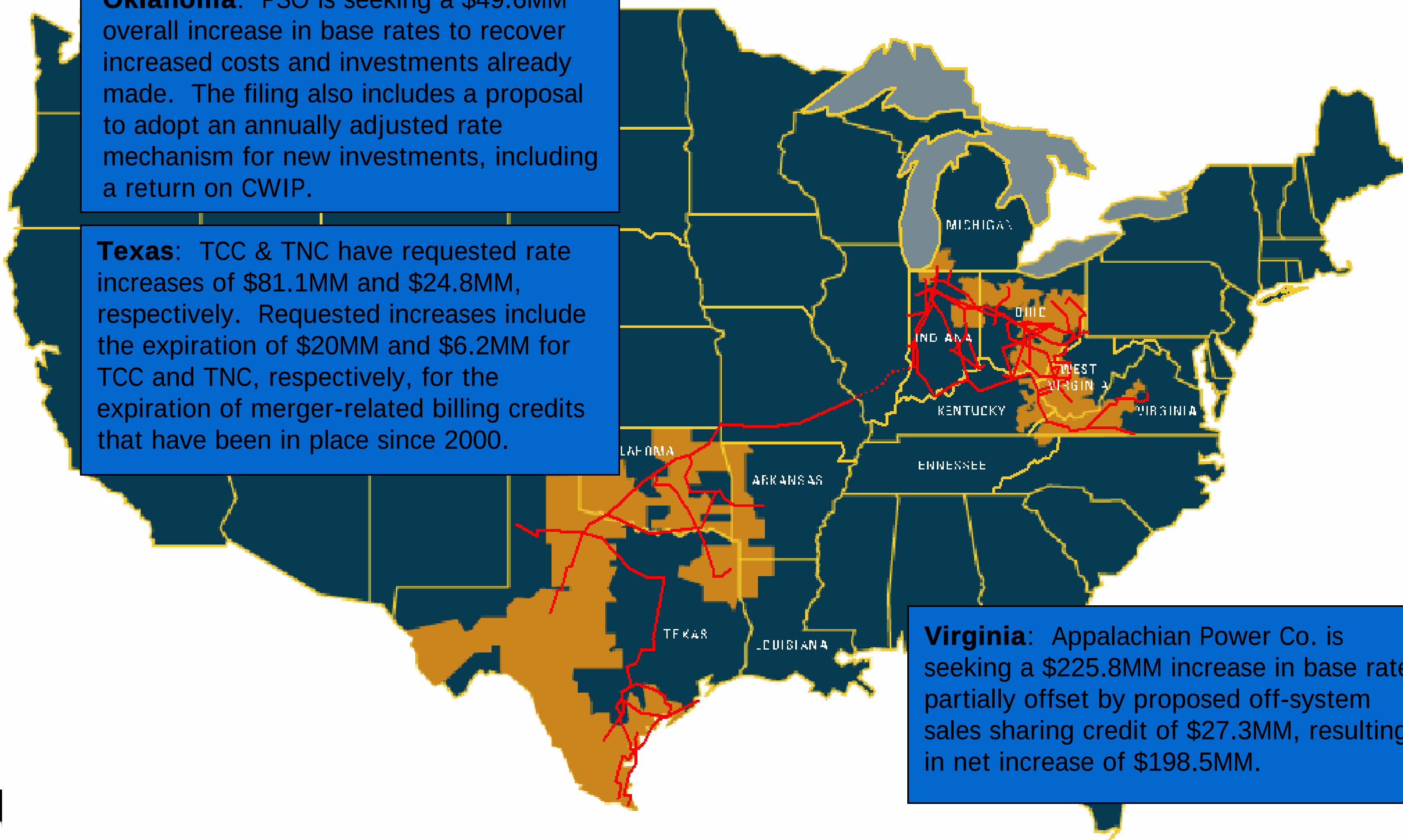
Incremental Rate Relief Composition



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

Rate Relief Is A Critical Element To AEP's Financial Success

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.

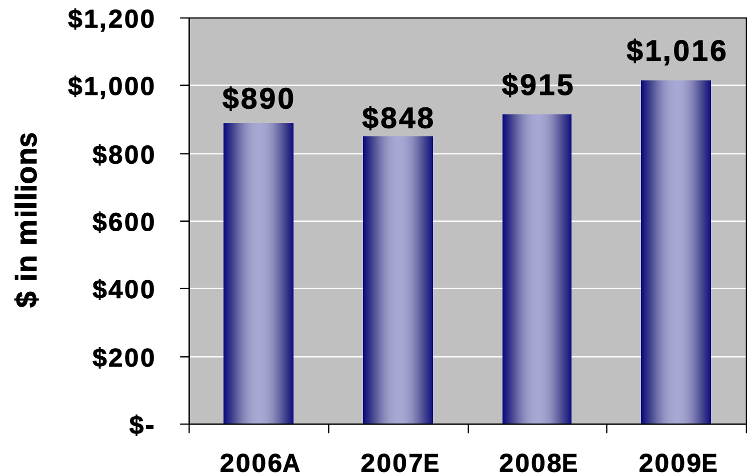
Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an average annual investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $60.8MM and $15.9MM for TCC & TNC distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment

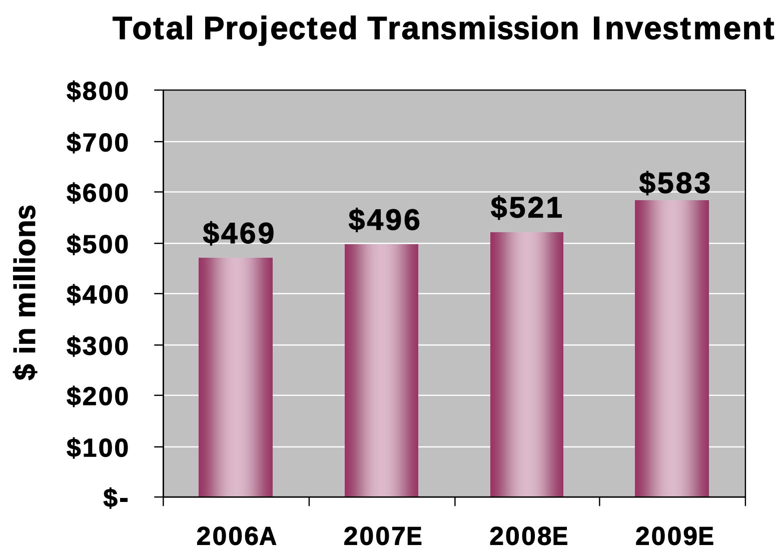


Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

Transmission Investment Forecast

- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of "postage stamp" rate
  - Final order expected in early to mid-2007
- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services
- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company and to set initial rates
  - FERC filing to transfer transmission assets to ETT submitted Feb. 15, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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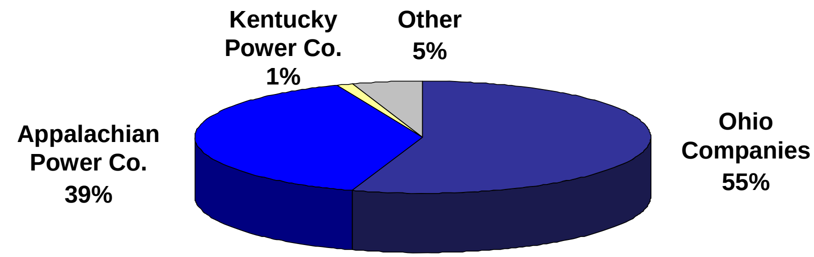
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

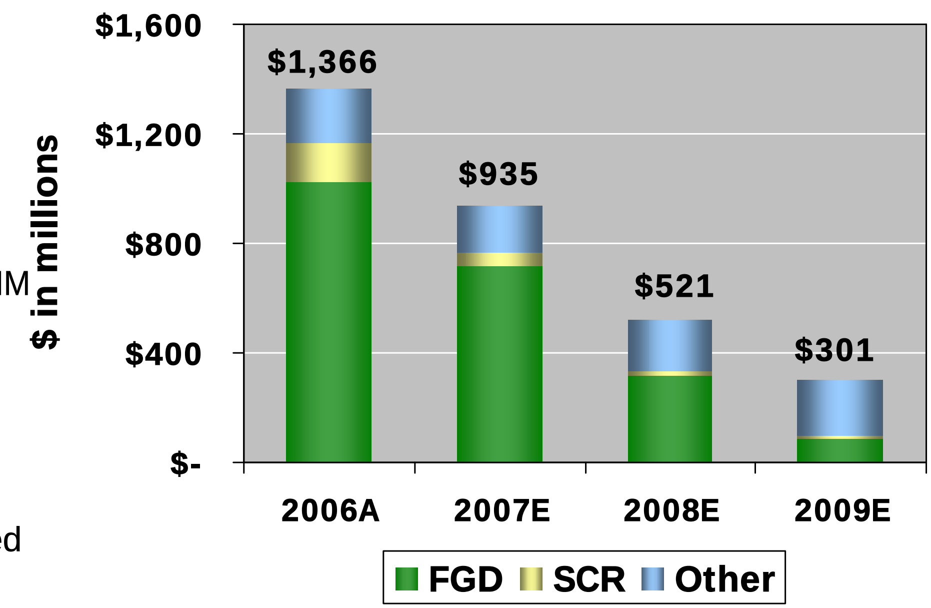
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures, pursuant to the 4% provision of the RSP
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



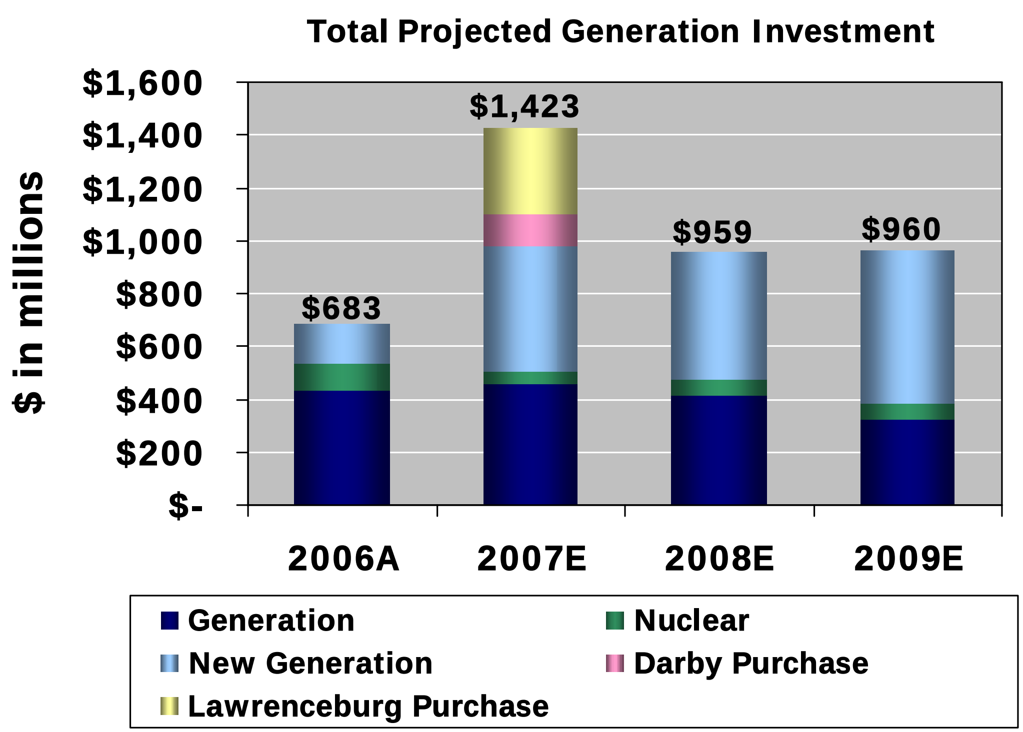
Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP
- Purchased Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



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Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	1Q07[(1)]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[(2)]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[(3)]	Coal	Ultra-supercritical	600[(3)]	2011
PSO	Red Rock	Oklahoma	$1.8 B[(4)]	Coal	Ultra-supercritical	950[(4)]	2011
CSP/OP	Great Bend	Ohio	Under Review[(5)]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[(5)]	Coal	IGCC	600	TBD

(1) Sale expected to close 1Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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Coming Soon – AEP's 2006 Corporate Responsibility Report

Our Vision for Sustainability

AEP enters its second century committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities. We will safely provide reliable, reasonably priced electric power while actively working to protect people and the environment. We will engage stakeholders and continue our role in making people's lives better today and for generations to come.

Our Challenges & Opportunities

•Leadership, management and strategy

•Climate Change

•Energy security, reliability and growth

•Environmental performance

•Workforce issues

•Stakeholder engagement

•Public Policy

We will continue to work as innovatively, efficiently, diligently and responsibly as we did during our first century. Sustainability is a journey, not a destination.

AEP®

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

Appendix

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 37,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

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Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

Rate Base Investment Coupled With Innovative Regulatory Plans Will Reduce Lag And Drive Earnings Growth

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AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

AEP Transmission Network – Largest in the Country

Operating Company Level
(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP ®

AEP Is The Leader In Transmission Expertise

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 45% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 48% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 25,746 MEGAWATTS

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	539*	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

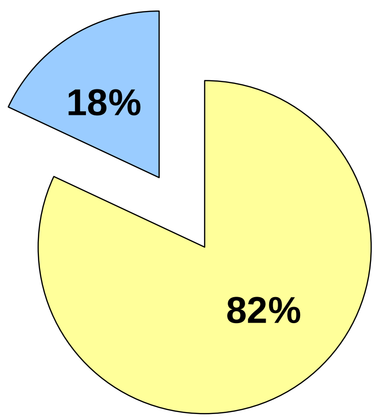
* Oklaunion's MW capacity represents combination of PSO, TCC & TNC ownership. TCC's 54 MW ownership of Oklaunion is currently under negotiation for sale.

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:

Active/Firm Costs to Remaining Estimated Costs



- Actuals To Date & Firm Costs
- Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP®

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. AEP intends to seek regulatory recovery approvals in advance of building the plant.

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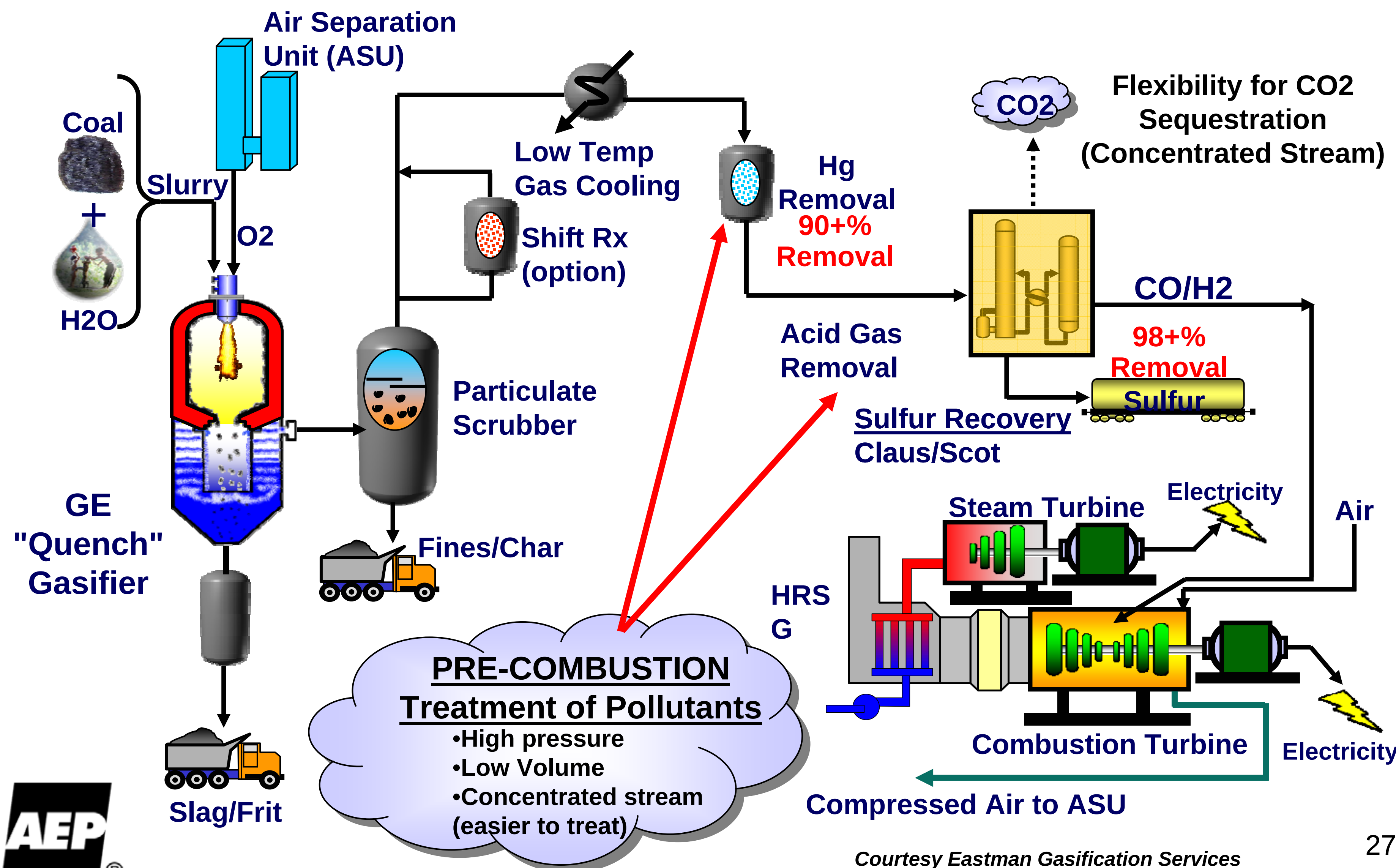
AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

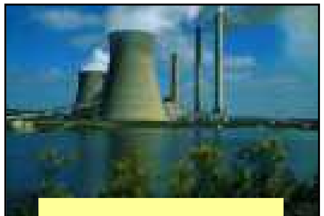
IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

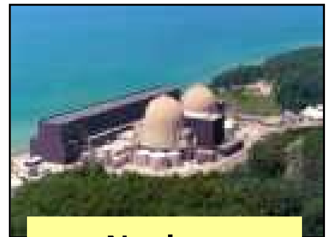
Permitting Process Will Take 1 – 2 Years

Domestic Generation Fleet

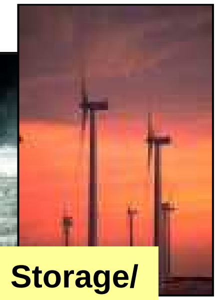


Coal/Lignite
70%

Nat. Gas/Oil
21%



Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
36,672 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	71%
SPP	23%
ERCOT	6%

Note: The figures on this slide exclude the Darby and Lawrenceburg plants, as these purchases have not yet closed.

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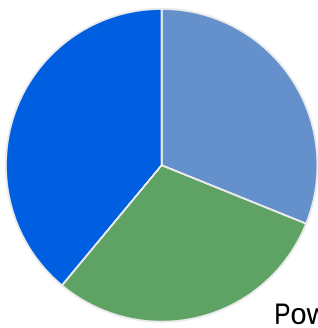
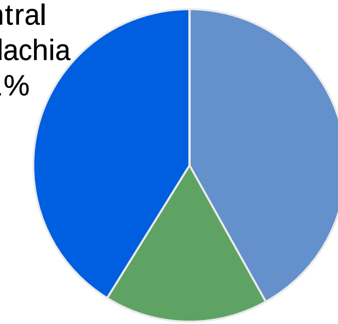
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

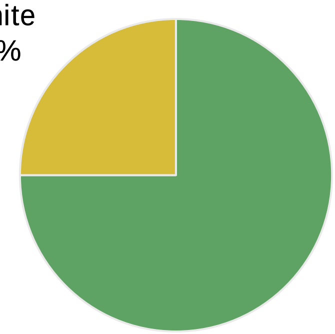
Total AEP System



AEP East



AEP West



Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

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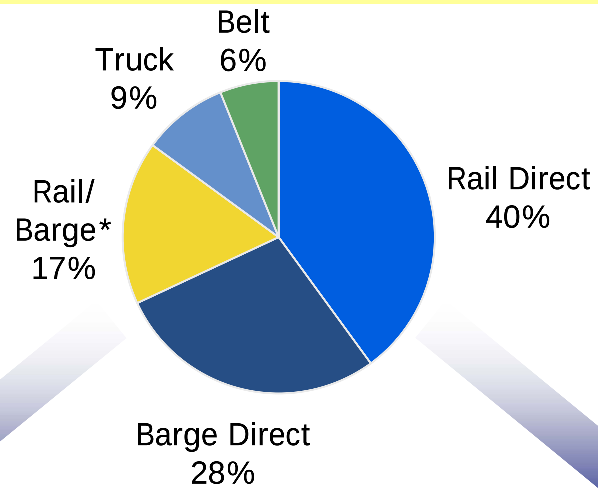
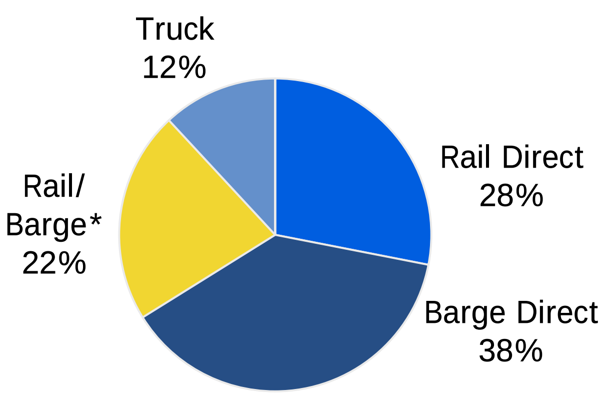
Coal Delivery

2006 Actual

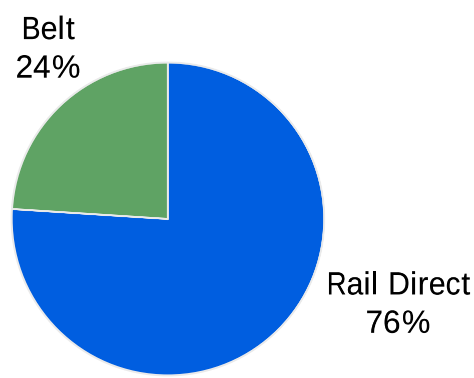
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval 1) to operate as an electric transmission utility in Texas; 2) to contribute transmission assets currently under construction by AEP subsidiary TCC to the joint venture company; and 3) establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%
  - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in early to mid-2007.

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 6, 2006	Hearings commenced
February 5, 2007	Briefs filed

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

Next Steps

APCo is now awaiting an initial recommendation from the Hearing Examiner (HE). APCo will have an opportunity to respond to the HE recommendation after it has been issued. Following this action, we then await an order from the SCC. No statutory deadline.

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. TCC and TNC requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony due
March 23, 2007	Staff testimony due
Mid-April 2007	Hearings to commence
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	11.25%	4.50%
Total	100%		8.02%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	11.25%	4.50%
Total	100%		7.97%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$588,170,858	$ 1,012,316,518
Cost of Capital	8.02%	8.02%
Return on Rate Base	$ 47,144,247	$ 81,141,219
Operation & Maintenance	$ 24,953,569	$ 234,900,166
Depreciation & Amortization	$ 16,050,664	$ 61,560,580
Income Taxes	$ 13,127,245	$ 21,909,492
Taxes other than Income	$ 14,691,850	$ 65,648,324
Total Cost of Service	$115,967,575	$ 465,159,781
Miscellaneous Revenues	$ (4,557,543)	$ (33,982,023)
Base Rate Revenue Requirement	$111,410,032	$ 431,177,758
Test Year Adjusted Base Rate Rev.	$ 90,790,725	$ 390,700,744
Requested Base Rate Increase	$ 20,619,307	$ 40,477,014

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$171,049,145	$ 288,872,851
Cost of Capital	7.97%	7.97%
Return on Rate Base	$ 13,639,241	$ 23,034,353
Operation & Maintenance	$ 12,775,116	$ 60,434,214
Depreciation & Amortization	$ 12,206,069	$ 28,670,726
Income Taxes	$ 3,126,651	$ 5,279,031
Taxes other than Income	$ 3,661,924	$ 12,093,639
Total Cost of Service	$ 45,409,001	$ 129,511,963
Miscellaneous Revenues	$ (365,848)	$ (7,216,050)
Base Rate Revenue Requirement	$ 45,043,153	$ 122,295,913
Test Year Adjusted Base Rate Rev.	$ 36,025,589	$ 112,706,901
Requested Base Rate Increase	$ 9,017,564	$ 9,589,012

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor testimony due
April 9, 2007	Rebuttal testimony due
May 1, 2007	Hearings to commence
June 20, 2007	Final order expected

* Figures are rounded

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,771	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 226	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,422	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (208)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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Capital Investment Is Funded By Cash From Operations And Debt Issuances

Forecasted Capital Expenditures

($ IN THOUSANDS)

Company	2007	2008	2009
AEP System*	**$ 3,867,000**	**$ 3,026,000**	**$ 2,974,000**
AEG	$ 343,000	$ 28,000	$ 34,000
APCo	$ 664,000	$ 531,000	$ 461,000
CSPCo	$ 439,000	$ 354,000	$ 233,000
I&M	$ 252,000	$ 264,000	$ 294,000
KPCo	$ 70,000	$ 114,000	$ 100,000
OPCo	$ 832,000	$ 368,000	$ 389,000
PSO	$ 319,000	$ 330,000	$ 466,000
SWEPCo	$ 537,000	$ 605,000	$ 540,000
TCC	$ 241,000	$ 214,000	$ 273,000
TNC	$ 143,000	$ 188,000	$ 149,000

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Figures exclude AFUDC.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6467 of 9556

2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$350-$450	43-45%
CSP	$439	$0-$50	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$350-$450	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances
(b) Ratios include impact of Rockport 2 lease
(c) Excludes impact of securitization on the equity ratio

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Long-Term Debt Maturity Profile

Year		2007		2008		2009
AEP Service Corp.	$	-	$	36,000,000	$	-
AEP, Inc.	$	345,000,000	$	-	$	-
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	325,000,000	$	200,000,000	$	150,000,000
Columbus Southern Power	$	-	$	112,000,000	$	-
Kentucky Power	$	322,964,000	$	30,000,000	$	-
Indiana Michigan	$	-	$	50,000,000	$	45,000,000
Ohio Power Company	$	-	$	44,542,074	$	106,000,000
Public Service of Oklahoma	$	-	$	-	$	50,000,000
Southwestern Electric Power	$	94,000,000	$	117,903,000	$	-
Texas Central Company	$	-	$	100,230,042	$	-
Texas North Company	$	8,151,000	$	-	$	-
Total	$	1,095,115,000	$	690,675,116	$	351,000,000

Note: Maturities remaining as of December 31, 2006

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Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

Commitment To Credit Quality

- Maintain minimum $200MM cash balance
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

Company	Target Equity Ratio
AEG	40%
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	44-46%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

AEP®

We Are Committed To Maintaining Our Current Credit Ratings
BBB / Baa2 / BBB

AEP and Climate Change

AEP AMERICAN ELECTRIC POWER

Bruce H. Braine
Vice President, Strategic Policy Analysis

Sanford C. Bernstein Investor Conference
June 14, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Company Overview

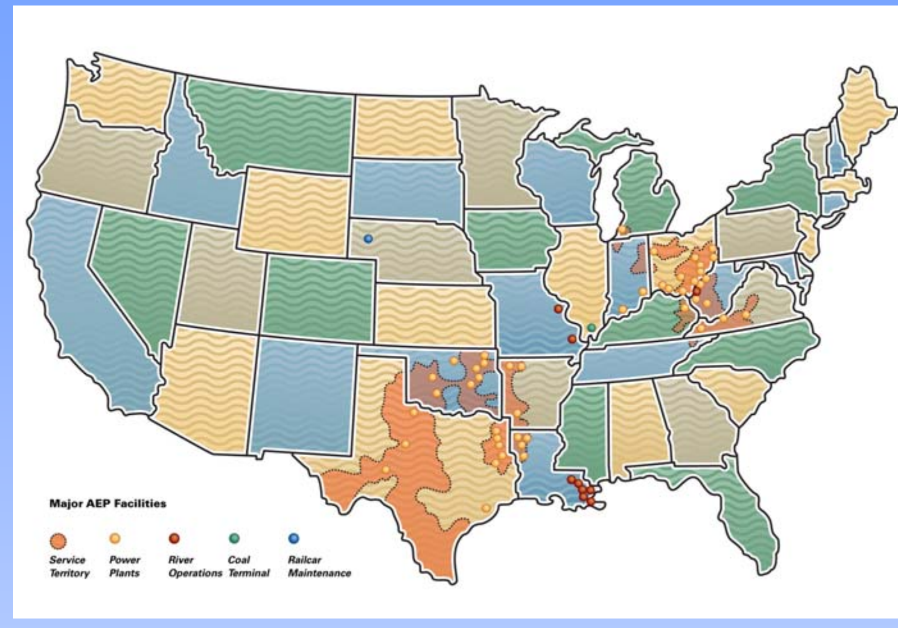
AEP®

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



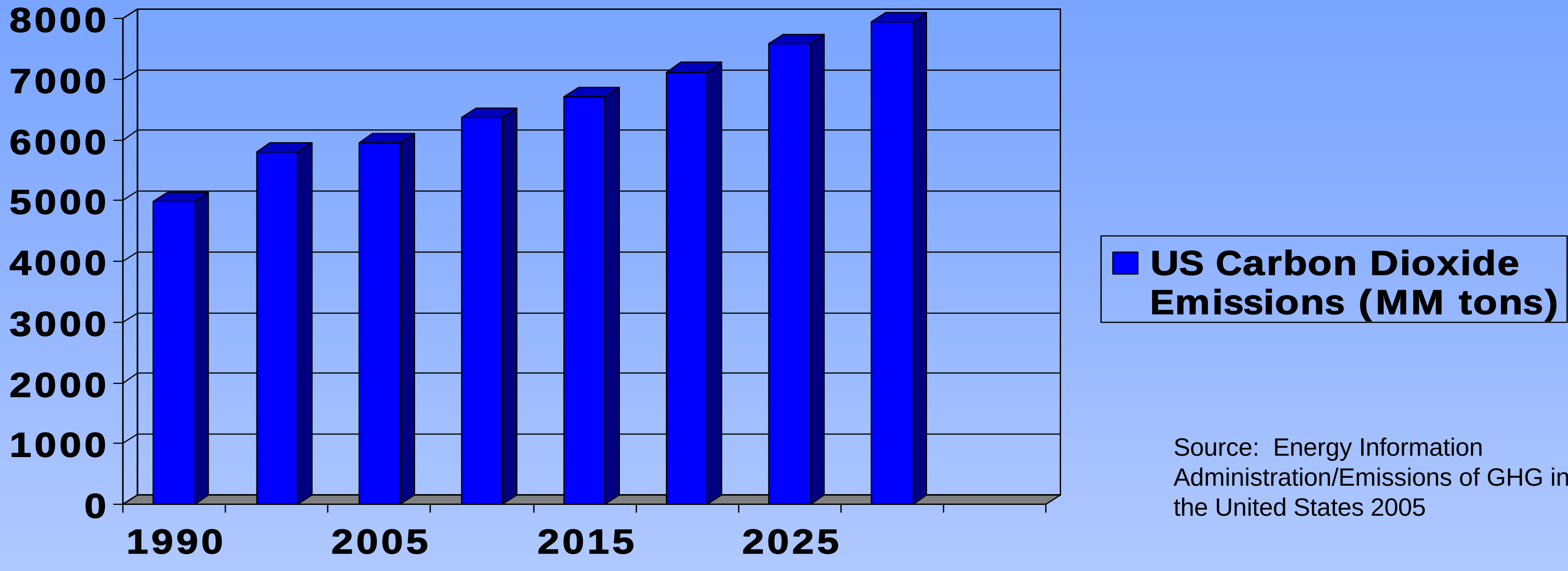
AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Presentation Topics

- **How is AEP preparing for ultimate climate legislation? What specific voluntary actions and proactive investments is the company undertaking?**
- **What type of climate legislation is likely? When will it become effective? How will climate legislation affect operations, capital investment, choice of generation, operations and earnings?**
- **What constitutes “reasonable” climate legislation?**

Investment Decisions Today Must Consider Likely Future CO_2 Emission Limits



Source: Energy Information Administration/Emissions of GHG in the United States 2005

Note: Chart above assumes no mandatory limits imposed on CO_2 emissions

- **Absent federal policies, long-term CO_2 growth is likely to be significant, driven by population and economic growth, electrification, transportation**

- **Likelihood of US GHG legislation is growing**
  - **Climate change science**
  - **Public perceptions**
  - **Political shifts in Congress**

Inclusion Of Climate Change In Investment Decisions And Taking Voluntary Actions To Reduce CO_2 Footprint Will Enhance Shareholder Return Prospects

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating/making longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP Long-Term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

- **Existing plant efficiency improvements**
- **Renewable Energy**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - **1.2MM tons of carbon sequestered**
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

AEP's reductions / offsets of CO_2:
- **2003-2005: 31 MMT**
- **2006-2010 (proj.): Additional 15 MMT**

New Program Additions (by 2011)

- **1000 MWs of Wind PPAs: 2MM tons/yr**
- **Domestic Offsets (methane): 2MM tons/yr**
- **Forestry: Tripling annual investment to increase to 0.5MM tons/yr by 2015**
- **Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr**
- **Additional actions (e.g. DSM): 0.2MM tons**

AEP's reductions / offsets of CO_2:
2011+: 5 MMT / YEAR

New Technology@ Existing Coal: Chilled Ammonia/Oxy Fuel

AEP Wind Operations/Purchases

Southwest Mesa (1999)

- **75 MW** (107 – 700 kW turbines)
- McCarney, TX
- Power Purchaser

Trent Mesa (2001)

- **150 MW** (100 - 1.5 MW turbines)
- Abilene/Sweetwater, TX

Desert Sky (2002)

- **160 MW** (107 -1.5 MW turbines)
- Bakersfield, TX

Summary

- **Owned/Operated: 385 MW**
- **Wind Purchases: 392 MW**
- **Total Existing Wind: 777 MW**
- **New Wind by 2011: 1000 MW**

AEP and New Clean Coal Technology

AEP®

Phase 1—CO_2 Capture / Storage
2008 Commercial Validation

Mountaineer Plant (WV) @ 30 MW → MOU (Alstom) **Chilled Ammonia** → CO_2 (Battelle) → **0.1 MM tons CO_2 / yr**

Phase 2—CO_2 Capture / Storage
2011 Commercial Operation

Northeastern Plant (OK)- 600 MW → MOU (Alstom) **Chilled Ammonia** → CO_2 EOR → **1.5 MM tons CO_2 / yr**

FUTUREGEN - First Near Zero Emissions Hydrogen/ Electric-AEP and Alliance members

AEP Carbon Capture & Storage Initiative

- In March, AEP announced a major carbon capture and storage initiative.
- AEP will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.
- AEP will also demonstrate and then install oxy-coal CO_2 capture & storage project at a commercial sized coal unit (about 200 MW)—feasibility study completed in 2008. (See Appendix)
- The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2008 and the second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2011.

AEP's 2006 Corporate Responsibility Report

Our Vision for Sustainability

AEP enters its second century committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities. We will safely provide reliable, reasonably priced electric power while actively working to protect people and the environment. We will engage stakeholders and continue our role in making people's lives better today and for generations to come.

Our Challenges & Opportunities

- **Leadership, management and strategy**
- **Climate Change**
- **Energy security, reliability and growth**
- **Environmental performance**
- **Workforce issues**
- **Stakeholder engagement**
- **Public Policy**

We Will Continue To Work As Innovatively, Efficiently, Diligently And Responsibly As We Did During Our First Century. Sustainability Is A Journey, Not A Destination.

Potential for Federal Climate Legislation

- **Legislation could pass as early as 2009-10 with limits taking effect as early as 2015. Any earlier requirements are unlikely.**
- **Moderate approach probably has best chance of passage -- offsetting emissions growth initially (during next decade) with significant reductions thereafter.**
- **Impacts in terms of utility operations, capital and earnings won't be until the 2015-20 period -- more substantial impacts probably not beginning until 2020 and after.**

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Climate Legislation: Longer Term Impacts on Investment/Operations

- Climate change legislation will likely lead to greater capital investment for compliance particularly in 2020 and after. This will mean for AEP:
  - Installation of carbon capture and storage at existing coal plants and at new plants
  - Replacement of some older coal fired units with new clean coal technologies or with combined cycle gas
  - Increased deployment of wind and biomass
  - Investment in end-use and supply side efficiency
- AEP investments over next 5-10 years envision transition from voluntary, proactive efforts to mandatory regime
  - New USC coal and IGCC plants
  - First retrofit carbon capture project
- Likely AEP operations impacts:
  - Greater utilization of our gas combined cycle units
  - Earlier shutdown/lower dispatch of older coal units

Climate Legislation: Impacts on Long Term Earnings

- For AEP, most significantly in the long term (2020 and after), climate change legislation will mean higher electricity prices for our customers since most of our generation serves retail customers under cost-of-service regulation.
- Cost pass-thru to customers would/should be largely earnings neutral.
- However, to the extent there is higher capital investment, this may build rate base and enhance earnings potential depending on rates of return.
- Wholesale margins and other deregulated generation may earn higher or lower margins depending on the legislation that passes and allowance allocations.

AEP Position: A “Reasonable” Approach to Climate Legislation

- Reductions and Timing--Moderate with Adequate Lead Times
- Scope of Program-- Economy Wide
- Point of Regulation (e.g. Upstream or Downstream)--Hybrid Approach
- Flexibility of the Program—Trading, Banking, Unrestricted Offsets, Early Action Credits
- Allowance Allocation And Other Cost Issues—Low auctions and safety valve
- International Linkage—emission requirements to foreign imports from non-participating countries

Scope/Reductions/Timing

- **Program Needs to Be Economy-Wide**
  - Utility Emissions are only one-third of total GHG emissions
  - EU Program --Utility and Large Industrial is Only About Half the CO_2 Emissions
  - Economy Wide – provides more cost-effective reductions, creates the right "incentives" and avoids inefficiencies
- **Moderate Level of Reductions/Start Slowly**
  - Important to Avoid Short Run Uneconomic Investment at Expense of Long-Run Improved Technology Choices
  - Recognize Lead Times Needed for New Investments; Stock Turnover and Regulations
  - Avoid Rate Shock
  - Significant Reductions should be Tied to Technology Advancement

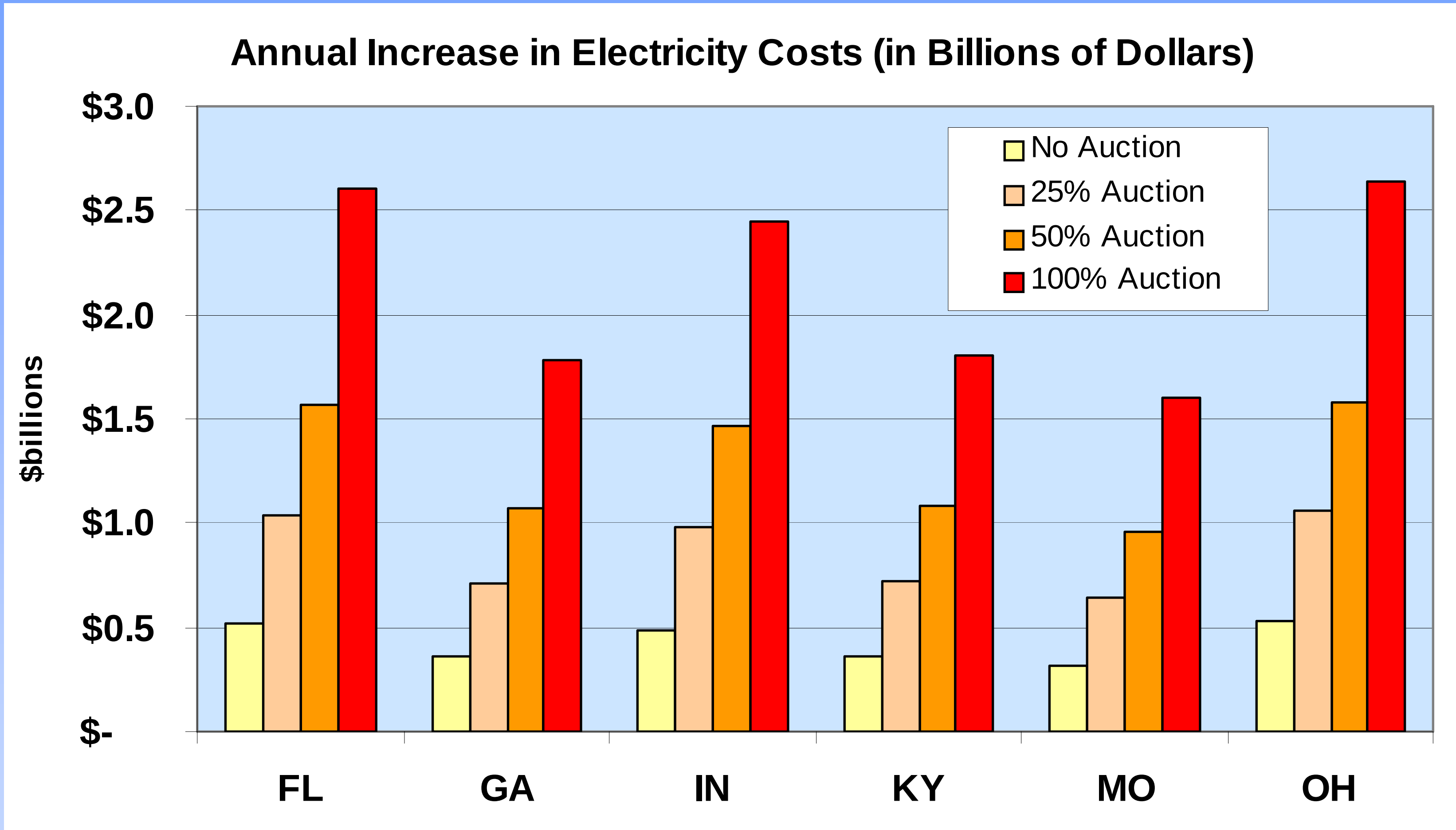
Flexibility of Program

- **Unrestricted Emissions Trading**
- **Unrestricted Emissions Banking**
- **All Greenhouse Gases Count**
  - Not just CO_2—Methane and N_2O and other non-CO_2 GHGs are 20% of total US GHGs and often cheaper to control
- **All Real and Verifiable Offsets Should Count (e.g. Forestry, Methane from landfills, agriculture)**
  - Many options cost less than \$10/ton CO_2 equivalent reduced vs. Utility Reductions generally \$10-50/ton
- **Credit for Early Action**

Allowance Auctions Increase Rates Significantly in "Cost-of-Service" States

- **Most generators are in states with cost-of-service regulation and part of vertically integrated utilities. (AEP generation is subject to cost based regulation in 10 out of our 11 states).**
  - **About 80% of US coal-fired generation is in cost of service states. Allowance auctions for these states result in large increases in electricity rates. (See next page)**
  - Example: Utility must reduce from 100 to 80 tons. Assume Allowance Price = $10.
    - No Auction: Utility gets 80 "no-cost" allowances and reduces by 20 at a cost of $200. **Total costs/customers rate impact = $200.**
    - 50% Auction: Utility gets 40 "no-cost" allowances, buys 40 from the auction for $400 and reduces by 20 at a cost of $200. **Total costs/customer rate impact = $600 or 3 times as much as the no auction case.**

Increase in Customer Electricity Costs Due to Allowance Auctions



Source: AEP estimate based on 2005 EIA electric sector revenue and emission data, an assumed CO_2 price of \$20/ton and a 20% reduction in electric sector CO_2 emissions.

Allowance Allocation Within the Electric Sector

- **Emissions-Based Allocations Are More Equitable---**Allowances should be allocated based on historic/current emissions to existing generators required to make reductions. **Allocation principle is all emitters make their "fair" pro-rata share of reductions**.
- **Output or Total KWh based Allocations Create Large Windfalls for Some Generators and Major Losses for Coal ---**
  - Allowances should NOT be allocated to sources that do not have emissions such as hydro and nuclear. Gas-fired plants should not receive "excess" allocations.
  - Nuclear, hydro and gas plants will already benefit (to the extent they are in "deregulated" states) due to higher power prices.
  - Output based allocations such as in the Carper bill increase costs to ratepayers of largely regulated, coal dependent states (e.g. the Midwest and Southeast) and provide large windfalls to deregulated gas and nuclear plants. For example, output-based allocation would increase costs to AEP and its customers by about $1 billion/year with no CO_2 benefit.

Appendix

Utility Investment Drives Growth

AEP®

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison (Tontitown)	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall (Arsenal Hill)	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk (Hempstead)	Arkansas	$1.3 B[1]	Coal	Ultra-supercritical	600[1]	2011
PSO	Red Rock	Oklahoma	$1.8 B[2]	Coal	Ultra-supercritical	950[2]	2012
CSP/OP	Great Bend	Ohio	Under Review[3]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[3]	Coal	IGCC	600	TBD

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) PSO will own 50%, or 475 megawatts, totaling approximately $900MM in capital investment.
(3) FEED (front-end engineering and design) study is completed. Final results will be available in June.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

Chilled Ammonia Technology Program

AEP®

Phase 1
2008 Commercial Operation

Mountaineer Plant (WV) → MOU (Alstom) **Chilled Ammonia** → CO_2 (Battelle)

Phase 2
2011 Commercial Operation

Northeastern Plant (OK) → MOU (Alstom) **Chilled Ammonia** → EOR; CO_2

Project Validation

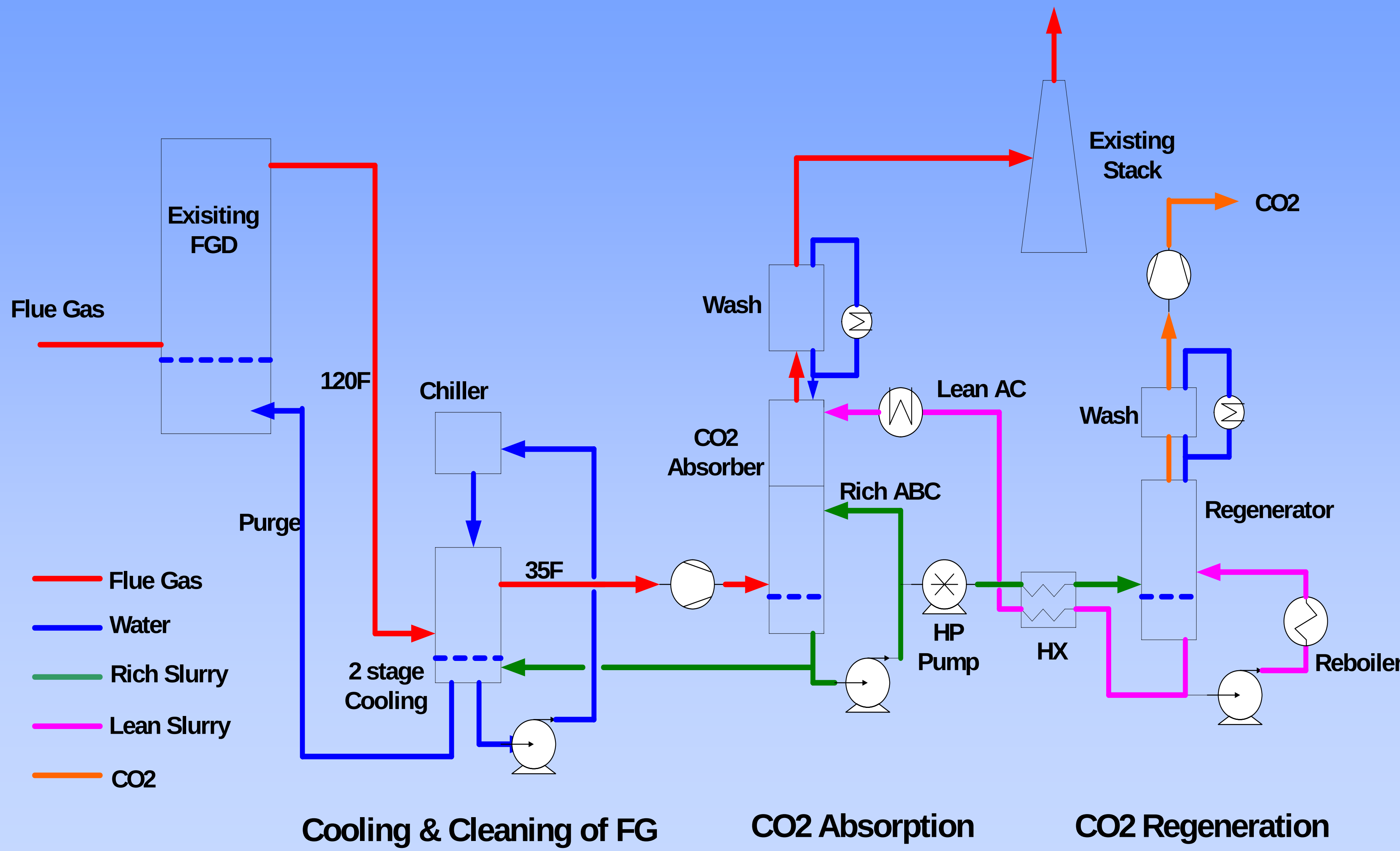
- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

Post-Combustion Carbon Solution Provides Pure Co_2 Stream For Capture

Schematic of the Chilled Ammonia Process



Chilled Ammonia Process Plant Footprint

Oxy-Fuel CO_2 Capture & Storage Project

AEP®

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

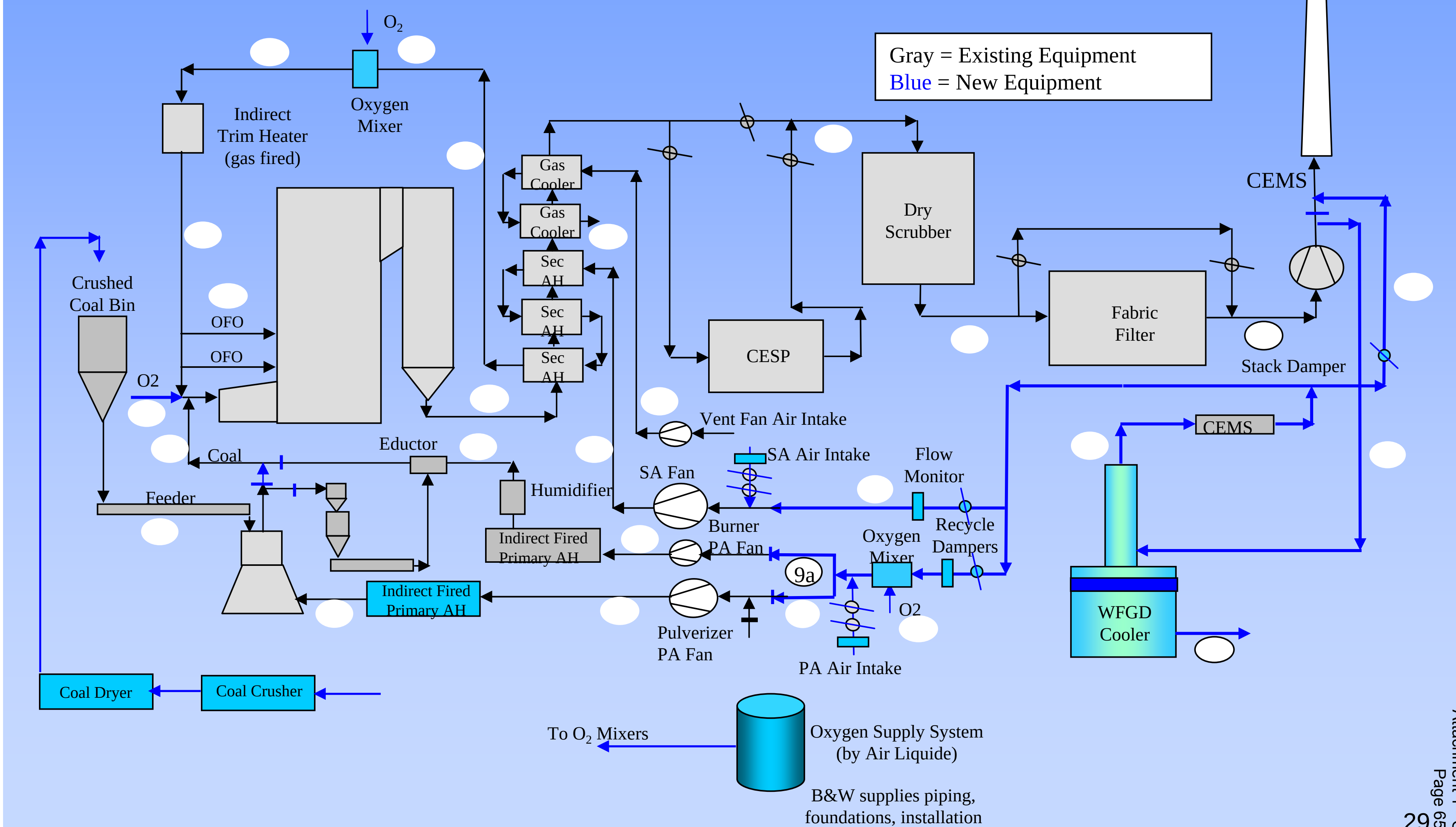
Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study completed 2Q 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Schematic of the Oxy-Fuel Process

CEDF CONVERSION SCHEMATIC



Oxy-Fuel Technology Initiative

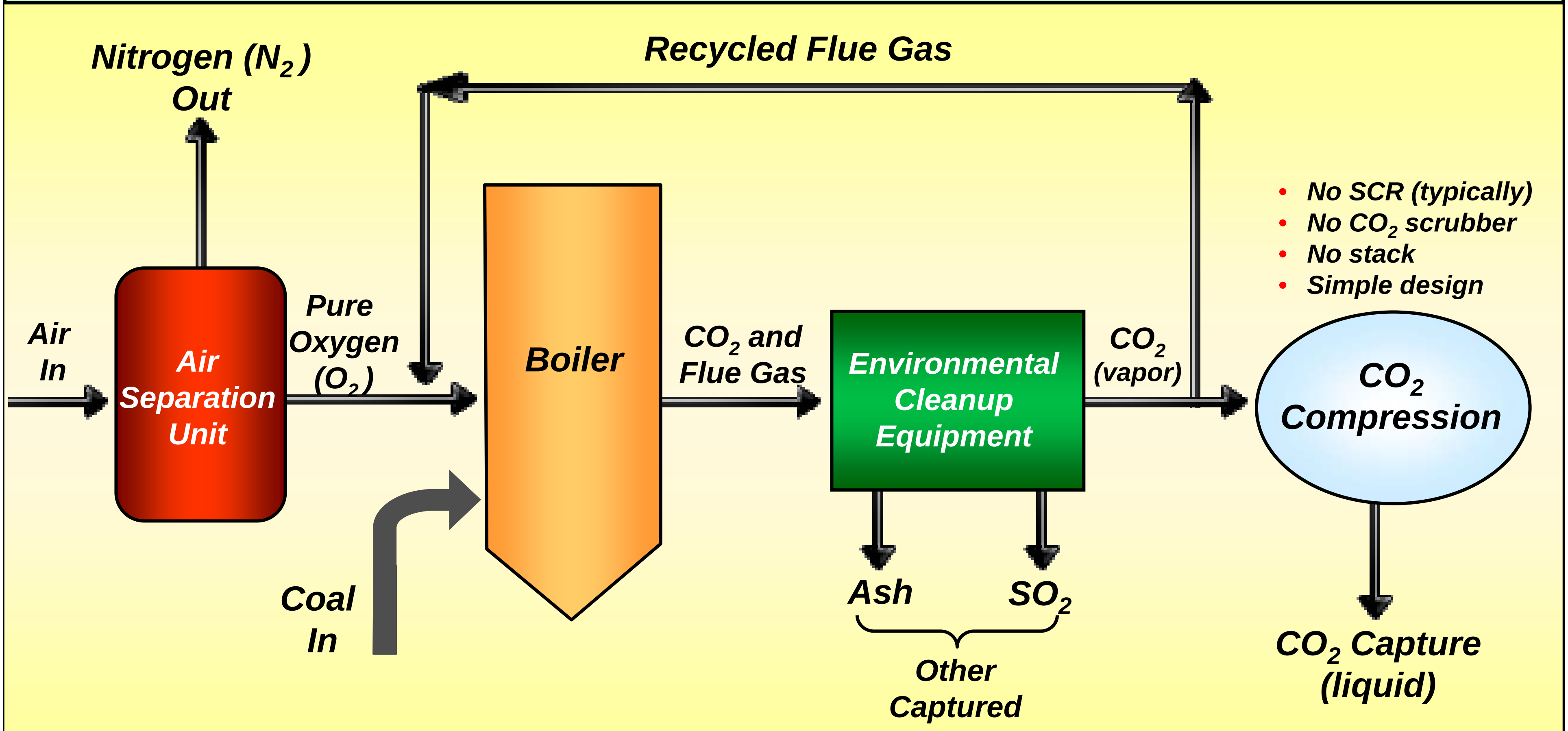


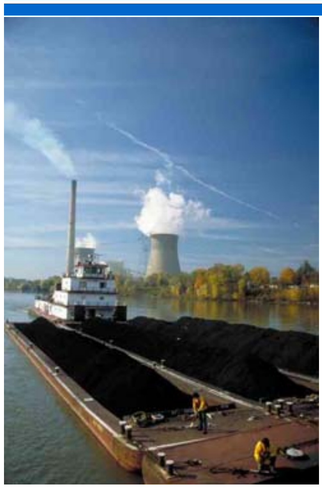
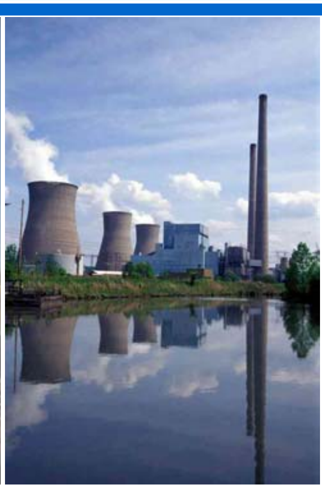
Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-Zero Emissions Using Oxy-fuel Combustion Technology

Deutsche Bank Energy & Utilities Conference

Miami, FL

May 30, 2007

AEP AMERICAN® ELECTRIC POWER


"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP®

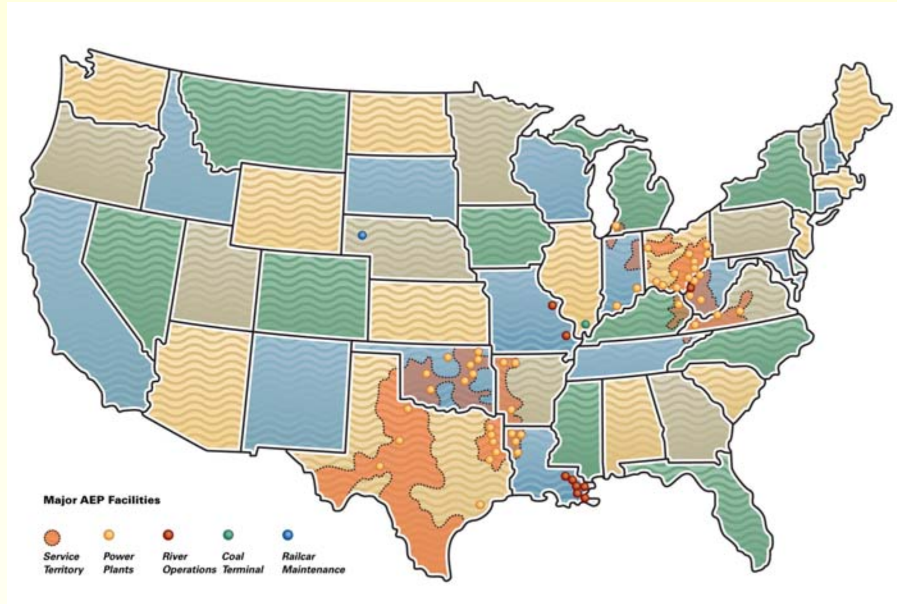
Holly Koeppel
EVP & Chief Financial Officer

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

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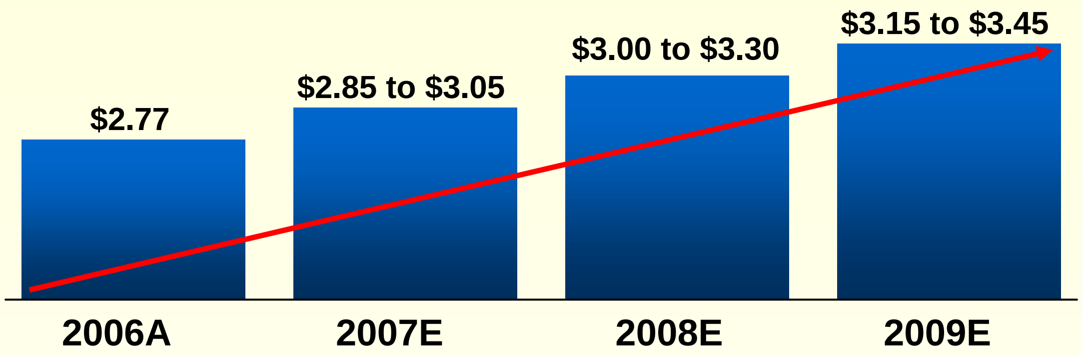
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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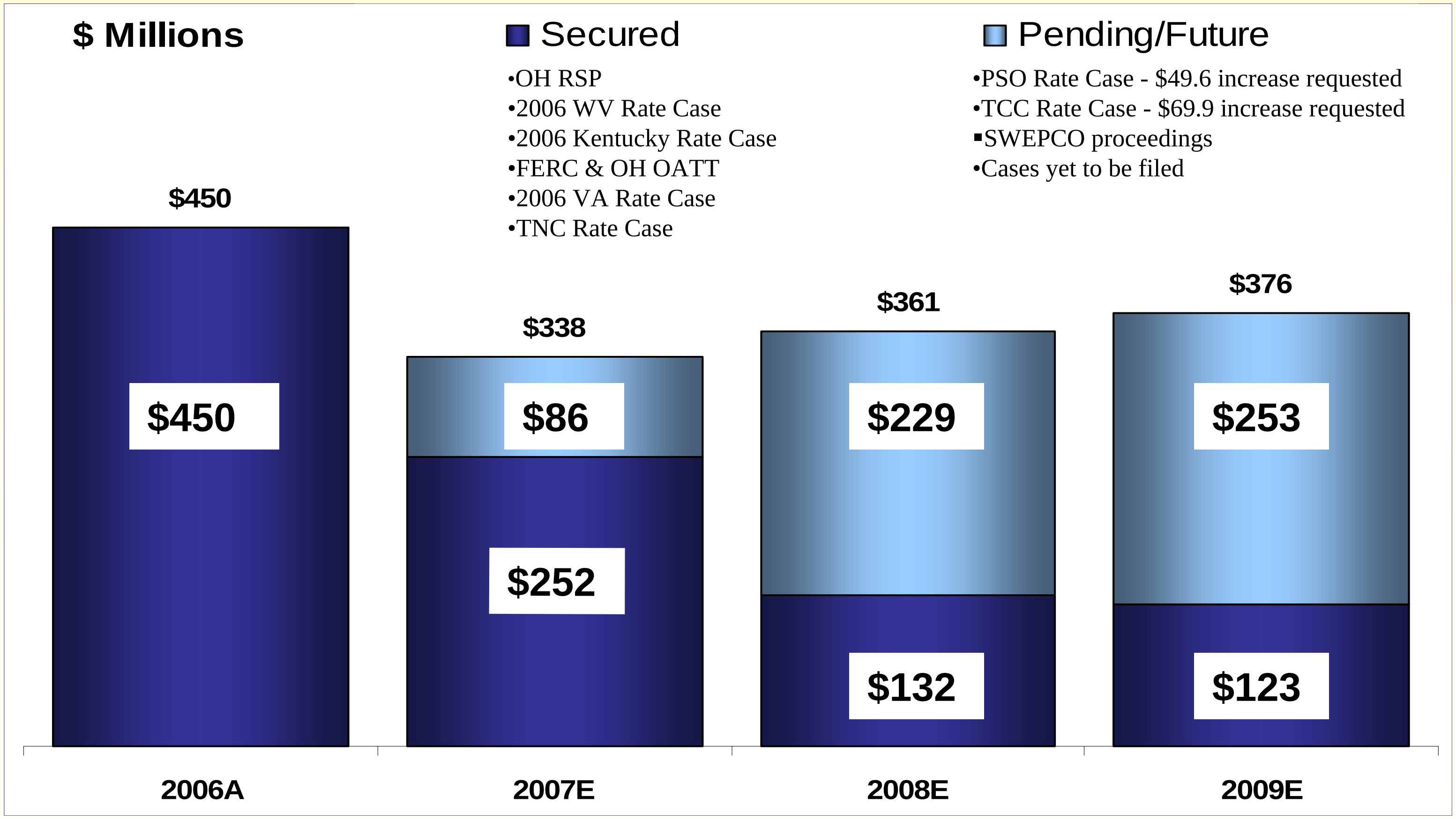
Our Strategy Remains Focused On Regulated Operations

Incremental Rate Relief Composition



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Rate Relief Is A Critical Element To AEP's Financial Success

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

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Environmental	$935	$521	$301	**$1,757**
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Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

AEP®

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

AEP®

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New Generation Facilities

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APCo	Mountaineer	West Virginia	Under Review(3)	Coal	IGCC	600	TBD

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(2) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(3) FEED (front-end engineering and design) study is completed. Final results will be available in June.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit filed and approved in Feb 2007
  - Units 3 and 4 online by summer peaking-season 2007; Units 1 and 2 online by Jan 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by Mar 2008

PSO

- Southwestern & Riverside Additions
  - Air permit received March 22, 2007
  - Commercial operation date of Dec 2007
  - Projects to be completed by Q1 2008
  - Regulatory Recovery
    - Settlement and final order in the Lawton Cogen case authorizes costs for Southwestern and Riverside peakers to be recovered through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

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SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

- Turk Plant (Fulton, AR)
  - Certificate of Need approvals (LA, AR, TX) expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for Sept 2007
    - AR and TX rate recovery will be addressed in separate filings
  - Approximately 85-90% of costs are firm
    - EPC contract for balance of plant work awarded in May 2007
    - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

- Red Rock Plant (Red Rock, OK)
  - Used and useful determination filed in Feb 2006 – approval expected by Sept 2007
  - Air permit approval expected in Aug 2007
  - Regulatory Recovery
    - Order expected in PSO rate filing by June 19, 2007 – filing includes request for CWIP treatment for new projects
  - Original cost estimate of $1.8 billion – revised cost estimate expected in July 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

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Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results to be filed in June 2007. Cost estimates expected to be in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony due June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – pre-draft report is expected in June 2007
- Regulatory Recovery Filing
  - Filing expected in June 2007 – will include request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

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Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

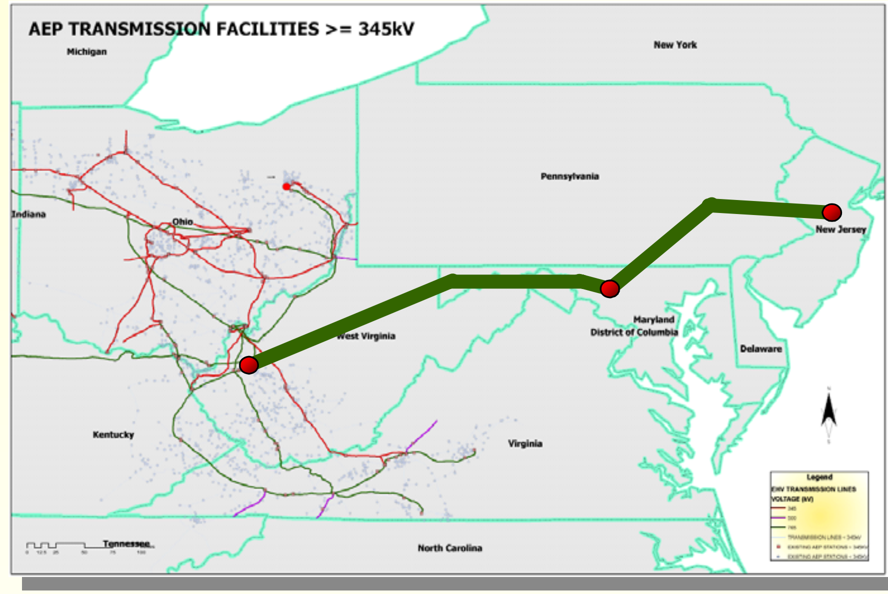
I-765$_{TM}$ PJM Transmission Project

Joint Venture with AYE

- 290 miles of the proposed 550 mile project
- Line will link AEP's Amos station in WV to AYE's proposed Kemptown station in MD with an intermediate station at AYE's Bedington station in WV
- JV project costs will encompass $1.1 billion, with each company owning 50%
- AEP's investment will total approximately $700 million, including ancillary projects
- Entire I-765$_{TM}$ project included in DOE's draft National Interest Electric Transmission Corridor
- FERC incentive rate treatment applies
- Operations to commence in the 2H07

Remaining I-765$_{TM}$ Project

- PJM is evaluating the Kemptown (MD) - Deans (NJ) line as a separate alternative



➢ Jointly owned with Allegheny, will improve eastern grid reliability

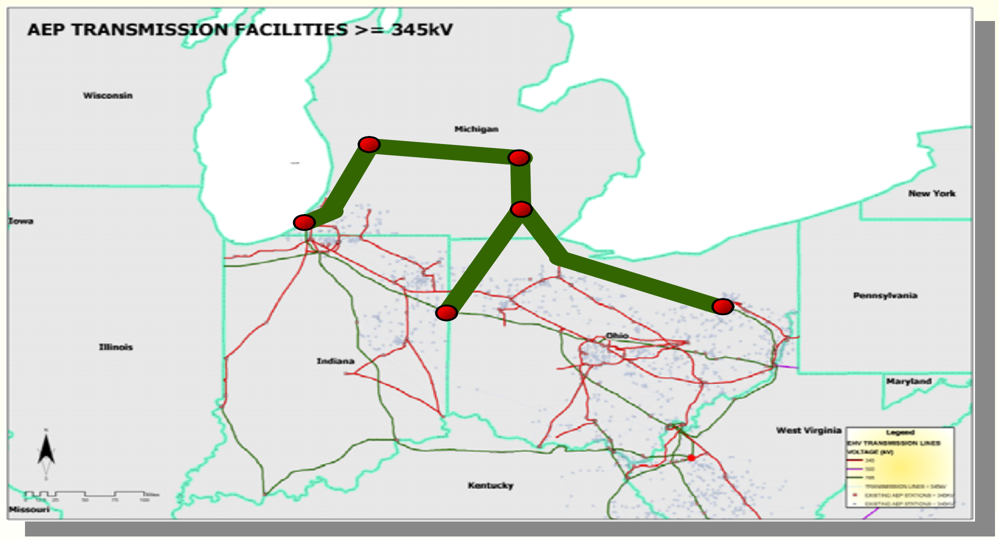
➢ Enhance Midwest-Mid-Atlantic power transfer capability by 5000 MW

➢ Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.

PJM's Targeted In-Service Date For the 290-Mile Project Is 2012

Michigan 765kV Study

- Agreement with ITC Transmission for Michigan 765-kV study
- Estimated $2B investment potential (before ownership division)
  - 630 line miles
  - Over 5000MW improved transfer capability
  - Anticipated rate impact <1mil/kWh
- 765-kV could help alleviate constraints
- Study results anticipated in 2Q07
- We anticipate signing an MOU with ITC on joint ownership in mid-2007



Project Construction Would Not Proceed Until Proper Regulatory Approvals Are Received And Cost Allocation Is Clarified

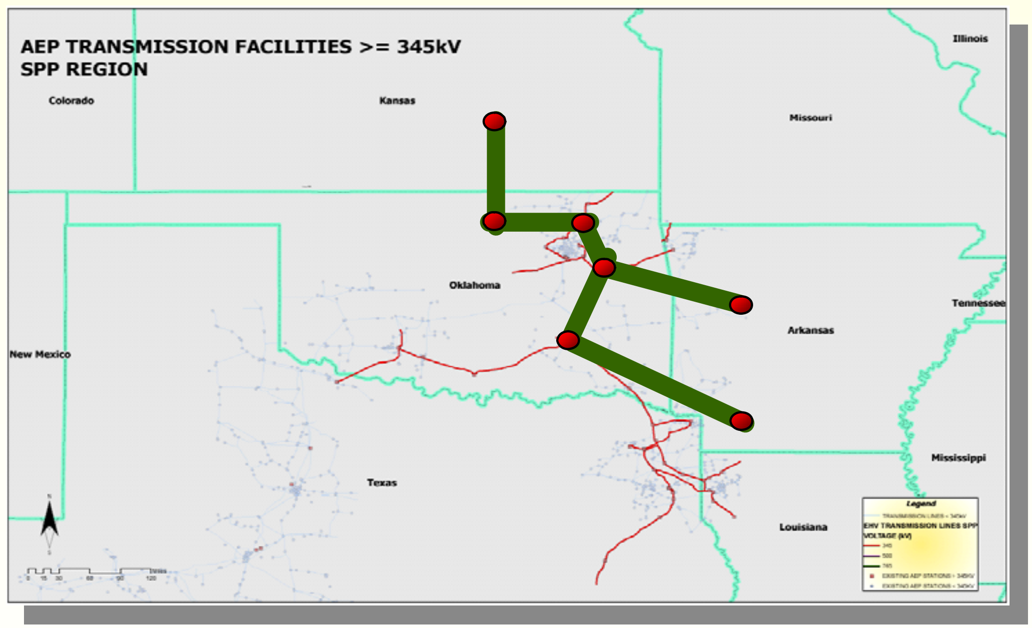
SPP Transmission Potential

- June 2006 SPP requested proposal to address congestion, reliability & access for new generation

- July 2006 AEP submitted proposal:

- Six 765-kV lines, 610 line miles from Arkansas to Wichita, Kansas, under construction 2012-2017
- Investment ~$3 billion
  - ~4000MW improved transfer capability
  - Anticipated rate impact 2mils/kWh

Next steps:
SPP issued EHV Overlay Study RFP to review 345 kV, 500 kV, and 765 kV potential projects in SPP with results expected in mid-2007



Long-term Opportunity For Large Transmission Investments to Reduce Congestion, Enhance Reliability and Access New Generation

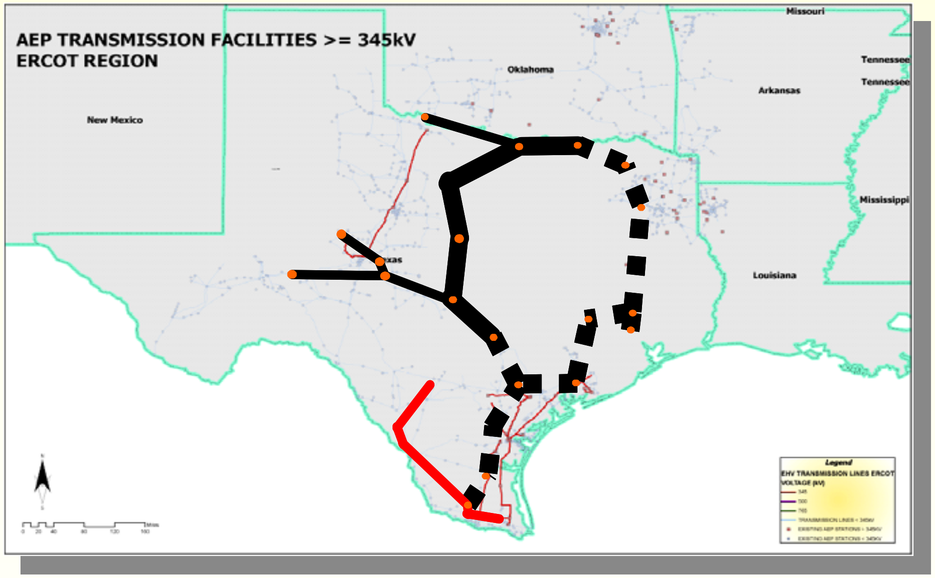
Electric Transmission Texas, LLC

Joint Venture with MidAmerican Energy

- Ownership – 50% AEP / 50% MidAmerican Energy
- 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
- AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
- Hearings with PUCT to be held July 16-19, 2007
- Initial funding in 3Q07 after regulatory approvals
- Debt – Initially bank financing

Competitive Renewable Energy Zone (CREZ) docket

- In February 2007, ETT proposed the development of a long-term transmission plan for ERCOT to address the Texas legislature's CREZ initiative. The plan includes:
  - $1.5 billion for Stage I of CREZ development by 2012
  - $1.5 billion for Stage II of CREZ development by 2015
  - $4.2 billion for Stage III for completion of ERCOT transmission backbone needed for long-term



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Operations of JV Could Begin As Soon As 3Q07 Upon Receipt of Regulatory Approvals

Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

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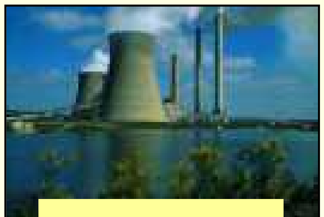
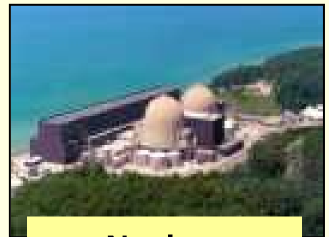
Appendix

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

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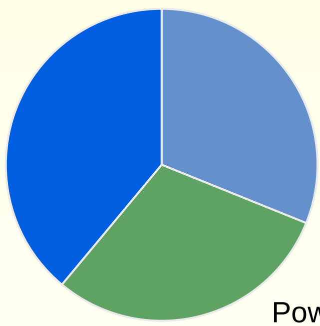
* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

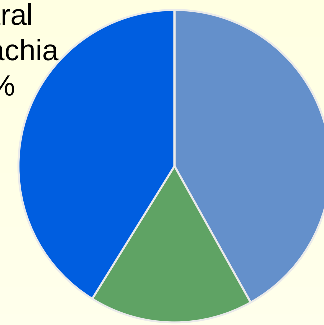
Total AEP System



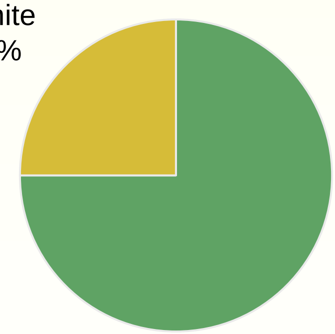
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



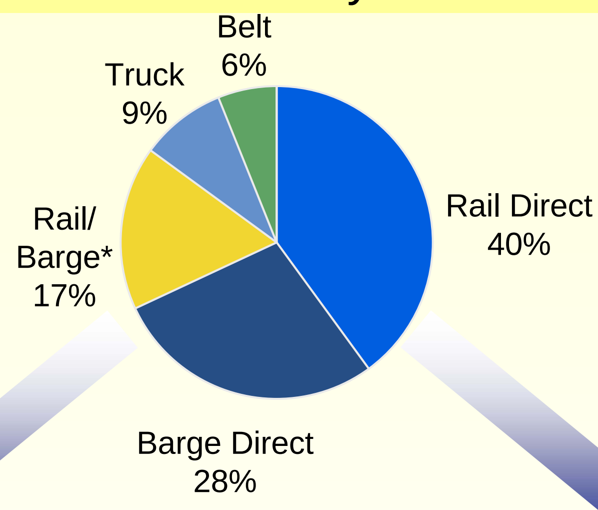
AEP West



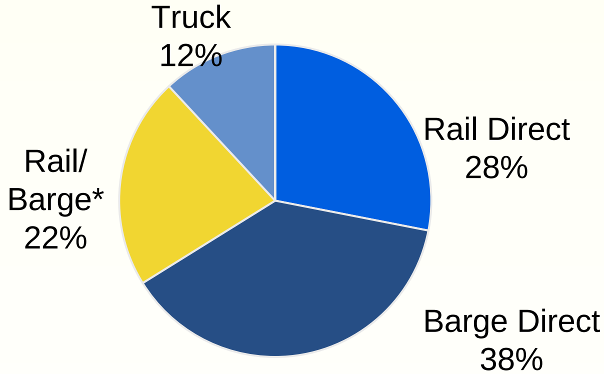
Coal Delivery

2006 Actual

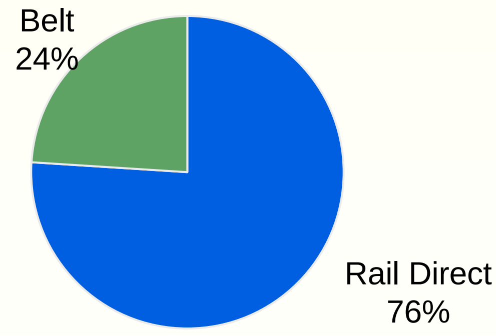
Total AEP System



AEP East

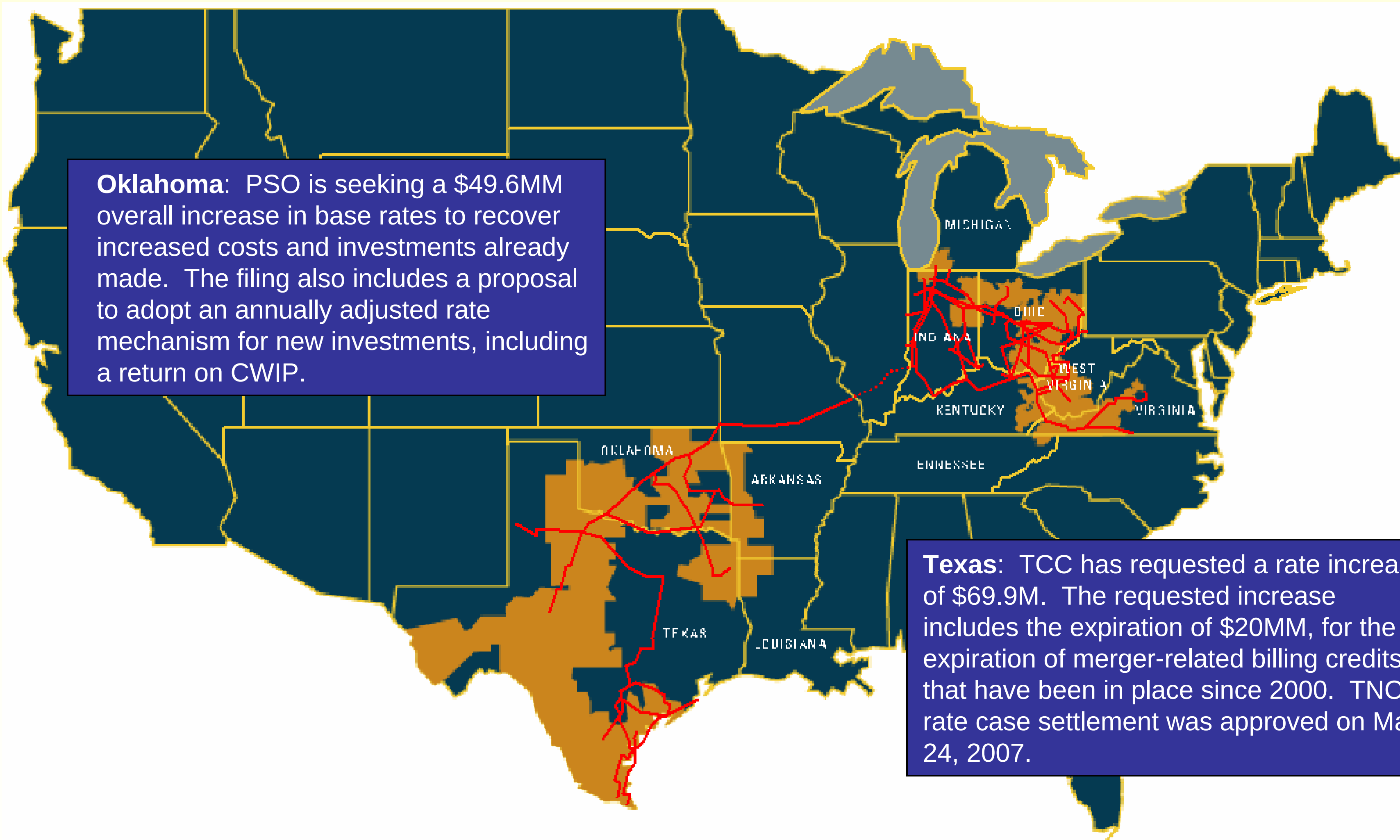


AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Base Case Regulatory Summary



Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC has requested a rate increase of $69.9M. The requested increase includes the expiration of $20MM, for the expiration of merger-related billing credits that have been in place since 2000. TNC's rate case settlement was approved on May 24, 2007.

New Transmission Investment Funding Plans

- **Electric Transmission Texas LLC**
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% MidAmerican Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- **AEP I-765$_{TM}$ Interstate Project**
  - Forming a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- **Other Transmission Projects**
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

Procedural Schedules and Details

- Turk Plant - Arkansas
  - Docket No. 06-154-U
  - Staff/Intervenor Testimony – June 29
  - Rebuttal Testimony – July 13
  - Public Hearings – July 19 or August 9

- Red Rock Facility - Oklahoma
  - PSO and OG&E Cases were consolidated by the OCC
  - PSO Docket Nos. 200500516 and 200600030
  - OG&E Docket No. 200700012
  - Staff/Intervenor Testimony - received May 21
  - Rebuttal Testimony – June 18
  - Hearings re. Used and Useful Determination – July 2
  - Hearings re. OG&E Cost Recovery – July 19
  - ALJ Report – August 6
  - Order – August 21

- Turk Plant - Louisiana
  - Docket No. U-29702
  - Staff/Intervenor Testimony – June 15
  - Rebuttal Testimony – July 16
  - Public Hearings – September 11-14

- ETT LLC - Texas
  - Docket No. 33734
  - Intervenor Testimony – June 8
  - Staff Testimony – June 18
  - Rebuttal Testimony – June 26
  - Hearings – July 16-19

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IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

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AEP Is Committed To IGCC Technology

IGCC Permitting Process

IGCC Permitting Issues

- **Air**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- **Wastewater**
  - ✓ Understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- **US ACE (US Army Corp of Engineers**)
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

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Permitting process takes 1 – 2 years and is well under way

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-10
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	In-service	☑	In-service
Mitchell 2	800	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	Upgrade In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2008
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	Upgrade In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

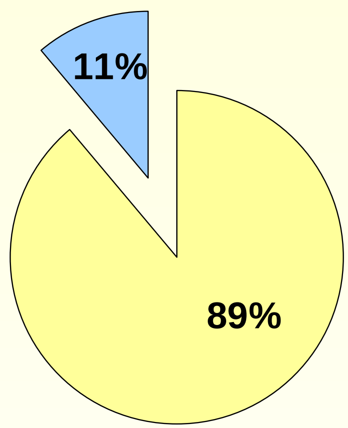
*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

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AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP®

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

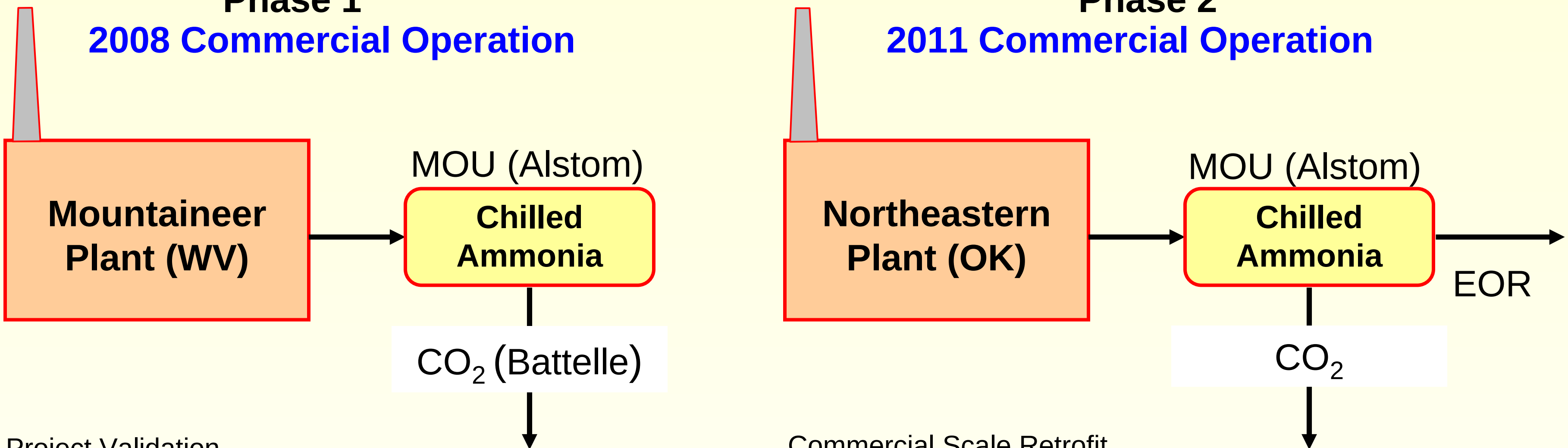
AEP®

Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



Project Validation

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

AEP®

Post-combustion Carbon Solution Provides Pure Co_2 Stream For Capture

Oxy-Fuel Technology Initiative

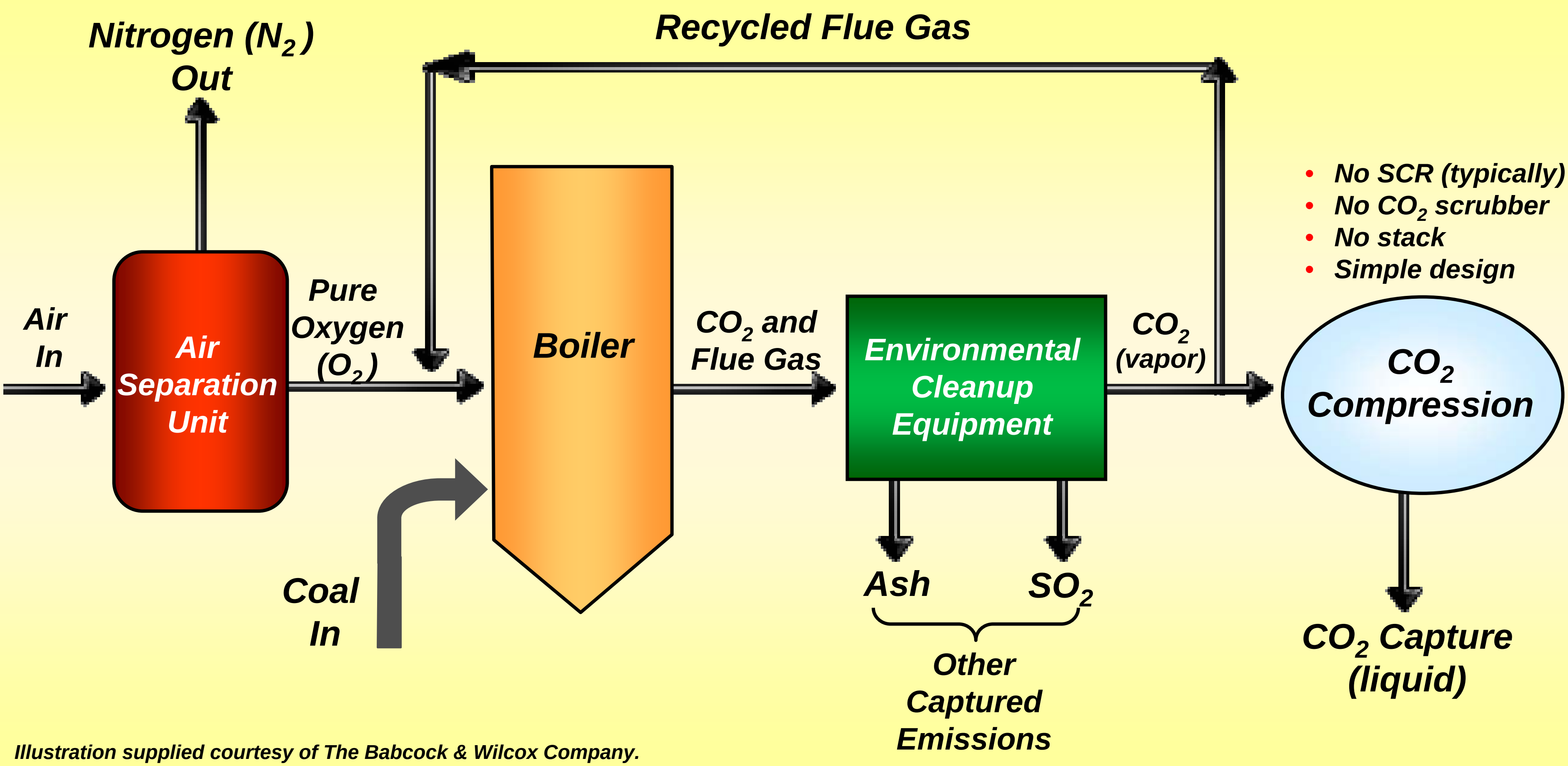


Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-zero Emissions Using Oxy-fuel Combustion Technology

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

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Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Evidentiary hearing commenced May 22, 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due June 8, 2007. Staff testimony is due June 18, 2007. Hearings are scheduled for July 16-19, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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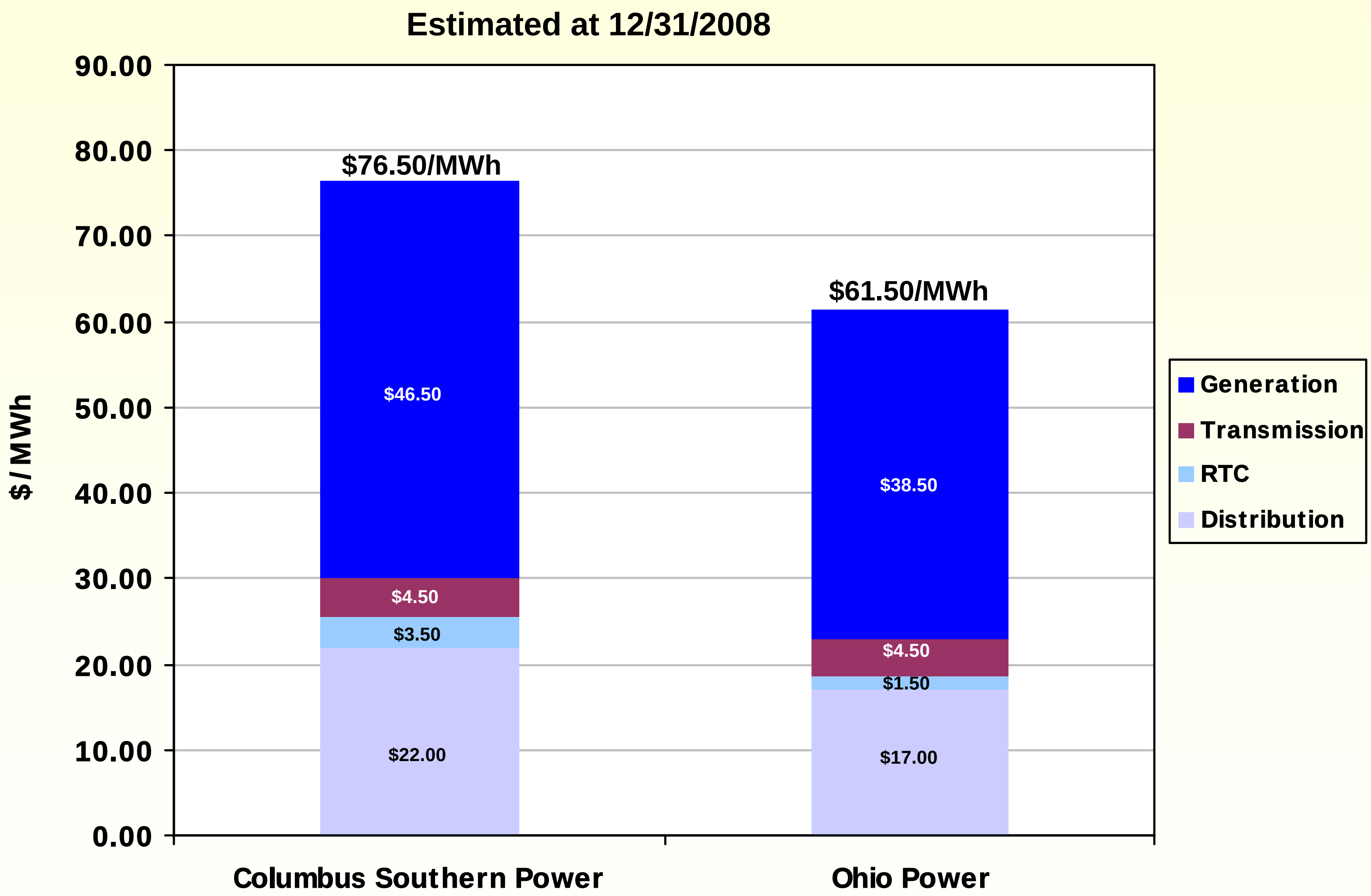
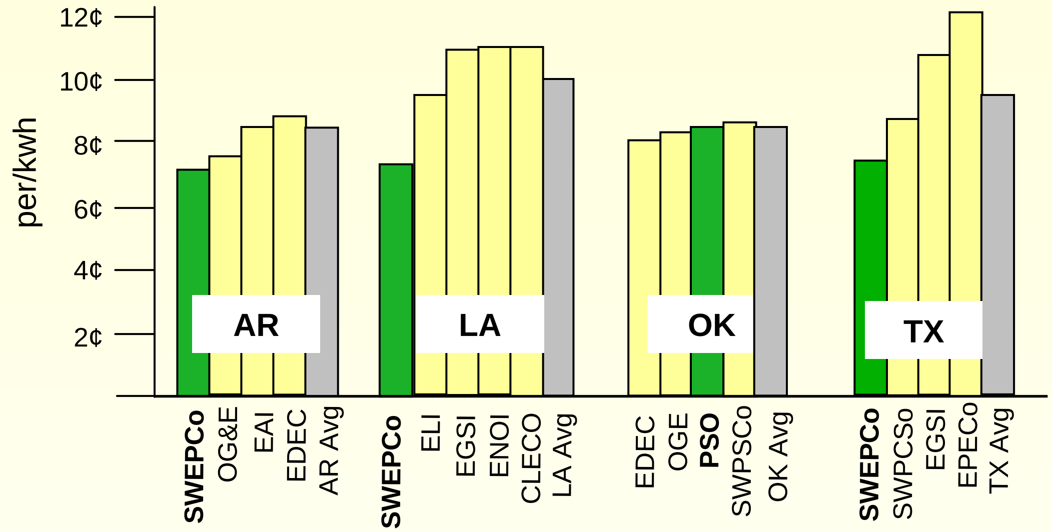
Average Unbundled AEP Ohio Rates



AEP Provides Low Cost Electric Service

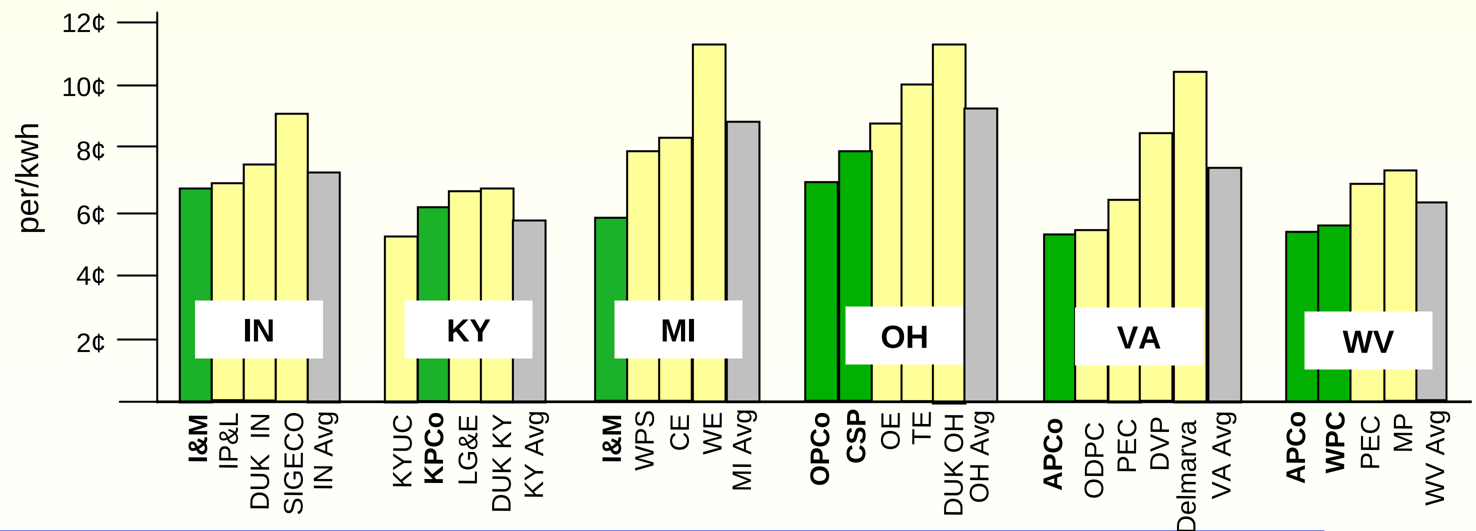
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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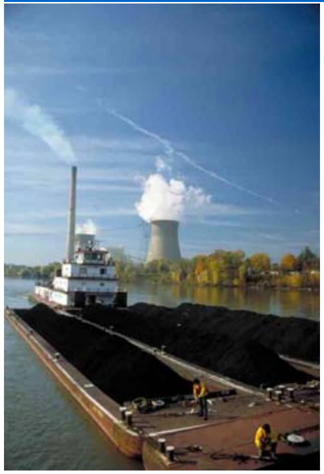
Midwest Utilities Conference

Park Hyatt Hotel

Chicago, IL

April 10, 2007



AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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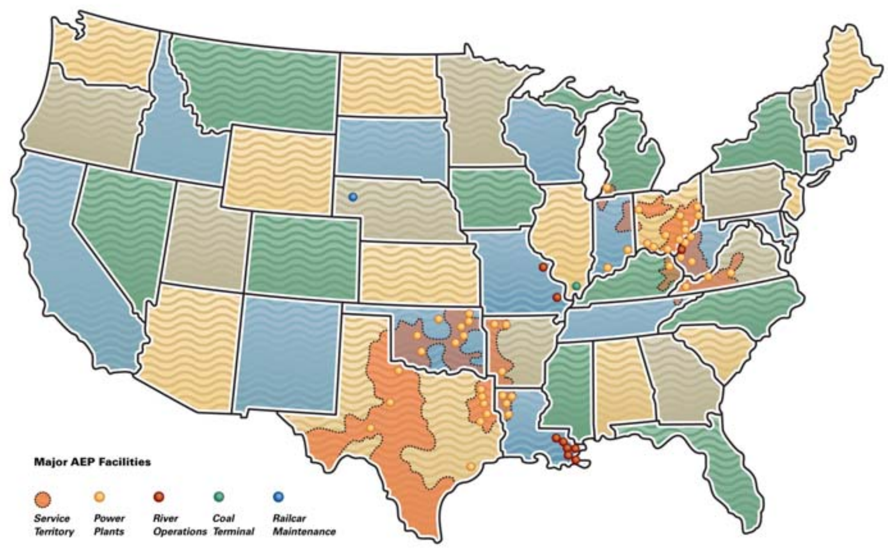
Stephen P. Smith
SVP & Treasurer

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



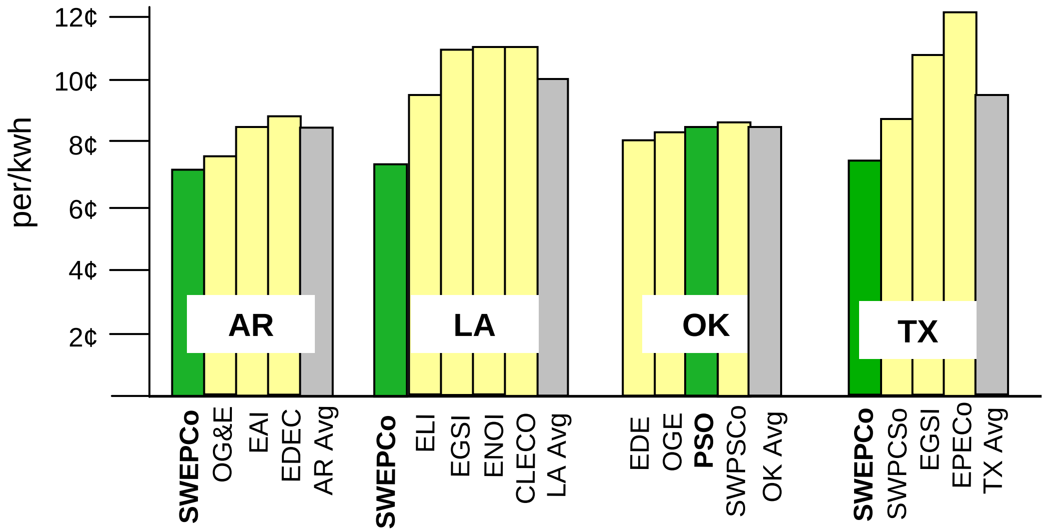
- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

AEP Provides Low Cost Electric Service

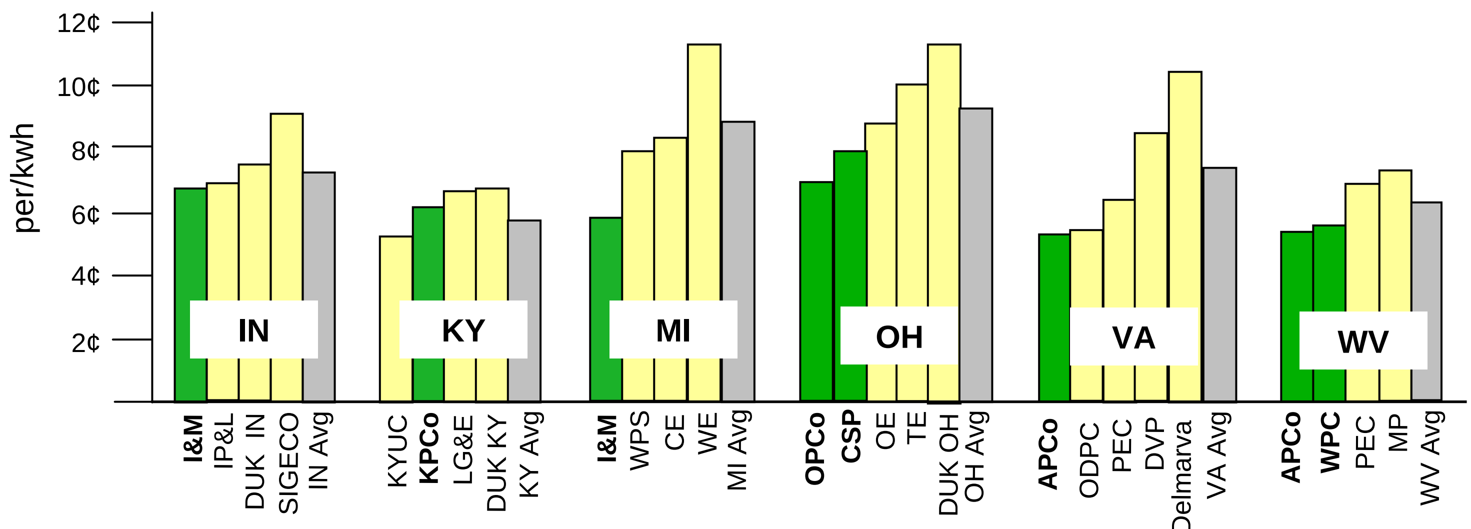
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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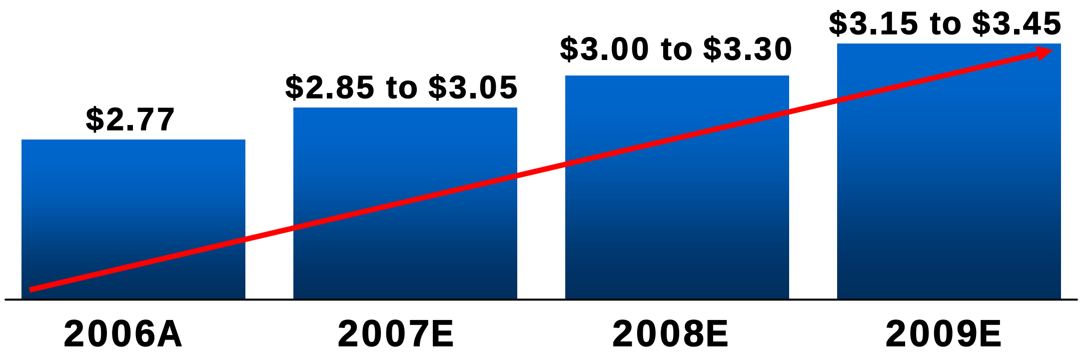
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

AEP®

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

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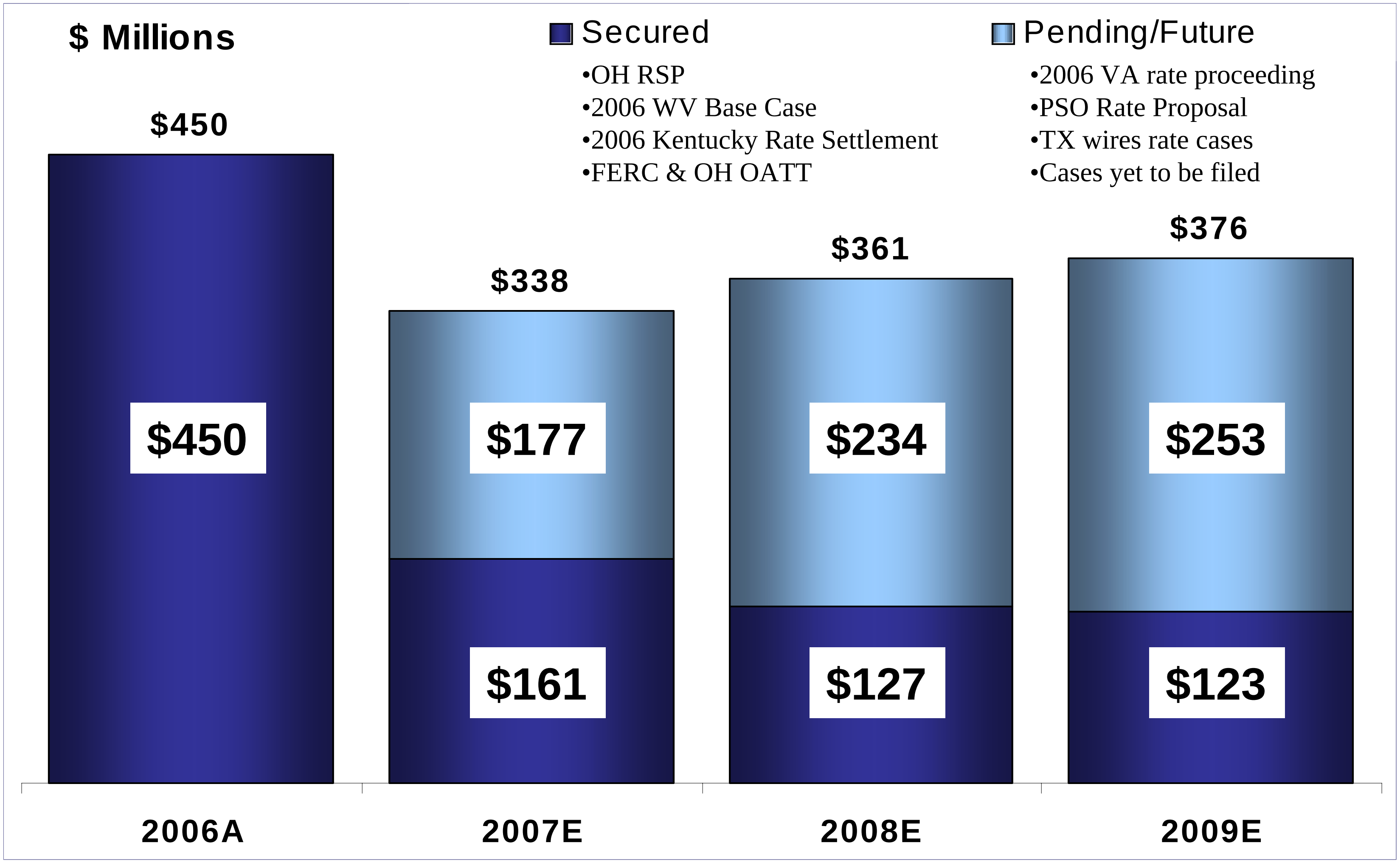
GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

Incremental Rate Relief Composition



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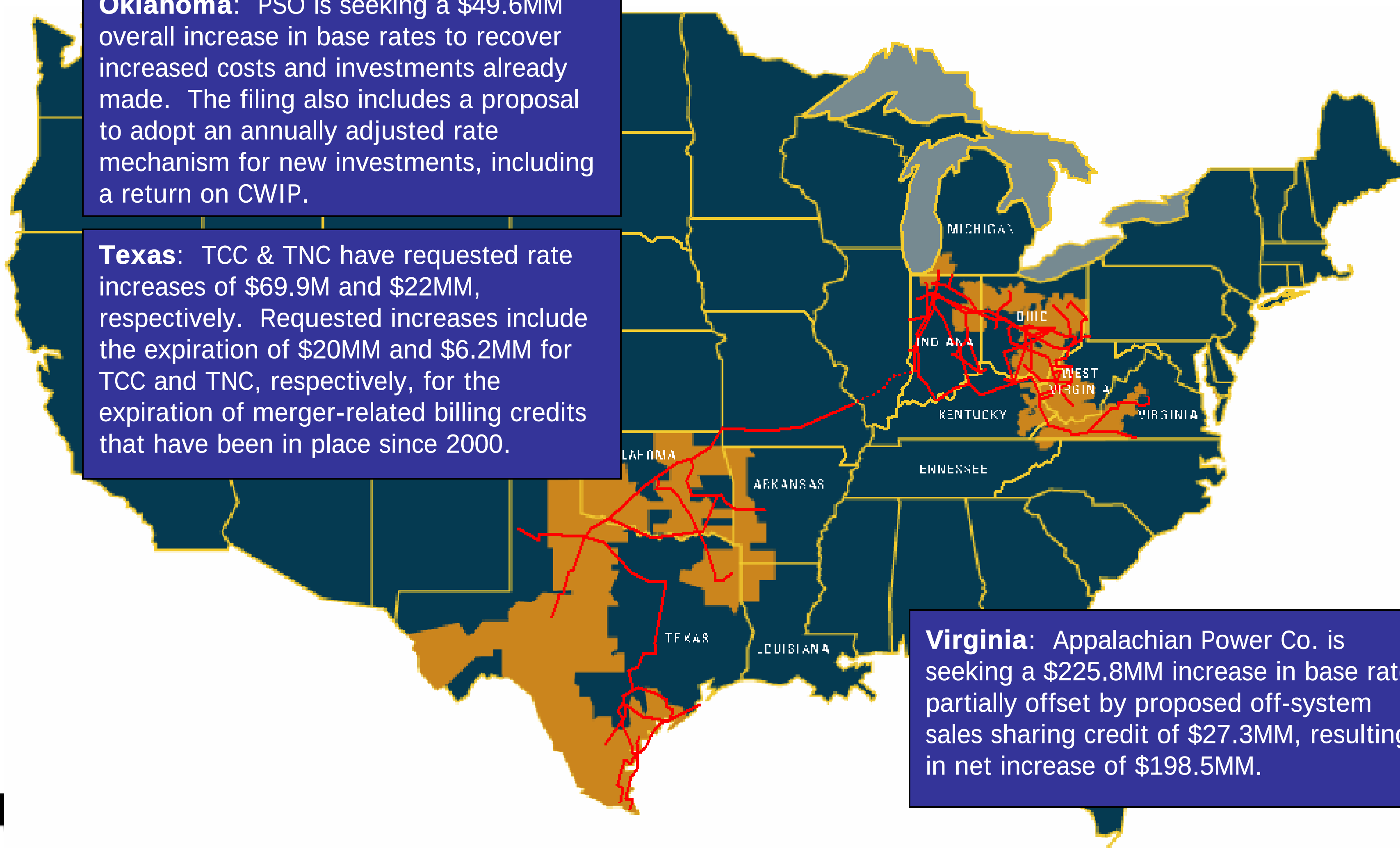
RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Base Case Regulatory Summary

Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $69.9M and $22MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.



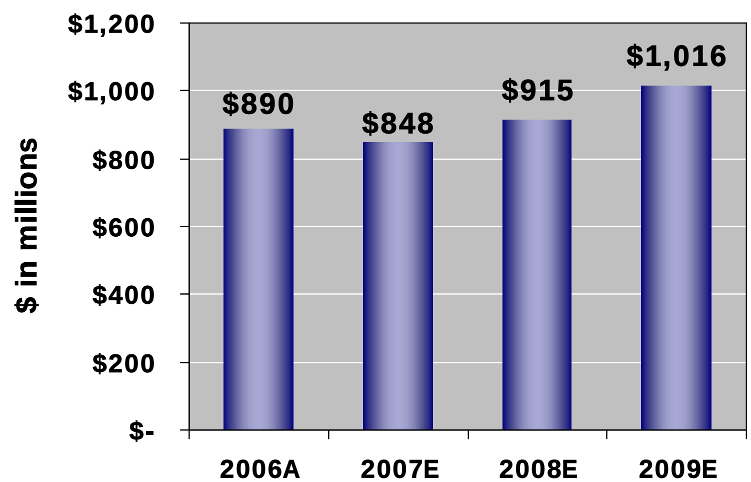
Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an average annual investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $69.9MM and $20MM for TCC & TNC transmission & distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

Transmission Investment Forecast

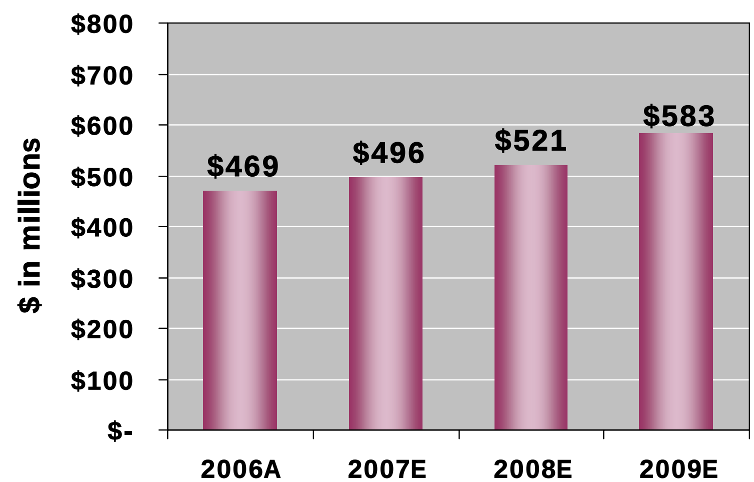
- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of “postage stamp” rate
  - Final order expected in mid-2007

- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services

- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company and to set initial rates
  - FERC filing to transfer transmission assets to ETT submitted Feb. 15, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



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The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

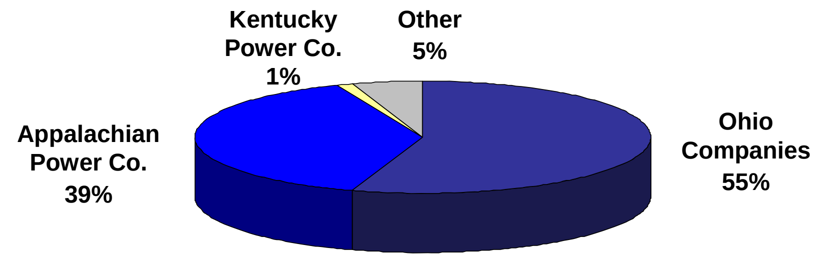
AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

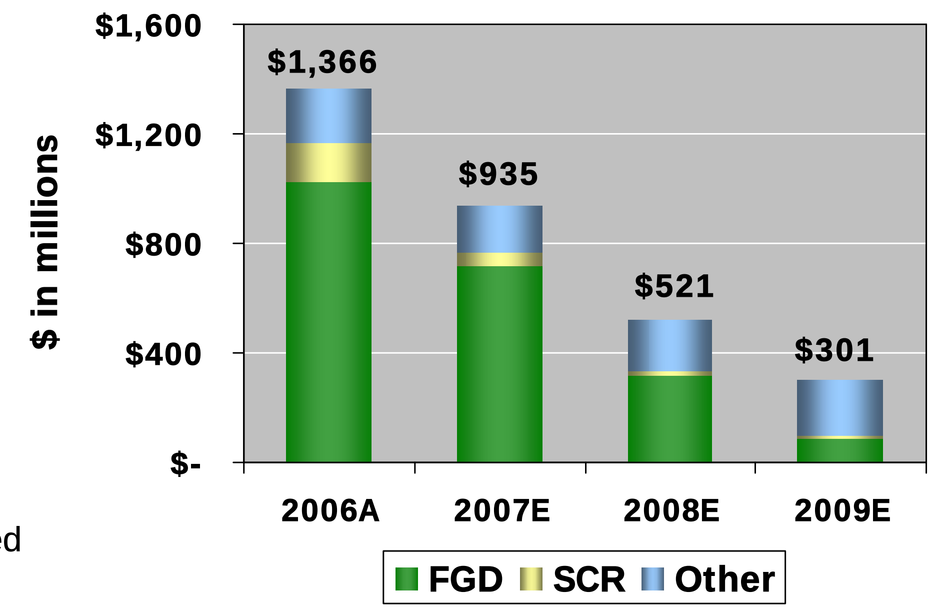
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures, pursuant to the 4% provision of the RSP
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

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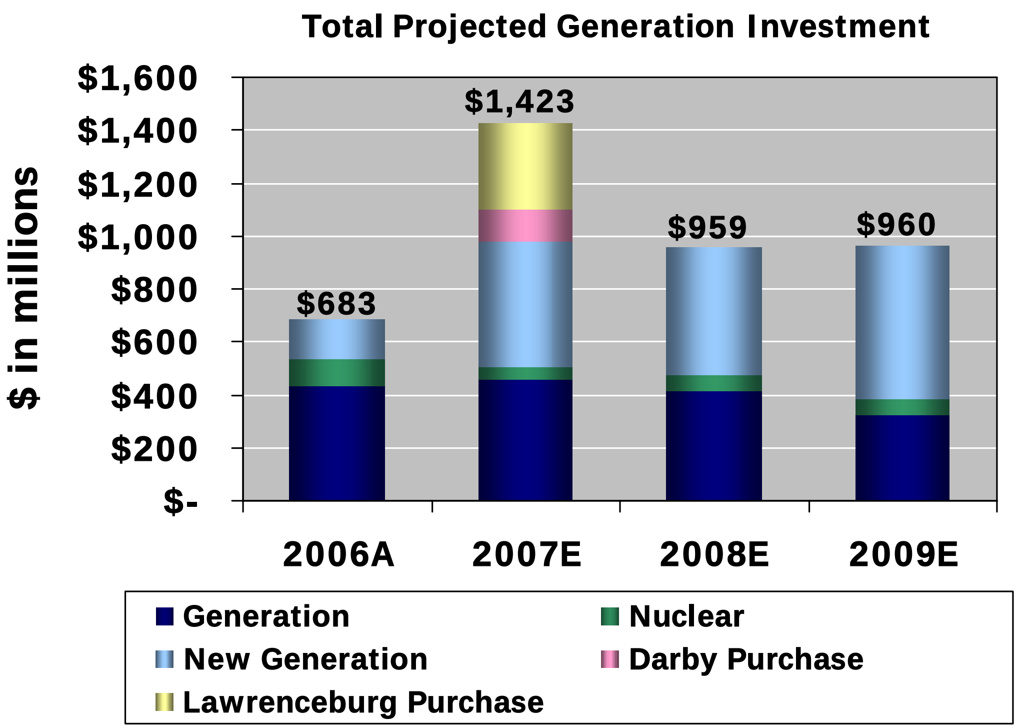
Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP
- Purchased Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



AEP®

Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07 (1)
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07 (2)
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	950 (4)	2011
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review (5)	Coal	IGCC	600	TBD

(1) Sale expected to close 2Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.2%
- Positive dividend outlook
- Stable credit profile

AEP®

Appendix

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 38,240 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

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Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

AEP®

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP®

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

AEP Transmission Network – Largest in the Country

Operating Company Level

(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP Is The Leader In Transmission Expertise

New Transmission Investment Funding Plans

- Electric Transmission Texas
  - 40% equity / 60% debt capital structure requested in PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% Mid-American Energy
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- Other Transmission Projects
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

AEP®

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

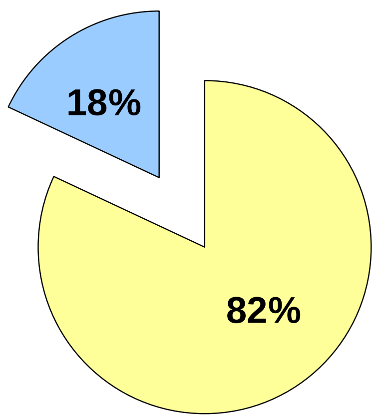
AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6569 of 9556

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

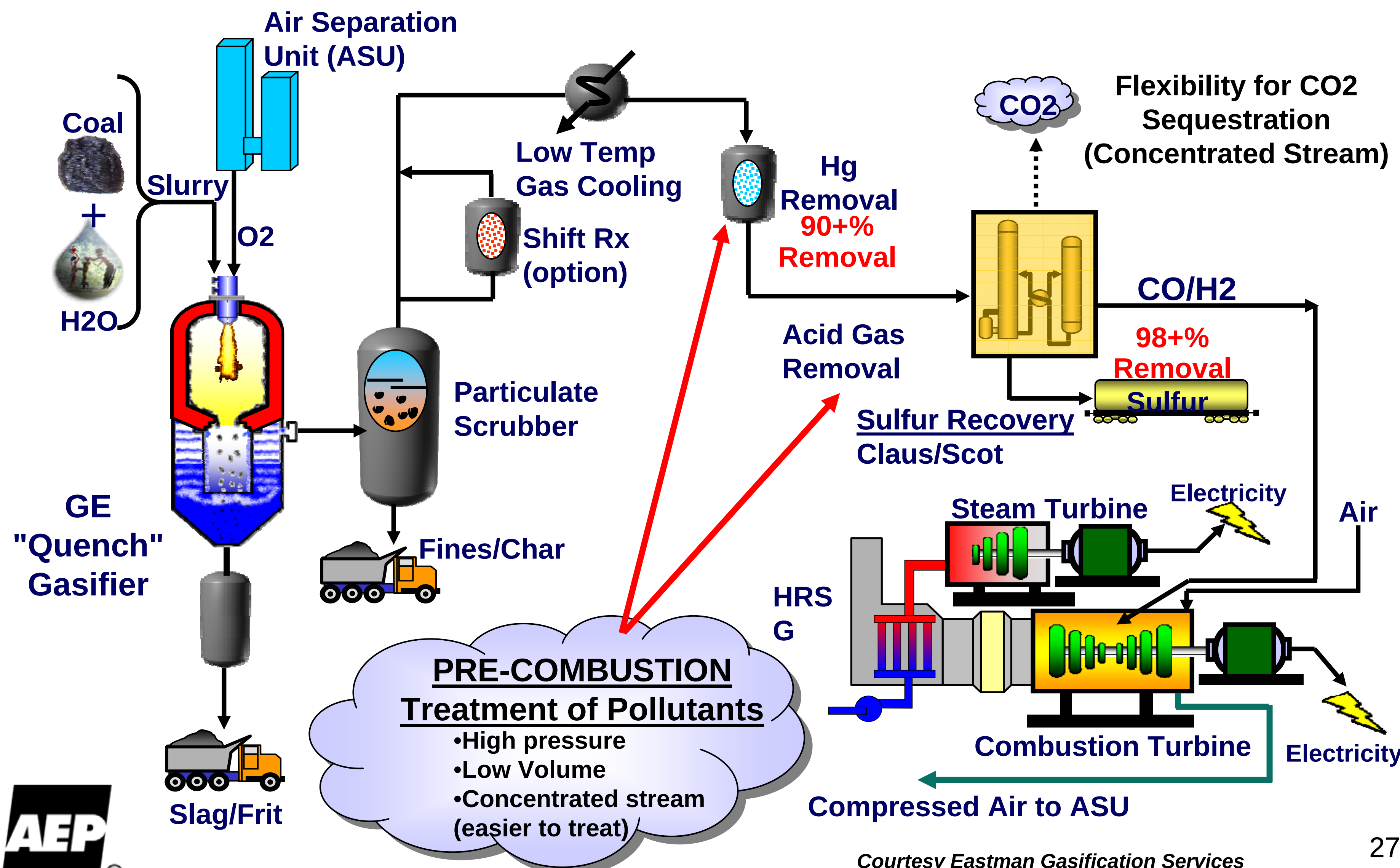
One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region.   AEP intends to seek regulatory recovery approvals in advance of building the plant.

AEP®

AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

Permitting Process Will Take 1 – 2 Years

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

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A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP ®

AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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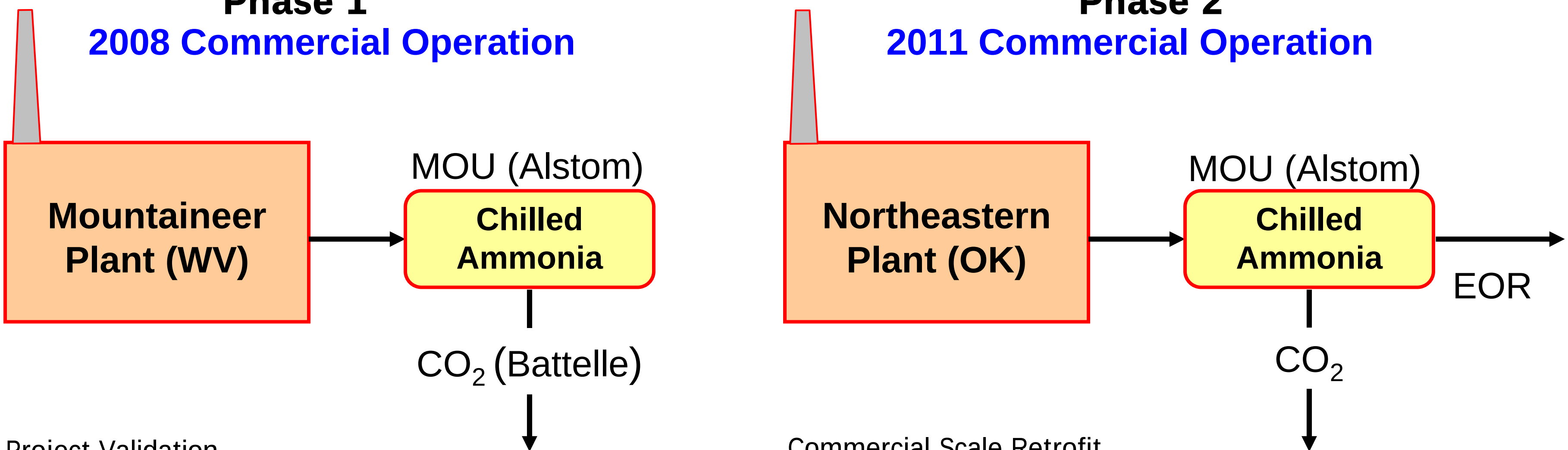
Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



<u>Project Validation</u>

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

<u>Commercial Scale Retrofit</u>

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

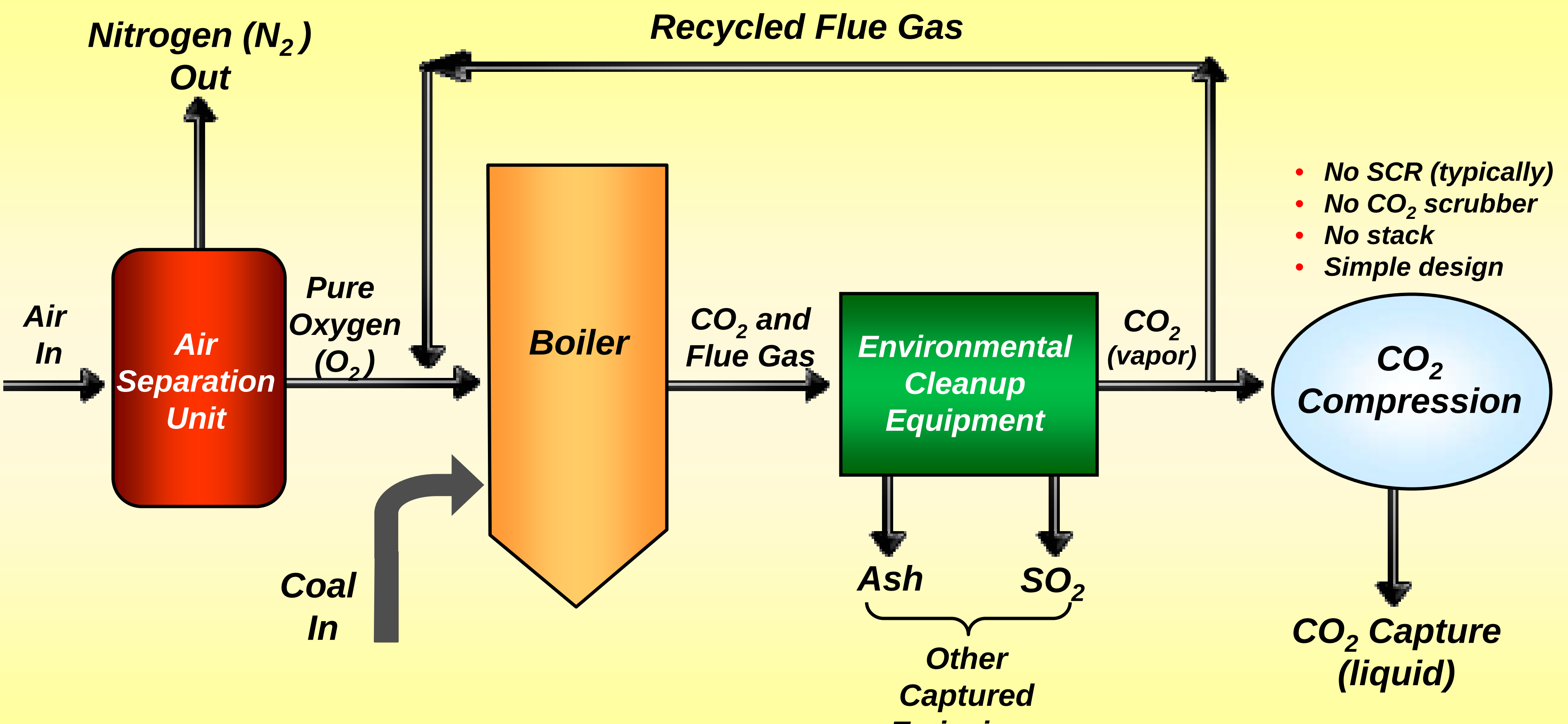

Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

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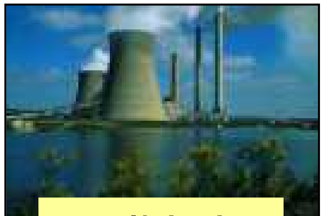
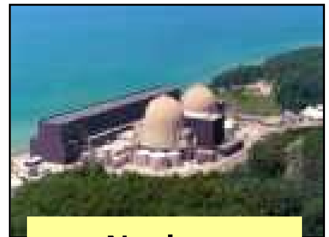
Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

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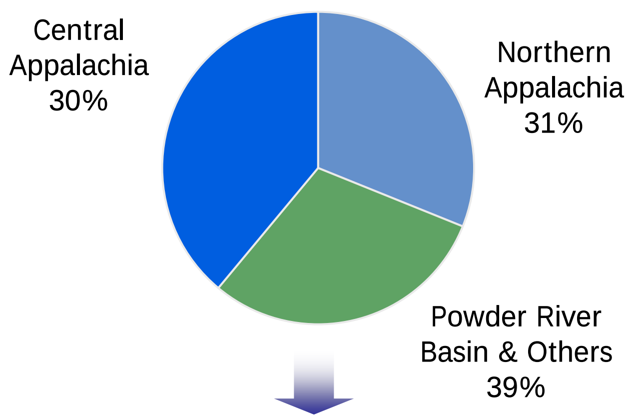
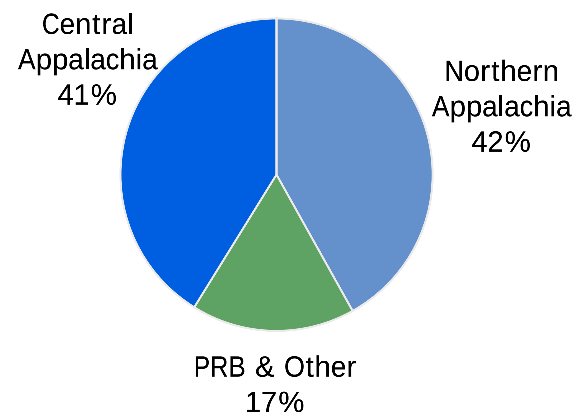
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

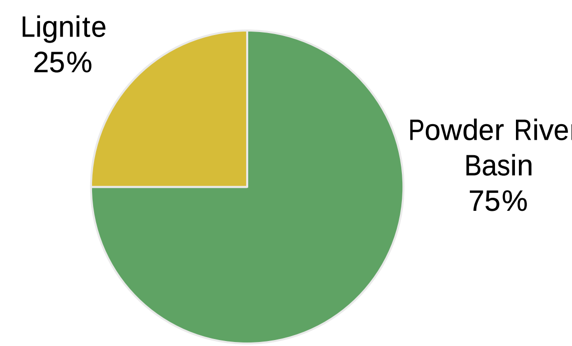
Total AEP System



AEP East



AEP West

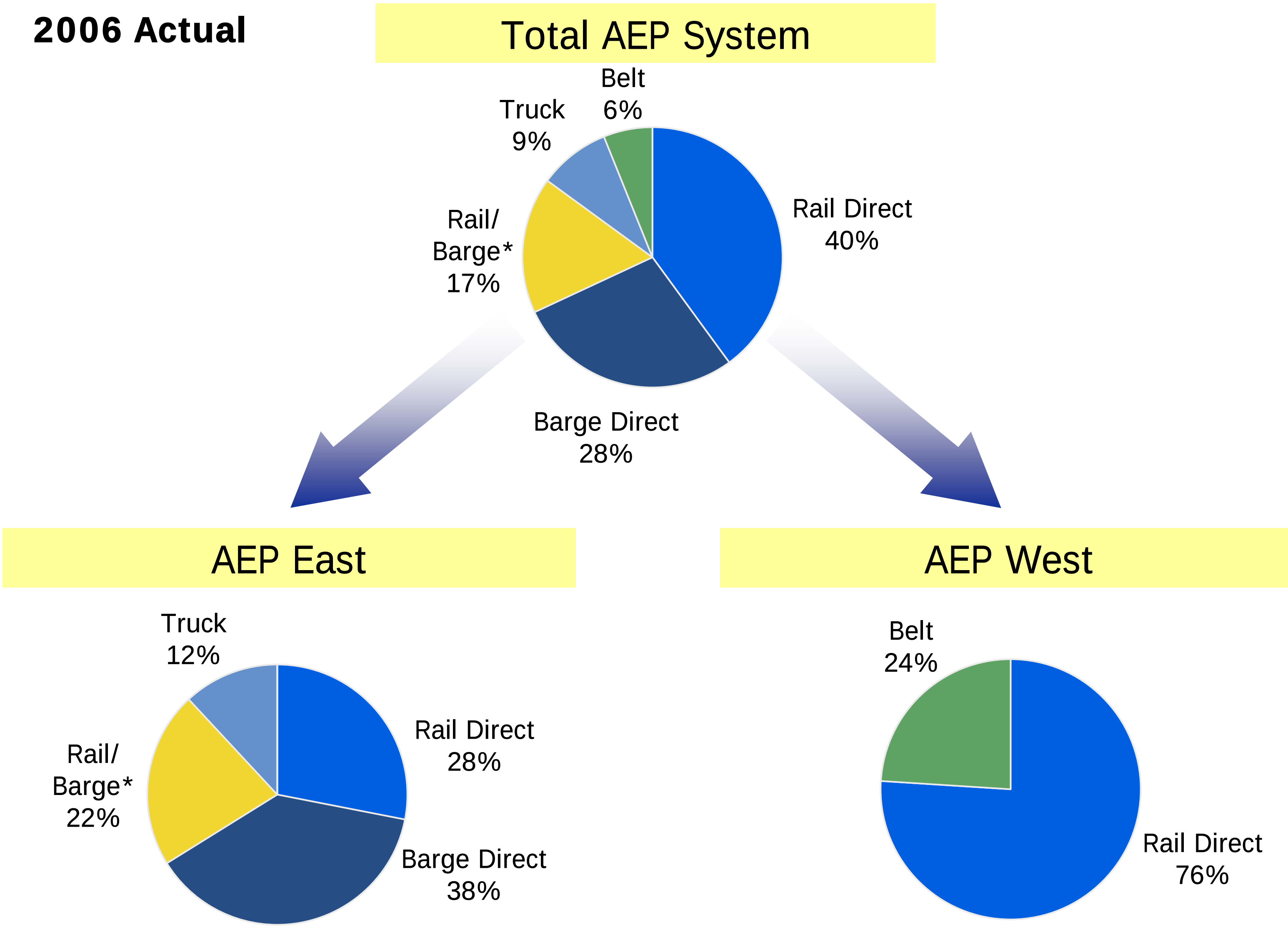


Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 7, 2007; Evidentiary hearing to commence May 22, 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in mid-2007.

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 7, 2006	Hearings commenced
February 5, 2007	Briefs filed
March 28, 2007	Hearing Examiner Recommendation filed

APCo has until April 18, 2007 to comment on the Hearing Examiner's report. Following this action, we will await an order from the SCC. No statutory deadline.

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

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Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power

Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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Forecasted Capital Expenditures

($ IN THOUSANDS)

Company	2007	2008	2009
AEP System*	**$ 3,867,000**	**$ 3,026,000**	**$ 2,974,000**
AEG	$ 343,000	$ 28,000	$ 34,000
APCo	$ 664,000	$ 531,000	$ 461,000
CSPCo	$ 439,000	$ 354,000	$ 233,000
I&M	$ 252,000	$ 264,000	$ 294,000
KPCo	$ 70,000	$ 114,000	$ 100,000
OPCo	$ 832,000	$ 368,000	$ 389,000
PSO	$ 319,000	$ 330,000	$ 466,000
SWEPCo	$ 537,000	$ 605,000	$ 540,000
TCC	$ 241,000	$ 214,000	$ 273,000
TNC	$ 143,000	$ 188,000	$ 149,000

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Figures exclude AFUDC.

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Long-Term Debt Maturity Profile

Year		2007		2008		2009
AEP Service Corp.	$	-	$	36,000,000	$	-
AEP, Inc.	$	345,000,000	$	-	$	-
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	325,000,000	$	200,000,000	$	150,000,000
Columbus Southern Power	$	-	$	112,000,000	$	-
Kentucky Power	$	322,964,000	$	30,000,000	$	-
Indiana Michigan	$	-	$	50,000,000	$	45,000,000
Ohio Power Company	$	-	$	44,542,074	$	106,000,000
Public Service of Oklahoma	$	-	$	-	$	50,000,000
Southwestern Electric Power	$	90,000,000	$	117,903,000	$	-
Texas Central Company	$	-	$	68,104,803	$	-
Texas North Company	$	8,151,000	$	-	$	-
Total	$	1,091,115,000	$	658,549,877	$	351,000,000

Note: Maturities remaining as of March 31, 2007

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6594 of 9556

2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$350-$450	43-45%
CSP	$439	$0-$50	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$350-$450	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances
(b) Ratios include impact of Rockport 2 lease
(c) Excludes impact of securitization on the equity ratio

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Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

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Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

Company	Target Equity Ratio
AEG	40%
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	44-46%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

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We Are Committed To Maintaining Our Current Credit Ratings
BBB / Baa2 / BBB

AMERICAN ELECTRIC POWER

Fall EEI Conference

November 9-12, 2008

Handout on Additional Topics

AEP AMERICAN ELECTRIC POWER

STRONG

FLEXIBLE

ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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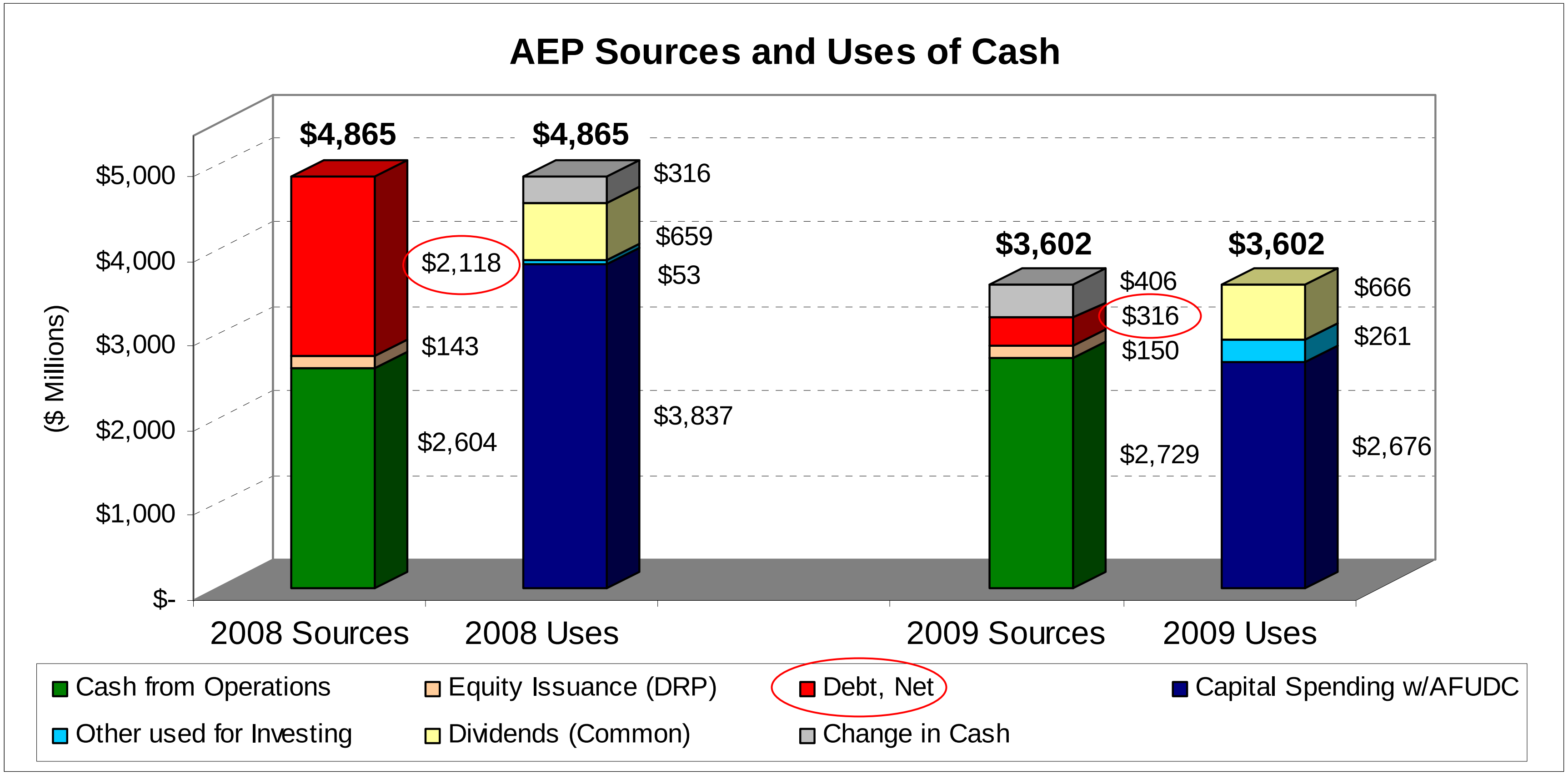
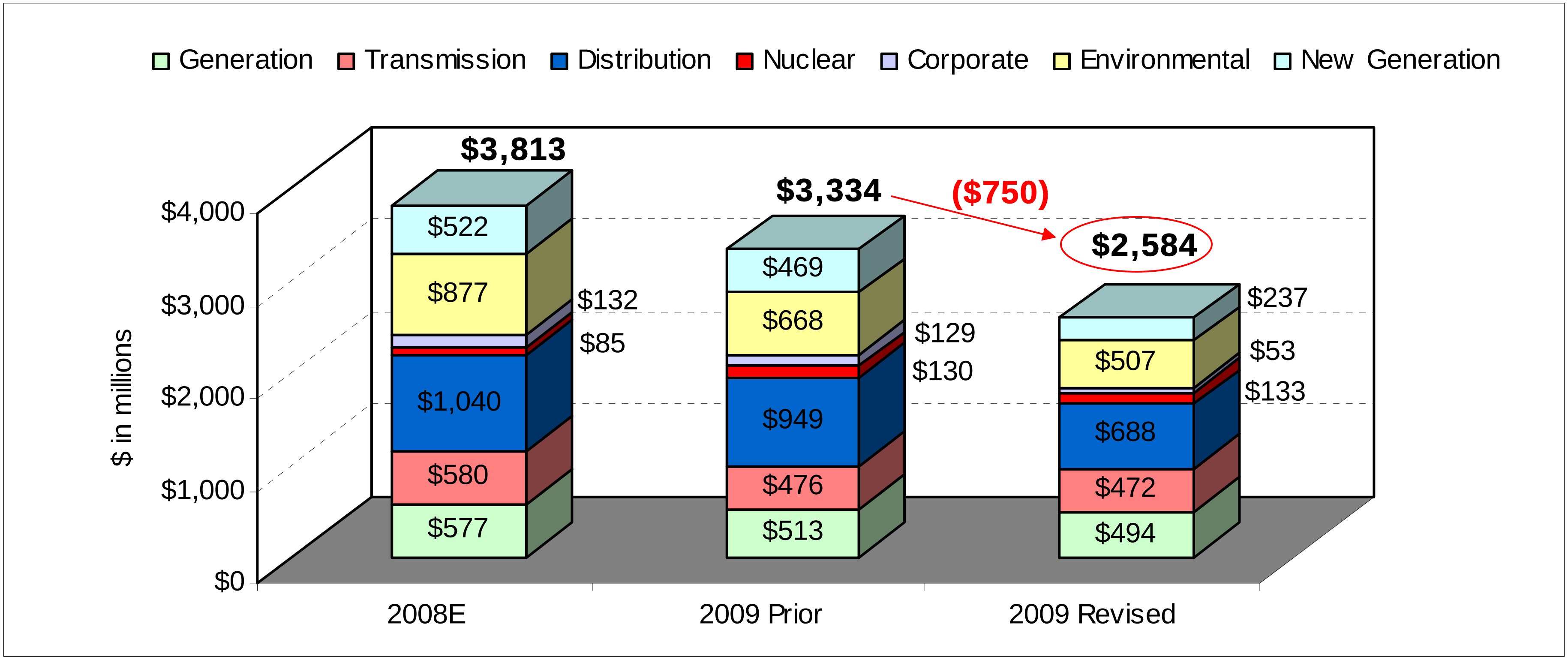
2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

2008 & 2009 Ongoing Earnings Guidance

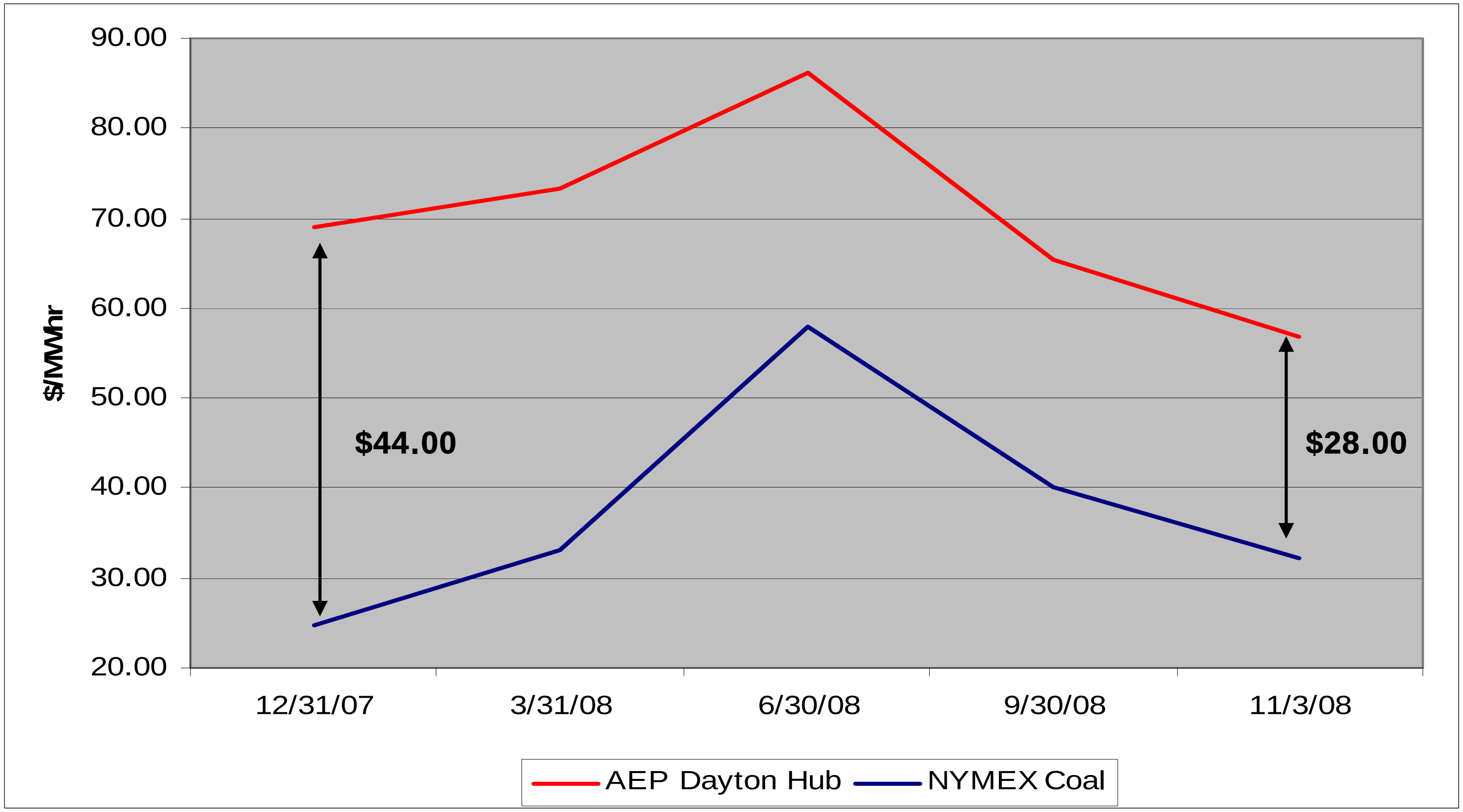
American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance		2009 Guidance	
	($ millions)	EPS	($ millions)	EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Depreciation & Amortization	(1,451)		(1,546)	
Taxes Other than Income Taxes	(779)		(790)	
Interest Exp & Preferred Dividend	(839)		(929)	
Other Income & Deductions	127		120	
Income Taxes	(602)		(641)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations:				
AEP River Operations	57	0.14	62	0.15
Generation & Marketing	20	0.05	13	0.03
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

Dark Spread Comparison

NYMEX Coal vs. AEP-Dayton Hub Peak Electricity



Coal Purchases:
2009: 95+%
2010: 85+%

Del. Coal Prices:
2007A: $36.58/ton
2008E: $46.82/ton

2009 estimated increase: 12%-15%

- Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- 10,000 heat rate used for conversion
- Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

DC Cook Unit 1 Update

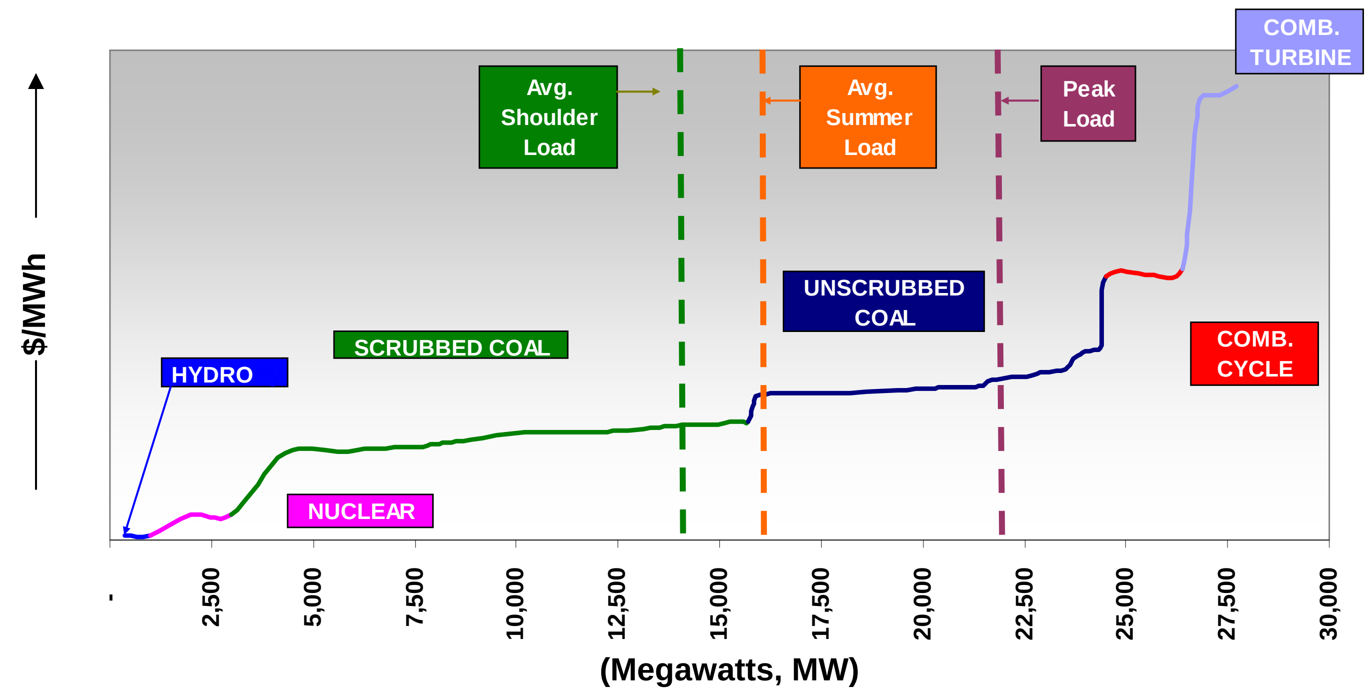
- Status
  - Off-line since September 20 due to vibrations caused by a broken turbine blade, which damaged the main turbine
  - Turbines and turbine rotors being assessed for repair vs. replace
  - Return to service schedule and cost estimates available in late November
- No incremental O&M or capital expected; Vendor warranties and property insurance will cover repair costs
- Active fuel clauses in Indiana and Michigan will allow for recovery of the fuel differential from retail customers
- Planned outage schedules have been adjusted to partially mitigate the impact of the Cook Unit 1 outage on available generation output for OSS purposes
- Accidental outage insurance of $3.5MM per week commencing in mid-December mitigates financial impact

We will provide an update on Cook once we receive additional information from our vendors

AEP Supply Stack

- ❑ Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- ❑ Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- ❑ Shoulder periods offer the flexibility to reschedule planned outages.

Typical AEP Supply Stack



With the loss of Cook 1 this fall season, a planned outage on a scrubbed coal unit was cancelled, leaving the supply stack in roughly the same position for off-system sales

Pension and OPEB Estimate

- The Pension plan and OPEB funds investment returns are each down about 25% YTD as of October 16, 2008. The drop in assets is mitigated slightly by a corresponding decrease in plan liability caused by a higher discount rate (from 6% to 7% for pensions and from 6.25% to 7.25% for OPEB).
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- As of October 16, 2008, we expect 2009 pension expense to increase $10MM over 2008 and the estimated OPEB expense to increase $30MM year over year.
- These increases are reflected in our current guidance.
- We are currently not expecting any mandatory contributions to pension in 2009.

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Handout of Additional Topics
Fall EEI Conference
November 3, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

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2010 Ongoing Earnings Guidance

	2009E: $2.90-$3.05	2010E: $2.80-$3.20
Utility Operations	$ 2.92	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.18	$ 0.09
Parent & Other	$(0.14)	$(0.12)

EARNINGS DRIVERS

- ↑ $317MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

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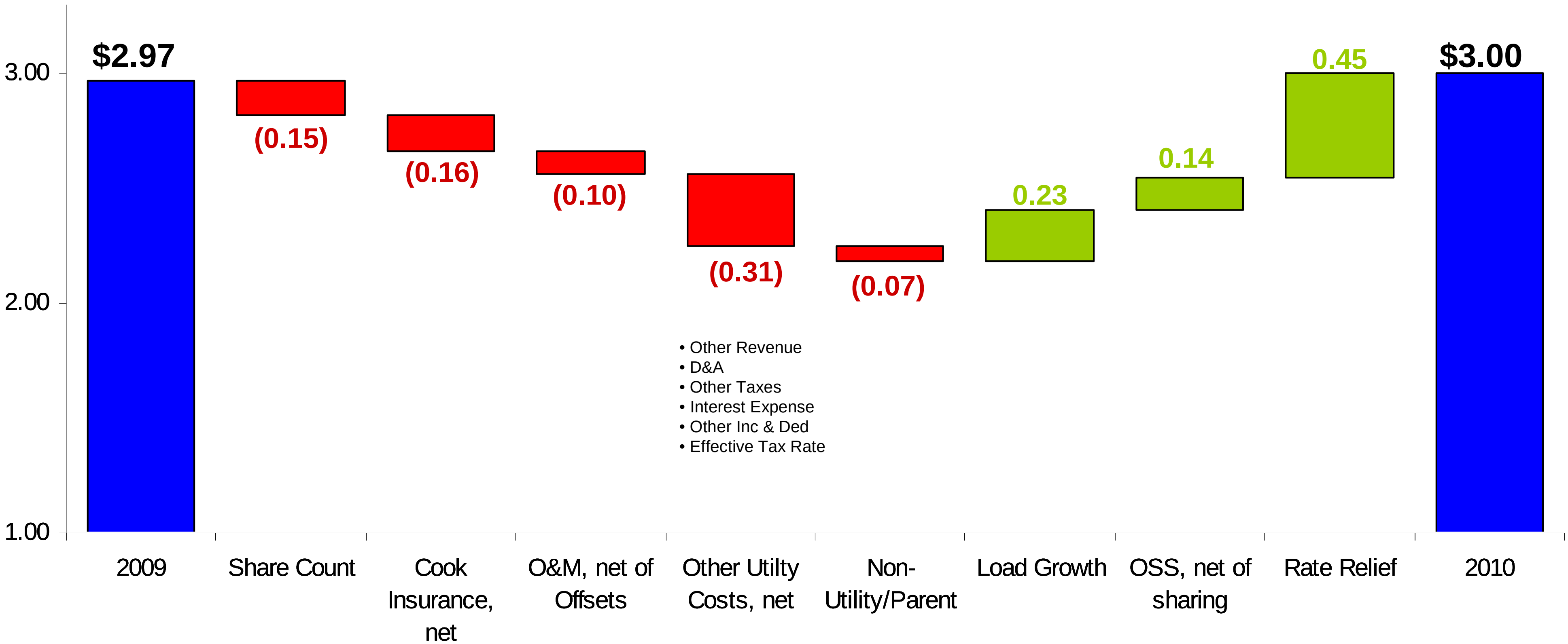
2010 Earnings Drivers



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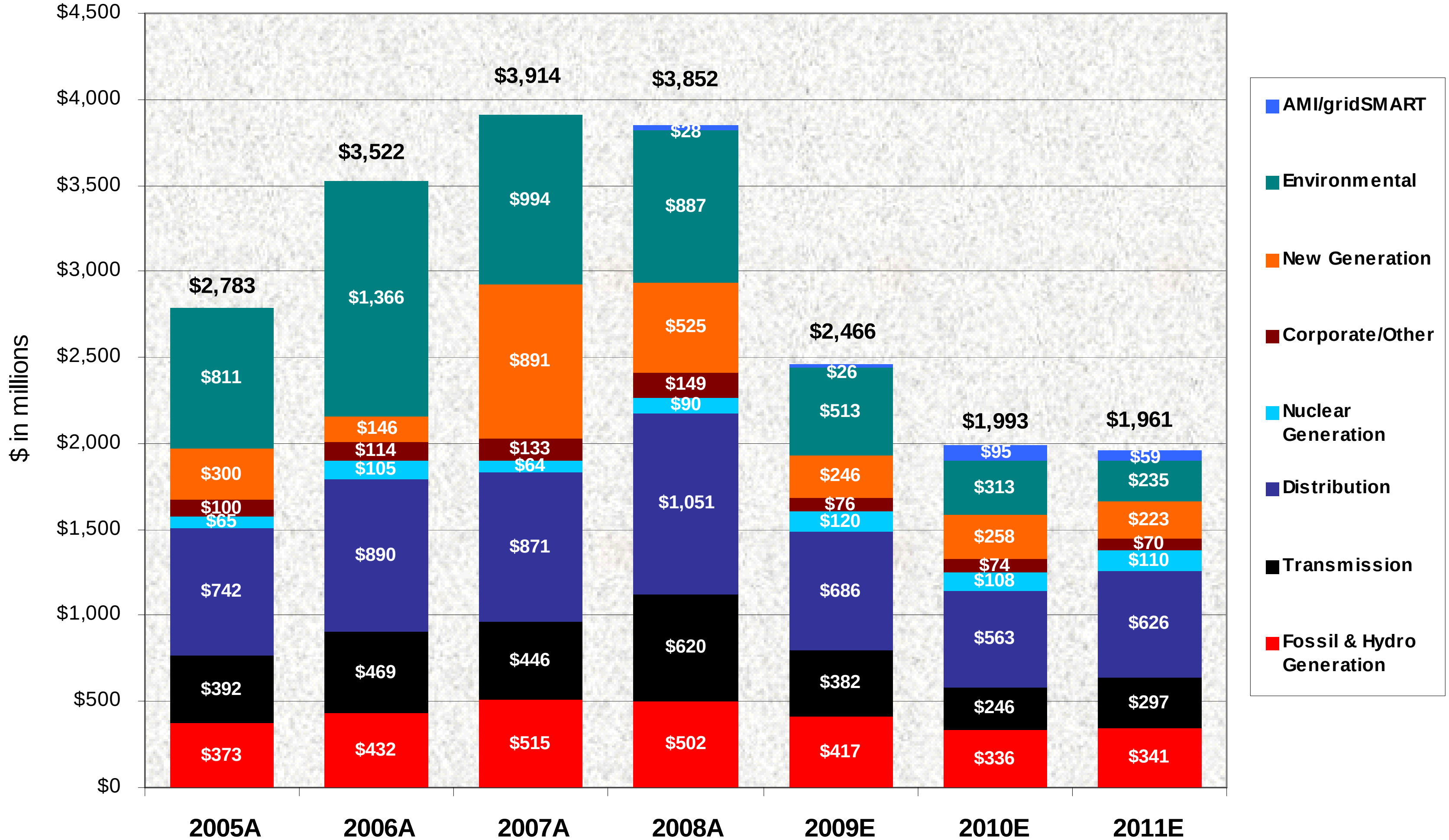
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

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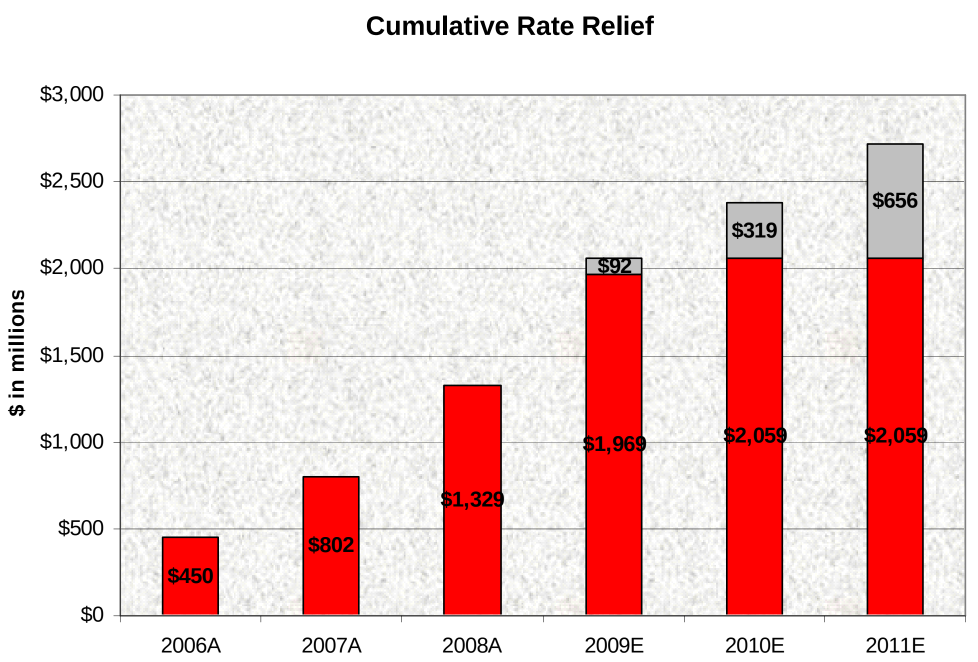
Investment in Utility Platform

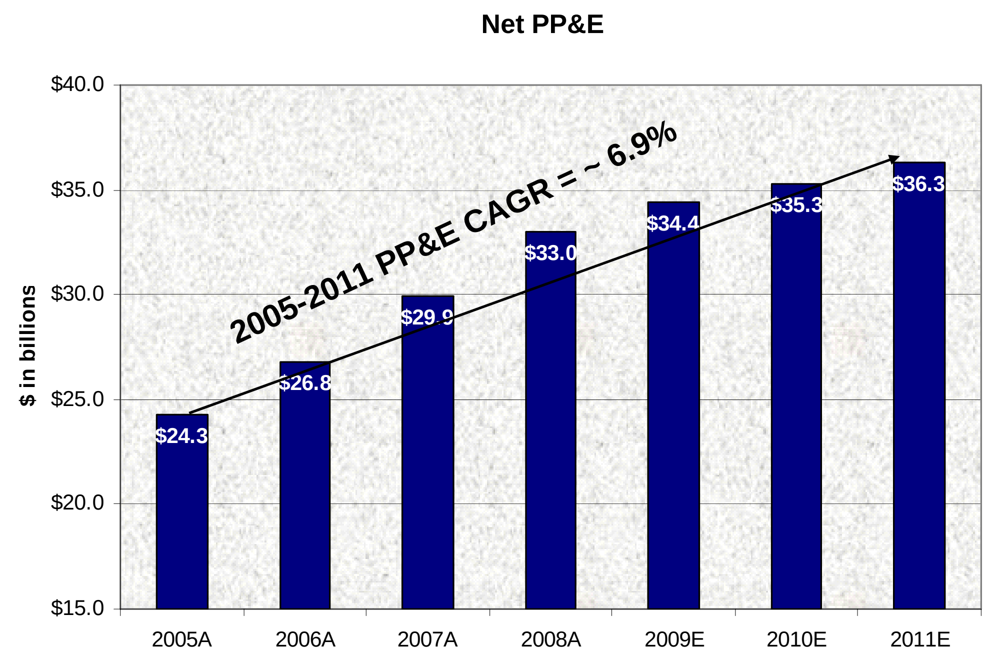
Track Record of Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$317[1]	$337

[1] *$90mm was secured for 2010 as of October 30, 2009*

Growth in Net PP&E



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Multi-Year Capital Investment Funding Plan

	Actual 2008	Projection 2009		Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (3,967)	$ (2,885)	*	$ (2,127)
Transmission Initiatives (JV Equity Contributions)	0	(49)		(93)
Dividend on Common Stock	(660)	(759)		(790)
Cash Sources (Uses)				
Cash from Operations	2,576	2,263		3,259
Proceeds from Sale of Assets	90	258		-
Common Stock Issued	159	1,744		150
Change in Debt, Net	2,266	(346)		(127)
Other	(231)	(436)		(274)
Change in Cash	233	(210)		(2)
Ending Cash Balance	$ 411	$ 201		$ 199

* - 2009 capital expenditure projection includes $340MM of construction-related accounts payable at 12/31

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Detailed Ongoing Earnings Guidance

2009E: $2.90 - $3.05

American Electric Power
2009 Guidance vs. 2010 Guidance

2010E: $2.80 - $3.20

		Performance Driver	2009 Guidance ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,754 GWh @ $ 38.4 /MWhr =	2,562	68,249 GWh @ $ 42.1 /MWhr =	2,873
2	Ohio Companies	47,284 GWh @ $ 57.8 /MWhr =	2,733	47,922 GWh @ $ 61.9 /MWhr =	2,968
3	West Regulated Integrated Utilities	39,112 GWh @ $ 29.8 /MWhr =	1,166	41,495 GWh @ $ 31.3 /MWhr =	1,298
4	Texas Wires	27,208 GWh @ $ 21.1 /MWhr =	575	27,510 GWh @ $ 21.9 /MWhr =	602
5	Off-System Sales (Net of Sharing)	13,525 GWh @ $ 16.7 /MWhr =	226	23,992 GWh @ $ 13.4 /MWhr =	322
6	Transmission Revenue - 3rd Party		356		353
7	Other Operating Revenue		779		554
8	Utility Gross Margin		8,397		8,970
9	Operations & Maintenance		(3,309)		(3,546)
10	Depreciation & Amortization		(1,582)		(1,625)
11	Taxes Other than Income Taxes		(768)		(791)
12	Interest Exp & Preferred Dividend		(924)		(986)
13	Other Income & Deductions		124		168
14	Income Taxes		(597)		(742)
15	Utility Operations On-Going Earnings		1,341		1,448
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		36		2
	Non-Utility Operations On-Going Earnings		83		45
19	Parent & Other On-Going Earnings		(64)		(58)
20	ON-GOING EARNINGS		1,364		1,444

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Pension and OPEB Estimate

- Investment returns for our pension plan and OPEB funds rebounded sharply in 2009. Year-to-date, the pension fund is up about 15% through September, with similar gains in the OPEB funds.
- Investment losses from 2008 continue to increase plan expense for both pension and OPEB, as the investment losses are smoothed in over several years.
- We expect combined pension and OPEB expense to increase $59MM from 2009 to 2010 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- There were no mandatory contributions to pension in 2009. Required pension contributions are estimated to be $62MM in 2010 and $389MM in 2011 including non-qualified plans.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB for 2009, and 5.25% and 5.45% for 2010 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

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DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: "A blade-rotor system design that failed to provide adequate stress margin"
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy through mid-December
  - Insurance proceeds are reflected as other operating revenue; During 2009 YTD, approximately 40% of the insurance payments were used to offset increased fuel costs to customers

AEP AMERICAN® ELECTRIC POWER

Fall EEI Conference
November 3, 2009

Carbon Capture and Storage Project – Mountaineer Plant (WV)

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AEP AMERICAN ELECTRIC POWER

Michael G. Morris - Chairman, President & CEO

Brian X. Tierney – Executive Vice President & CFO

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Policy Update

- **AEP supports Climate Change Legislation**
  - AEP supports the American Clean Energy and Security Act (ACES) passed in the House
  - Senate bill released at the end of September. AEP will work for constructive changes to help passage in the Senate
  - EPA issued two new climate rules for comment at the end of September
- **Outlook for Legislation**
  - Timing of Climate Change Legislation Passage
  - Outlook for Energy-Only Bill

Mountaineer Plant (WV)

Desert Sky (TX)

AEP AMERICAN® ELECTRIC POWER

Mountaineer CCS Update

PROJECT STATUS

- September 2 – successfully captured CO_2
- October 1 - began underground injection and storage
- October 30 – facility dedicated

NEXT STEPS

- Monitor the CO_2 behavior once underground
- Assess the parasitic load impact of the equipment on the plant
- DOE funding requested for 50% of commercial phase of project ($334MM); project expected to be operational between 2012 and 2015

PROJECT DESCRIPTION

- Alstom's chilled ammonia process captures CO_2 from a 20 MWe slipstream of flue gas at AEP's Mountaineer plant located in New Haven, WV
- Captured CO_2, transformed to a semi-liquid state, is pumped into sandstone or dolomite layers approximately 1.5 miles underground. Caprock will hold the CO_2 in place permanently.

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Accomplishments and Priorities

2004 - 2009

- ✓ Returned to the operating company model to enhance our constructive local relationships
- ✓ Secured over $2B in rate relief across the AEP system with solid regulatory relationships in all eleven jurisdictions
- ✓ Designed and implemented a $5.2 billion environmental retrofit program
- ✓ Effectively managed our credit and liquidity
- ✓ Paid over $3 billion in dividends
- ✓ Safe, diverse and motivated employee culture

2010 +

- ❑ Navigate through ongoing economic conditions
- ❑ Maintain capital spending and balance sheet discipline
- ❑ Continue delivering successful regulatory outcomes
- ❑ Participate in policy making at both the federal and state levels, particularly related to environmental/climate and transmission issues
- ❑ Invest in the next generation of energy infrastructure: high-voltage transmission, CCS, gridSMART℠

AEP AMERICAN ELECTRIC POWER

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- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
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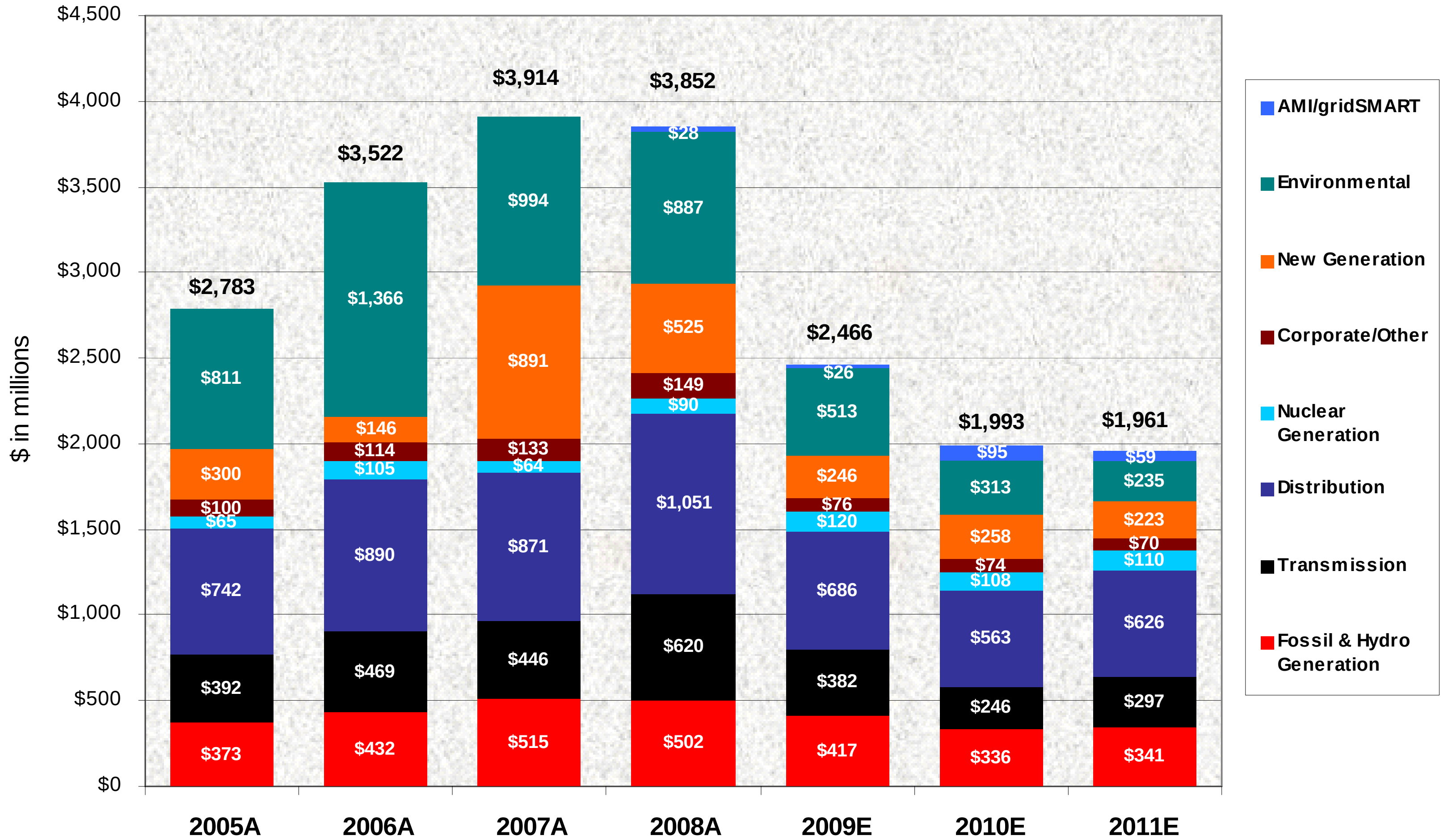
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

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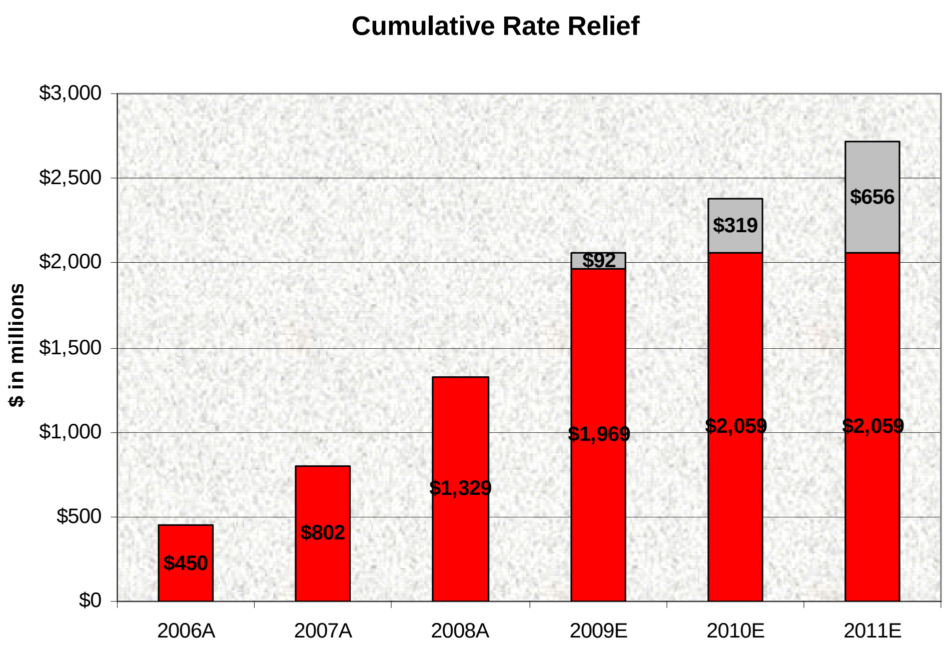
Investment in Utility Platform

Track Record of Rate Relief



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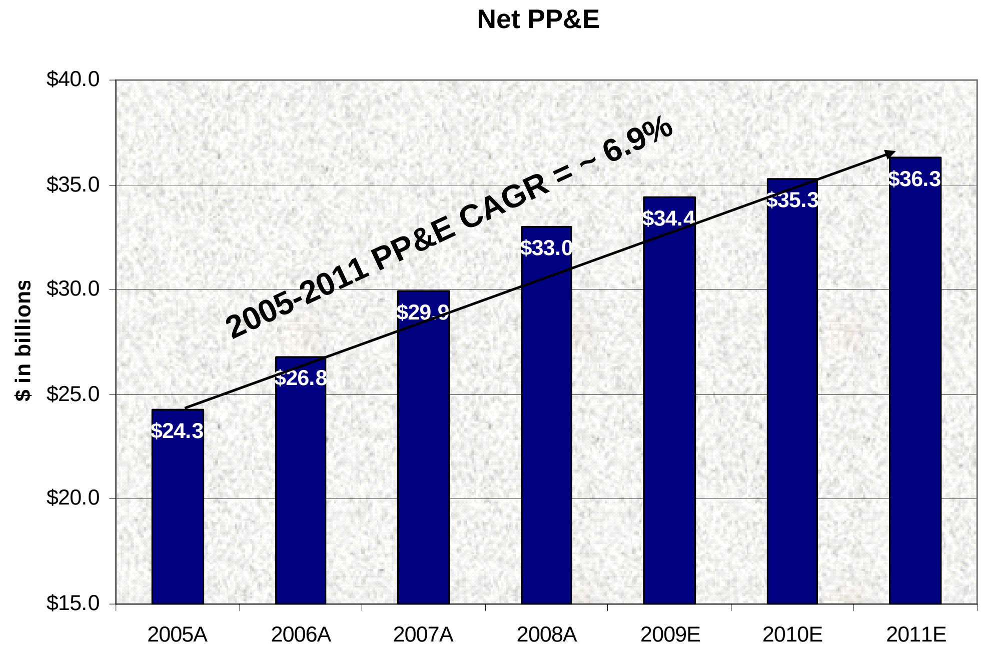

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Transmission Investment Opportunities

- **ETT: Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013 with $236MM spent as of 9/30/2009
  - ETT's opportunity could reach $3.1B in the next decade

- **Transco: Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$118MM

- **Joint Ventures: Outside of our footprint, with ETA or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RPS will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

Transco

- **Transco will be used to develop significant new on-system, AEP-owned investment**
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- **Next steps:**
  - Obtain state utility status where required and join PJM and SPP as a transmission owner
  - File FERC tariff for Transco in late 2009, with rates effective and first projects in service in 2010
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

AEP AMERICAN ELECTRIC POWER

JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14

- 110 miles of 765 kV
- Partners: Westar (50%) & MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14

- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

ETT — COD: 2010-2013

- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $600 million+
- ROE: 9.96%

PJM

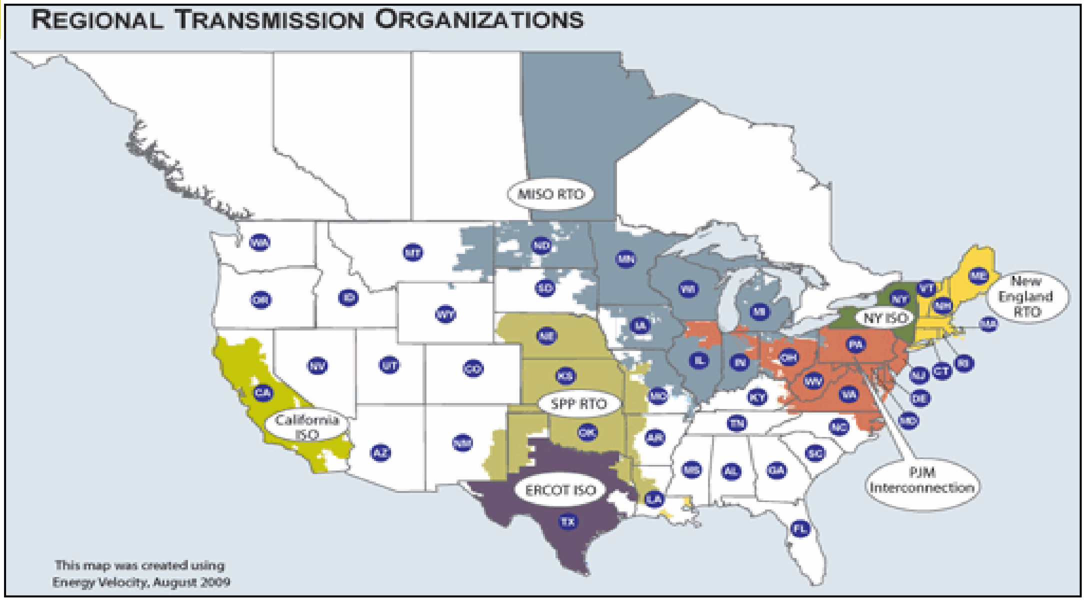
PATH-WV — COD: 2014

- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015

- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%



FUTURE DEVELOPMENT

SMARTransmission Study

- Interregional EHV & Wind Integration Study
- Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay

- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various

- Additional CREZ spend of ~ $1 billion+ (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $1.5 billion (COD 2010-2017)

PJM

PJM Expansion

- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio

- 700 miles of Proposed 765 kV

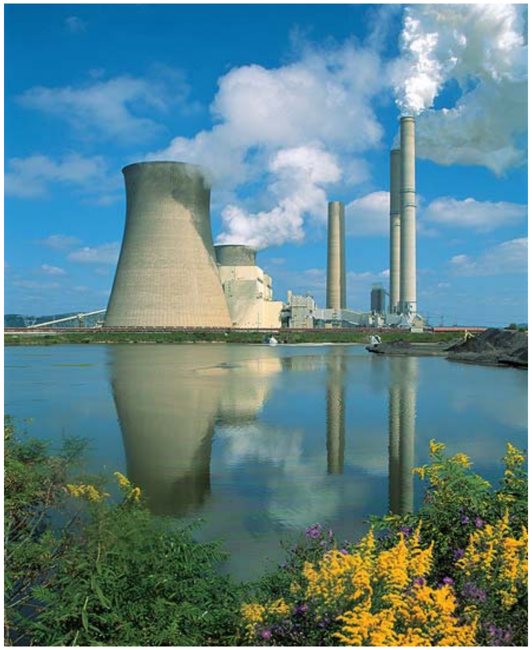
AEP AMERICAN® ELECTRIC POWER

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment

- **Consistent dividend policy**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders

- **Growth Opportunities**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
  - Capital investment to comply with carbon legislation



General JM Gavin Plant (OH)

AEP AMERICAN ELECTRIC POWER

AEP AMERICAN ELECTRIC POWER®

Fixed Income Luncheon
Hosted by Goldman Sachs
New York, NY
June 29, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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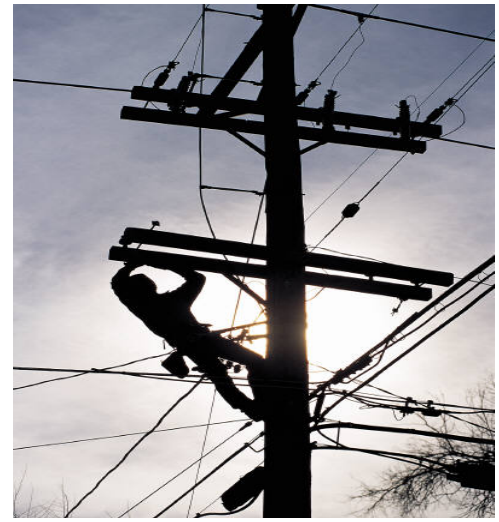
Industry Leadership

One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0

The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

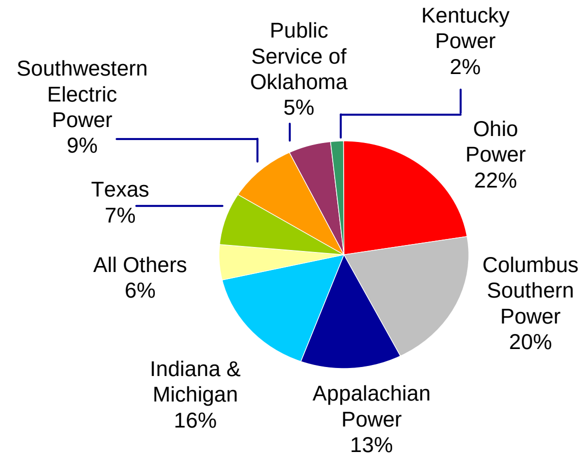
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

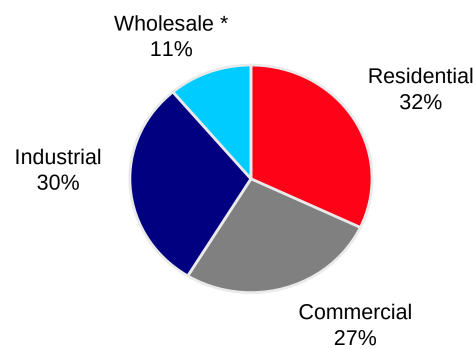
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

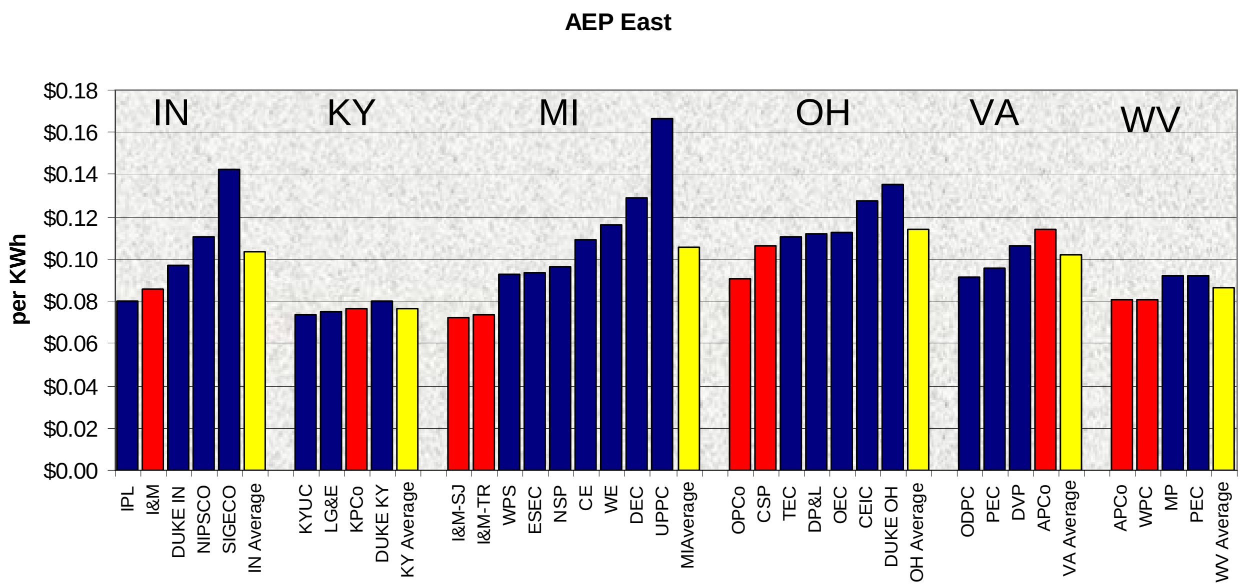


2009 Retail Load



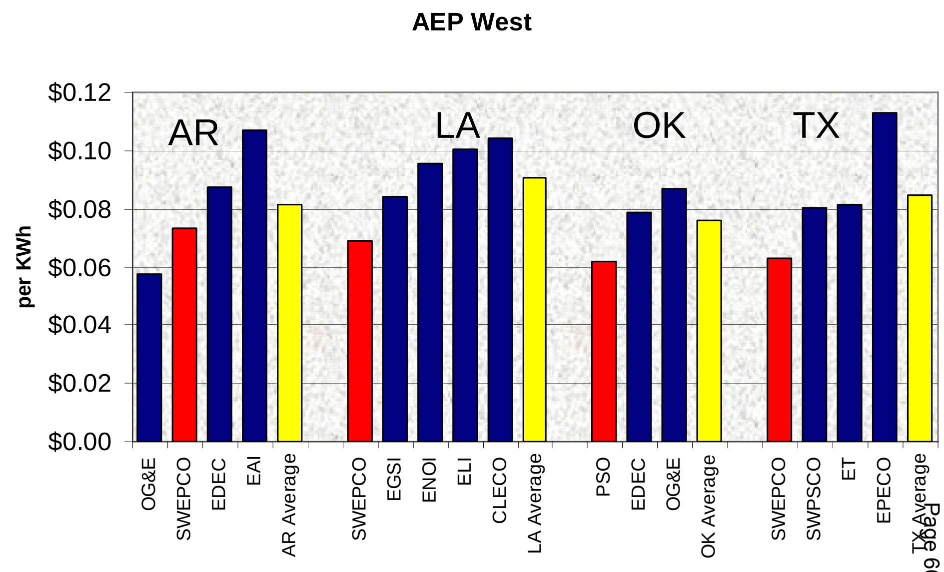
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Residential Rates Comparison



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

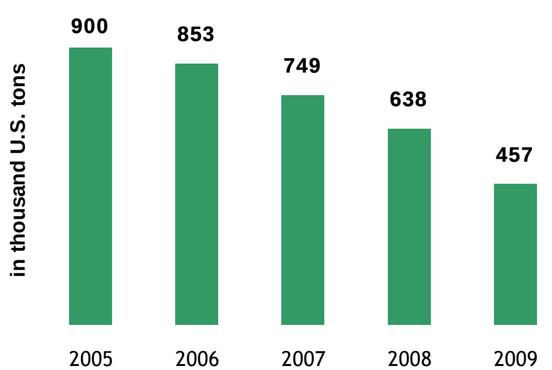
AEP Company
Other Utilities within state
State Average



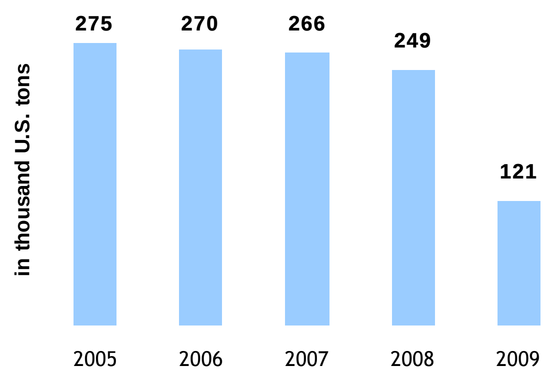
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6636 of 9556

Our Fleet Will Continue to Transform

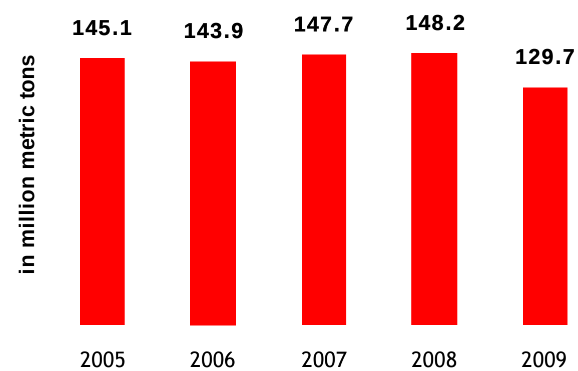
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



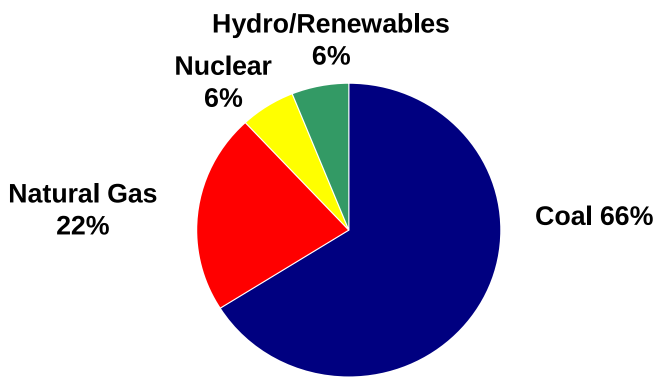
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



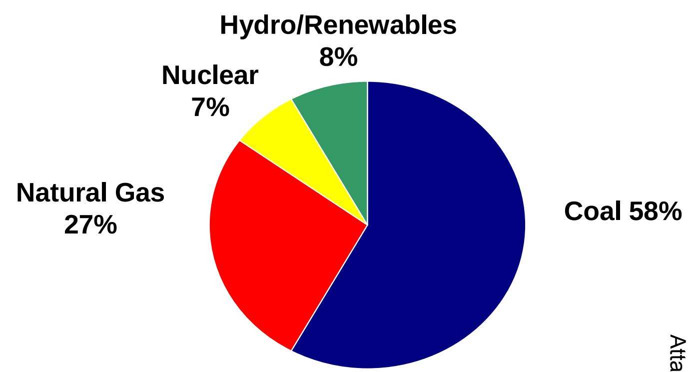
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ \$5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The total projected cost of the plant is $380 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.7 billion with AEP's share approximately $1.3 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009

Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

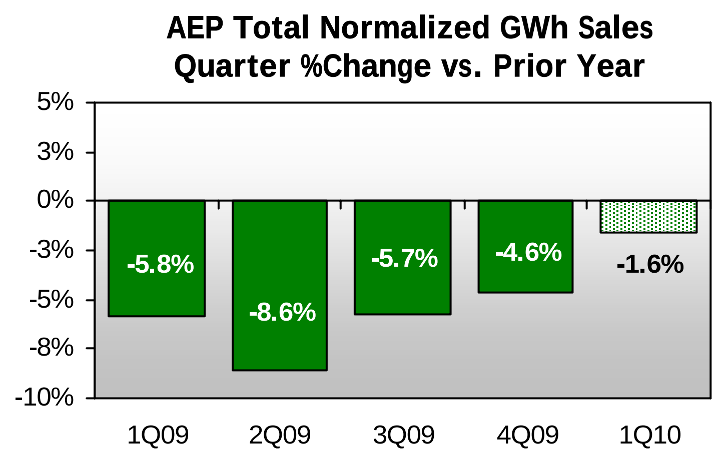
2010 Ongoing Earnings Guidance

2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**



<u>Quarter over Quarter change by segment:</u>

Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

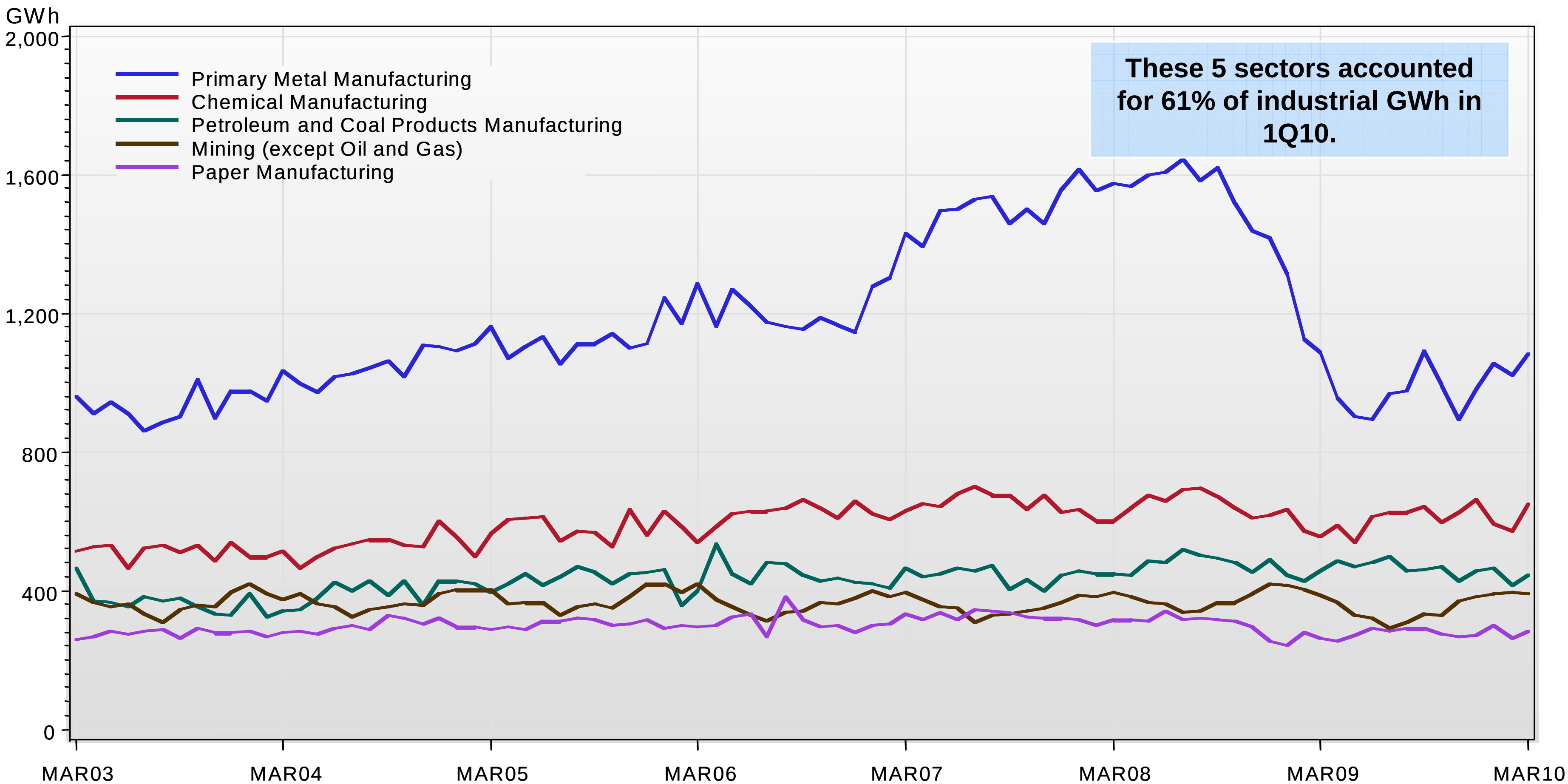
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

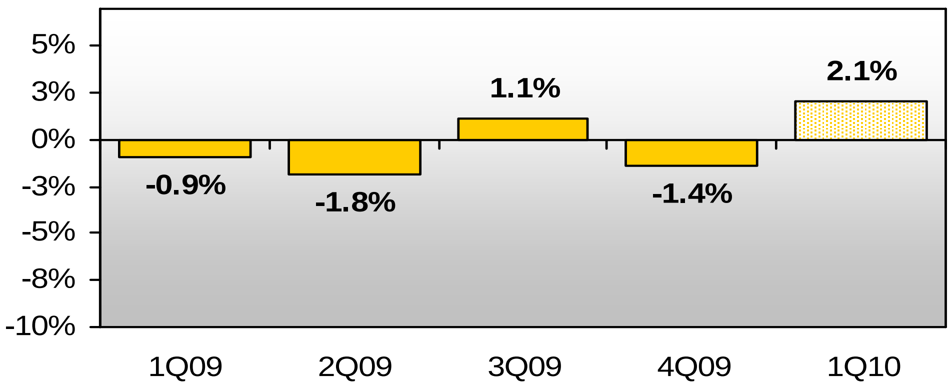
Industrial Sales

AEP Industrial GWh by Sector

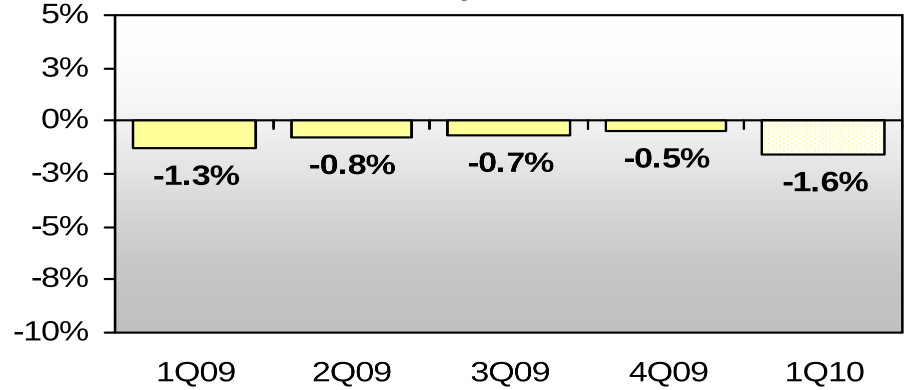


Normalized Load Trends

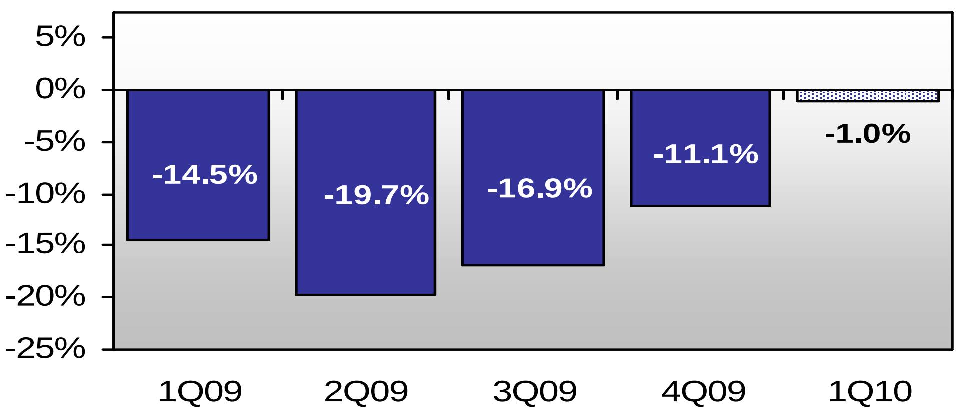
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



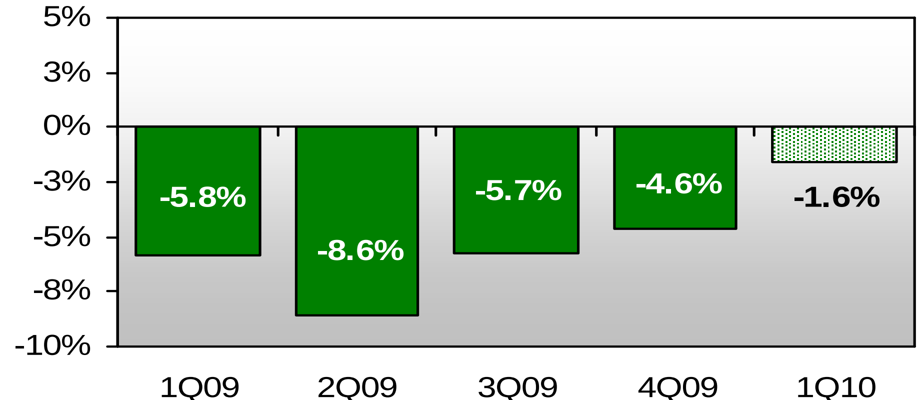
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year

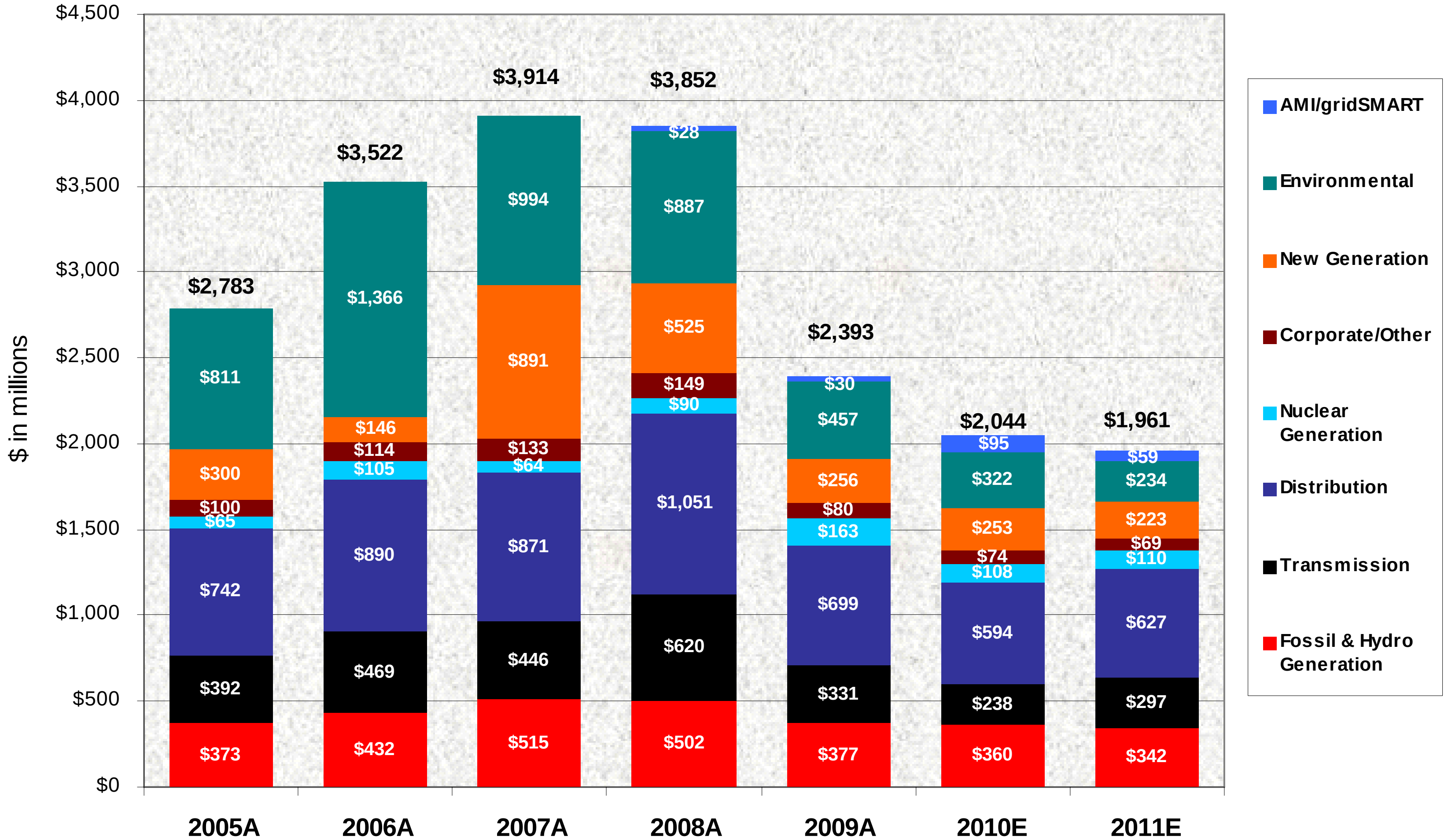


AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

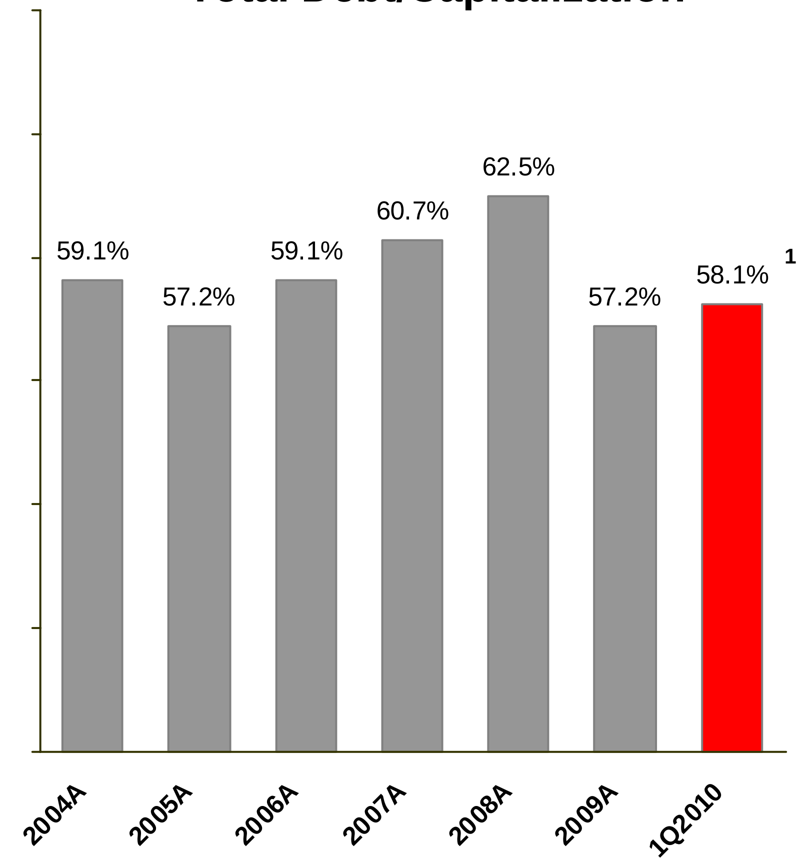
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $651 million are classified as short-term debt; The 1Q2010 debt/capitalization ratio would be 57.3%, excluding AEP Credit.

Current Liquidity Summary As of June 24, 2010

Liquidity Summary (unaudited)	**Actual 06/24/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	740	
Less		
Commercial Paper Outstanding	(747)	
Letters of credit issued	(638)	
Net Available Liquidity	**$2,787**	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)
Data as of June 24, 2010

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable, N=Negative Outlook

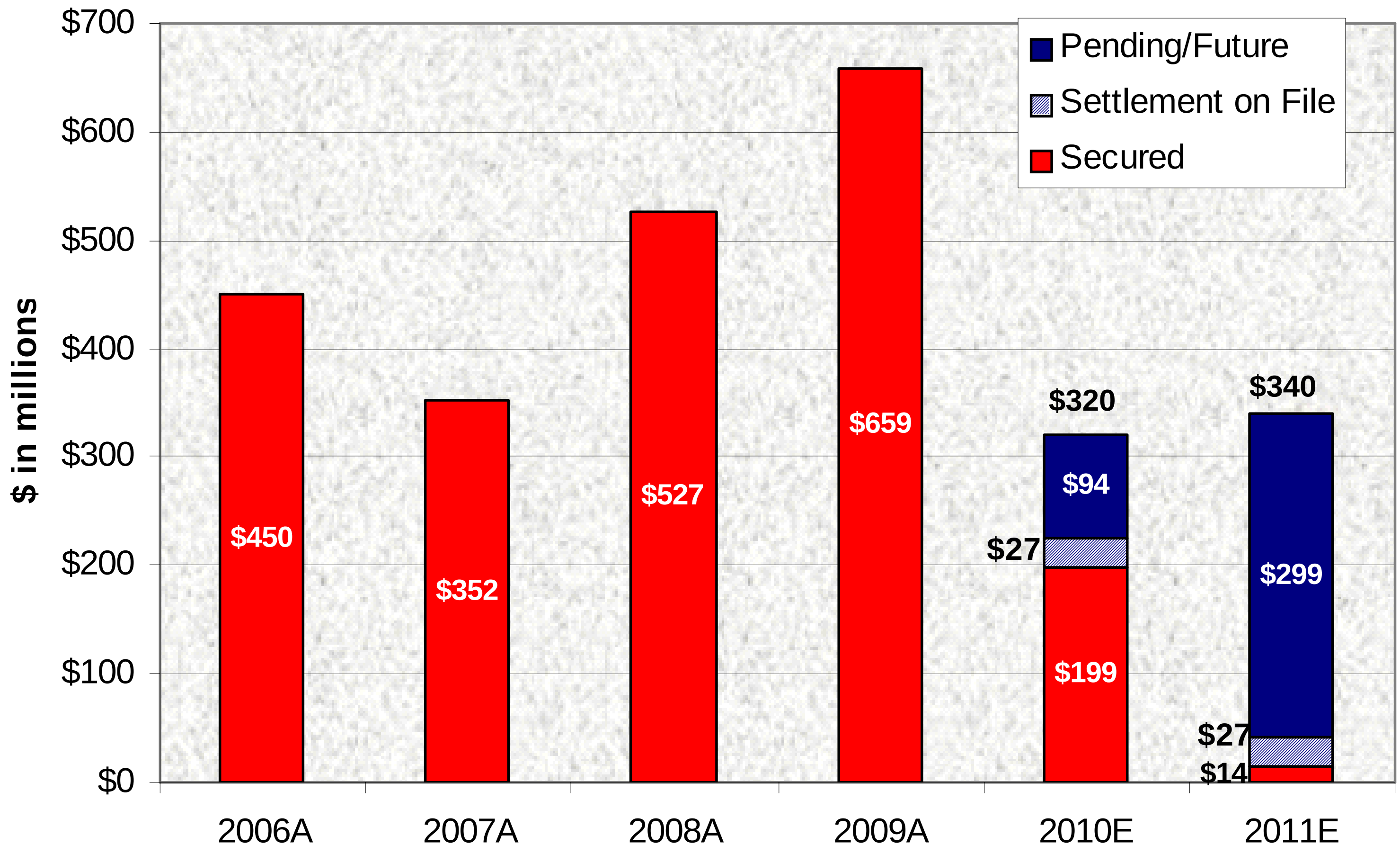
AEP & Operating Company Metrics

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires (1)	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Virginia, West Virginia and others yet to be filed

Settlement on File represents the Kentucky rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Current Base Rate Cases

APCo - Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$154**	$33-$63
Rate base/investment	$2,057	$2,116
Return on equity	13.35%	10.1% - 10.4%
Equity component	41.61%	41.53%

Status: Hearings concluded on April 2, 2010. Briefs filed on May 18, 2010. Commission Order due July 15, 2010. Rates to be effective August 1, 2010.

APCo - West Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

KPCo - Kentucky

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$124**	$41
Rate base/investment	$995	$995
Return on equity	11.75%	10.10%
Equity component	42.91%	42.91%
Riders requested	Wind & Reliability	

Status: On May 19, a settlement agreement was filed with the KPSC providing for a $64 million annual rate increase, effective June 29, 2010.

I&M - Michigan

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$63**	n/a
Rate base/investment	$601	
Return on equity	11.75%	
Equity component	44.19%	
Riders requested	Numerous	

Status: Case filed on January 27, 2010. Hearings scheduled for August 9-17, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Proposal for decision expected by November 16, 2010.

$565 million of total base rate increase requests on file

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. A settlement agreement was filed with the KPSC on May 20, 2010, with a $64 million base rate increase, which includes $10 million on reliability spending at an ROE of 10.5%. Commission approval is pending.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

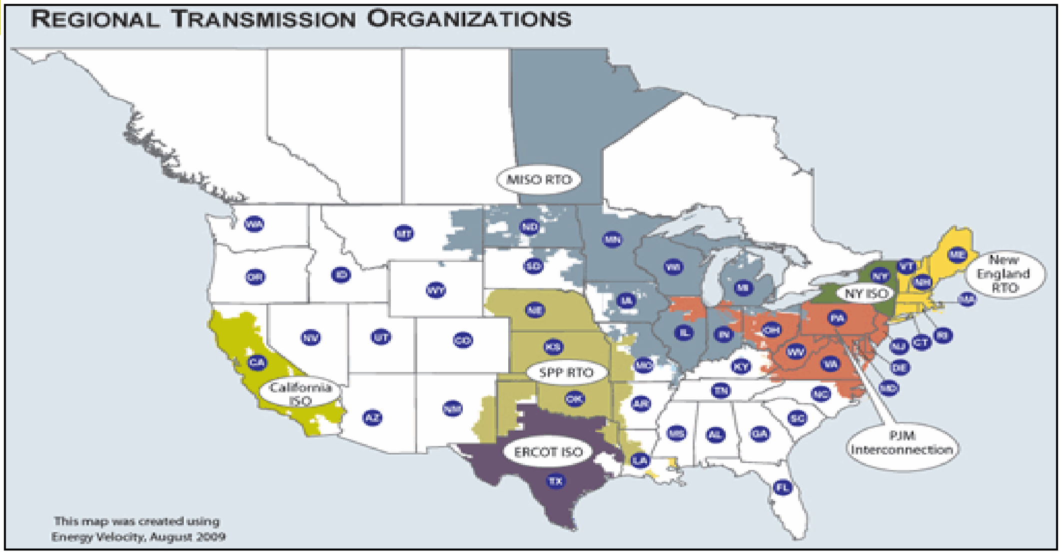
Making it Happen: EHV Projects Under Development

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind — COD: 2013-14	**ETT — COD: 2010-2017**	**PATH-WV — COD: 2014**	**Pioneer — COD: 2015**
▪ *110 miles of 765 kV* ▪ *Partners: Westar (50%) & Electric Transmission America (50%)* ▪ *Estimated Cost: $400 million* ▪ *ROE: 12.8%*	▪ *345 kV ERCOT Expansion* ▪ *Partner: MidAmerican Energy (50%)* ▪ *Estimated Cost: $1.4 billion* ▪ *ROE: 9.96%*	▪ *275 miles of 765 kV* ▪ *Partner: Allegheny Energy (50%)* ▪ *Estimated Cost: $1.2 billion* ▪ *ROE: 14.3%*	▪ *240 miles of 765 kV* ▪ *Partner: Duke Energy (50%)* ▪ *Estimated Cost: $1 billion* ▪ *ROE: 12.54%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*



FUTURE DEVELOPMENT

SMARTransmission Study

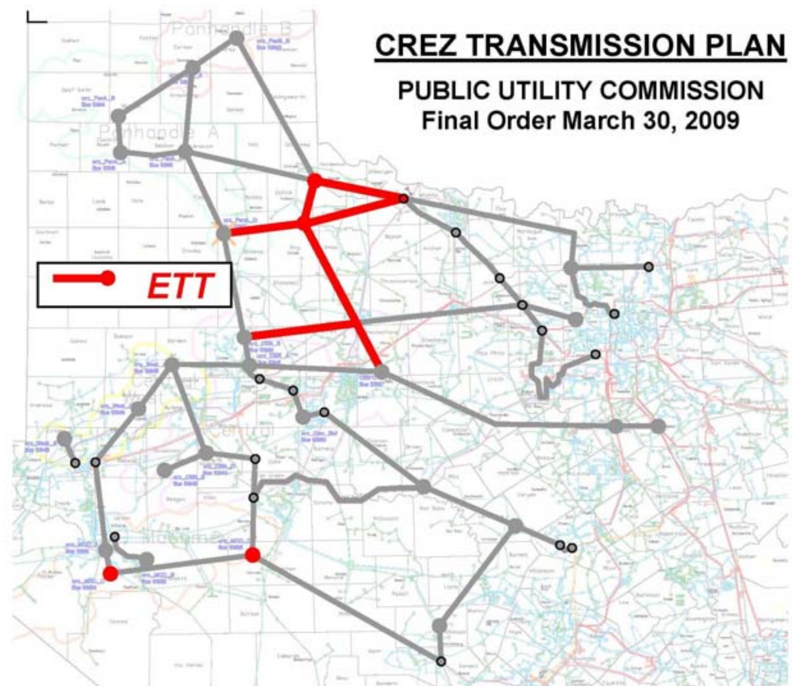
- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT — COD: various**	**PJM Expansion**	**EHV Michigan/Ohio**
▪ *Regional Expansion of 765 kV Backbone*	▪ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ▪ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	▪ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	▪ *700 miles of Proposed 765 kV*

Electric Transmission Texas, LLC

Overview:

- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.

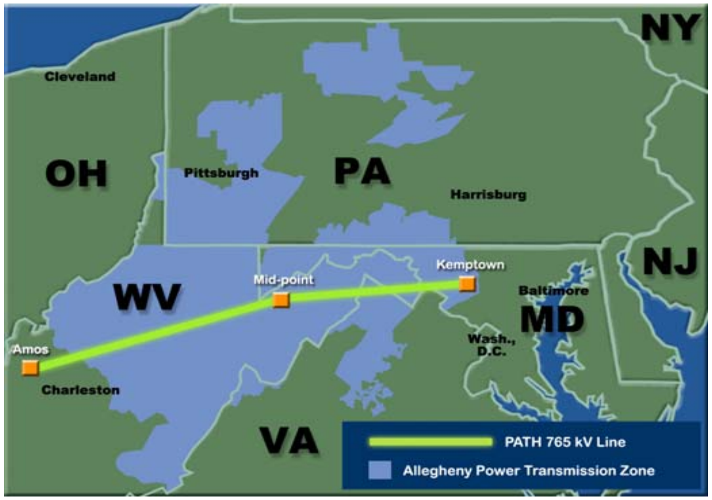
Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: June 1, 2015, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

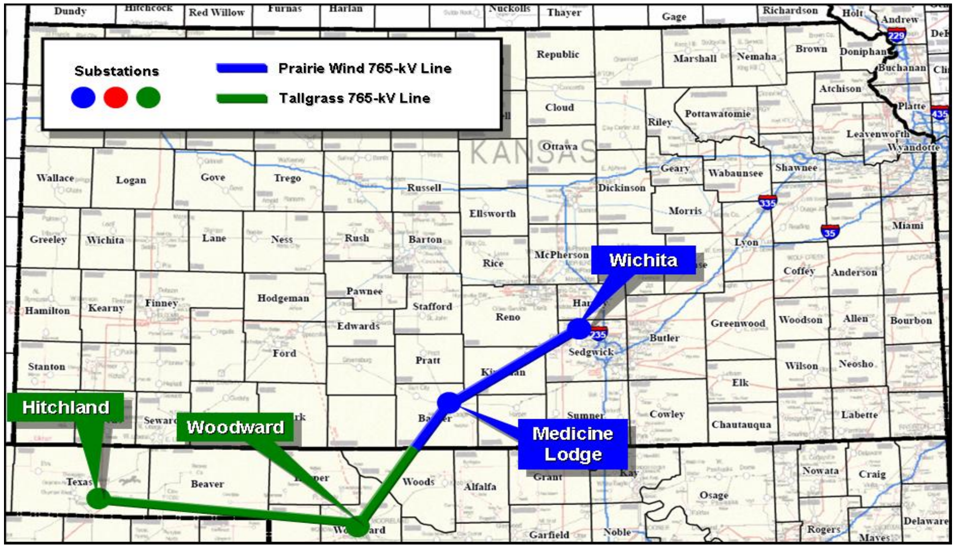
Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice to construct anticipated to be received summer 2010.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

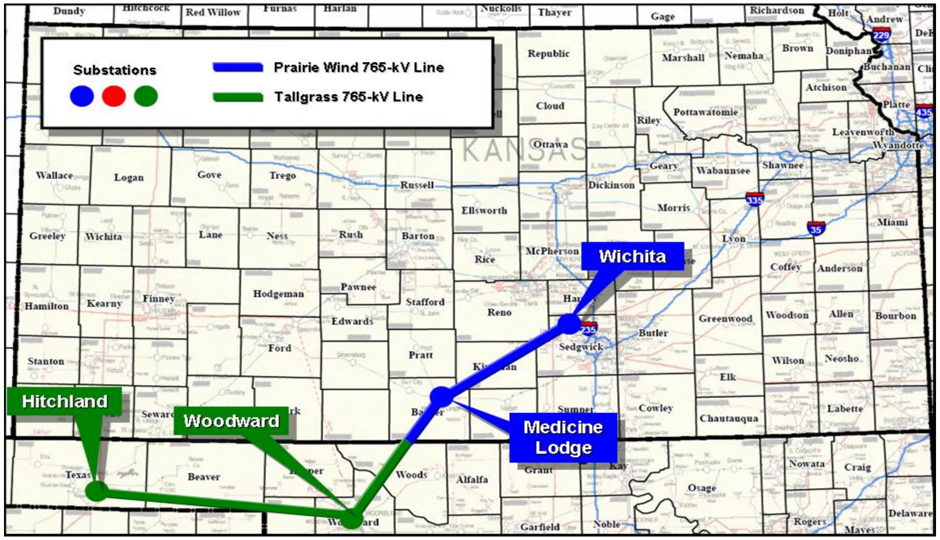
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice to construct anticipated to be received summer 2010.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

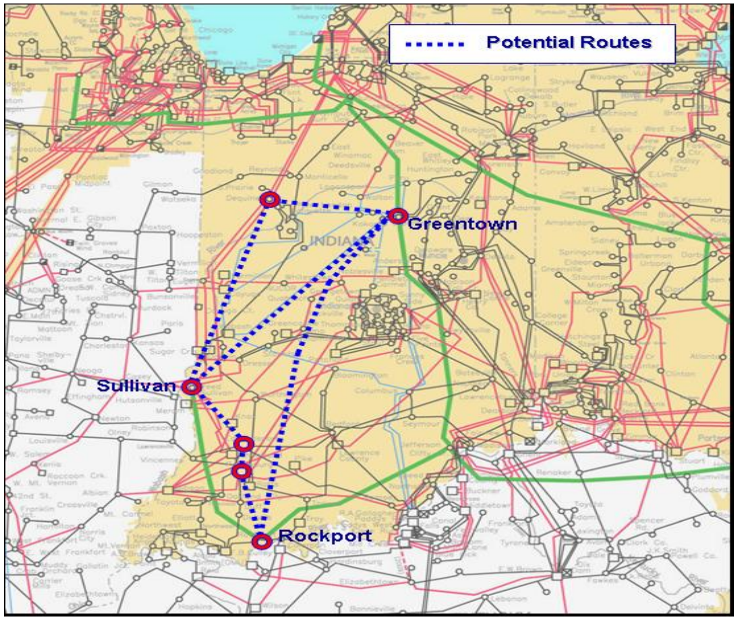
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

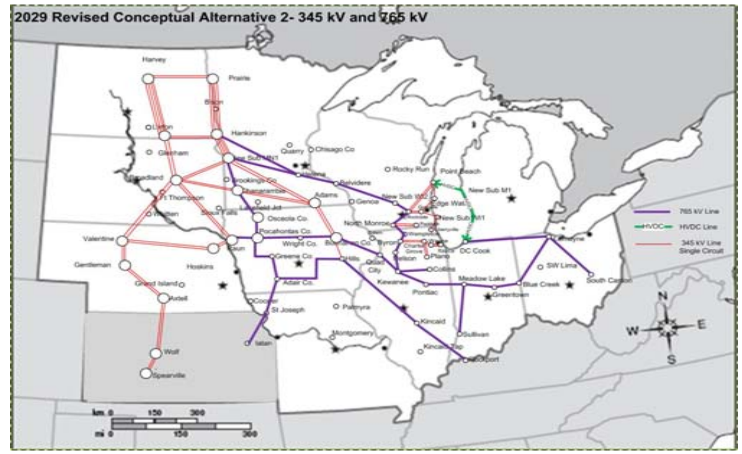
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

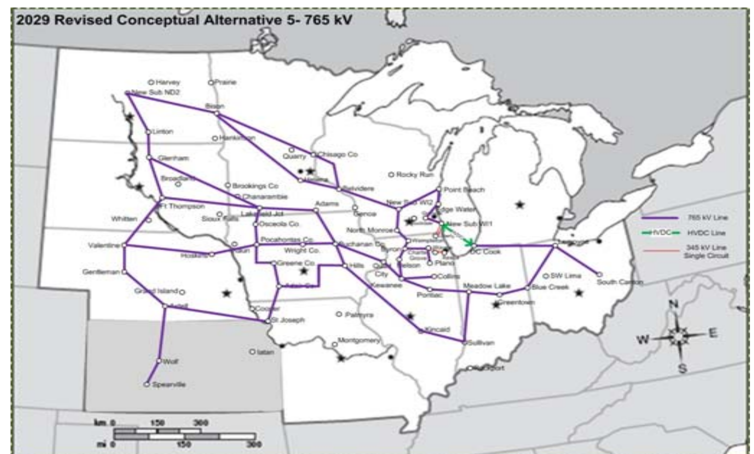
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives

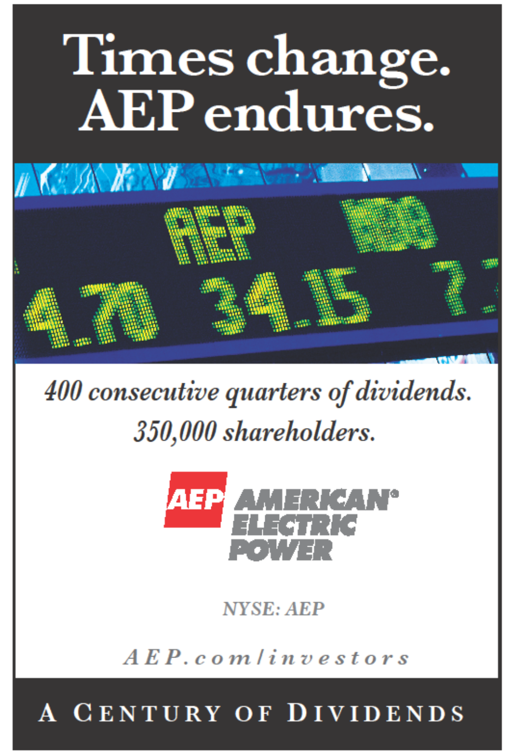




The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Value Proposition

- **Current Yield Opportunity of 5.1%[1]**
  - **June 10th – 400th consecutive quarterly dividend was paid to shareholders**
  - **50-60% payout ratio targeted**
  - **Dividend increased 2.44% on April 27th**
- **Earnings Growth Prospects**
  - **Investment in utility platform greater than depreciation level (2 - 4%)**
  - **With transmission opportunities (4 - 8%)**



Attractive total return potential

[1] yield percentage based on AEP closing price of $32.99 on 06/25/2010

AMERICAN ELECTRIC POWER

Goldman Sachs Fourth Annual

Alternative Energy Conference

New York, NY

May 20, 2009

AEP AMERICAN ELECTRIC POWER®

STRONG
FLEXIBLE
ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Table of Contents

AEP AMERICAN® ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

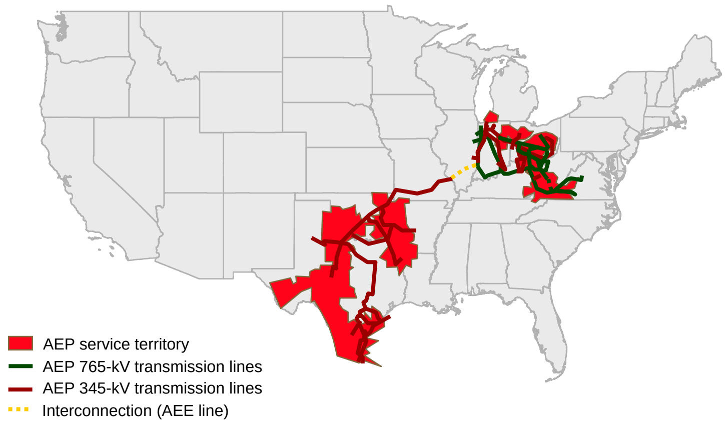
- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

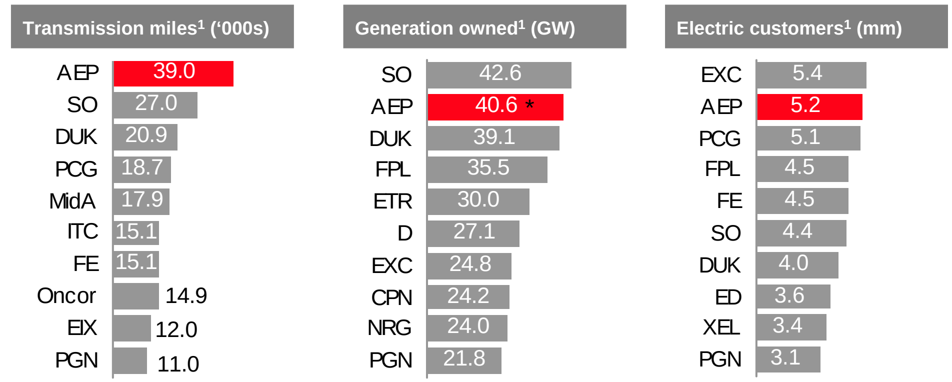
- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

Premier Regulated Utility Platform

Overview

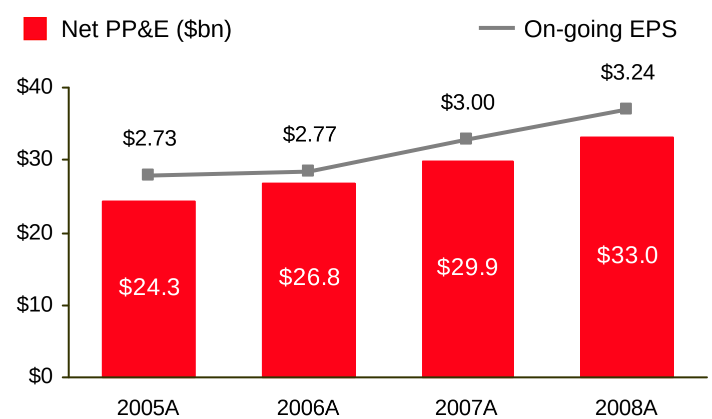


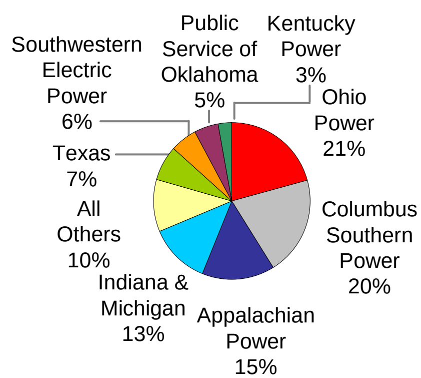
AEP's Leadership Position



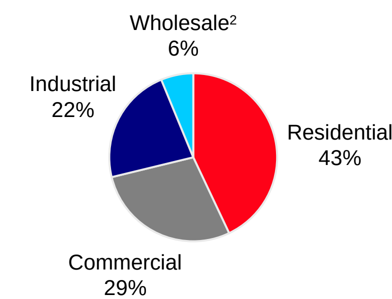
* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations





2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*

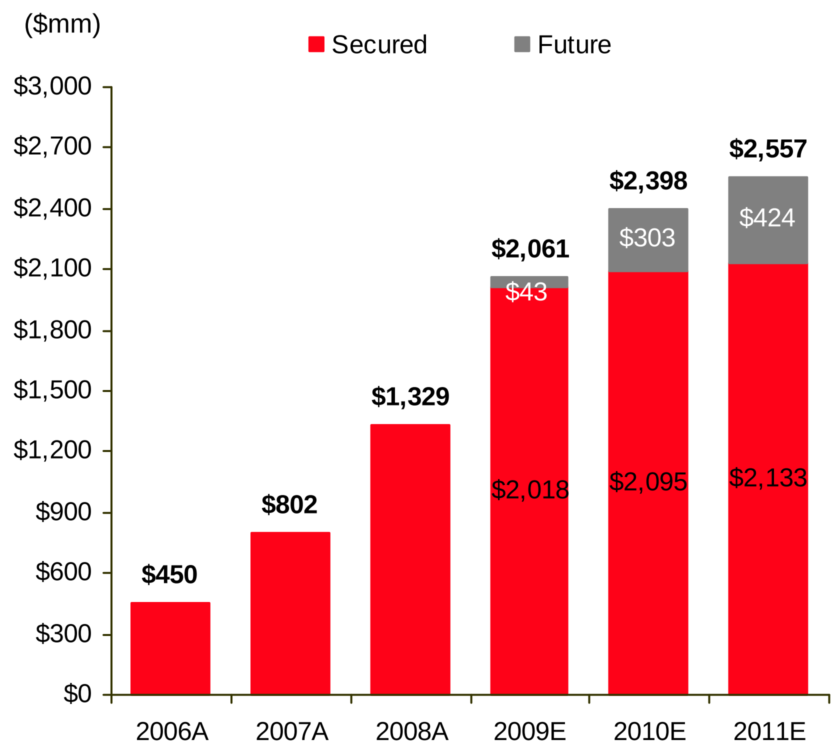
- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

¹ Source: Company filings
² Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

AEP AMERICAN ELECTRIC POWER

Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] *$77mm and $38mm was secured for 2010 and 2011, respectively, as of May 15, 2009*

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($455MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($25MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
- Anticipated filings:
  - APCo VA and others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in all jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

AEP AMERICAN ELECTRIC POWER

Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Order	2010 ESP Appl.	2010 PUCO Order	2011 ESP Appl.	2011 PUCO Order	Cumulative ESP Appl.	Cumulative PUCO Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC)	214.5M	64.3M	455.1M	228.6M	510.8M	265.7M	2064.6M	916.0M
(Incl. OVEC of $68.8M)								
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	51.0M	0.0M	0.0M	0.0M	0.0M	0.0M	153.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	182.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	562.6M
Total Cash Increase	462.8M	246.5M	595.1M	234.9M	684.4M	269.4M	3263.3M	1478.6M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC

- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U). An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
10/20/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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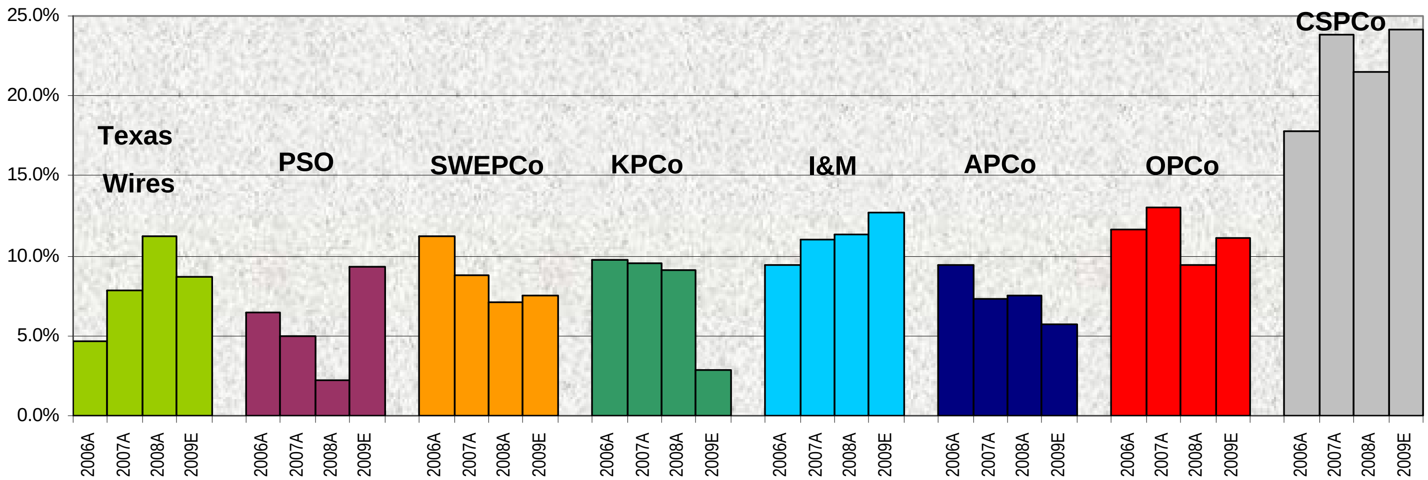
Net Income & Pro-Forma Earned ROE by Operating Company

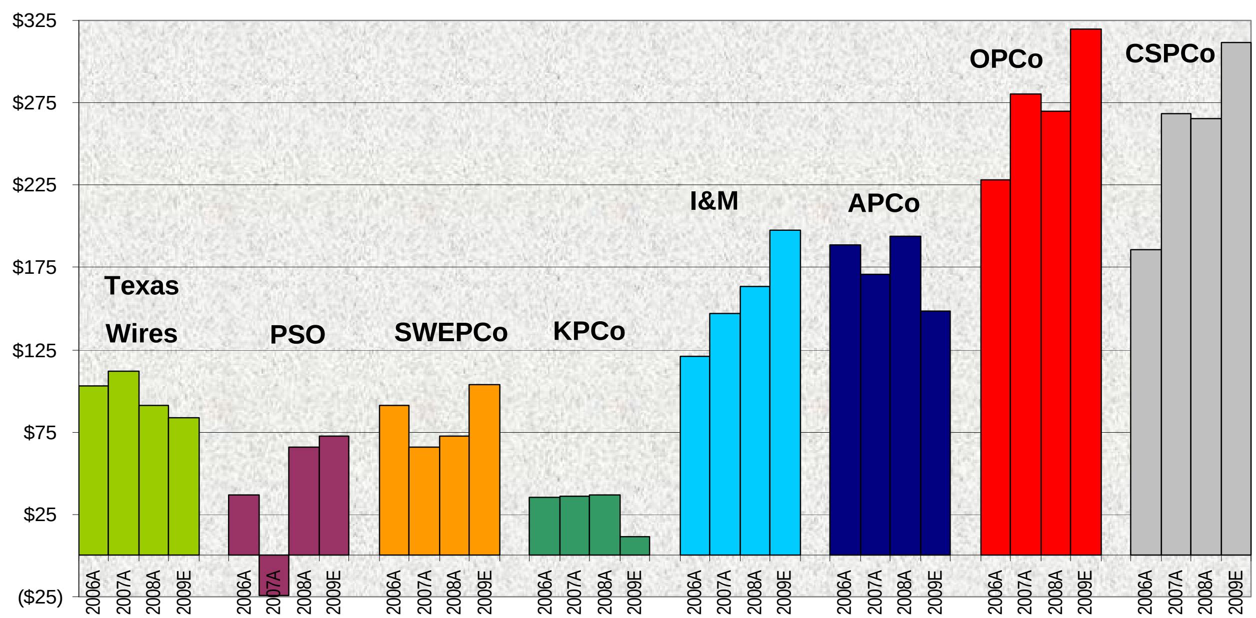


Pro-Forma Earned ROEs

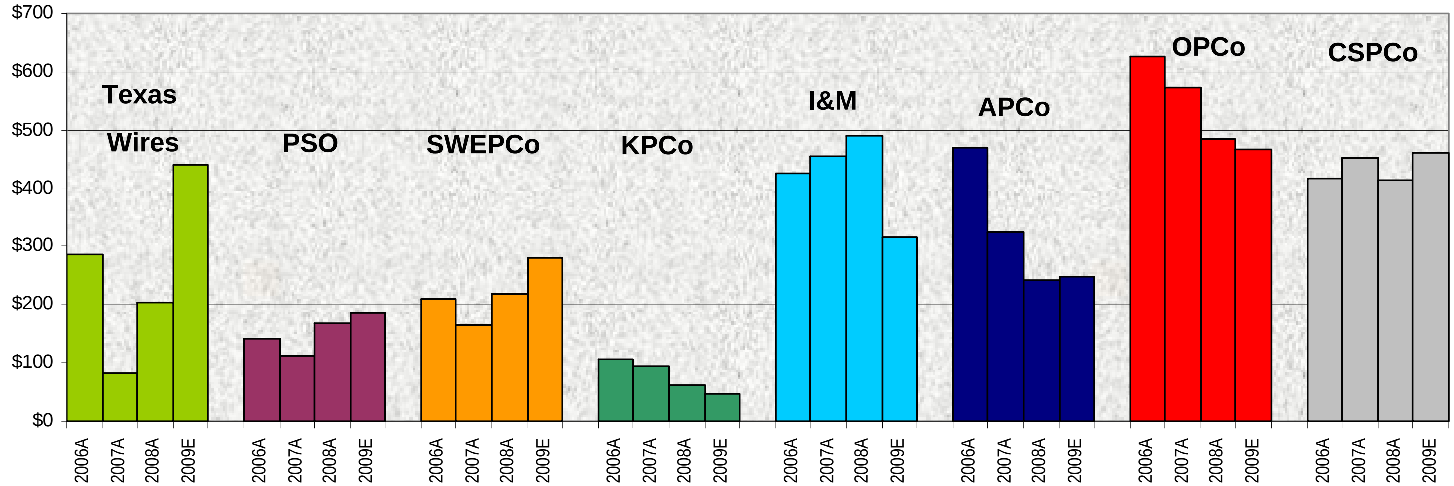
Earned ROEs represent 12 months ended December 31. Regulatory Lag ranges from 3-15 months by jurisdiction.

Net Income by Operating Company

($ in millions)



Cash Flow and Capex by Operating Company

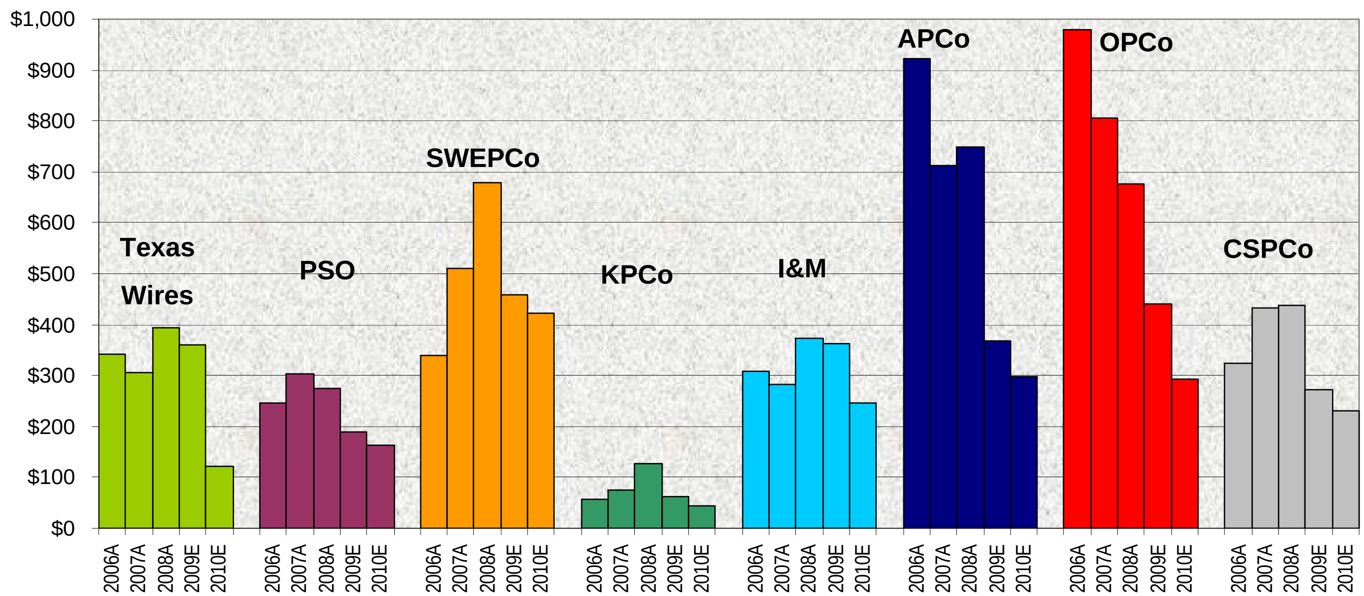


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with <u>allocated</u> credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

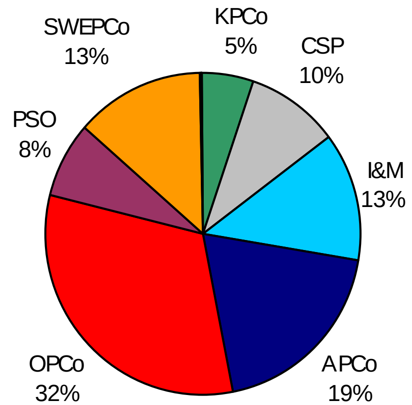
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

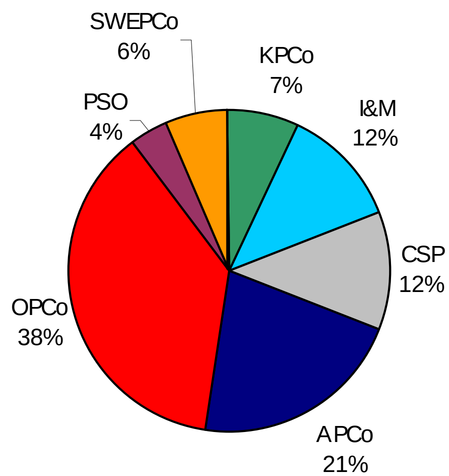
AEP AMERICAN ELECTRIC POWER

CO_2 Cost Recovery – Should Follow SO_2 & NOx

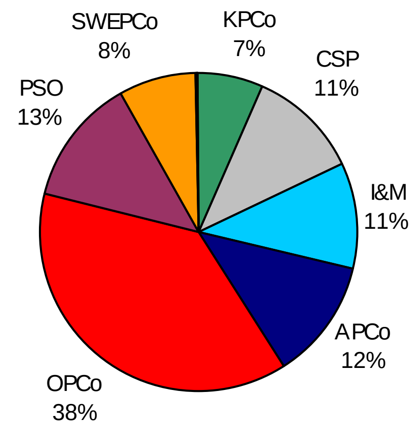
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



2008 AEP System NOx Emissions
248k tons



- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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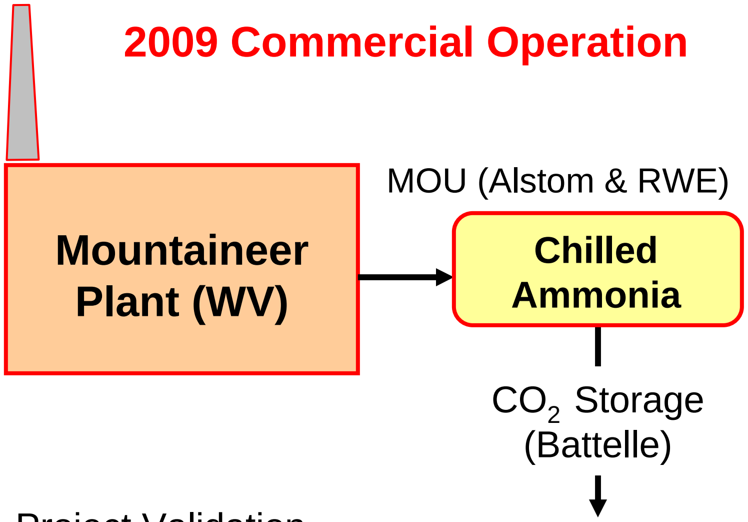
Carbon Capture & Storage



Project Validation

- Alstom “Chilled Ammonia” Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies’ Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Geologic storage for CO_2

Represents Post-Combustion Capture

- Conventional or Advanced Amines; Chilled Ammonia
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the ‘economic’ hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

AEP AMERICAN ELECTRIC POWER

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $1.2 billion in capital investment.

- Turk – AEP self-reported impacts to jurisdictional wetlands in March 2009. Work continues outside the jurisdictional areas. Hearing on the air permit appeal is scheduled for June 2009.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

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DC Cook Unit 1 Update

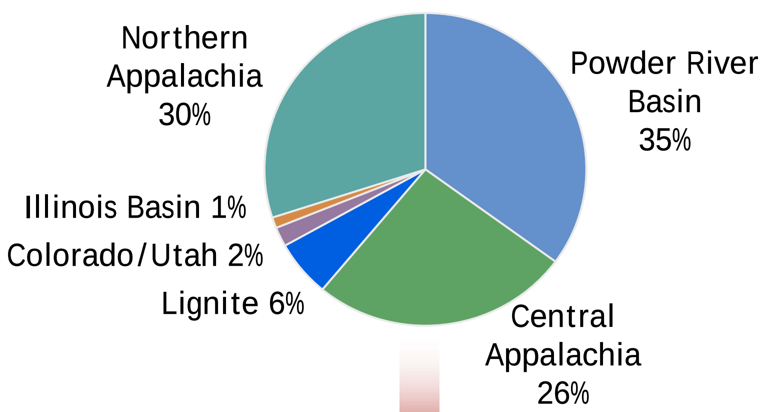
- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 1Q09, approximately 40% of the insurance payments ($20MM) were used to offset increased fuel costs to customers

AMERICAN ELECTRIC POWER

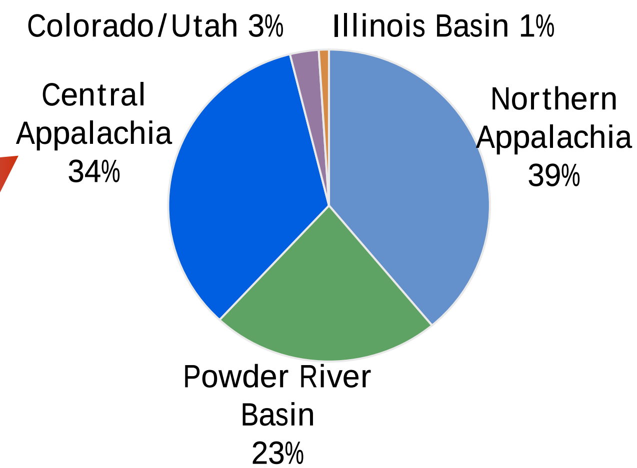
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

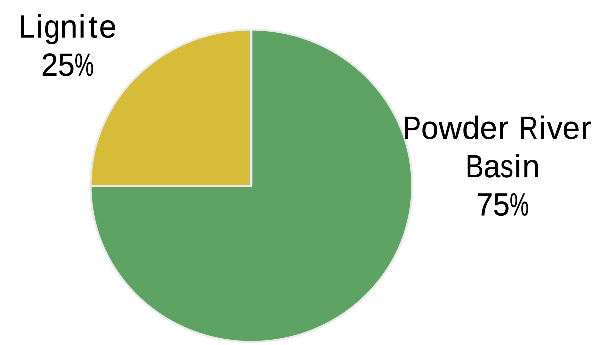
Total AEP System



AEP East



AEP West



Coal Stats:

- 98% contracted for 2009
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 12% price increase in 2009 ~ $52.00/ton

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

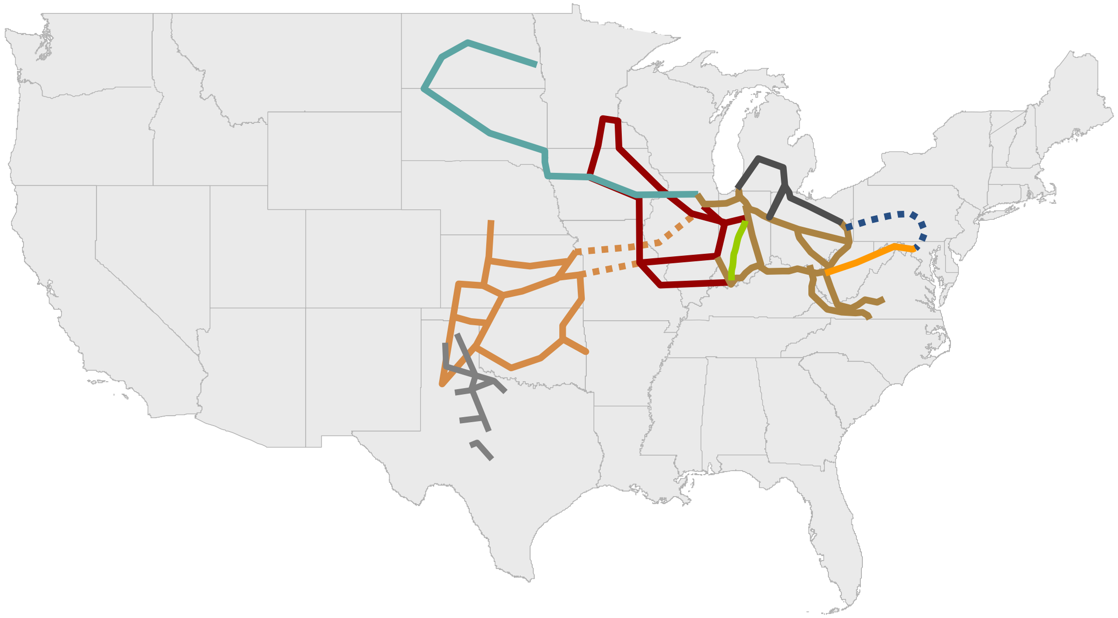
Pioneer — **COD: 2015**
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013-14**
- *230 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $600 million*
- *ROE: 12.8%*

ETT — **COD: 2013**
- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**
- *700 miles of 765 kV*
- *Partner: ITC*

PJM Projects
- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**
- *1000+ miles of 765 kV*
- *Partner: Hartland Wind LLC*

MISO Vision Plan
- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**
- *765 kV Backbone*

ETT — **COD: ~2018**
- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

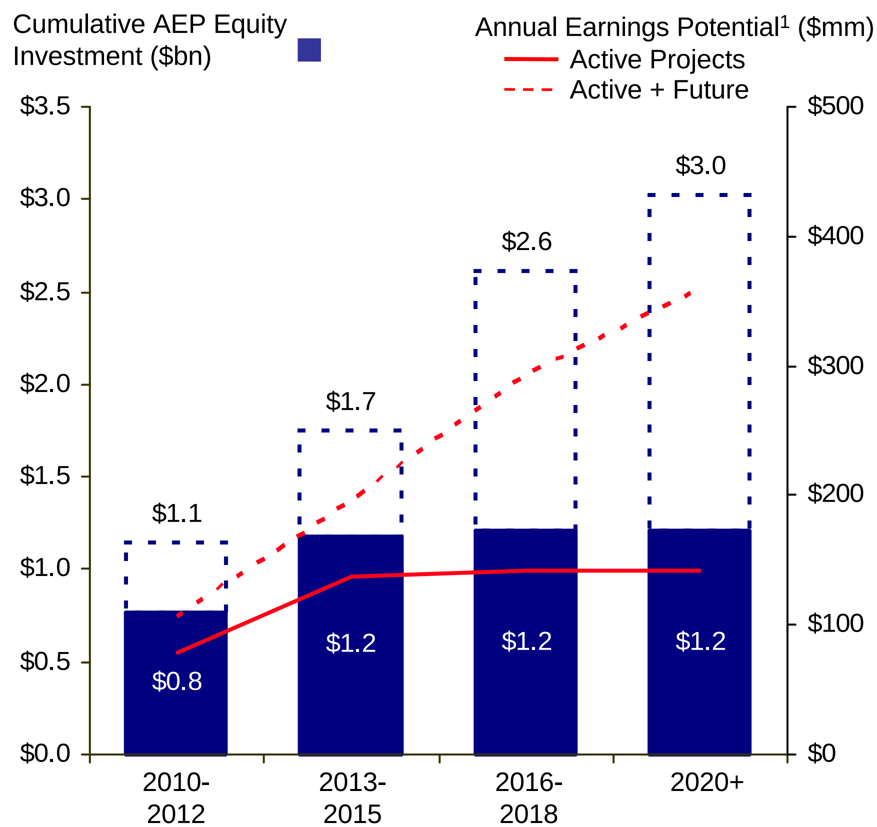
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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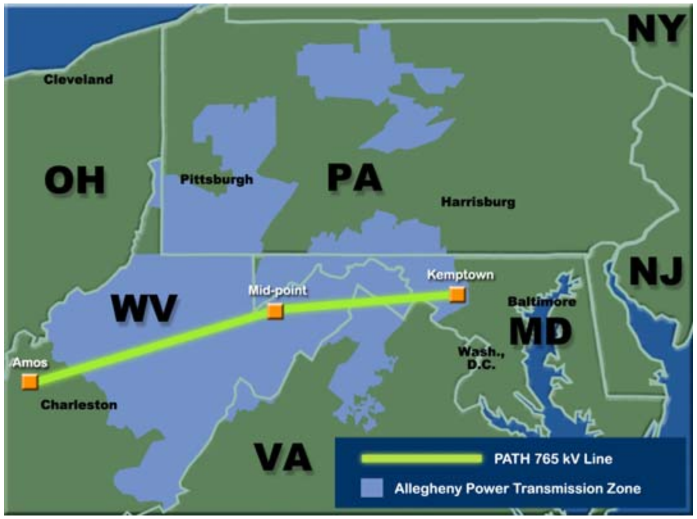
EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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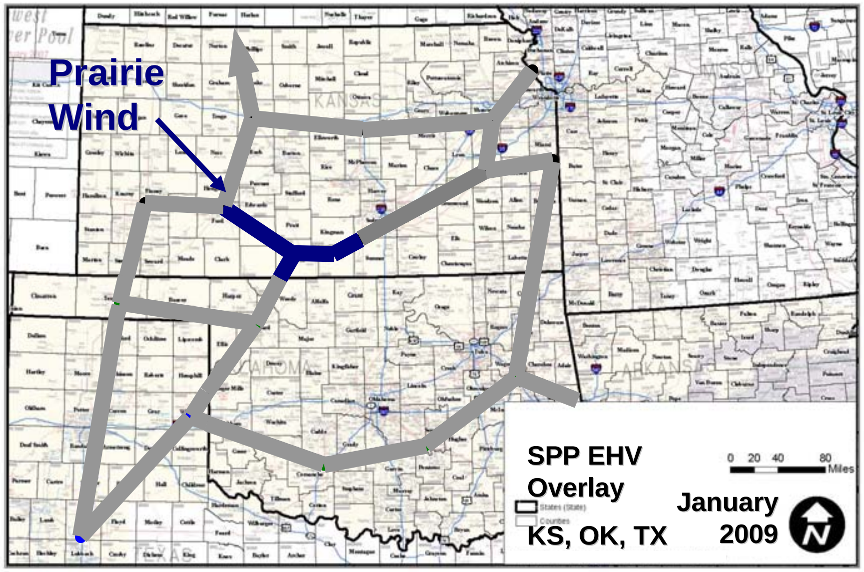
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Competing ITC Great Plains project

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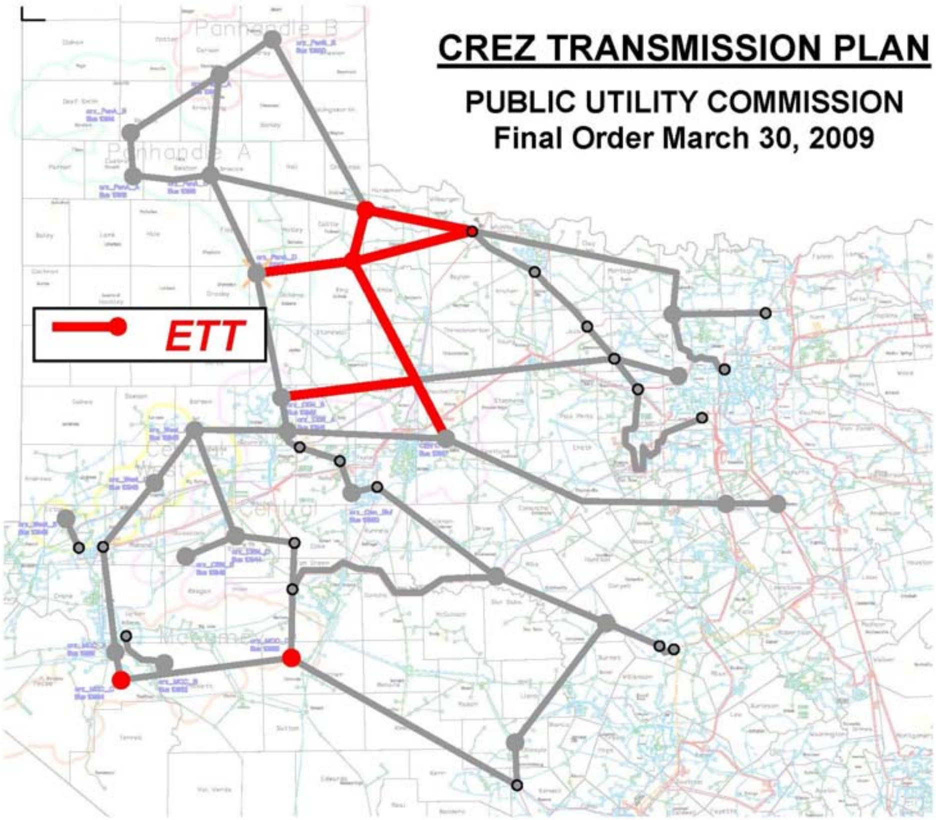
Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

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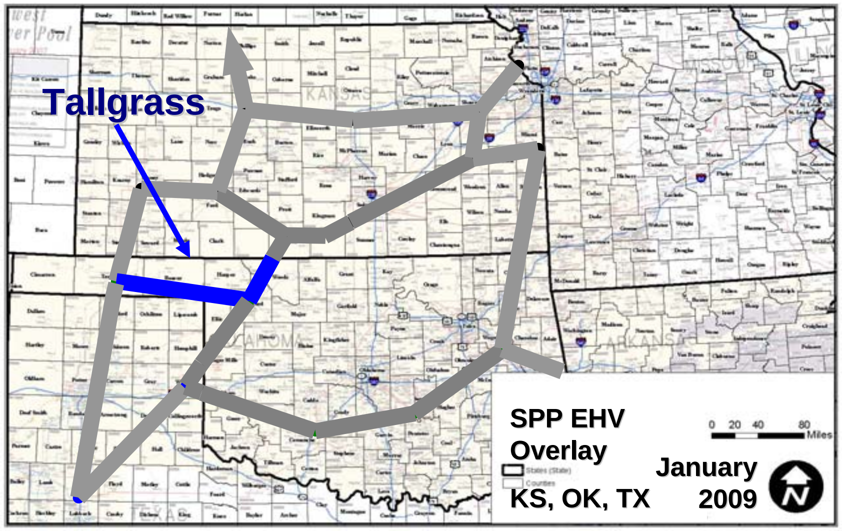
Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

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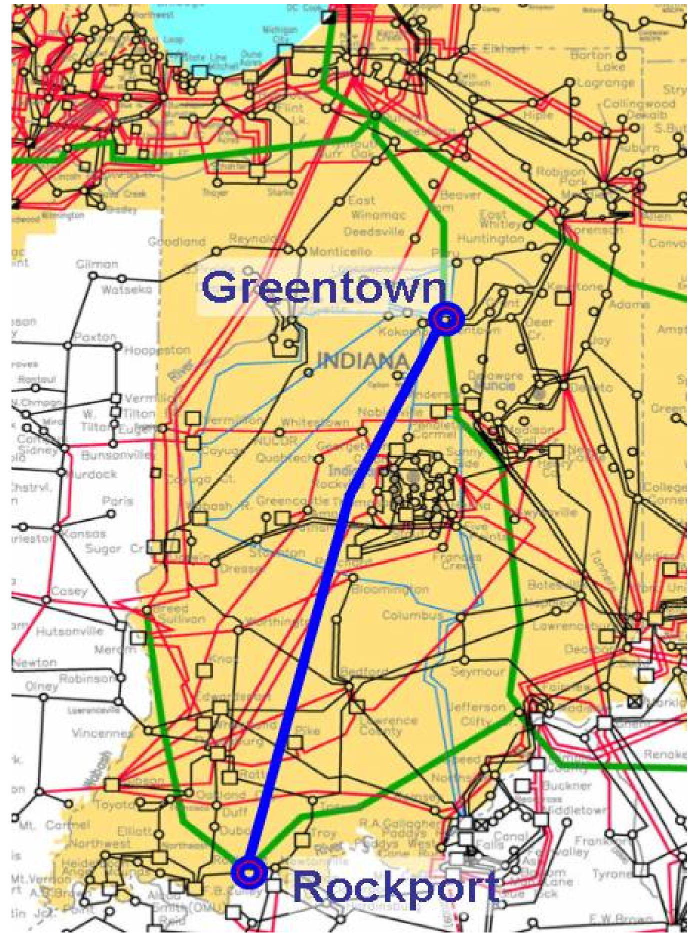
Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6688 of 9556

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

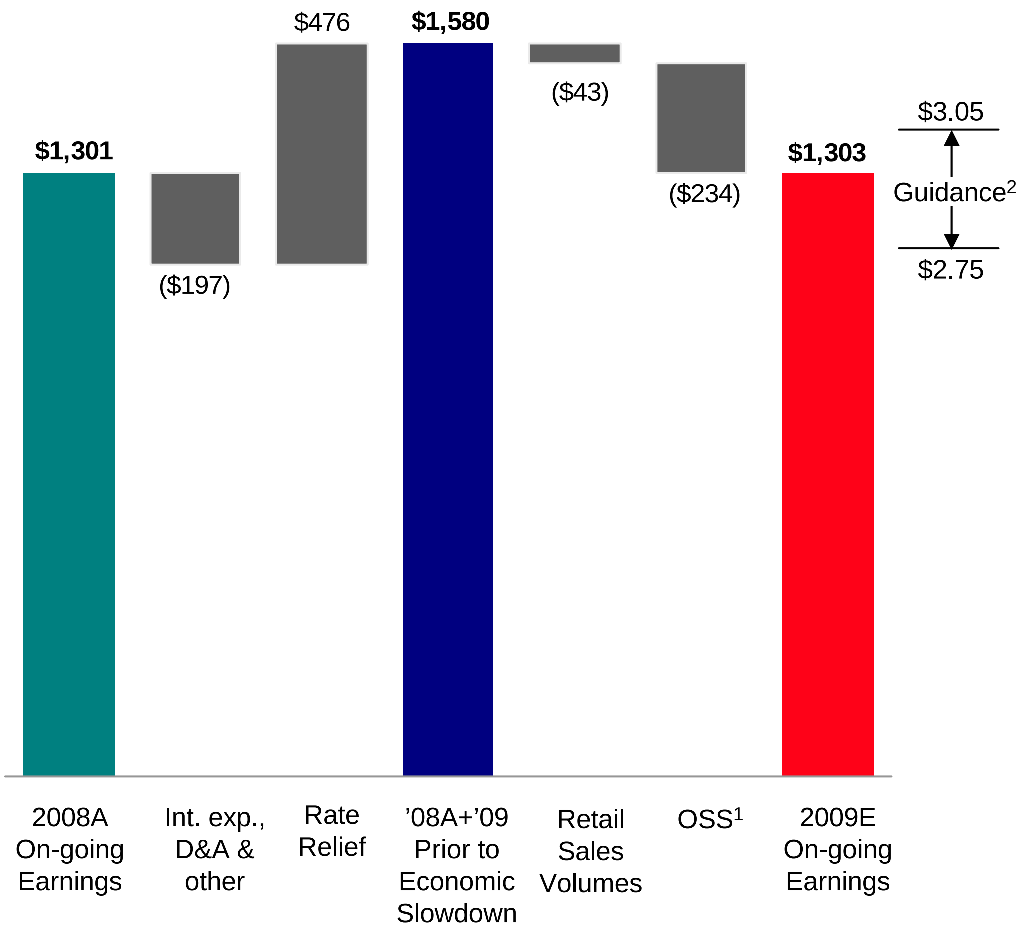
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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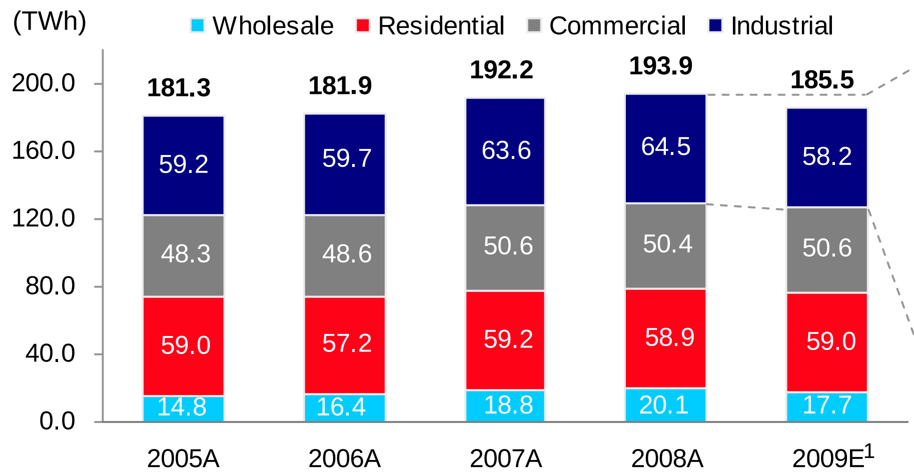
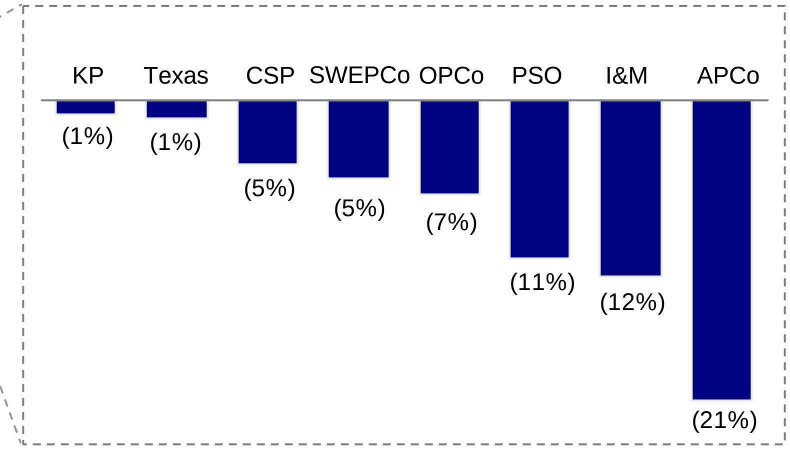
Key Drivers of Revised 2009 Guidance: Retail Sales

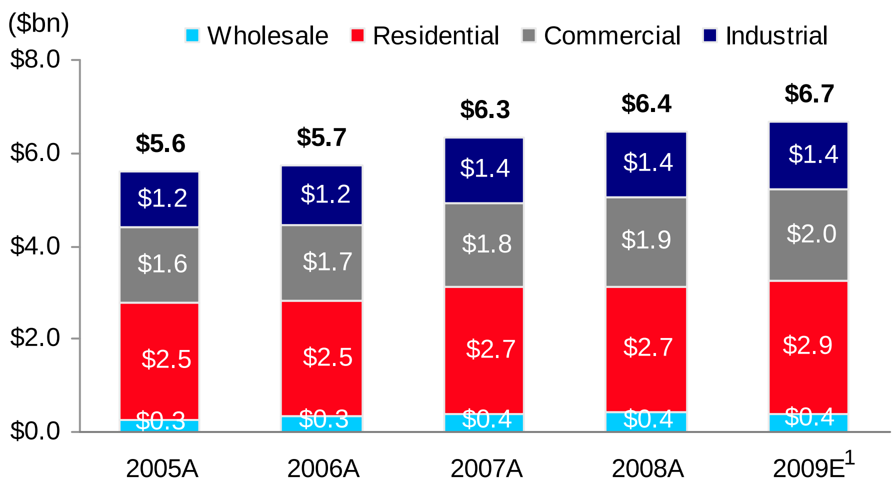
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

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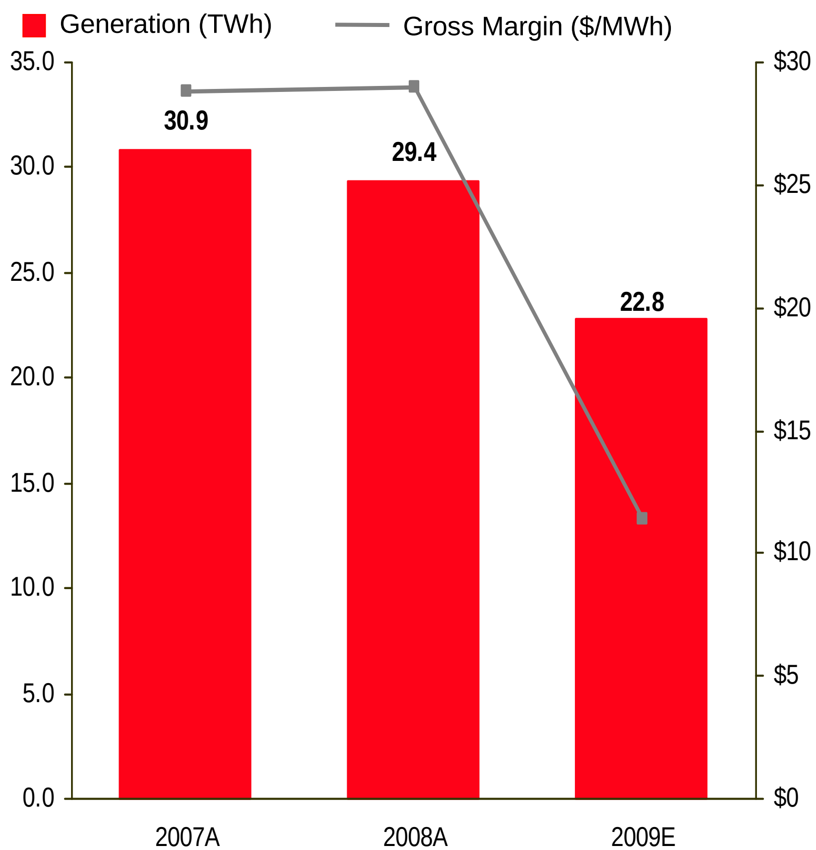
[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

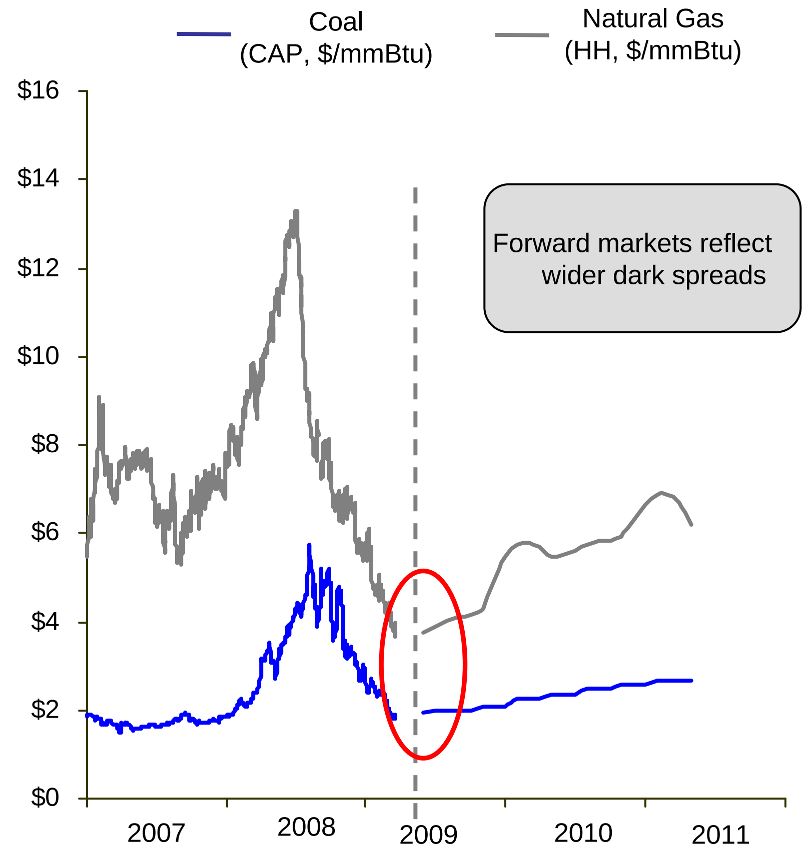
Key Drivers of Revised 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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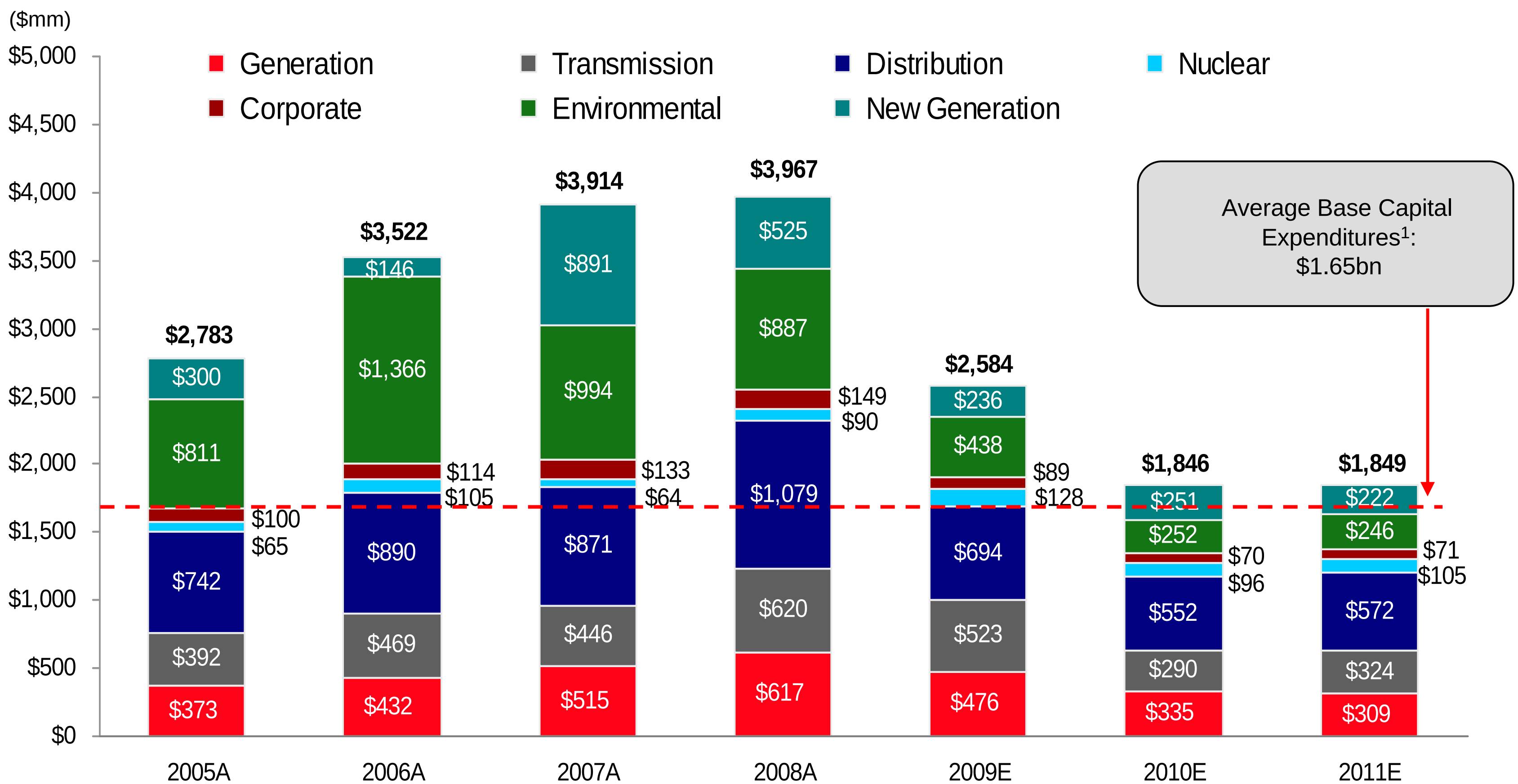
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

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Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

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Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	R	BBB	S	BBB+	S
AEP Texas North Company	Baa1	R	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa1	R	BBB	S	BBB+	S

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

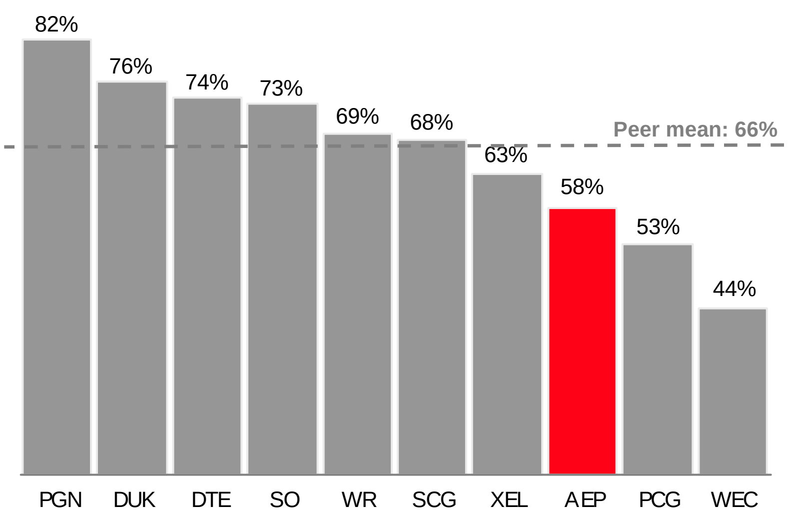
($ in millions)
(as of March 31, 2009)

Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ 150	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ 70	$ 679	$ -
Public Service of Oklahoma	$ 50	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 270	$ 1,791	$ 625

Dividend Overview

- We have paid 395 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

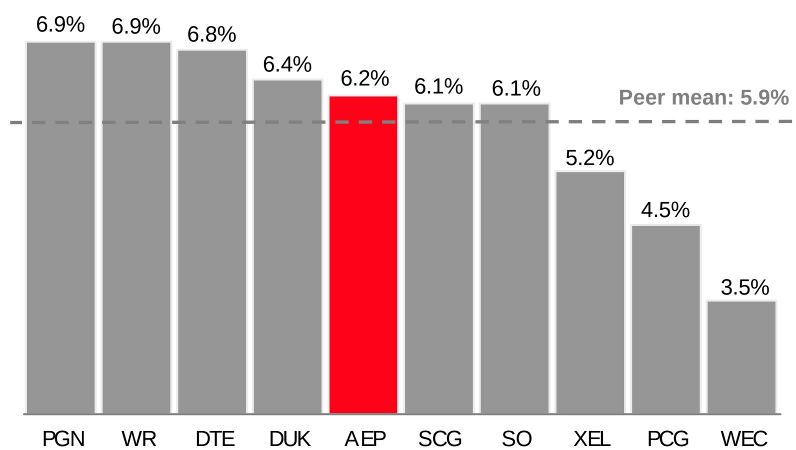
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 5/12/09

Dividend Yield vs. Integrated Electric Peers



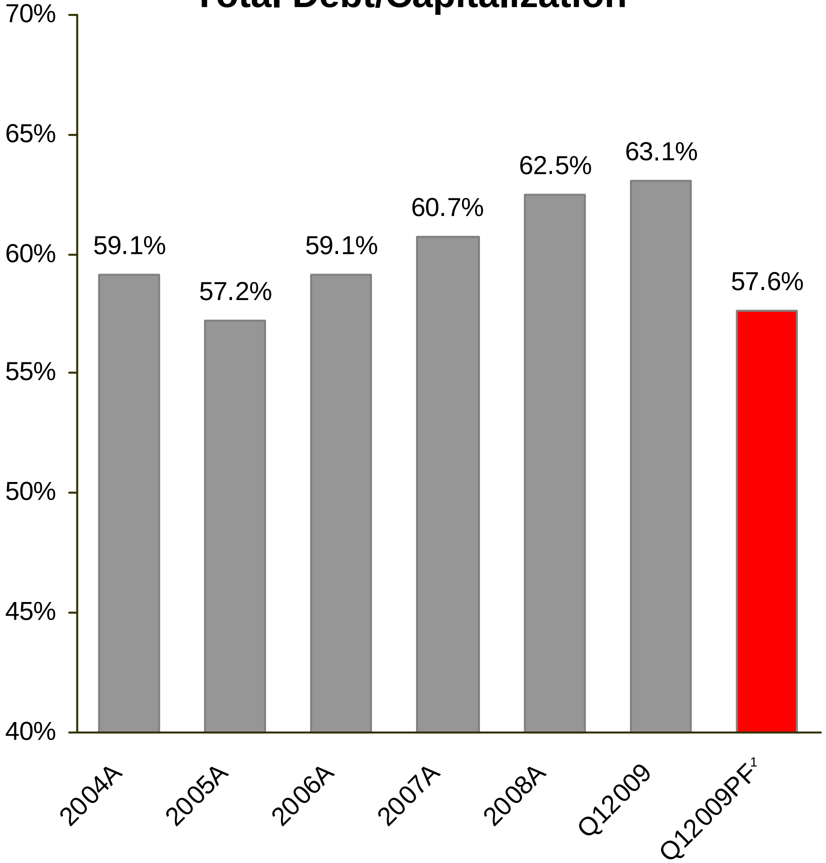
Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 5/12/09

AEP AMERICAN ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt
[1] Pro forma assumes proceeds from the equity offering were used to reduce debt

Current Liquidity Summary

- Liquidity provided by 27 banks
- Our largest lender accounts for less than 10% of bank commitments

($mm)	04/20/2009	Maturity
Revolving credit facility	$1,500	March 2011
Revolving credit facility	1,454	April 2012
Revolving credit facility	627	April 2011
Total Credit Facilities	**$3,581**	
Plus: AEP, Inc. cash and investments	1,135	
Less: Draw on credit facilities	(969)[1]	
Less: Letters of credit issued	(492)	
Net Available Liquidity	**$3,255**	

1- An additional $500MM has been repaid subsequent to 4/20/09.

AEP AMERICAN ELECTRIC POWER

AEP AMERICAN® ELECTRIC POWER

Goldman Sachs 10th Annual Power & Utility Conference New York City August 12, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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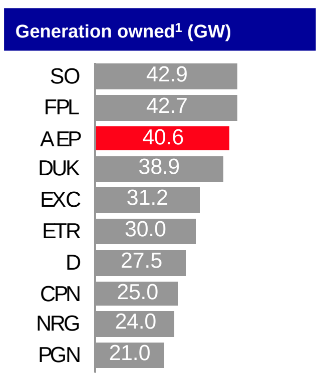
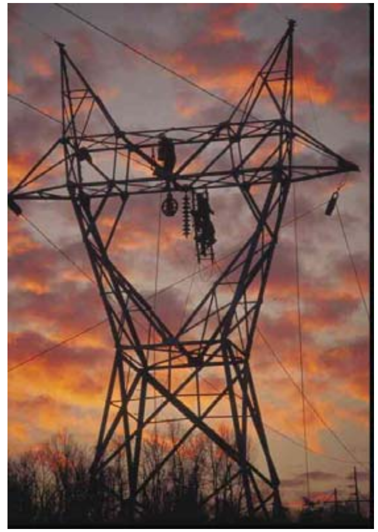
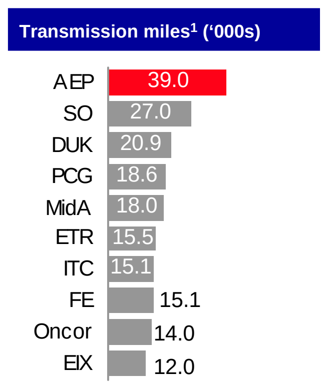
Industry Leadership

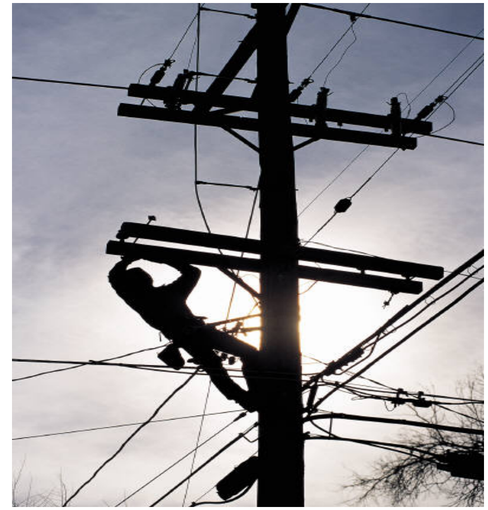
One of the largest U.S. electricity generators



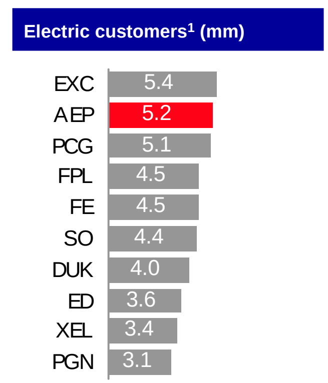


The largest U.S. electricity transmitter





One of the largest U.S. electricity distributors serving 5.2MM customers



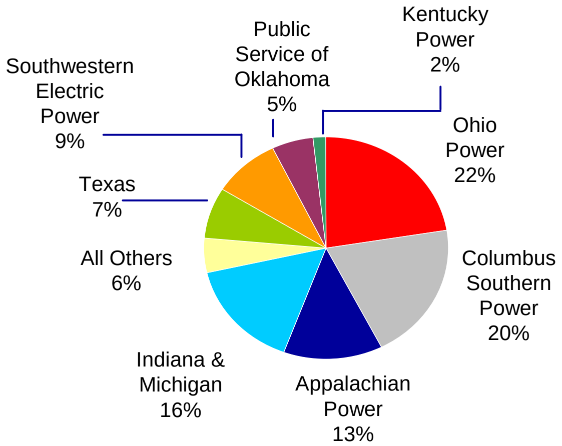
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

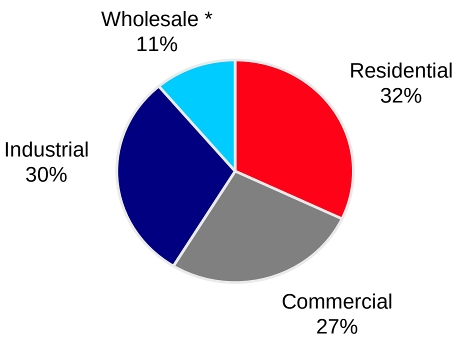
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

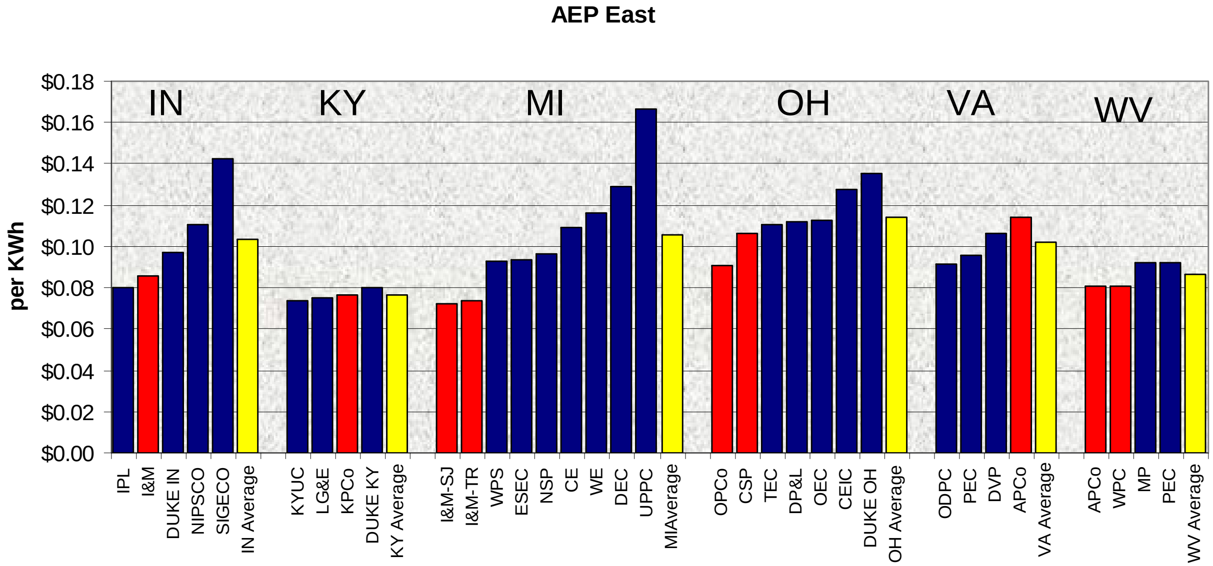


2009 Retail Load



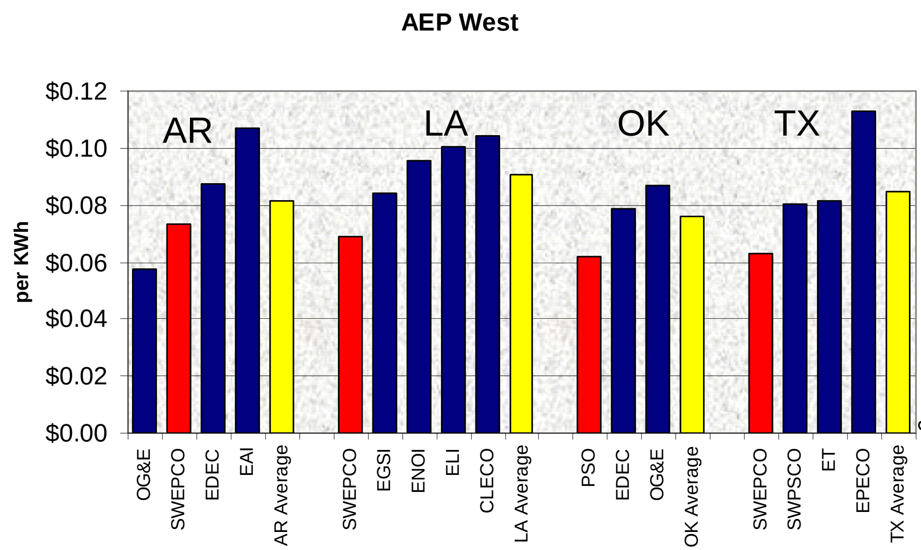
Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

Residential Rates Comparison



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP Company
Other Utilities within state
State Average



Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

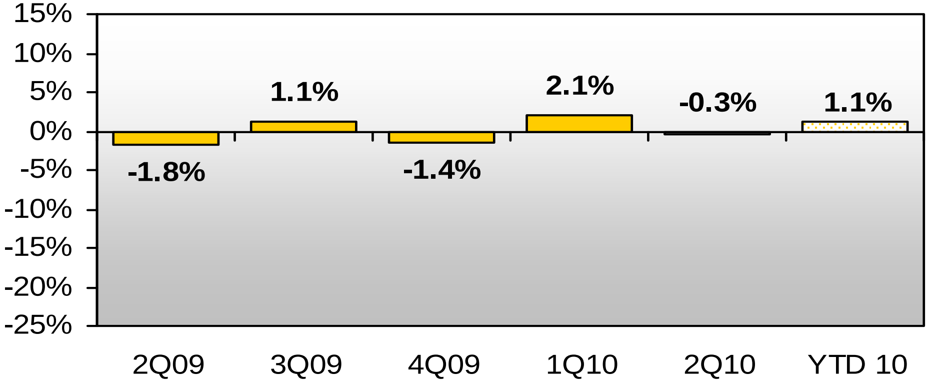
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		[illegible]
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

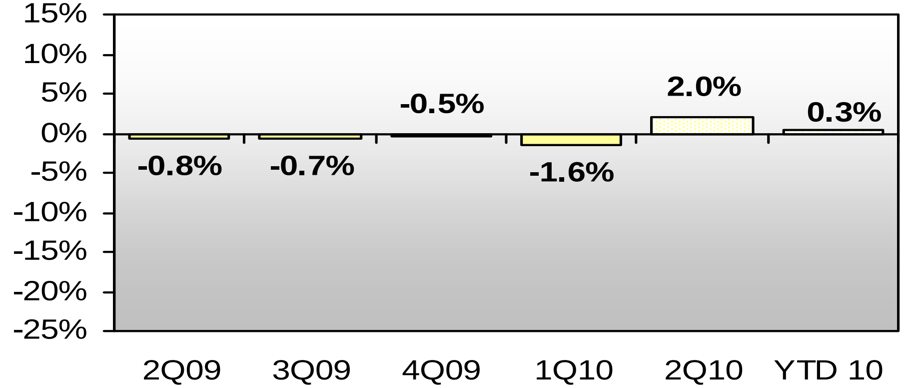
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends

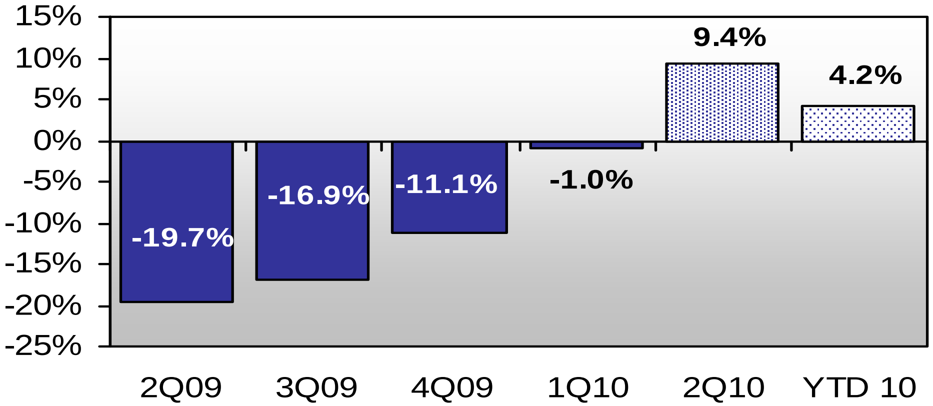
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



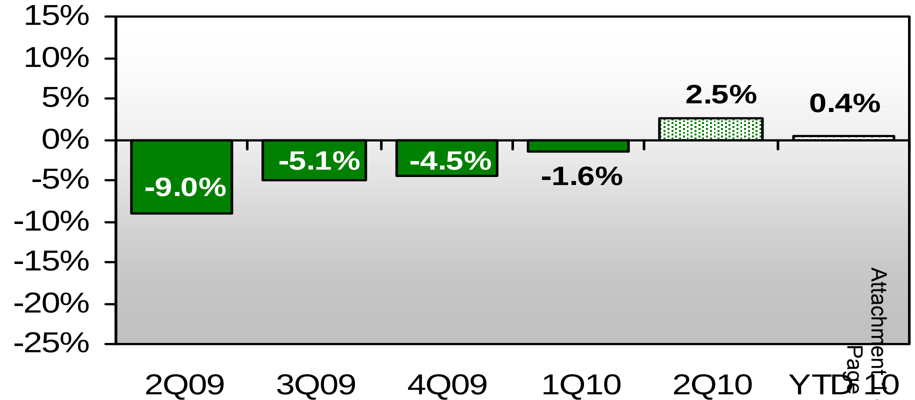
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



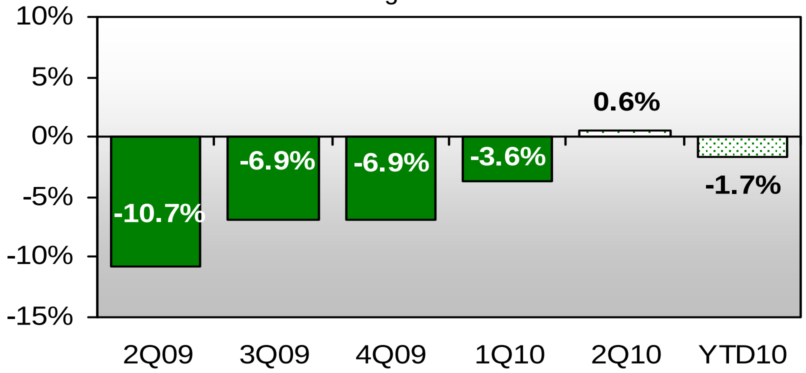
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



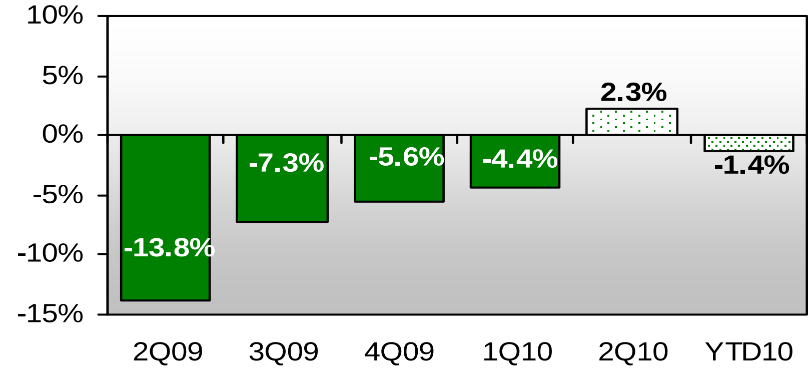
*includes firm wholesale load

Normalized Load Trends by Region

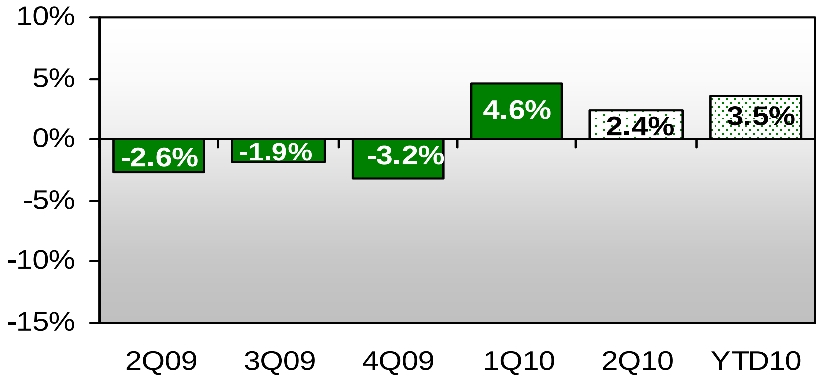
Reg East Total Normalized GWh Sales*
% Change vs. Prior Year



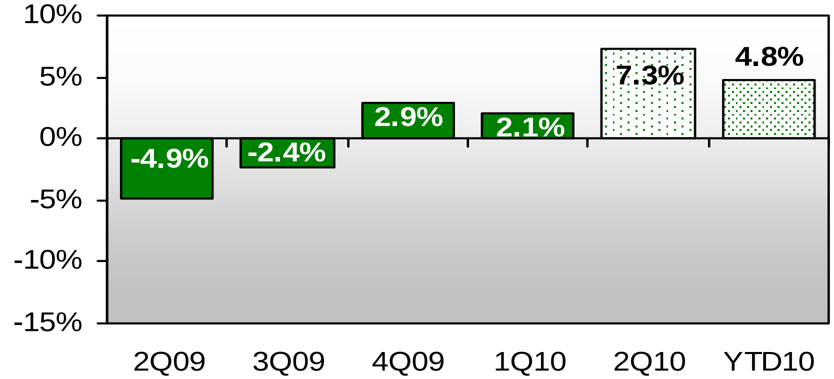
Ohio Total Normalized GWh Sales*
% Change vs. Prior Year



Reg West Total Normalized GWh Sales*
% Change vs. Prior Year



Texas Wires Total Normalized GWh Sales*
% Change vs. Prior Year



*includes firm wholesale load

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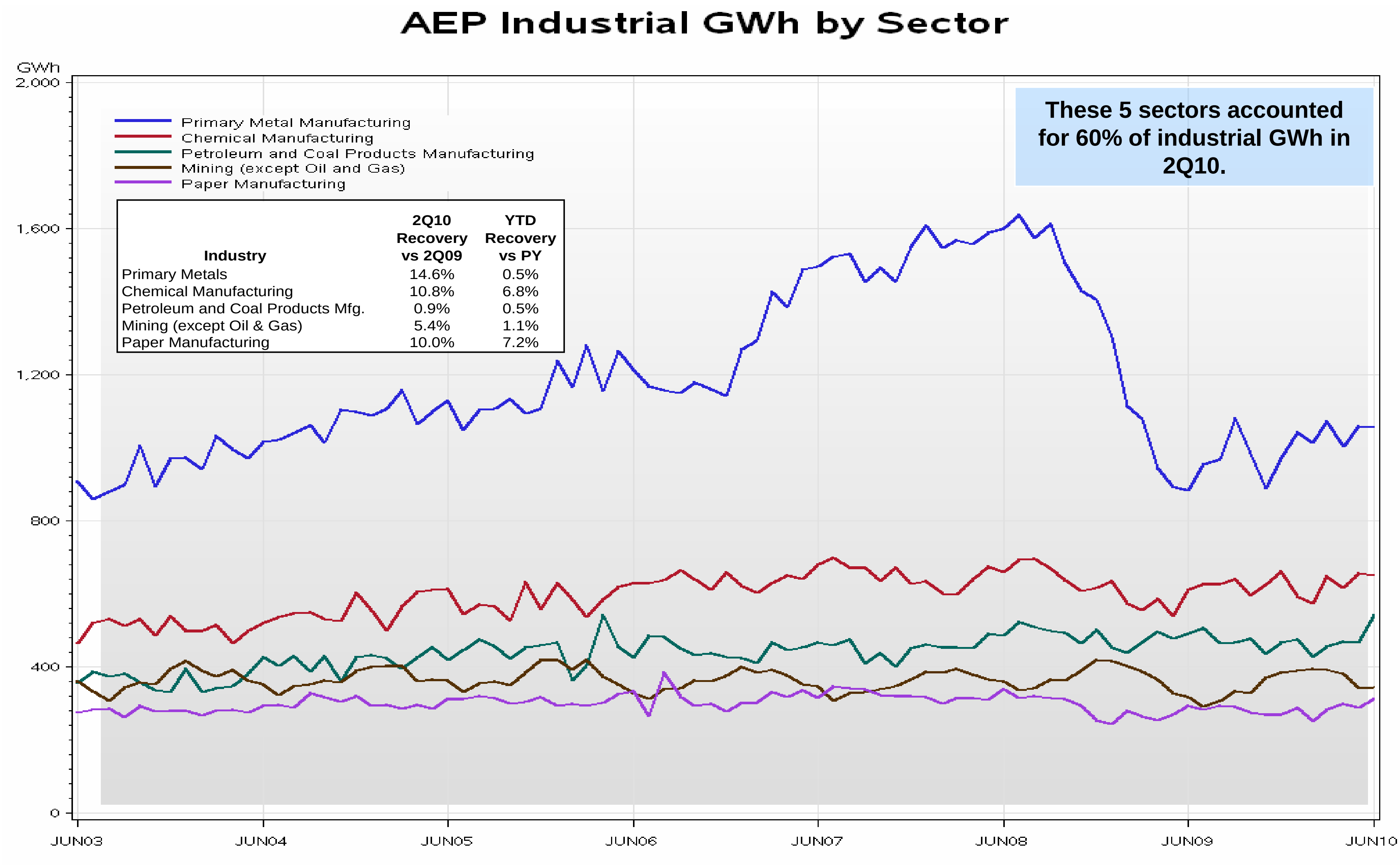
Industrial Sales



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

Off System Sales Gross Margin Detail

2Q10

	2Q09 GWh	2Q09 Realization	2Q09 ($millions)	2Q10 GWh	2Q10 Realization	2Q10 ($millions)
OSS Physical Sales	3,622	$ 10.13	$ 37	3,980	$ 11.21	$ 45
Marketing/Trading	-		$ 52	-		$ 31
Pre-Sharing Gross Margin	3,622		$ 88	3,980		$ 76
Margin Shared			$ (19)			$ (18)
Net OSS			$ 70			$ 58

- Physical off-system sales margins exceeded last year by $8M
- Volumes up 10% versus last year led by a 37% increase in June
- Improved AEP/Dayton Hub pricing: 13% increase in liquidation prices
- Lower Trading & Marketing results by $20M

YTD10

	YTD09 GWh	YTD09 Realization	YTD09 ($millions)	YTD10 GWh	YTD10 Realization	YTD10 ($millions)
OSS Physical Sales	6,213	$ 12.91	$ 80	8,724	$ 12.24	$ 107
Marketing/Trading	-		$ 93	-		$ 69
Pre-Sharing Gross Margin	6,213		$ 173	8,724		$ 176
Margin Shared			$ (42)			$ (44)
Net OSS			$ 131			$ 132

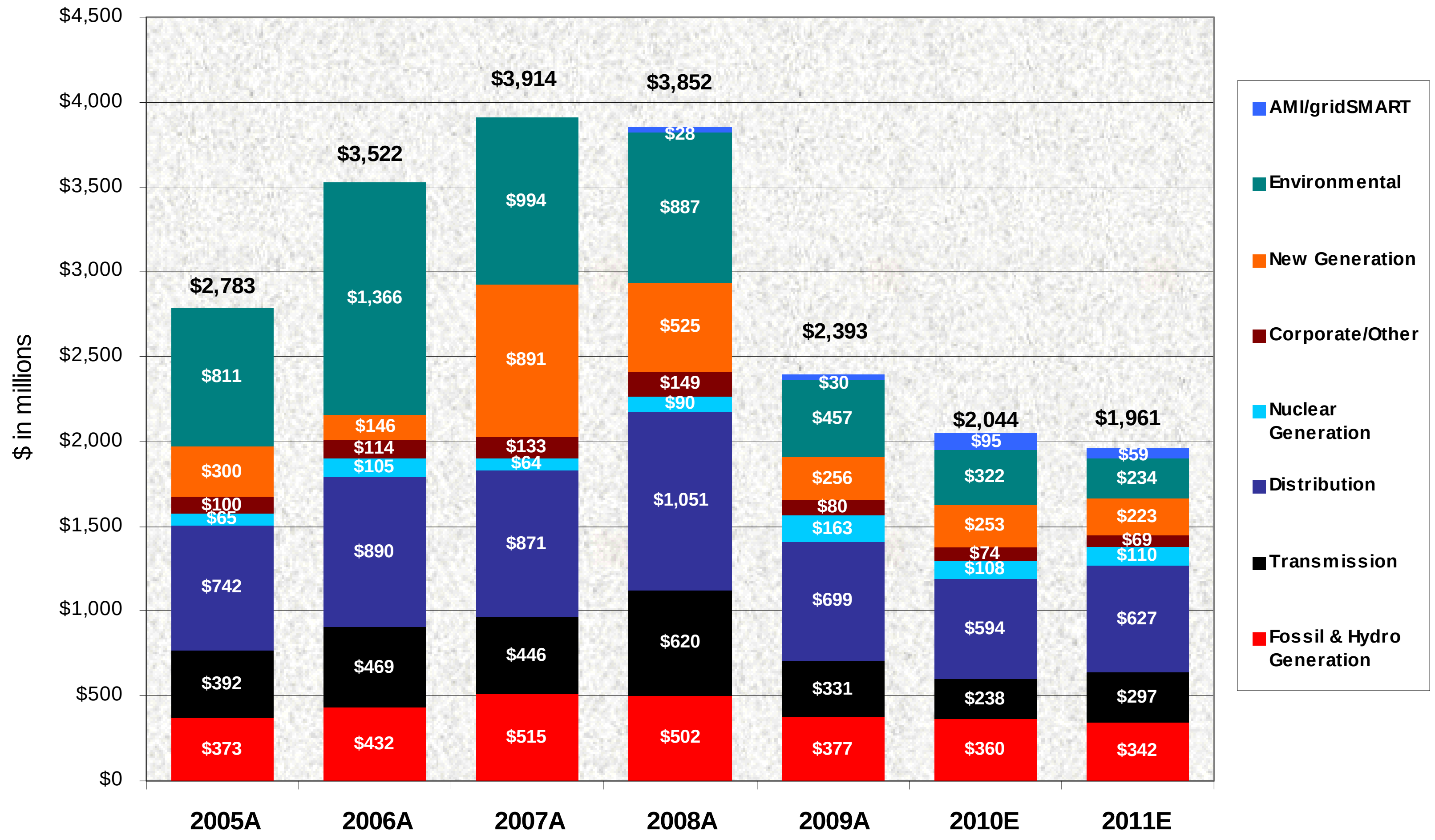
- Physical off-system sales margins exceeded last year by $27M
- Volumes up 40% versus last year
- Improved AEP/Dayton Hub pricing: 5% increase in liquidation prices
- Lower Trading & Marketing results by $24M

* May not foot due to rounding

Outlook

- Retail Load Volume & Margin recovery slower than previously anticipated
- Off-System Sales margin challenged by market prices
- Rate Changes on target for remainder of the year
- O&M Cost Reduction & Restructuring Program
  - Severance of 2,461 employees
- Operating Company Refinements
- 2010 Earnings Guidance $2.80 - $3.20 per share

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

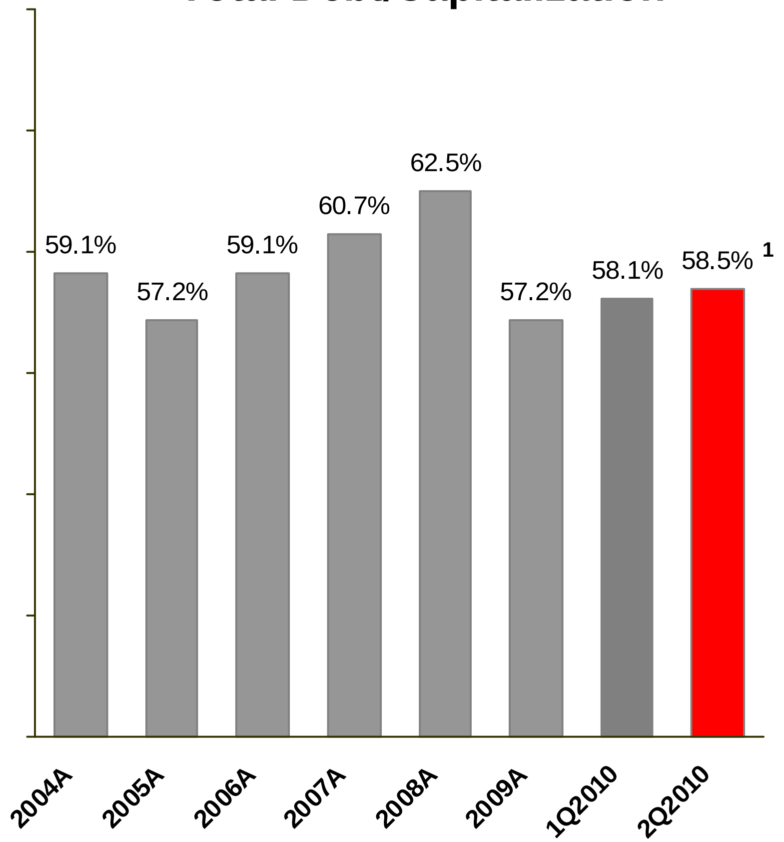
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.

Current Liquidity Summary As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company[(1)]	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

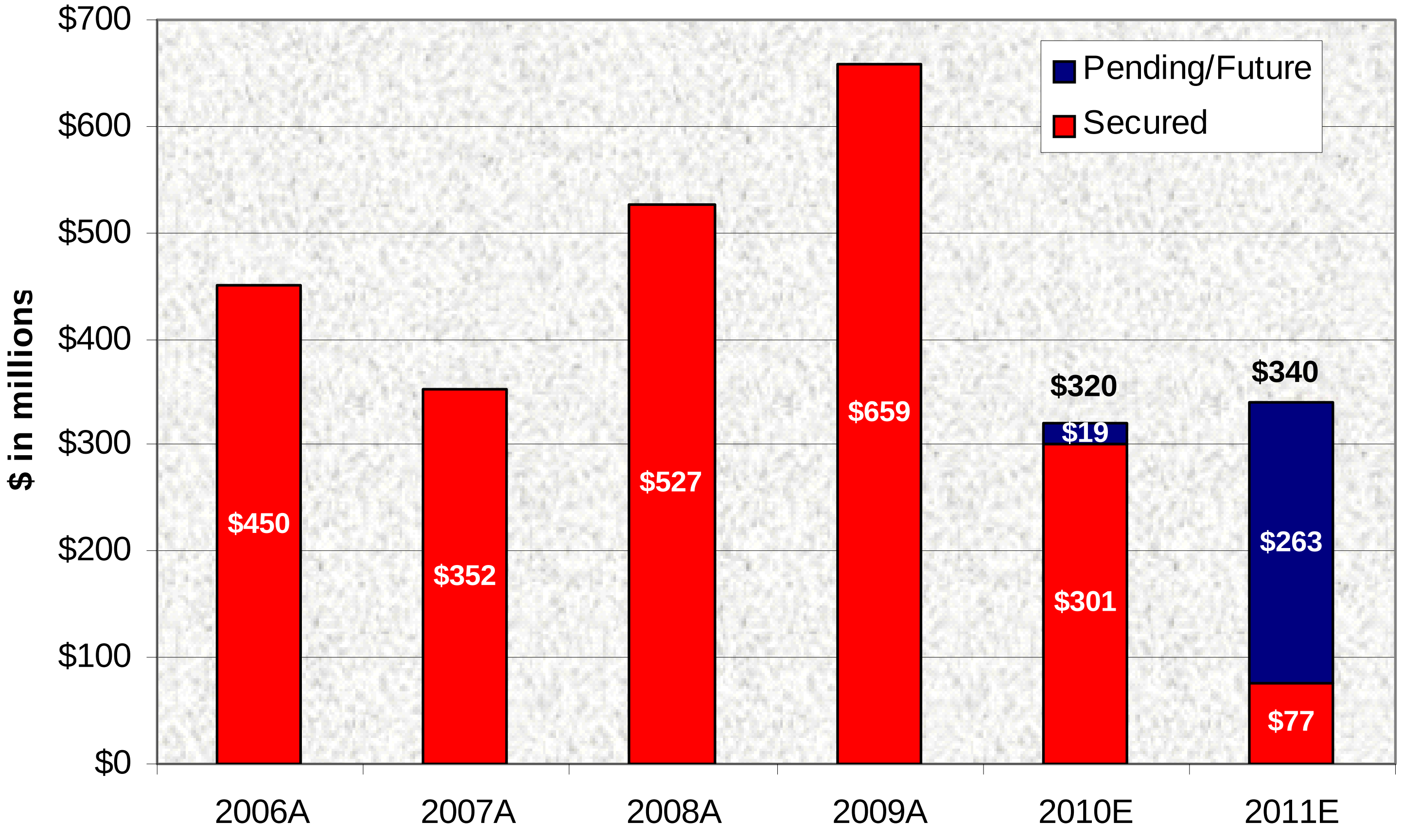
S=Stable

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Oklahoma, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Recent Rate Case Outcomes

APCo – Virginia Base Rate Case

	(Millions)
Company's Proposed Request	$ 167.0
Adjustments:	
Rate Base/Revenue Adj.	$ 3.5
Return on Equity 10.53% vs. 13.35%	$ (41.0)
Member Load Ratio	$ (15.0)
Capacity Rate	$ (12.8)
CCS Project	$ (9.8)
PJM Ancillaries	$ (7.4)
Environmental	$ (5.3)
ICP @ 50%	$ (4.2)
ADITC	$ (3.6)
Deferred Fuel Balance	$ (2.4)
Umbrella Trust	$ (1.3)
Deferred Wind Balance	$ (1.2)
Other Miscellaneous	$ (5.0)
Total Adjustments	$ (105.5)
Commission Order	$ 61.5

KPCo – Kentucky Base Rate Case

	(Millions)
Company's Proposed Request	$ 123.6
Adjustments:	
Wind Purchased Power Agreements	$ (14.5)
Depreciation	$ (10.7)
Return on Equity 10.5% vs. 11.75%	$ (8.5)
System Sales	$ (7.5)
Capacity Payments	$ (7.2)
Reliability Expenditures	$ (6.3)
Storm Adjustments	$ (5.6)
OATT Transmission	$ (2.2)
Other Miscellaneous	$ 2.6
Total Adjustments	$ (59.9)
Approved Settlement	$ 63.7

Current Base Rate Cases

$ in millions

I&M - Michigan

	Company Filing	Staff Testimony
Rate increase	**$63**	$34
Rate base/investment	$601	$585
Return on equity	11.75%	10.35%
Equity component	44.19%	44.14%
Riders requested	Numerous	Denied except Net Lost Revenues

Status: Case filed on January 27, 2010. Hearings scheduled for August 9-17, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Order due January 25, 2011.

APCo - West Virginia

	Company Filing	Staff Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

PSO - Oklahoma

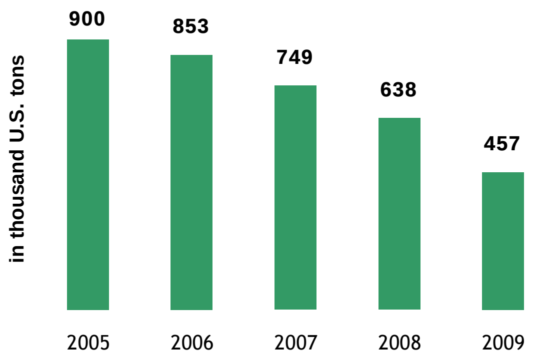
	Company Filing	Staff Testimony
Rate increase	**$83**	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

Status: Case filed on July 9, 2010. Procedural schedule pending.

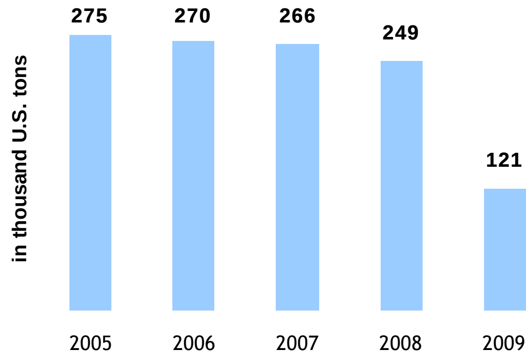
$370 million total base rate increase requests on file

Our Fleet Will Continue to Transform

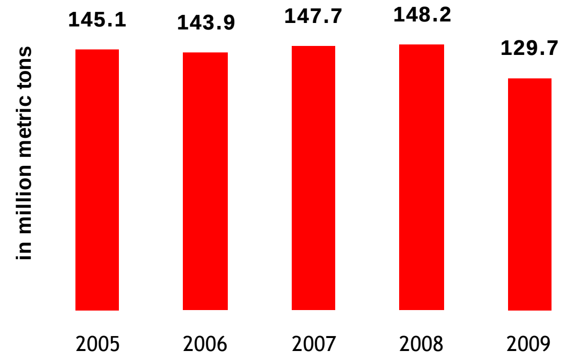
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



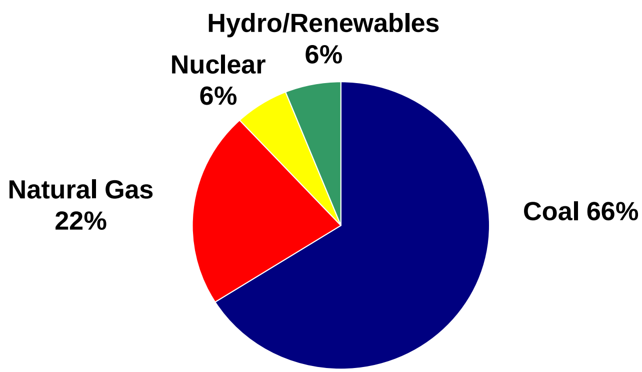
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



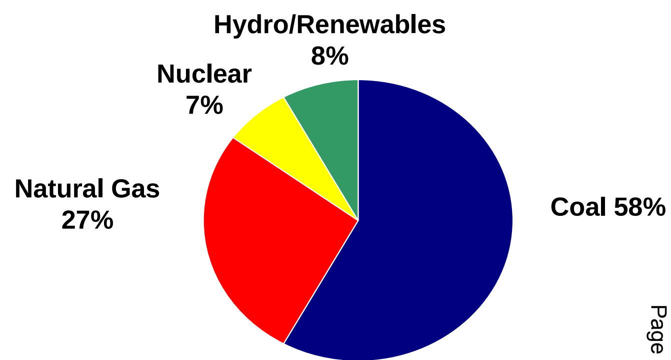
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ $5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

AEP
A CENTURY OF DIVIDENDS • 1910 • 2010

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The final estimated cost of the plant is $433 million including $49MM of AFUDC.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009

Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2017

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — COD: 2014

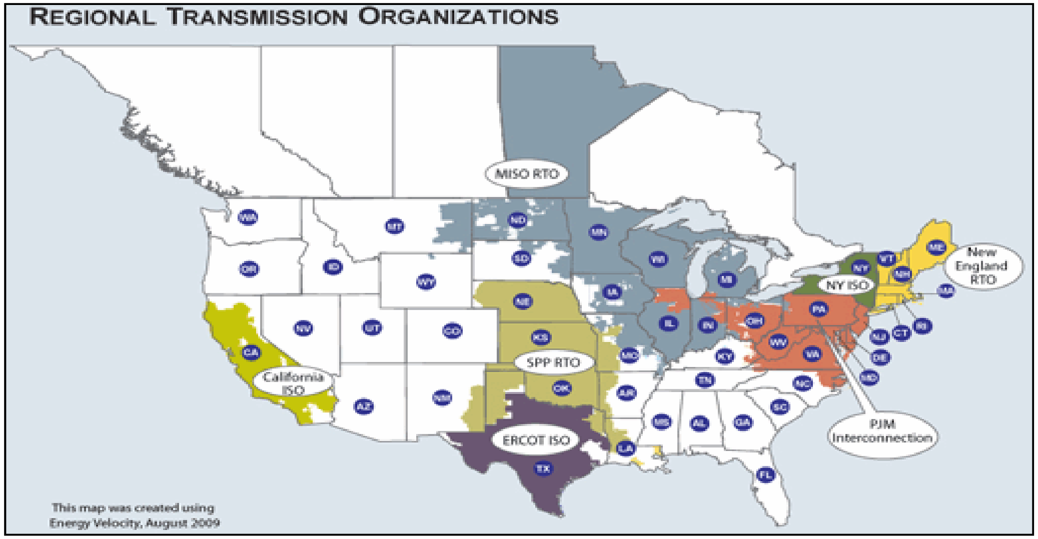
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

ACTIVE PROJECTS



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — COD: various

- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion

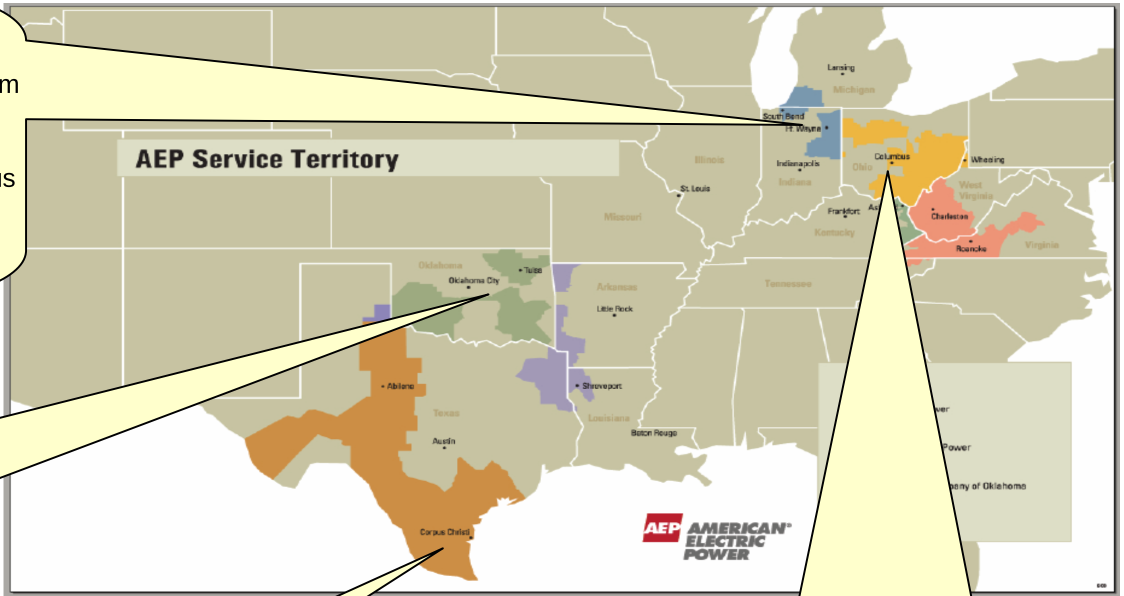
- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP | ERCOT | PJM | PJM/MISO

AEP's "Smart Grid" Deployment Status



Indiana Michigan Power (Completed, 12/2008)
- 10,000 AMI pilot program (GE meters, Silver Spring AMI Network)
- Distribution automation (GE ENMAC Distribution Management System and Integrated Volt-Var Control (IVVC))
- Two-tiered, two-season time-of-use tariffs with Critical Peak Pricing
- Customer web portal displaying 15-minute interval data up-to-previous day
- Field testing direct load control using Programmable communicating thermostats

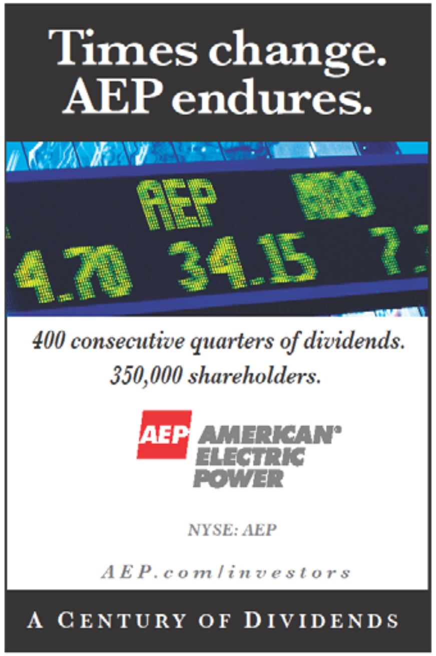
Public Service of Oklahoma (Final Planning)
- Applied for and approved for $7million low interest loan from OK Department of Commerce (ARRA source)
- Planned scope is 10,000 meters
- Increased penetration of In Home Devices for usage monitoring
- Distribution technologies include DA and IVVC

AEP Texas (underway)
- Legislature enabled and commission directing TDSPs to deploy advanced metering
- Enables REPs to innovate around electricity pricing and consumer technologies
- Filed and received approval from PUCT for 4-year deployment of 970,000 meters, $270 million project
- AEP Texas to collect a surcharge over 11 years
- Includes 10,000 in-home displays for low income customers
- Landis & Gyr Meters and AMI network

AEP Ohio (underway)
- PUCO-Approved 110,000 AMI deployment in NE Central Ohio
- Selected by DOE as a Smart Grid Demonstration Project for $75million in federal funding, 42-month deployment/evaluation
- Partnered with Battelle
- Full suite of distribution grid management technologies on over 70 distribution circuits
- Advanced technology deployment (Energy storage, PHEVs)
- Enhanced time-of-use tariffs, including a field trial of realtime pricing
- Home area networks & grid-friendly appliances

Value Proposition

- **Current Yield Opportunity of 4.7%[1]**
  - June 10th - 400th consecutive quarterly dividend was paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $36.10 on 07/29/2010

Goldman Sachs Annual Power & Utility Conference

June 2, 2005
The Four Seasons Hotel
Las Vegas, NV

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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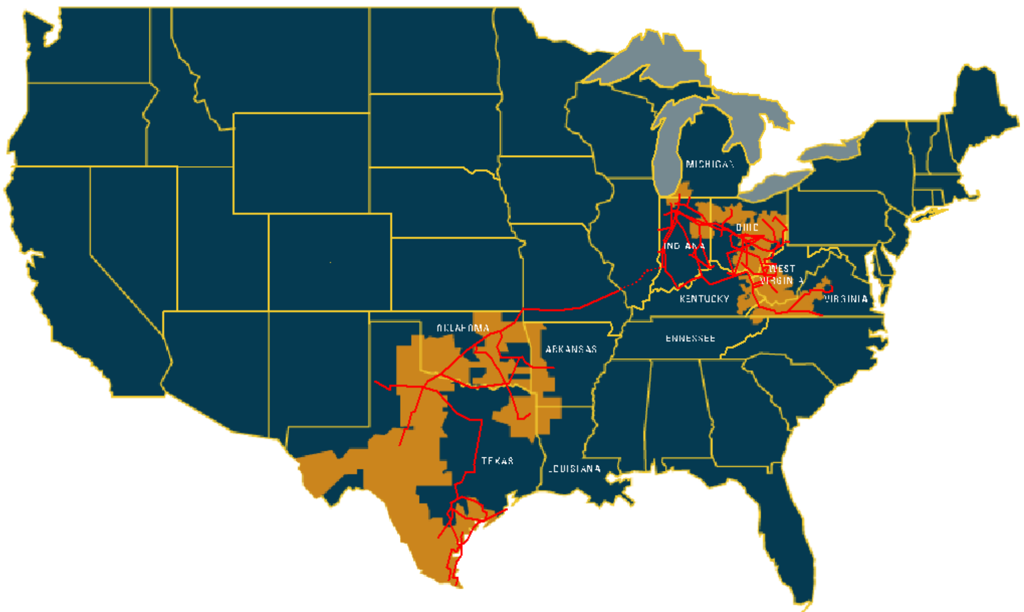
Asset Portfolio

Strength & Scale in Assets & Operations



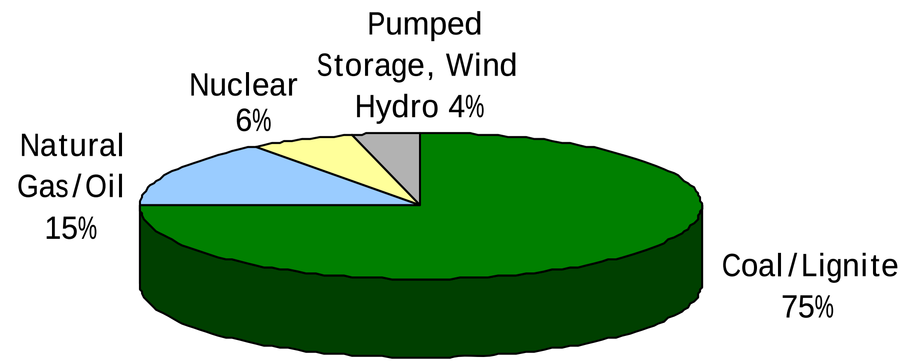
Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Introduction

The generation assets are co-managed by the Power Generation and the Commercial Operation Groups within AEP - each with a deliberate focus on roles and responsibilities within the organization

Power Generation
Operate 35,500 MW

Commercial Operations
Coal, gas, power and emissions markets

Fossil and Hydro Generation
Bill Sigmon, SVP

Generation Dispatch

Nuclear Generation

Energy Marketing
Brian Tierney, SVP

Engineering, Environmental & Technical Services
John McManus, VP Environmental Services

Fuel, Emissions & Logistics
Chuck Zebula, SVP

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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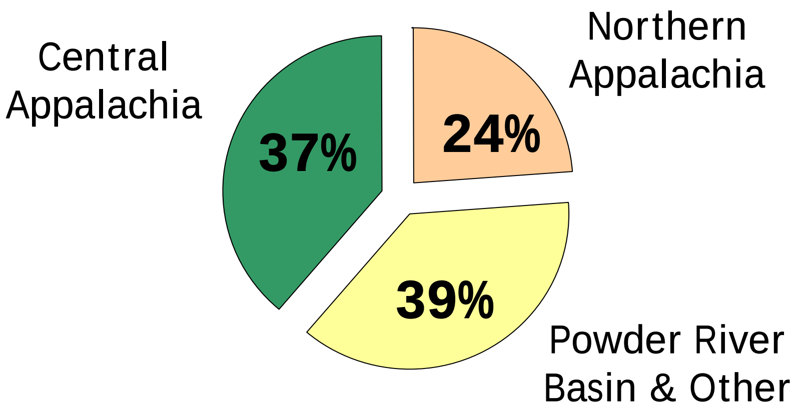
Coal Procurement

AEP SYSTEM

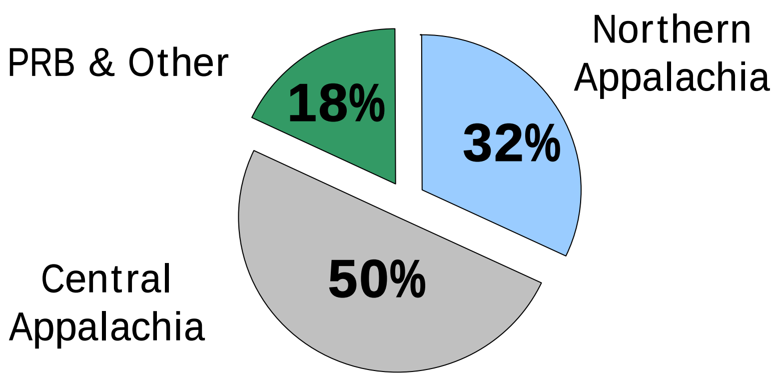


Coal Supply

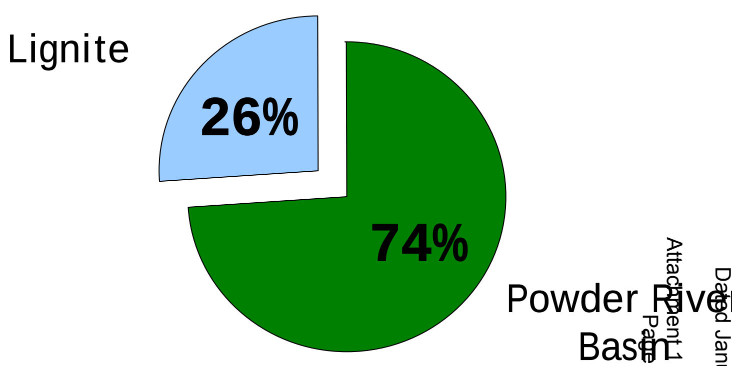
(on average)

- ➢Purchase 75 MM tons per year
- ➢Avg. delivered price ~ $28.50/ton in 2004
- ➢Essentially 100% purchased for 2005
- ➢Approximately 10% price increase in 2005

EASTERN SYSTEM

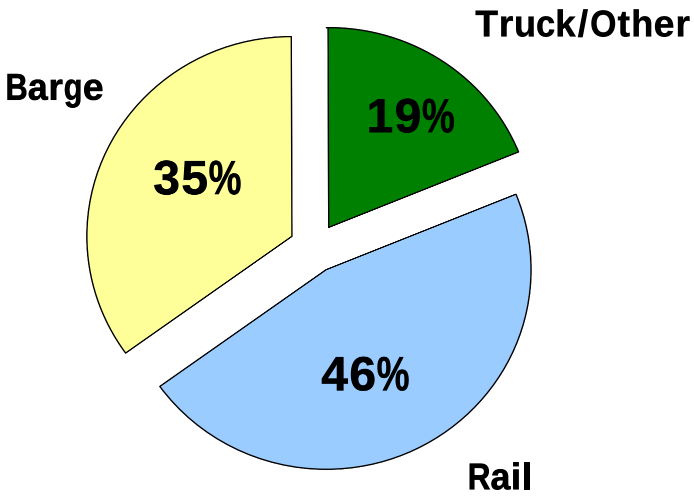


WESTERN SYSTEM



Coal Delivery Mix

DELIVERY MODE DIVERSITY
25 GW coal capacity



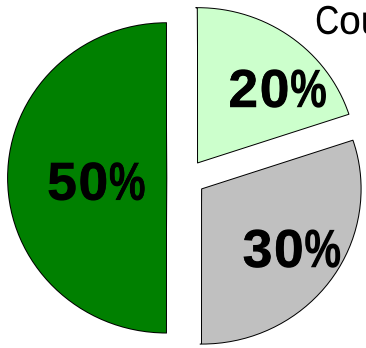
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM

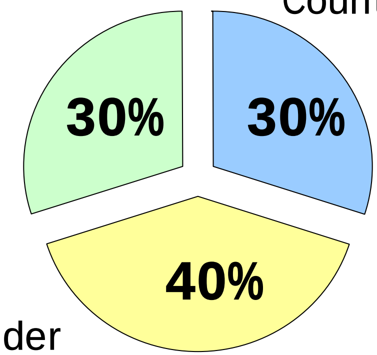


Fuel Cost Recovery
(on average)

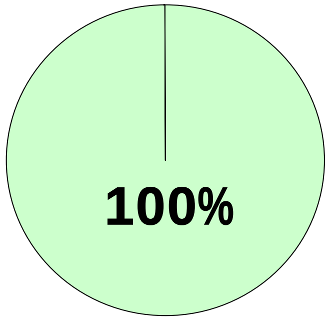
- ➢Fuel recovery varies by jurisdiction
- ➢70% of fuel cost is recoverable across the AEP System
- ➢Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

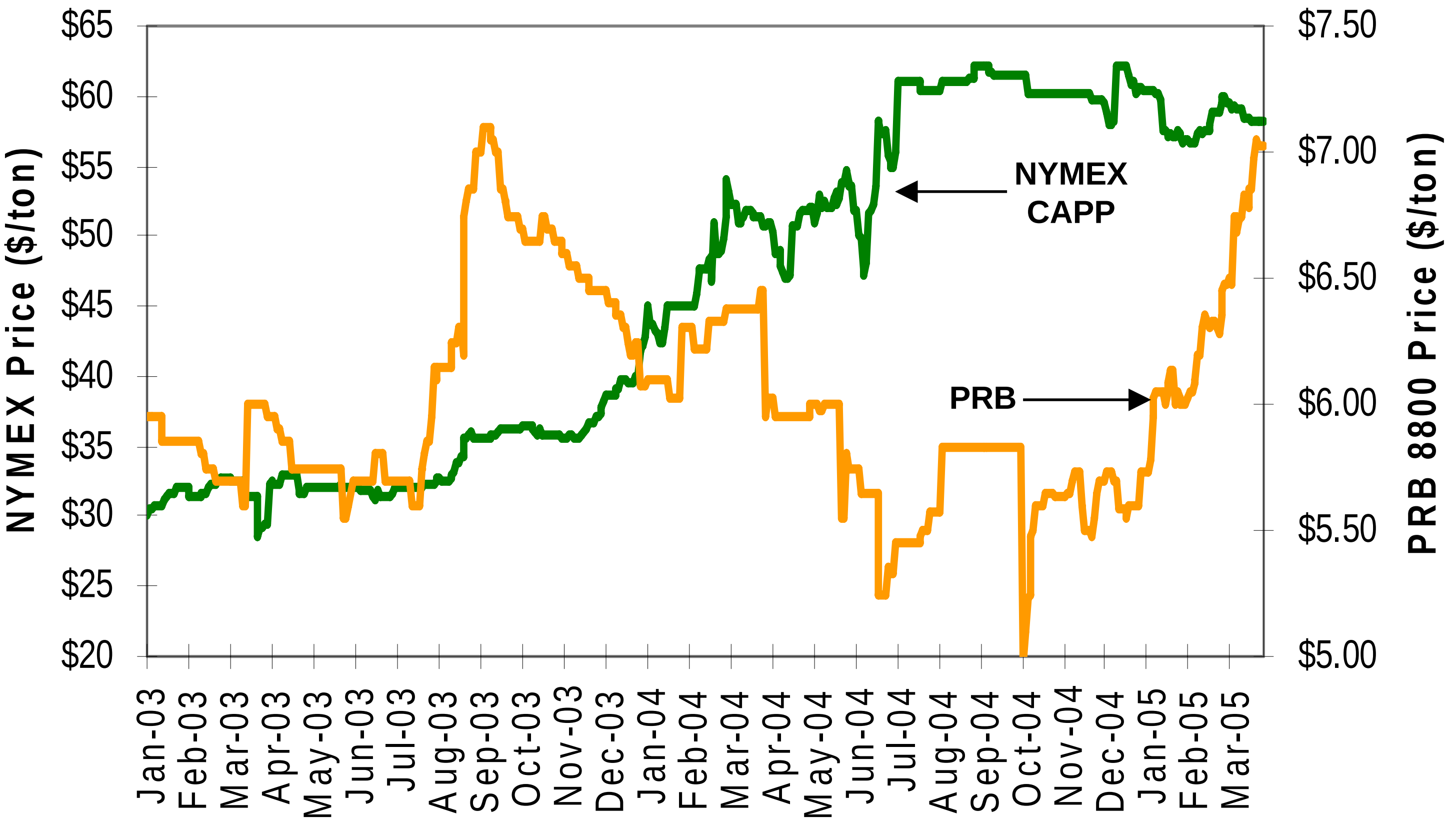


WESTERN SYSTEM



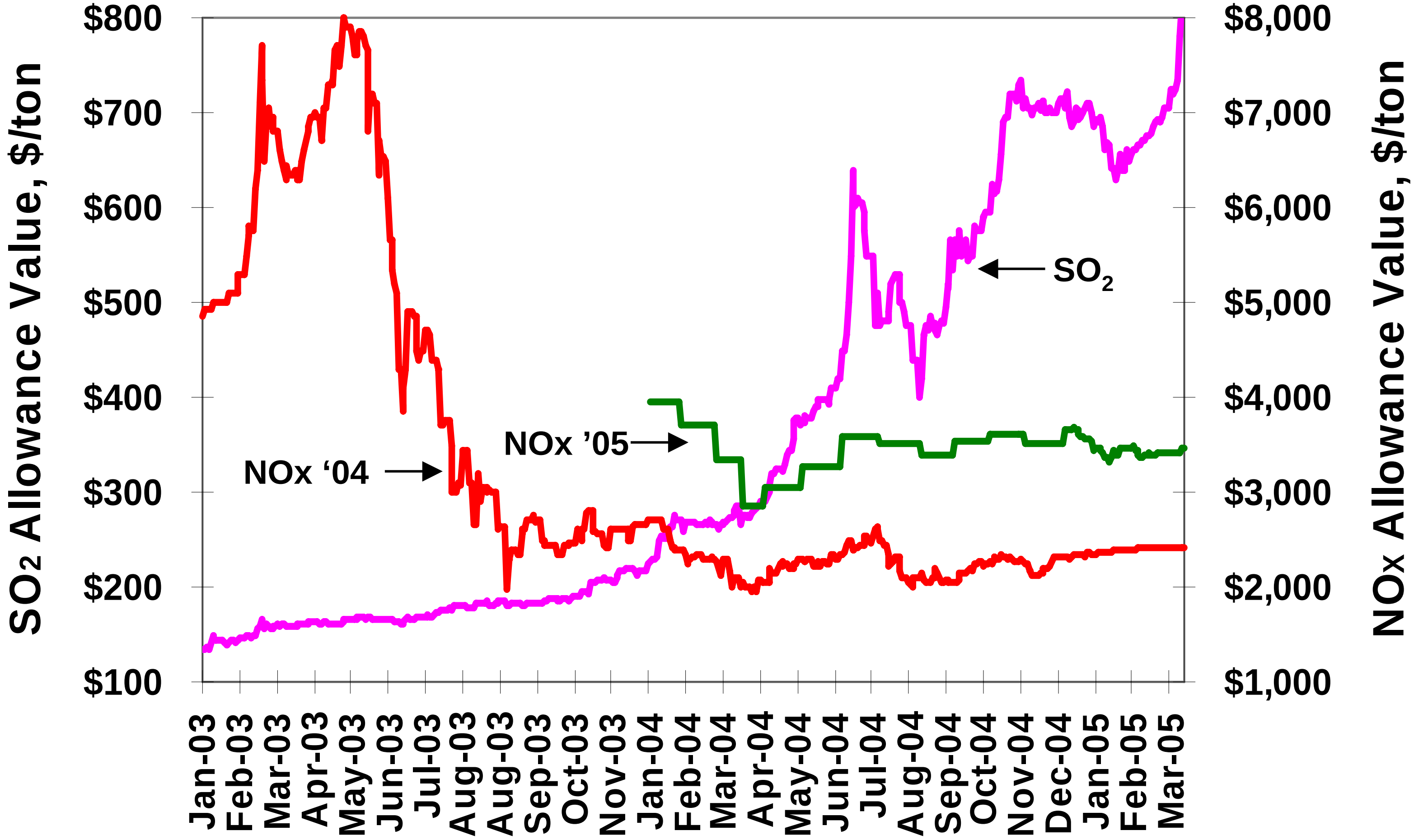
Coal Markets

The tale of two markets – one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



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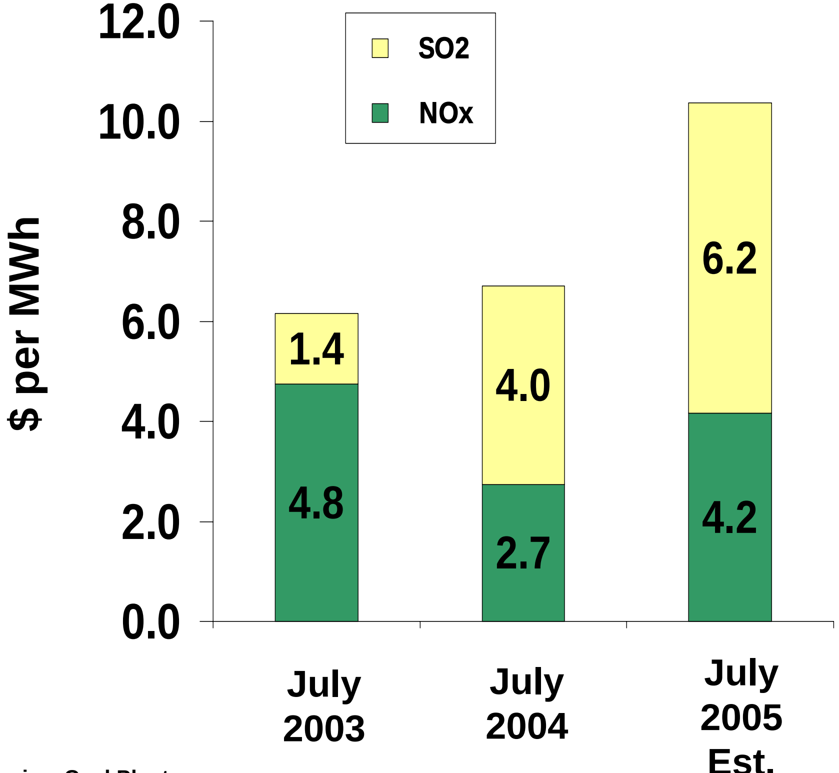
Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



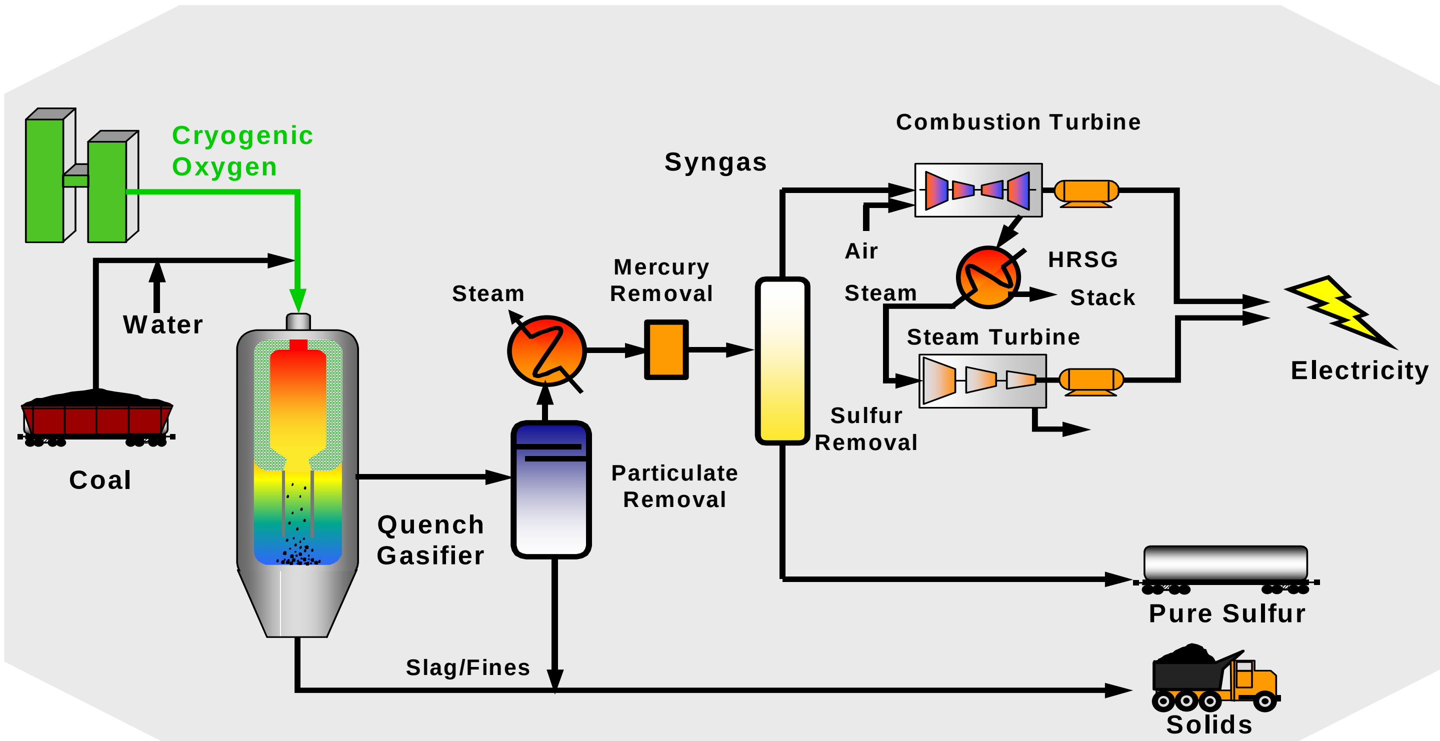
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 – 2 YEARS

Next Steps

<u>2005</u>

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:

1. Annual SO_2 Trading Program
2. Annual NO_x Trading Program
3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

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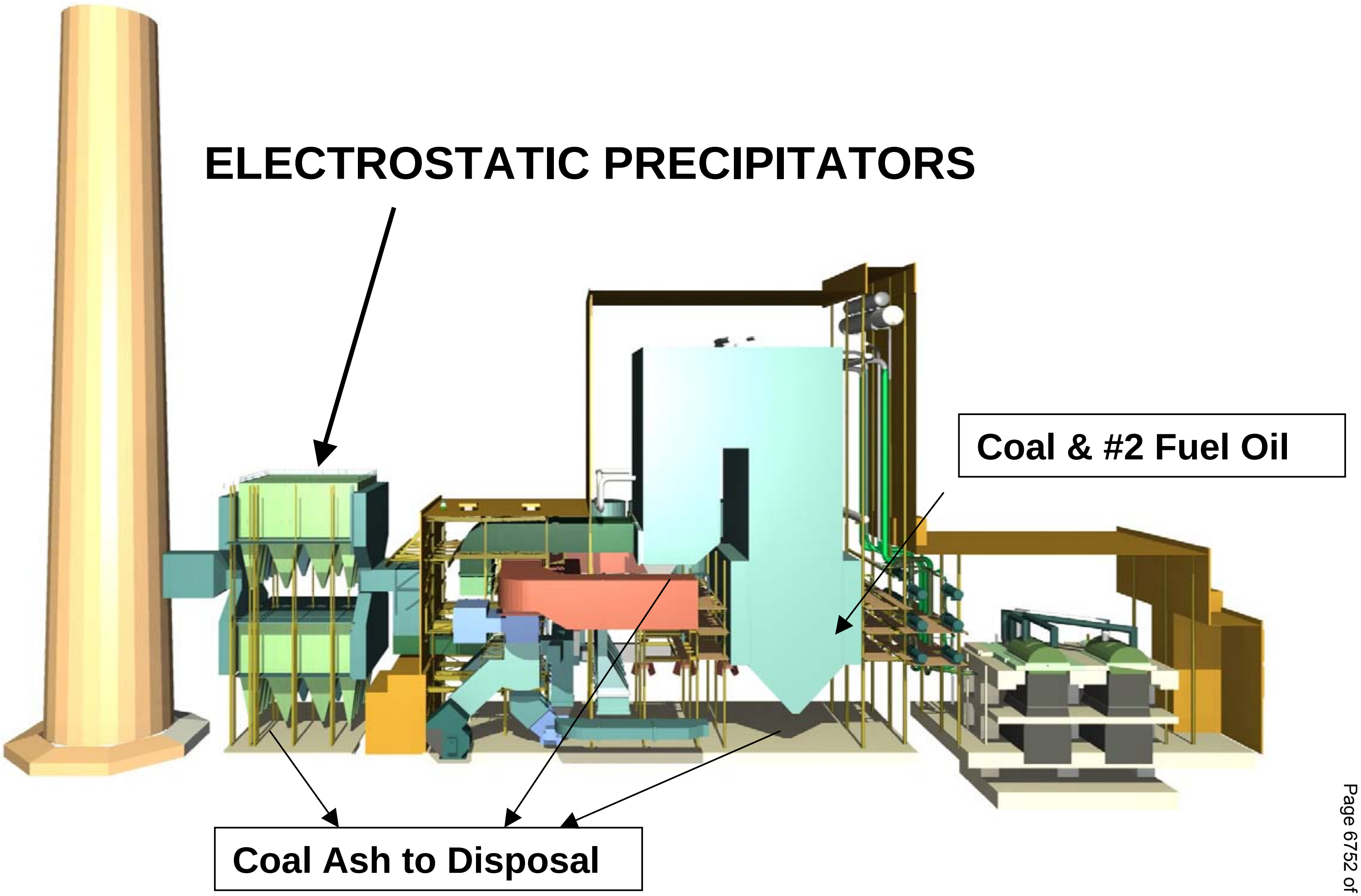
Mercury Rule

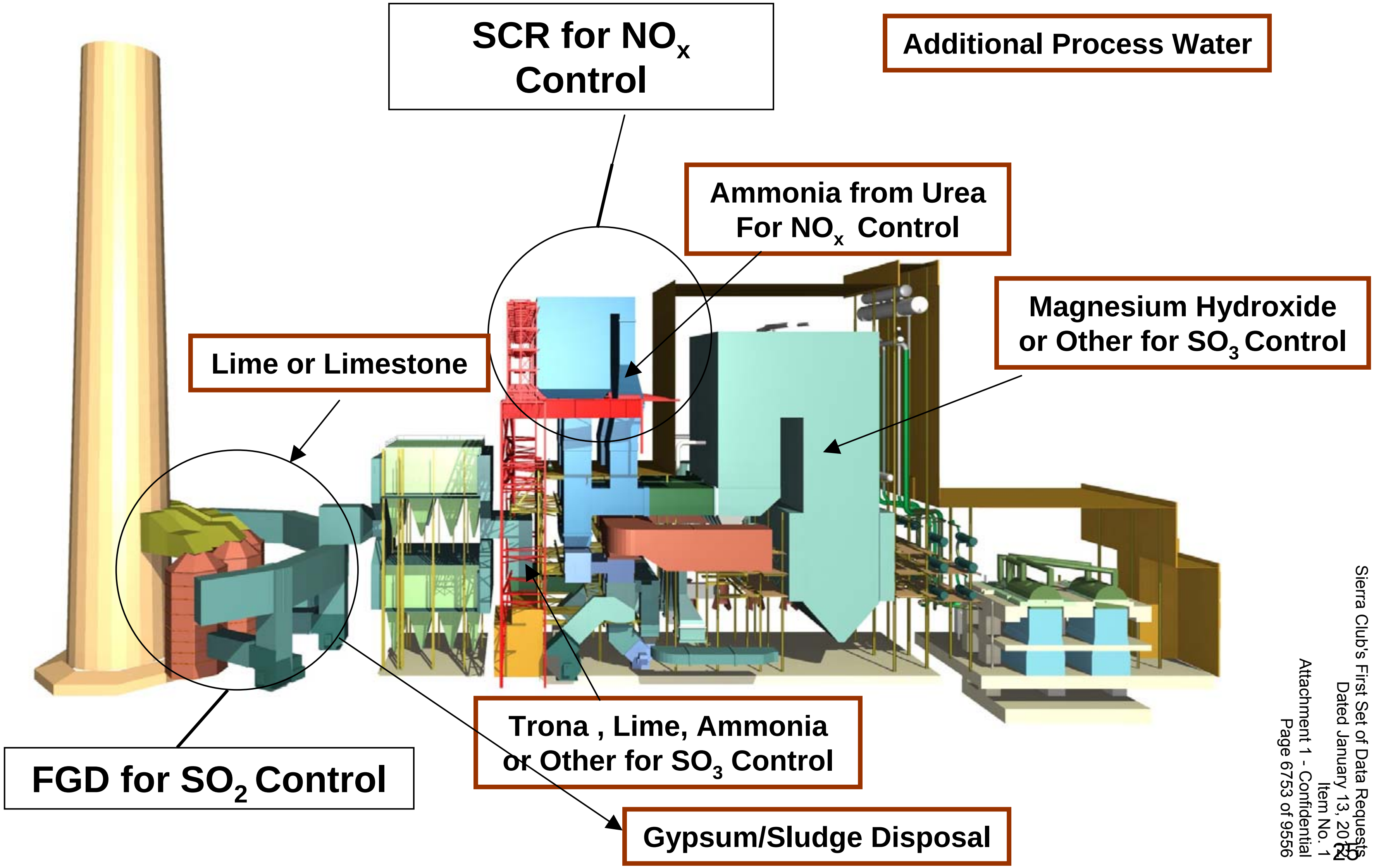
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s

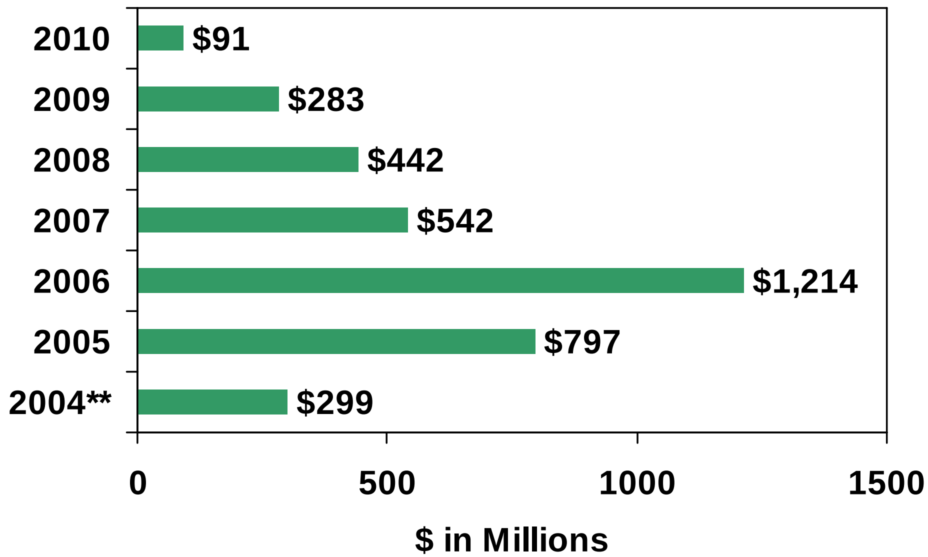


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)



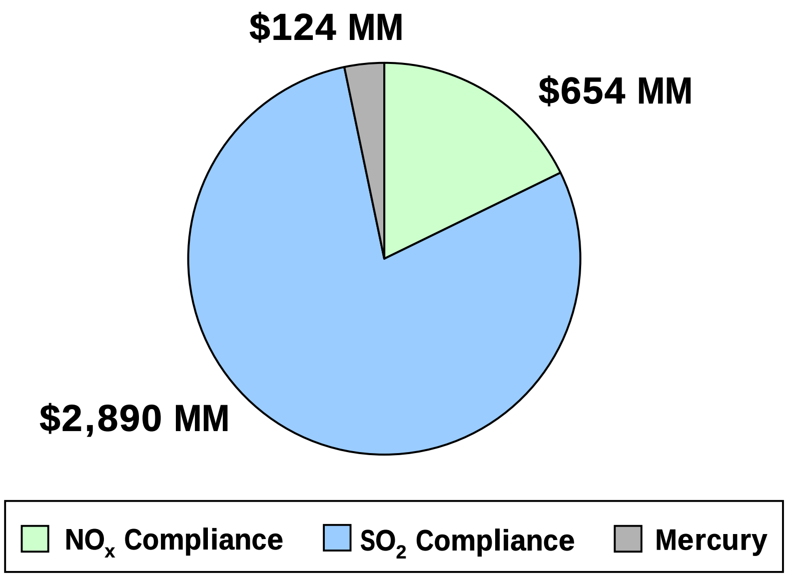
Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs
$1.9 Billion:
$0.6 billion for NOx
$1.2 billion for SO_2

Future Programs
$1.8 Billion:
$1.7 billion for SO_2
$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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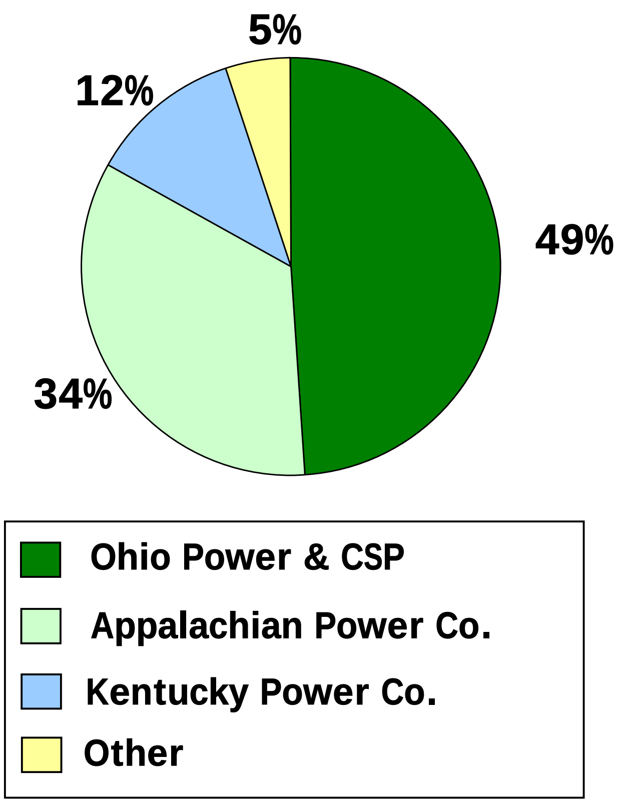
Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD	SCR

Completed

FGD:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD:

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR:

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

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Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
• Unbundled rates for default customers frozen until 12/31/2005
• Pursuant to RSP Plan approved by PUCO 1-26-05:
  • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  • CSP ”G” rates to increase 3% per year (2006-2008).
  • OP “G” rates to increase 7% per year (2006-2008).
  • Transmission rates can upon filing reflect change in RTO costs.
• No active fuel clause
• Application for IGCC plant recovery filed on 3-18-05, Hearings scheduled to begin 8-8-05.
	West Virginia (Regulated)
	• Base rates not frozen
	• Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
	• No active fuel clause

Virginia (Restructured) • Capped rates for default customers frozen through end of 2010 • Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms • Active annual fuel clause	**Indiana (Regulated)** • Subject to IURC order approving a settlement agreement, base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.
Kentucky (Regulated) • Base rates not frozen • Fuel clause, adjusted monthly • Environmental surcharge costs are adjusted monthly for approved environmental compliance plan • Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004	**Michigan (Restructured, but Regulated)** • Base rates not frozen. • Active annual fuel clause.
Tennessee (Regulated) • Base rates not frozen • Automatic fuel clause, adjusted monthly	

Regulatory Matrix - West

Texas (Regulated) • SWEPCO-Texas retail competition delayed until at least 2007 • Bi-annual fuel clause adjustment opportunity **Texas (Restructured)** • TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) • TCC wires rate case order expected in June 2005. • TCC final fuel reconciliation (July 98-Dec. 01) decision issued in April 2005. TCC will appeal decision. • TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC. • TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.	**Oklahoma (Regulated)** • General rate case filed Oct. 31, 2003 • On 5-2-05 the OCC issued an order approving a settlement agreement which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider. • 2001 Fuel review case •Hearings expected in August 2005. Scope expanded to cover 2002-2004 margin allocation issue. • 2003 Fuel review case • Likely to include motions to expand scope to include prudence review
Louisiana (Regulated) • Base rates capped through June 15, 2005 • Currently under a merger required financial review • Fuel clause, adjusted monthly	**Arkansas (Regulated)** • Base rates not frozen • Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Revenues				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

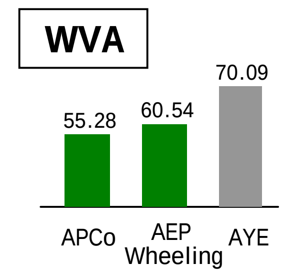
* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

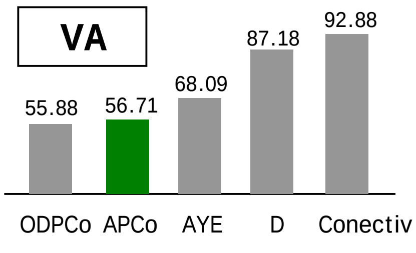
** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

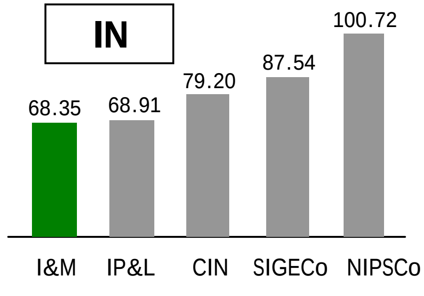
AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

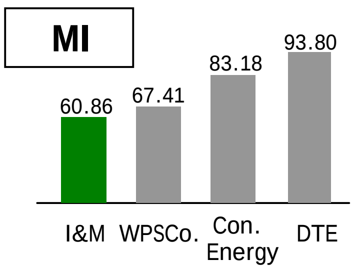
AEP: The Low Cost Provider

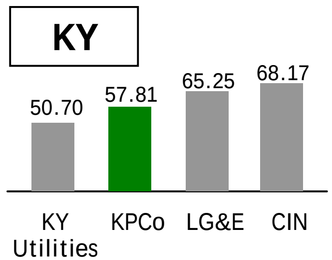
Regulated Rates

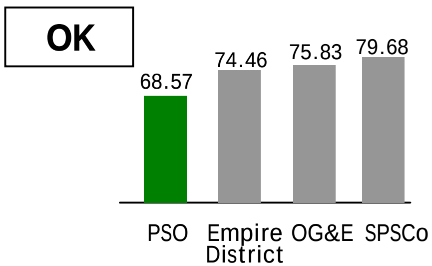


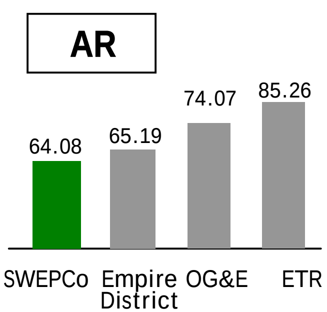


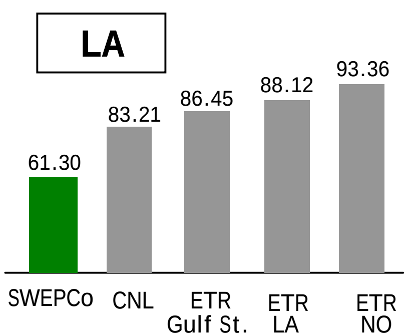


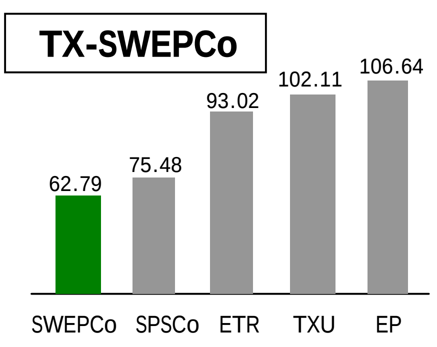




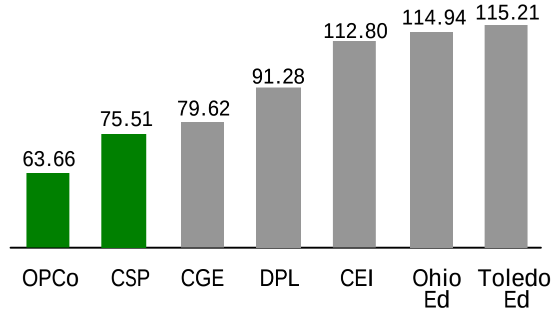








Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

Fossil fleet variable cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	(529)	***
Total from Investing	**$ (376)**	**$ (1,721)**	
Cash from Financing:			
Common Equity	17	(155)	****
Net Long Term Debt Issued/(Retired)	(1,829)	621	
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (129)**	
Net Change in Cash	**$ (556)**	**$ 73**	
Ending Cash Balance	**$ 420**	**$ 493**	

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

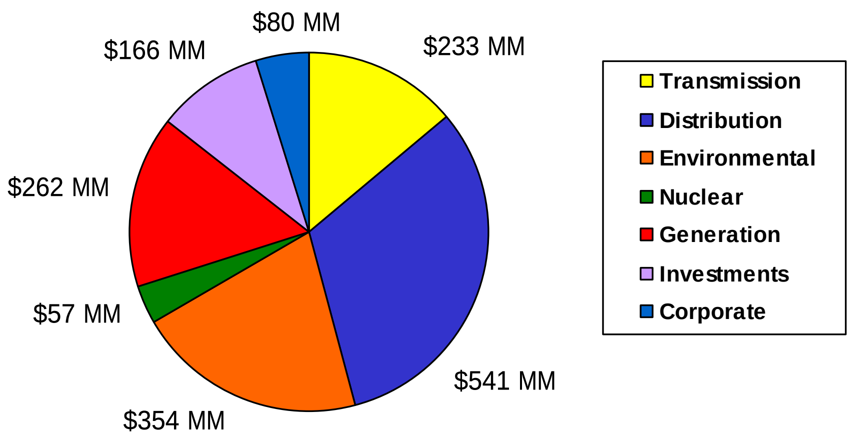
**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

***** Includes $550MM of parent debt reduction**

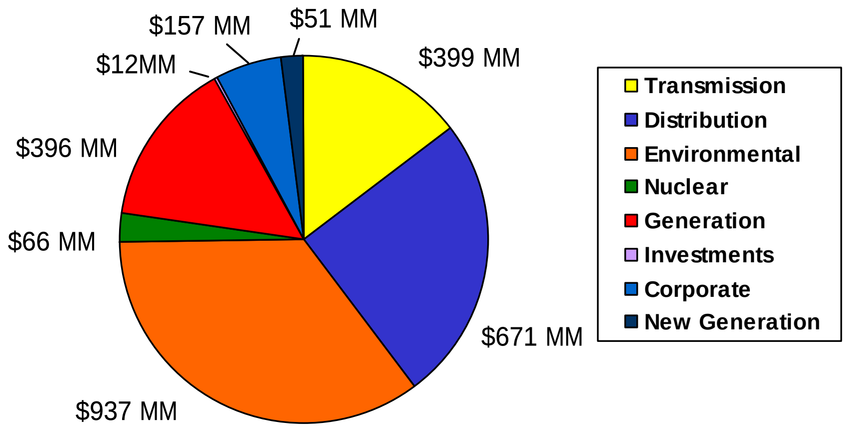
******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex

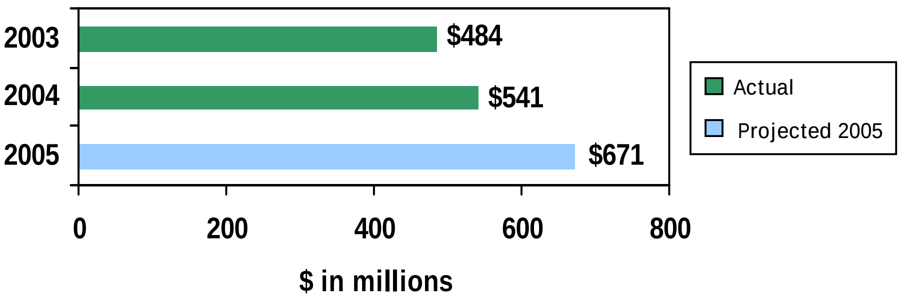
2004 Actual Totaled $1.69 Billion

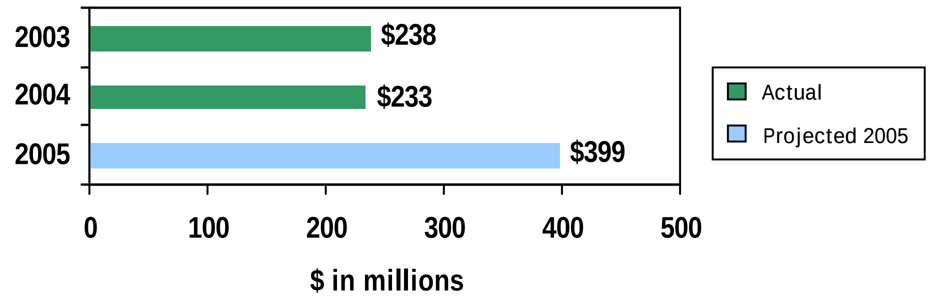


2005 Projected Totals $2.69 Billion



Energy Delivery Investment





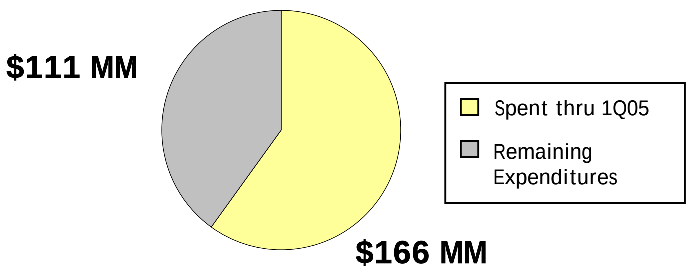
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**875,376,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Excludes $65.8 million of mortgage bonds due in 2005 that were defeased

(4) Excludes TCC securitization bonds

Capitalization

Capital Structure	Actual 12/31/04			Actual 3/31/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,359	-	12,359
Short-term Debt	23	-	23	19	-	19
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	8,268	8,268
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,378**	**8,329**	**20,707**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.8%***	***40.2%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	(66)	66	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,241	-	1,241
Securitization Bonds	(698)	-	(698)	(668)	-	(668)
Spent Nuclear Fuel Trust	(229)	-	(229)	(230)	-	(230)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,264**	**8,918**	**21,182**	**12,361**	**8,605**	**20,966**
% of Adjusted Capitalization	***57.9%***	***42.1%***	***100.0%***	***59.0%***	***41.0%***	***100.0%***
Assuming Available Cash is used to Pay Down Debt	(420)	-	(420)	(1,258)	-	(1,258)
Capitalization net of Cash	**11,844**	**8,918**	**20,762**	**11,103**	**8,605**	**19,708**
% of Capitalization net of Cash	***57.0%***	***43.0%***	***100.0%***	***56.3%***	***43.7%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 59.0% AT 3/31/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

<u>2005</u>

- *Outcome of pending regulatory proceedings*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Earnings Guidance

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Goldman Sachs & Clients Office Visit
Columbus, OH
April 6, 2010

765-kV Transmission Line (Wyoming-Jacksons Ferry)

General JM Gavin Coal Plant (OH)

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filing made in Ohio
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

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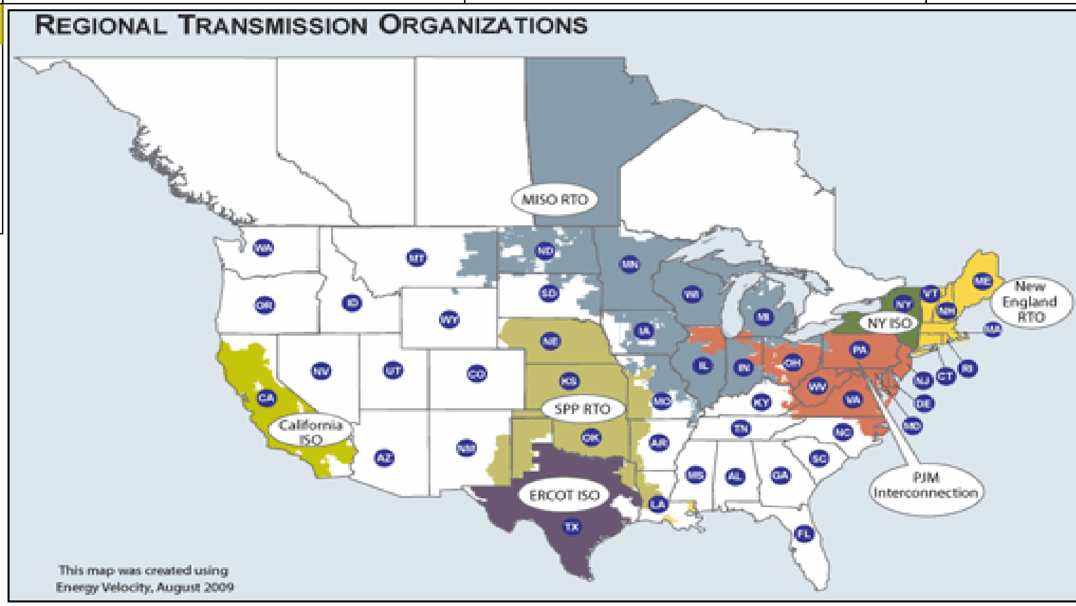
JV Strategy – Nationwide Grid Expansion

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2017	**PATH-WV** COD: 2014	**Pioneer** COD: 2015
110 miles of 765 kV *Partners: Westar (50%) & Electric Transmission America (50%)* *Estimated Cost: $400 million* *ROE: 12.8%*	*345 kV ERCOT Expansion* *Partner: MidAmerican Energy (50%)* *Estimated Cost: $1.4 billion* *ROE: 9.96%*	*275 miles of 765 kV* *Partner: Allegheny Energy (50%)* *Estimated Cost: $1.2 billion* *ROE: 14.3%*	*240 miles of 765 kV* *Partner: Duke Energy (50%)* *Estimated Cost: $1 billion* *ROE: 12.54%*

Tallgrass COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
Regional Expansion of 765 kV Backbone	*Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	*Regional Expansion of 765 kV, 500 kV and 345 kV systems*	*700 miles of Proposed 765 kV*

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Electric Transmission Texas, LLC

Overview:

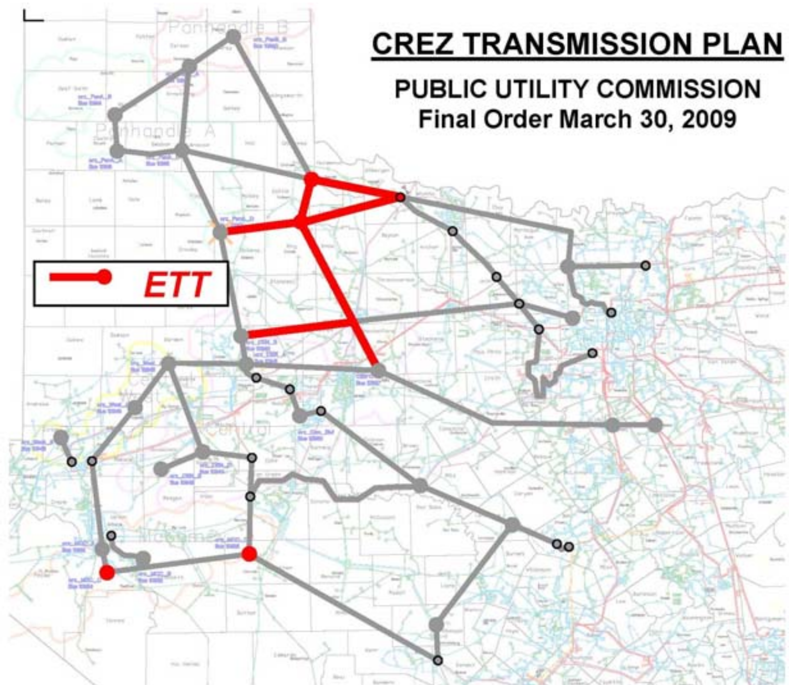
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2017: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects pending transfer in service 2010-2013: $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT
Electric Transmission Texas

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EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

Potomac-Appalachian Transmission Highline

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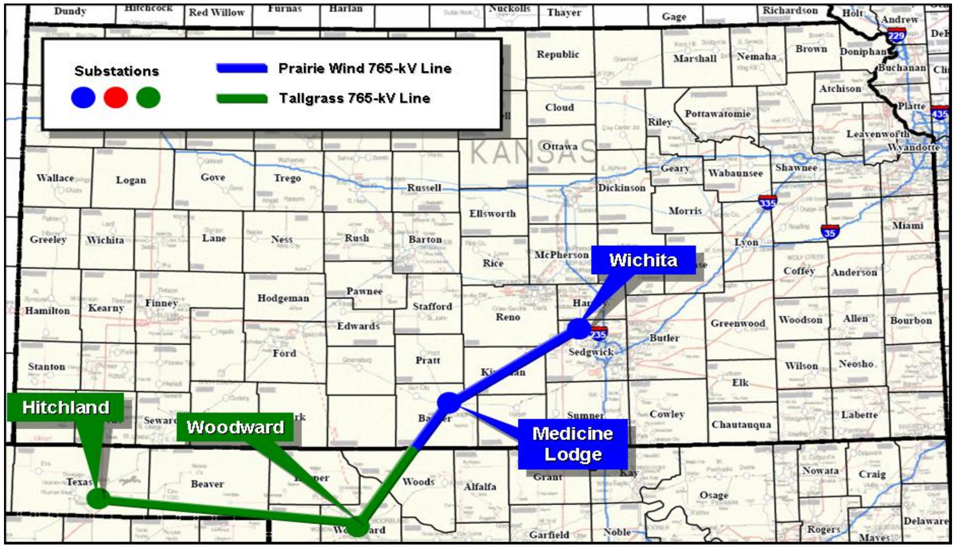
Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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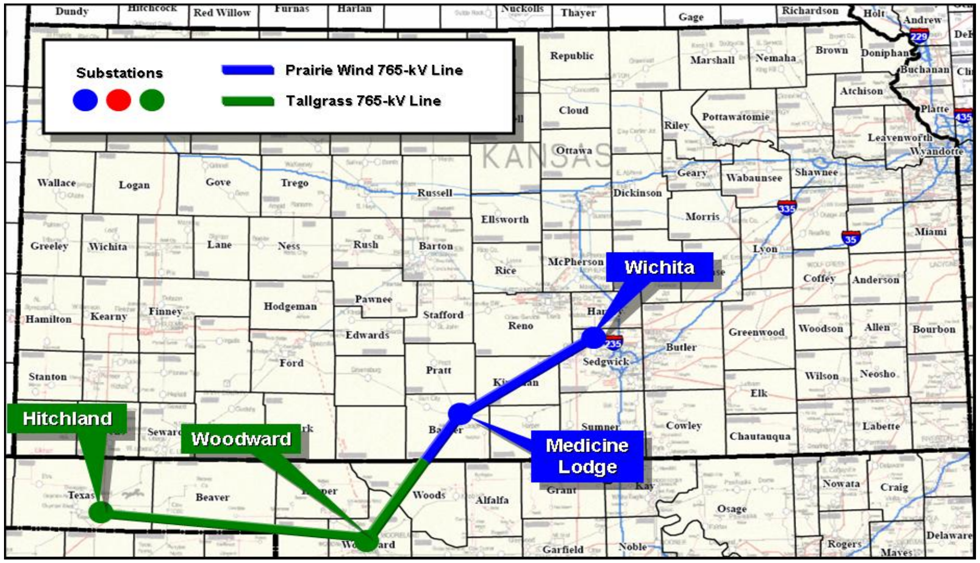
Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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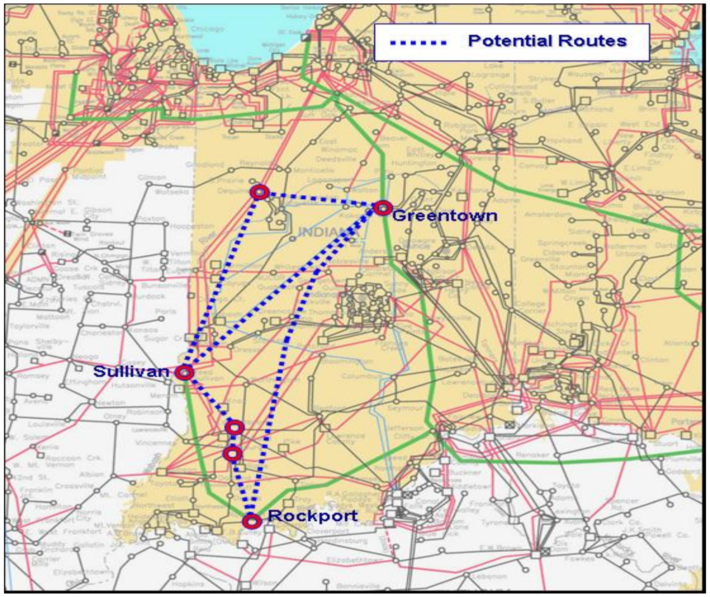
Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

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Upper Midwest EHV Development—SMART Study

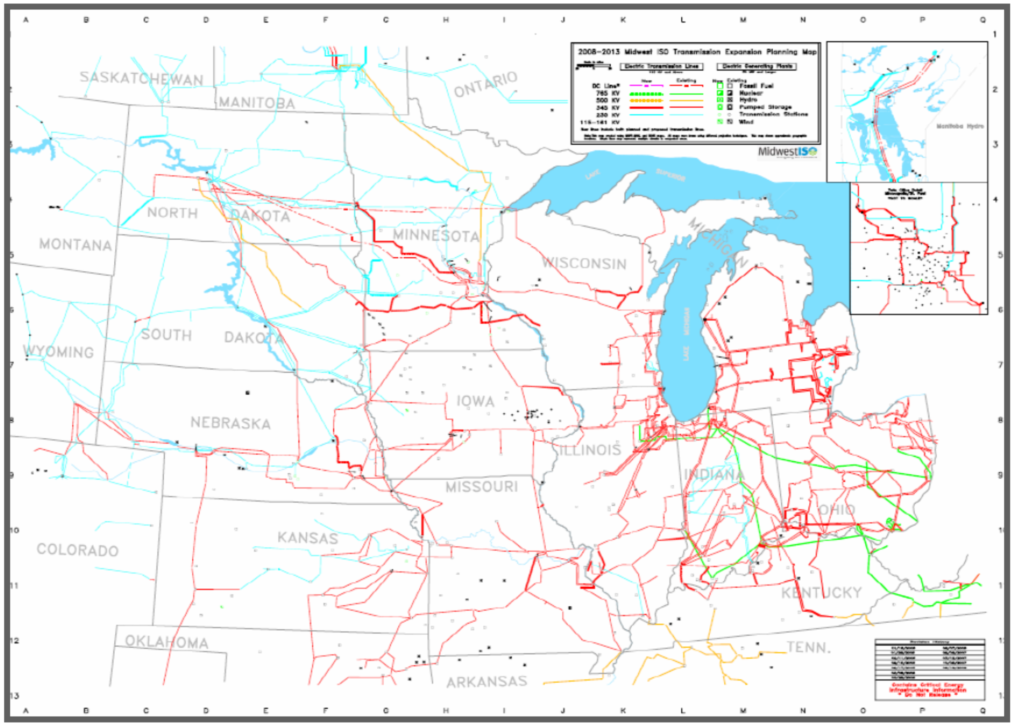
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2Q2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

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Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

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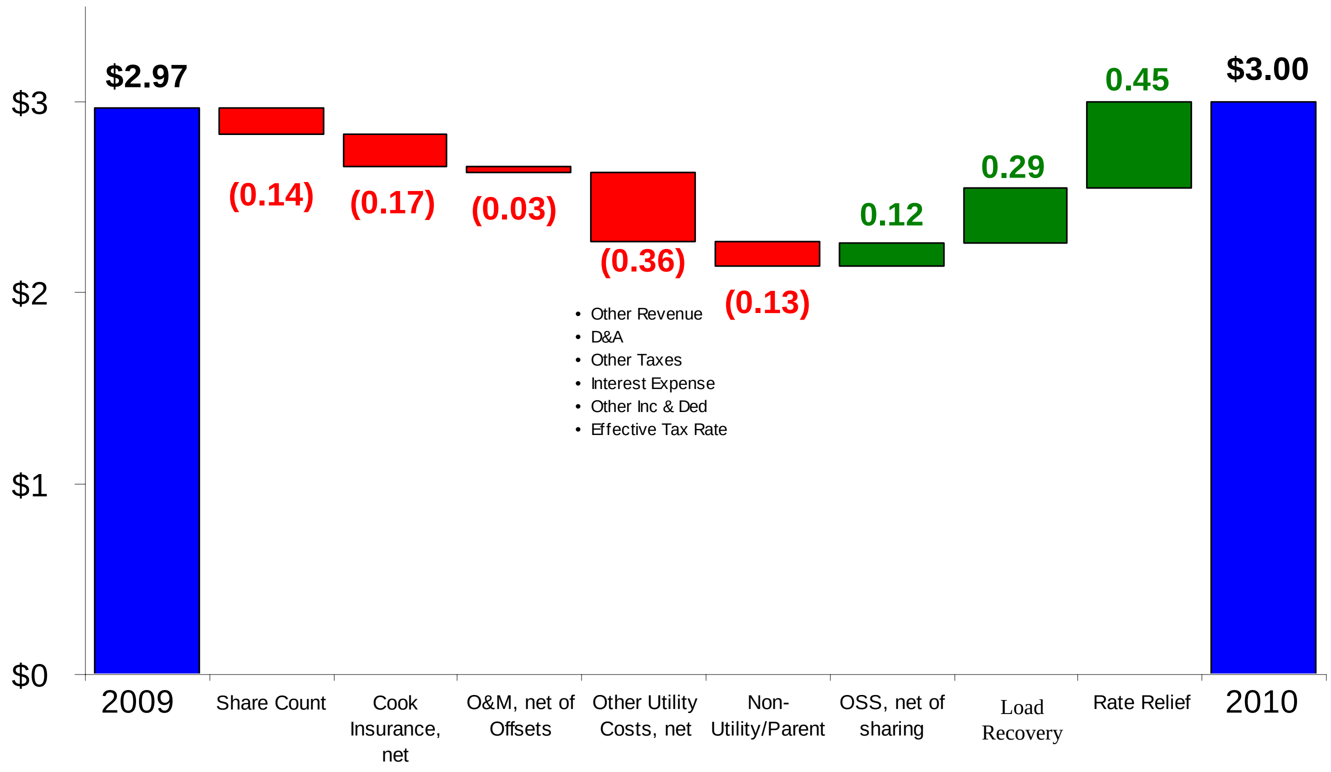
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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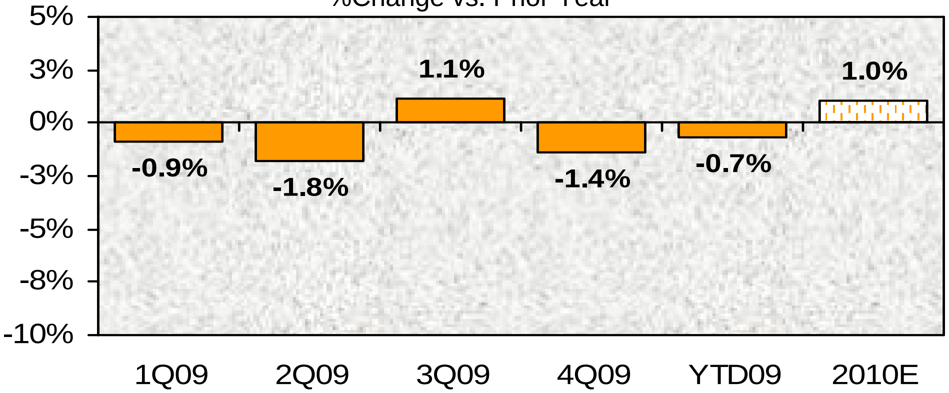
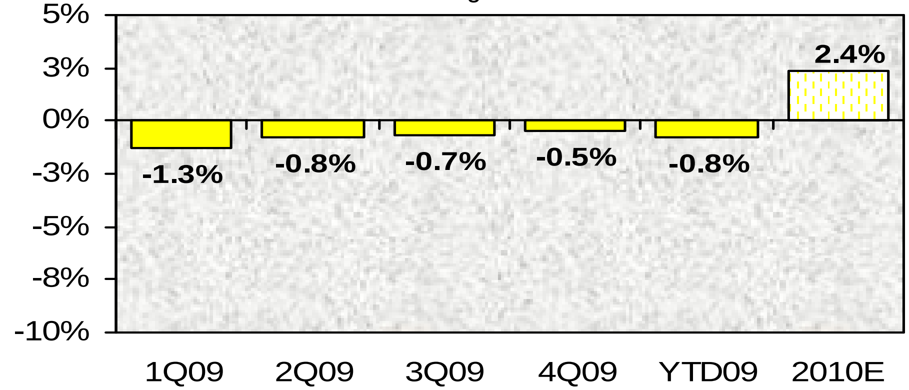
Normalized Load Trends

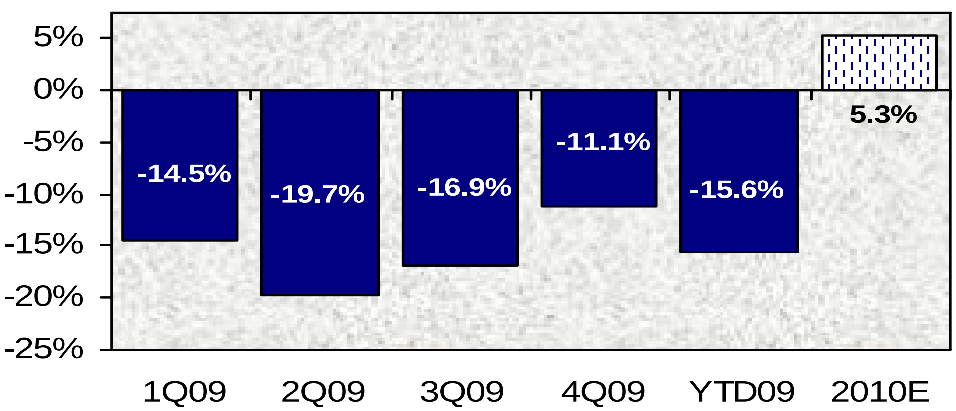
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



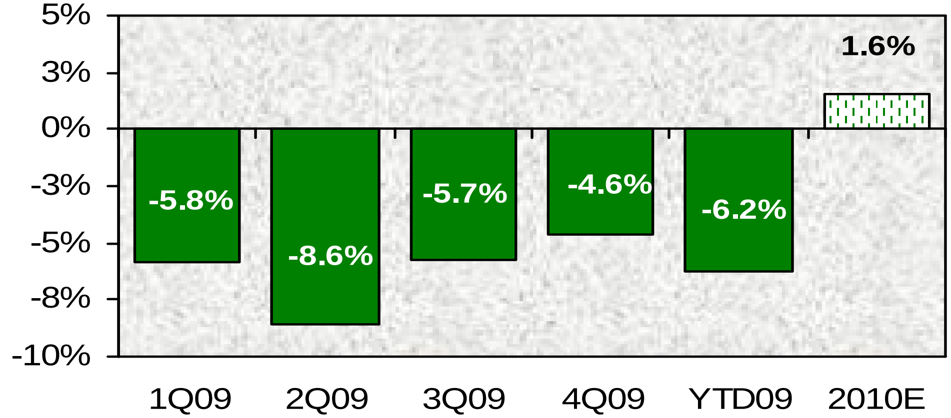
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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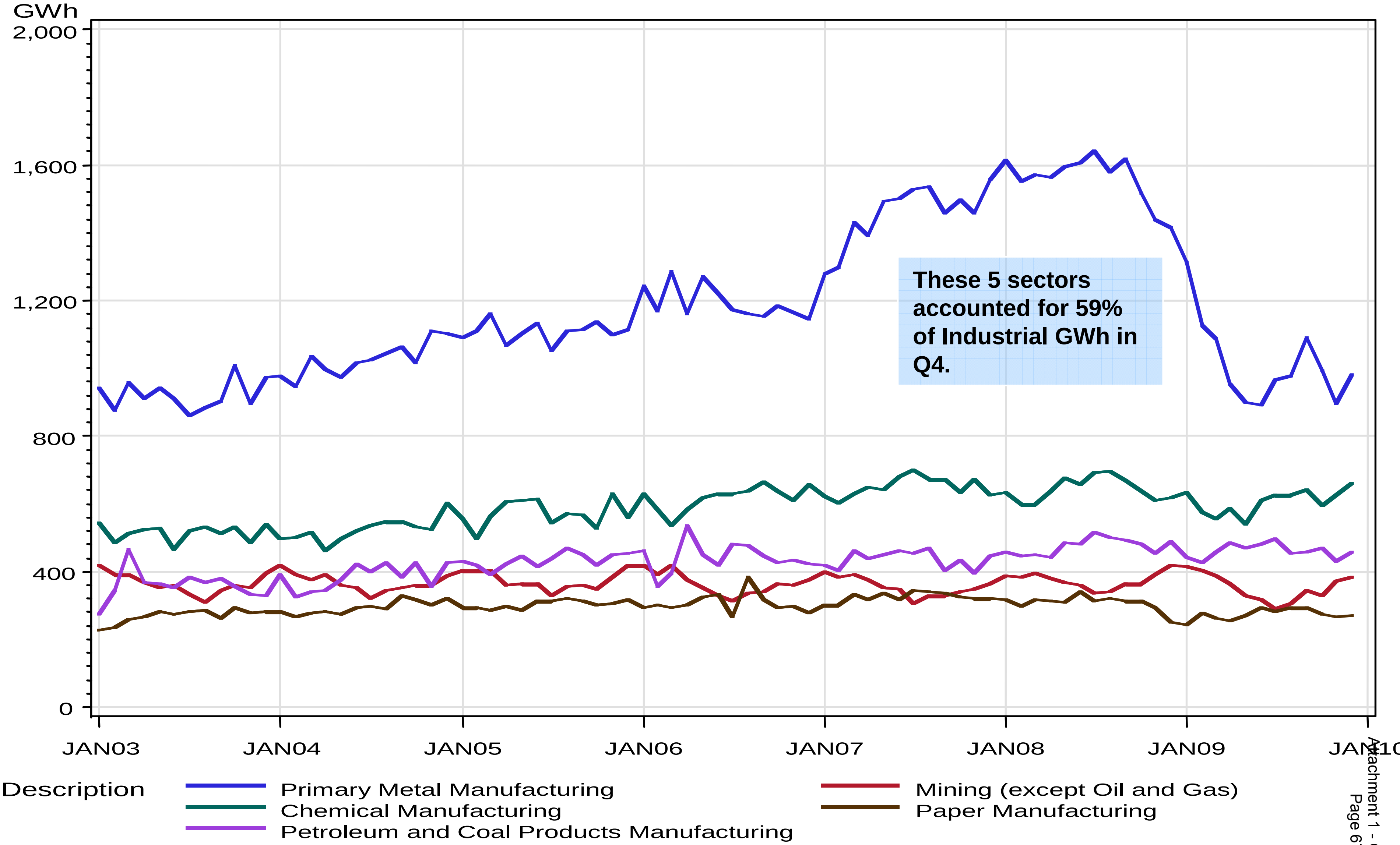
Industrial Sales Volumes



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Additional 2010 Earnings Drivers

O&M Assumptions

- **$23MM increase over 2009, net of revenue offsets**
- **Includes $80MM increase in employee and operational expenses**

Rate Relief Assumptions

- **$320MM, net of trackers**
- **$167MM secured**
  - **AR, OH, OK, VA, WV**
- **Active or pending rate cases include KY, MI, TX, VA, WV and others**

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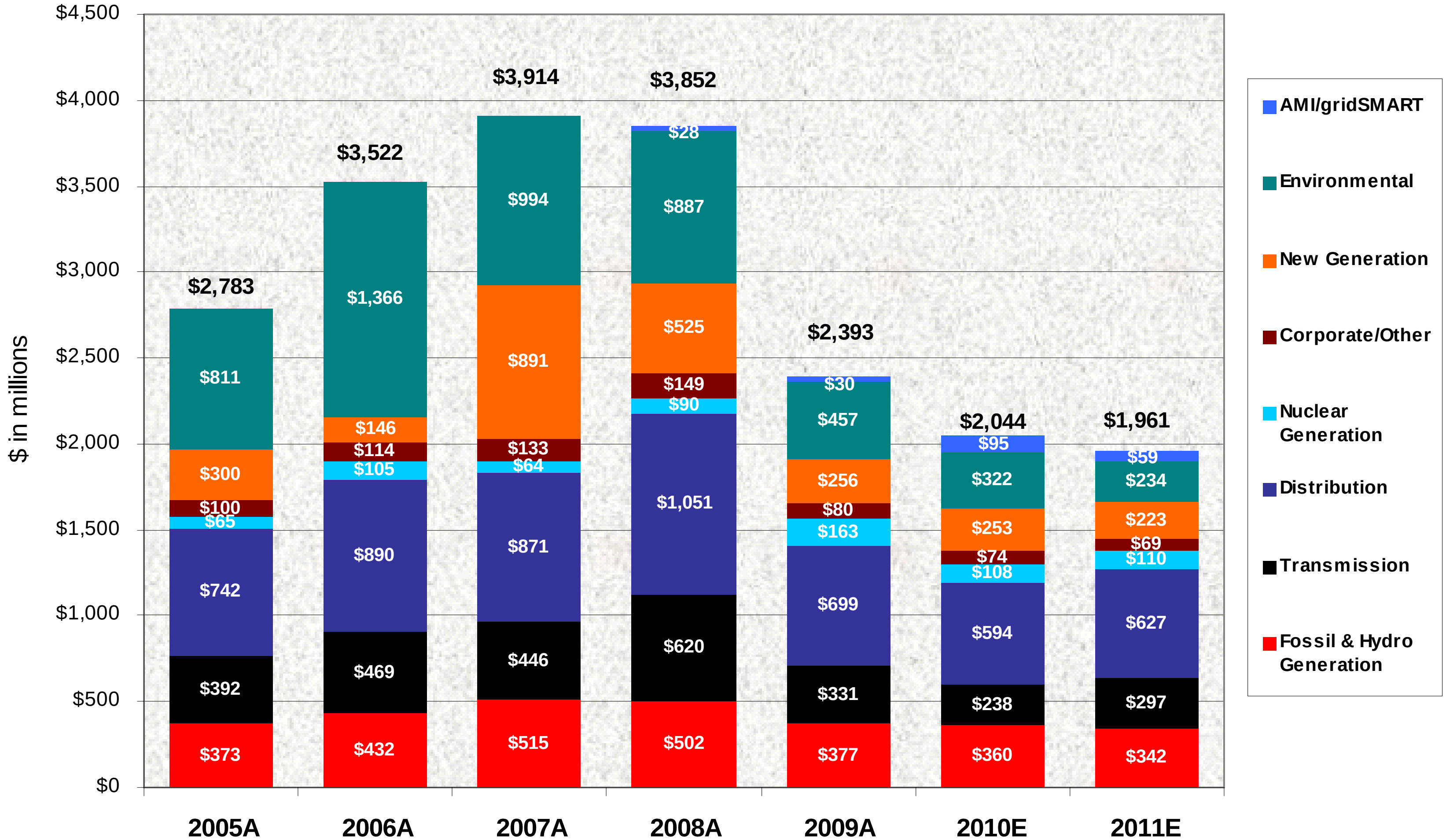
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

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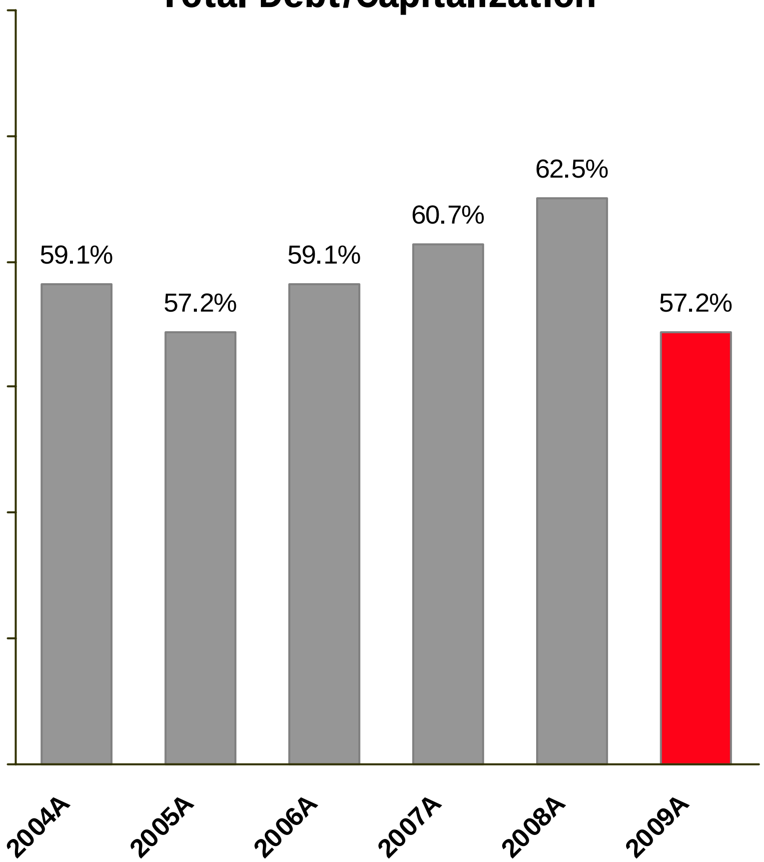
Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ -	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 195
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 680	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company[(1)]	$ -	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,030	$ 623	$ 565

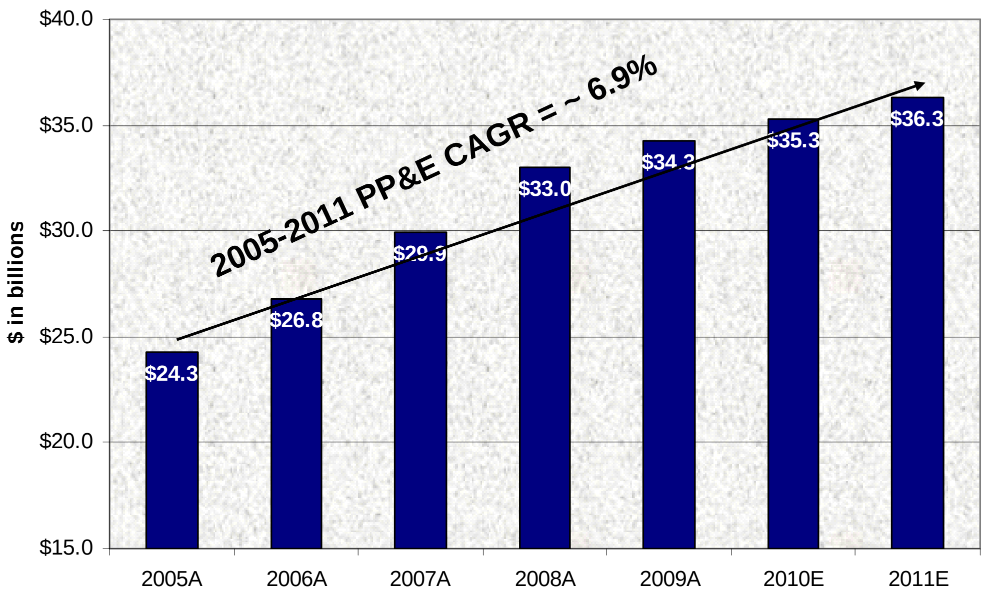
(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)

Data as of March 31, 2010

AEP AMERICAN® ELECTRIC POWER

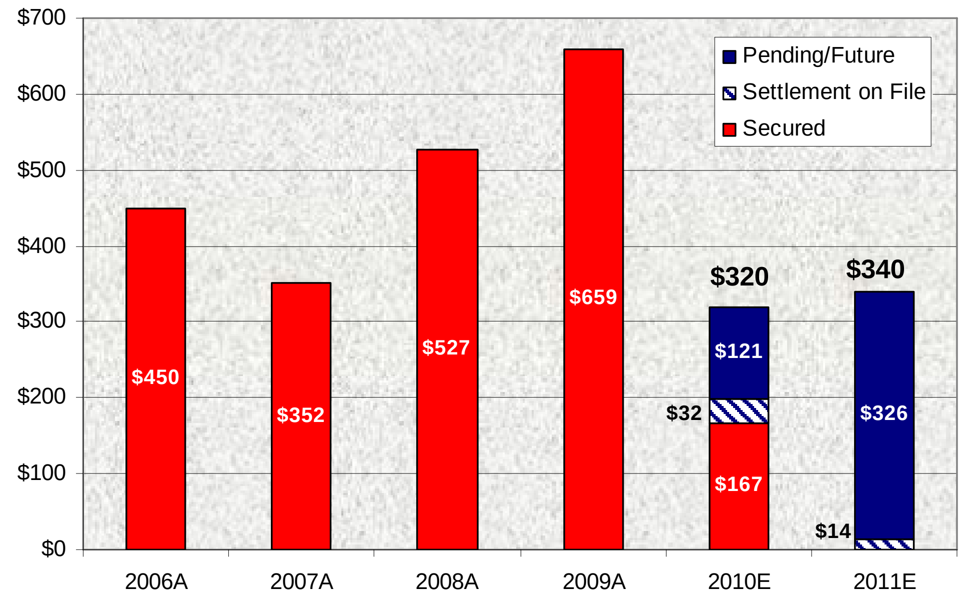
Traditional Rate Making Environment

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Settlement on file relates to SWEPCO Texas rate case

AEP AMERICAN® ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing commenced March 30, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. A settlement was filed in March 2010 resulting in a revenue increase of $25MM, an ROE of 10.33%, reduced depreciation expense of $17MM and expiration of merger credits of $7MM. An order is expected in April 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

AEP AMERICAN ELECTRIC POWER®

AEP AMERICAN® ELECTRIC POWER

Goldman Sachs 6th Annual Clean Energy & Power Conference

December 9, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Detailed Ongoing Earnings Guidance

2010A: $3.03

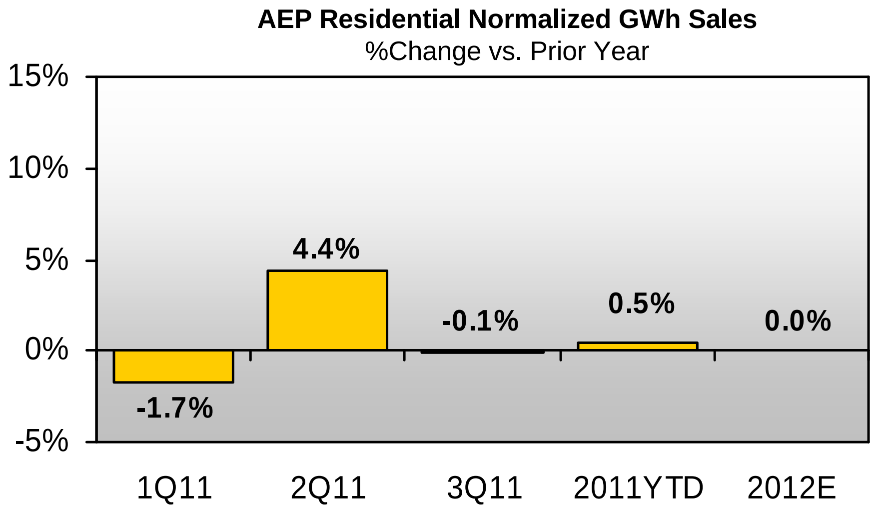
2011E: $3.07 - $3.17

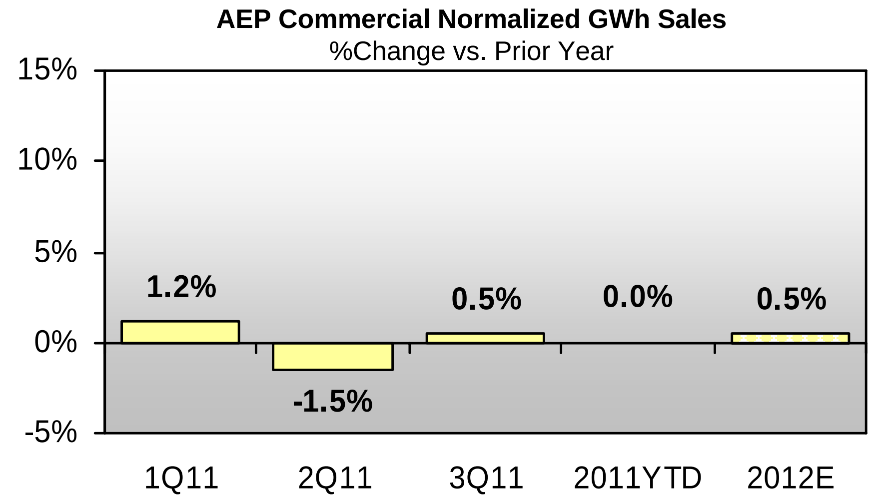
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

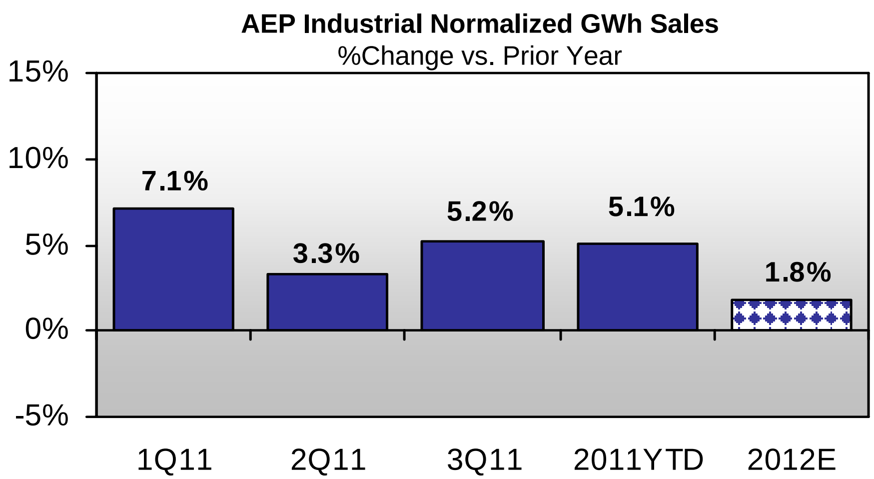
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

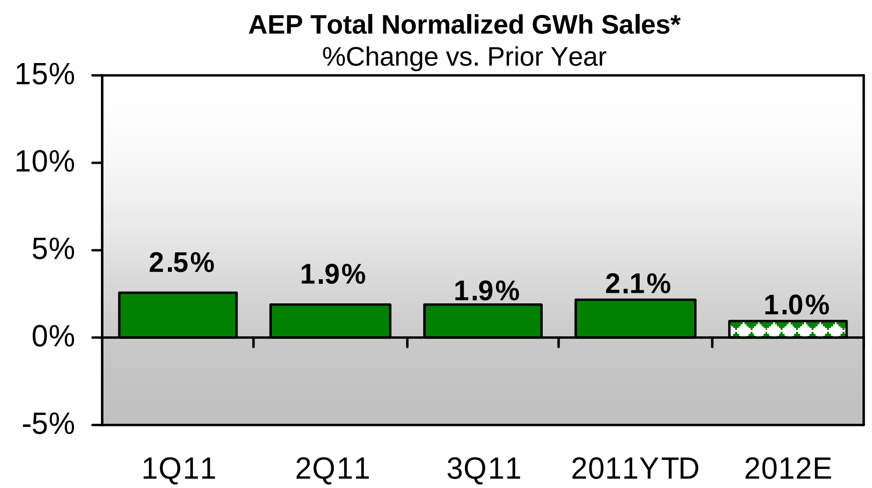
**original guidance given 01/28/2011*

Normalized Load Trends









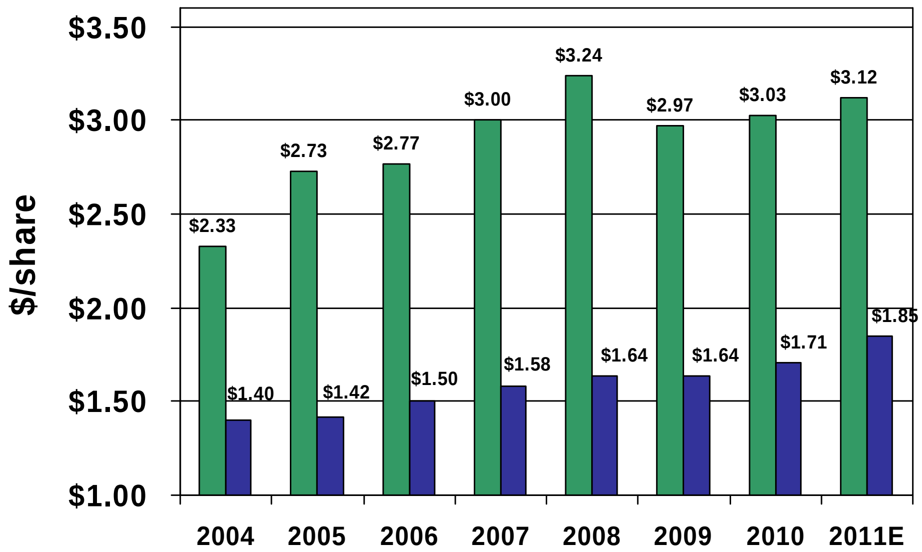
Note: Chart represents connected load

*includes firm wholesale load

Earnings and Dividend Growth

AEP®

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

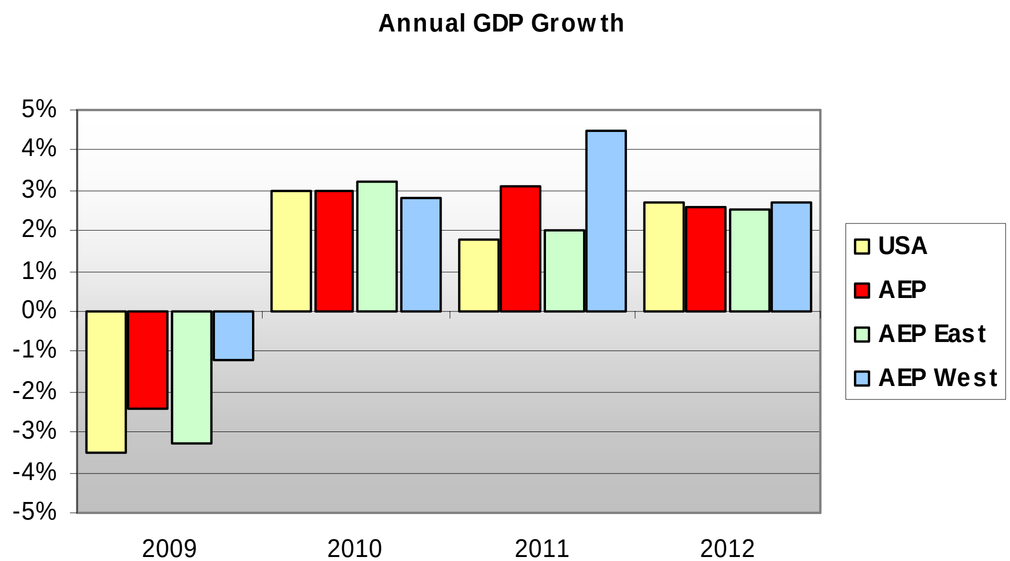
Dividend payout ratio target of 50–60%

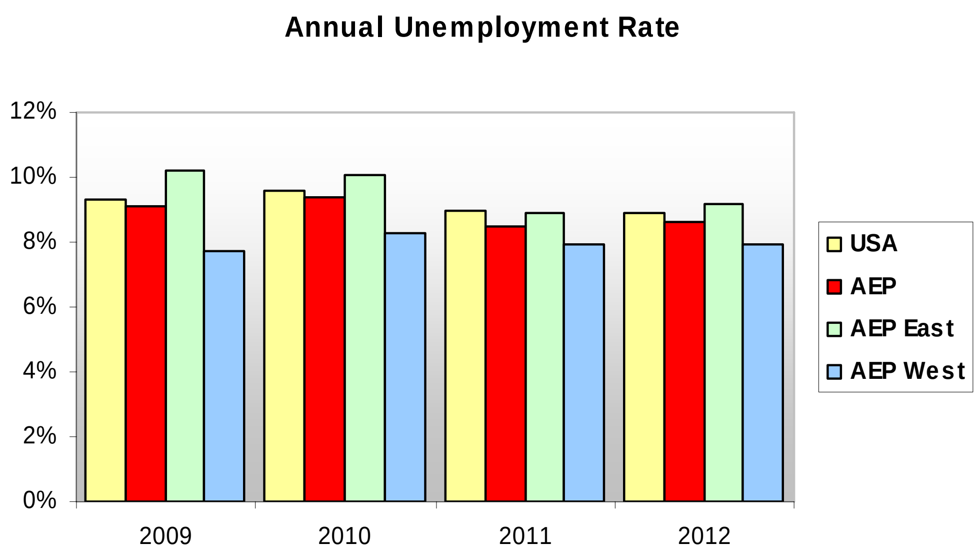
2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

Economic Conditions/Load

- AEP's GDP growth at 3.1% in 2011 has been better than the US at 1.8%
- AEP West region continues to experience stronger growth than AEP East





- AEP East unemployment remains higher than AEP West
- AEP Total unemployment has started to improve relative to the US

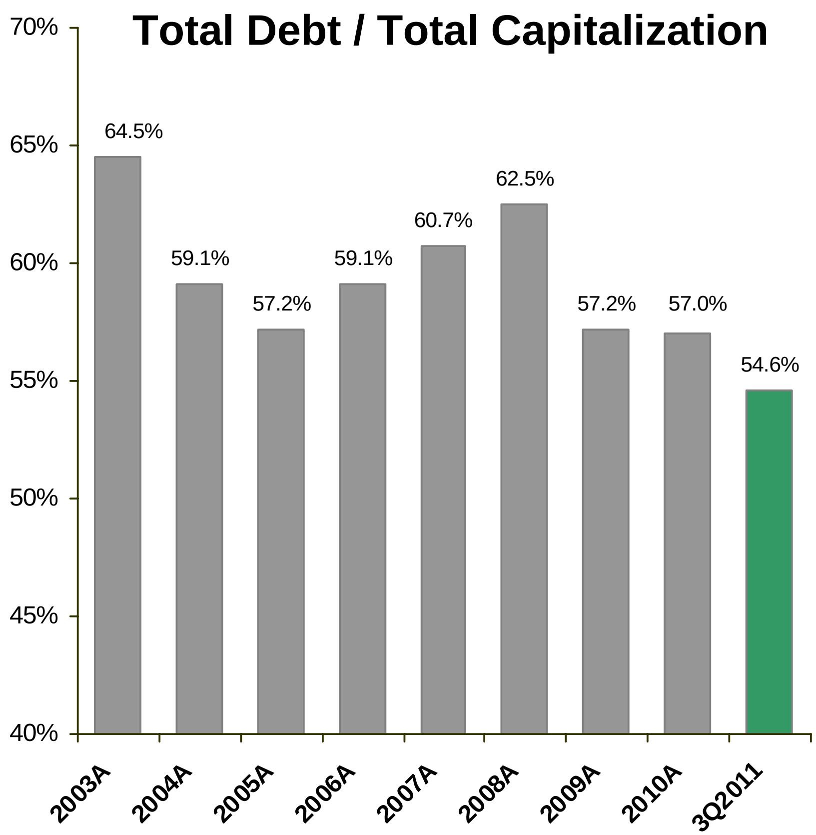
Sensitivities for 2012

EPS Sensitivities

Major Drivers		
Driver	**Driver Change**	**EPS Effect**
Average Load Growth	1%	$0.10
Off System Sales, net of sharing	10%	$0.05
Utility O&M	1%	$0.04
Capital Spending	$250M	$0.02

Operating Company Returns		
Company	**% Earnings Contribution**	**EPS Effect of 1% ROE Change**
AEP Ohio	42%	$0.10
APCo (incl WPCo)	16%	$0.06
SWEPCO	11%	$0.04
I&M	10%	$0.04
AEP Texas	8%	$0.02
PSO	6%	$0.02
KPCo	3%	$0.01
Other	4%	$0.02

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.50%	15%- 20%

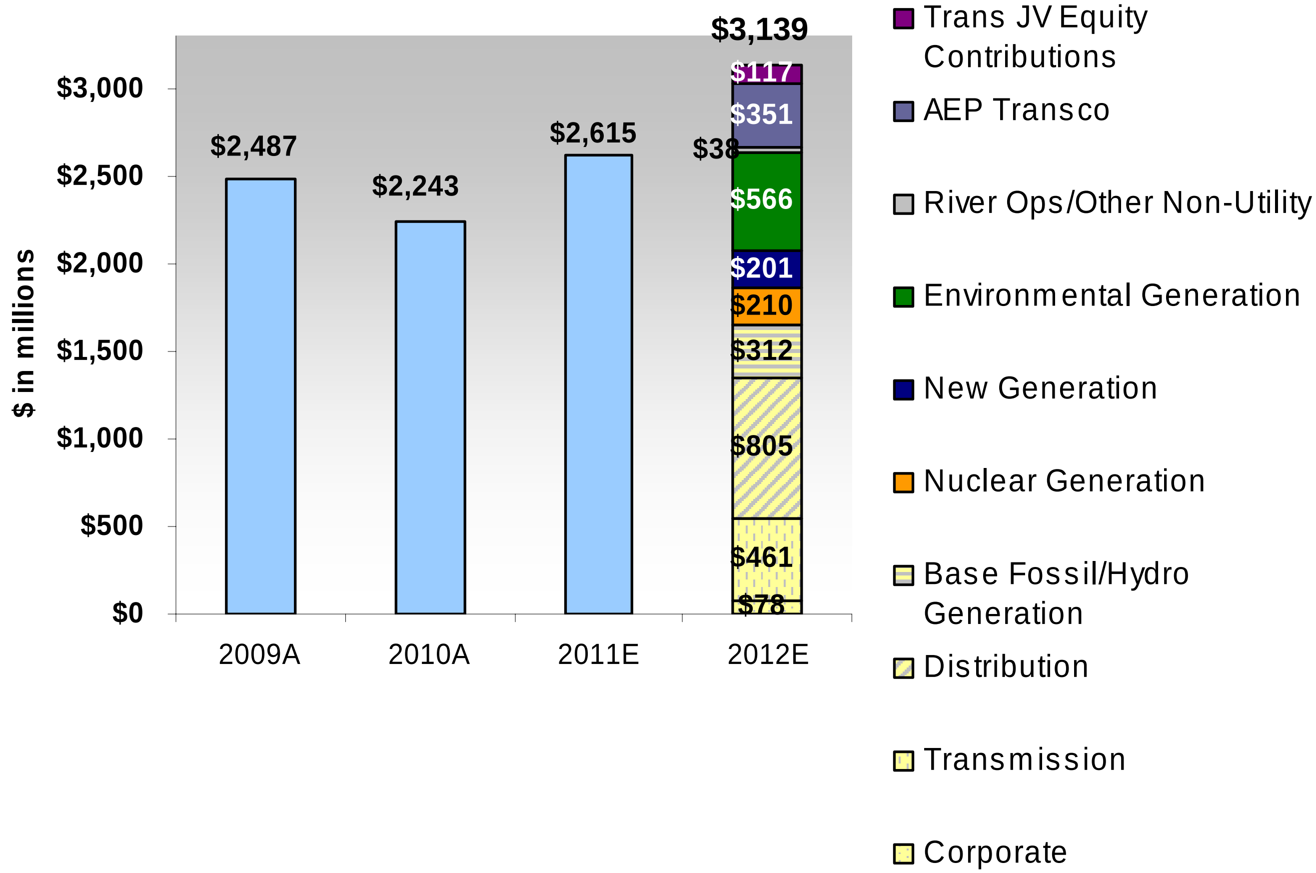
Note: Credit statistics represent the 12 month trailing as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

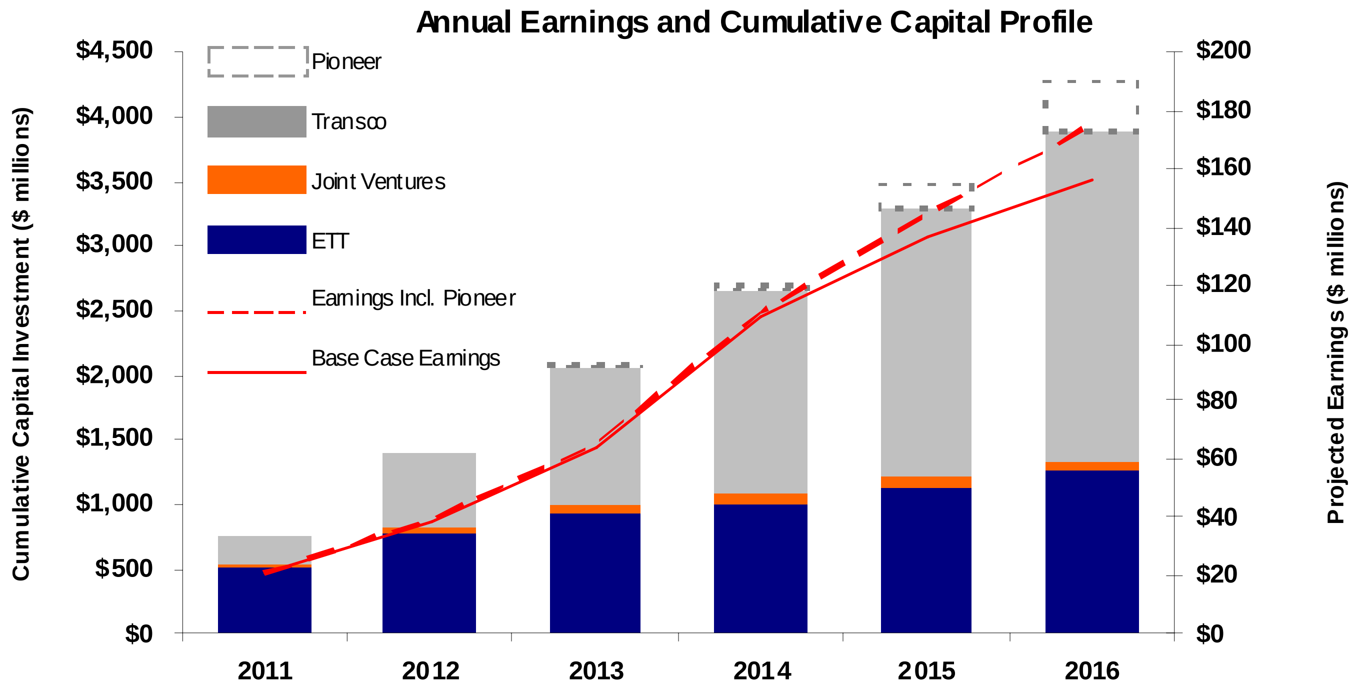
Capital Allocation

2012 AEP System Capital $3.1B



Major projects include: Turk Plant, Reliability upgrades, ETT contributions and Transco growth

Transmission Earnings & Capital Profile



[1] High Case includes AEP's share of Pioneer (50% ownership)

[2] Transco base case includes approximately $21MM in 2012 capital spend that is dependent upon state approval of Arkansas and Kentucky

[3] Joint Ventures include: PATH (50% ownership) assuming an ongoing suspension and Prairie Wind (25% ownership) assuming construction at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 11-13% for FERC projects; 60/40 debt/equity capitalization and 9.96% ROE (through 2013) and 55/45 debt/equity capitalization and 10% ROE (2014 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission Investment Opportunities

Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:** Current rate base is $482 million; expected to grow as follows:
  - 2011: $495 million
  - 2012: $750 million
  - 2013: $1,200 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $210 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

ROE Optimization

ROE by Jurisdiction		
Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia APCO – West Virginia Wheeling	10.53% 10.00% 10.00%	6.88%
I&M – Indiana I&M – Michigan	10.50% 10.35%	8.24%
SWEPCO – Louisiana SWEPCO – Arkansas SWEPCO – Texas	10.57% 10.25% 10.33%	10.05%
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule

Hearing has been delayed pending settlement discussions

Summary Rate Case Information

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M requested to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

Recovery Mechanisms Across Jurisdictions

	SO_2 Allowances*	NO_x Allowances*	CO_2 Allowances	GHG Offsets	Environmental Investment	Energy Efficiency	Renewables	Purchased Power	OATT
AEP East									
Indiana	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**CCTR/BR**	**Rider**	**FAC**	**FAC/BR**	**PJM Tracker**
Kentucky	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**		**FAC**	**Base Rates**
Michigan	**PSCR**	**PSCR**	**PSCR**	**PSCR**	**Base Rates**	**Surcharge**	**PSCR/REP**	**PSCR**	**Base Rates**
Ohio	**FAC**	**FAC**	**FAC**	**FAC**	**SSO**	**Rider**	**FAC**	**FAC**	**TCRR**
Tennessee	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**			**FERC Tariff**	**PPAR**
Virginia	**ERAC**	**ERAC**	**ERAC**	**ERAC**	**ERAC/BR**	**RAC**	**RPSRAC**	**FAC/BR**	**TRAC**
West Virginia	**ENEC**	**ENEC**	**ENEC**	**ENEC**	**ENEC/BR**	**Rider**	**ENEC**	**ENEC**	**ENEC**
AEP West									
Arkansas	**ECR**	**ECR**	**FAC**	**FAC**	**Surch/BR**	**EECR**	**FAC**	**ECR/BR**	**Base Rates**
Louisiana	**EAC**	**EAC**	**Rider**	**Rider**	**Formula BR**		**FAC**	**EAC/FRP**	**Formula BR**
Oklahoma	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Rider**	**FAC**	**FAC/PPC**	**SPP tracker**
Texas(SWP)	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**EECRF**	**FAC**	**FAC/BR**	**TCRF**

* - For certain jurisdictions where necessary, confirmation of the replacement of CAIR with CSAPR is occurring with applicable commissions

ECCR	Environmental Compliance Cost Rider
CCTR	Clean Coal Technology Rider
BR	Base Rates
FAC	Fuel Adjustment Clause
PSCR	Power Supply Cost Recovery Rider
REP	Renewable Energy Plan
SSO	Standard Service Offer
TCRR	Transmission Cost Recovery Rider
PPAR	Purchased Power Adjustment Rider
ERAC	Environmental Rate Adjustment Clause
RAC	Rate Adjustment Clause
RPSRAC	Renewable Portfolio Standard Rate Adjustment Clause
TRAC	Transmission Rate Adjustment Clause
ENEC	Expanded Net Energy Cost
ECR	Energy Cost Recovery Rider
EECR	Energy Efficiency Cost Rate
FRP	Formula Rate Plan
PPC	Purchased Power Capacity Rider
EECRF	Energy Efficiency Cost Recovery Rider
TCRF	Transmission Cost Recovery Factor

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).

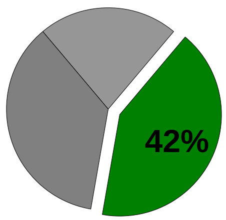
- Various legal challenges are on-going related to the plant (see 10-Q).

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

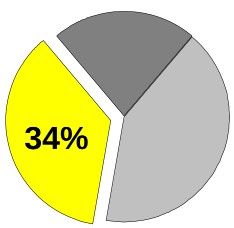
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

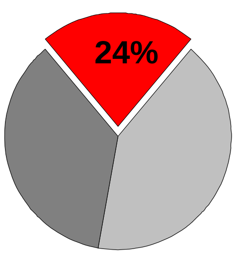
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	Has FGD
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Lawrenceburg **	1,186	2004	NG Combined Cycle
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	4,921		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**13,432**		

* May need FGD upgrades

** CSP has a PPA with AEGCo for the Lawrenceburg Plant. The contract extends through 2017, with a two-year optional renewal.

Total Ohio Generation	13,432 MW
Less units slated for retirement	2,500 MW
Total remaining portfolio	10,932 MW
Remaining Portfolio:	
Coal	77%
Has FGD & SCR - 83%	
Has FGD; may require SCR - 10%	
May be replaced with gas - 7%	
Natural gas & hydro units	23%
	100%

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JP Morgan Investment Advisors
Mark Gannon-Fixed Income
March 24, 2010

765-kV Transmission Line (Wyoming-Jacksons Ferry)

General JM Gavin Coal Plant (OH)

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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AEP AMERICAN® ELECTRIC POWER

A Portfolio Approach: AEP's Long-Term CO_2 Reduction Commitment

Existing Programs

– Existing Plant Efficiency Gains
– Renewable Energy
  – 1400 MW wind
  – 300+ MW hydro
– Domestic Offsets
  – Over 63MM trees planted = 1.2MM tons of CO_2 uptake
– International Offsets
  – 1MM tons of forest carbon sequestered through 2009
– Chicago Climate Exchange

AEP's reductions/offsets of CO_2:
– 2003-2010: 50 MMT+ Total

New Additions (by 2012)

– 2000 MW Wind PPAs
– Domestic Offsets
  – Methane, Forestry
– Fleet Vehicle/Aviation Offsets
– Energy Efficiency & DSM
– Biomass Co-firing

– New Technology
  – New Generation: Ultra Super Critical Coal
  – Carbon Capture and Storage (CCS) for existing fleet
    – Chilled Ammonia

AEP's reductions/offsets of CO_2:
– 2011+: 5 MMT/yr

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Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service		
Amos 2	800	☑	In-service		
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	In-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

Captured CO_2 first time on 09/01/09; Injected CO_2 first time on 10/1/2009

Mountaineer Plant (WV) → **Chilled Ammonia 20MWe scale (Alstom)**

CO_2 Storage (Battelle)

2 injection wells & 3 monitoring wells

Captures and Stores ~100,000 metric tons of CO_2 /yr.

Phase 2

Awarded $334MM DOE Funding; Expected Commercial Operation: 2015

Mountaineer Plant (WV) → **Chilled Ammonia ~235MWe scale (Alstom)**

CO_2 Storage

Captures and Stores 1.5 Million metric tons of CO_2/yr, 1.5 miles below the surface

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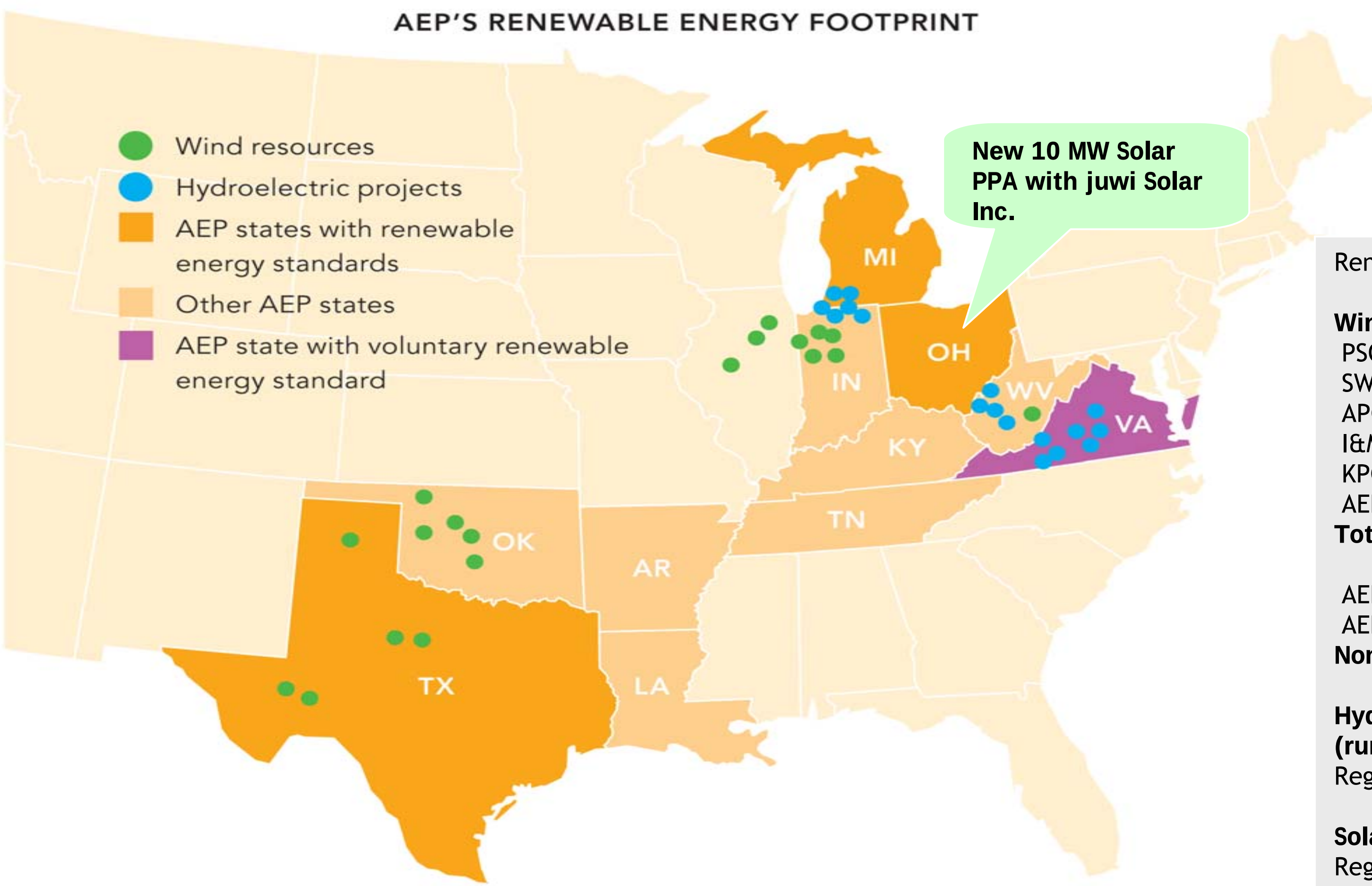
AEP Renewable Footprint



Renewables Portfolio*

Wind		
PSO - 5 PPAs		591MW
SWEPCo - 1 PPA		79MW
APCo - 4 PPAs		376MW
I&M - 2 PPAs		150MW
KPCo - 1 PPA		100MW
AEP Ohio - 2 PPAs		110MW
Total Regulated		**1406MW**
AEPEP -	owned	311MW
AEPEP -	2 PPAs	177MW
Non-regulated		**487 MW**
Hydro (run-of-river)		
Regulated - owned / PPA		**364MW**
Solar		
Regulated - PPA		**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

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New Generation Projects

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.6 billion with AEP's share approximately $1.2 billion and will begin commercial operation in 2012.
  - SWEPCo's share of the plant's costs will be allocated on the basis of electric load among customers in Arkansas, Louisiana and Texas.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

John W. Turk Jr. Ultra-Supercritical Coal Plant

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit scheduled for commercial operation in 2010.
  - The total projected cost of the plant is $378 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant will be used to service the needs of customers in the Arkansas, Louisiana and Texas service territories.

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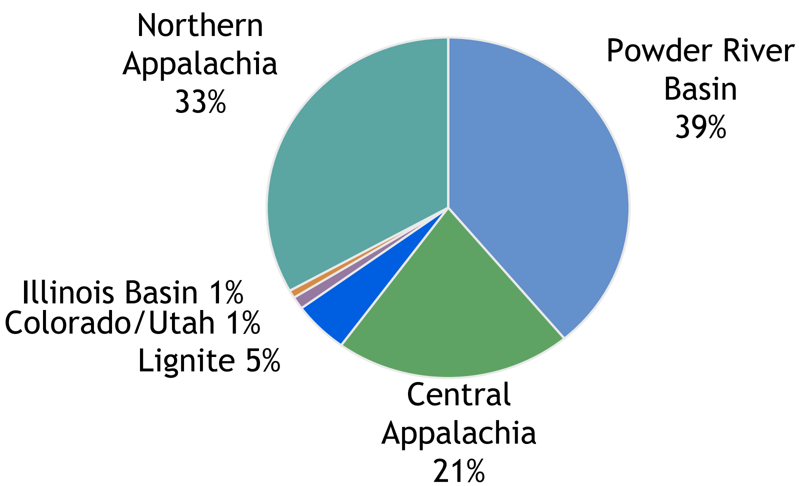
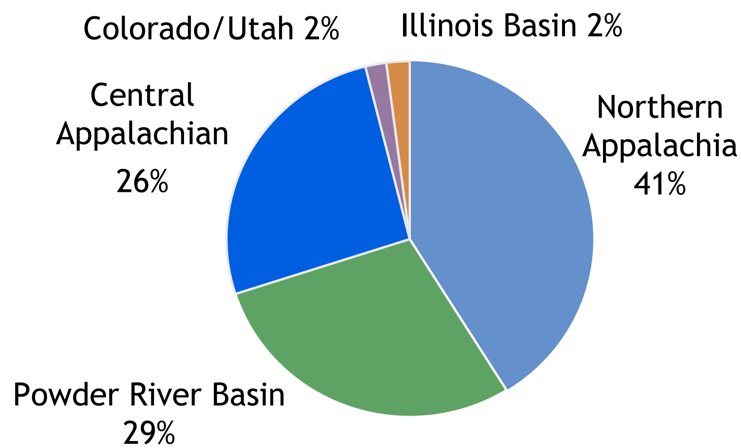
Coal Procurement – 2010 Projected

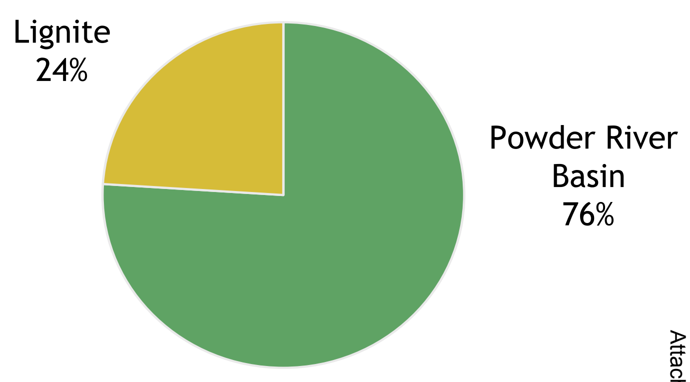
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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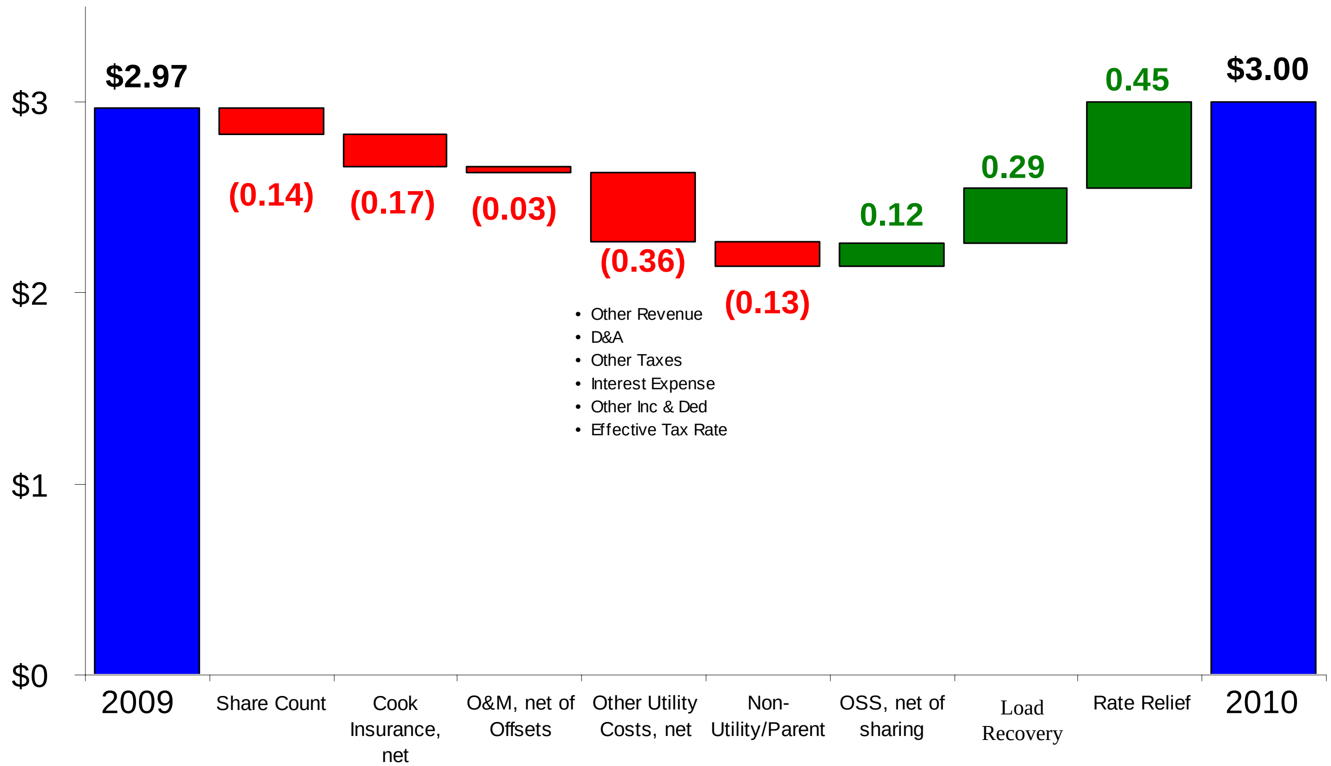
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6833 of 9556

Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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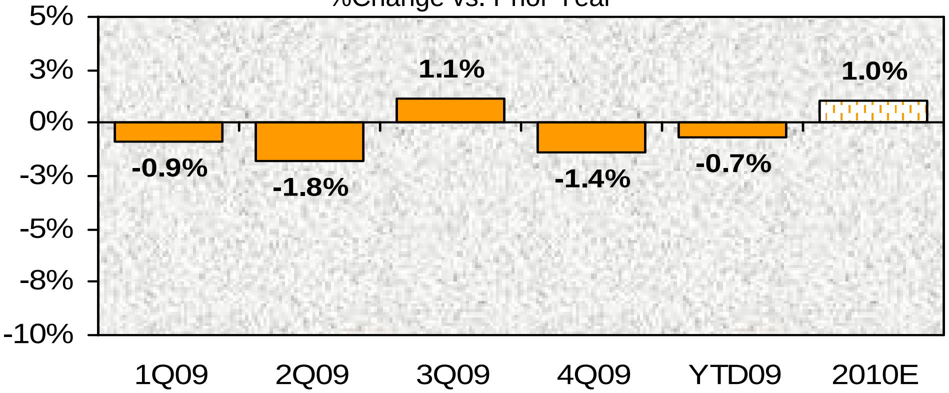
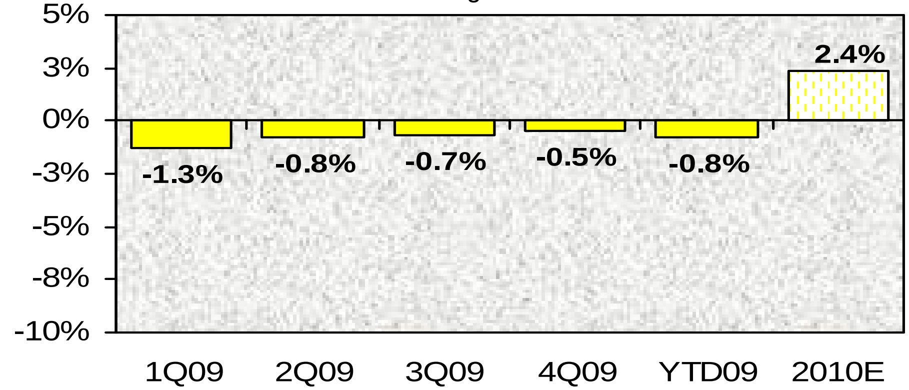
Normalized Load Trends

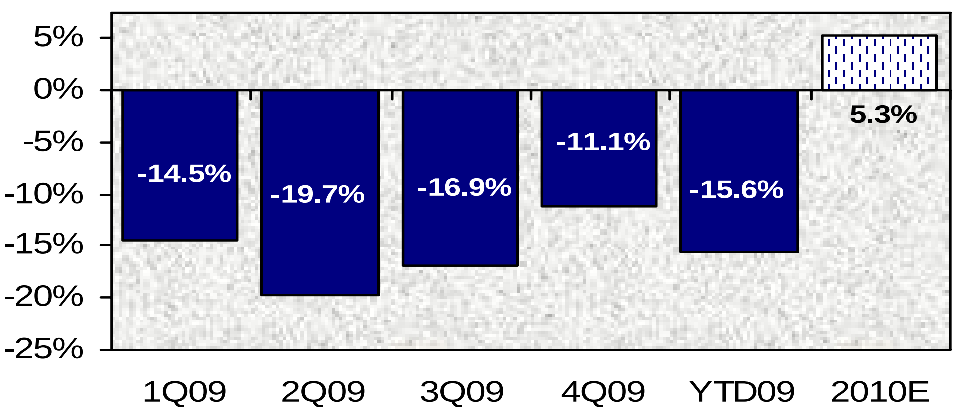
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



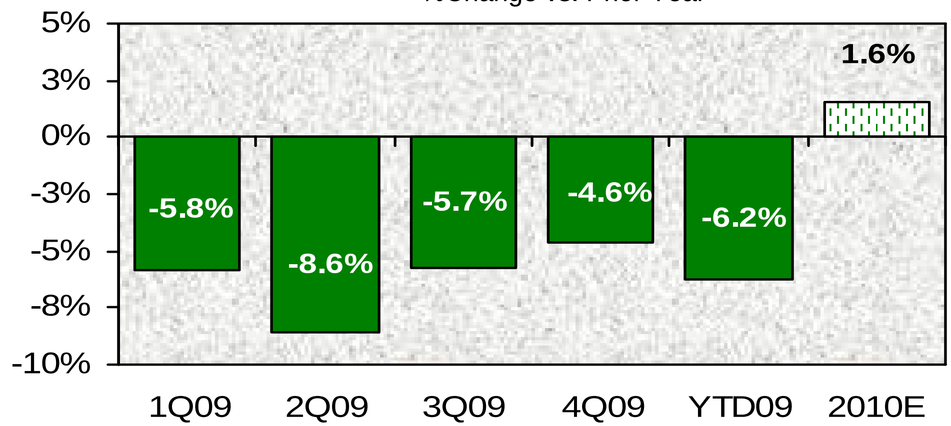
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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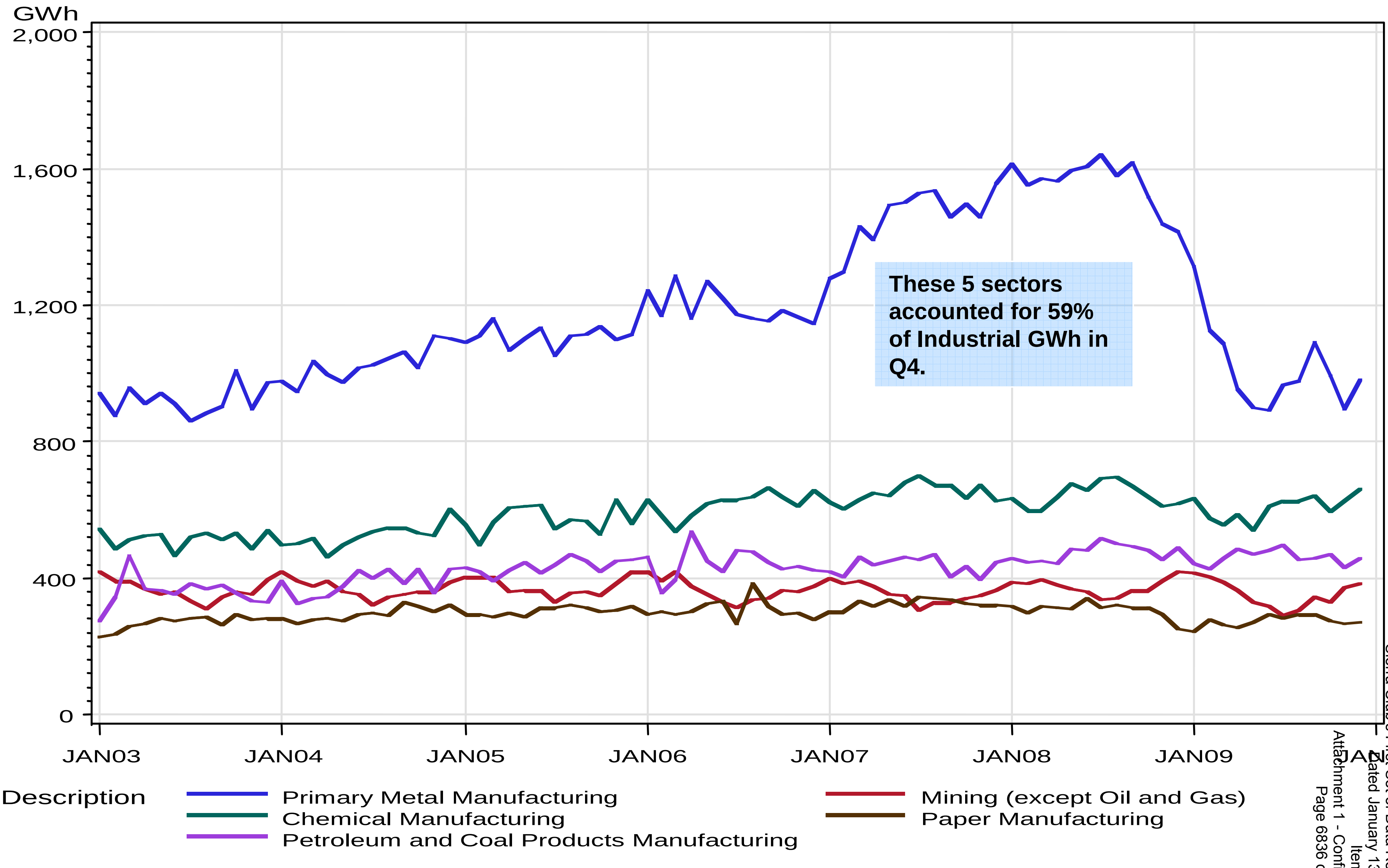
Industrial Sales Volumes



Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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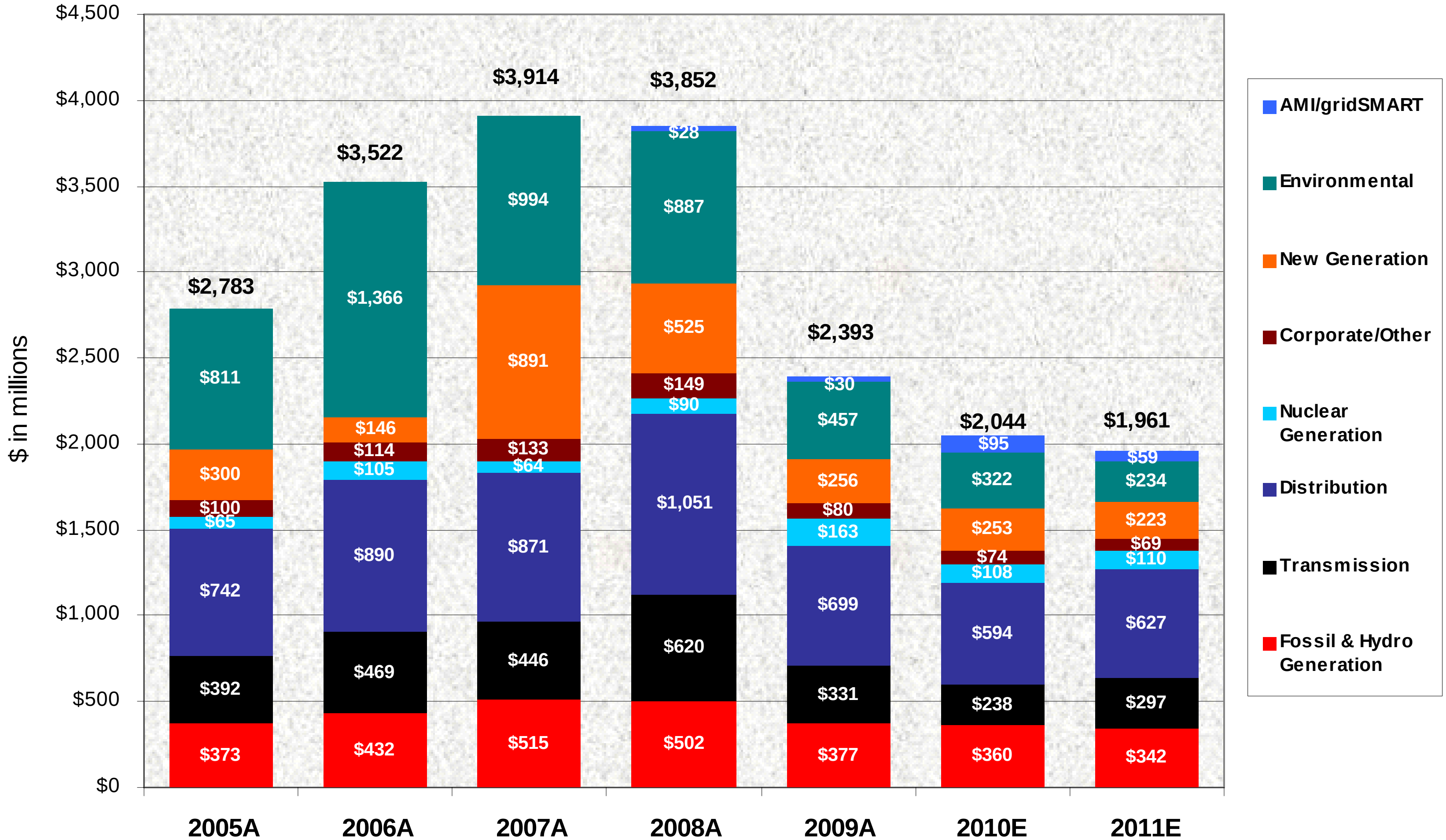
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

AEP AMERICAN ELECTRIC POWER®

Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

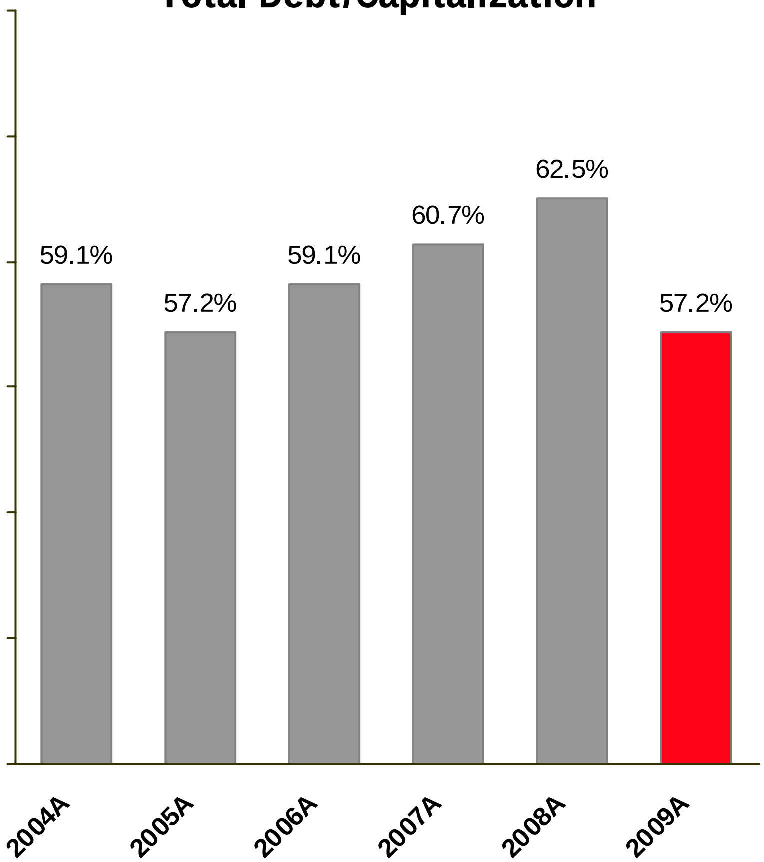
Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

AEP AMERICAN® ELECTRIC POWER

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 12/31/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

Long-term Debt Maturity Profile

($ in millions)

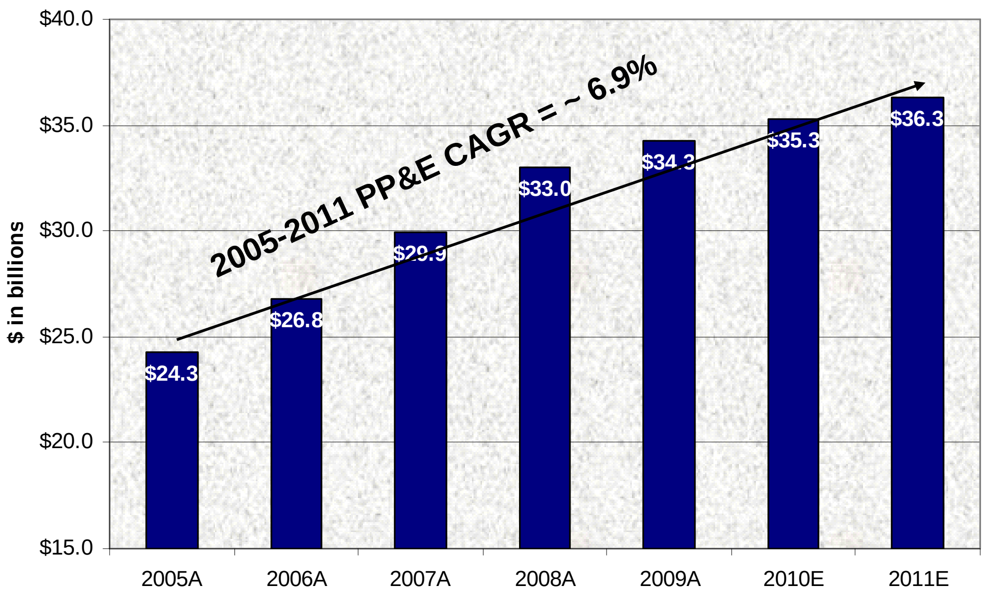
Year		2010		2011		2012
AEP, Inc.	$	-	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	680	$	-	$	-
Public Service of Oklahoma	$	-	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company(1)	$	-	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,030	$	623	$	415

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)
Data as of March 30, 2010

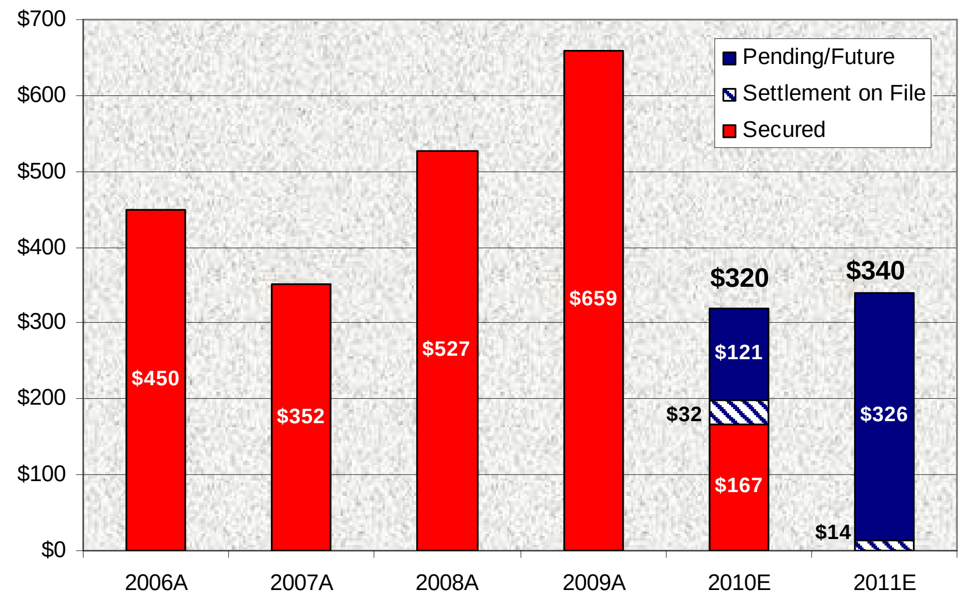
AEP AMERICAN® ELECTRIC POWER

Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Settlement on file relates to SWEPCO Texas rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

AEP AMERICAN® ELECTRIC POWER

AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company: AEP Appalachian Transmission Company Inc., AEP West Virginia Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company inc., AEP Oklahoma Transmission Company Inc., and AEP Southwestern Transmission Company Inc.
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filings made/to be made in Ohio, Virginia and West Virginia
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

AEP AMERICAN® ELECTRIC POWER

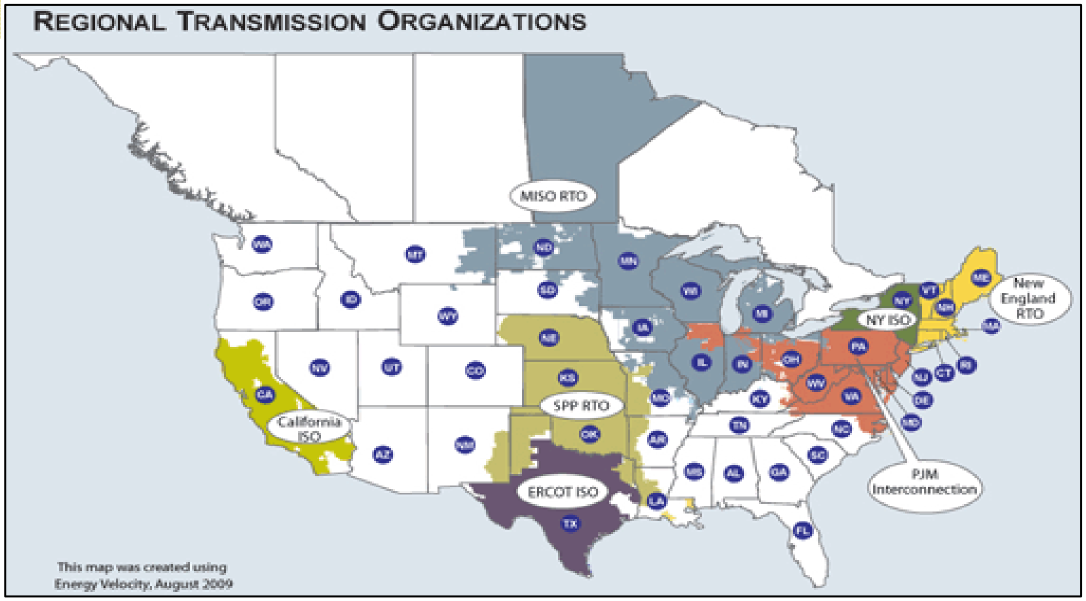
JV Strategy – Nationwide Grid Expansion

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2017	**PATH-WV** COD: 2014	**Pioneer** COD: 2015
▪ *110 miles of 765 kV* ▪ *Partners: Westar (50%) & Electric Transmission America (50%)* ▪ *Estimated Cost: $400 million* ▪ *ROE: 12.8%*	▪ *345 kV ERCOT Expansion* ▪ *Partner: MidAmerican Energy (50%)* ▪ *Estimated Cost: $1.4 billion* ▪ *ROE: 9.96%*	▪ *275 miles of 765 kV* ▪ *Partner: Allegheny Energy (50%)* ▪ *Estimated Cost: $1.2 billion* ▪ *ROE: 14.3%*	▪ *240 miles of 765 kV* ▪ *Partner: Duke Energy (50%)* ▪ *Estimated Cost: $1 billion* ▪ *ROE: 12.54%*

Tallgrass COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ACTIVE PROJECTS



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay	ETT COD: various	PJM Expansion	EHV Michigan/Ohio
▪ *Regional Expansion of 765 kV Backbone*	▪ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ▪ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	▪ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	▪ *700 miles of Proposed 765 kV*
SPP	ERCOT	PJM	PJM/MISO

AEP AMERICAN® ELECTRIC POWER

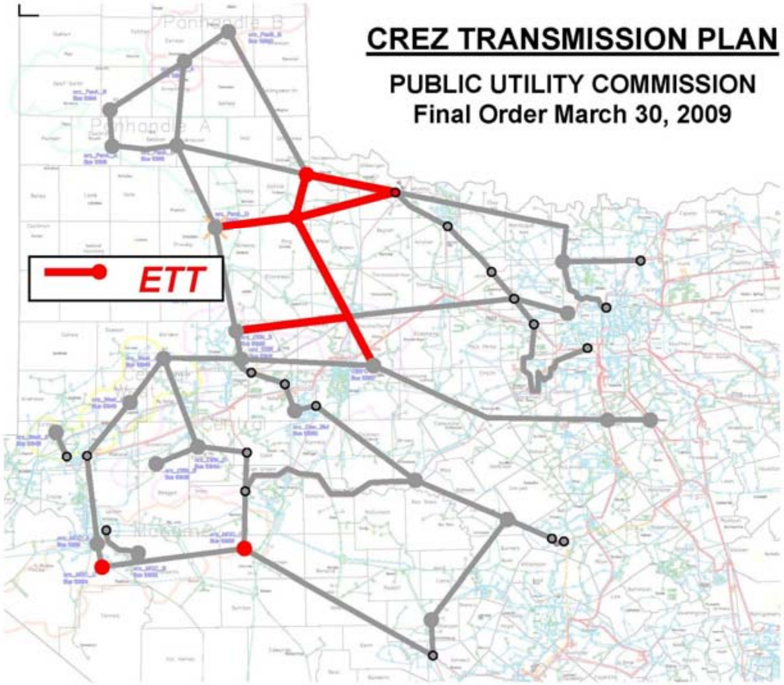
Electric Transmission Texas, LLC

Overview:

- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

- **Opportunities:**
  - Projects in service 2010-2017: $1.4 billion
  - CREZ projects in service 2012-2013: $1.1 billion
  - Other projects pending transfer in service 2010-2013: $600 million

- **Next Steps:**
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

AMERICAN ELECTRIC POWER

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

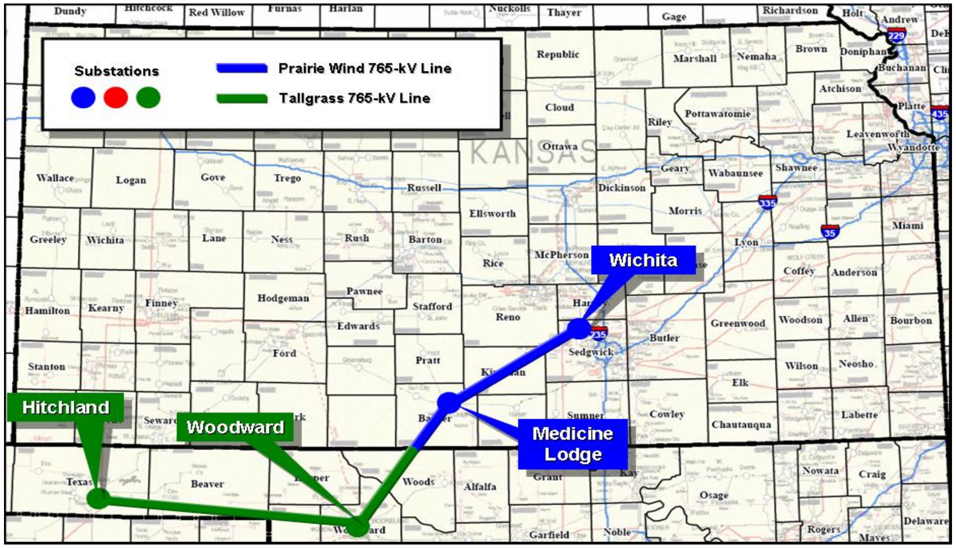
PATH
Potomac-Appalachian Transmission Highline

AEP AMERICAN® ELECTRIC POWER

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

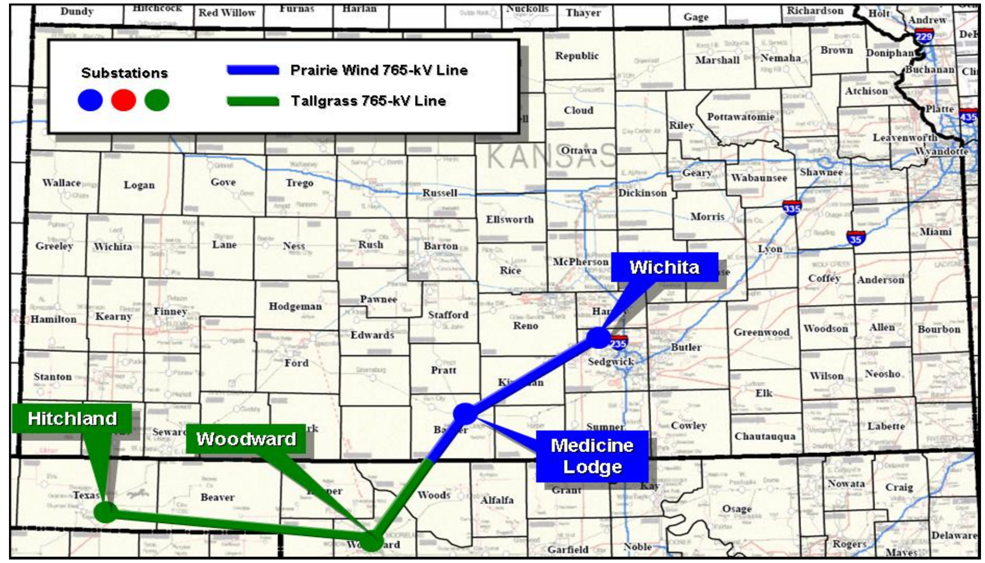
- RTO Approval
- Siting

AEP AMERICAN ELECTRIC POWER

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP’s ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

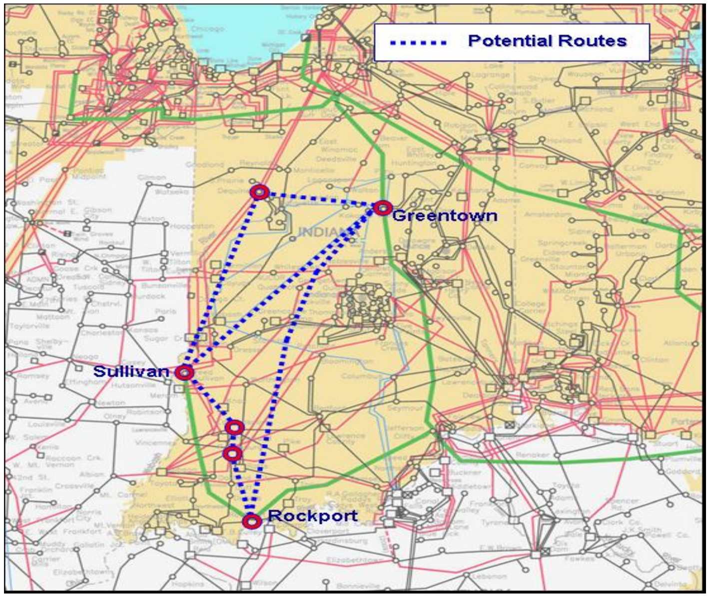
- RTO Approval
- Siting

AEP AMERICAN ELECTRIC POWER

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP’s Rockport Station to Duke’s Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP’s ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of “system solutions”
- Siting

AEP AMERICAN ELECTRIC POWER

Upper Midwest EHV Development—SMART Study

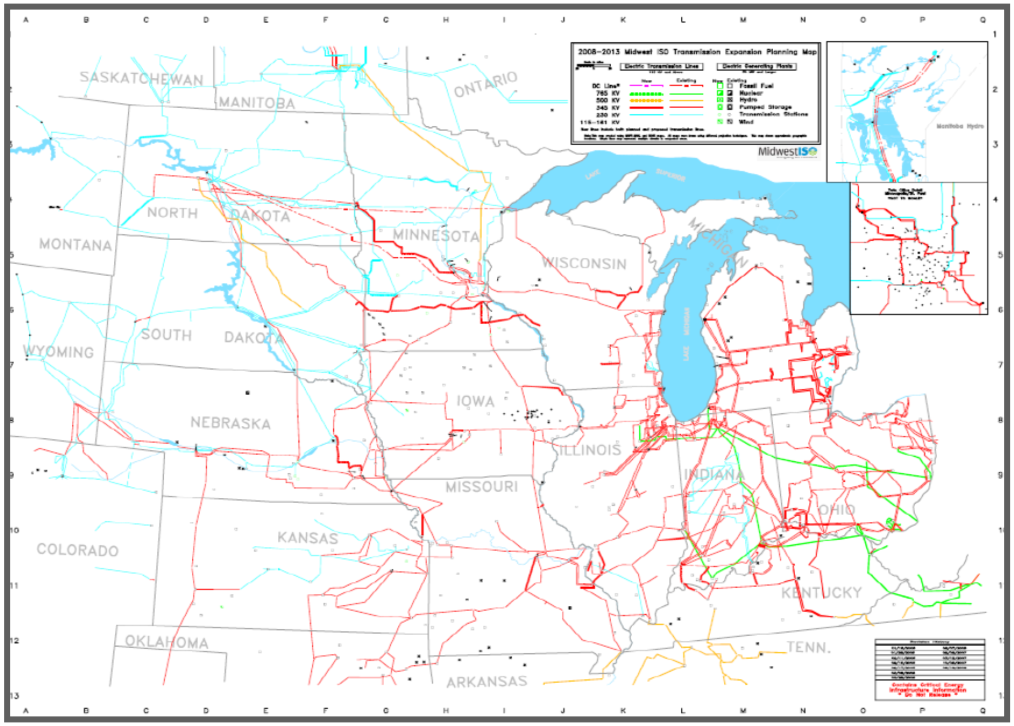
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2Q2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

AEP AMERICAN® ELECTRIC POWER

HARRIS NESBITT
TEXAS POWER FORUM

AMERICAN ELECTRIC POWER

AUSTIN, TX
MARCH 24, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Craig Baker – SVP, Regulatory Services

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AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

Principal industries served:
- Oil and gas extraction
- Food processing
- Apparel
- Metal refining
- Chemical and petroleum refining
- Plastics
- Machinery equipment

Total Customers:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**

Generating Capacity	**54 MW***
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**5,000**
Distribution Miles	**28,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data (in thousands)

Revenue	$	793,000
% of AEP Retail		5%
Net Income (Loss)	$	(174,000)
Capital Expenditure	$	179,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	4,905,000
Net Plant Assets	$	2,021,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$278,400	$247,000	$222,100

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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AEP Texas Central Company

AEP TEXAS CENTRAL
MAJOR CUSTOMERS

Valero Energy Corporation
Flint Hills Resources
Air Liquide America, LP
Equistar Chemicals LP
El Paso Energy Corp.
HEB Grocery Company LP
Ingleside Cogeneration Ltd Par
Citgo Petroleum Corporation
Wal-Mart Stores, Inc.
Formosa Utl Ven Ltd.

- **Top 10 customers = 67% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **53 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas Central Power Plants (excluding mothballed and decommissioned plants)

Name	Location	Megawatt Capacity	Fuel
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

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AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**<u>5,000</u>**
Total	**183,000**

Generating Capacity **377 MW**
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**4,500**
Distribution Miles	**12,000**

Principal industries served:

Agriculture and the manufacturing or processing of Cotton seed products

Oil products

Precision and consumer metal products

Meat products

Gypsum products

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data (in thousands)

Revenue	$	459,000
% of AEP Retail		1%
Net Income	$	33,000
Capital Expenditure	$	65,000

2005 Asset Data (in thousands)

	As of 12/31/05	
Total Assets	$	1,044,000
Net Plant Assets	$	807,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 72,500	$ 71,600	$ 89,400

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AEP Texas North Company

AEP TEXAS NORTH
MAJOR CUSTOMERS

Chevron Texaco Corporation
Kinder Morgan
Occidental Permian Ltd.
Crown Cork & Seal Co., Inc
Rhodia Inc.
Plains All American Pipeline (Equilon)
Georgia-Pacific Corporation
Ethicon, Inc.
Wal-Mart Stores, Inc.
Tyson Foods Inc. (Wright Brand)

- **Top 10 customers = 32% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas North Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: 3	**Appointed/Elected**: Appointed	**Term**: 6 years	**Political Makeup**: **R:3**

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

Texas Regulatory Activity

<u>TCC Stranded Cost Recovery Case</u>

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
    - ➢ Final order expected in May 2006
    - ➢ September 1, 2006 - Issuance of securitization bonds if no appeal

<u>Procedural Schedule for TCC Securitization</u>

- ✓ April 17, 2006 – Intervenors File Testimony
- ✓ April 24, 2006 – Staff Files Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 2-4, 2006 – Hearings On Merit

- April 2006 – Request approval for CTC to address other true-up items
    - ➢ Expected $475 million credit to customers
    - ➢ Jan 2007 – CTC to be implemented

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ Indiana Depreciation Petition
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

Regulatory Activity Underway

Appalachian Power

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case – Gave notice to VA SCC on March 1, 2006 of intent to file general rate case no sooner than May 1, 2006

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million*
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

*Includes:
$16MM Base Rates
$56MM ENEC
$2MM Misc

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ April 7, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 - 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- ✓ $41 million annual increase in base rates
- ✓ To be effective March 30, 2006

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

April 7, 2006	Company Rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order is issued.

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Summary Rate Case Information

A Century of Firsts

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure - Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement - Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

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2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.6[illegible]
	Shares Outstanding (in millions)			390			39[illegible]

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capital Structure

Capital Structure	Actual 12/31/05		
$ in millions	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	12,226	-	12,226
Short-term Debt	10	-	10
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***
Adjustments			
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213
Securitization Bonds	(648)	-	(648)
Spent Nuclear Fuel Trust	(228)	-	(228)
Total Adjusted Capitalization	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***

ADJUSTED DEBT/CAPITALIZATION: 58.00%

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

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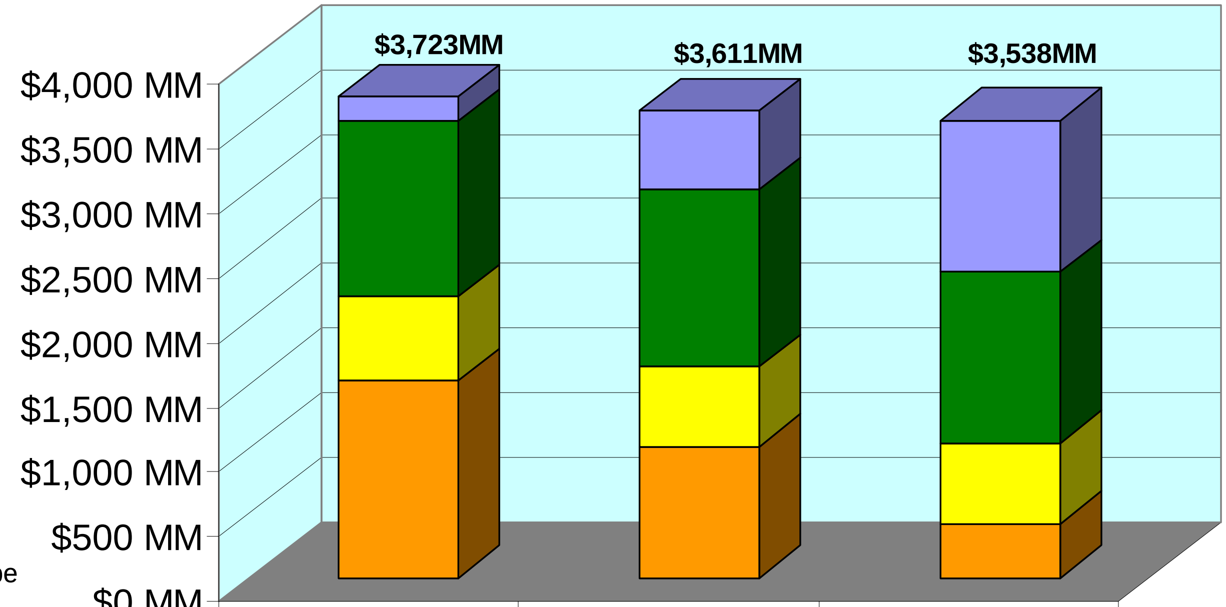
Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

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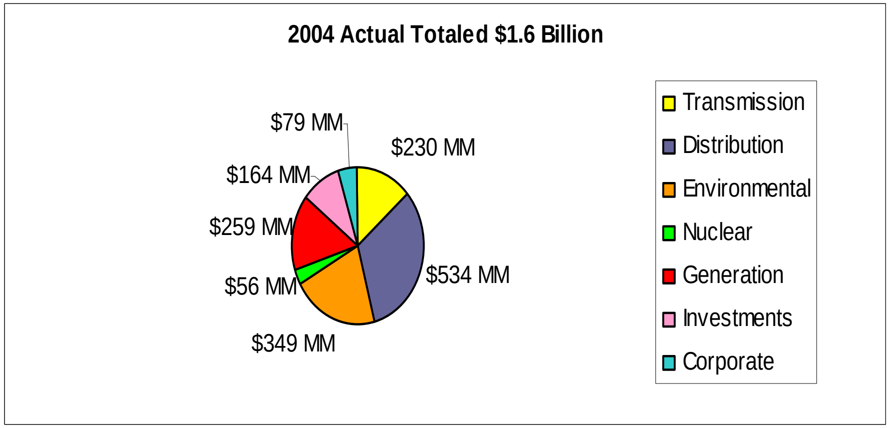
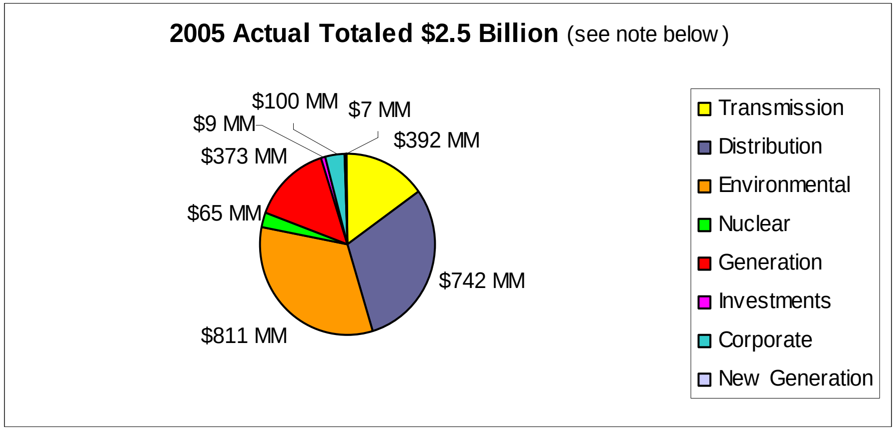
New Generation

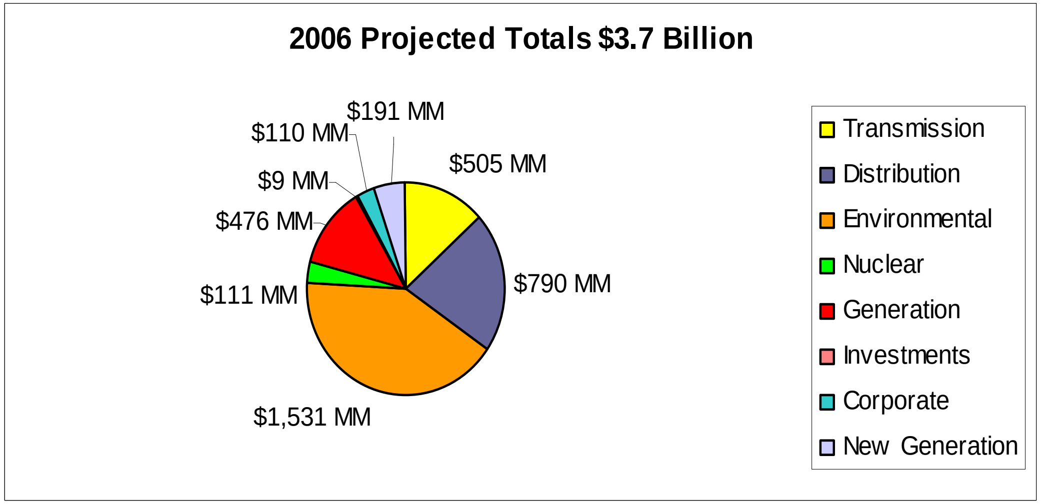
IGCC	PSO RFPs	SWEPCO RFPs
• Expect to obtain permits and finalize engineering by 2007 • Construction of 600 megawatt facility to begin in 2007 • Commercial operation date expected in 2010	• Submitted RFPs totaling 900 megawatts of baseload and peaking capacity • Commercial operation dates expected in 2008 and 2011	• Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity • PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment 2004-2006

Figures exclude AFUDC







Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

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Forecasted Capital Expenditures

Company	2006	2007	2008
		(in thousands)	
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

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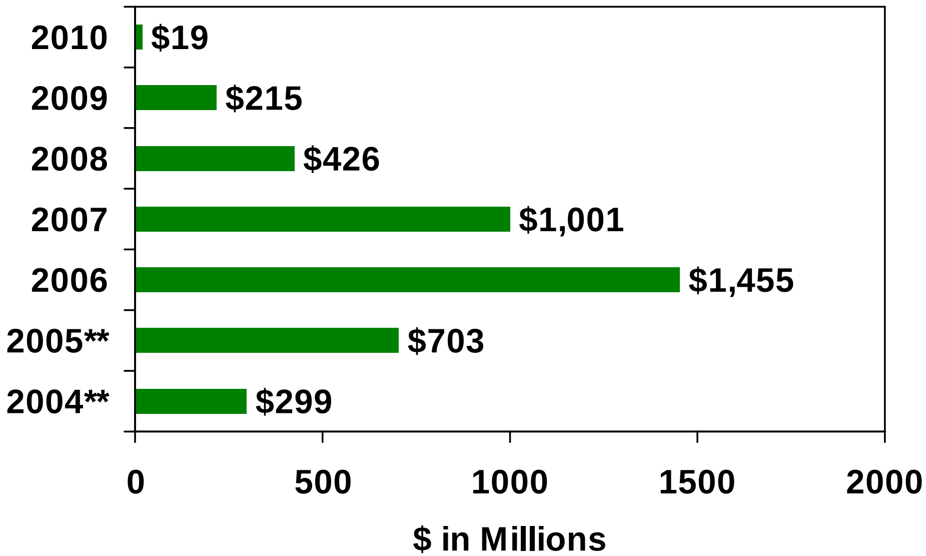
$4.1 Billion Environmental Investment

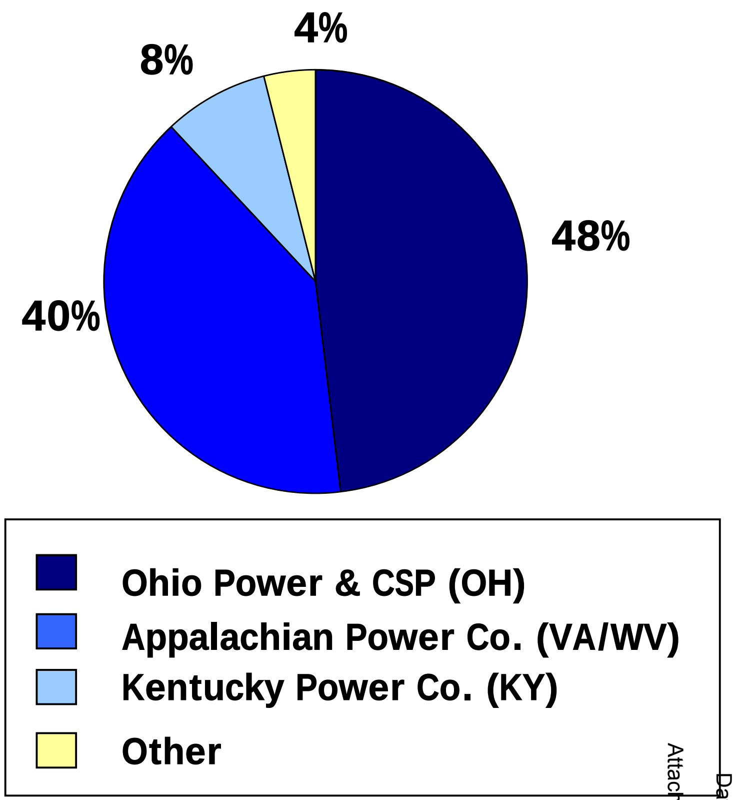
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation

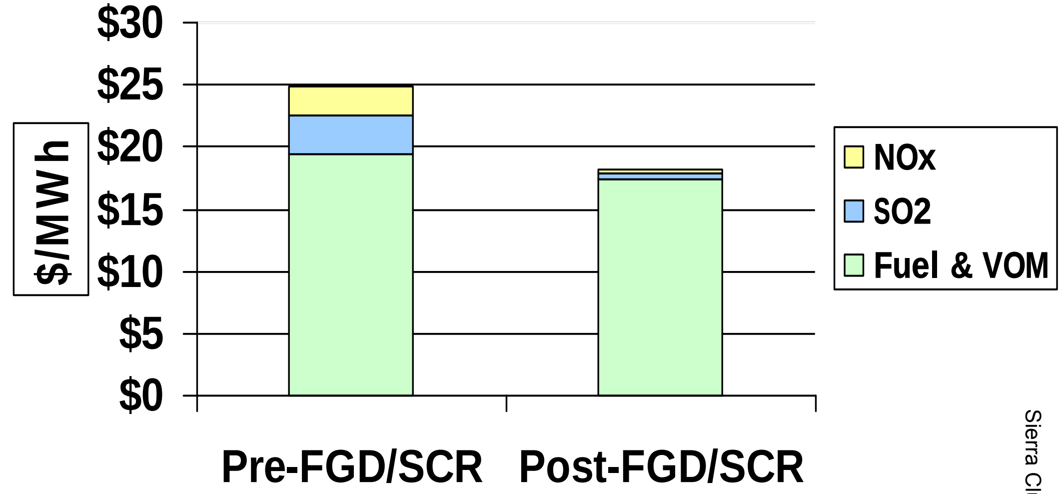


MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*

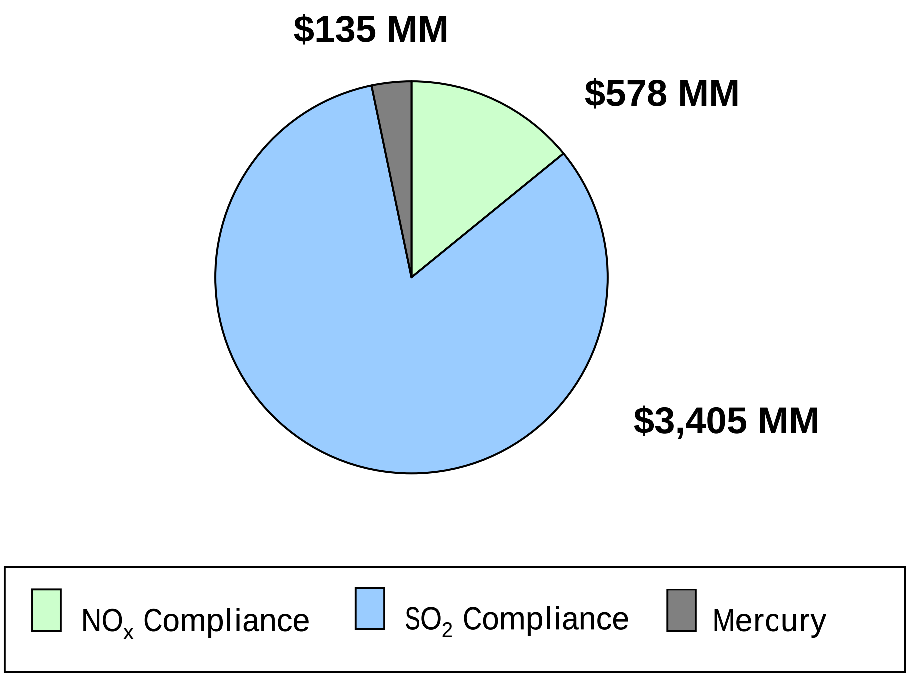


* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Figures Include AFUDC

Environmental Installations

A Century of Firsts

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

2006 – 2010

2006 – 2009

Planned or Under Construction

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

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Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

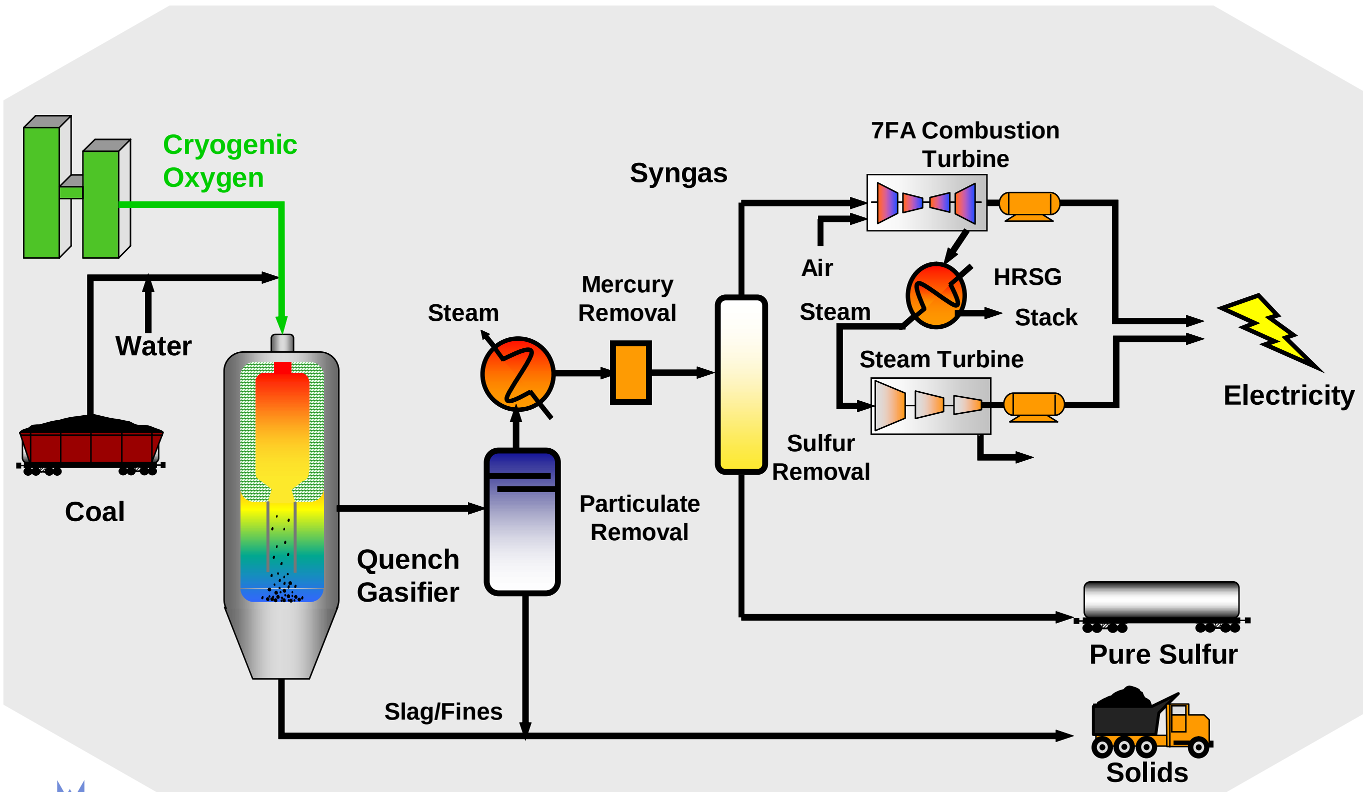
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking to the Future - IGCC



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AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing in IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

•Source: Results of AEP analysis based on EPRI studies.

• Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.

• Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.

• Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.

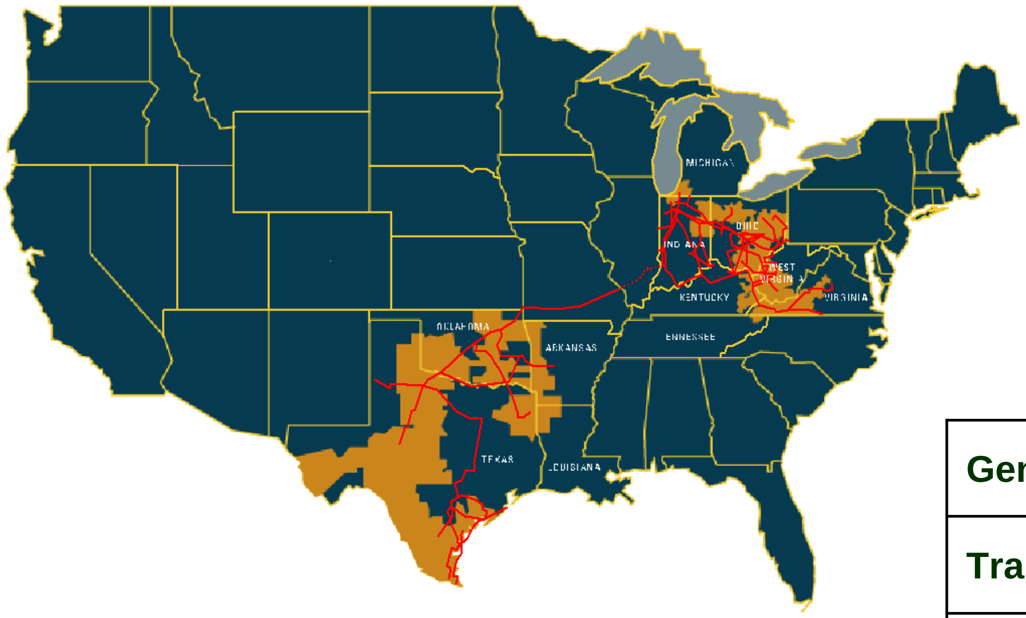
• Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.

• Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.

• Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Strength & Scale in Assets & Operations



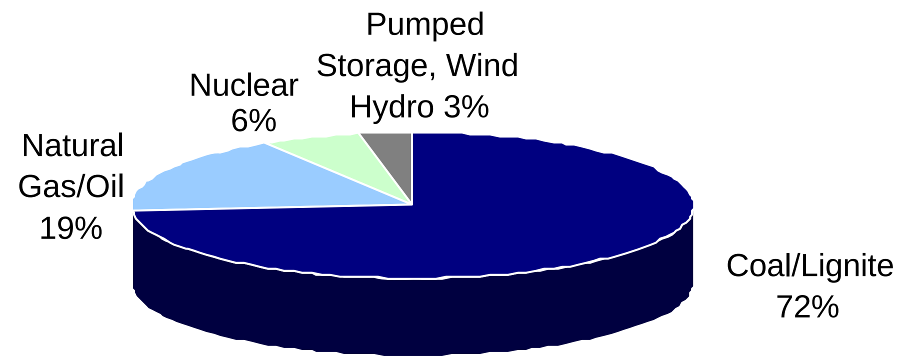
Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Asset Portfolio: Generation Fleet Composition

Capacity by Fuel Mix



- 35,600 MW Domestic Capacity
- 85% System Availability Factor YE 2005
- 63% System Capacity Factor YE 2005

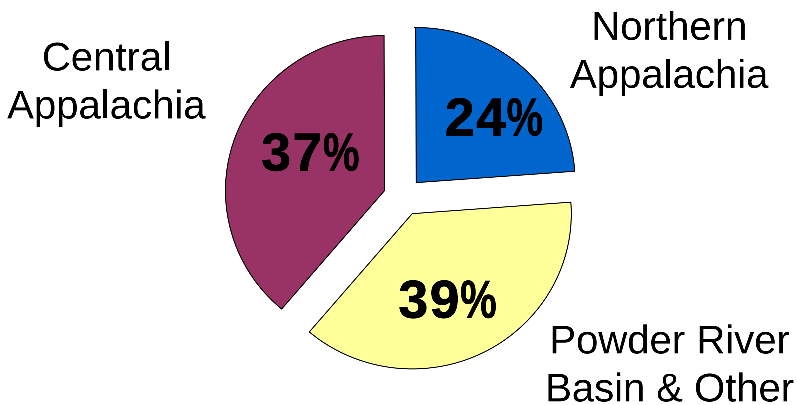
	Baseload	Load-Following	Peaking
PJM	23,985	0	1,954
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**29,902**	**3,516**	**2,142**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Coal Procurement

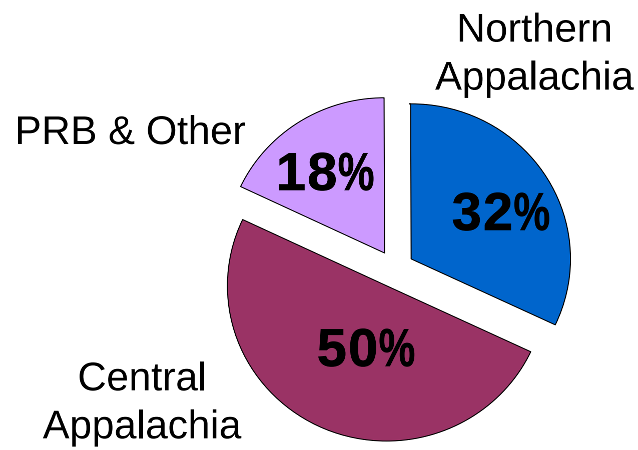
AEP SYSTEM



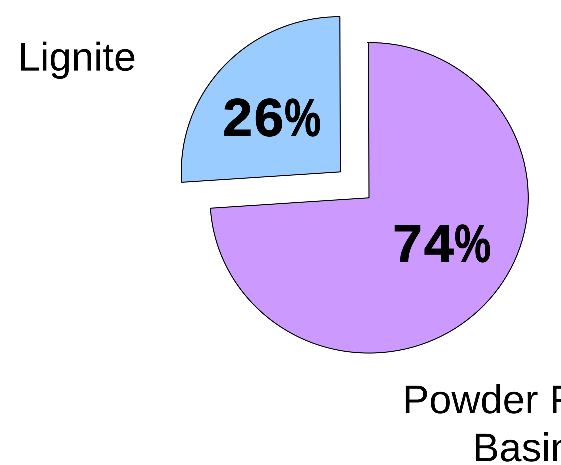
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Essentially >95% purchased for 2006
- Approximately 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM

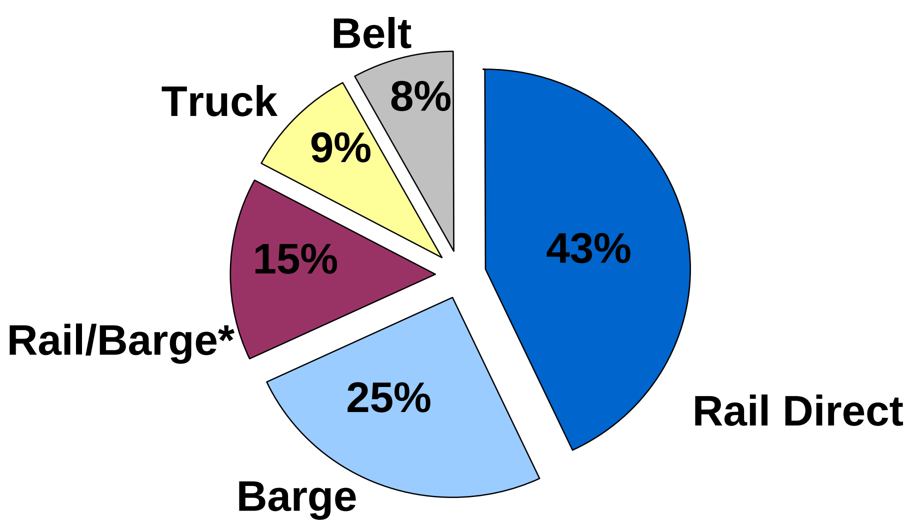


WESTERN SYSTEM

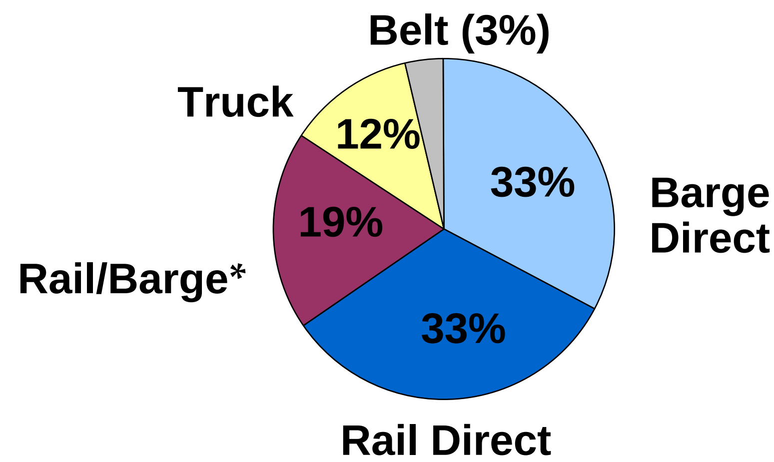


Coal Delivery

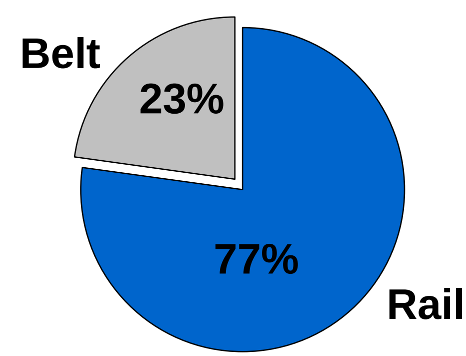
AEP SYSTEM
DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



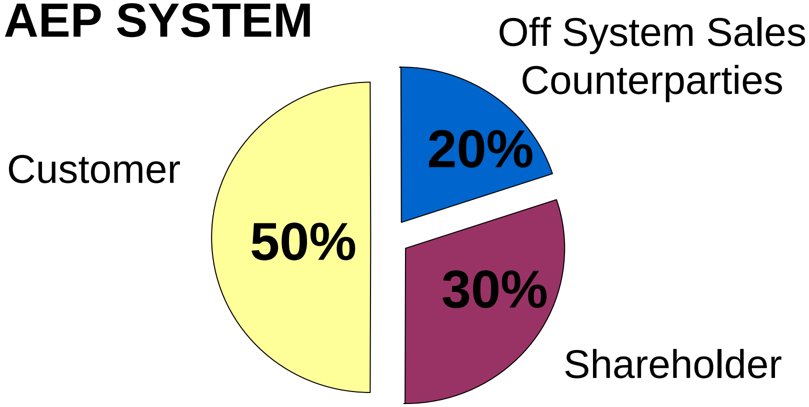
WESTERN SYSTEM
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

Fuel Recovery

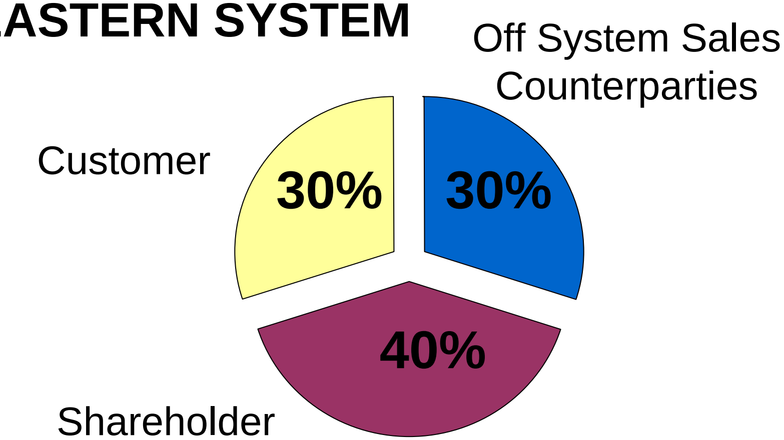
AEP SYSTEM



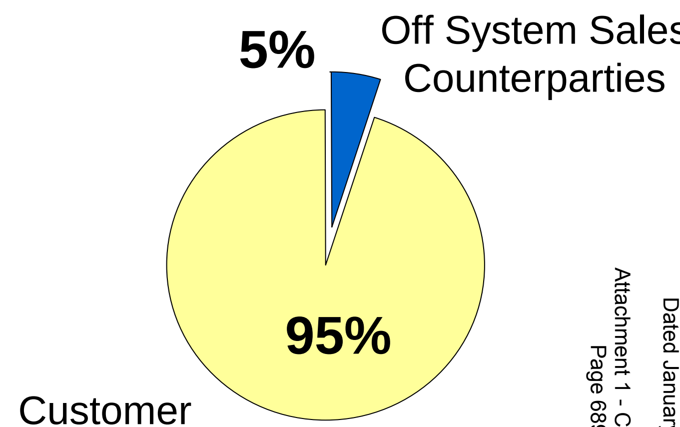
Fuel Cost Recovery

(on average)

EASTERN SYSTEM



WESTERN SYSTEM



- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KGP, KPCo
  - AEP WEST: PSO, SWEPCO

Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

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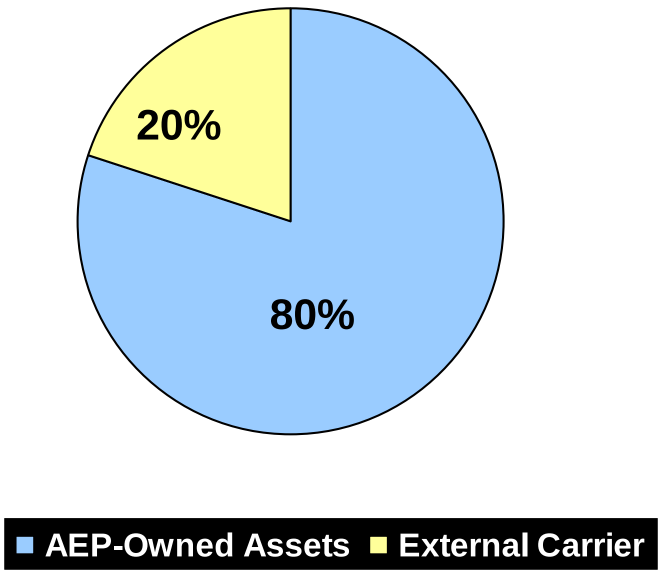
AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

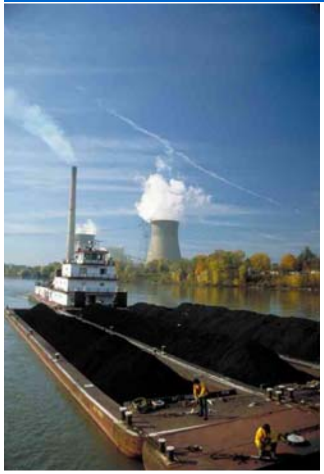
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Highbridge Capital Office Visit

Columbus, OH

February 21, 2007



AEP AMERICAN ELECTRIC POWER®

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission structures; accounting pronouncements; performance of pension and other post retirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP®

Michael G. Morris
Chairman, President & CEO

Upcoming Investor Communication Activities*

Mar. 5-6, 2007	EEI International Conference – London (Generation Panel Discussion)
Mar. 15, 2007	Morgan Stanley Conference – NYC (AEP Generation Sustainability Strategy)
Apr. 24, 2007	Annual Meeting of Shareholders – Shreveport, LA
Apr. 26, 2007	1Q07 Earnings Call

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*Note: Events at which Mike Morris is scheduled to speak with investors/analysts.

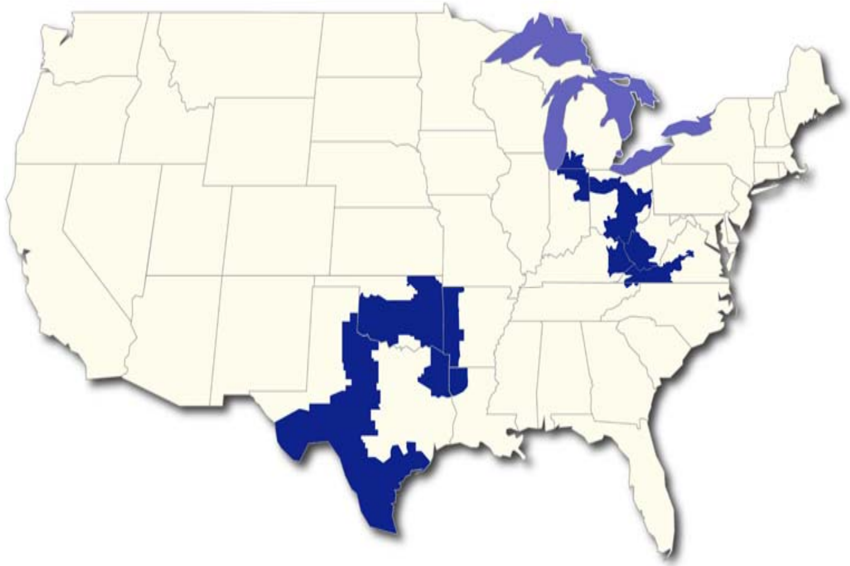
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,000 MW	# 3
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
70%	21%	6%	2%	1%

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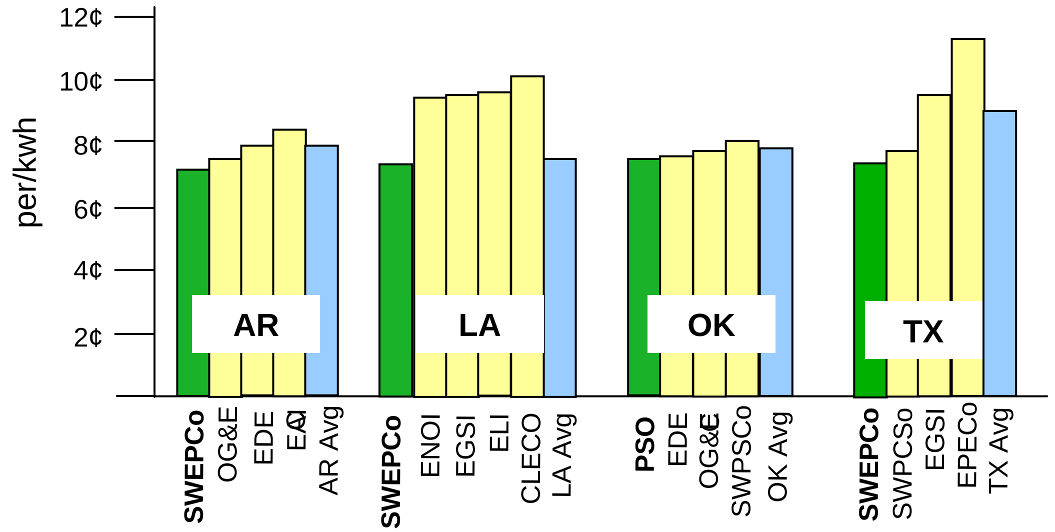
AEP Enjoys Significant Presence Throughout the Energy Value Chain

AEP Provides Low Cost Electric Service

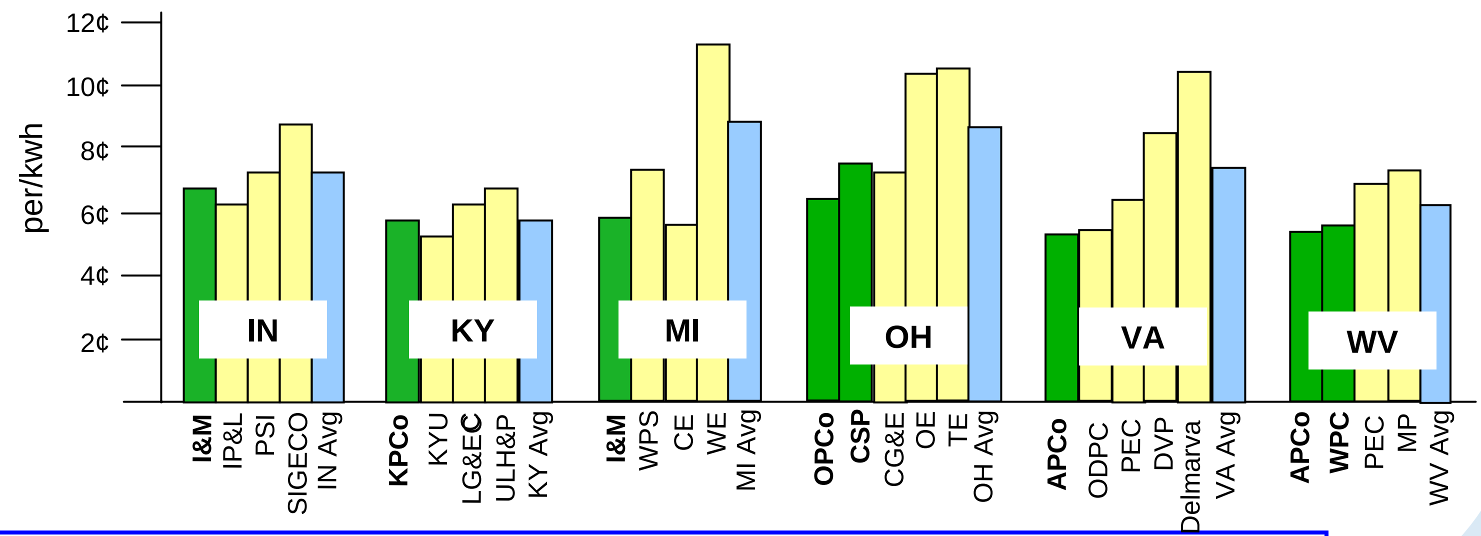
AEP West



Residential Average rates @ 12/31/2005

Source: Winter 2006 EEI Typical Bills and Average Rates Report

AEP East



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2006-2009 Projected Annual Rate Increase Of 3.8%

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

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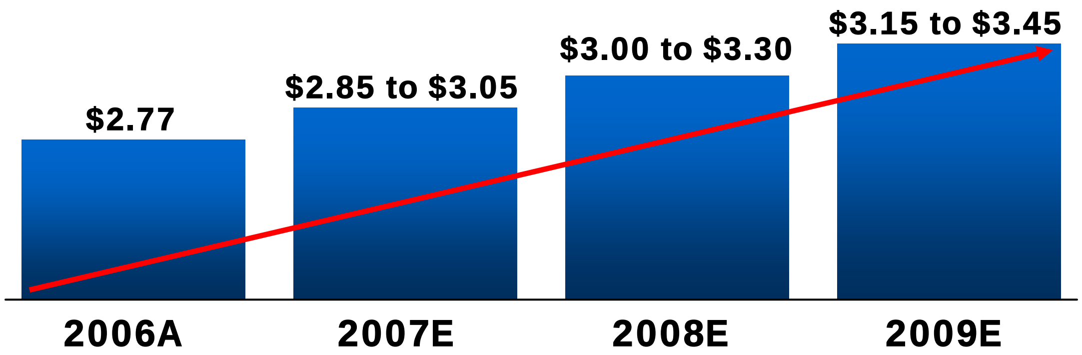
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash
From Operations via Rate Relief and Debt Issuances

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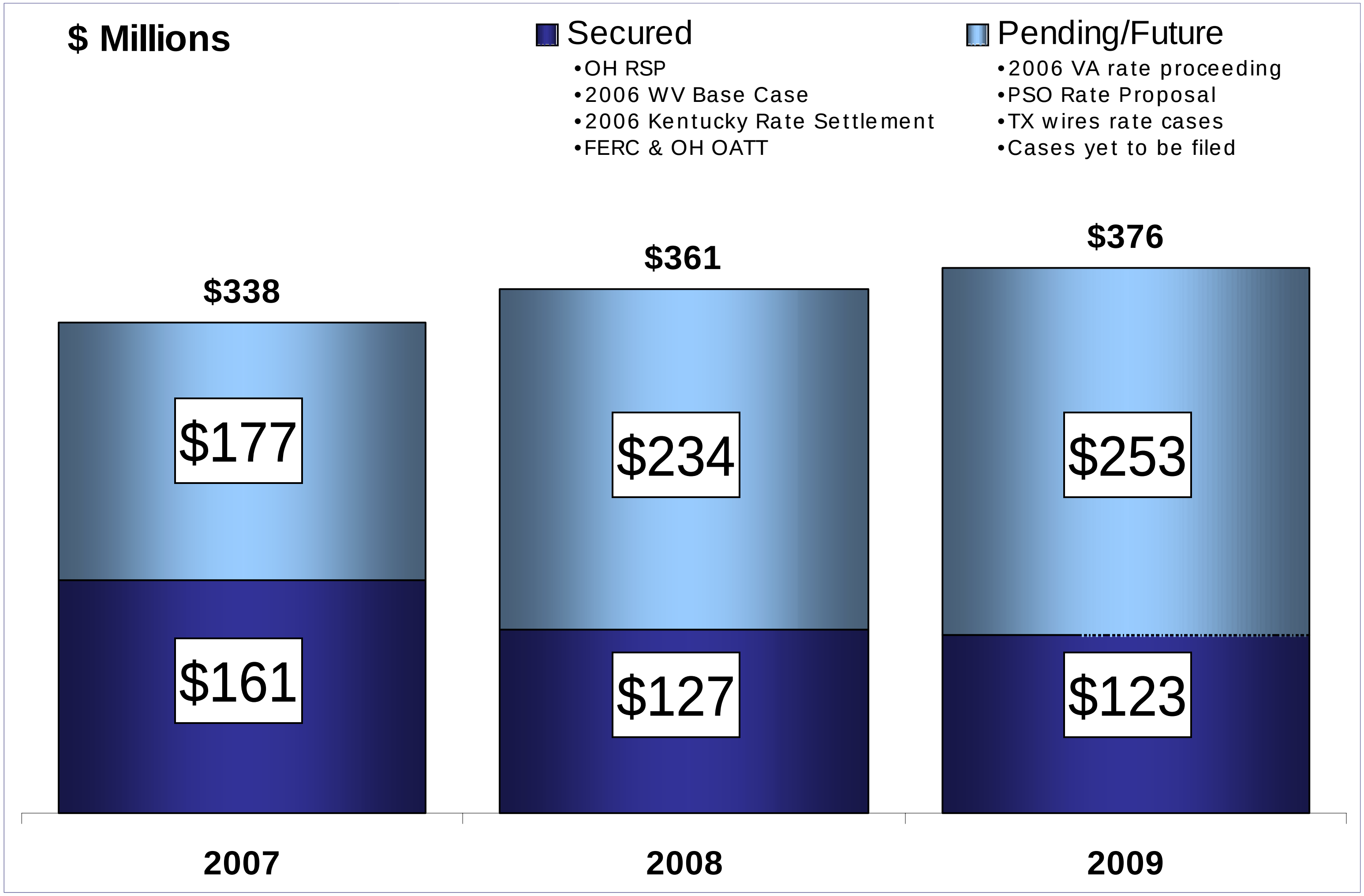
Incremental Rate Relief Composition



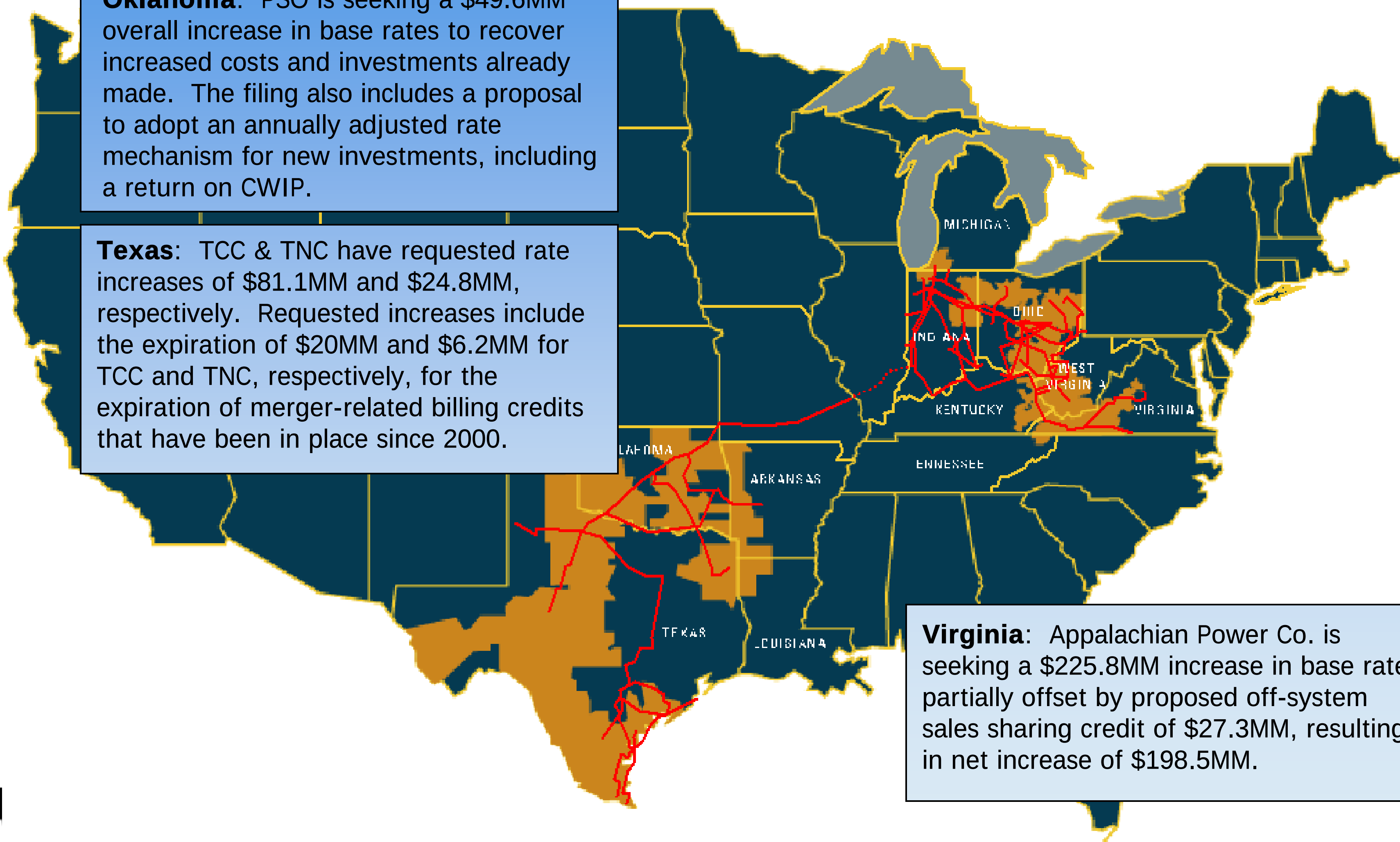
Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

Rate Relief Is A Critical Element To AEP's Financial Success

Base Case Regulatory Summary

Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.



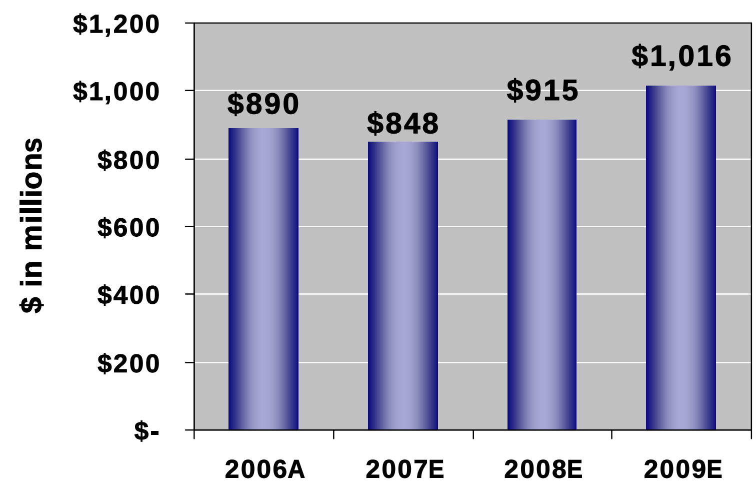
Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an annual average investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $60.8MM and $15.9MM for TCC & TNC distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

Transmission Investment Forecast

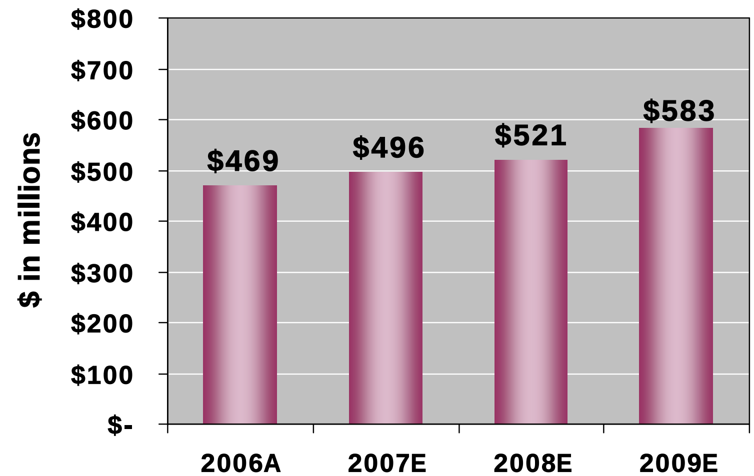
- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of "postage stamp" rate
  - Final order expected in early to mid-2007

- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services

- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company
  - FERC filing to transfer transmission assets to ETT submitted Jan. 22, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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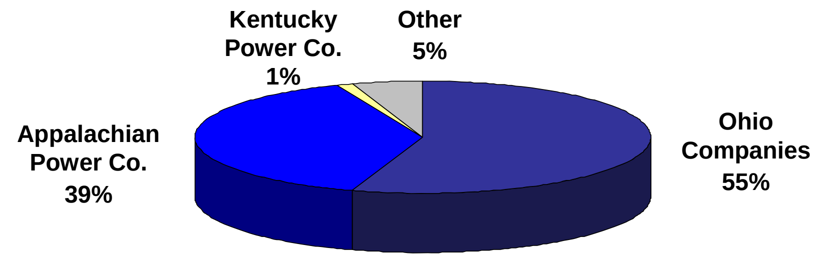
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

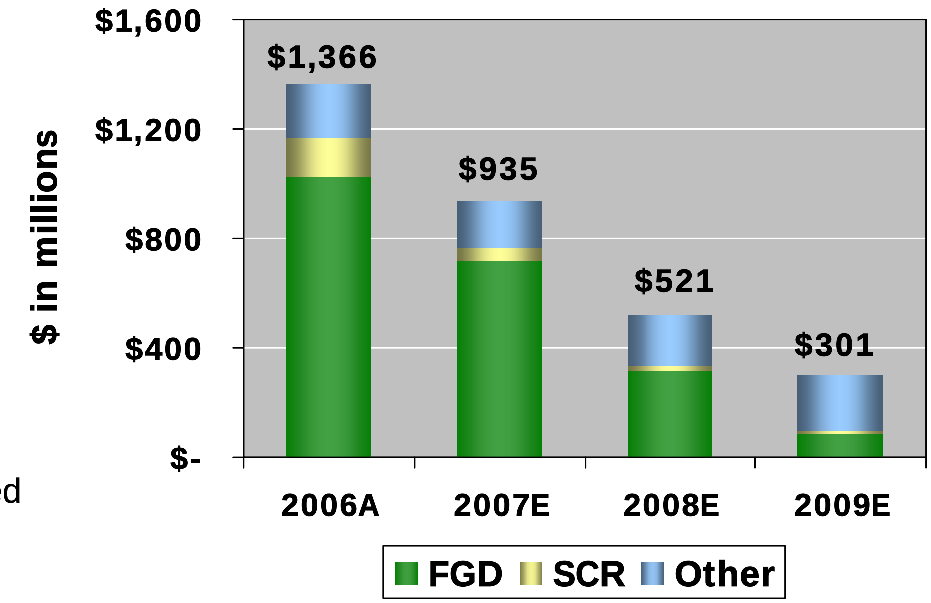
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures – activation of 4% rider
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



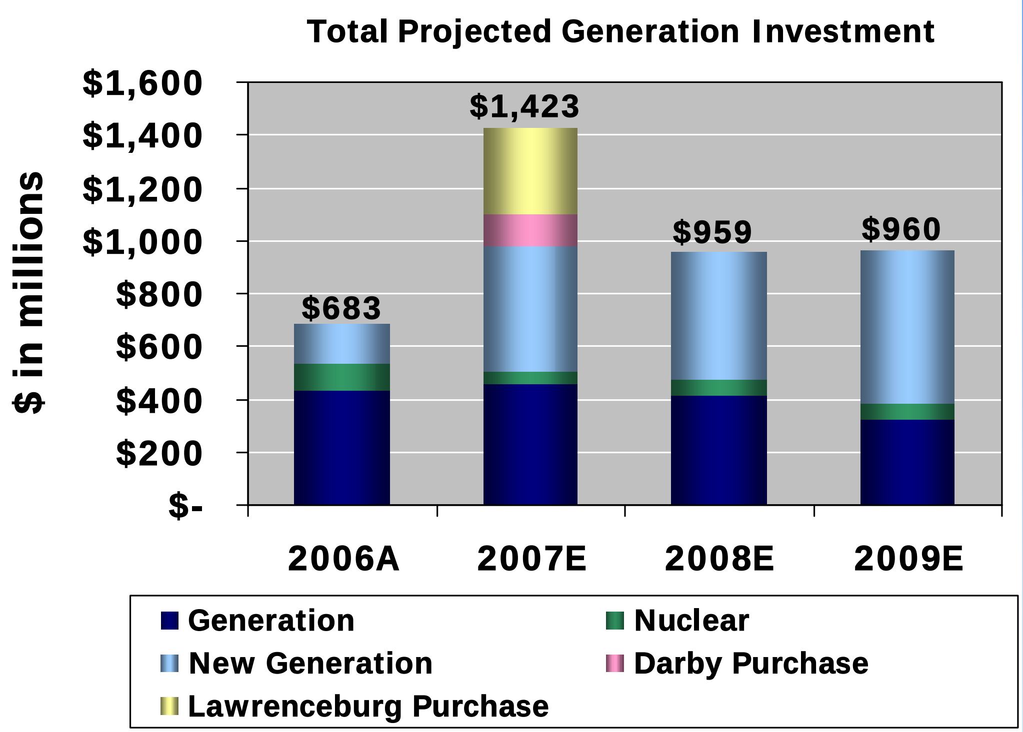
Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP
- Distressed Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



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Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	1Q07 (1)
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07 (2)
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	950 (4)	2011
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review (5)	Coal	IGCC	600	TBD

(1) Sale expected to close 1Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

AEP®

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.6%
- Positive dividend outlook
- Stable credit profile

Appendix

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 37,000 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

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Summary of 5-7 % Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

AEP®

Rate Base Investment Coupled With Innovative Regulatory Plans Will Reduce Lag And Drive Earnings Growth

AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP®

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

AEP Transmission Network – Largest in the Country

Operating Company Level

(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

AEP®

AEP Is The Leader In Transmission Expertise

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 45% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 48% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 25,746 MEGAWATTS

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	Projected 2007
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	539*	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

* Oklaunion's MW capacity represents combination of PSO, TCC & TNC ownership. TCC's 54 MW ownership of Oklaunion is currently under negotiation for sale.

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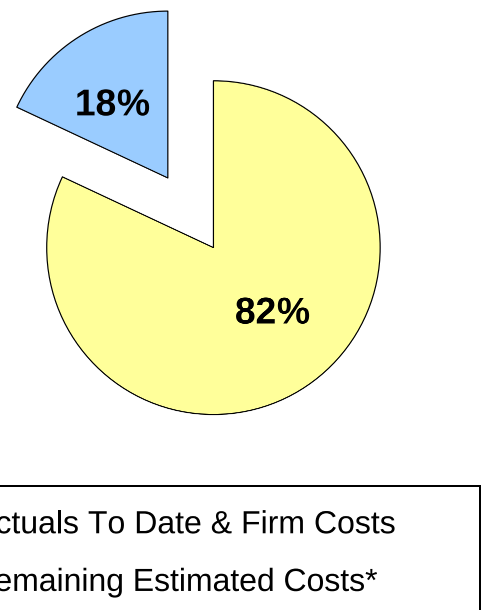
Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

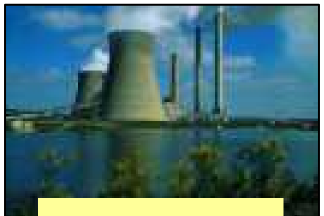
Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

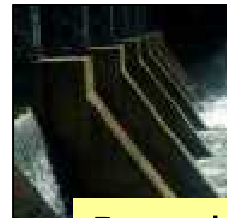
Domestic Generation Fleet

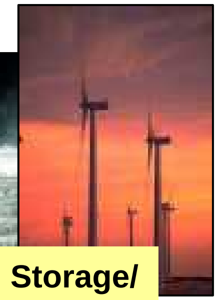


Coal/Lignite
70%

Nat. Gas/Oil
21%

Nuclear
6%





Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
36,672 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

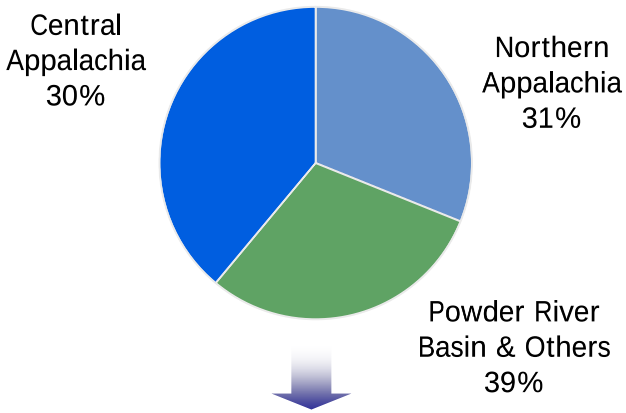
RFC (formerly ECAR)	71%
SPP	23%
ERCOT	6%

Note: The figures on this slide exclude the Darby and Lawrenceburg plants, as these purchases have not yet closed.

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

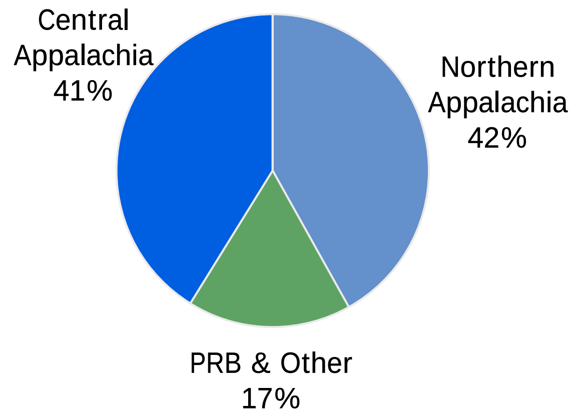
Total AEP System



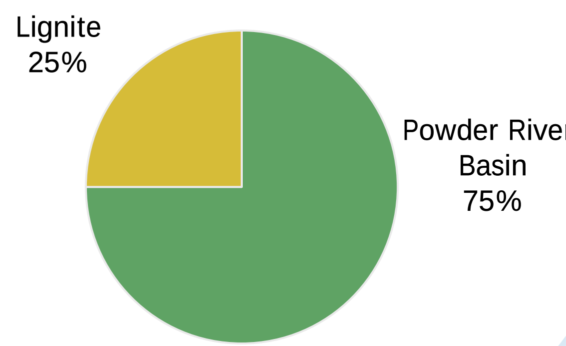
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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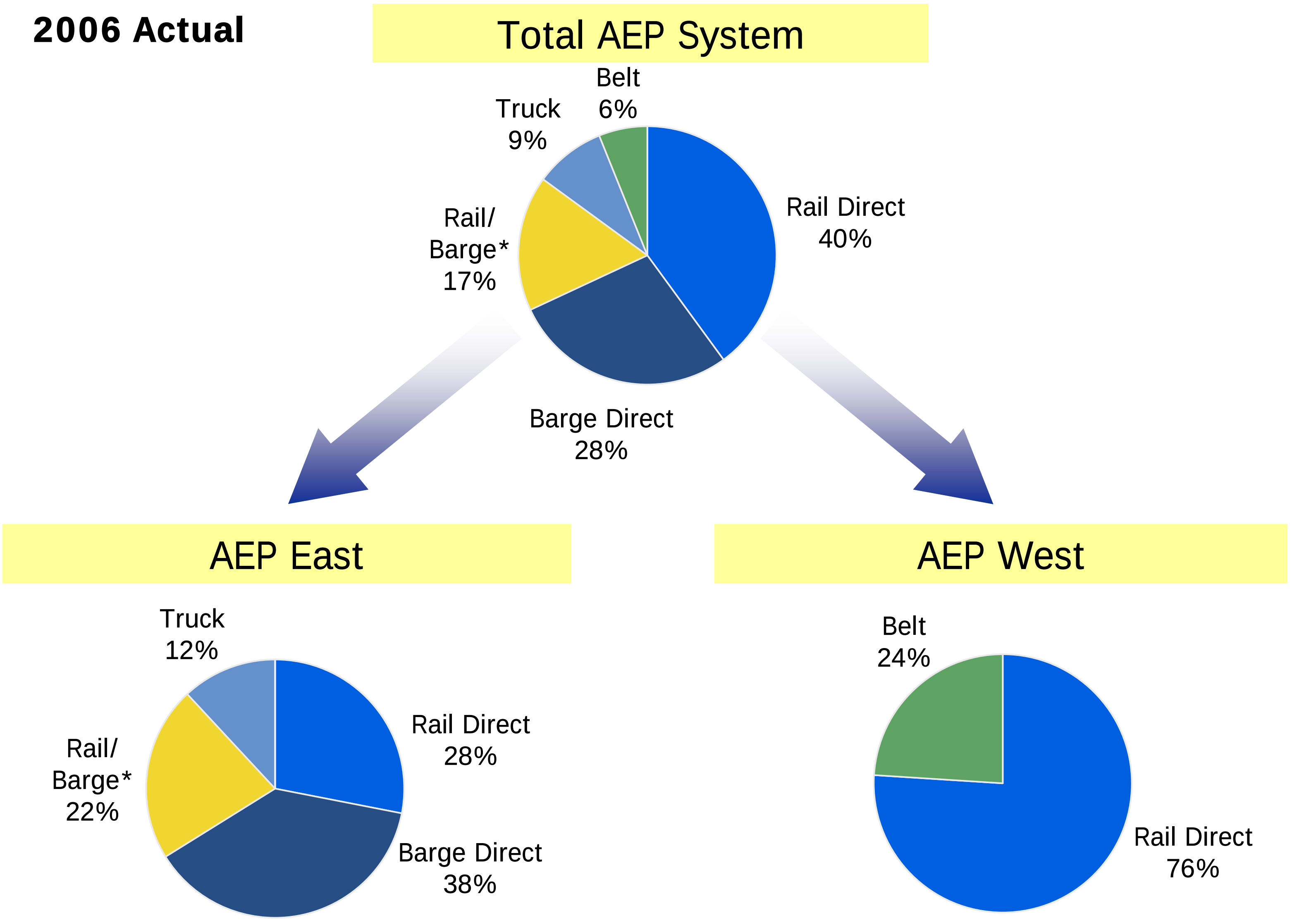
Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Regulatory Activity

Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
    - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due Feb. 14, 2007; Evidentiary hearing to commence Feb. 27, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the allowed 4% provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval 1) to operate as an electric transmission utility in Texas; 2) to contribute transmission assets currently under construction by AEP subsidiary TCC to the joint venture company; and 3) establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%
  - An order is expected in Fall 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each acquire a 50% interest in the joint venture

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $111MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in early to mid-2007

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Regulatory Activity

FERC Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in early to mid-2007.

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2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power

Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Multi-Year Capital Investment Funding Plan

	Actual 2006	Projection 2007	2008	2009
Planned Capital Investment (Excluding AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,771	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 226	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,422	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (208)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.5x to 4.0x
FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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Capital Investment Is Funded By Cash From Operations And Debt Issuances

Investing in IGCC

Arranged by Citigroup

AEP Headquarters

Columbus, Ohio

November 2, 2006

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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IGCC – Significant Role in New Generation Plan

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in OH in 2007, assuming regulatory approval
- Certificates of Convenience and Necessity (CCN) applications filed in OH and WV and currently in process.

SWEPCO

- May 31, 2006- Announced plans to build $1.7 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling 320 MW at Tontitown, AR and combined-cycle gas plant totaling 480 MW at Arsenal Hill
- Aug 2006 – Announced plans to build $1.3 billion 600 MW base load ultra-supercritical coal-fueled plant – expected SWEPCO investment will be approx. 75%
- Commercial operation dates between 2007 and 2011

PSO

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

Integrated Gasification Combined Cycle

AEP IS COMMITTED TO IGCC TECHNOLOGY

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region.   AEP intends to seek regulatory recovery approvals in advance of building the plant.

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO_2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO_2 Capture ($/MWh)	94	87	137

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO_2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Regulatory Activity

Ohio IGCC Activity

March 18, 2005: CSP and OPCO filed an application with the PUCO seeking authority to recover costs related to building and operating an IGCC plant if built in Ohio.

October 2, 2006: Filed state environmental permit application with the Ohio Environmental Protection Agency

West Virginia IGCC Activity

January 11, 2006: Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

October 2, 2006: Filed state environmental permit application with the West Virginia Department of Environmental Protection

AEP WILL PIONEER CONSTRUCTION OF FIRST COMMERCIAL SCALE IGCC PLANT IN THE WORLD

IGCC Activity in Ohio

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2012* (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2012* (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 filing – following completion of FEED study
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2012*:

- Design, construct and start-up plant

Construction of IGCC plant takes approximately 4 years from ground-breaking to start-up

***PROJECT TIMING DEPENDENT ON REGULATORY RECOVERY ASSURANCES**

IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMITTING PROCESS WILL TAKE 1 – 2 YEARS

AMERICAN ELECTRIC POWER

INVESTOhio

Columbus, Ohio

September 15, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG

FLEXIBLE

ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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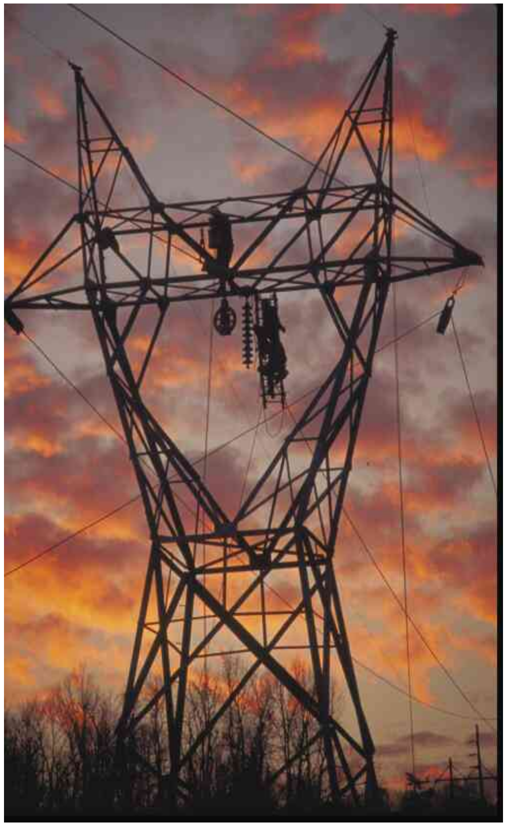
AEP AMERICAN ELECTRIC POWER

Chuck Zebula
Senior Vice President, Investor Relations & Treasurer

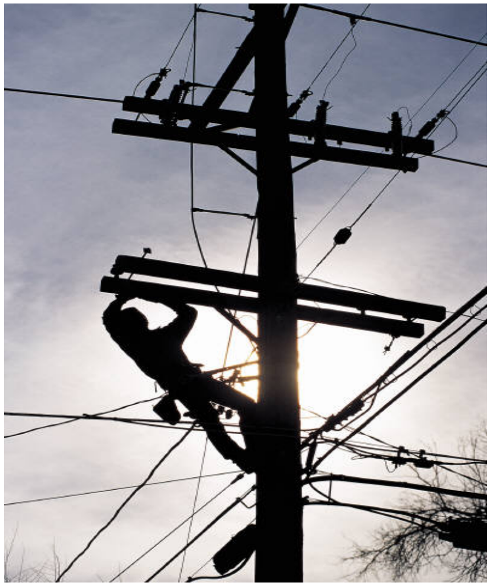
AEP AMERICAN ELECTRIC POWER

AEP is . . .

One of the largest electricity generator in the United States, owning over 39,000 MW of generating capacity



The largest electricity transmitter in the United States, owning over 39,000 miles of transmission



The largest electricity distributor in the United States, owning and operating over 213,000 miles of distribution

AEP AMERICAN ELECTRIC POWER

Company Overview

- 5.2 million customers in 11 states
- 21,700 employees
- Industry-leading size and scale of assets
- 11 Operating Companies
  - Appalachian Power Co. (VA, WV)
  - Columbus Southern Power Co. (OH)
  - Indiana Michigan Power Co. (IN, MI)
  - Kentucky Power Co. (KY)
  - Kingsport Power Co. (TN)
  - Ohio Power Co. (OH)
  - Public Service Co. of Oklahoma (OK)
  - Southwestern Electric Power Co. (LA, AR, TX)
  - Texas Central Co. (TX)
  - Texas North Co. (TX)
  - Wheeling Power Co. (WV)

AEP AMERICAN ELECTRIC POWER

AEP enjoys a diverse geographic footprint.

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

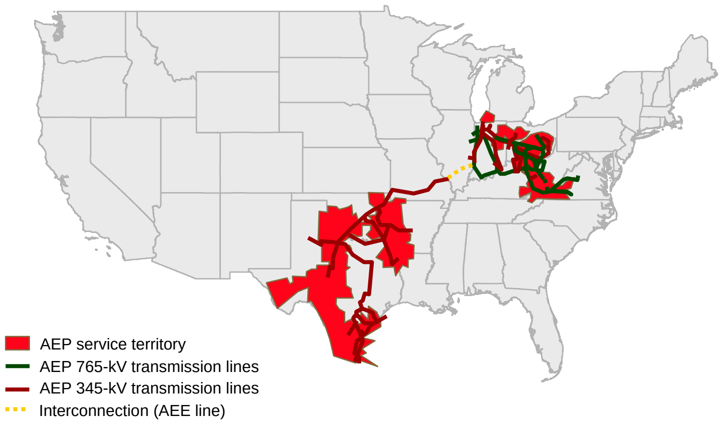
- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

Premier Regulated Utility Platform

Overview

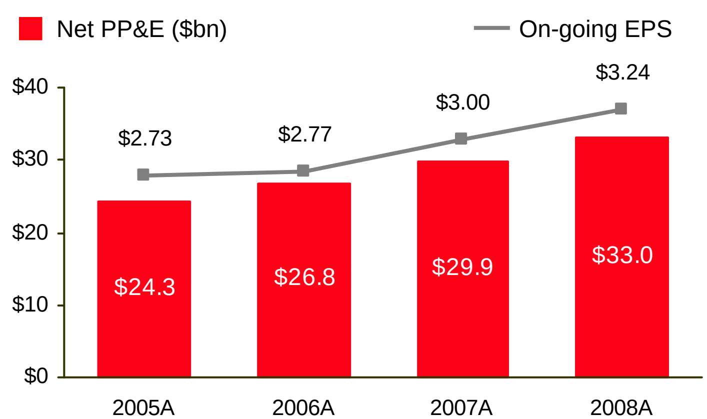


AEP's Leadership Position

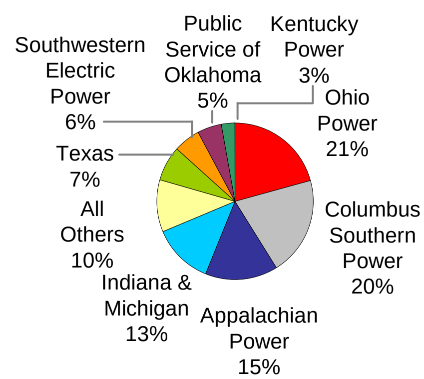
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn

- *Highly diversified regulated utility earnings contribution*

[1] *Source: Company filings*

AEP AMERICAN ELECTRIC POWER

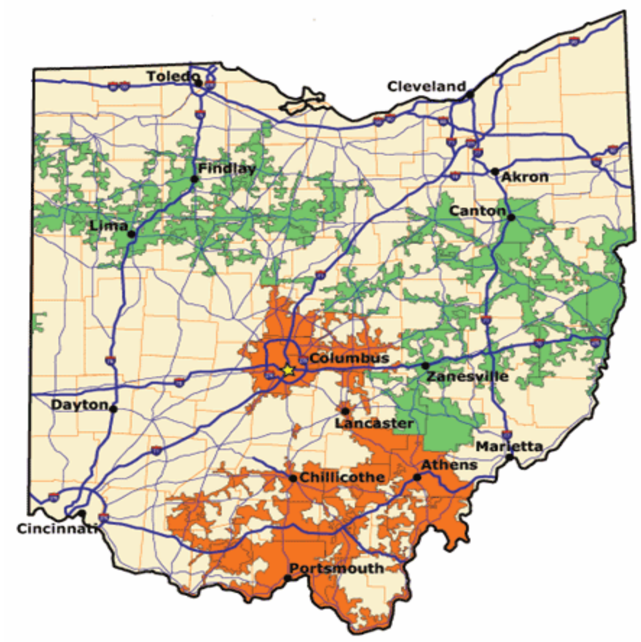
Strong Ohio Presence

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2008, CSPCo had 1,323 employees. CSPCo’s service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio.

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2008, OPCo had 2,434 employees.



PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals
Petroleum Refining
Food Products
Rubber & Plastic Products
Fabricated Metals
Stone, Clay and Concrete Products

Total Customers at 12/31/08:

• Residential	1,277,000
• Commercial	170,500
• Industrial	10,500
• Other	3,000
Total	1,461,000
Generation Capacity (MW)	12,179
Transmission Miles	8,924
Distribution Miles	45,277

AEP AMERICAN ELECTRIC POWER

Diversified Fuel Mix

Coal/Lignite

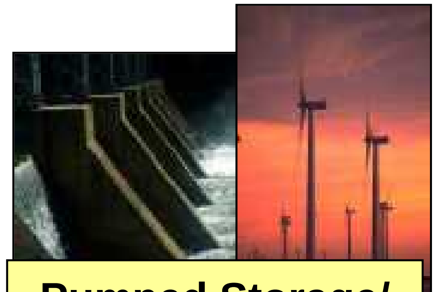
66%

Natural Gas/ Oil

23%

Nuclear

6%



Pumped Storage/ Hydro/Wind

5%

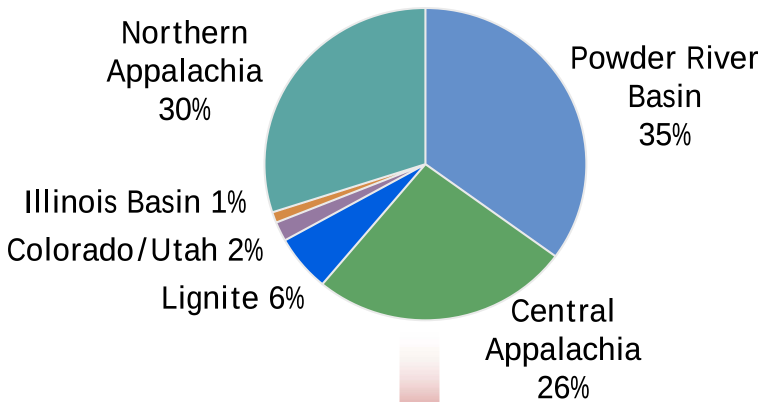
AEP's Generation Fleet

39,200 MW Capacity

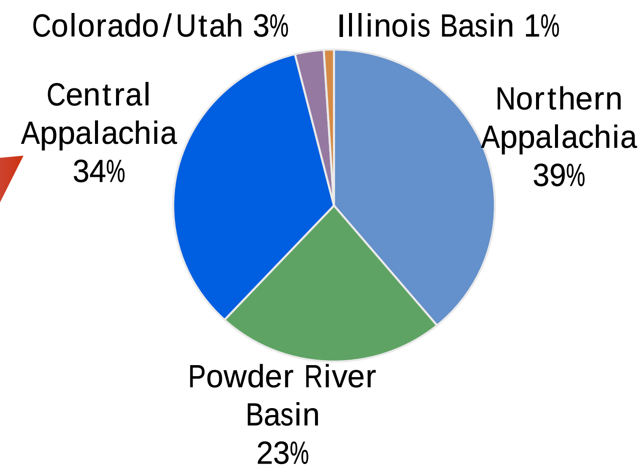
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

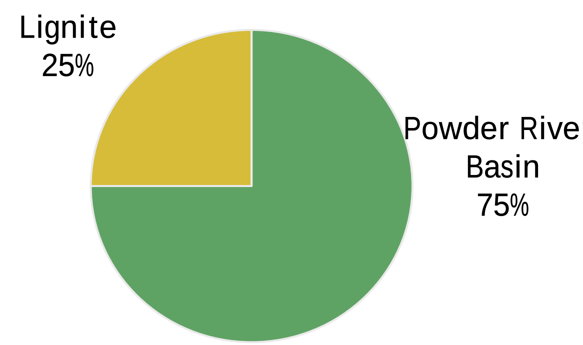
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

AMERICAN ELECTRIC POWER

AEP River Operations

- Full-service Inland Waterways carrier
  - 2,978 hopper barges
  - 58 towboats & 25 harbor boats
- Tonnage & Commodity:
  - Captive: (for AEP) 37MM tons of coal
  - Commercial: 35MM tons of coal/grain/bulk
- Gulf Operations
  - Barge cleaning and repair
  - Fleeting and shifting
  - Midstream transfers
- Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA

Inland Waterway Routes For AEP River Operations

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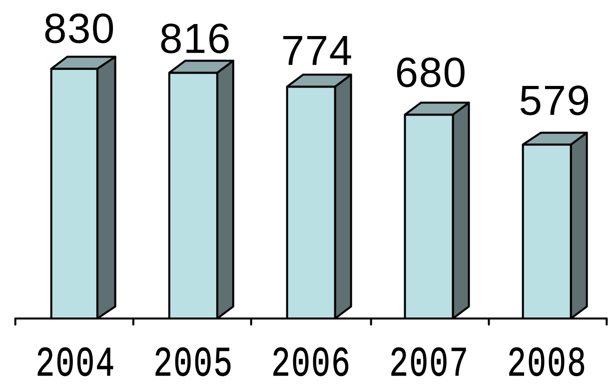
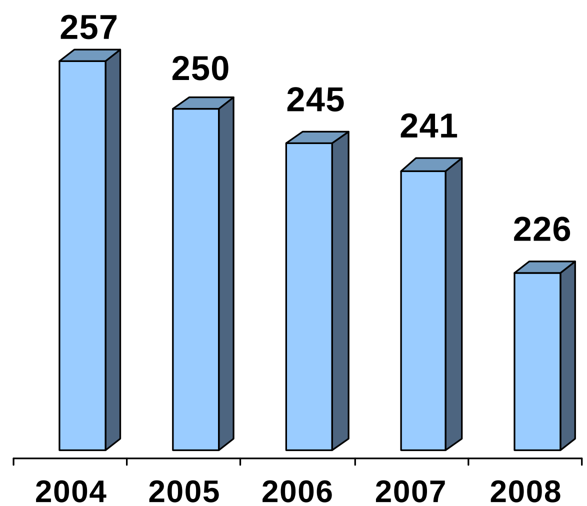
Environmental Program

- Environmental retrofits keep coal plants viable in order to take advantage of vast domestic fuel resources
- Scrubbers and SCRs reduce emissions of SO_2, NOx and Mercury
- Environmental technology installed on existing plants delays the premature retirement of those plants, thereby keeping low cost generation assets available to the market
- Since 2004, we have invested $4.4 billion in environmental retrofits to meet obligations required by environmental regulations

Annual SO_2 Emissions
(in kilotons)



Annual NOx Emissions
(in kilotons)



AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop "transmission superhighway" to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

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Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America's power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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AEP AMERICAN ELECTRIC POWER

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US with legislation rather than regulation
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of international trade provisions to protect American jobs

AEP supports the American Clean Energy and Security Act of 2009

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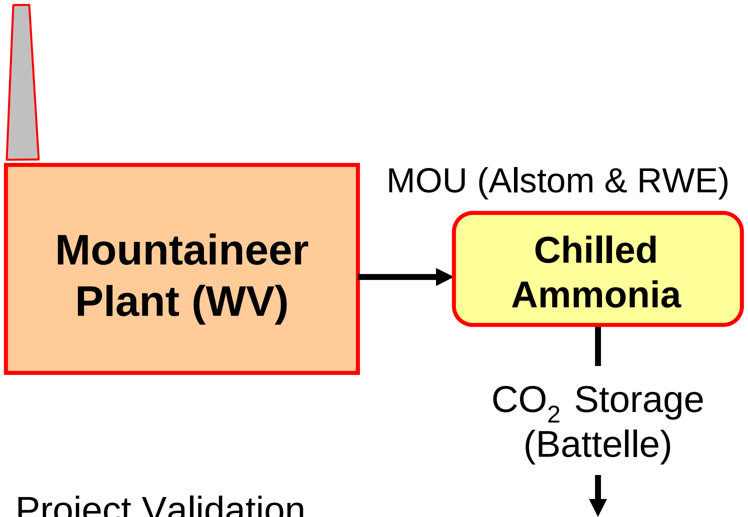
Carbon Capture & Storage



Project Validation

- Alstom “Chilled Ammonia” Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies’ Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- Operations commenced September 2009
- Geologic storage for CO_2
- Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the ‘economic’ hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

Pioneer — **COD: 2015**

- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV — **COD: 2014**

- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass — **COD: 2013-14**

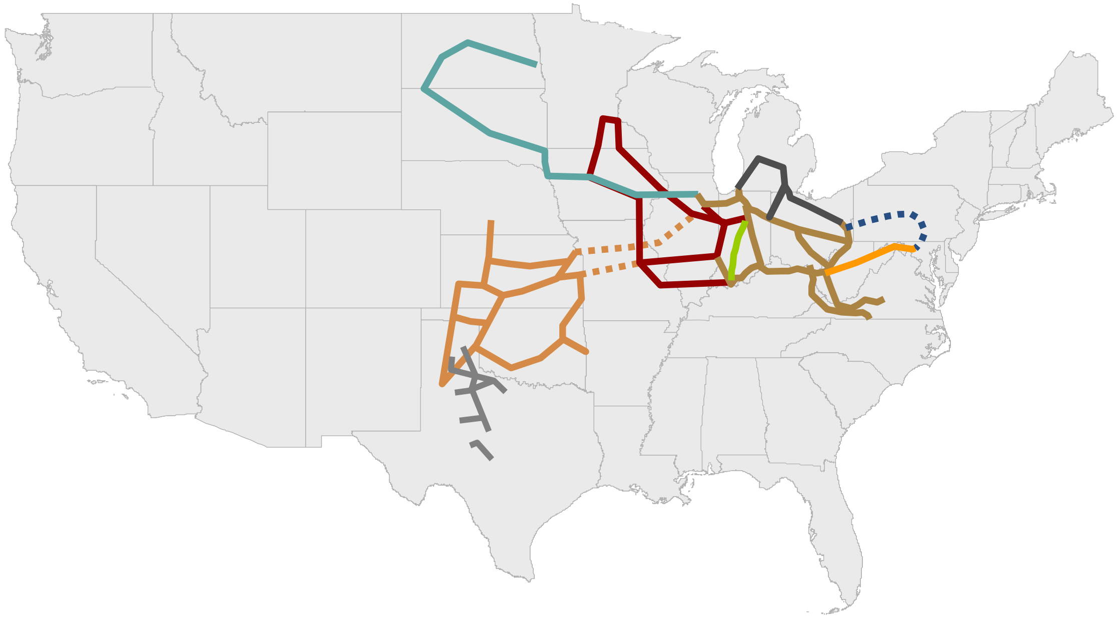
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind — **COD: 2013**

- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT — **COD: 2013**

- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan — **COD: ~2020**

- 700 miles of 765 kV

PJM Projects

- Enhance existing 765/345 kV

Hartland — **COD: ~2020**

- 1000+ miles of 765 kV

MISO Vision Plan

- 765 kV Backbone

SPP Overlay — **COD: 2013-14**

- 765 kV Backbone

ETT — **COD: ~2018**

- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Overview of 2009 Guidance

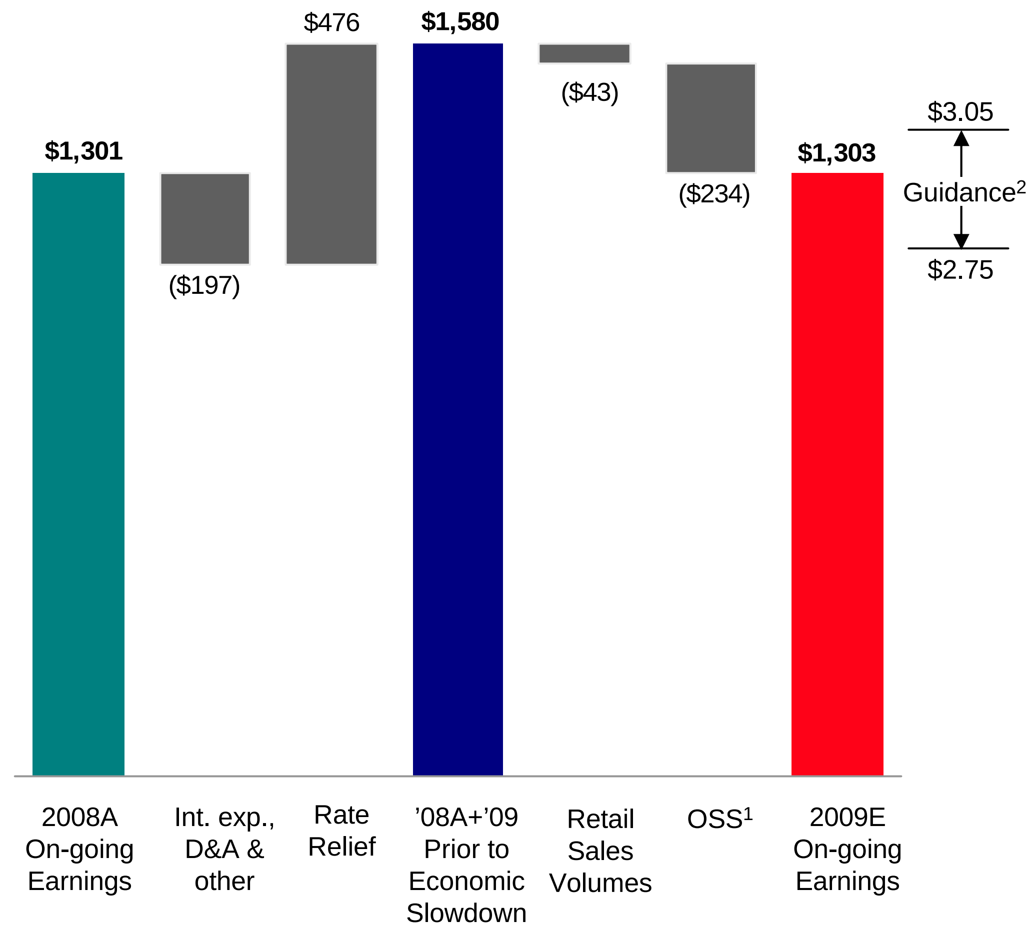
2009 Earnings Drivers:

- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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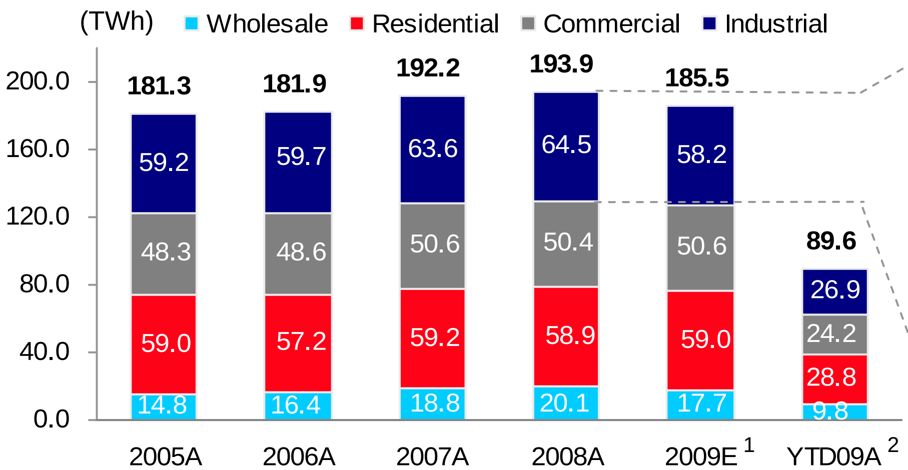
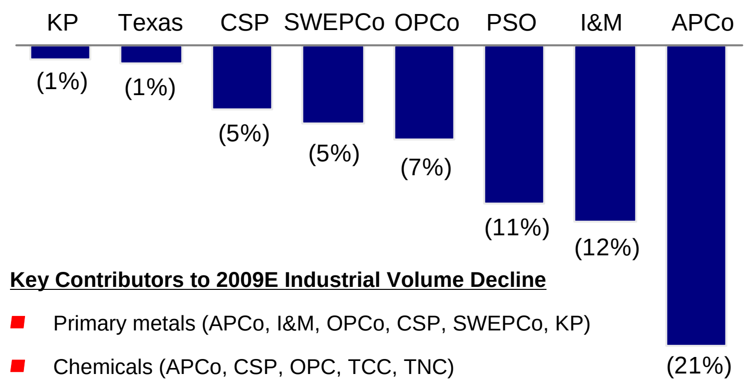
Key Drivers of 2009 Guidance: Retail Sales

Retail Load by Customer Class



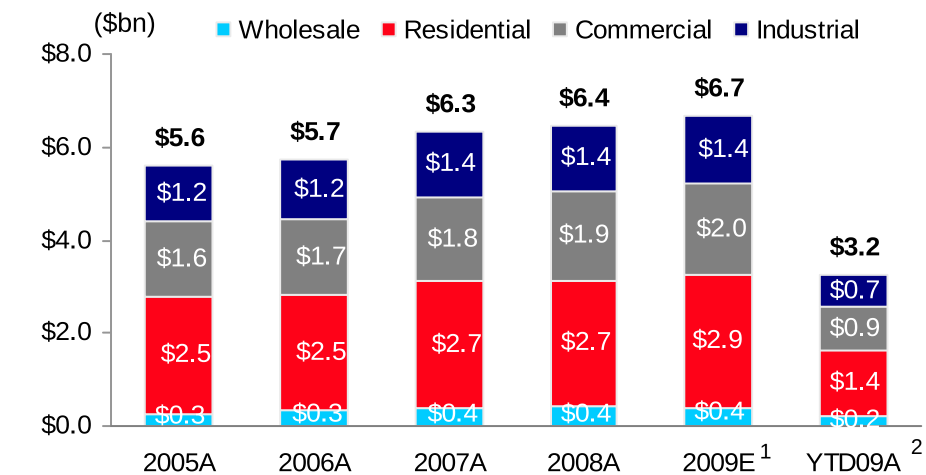
Forecast Drop in 2009 Industrial Sales

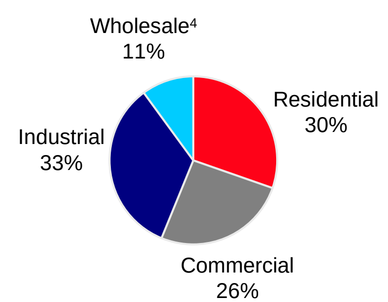


Key Contributors to 2009E Industrial Volume Decline

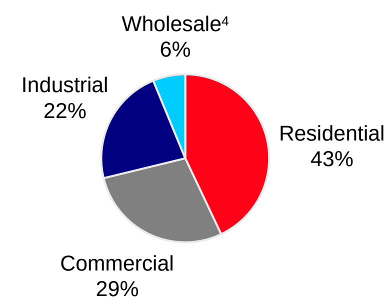
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Chemicals (APCo, CSP, OPC, TCC, TNC)
- Paper (APCo, PSO, SWEPCo)
- Plastics & Rubber (APCo, CSP, OPCo, I&M)

Retail Base Revenue[3] by Customer Class





2008 Retail Load = 193.9 TWh



2008 Retail Base Revenue [3] = $6.4bn

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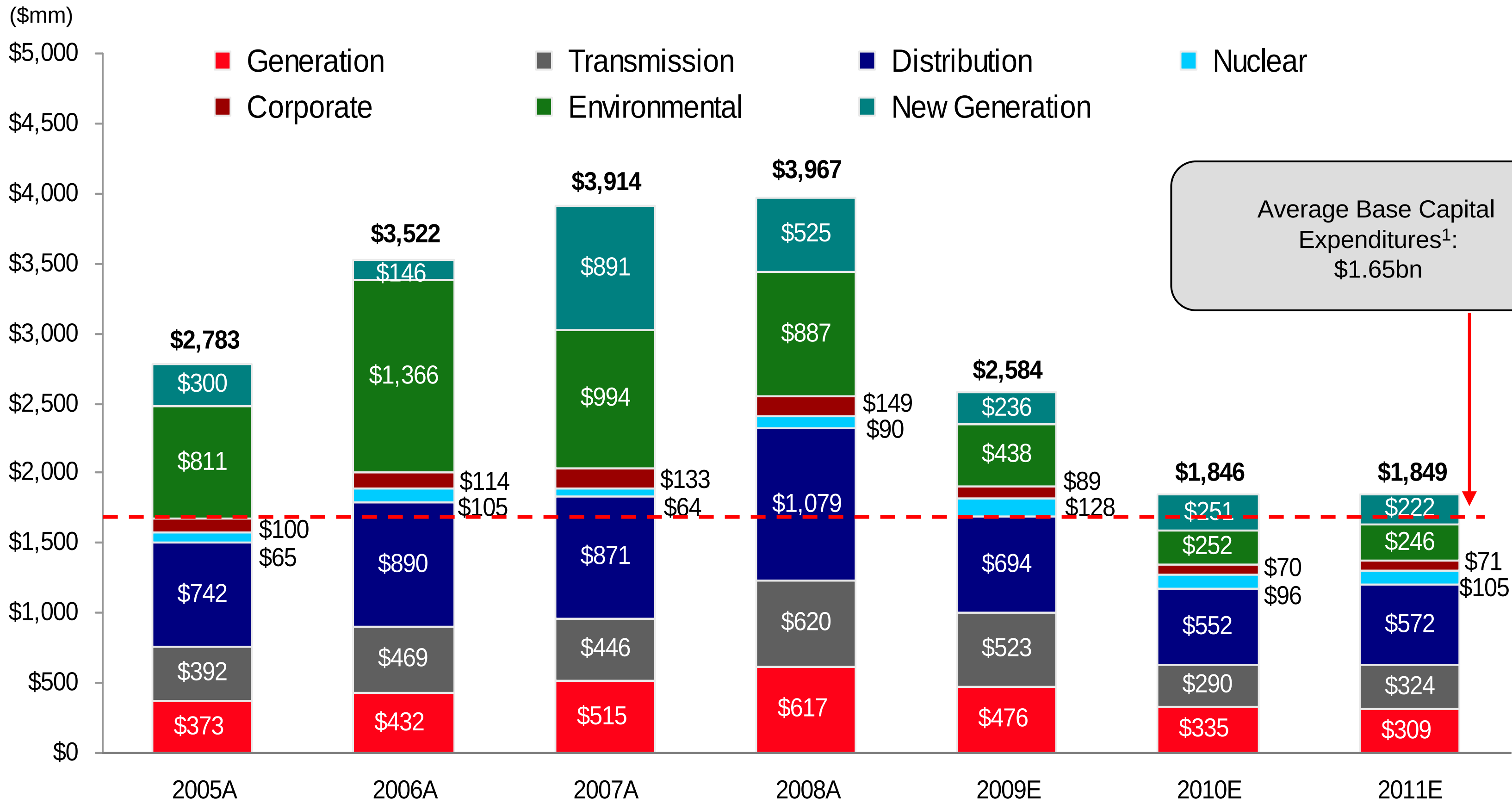
[1] *2009E assumes normalized weather*
[2] *YTD09A represents actual results through June 30, 2009*

[3] *Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables*
[4] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



	2005A	2006A	2007A	2008A	2009E	2010E	2011E
Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

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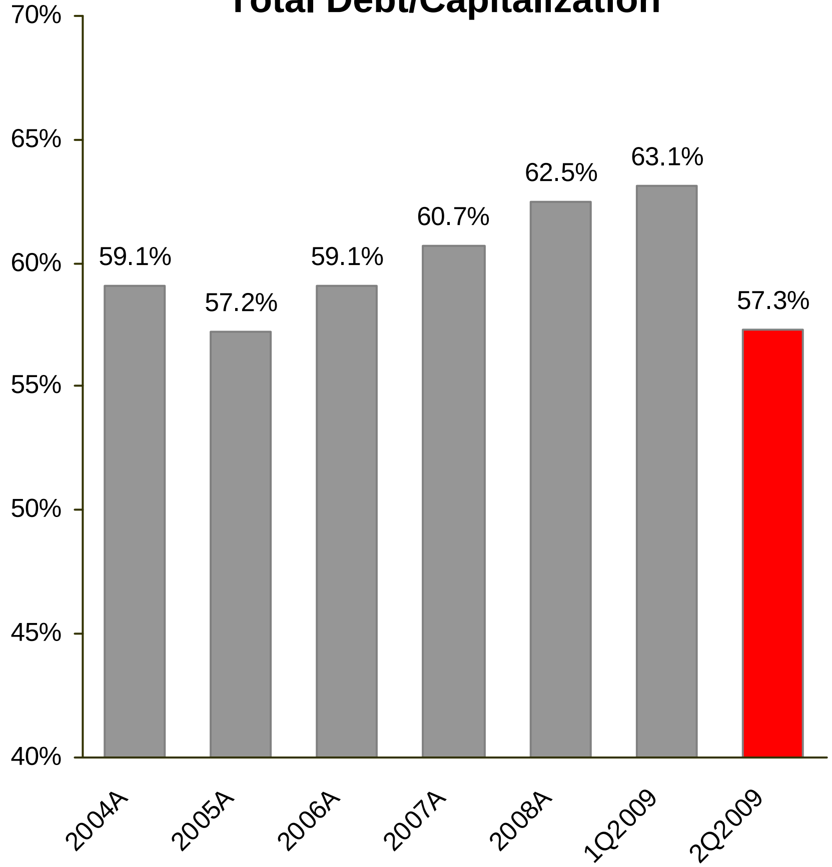
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 6/30/09	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

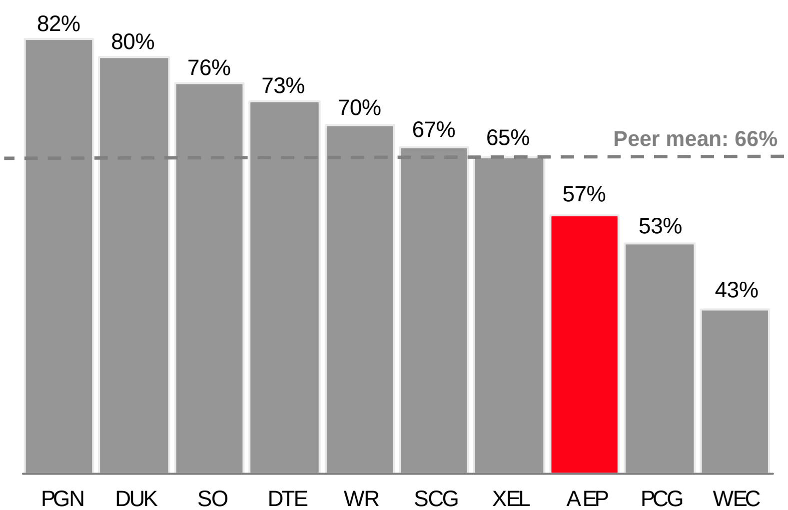
(a) Repaid in July 2009

AMERICAN ELECTRIC POWER

Dividend Overview

- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

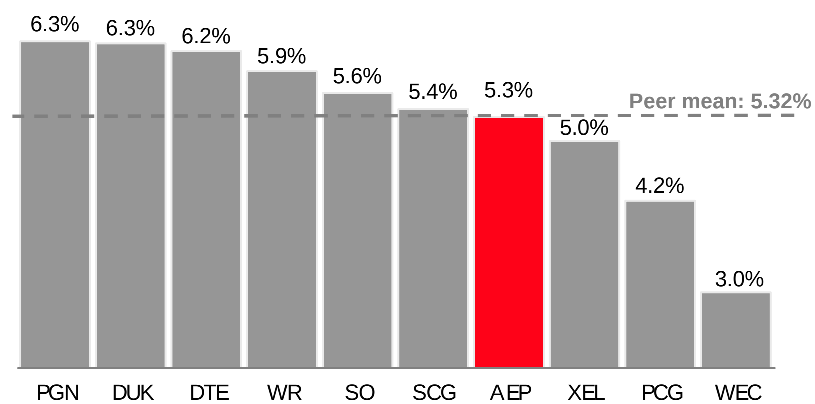
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 9/1/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 9/1/09

AEP AMERICAN® ELECTRIC POWER

What AEP Offers

- ***Strength and scale in assets & operations***
- ***Focused utility model***
- ***Sustainable earnings growth driven by utility platform & capital investment***
- ***Strong dividend yield with respect to peers***
- ***Balance sheet and credit profile stability***

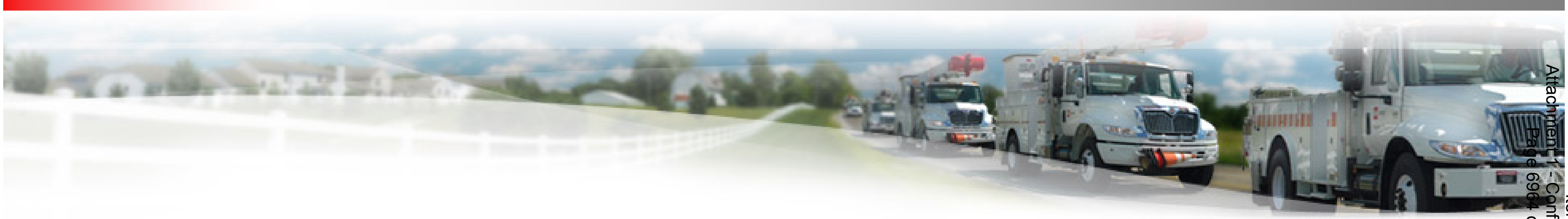
AEP AMERICAN ELECTRIC POWER

Questions?

AEP AMERICAN ELECTRIC POWER®

2011 INVESTOhio Equity Conference

Columbus, OH
September 22, 2011



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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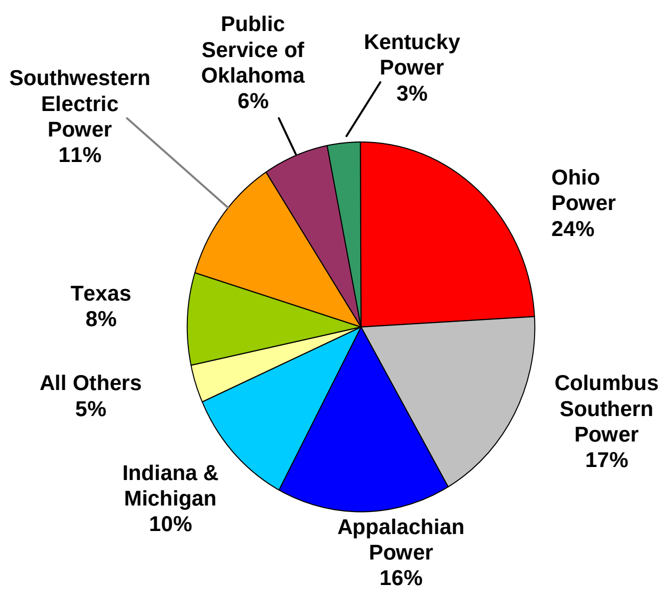
Diversified Utility Platform

2010 On-Going Earnings Contribution



Items to Watch

- Economic Recovery
- Ohio ESP and Other Filings
- EPA Regulations
- ETT and Transcos
- On-going Rate Cases
  - Virginia
  - Michigan
  - Ohio Distribution

June YTD 2011 Performance

June YTD 2011 Reconciliation

	EPS	Ongoing Earnings ($ in millions)
2010	$ 1.50	$720
Operations & Maintenance	$ (0.04)	
Other Costs, net	$ (0.05)	
Customer Switching	$ (0.06)	
Rate Changes	$ 0.15	
Off-System Sales	$ 0.07	
Weather	$ (0.02)	
2011	$ 1.55	$744

EPS Based on 482MM shares in YTD11

YTD 2011 Performance Drivers

- O&M increase of $30M, net of offsets, primarily due to higher storm expenses
- Other Costs, Net increased $35M primarily due to gain on sale of ICE shares in 2Q10 and increased taxes
- Customer Switching in Ohio up $43M from last year
- Rate Changes, net of offsets, of $110M from multiple operating jurisdictions
- Off-System Sales, net of sharing, were favorable by $49M due to higher volumes and higher power prices
- Weather was unfavorable by $15M vs. prior year, favorable $67M vs. normal

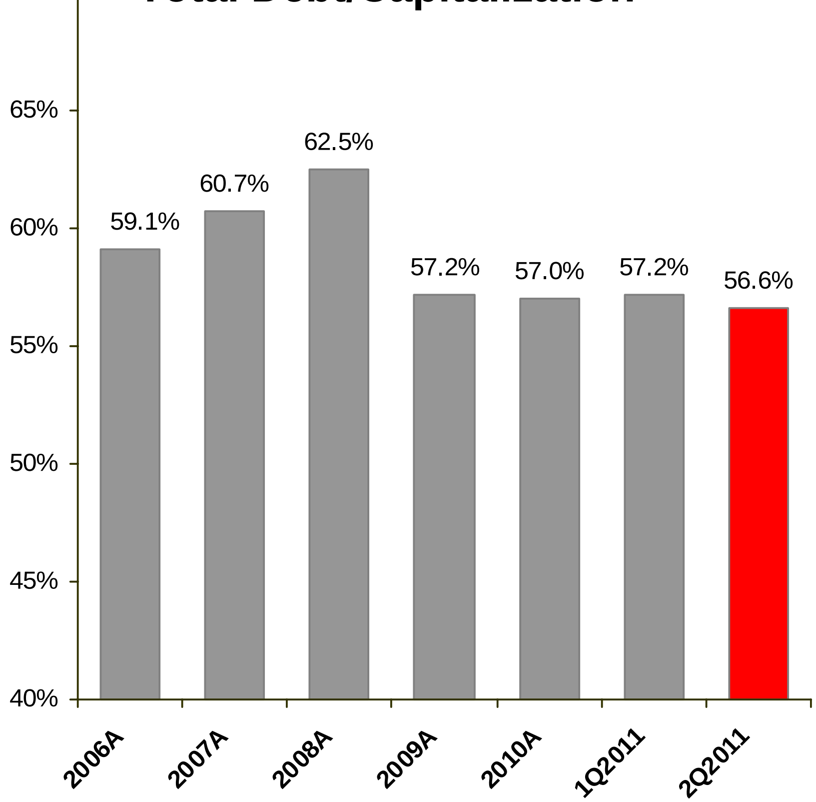
2011 On-going Earnings Guidance of $3.00 - $3.20 per share

AEP Texas Central Supreme Court Remand

- In early 2006, TCC received an order in the stranded cost proceeding enabling it to securitize $1.7 billion in stranded assets in October 2006, but denied recovery for other items.
  - TCC's inability to sell all of the capacity it was required to auction resulted in the PUCT rejecting the auction prices for purposes of calculating a legislatively-prescribed market-based true-up.
  - This led to a disallowance of $421 million and an after-tax impairment of $274 million being booked in 2005.
- In July 2011, the Texas Supreme Court reversed the PUCT's decision to reject use of auction prices, and the issue has been remanded to the PUCT.
- TCC is entitled to recovery of the $421 million plus carrying costs back to 2002. The carrying costs are expected to be $382 million.
- There will be regulatory proceedings and likely settlement discussions before the final amount is approved. TCC can securitize the recovery.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Significant Investment Opportunities in Environmental Retrofits and Transmission
- Strong Value and Total Return Proposition

Mountaineer Plant (WV)

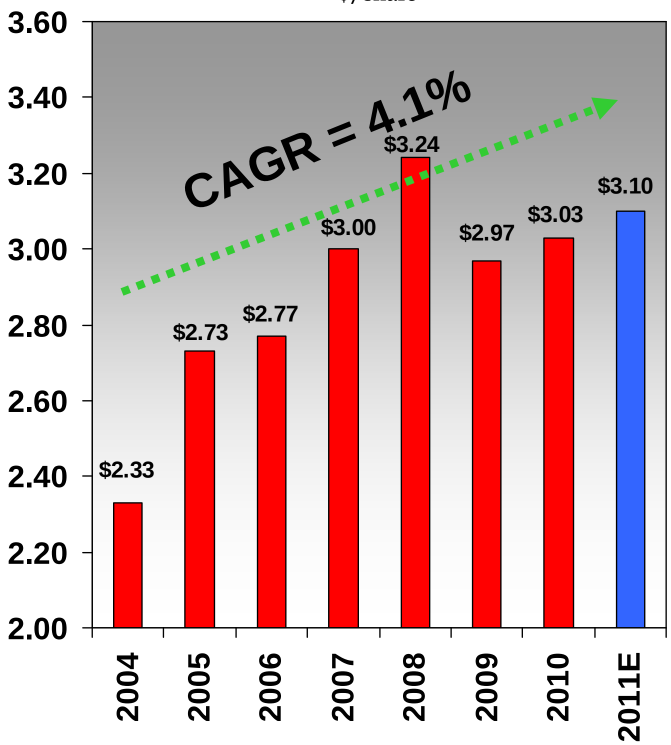
Appendix

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 6973 of 9556

Earnings and Dividends

On-Going EPS History Since 2004

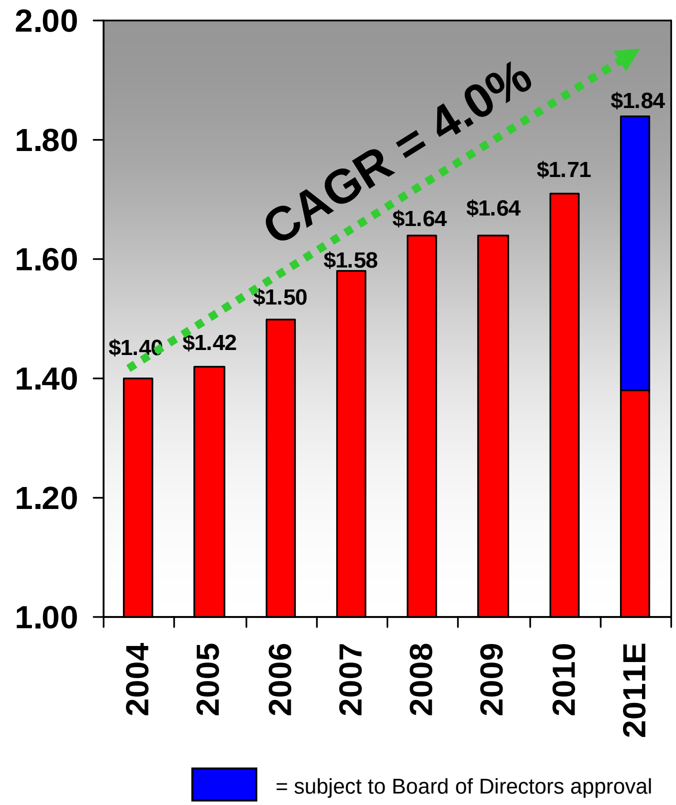
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend paid September 9, 2011
- 50-60% payout ratio target
- Current yield near 5%

Detailed Ongoing Earnings Guidance

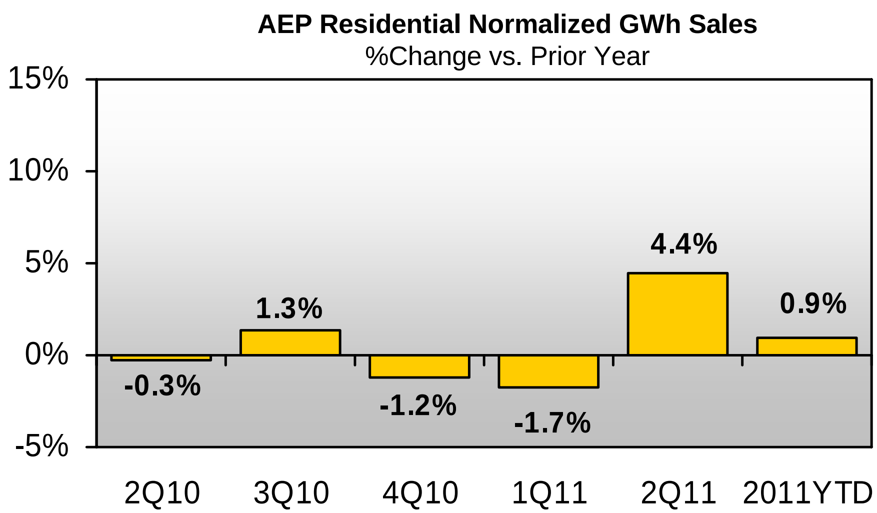
2010A: $3.03

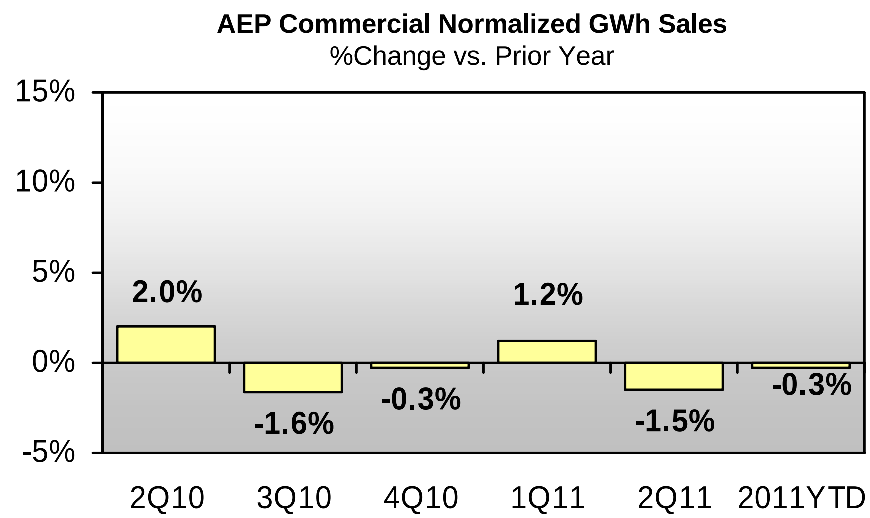
2011E: $3.00 - $3.20

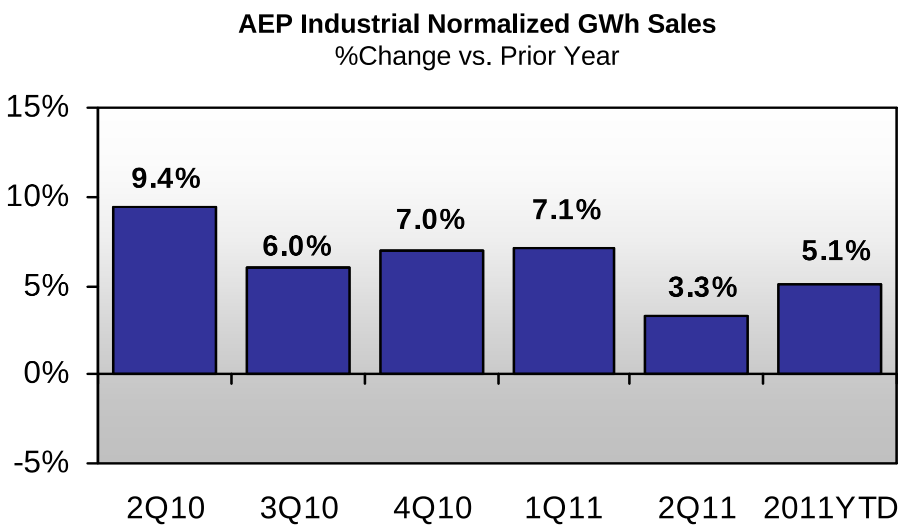
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

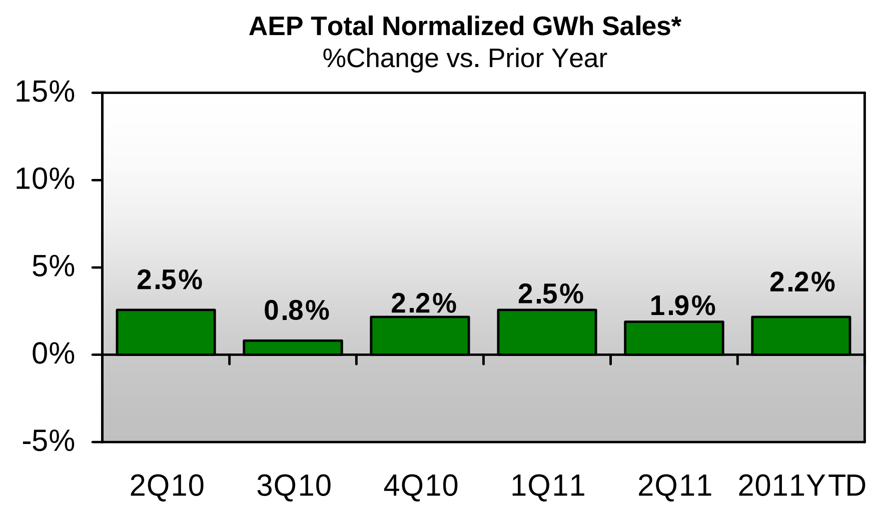
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends









*includes firm wholesale load

Note: Chart represents connected load

KPSC Case No. 2011-00401
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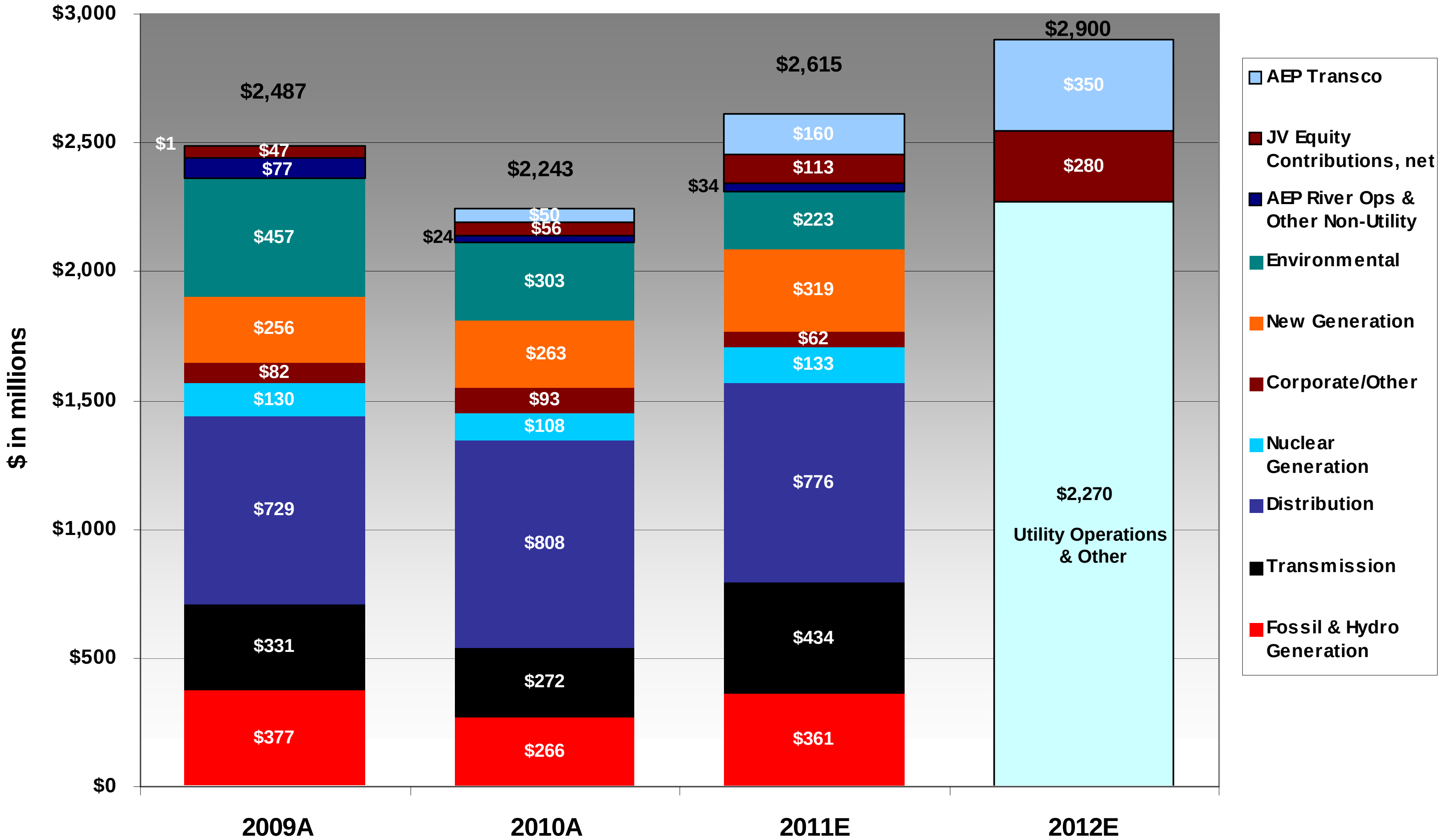
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

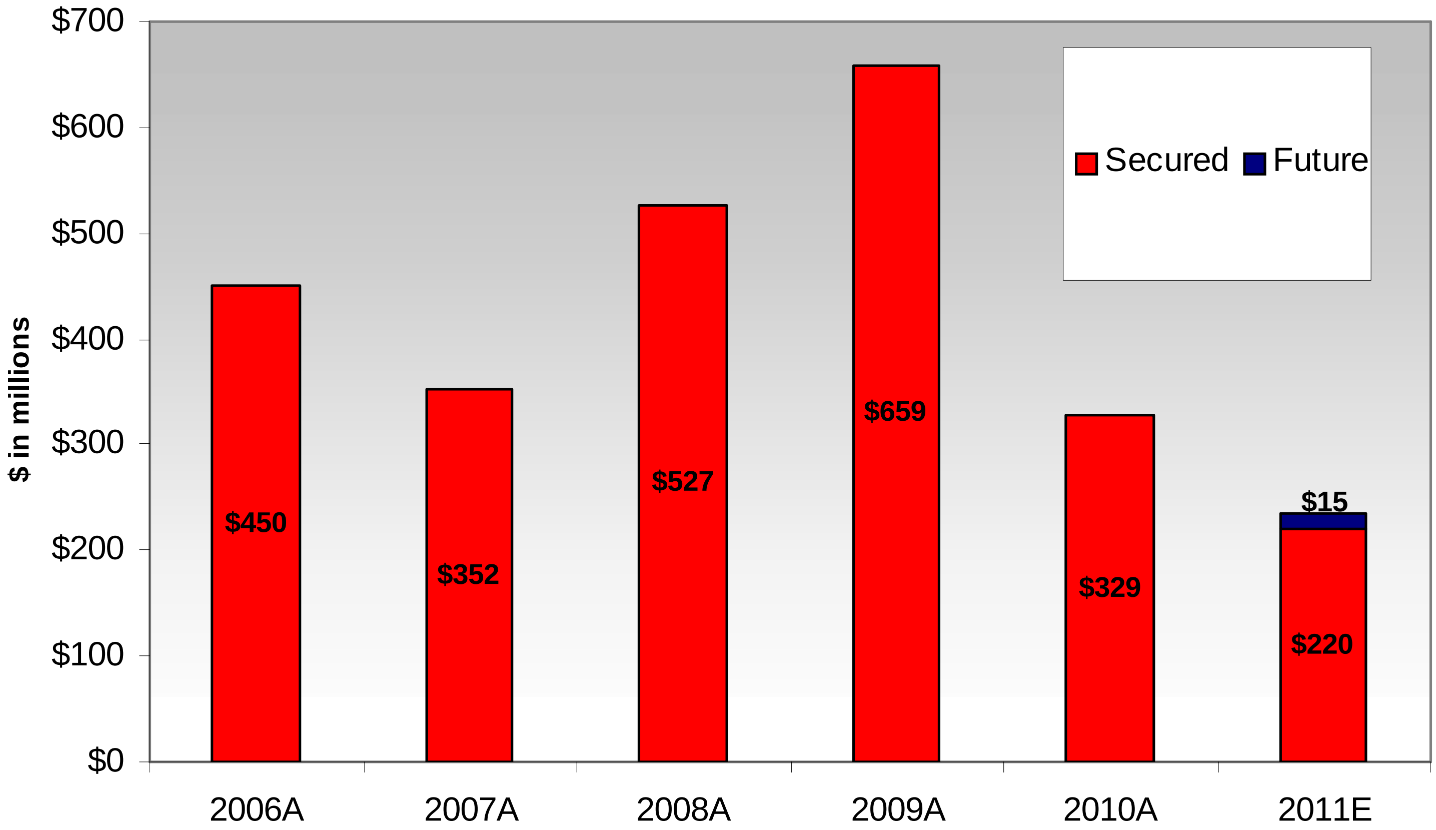
Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. See ESP Settlement slide for a discussion of the Distribution Investment Rider which authorizes a rate increase of $86 million in 2012.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Rates Implemented, subject to refund	January 1, 2012
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

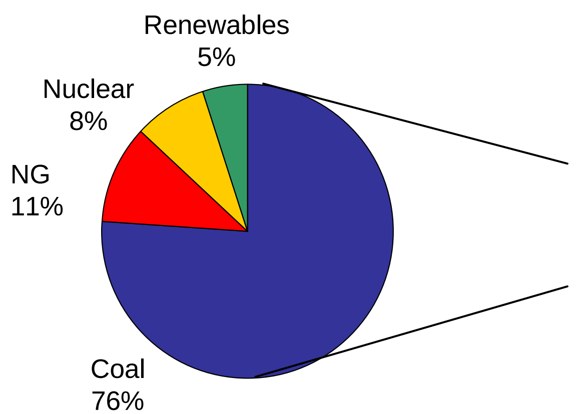
** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Generation Capacity

East Capacity – 27,253 MW

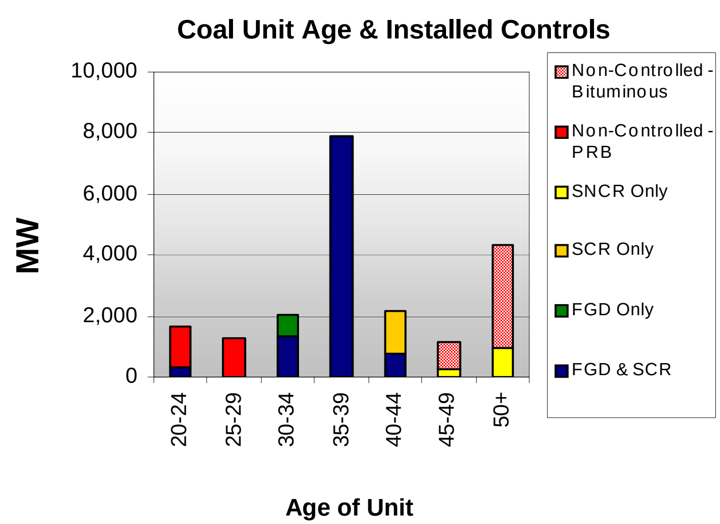
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



Coal Source

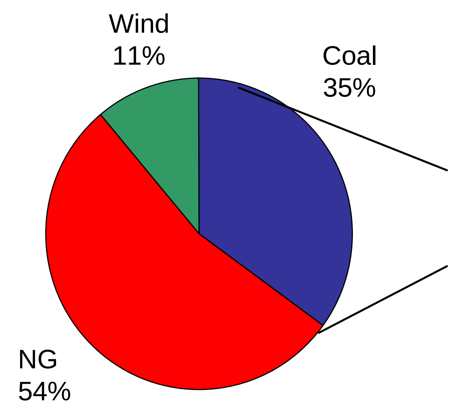
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

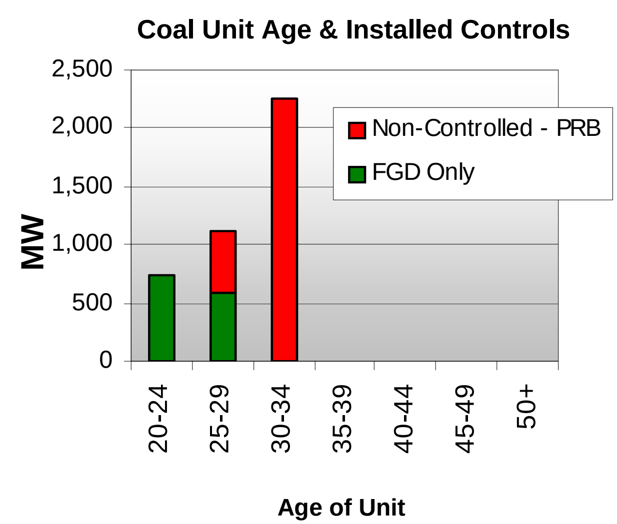
PSO, SWEPCO, TNC, Wind



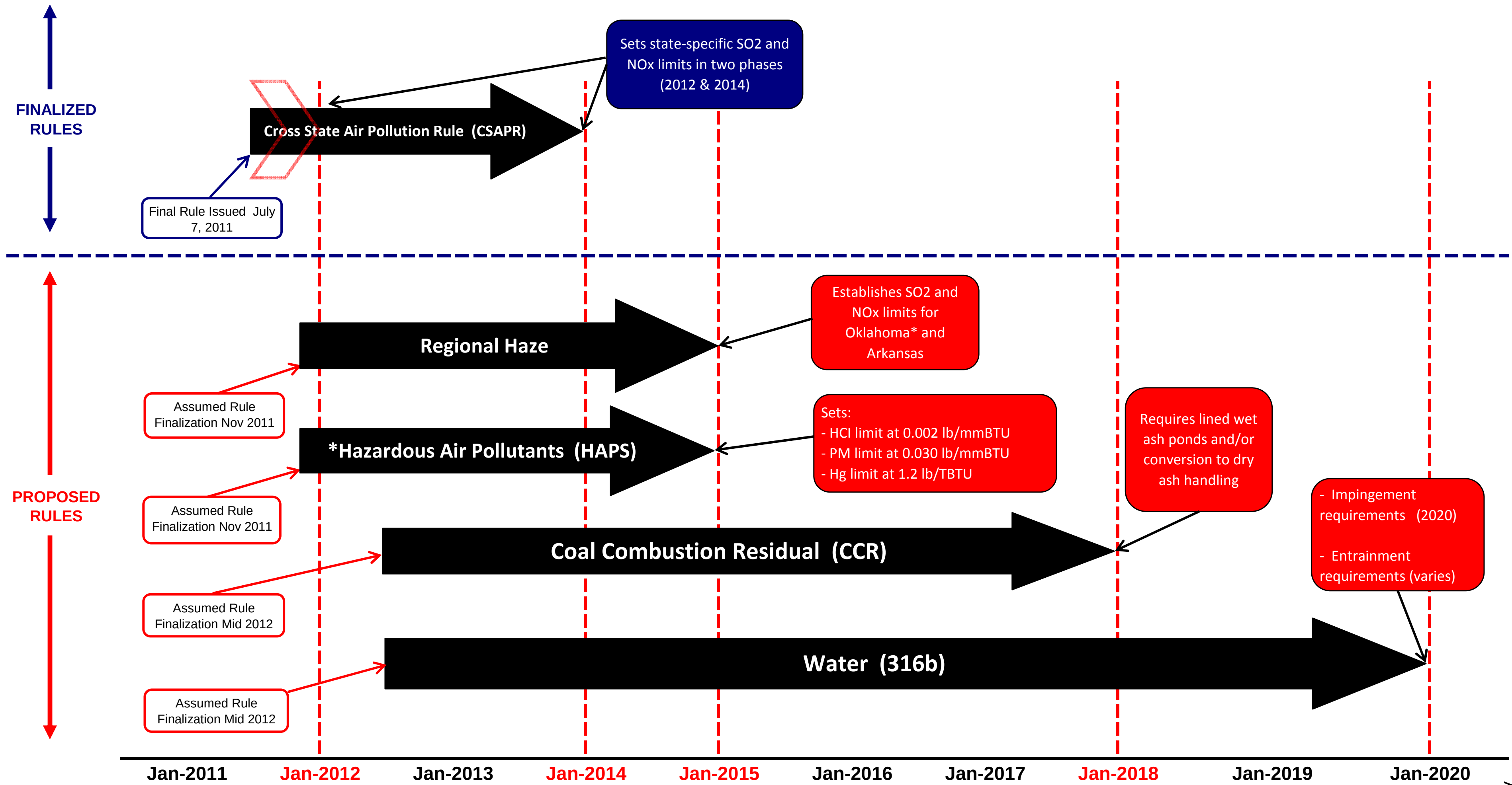
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



EPA Regulatory Deadlines



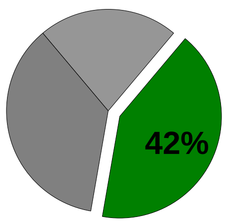
*** Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.**

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

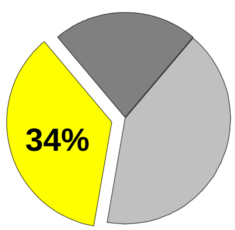
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

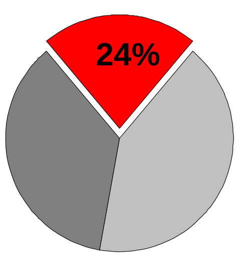
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5	510	Refuel with Natural Gas			
	Gavin 1	1320	FGD upgrade			
	Gavin 2	1320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	*
APCO	Clinch River 1	211	Refuel with Natural Gas			
	Clinch River 2	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	**
I&M	Rockport 1	1320	FGD, SCR			
	Rockport 2	1320	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670**	***
KPCO	Big Sandy 1	640	New Natural Gas			
	Total MW	**640**	**Total Expected Cost**		**525**	

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

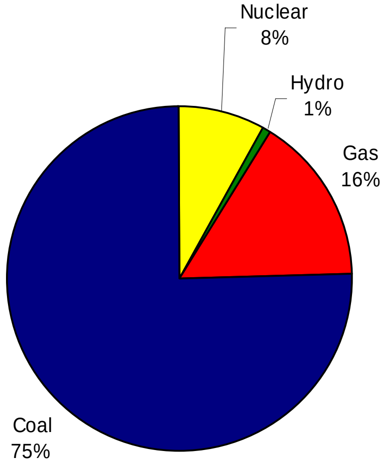
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

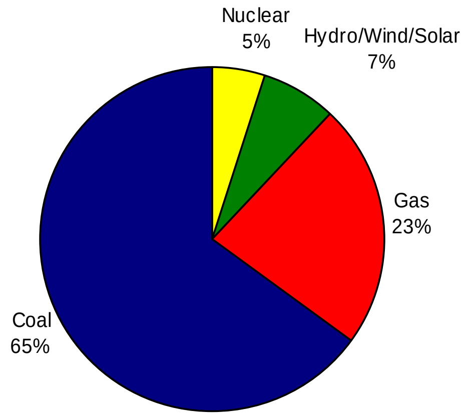
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

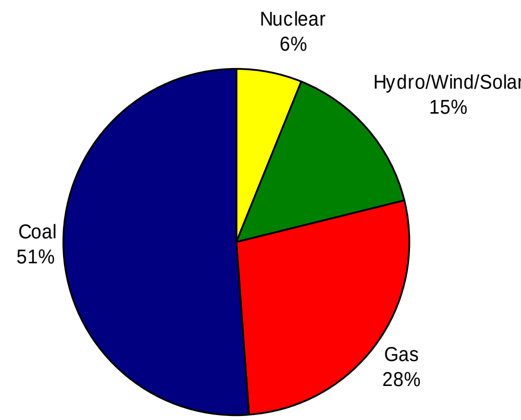
1990 AEP Generating Capacity by Fuel
37,428 total MW's



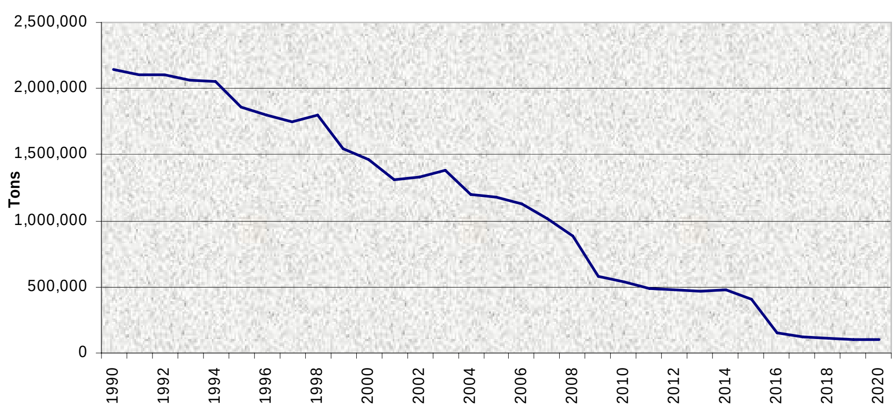
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

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Transmission Investment Strategy

AEP®

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $210 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

AEP

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

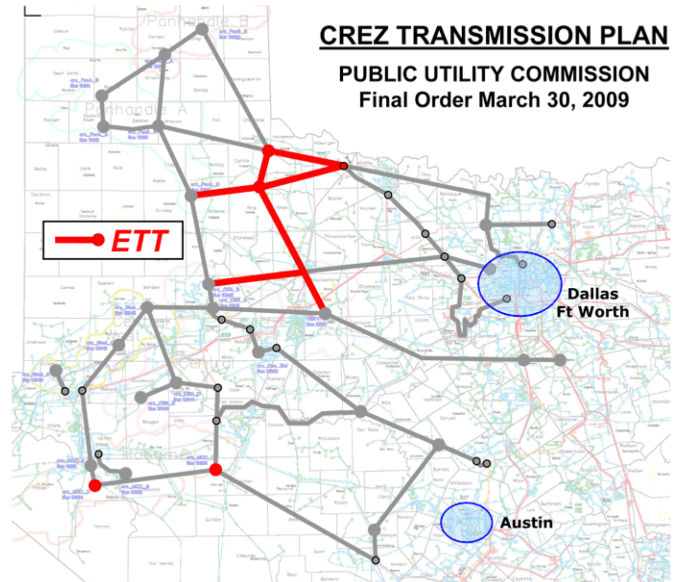
Current rate base is $412 million; expected to grow as follows:

2011: $490 million
2012: $750 million
2013: $1,200 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.5 B:**
  - Approximately 500 miles of lines and 29 substations with in-service dates through 2020

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.4 B:**
  - Nine new transmission lines totaling approximately 600 miles and 16 substations
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway; 5 lines already approved

Joint Venture Strategy: Long-term

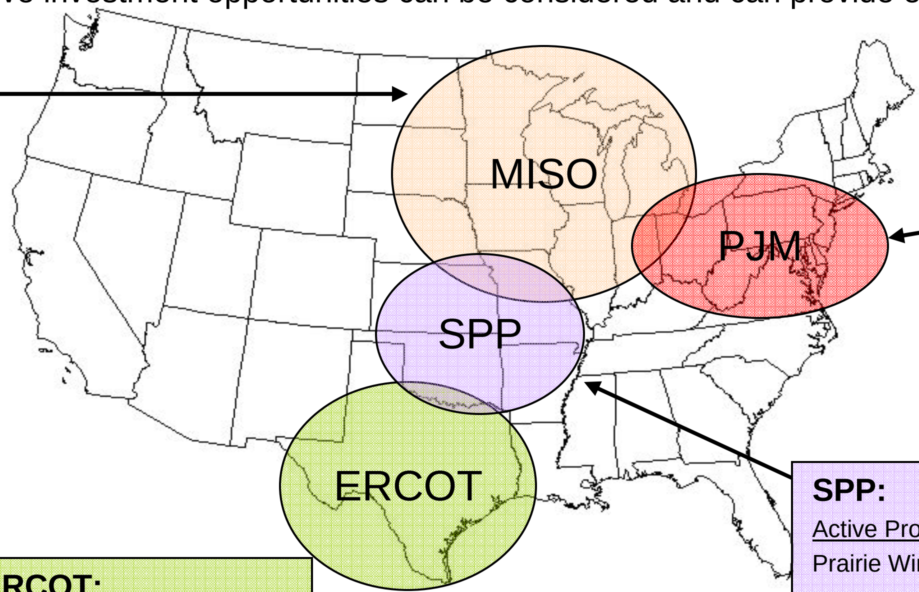
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Investor Breakfast Meeting
Hosted by Jefferies & Company, Inc.

New York City

June 2, 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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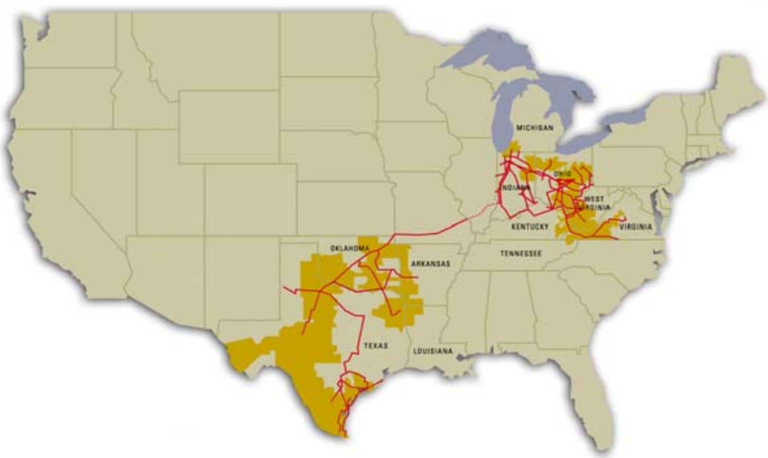
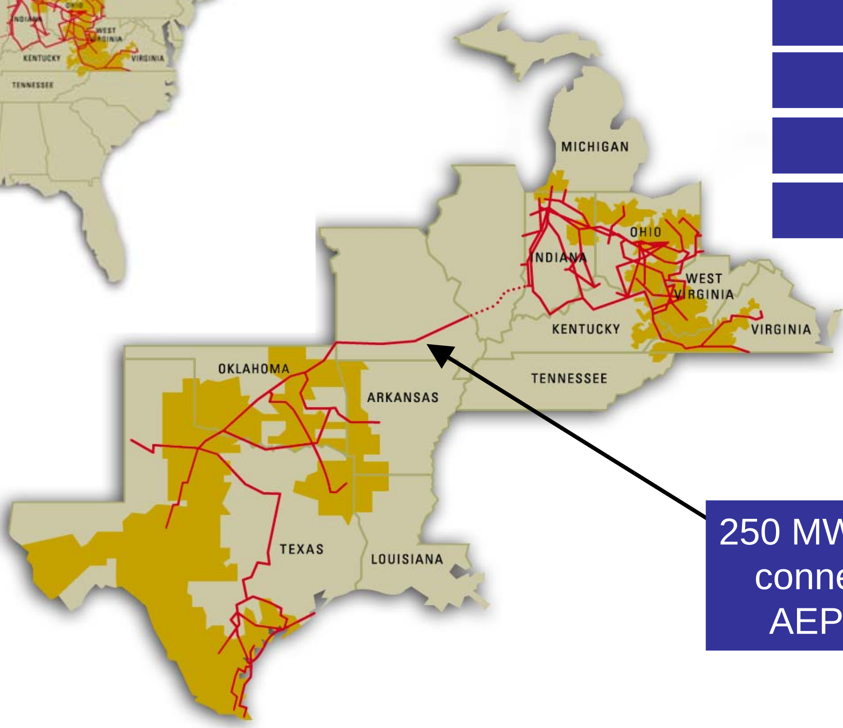
Company Overview

Where We Operate





- Ohio
- Indiana
- West Virginia
- Virginia
- Kentucky
- Michigan
- Tennessee

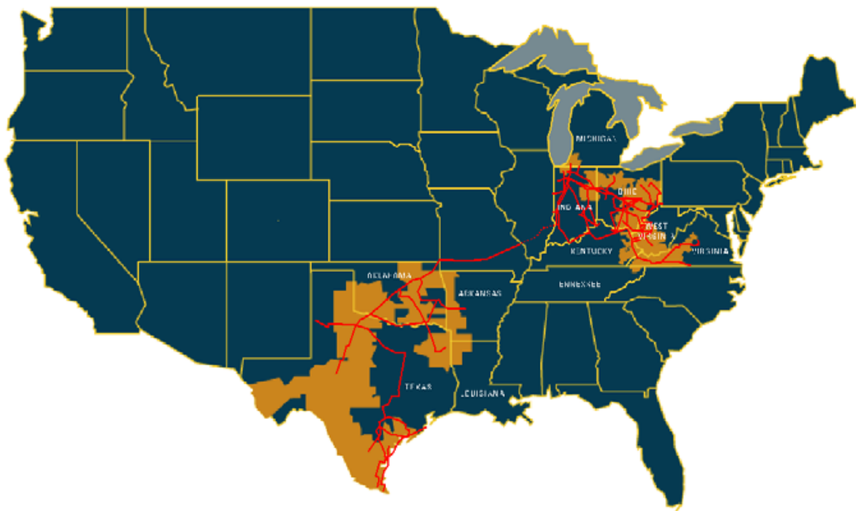
- Oklahoma
- Texas
- Louisiana
- Arkansas

250 MW transmission line connects AEP East & AEP West territories

2

Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



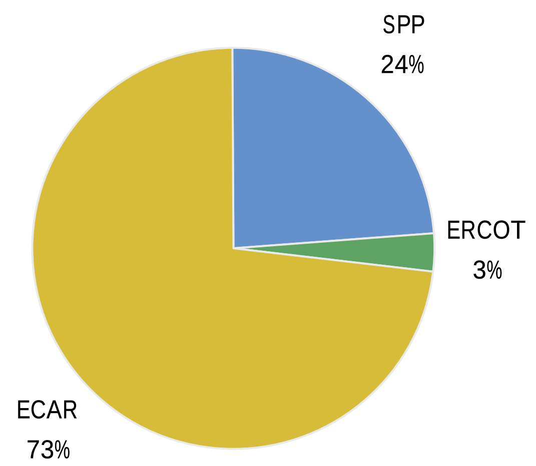
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

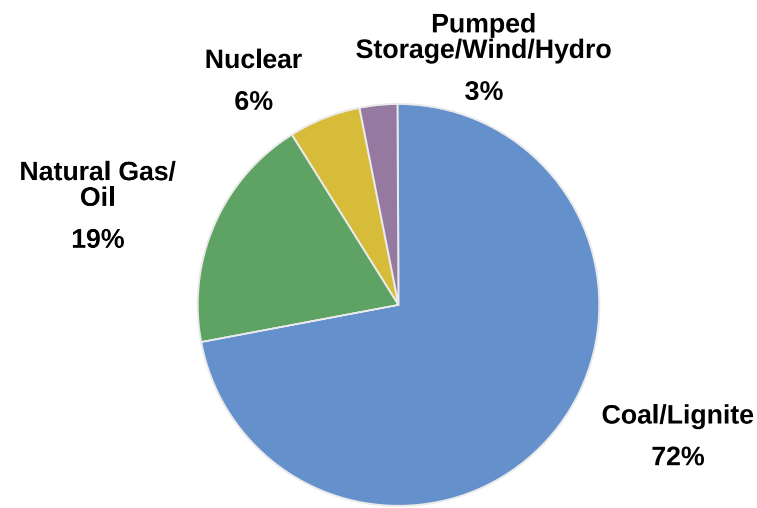
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

Operating Statistics

Commercial Availability Factor

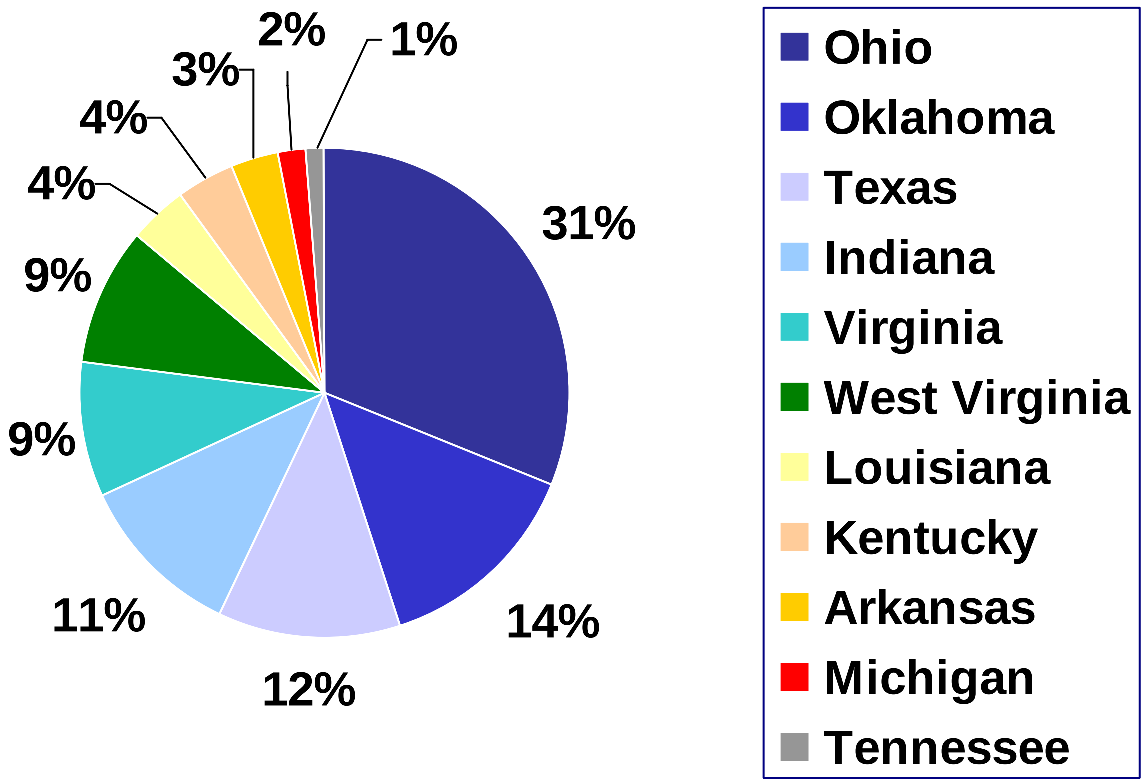
2004	85.24%
2005	84.50%

Capacity Factor

2004	62.06%
2005	62.53%

2005 Retail Revenue

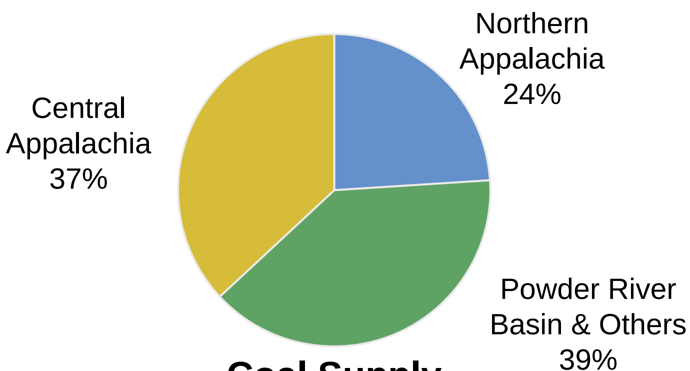
Retail Revenue Composition by State



Fuel

Coal Procurement

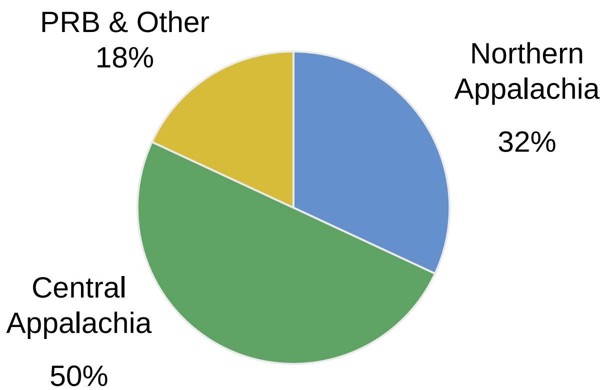
Total AEP System



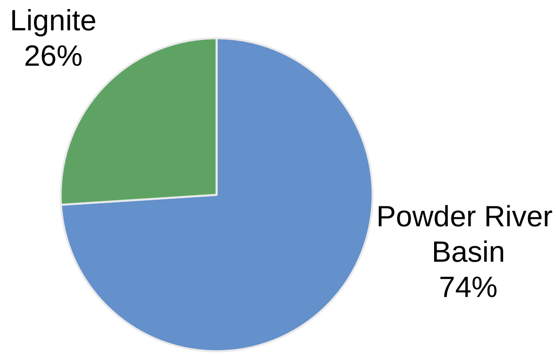
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 90%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System



AEP Western System



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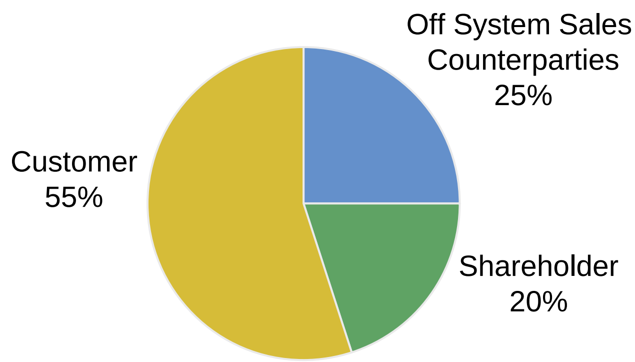
Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

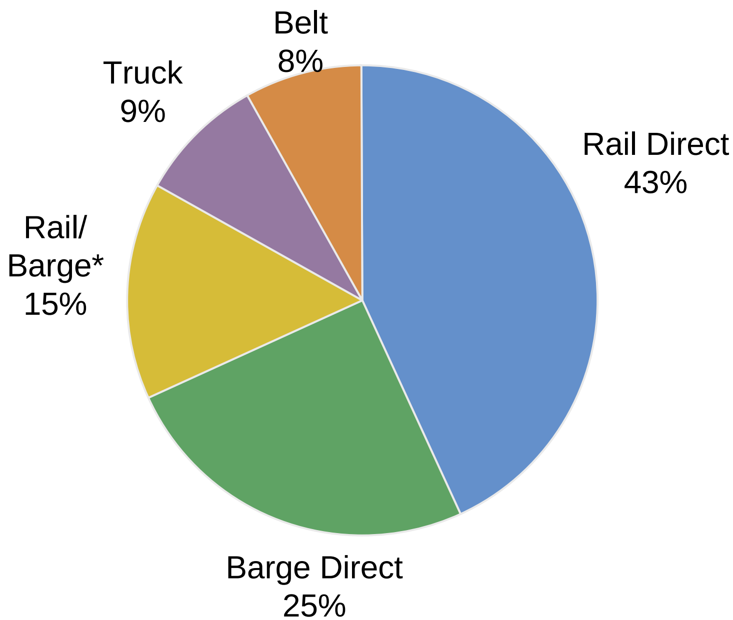
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Coal Delivery

Total AEP System

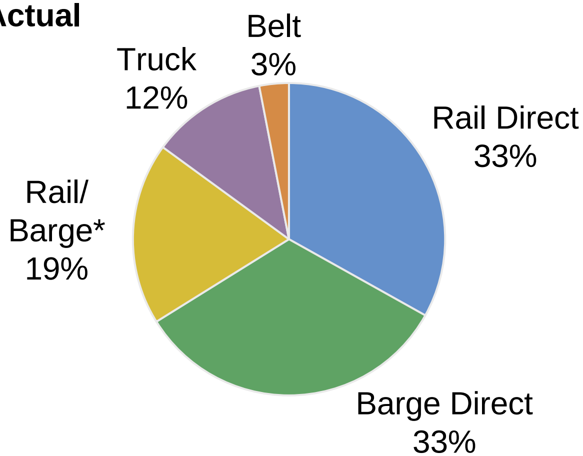
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

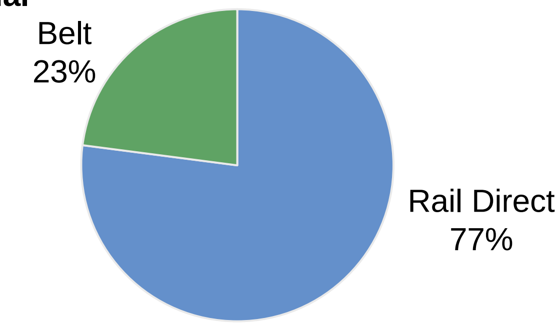
AEP Eastern System

2005 Actual



AEP Western System

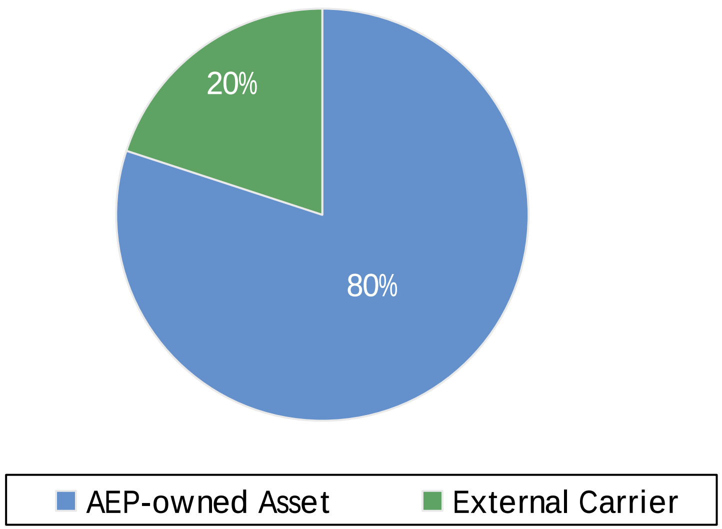
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

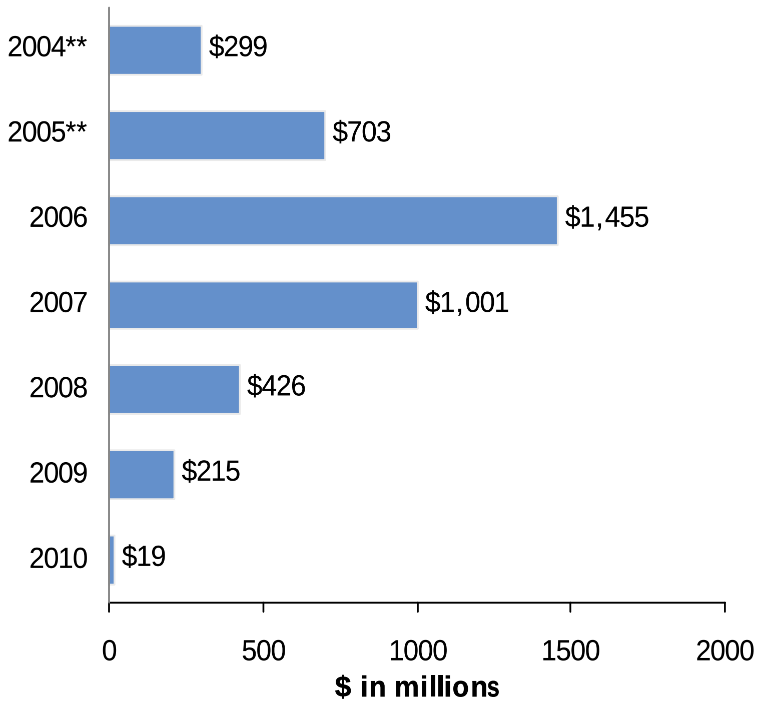
- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

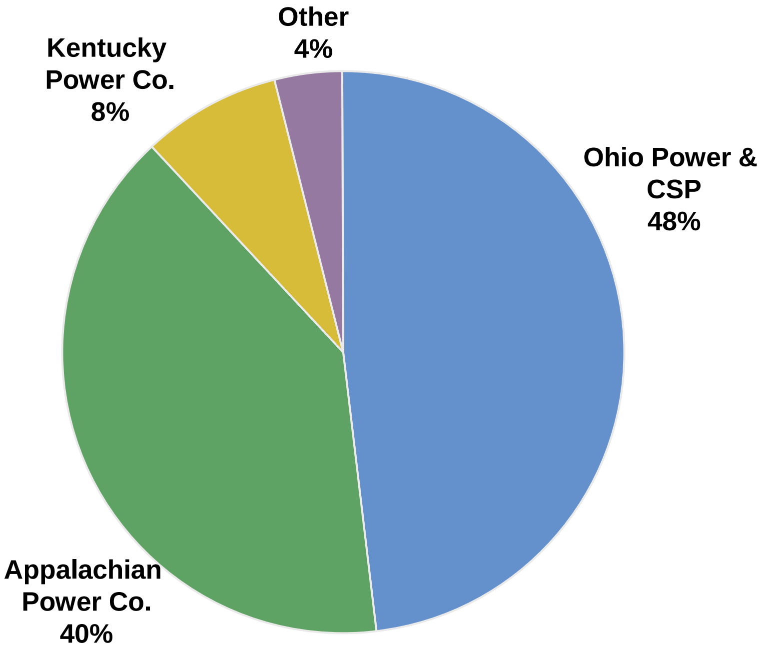
Environmental

$4.1 Billion Environmental Investment

Environmental Capital Investment*



Projected Environmental Investment Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

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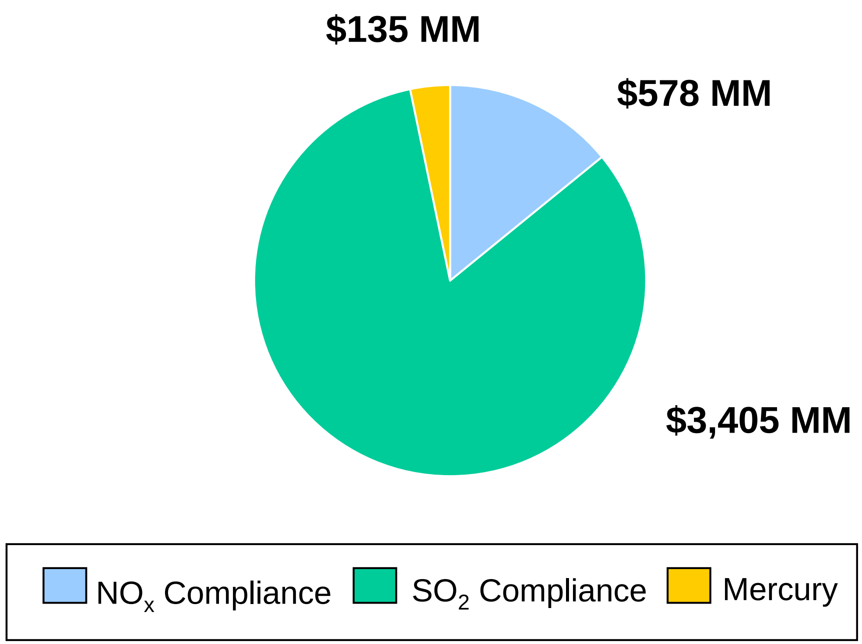
Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$2.0 Billion for SO_2

$0.1 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC

Environmental Installations

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD: 2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR: 2006 – 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

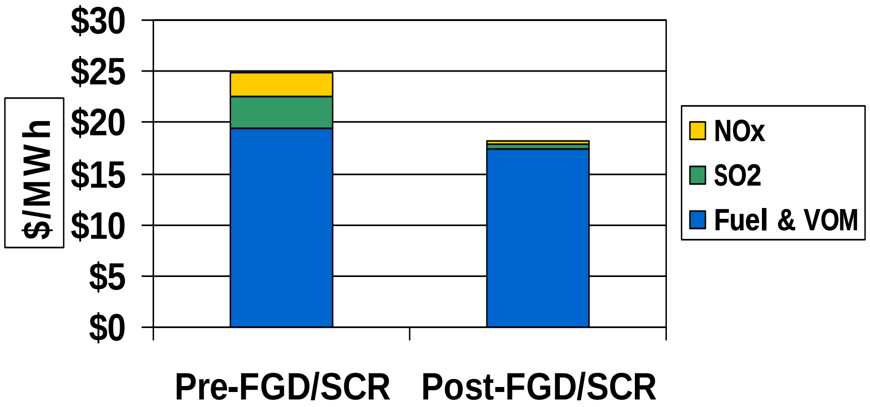
Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

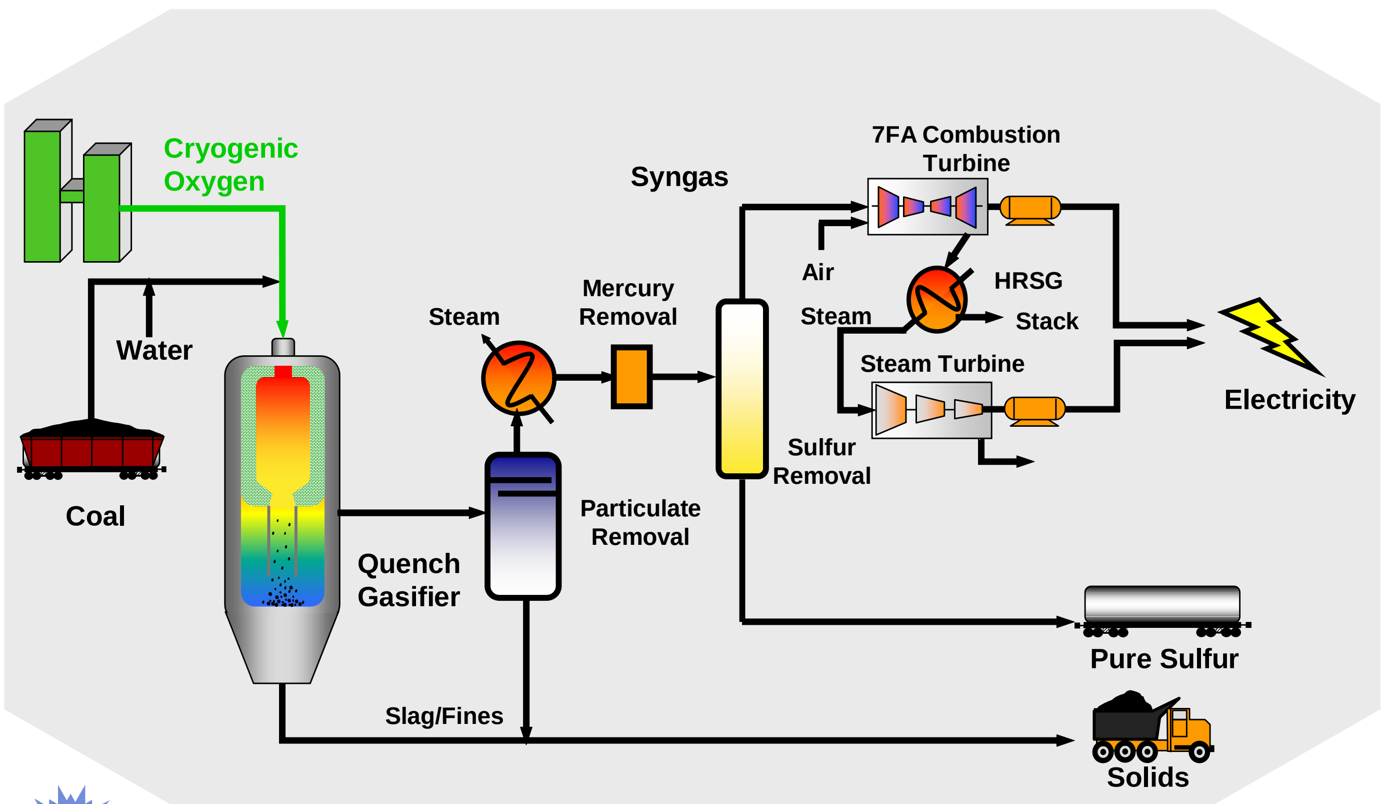
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8700**	**8600**	**7200**
Total Plant Cost (EPC) ($/kW)	**1700**	**1900**	**480**
Production Cost ($/MWh)	**17**	**16**	**57**
Cost of Electricity, without CO_2 Capture ($/MWh)	**58**	**63**	**90**
Estimated Cost of Electricity, with CO_2 Capture ($/MWh)	**94**	**87**	**137**

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO_2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Regulatory Overview

Regulatory Activity Underway

- TCC Request for Securitization of Stranded Costs
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia – Settlement Pending
- IGCC – Received Rate Authorization of Pre-Construction Costs

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
- May 22, 2006 – Settlement agreement filed with PUCT in securitization proceeding
  - Securitization financing order expected in June
  - Issuance of securitization bonds expected late 3Q06

Settlement Agreement (if approved):

- Securitization amount of $1.72 billion
- Securitization order not appealable
- Issues to be settled by the Commission:
  - Correct amount for ADFIT (assumed to be $315 million)
  - The treatment of ADFIT benefits either to be recovered through a CTC or as a reduction of the securitized amount
  - The treatment of EDFIT and ADITC ($90 million in total) either as a reduction to the costs to be recovered through a CTC or as a reduction to the securitized amount

- June 2006 – Request approval for CTC to address other true-up items
  - Expected $476 million credit to customers (assuming ADFIT is refunded through CTC)
  - Sept 2006 – CTC to be implemented

Regulatory Activity Underway

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Procedural schedule has been set with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, upon which, the full rate increase requested by APCO-VA will be implemented, subject to refund.

Procedural Schedule

June 30, 2006	Company to file additional direct testimony
Sept 1, 2006	Intervenor testimony due
Oct 4, 2006	SCC Staff testimony due
Oct 19, 2006	Company to file rebuttal testimony
Nov 17, 2006	Hearings to commence

Regulatory Activity Underway

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2006 – Joint Settlement Agreement

- Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Settlement Details

- ✓ Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
$23MM	WJF & FGD investment @ 12/31/05
$61MM	Gross revenue increase
($17MM)	ENEC over-recovery negative surcharge
$44MM	Net increase effective 7/28/06

- ✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2010:

- Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate, for certain specific incremental costs
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

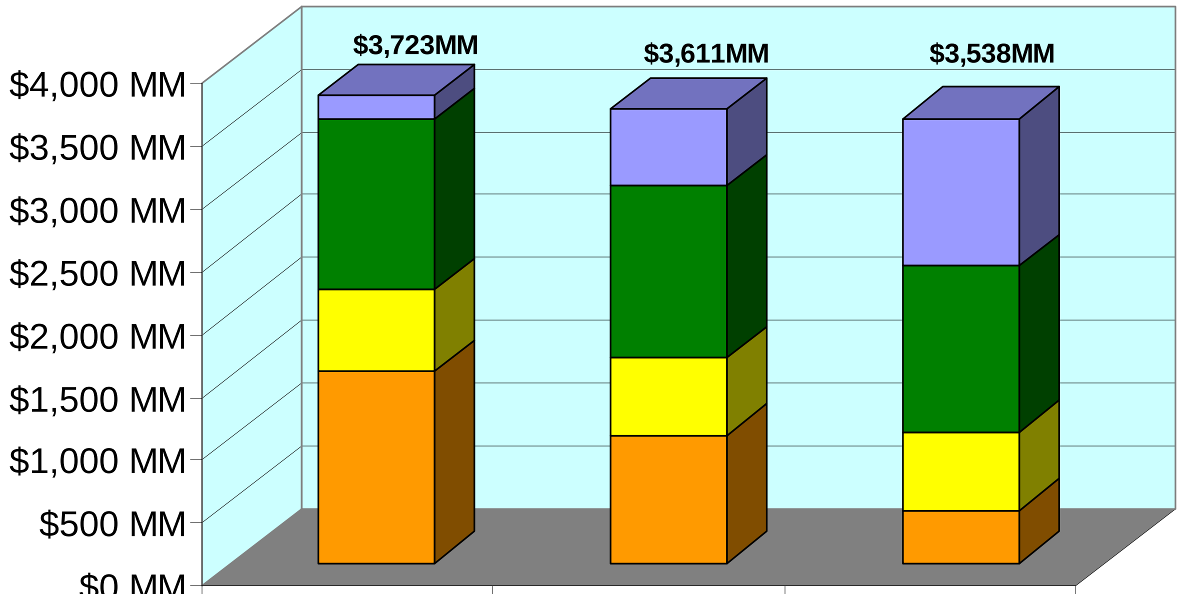
- $41 million annual increase in base rates
- Rates effective March 30, 2006

Capital Investment

Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE - INVESTMENT LEVEL WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

New Generation

IGCC

- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in 2007
- Commercial operation date expected in 2010

SWEPCO

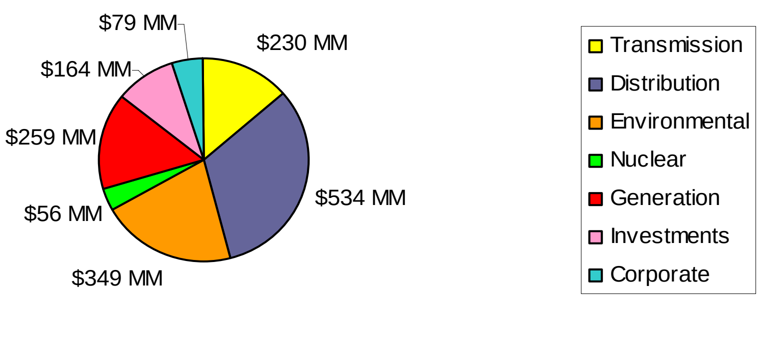
- On May 31, 2006 SWEPCo announced plans to build $1.4 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling up to 450 MW, combined-cycle gas plant totaling 480 MW and a new base load coal- or lignite fueled plant

PSO RFPs

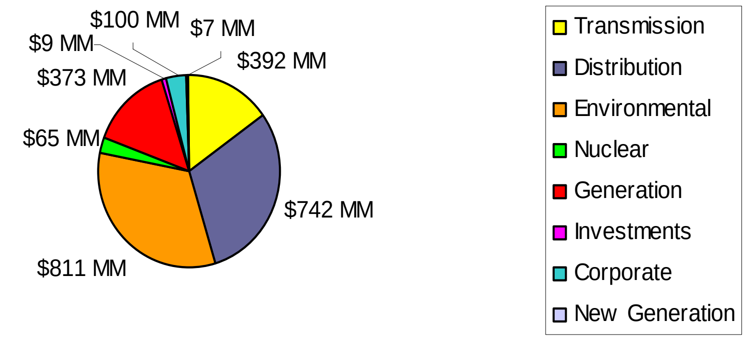
- Submitted RFPs totaling 900 MW of baseload and peaking capacity
- Two peaking RFPs totaling 340 MW awarded
- Commercial operation dates expected in 2008 and 2011

Capital Investment 2004 - 2006

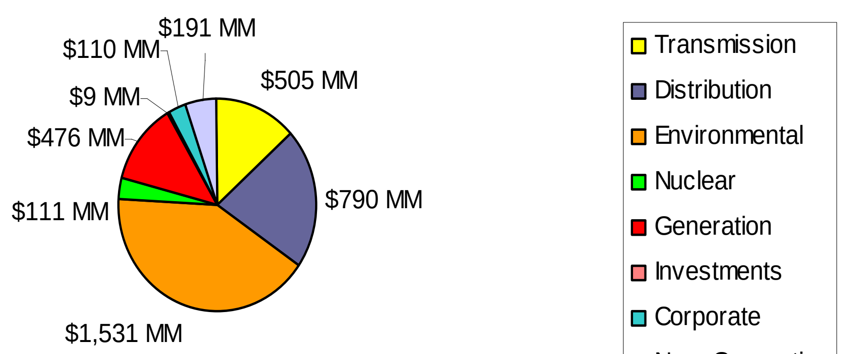
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Finance

2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

Summary of Major 2006 Financial Performance Drivers

- Load Growth of 2.5%
- $500MM rate recovery assured or in progress
- Rising fuel costs of 11-13%
- Higher planned outages, increased retail load and sale of TCC generation to impact off system sales
- Decline in utility O&M
- Parent Company improvement (debt & interest expense reduction)

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 PERFORMANCE

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capital Structure

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.5% AT 3/31/06

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Ratings Actions

- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Forecasted Capital Expenditures

Company (in thousands)	2006	2007	2008
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

2006 Key Operating Company Highlights

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	(in millions) Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 (completed*)	42-45%
CSP	$343	$100 - $150	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$50 - $75	42-45%
OPCo	$1,070	$450 - $550	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$100 - $150	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

*Issuances completed in 2006 totaling $550 Million

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

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Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Long-Term Debt Maturity Profile[1]

Year	2006[2]	2007	2008
AEP Service Corporation	$ 2,000,000[3]	$ 2,000,000[3]	$ 34,000,000
AEP Inc.	$ 395,860,000[4]	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Ohio Power Company	$ 7,640,000[3]	$ 17,854,000[3]	$ 55,188,409[3]
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 11,047,000[3]	$ 95,312,136[3]	$ 12,538,117[3]
Texas Central Company	$ -	$ -	$ 18,581,000
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 716,547,000**	**$ 1,133,781,136**	**$ 512,307,526**

(1) Excludes tax exempt bond remarketings and securitization bonds

(2) Maturities remaining as of March 31, 2006

(3) Includes sinking fund payments, where applicable

(4) AEP Inc. $396 million global bond matured on May 15, 2006

Debt Schedules

American Electric Power Service Corp			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	4.709%	08/16/2007	$345,000,000
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bonds	5.010%	01/15/2008	$103,272,491
Securitization Bonds	5.560%	01/15/2010	$107,094,258
Securitization Bonds	5.960%	07/15/2013	$214,926,738
Securitization Bonds	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,817,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Appalachian Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,058,600

Columbus Southern Power			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Indiana Michigan Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/1/2015	$125,000,000
Weighted Average or Total	4.971%		$1,220,083,600

Kentucky Power			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$11,707,314
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/1/2015	$200,000,000
Weighted Average or Total	4.386%		$1,881,953,514

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$24,974,947
Notes Payable	Floating	06/30/2008	$12,538,117
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	4.750%		$702,020,664

Note: Debt Schedules as of March 31, 2006

Appendix

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. On April 24th, APCo and Wheeling Power, together with the PSC staff and the Consumer Advocate in WV, filed a joint settlement agreement in the companies' rate case. The agreement provides for an initial $44 million increase in revenues, effective July 28, 2006. The initial increase consists of a $56 million increase for fuel and purchased power expenses, and $23 million for recovery of WJF transmission line costs and environmental investments to date. These increases are partially offset by an $18 million base rate reduction and a $17 million credit to customers for previously over-recovered fuel costs. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure – Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base – Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Procedural Schedule

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearing
April 24, 2006	Settlement agreement filed
May 4, 2006	Legal briefs filed
May 15, 2006	Response briefs filed

Statutory Deadline: July 28, 2006

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

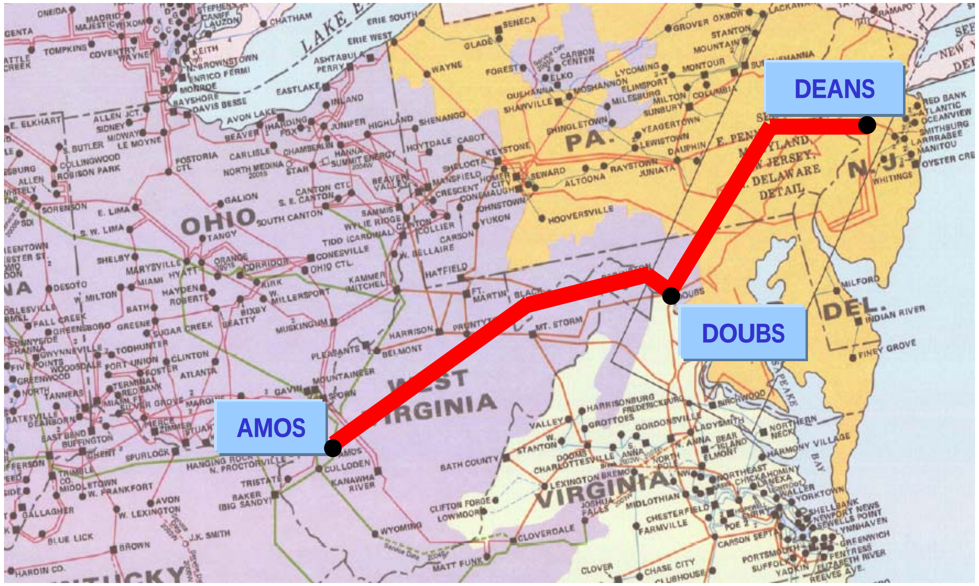
Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Interstate Project



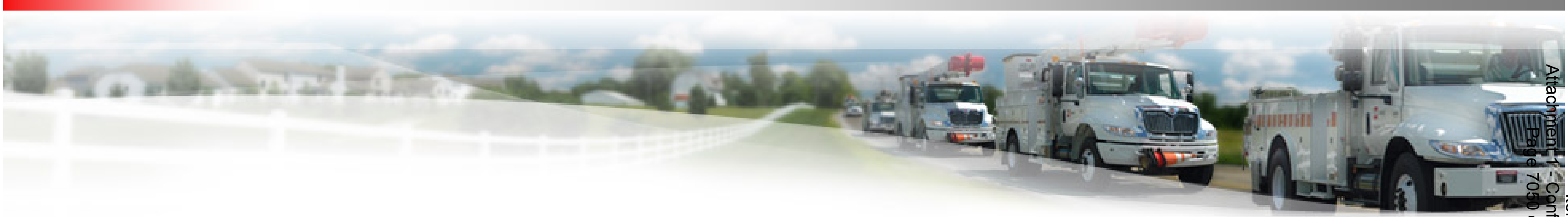
Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

AEP AMERICAN® ELECTRIC POWER

ISI Analyst Meeting Handout

October 6, 2011



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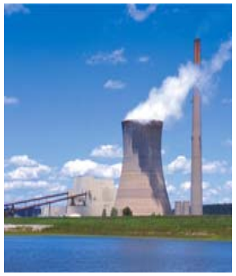
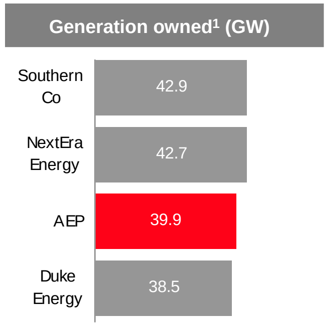
AEP Overview

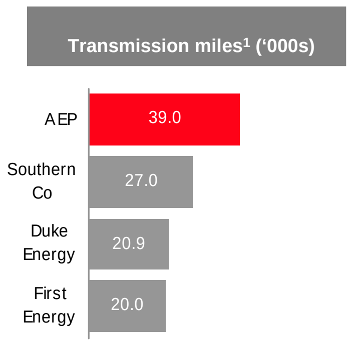
American Electric Power



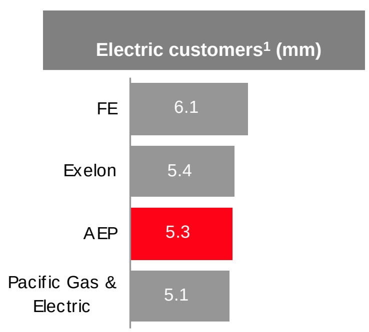
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

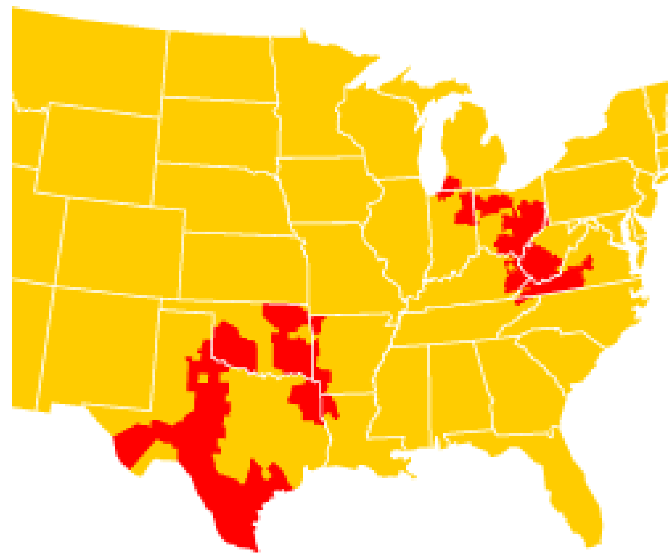


One of the largest U.S. electricity distributors



¹ : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

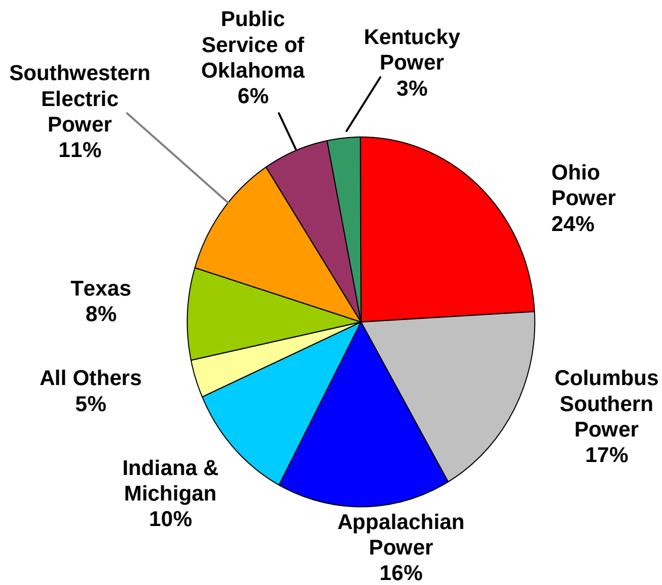
$17.9B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

Diversified Utility Platform

AEP®

2010 On-Going Earnings Contribution



Items to Watch

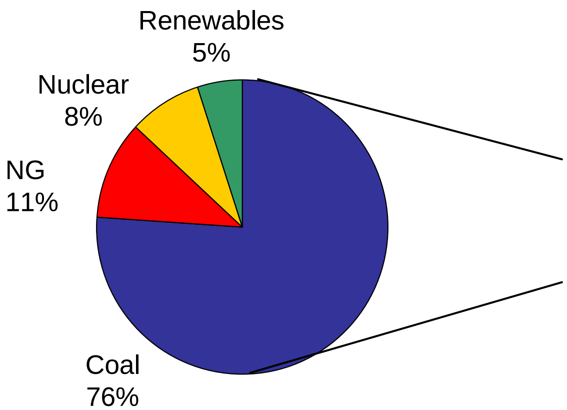
- Economic Recovery
- Ohio ESP and Other Filings
- EPA Regulations
- ETT and Transcos
- On-going Rate Cases
  - Virginia
  - Michigan
  - Ohio Distribution

Generational/Environmental Update

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

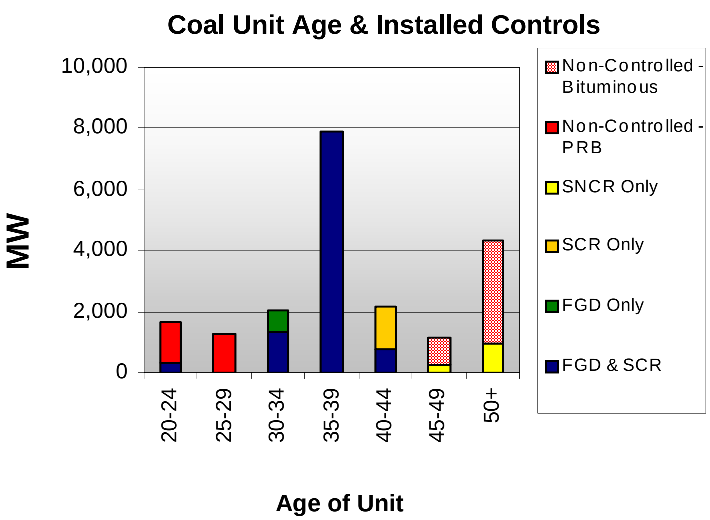


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

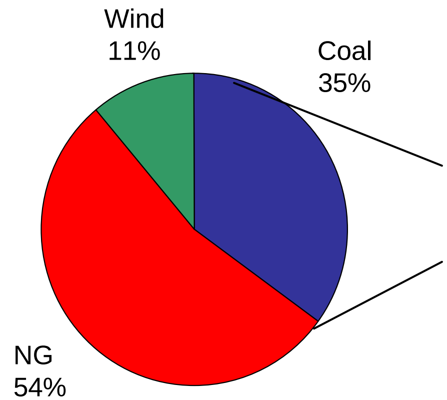
Avg. Delivered Cost

2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

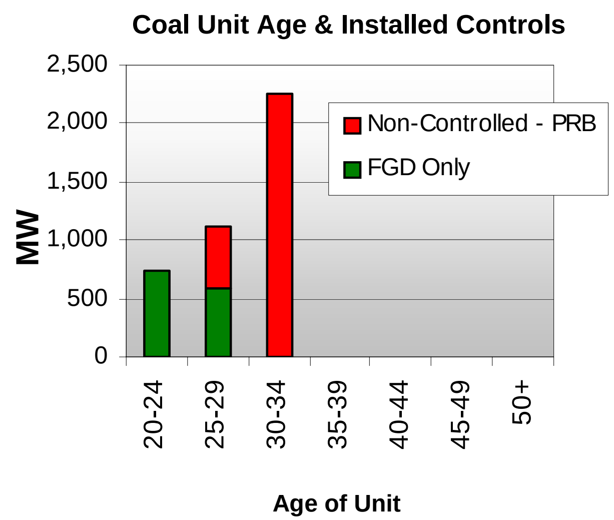


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



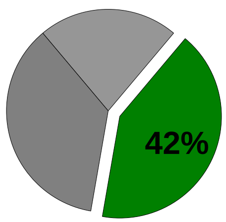
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7056 of 9556

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

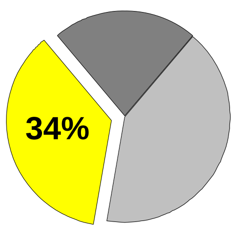
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

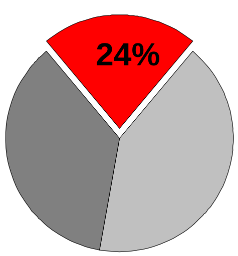
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	May need SCR, DSI
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	3,735		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**12,246**		

*May need FGD upgrades

Total Ohio Generation	12,246 MW
Less units slated for retirement	2,538 MW
Total remaining portfolio	9,708 MW
Fully scrubbed & SCR's	71%
Natural gas & hydro units	15%
Has FGD but may require SCR	8%
May be replaced with gas	6%
	100%

CSP has a 1,100MW PPA for the Lawrenceburg Plant. The contract extends through 2017, with a 2 year optional renewal.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5	510	Refuel with Natural Gas		
	Gavin 1	1320	FGD upgrade		
	Gavin 2	1320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800** *
APCO	Clinch River 1	211	Refuel with Natural Gas		
	Clinch River 2	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765** **
I&M	Rockport 1	1320	FGD, SCR		
	Rockport 2	1320	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670** ***
KPCO	Big Sandy 1	640	New Natural Gas		
	Total MW	**640**	**Total Expected Cost**		**525**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

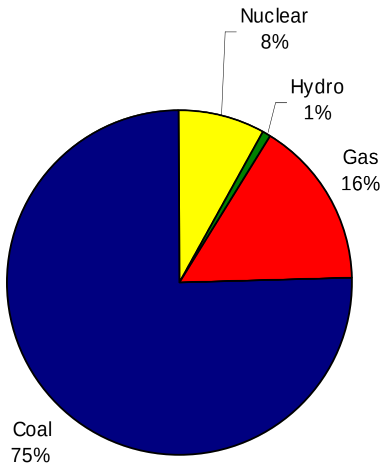
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

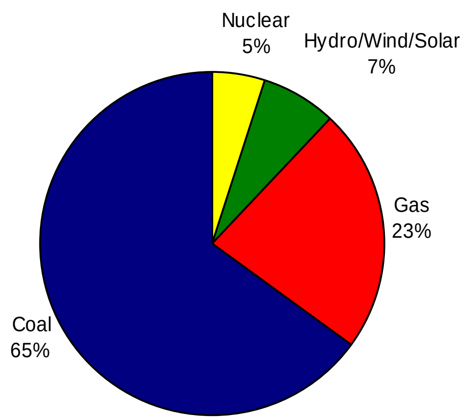
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

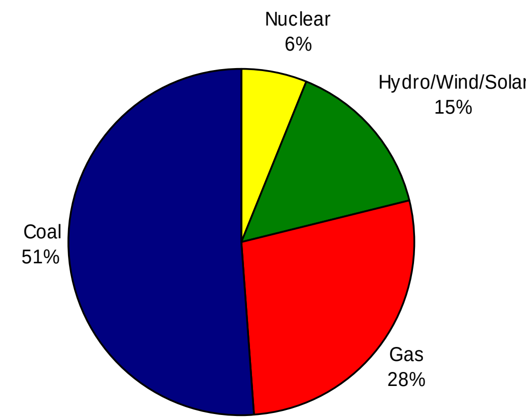
1990 AEP Generating Capacity by Fuel
37,428 total MW's



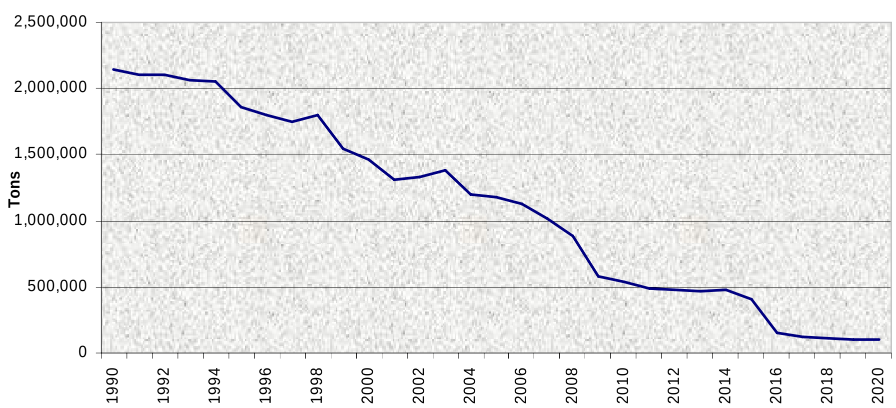
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

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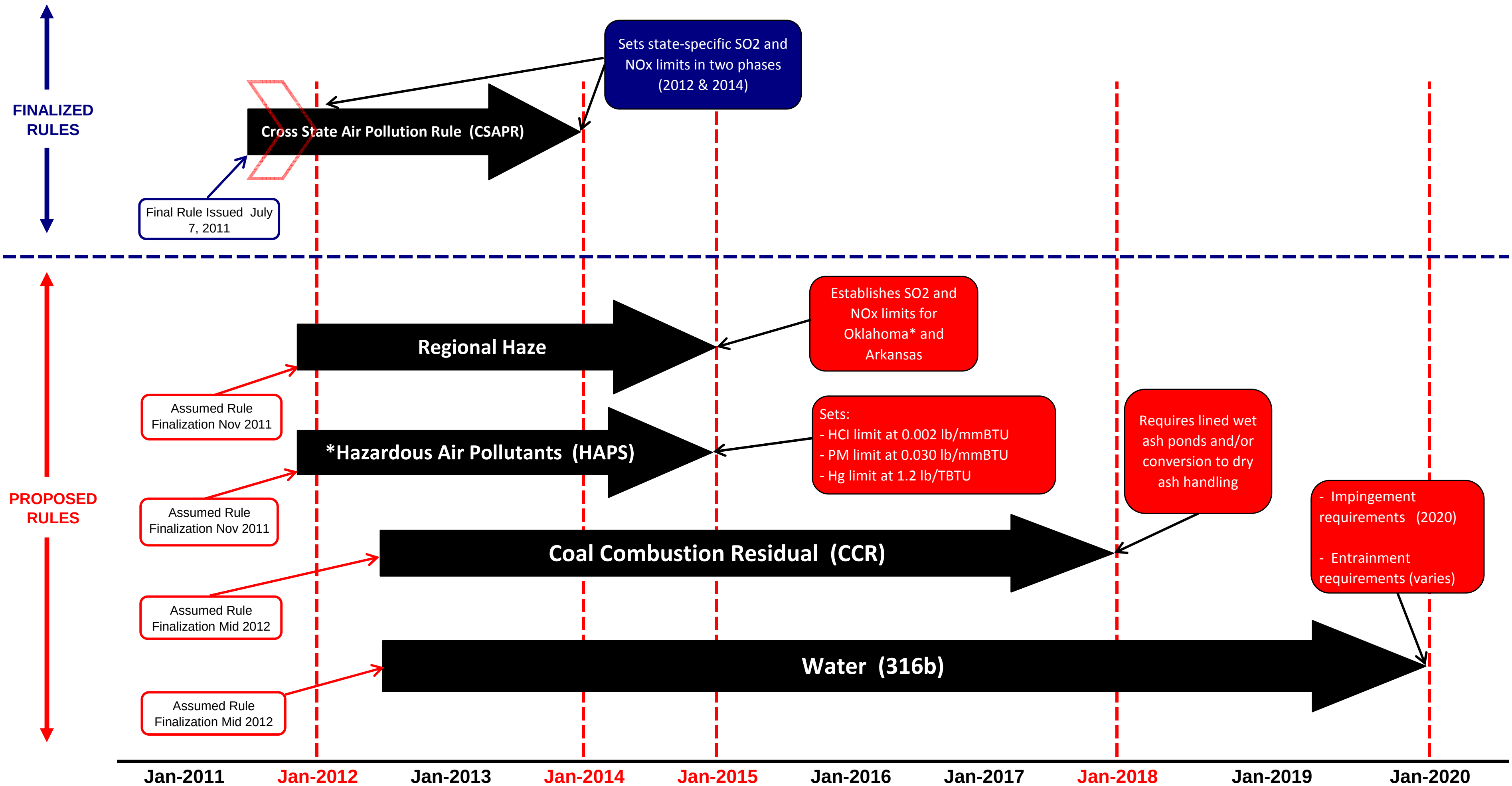
EPA Regulatory Deadlines



*** Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.**

Strictly Confidential

Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.
- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.2 billion capitalized expenditures 6/30/11. SWEPCO's contractual commitments $157MM.
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Turk Plant Proceedings

Water Permit

- In 2009 a wetlands permit was issued by the U.S. Army Corps of Engineers.
- In 2010 the Sierra Club, Audubon Society and others filed a complaint in Federal Court challenging the Corps of Engineers permit and NEPA review
- Later in 2010 the Hempstead County Hunting Club also filed a complaint challenging the Corps permit and claiming that SWEPCO was not entitled to proceed under the exemption from the state CECPN requirements.
- A preliminary injunction was issued in October 2010 halting remaining work under the Corps permit and the CECPN claims were certified to the Arkansas Supreme Court
- In 2011 Arkansas Supreme Court determined that claims must first be brought before the APSC and that federal court does not have jurisdiction to hear state law claims.
- Preliminary injunction was upheld by the Court of Appeals in July, 2011.
- After the settlement with the Hunting Club and all named individuals, SWEPCO filed motions to dismiss the remaining claims
- Cross motions for summary judgment are also pending before the District Court

Air Permit

- Received required air permit approval from Arkansas Dept. of Environmental Quality (ADEQ) in Nov 2008.
- In Dec 2008, opponents filed an appeal with the Arkansas Pollution Control & Ecology Commission.
- Permit was Affirmed by the Commission in January 2010.
- Same parties filed an appeal with the Hempstead County Circuit Court.
- Circuit Court affirmed Commission's decision in December 2010.
- Same parties filed an appeal with the Arkansas Court of Appeals.
  - Briefing underway
  - A decision is likely early next year

In July 2011, SWEPCO reached an agreement resolving all pending matters with the Hunting Club and several other parties. The Hunting Club's challenge regarding the Water Permit was dismissed and the appeal of the Air Permit was withdrawn. SWEPCO was unable to resolve claims by the Sierra Club and the Audubon Society. Their challenges to the wetlands and air permits will continue.

Regulatory Update

Ohio ESP Settlement

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders.
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger.
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million.
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day.
    - Year one (2012), 21 percent will be available at RPM price; Year two (2013), 31 percent will be available at RPM price; Year three (2014 through May 2015), 41 percent will be available at RPM price.
    - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals.
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.
- **Hearing Scheduled for October 4, 2011**

Gradual Transition to Market and Regulatory Stability in Ohio

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule and settlement agreement are both pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

AEP®

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed.   APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Rates Implemented, subject to refund	January 1, 2012
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

AEP®

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule - TBD

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

Jurisdictional Fuel Clause Summary

Jurisdiction	Active Fuel Clause	Frequency
Arkansas	Yes	Annually
Indiana	Yes	Semi-Annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	Yes	Quarterly
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Tri-Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Texas Central Supreme Court Remand

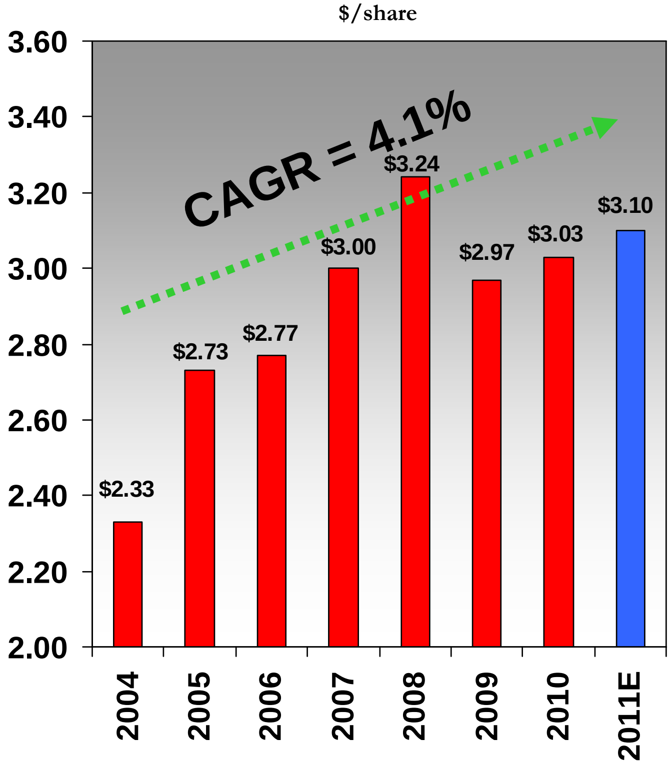
- In early 2006, TCC received an order in the stranded cost proceeding enabling it to securitize $1.7 billion in stranded assets in October 2006, but denied recovery for other items.
  - TCC's inability to sell all of the capacity it was required to auction resulted in the PUCT rejecting the auction prices for purposes of calculating a legislatively-prescribed market-based true-up.
  - This led to a disallowance of $421 million and an after-tax impairment of $274 million being booked in 2005.
- In July 2011, the Texas Supreme Court reversed the PUCT's decision to reject use of auction prices, and the issue has been remanded to the PUCT.
- TCC is entitled to recovery of the $421 million plus carrying costs back to 2002 at a rate of 7.47%.
- There will be regulatory proceedings and likely settlement discussions before the final amount is approved. TCC can securitize the recovery.

Financial Update

Earnings and Dividends

On-Going EPS History Since 2004

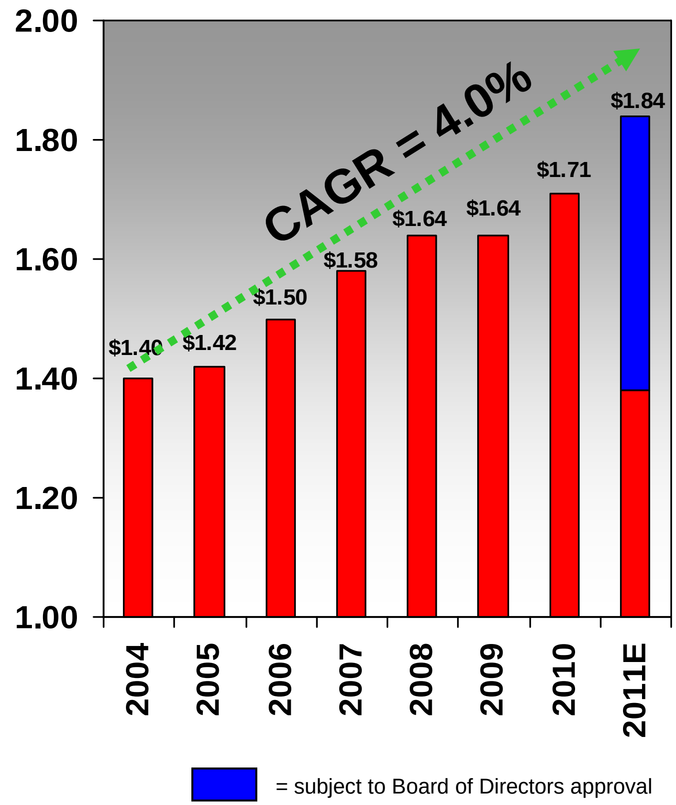
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend increased 12% in 2010
- 405th consecutive quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield near 5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

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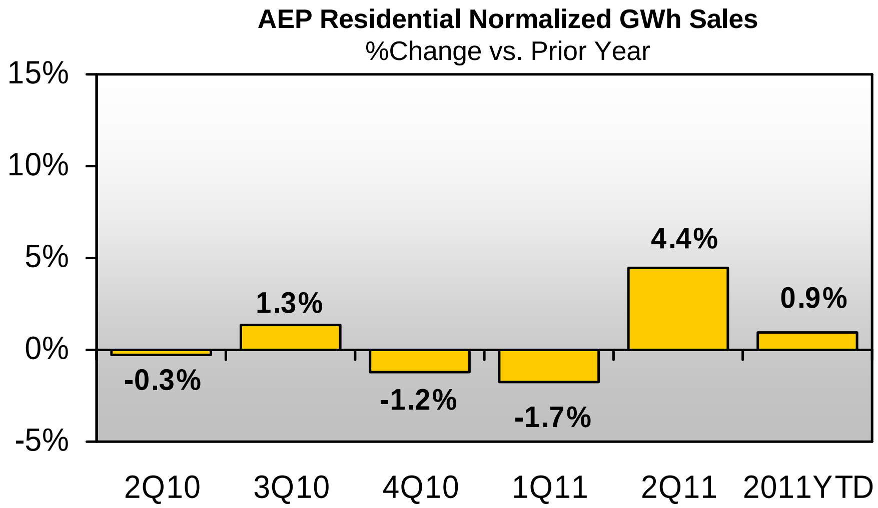
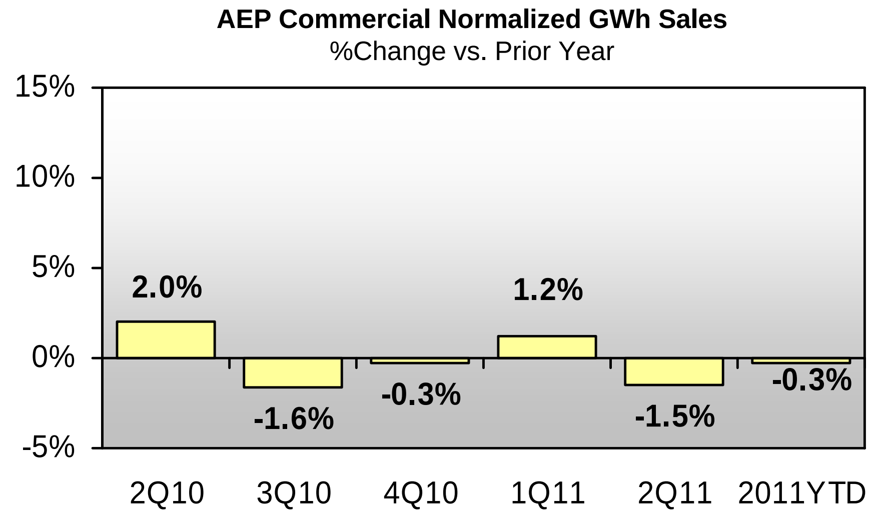
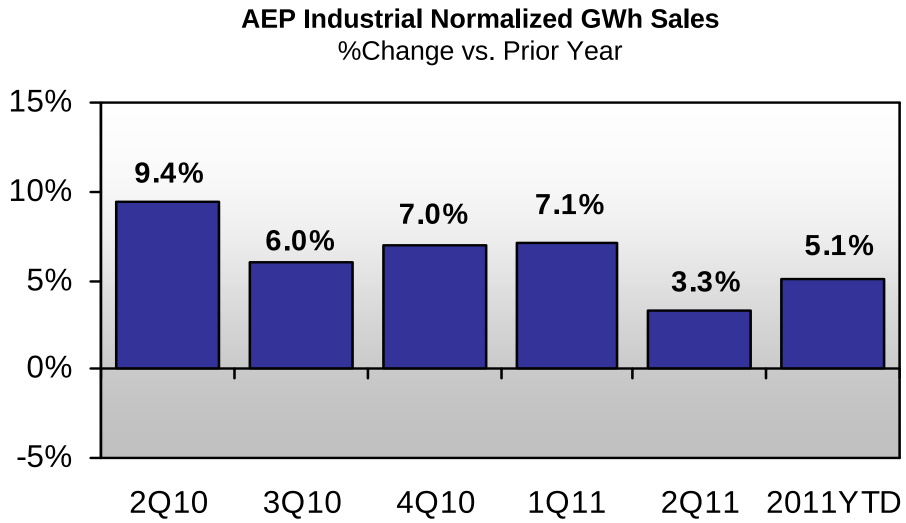
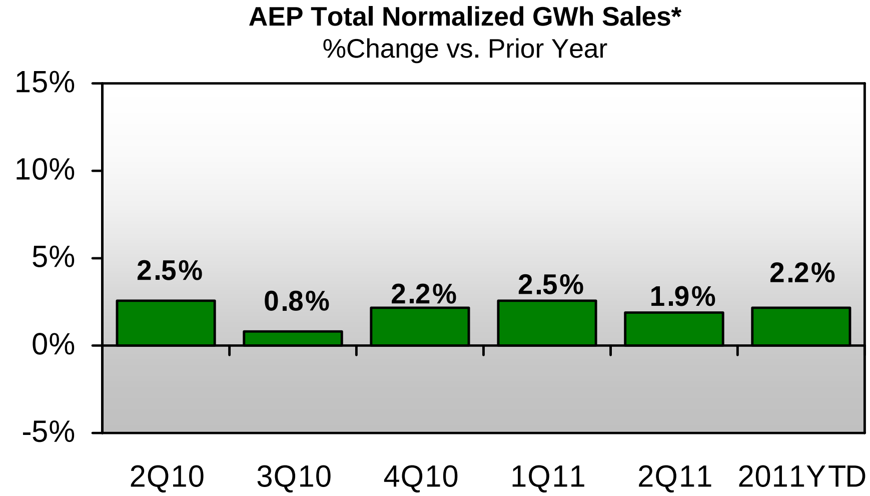
Normalized Load Trends









*includes firm wholesale load

Note: Chart represents connected load

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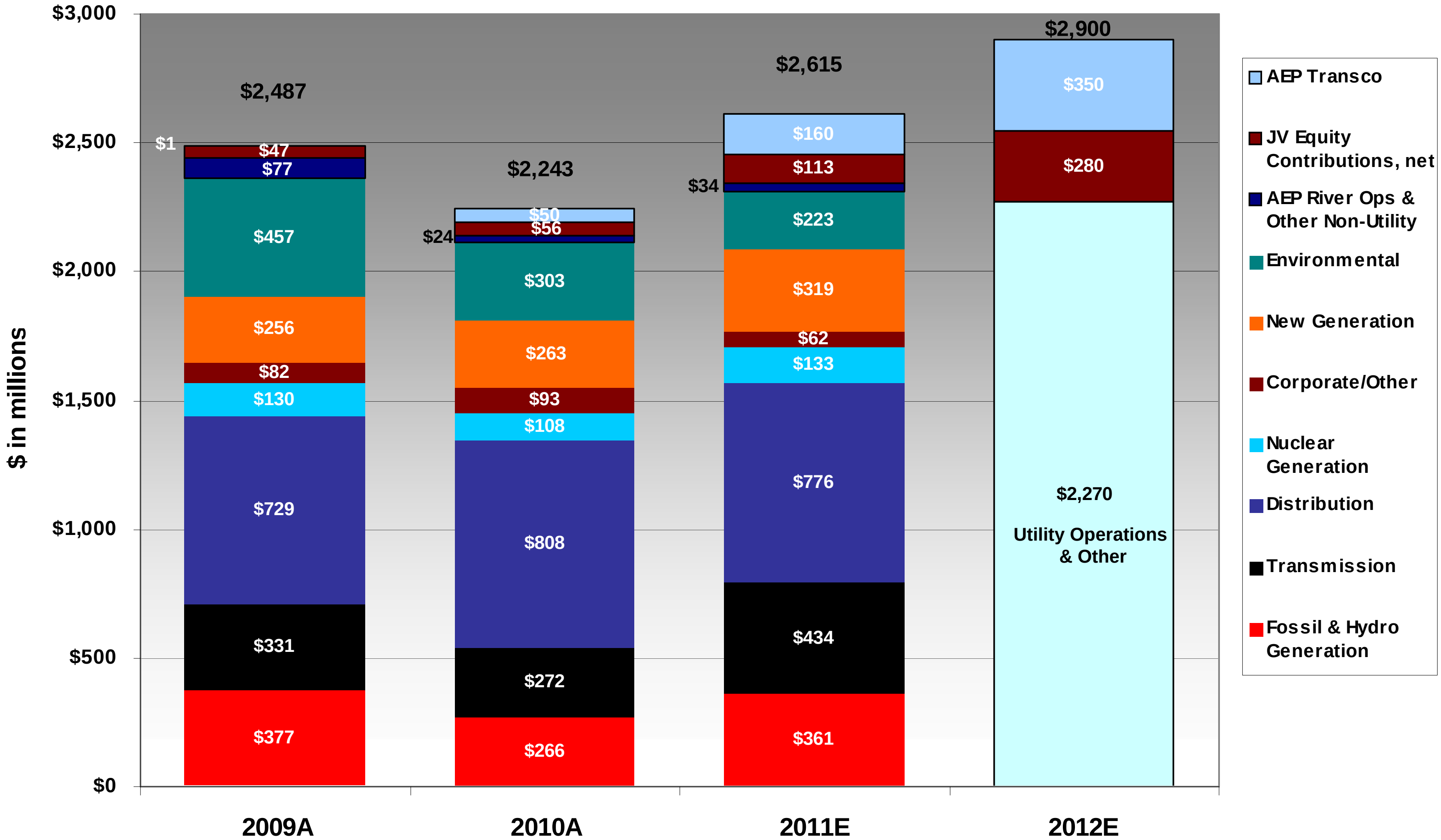
Capital Expenditures

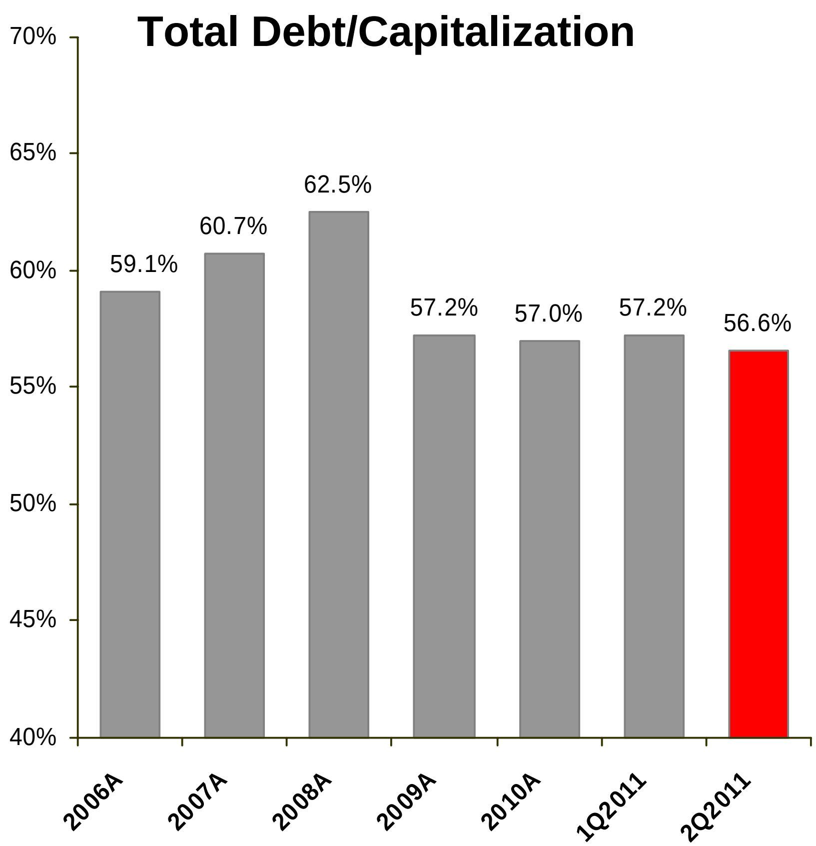


Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

$ in millions	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

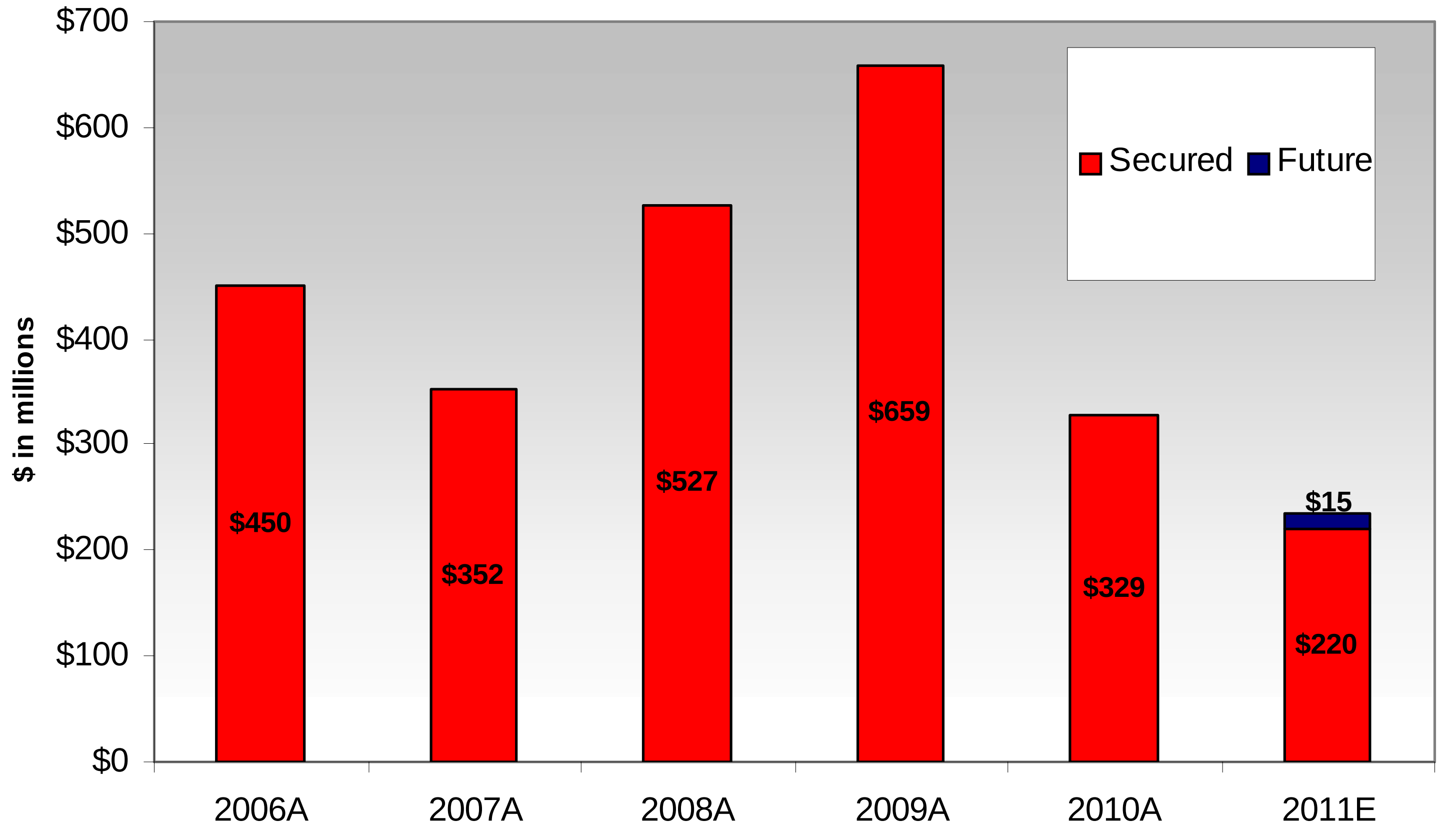
Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Long-Term Debt Maturity Profile

($ in millions)	2012	2013	2014	2015	2016
American Electric Power Company, Inc.	-	-	-	$243	-
AEP Generating Company	-	-	-	-	-
Appalachian Power Company	$250	-	-	$500	-
Columbus Southern Power Company	$150	$250	-	-	-
Indiana Michigan Power Company	$100	-	$175	$125	-
Ohio Power Company	-	$500	$225	-	$350
Public Service Company of Oklahoma	-	-	-	-	$150
Southwestern Electric Power Company	-	-	-	$250	-
AEP Texas North Company	-	$225	-	-	-
Senior Notes	$500	$975	$400	$1,118	$500
AEP Generating Company	-	-	-	-	-
Appalachian Power Company	$65	$195	$204	-	-
Columbus Southern Power Company	$45	$56	$60	-	-
Indiana Michigan Power Company	-	$77	$100	-	-
Ohio Power Company	-	$50	$119	$86	-
Public Service Company of Oklahoma	-	-	$34	-	-
Southwestern Electric Power Company	-	-	-	$54	-
AEP Texas Central Company	$60	-	-	-	-
Pollution Control Bonds	$170	$378	$516	$140	$0
Indiana Michigan Power Company	-	$65	$70	$63	-
Southwestern Electric Power Company	$20	-	-	-	-
Notes Payable	$20	$65	$70	$63	$0
AEP Texas Central Company	-	$381	-	$250	$192
Securitization Bonds (amortizing)	-	$381	-	$250	$192
Total	**$690**	**$1,800**	**$986**	**$1,570**	**$692**

Notes:

Includes mandatory tenders as of put date and VRDNs at Letter of Credit expiration date

Transmission Update

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $210 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transco's is 11.49%
  - ROE order for West Transco's is 11.20%

State Filing Status Update:

- **Ohio** – PUCO approved the Ohio Transco December 29, 2010
- **Michigan and Oklahoma** – do not require state filing
- **Indiana** - draft settlement agreement filed; waiting on Commission approval
- **Arkansas –** filed May 6, 2011; procedural schedule set with hearings to begin February 15, 2012
- **Louisiana** – filed August 12, 2011; no procedural schedule set
- **Kentucky** – hearings set for October 19, 2011
- **West Virginia** –hearing held June 14, 2011; briefs filed July 2, 2011
- **Virginia** – original filing withdrawn to give additional time to resolve issues with Staff; re-filing expected in 4Q11

$210M capital spend forecasted for 2011

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

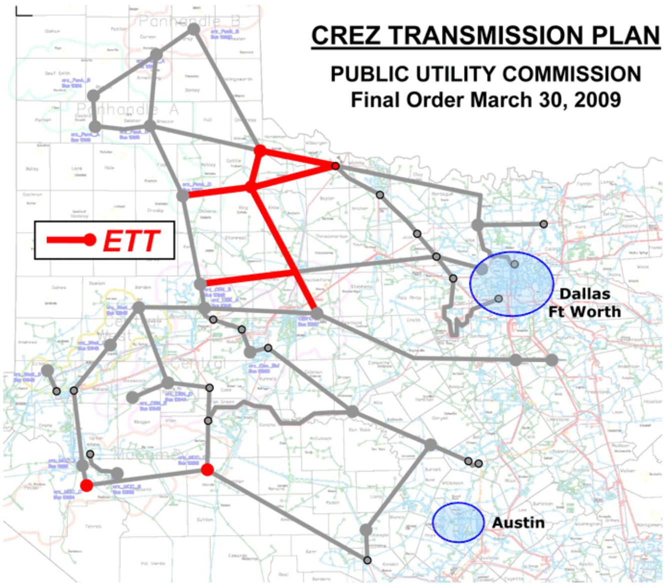
Current rate base is $412 million; expected to grow as follows:

2011: $490 million
2012: $750 million
2013: $1,200 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **<u>Additional Projects in the Pipeline ~$1.5 B:</u>**
  - Approximately 500 miles of lines and 29 substations with in-service dates through 2020

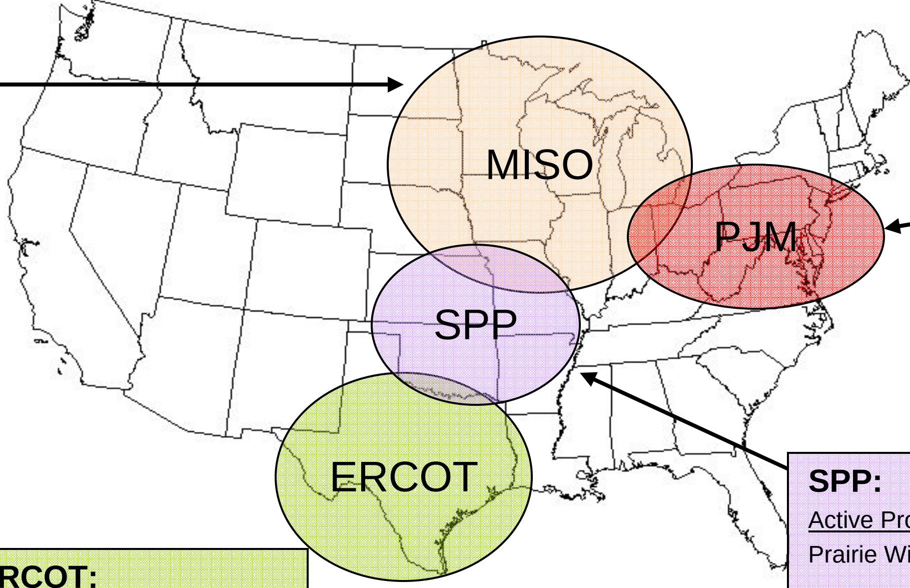
- **<u>Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.4 B:</u>**
  - Nine new transmission lines totaling approximately 600 miles and 16 substations
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway; 5 lines already approved

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

AEP AMERICAN® ELECTRIC POWER

Japan Investor Meetings
February 16-17, 2011

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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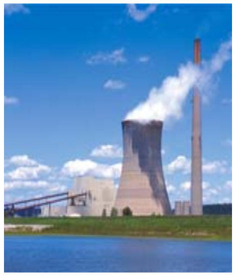
American Electric Power



One of the largest U.S. electricity generators

Generation owned[1] (GW)	
Southern Co	42.9
NextEra Energy	42.7
AEP	39.9
Duke Energy	38.5

The largest U.S. electricity transmitter

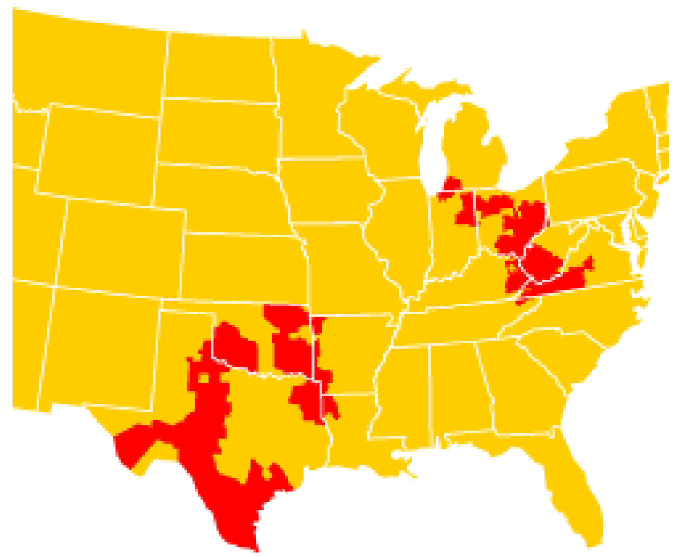
Transmission miles[1] ('000s)	
AEP	39.0
Southern Co	27.0
Duke Energy	20.9
Pacific Gas & Electric	18.6

One of the largest U.S. electricity distributors

Electric customers[1] (mm)	
Exelon	5.4
AEP	5.3
Pacific Gas & Electric	5.1
NextEra Energy	4.5

[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

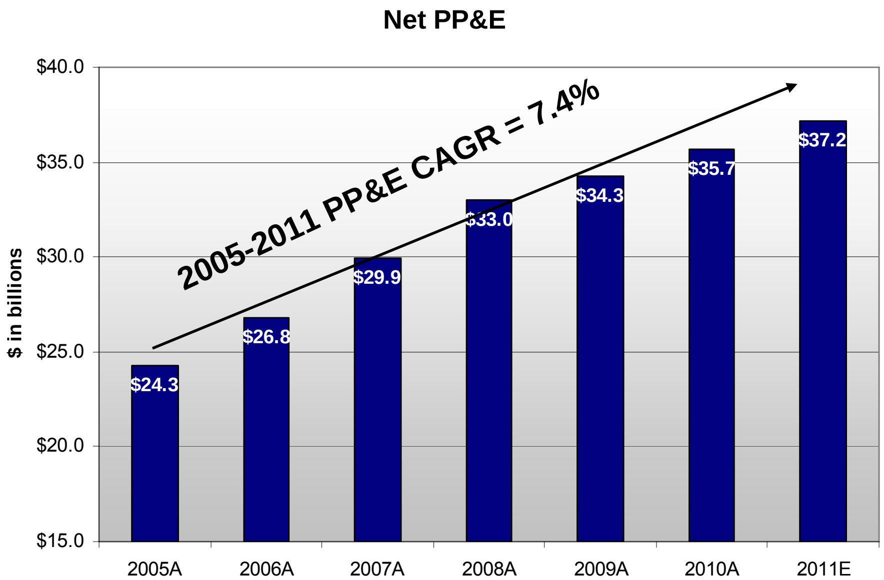
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

Traditional Ratemaking Environment

Growth in Net PP&E

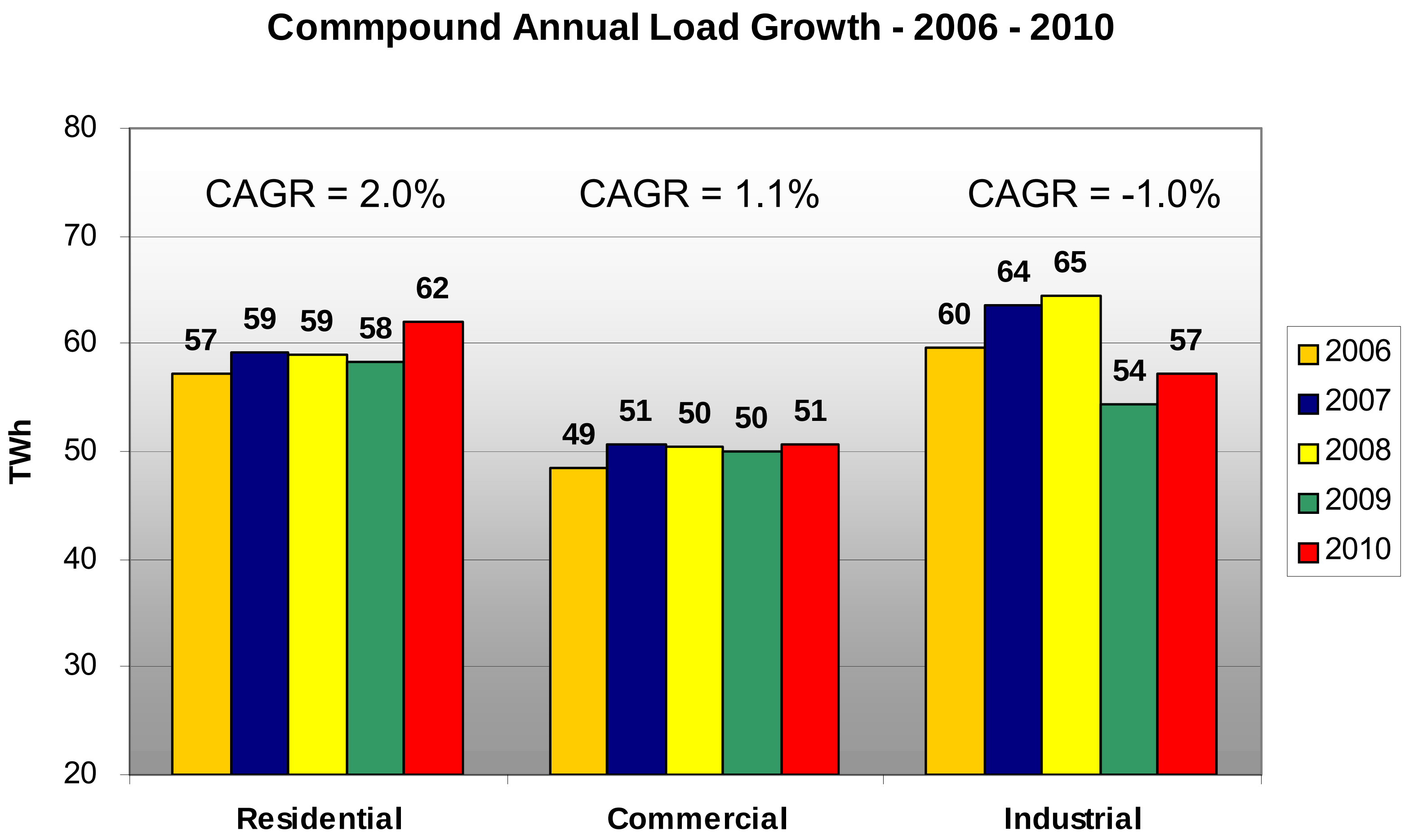


Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

Regulatory Framework

- Base Rates
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- Recovery of Fuel Costs
  - Active fuel clauses in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)

Load Growth



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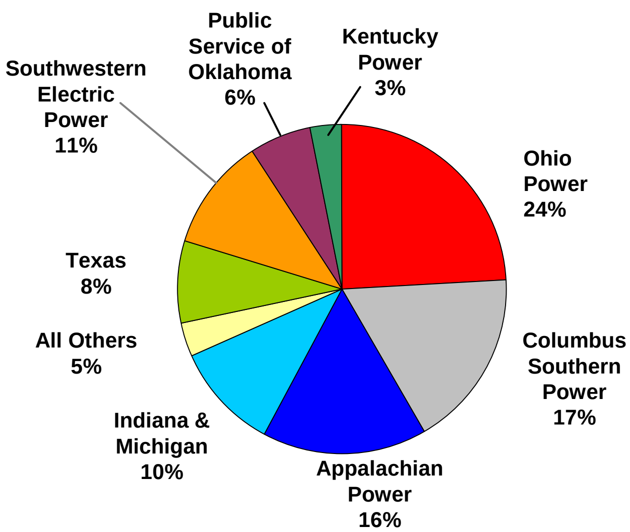
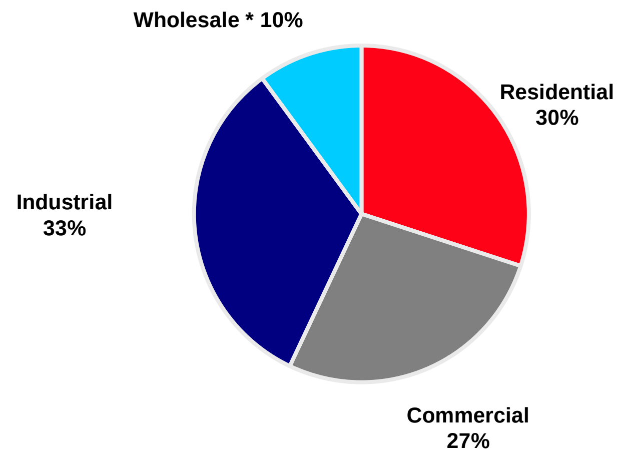
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load

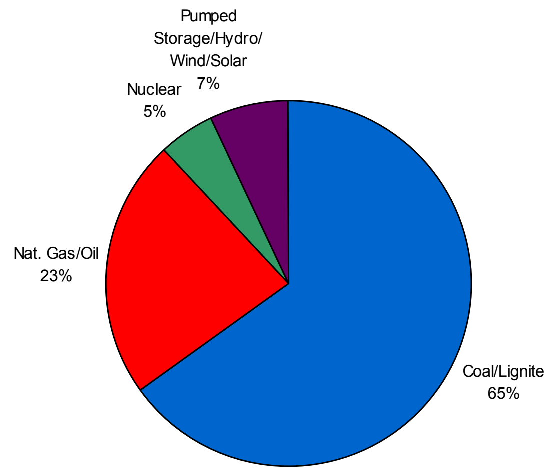


** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

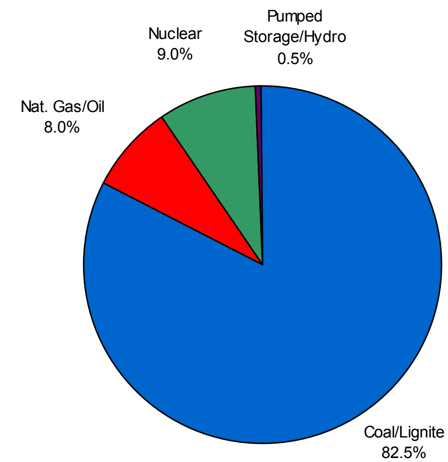
Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Domestic Generation Fleet

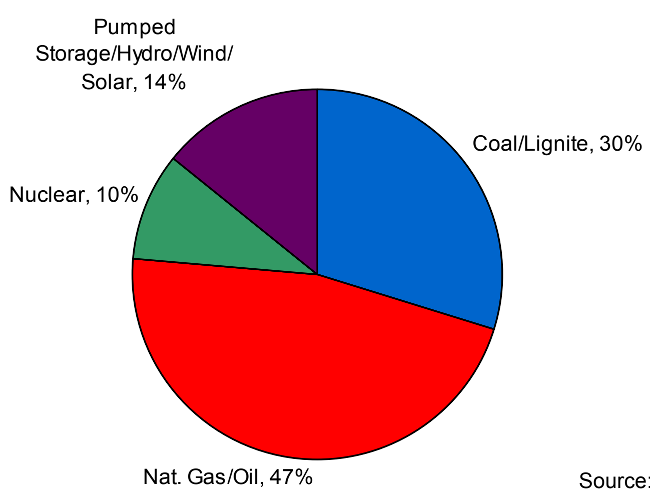
Generation Capacity by Fuel Type
Based on 39,910 MW



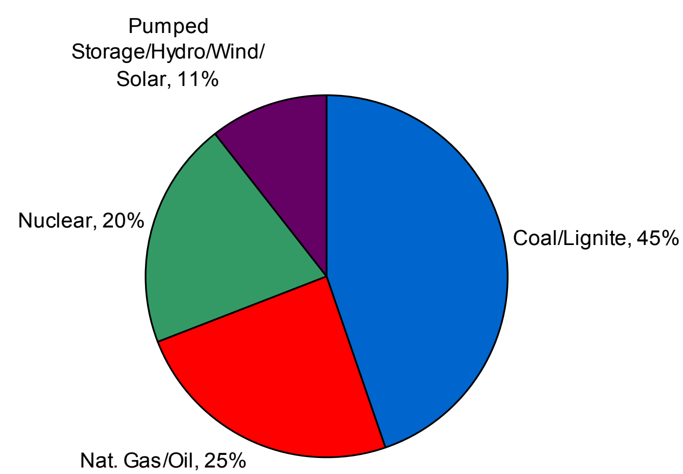
2010 Generation Production by Fuel Type
Based on 173.2 TWh



Generation Capacity by Fuel Type
Based on 1,063,848 MW



2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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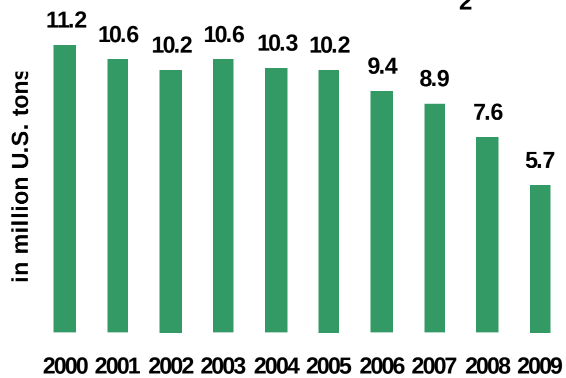
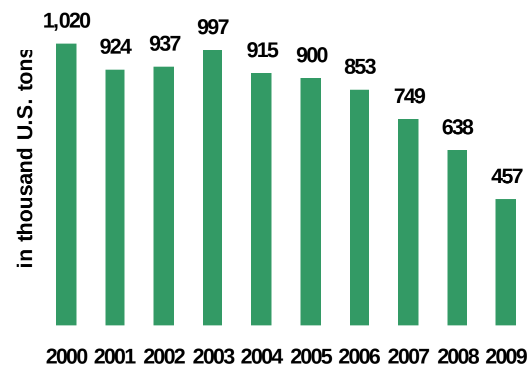
Emissions Reductions since 2000

U.S. Power Plant SO_2 Emissions



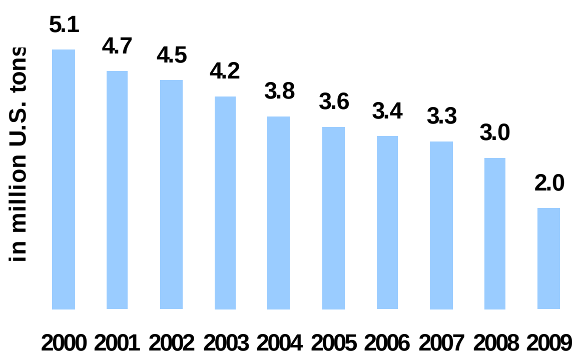
49% reduction since 2000

AEP SO_2 Emissions



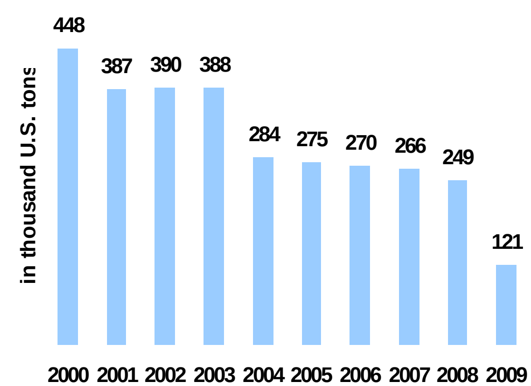
55% reduction since 2000

U.S. Power Plant NOx Emissions



61% reduction since 2000

AEP NOx Emissions

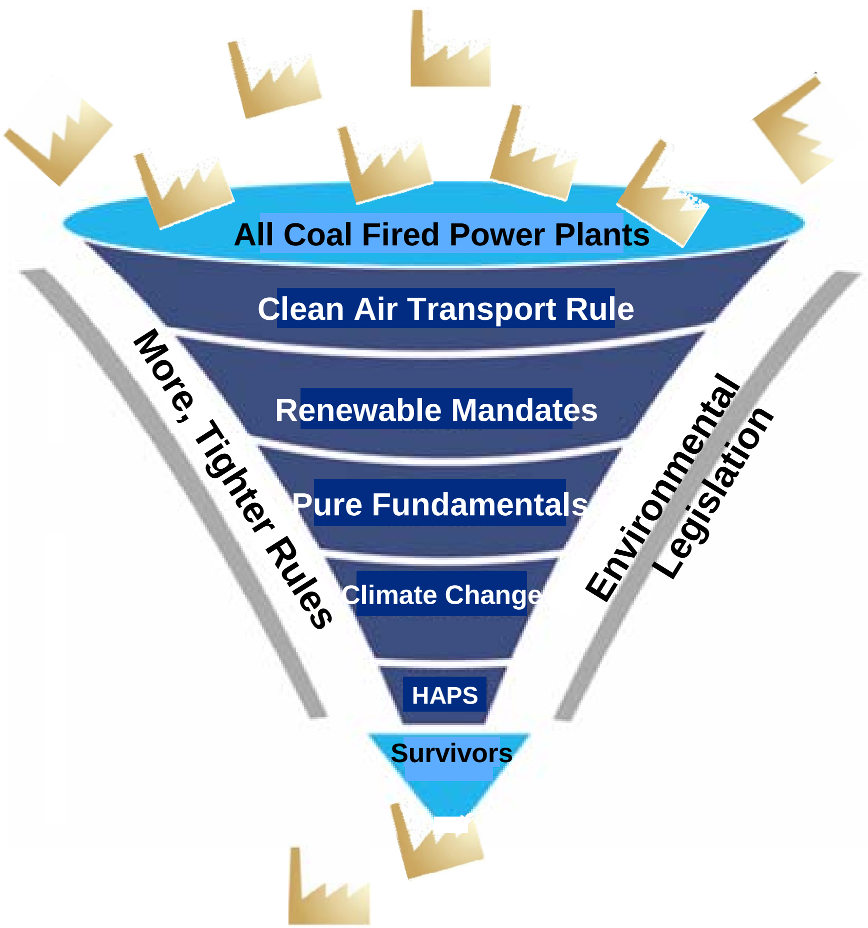


73% reduction since 2000

Source: EPA, 2010; Acid Rain Program

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

The Pressure on Coal Generation



Key EPA Actions Pending

- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in March 2011
- Cooling Water Intakes – Expect Proposed Rule in Spring 2011
- Greenhouse Gas Tailoring Rule – January 2011

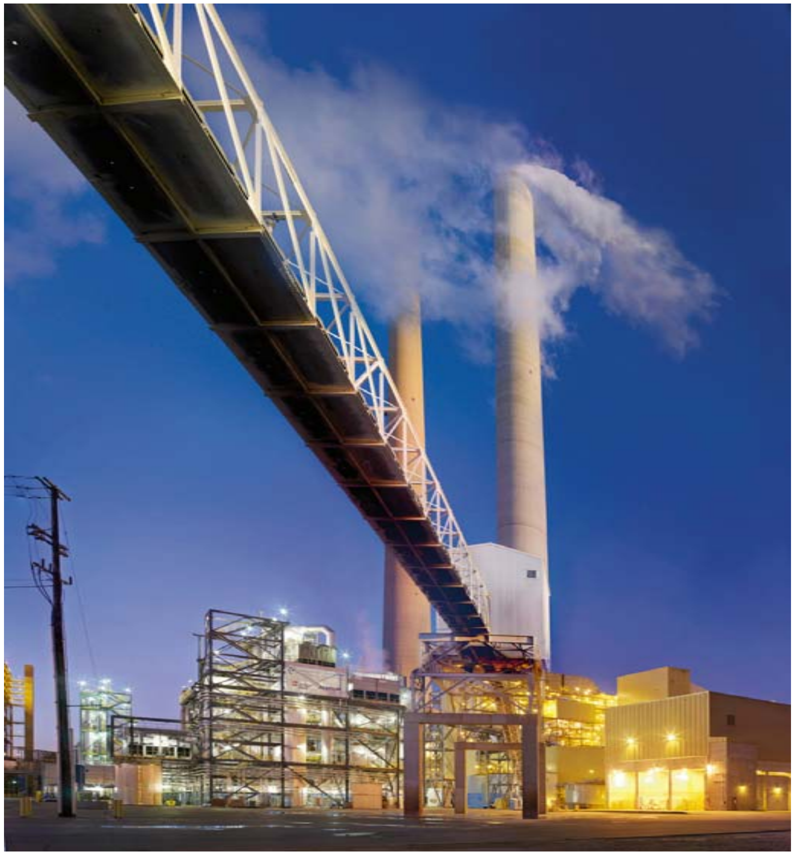
Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

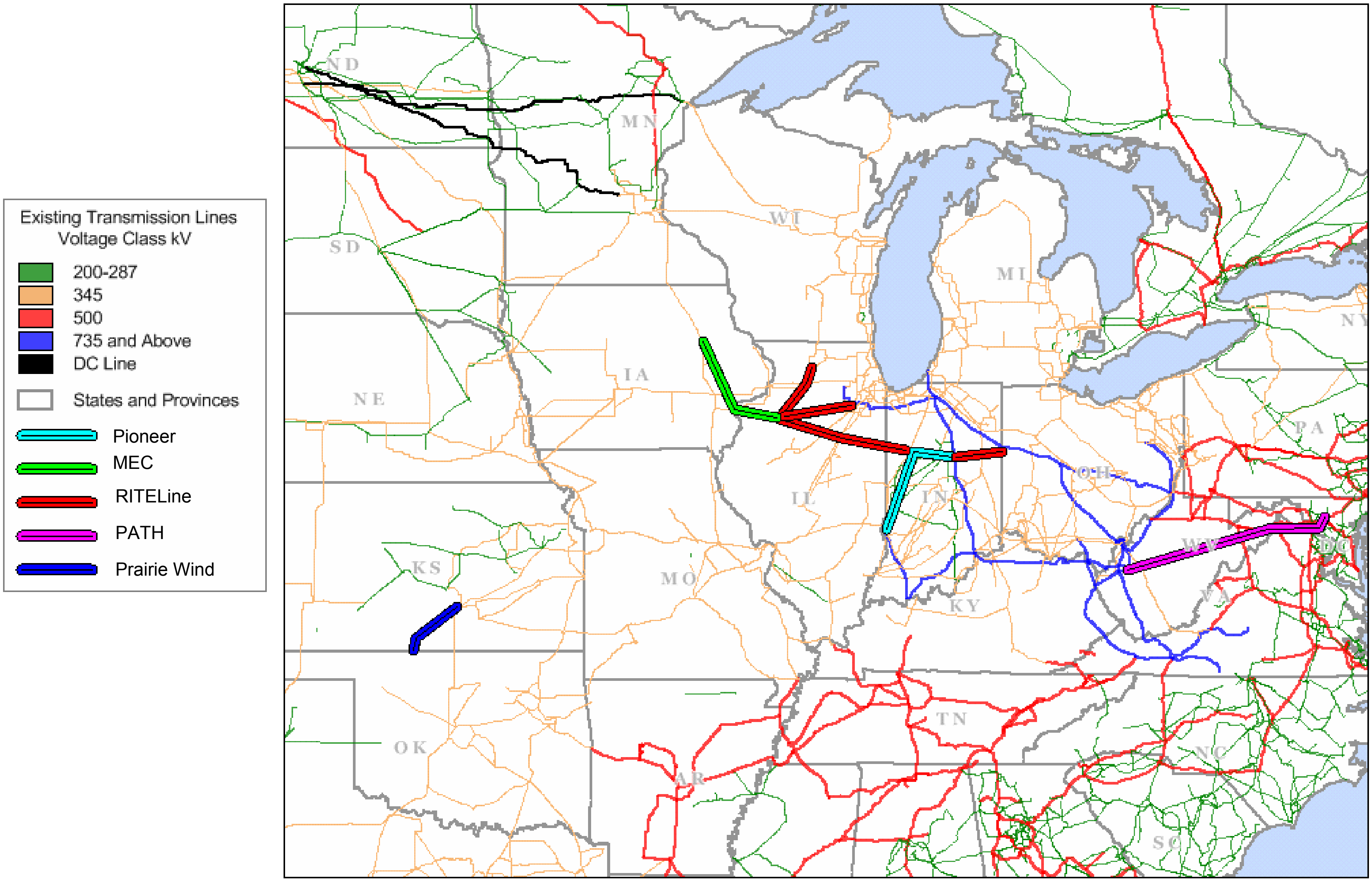
PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process



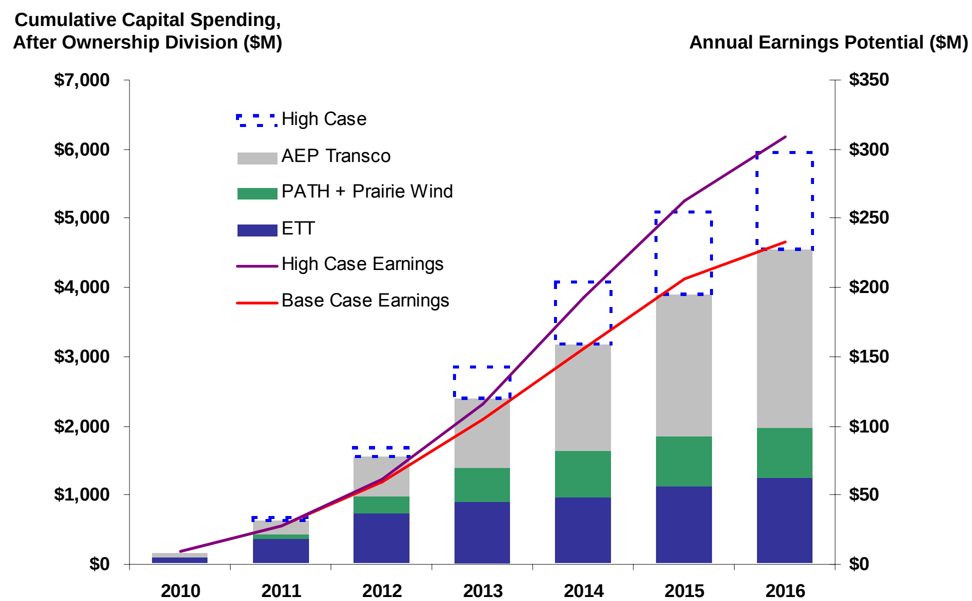
Carbon Capture and Storage project
Mountaineer Plant - New Haven, WV

Current/Proposed Transmission Projects



Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on one CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kV (25% ownership), ETA-Exelon (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

Evolving Transmission Regulatory Policy

Transmission Framework

- Regulated by the Federal Energy Regulatory Commission
- Based on Cost of Service
- Formula Rate Treatment Reduces Regulatory Lag
- Costs Socialized Beyond Retail Customers
- Incentive ROEs available – particularly for technology enhancements

Planning, cost allocation and siting continue to be issues the industry and the United States must resolve

AEP's "Smart Grid" Deployment – Pilot Projects

AEP®

Indiana Michigan Power - South Bend Pilot (Completed – September 2010)

- 10,000 AMI meters
- Integrated Mesh communication network
- Distribution grid management – centralized & decentralized
- Consumer programs: 2-tier time-of-day rates and technology enabled direct load control using PCTs
- Customer web portal
- Initial meter data management system development

AEP Ohio– central Ohio– (2009-2013)

- Awarded US DOE Smart Demonstration Project
- 133,000 meters using integrated mesh network
- Advanced distribution grid management with volt-VAR control
- Advanced consumer programs including critical peak and real-time pricing
- Extensive consumer outreach and communication
- Innovative web portal
- Large scale distributed storage
- Concentrated PHEV implementation
- Smart appliance deployment
- Industry first smart grid cyber security center

AEP Texas – Statewide (2009-2012)

- Legislature enabled and commission directed T&D service providers to deploy advanced metering
- 970,000 meters using mesh network communications
- Enable Texas retail service providers to provide innovative pricing and in-home consumer technologies
- 10,000 in-home displays for low income customers
- Statewide portal for usage and home device provisioning

PSO– Owasso Pilot (Implement in 2011)

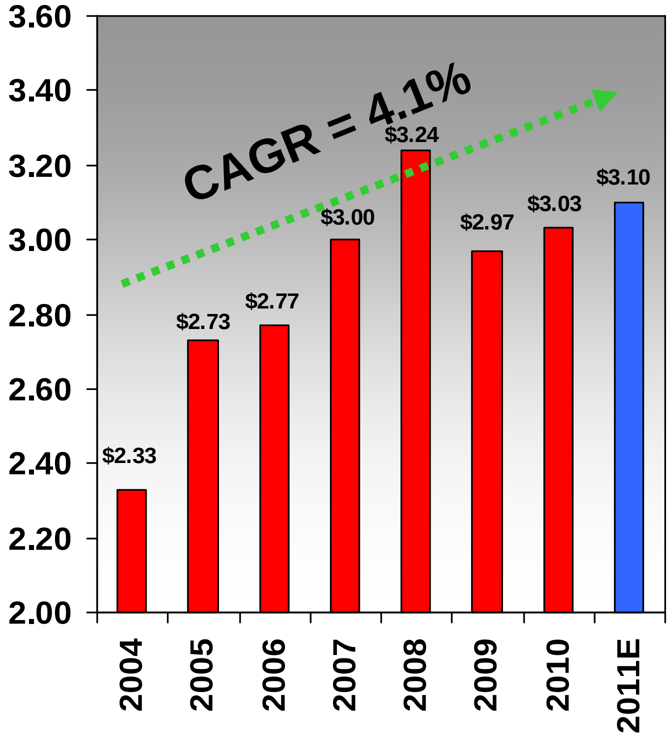
- 13,000 AMI meters
- AMI and distribution control communication networks
- Distribution automation
- Distribution Volt-VAR control
- High level of in-home devices – displays and PCTs
- Customer programs – time-of-day and direct load control programs
- Web portal

gridSMART attributes from the utility side of the meter look promising; customers with low rates may not see material savings/benefits

Earnings and Dividends

On-Going EPS History Since 2004

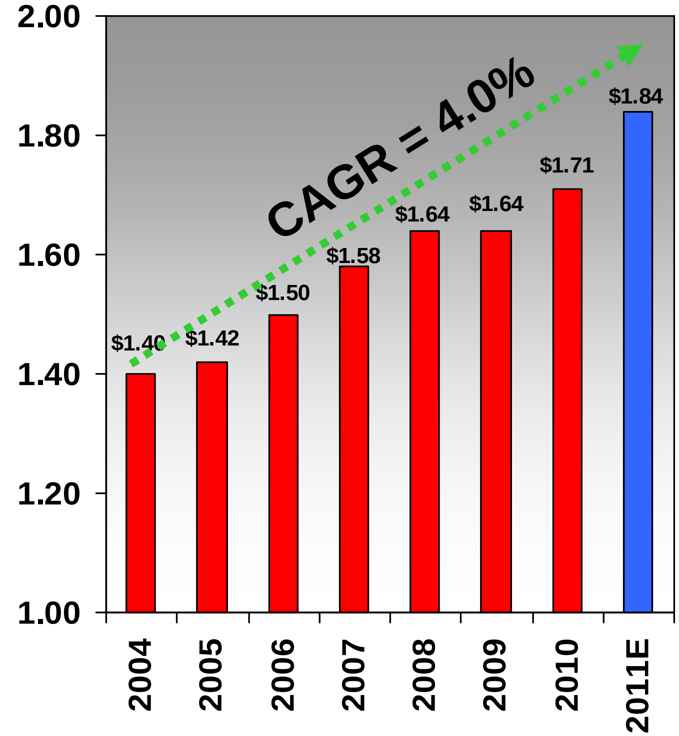
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

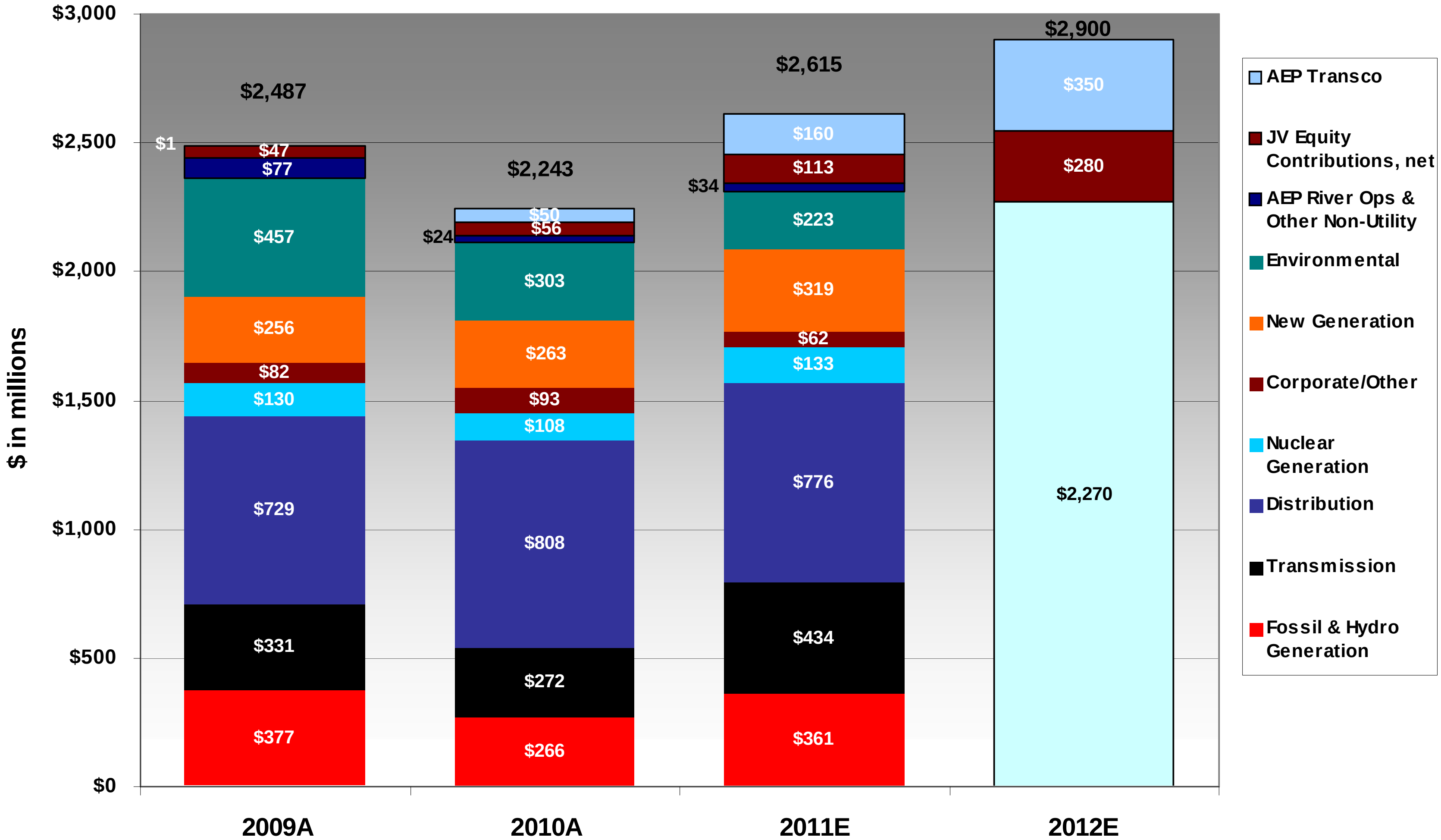
$/share



= subject to Board of Directors approval

- Dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend declared in January
- 50-60% payout ratio target
- Current yield over 5%

Capital Expenditures



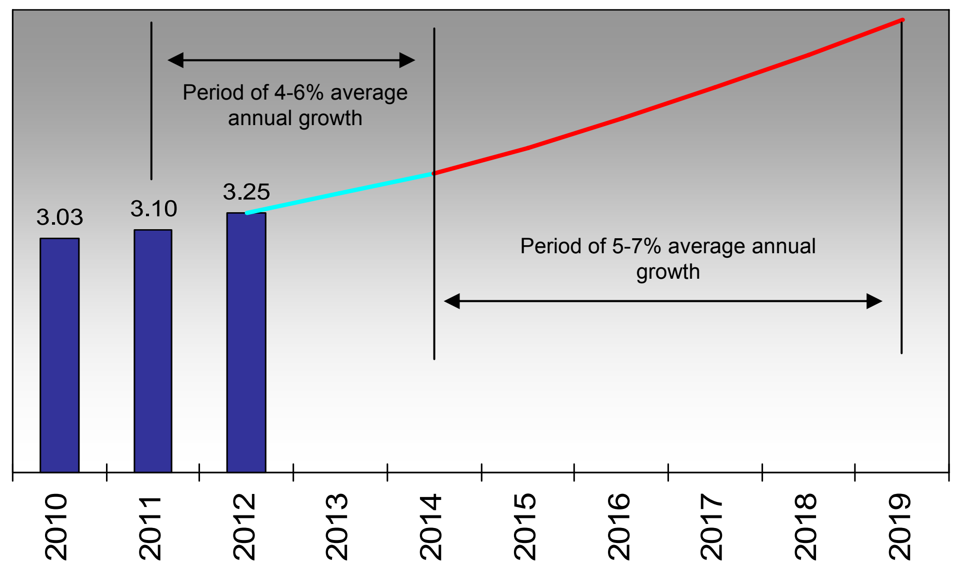
Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Long-term EPS Growth Rate

AEP®

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
- Strong Value and Total Return Proposition

Mountaineer Plant (WV)

AEP AMERICAN® ELECTRIC POWER

JP Morgan Utility Corporate Access Day

Boston, MA
March 24, 2011

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American Electric Power

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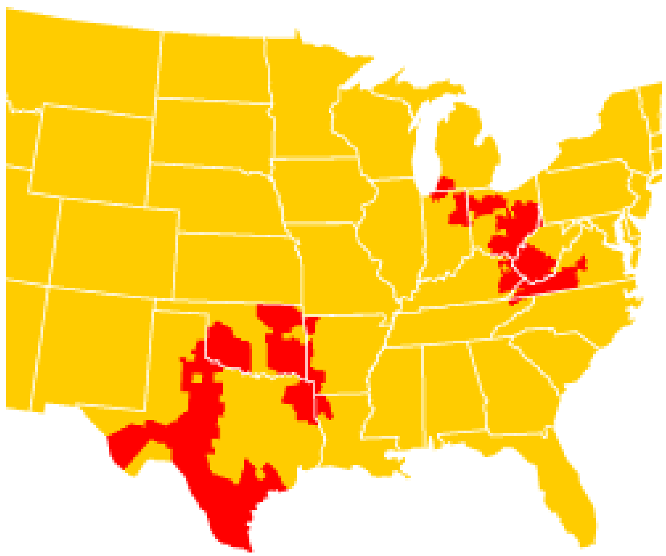
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



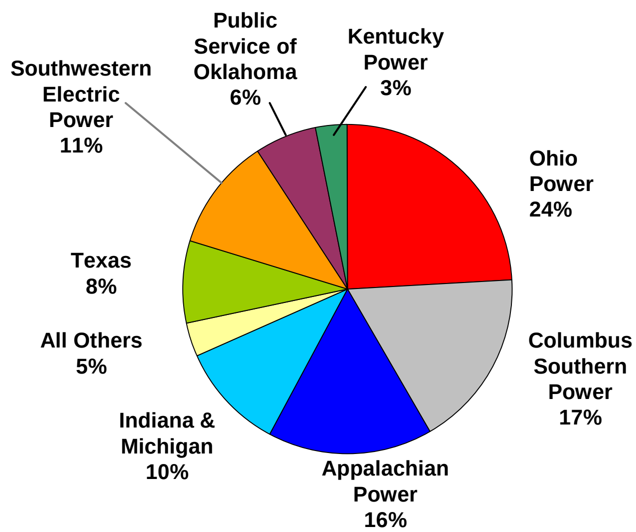
AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

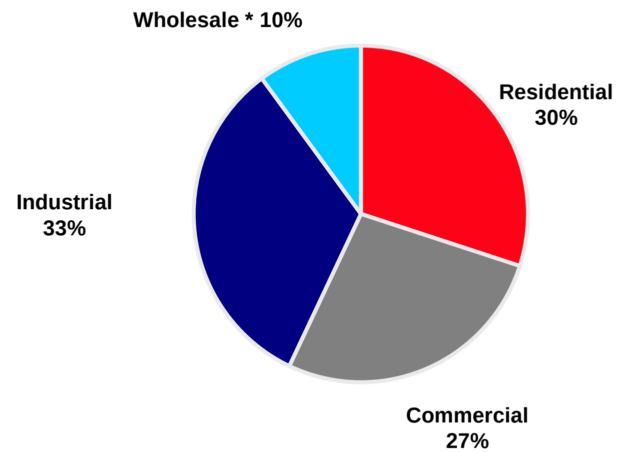
$16.5B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



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Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

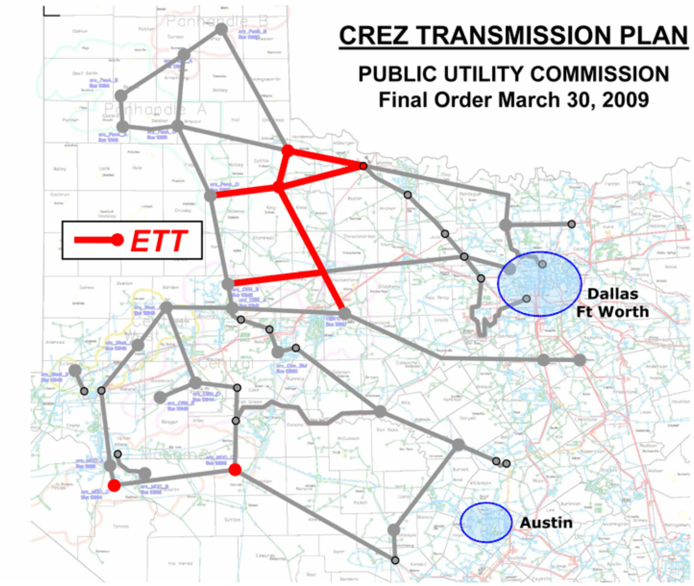
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

Filing Status Update:

- ***Ohio*** *(filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia*** *(filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia*** *(withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

$160M capital spend forecasted for 2011

Joint Venture Strategy: Long-term

- **<u>Strategy</u>:** JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

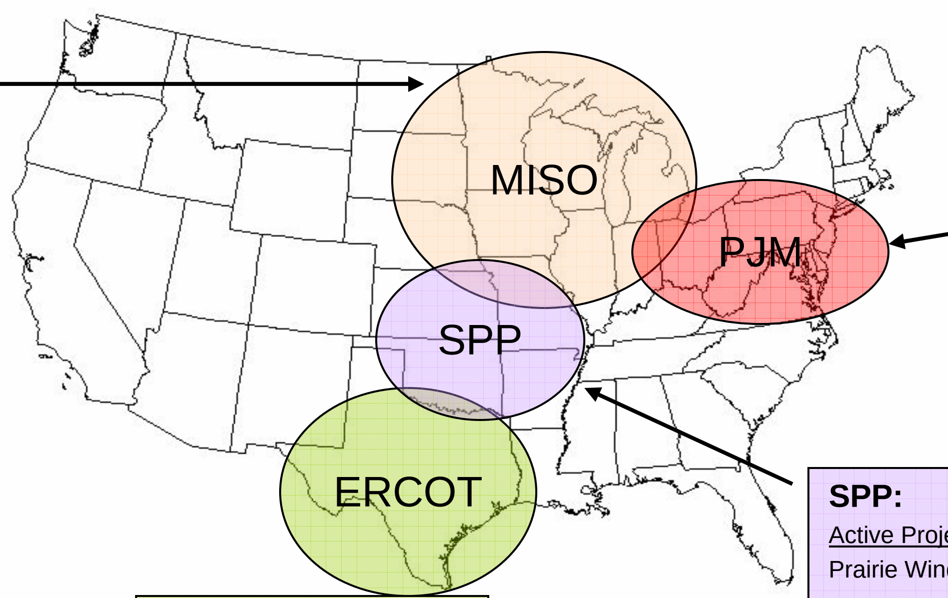
- **<u>Future:</u>** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **<u>Future flexibility</u>:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:

<u>Active Projects:</u>
MEC Project
Pioneer

<u>Drivers for Growth:</u>
Reliability
Wind Integration



PJM:

<u>Active Projects:</u>
Pioneer
RITELine

<u>Drivers for Growth:</u>
Congestion
Reliability
Operational

ERCOT:

<u>Active Projects:</u>
ETT

<u>Drivers for Growth:</u>
Wind Integration
Insufficient EHV Transmission

SPP:

<u>Active Projects:</u>
Prairie Wind

<u>Drivers for Growth:</u>
Reliability
Wind Integration

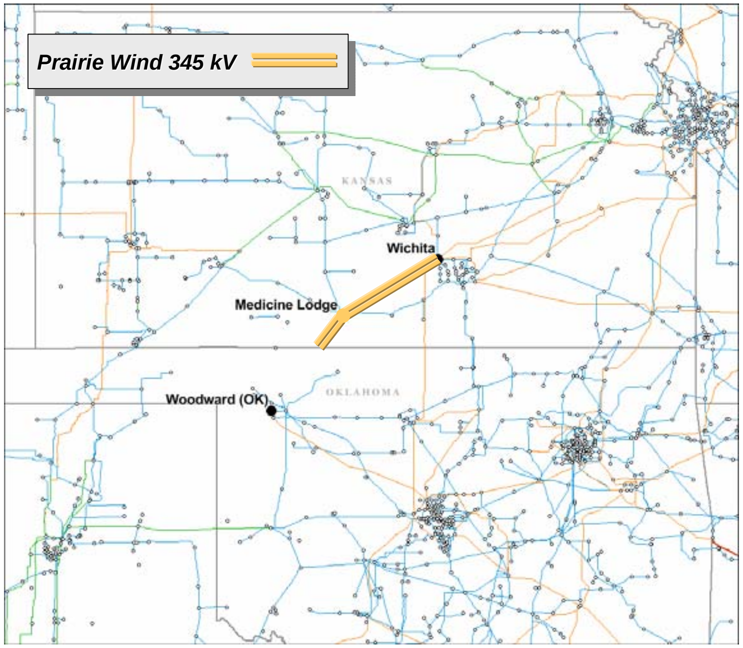
Prairie Wind Transmission, LLC

AEP®

<u>Project Description</u>: 110 miles of EHV transmission lines extending from Wichita, KS to the KS/OK border

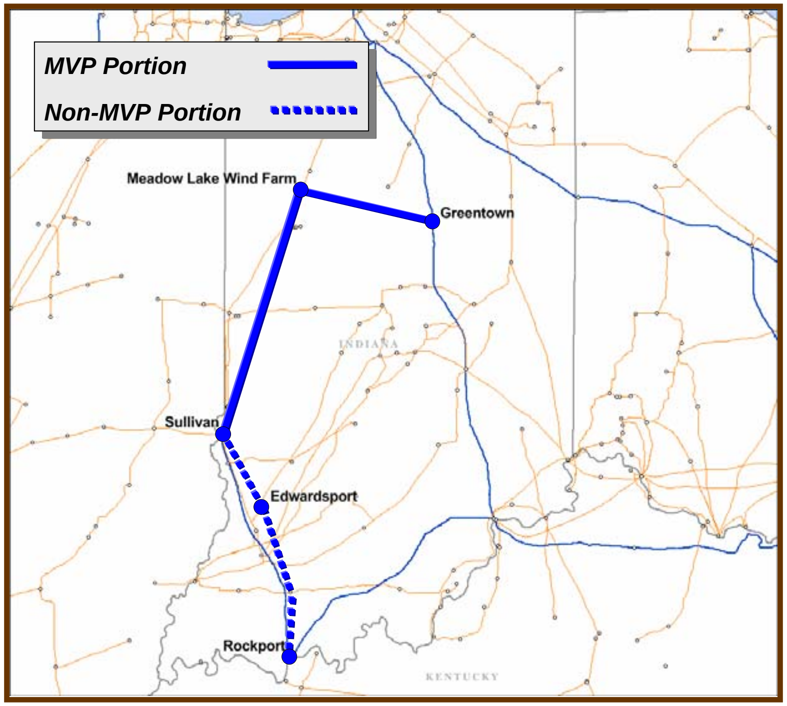
Overview:

- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
- The project is expected to cost $225 million and be in-service by 2013-2014
- AEP's ownership of the joint venture is 25%
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice To Construct was issued to Westar July 2010. Currently working on a novation of the NTC to Prairie Wind. As a Transmission Owner, Prairie Wind will be entitled to collect revenue upon the novation of the Notice to Construct.
  - Currently approved at 345 kV.
  - Siting permit application filed in February 2011.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Pioneer



MVP = Multi-Value Project; projects that MISO has identified as supporting a public policy requirement or addressing reliability and/or multiple economic issues in multiple transmission zones. The costs of these projects will be allocated across the entire RTO.

Ownership Structure: 50/50 (AEP/Duke)

Total Project Cost: Up to $1 Billion

Approved ROE: 12.54%

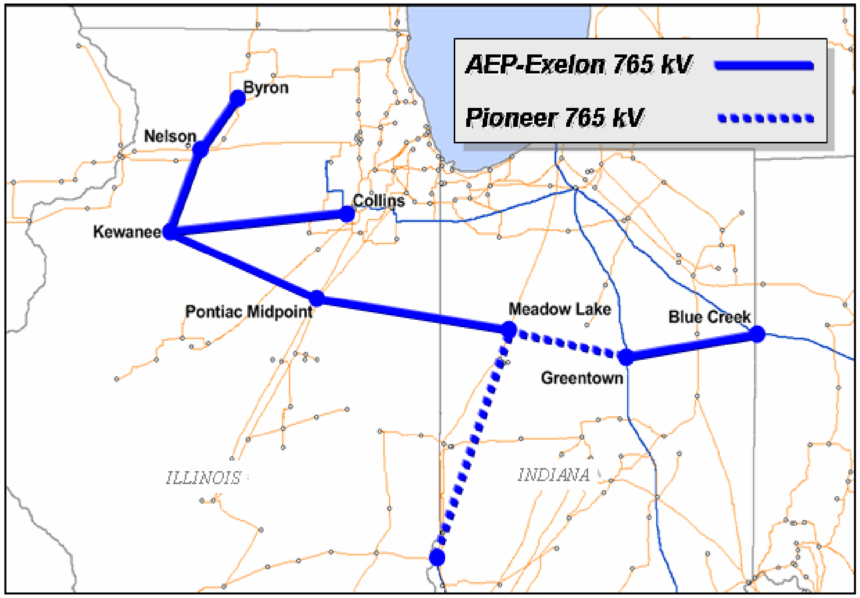
Line Miles: Up to 240

In-Service Date: 2016 (Estimate)

Greatest Risk: RTO Approval & cost allocation between PJM and MISO

RITELine Project

- AEP, ETA and Exelon Corporation executed a Memorandum of Understanding on October 26, 2010 for the development of the Reliability Interregional Transmission Extension Line (“RITELine”) project



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- Estimated Project Cost: $1.6 billion

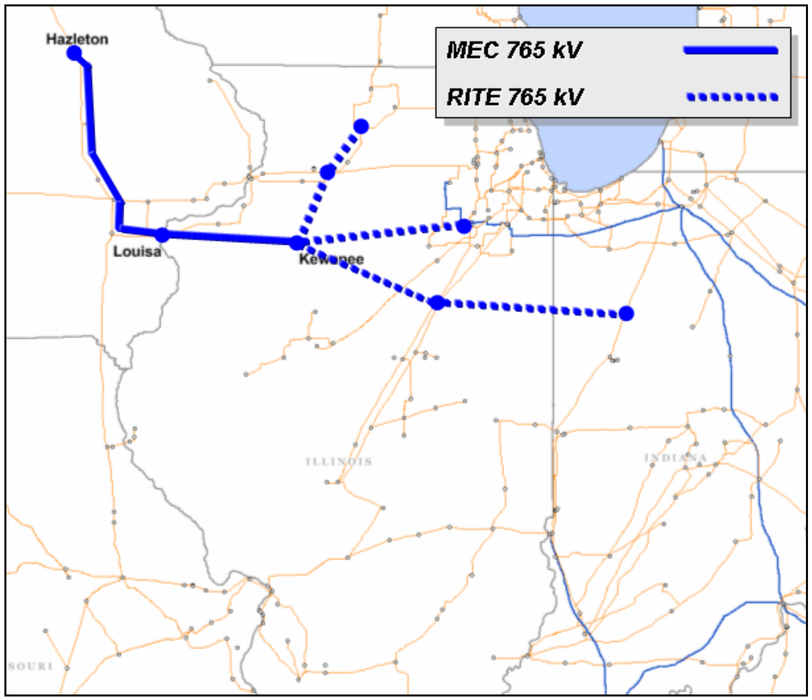
  AEP = $152 million
  ETA = $350 million
  $175M AEP
  $175M MEHC
  Exelon = $1.086 billion

- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV line)

- Extends approximately 420 miles from the Byron Substation in Illinois to the Blue Creek substation at the Ohio/Indiana border and from Kewanee to the Collins Substation in Illinois

MEC Project

- ETA and MidAmerican Energy Company executed a Memorandum of Understanding on October 28, 2010 for the development of the MEC project



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- Estimated Project Cost: $650 million

  ETA = $325 million
  $162.5M AEP
  $162.5M MEHC
  MEC = $325 million

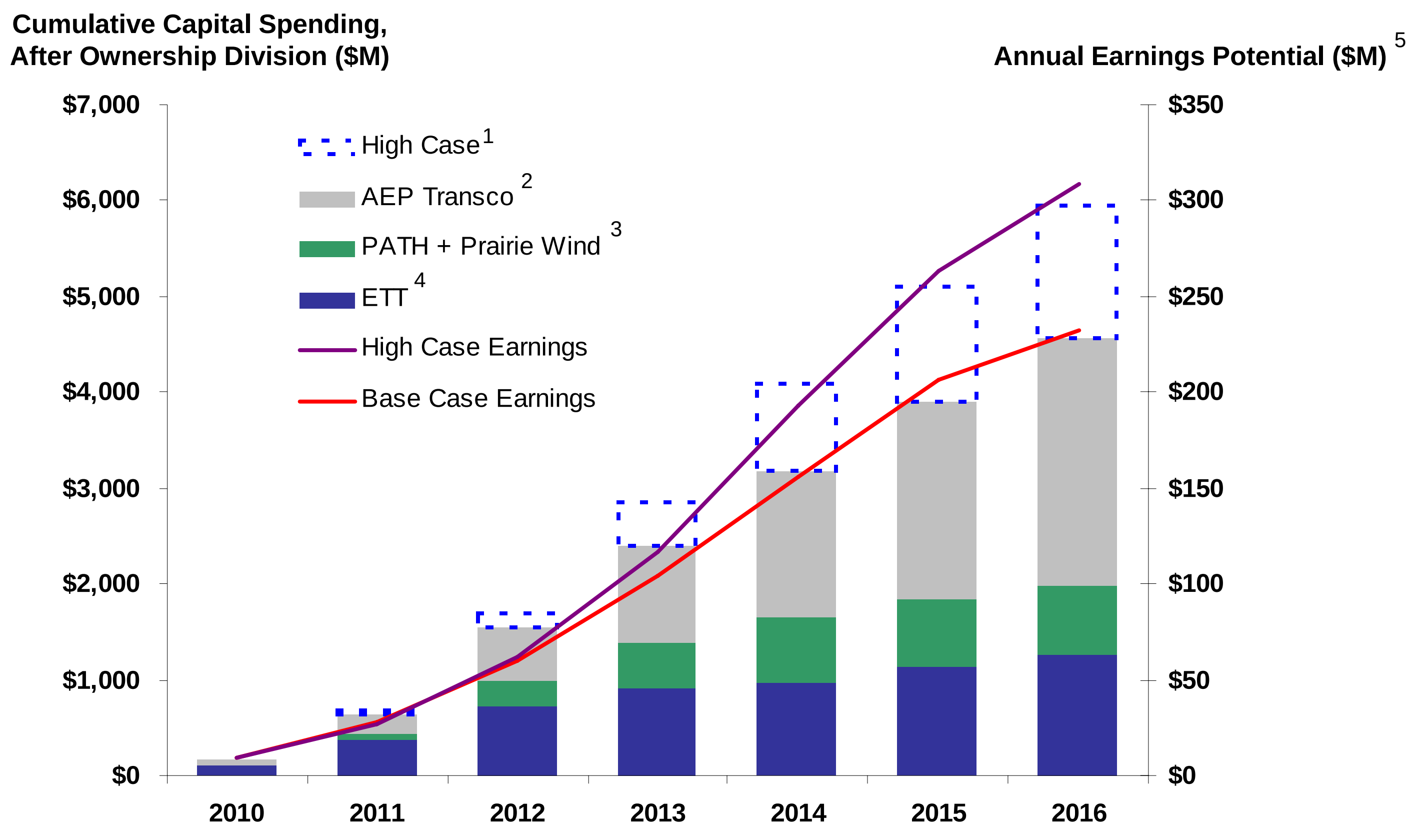
- 765 kV transmission line (or a designated lower-voltage solution such as double-circuit 345 kV)

- Extends approximately 180 miles from the Kewanee Substation in Illinois to the Louisa substation in Iowa and northwest to the Hazelton substation

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

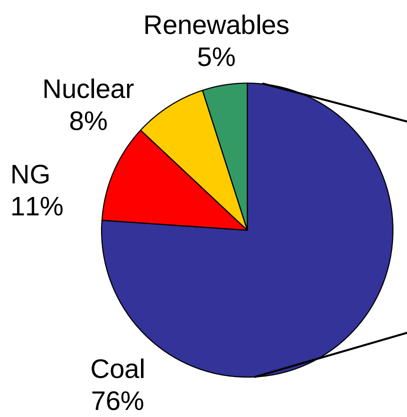
[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

AEP Generation Capacity

AEP®

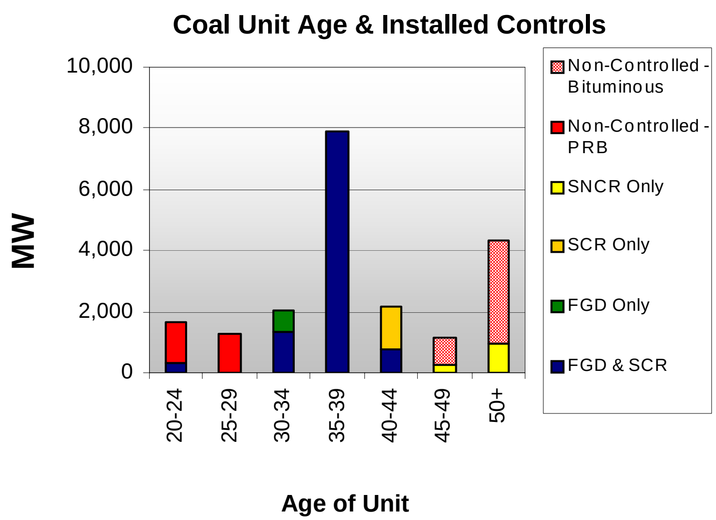
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



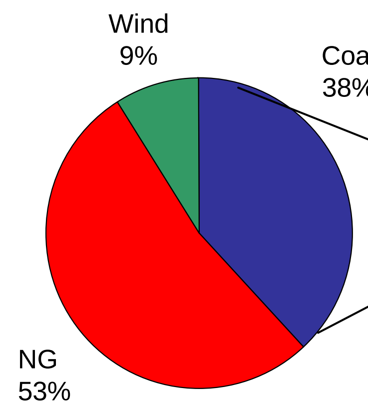
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



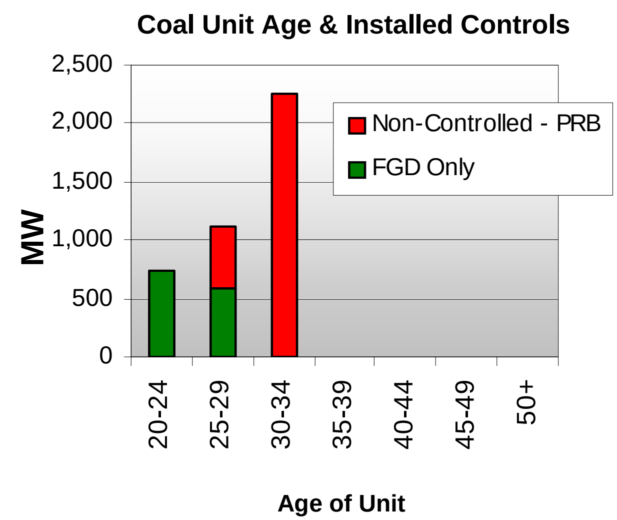
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



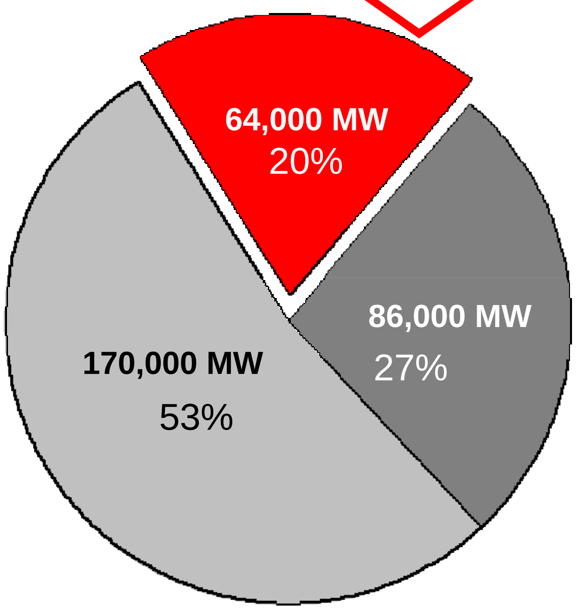
Continual Evaluation is Required

AEP®

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

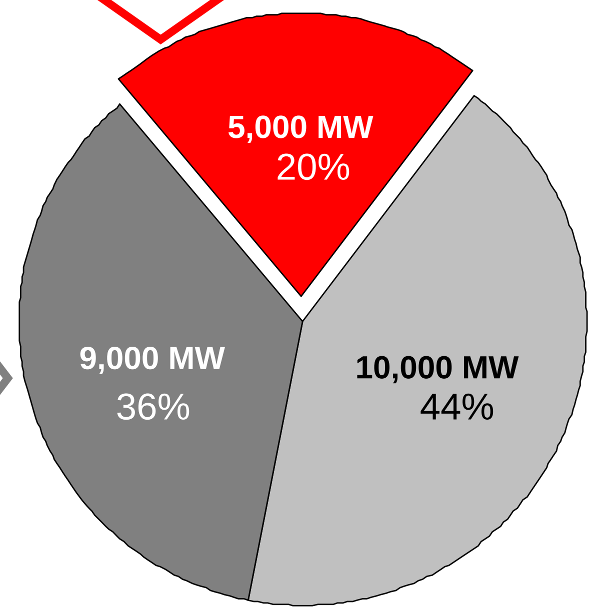
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements

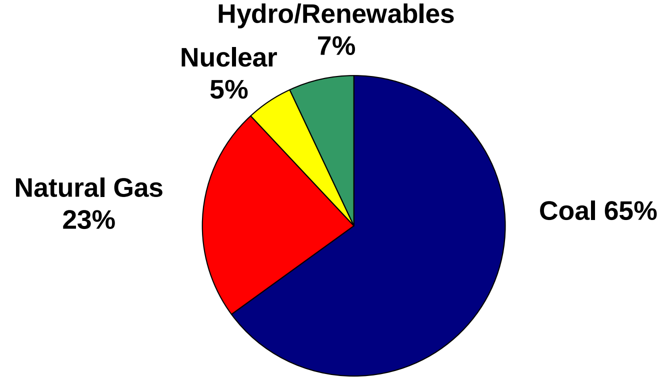


AEP Coal

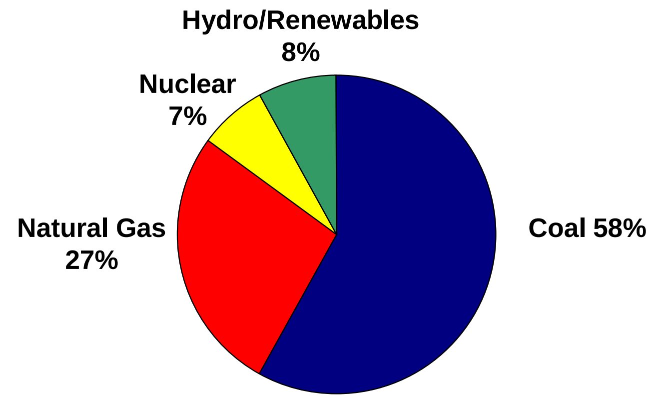
Nearly 50% of U.S. coal plants are exposed

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (under construction)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2010

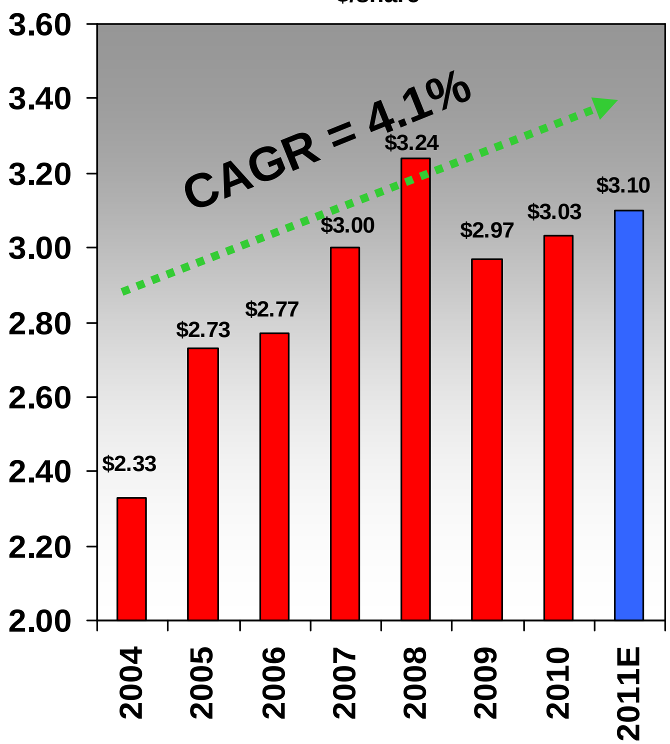


Projected Capacity - 2017

Earnings and Dividends

On-Going EPS History Since 2004

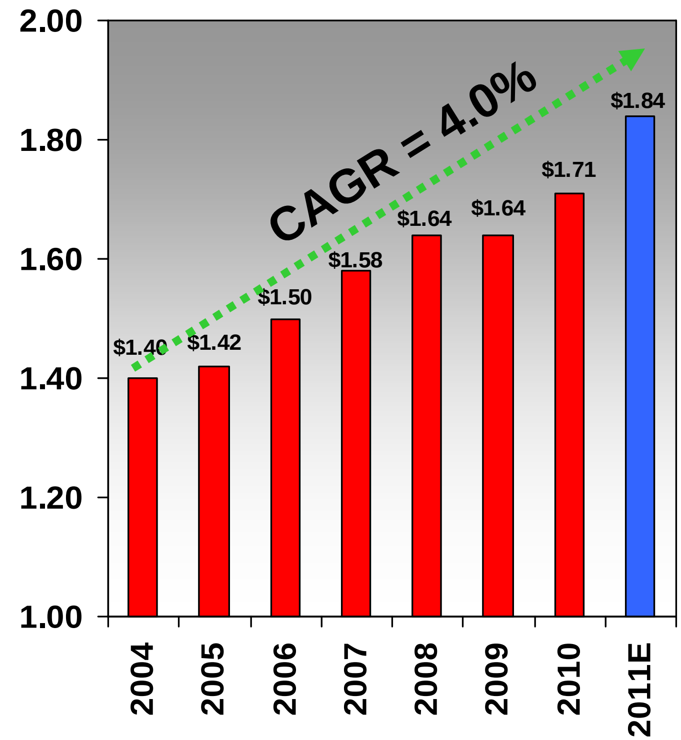
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



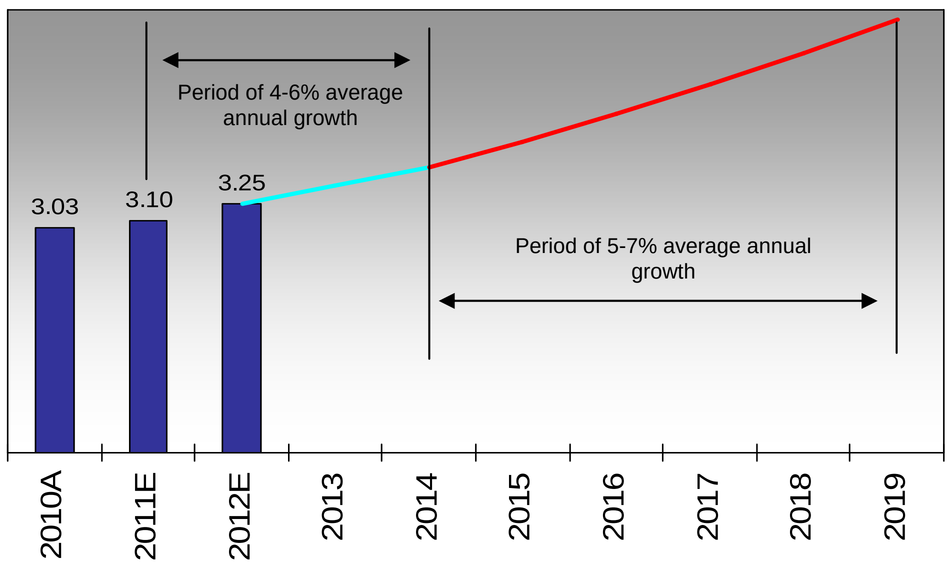
= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Detailed Ongoing Earnings Guidance

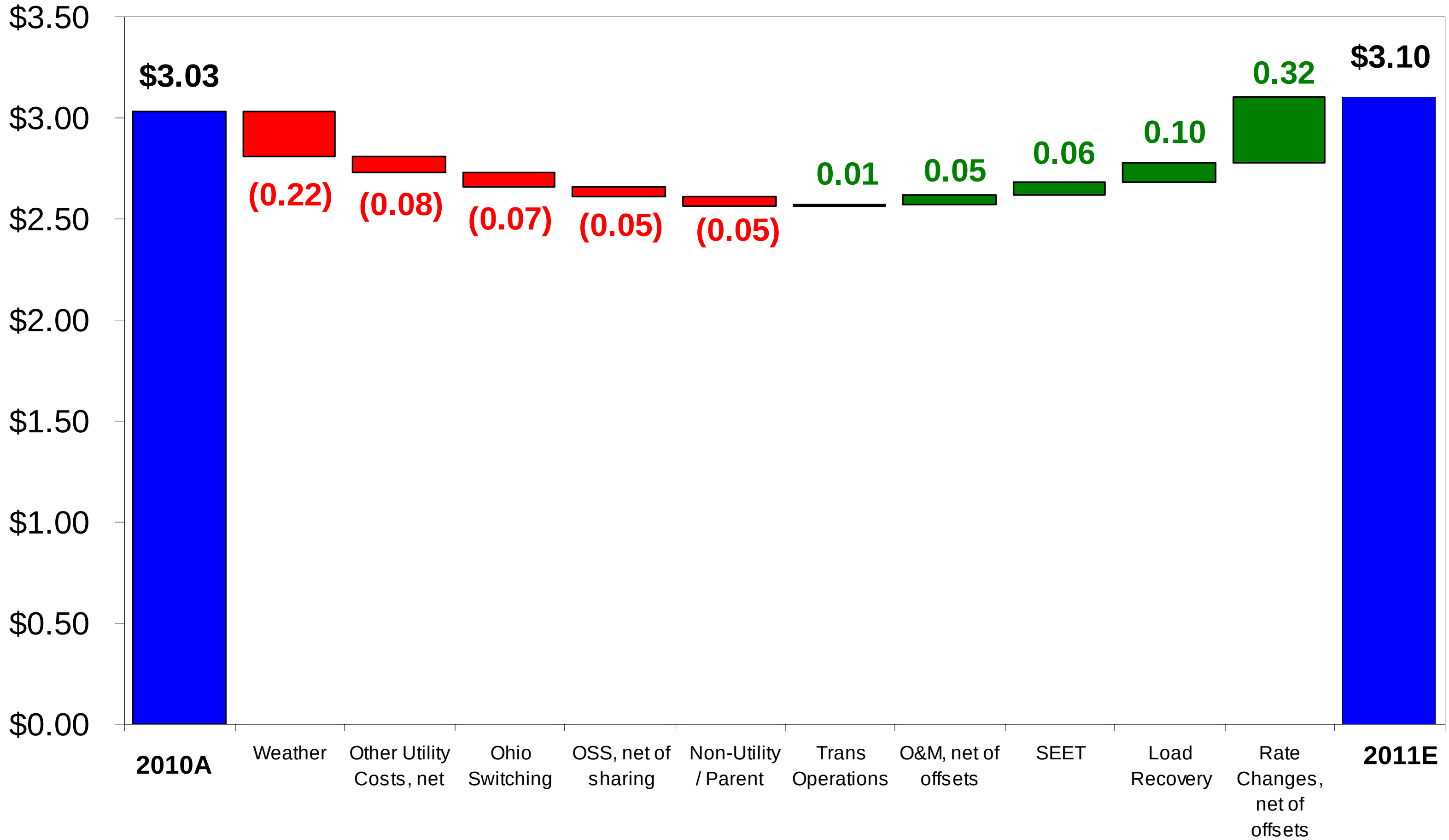
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

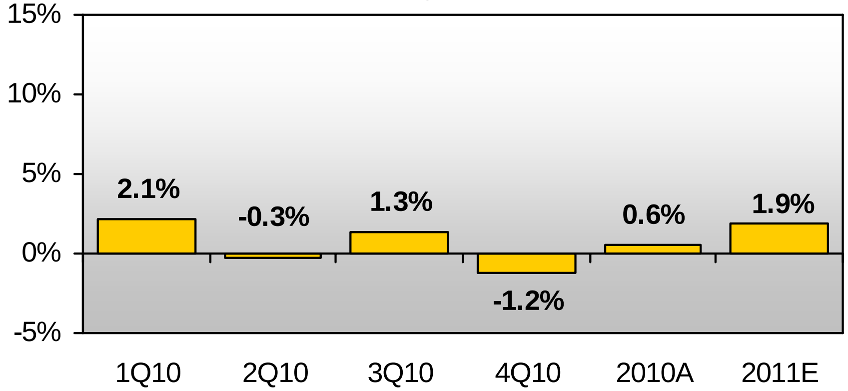


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

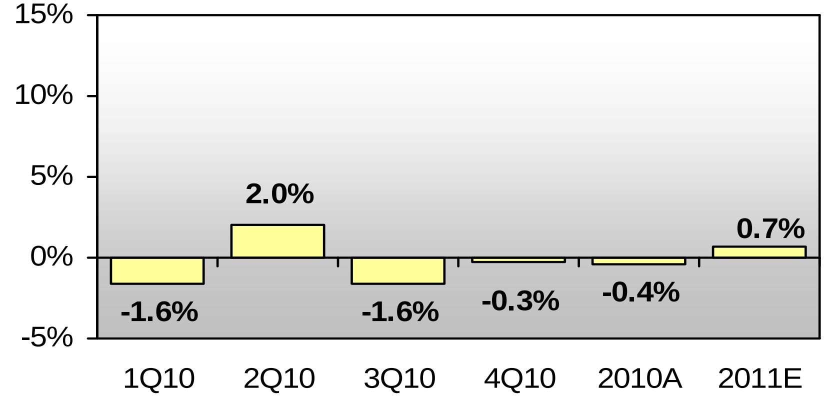
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

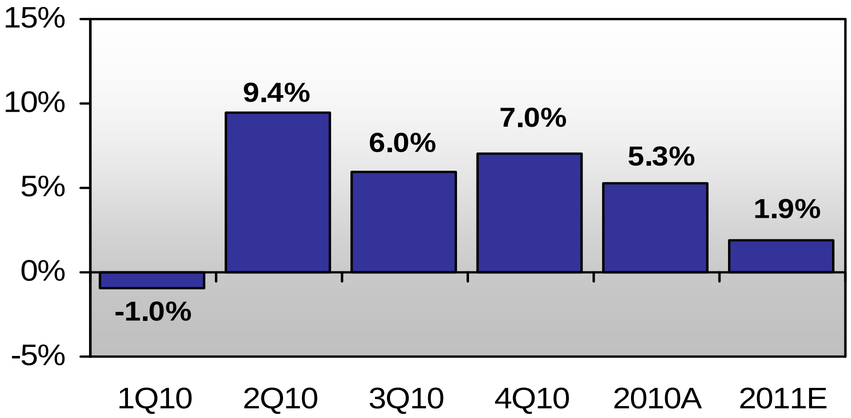
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



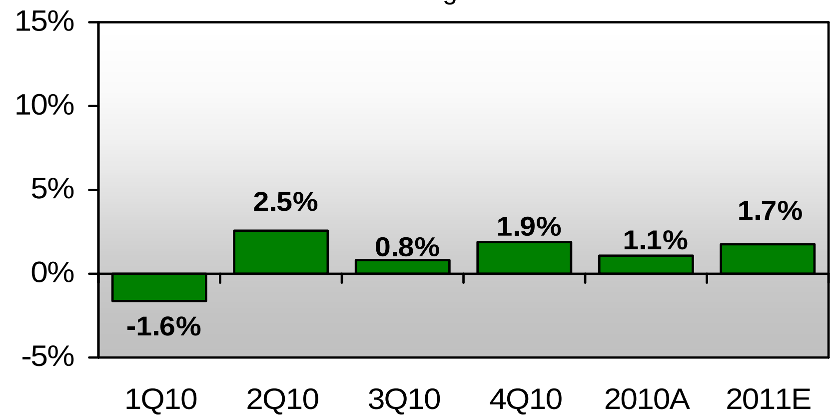
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

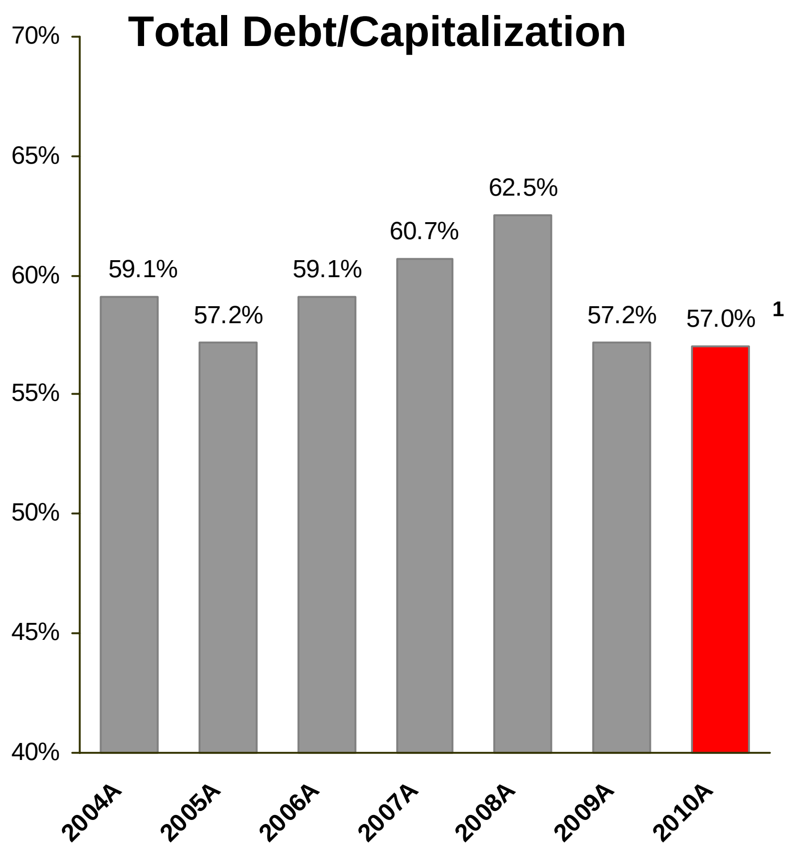
Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



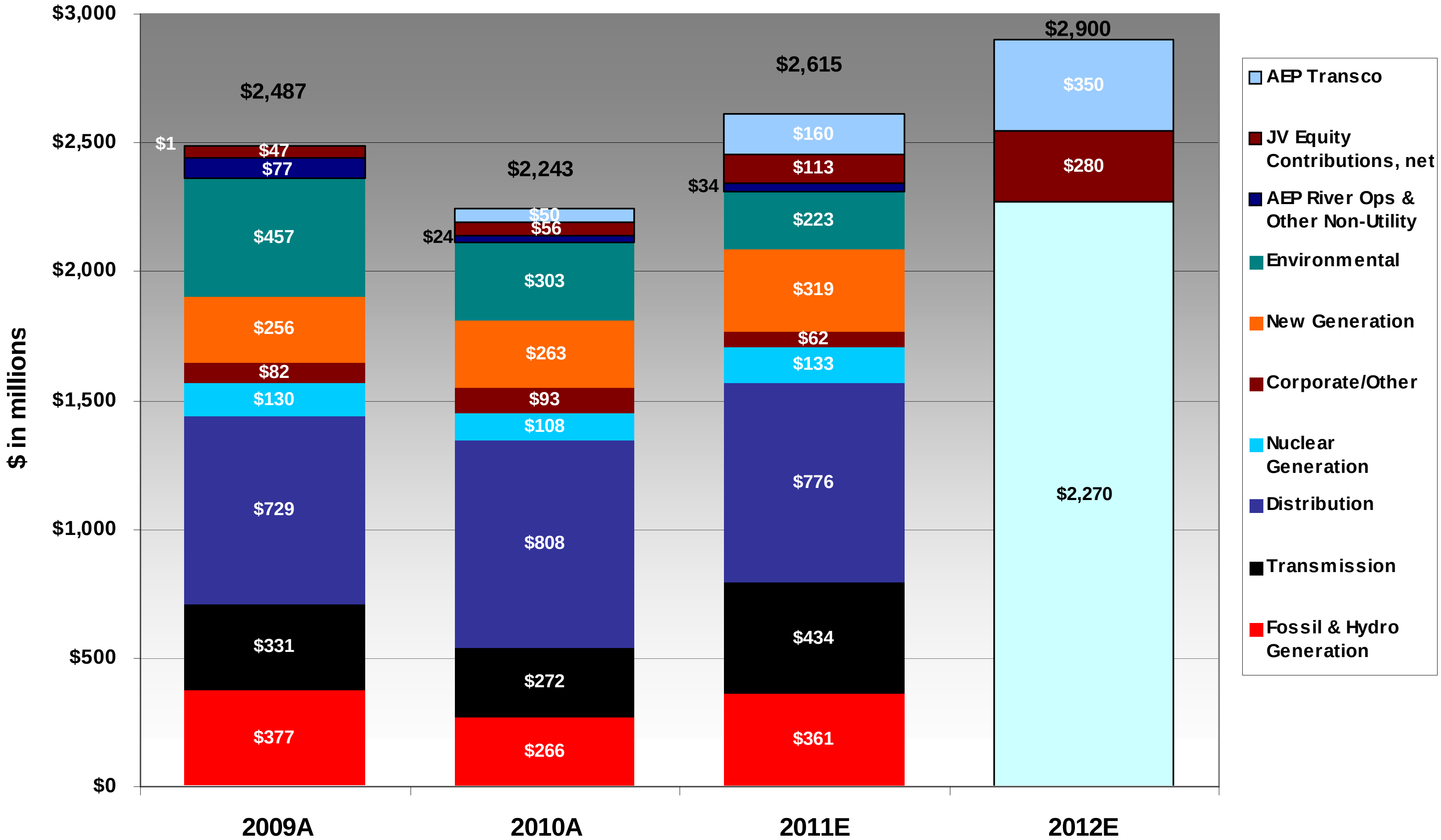
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

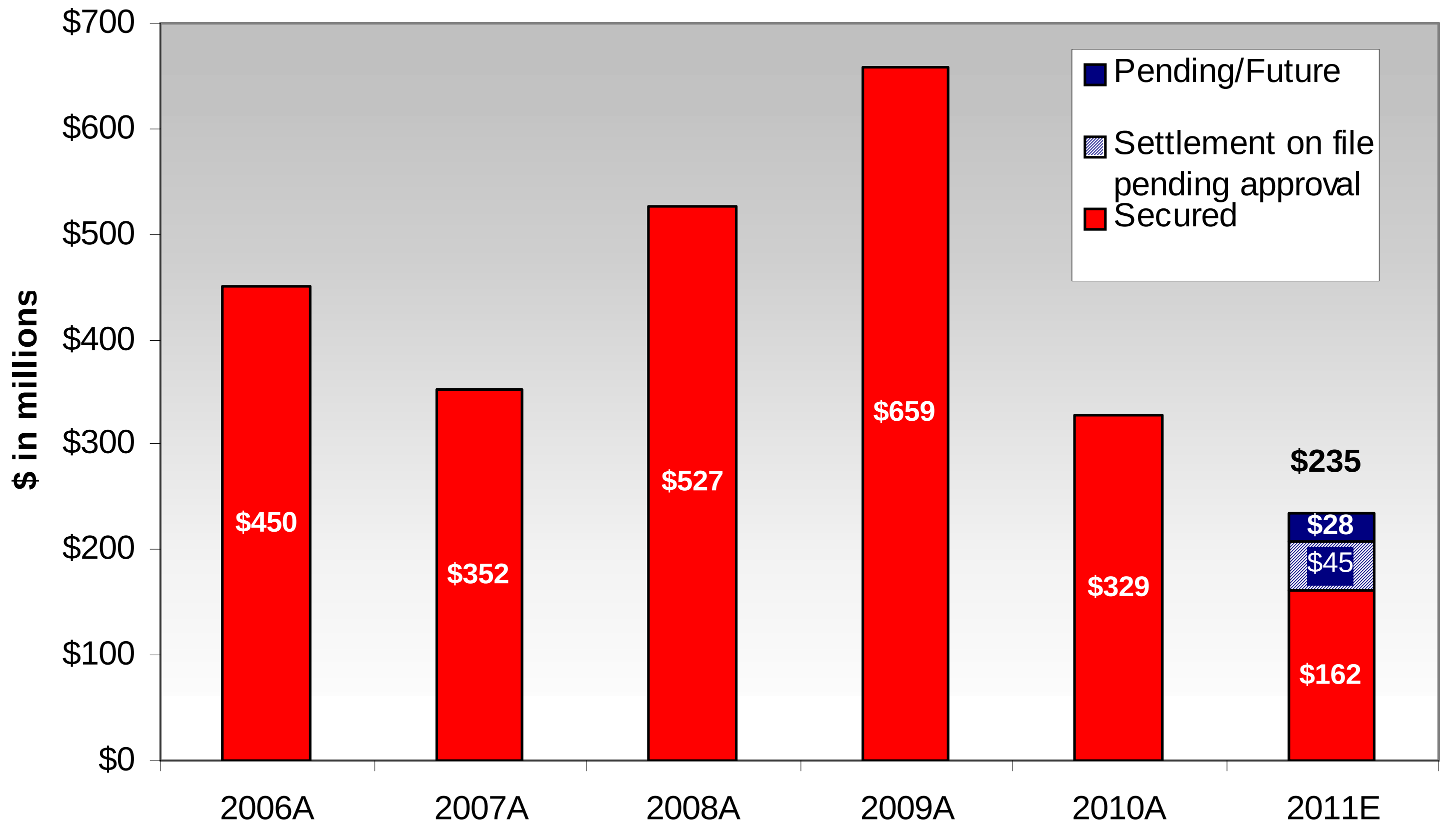
[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Ohio ESP Filing – Core Policy Issues

Investment in Ohio	Jobs in Ohio	Energy Security
Supports economic development and essential tax base	**Jobs are a key component of growth potential in Ohio**	**Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio**
Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation	Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states	Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio	Rate Redesign	29-Month ESP Period	Alternative Long Term Option	Ohio Growth Fund	Distribution Components Included
Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis	Generation rates redesigned to resemble market pricing structures	ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)	Alternative longer-term price certainty option offered for qualifying commercial & industrial customers	Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory	Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

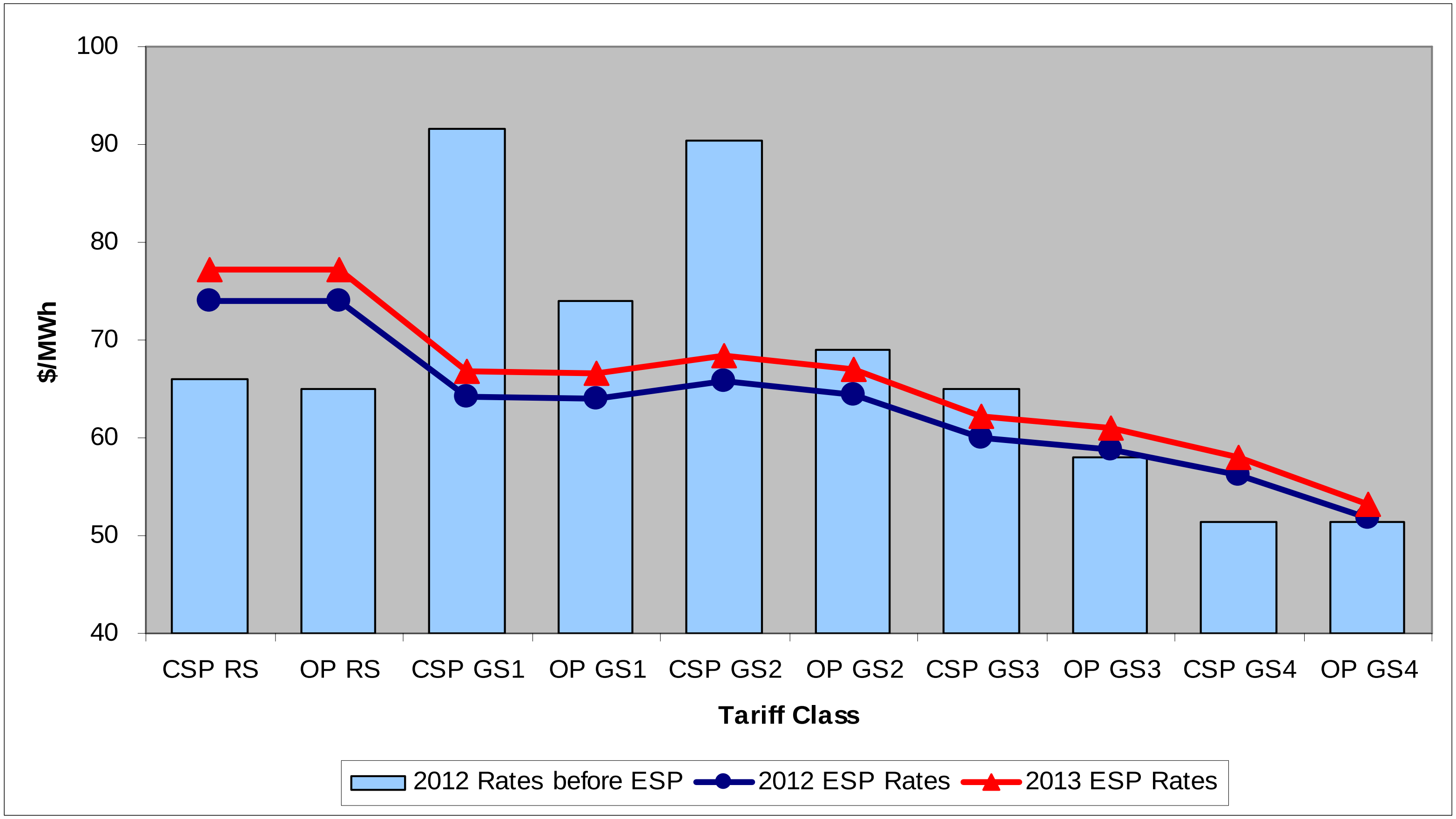
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7139 of 9556

Ohio Timeline

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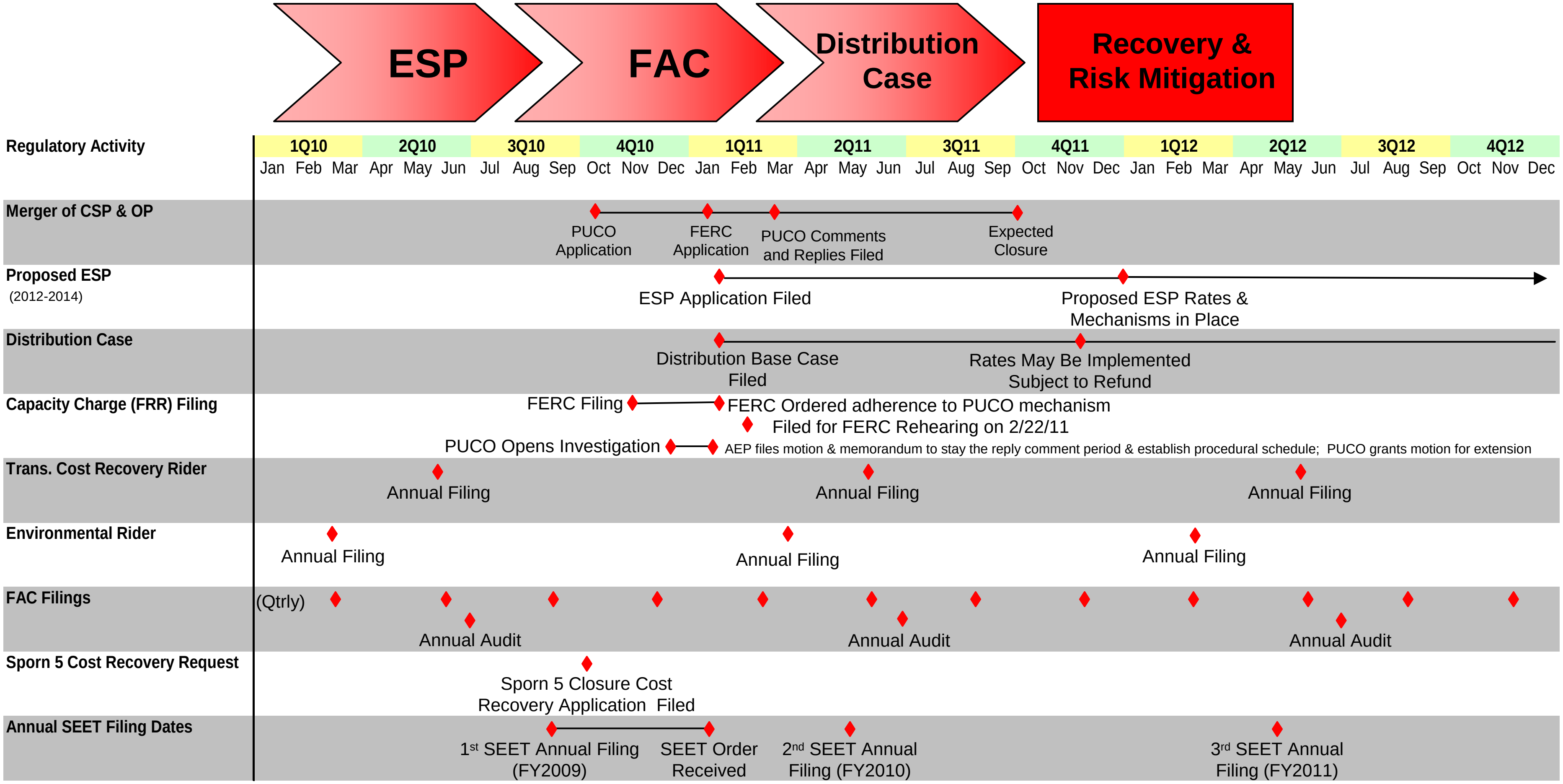

AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

American Electric Power, Inc.

Los Angeles Road Show

Hosted by UBS Investment Bank

August 6-7, 2007

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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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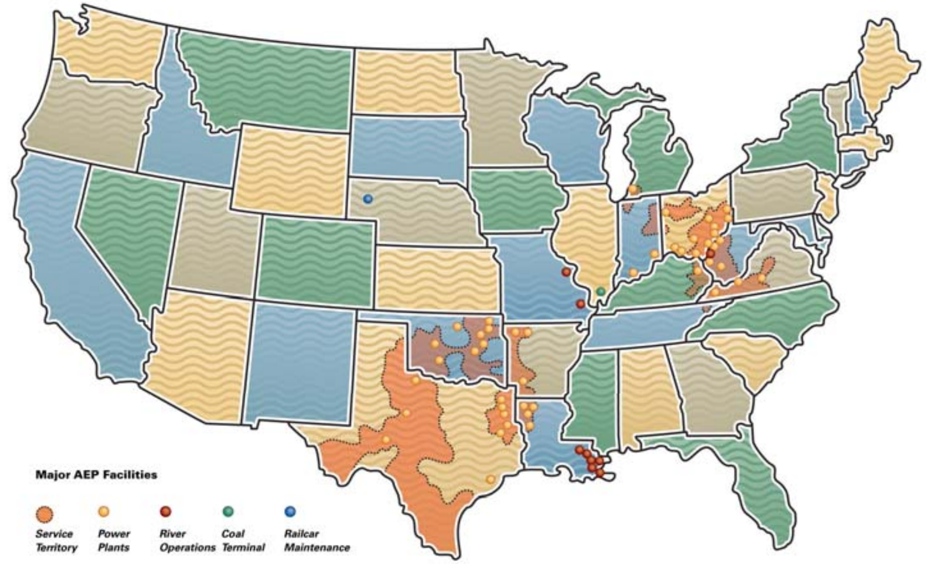
Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

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Strategic Direction

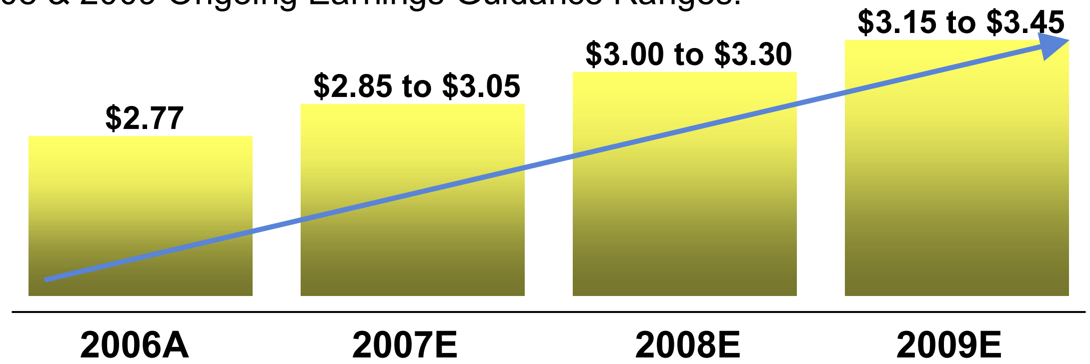
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

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Summary of 5-7% Long-Range Growth Components

- ✓ Energy sales growth of 1.5%
- ✓ Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- ✓ Transmission company
- ✓ Commercial operations
- ✓ Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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New Generation And Transmission Projects Largely Reflect Upside To The Long-Range Earnings Growth Target Of 5-7%

AEP OHIO – Post-2008

- Continued dialogue with fellow utilities
- Potential proposal from the governor's office sometime this summer
- Potential legislation crafted late 2007/early 2008
- The price of electricity in Ohio is going up to be more reflective of what is happening in the markets
- 'Stair-step' in a rate increase that is bigger than the current RSPs of 3% and 7%
- We will pursue recording the shortfall between the stair-step level and market prices as a regulatory asset – along with securitization at a legislative level

It Is Our Hope That We Can Craft A Reasonable Compromise That Will Allow Us To Achieve At Or Near Market Prices Without Causing Rate Shock To Our Customers And The Ohio Economy

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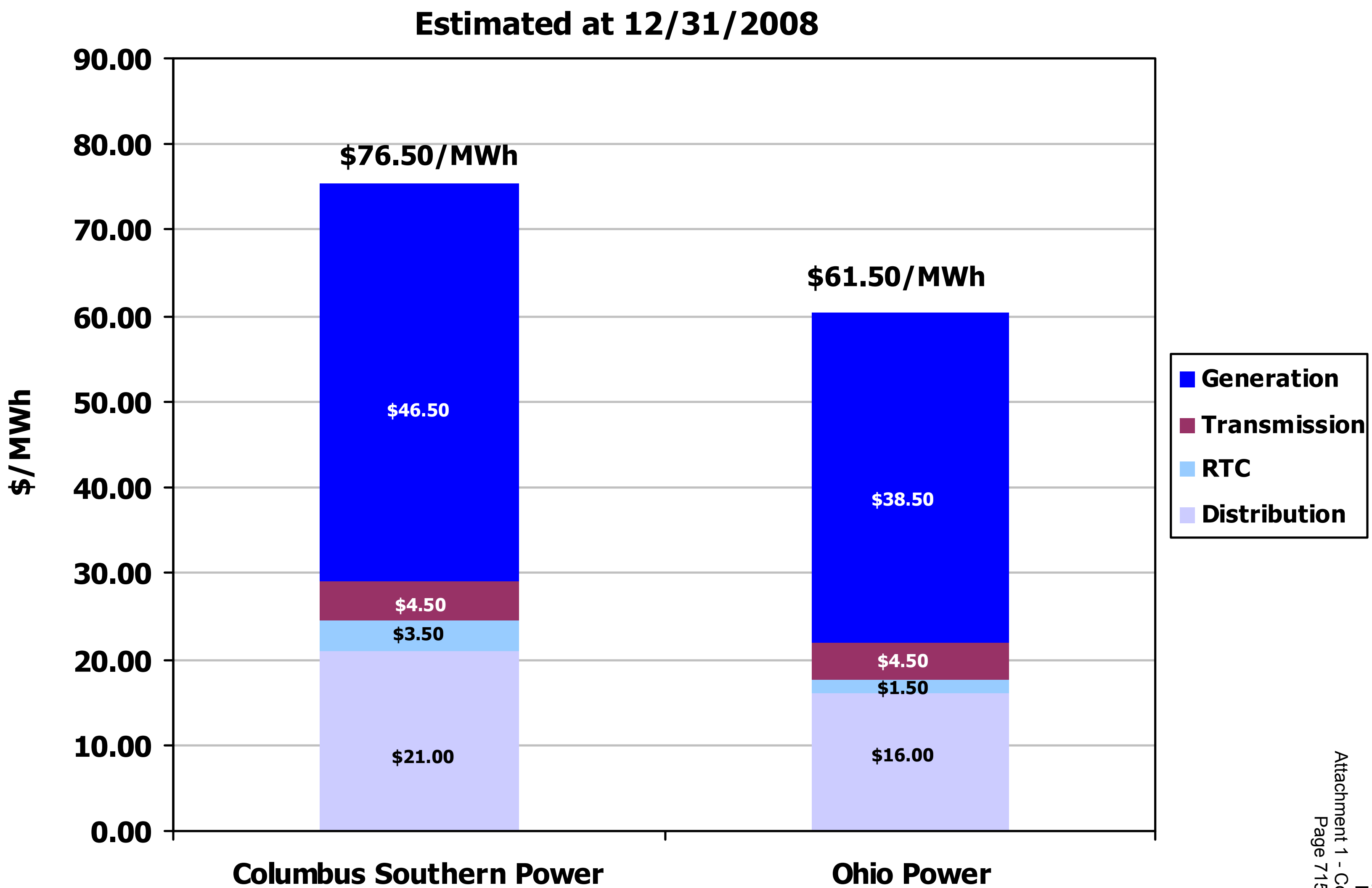
Average Unbundled AEP Ohio Rates



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Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

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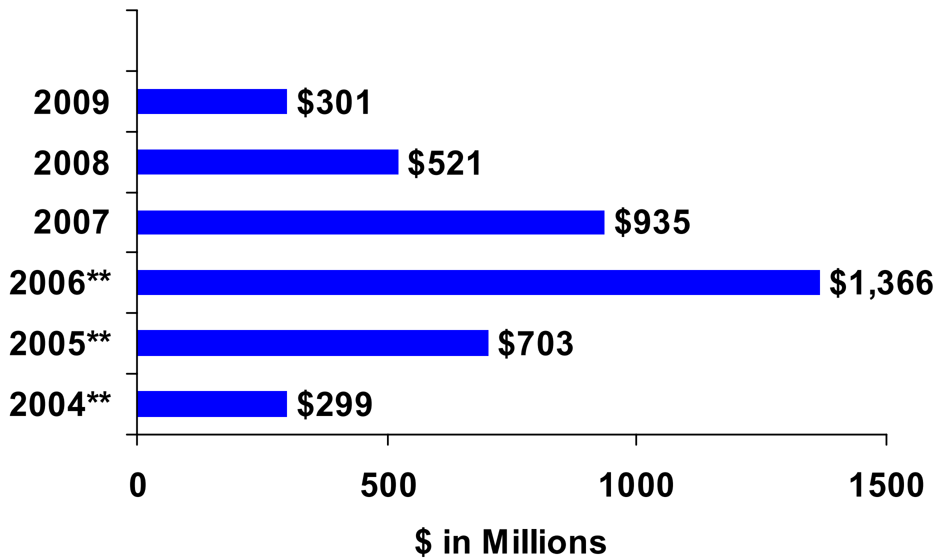
$4.1 Billion Environmental Investment

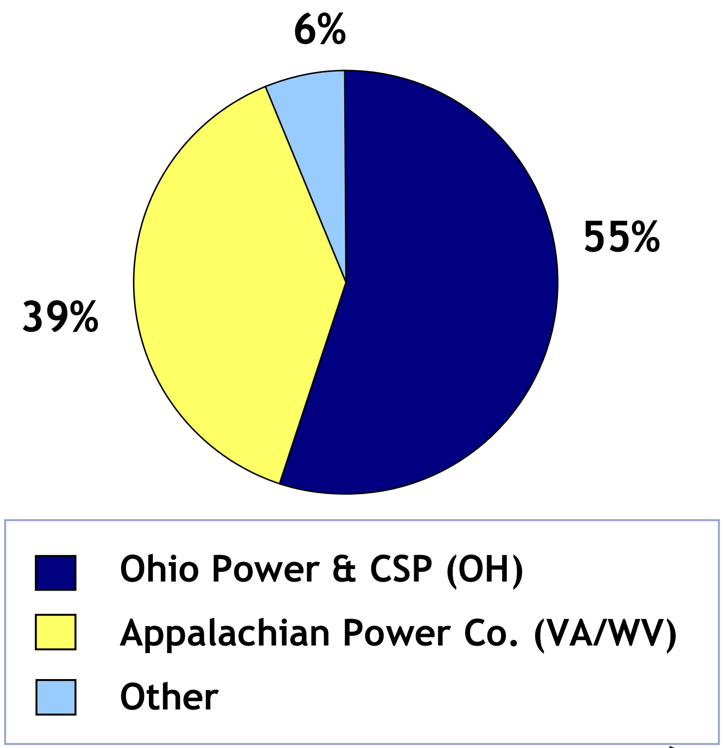
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



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Majority Of 2006 & 2007 Dollars Will Be Invested In Ohio & APCo

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
<u>East Plants</u>					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
<u>CCD Plants</u>					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
<u>West Plants</u>					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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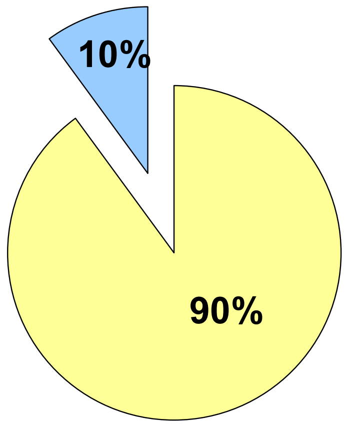
Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Pullman Power – Stack Supplier
- Babcock Power – SCR
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

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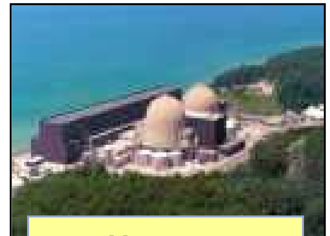
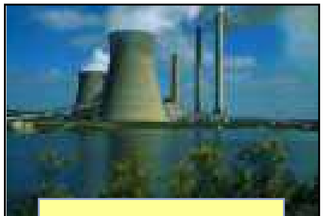
Domestic Generation Fleet

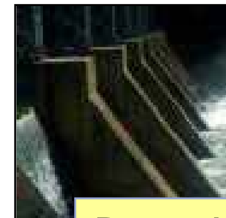
Nat. Gas/Oil
24%

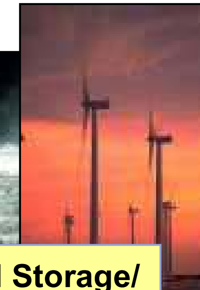


Nuclear
6%



Coal/Lignite
67%





Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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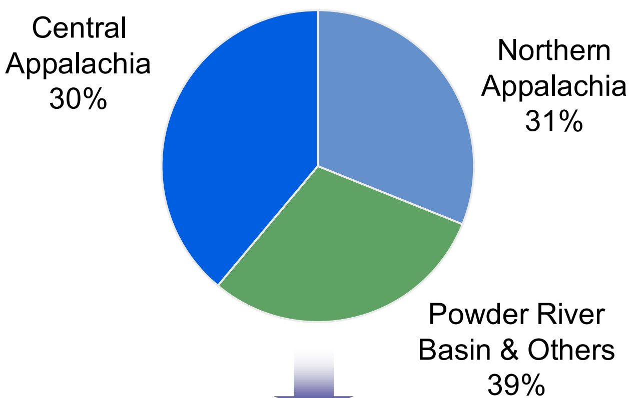
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

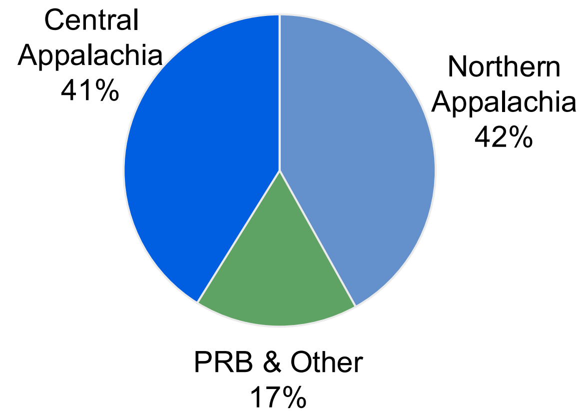
Total AEP System



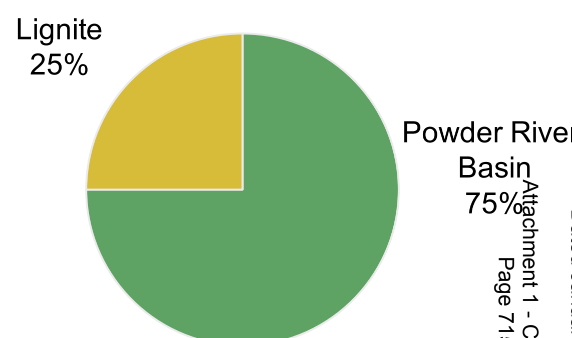
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

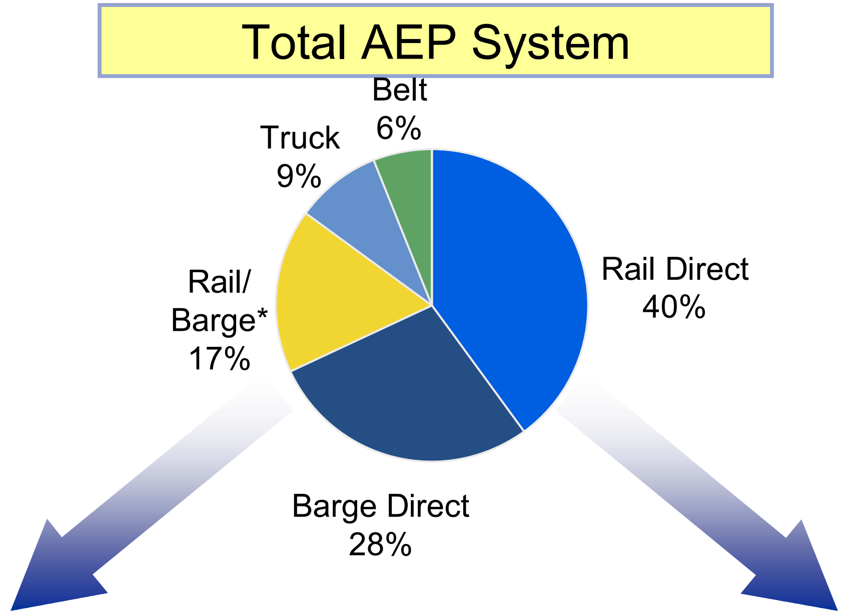


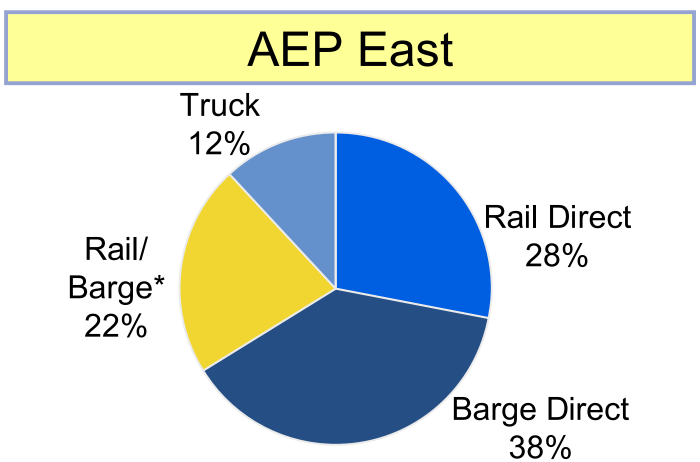
AEP West

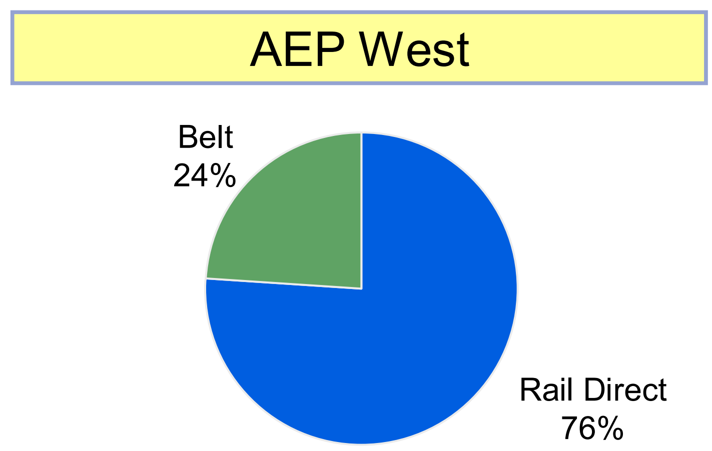


Coal Delivery

2006 Actual







* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Purchased Generation

Waterford

- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

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New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 [1]	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B [2]	Coal	Ultra-supercritical	600 [2]	2011
PSO	Red Rock	Oklahoma	$1.8 B [3]	Coal	Ultra-supercritical	900 [3]	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review [4]	Coal	IGCC	630	2017

(1) 150MW were declared in commerical operation on July 12, 2007.
(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(3) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

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AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

- Mattison Plant (Tontitown, AR)
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- Stall Plant (Arsenal Hill, LA)
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
- Air permit approval expected in August 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

- Used and Useful Determination filed in February 2006 – Hearings concluded July 31, 2007 and order is expected in September 2007
- Air permit approval expected in October 2007
- Regulatory Recovery
  - Order expected in PSO rate case filing in July 2007 – filing included request for CWIP treatment for new projects
- Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

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IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

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AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

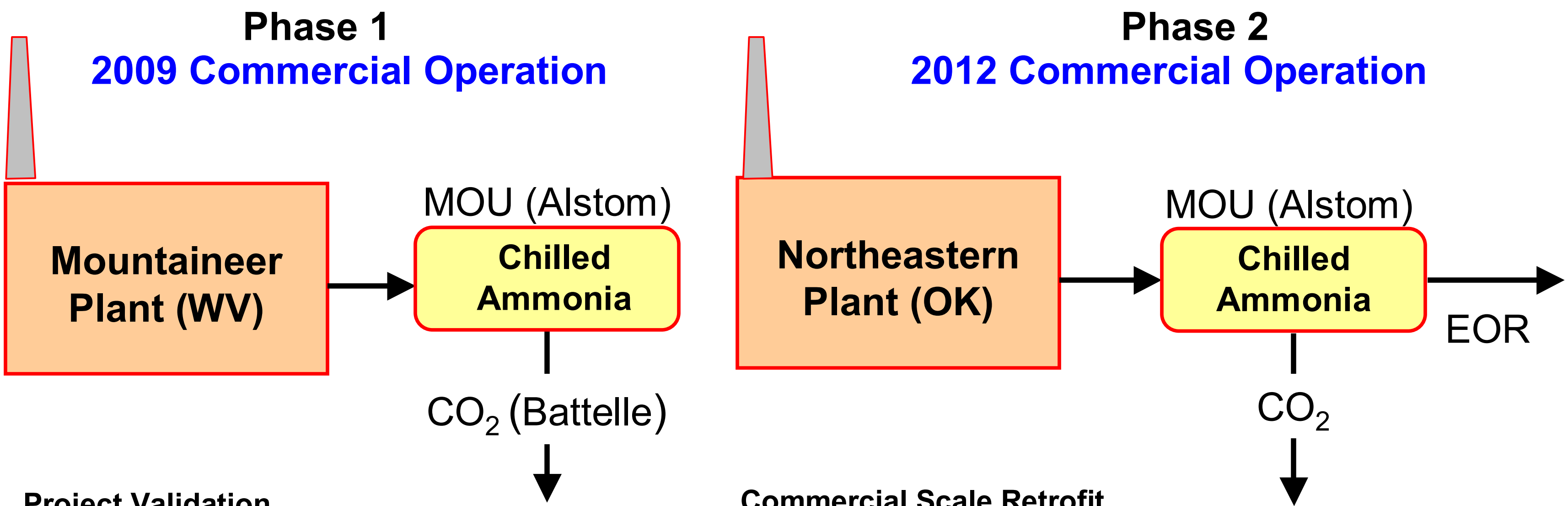
- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

AEP®

Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

AEP®

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+ **

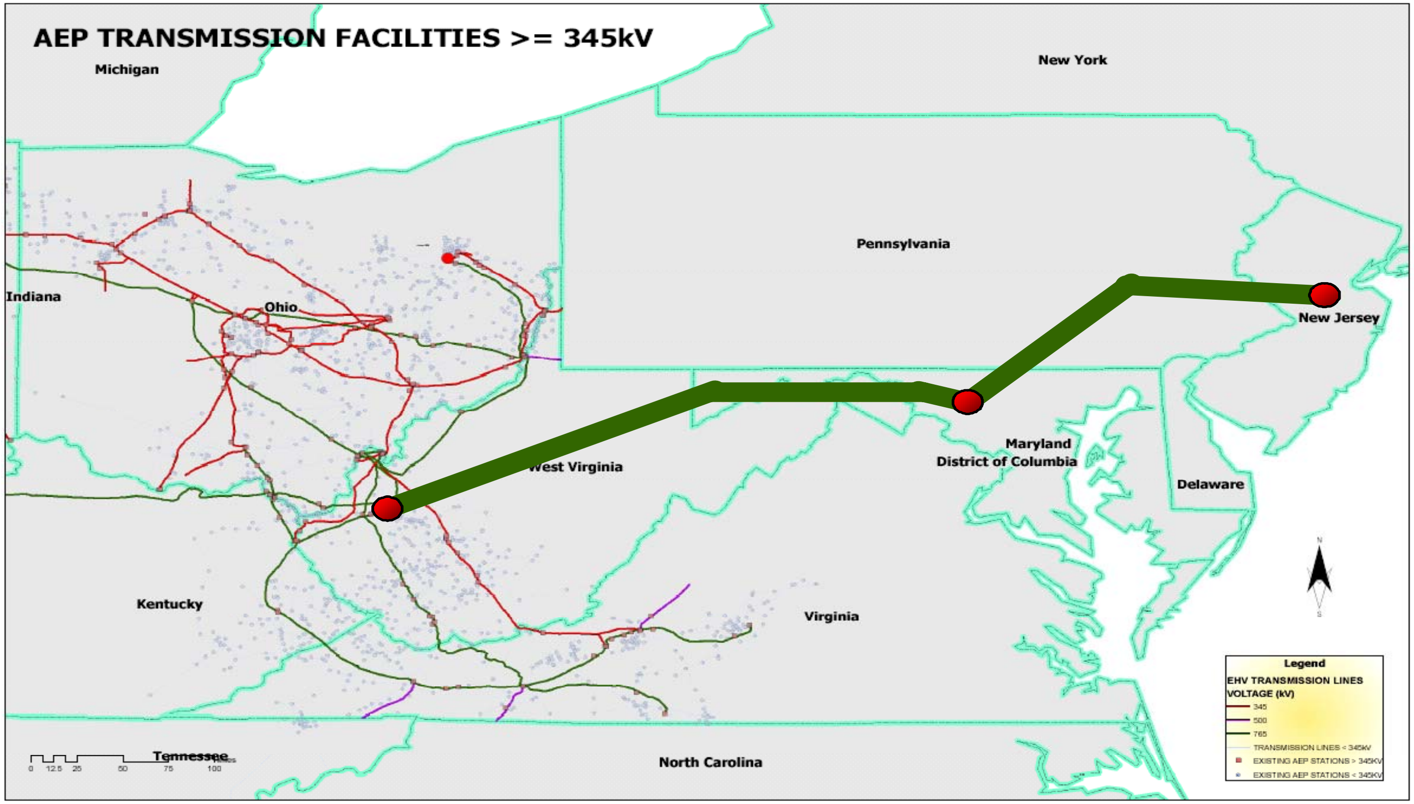
* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution and timing dependent on ownership structure, capitalization, ROE and date assets are put in-service

AEP®

Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765-PJM



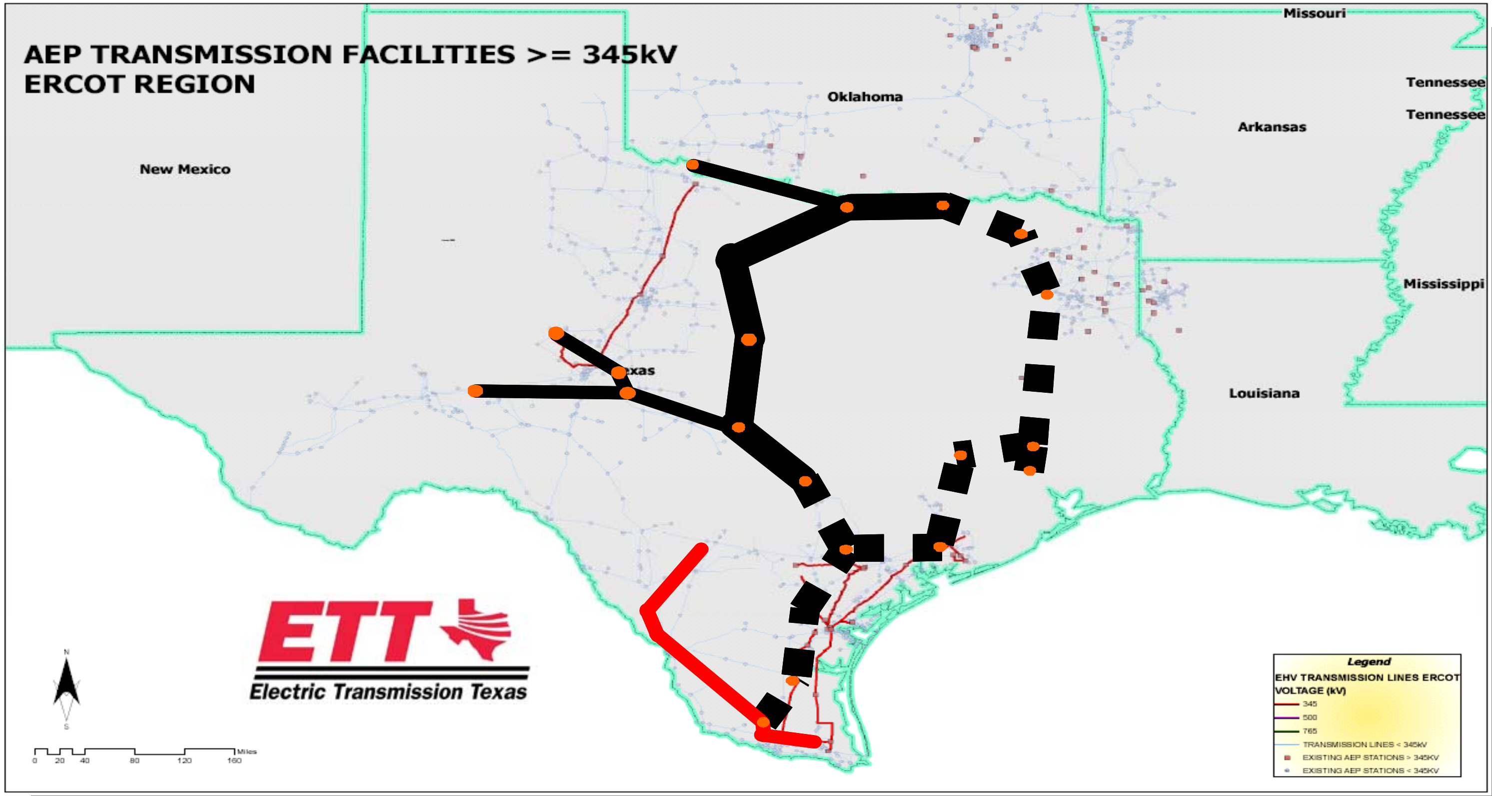
- JV with Allegheny to build a 290 mile West Virginia – Maryland line (Approved by PJM in June 2007). Total estimated cost of $1.8 billion (AEP portion appprox. $600 million). (Second leg which would continue to New Jersey still under consideration by PJM.)

- Enhances Midwest-Mid-Atlantic reliability and improves power transfer capability by 5000 MW.

- Reduces network line losses by 280 MW.

AEP®

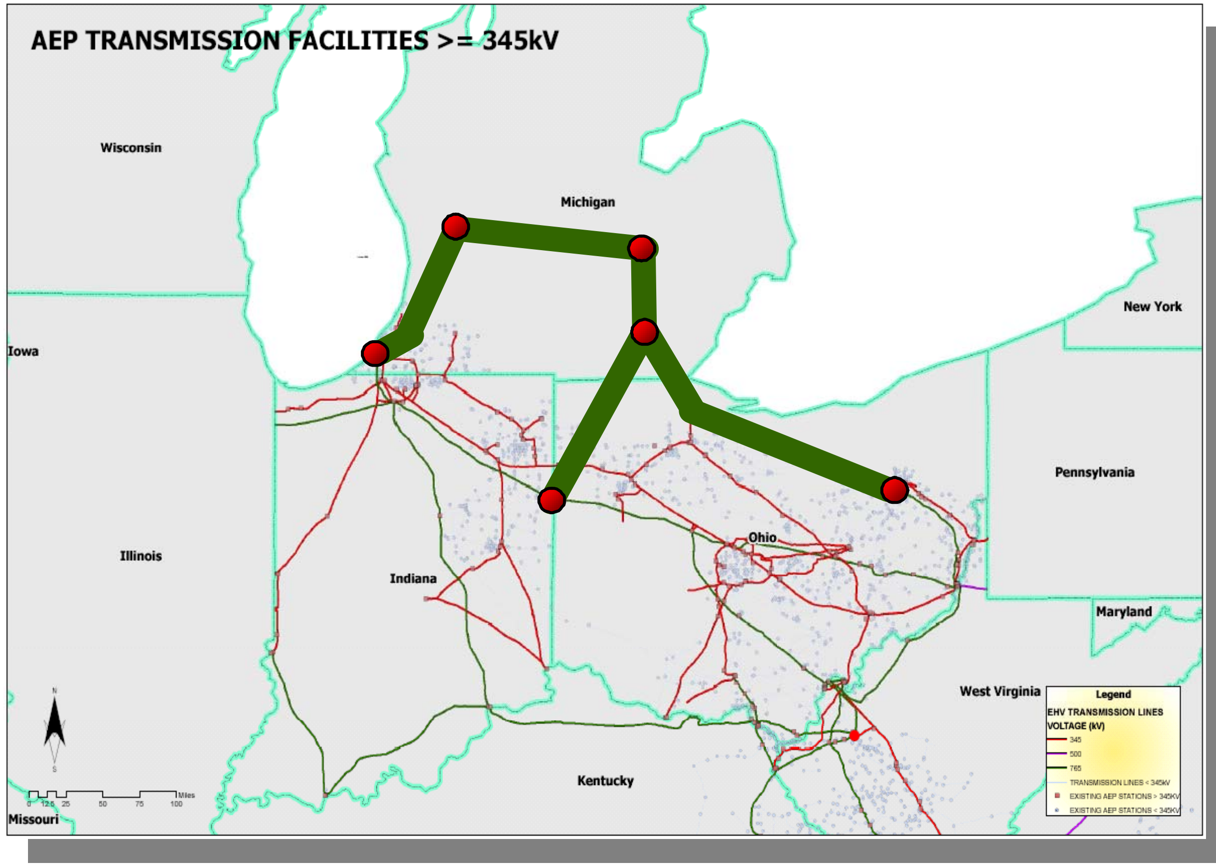
765-ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets.
- AEP exploring ERCOT transmission investment opportunity, including 420 miles of 765-kV initially.
- Up to 4000MW improved transfer capability.

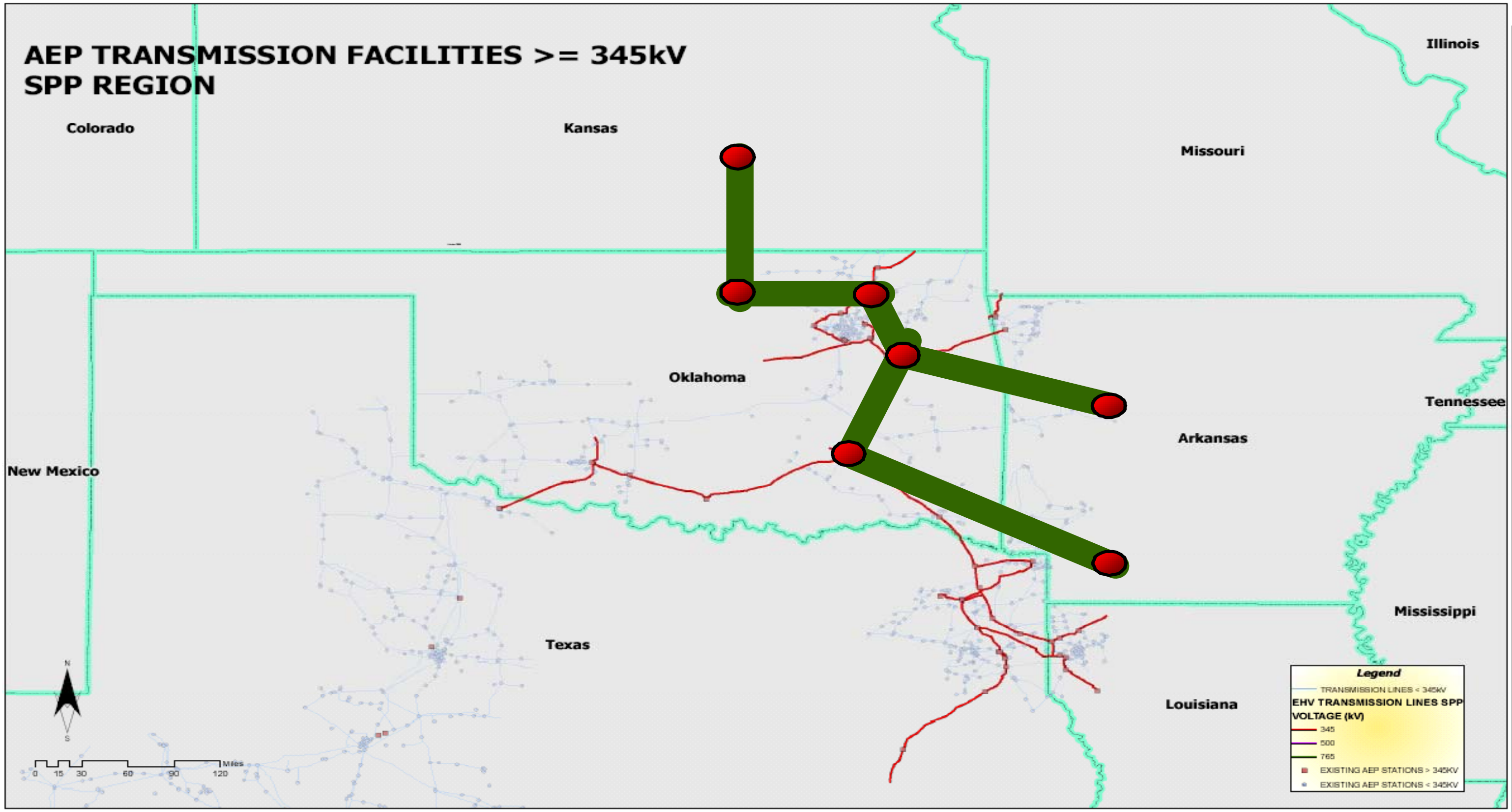
3

765-Michigan



- Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of 700 miles of 765-kV lines in Ohio and Michigan. Completed study should be available in the third quarter of 2007.
- Over 3000MW improved transfer capability.
- Reduces network line losses by 250 MW.

765-SPP



- In July 2006, AEP submitted a conceptual project to SPP for six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, with a proposed construction period of 2012-17.
- SPP issued its EHV Overlay Study in June 2007 reviewing 345 kV, 500 kV, and 765 kV potential projects in SPP. An alternative, which includes a 765-kV line in Oklahoma and Kansas connecting the east to PJM, was chosen as the preferred alternative.

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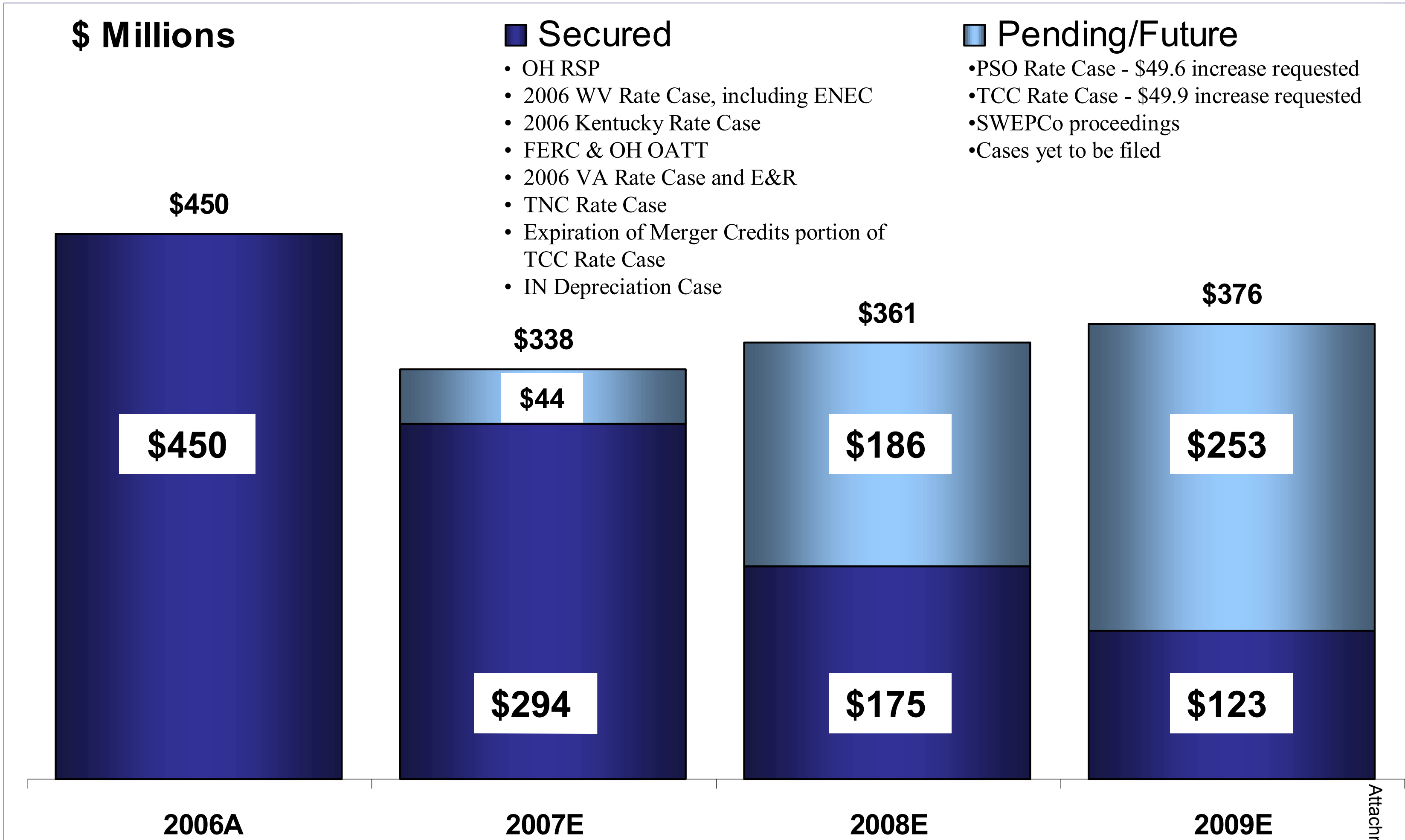
New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - **40% equity / 60% debt capital structure requested at the PUCT follows Texas' precedent for T&D companies' filings**
  - **Equity – 50% AEP / 50% MidAmerican Energy**
  - **AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary**
  - **Debt – Initially bank financing**
  - **Initial funding in 3Q07 after regulatory approvals**

- AEP I-765$_{TM}$ Interstate Project
  - **Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project**
  - **JV portion of the I-765$_{TM}$ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007**
  - **Equity – 50% AEP / 50% Allegheny**
  - **AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary**
  - **Operations to commence in the second half of 2007**
  - **I-765$_{TM}$ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007**

- Other Transmission Projects
  - **Equity percentage of capital structure will target FERC precedents**
  - **Equity ownership percentage will vary by project**
  - **Will seek FERC transmission incentives:**
    - **Incentive ROE**
    - **Return on CWIP**
    - **Abandonment recovery**
    - **Expensing pre-construction expenses**

Incremental Rate Relief Composition



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Rate Relief Is A Critical Element To AEP's Financial Success

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓$54.8 million covers increased costs related to coal and purchased power
  - ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

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In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7178 of 9556

Regulatory Activity Underway

- AEP Texas Central Company General Rate Case
- PSO General Rate Case
- CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- I&M Indiana Rate Petition
- Virginia Filings - Fuel Factor and E&R
- Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- FERC Seams Elimination Cost Adjustment Proceedings
- SPP OATT Formula Rate Filing
- New Generation
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007. The expiration of the merger credits for TCC was approved by the PUCT in June 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
July 2007	Final order expected

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover \$24.5MM and \$8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a \$15MM increase at CSP and a \$3.7MM increase at OP; OCC recommended a \$19.9MM increase for CSP and a \$3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31 2008. This schedule is subject to IURC approval.

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Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings were held July 16 and 17, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- No procedural schedule has been set but Virginia legislation requires a decision within nine months.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for PSO's Used and Useful Determination and OG&E's cost recovery were held July 9-31, 2007.
- We await an ALJ report in August 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings will begin August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings are scheduled for September 27-28, 2007.

AEP®

Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	S&P Business Profile	S&P Senior Unsecured	Fitch Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

AEP®

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

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Adjusted Debt/Capitalization: 58.3%

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		2006 Performance Driver	2006 Actual ($ millions)	2007 Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP®

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

AEP®

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.6x to 4.0x
FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

AEP®

Capital Investment Is Funded By Cash From Operations And Debt Issuances

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

AMERICAN ELECTRIC POWER

Lazard

Alternative Energy Conference

New York, NY

June 3, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG

FLEXIBLE

ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

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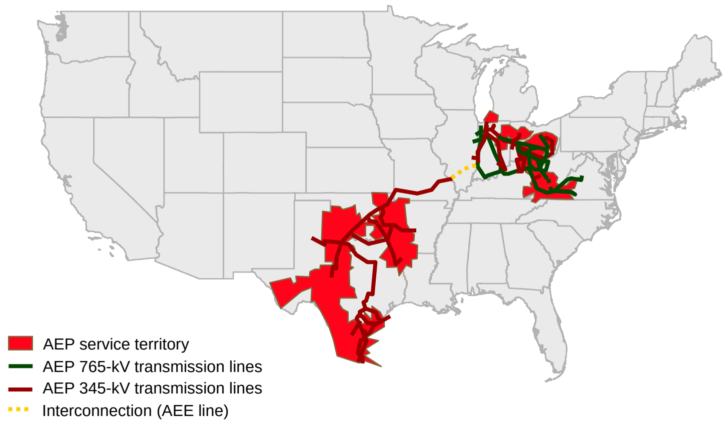
Premier Regulated Utility Platform

Overview



AEP's Leadership Position

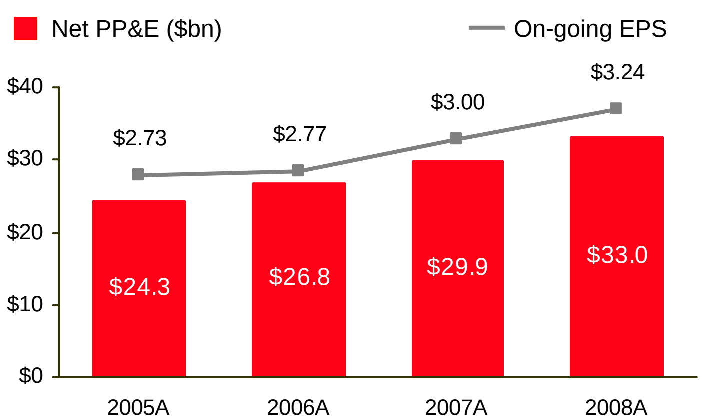
Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

Generation owned[1] (GW)	
SO	42.6
AEP	40.6 *
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

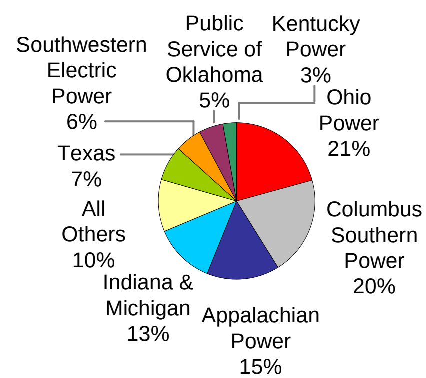
Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

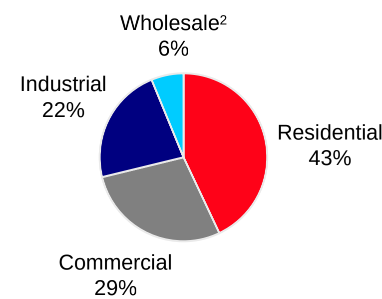
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Attachment 1 - Confidential
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Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

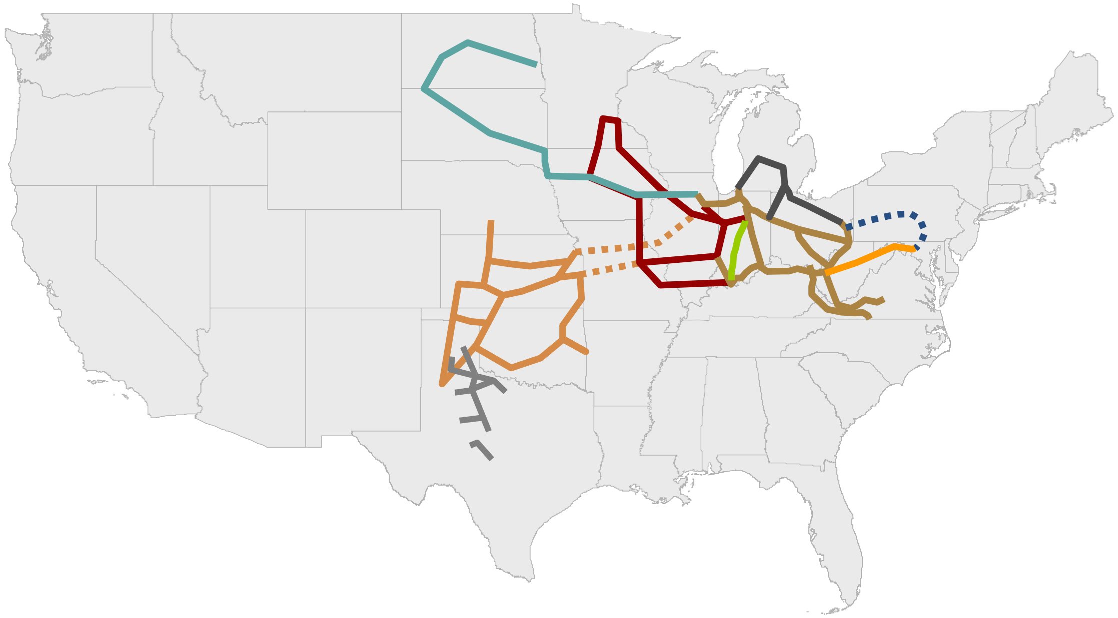
Pioneer — COD: 2015
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — COD: 2014
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — COD: 2013-14
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — COD: 2013
- *110 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

ETT — COD: 2013
- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — COD: ~2020
- *700 miles of 765 kV*
- *Partner: ITC*

PJM Projects
- *Enhance existing 765/345 kV*

Hartland — COD: ~2020
- *1000+ miles of 765 kV*
- *Partner: Hartland Wind LLC*

MISO Vision Plan
- *765 kV Backbone*

SPP Overlay — COD: 2013-14
- *765 kV Backbone*

ETT — COD: ~2018
- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

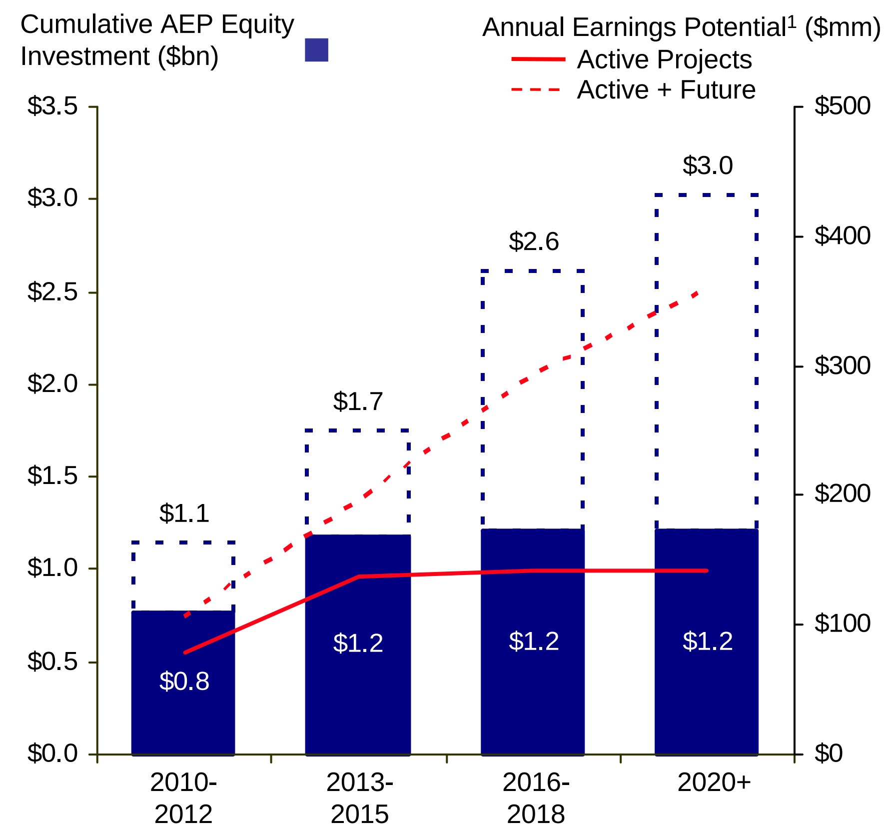
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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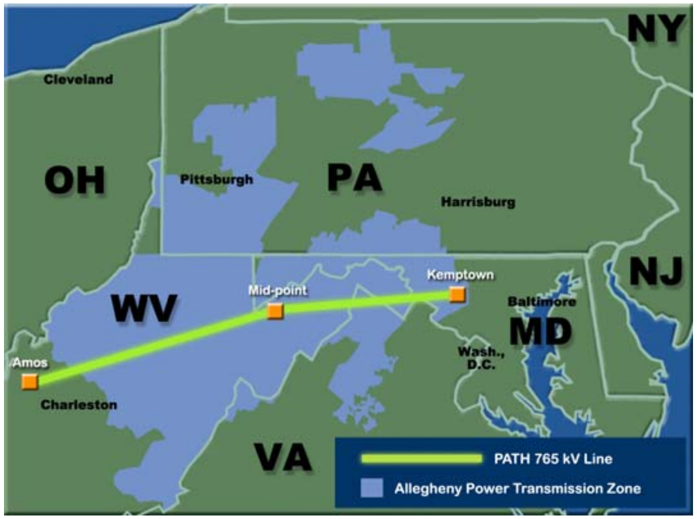
EHV Transmission in PJM: PATH

<u>Project Description:</u> 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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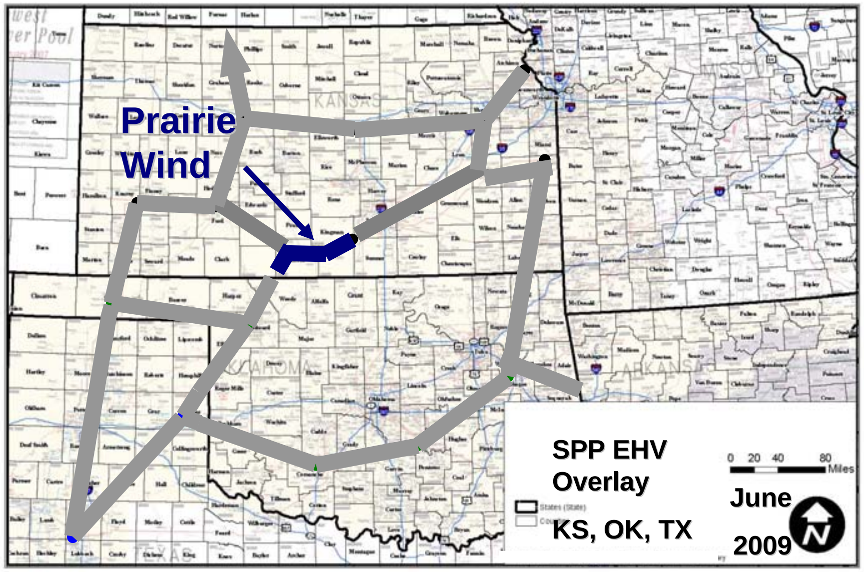
Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and be in-service by 2013. Settlement approval by the KCC is still pending.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

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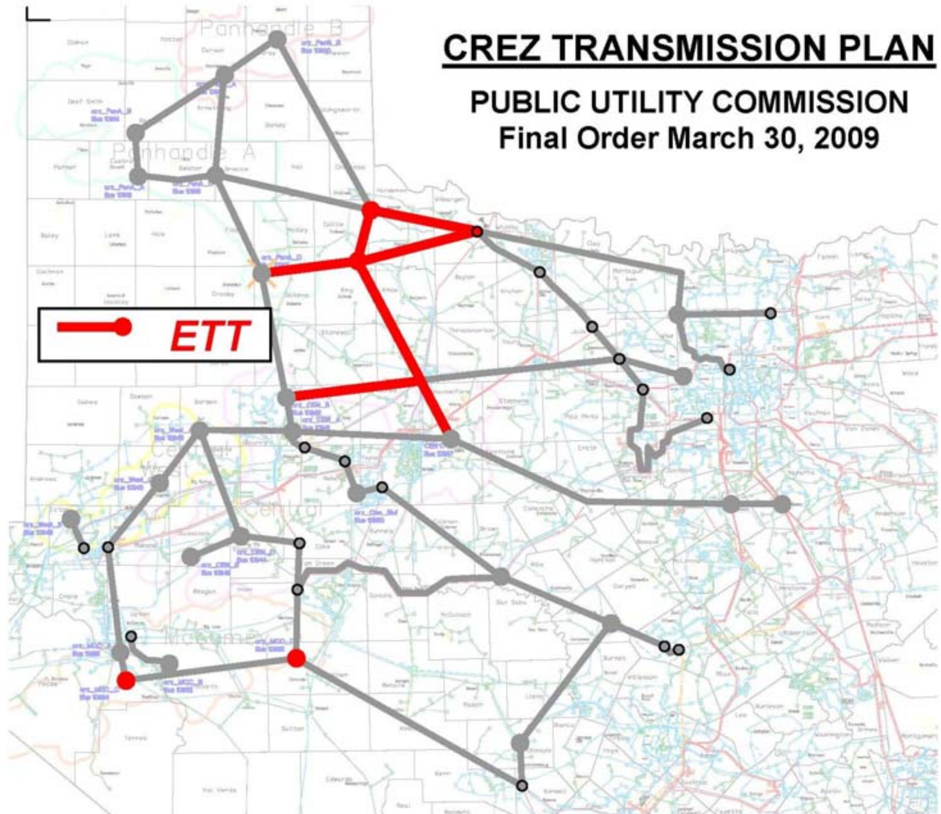
Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. \$840MM of \$4.9B total.
  - The filing calls for completion of the plan by 2013.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in early 2010.

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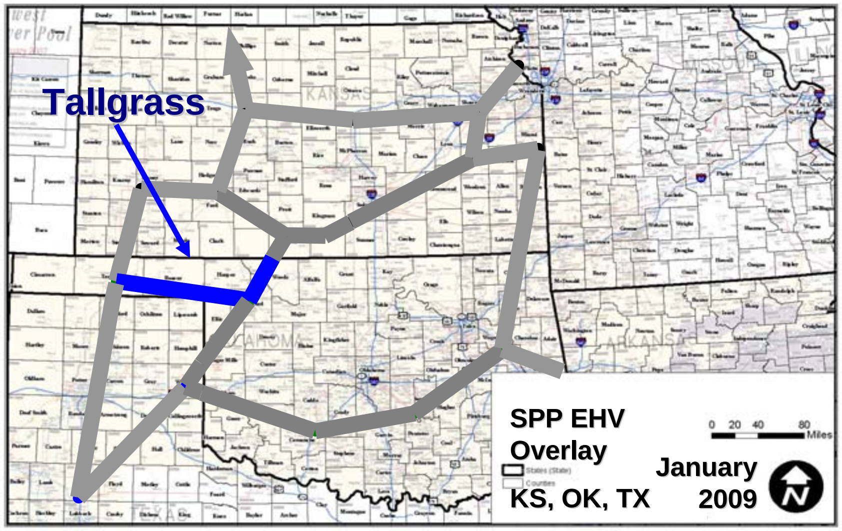
ETT Electric Transmission Texas

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

Overview

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013.
- AEP's ownership of the joint venture is 25%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received in December 2008:
  - ❑ Cash return on CWIP and 12.8% incentive ROE
  - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
  - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval

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Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing

Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

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Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost \$5-\$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

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AMERICAN ELECTRIC POWER, INC.

Lehman Brothers 2007 CEO Energy Conference – September 5, 2007

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AEP AMERICAN ELECTRIC POWER

Holly K. Koeppel – EVP & Chief Financial Officer

Near Term Investor Communication Activities

- September 12, 2007 – Tokyo Investor Meetings
- September 26, 2007 – Merrill Lynch 2007 Power & Gas Leaders Conference, NYC
- October 4, 2007 – Strategic Direction: Financial Analyst/Investor Conference, NYC
- October 11, 2007 – Dublin Investor Meetings
- October 24, 2007 – 3Q07 Earnings Call

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AEP Strategic Direction

Delivering Value to Investors and Cost-Effective Service to our Customers

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Grow our transmission business
- Achieve adequate returns on all assets

Our core utility mission: Bring reasonably priced electric service to our customers, thereby strengthening our communities and rewarding our investors

AEP AMERICAN ELECTRIC POWER

Capital Investment Focus

- Completion of our intensive environmental retrofit program, coupled with associated rate relief, allows us to redeploy capital into other areas
- Near-term
  - In our western footprint, our capital investment will focus on new generation
  - In our eastern footprint, our capital investment will focus on modernization of the distribution infrastructure, also known as the 'Modern Grid' program
  - In both the east and west, we will focus on successful demonstration and implementation of the chilled ammonia technology for carbon capture
- Long-term
  - Throughout our service territory, transmission and IGCC will be our long-term capital investment focus

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528** *
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden Plant Purchase	$85
2007 Including Lawrenceburg & Dresden	**$3,952**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

* Includes Lawrenceburg purchase of $325MM and Dresden purchase of $85MM in 2007

Growth investment to be funded by cash from operations via rate relief and debt issuances

AMERICAN ELECTRIC POWER

Environmental Investment Forecast

Ohio Rate Stabilization Plan

- Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
- Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related investments – activation of 4% rider

West Virginia Rate Settlement

- Mechanism in place to provide rate increases through 2009 for ongoing environmental investments

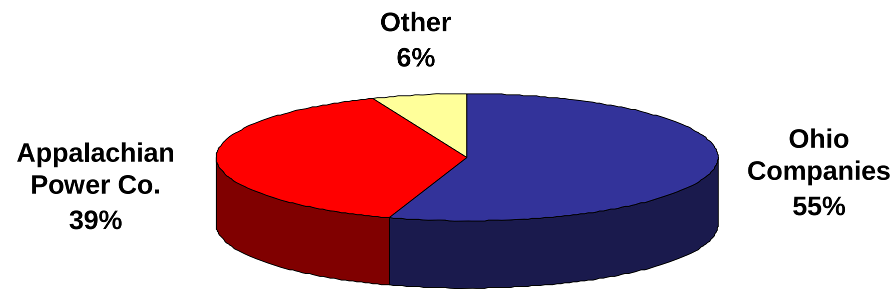
Virginia E&R Mechanism

- Allows APCo-VA to recover incremental environmental & reliability costs
- Last filing - order issued Nov. 20, 2006 granting $21.4MM of recovery
- Additional filing made in July 2007 requesting recovery of $60MM of E&R costs

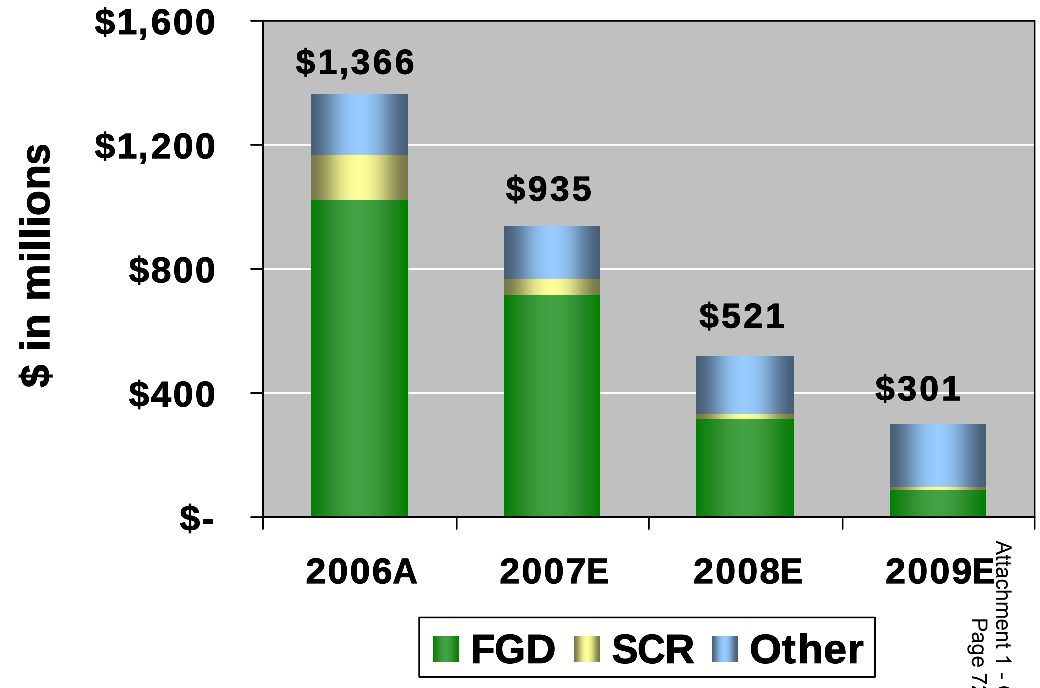
Kentucky Environmental Surcharge

- Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



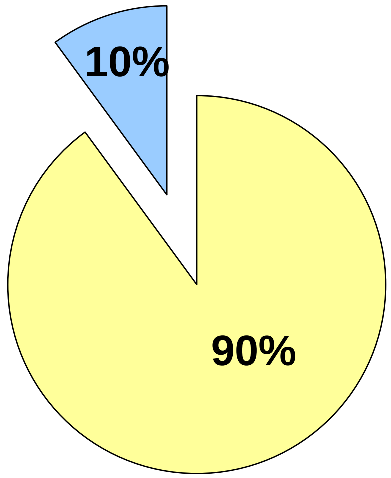
Total Projected Environmental Investment



Materials and Vendors – AEP's Advantage

Environmental Program Costs:

Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

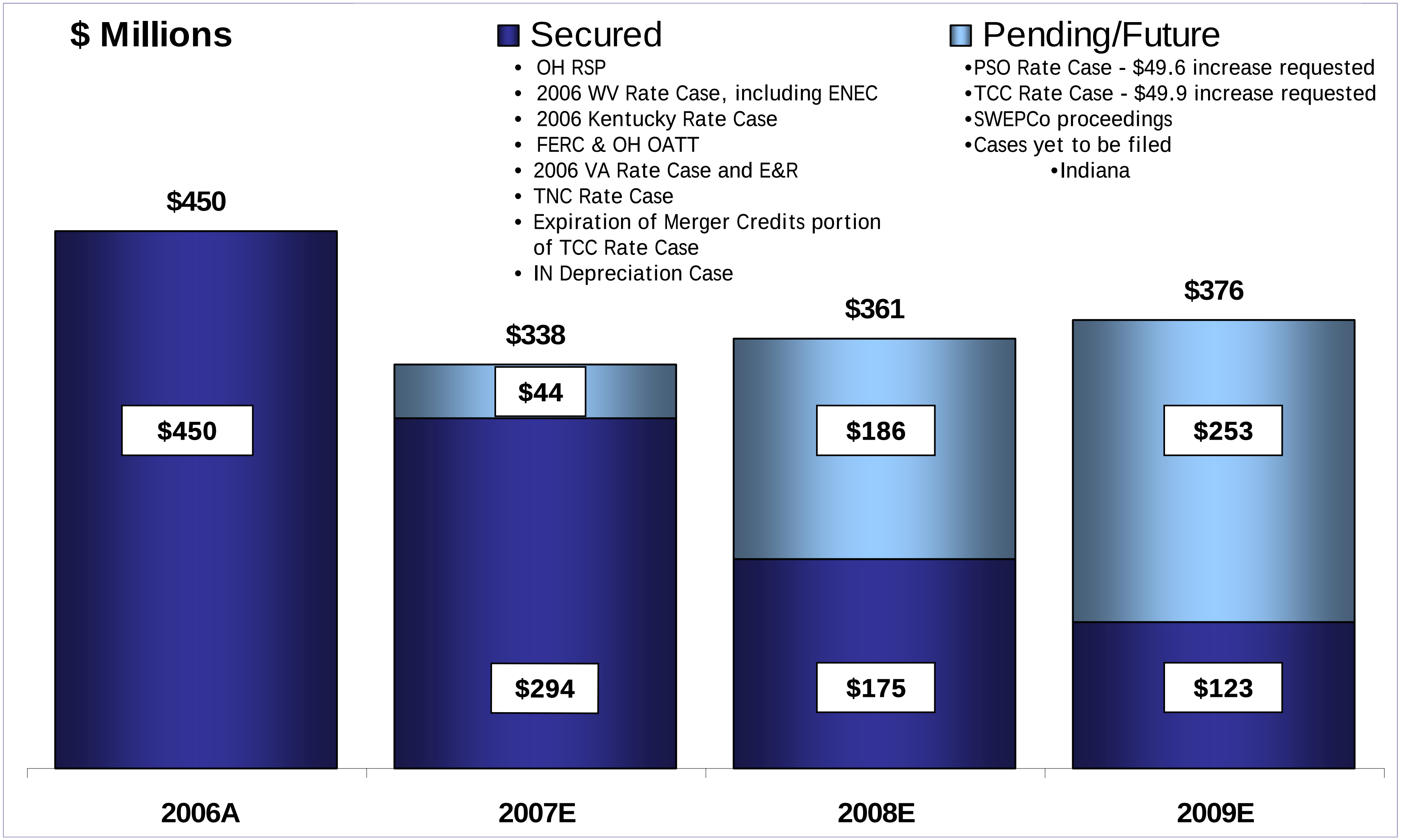
- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Babcock Power – SCR
- Pullman Power – Stack Supplier
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

First-Mover Advantage:

- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- AEP capital costs for a scrubber average approximately $250/kW
- We have since seen a 30-60% increase in material costs and a 15% increase in labor rates
- An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

AEP's customers and shareholders benefit from first-mover advantage through lower contracted pricing & reduced market escalation exposure

Incremental Rate Relief Composition



Rate relief is a critical element to AEP's financial success and allows us to pursue additional generation, transmission and infrastructure investment

Near-term Capital Spending

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Generation Investment Forecast

Public Service Company of Oklahoma Rate Proposal

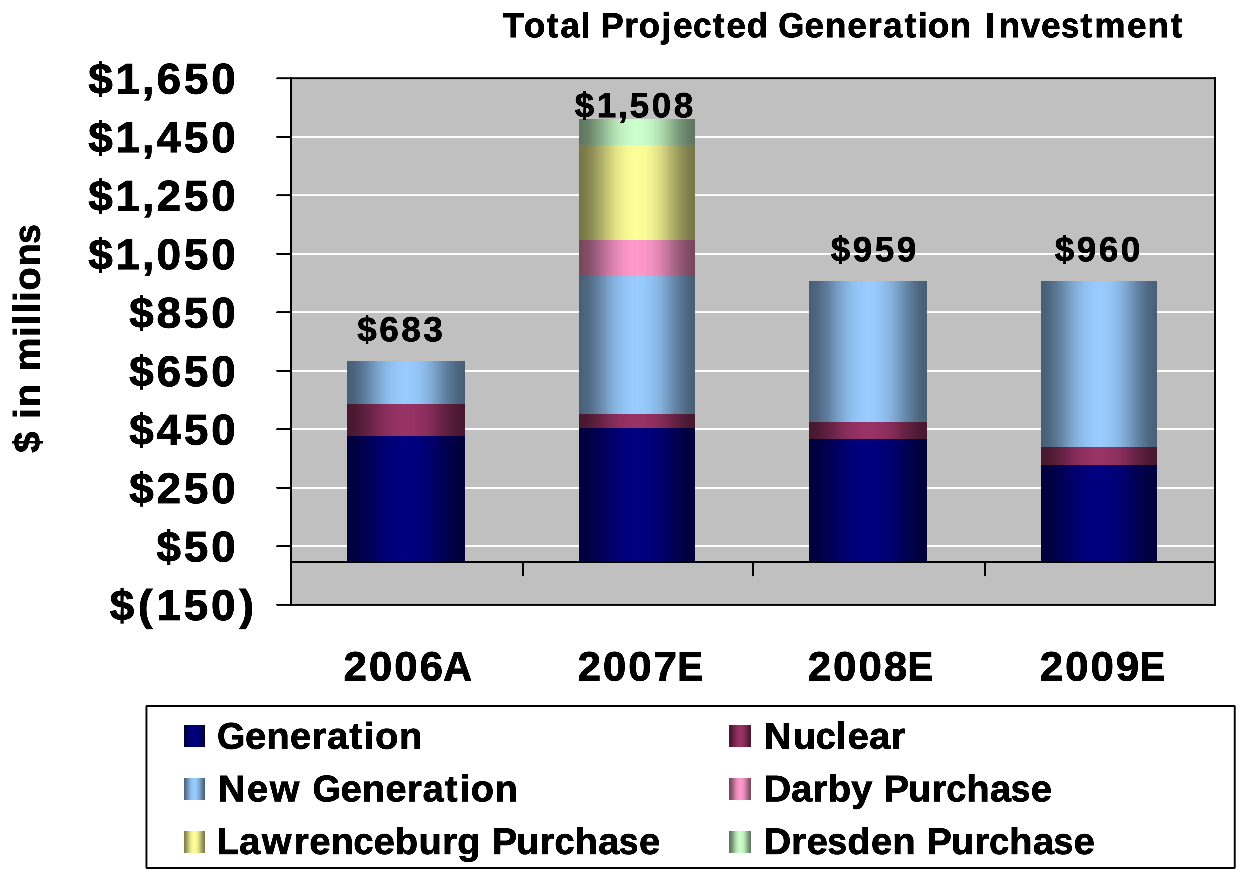
- Proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP

Distressed Generation Initiative

- New generation resources required to meet growing electricity needs of our customers
- Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 and 1,620 MW in 2007

WV and VA IGCC Filings

- Filings made with both commissions requesting return on CWIP, including development design and planning costs



Investing in generation to meet the growing electricity demands of our customers at an attractive price

Purchased Generation

Waterford
- 821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005
- $268/kW

Lawrenceburg
- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007
- $295/kW

2,946 MW of gas-fired generation added since 2005

Darby
- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007
- $227/kW

Ceredo
- 505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005
- $198/kW

Addition of gas-fired generation allows us to meet the growing needs of our customers and provides the company with greater fuel flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	900 (4)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	630	2017

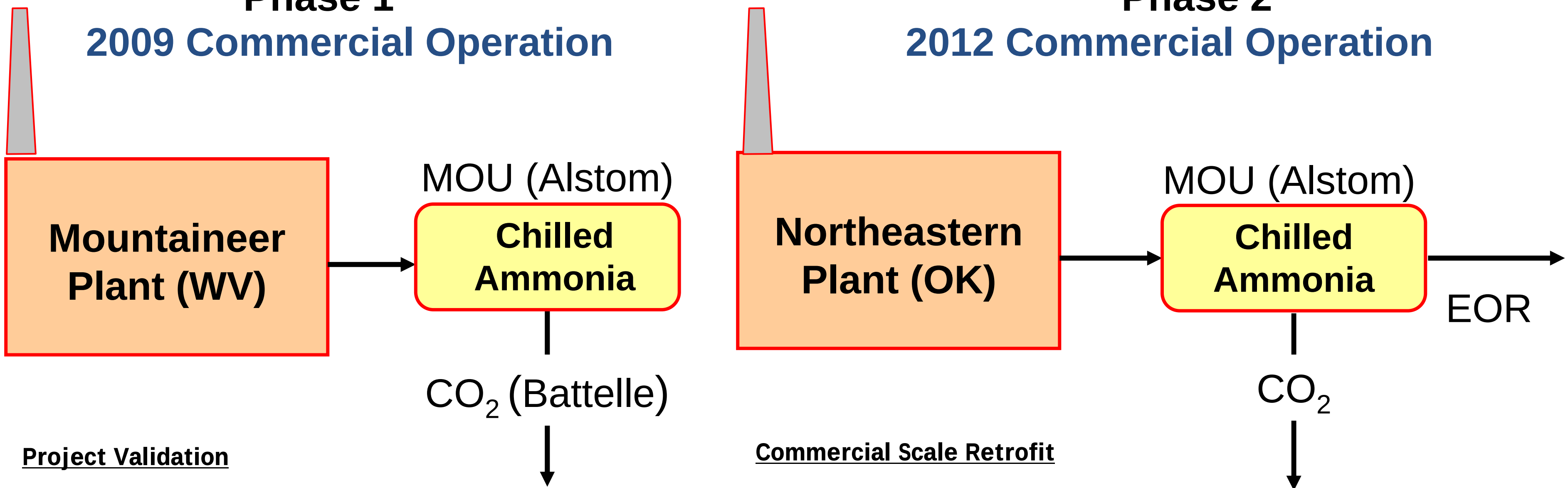
(1) 150MW were declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(5) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP is meeting the growing electricity needs of customers through the pursuit of new, economic generation facilities

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



Project Validation

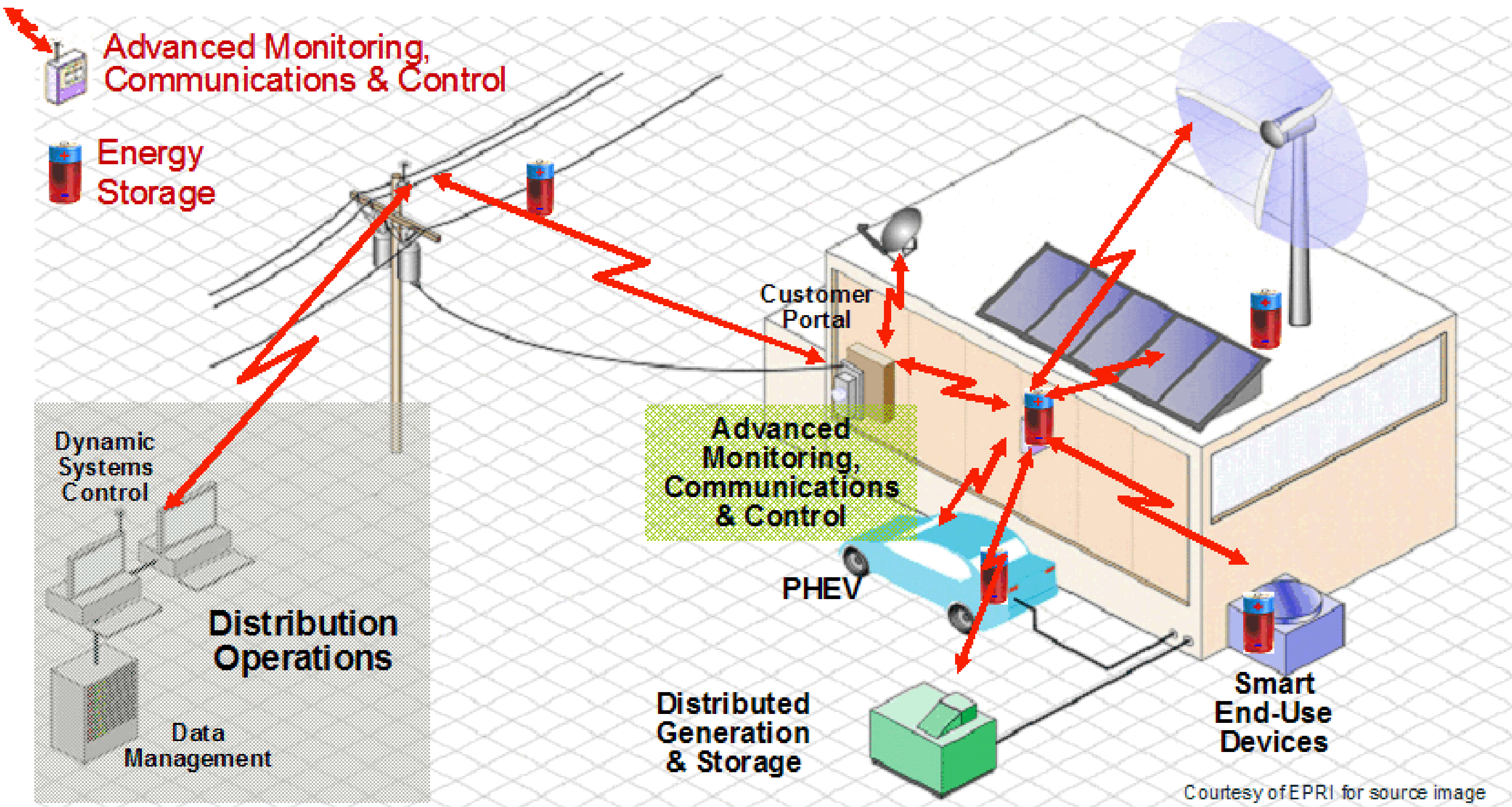
- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

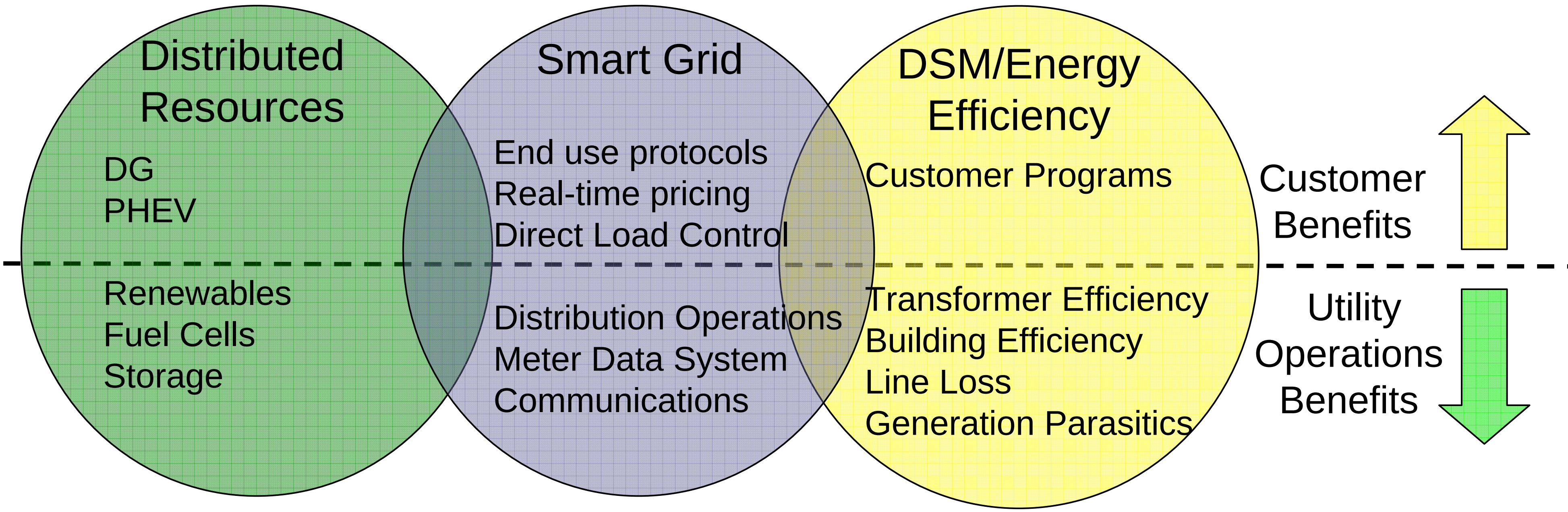
- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion carbon solution provides pure CO_2 stream for capture

Distribution Operations of the Future



The “Modern Grid” Initiative



AEP has initiated an internal project to help clarify these inter-relationships, and develop our strategy for deploying these programs and technologies

Modern Grid Initiative

- Project to develop a vision for AEP's distribution and customer services business in the future, including the development of new customer programs and a plan to deploy advanced technologies
- Focus on:
  - Enabling greater customer control over energy usage
  - Enhancing conservation activities
  - Optimizing the operation of AEP's distribution business
- AEP needs to pursue:
  - Using real-time status intelligence on our distribution system to improve operations and customer service
  - Providing customers with real-time pricing signals
  - Providing customers with program options that encourage reduced energy consumption
  - Promoting the use of electric vehicles and distributed generation
  - Utilizing advanced electricity storage for peak usage and power outages
  - Enabling technologies such as biomass, solar and fuel cells
  - Modeling future customer behaviors as a consumer of our own products
- Examples include:
  - Customer Energy Efficiency and Demand-Side Management Programs
  - Advanced Metering Infrastructure (AMI) & Distribution Automation (DA)
  - Distributed Generation and Storage

Pace of our Modern Grid Implementation Determined by Regulators

- **Arkansas** – SWEPCo filed 'quick-start' programs with the commission on July 1, 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency lad management pilot and a pay-for-for-performance pilot that results in a payment to customers who curtail load upon request. We are awaiting commission approval.
- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and administering a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.
- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.
- **Ohio**
  - Recent Governor remarks indicate modernization of Ohio's infrastructure is a high priority and his plan would allow single-issue rate cases for these high-priority investments and system upgrades.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.
- **Texas**
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.
- **Virginia** – The Virginia commission has initiated a docket to address various aspects of demand-side management and energy efficiency.

Energy efficiency is an investment, which should be treated by regulators in the same manner as investments in generation, transmission and distribution

Long-term Capital Spending

Significant Opportunity for Investment

The current U.S. transmission system cannot support the demand of tomorrow's energy supply needs

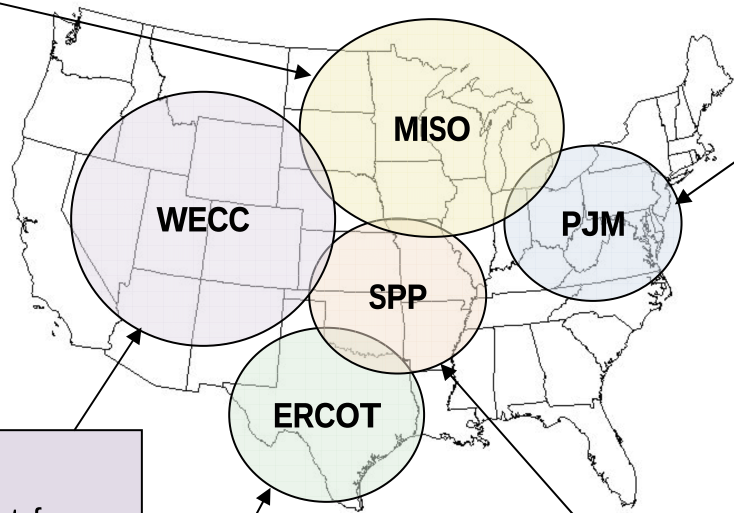
- Investment in transmission has lagged load growth
- Transmission congestion equates to increased costs to customers
- Large-scale wind generation in remote areas requires a high-capacity transmission system for efficient energy movement to load centers

Transmission Investment Opportunities

Investigation of opportunities needs to be mindful of regional drivers

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues



PJM

Congestion will be reduced and reliability will be increased

WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

ERCOT

Load growth and access to wind resources driving transmission investment

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

~ $3 Billion I765$_{TM}$ Project in PJM
~ $2 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

Building the next US interstate system for enhanced reliability and market efficiency

Why Invest in AEP?

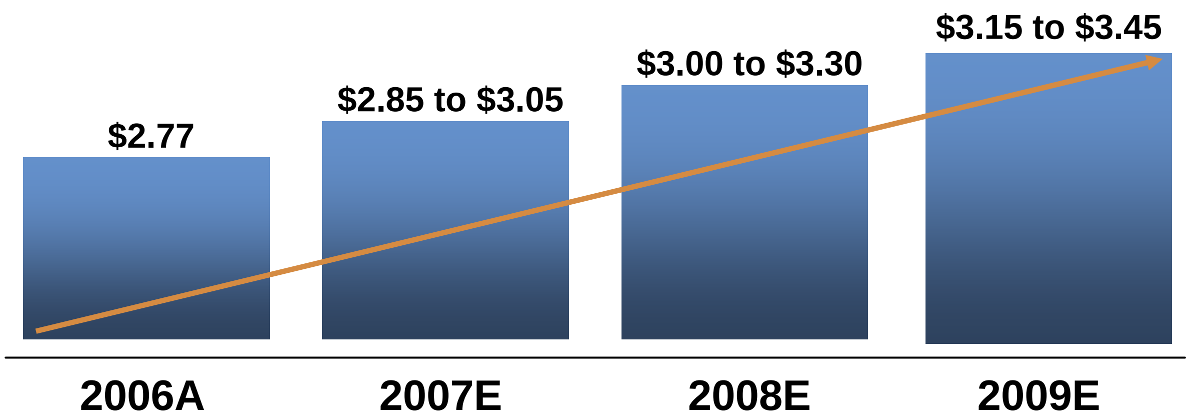
- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

Questions

Appendix

Long Range Performance – Consistent and Predictable Growth

2007, 2008 & 2009 Ongoing Earnings Guidance Ranges: 5-7% Annual Growth



- Continued disciplined investment in existing utility operations:
  - Reliability
  - Environmental
  - New Generation & Distribution Infrastructure
- Investment in new transmission opportunities
- New investment coupled with rate recovery
- Continued cost control
- Timely Rate Relief
- Maintain Credit Ratings
  - BBB/Baa2/BBB

Future earnings growth driven by native load growth and substantial utility investment opportunity focused on regulated operations

Summary of 5-7% Long-Range Growth Components

Energy sales growth of 1.5%

Rate base investment

- Generation plant purchases & build
- Transmission – interstate & intrastate
- Distribution
- Reliability

Transmission company

Commercial operations

Regulatory strategy

- Achieve timely returns
- Seek cash returns on investment during construction
- Create & secure innovative rate plans
  - Pursue post-2008 solution in Ohio
  - Expand use of trackers
  - Formula rates

New baseload generation and transmission projects largely reflect upside to the long-range earnings growth targets of 5-7%

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2009
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☐	Delayed
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5 & 6	750		N/A	☑	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service

At the conclusion of our current environmental retrofit program, over 47% of our coal-fired generation fleet will be equipped with SCRs and over 50% will be scrubbed (FGD).
AEP's total coal fleet capacity = 24,630 megawatts *

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve

AEP AMERICAN ELECTRIC POWER

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

Incremental Reduction quantity: 5MM tons/yr

Timing: To take effect/receive credits by 2011

Methods

- +1000 MWs of Wind PPAs – 2MM tons/yr
- Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
- Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
- Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
- Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

IGCC and Ultra-supercritical coal plants

Commercial solutions for existing fleet

- Chilled Ammonia
- Oxy-Coal

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

10 MW_e scale

Teamed with B&W at its Alliance Research Center and 16 other utilities

Demo complete 3Q 2007

AEP funding of $50k

Commercial Scale Retrofit

Retrofit on existing AEP sub-critical unit (several available)

150 – 230 MW_e scale retrofit

4,000 – 5,000 tons CO_2 per day

Team with B&W

AEP funding of ~ $1.5M for feasibility study

Feasibility study to be completed in late 2007/early 2008

Combustion conversion technology for existing coal fleet – longer lead time with enhanced viability and long term potential

PJM I-765™

Execution in Action

Overview

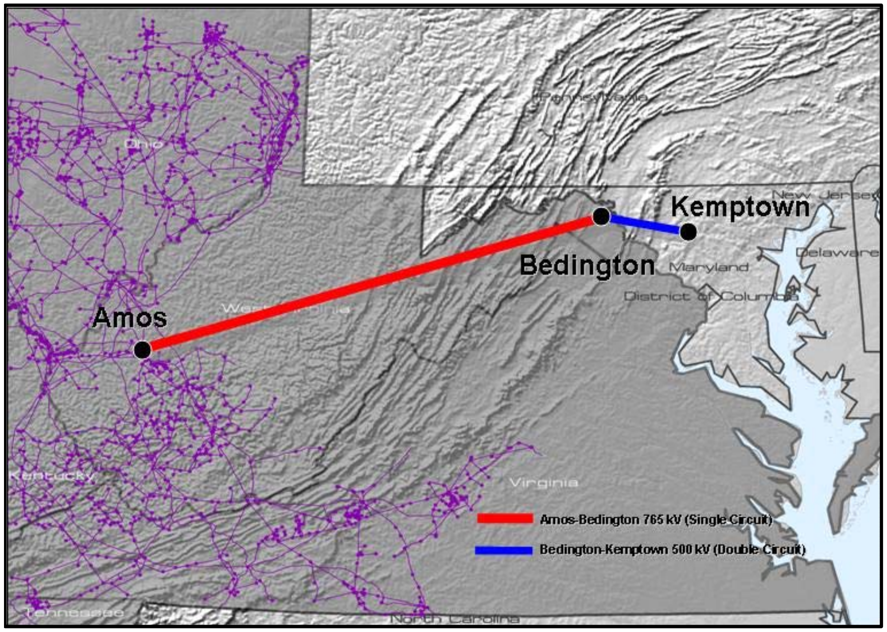
- $3 billion investment (before ownership division)
- 550 line miles
- 5000MW improved transfer capability
- To be completed in 2 phases (1st phase PJM approved)

Benefits

- Improves eastern grid reliability
- Improves market efficiency with reduced congestion
- Reduces consumer cost $1B (est.) annually in the east
- Reduces network line losses by 280 MW at peak
- Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
- Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation

Phase I Progress to Date

- AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
- Total estimated cost of $1.8 billion
- AEP portion approximately $600 million
- Expected completion 2012

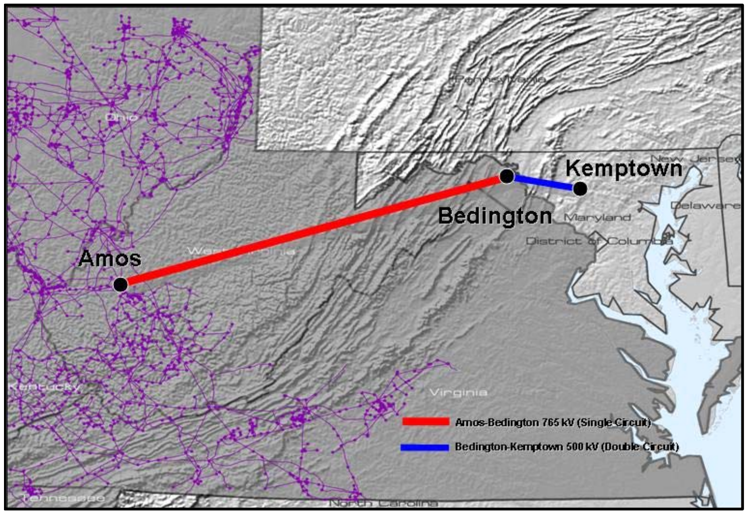


PJM I-765^{TM} Phase I cont'd

Execution in Action

Funding Plans/Transaction Structure

- Formed a joint venture with Allegheny Energy for 290 miles of the proposed 550 mile project
- JV portion of the I-765^{TM} Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007
- Equity – 50% AEP / 50% Allegheny
- AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
- Operations to commence in the second half of 2007
- I-765^{TM} Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007



Key Regulatory Activity Completed

- FERC declaratory order approved July 2006
- PJM approved plan June 2007

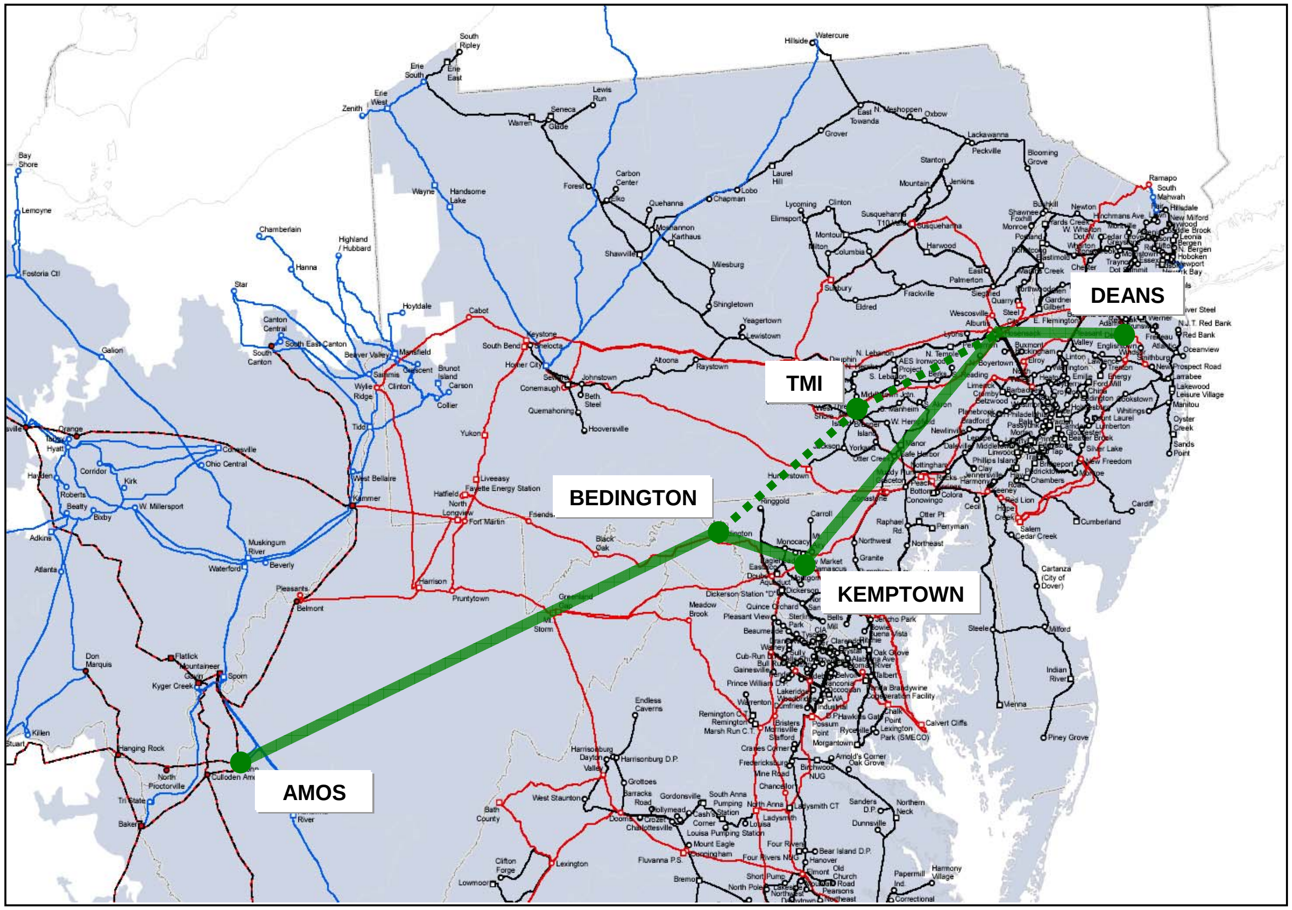
Key Next Steps

- Complete FERC Filing – Fall 2007
  - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
- Siting Approved – Fall 2009
- Completion – Fall 2012

PJM I-765™ Phase II (Bedington-Deans)

Second phase of original AEP 550-mile I-765 proposal

- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



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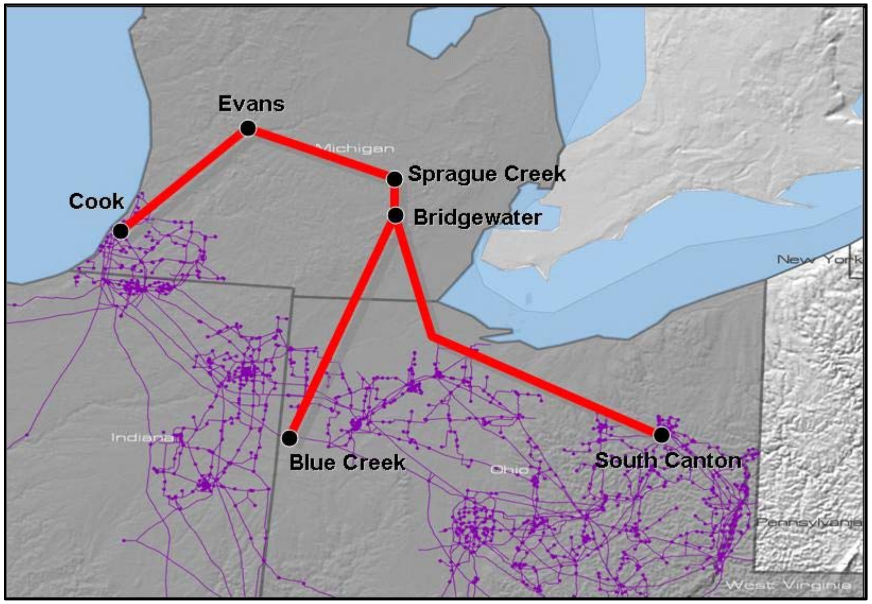
765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.0 billion investment (before ownership division)
- *Benefits*
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

Overview

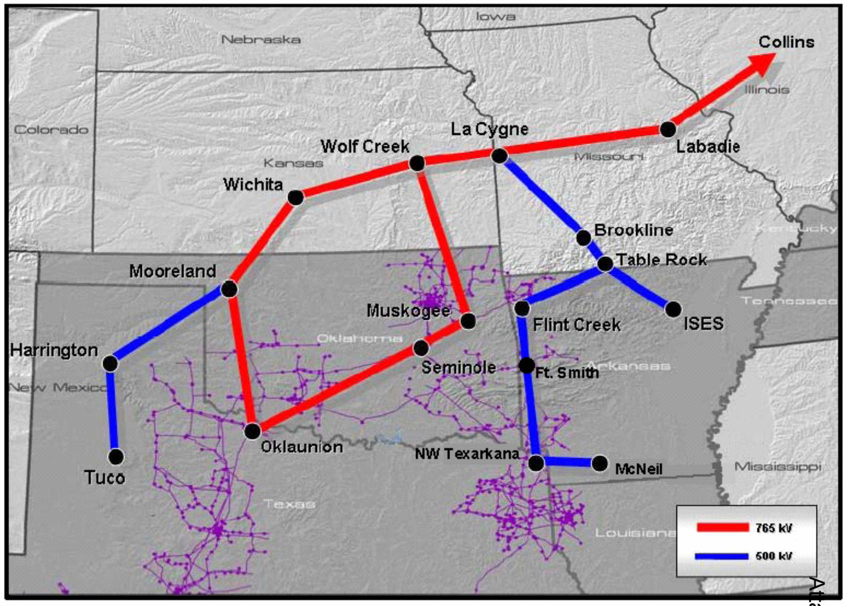
- July 2006 AEP submitted conceptual project for six 765-kV lines
- Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
- 610 miles from Kansas to Arkansas
- $3.0 billion investment (before ownership division)
- Proposed 2012-2017 construction period
- SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
- SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri

Benefits

- 4,000 MVA capability

Next Steps

- Study disclosure – Fall 2007
- JV formation (Partner-TBD) – Fall 2007
- SPP RTO/BOD EHV Overlay approval – Summer 2009
- SPP RTO FERC Filing – Fall 2009
- Siting approval – Fall 2011
- Estimated completion – Summer 2017



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ETT Status Update

ETT: Delivering Power for Texas' Future

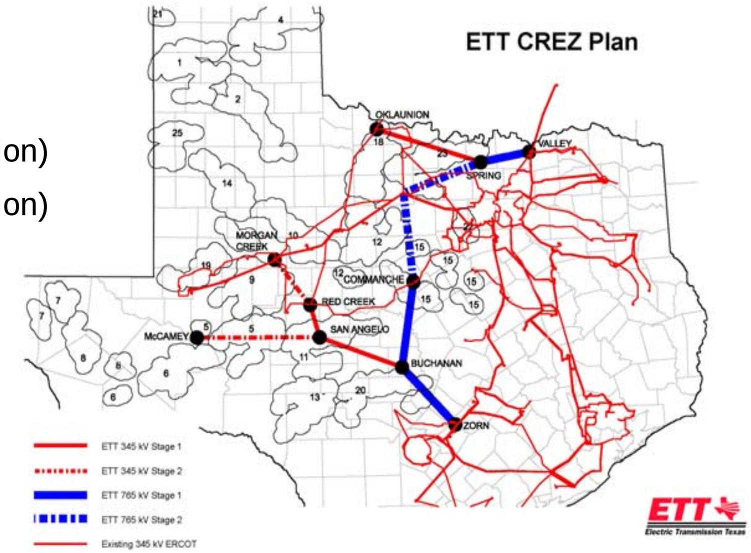
- *Transaction Structure*
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP; business manager provided by MidAmerican.
  - Investment opportunities can be offered by either partner and accepted or rejected by ETT.

- *Transaction Status*
  - Formation documents finalized and Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in September 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

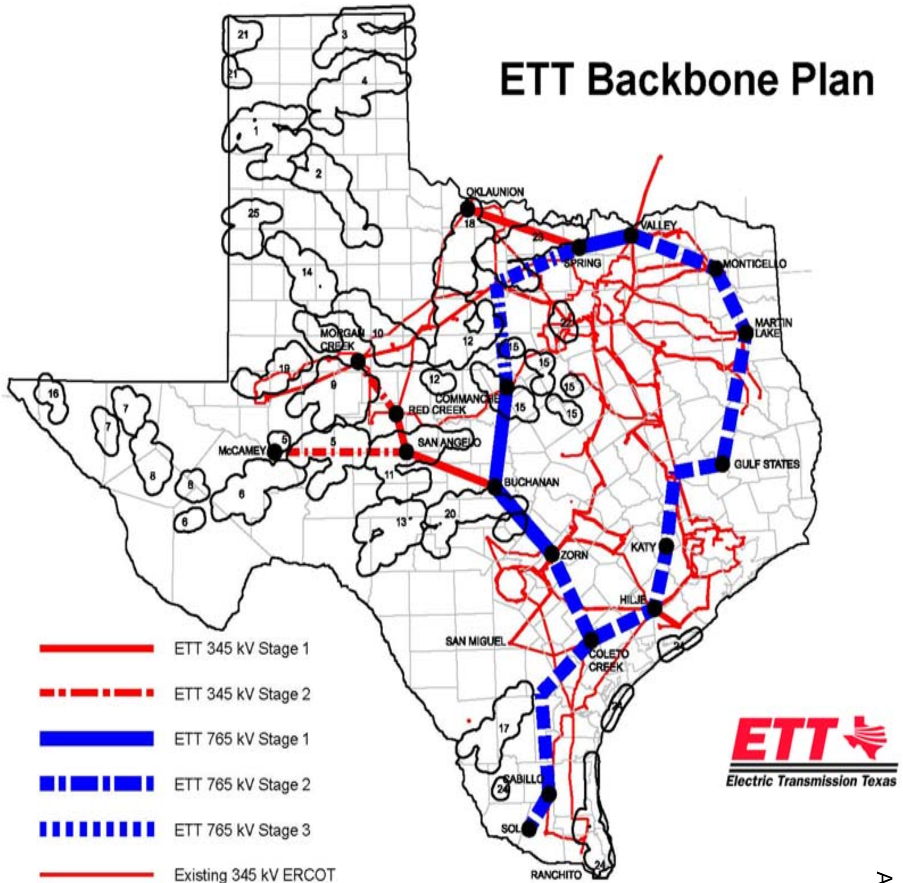


- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

CREZ & Backbone Opportunities – cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).



2007 Ongoing Guidance: $2.85 to $3.05 per share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		2006 Performance Driver	2006 Actual ($ millions)	2007 Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance *
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash on hand is expected to be $205 million by the end of 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital investment is funded by cash from operations and debt issuances

Lehman Brothers
CEO Energy/Power Conference

September 8, 2005

AEP AMERICAN ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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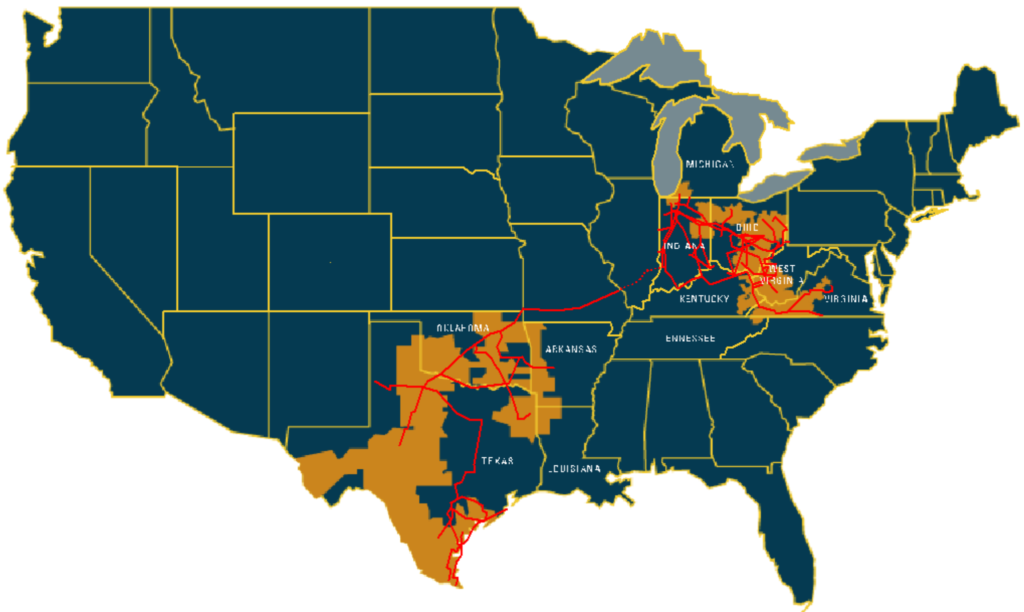
Strength & Scale in Assets & Operations



Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Utility Investment to Drive Earnings Growth

Investment Opportunities:

- Traditional Maintenance
- Environmental
- New Generation

Preserves low cost production advantage and extends generation asset life

- IGCC

Environmentally sensitive investment can be blended with AEP's low production cost

- Energy Delivery Infrastructure

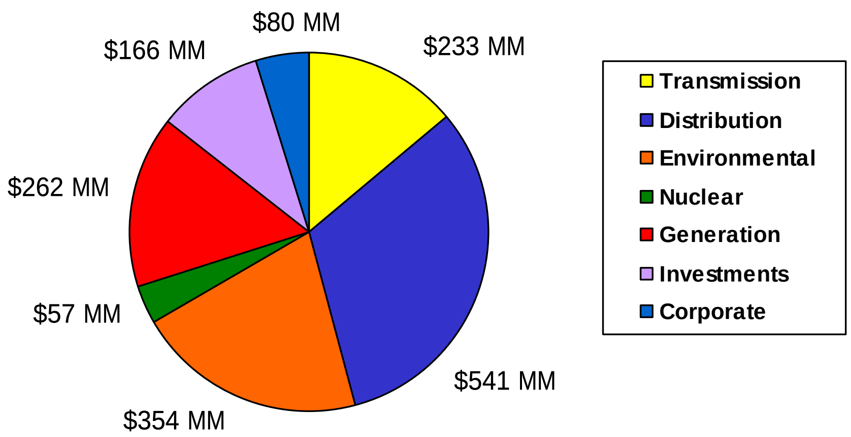
Annual Growth Rate 3-5%:

- Organic demand growth rate of 2%
- Utility investment recovery to add 1-3% to growth

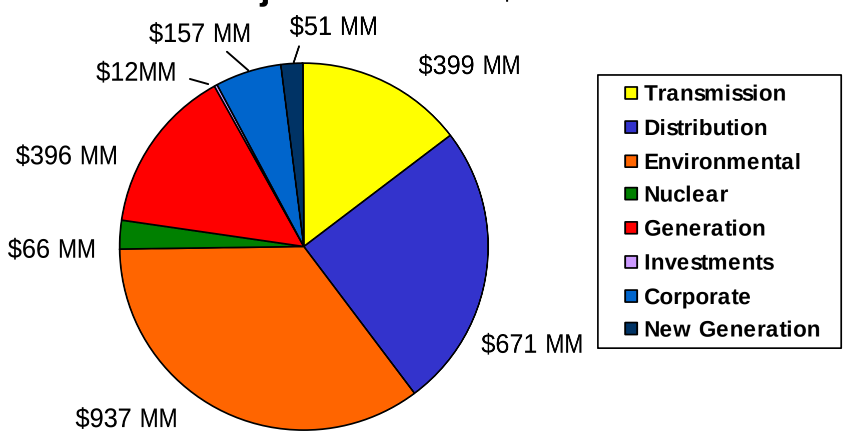
PRUDENT INVESTMENT WILL PRESERVE LOW COST ADVANTAGE AND DRIVE EARNINGS GROWTH

2005 Capex

2004 Actual Totaled $1.69 Billion



2005 Projected Totals $2.69 Billion



Note: 2005 capital expenditures exclude the announced Waterford and Monongahela Power transactions.

AEP's Environmental Compliance Strategy

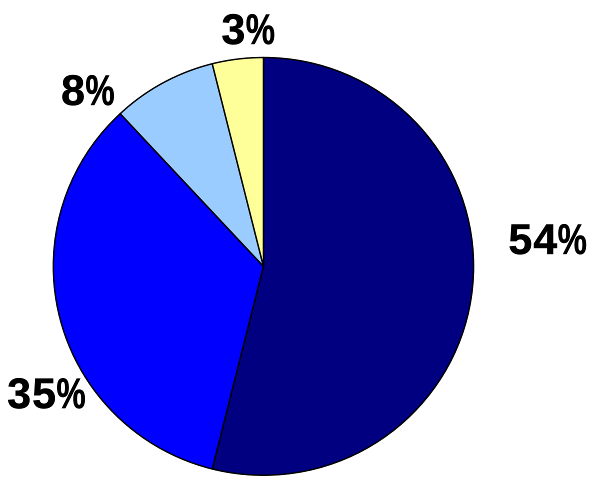
NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Much of this investment will be for:**
  - **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
  - **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
  - **SCR and FGD systems together offer co-benefit of mercury capture.**
  - **Sale of gypsum (by-product) avoids future landfill costs.**
  - **Provides fuel flexibility.**

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

$4.1 Billion Environmental Investment: Spending by Company

Projected Environmental Investment Allocation



- Ohio Power & CSP (OH)
- Appalachian Power Co. (VA/WV)
- Kentucky Power Co. (KY)
- Other

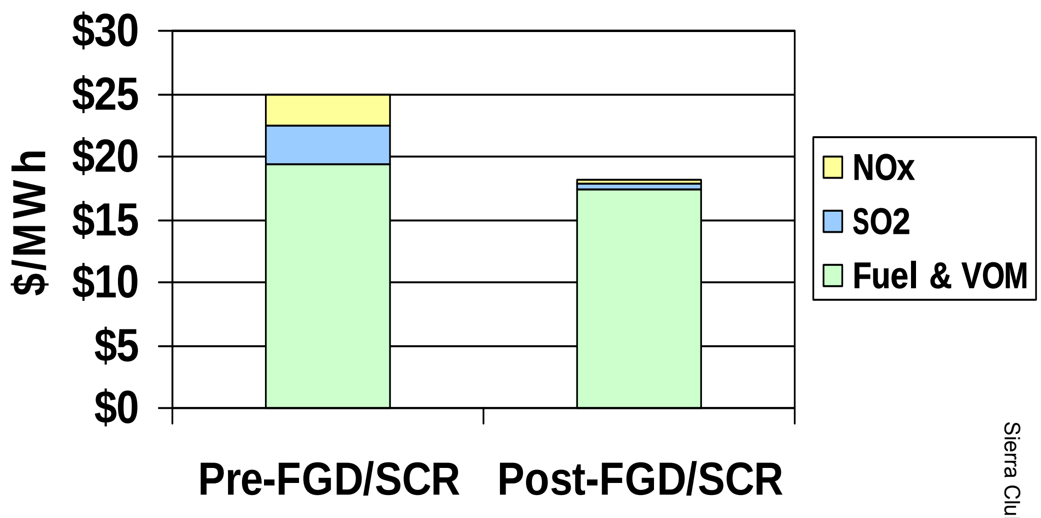
Funding the Environmental Investments

- **Ohio**: 54% ($2.2 billion)
  - Approved annual increases 2006-2008
    - CSP – 3% annually
    - OP – 7% annually
- **Virginia/West Virginia**: 35% ($1.4 billion)
  - VA: Annual Rate Relief through Environmental & Reliability cost recovery mechanism
  - Two rate case opportunities through 2010
  - WV: General rate increase filed 8/26/05 including environmental, reliability & fuel recovery
- **Kentucky**: 8% ($319 million)
  - Automatic surcharge mechanism

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*

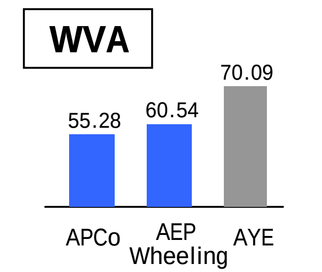


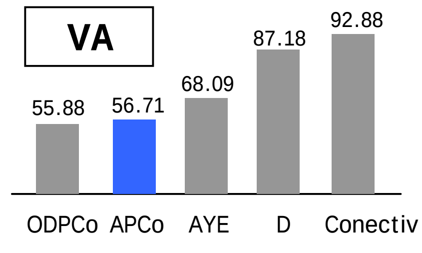
* Assumes annual NOx program

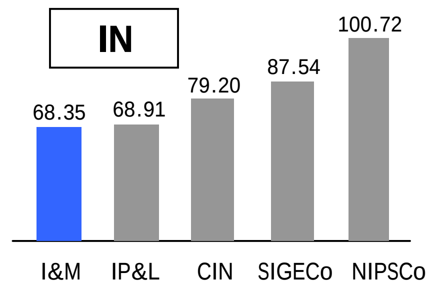
AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

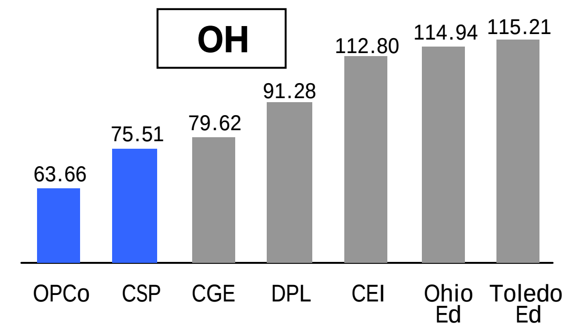
AEP: The Low Cost Provider

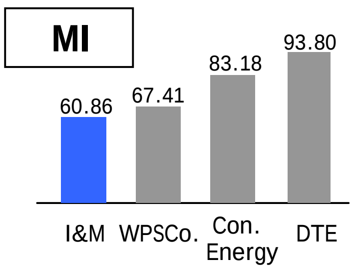
Comparative Rates

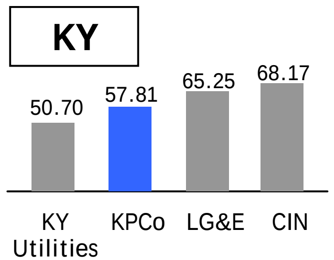


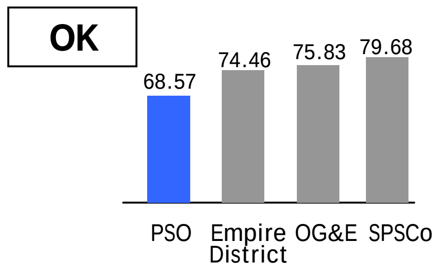


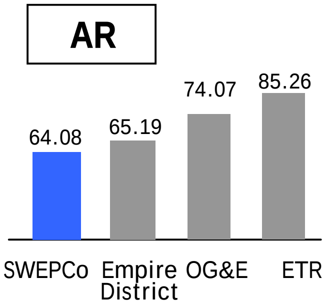


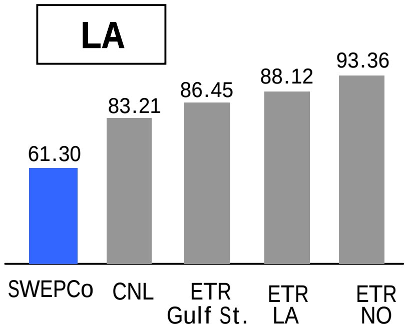


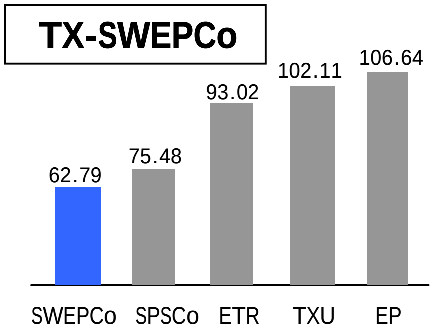












Wholesale

AEP System fossil fleet average variable book cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

Investing in IGCC

Ohio IGCC Procedural Schedule

- **August 16, 2005: Evidentiary Hearings Concluded**
- **September 13, 2005: Initial Briefs Due**
- **October 3, 2005: Reply Briefs Due**

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.
** Total plant cost include land, overheads, AFUDC, etc.
*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Investment in Asset Base Will Drive Earnings

Potential Return On Investment

Assumptions	Environmental Investment	600MW IGCC Investment*
Projected Investment	$4.1 Billion	$1.0 Billion
Approx. Debt/Equity Ratio	60% debt / 40% equity	52% debt / 48% equity**
Return on Equity	10-12%	11.75%***
Potential EPS Impact (based on 393 MM shares)	+ $0.42 to $0.50	+ $0.14

* Assume a similar return for an additional 600 MW IGCC facility

** Requested debt/equity ratio per AEP Ohio IGCC filing

*** Requested ROE in AEP Ohio IGCC filing

EPS CONTRIBUTION FROM INVESTMENT WILL BE SUBSTANTIAL

Funding the Investment

- Cash flow from operations
- Rate Relief
  - Ohio approved annual generation rate increases for 2006-2008
  - Virginia annual rate relief through environmental & reliability cost recovery mechanism plus two rate case opportunities through 2010
  - West Virginia general rate increase filed 8/26/05 including environmental, reliability & fuel recovery
  - Kentucky automatic environmental surcharge mechanism
- Asset Sales
  - 2005 proceeds estimated to be $1.5 billion
- Texas Securitization/Texas Competition Transition Charge
  - Seeking recovery of $2.4 billion
- Debt Issuances
  - Maintain debt-to-capitalization ratio of approximately 60%

UTILITY INVESTMENT TO BE FUNDED BY A VARIETY OF TRADITIONAL SOURCES

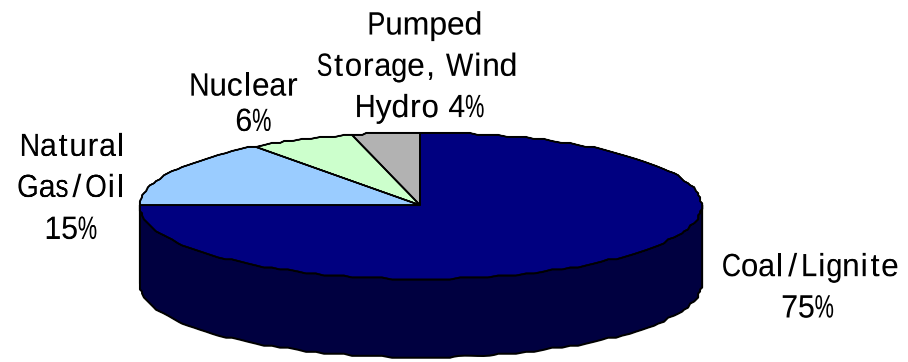
Appendix

Asset Portfolio

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity). Also excludes the Waterford and Ceredo generating facilities.

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

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Dated January 13, 2012
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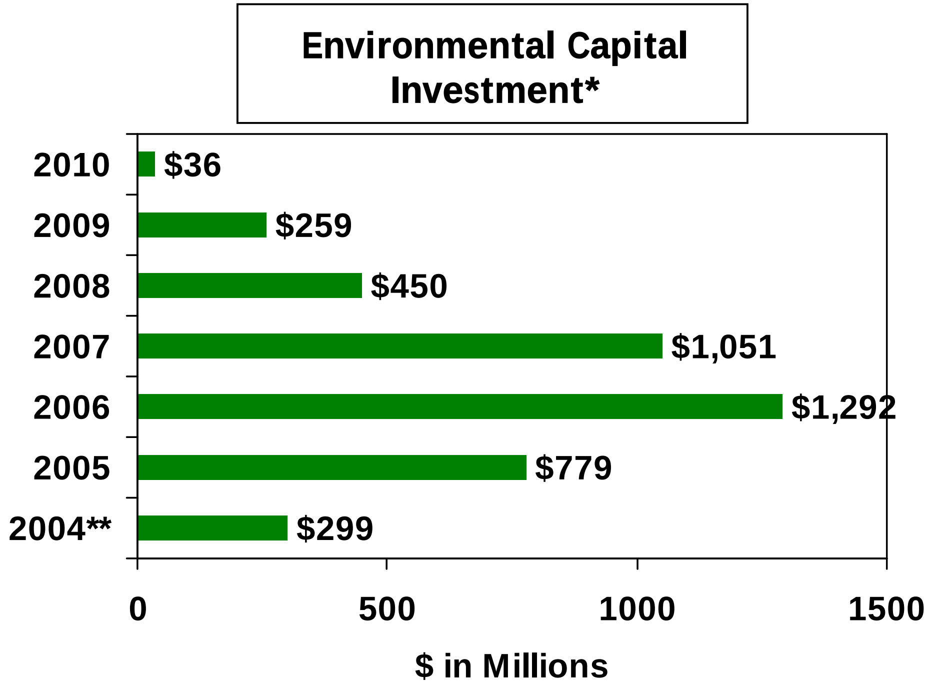
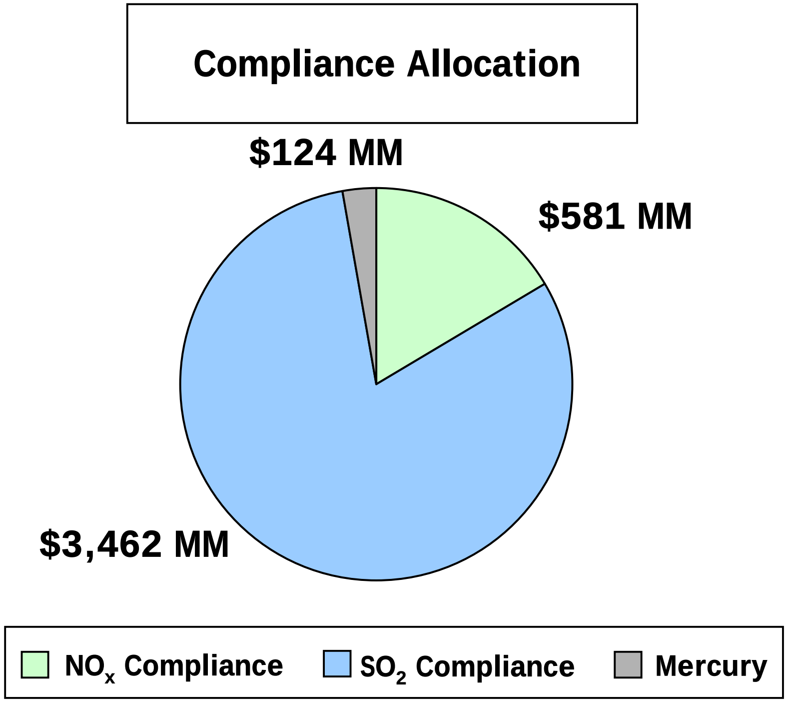
Environmental Investment

Environmental Investment: $4.1 Billion Through 2010





*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Current Programs
$2.0 Billion:
$0.5 billion for NOx
$1.5 billion for SO_2

Future Programs
$2.1 Billion:
$1.9 billion for SO_2
$0.2 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Investment

	FGD	SCR
Completed	see tables below	see tables below

Completed — FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Completed — SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction — FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

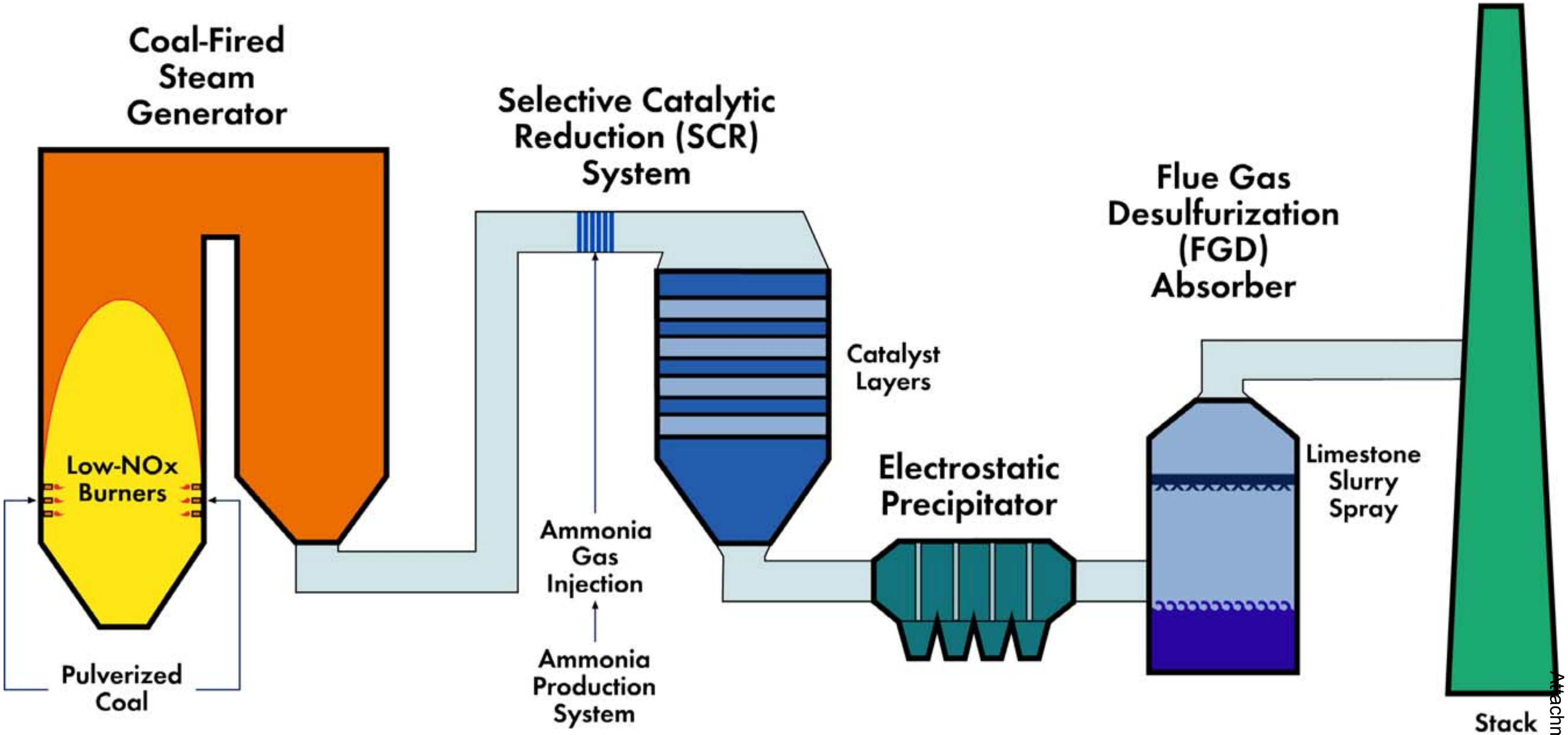
Planned or Under Construction — SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2006 - 2009

Note: MW capacity shown represents AEP's owned capacity only

The Flue Gas Stream



Materials and Vendors

Material Costs

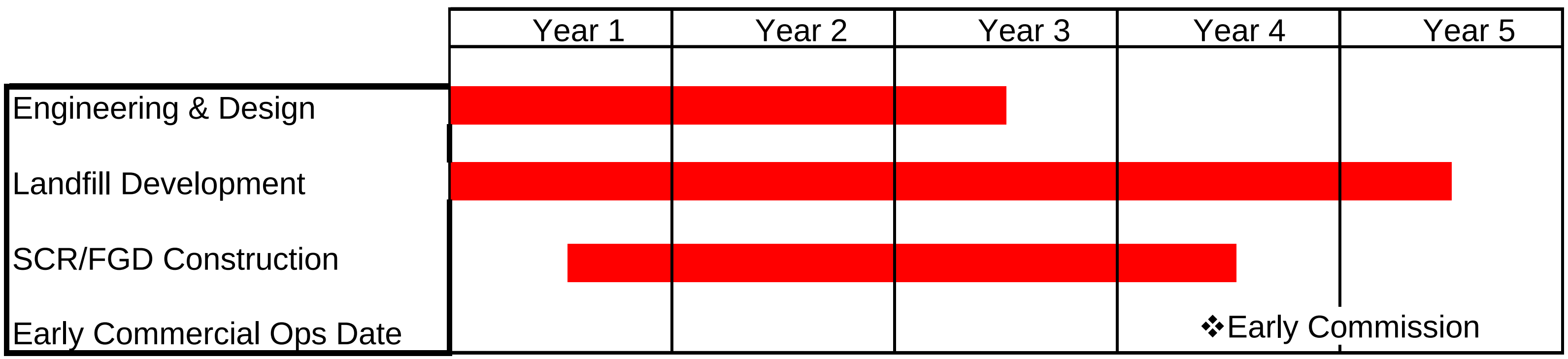
- The primary materials used during construction are steel and alloys, the cost of which is volatile. We closely monitor the cost of such materials and strive to proactively manage our cost exposure.

Typical Vendors

- FGD
  - B&W
  - Alstom
  - B & V Chyioda
- SCR
  - Babcock-Riley Power
- Stack Supplier
  - Pullman Power Inc.

Typical FGD/SCR Project Milestone Schedule

- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, bid Phase 3 Construction At 30 – 60 % design complete
- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path



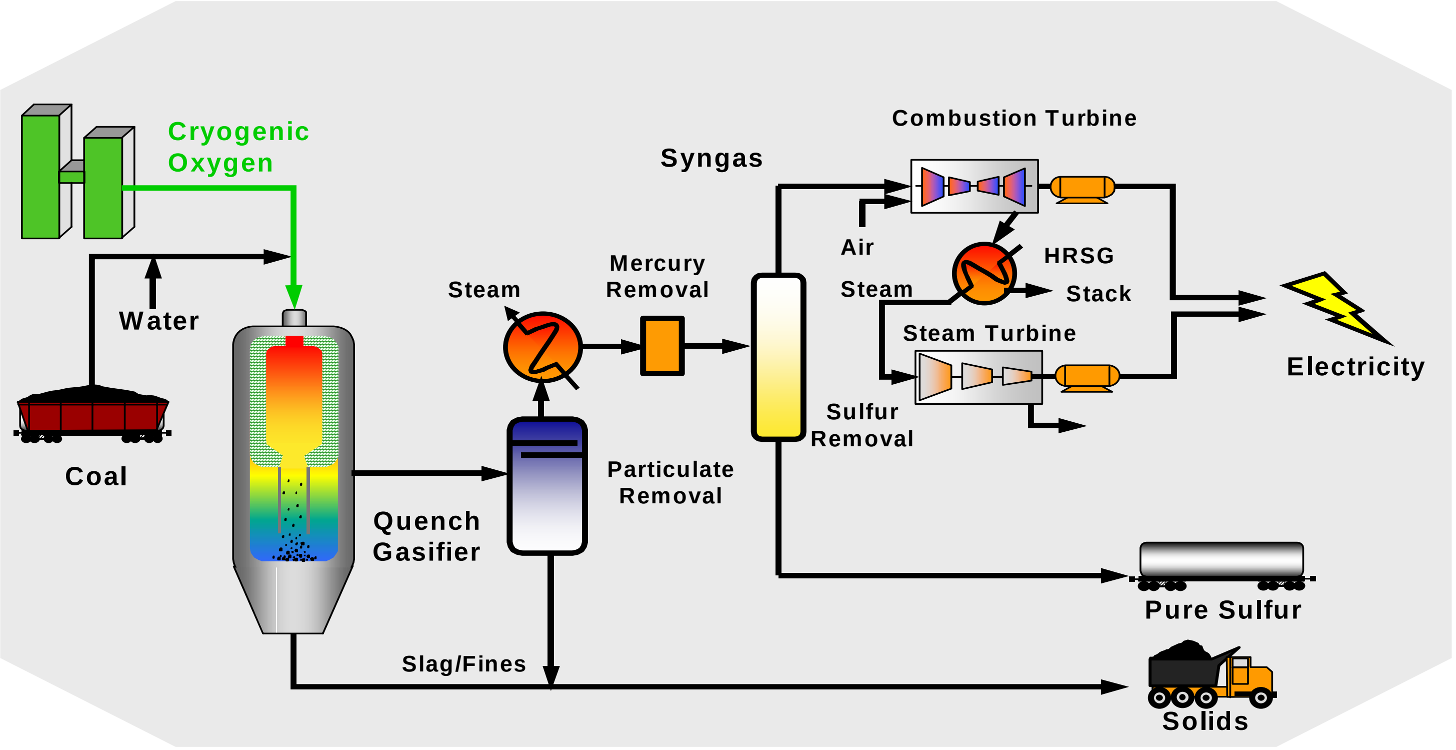
Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.

PLANT MODIFICATIONS WILL MITIGATE FGD AND SCR CAPACITY CONSUMPTION

Investing in IGCC

Looking to the Future - IGCC



AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

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IGCC Permitting Issues

- **Air** – to evaluate best available control technology (BACT)
- **Wastewater** – to understand wastewater streams
- **US COE** (Corp of Engineers) – to obtain permits for construction of river facilities
- **NEPA Process** – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

<u>2005</u>

- Secure cost recovery plan – Summer
- Finalize site selection - Fall
- Negotiate with suppliers – Throughout 2005

- 2005—2007: Obtain permits and finalize engineering and procurement

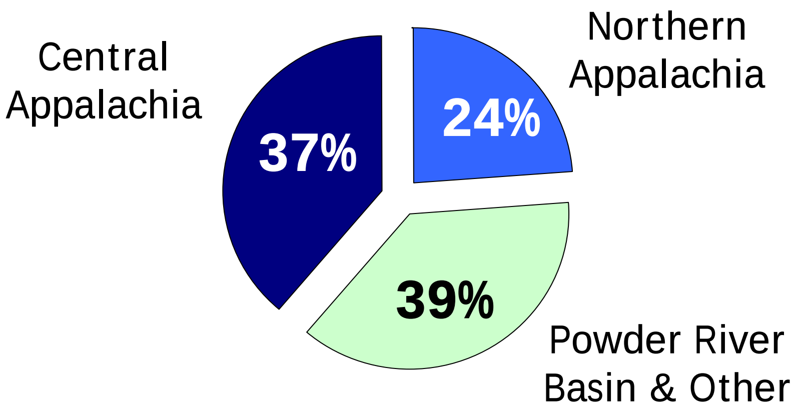
- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Fuel, Emissions & Logistics

Coal Procurement

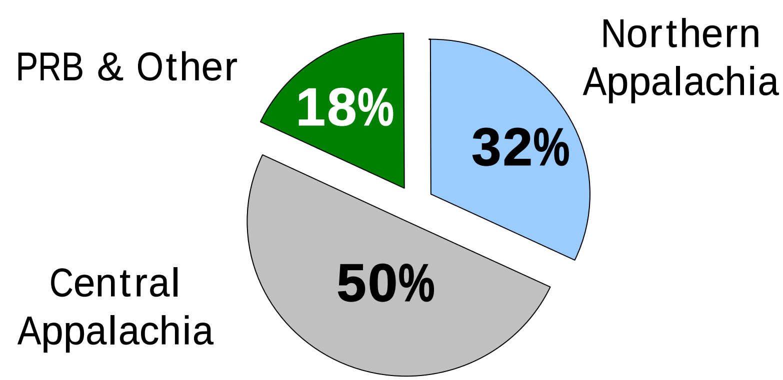
AEP SYSTEM



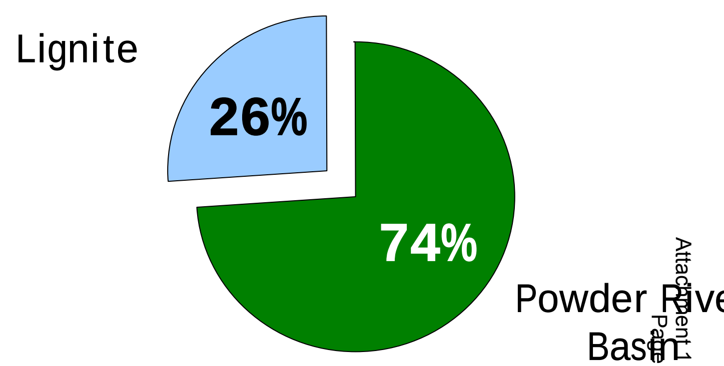
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 12%-14% price increase in 2005
  - Increase being pressured by strong burn
  - PRB deliveries will impact results

EASTERN SYSTEM



WESTERN SYSTEM



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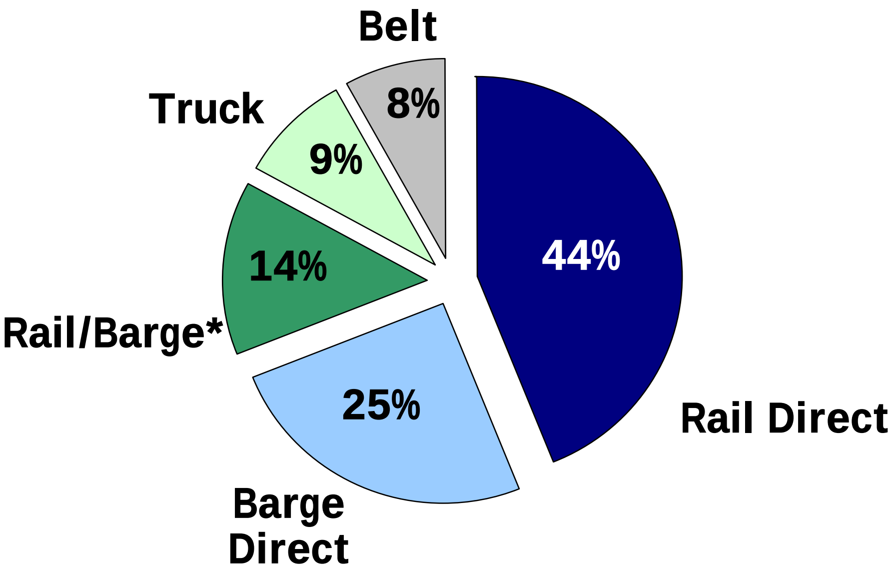
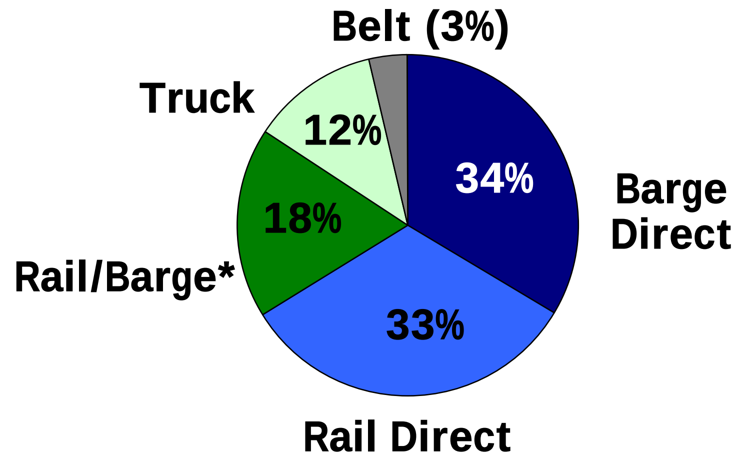
Coal Delivery Mix

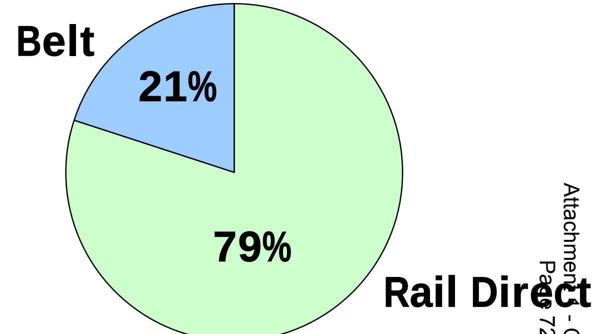
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



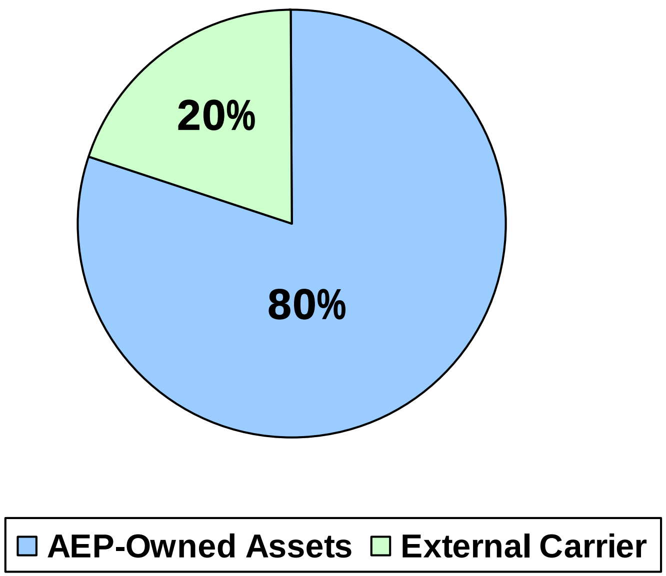
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

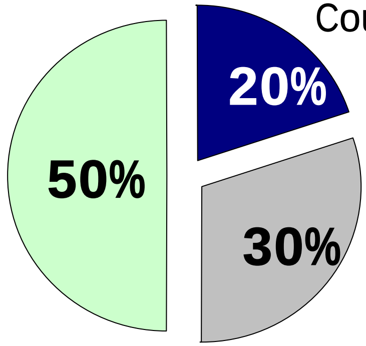
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM



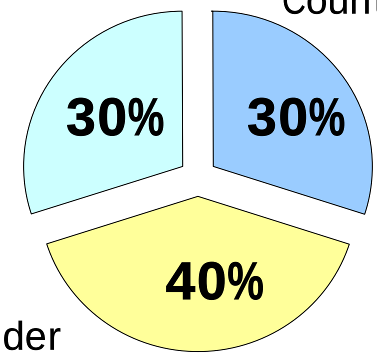
Fuel Cost Recovery

(on average)

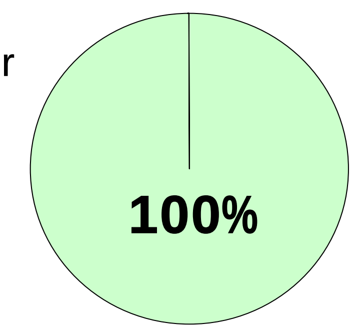
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, Hearings are done. Initial and reply briefs are due 9-13-05 and 10-3-05, respectively.
- Hearings set for 10-11-05 on CSP’s possible acquisition of Mon Power’s Ohio service territory.

West Virginia (Regulated)
- Base rates not frozen
- No active fuel clause
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- On 8-26-05 AP & WP filed with the WVPSC for a $183 million revenue increase to be phased in over a four-year period beginning in mid 2006. The filing consists of a general rate case, reinstatement of the ENEC, to implement scheduled incremental rate increases for major clean air & transmission investments, and the implementation of a system reliability tracker mechanism.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause
- On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental costs for environmental compliance and T&D System reliability (E&R) of $62.1 million, effective on an interim basis beginning 8-1-05. The commission has scheduled hearings to begin 2-7-06 and has stayed the effective date of rates pending resolution of a legal issue that parties have been requested to submit briefs on by 9-6-05.

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004
- On 8-26-05 the Company filed a notice of intent with the KPSC of its intention to file a case on or before 9-26-05 using a 6-30-05 ending test year. The level of rate increase was not specified. The Company expects an effective date on or before April 1, 2006 based on a 9-26-05 filing date.

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)
- Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated) • SWEPCO Texas retail competition delayed until at least 2007. PUC Chairman believes the precursors for full and open competition are not yet in place and will not exist prior to 2009. The Chairman committed to the Texas Legislature that the commission would consider maintaining the current status of competition in the SWEPCO Texas (and SPP portion of TNC) areas in future proceedings. • Bi-annual fuel clause adjustment opportunity **Texas ERCOT Area (Restructured)** • TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) Hearings-late Sept. • TCC wires rate case PUCT approved final order on July 15. Final order results in slight rate decrease with a positive earnings impact. Rate expected to be effective no earlier than September 2005. • TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing is final and appeals were filed in state and federal court in August 2005. • TNC true-up order approved in May 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC. The results of the true-up case were filed in TNC's Competition Transition Charge (CTC) proceeding in August 2005. • TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.	**Oklahoma (Regulated)** • On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval. Staff submitted testimony supporting an annual cap of $22.59 million up from the $11.81 million cap currently in place. The ALJ has recommended approval of the Staff proposed rider cap. It is now pending a Commission decision. • Annual Fuel Clause • 2001 Fuel review case Hearings scheduled for Sept. 2005 have now been continued to a later date to be determined. Scope expanded to cover 2002-2004 margin allocation issue. Intervenors have submitted testimony which would substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error. • 2003 Fuel review case Scope has been expanded to include a prudence review.
Louisiana (Regulated) • Base rates not frozen • Currently under a merger required financial review • Fuel clause, adjusted monthly	**Arkansas (Regulated)** • Base rates not frozen • Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	POLR Rider	Revenues & POLR Rider*			Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs***	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit**	0	25	25	26	0	25	25	26
Recovery of RTO costs***	0	23	23	23	0	23	23	23
Total ETP Impact	**0**	**48**	**48**	**49**	**0**	**48**	**48**	**49**

* Incremental over 2004 base year

** Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

*** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

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Components of TCC's Net True-up Regulatory Asset

	30-Jun-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 887	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(3)	(10)
Net Stranded Generation Costs	1,133	1,136
Carrying Costs on Stranded Generation Plant Costs	215	225
Net Stranded Generation Costs Designated for Securitization	1,348	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	102	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(209)	(212)
Net Other Recoverable True-up Amounts	315	287
Total Recorded Net True-up Regulatory Asset	$ 1,663	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $317 million recognized as income thru 6/30/05

Carrying charges for 2005 expected to be $87 million

Equity Component: $166 million to be recognized in income as collected

TCC SEEKING STRANDED COST RECOVERY OF $2.4 BILLION

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	21	
Total from Investing	**$ (376)**	**$ (1,171)**	
Cash from Financing:			
Common Equity	17	(54)	***
Net Long Term Debt Issued/(Retired)	(1,829)	71	****
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (578)**	
Net Change in Cash	**$ (556)**	**$ 174**	
Ending Cash Balance	**$ 420**	**$ 594**	

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

*****Equity units terms require issuance of $345MM common shares in August 2005; offset by $427MM share buyback program**

****** Includes $550MM of parent debt reduction**

Note: 2005 capital expenditures exclude the announced Waterford and Monongahela Power transactions.

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc	$	-	$	395,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	-	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	300,000,000	$	-
Ohio Power Co.	$	-	$	-	$	-
Public Service of Oklahoma	$	-	$	-	$	-
Southwestern Electric Power	$	200,000,000	$	6,215,000	$	94,000,000
Texas Central Co.[2]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**273,609,000**	$	**902,710,000**	$	**1,112,615,000**

(1) Maturities remaining as of June 30, 2005

(2) Excludes TCC securitization bonds

Capitalization

Capital Structure	Actual 3/31/05			Actual 6/30/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,359	-	12,359	11,916	-	11,916
Short-term Debt	19	-	19	14	-	14
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,268	8,268	-	8,382	8,382
Total Capitalization per Balance Sheet	**12,378**	**8,329**	**20,707**	**11,930**	**8,443**	**20,373**
% of Capitalization per Balance Sheet	***59.8%***	***40.2%***	***100.0%***	***58.6%***	***41.4%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,227	-	1,227
Securitization Bonds	(668)	-	(668)	(668)	-	(668)
Spent Nuclear Fuel Trust	(230)	-	(230)	(232)	-	(232)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,361**	**8,605**	**20,966**	**11,897**	**8,719**	**20,616**
% of Adjusted Capitalization	***59.0%***	***41.0%***	***100.0%***	***57.7%***	***42.3%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.7% AT 6/30/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's*			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

* On August 26, 2005 Moody's placed AEP Inc.'s senior unsecured and commercial paper ratings on review for a possible upgrade

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2005 Earnings Guidance Range: $2.30 to $2.50

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2008 Lehman Brothers CEO Energy/Power Conference

New York, NY

September 3, 2008

AEP AMERICAN® ELECTRIC POWER

Michael G. Morris

Chairman, President & CEO

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP's Key Strategic Priorities

- Work for best possible outcome for the long-term value of our business in Ohio

- Invest in our vast energy platform to provide low-risk growth opportunities for our shareholders and reliable, cost effective energy solutions to our customers
  - Execute transmission strategies to enhance reliability, enable low-cost and renewable energy transport to market and support long-term earnings growth
  - Implement customized state-by-state investment strategies to achieve sustainable returns

Execution and regulatory success will determine results.

AEP Ohio Electric Security Plan

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART[SM] Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony is due October 17, Staff testimony is due October 24 and the public hearing commences on November 3, 2008. We anticipate an order at the end of 2008.

AEP®

Transmission Opportunities

AMERICAN ELECTRIC POWER
TRANSMISSION 765
765KV INTERSTATE TRANSMISSION PROJECT™

PATH
Potomac-Appalachian Transmission Highline

ETT
Electric Transmission Texas

Transmission Investment and Energy Policy

- A major debate over national energy policy will occur over the next few years.

- Emerging policies must support and encourage development of new transmission investment to meet future energy needs.
  - Existing infrastructure is deteriorating and inadequate
  - Carbon policies will force the need for renewables
  - Technological innovation should be strongly supported

- New policies must address several critical issues.
  - Federal siting authority
  - Cost allocation
  - Incentives

To advance our transmission business strategy, AEP has taken a leadership position in both national and regional public policy debates.

Building the Nation's Leading Interstate Electric Transmission Company

Our Goal: Contribute sustainable shareholder growth by leveraging AEP's position as the nation's leading transmission provider to become the nation's leading developer and owner of interstate transmission investment.

EXPERIENCE

- AEP is recognized as the industry leader in transmission.

PLATFORM

- AEP's asset base provides a strong starting point for new transmission investment within our footprint.

GROWTH

- AEP assets and leadership will open opportunities for significant new regional investments, beyond our traditional retail service territory boundaries.

By leveraging existing assets, expertise and leadership, AEP will grow shareholder value by creating a significant new transmission investment opportunity.

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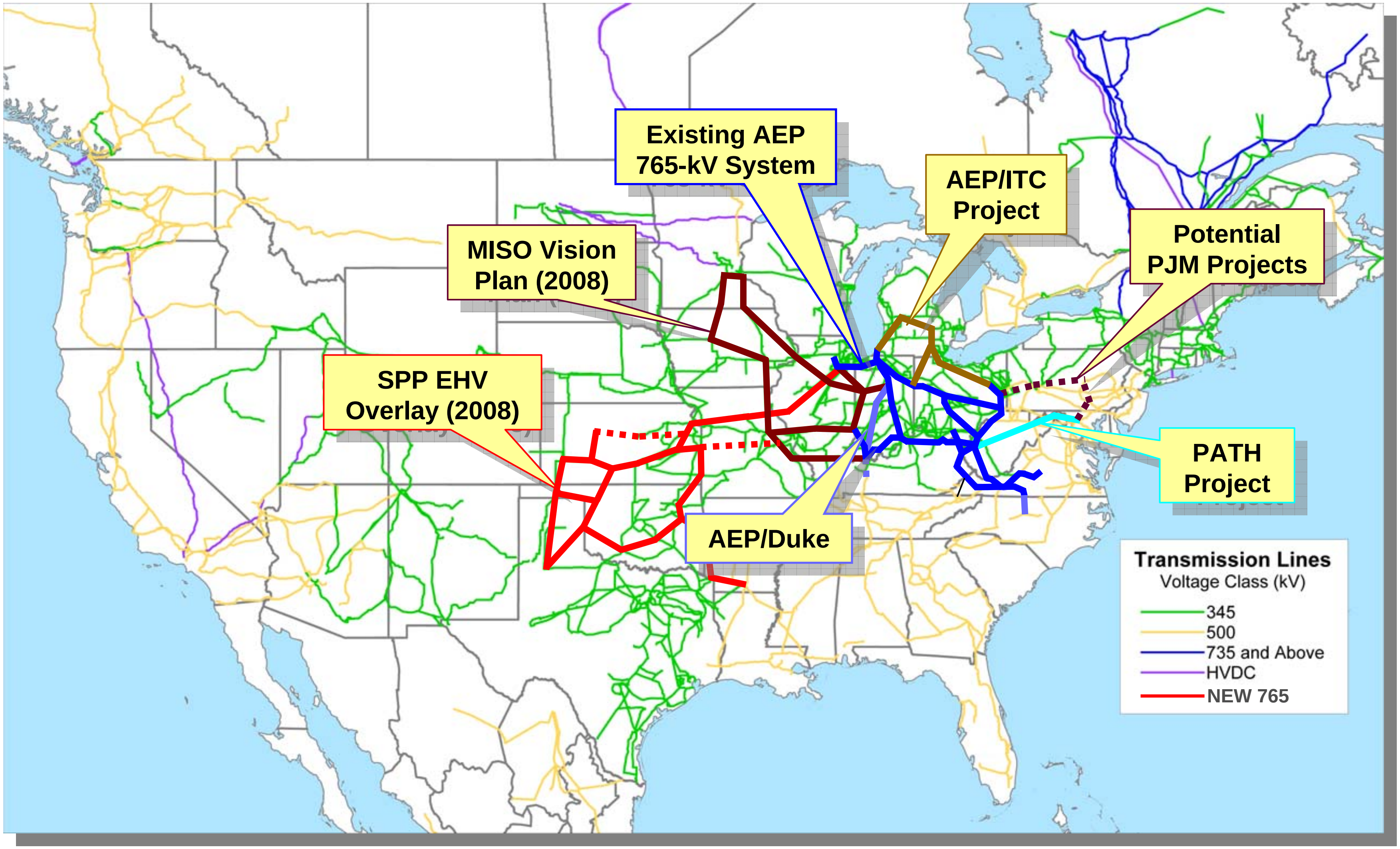
The Business Potential

- **Faced with ever rising energy costs, aging infrastructure and emerging climate change policies, transmission development is needed more than ever before to:**
  - Enhance reliability
  - Enable existing low-cost generation a path to market
  - Move renewable resources from generation centers to load centers
- **AEP Projects Underway:**
  - Electric Transmission Texas (JV with MidAmerican Energy Holdings)
  - Electric Transmission America (JV with MidAmerican Energy Holdings)
    - ETA JV with Westar Energy
    - ETA JV with OGE
  - Potomac-Appalachian Transmission Highline (JV with Allegheny Energy)
  - Pioneer Transmission (JV with Duke Energy)

"Many of our resources, whether it's wind or sun or geothermal, they're out in rural areas...and we just don't have any infrastructure. If we're going to take this whole energy piece on the renewable side seriously … we've got to get the transmission and infrastructure piece right" *Utah Gov. Jon Huntsman - AP Western Governors, Utility Heads Seeks Energy Solutions July 1, 2008*

Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

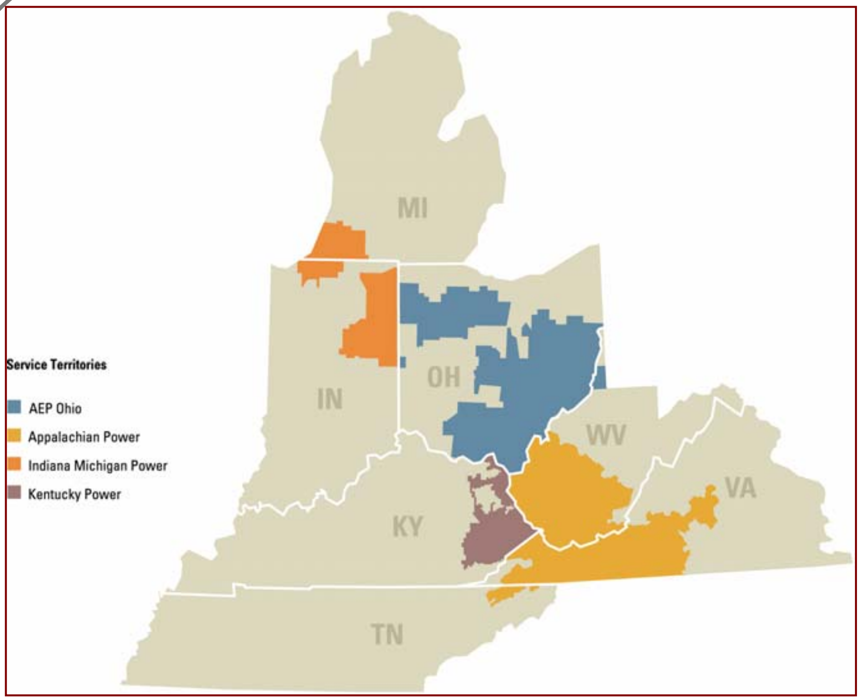
Making it Happen: Challenges

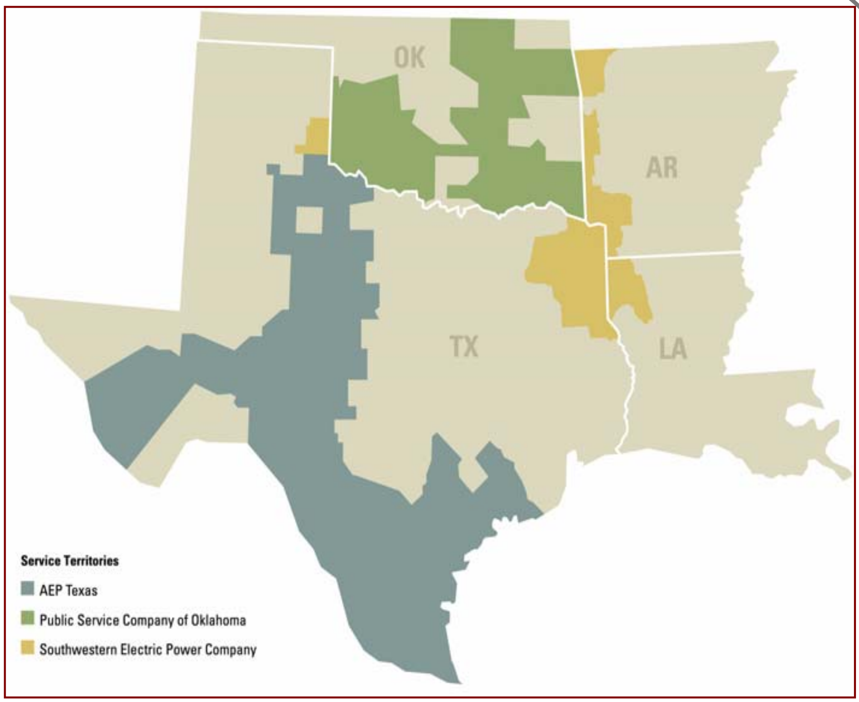
- Capital requirements: Infrastructure development through JVs requires committed capital to secure timely project development.

- Regulatory challenges: Federal policies should: favor spreading the costs broadly across customers on a regional basis; provide incentives for transmission development and investment; and address challenges associated with siting EHV projects.

- Managing a development business- Pursue standardized deal structures to permit more efficient portfolio management. Organize business processes to support JV goals and timetables. Pursue alliances to reduce risks associated with commodities and the provision of direct services. Exercise fiscal discipline to minimize expenditures prior to cost recovery.

"We need a true nationwide transmission version of our interstate highway system; a grid of extra-high voltage backbone transmission lines reaching out to remote resources and overlaying, reinforcing, and tying together the existing grid in each interconnection to an extent never before seen." *Suedeen Kelly-Commissioner FERC*





AEP's Generation and Distribution Investment Strategies

Generation & Distribution Investment Opportunities

- gridSMART^{SM} – as commodity costs and electric prices rise, investments that improve customer options and lower customer bills are key items on the minds of AEP's state regulators
- AEP East States – continue to invest in the existing generation platform and plan for key capacity additions to enable continued availability of low-cost energy to our customers and the market
- AEP West States - address the capacity/energy deficit through investments in new generation

gridSMART^{SM} Evolution – AEP East

	State Policy	AEP Action Plans
AEP OHIO – A unit of American Electric Power	SSB 221 provides targets and provisions for DSM/EE programs and supports infrastructure modernization.	Filed an Electric Security Plan (2008) which includes a model city pilot in NE Columbus and addresses DSM/EE programs.
AEP APPALACHIAN POWER – A unit of American Electric Power	Policy in VA is beginning to drive both renewables standards and DSM/EE programs.	AMR investments in VA and WV will defer new AMI for several years. New 2 MW NaS battery in Milton, WV will test dynamic islanding – supplying electricity while disconnected from the grid.
AEP KENTUCKY POWER – A unit of American Electric Power	KY's commission rules regarding DSM/EE programs are the model we seek in other states. However, like in other states, cost effective programs are difficult to implement due to KPCo's low rates.	Existing programs are focused on low-income weatherization and heat pump programs for mobile homes and receive favorable recovery.
AEP INDIANA MICHIGAN POWER – A unit of American Electric Power	IN & MI both have strong interests in efficiency programs. MI is considering requiring 2% of state revenues allocated to EE.	Broadly focused South Bend Pilot includes AMI, distribution automation, demand response, pre-paid meters. NaS battery installation in IN in 2008 to demonstrate storage with intermittent wind.

The eastern states are evolving in their positions regarding demand management, energy efficiency and AMI investments.

gridSMART[SM] Evolution – AEP West

	State Policy	AEP Action Plans
AEP TEXAS — A unit of American Electric Power	Current legislation supports concurrent cost recovery of DSM/EE programs. Legislature expecting distribution service providers in ERCOT to file plans for smart meter deployment.	Executing aggressive DSM/EE programs with targets of 15% and 20% offset to growth in 2008 & 2009. Will file by Oct. 31, 2008 a deployment plan for smart meters.
AEP PUBLIC SERVICE COMPANY OF OKLAHOMA — A unit of American Electric Power	Heavily involved in DSM rulemaking with OCC and rules to be developed in Oct 2008. Small DSM/EE program ($4.3M) approved.	Conducting small scale Distribution Automation pilot in South Tulsa. In process of implementing DSM/EE programs.
AEP SOUTHWESTERN ELECTRIC POWER COMPANY — A unit of American Electric Power	DSM/EE program costs are recoverable thru a rider in AR and base rates in LA and TX. There is no statutory support for AMI outside of TX footprint.	Continue DSM/EE in AR and in TX.

Texas currently has the most progressive legislative stance with regards to supporting AMI. PSO and SWEPCo have active DSM/EE programs with Distribution Automation pilots proposed in each state.

Regional Capacity and Energy Situation: AEP East

Generation planning in the East is a mix of regional and state-level strategy. Planning is regional because capacity requirements and energy to serve native load are shared under AEP's pooling agreement. Execution is state-by-state because regulators control cost-recovery approval for any new plants and sharing of off-system sales margins.

AEP OHIO – A unit of American Electric Power

- OPCo is significantly long capacity.
- CSP gradually gets capacity short as plants are retired.
- SSB 221 sets significant renewable and advanced energy standards, but contains provisions for a waiver of the requirements if the costs are too high.

AEP APPALACHIAN POWER – A unit of American Electric Power

- APCo is the most capacity-short company in the East.
- WV has a strong long-term interest in coal.
- Law in VA sets voluntary renewable targets.
- AEP continues to pursue wind energy through long-term PPAs.

AEP KENTUCKY POWER – A unit of American Electric Power

- KPCo is short capacity, but less so than APCo.
- KY also has a strong long-term interest in coal.

AEP INDIANA MICHIGAN POWER – A unit of American Electric Power

- I&M is long capacity (no new fossil generation in the near or mid-term).
- IN & MI legislatures are considering RPS standards, with wind being the renewable of choice in IN.

New Generation Plan: AEP East

CAPACITY POSITION

- AEP East will be capacity deficient in approximately 2012 without new capacity additions.

ENERGY POSITION

- AEP can generate economic energy well in excess of native load for the next ten years.

2008-2010 Projected AEP East New Generation Capital Expenditures

	2008	2009	2010
Dresden- 580 MW (owned by AEG; capacity to APCo)	$99MM	$102MM	$3MM
Potential I&M Wind Farm	-	$33MM	$106MM

In the East, large-scale capital investment in new generation is not required in the near-term. AEP continues considering IGCC with carbon-capture options.

Regional Capacity and Energy Situation: AEP West

AEP®

CAPACITY POSITION

- PSO and SWEPCo are currently capacity deficit and filling their needs with market purchases.

PSO New Generation Situation

- Regulators will act, but regional economic interest still prevails.
- As a clear example, the Oklahoma Commission acknowledged and approved PSO's need for 450MW of baseload capacity, but denied a CCN and cost recovery for the proposed coal-fired Red Rock plant.
- An RFP was issued to purchase needed capacity and energy and proposals were due August 22. Evaluation of the proposals is underway.

ENERGY POSITION

- PSO and SWEPCo are also facing significant, growing energy deficits.

SWEPCo New Generation Situation

- SWEPCo's states have less vested interest in gas-only to meet the region's energy needs for 2013 and beyond and are in various stages of approval for the Stall (509 MW gas-CC) plant. The Turk Plant (447 MW coal) has been approved by all three jurisdictions and we await the air permit from the ADEQ.

2008-2010 Projected AEP West New Generation Capital Expenditures

	2008	2009	2010
Stall	$207MM	$85MM	$32MM
Turk	$115MM	$249MM	$227MM

PSO and SWEPCo face immediate and growing infrastructure shortages. We have implemented an RFP process to purchase the needed capacity and energy in Oklahoma and are building new generation in Arkansas and Louisiana to meet SWEPCo's capacity and energy needs.

Conclusion: AEP's Key Strategic Priorities

Work for best possible outcome for the long-term value of our business in Ohio

- Comprehensive Electric Security Plan filed on July 31, 2008

Invest in our vast energy platform to provide for growth:

Execute transmission strategies to support long-term earnings growth

- Leverage AEP experience and existing infrastructure
- Enhance reliability
- Move low-cost energy and renewable resources from generation centers to load centers
- Strategic alliances to distribute financial and operational risks

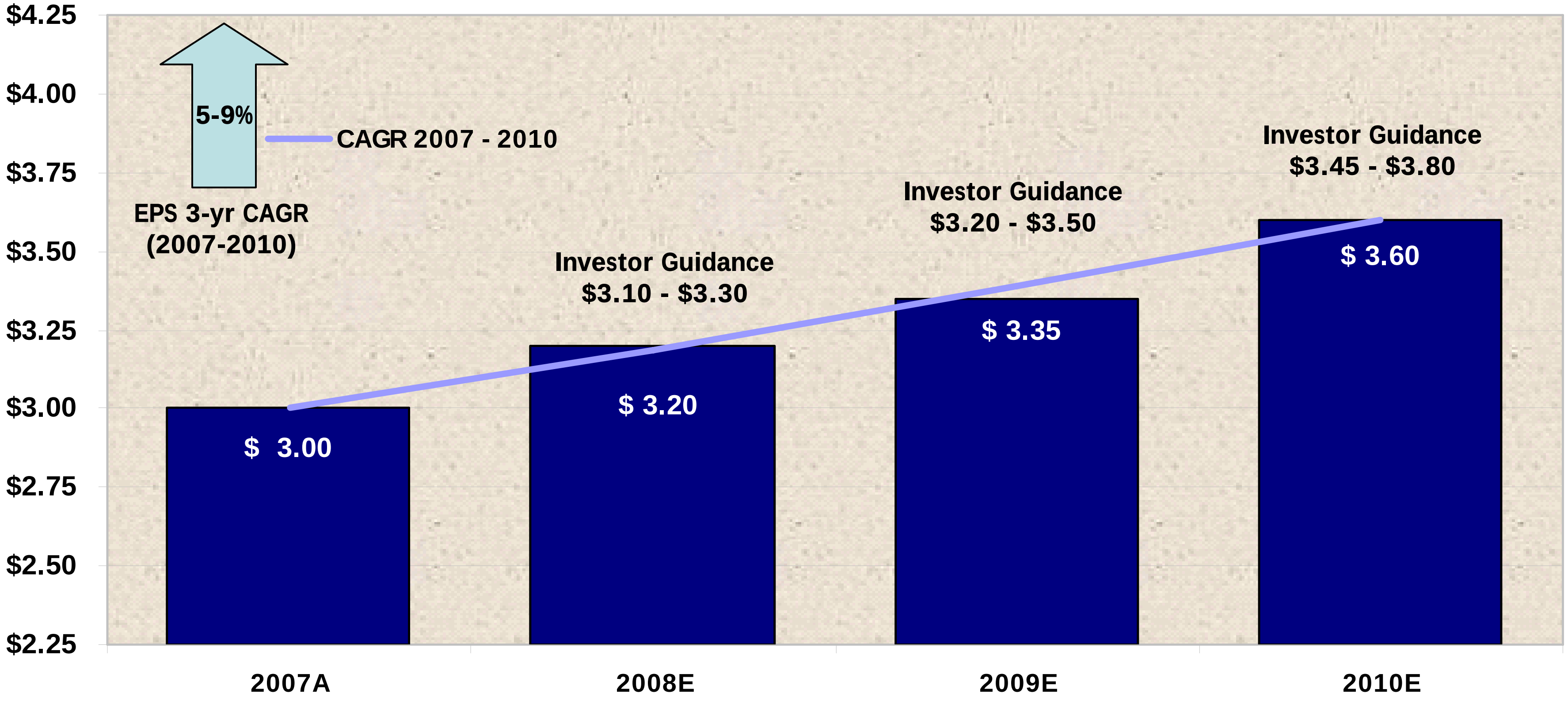
Implement customized state-by-state strategies to achieve sustainable returns

- gridSMART℠ provides customers added optionality during a time of rising commodity prices
- Investments in generation and distribution that align with the interests of our regulators
- Fuel cost recovery in each jurisdiction mitigates the impacts of rising commodity costs

Continued disciplined capital investment/rate base growth, new generation investments in the West and investments in interstate transmission are the main drivers of earnings growth over the next several years.

The AEP Value Proposition

Leveraging our vast energy platform with low-risk investments in infrastructure to enable sustainable growth.



AEP's ability to ensure a disciplined approach to capital investment allows us to sustainably grow earnings and shareholder value.

Questions

Appendix

Detailed Ongoing Earnings Guidance

2007A: $3.00

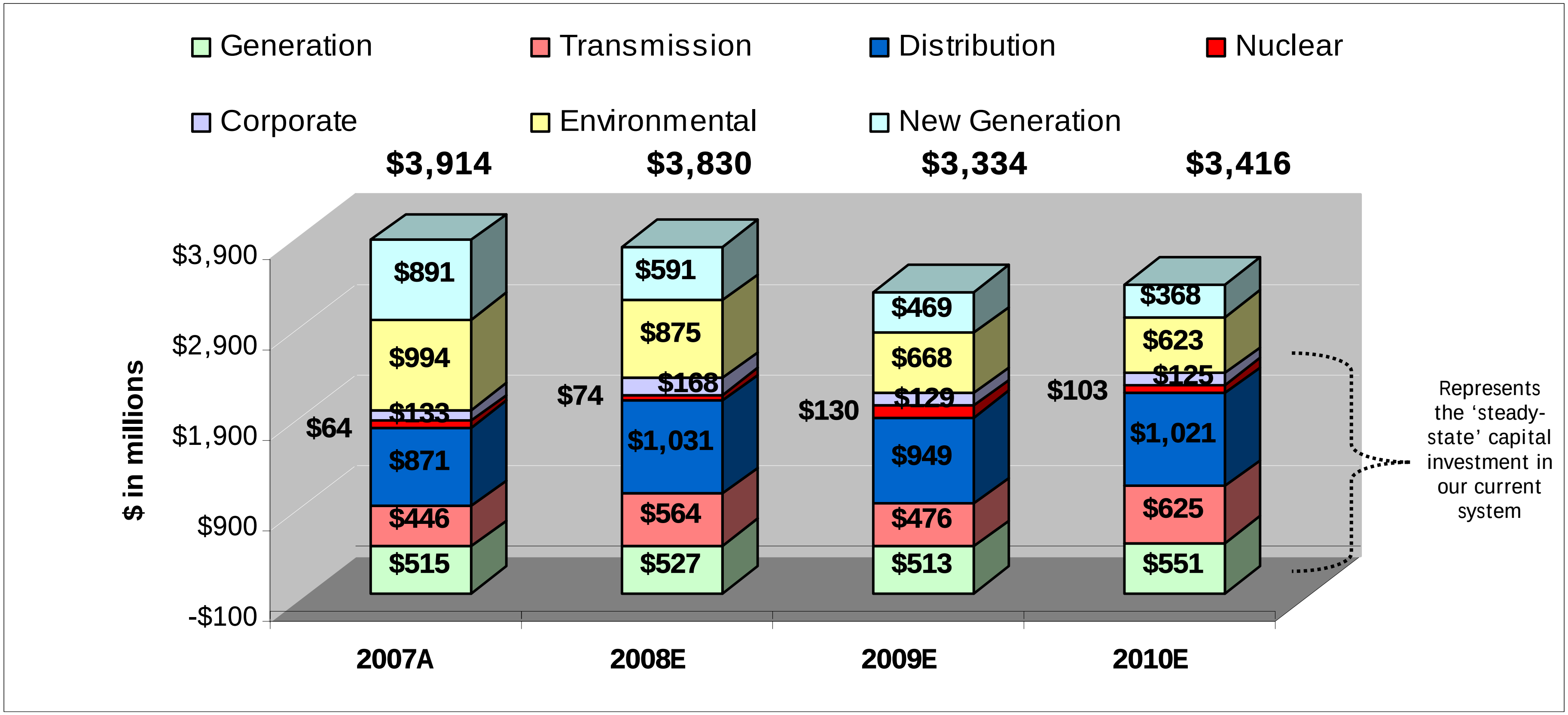
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4-Year Capital Investment Forecast



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7314 of 9556

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$583	$474	**$2,495**
I&M	$282	$386	$458	$497	**$1,623**
KPCo	$76	$127	$89	$106	**$398**
TCC	$212	$208	$186	$282	**$888**
TNC	$93	$120	$87	$91	**$391**
PSO	$303	$277	$257	$419	**$1,256**
SWEPCo	$511	$741	$710	$681	**$2,643**
CSP	$432	$404	$312	$308	**$1,456**
OPCo	$805	$635	$441	$411	**$2,292**
Other Companies	$488	$206	$211	$147	**$1,052**
Total Capex	**$3,914**	**$3,830**	**$3,334**	**$3,416**	**$14,494**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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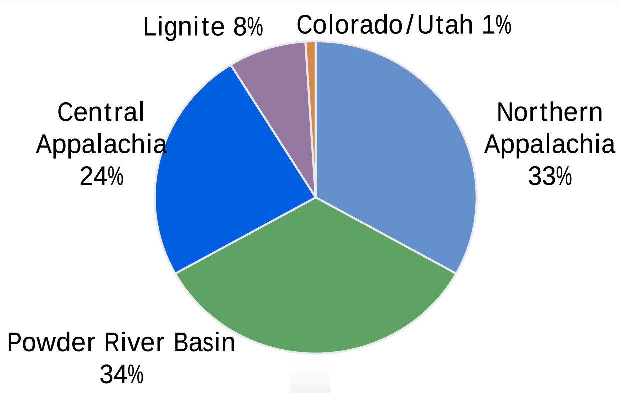
Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

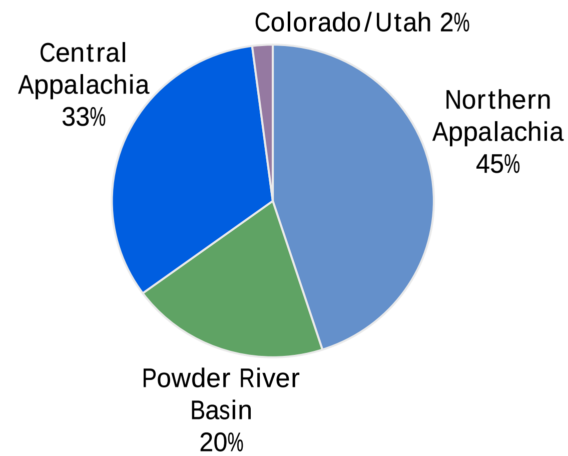
Total AEP System



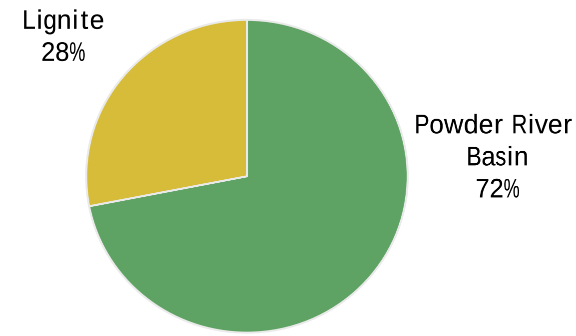
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East

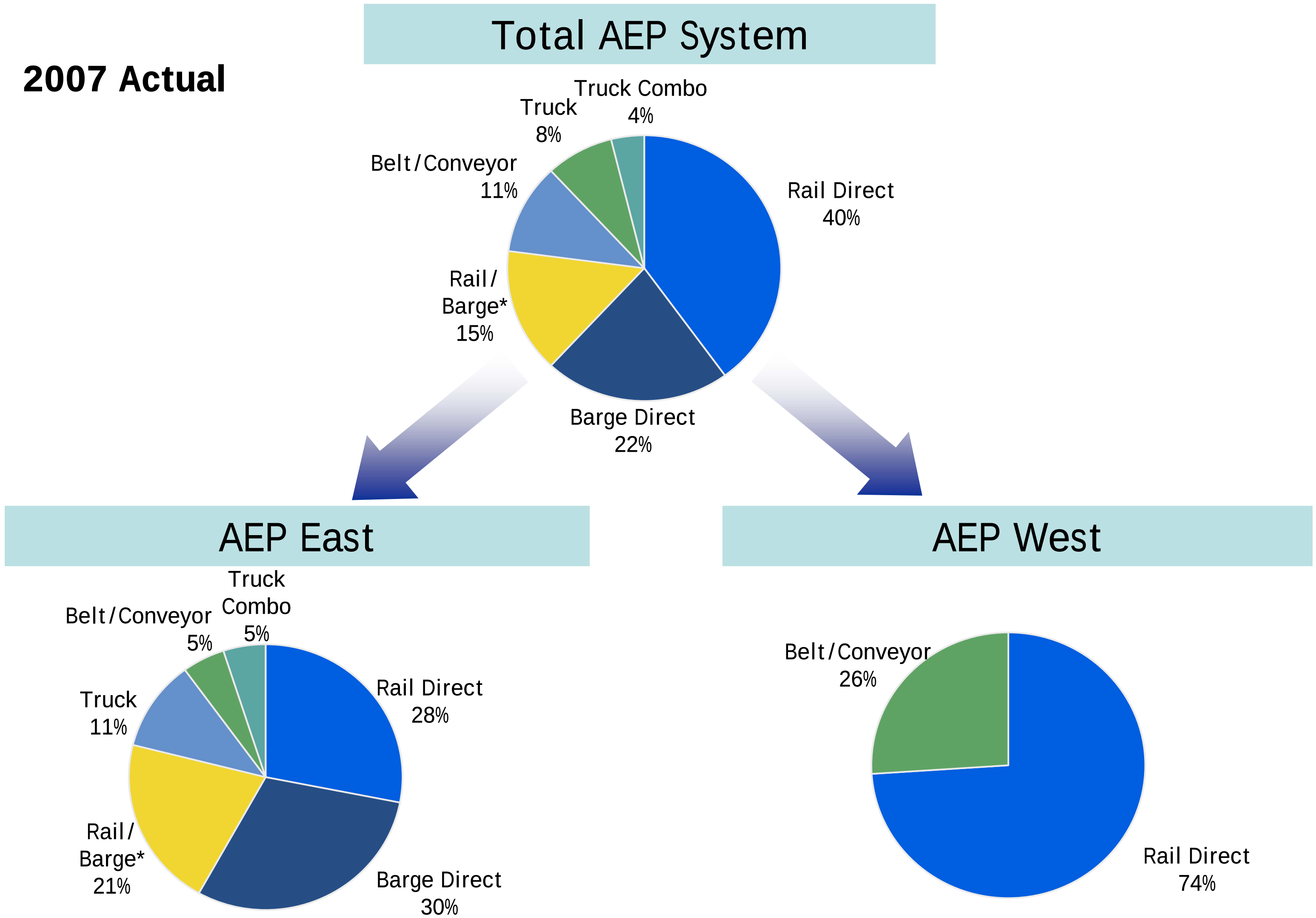


AEP West



Coal Delivery

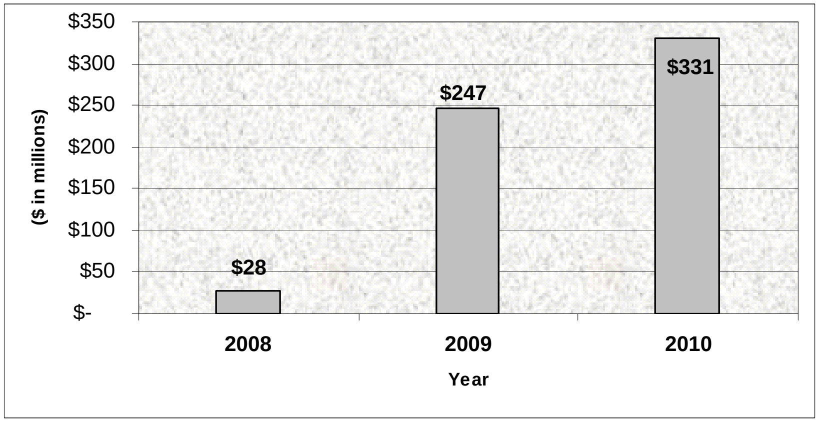
2007 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Transmission – Investments and Earnings Contributions

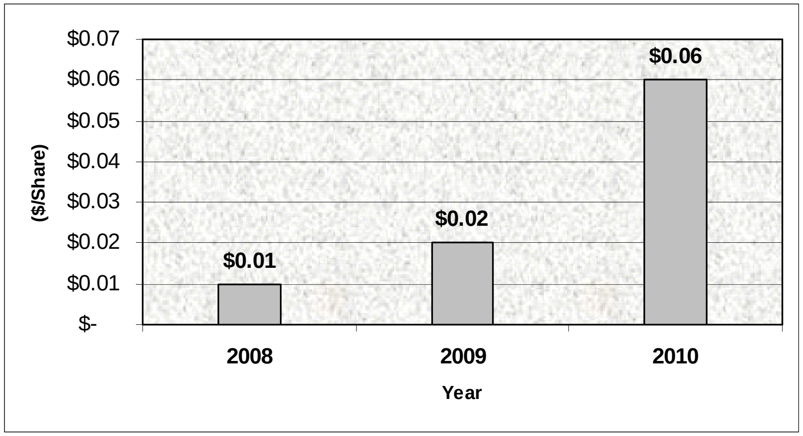
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

PATH Potomac-Appalachian Transmission Highline

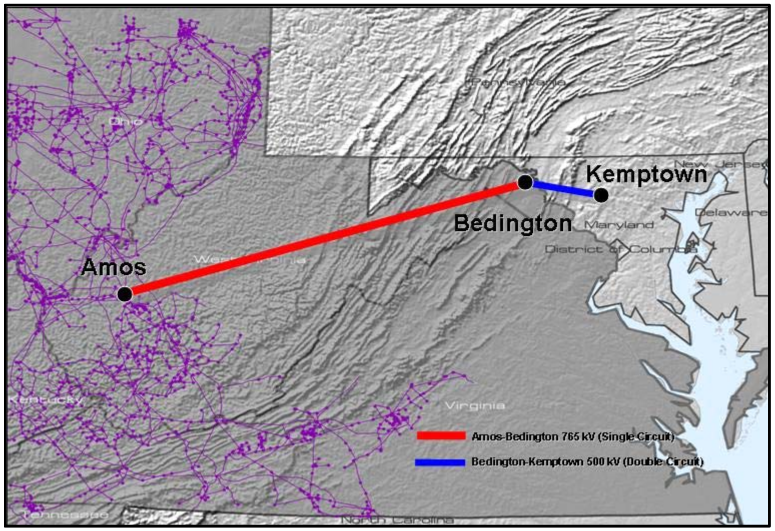
Transmission will provide a near and long-term catalyst for earnings growth.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

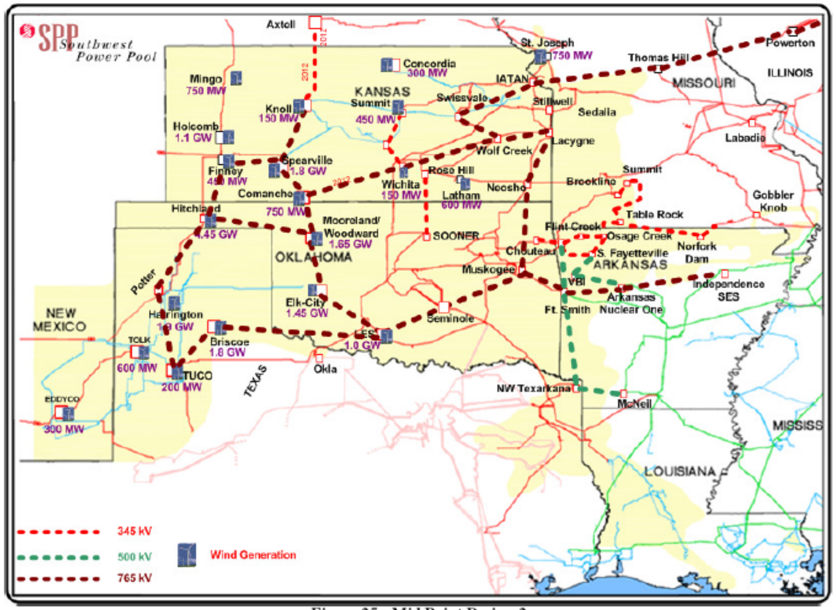


Figure 25: Mid Point Design 2

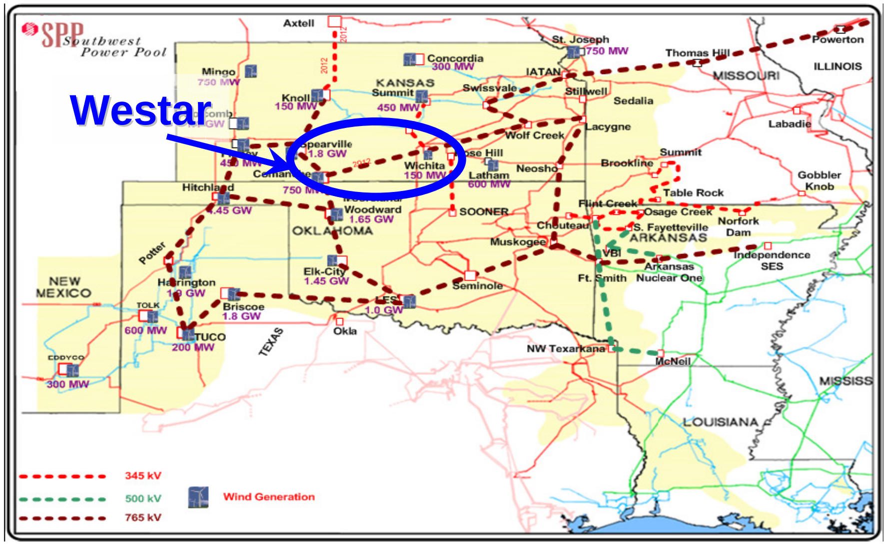
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- *Next Steps*
  - Filed CPCN – 2Q2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – Fall 2008
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



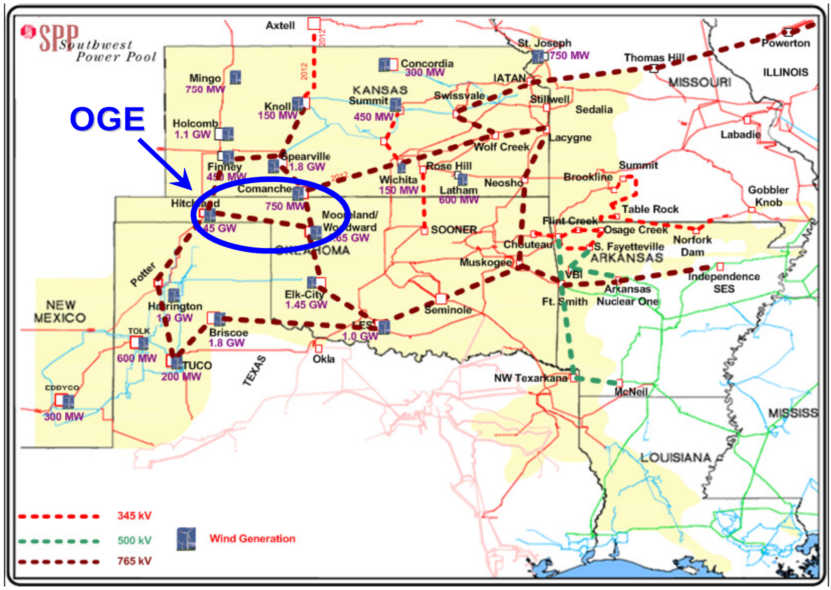
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- ❑ *Overview*
  - ❑ On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - ❑ The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - ❑ The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - ❑ Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - ❑ AEP's ownership of the joint venture is 25%
  - ❑ AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - ❑ Other responsibilities will be handled by the partners or outsourced
- ❑ *Next Steps*
  - ❑ File CPCN –2008
  - ❑ SPP RTO EHV Overlay Approval – 2009
  - ❑ FERC Formula Rate – Fall 2008
  - ❑ SPP Cost Allocation Filing – 2009
  - ❑ Siting Approval – 2009
  - ❑ Estimated Completion – 2013

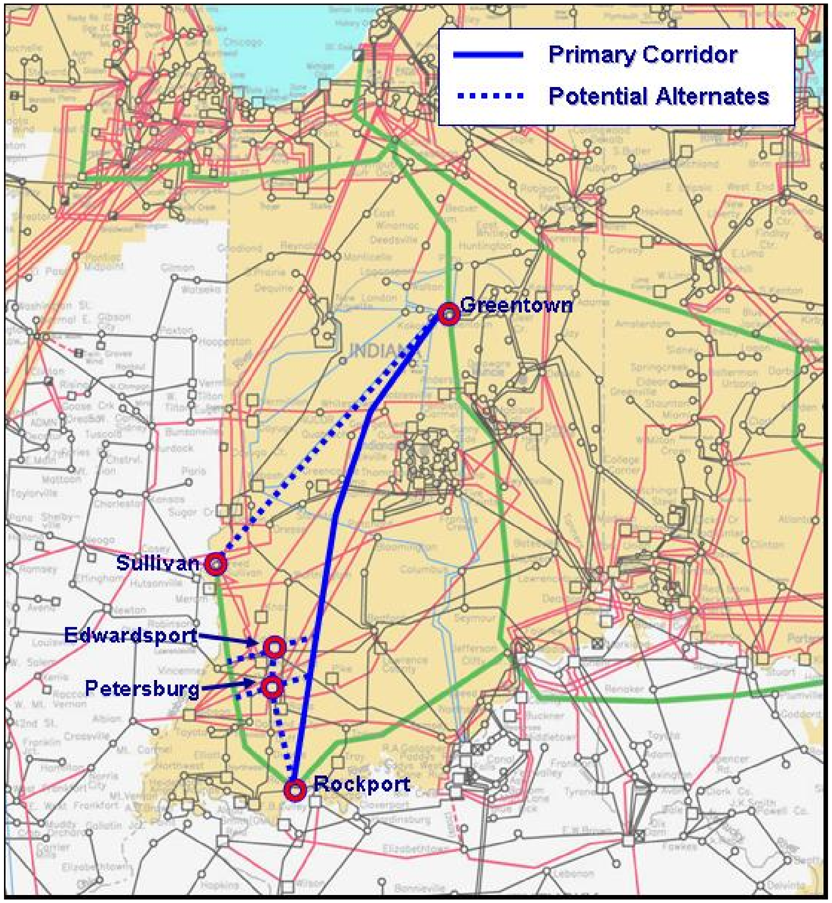


Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on the routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.
- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

Overview

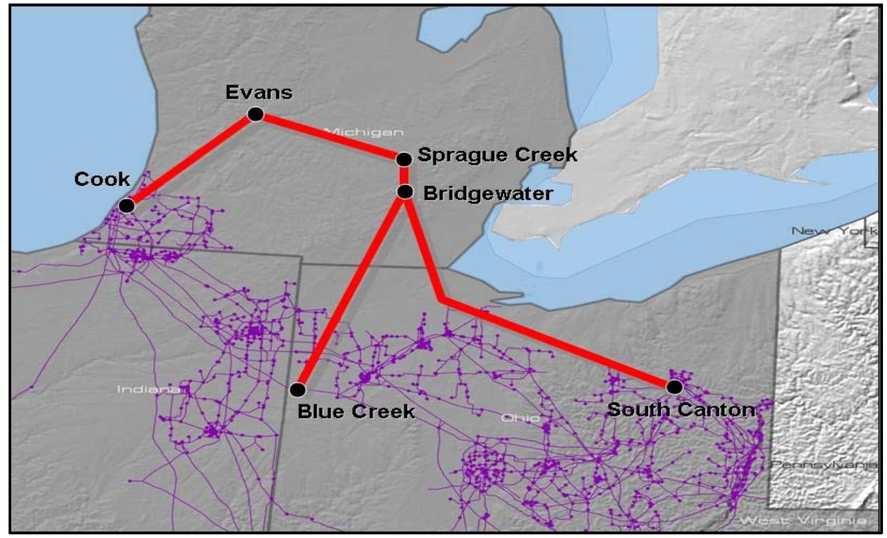
- ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
- Study was released Q3 2007
- 700 miles of 765-kV line in Ohio and Michigan
- $2.6 billion investment (before ownership division)
- AEP and ITC are in discussions to form a Joint Venture

Benefits

- Up to 5,000 MW improved transfer capability
- Reduces network line losses by 250 MW

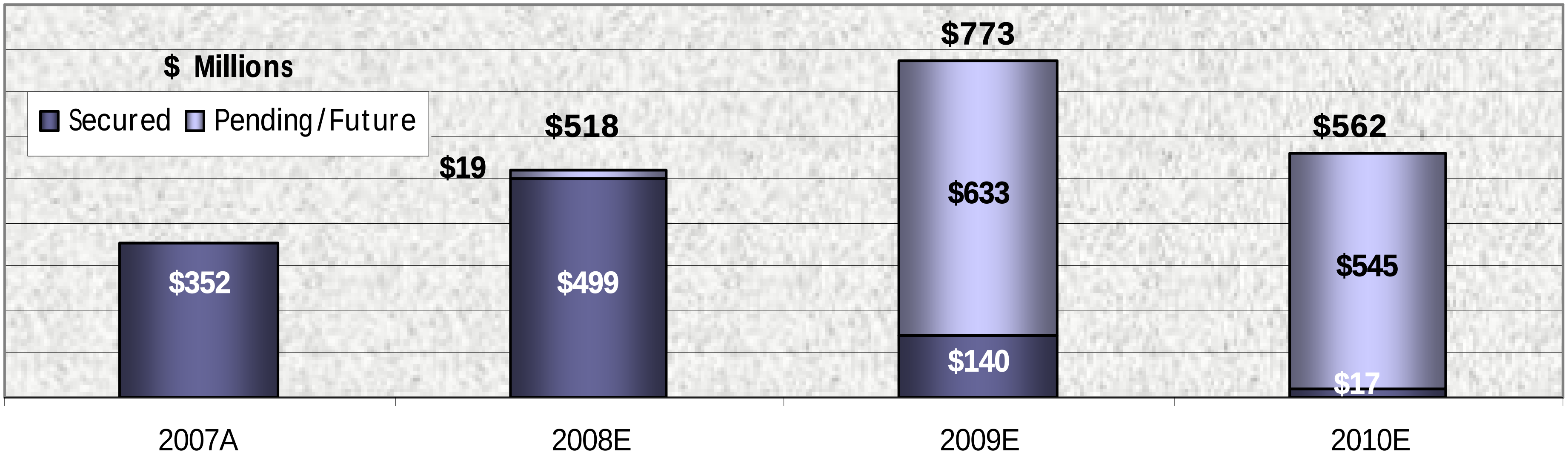
Next Steps

- Agreement on JV (AEP/ITC) - Summer 2008
- JV Formation - 2008
- MISO and PJM Review/Approval - 2009
- FERC Formula Rate & Cost Allocation Filing - 2009
- Siting Approval – 2011-2012
- Estimated Completion – 2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Incremental Rate Relief



- 96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Construction Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.

- 2008 Pending: Virginia base case rates subject to refund ($208MM requested).

- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM requested), Ohio ESP, other cases yet to be filed.

Secured $499MM of $518MM for 2008

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order							Expected Order					

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing Begins						12/1/08						
Expected Order												Expected Order
Louisiana - Stall Plant		Expected Order										
Ohio - ESP Filing												
Company Testimony Filed	07/31/08											
Intervenor Testimony				10/17/08								
Staff Testimony				10/24/08								
Hearing Begins					11/03/08							
Expected Order						Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Staff/Intervenor Testimony				10/29/08								
Rebuttal Testimony					11/19/08							
Settlement Conference						12/01/08						
Hearing Begins						12/08/08						
Rates Effective *							01/08/09					

* Subject to refund, with interest

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- SWEPCo Stall Plant Filings in Louisiana and Arkansas

Highlights of AEP Ohio's ESP Filing

		2009 CSP	2009 OPCo	2010 CSP	2010 OPCo	2011 CSP	2011 OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		**Other Components**		**Other Components**		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested phase-in of proposed incremental FAC expenses during the three-year ESP period. Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 &PJN-10 provides calculation of environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows the capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: Requested an annual 7% & 6.5% per year increase in Distribution for CSP & OPCo, respectively. Exhibit DMR-4 shows expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response & energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009 CSP	2009 OPCo	2011 CSP	2011 OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	-$80.7M	-$27.1M	$22.8M	$15.2M

A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Required Rate Relief - Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2 *
Rate of Return		8.64%
Operating Income Requirement	$	133.5
Pro-Forma Operating Income	$	53.0
Difference	$	80.5
Revenue Conversion Factor		1.647045
Total Required Rate Relief	$	132.6

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1	*
Rate of Return		8.52%	
Operating Income Requirement	$	205.7	
Adjusted Operating Income	$	79.2	
Difference	$	126.5	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	207.9	

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony was received August 13, Staff testimony was received August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $507MM and the new revenue requirement requested is $606MM. Approximately $31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008. A draft air permit approval was released for public comment on August 11, 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued a written order approving construction of the plant on August 12, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable and the ALJ recommended approval. An order is expected in the second half of 2008.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Commitment to Credit Quality

- ❑ Maintain adequate liquidity
- ❑ $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- ❑ Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- ❑ Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- ❑ Target long term dividend payout ratio range of 55-60%
- ❑ Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

EEI International Utility Conference London March 13-15, 2011

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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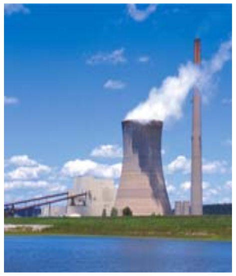
Nick Akins - President

Brian Tierney – EVP and CFO

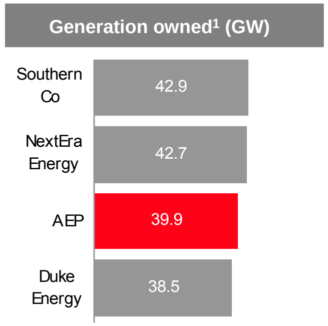
Chuck Zebula – Treasurer & SVP IR

Bette Jo Rozsa – Managing Director, IR

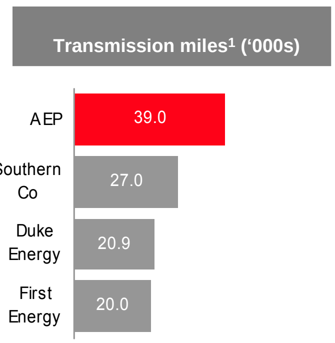
American Electric Power



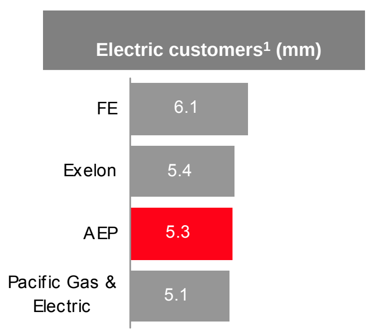
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

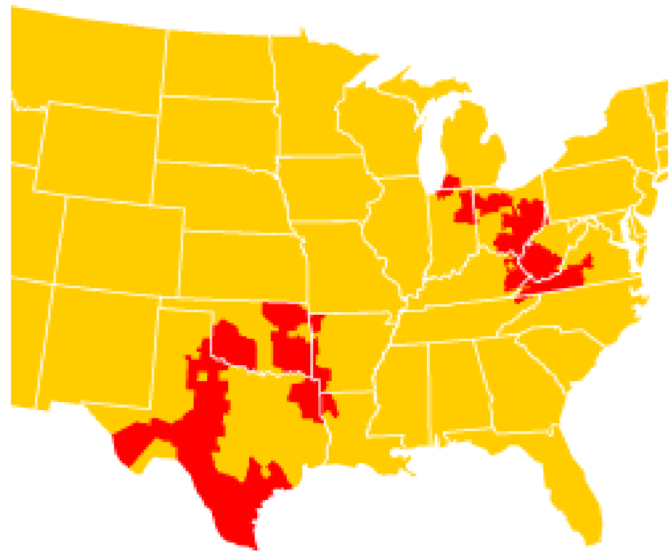


One of the largest U.S. electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

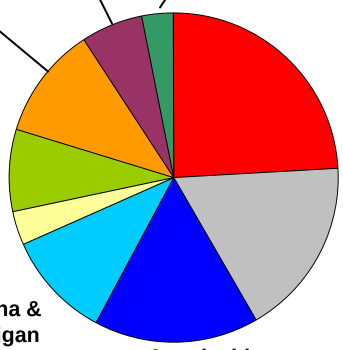
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17B Market Capitalization
BBB/Baa2/BBB credit rating

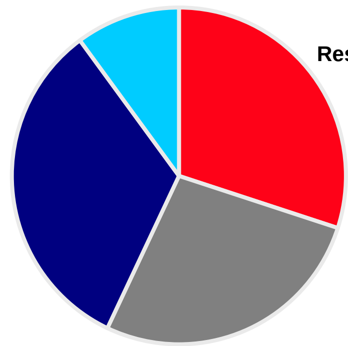
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load

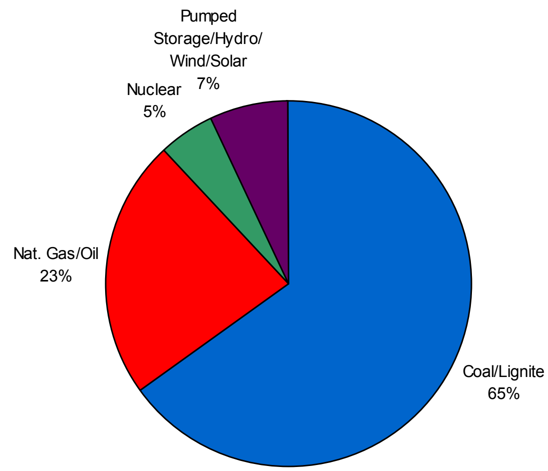


** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

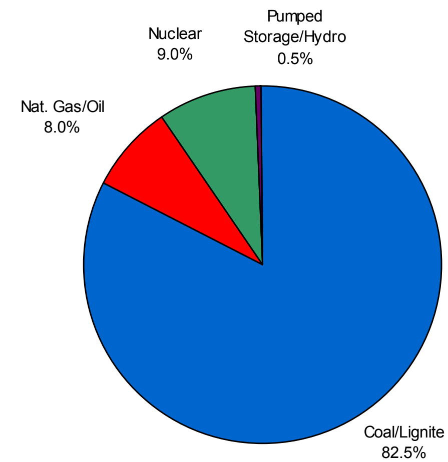
Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Domestic Generation Fleet

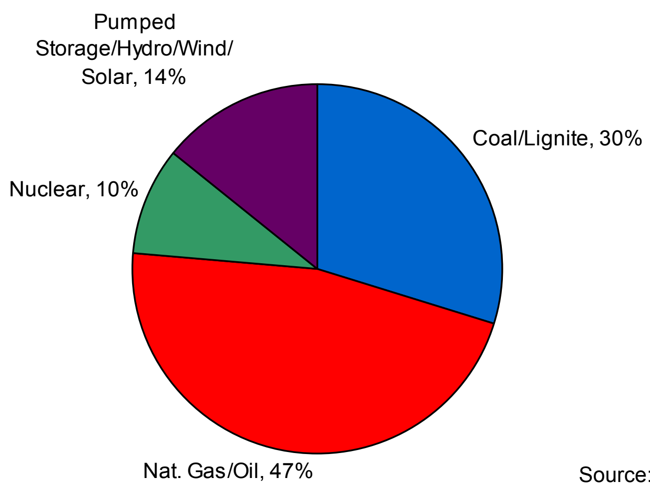
Generation Capacity by Fuel Type
Based on 39,910 MW



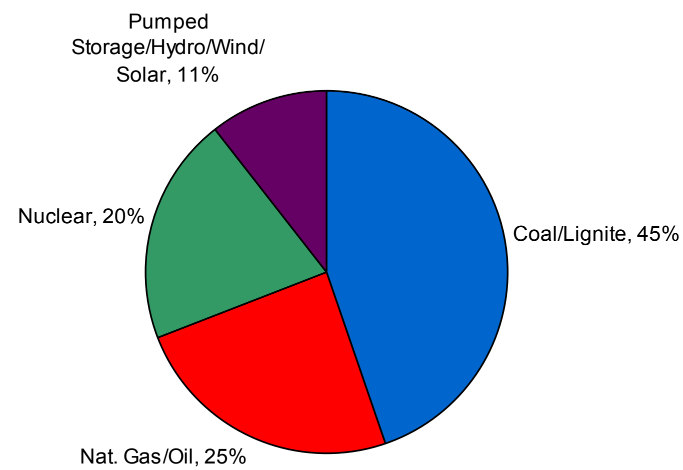
2010 Generation Production by Fuel Type
Based on 173.2 TWh



Generation Capacity by Fuel Type
Based on 1,063,848 MW



2009 Generation Production by Fuel Type
Based on 3,953.1 TWh

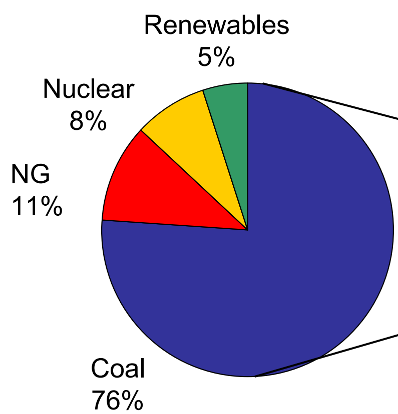


Source: www.eia.doe.gov

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

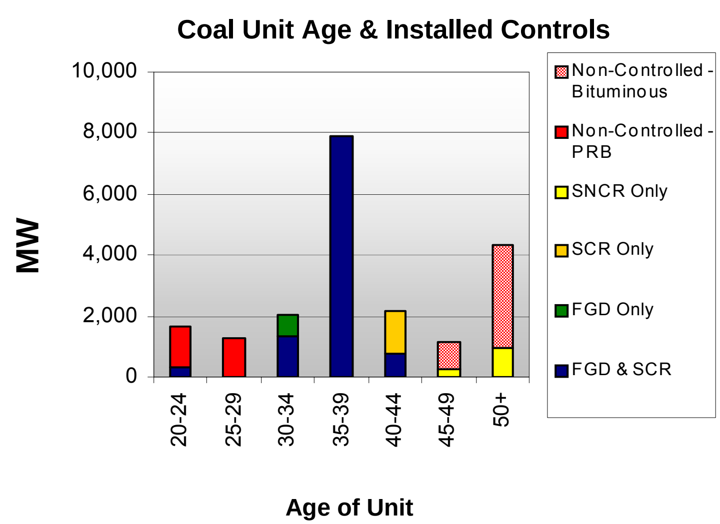


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

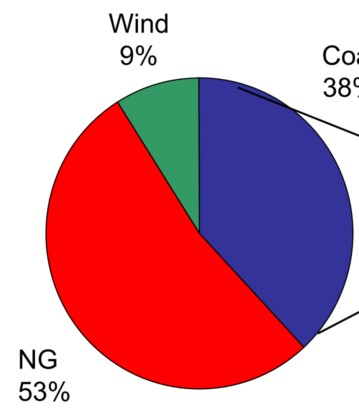
Avg. Delivered Cost

2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

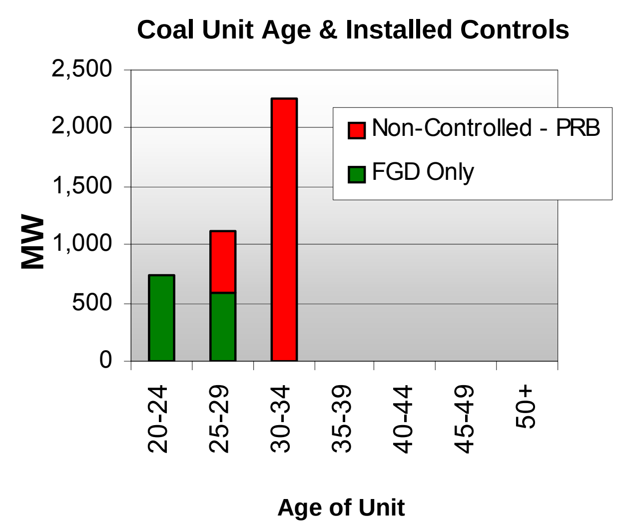


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

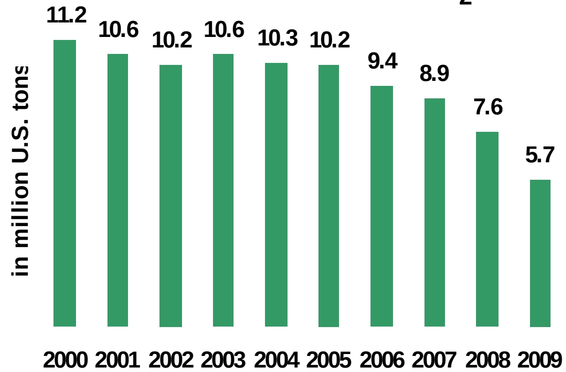


7

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

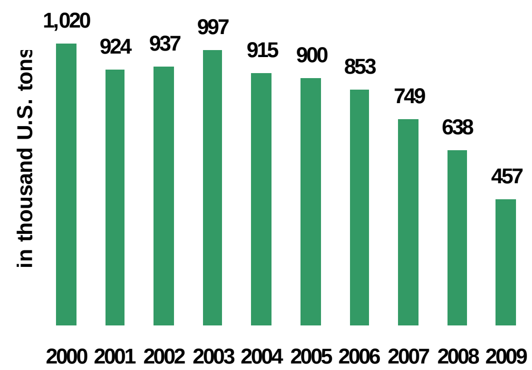
Emissions Reductions since 2000

U.S. Power Plant SO_2 Emissions



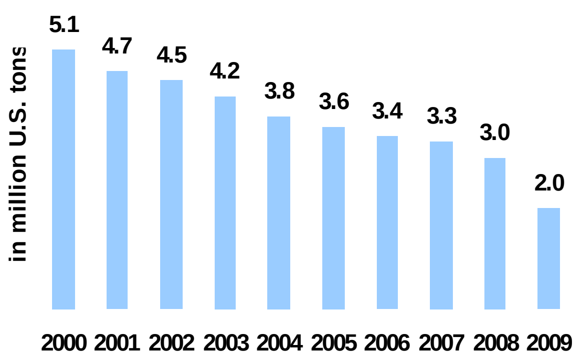
49% reduction since 2000

AEP SO_2 Emissions



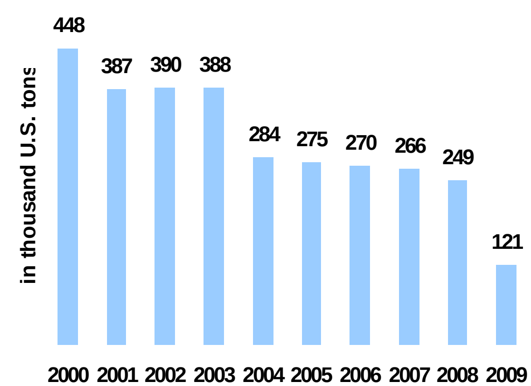
55% reduction since 2000

U.S. Power Plant NOx Emissions



61% reduction since 2000

AEP NOx Emissions

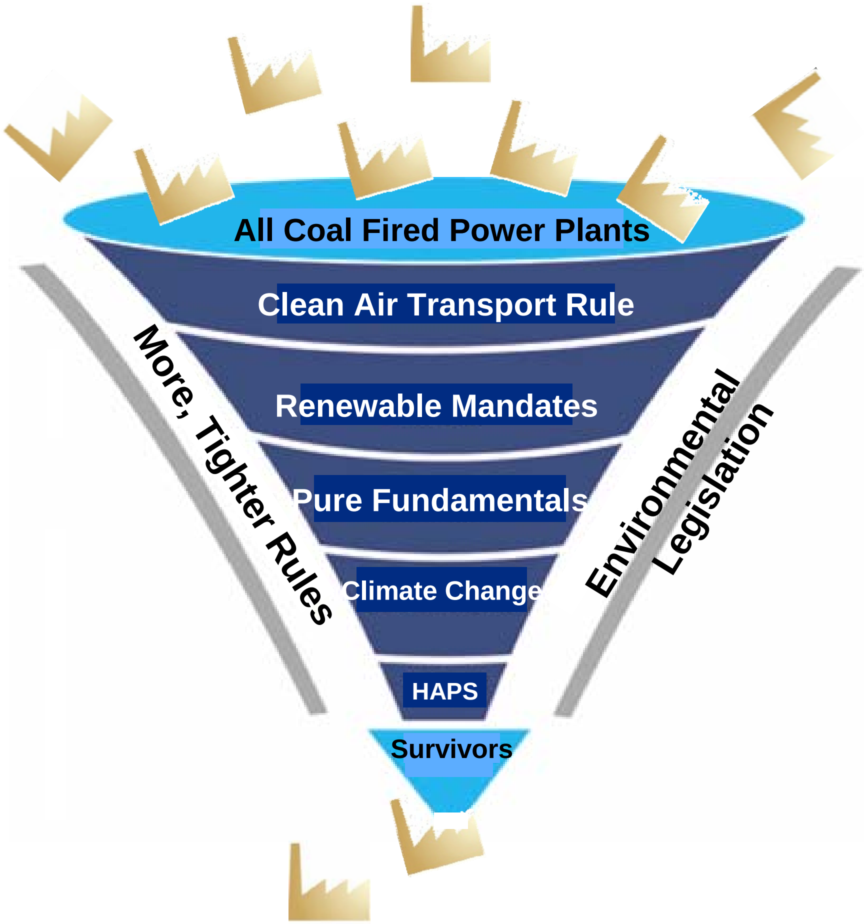


73% reduction since 2000

Source: EPA, 2010; Acid Rain Program

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

The Pressure on Coal Generation



Key EPA Actions Pending

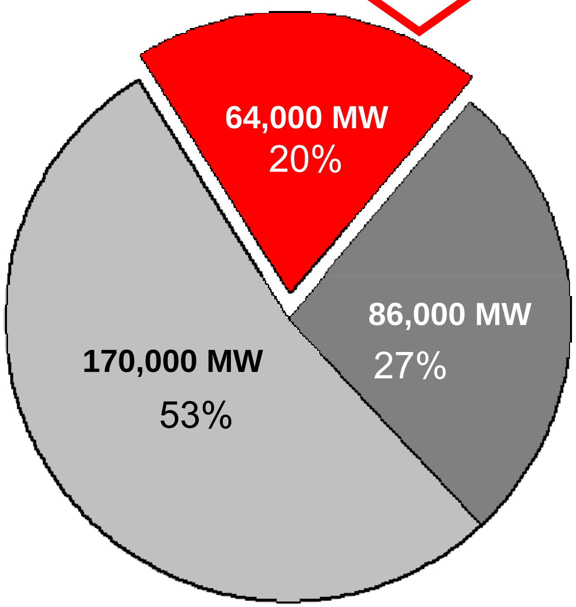
- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in March 2011
- Cooling Water Intakes – Expect Proposed Rule in Spring 2011
- Greenhouse Gas Tailoring Rule – January 2011

Continual Evaluation is Required

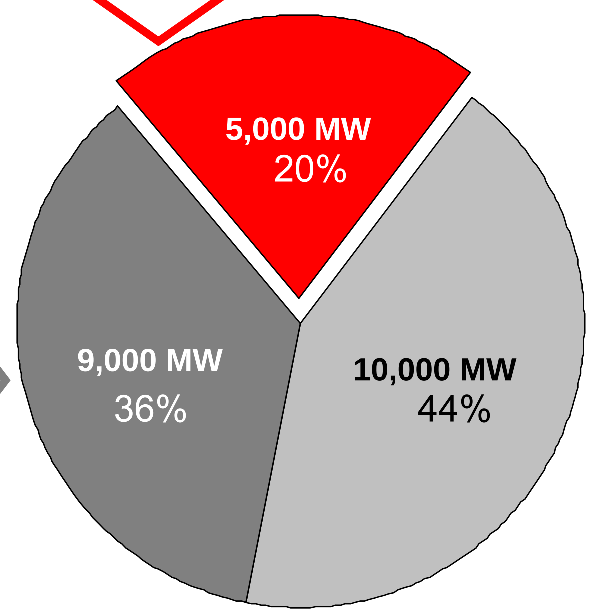
"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements

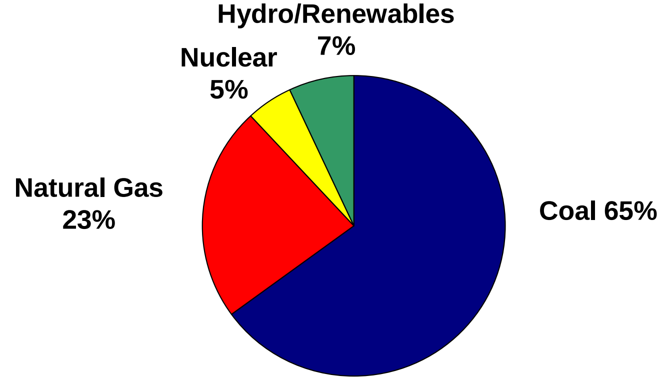


Nearly 50% of U.S. coal plants are exposed

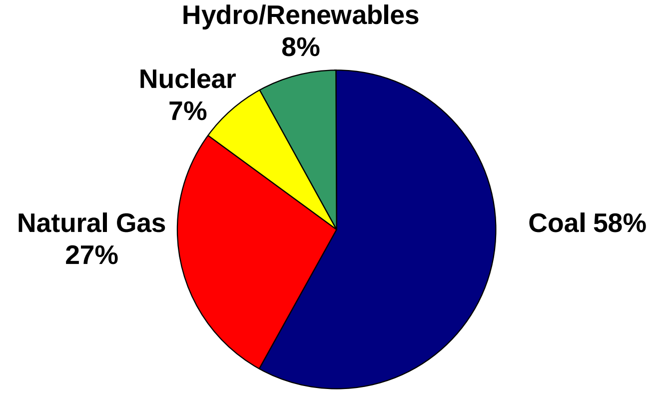
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2010



Projected Capacity - 2017

Carbon Capture and Storage

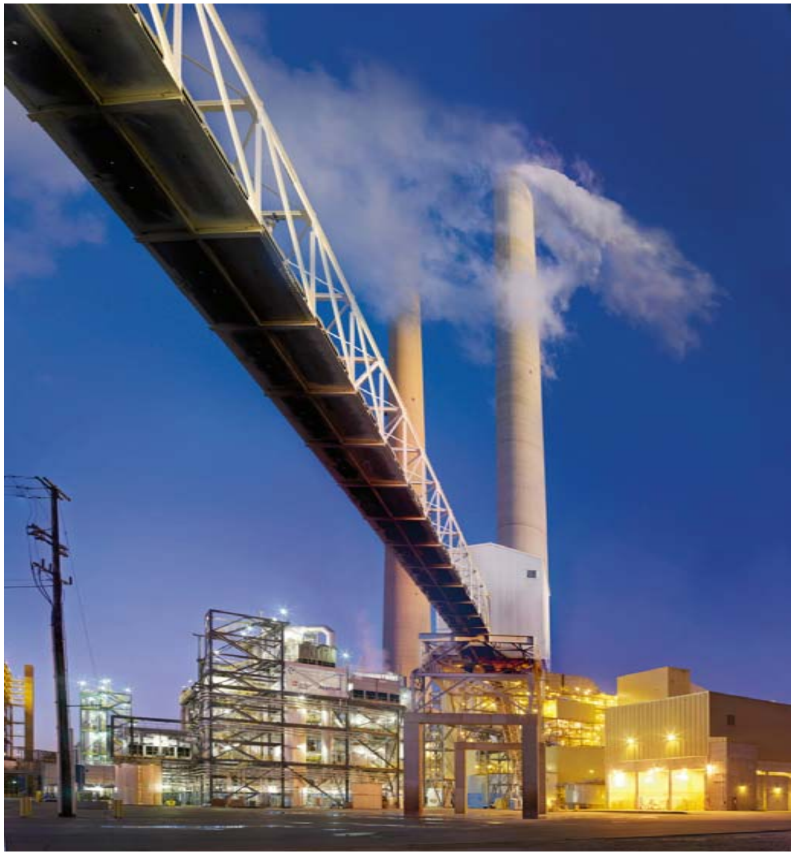
AEP®

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process



Carbon Capture and Storage project
Mountaineer Plant - New Haven, WV

AEP's "Smart Grid" Deployment – Pilot Projects

AEP®

Indiana Michigan Power - South Bend Pilot (Completed – September 2010)

- 10,000 AMI meters
- Integrated Mesh communication network
- Distribution grid management – centralized & decentralized
- Consumer programs: 2-tier time-of-day rates and technology enabled direct load control using PCTs
- Customer web portal
- Initial meter data management system development

AEP Ohio– central Ohio– (2009-2013)

- Awarded US DOE Smart Demonstration Project
- 133,000 meters using integrated mesh network
- Advanced distribution grid management with volt-VAR control
- Advanced consumer programs including critical peak and real-time pricing
- Extensive consumer outreach and communication
- Innovative web portal
- Large scale distributed storage
- Concentrated PHEV implementation
- Smart appliance deployment
- Industry first smart grid cyber security center

AEP Texas – Statewide (2009-2012)

- Legislature enabled and commission directed T&D service providers to deploy advanced metering
- 970,000 meters using mesh network communications
- Enable Texas retail service providers to provide innovative pricing and in-home consumer technologies
- 10,000 in-home displays for low income customers
- Statewide portal for usage and home device provisioning

PSO– Owasso Pilot (Implement in 2011)

- 13,000 AMI meters
- AMI and distribution control communication networks
- Distribution automation
- Distribution Volt-VAR control
- High level of in-home devices – displays and PCTs
- Customer programs – time-of-day and direct load control programs
- Web portal

gridSMART® attributes from the utility side of the meter look promising; customers with low rates may not see material savings/benefits

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market.
  - Total project cost: $3 billion with a 9.96% ROE
- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism.
  - Will spend $160 million in 2011 and more than $350 million in 2012; Expected ROE will be in the 11.2%-11.49% range
- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

765-kV Tower

Texas Transmission Growth Strategy :Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

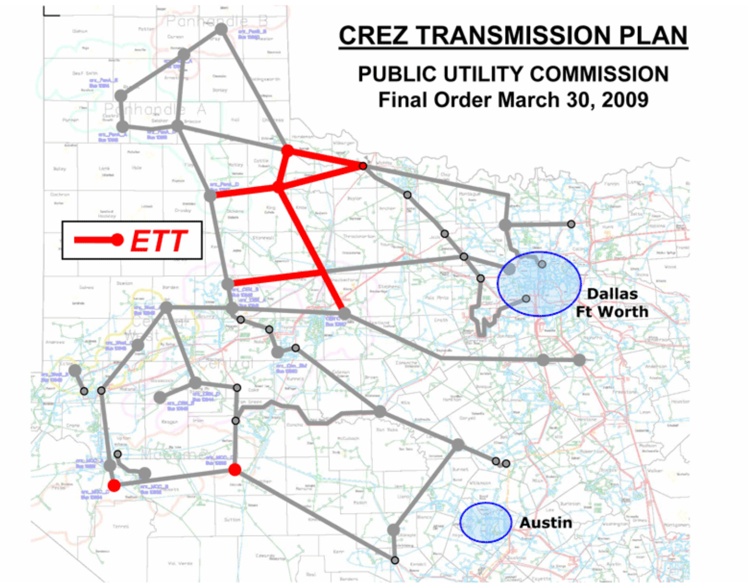
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

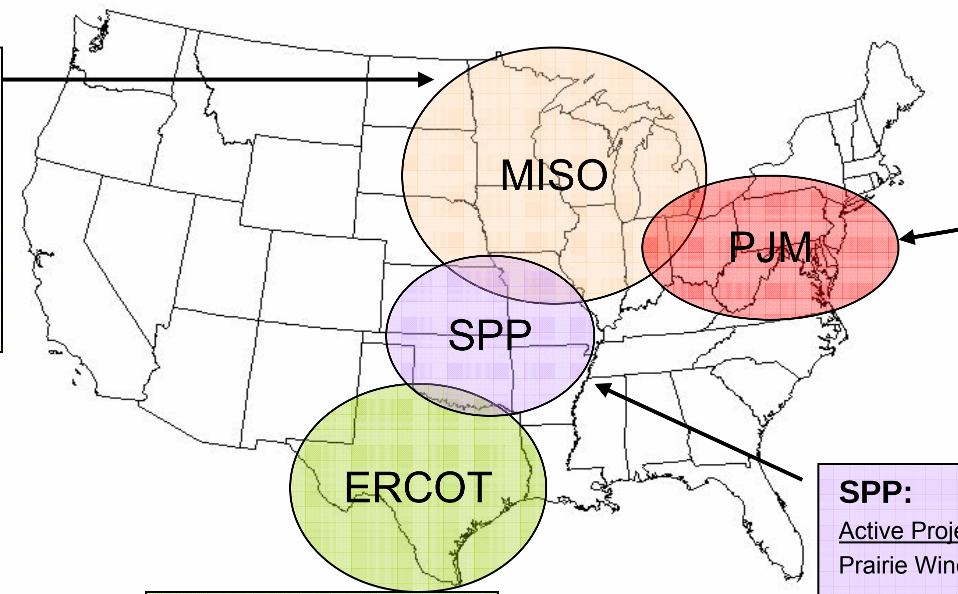
- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
PATH
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Capital Allocation

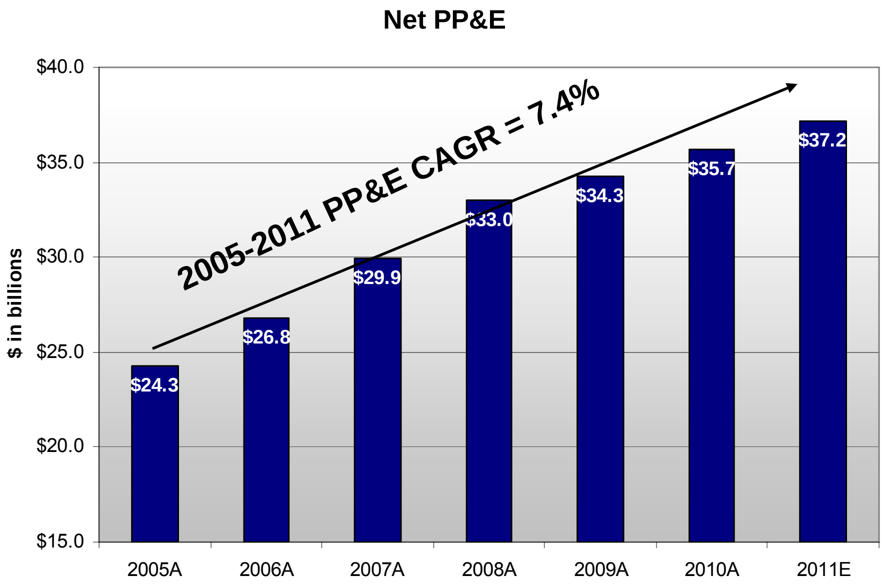
AEP®

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Capital for Growth
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012
- Return of Capital to Shareholders
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings
- Capital to Reduce Risk
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Traditional Ratemaking Environment

Growth in Net PP&E

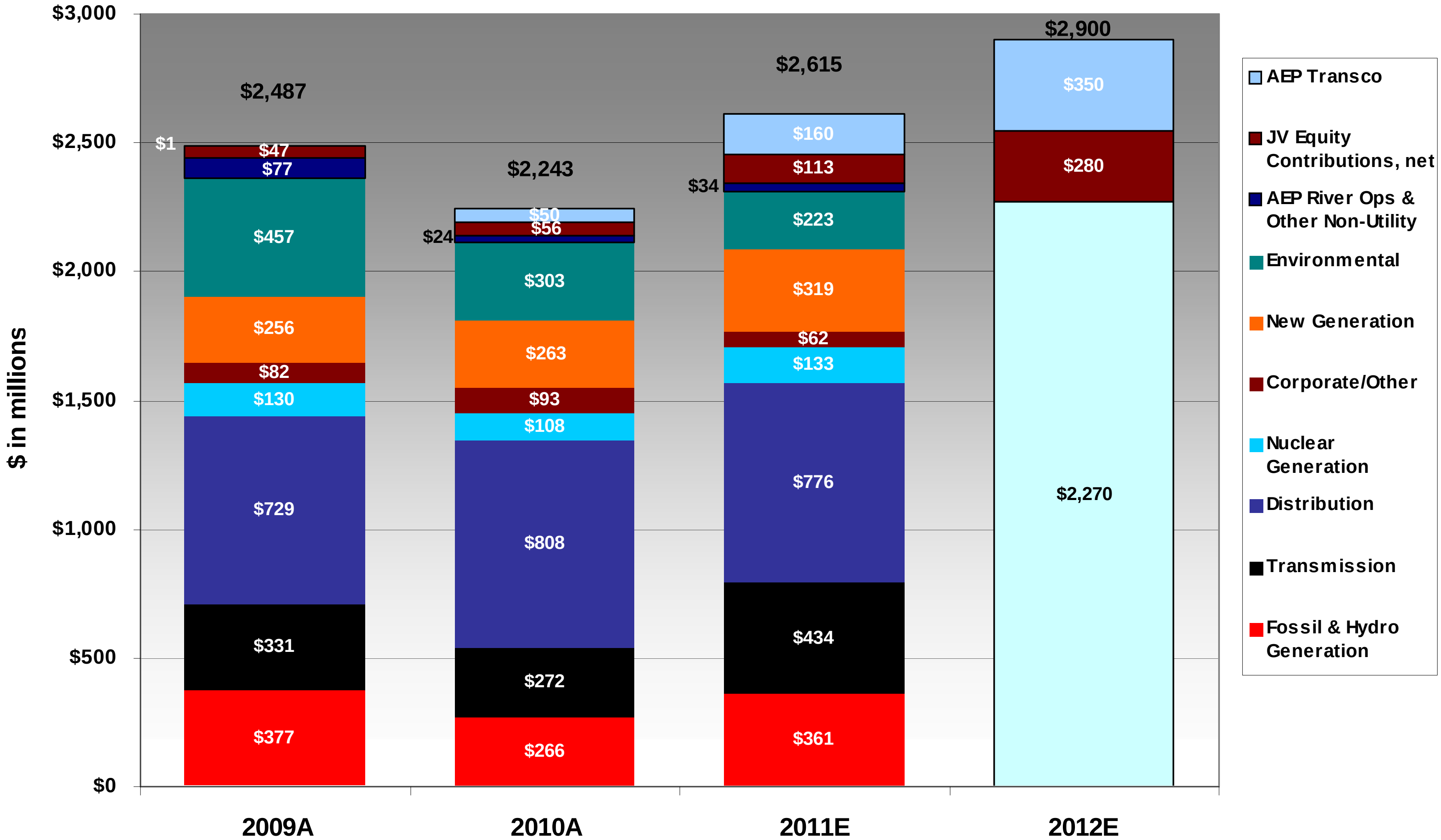


Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

Regulatory Framework

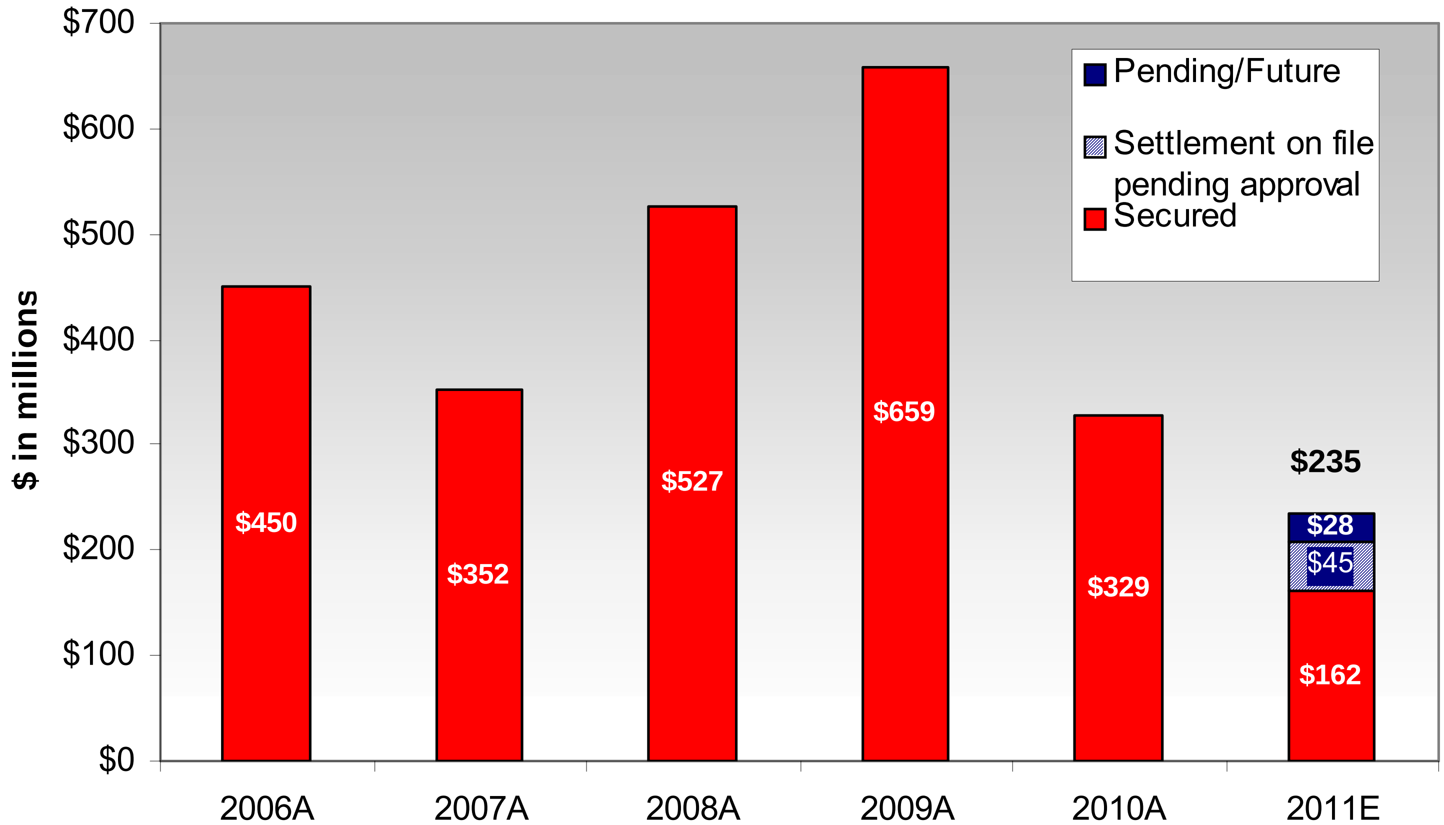
- Base Rates
  - — Recovery of capital and financing costs
  - — Recovery of set level of O&M costs
- Recovery of Fuel Costs
  - — Active fuel clauses in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - — Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

Detailed Ongoing Earnings Guidance

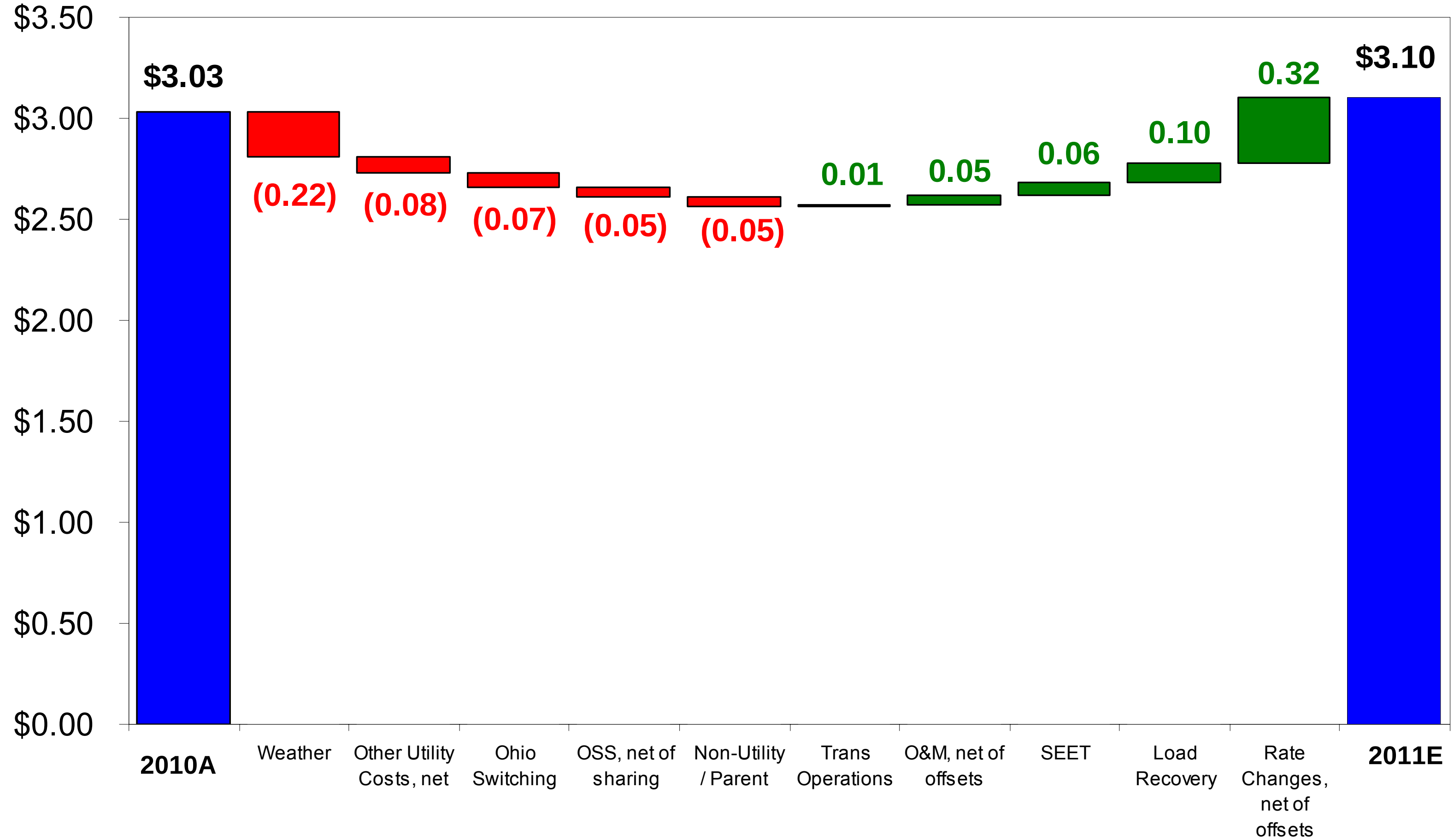
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

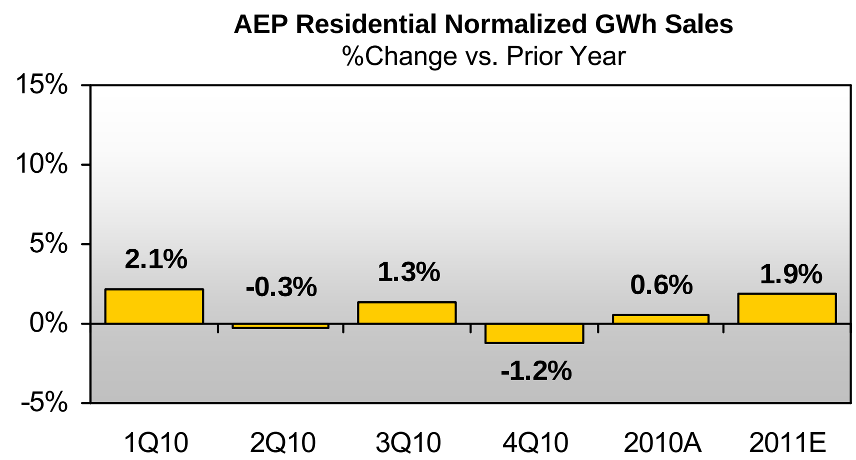
2011 Earnings Drivers

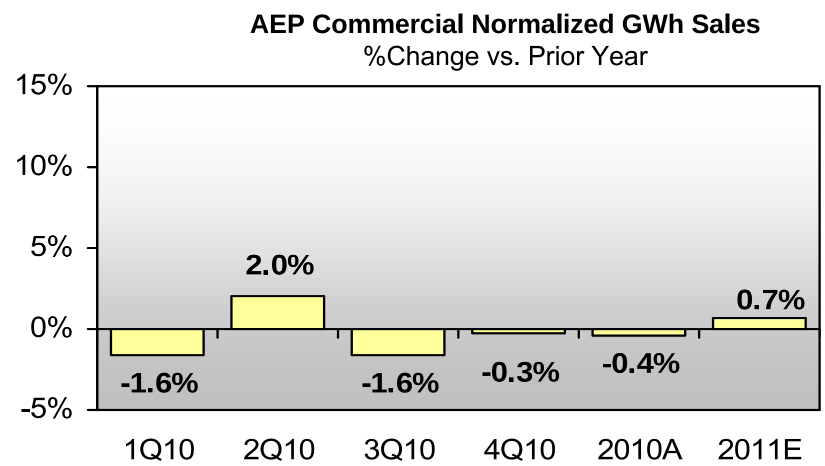


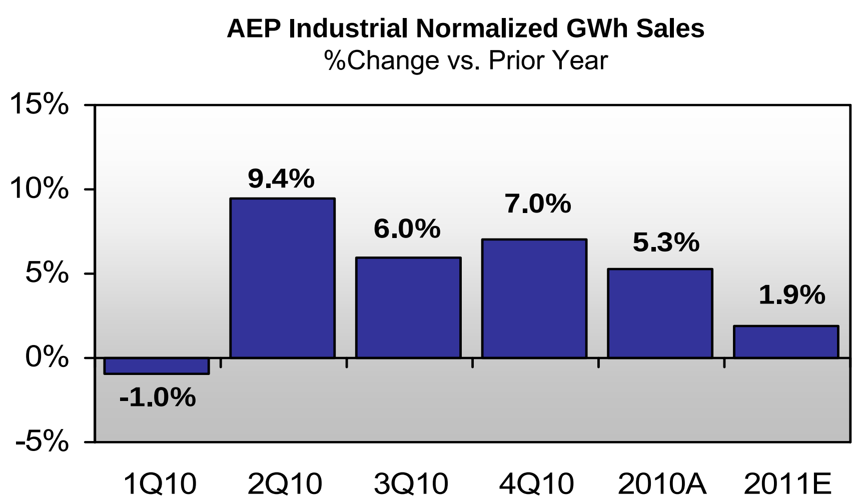
- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

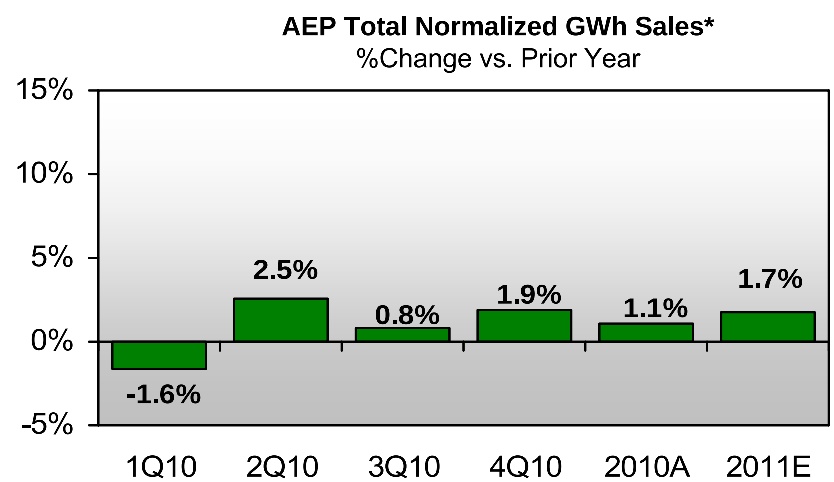
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends









*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

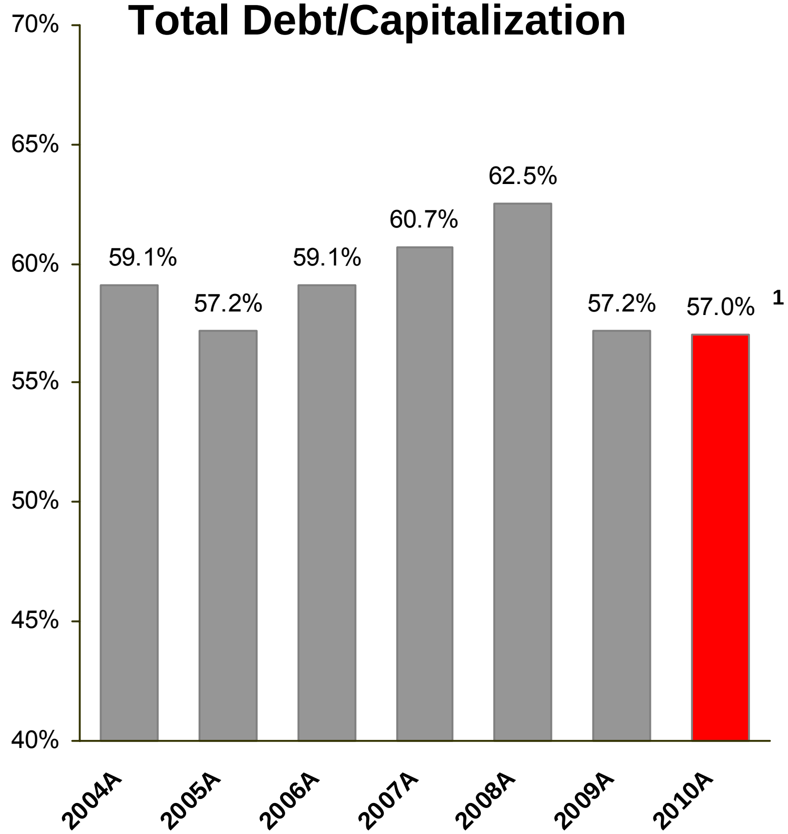
	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity

Total Debt/Capitalization



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: *Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.*

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

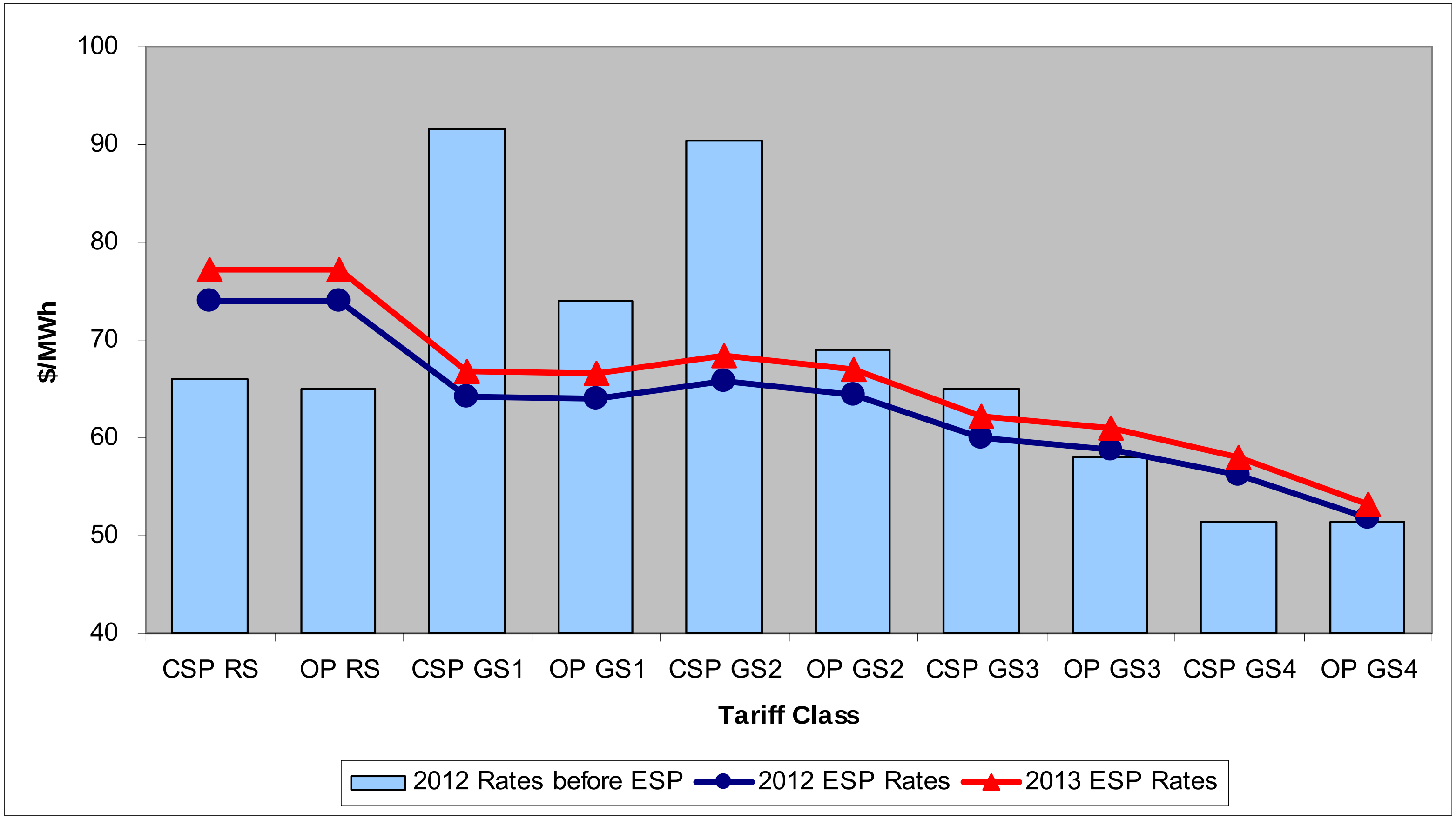
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

AEP®

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

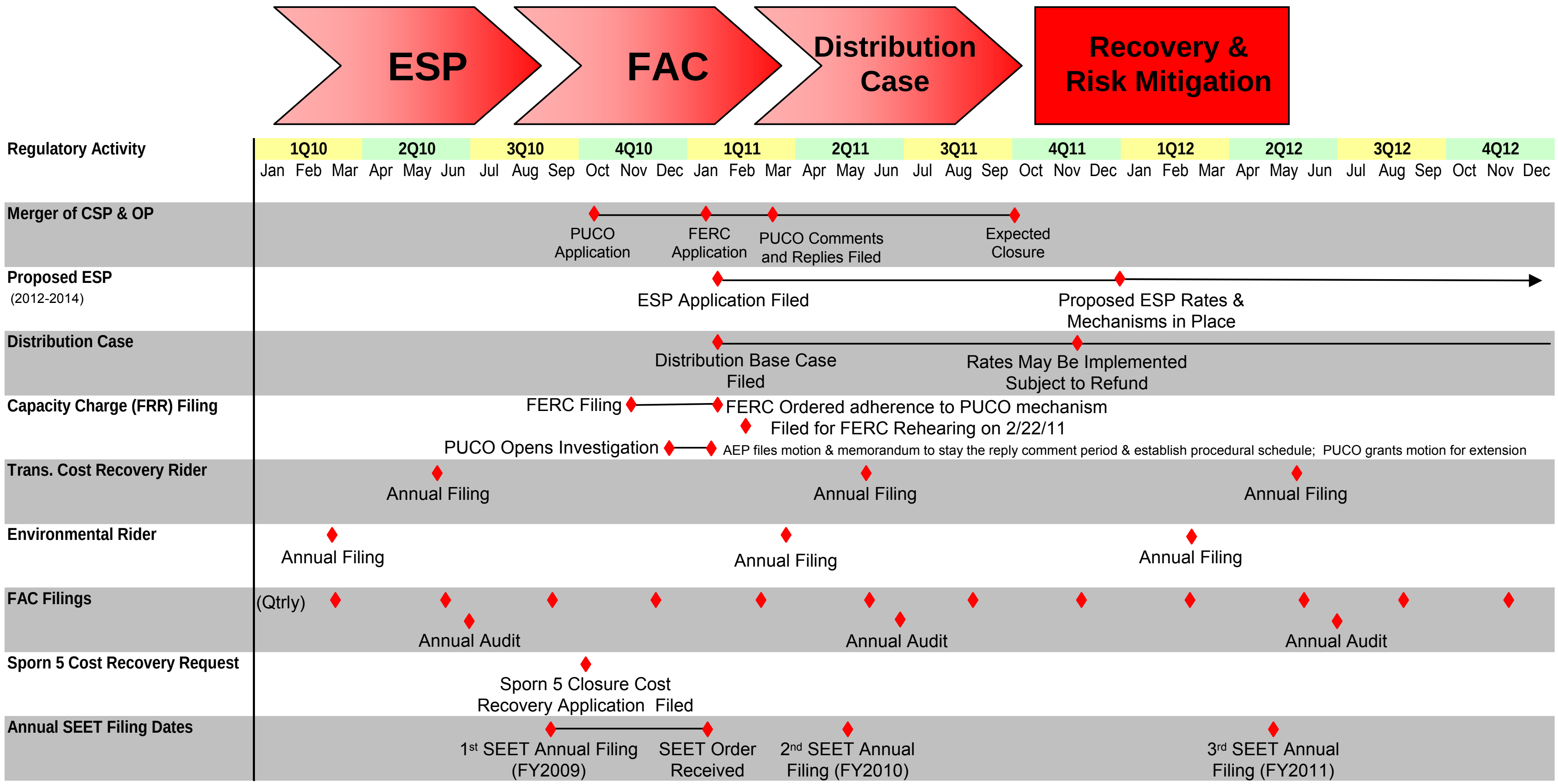
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Earnings and Dividends

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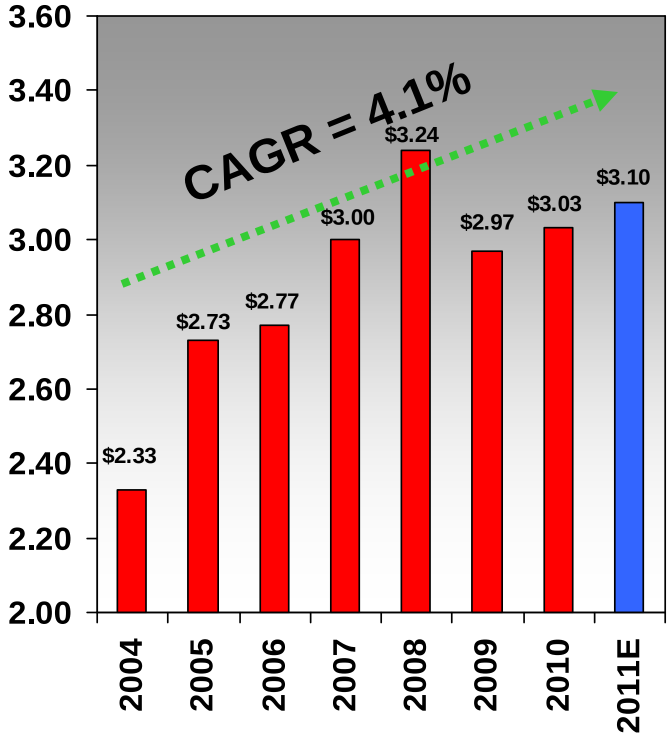
On-Going EPS History Since 2004

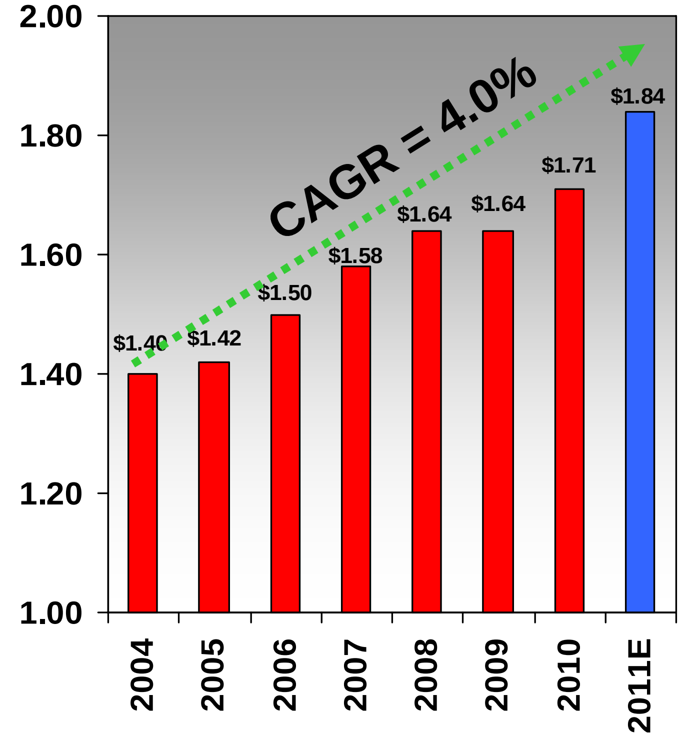
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

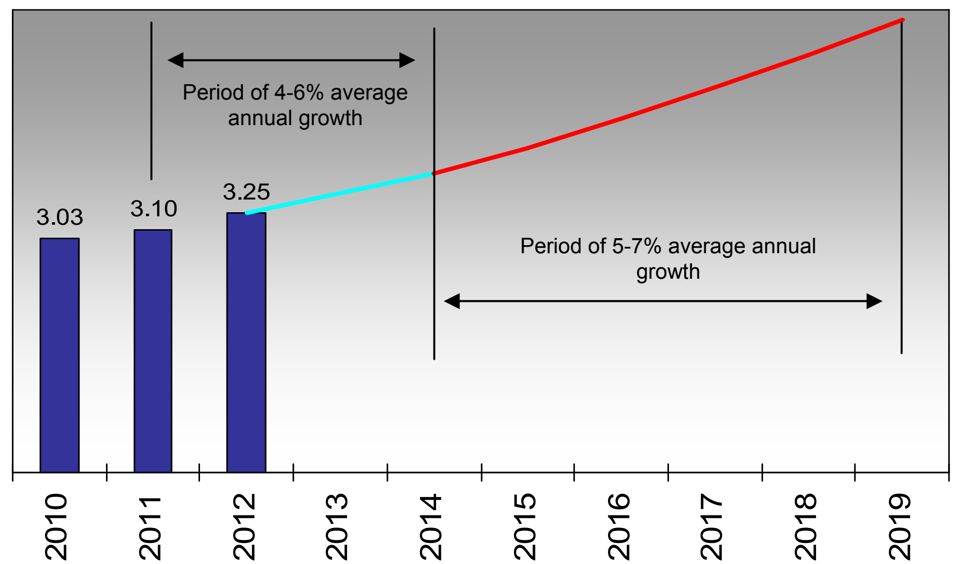
- Dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy

- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Highlights

- **Regulated Electric Utility**
  - Regulatory and economic diversity
  - Operating Company Model
- **Focus on Capital Allocation**
  - Capital for Growth
  - Return of Capital to Shareholders
- **Strong Balance Sheet**
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- **Growth Opportunities**
  - Capital for utility platform
  - Transmission projects
- **Dividend yield over 5%**

Mountaineer Plant (WV)

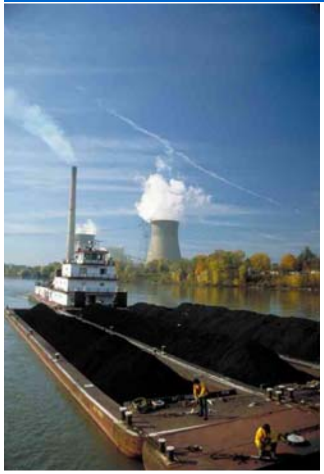
Buckeye Bus Tour 2007

Arranged by Merrill Lynch

AEP Headquarters

Columbus, OH

May 16, 2007



AEP AMERICAN ELECTRIC POWER®

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Participants

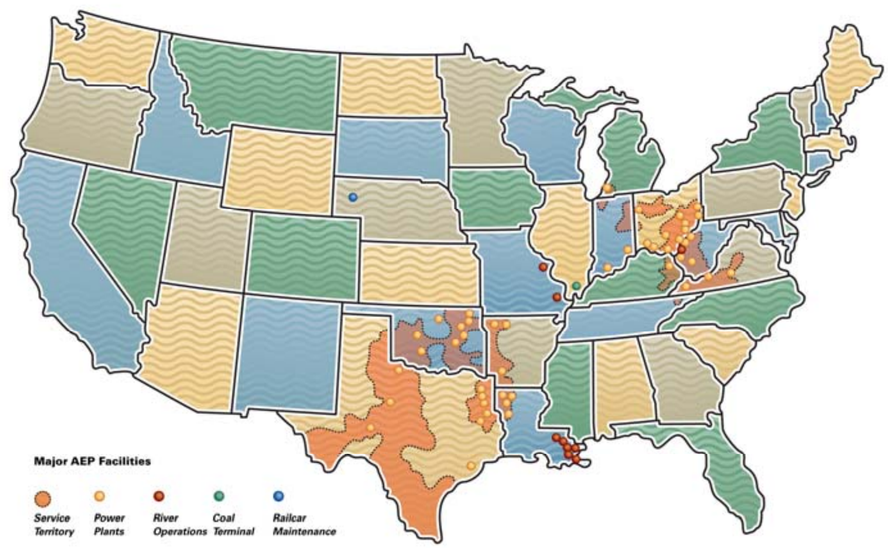
<u>8:00—9:30 AM</u>	
Mike Morris	***Chairman, President & CEO***
Holly Koeppel	***EVP & CFO***
Craig Baker	***SVP Regulatory Services***
Brian Tierney	***SVP Commercial Operations***
<u>9:30—11:00AM</u>	
Bruce Braine	***VP Strategic Policy Analysis (Topic will be carbon)***
Mike Heyeck	***SVP Transmission***
Mike Rencheck	***SVP Engineering, Project & Field Services***
Bill Sigmon	***SVP Fossil & Hydro Generation***
Chuck Zebula	***SVP Fuel, Emissions & Logistics***

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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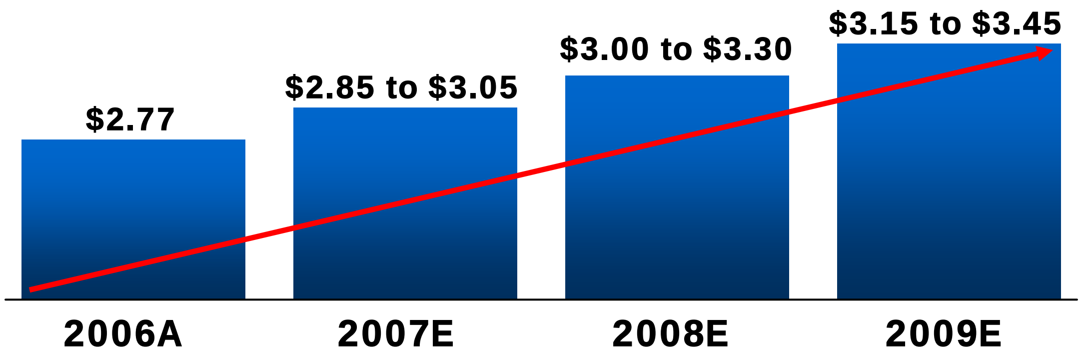
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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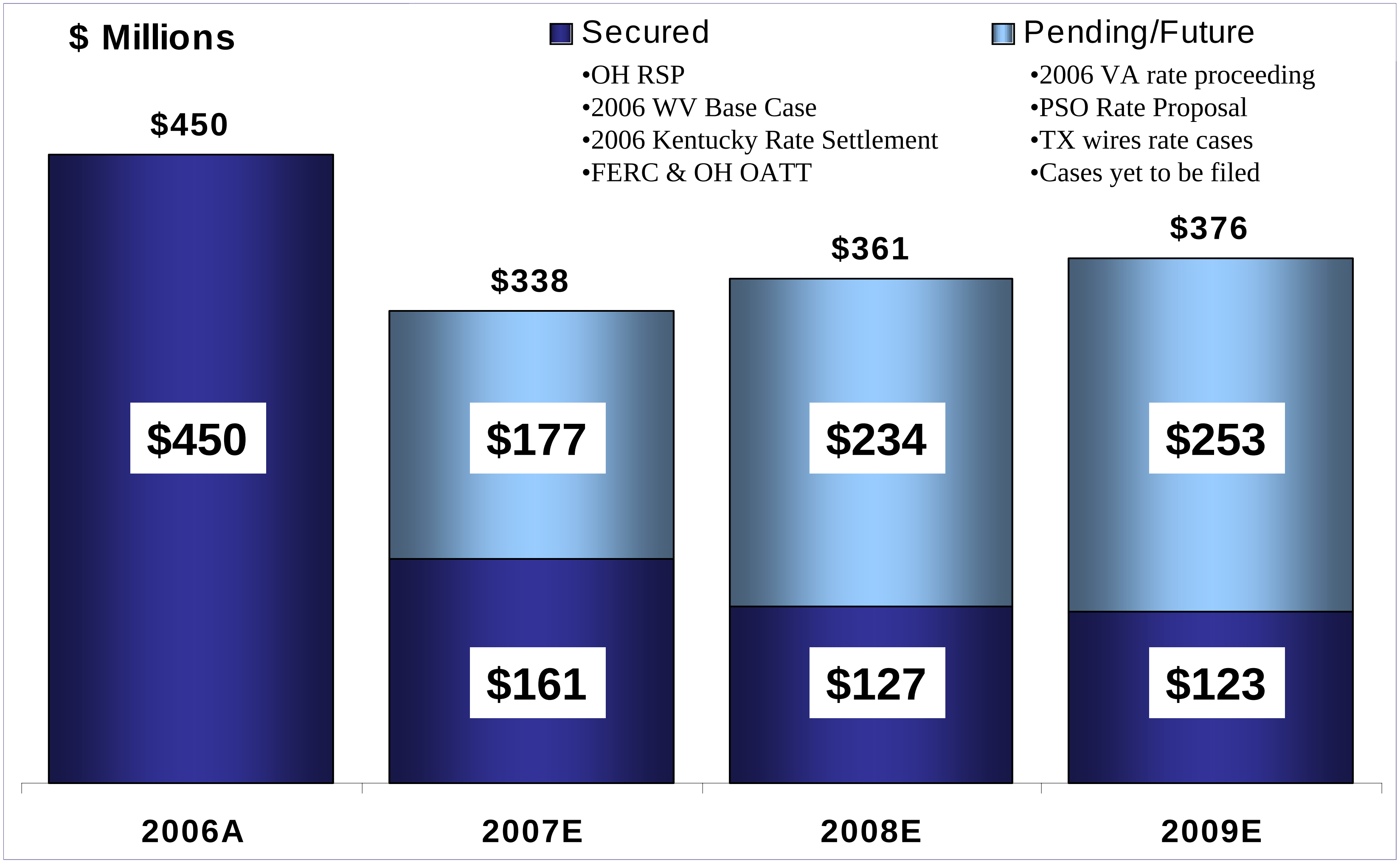
Our Strategy Remains Focused On Regulated Operations

Incremental Rate Relief Composition



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RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2012
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale closed on April 25, 2007 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

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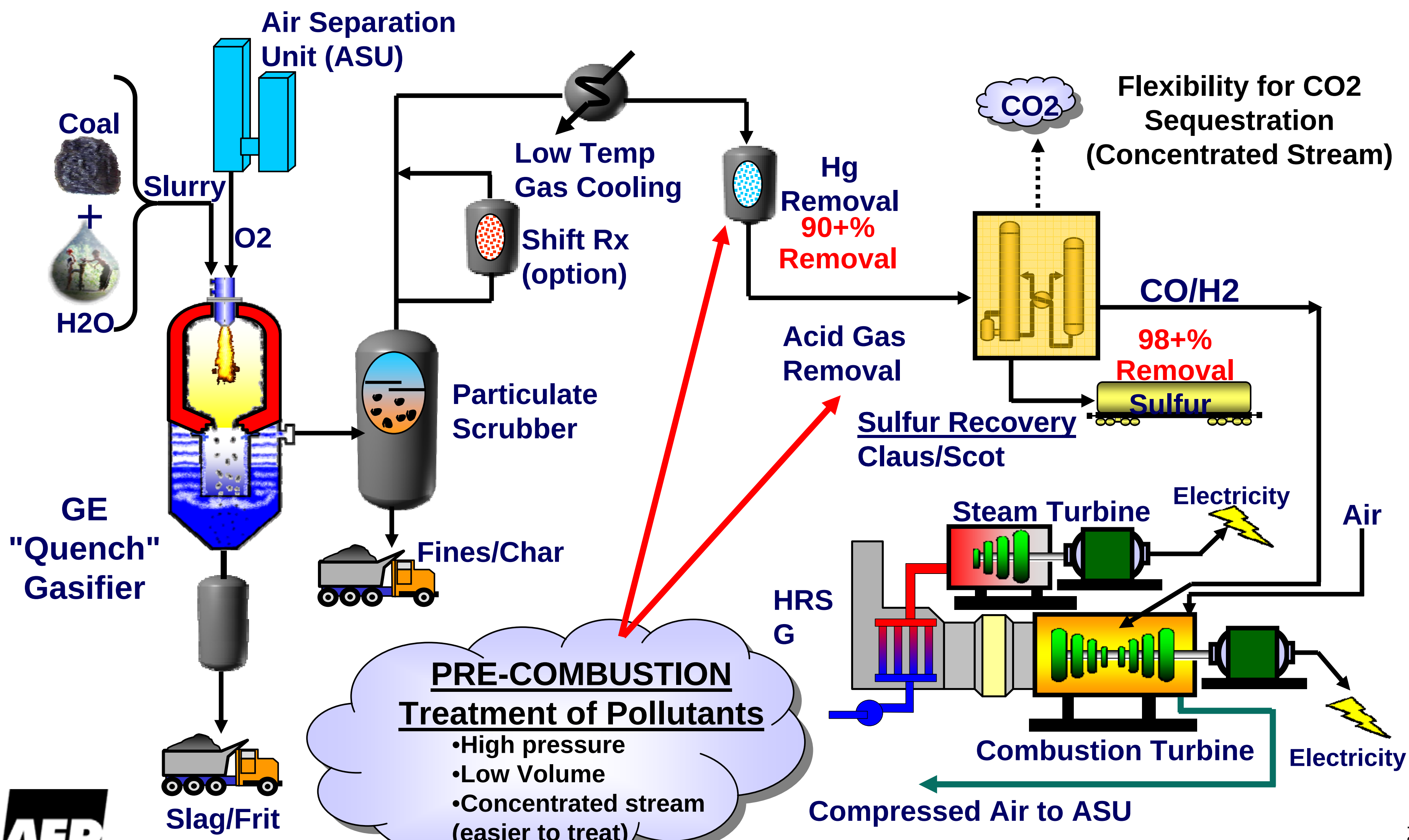
AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

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IGCC Permitting Process

IGCC Permitting Issues

- **Air**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- **Wastewater**
  - ✓ understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- **US ACE (US Army Corp of Engineers**)
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

Permitting process takes 1 – 2 years and is well under way

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

New Transmission Investment Funding Plans

- Electric Transmission Texas LLC
  - 40% equity / 60% debt capital structure requested at the PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% Mid-American Energy
  - AEP's 50% investment will be held at the AEP Utilities, Inc. subsidiary
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- AEP I-765 Interstate Project
  - Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007

- Other Transmission Projects
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives:
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

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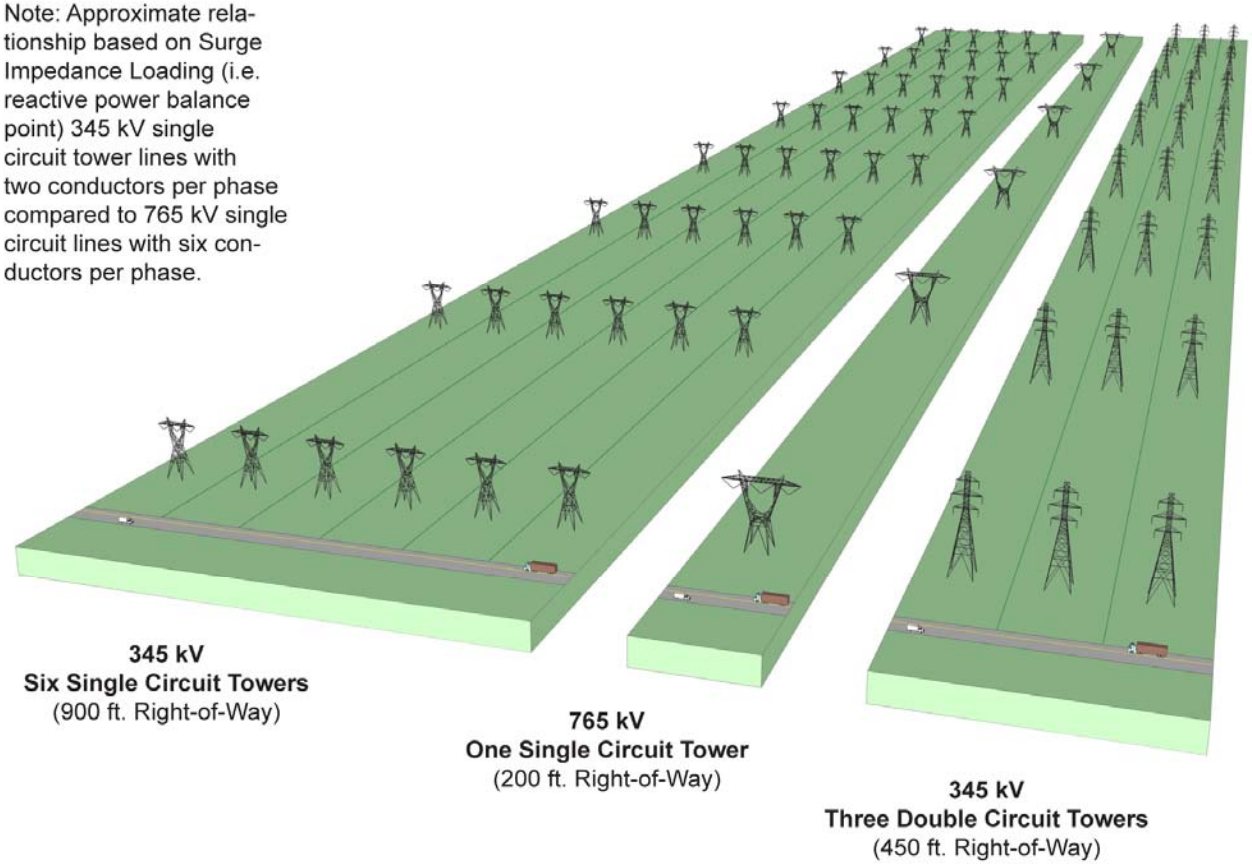
765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



From a siting standpoint, 765 kV is much more efficient in terms of economies of scale and right-of-way than lower capacity lines

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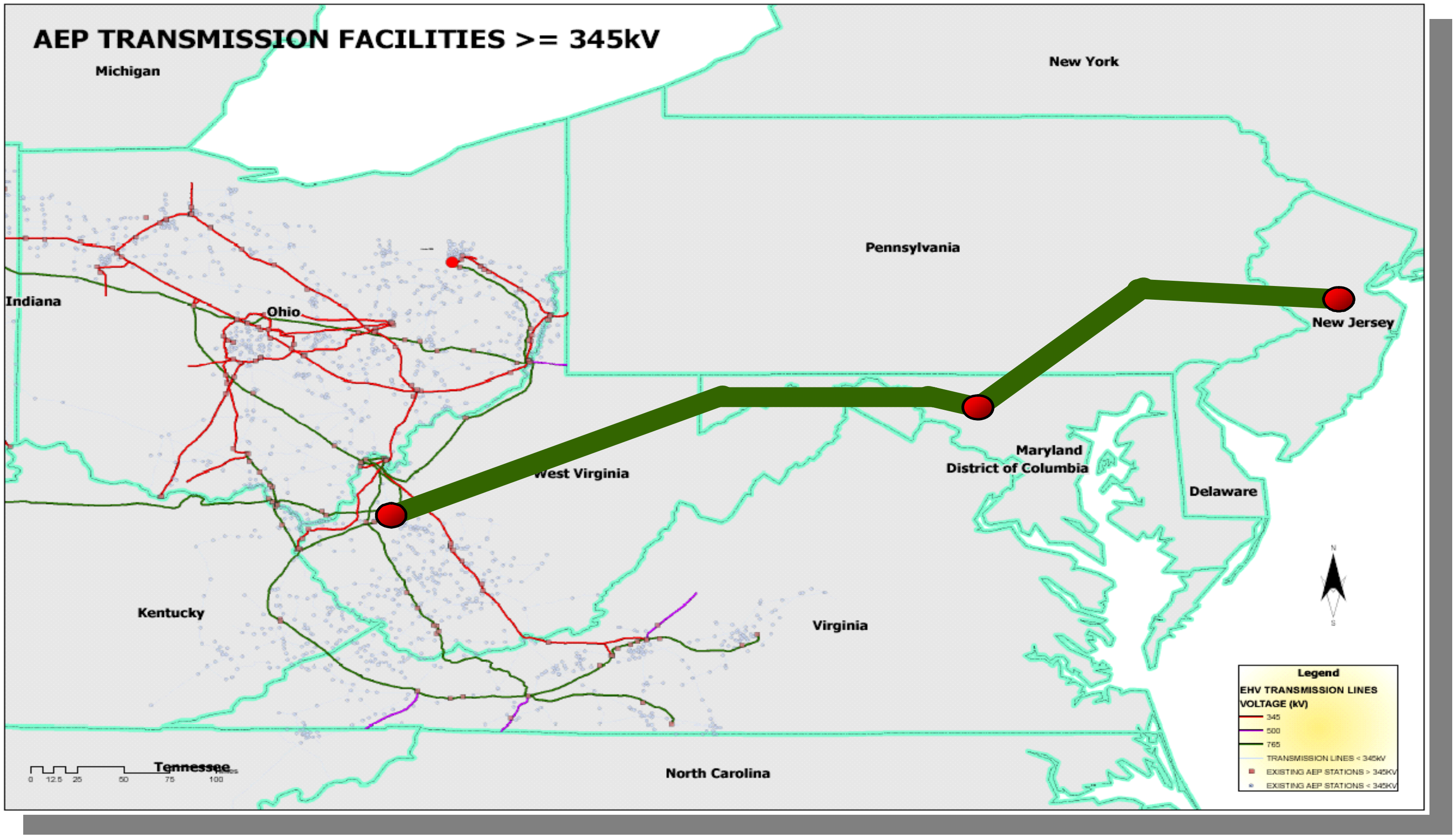
765 PJM



- Jointly owned with Allegheny, will improve eastern grid reliability
- Enhance Midwest-Mid-Atlantic power transfer capability by 5000 MW
- Reduces network line losses by 280 MW at peak with heavy Midwest – Mid-Atlantic power transfers.

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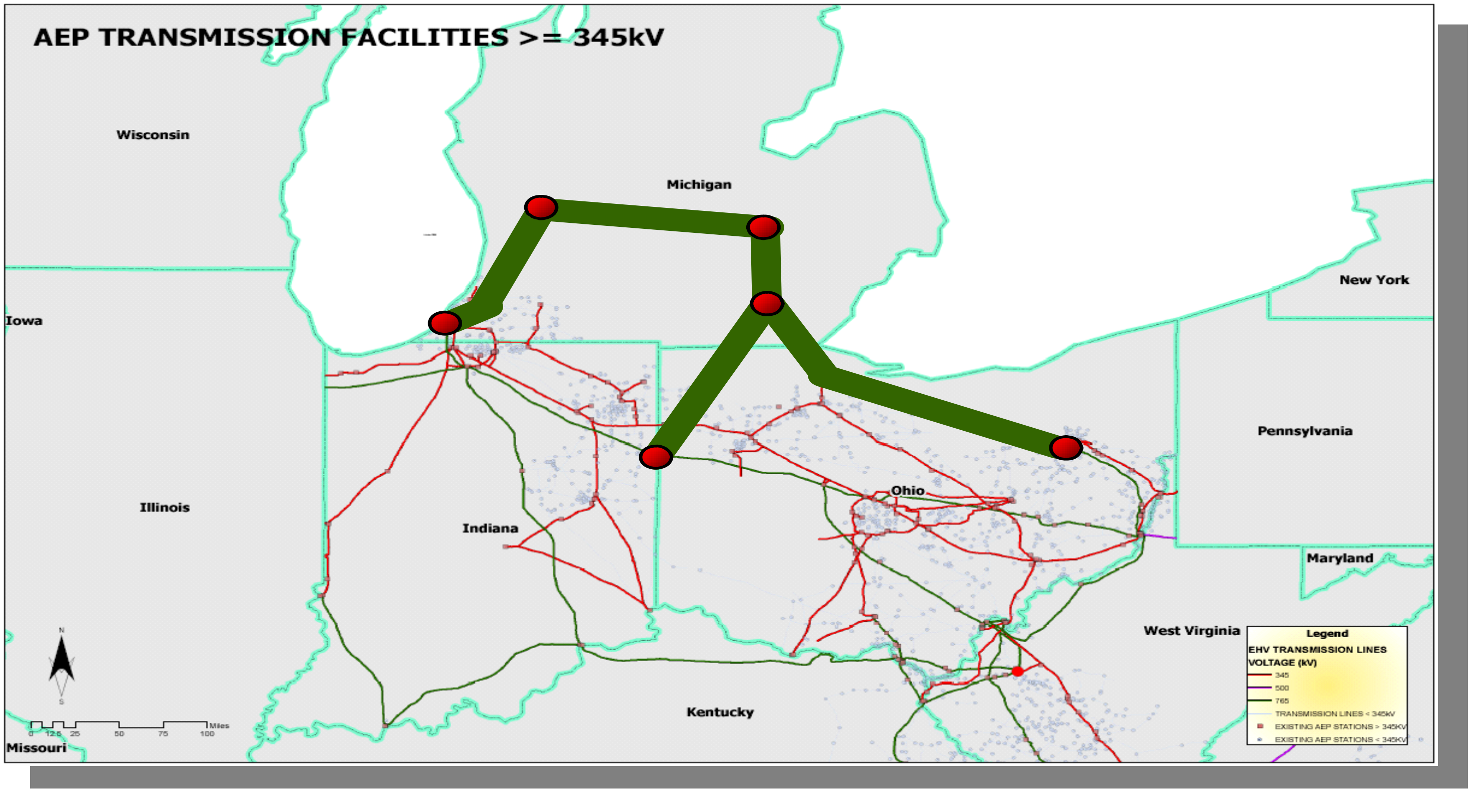
765-Michigan



- ➢Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of a new line in MI.
  - ➢675 line miles
  - ➢Over 4000MW improved transfer capability
  - ➢765-kV anticipated to alleviate constraints

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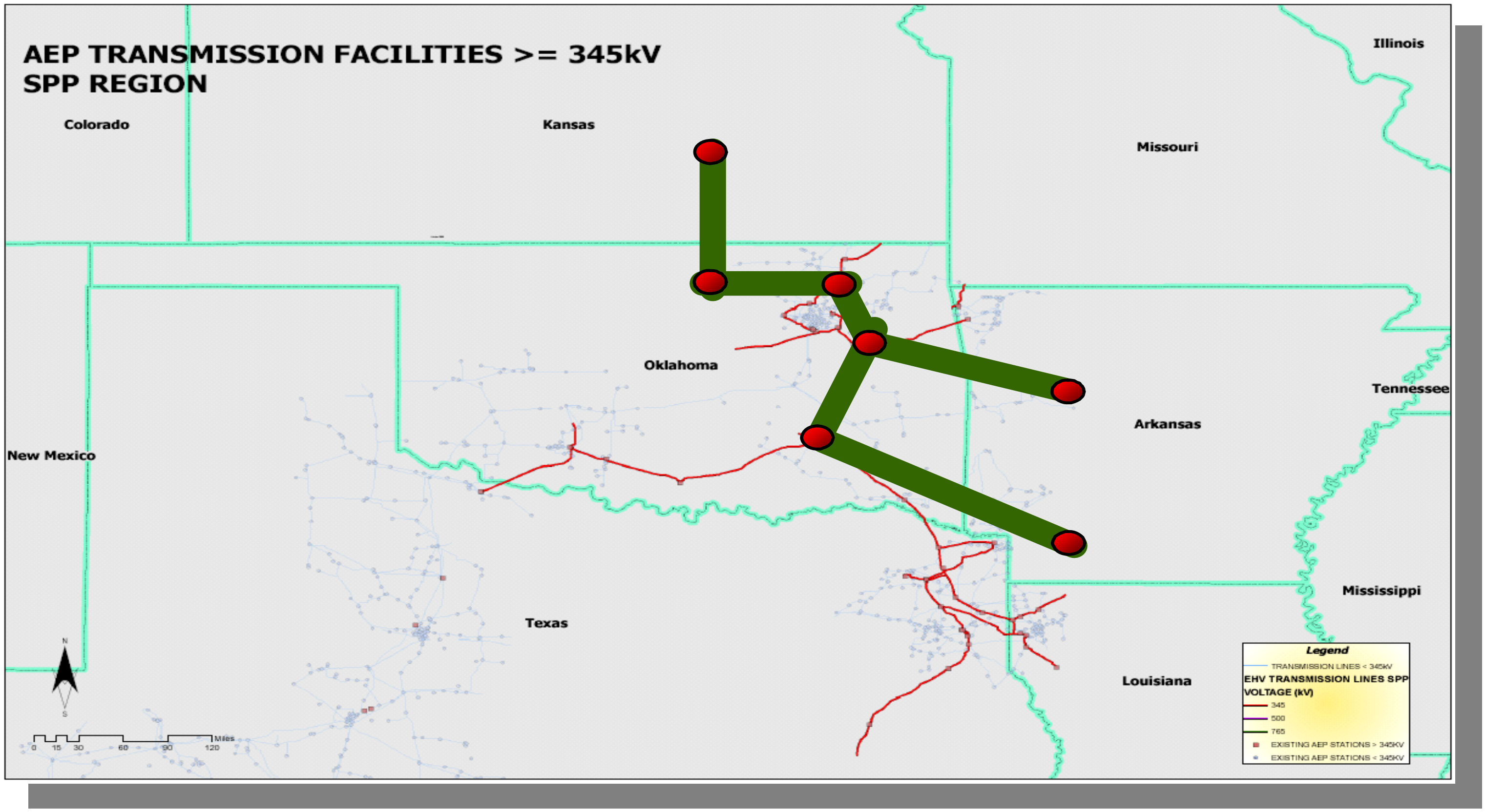
765-SPP



➢July ‘06 AEP submitted conceptual project to SPP:

Six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, proposed construction period 2012-17

➢Next steps:

SPP issued EHV Overlay Study RFP to review 345 kV, 500 kV, and 765 kV potential projects in SPP with results expected in mid-2007

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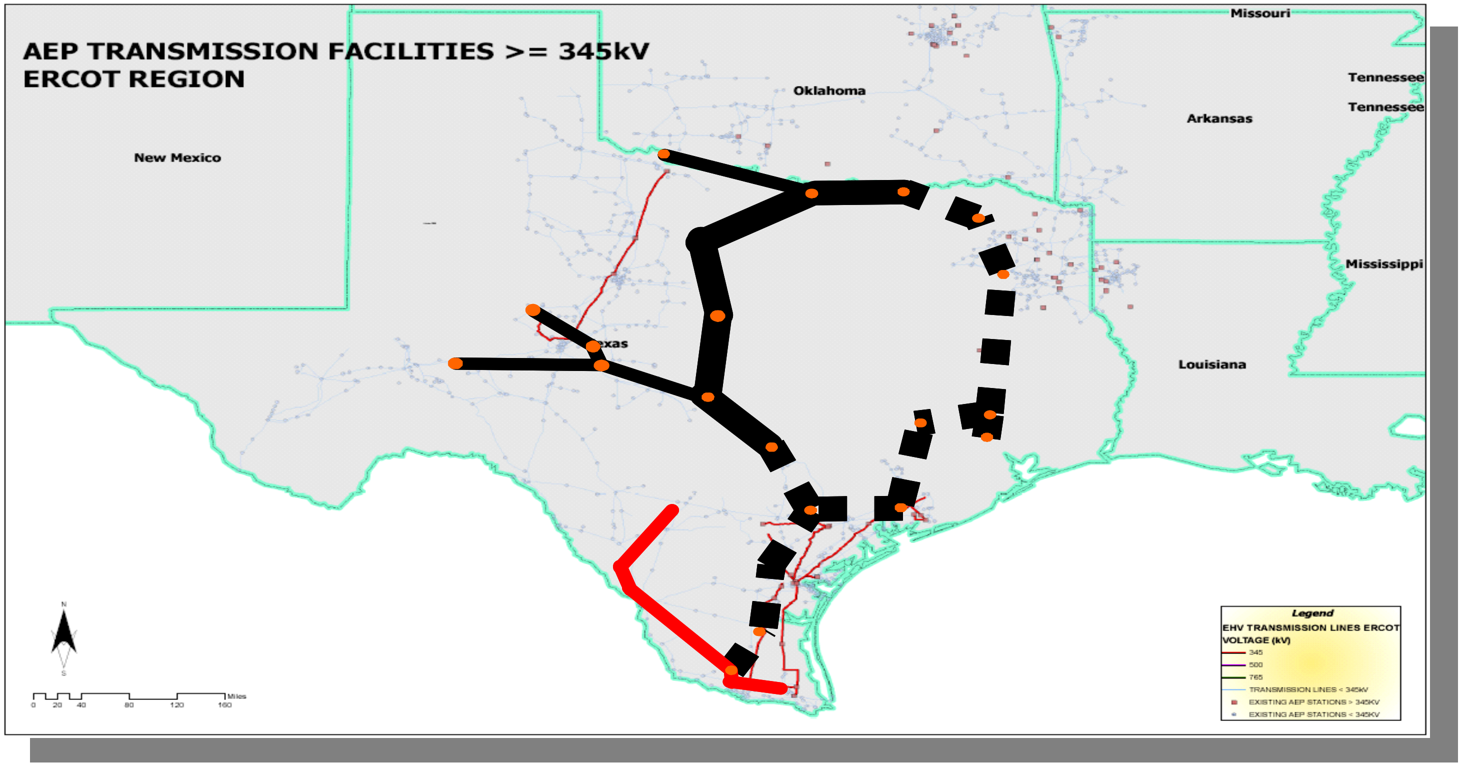
765-ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets
- AEP exploring 765-kV ERCOT transmission investment opportunity
- 420 line miles
- Up to 4000MW improved transfer capability

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Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008-09
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	Projected 2007	✓	Projected 2007
Mitchell 2	800	✓	Projected 2007	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	✓	In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2007
Muskingum River 5	585	✓	In-service	☐	Delayed
Pirkey	580	☐	N/A	✓	In-service
Oklaunion	485	☐	N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262	☐	N/A	✓	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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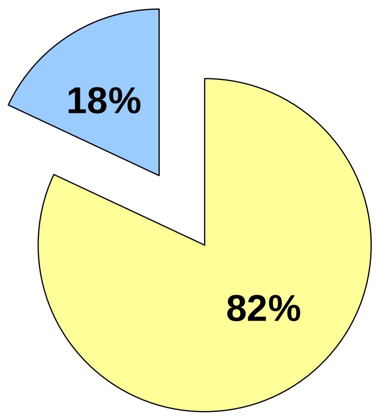
Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

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AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

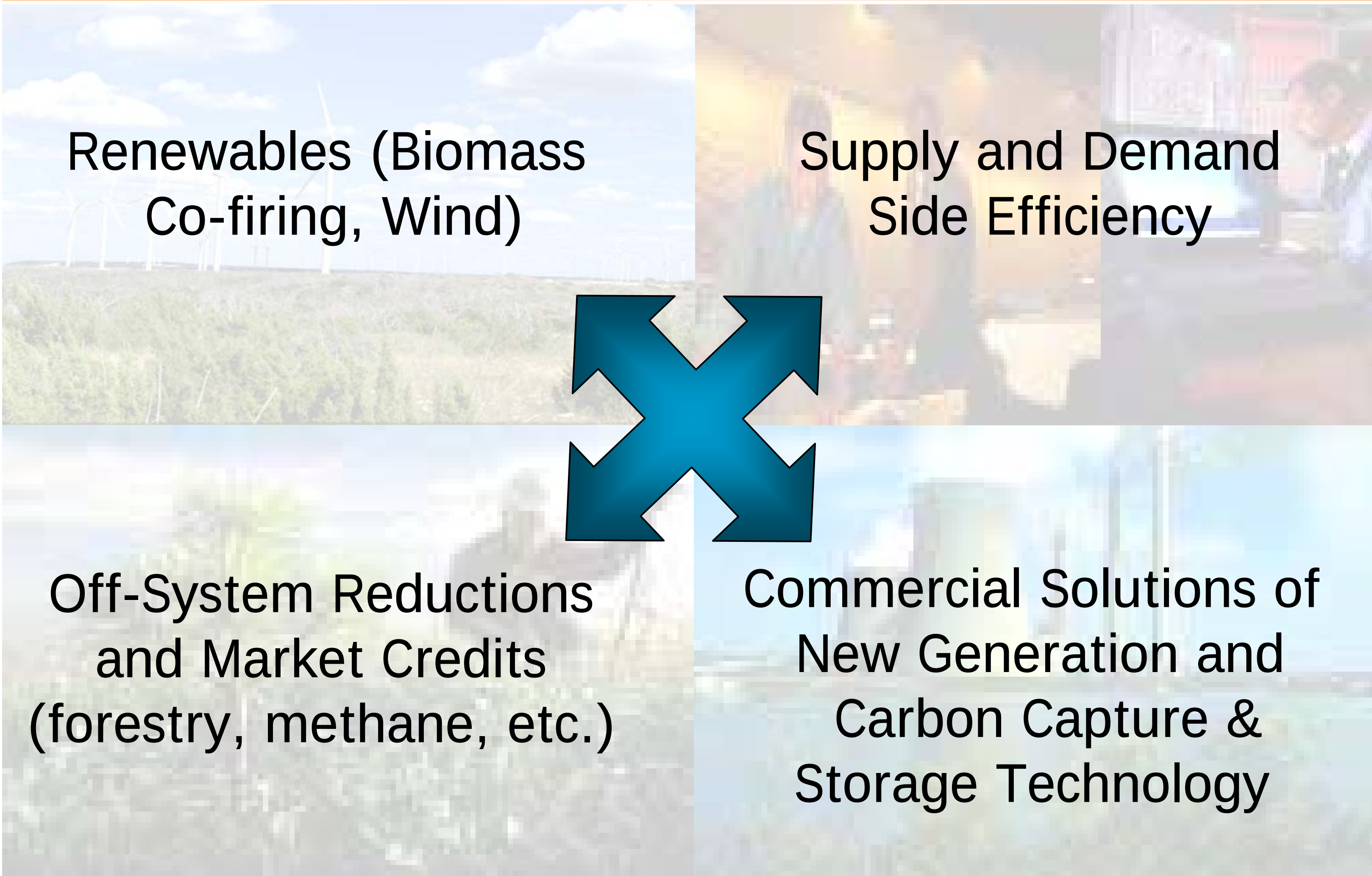
- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change

- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities

- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio



AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

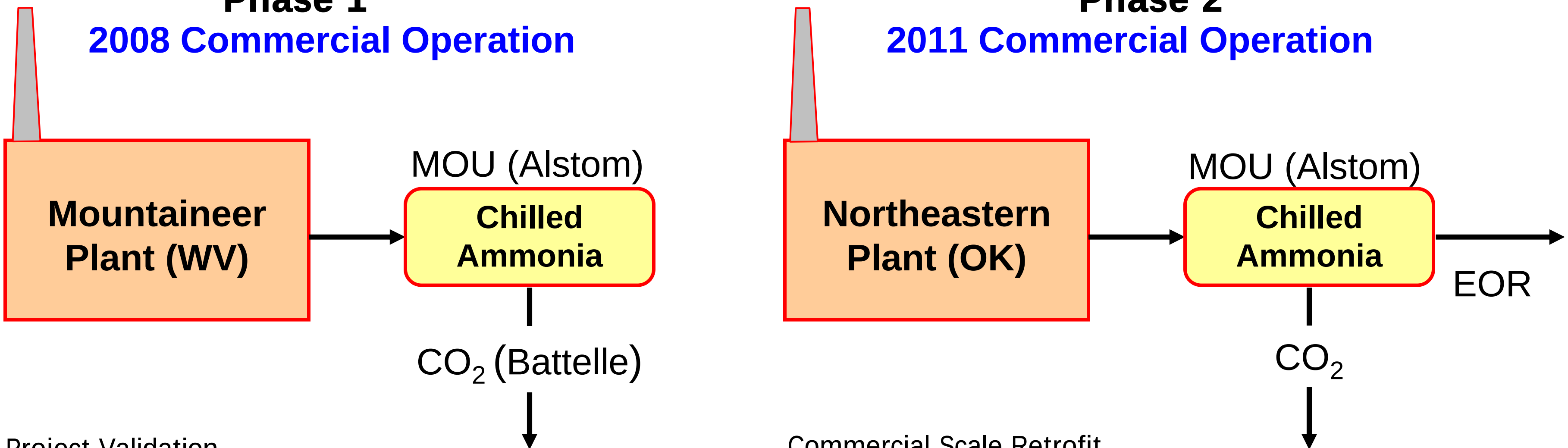
AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



Project Validation

- 30 MW$_t$ (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW$_t$ field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost $50 – $80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW$_e$ scale (megawatt electric)
- ~ 600 MW$_t$ scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~$225 – $300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

AEP®

POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

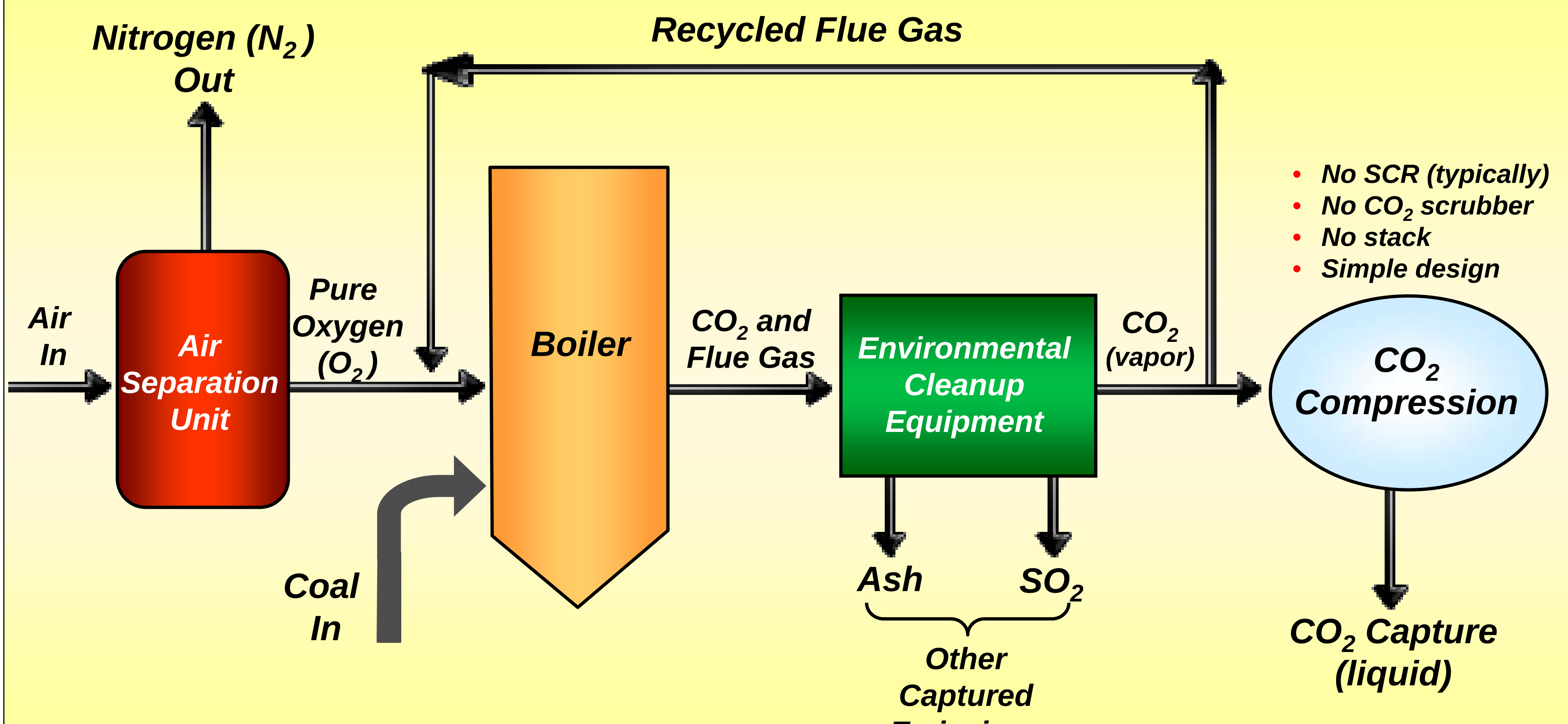


Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

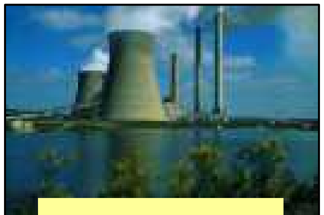
- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed 2Q 2008

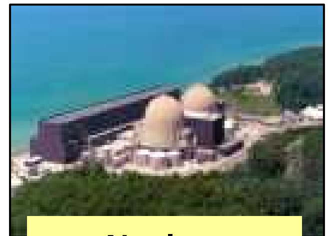
COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

Operational Performance

	Equivalent Capacity Factor		Equivalent Availability Factor		Equivalent Forced Outage Rate	
	Q1 2007	Q1 2006	Q1 2007	Q1 2006	Q1 2007	Q1 2006
East:	**68.91%**	**70.63%**	**81.78%**	**86.12%**	**8.01%**	**6.71%**
Coal:	73.07%	73.85%	78.52%	84.00%	8.71%	7.47%
Super-Critical *	73.54%	75.92%	76.58%	83.32%	7.84%	6.97%
Sub-Critical *	71.46%	66.75%	84.52%	86.11%	11.17%	9.02%
Gas **	1.61%	0.17%	95.43%	95.21%	3.11%	0.15%
Hydro	13.32%	12.92%	88.47%	96.28%	17.88%	4.31%
Nuclear	102.01%	95.71%	99.98%	95.31%	0.00%	0.00%
SPP:	**41.88%**	**39.15%**	**86.34%**	**83.34%**	**4.21%**	**3.53%**
Coal:	76.55%	67.30%	81.67%	72.46%	2.96%	4.16%
Super-Critical *	81.99%	75.21%	84.65%	77.73%	2.90%	7.57%
Sub-Critical *	74.50%	64.29%	80.55%	70.46%	2.98%	2.66%
Gas	18.61%	19.68%	89.48%	90.86%	5.69%	2.80%
Texas:						
Coal	**43.84%**	**67.68%**	**42.20%**	**73.21%**	**40.48%**	**10.48%**
AEP System	**62.83%**	**62.67%**	**82.30%**	**85.28%**	**7.72%**	**6.22%**

* Super-critical includes coal units with a net maximum capacity of 450MW or greater; Sub-critical includes coal units with a net maximum capacity less than 450MW.

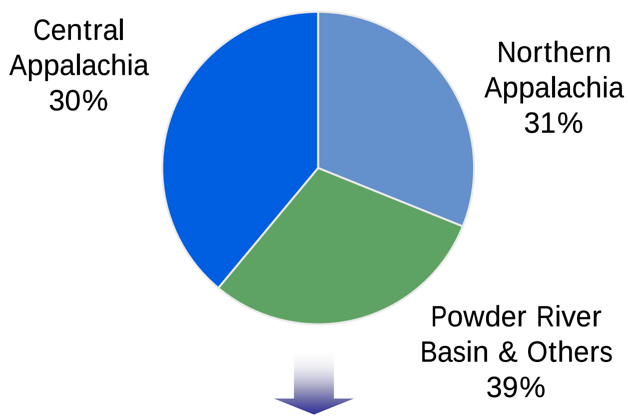
** East gas units are evaluated using Equivalent Forced Outage Factor. Since these units run infrequently, this factor gauges performance based on period hours instead of service hours.

AEP®

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

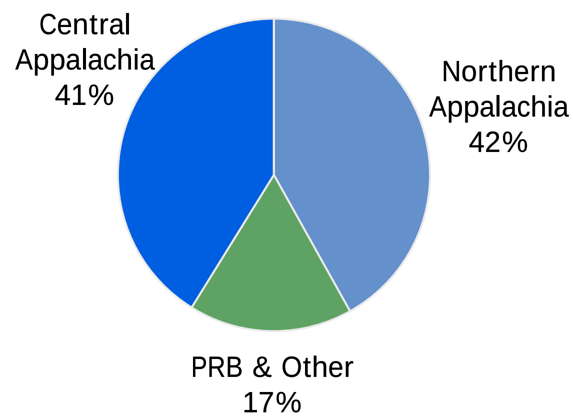
Total AEP System



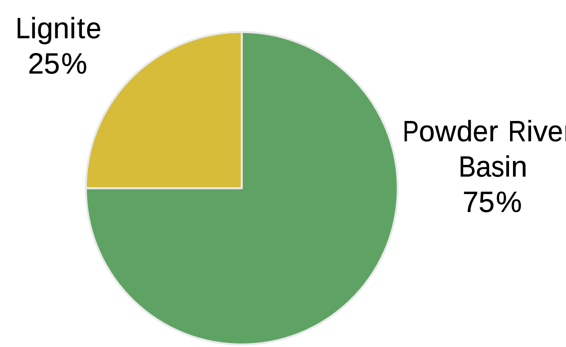
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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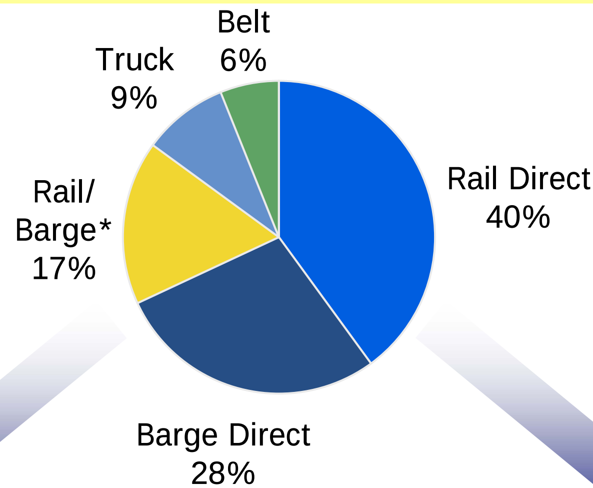
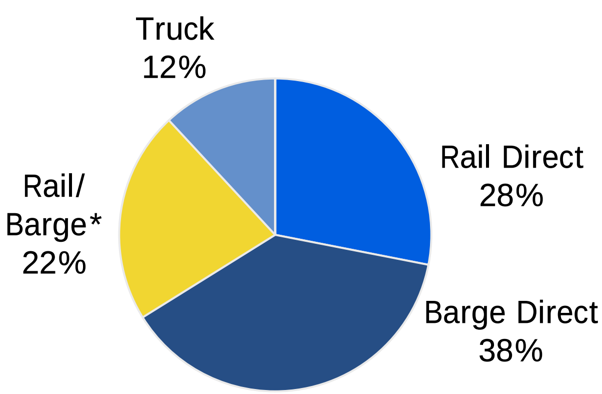
Coal Delivery

2006 Actual

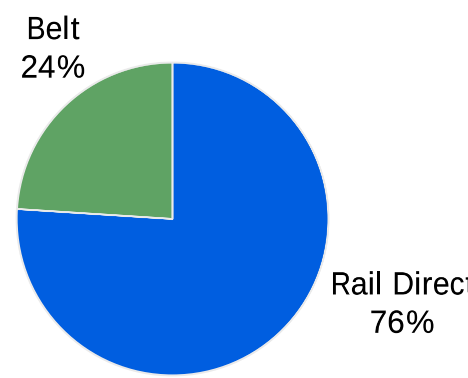
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

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CASH ON HAND EXPECTED TO BE $205 MILLION AT YEAR END 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ **43**	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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Capital Structure

Capital Structure	Actual 12/31/2006			Actual 3/31/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	13,902	-	13,902
Short-term Debt	18	-	18	175	-	175
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,540	9,540
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**14,077**	**9,601**	**23,678**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.5%***	***40.5%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(27)	-	(27)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(251)	-	(251)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**12,679**	**9,601**	**22,280**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***56.9%***	***43.1%***	***100.0%***

ADJUSTED DEBT/CAPITALIZATION: 56.90%

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2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$400-$500	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

MAINTAIN FINANCIAL STRENGTH OF UTILITY COMPANIES BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

Long-Term Debt Maturity Profile

($ in millions)

Year		2007		2008		2009
AEP Service Corp.	$	-	$	36	$	-
AEP, Inc.	$	345	$	-	$	-
AEG	$	-	$	-	$	-
APCo	$	325	$	200	$	150
CSPCo	$	-	$	112	$	-
KPCo	$	323	$	30	$	-
I&M	$	-	$	50	$	45
OPCo	$	-	$	45	$	106
PSO	$	-	$	-	$	50
SWEPCo	$	90	$	118	$	-
TCC	$	-	$	68	$	-
TNC *	$	8	$	-	$	-
Total	$	1,091	$	659	$	351

Note: Maturities remaining as of March 31, 2007

* - represents TNC first mortgage bonds that were defeased in December 2005

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Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

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Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	**Senior Unsecured**	**Business Profile**	**Senior Unsecured**	**Senior Unsecured**
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

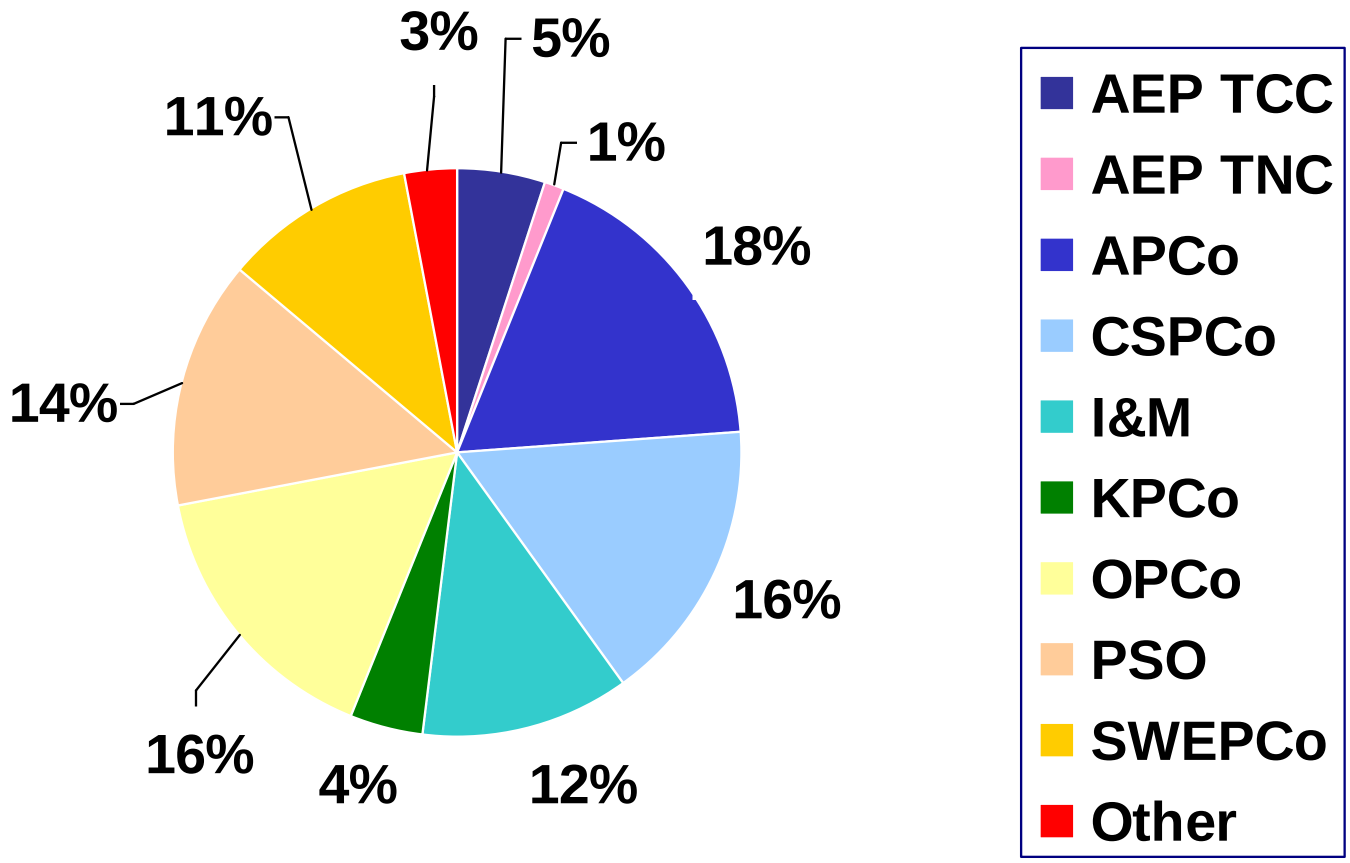
(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

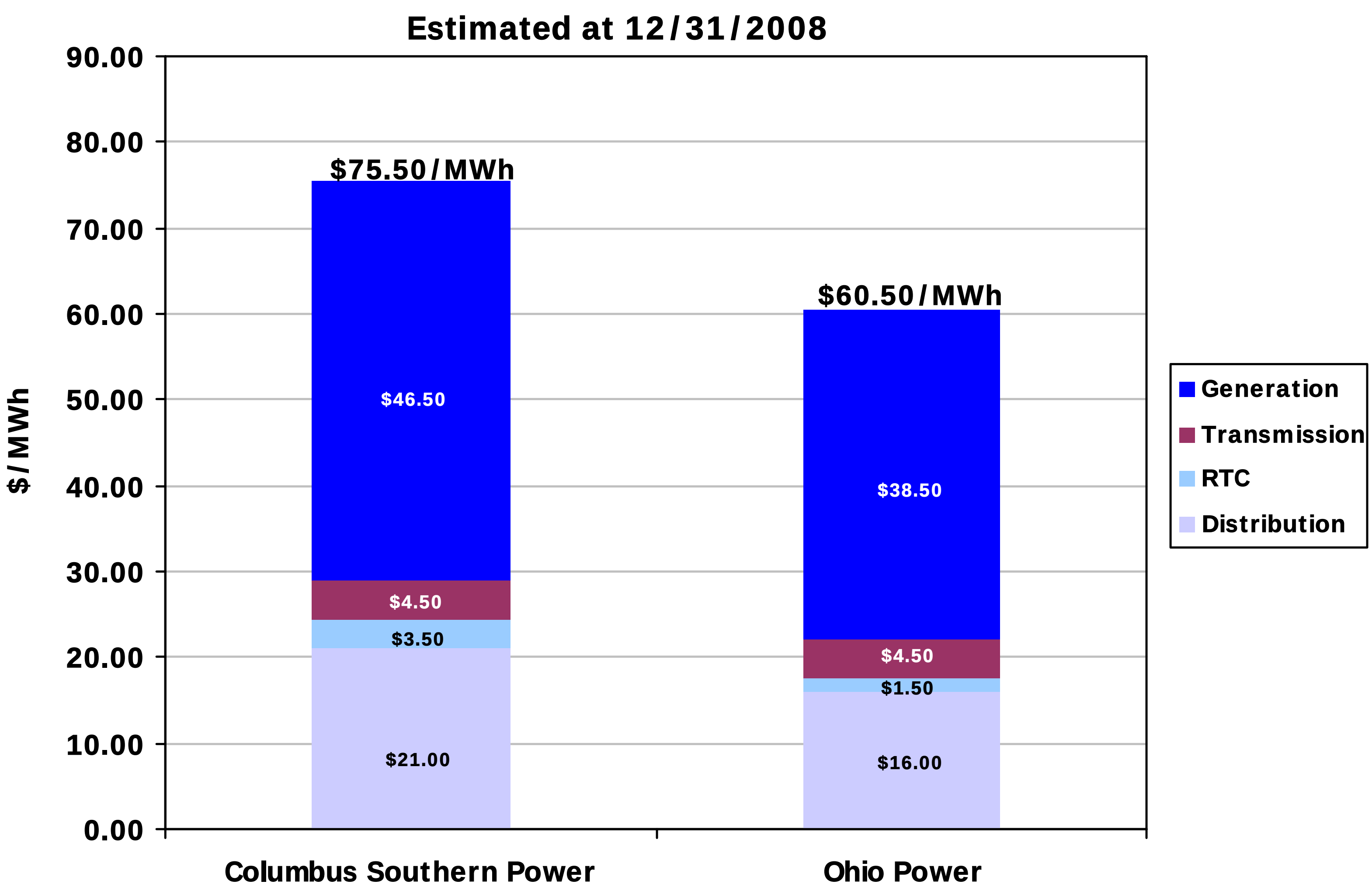
WE ARE COMMITTED TO MAINTAINING OUR CURRENT CREDIT RATINGS

2006 Retail Revenue

Retail Revenue Composition by Operating Company

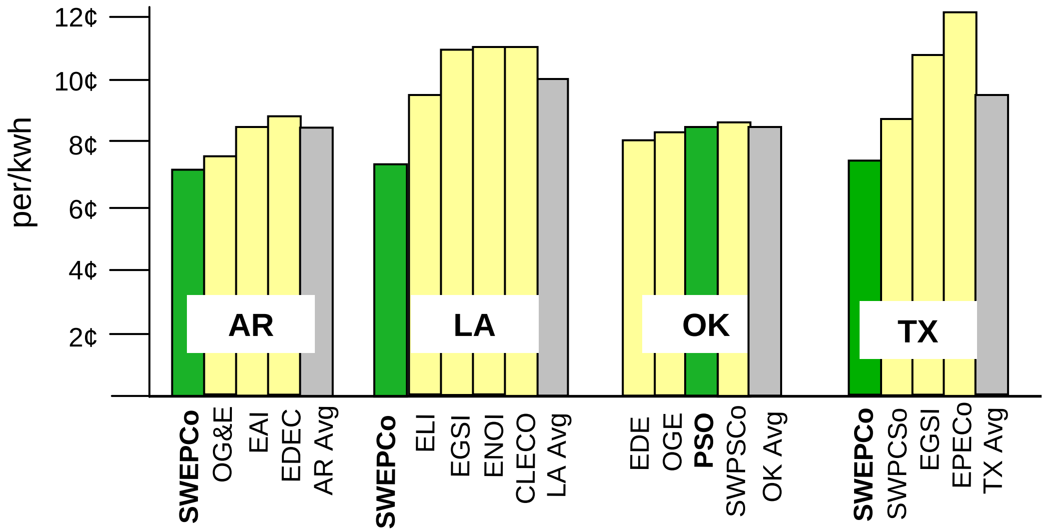


Average Unbundled AEP Ohio Rates



AEP Provides Low Cost Electric Service

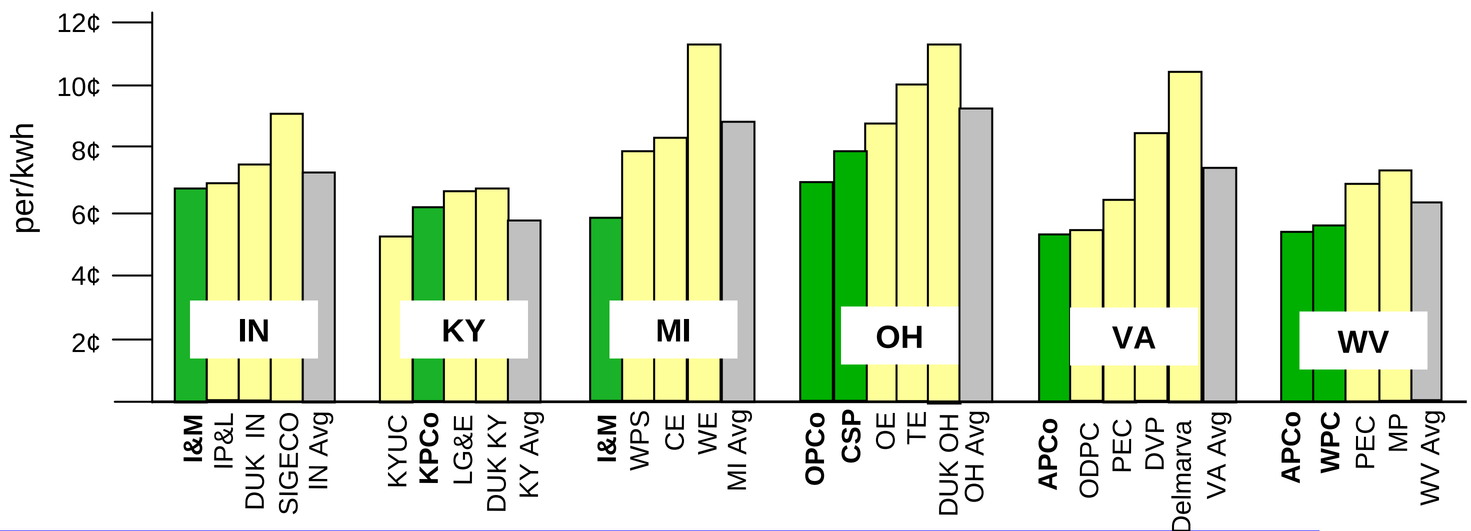
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



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2006-2009 Projected Annual Rate Increase Of 3.8%

Earned ROE's

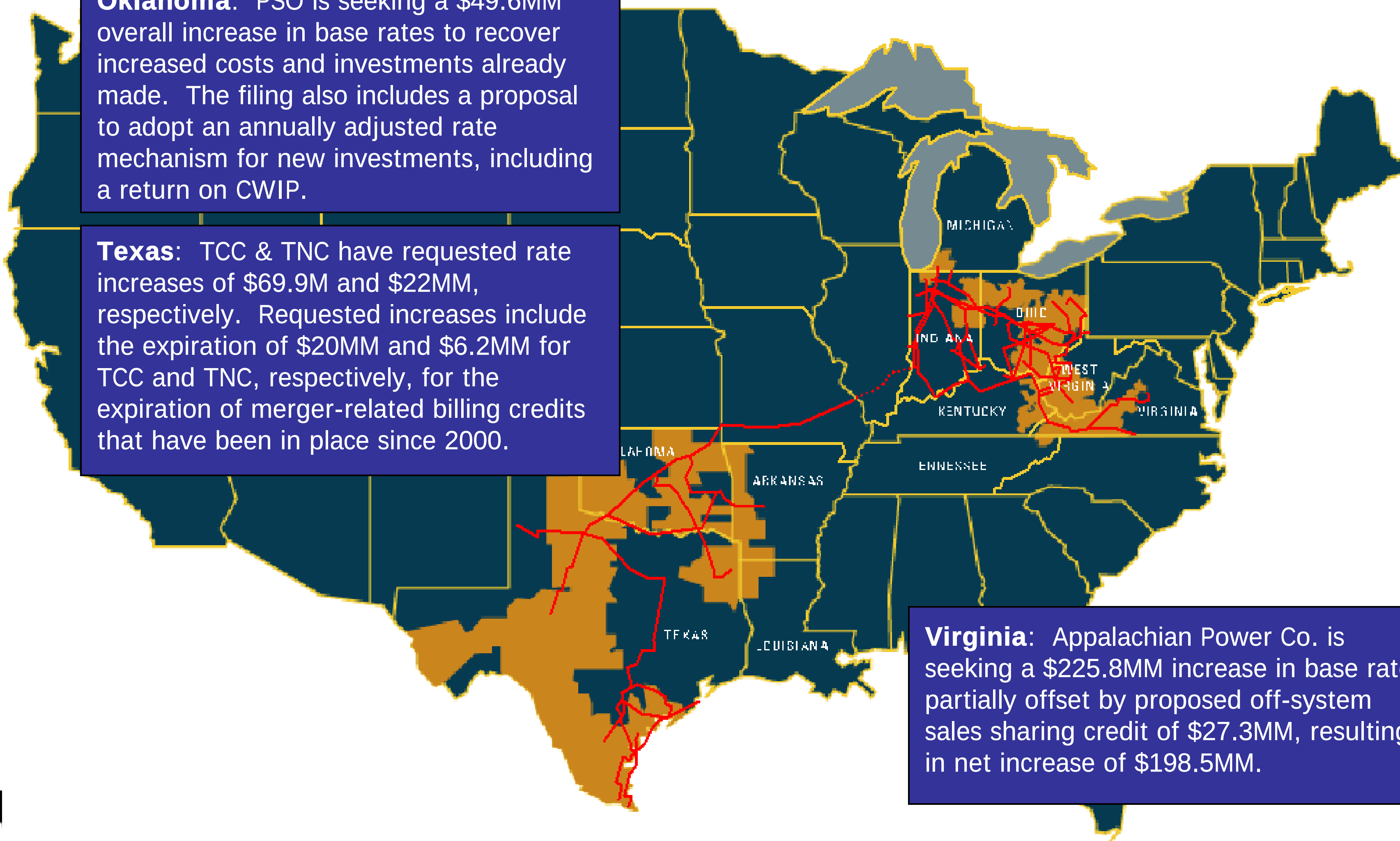
Company	Earned ROE as of March 31, 2007
AEP Texas Central Company	**5.81%**
AEP Texas North Company	**5.24%**
Appalachian Power Company	**8.97%**
Columbus Southern Power Company	**17.14%**
Indiana Michigan Power Company	**7.12%**
Kentucky Power Company	**11.06%**
Ohio Power Company	**10.57%**
Public Service Company of Oklahoma	**3.75%**
Southwestern Electric Power Company	**10.11%**

These ROE's are based on GAAP, Not Rate Base

Base Case Regulatory Summary

Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $69.9M and $22MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.



Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Regulatory Activity

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 11, 2007; Evidentiary hearing to commence May 22, 2007.

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Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
    - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
- April 2007 Commission decision:
  - Reaffirmed PJM's current "license plate" rate design, reversing the finding of the ALJ; each utility pays for transmission service based on the costs of transmission facilities located in the same, sub-regional zone that the utility is located in
  - Directed PJM to develop a detailed methodology to be included in PJM's tariff for determining who benefits from and therefore, who pays for new facilities below 500 kV.
  - Determined that the costs of all new PJM-planned facilities that operate at or above 500 kV should be shared on a region-wide basis.

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7429 of 9556

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

AEP

Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 7, 2006	Hearings commenced
February 5, 2007	Briefs filed
March 28, 2007	Hearing Examiner Recommendation filed

APCo filed its comments on the Hearing Examiner's report on April 18, 2007 and now awaits an order from the SCC. No statutory deadline.

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base $2.3 billion

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

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Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

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Merrill Lynch Global Power & Gas Leaders Conference

September 27, 2005
St. Regis Hotel

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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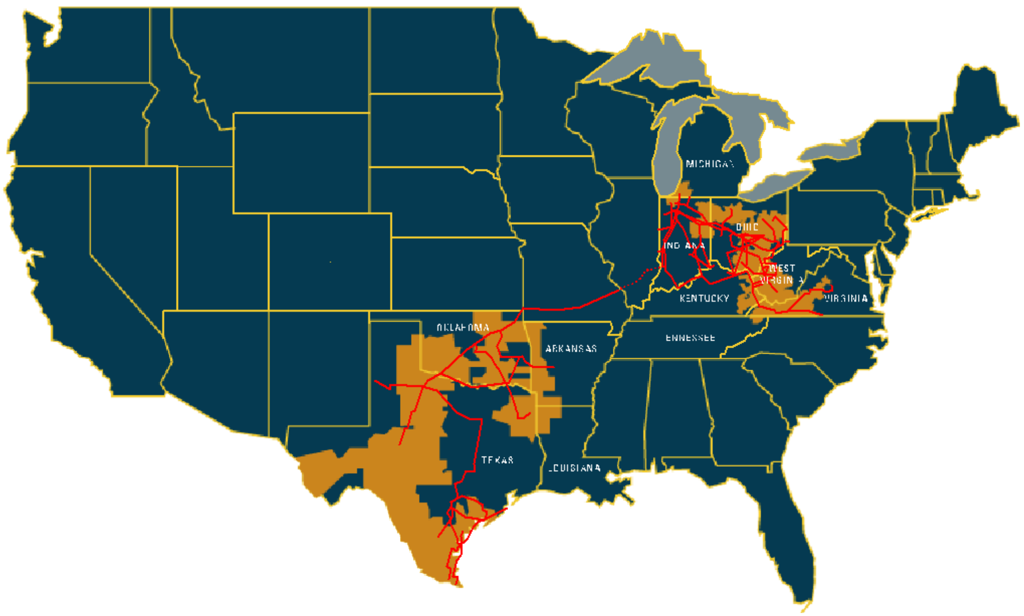
“Growing the Ratebase”

Mike Morris
Chairman, President & Chief Executive Officer

Strength & Scale in Assets & Operations



Generation	35,500 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Utility Investment to Drive Earnings Growth

Investment Opportunities:

- Traditional Maintenance
- Environmental
- New Generation

Preserves low cost production advantage

- IGCC

Environmentally sensitive investment can be blended with AEP's low production cost

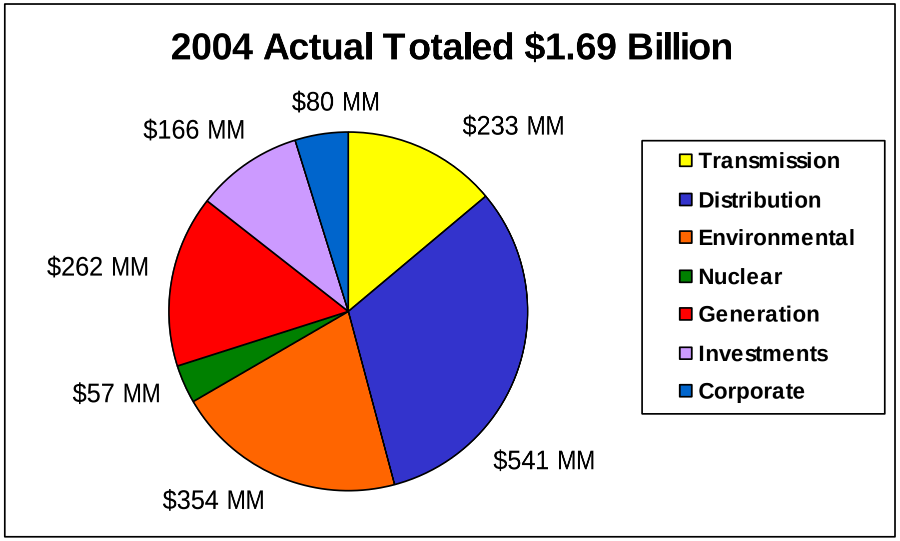
- Energy Delivery Infrastructure

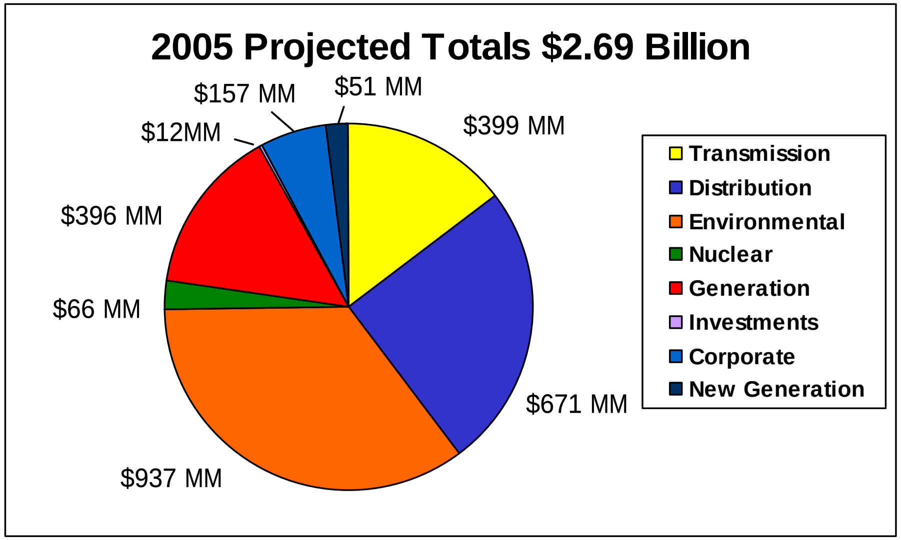
Annual Growth Rate 3-5%:

- Organic demand growth rate of 2%
- Utility investment recovery to add 1-3% to growth

PRUDENT INVESTMENT WILL PRESERVE LOW COST ADVANTAGE AND DRIVE EARNINGS GROWTH

2005 Capex





Note: 2005 capital expenditures exclude the announced Waterford and Monongahela Power transactions.

AEP's Environmental Compliance Strategy

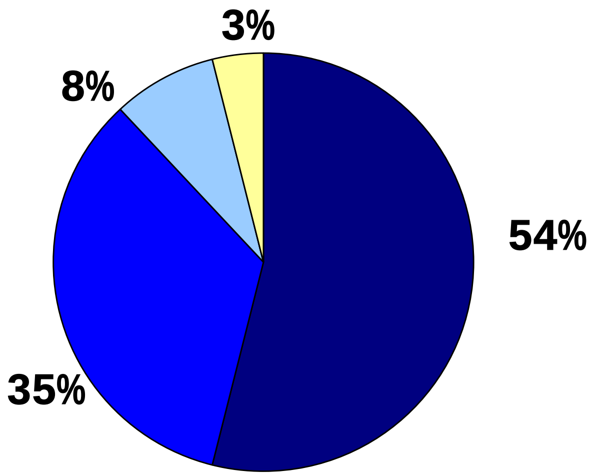
NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Much of this investment will be for:**
  - **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
  - **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
  - **SCR and FGD systems together offer co-benefit of mercury capture.**
  - **Sale of gypsum (by-product) avoids future landfill costs.**
  - **Provides fuel flexibility.**

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

$4.1 Billion Environmental Investment: Spending by Company

Projected Environmental Investment Allocation



- Ohio Power & CSP (OH)
- Appalachian Power Co. (VA/WV)
- Kentucky Power Co. (KY)
- Other

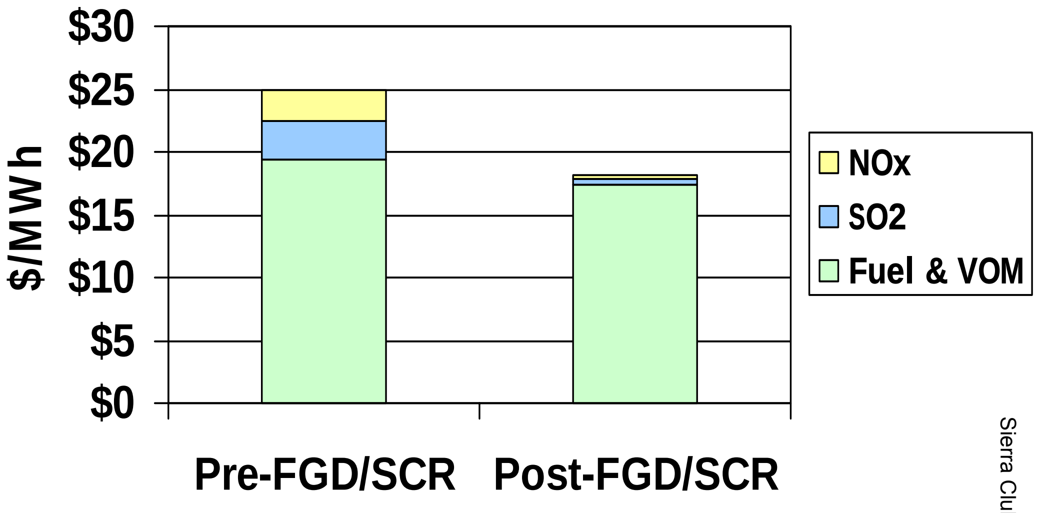
Funding the Environmental Investments

- **Ohio**: 54% ($2.2 billion)
  - Approved annual generation increases 2006-2008
    - CSP – 3% annually
    - OP – 7% annually
- **Virginia/West Virginia**: 35% ($1.4 billion)
  - VA: Annual rate relief through Environmental & Reliability cost recovery mechanism; Two rate case opportunities through 2010
  - WV: General rate increase filed 8/26/05 including environmental, reliability & fuel recovery
- **Kentucky**: 8% ($319 million)
  - Automatic surcharge mechanism

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant Comparison of Variable Production Cost Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

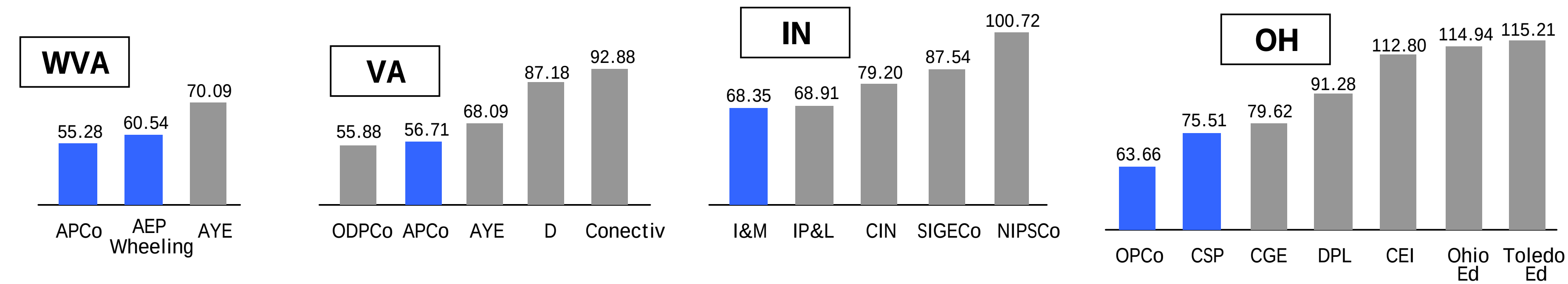
AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

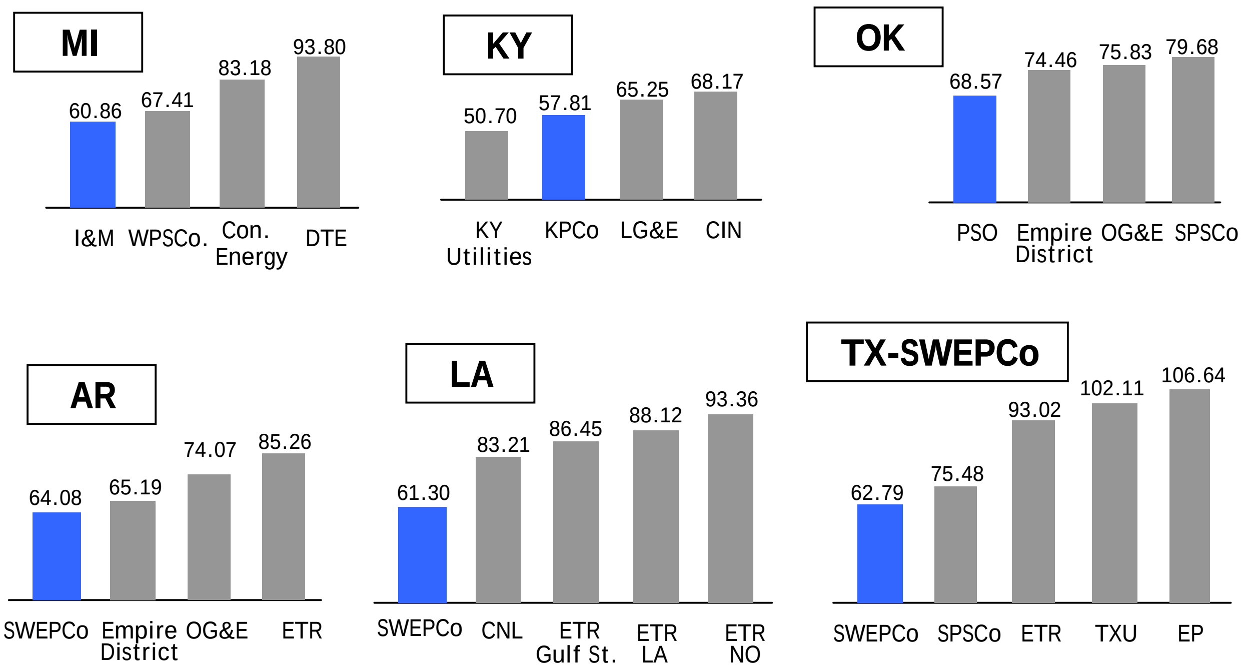
9

AEP: Low Cost Provider Today

Typical Bill Comparison

- AEP Company 2004 average monthly residential bill
- Competitor 2004 average monthly residential bill





Wholesale

AEP System fossil fleet average variable book cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Note: Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Ohio rates represent POLR bundled residential rates.

Source: Billing amounts (excluding wholesale) sourced from the EEI 2004 Typical Bills and Average Rates Report.

Investing in IGCC

AEP®

Ohio IGCC Procedural Schedule

- August 16, 2005: Evidentiary Hearings Concluded
- September 20, 2005: Initial Briefs Due
- October 11, 2005: Reply Briefs Due

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Investment in Asset Base Will Drive Earnings

Potential Return On Investment

Assumptions	Environmental Investment	600MW IGCC Investment*	Utility Maintenance Capex
Projected Investment	$4.1 Billion	$1.0 Billion	$1.0 Billion****
Approx. Debt/Equity Ratio	60% debt / 40% equity	52% debt / 48% equity**	60% debt / 40% equity
Return on Equity	10-12%	11.75%***	10-12%

Total Potential EPS Impact After 2010 (based on 393 MM shares) — **+ $0.66 - $0.76**

* Assume a similar return for an additional 600 MW IGCC facility
** Requested debt/equity ratio per AEP Ohio IGCC filing
*** Requested ROE in AEP Ohio IGCC filing
**** Annual investment net of depreciation

EPS CONTRIBUTION FROM INVESTMENT WILL BE SUBSTANTIAL

Funding the Investment

- Cash flow from operations
- Rate Relief
  - Ohio approved annual generation rate increases for 2006-2008
  - Virginia annual rate relief through environmental & reliability cost recovery mechanism plus two rate case opportunities through 2010
  - West Virginia general rate increase filed 8/26/05 including environmental, reliability & fuel recovery
  - Kentucky automatic environmental surcharge mechanism & general rate case to be filed September 2005
- Asset Sales
  - 2005 proceeds estimated to be $1.5 billion
- Texas Securitization/Texas Competition Transition Charge
  - Seeking recovery of $2.4 billion
- Debt Issuances
  - Maintain debt-to-capitalization ratio of approximately 60%

UTILITY INVESTMENT TO BE FUNDED BY A VARIETY OF TRADITIONAL SOURCES

Regulatory Track Record

December 2004: SWEPCO Louisiana Service Quality Improvement Program – LPSC issued order approving amendment to SQIP allowing deferral of incremental tree management and trimming costs with carrying costs for future rate recovery;

January 2005: Ohio Rate Stabilization Plan approved by PUCO - Annual generation increases 2006-2008: 3% for Columbus Southern Power, 7% for Ohio Power; Opportunity to request incremental generation 4% increase in each year 2006-2008;

May 2005: Settled PSO rate case - Neutral to earnings; Approved $11.81MM Reliability Enhancement Plan; annual rider may be increased to $23.68MM per OCC Staff testimony & ALJ recommendation (currently pending);

August 2005: TCC Wires rate case – $11.5 million positive earnings impact;

September 2005: Kentucky Environmental Surcharge approved - $1.8MM increase in annual revenue

---

Active filings: FERC Transmission case (settlement pending), FERC SECA/Regional rate design case, TCC True-Up, IGCC in Ohio, Monongahela Power acquisition in Ohio, VA E & R case, WV general rate case, notice filed in Kentucky for rate case

PRUDENT INVESTMENTS COUPLED WITH DILIGENT WORK IN THE REGULATORY ARENA ARE PROVING SUCCESSFUL IN ACHIEVING REGULATORY RECOVERY AND EARNINGS CONTRIBUTION

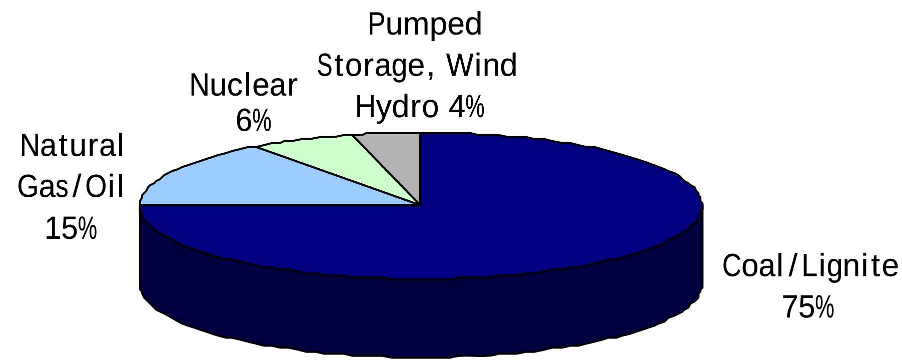
Appendix

Asset Portfolio

Generation Fleet Composition

- 35,500 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,143**	**3,516**	**774**

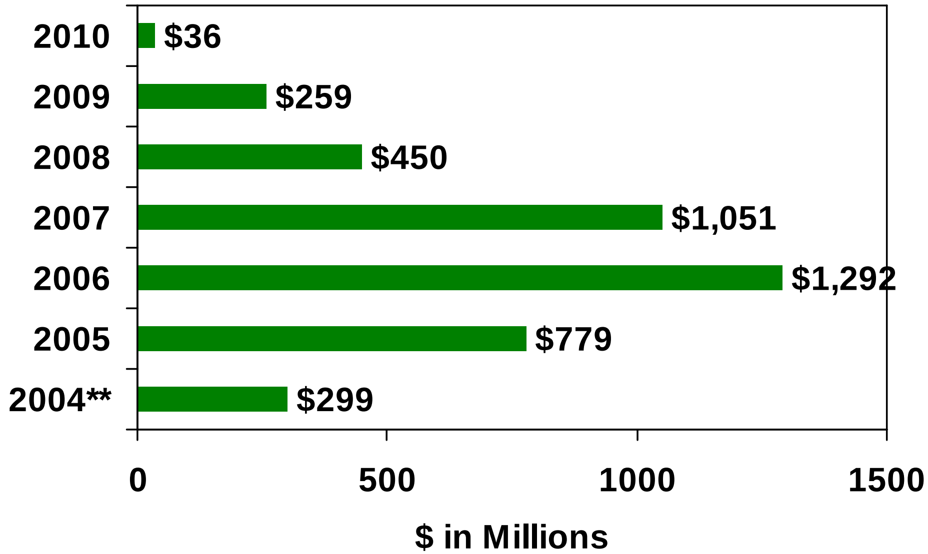
* Figures do not include mothballed or decommissioned units (1,015 MW of capacity). Also excludes the Waterford and Ceredo generating facilities.

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Environmental Investment

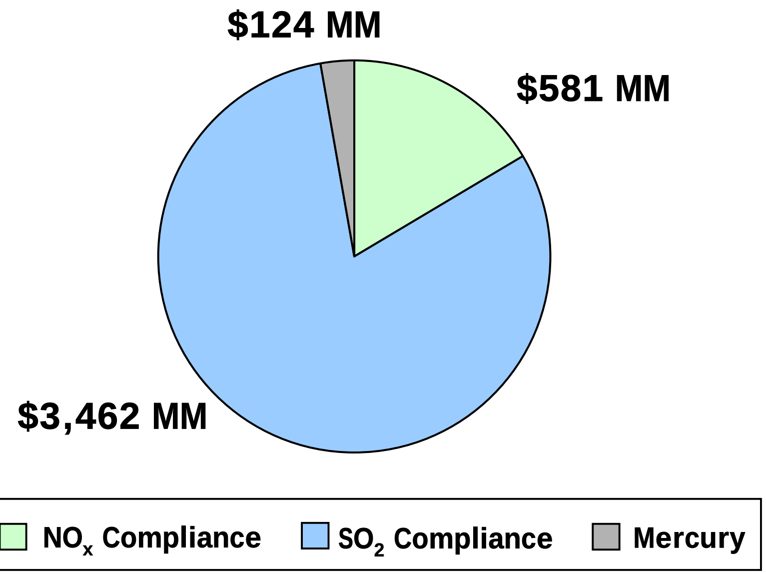
Environmental Investment: $4.1 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs	Future Programs
$2.0 Billion:	$2.1 Billion:
$0.5 billion for NOx	$1.9 billion for SO_2
$1.5 billion for SO_2	$0.2 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Investment

	FGD	SCR

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

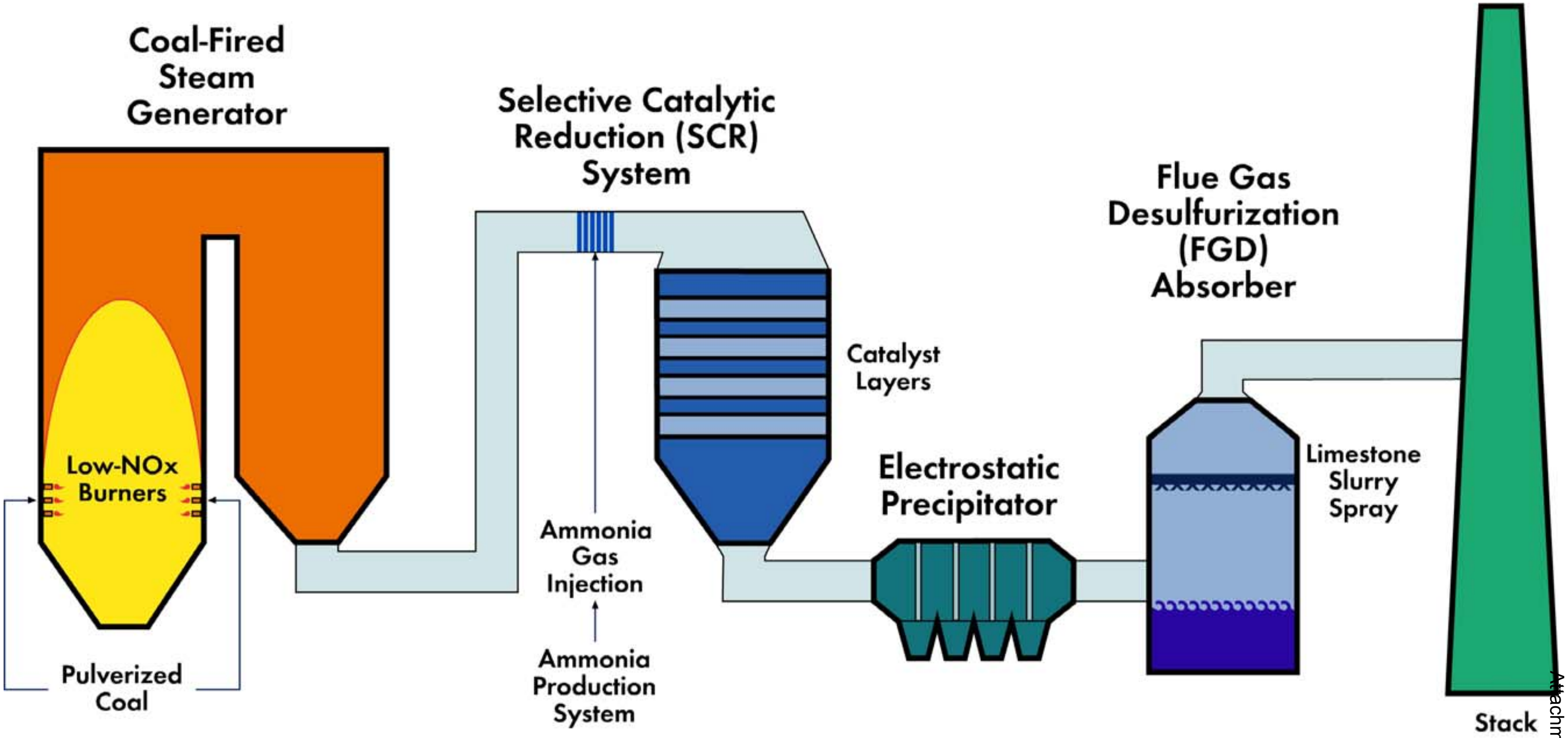
Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2006 - 2009

Note: MW capacity shown represents AEP's owned capacity only

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7453 of 9556

The Flue Gas Stream



Materials and Vendors

Material Costs

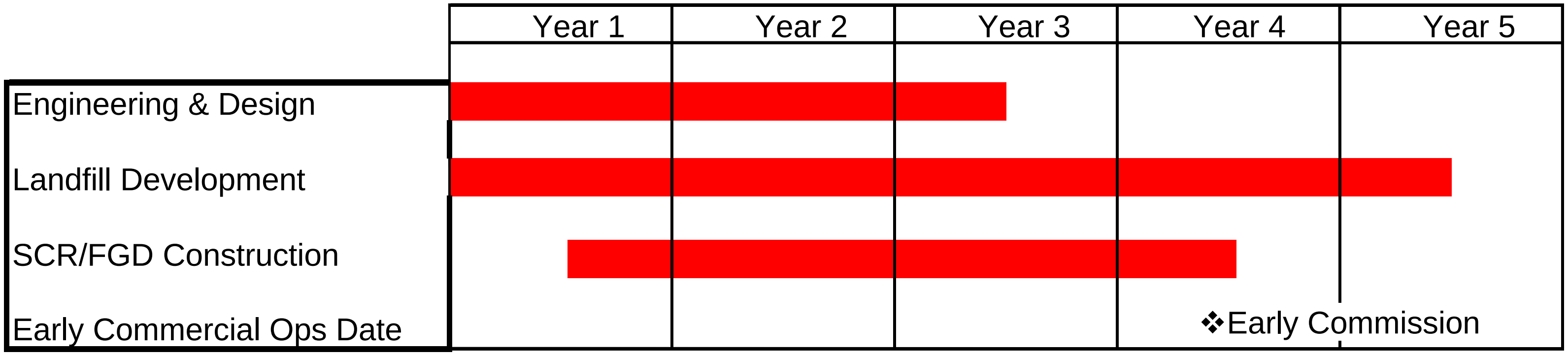
- The primary materials used during construction are steel and alloys, the cost of which, is volatile. We closely monitor the cost of such materials and strive to proactively manage our cost exposure.

Typical Vendors

- FGD
  - B&W
  - Alstom
  - B & V Chyioda
- SCR
  - Babcock-Riley Power
- Stack Supplier
  - Pullman Power Inc.

Typical FGD/SCR Project Milestone Schedule

- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, bid Phase 3 Construction At 30 – 60 % design complete
- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path



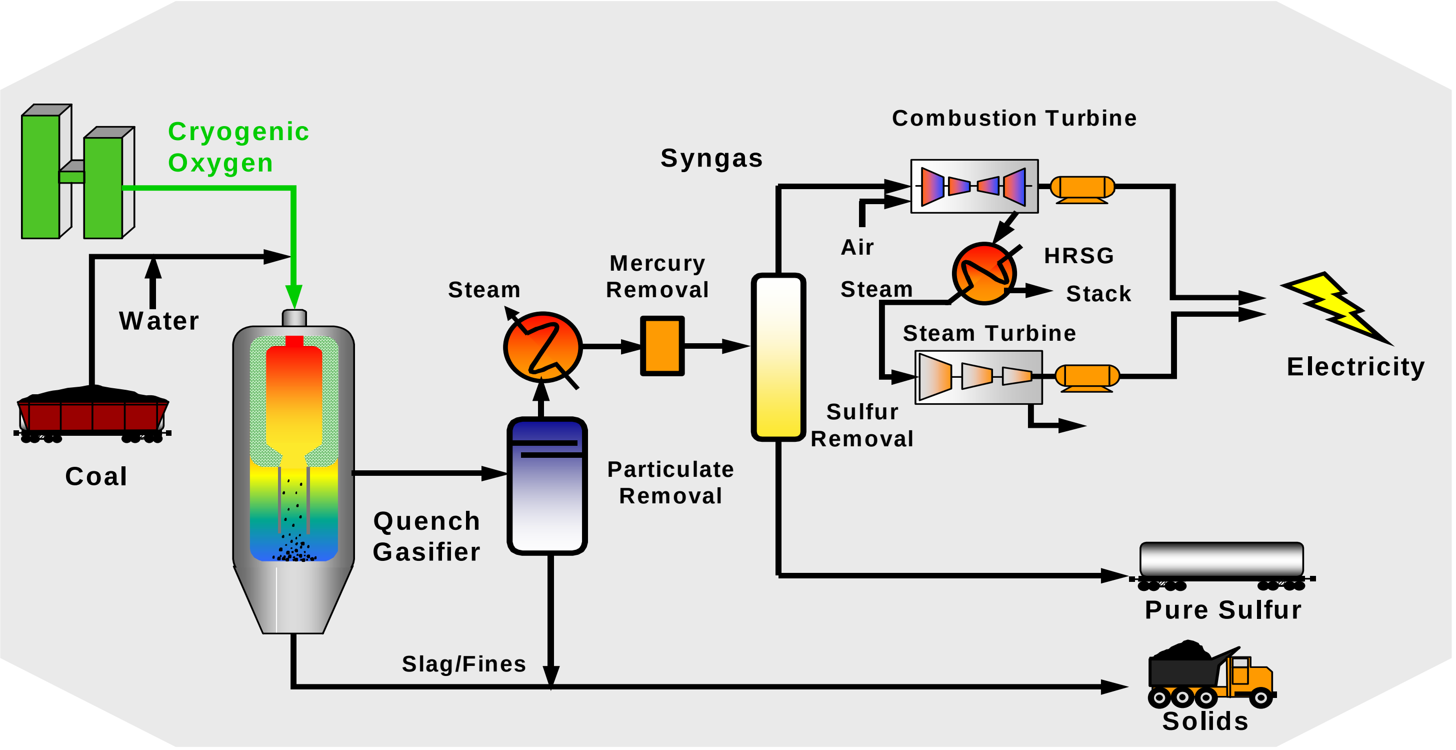
Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.

PLANT MODIFICATIONS WILL MITIGATE FGD AND SCR CAPACITY CONSUMPTION

Investing in IGCC

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- Secure cost recovery plan
- Finalize site selection
- Negotiate with suppliers

- 2005—2007: Obtain permits and finalize engineering and procurement

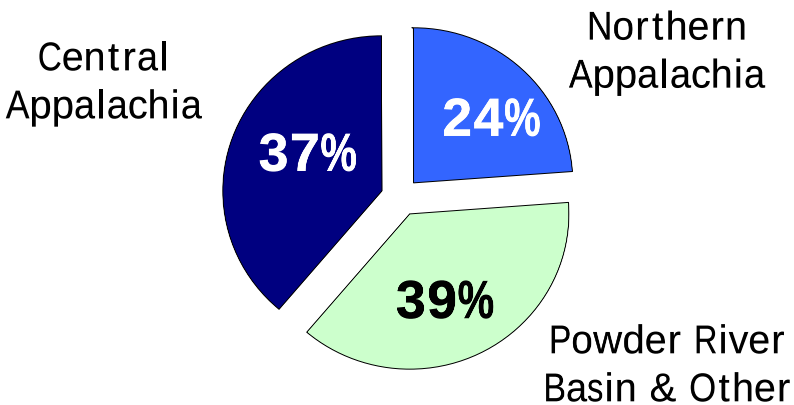
- 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Fuel, Emissions & Logistics

Coal Procurement

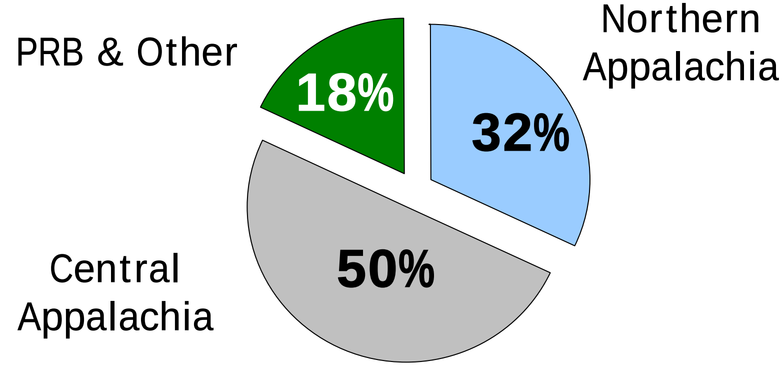
AEP SYSTEM



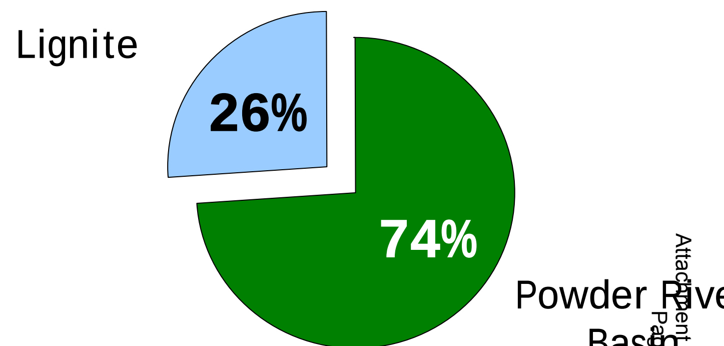
Coal Supply
(on average)

- ➢ Purchase 75 MM tons per year
- ➢ Avg. delivered price ~ $28.50/ton in 2004
- ➢ Essentially 100% purchased for 2005
- ➢ Approximately 12%-14% price increase in 2005
    - Increase being pressured by strong burn
    - PRB deliveries will impact results

EASTERN SYSTEM

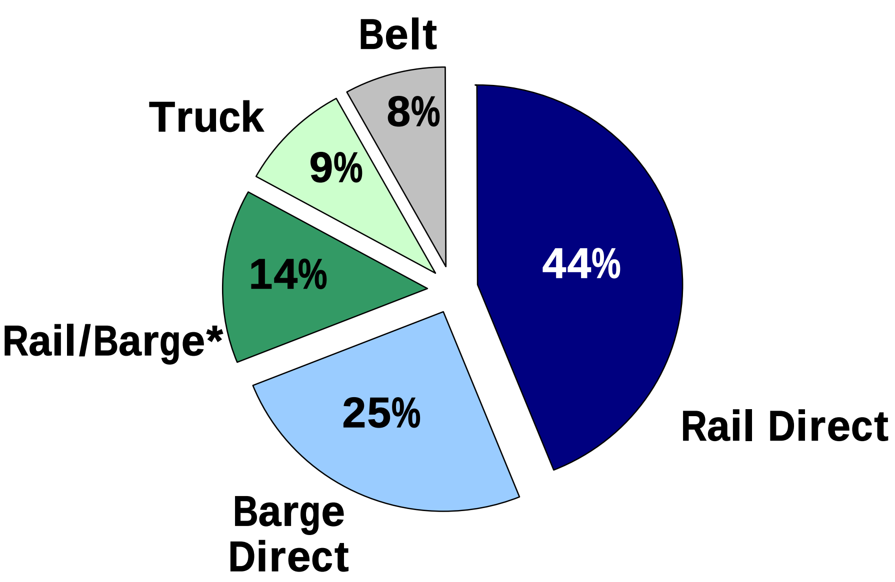


WESTERN SYSTEM

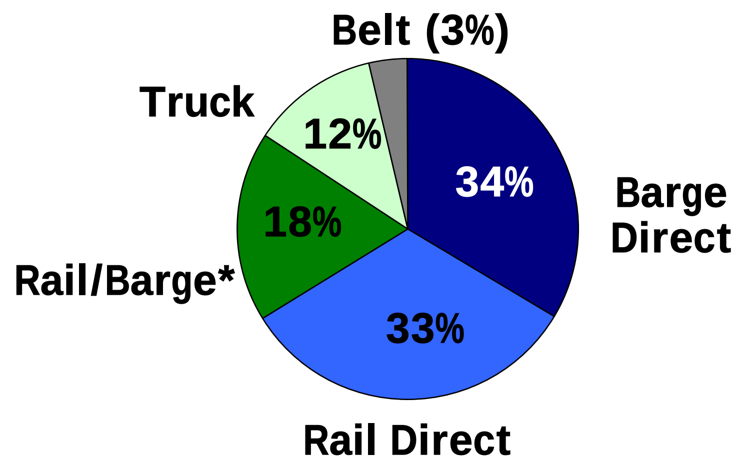


Coal Delivery Mix

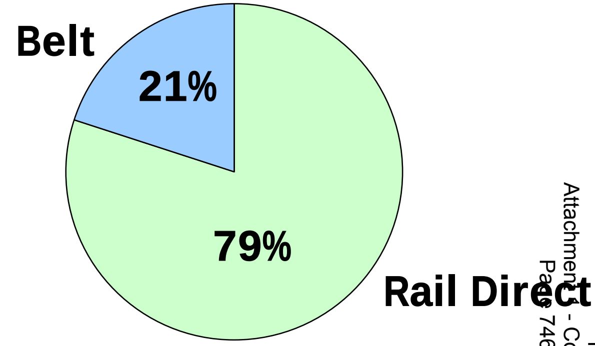
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



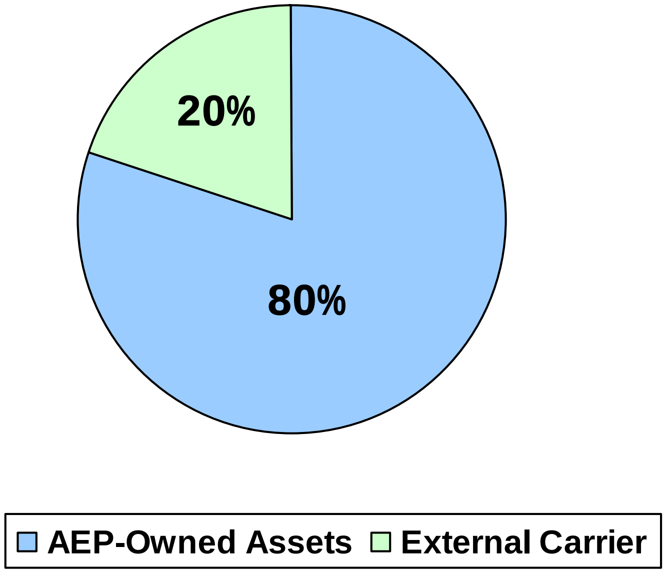
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

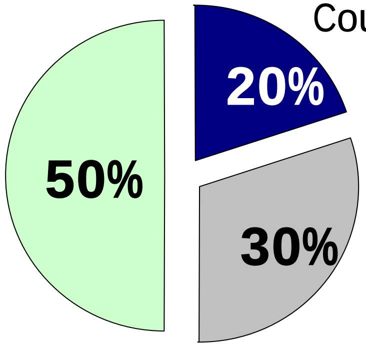
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM

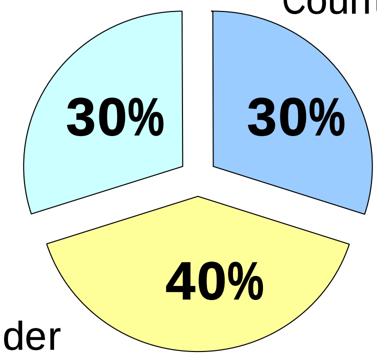


Fuel Cost Recovery
(on average)

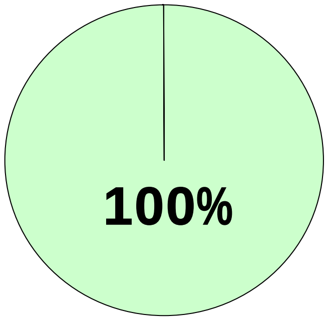
- ➢Fuel recovery varies by jurisdiction
- ➢70% of fuel cost is recoverable across the AEP System
- ➢Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



Regulatory Matrix – East

Ohio (Restructured)
• Unbundled rates for default customers frozen until 12/31/2005
• Pursuant to RSP Plan approved by PUCO 1-26-05:
  • Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  • Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  • CSP "G" rates to increase 3% per year (2006-2008).
  • OP "G" rates to increase 7% per year (2006-2008).
  • Transmission rates can upon filing reflect change in RTO costs.
• No active fuel clause
• Application for IGCC plant recovery filed on 3-18-05, Hearings are done. Initial and reply briefs were due 9-20-05 and 10-11-05, respectively.
• Hearings set for 10-11-05 on CSP's possible acquisition of Mon Power's Ohio service territory.
	West Virginia (Regulated)
	• Base rates not frozen
	• No active fuel clause
	• Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
	• On 8-26-05 AP & WP filed with the WVPSC for a $183 million revenue increase to be phased in over a four-year period beginning in mid 2006. The filing consists of a general rate case, reinstatement of the ENEC, to implement scheduled incremental rate increases for major clean air & transmission investments, and the implementation of a system reliability tracker mechanism.
	• On 8-31-05 AP and Reliant jointly filed with the WVA PSC for approval to buy Ceredo.

Virginia (Restructured) • Capped rates for default customers frozen through end of 2010 • Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms • Active annual fuel clause • On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental costs for environmental compliance and T&D System reliability (E&R) of $62.1 million, effective on an interim basis beginning 8-1-05. The commission has scheduled hearings to begin 2-7-06 and has stayed the effective date of rates pending resolution of a legal issue concerning the commission's authority to approve interim rates in this proceeding.	**Kentucky (Regulated)** • Base rates not frozen • Fuel clause, adjusted monthly • Environmental surcharge costs are adjusted monthly for approved environmental compliance plan • Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004 • On 8-26-05 the Company filed a notice of intent with the KPSC of its intention to file a case on or before 9-26-05 using a 6-30-05 ending test year. The level of rate increase was not specified. The Company expects an effective date on or before April 1, 2006 based on a 9-26-05 filing date.
Michigan (Restructured, but Regulated) • Base rates not frozen. • Active annual fuel clause.	**Indiana (Regulated)** • Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.
Tennessee (Regulated) • Base rates not frozen • Automatic fuel clause, adjusted monthly	

Regulatory Matrix - West

Texas (Regulated) • SWEPCO Texas retail competition delayed until at least 2007. PUC Chairman believes the precursors for full and open competition are not yet in place and will not exist prior to 2009. The Chairman committed to the Texas Legislature that the commission would consider maintaining the current status of competition in the SWEPCO Texas (and SPP portion of TNC) areas in future proceedings. • Bi-annual fuel clause adjustment opportunity **Texas ERCOT Area (Restructured)** • TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested) Hearings-late Sept. • TCC wires rate case PUCT approved final order on July 15. Final order results in slight rate decrease with a positive earnings impact. Rates are effective on September 6, 2005. • TCC final fuel reconciliation (July 98-Dec. 01) order on rehearing is final and appeals were filed in state and federal court in August 2005. • TNC true-up order approved in May 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC. The results of the true-up case were filed in TNC's Competition Transition Charge (CTC) proceeding in August 2005. • TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. District Court affirmed PUC on September 9, 2005. TNC will appeal. No action to date on appeals filed in federal courts in Dec. 2004.	**Oklahoma (Regulated)** • On 6-3-05 PSO filed to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval. Staff submitted testimony supporting an annual cap of $23.68 million up from the $11.81 million cap currently in place. The ALJ has recommended approval of the Staff proposed rider cap. The ALJ recommendation also allows for the recovery of return, depreciation, taxes, etc. associated with converting overhead distribution lines to underground. It is now pending a Commission decision. • Annual Fuel Clause • 2001 Fuel review case Hearings scheduled for Sept. 2005 have now been continued to a later date to be determined. Scope expanded to cover 2002-2004 margin allocation issue. Intervenors have submitted testimony which would substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error. • 2003 Fuel review case Scope has been expanded to include a prudence review.
Louisiana (Regulated) • Base rates not frozen • Currently under a merger required financial review • Fuel clause, adjusted monthly	**Arkansas (Regulated)** • Base rates not frozen • Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	POLR Rider	Revenues & POLR Rider*			Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs***	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit**	0	25	25	26	0	25	25	26
Recovery of RTO costs***	0	23	23	23	0	23	23	23
Total ETP Impact	**0**	**48**	**48**	**49**	**0**	**48**	**48**	**49**

* Incremental over 2004 base year

** Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

*** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

Components of TCC's Net True-up Regulatory Asset

	30-Jun-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 887	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(3)	(10)
Net Stranded Generation Costs	1,133	1,136
Carrying Costs on Stranded Generation Plant Costs	215	225
Net Stranded Generation Costs Designated for Securitization	1,348	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	102	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(209)	(212)
Net Other Recoverable True-up Amounts	315	287
Total Recorded Net True-up Regulatory Asset	$ 1,663	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $317 million recognized as income thru 6/30/05

Carrying charges for 2005 expected to be $87 million

Equity Component: $166 million to be recognized in income as collected

TCC SEEKING STRANDED COST RECOVERY OF $2.4 BILLION

Finance

2005 Cash Flow Projection

	2004 Actual	2005 Guidance	
Beginning Cash Balance	**$ 976**	**$ 420**	
Cash from Operations:			
Income from Continuing Operations	1,006	936	*
Depreciation & Amortization	1,300	1,305	
Pension Funding in Excess of Expense	(200)	(353)	
TCC ECOM/Carrying Cost	(304)	(101)	
Extraordinary Loss (net of tax)	121	-	
Other	674	136	
Total from Operations	**$ 2,597**	**$ 1,923**	
Cash from Investing:			
Capital Expenditures	(1,693)	(2,690)	
Asset Sales	1,357	1,498	**
Other	(40)	21	
Total from Investing	**$ (376)**	**$ (1,171)**	
Cash from Financing:			
Common Equity	17	(54)	***
Net Long Term Debt Issued/(Retired)	(1,829)	71	****
Preferred Stock Redeemed	(10)	(66)	
Short Term Debt Change, Net	(400)	16	
Common Dividends	(555)	(545)	
Total from Financing	**$ (2,777)**	**$ (578)**	
Net Change in Cash	**$ (556)**	**$ 174**	
Ending Cash Balance	**$ 420**	**$ 594**	

*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

*****Equity units terms require issuance of $345MM common shares in August 2005; offset by $427MM share buyback program**

****** Includes $550MM of parent debt reduction**

Note: 2005 capital expenditures exclude the announced Waterford and Monongahela Power transactions.

Long-term Debt Maturity Profile

Year[1]		2005		2006		2007
AEP Inc	$	-	$	395,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	-	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	300,000,000	$	-
Ohio Power Co.	$	-	$	-	$	-
Public Service of Oklahoma	$	-	$	-	$	-
Southwestern Electric Power	$	200,000,000	$	6,215,000	$	94,000,000
Texas Central Co.[2]	$	-	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**273,609,000**	$	**902,710,000**	$	**1,112,615,000**

(1) Maturities remaining as of June 30, 2005

(2) Excludes TCC securitization bonds

Capitalization

Capital Structure	Actual 3/31/05			Actual 6/30/05		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,359	-	12,359	11,916	-	11,916
Short-term Debt	19	-	19	14	-	14
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,268	8,268	-	8,382	8,382
Total Capitalization per Balance Sheet	**12,378**	**8,329**	**20,707**	**11,930**	**8,443**	**20,373**
% of Capitalization per Balance Sheet	***59.8%***	***40.2%***	***100.0%***	***58.6%***	***41.4%***	***100.0%***
Adjustments						
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Defeased First Mortgage Bonds	(84)	-	(84)	(84)	-	(84)
Off-balance Sheet Leases	1,241	-	1,241	1,227	-	1,227
Securitization Bonds	(668)	-	(668)	(668)	-	(668)
Spent Nuclear Fuel Trust	(230)	-	(230)	(232)	-	(232)
Equity Credit for Equity Units	(276)	276	-	(276)	276	-
Total Adjusted Capitalization	**12,361**	**8,605**	**20,966**	**11,897**	**8,719**	**20,616**
% of Adjusted Capitalization	***59.0%***	***41.0%***	***100.0%***	***57.7%***	***42.3%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.7% AT 6/30/05

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's*			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P2	-	S	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa2	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

* On September 14, 2005 Moody's upgraded AEP Inc.'s senior unsecured and commercial paper ratings to Baa2 and P-2, respectively.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7476 of 9556

2005 Earnings Guidance Range: $2.30 to $2.50

		2004 Actual Performance Driver	2004 Actual ($ millions)	2004 Actual EPS	2005 Forecast Performance Driver	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.[illegible]0
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Merrill Lynch Transmission & Power Equipment Conference

AMERICAN ELECTRIC POWER • 100TH ANNIVERSARY

1906 2006

A Century of Firsts

February 27, 2006
The Grand Hyatt Hotel
New York

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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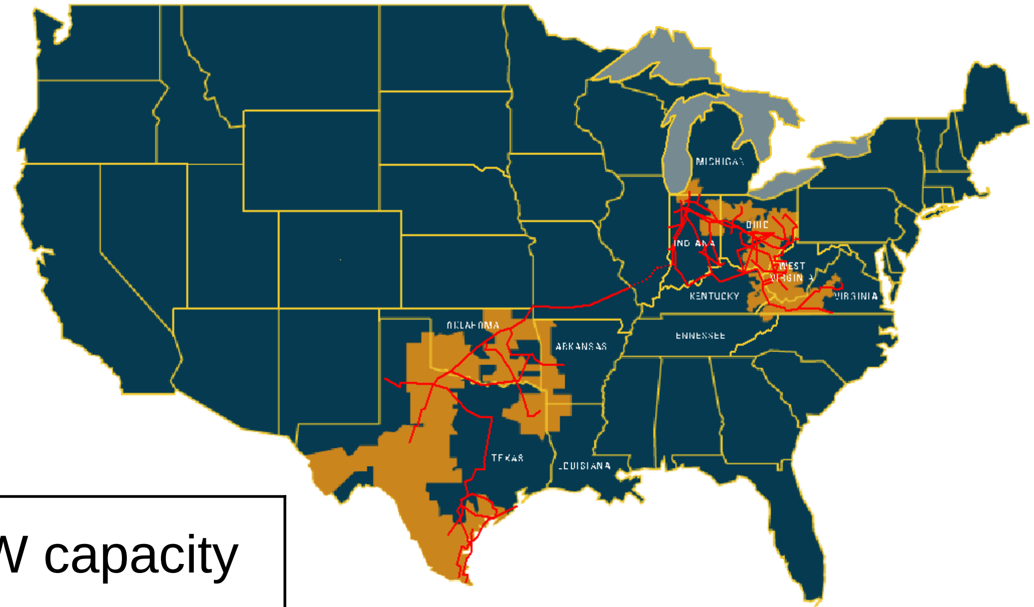
Strength & Scale in Assets & Operations



Generation*	35,600 MW capacity
Transmission	39,000 miles
Distribution	206,000 miles
Customers	5 million

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

AEP Transmission Assets

A Century of Firsts

Operating Company Level - (Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
APCo	644	97	383	106	0	3,281	0	43	1,077	791	0	230	0	**6,652**
CSP	0	0	884	0	0	824	0	0	469	0	59	0	0	**2,236**
I&M	615	0	1,614	0	0	1,663	0	0	705	0	0	744	0	**5,341**
KGPCo	0	0	0	0	0	0	0	0	3	0	0	27	0	**30**
KPCo	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
OPCo	509	0	909	0	0	2,463	0	0	2,168	0	0	366	112	**6,527**
PSO	0	0	579	34	8	2,123	10	0	812	0	0	0	0	**3,566**
SWEPCo	0	0	660	0	228	1,171	42	0	1,402	0	0	0	0	**3,503**
TCC	0	0	641	0	0	2,568	0	0	1,779	0	0	0	0	**4,987**
TNC	0	0	222	0	0	1,579	14	0	2,699	0	0	0	0	**4,514**
WPCo	0	16	9	0	0	175	0	0	88	0	0	0	0	**288**
Total	**2,026**	**113**	**5,909**	**140**	**282**	**16,166**	**67**	**43**	**11,746**	**846**	**59**	**1,370**	**112**	**38,879**

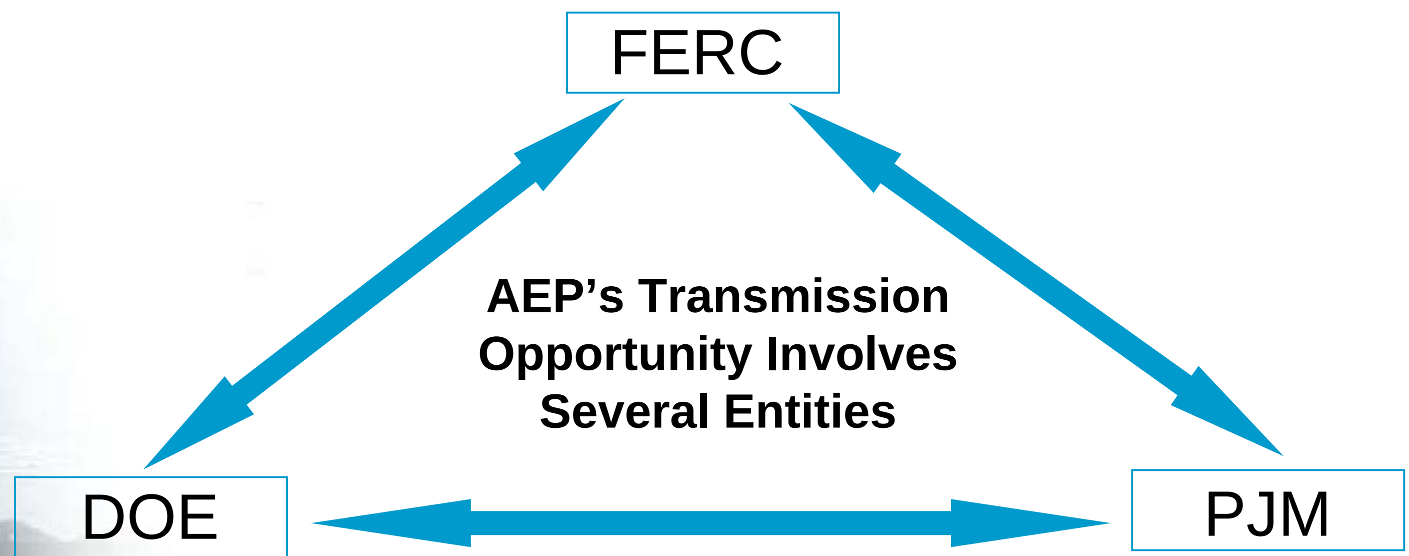
State Level - (Circuit Miles)

State	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	88 kV	69 kV	46 kV	40 kV	34.5 kV	23 kV	Total
Arkansas	0	0	28	0	228	168	42	0	461	0	0	0	0	**927**
Indiana	599	0	1,380	0	0	1,424	0	0	406	0	0	596	0	**4,405**
Kentucky	258	0	8	0	46	320	0	0	544	55	0	3	0	**1,234**
Louisiana	0	0	105	0	0	245	0	0	230	0	0	0	0	**580**
Michigan	16	0	234	0	0	239	0	0	299	0	0	148	0	**936**
Ohio	509	0	1,793	0	0	3,287	0	0	2,637	0	59	366	112	**8,763**
Oklahoma	0	0	625	34	8	2,148	10	0	812	0	0	0	0	**3,638**
Tennessee	0	0	0	91	0	154	0	0	3	0	0	27	0	**275**
Texas	0	0	1,343	0	0	4,879	14	0	5,189	0	0	0	0	**11,425**
W. Virginia	352	17	323	0	0	1,593	0	43	456	743	0	89	0	**3,617**
Virginia	292	96	69	15	0	1,708	0	0	709	48	0	141	0	**3,078**
Total	**2,026**	**113**	**5,909**	**140**	**282**	**16,166**	**67**	**43**	**11,746**	**846**	**59**	**1,370**	**112**	**38,879**

90 MILE WYOMING-JACKSONS FERRY 765-kV TRANSMISSION LINE SCHEDULED TO ENTER SERVICE MID-2006. THE NEW LINE WILL RUN FROM WYOMING, W.VA. TO JACKSONS FERRY, VA.

AEP Transmission Opportunity

The Energy Policy Act of 2005 provides an unprecedented opportunity for transmission development, and AEP is in an enviable position to build upon our core strength to extend our strong 765 kV system to meet the nation's urgent need for interstate transmission.



AEP Transmission Strategy Overview

Vision & Mission

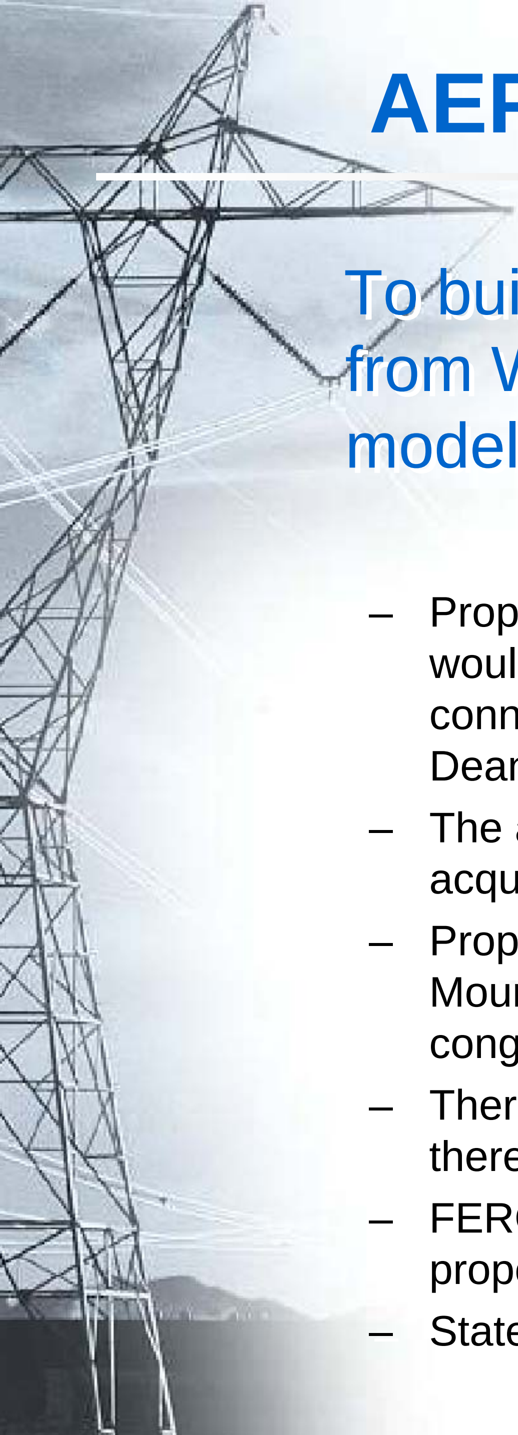
- To maintain our leadership in technical innovation of transmission systems and our position as the largest transmission company in the United States
- To set the standards for transmission safety, efficiency, and reliability

Strategic Opportunities

- To grow a vibrant Transmission business integrated within AEP, taking advantage of the tenets of the Energy Policy Act of 2005
- To aggressively seek recovery through various state/federal recovery mechanisms
- To significantly influence national debate on transmission aspects of the Energy Policy Act of 2005
- To advocate Transmission nationally as an enabler of economic opportunity, environmental optimization, and national security
- To advocate a national interstate grid, our core transmission strength

AEP Transmission Strategic Actions

- Settled FERC rate case for $22 million revenue increase in 2006, and revised OATT rates in Ohio while seeking recovery in other jurisdictions
- Developed opinion papers:
  - "Electric Transmission – Building the Next Interstate System," published in *Public Utilities Fortnightly* in January 2006
  - "R&D Technological Advances to Increase Power Grid Reliability: A Call to Action" with EPRI
- Participated in technical forums and policy debates, and provided comments on proposed rulemakings

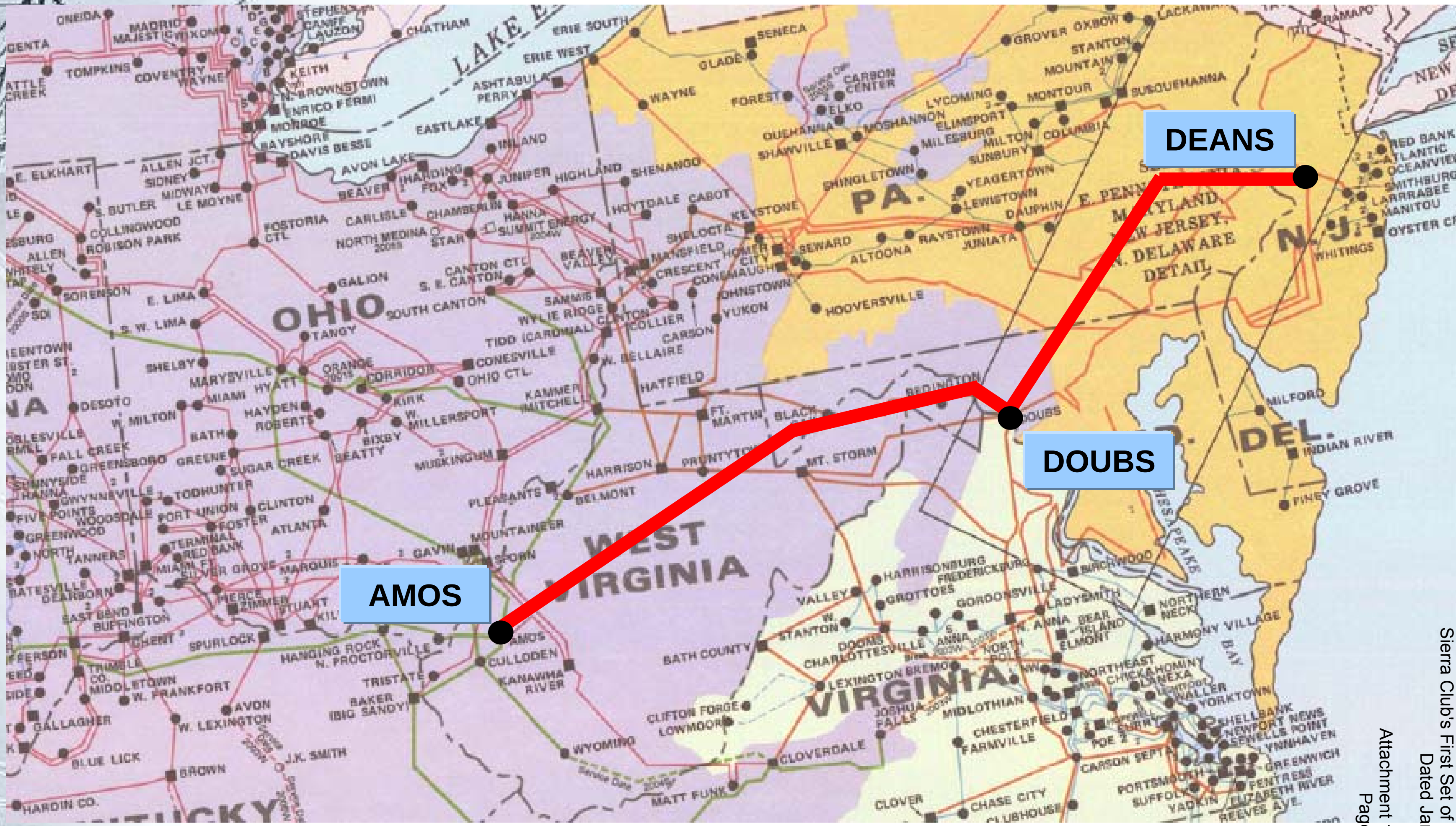


AEP Proposes Interstate Project

To build a new 765 kV transmission line stretching from West Virginia to New Jersey and to create a model to enhance AEP's transmission business.

- Proposed transmission superhighway will span approximately 550 miles and would originate at AEP's Amos transmission station in Putnam County, WV, connect through Doubs Station in Frederick County, MD, and terminate at the Deans Station in Middlesex County, NJ.
- The anticipated in-service date is 2014 assuming three years to site and acquire rights-of way and five years to build the line.
- Proposed route follows a corridor conceptually identified by PJM as Project Mountaineer, a transmission route needed to address critical transmission congestion within the PJM footprint.
- There is significant opportunity to improve west-east transfer capability and thereby reduce congestion and losses by developing I-765.
- FERC has indicated a stated need for transmission development and has proposed incentives for significant congestion relief.
- States appear receptive to transmission development.

Proposed AEP Interstate Project Route



Map of the Proposed AEP Interstate Project 765 kV Transmission Line Route

(Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

Interstate Project Benefits

- Improves market efficiency with reduced congestion, lowering consumer costs in the east
  - PJM congestion costs in 2004 totaled approximately $800 million, and in 2005, congestion costs are expected to exceed $1 billion
- Improves peak west-east transfer capability by 5000 MW
- Reduces network losses by 280 MW at peak with heavy west-east transfers
- Improves reliability significantly from the Midwest to the east
- Provides opportunity for AEP surplus generation and other generation in the area that can compete
- Provides opportunity for siting new generation for AEP and others
- Provides AEP traditional rate base opportunity with potential ROE bonus and other FERC NOPR incentives
- Creates ownership options

Interstate Project Regulatory Plan

- Project within PJM jurisdiction
  - Must participate in PJM regional planning process, but alignment with Mountaineer Project concept likely mitigates risk
  - Rights of first refusal

- FERC filing required
  - Propose Transco structure (as public utility, not merchant) under FERC jurisdiction
  - Propose pricing for Transco facilities using the regional “highway/byway” rate approach that matches our pending pricing proposal before FERC

- Request incentives as outlined in the NOPR

- AEP has filed with the DOE to have the proposed route designated as a National Interest Electric Transmission Corridor (NIETC) to expedite line certification and siting process

Buckeye Bus Tour
arranged by Merrill Lynch

AEP Headquarters
Columbus, Ohio

June 1, 2006

AEP
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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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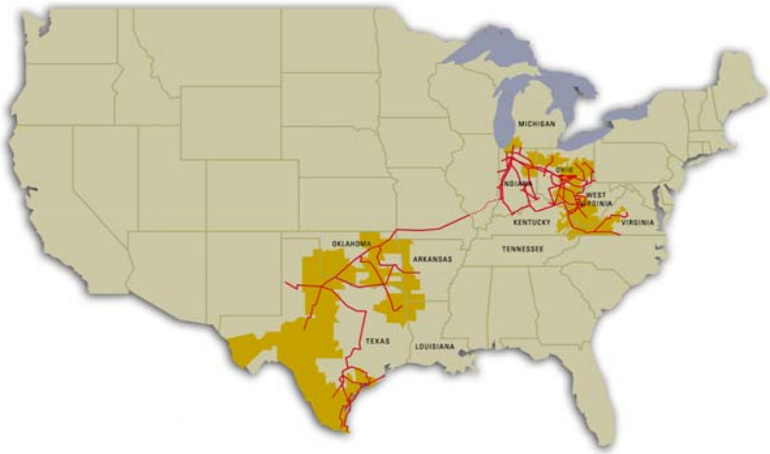
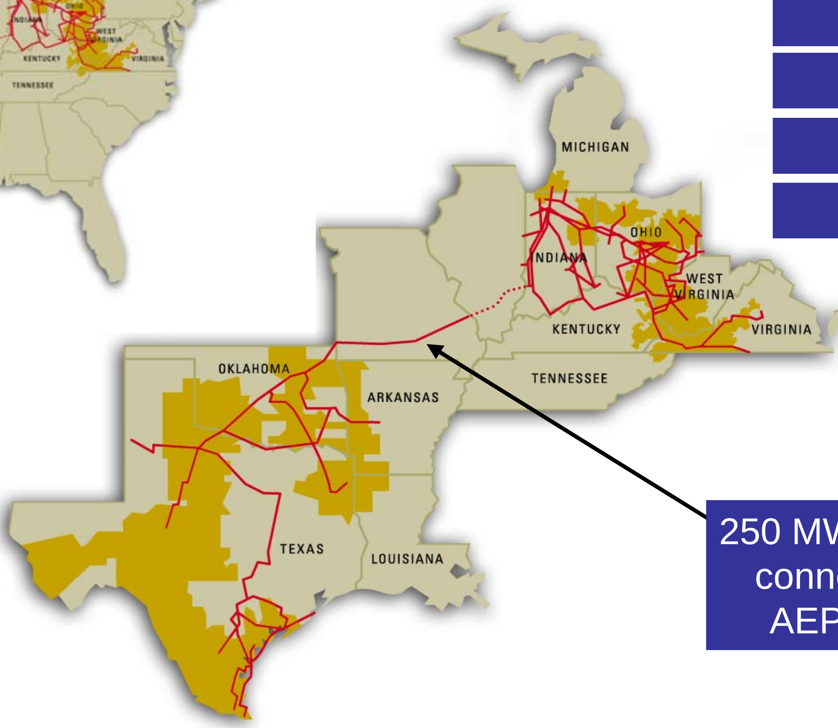
Company Overview

Where We Operate





Ohio
Indiana
West Virginia
Virginia
Kentucky
Michigan
Tennessee

Oklahoma
Texas
Louisiana
Arkansas

250 MW transmission line connects AEP East & AEP West territories

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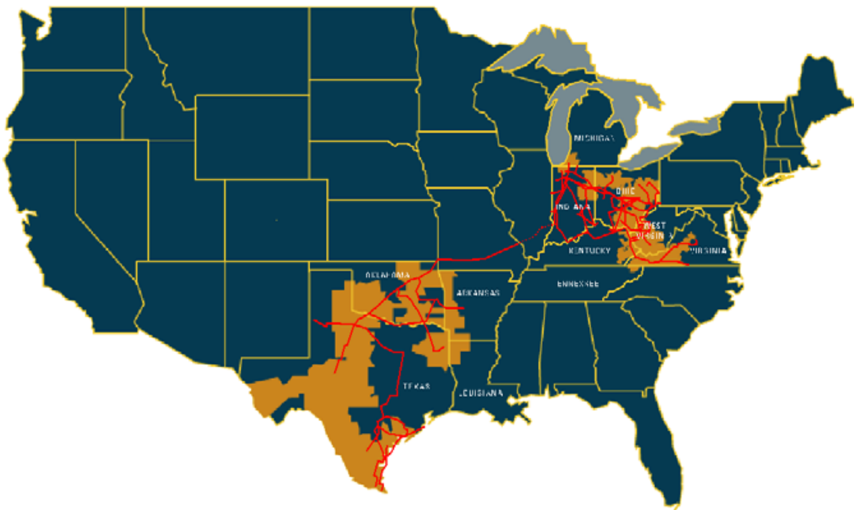
p.

Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



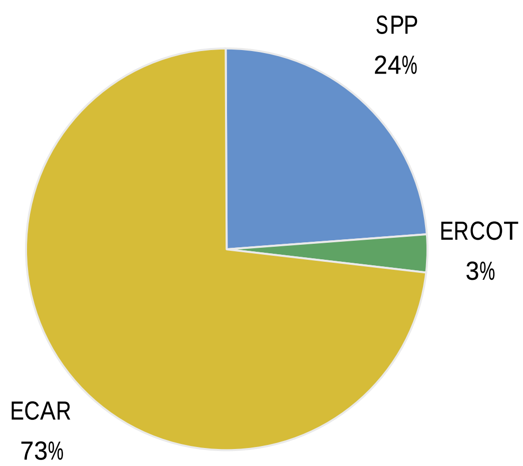
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

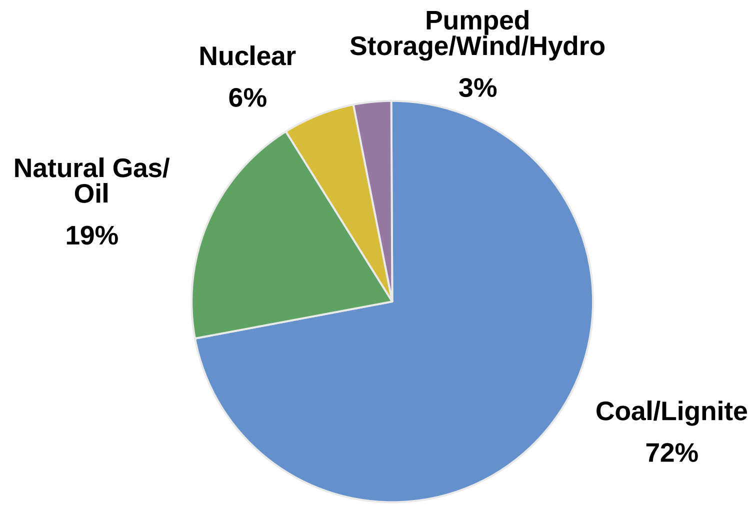
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

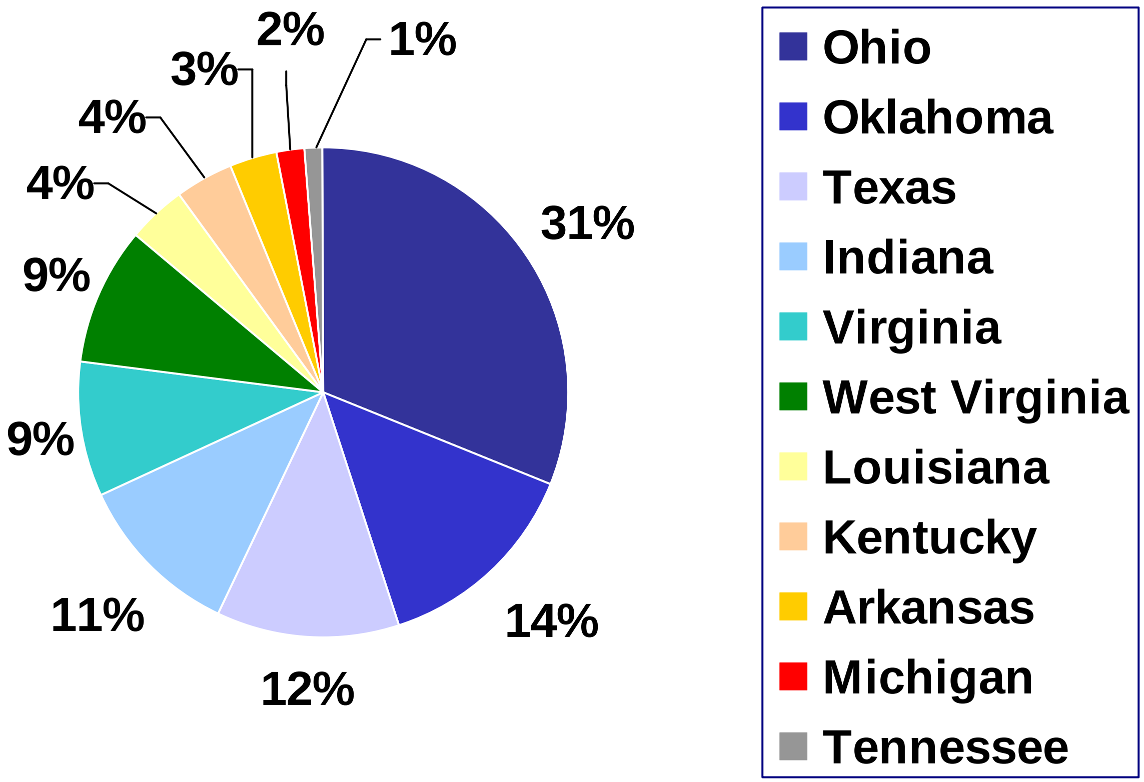
Operating Statistics

Commercial Availability Factor	
2004	85.24%
2005	84.50%

Capacity Factor	
2004	62.06%
2005	62.53%

2005 Retail Revenue

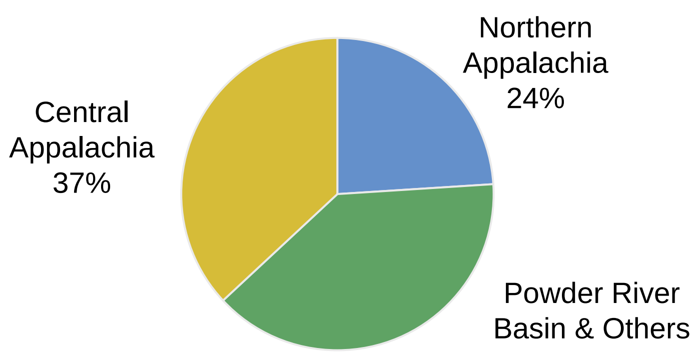
Retail Revenue Composition by State



Fuel

Coal Procurement

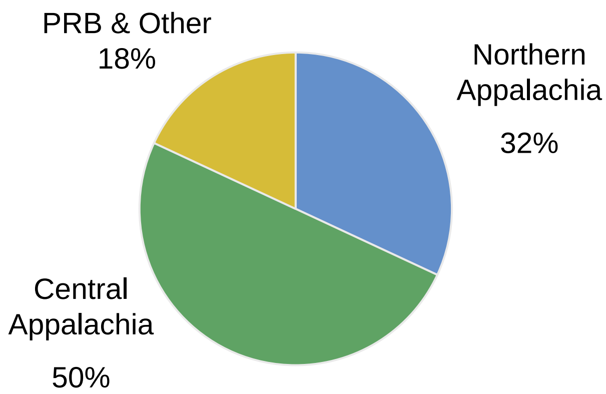
Total AEP System



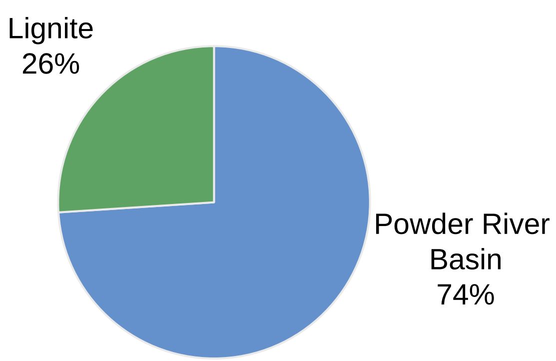
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 90%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System

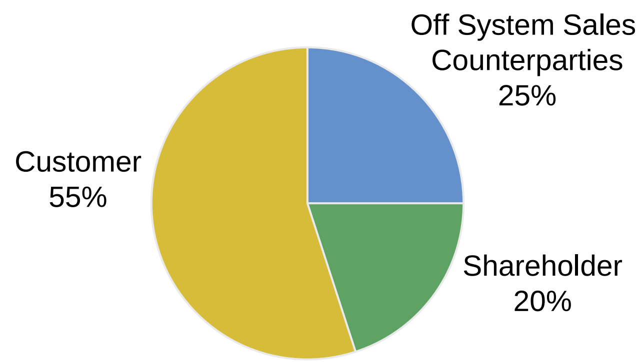


AEP Western System



Fuel Recovery

AEP System



Fuel Cost Recovery (on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

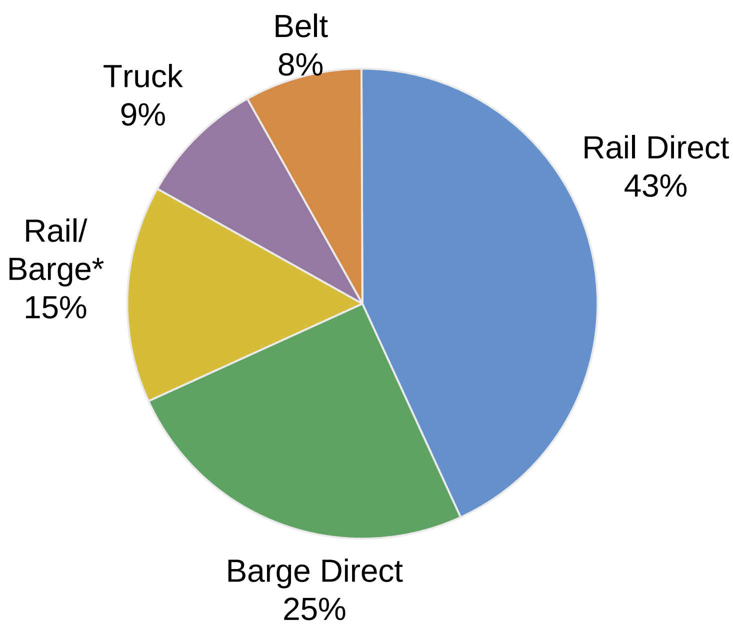
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Coal Delivery

Total AEP System

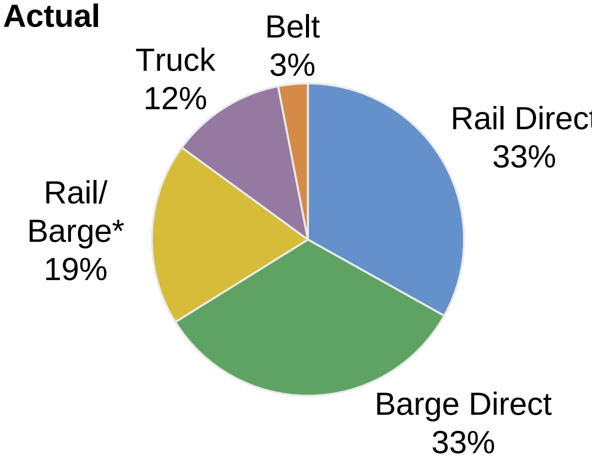
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

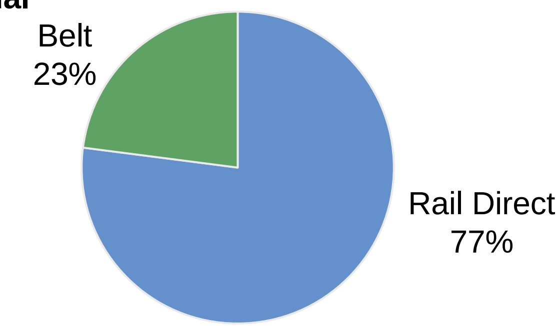
AEP Eastern System

2005 Actual



AEP Western System

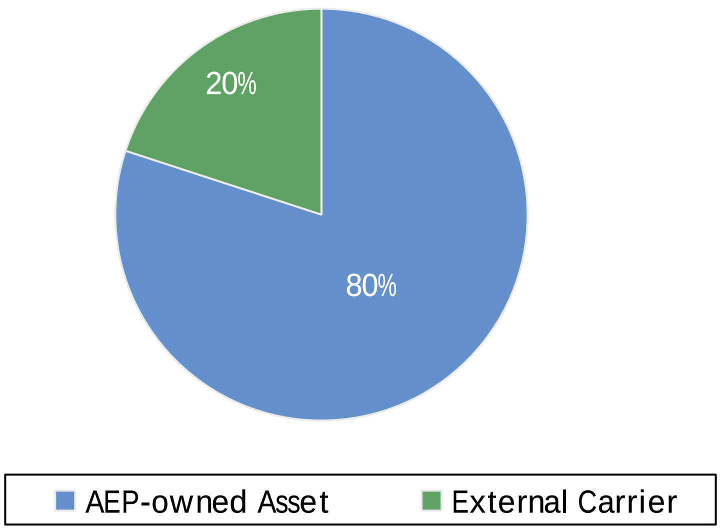
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

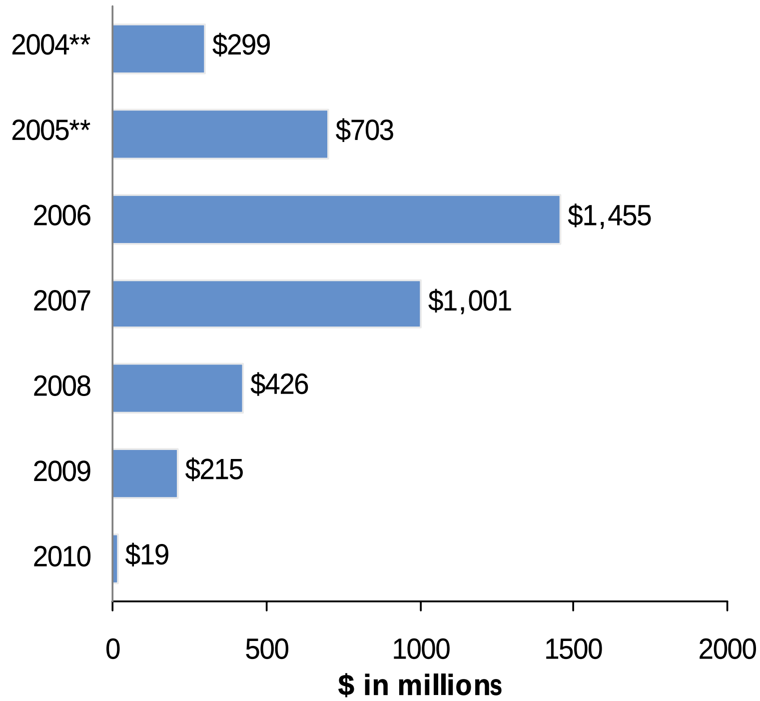
- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

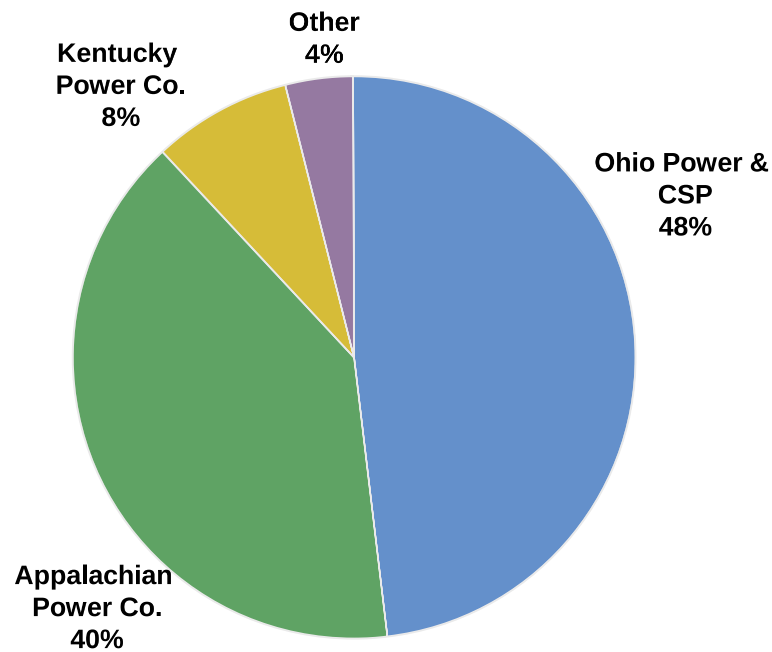
Environmental

$4.1 Billion Environmental Investment

Environmental Capital Investment*



Projected Environmental Investment Allocation



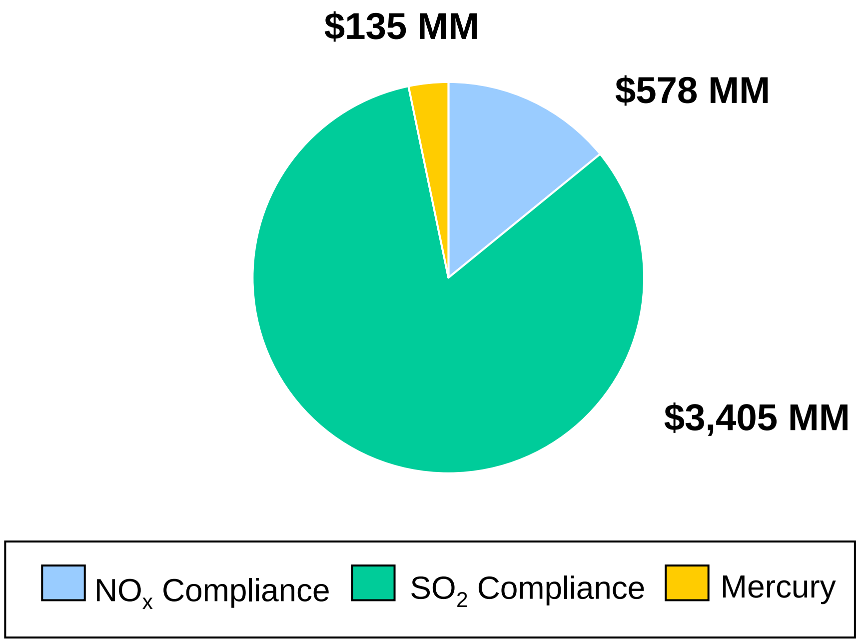
*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$2.0 Billion for SO_2

$0.1 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC

Environmental Installations

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

2006 – 2009

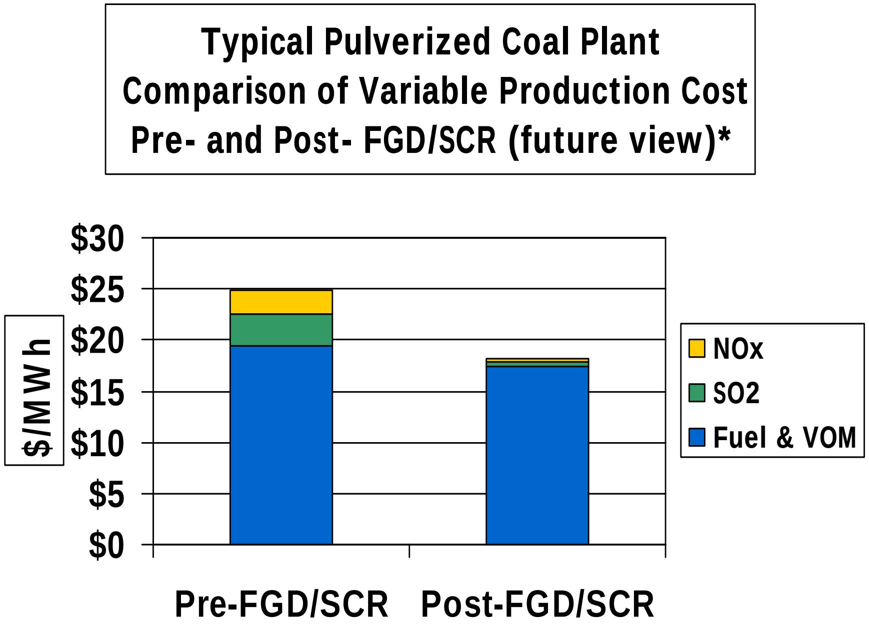
Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

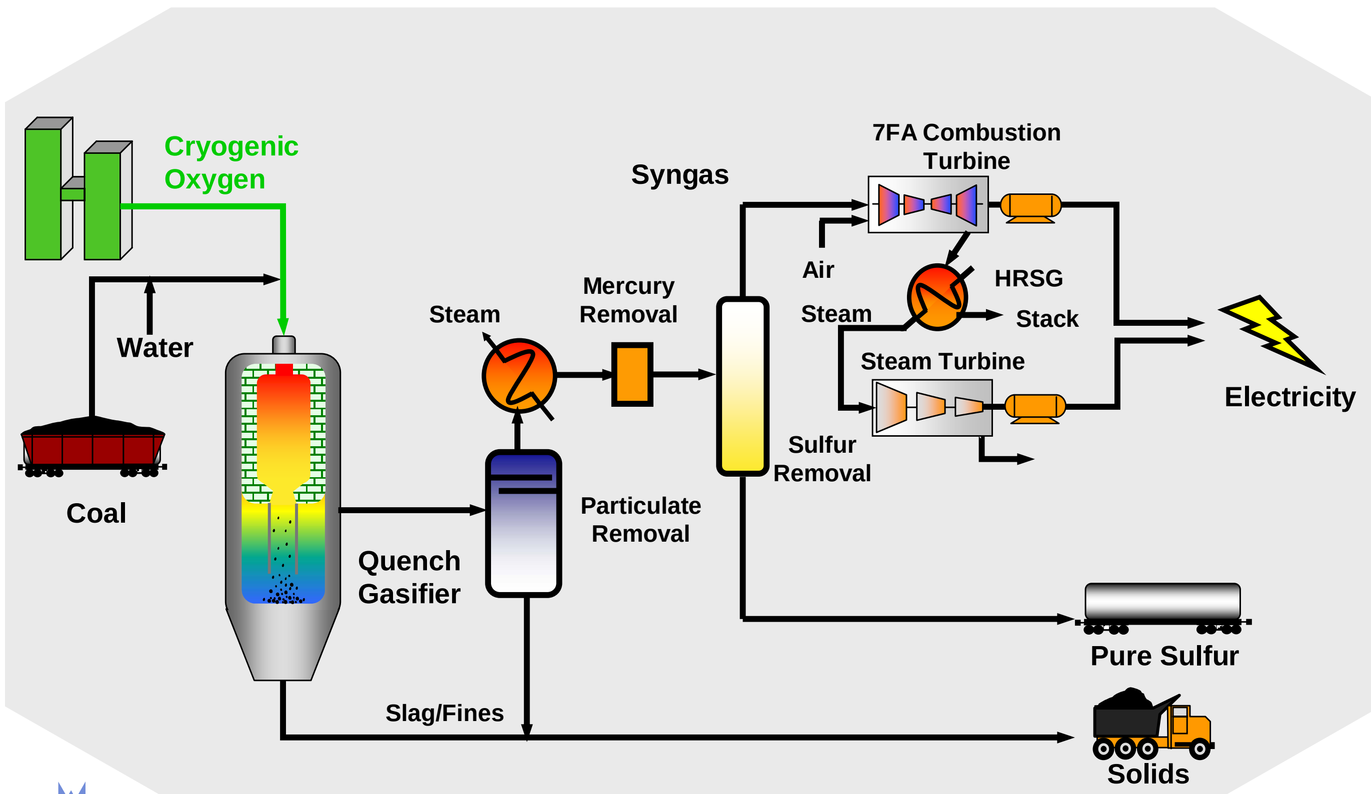
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



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AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8700**	**8600**	**7200**
Total Plant Cost (EPC) ($/kW)	**1700**	**1900**	**480**
Production Cost ($/MWh)	**17**	**16**	**57**
Cost of Electricity, without CO2 Capture ($/MWh)	**58**	**63**	**90**
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	**94**	**87**	**137**

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Regulatory Overview

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Regulatory Activity Underway

- TCC Request for Securitization of Stranded Costs
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia – Settlement Pending
- IGCC – Received Rate Authorization of Pre-Construction Costs

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
- May 22, 2006 – Settlement agreement filed with PUCT in securitization proceeding
  - Securitization financing order expected in June
  - Issuance of securitization bonds expected late 3Q06

Settlement Agreement (if approved):

- Securitization amount of $1.72 billion
- Securitization order not appealable
- Issues to be settled by the Commission:
  - Correct amount for ADFIT (assumed to be $315 million)
  - The treatment of ADFIT benefits either to be recovered through a CTC or as a reduction of the securitized amount
  - The treatment of EDFIT and ADITC ($90 million in total) either as a reduction to the costs to be recovered through a CTC or as a reduction to the securitized amount

- June 2006 – Request approval for CTC to address other true-up items
  - Expected $476 million credit to customers (assuming ADFIT is refunded through CTC)
  - Sept 2006 – CTC to be implemented

Regulatory Activity Underway

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Procedural schedule has been set with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

Regulatory Activity Underway

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2006 – Joint Settlement Agreement

- Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Settlement Details

- ✓ Increase effective July 28, 2006:

($18MM) Base Rates

$56MM ENEC

$23MM WJF & FGD investment @ 12/31/05

$61MM Gross revenue increase

($17MM) ENEC over-recovery negative surcharge

$44MM Net increase effective 7/28/06

- ✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2010:

- Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

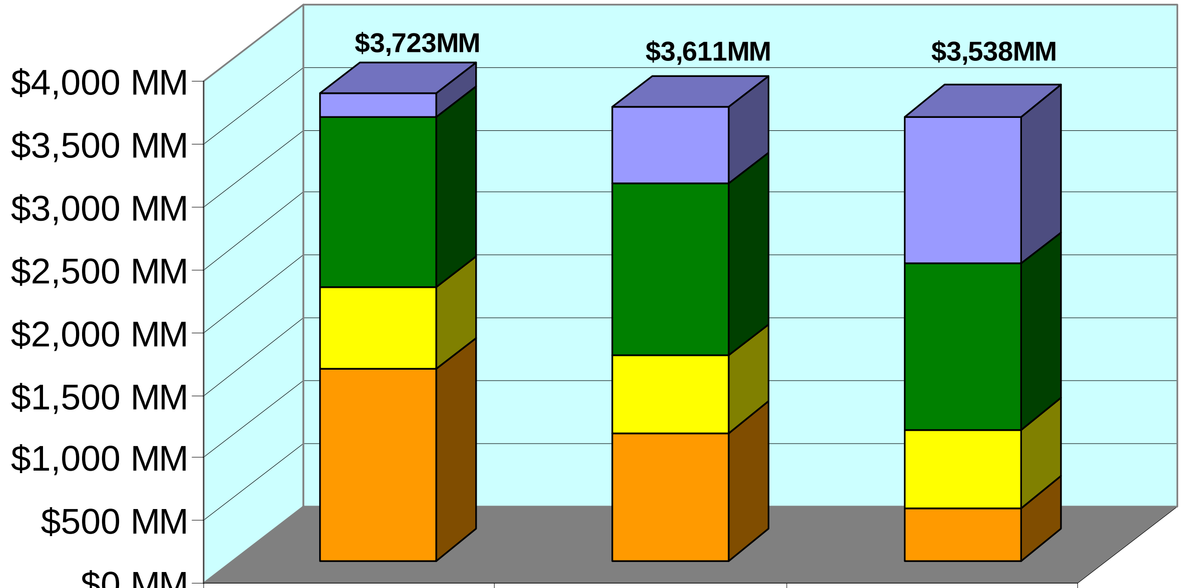
- $41 million annual increase in base rates
- To be effective March 30, 2006

Capital Investment

Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE - INVESTMENT LEVEL WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

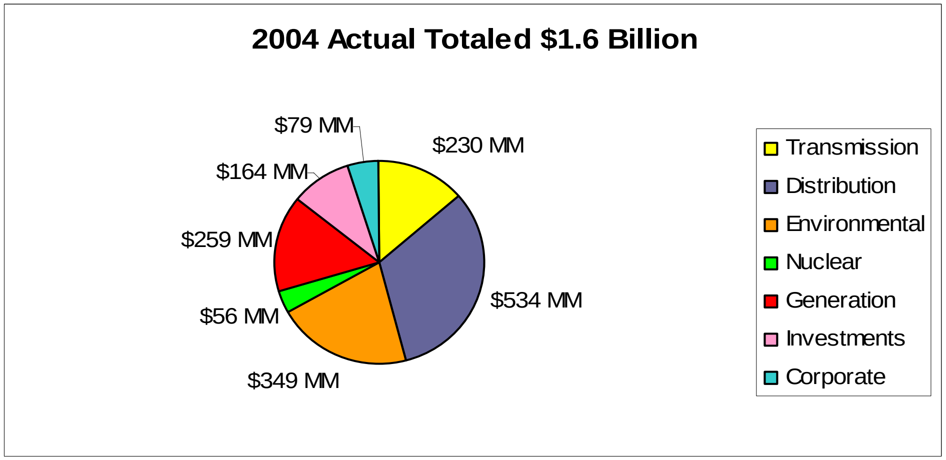
Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

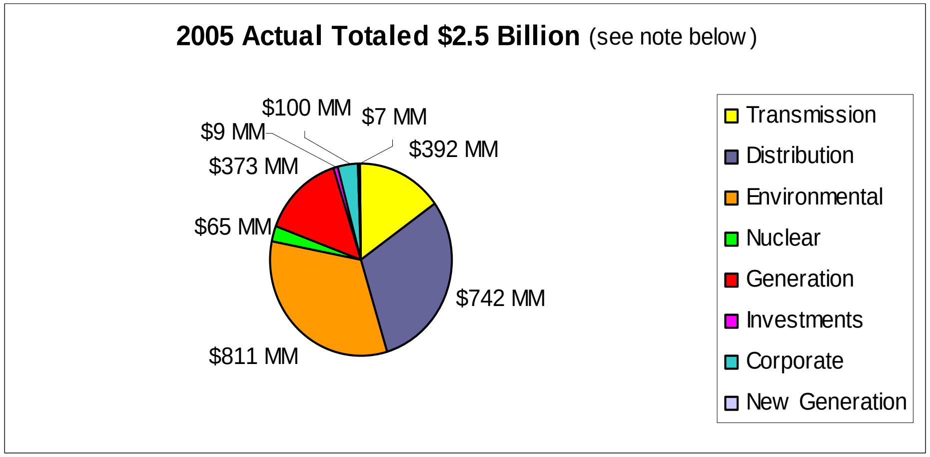
REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

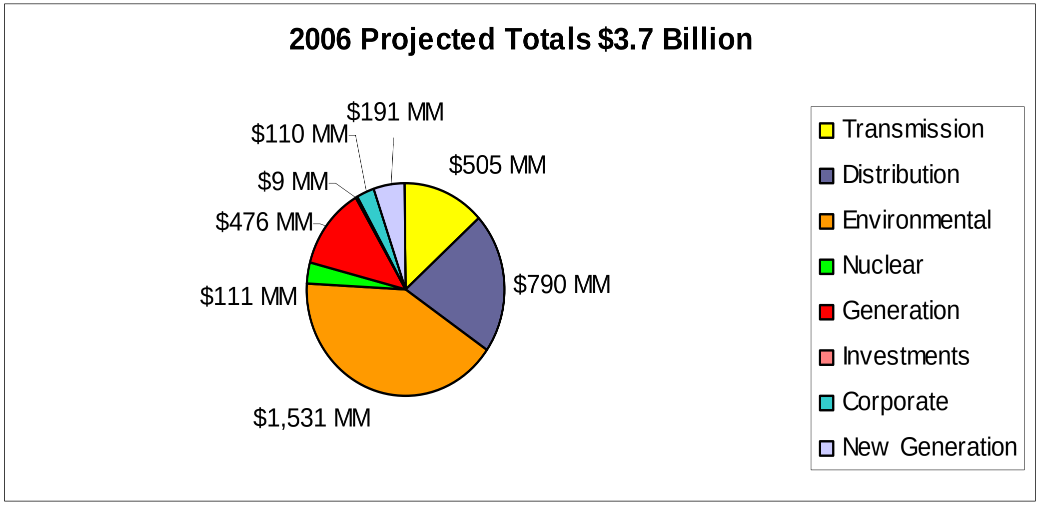
New Generation

IGCC	PSO RFPs	SWEPCO RFPs
➢ Expect to obtain permits and finalize engineering by 2007 ➢ Construction of 600 megawatt facility to begin in 2007 ➢ Commercial operation date expected in 2010	➢ Submitted RFPs totaling 900 megawatts of baseload and peaking capacity ➢ Two peaking RFPs totaling 340 megawatts awarded ➢ Commercial operation dates expected in 2008 and 2011	➢ Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity ➢ PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment 2004 - 2006







Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.

Figures exclude AFUDC.

Finance

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7524 of 9556

2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

Summary of Major 2006 Financial Performance Drivers

- Load Growth of 2.5%
- $500MM rate recovery assured or in progress
- Rising fuel costs of 11-13%
- Higher planned outages, increased retail load and sale of TCC generation to impact off system sales
- Decline in utility O&M
- Parent Company improvement (debt & interest expense reduction)

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 PERFORMANCE

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capital Structure

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.5% AT 3/31/06

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Ratings Actions

- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Forecasted Capital Expenditures

Company (in thousands)	2006	2007	2008
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

2006 Key Operating Company Highlights

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	(in millions) Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 (completed*)	42-45%
CSP	$343	$100 - $150	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$50 - $75	42-45%
OPCo	$1,070	$450 - $550	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$100 - $150	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

* Issuances completed in 2006 totaling $550 Million

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Long-Term Debt Maturity Profile[1]

Year	2006[2]	2007	2008
AEP Service Corporation	$ 2,000,000[3]	$ 2,000,000[3]	$ 34,000,000
AEP Inc.	$ 395,860,000[4]	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Ohio Power Company	$ 7,640,000[3]	$ 17,854,000[3]	$ 55,188,409[3]
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 11,047,000[3]	$ 95,312,136[3]	$ 12,538,117[3]
Texas Central Company	$ -	$ -	$ 18,581,000
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 716,547,000**	**$ 1,133,781,136**	**$ 512,307,526**

(1) Excludes tax exempt bond remarketings and securitization bonds
(2) Maturities remaining as of March 31, 2006
(3) Includes sinking fund payments, where applicable
(4) AEP Inc. $396 million global bond matured on May 15, 2006

Debt Schedules

American Electric Power Service Corp			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	4.709%	08/16/2007	$345,000,000
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

AEP Texas Central*			
Series	**Interest**	**Maturity**	**Amount**
First Mortgage Bond	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bonds	5.010%	01/15/2008	$103,272,491
Securitization Bonds	5.560%	01/15/2010	$107,094,258
Securitization Bonds	5.960%	07/15/2013	$214,926,738
Securitization Bonds	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North			
Series	**Interest**	**Maturity**	**Amount**
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,817,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,058,600

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Indiana Michigan Power Company			
Series	Interest	Maturity	Amount
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/1/2015	$125,000,000
Weighted Average or Total	4.971%		$1,220,083,600

Kentucky Power			
Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$11,707,314
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/1/2015	$200,000,000
Weighted Average or Total	4.386%		$1,881,953,514

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$24,974,947
Notes Payable	Floating	06/30/2008	$12,538,117
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	4.750%		$702,020,664

Note: Debt Schedules as of March 31, 2006

Appendix

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. On April 24th, APCo and Wheeling Power, together with the PSC staff and the Consumer Advocate in WV, filed a joint settlement agreement in the companies' rate case. The agreement provides for an initial $44 million increase in revenues, effective July 28, 2006. The initial increase consists of a $56 million increase for fuel and purchased power expenses, and $23 million for recovery of WJF transmission line costs and environmental investments to date. These increases are partially offset by an $18 million base rate reduction and a $17 million credit to customers for previously over-recovered fuel costs. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure – Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base – Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	1,676	1,970	2,018	2,253

Procedural Schedule

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearing
April 24, 2006	Settlement agreement filed
May 4, 2006	Legal briefs filed
May 15, 2006	Response briefs filed

Statutory Deadline: July 28, 2006

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

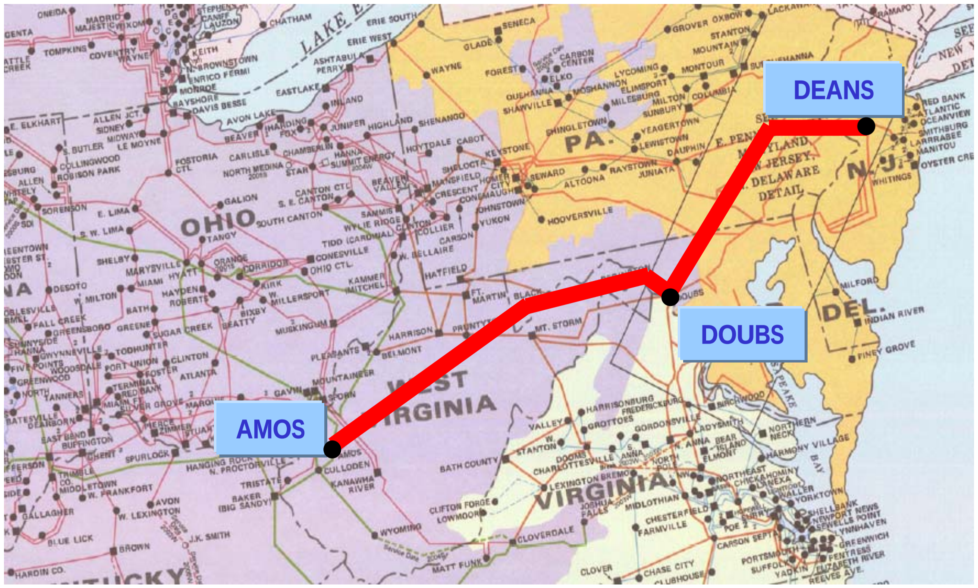
Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

2008 Merrill Lynch Power & Gas Leaders Conference

New York, NY

September 24, 2008

AEP AMERICAN ELECTRIC POWER®

Michael G. Morris

Chairman, President & CEO

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP's Key Strategic Priorities

Work for best possible outcome for the long-term value of our business in Ohio

- ❑ Comprehensive Electric Security Plan filed on July 31, 2008

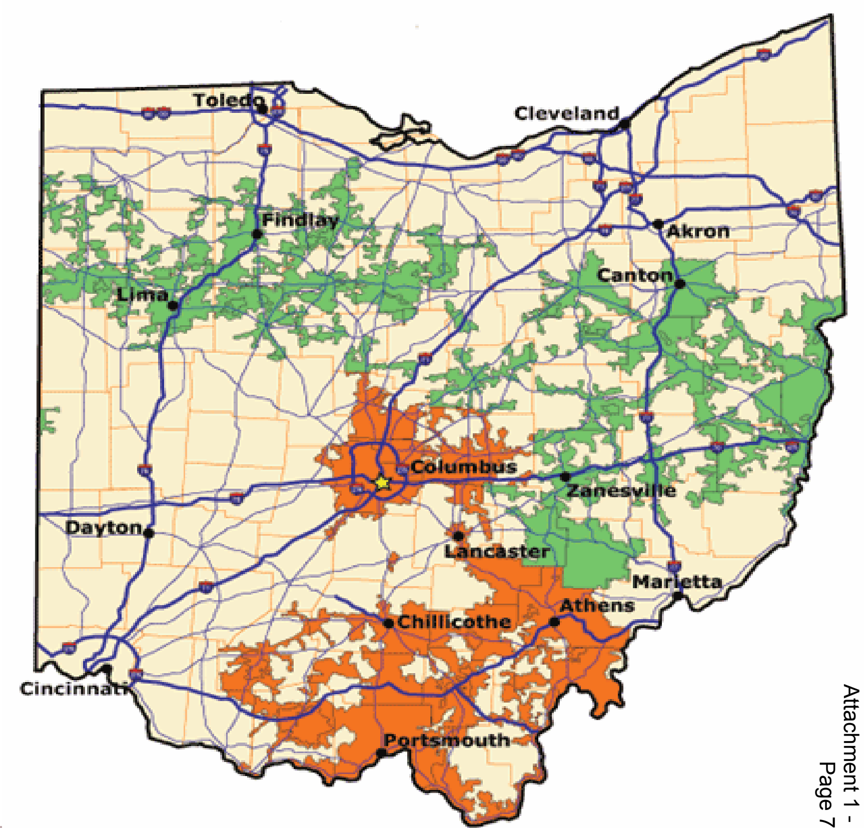
Invest in our vast energy platform to provide for growth:

- ❑ **Execute transmission strategies to support long-term earnings growth**
- ❑ **Implement customized state-by-state strategies to achieve sustainable returns**
  - ➢ gridSMART[SM] provides customers added optionality during a time of rising commodity prices
  - ➢ Investments in generation and distribution that align with the interests of our regulators
  - ➢ Fuel cost recovery in each jurisdiction mitigates the impacts of rising commodity costs

While today we will discuss our Ohio filing and managing commodity exposure, it is important to keep in mind that a continued disciplined capital investment/rate base growth, and investments in interstate transmission are the other main drivers of earnings growth over the next several years.

AEP Ohio Electric Security Plan

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing addresses a range of issues that are broader than simply focusing on the Standard Service Offer (SSO) and includes the following key components:
  - Renewable Energy
  - gridSMART[SM] Phase 1
  - Distribution Reliability Enhancement
  - Energy Efficiency and Demand Response
  - Economic Development



Components of Filing

- Renewable Energy: RFP for up to 300 MW of renewable sources of energy has yielded reasonable wind bids including the possibility of a "jump start" on wind sources physically located in Ohio.

- Gridsmart: Phased-in approach to implementing specific components, including Automated Meter Infrastructure (AMI), Home Area Networks (HAN) and Distribution Automation (DA)

  - Phase 1 will be installed over a three-year period in the northeast area of central Ohio

- Distribution Reliability: Designed to reach a higher level of reliability and includes incremental vegetation management and expansion of current base programs

- Energy Efficiency & Demand Response: AEP is conducting a Market Potential Study collaboratively with a group to explore and develop a suite of cost effective programs.

Customer Rate Impacts

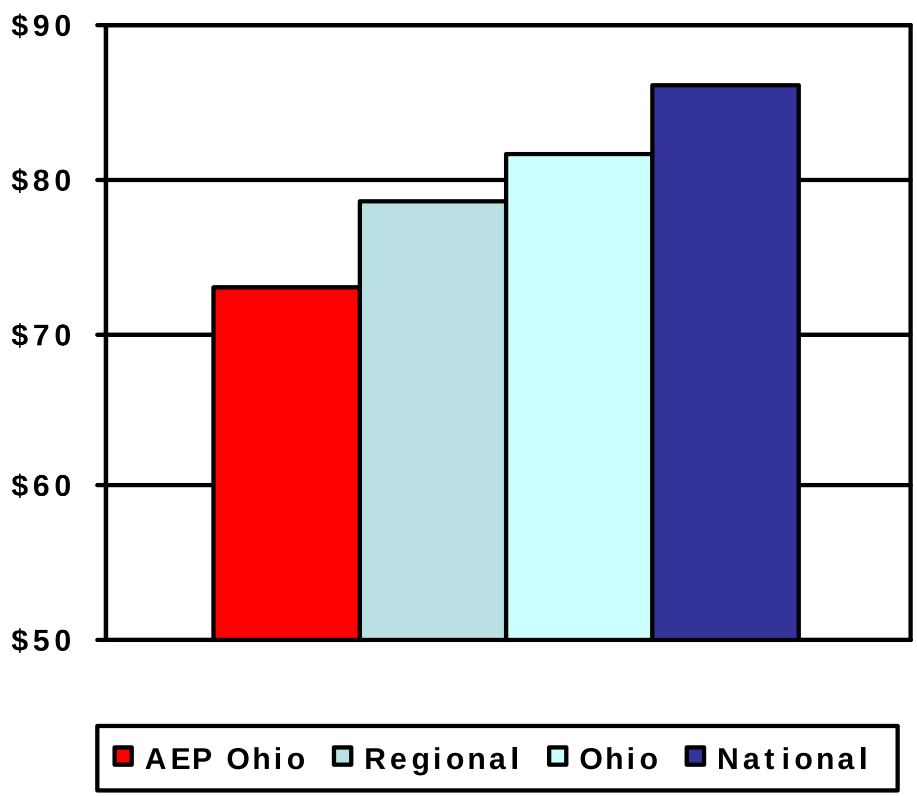
- Key components included in rates include:
  - Phase-in of FAC expenses
  - Environmental capital (carrying charge on investments not currently reflected in rates)
  - Basic non-fuel generation (primarily continuation of the 3% & 7% consistent with RSP increases)
  - Energy efficiency and demand reduction riders
  - Distribution (enhanced reliability and gridSMART)
  - Regulatory assets amortization (SB3 implementation, etc.)
  - Provider of last resort (POLR)

Next Steps:
Intervenor testimony is due October 31, 2008
Staff testimony is due November 7, 2008
Public hearing commences on November 17, 2008. We anticipate an order at the end of 2008.

Proposed rate plan results in annual increase of approximately 15% on customers' total bill, with deferral and phase-in of Fuel Activation Clause (FAC) expenses

A Look At How We Compare

AEP Ohio's rates are well below regional and national averages



Based on EEI Typical Bills and Average Rates Report – Winter 2008. Average CSP and OPCo residential bill using 750 kWh per month.

Rates across the country will continue to escalate as commodity prices increase

Coal and Transportation Position

Committed Coal Position

% of forecasted burn

- **2008 99%**
- **2009 94%**
- **2010 88%**

- **Continue to secure short/medium/ long-term fuel supply contracts-continue to manage as a portfolio**
- **Testing alternate fuel blends at various plant to optimize plant economics and fuel choice flexibility**
- **Continuing to evaluate additional delivery options to increase capability and flexibility**
- **Transportation positions have been secured for rail contracts and are not up for renegotiation during the period.**
- **Transportation utilizing barges through AEP River Operations provides a meaningful hedge and reliable service.**

AEP buys 55% of all the coal that is mined in Ohio

AEP River Operations

- **Full-service Inland Waterways carrier**
  - **2,900 hopper barges**
  - **60+ towboats/20 tugs**
- **Tonnage & Commodity:**
  - **Captive: (for AEP)-37MM tons of coal;**
  - **Commercial: 35MM tons of coal/grain/bulk**
- **Gulf Operations**

  Barge cleaning and repair

  Fleeting and shifting

  Midstream transfers
- **Operating Centers in Lakin, WV, Cape Girardeau, MO, Paducah, KY, Convent and Belle Chase, LA**

Inland Waterway Routes For AEP River Operations

Questions

Appendix

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

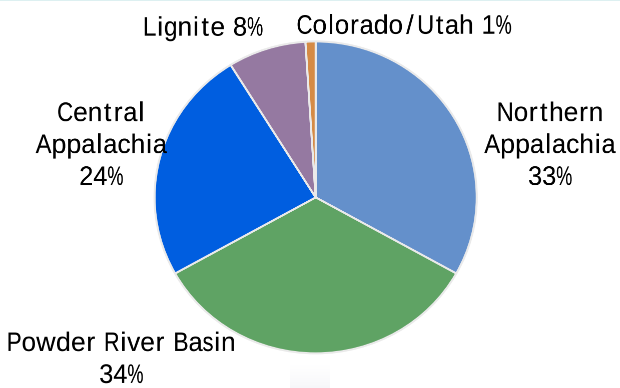
		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

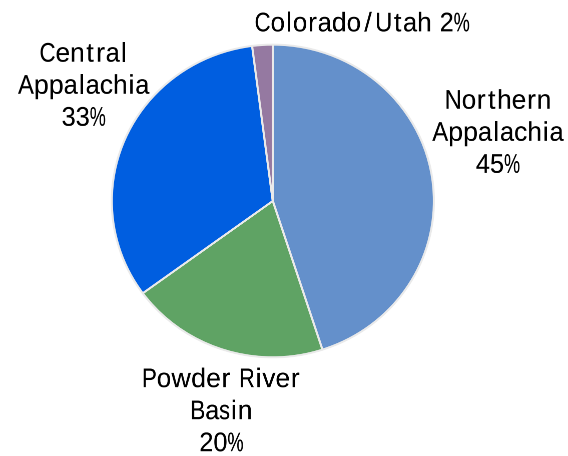
Total AEP System



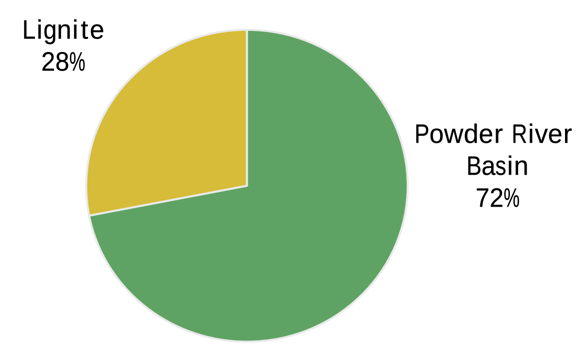
Coal Stats:

- > 99% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East



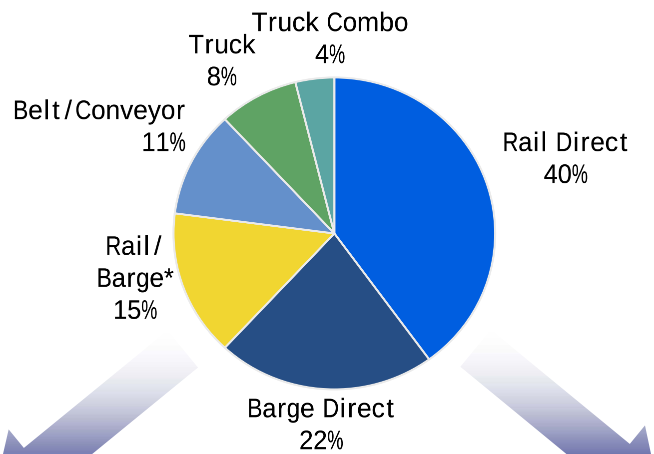
AEP West



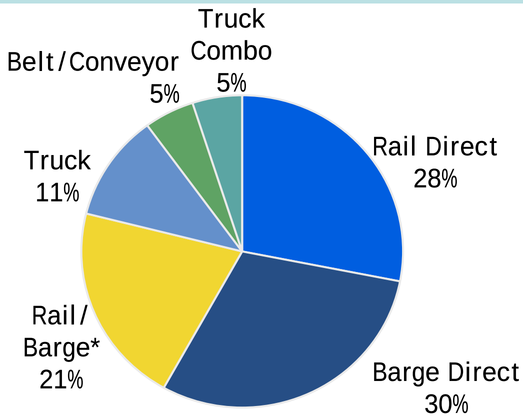
Coal Delivery

2007 Actual

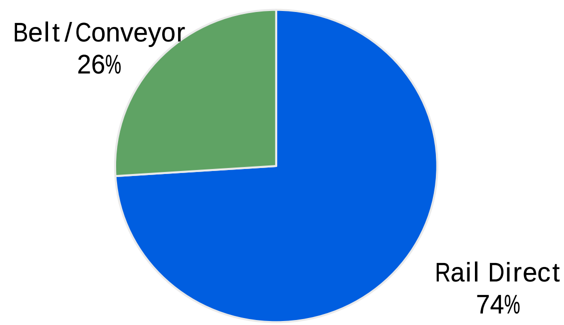
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

gridSMART℠ Evolution – AEP East

	State Policy	AEP Action Plans
AEP OHIO — A unit of American Electric Power	SSB 221 provides targets and provisions for DSM/EE programs and supports infrastructure modernization.	Filed an Electric Security Plan (2008) which includes a model city pilot in NE Columbus and addresses DSM/EE programs.
AEP APPALACHIAN POWER — A unit of American Electric Power	Policy in VA is beginning to drive both renewables standards and DSM/EE programs.	AMR investments in VA and WV will defer new AMI for several years. New 2 MW NaS battery in Milton, WV will test dynamic islanding – supplying electricity while disconnected from the grid.
AEP KENTUCKY POWER — A unit of American Electric Power	KY's commission rules regarding DSM/EE programs are the model we seek in other states. However, like in other states, cost effective programs are difficult to implement due to KPCo's low rates.	Existing programs are focused on low-income weatherization and heat pump programs for mobile homes and receive favorable recovery.
AEP INDIANA MICHIGAN POWER — A unit of American Electric Power	IN & MI both have strong interests in efficiency programs. MI is considering requiring 2% of state revenues allocated to EE.	Broadly focused South Bend Pilot includes AMI, distribution automation, demand response, pre-paid meters. NaS battery installation in IN in 2008 to demonstrate storage with intermittent wind.

The eastern states are evolving in their positions regarding demand management, energy efficiency and AMI investments.

gridSMART^{SM} Evolution – AEP West

	State Policy	AEP Action Plans
AEP TEXAS — A unit of American Electric Power	Current legislation supports concurrent cost recovery of DSM/EE programs. Legislature expecting distribution service providers in ERCOT to file plans for smart meter deployment.	Executing aggressive DSM/EE programs with targets of 15% and 20% offset to growth in 2008 & 2009. Will file by Oct. 31, 2008 a deployment plan for smart meters.
AEP PUBLIC SERVICE COMPANY OF OKLAHOMA — A unit of American Electric Power	Heavily involved in DSM rulemaking with OCC and rules to be developed in Oct 2008. Small DSM/EE program ($4.3M) approved.	Conducting small scale Distribution Automation pilot in South Tulsa. In process of implementing DSM/EE programs.
AEP SOUTHWESTERN ELECTRIC POWER COMPANY — A unit of American Electric Power	DSM/EE program costs are recoverable thru a rider in AR and base rates in LA and TX. There is no statutory support for AMI outside of TX footprint.	Continue DSM/EE in AR and in TX.

Texas currently has the most progressive legislative stance with regards to supporting AMI. PSO and SWEPCo have active DSM/EE programs with Distribution Automation pilots proposed in each state.

Regional Capacity and Energy Situation: AEP East

Generation planning in the East is a mix of regional and state-level strategy. Planning is regional because capacity requirements and energy to serve native load are shared under AEP's pooling agreement. Execution is state-by-state because regulators control cost-recovery approval for any new plants and sharing of off-system sales margins.

AEP OHIO
A unit of American Electric Power

- OPCo is significantly long capacity.
- CSP gradually gets capacity short as plants are retired.
- SSB 221 sets significant renewable and advanced energy standards, but contains provisions for a waiver of the requirements if the costs are too high.

AEP APPALACHIAN POWER
A unit of American Electric Power

- APCo is the most capacity-short company in the East.
- WV has a strong long-term interest in coal.
- Law in VA sets voluntary renewable targets.
- AEP continues to pursue wind energy through long-term PPAs.

AEP KENTUCKY POWER
A unit of American Electric Power

- KPCo is short capacity, but less so than APCo.
- KY also has a strong long-term interest in coal.

AEP INDIANA MICHIGAN POWER
A unit of American Electric Power

- I&M is long capacity (no new fossil generation in the near or mid-term).
- IN & MI legislatures are considering RPS standards, with wind being the renewable of choice in IN.

Regional Capacity and Energy Situation: AEP West

CAPACITY POSITION

- PSO and SWEPCo are currently capacity deficit and filling their needs with market purchases.

PSO New Generation Situation

- Regulators will act, but regional economic interest still prevails.
- As a clear example, the Oklahoma Commission acknowledged and approved PSO's need for 450MW of baseload capacity, but denied a CCN and cost recovery for the proposed coal-fired Red Rock plant.
- An RFP was issued to purchase needed capacity and energy and proposals were due August 22. Evaluation of the proposals is underway.

ENERGY POSITION

- PSO and SWEPCo are also facing significant, growing energy deficits.

SWEPCo New Generation Situation

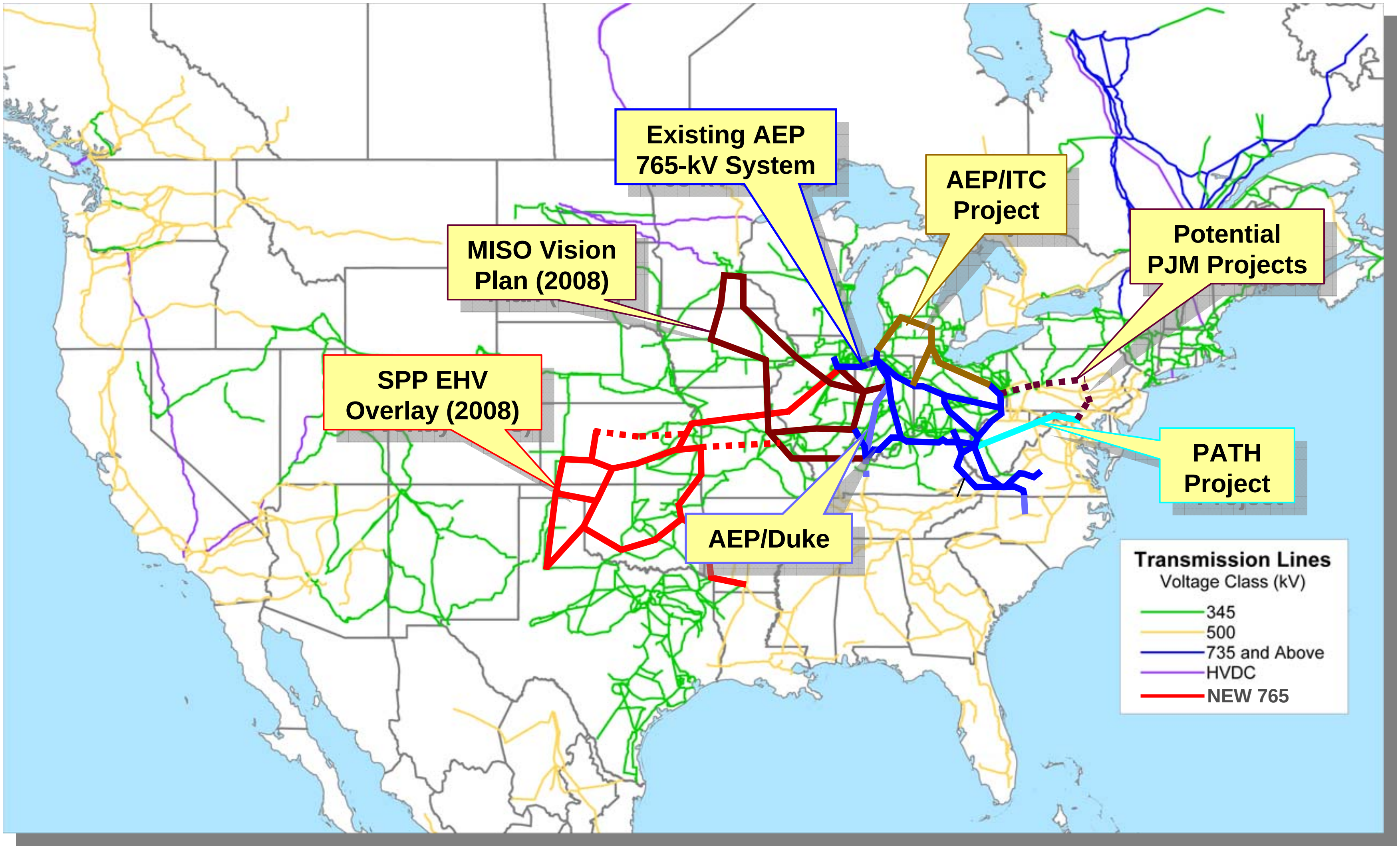
- SWEPCo's states have less vested interest in gas-only to meet the region's energy needs for 2013 and beyond and are in various stages of approval for the Stall (509 MW gas-CC) plant. The Turk Plant (447 MW coal) has been approved by all three jurisdictions and we await the air permit from the ADEQ.

2008-2010 Projected AEP West New Generation Capital Expenditures

	2008	2009	2010
Stall	$207MM	$85MM	$32MM
Turk	$115MM	$249MM	$227MM

PSO and SWEPCo face immediate and growing infrastructure shortages. We have implemented an RFP process to purchase the needed capacity and energy in Oklahoma and are building new generation in Arkansas and Louisiana to meet SWEPCo's capacity and energy needs.

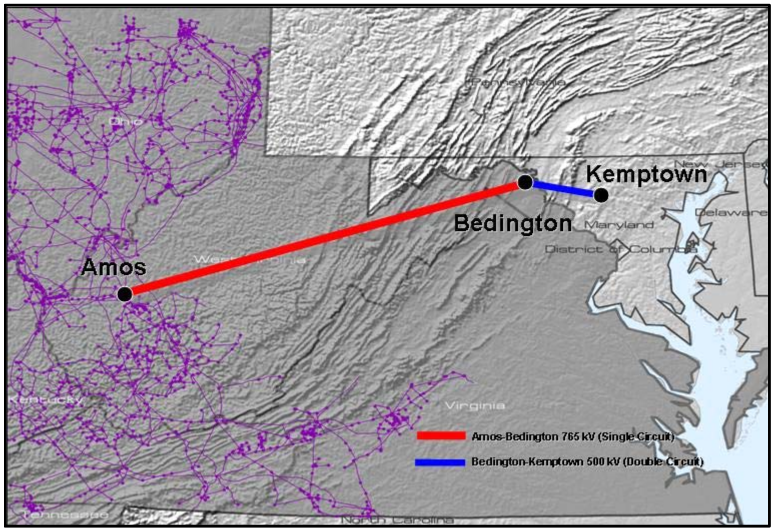
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

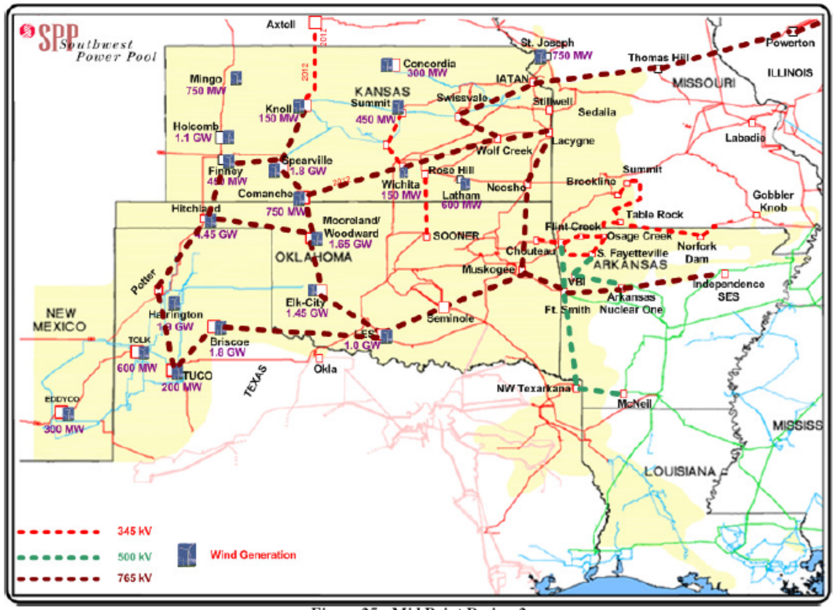


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

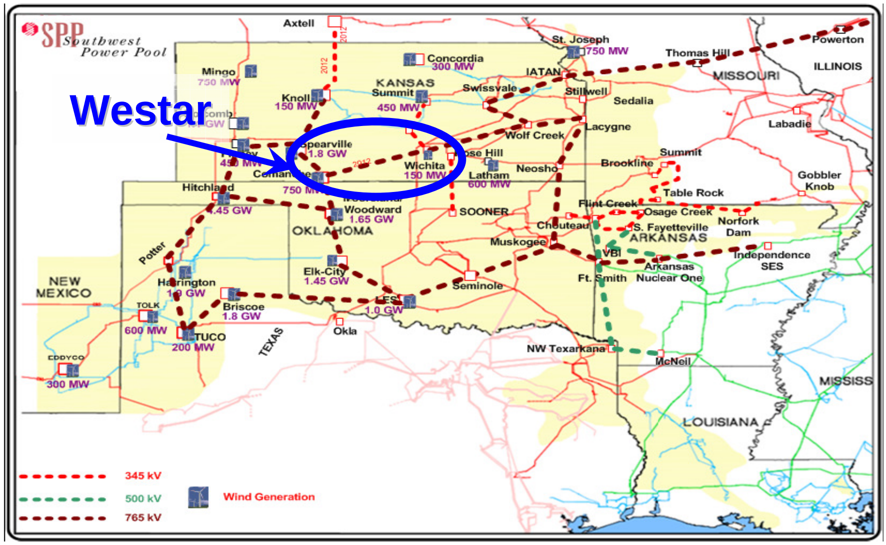
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7567 of 9556

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- **Overview**
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced



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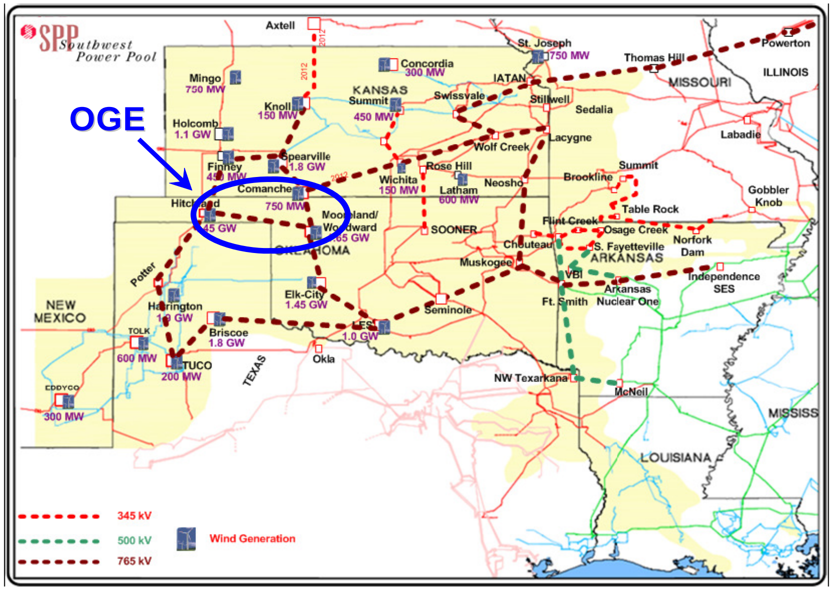
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- **Next Steps**
  - Filed CPCN – 2Q2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – Fall 2008
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- **Overview**
  - On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced



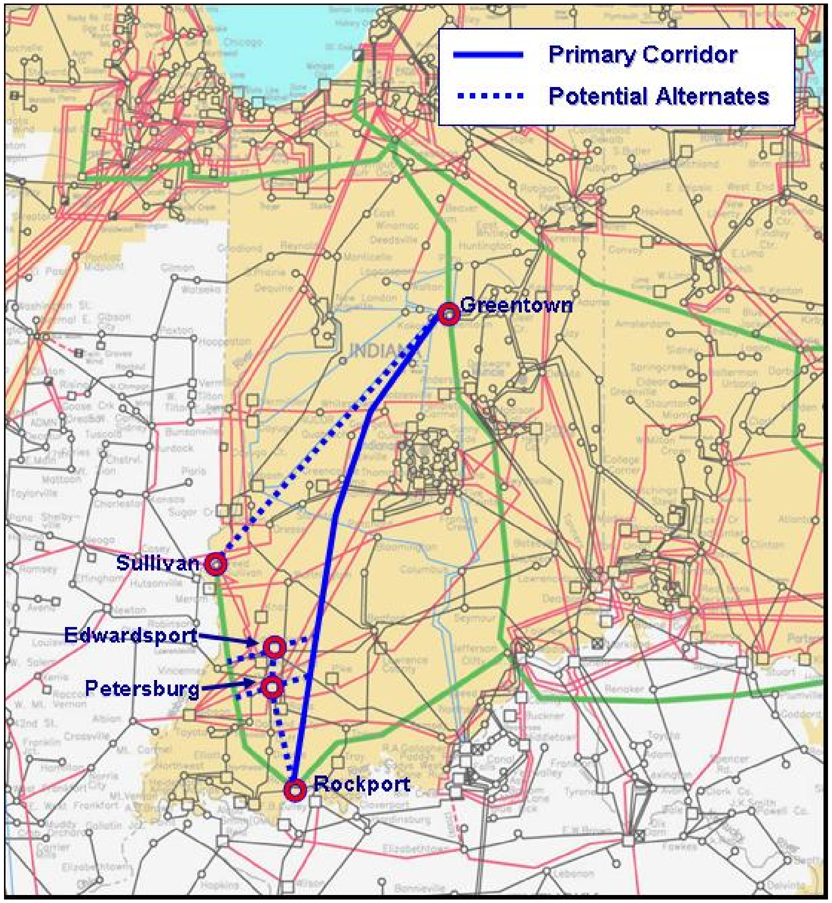
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- **Next Steps**
  - File CPCN –2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate – Fall 2008
  - SPP Cost Allocation Filing – 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on the routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.
- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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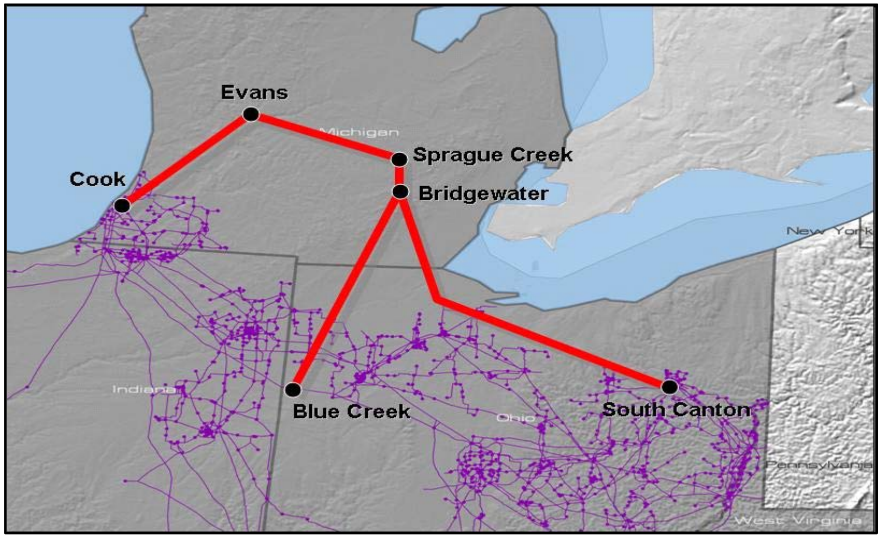
I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

Overview

- ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
- Study was released Q3 2007
- 700 miles of 765-kV line in Ohio and Michigan
- $2.6 billion investment (before ownership division)
- AEP and ITC are in discussions to form a Joint Venture



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Benefits

- Up to 5,000 MW improved transfer capability
- Reduces network line losses by 250 MW

Next Steps

- Agreement on JV (AEP/ITC) - Summer 2008
- JV Formation - 2008
- MISO and PJM Review/Approval - 2009
- FERC Formula Rate & Cost Allocation Filing - 2009
- Siting Approval – 2011-2012
- Estimated Completion – 2015-2021

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order							Expected Order					

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing Begins						12/1/08						
Expected Order												Expected Order
Ohio - ESP Filing												
Company Testimony Filed	07/31/08											
Intervenor Testimony				10/131/08								
Staff Testimony				11//07/08								
Hearing Begins					11/17/08							
Expected Order						Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Staff/Intervenor Testimony				10/29/08								
Rebuttal Testimony					11/19/08							
Settlement Conference						12/01/08						
Hearing Begins						12/08/08						
Rates Effective *							01/08/09					

* Subject to refund, with interest

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval
- SWEPCo Stall Plant Filing in Louisiana-construction approval

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- SWEPCo Stall Plant Filing in Arkansas

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Highlights of AEP Ohio's ESP Filing

		2009 CSP	2009 OPCo	2010 CSP	2010 OPCo	2011 CSP	2011 OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		Other Components		Other Components		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested phase-in of proposed incremental FAC expenses during the three-year ESP period. Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 &PJN-10 provides calculation of environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows the capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: Requested an annual 7% & 6.5% per year increase in Distribution for CSP & OPCo, respectively. Exhibit DMR-4 shows expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response & energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009 CSP	2009 OPCo	2011 CSP	2011 OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	-$80.7M	-$27.1M	$22.8M	$15.2M

A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2	*
Rate of Return		8.64%	
Operating Income Requirement	$	133.5	
Pro-Forma Operating Income	$	53.0	
Difference	$	80.5	
Revenue Conversion Factor		1.647045	
Total Required Rate Relief	$	132.6	

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1	*
Rate of Return		8.52%	
Operating Income Requirement	$	205.7	
Adjusted Operating Income	$	79.2	
Difference	$	126.5	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	207.9	

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony was received August 13, Staff testimony was received August 27, Rebuttal testimony received September 3 and hearing commenced on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$507MM and the new revenue requirement requested is \$606MM. Approximately \$31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the fourth quarter of 2008. A draft air permit approval was released for public comment on August 11, 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued a written order approving construction of the plant on August 12, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding was suspended pending outcome in Louisiana. Now that Louisiana approval has been received, we will seek an expedited ruling from Arkansas.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable and the ALJ recommended approval. An order is expected in the second half of 2008.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Commitment to Credit Quality

- ❑ Maintain adequate liquidity
- ❑ $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- ❑ Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- ❑ Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- ❑ Target long term dividend payout ratio range of 55-60%
- ❑ Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Merrill Lynch Power & Gas Leaders Conference
Merrill Lynch Headquarters
4 World Financial Center, NY
September 26, 2007

American Electric Power

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Strategic Direction

Delivering Value to Investors and Cost-Effective Service to our Customers

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Grow our transmission business
- Achieve adequate returns on all assets

Our core utility mission: Bring reasonably priced electric service to our customers, thereby strengthening our communities and rewarding our investors

Our Strategy has a Capital Investment Focus

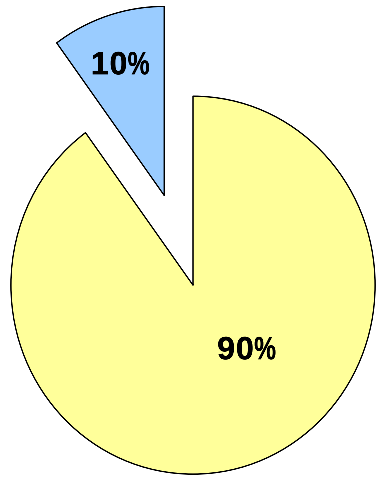
- Near-term
  - Completion of our intensive environmental retrofit program, coupled with associated rate relief, allows us to redeploy capital into other areas
- Mid-term
  - In our western footprint, our capital investment will focus on new generation
  - In our eastern footprint, our capital investment will focus on modernization of the distribution infrastructure, also known as the 'Modern Grid' program
  - In both the east and west, we will focus on successful demonstration and implementation of the chilled ammonia technology for carbon capture
- Long-term
  - Throughout our service territory, transmission, carbon technology, and IGCC will be our long-term capital investment focus

Capital investment opportunities will drive earnings growth for the foreseeable future

Environmental Investment Forecast

Environmental Program Costs:

Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs

First-Mover Advantage:

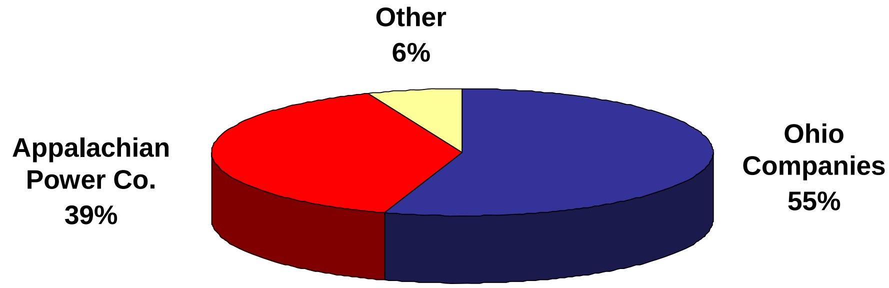
By locking in our environmental program costs in the early portion of this decade, AEP has a clear ‘first-mover’ advantage

AEP capital costs for a scrubber average approximately $250/kW

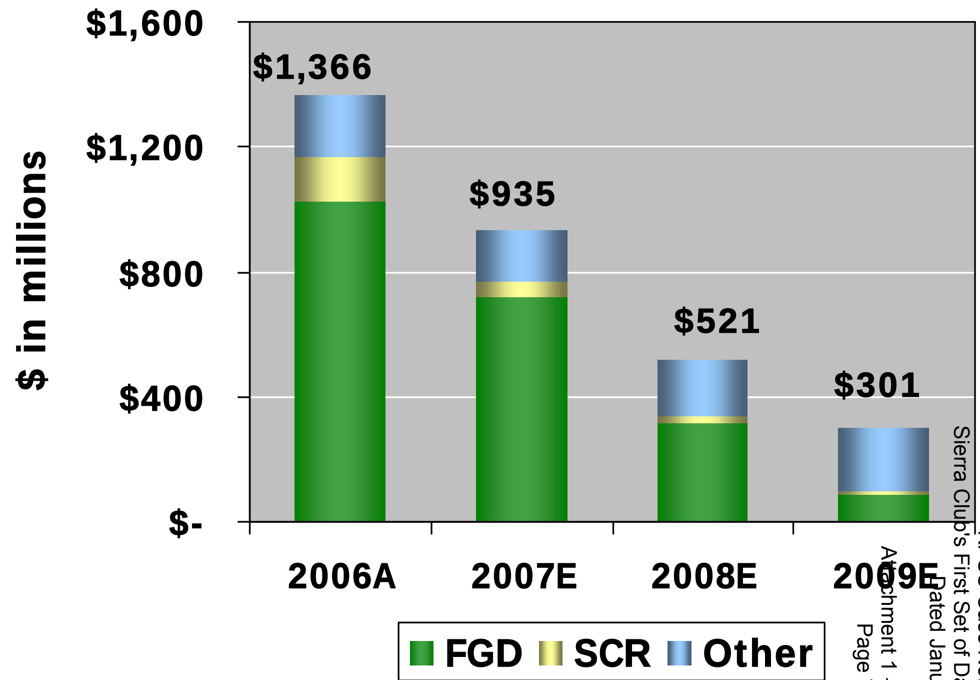
We have since seen a 30-60% increase in material costs and a 15% increase in labor rates

An FGD system for a nominal 600MW plant in 2005 $ was approximately $225/kW and in 2007 $ is $320/kW

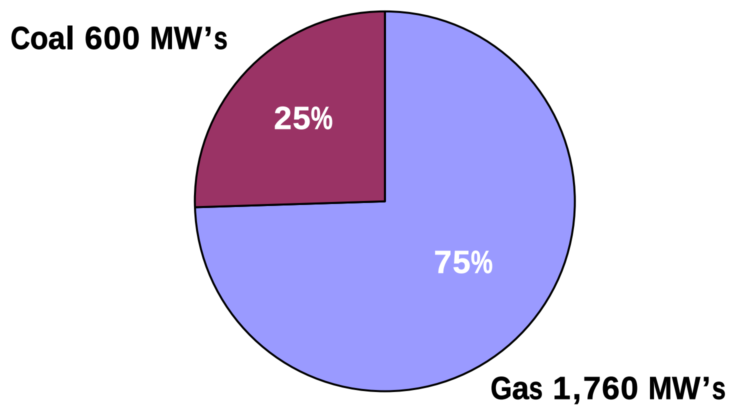
Projected Environmental Investment Allocation (2006A – 2009E)



Total Projected Environmental Investment

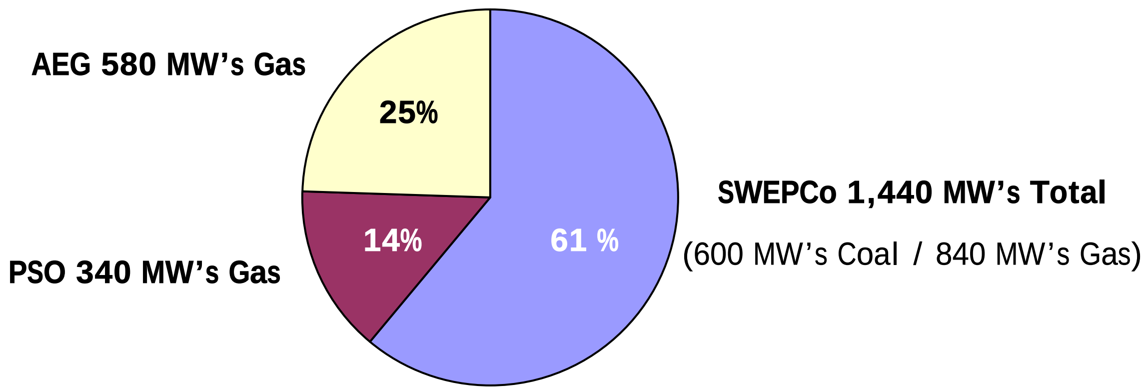


New Generation Facilities – Mostly Gas in Near Term



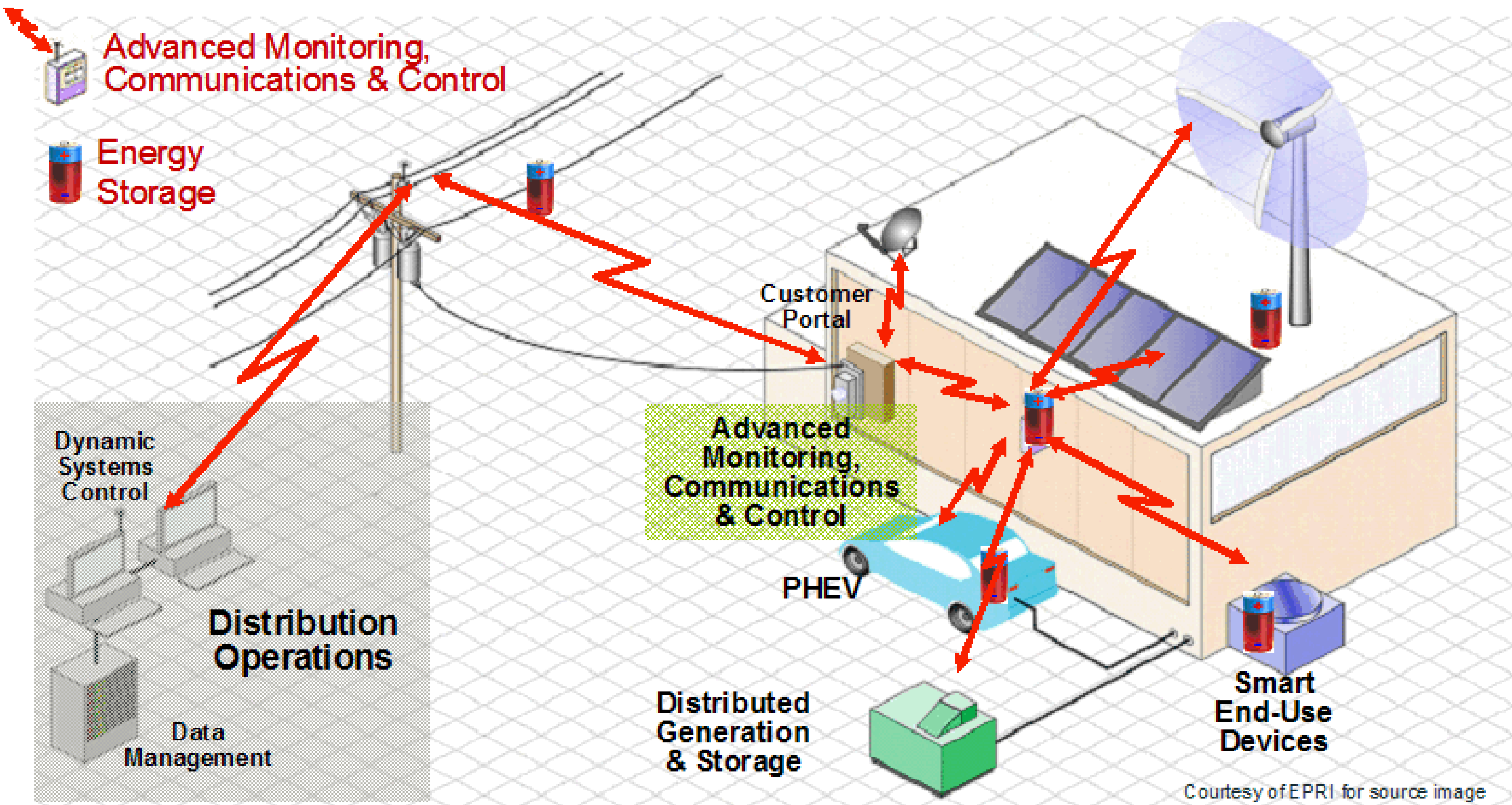
Project Name	Fuel Type	MW Capacity	Projected Costs
Mattison	Gas	340	$130 MM
Southwestern	Gas	170	$57 MM
Riverside	Gas	170	$57 MM
Dresden	Gas	580	$348 MM - $406 MM
Stall	Gas	500	$300 MM
Turk	Coal	600	$1.3 B

In addition, AEP has purchased approximately 3,000 MW gas capacity through distressed generation initiatives.



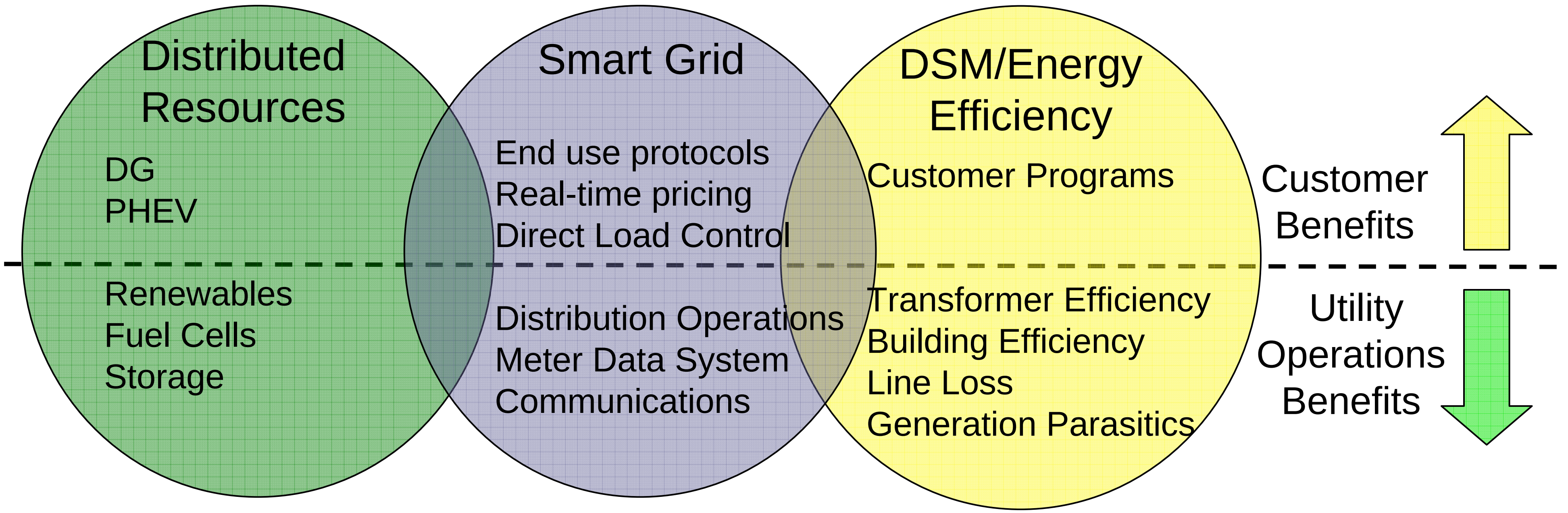
AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities

Distribution Operations of the Future



AEP AMERICAN ELECTRIC POWER

The "Modern Grid" Initiative



AEP has initiated an internal project to help clarify these inter-relationships, and develop our strategy for deploying these programs and technologies

Modern Grid Initiative

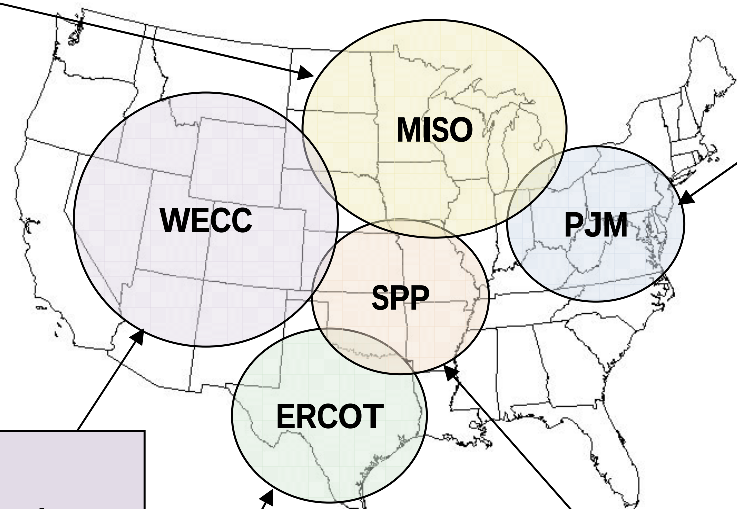
- Project to develop a vision for AEP's distribution and customer services business in the future, including the development of new customer programs and a plan to deploy advanced technologies
- Focus on:
  - Enabling greater customer control over energy usage
  - Enhancing conservation activities and overall environmental performance
  - Optimizing the operation of AEP's distribution business
- AEP needs to pursue:
  - Providing customers with real-time pricing signals
  - Providing customers with program options that encourage reduced energy consumption and lower peak demand
  - Promoting the use of electric vehicles and distributed generation
  - Using real-time system intelligence on our distribution system to improve operations and customer service
  - Utilizing advanced electricity storage for peak usage and power outages
  - Enabling technologies such as biomass, solar and fuel cells
  - Modeling future customer behaviors as a consumer of our own products
- Examples include:
  - Customer Energy Efficiency and Demand-Side Management Programs
  - Advanced Metering Infrastructure (AMI) & Distribution Automation (DA)
  - Distributed Generation, Renewable Resources and Energy Storage

Transmission Investment Vision

Investigation of opportunities needs to be mindful of regional drivers

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues



PJM

Congestion will be reduced and reliability will be increased

WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

ERCOT

Load growth and access to wind resources driving transmission investment

We advocate a long-term transmission vision with a national interstate focus & 765kV technology

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

~ $3 Billion I765$_{TM}$ Project in PJM
~ $2 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

Building the next US interstate system for enhanced reliability and market efficiency

Electric Transmission America (ETA)

Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 12, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by the Joint Venture would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
- AEP will act as project manager and will develop, build and operate transmission lines and facilities for ETA.

This JV reflects a natural progression and expansion of our partnership with MidAmerican.

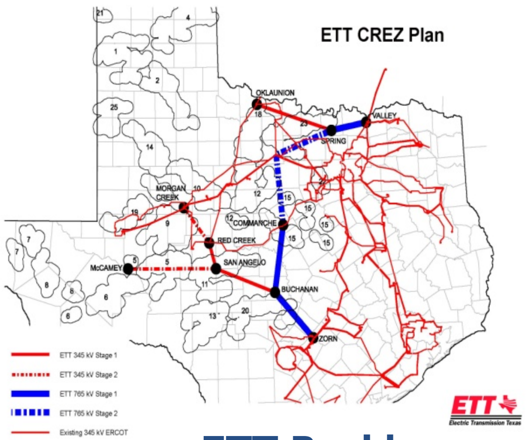
Electric Transmission Texas (ETT)

- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in the fall of 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

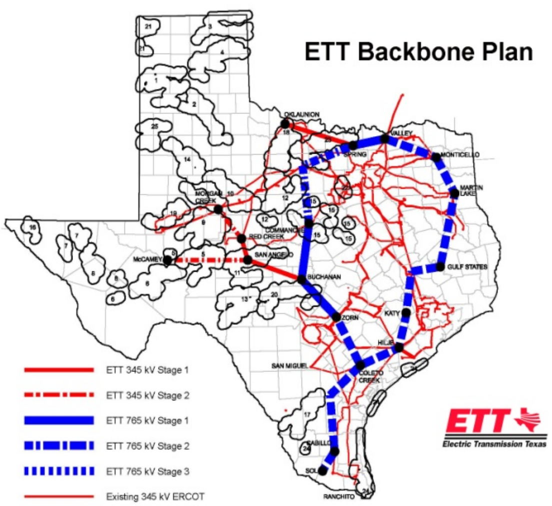
- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

ETT CREZ



ETT Backbone



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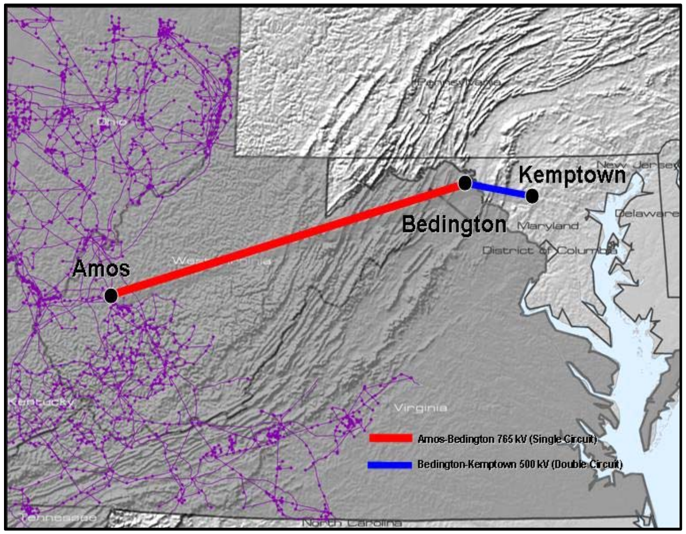
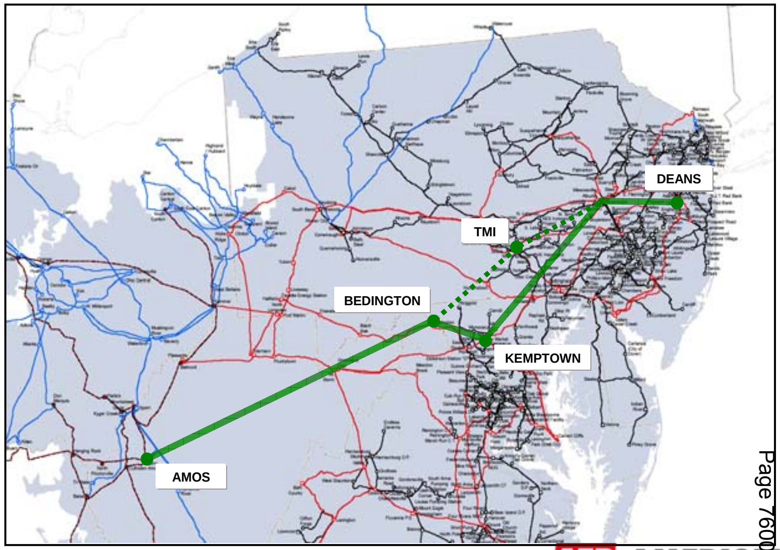
Transmission Project Updates

- *PJM I-765 TM Phase I Progress to Date*
  - AEP and Allegheny entered into the PATH (Potomac- Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012
- *Key Next Steps*
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012
- *PJM I-765 TM Phase II Update*
  - Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
  - Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
  - Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.

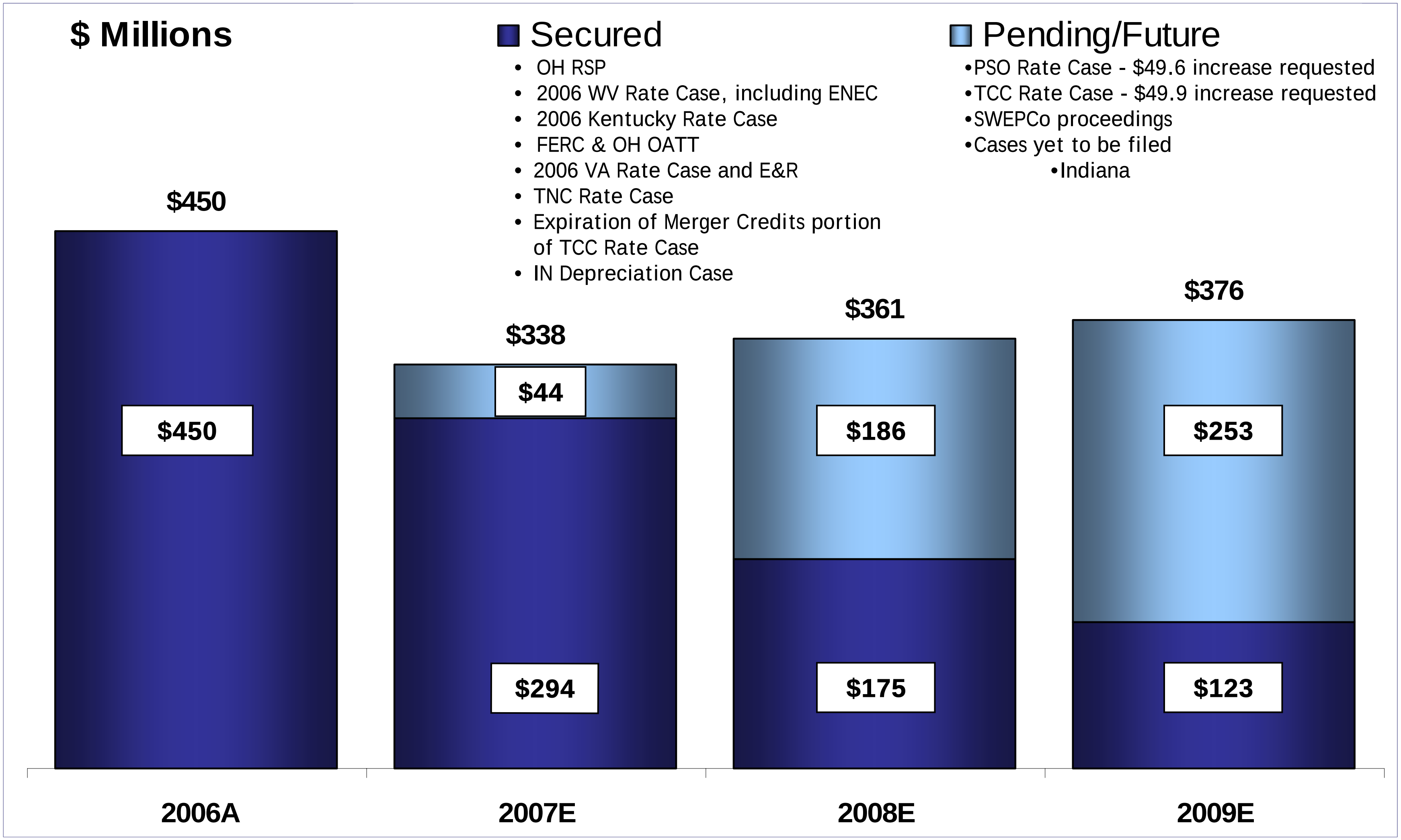
PJM Phase I



PJM Phase II



Incremental Rate Relief Composition



Rate relief is a critical element to AEP's financial success and allows us to pursue additional generation, transmission and infrastructure investment

Demonstrated Success in Regulatory Recovery

Track record for rate recovery of capital investment:

- Kentucky Environmental Surcharge—Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act.
- Ohio Rate Stabilization Plan—3% & 7% generation rate increases for CSP & OP, respectively for 2006-2008; Activation of additional 4% rider for additional generation-related investments.
- Virginia E&R mechanism—allows APCo-VA to recover incremental environmental & reliability costs.
- West Virginia rate settlement—Mechanism in place to provide rate increases through 2009 for ongoing environmental and transmission investments.

We expect to achieve similar success with rate recovery of Modern Grid, Transmission and New Generation Investments

Discussion of Industry Issue

Is Coal Generation Viable in Today's Regulatory Environment?

In Summary:

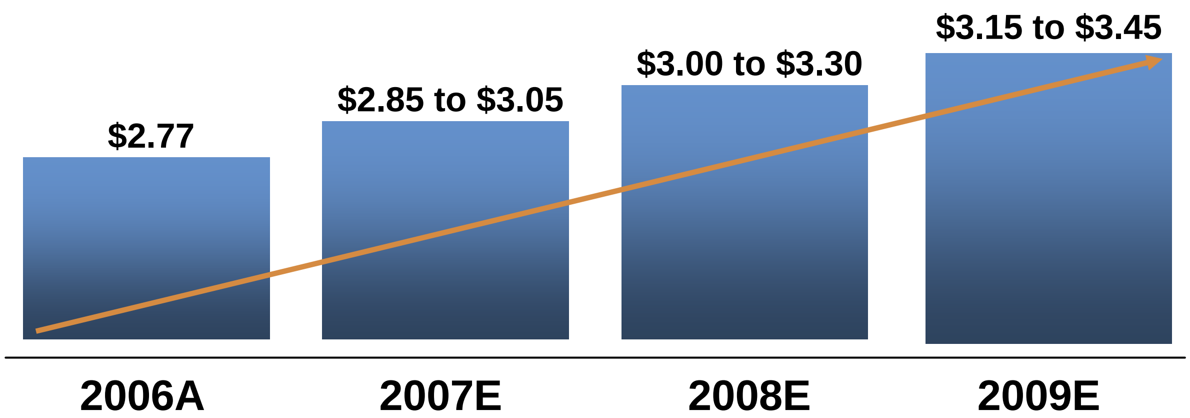
- AEP has embarked on an intensive capital investment program.
- We have achieved a successful track record of regulatory recovery of those investments and have demonstrated discipline where regulatory recovery wasn't assured.
- We will continue to take advantage of capital investment opportunities in the near, mid & long term:
  - Environmental
  - New Generation
  - Modern Grid
  - New Transmission
  - These capital investment opportunities will continue to enhance our earnings potential

Questions?

Appendix

Long Range Performance – Consistent and Predictable Growth

2007, 2008 & 2009 Ongoing Earnings Guidance Ranges: 5-7% Annual Growth



- Continued disciplined investment in existing utility operations:
  - Reliability
  - Environmental
  - New Generation & Distribution Infrastructure
- Investment in new transmission opportunities
- New investment coupled with rate recovery
- Continued cost control
- Timely Rate Relief
- Maintain Credit Ratings
  - BBB/Baa2/BBB

Future earnings growth driven by native load growth and substantial utility investment opportunity focused on regulated operations

2007 Ongoing Guidance: $2.85 to $3.05 per share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance *
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash on hand is expected to be $205 million by the end of 2007

Commitment To Credit Quality

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's	S&P		Fitch
	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

AEP AMERICAN ELECTRIC POWER

Capital Structure

Capital Structure	Actual 12/31/2006			Actual 6/30/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,588	-	14,588
Short-term Debt	18	-	18	438	-	438
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,656	9,656
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,026**	**9,717**	**24,743**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.7%***	***39.3%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(253)	-	(253)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,614**	**9,717**	**23,331**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.3%***	***41.6%***	***100.0%***

Adjusted Debt/Capitalization: 58.3%

Multi-Year Capital Investment Funding Plan

	Actual 2006	Projection 2007	Projection 2008	Projection 2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital investment is funded by cash from operations and debt issuances

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528** *
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden Plant Purchase	$85
2007 Including Lawrenceburg & Dresden	**$3,952**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

* Includes Lawrenceburg purchase of $325MM and Dresden purchase of $85MM in 2007

Growth investment to be funded by cash from operations via rate relief and debt issuances

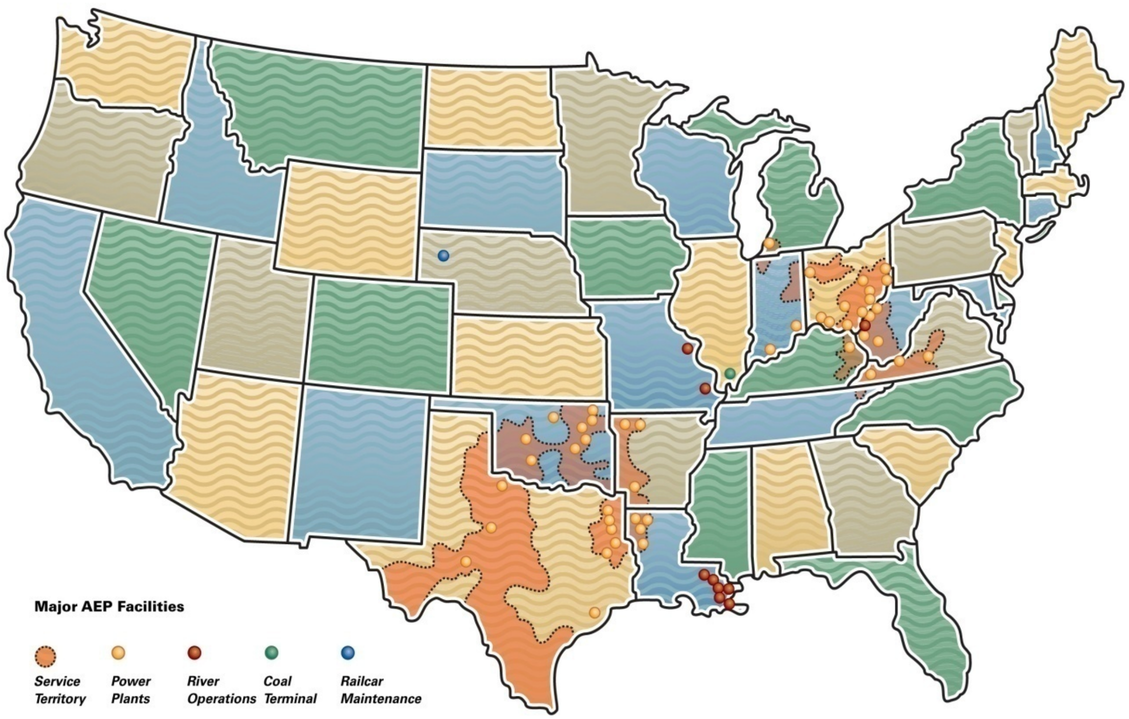
AMERICAN ELECTRIC POWER

Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

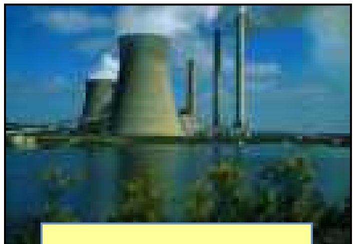


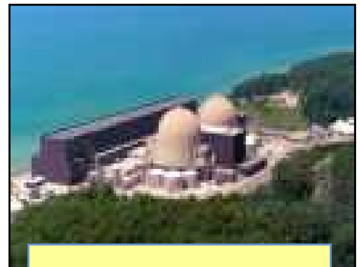
- Coal & transportation assets:
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

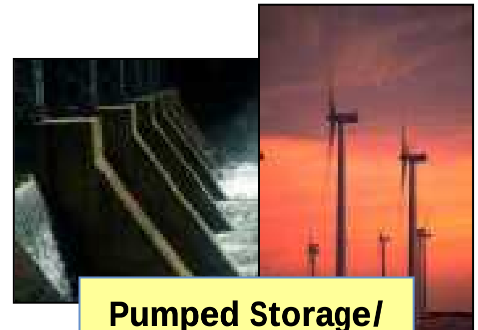
AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP AMERICAN ELECTRIC POWER®

Domestic Generation Fleet







Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

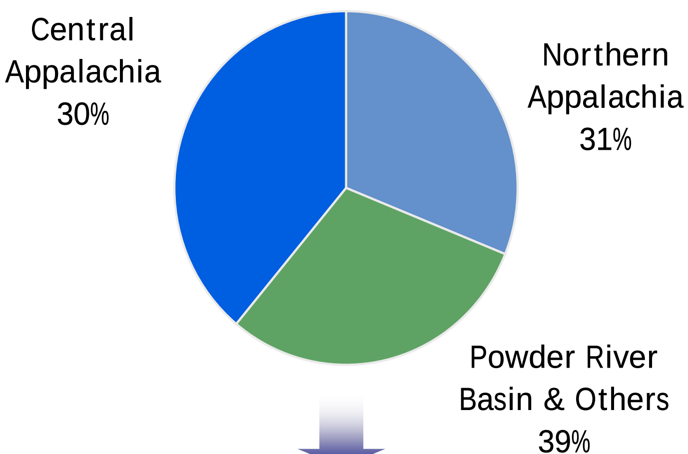
NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Coal Procurement - 2007 Projected

AEP purchases approx. 76 million tons of coal per year

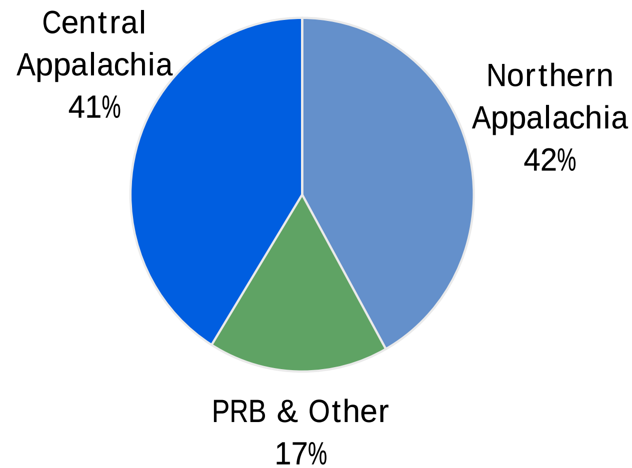
Total AEP System



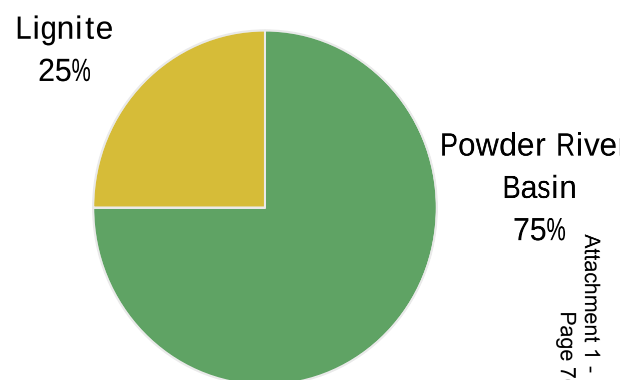
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
- Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



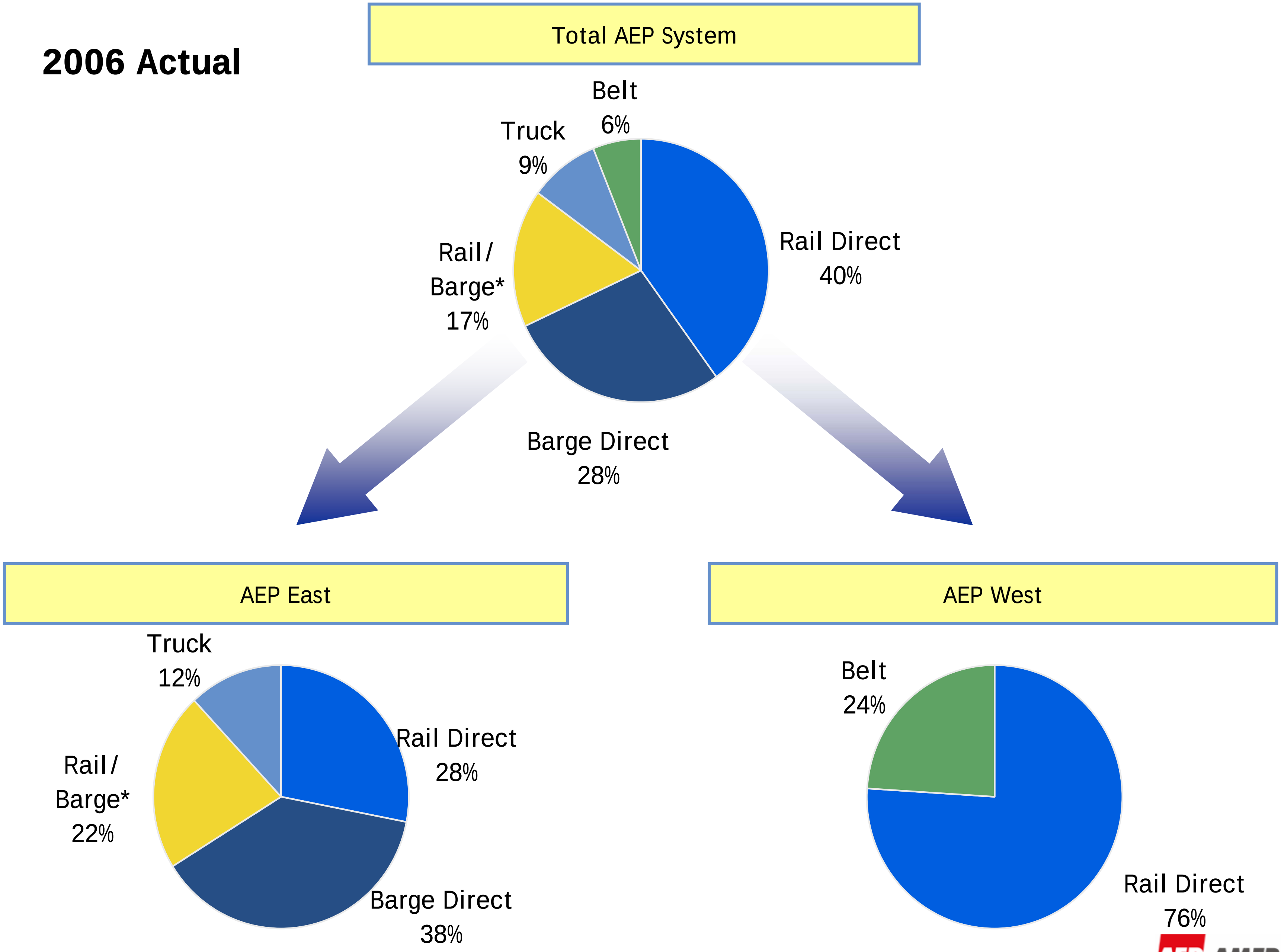
AEP West



AEP AMERICAN ELECTRIC POWER

Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
West Plants					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

At the conclusion of our current environmental retrofit program, over 47% of our coal-fired generation fleet will be equipped with SCRs and over 50% will be scrubbed (FGD).
AEP's total coal fleet capacity = 24,630 megawatts *

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP AMERICAN ELECTRIC POWER

Purchased Generation

Waterford
–821 MW combined-cycle gas plant
–$220MM purchase price
–Columbus Southern Power completed purchase on Sept. 28, 2005
–$268/kW

Lawrenceburg
–1140 MW combined-cycle gas plant
–$325MM purchase price
–AEG completed purchase on May 16, 2007
–$295/kW

2,946 MW of gas-fired generation added since 2005

Darby
–480 MW simple-cycle gas plant
–$102MM purchase price
–Columbus Southern Power completed purchase on April 25, 2007
–$227/kW

Ceredo
–505 MW simple-cycle gas plant
–$100MM purchase price
–APCo completed purchase on Dec. 15, 2005
–$198/kW

Addition of gas-fired generation allows us to meet the growing needs of our customers and provides the company with greater fuel flexibility

AEP AMERICAN ELECTRIC POWER

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis.
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities

New Gas-Fired Generation Facilities

SWEPCo

- **Mattison Plant (Tontitown, AR)**
  - Certificate of Need filings (LA, AR, TX) were approved in all 3 states
  - Air permit received in February 2007
  - Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008
- **Stall Plant (Arsenal Hill, LA)**
  - Certificate of Need filings (LA, AR, TX)
    - TX settled in Feb 2007
    - AR & LA decisions expected by year-end 2007
  - Air permit filed on April 27, 2007 – expecting approval by March 2008
  - Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

New Ultra-Supercritical Coal Facility

Turk Plant (Fulton, AR)

SWEPCo

- Certificate of Need approvals (LA, AR, TX) expected in the fourth quarter of 2007
- Air permit approval expected in Fall 2007
- Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings commenced September 11, 2007
  - AR and TX rate recovery will be addressed in separate filings
- Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - West Virginia filing made in June 2007 – included request for cash recovery mechanism
  - Virginia filing made in July 2007 requesting cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.

Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.

Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.

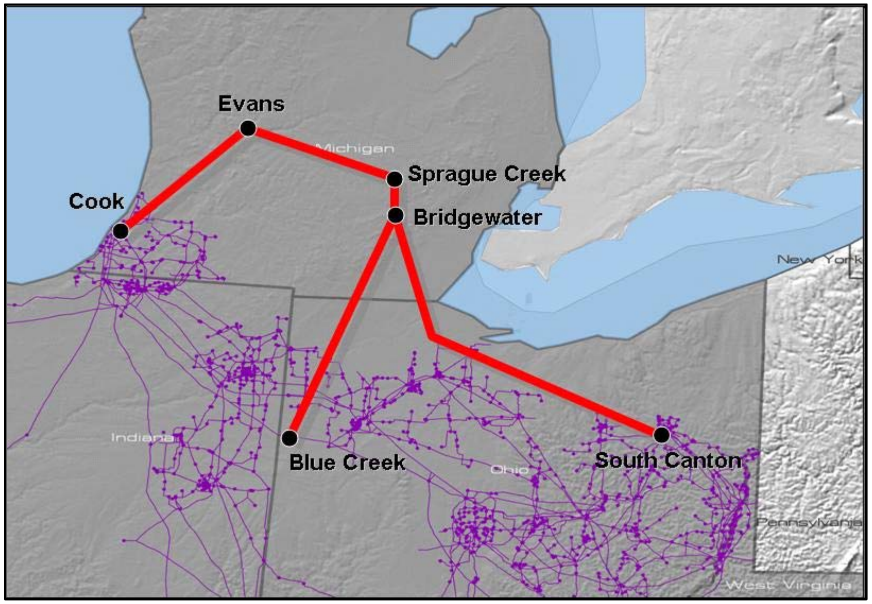
Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.

Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
- *Benefits*
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

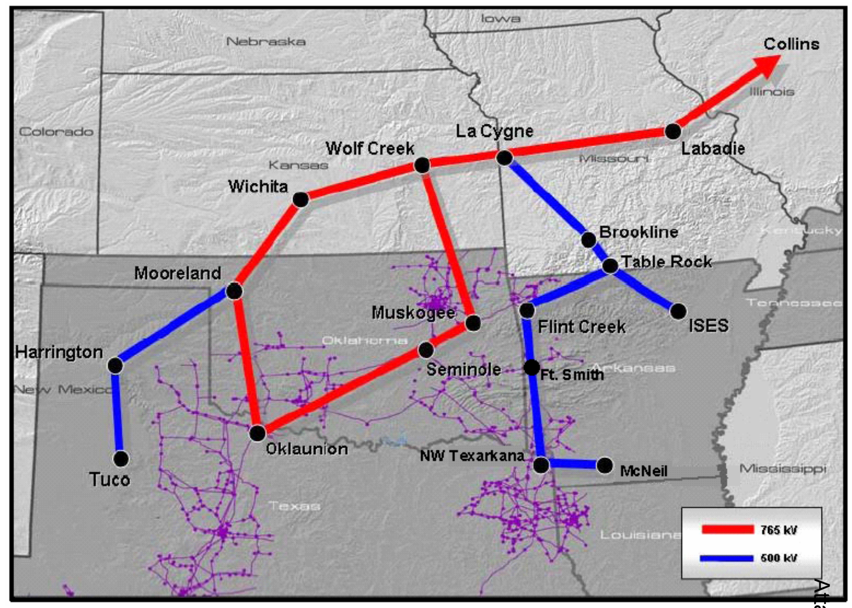
765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

- ### *Overview*
  - July 2006 AEP submitted conceptual project for six 765-kV lines
  - Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
  - 610 miles from Kansas to Arkansas
  - $3.0 billion investment (before ownership division)
  - Proposed 2012-2017 construction period
  - SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
  - SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri

- ### *Benefits*
  - 4,000 MVA capability

- ### *Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

Incremental Reduction quantity: 5MM tons/yr

Timing: To take effect/receive credits by 2011

Methods

- +1000 MWs of Wind PPAs – 2MM tons/yr
- Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
- Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
- Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
- Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

IGCC and Ultra-supercritical coal plants

Commercial solutions for existing fleet

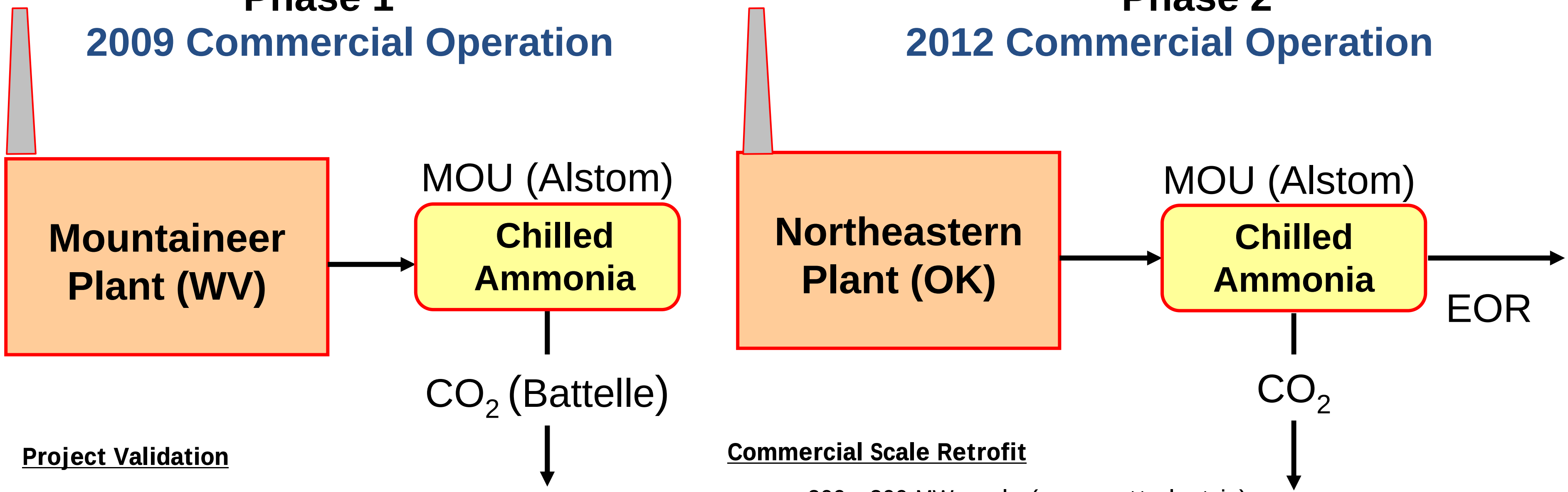
- Chilled Ammonia
- Oxy-Coal

AEP is committed to a 5mm ton/yr reduction in CO_2 emissions which offsets approx half of the emissions projected from new generation projects previously announced

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion carbon solution provides pure CO_2 stream for capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

10 MW_e scale

Teamed with B&W at its Alliance Research Center and 16 other utilities

Demo complete 3Q 2007

AEP funding of $50k

Commercial Scale Retrofit

Retrofit on existing AEP sub-critical unit (several available)

150 – 230 MW_e scale retrofit

4,000 – 5,000 tons CO_2 per day

Team with B&W

AEP funding of ~ $1.5M for feasibility study

Feasibility study to be completed in late 2007/early 2008

Combustion conversion technology for existing coal fleet – longer lead time with enhanced viability and long term potential

2007 Regulatory Activity Completed

Appalachian Power - Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power - West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓ $54.8 million covers increased costs related to coal and purchased power
  - ✓ $28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓ Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

Indiana Michigan Power - Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

In Hand to Date - $294MM of the $338MM Rate Recovery in 2007 Guidance

AEP AMERICAN ELECTRIC POWER

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Virginia Filings - Fuel Factor and E&R
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Pace of our Modern Grid Implementation Determined by Regulators

- **Arkansas** – SWEPCo filed 'quick-start' programs with the commission on July 1, 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-for-performance pilot that results in a payment to customers who curtail load upon request. We are awaiting commission approval.
- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and administering a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.
- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.
- **Ohio**
  - Recent Governor remarks indicate modernization of Ohio's infrastructure is a high priority and his plan would allow single-issue rate cases for these high-priority investments and system upgrades.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.
- **Texas**
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.
- **Virginia** – The Virginia commission has initiated a docket to address various aspects of demand-side management and energy efficiency.

Energy efficiency is an investment, which should be treated by regulators in the same manner as investments in generation, transmission and distribution

New York/Boston Investor Meetings
Hosted by Deutsche Bank
June 29-30, 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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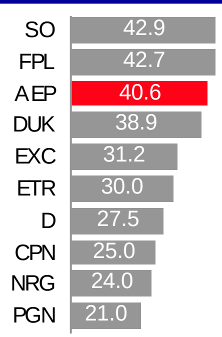
Industry Leadership

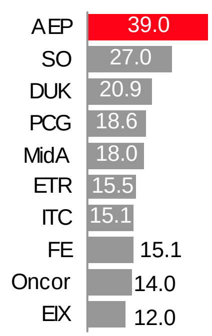
One of the largest U.S. electricity generators

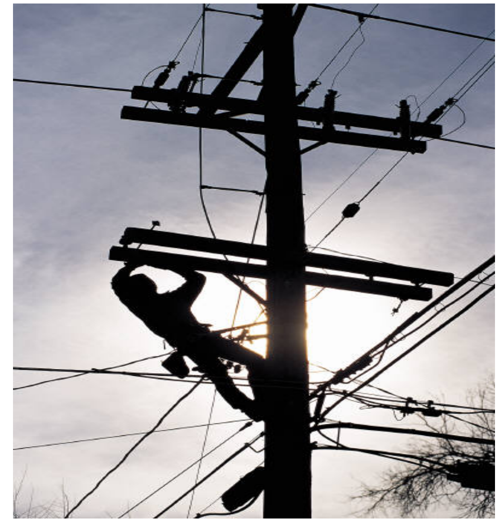
Generation owned[1] (GW)



The largest U.S. electricity transmitter

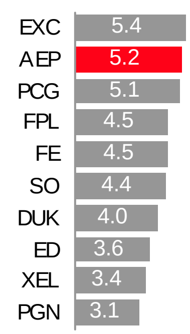
Transmission miles[1] ('000s)





One of the largest U.S. electricity distributors serving 5.2MM customers

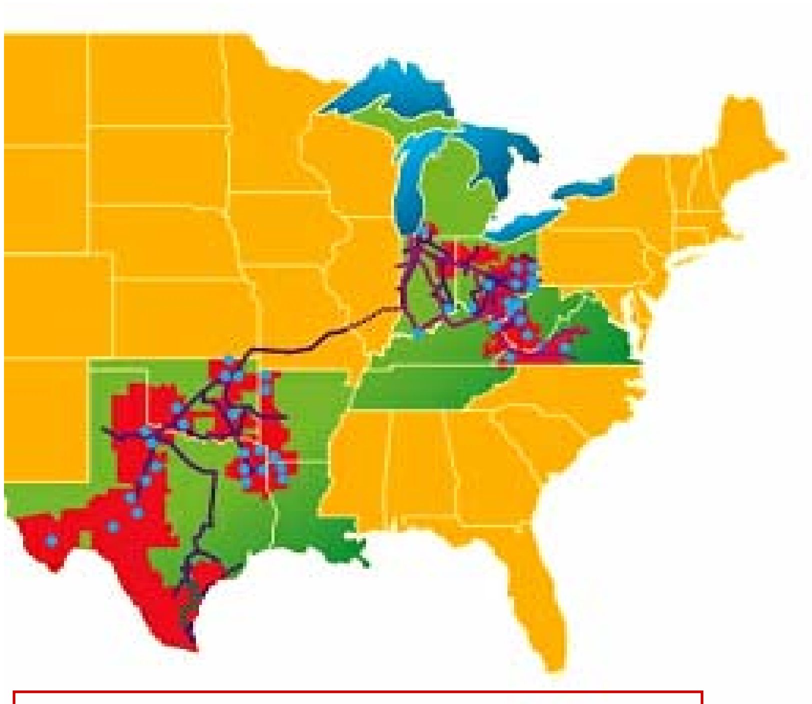
Electric customers[1] (mm)



[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

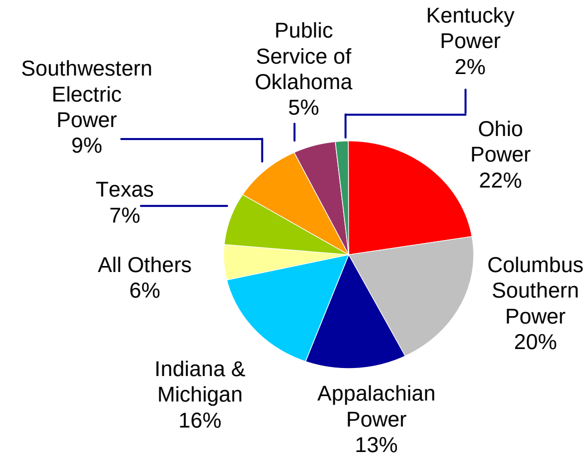
Highly Diversified Regulated Utility Platform

5.2 million customers in 11 states

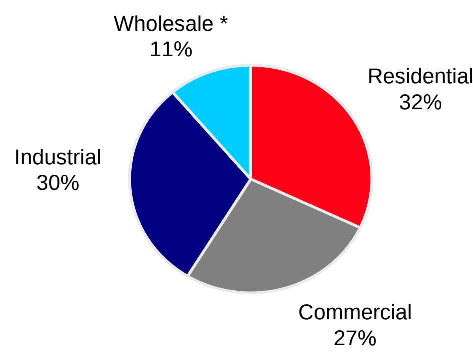


Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



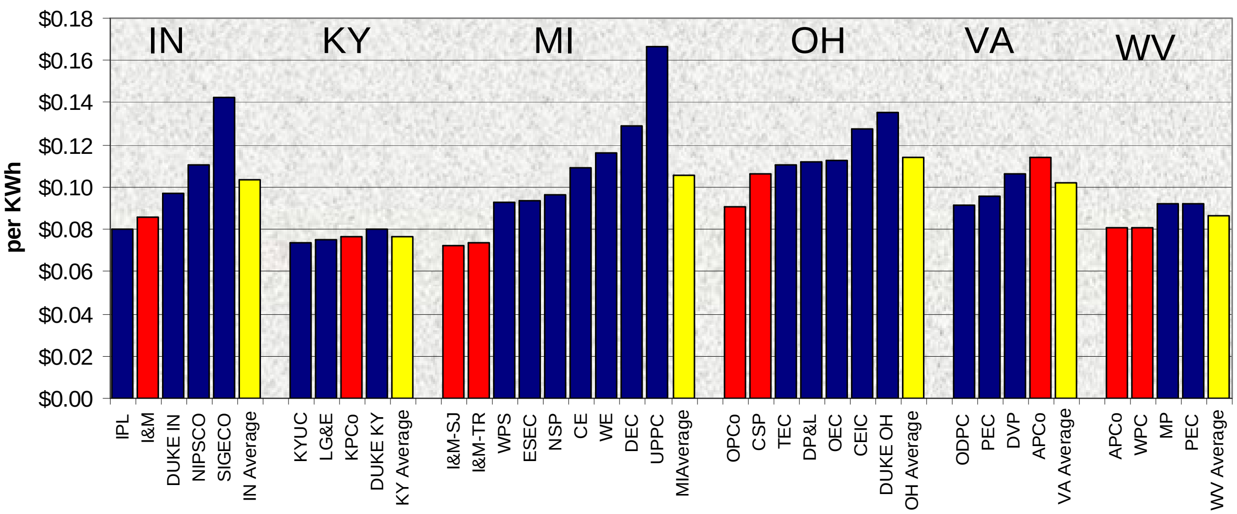
2009 Retail Load



Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

Residential Rates Comparison

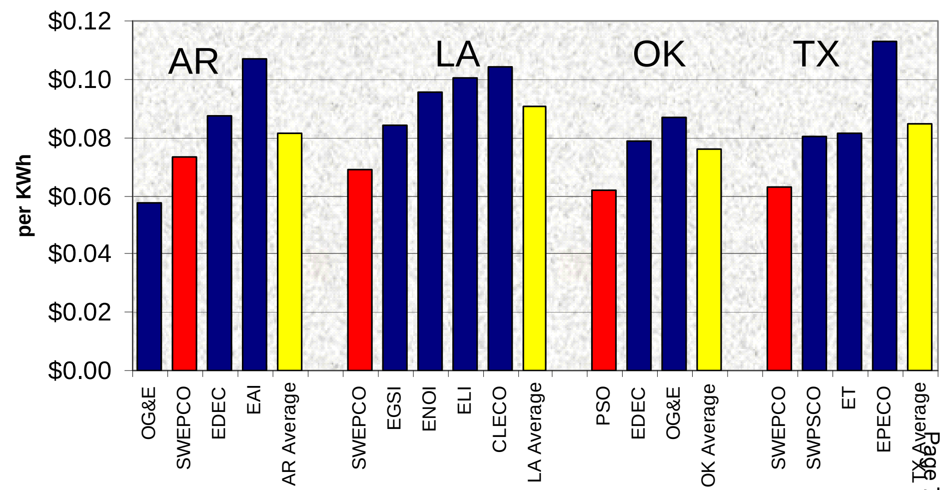
AEP East



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and
Average Rates Report

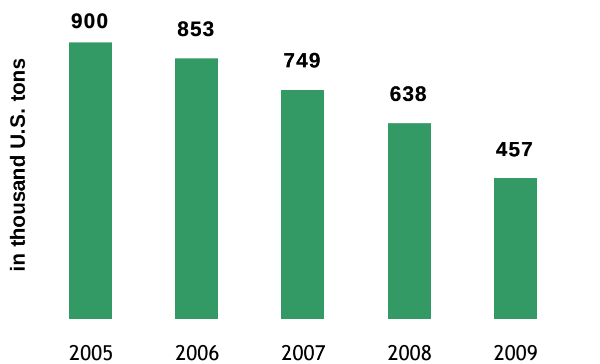
AEP Company
Other Utilities within state
State Average

AEP West

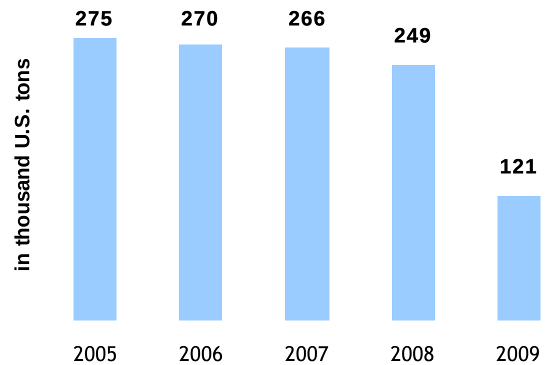


Our Fleet Will Continue to Transform

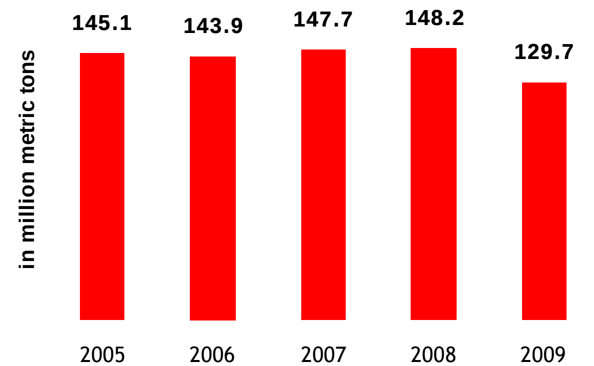
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



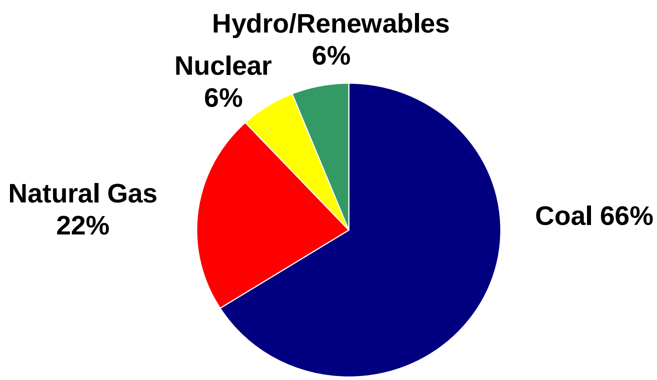
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



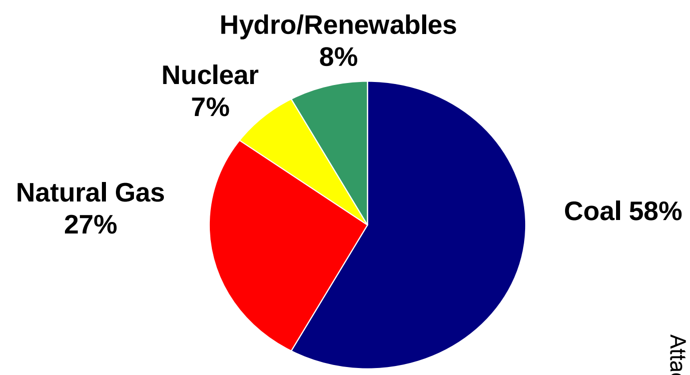
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ $5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The total projected cost of the plant is $380 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.7 billion with AEP's share approximately $1.3 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009

Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

2010 Ongoing Earnings Guidance

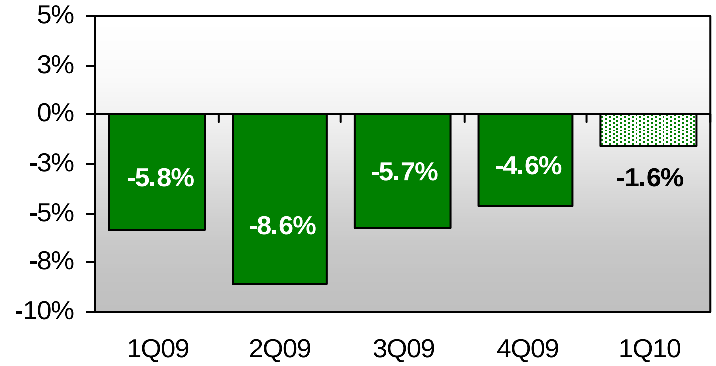
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**

AEP Total Normalized GWh Sales
Quarter %Change vs. Prior Year



<u>Quarter over Quarter change by segment:</u>
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

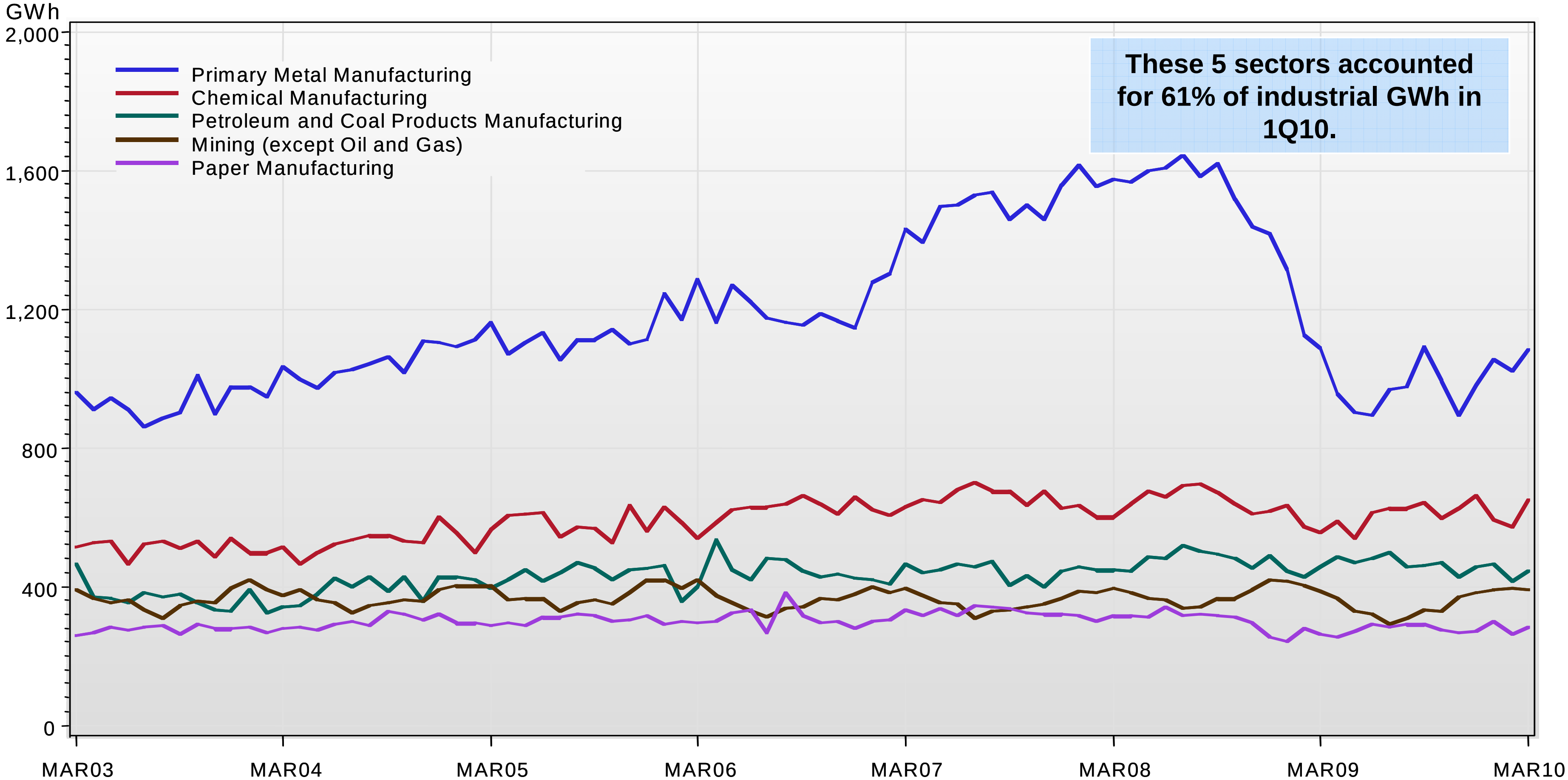
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

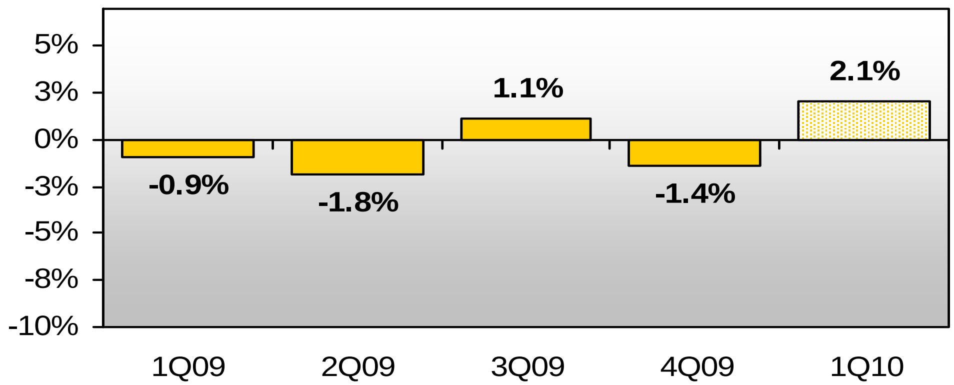
Industrial Sales

AEP Industrial GWh by Sector

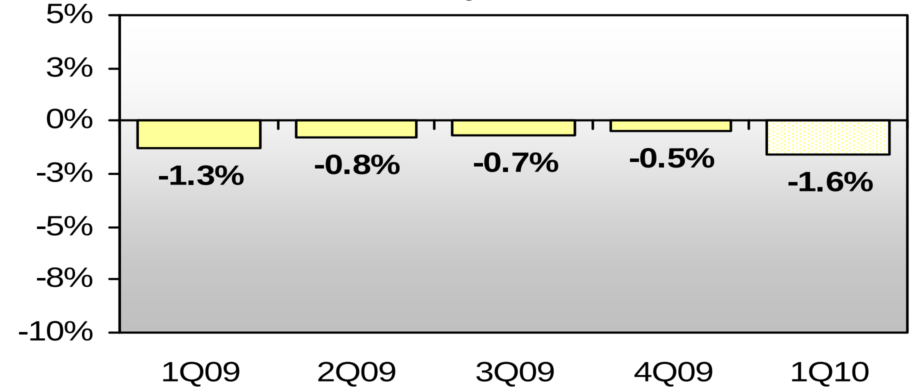


Normalized Load Trends

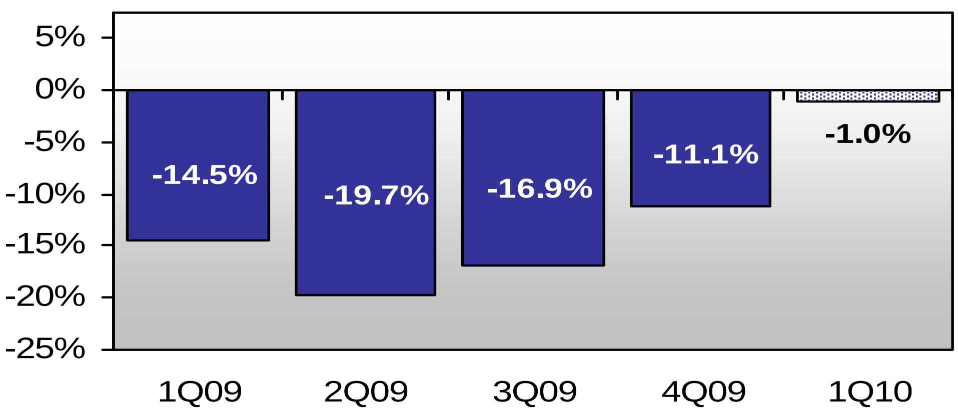
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



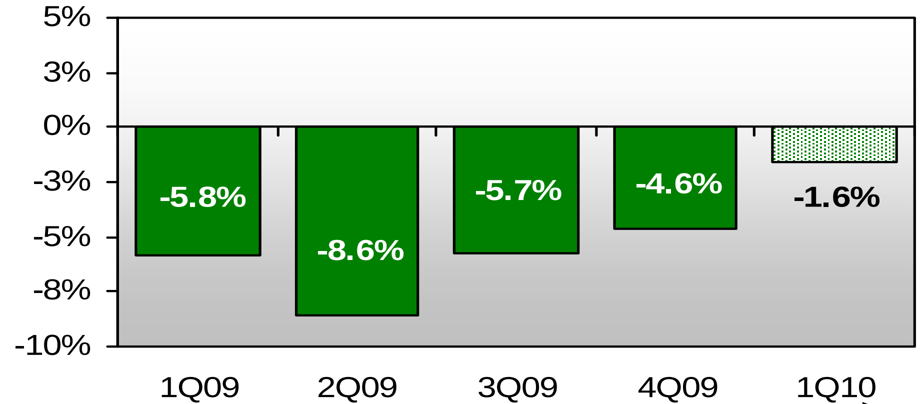
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year

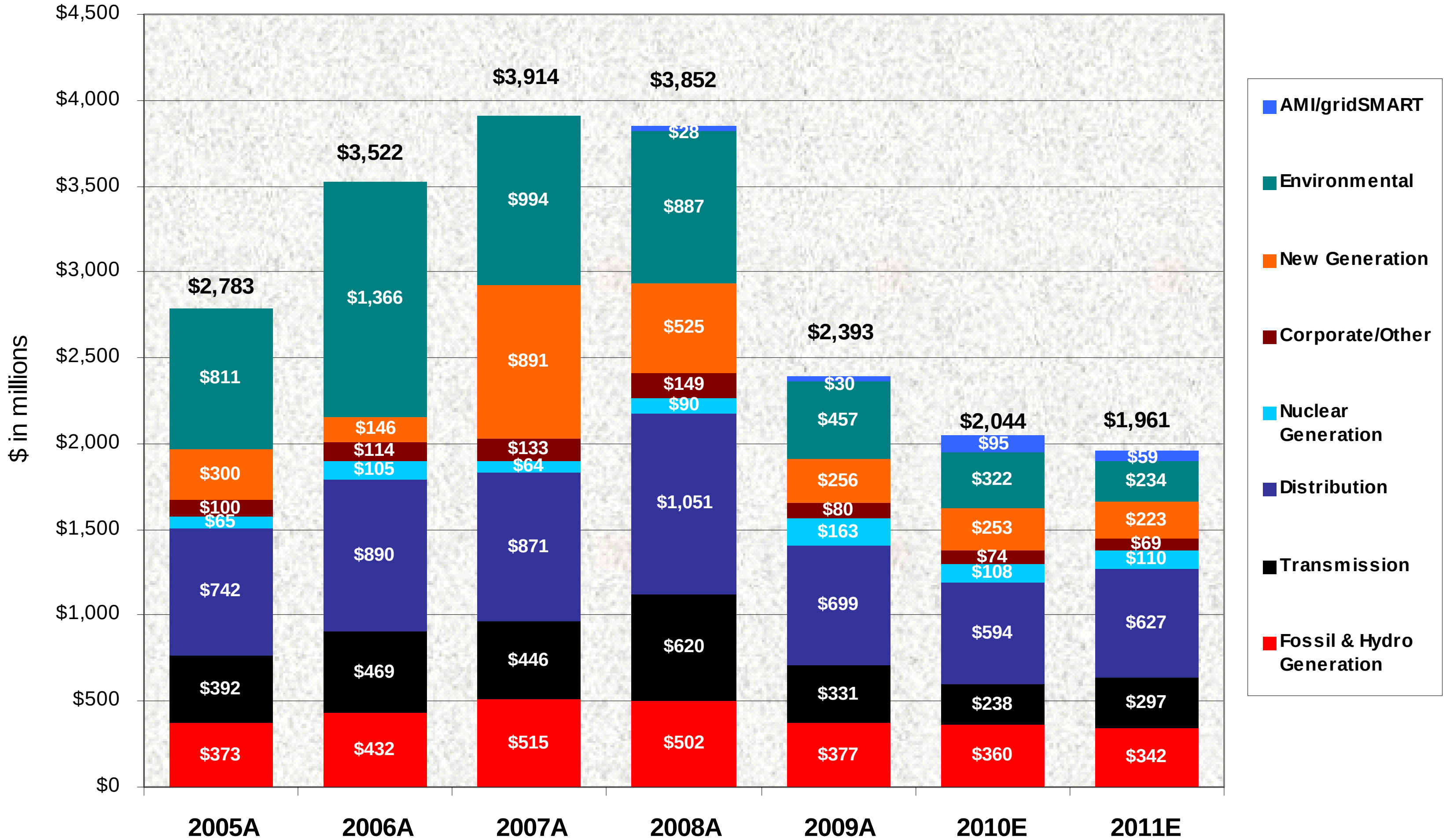


AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

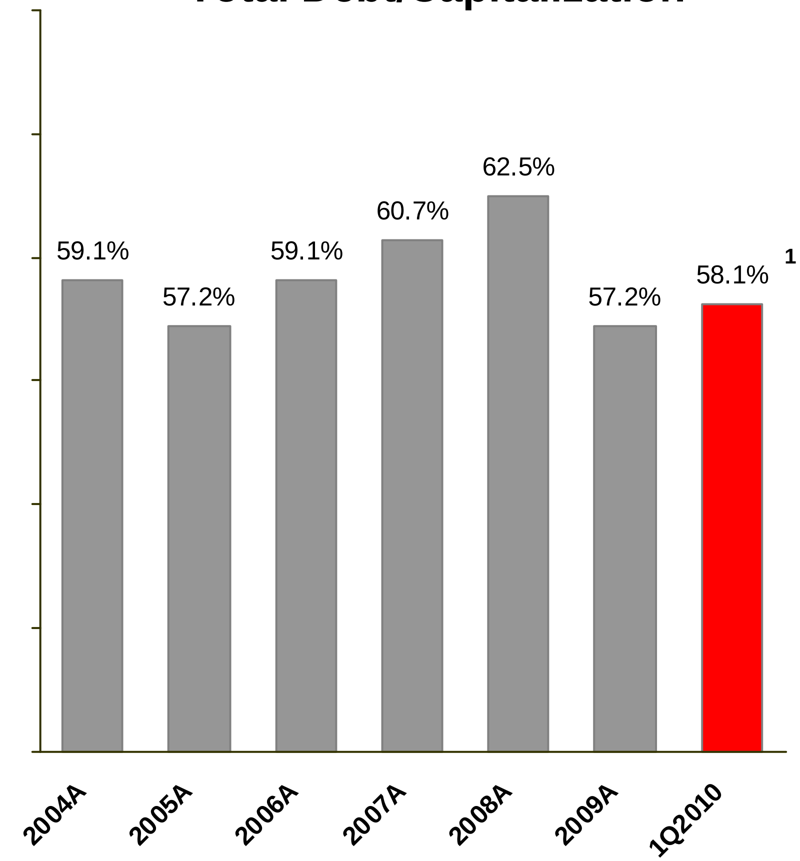
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $651 million are classified as short-term debt; The 1Q2010 debt/capitalization ratio would be 57.3%, excluding AEP Credit.

Current Liquidity Summary
As of June 24, 2010

Liquidity Summary (unaudited)	**Actual 06/24/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	740	
Less		
Commercial Paper Outstanding	(747)	
Letters of credit issued	(638)	
Net Available Liquidity	**$2,787**	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)
Data as of June 24, 2010

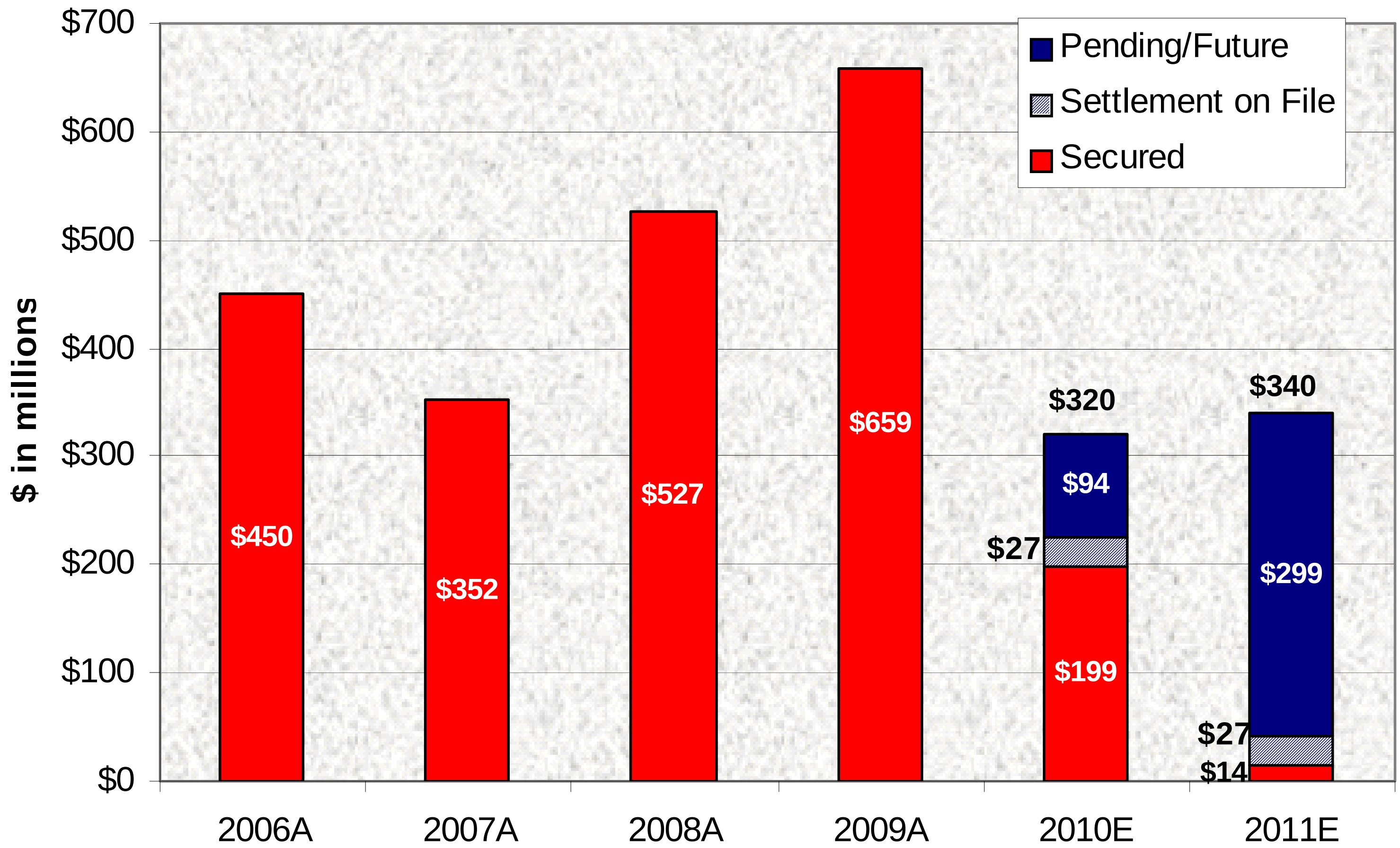
AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable, N=Negative Outlook

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Virginia, West Virginia and others yet to be filed

Settlement on File represents the Kentucky rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Current Base Rate Cases

APCo - Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$154**	$33-$63
Rate base/investment	$2,057	$2,116
Return on equity	13.35%	10.1% - 10.4%
Equity component	41.61%	41.53%

Status: Hearings concluded on April 2, 2010. Briefs filed on May 18, 2010. Commission Order due July 15, 2010. Rates to be effective August 1, 2010.

APCo - West Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010.

KPCo - Kentucky

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$124**	$41
Rate base/investment	$995	$995
Return on equity	11.75%	10.10%
Equity component	42.91%	42.91%
Riders requested	Wind & Reliability	

Status: On May 19, a settlement agreement was filed with the KPSC providing for a $64 million annual rate increase, effective June 29, 2010.

I&M - Michigan

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$63**	n/a
Rate base/investment	$601	
Return on equity	11.75%	
Equity component	44.19%	
Riders requested	Numerous	

Status: Case filed on January 27, 2010. Hearings scheduled for August 9-17, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Decision expected by November 16, 2010.

$565 million of total base rate increase requests on file

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — **COD: 2013-14**
- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — **COD: 2013-14**
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

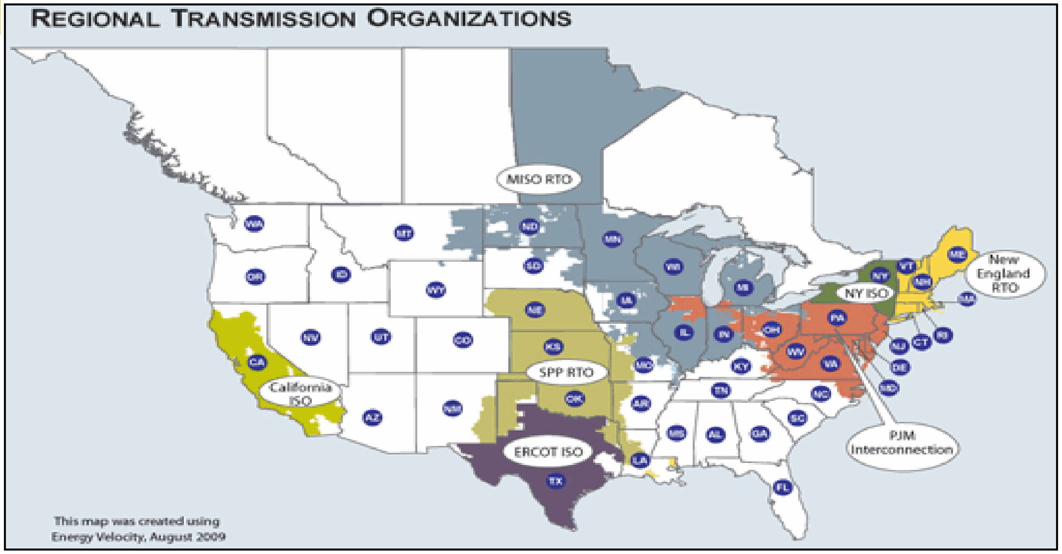
ETT — **COD: 2010-2017**
- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — **COD: 2014**
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — **COD: 2015**
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study
- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay
- *Regional Expansion of 765 kV Backbone*

ETT — **COD: various**
- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion
- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio
- *700 miles of Proposed 765 kV*

SPP — **ERCOT** — **PJM** — **PJM/MISO**

Electric Transmission Texas, LLC

Overview:

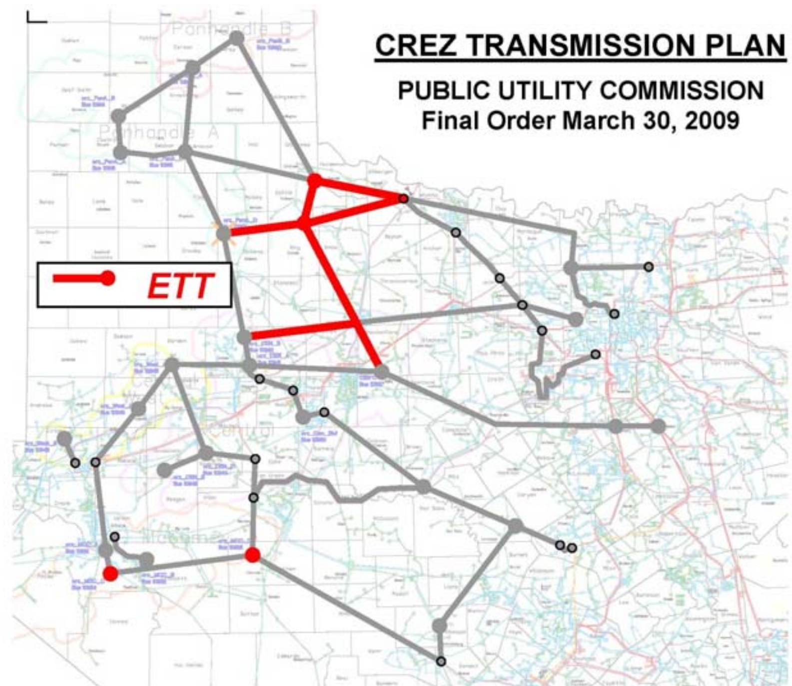
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT
Electric Transmission Texas

EHV Transmission in PJM: PATH

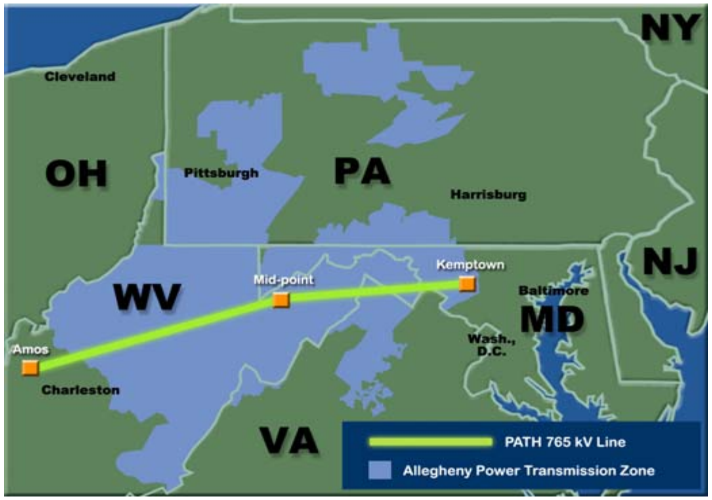
Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.



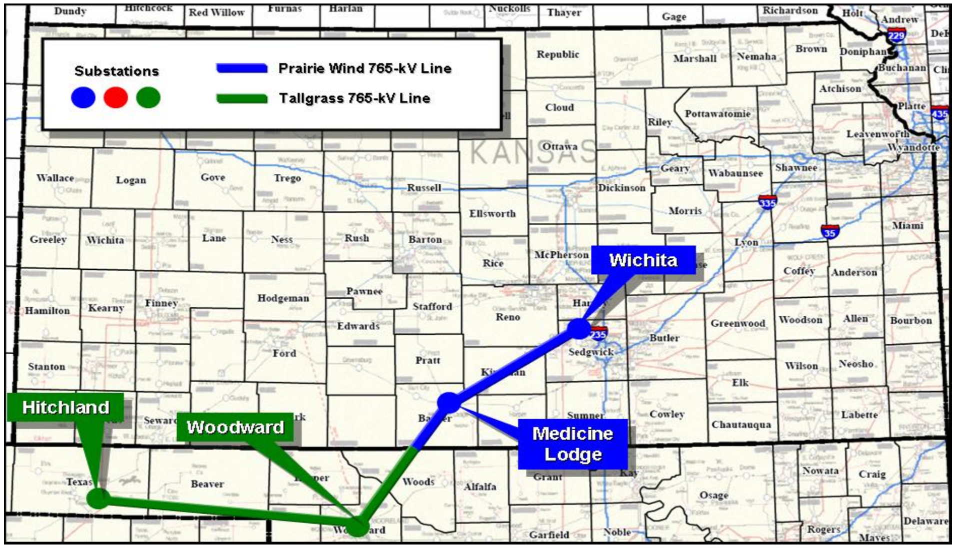
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

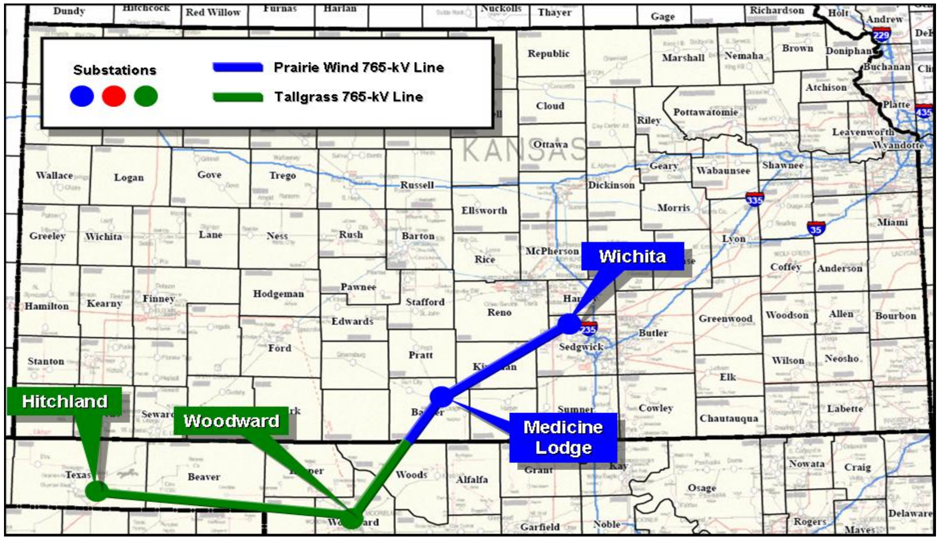
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

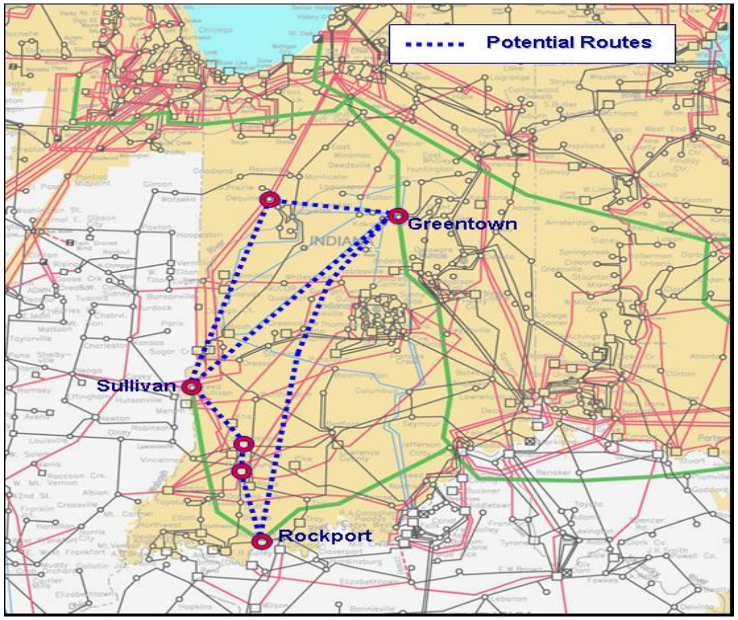
Key Challenges:

- Siting

Pioneer Transmission, LLC

<u>Overview</u>:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

<u>Key Challenges</u>:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

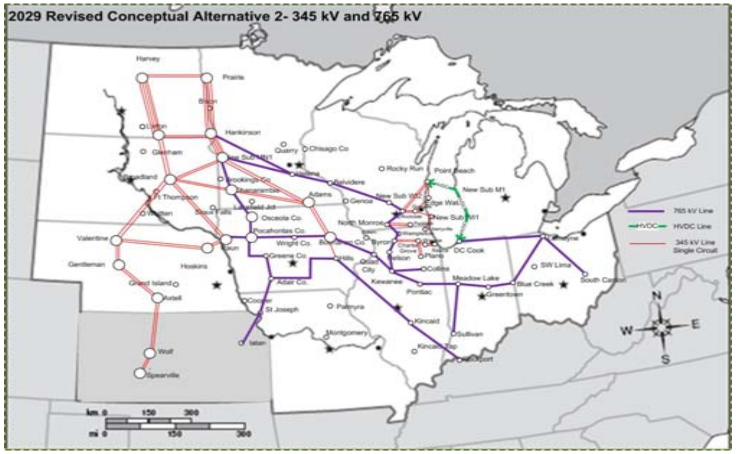
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

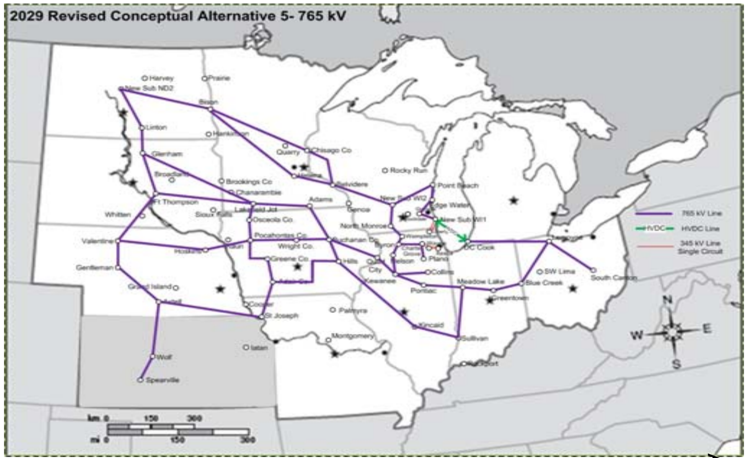
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives





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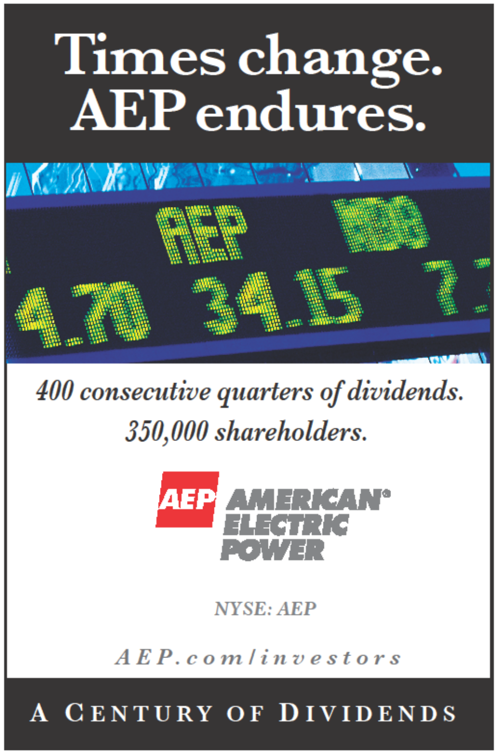
Value Proposition

- **Current Yield Opportunity of 5.1%[1]**
  - June 10th – 400th consecutive quarterly dividend was paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $32.72 on 06/24/2010

Midwest Utilities Seminar

The Park Hyatt
Water Tower Square
Chicago, IL
April 4, 2006

A Century of Firsts

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Executive Vice President & Chief Financial Officer

Framework For 2006

- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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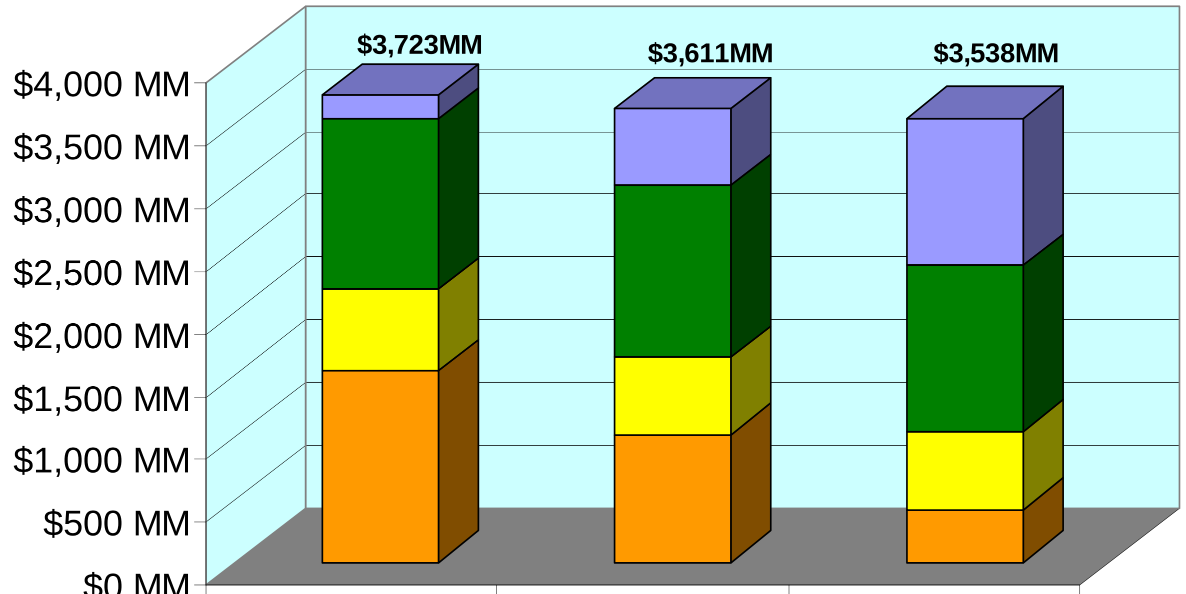
Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC

New Build Generation & Ongoing Infrastructure Replacement investment can be throttled



	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

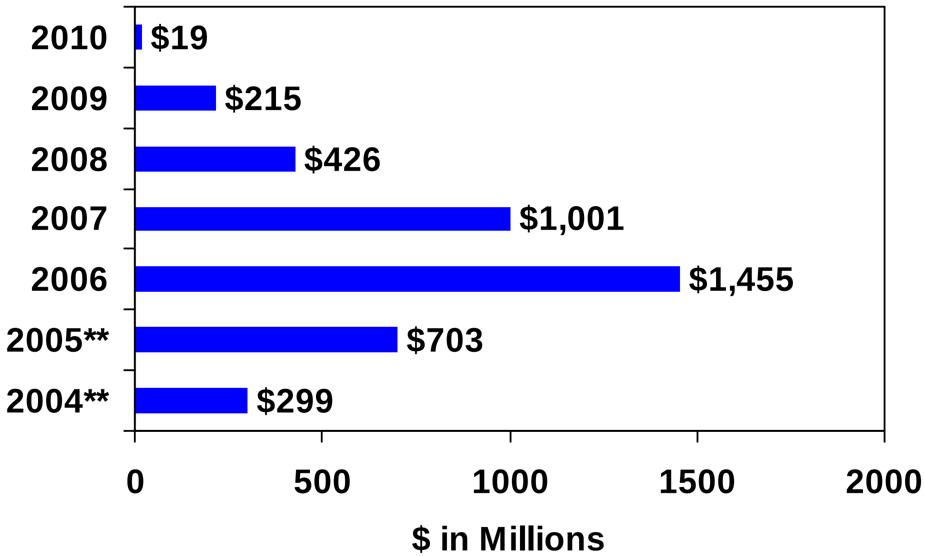
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

$4.1 Billion Environmental Investment

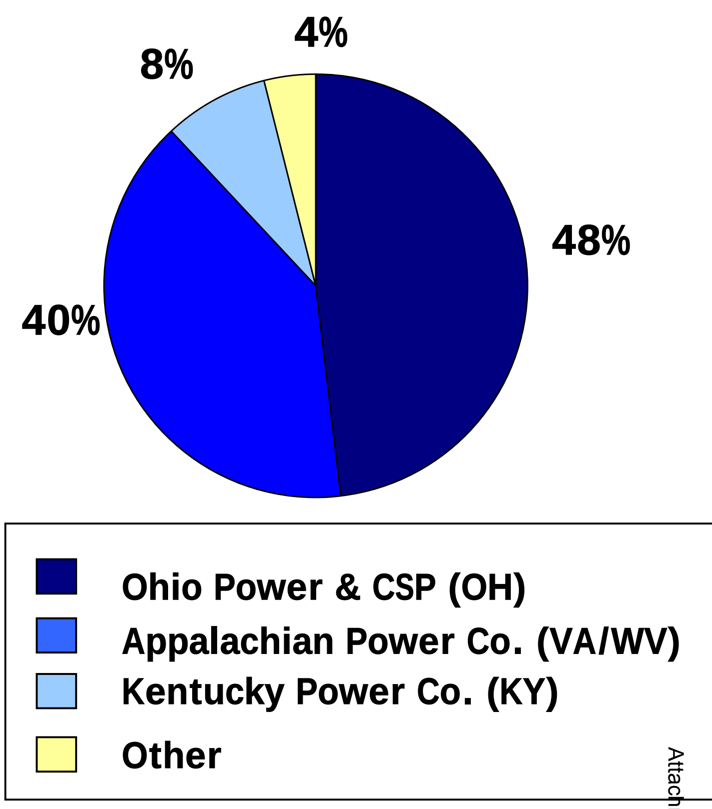
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation



MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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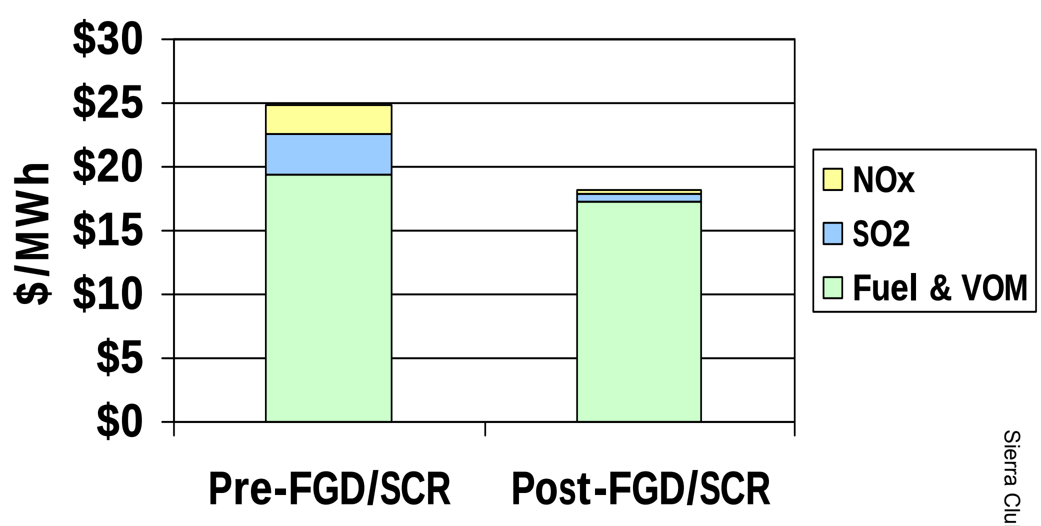
Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing – Final Order Issued
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ Indiana Depreciation Petition
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Texas Regulatory Activity

<u>TCC Stranded Cost Recovery Case</u>

February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion

- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - ➢ Final order expected in May 2006
  - ➢ September 1, 2006 - Issuance of securitization bonds if no appeal

<u>Procedural Schedule for TCC Securitization</u>

- ✓ April 17, 2006 – Intervenors File Testimony
- ✓ April 24, 2006 – Staff Files Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 2-4, 2006 – Hearings On Merit

- April 2006 – Request approval for CTC to address other true-up items
  - ➢ Expected $475 million credit to customers
  - ➢ Jan 2007 – CTC to be implemented

Regulatory Activity Underway

<u>Ohio Companies Pass through of FERC OATT Changes</u>

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

<u>Indiana Depreciation Filing</u>

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

Regulatory Activity Underway

AEP®

Appalachian Power

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case – Gave notice to VA SCC on March 1, 2006 of intent to file general rate case no sooner than May 1, 2006

Appalachian Power & Wheeling Power - West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.
- ✓ APCO was granted the authority to begin deferral accounting for ENEC beginning July 1, 2006.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million*
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

*Includes:
$16MM Base Rates
$56MM ENEC
$2MM Misc

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ April 7, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

IGCC Regulatory Activity

AEP®

Ohio - Cost Recovery Filing

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio Next Steps

2006:

- ✓ **Secure cost recovery plan**
  - **Final PUCO Order expected in 2Q06**
- ✓ **Finalize site selection**
- ✓ **Negotiate with suppliers**

2006—2007:

- ✓ **Obtain permits and finalize engineering and procurement**

2007—2010:

- ✓ **Construct and start-up plant**

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 - 2008)

- ✓ Annual 3% and 7% generation rate increases at CSP & OP, respectively
- ✓ POLR rate rider for environmental additions
- ✓ Ability to request additional 4% annual increase in generation rate
- ✓ Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- ✓ $41 million annual increase in base rates
- ✓ Rates implemented March 30, 2006

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

Appendix

2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

Summary of Major 2006 Earnings Drivers

- ✓ Load growth of 2.5%
- ✓ $500MM rate recovery assured or in progress
- ✓ Rising fuel costs of 11-13%
- ✓ Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- ✓ Decline in utility operations O&M
- ✓ Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

AEP®

2006 EPS Guidance Range is $2.50 to $2.70

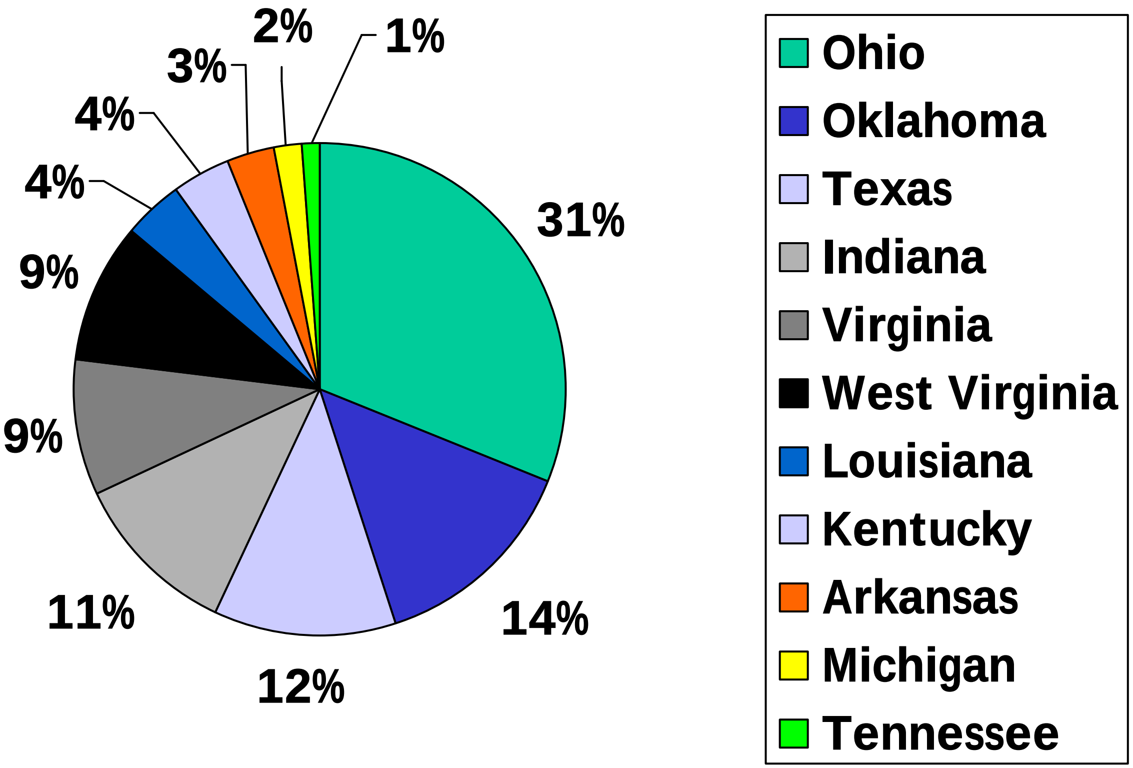
2006

- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

2005 Retail Revenue

Retail Revenue Composition by State



2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

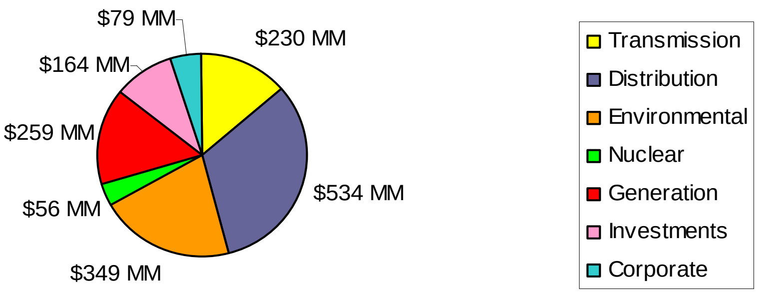
Capitalization

Capital Structure	Actual 12/31/04			Actual 12/31/2005		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,226	-	12,226
Short-term Debt	23	-	23	10	-	10
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	(66)	66	-	30	(30)	-
Defeased First Mortgage Bonds	(84)	-	(84)	(30)	-	(30)
Off-balance Sheet Leases	1,241	-	1,241	1,213	-	1,213
Securitization Bonds	(698)	-	(698)	(648)	-	(648)
Spent Nuclear Fuel Trust	(229)	-	(229)	(228)	-	(228)
Total Adjusted Capitalization	**12,540**	**8,642**	**21,182**	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***59.2%***	***40.8%***	***100.0%***	***58.0%***	***42.0%***	***100.0%***

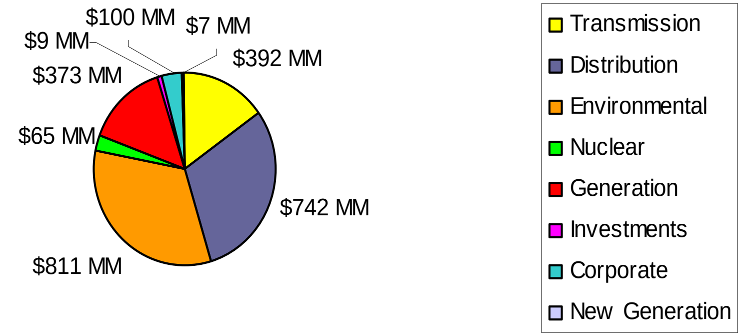
ADJUSTED DEBT-TO-CAP OF 58.0% AT 12/31/05

Capital Investment 2004 - 2006

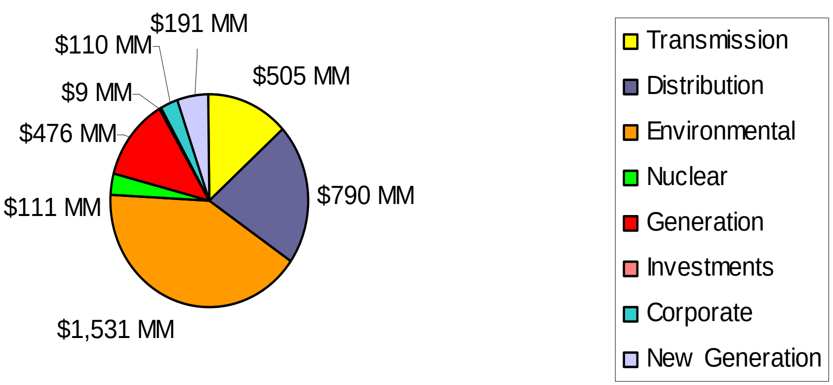
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

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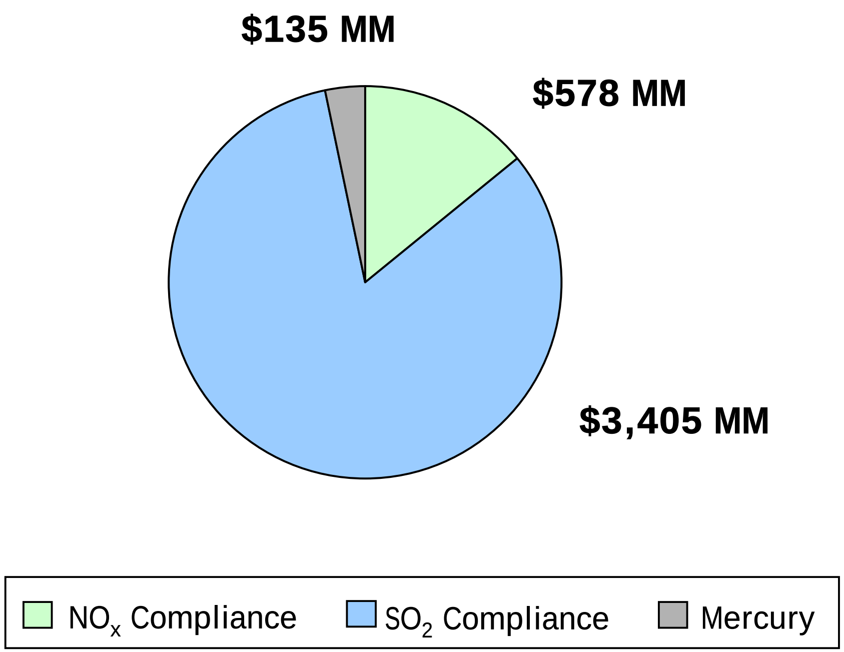
Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Figures Include AFUDC.

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Environmental Installations

AEP®

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD – 2006 – 2010

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR – 2006 – 2009

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Integrated Gasification Combined Cycle

AEP®

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

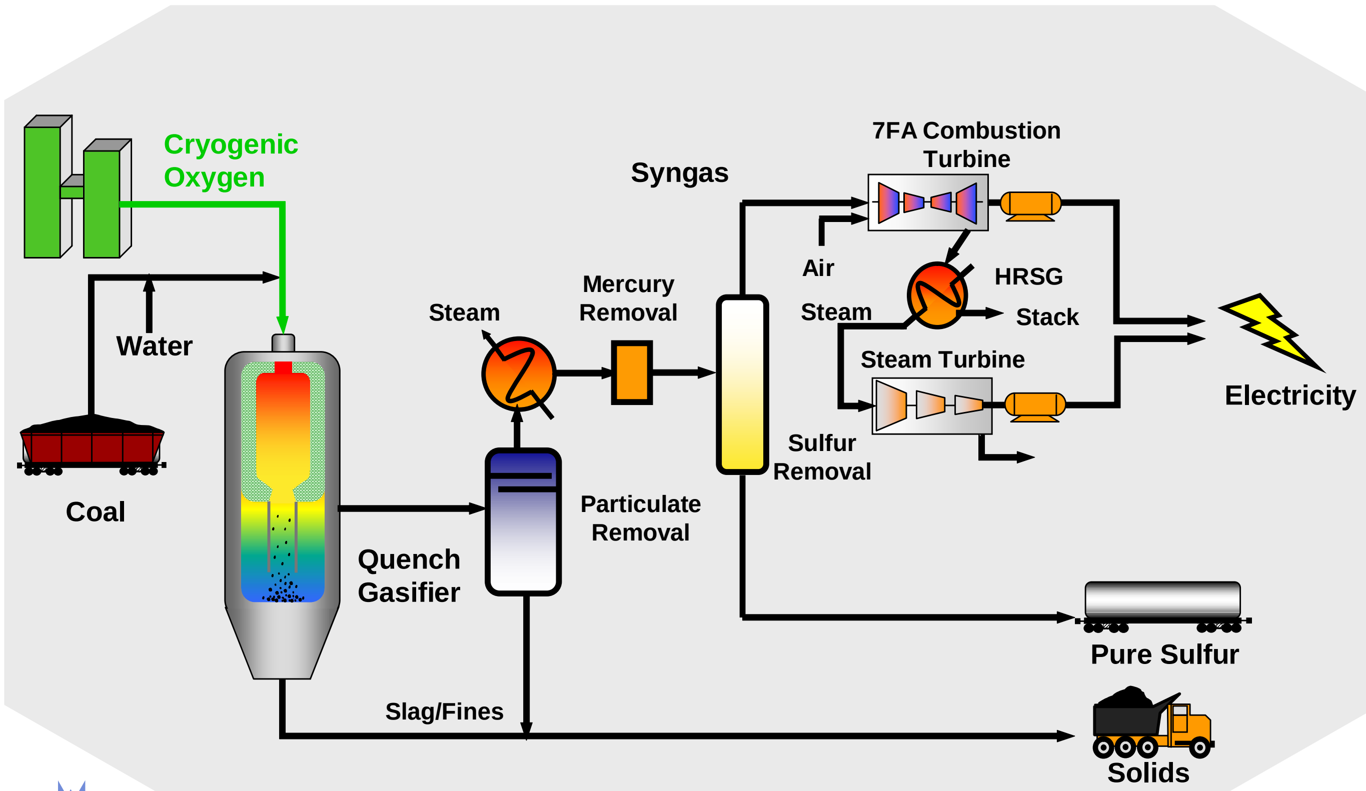
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



NETL

162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

AEP®

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure - Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base - Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order issued.

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

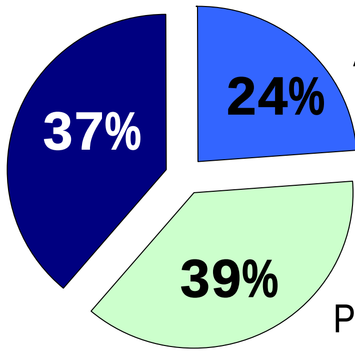
Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

Coal Procurement

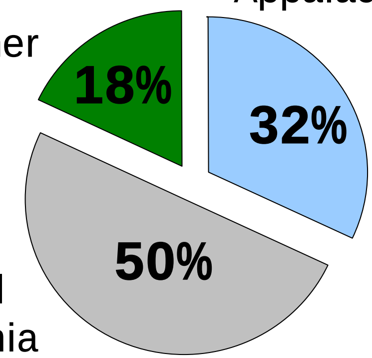
AEP SYSTEM



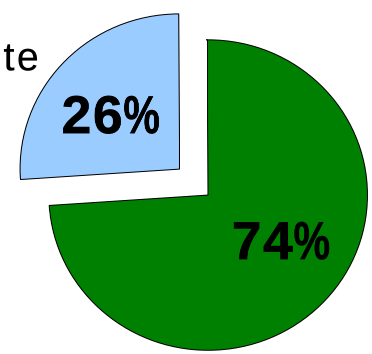
Coal Supply
(on average)

- ➢ Purchase 75 MM tons per year
- ➢ Avg. delivered price ~ $32.52/ton in 2005
- ➢ Essentially >95% purchased for 2006
- ➢ Approximately 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM



WESTERN SYSTEM



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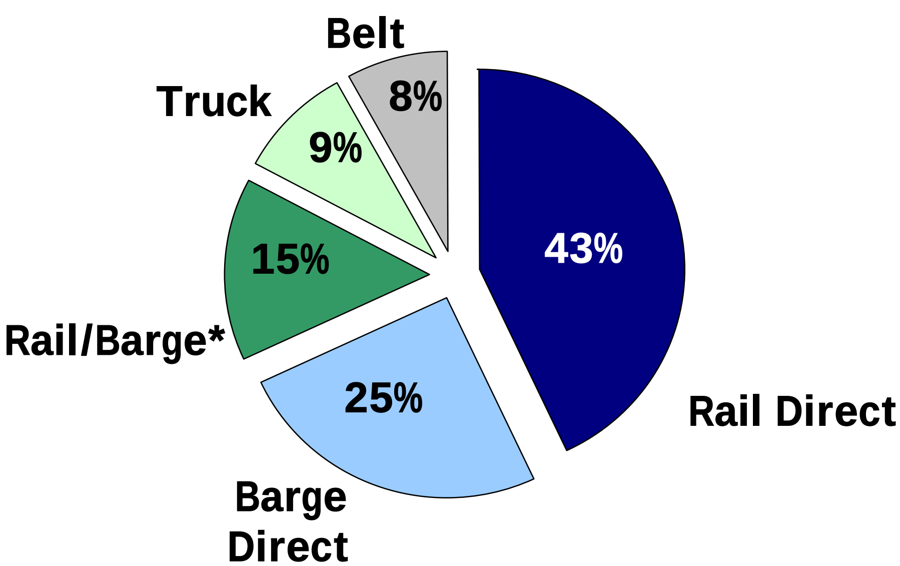
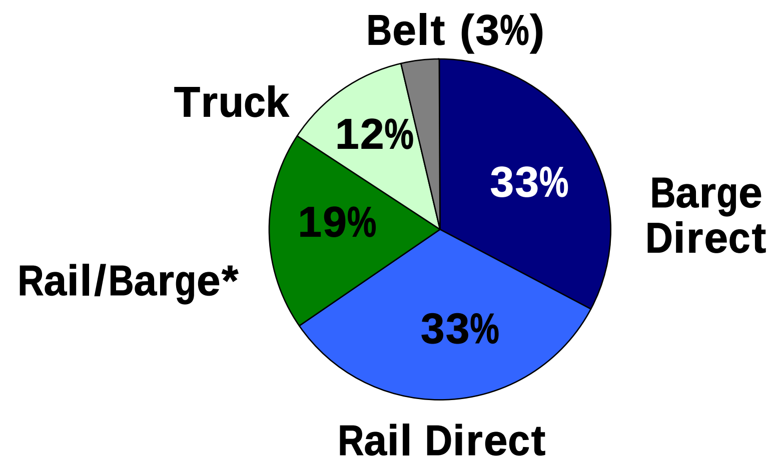
Coal Delivery

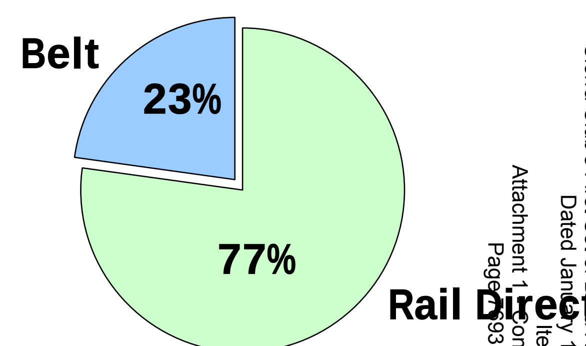
AEP SYSTEM DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



WESTERN SYSTEM
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

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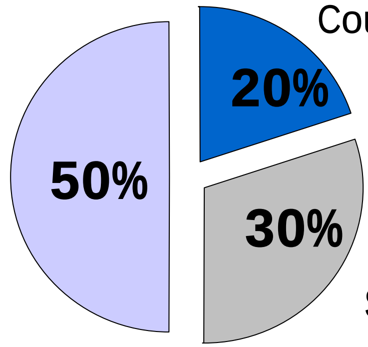
Fuel Recovery

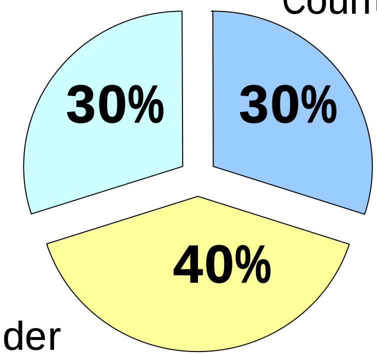
AEP SYSTEM



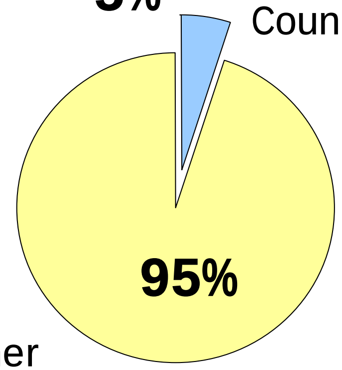
Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M – MI, KGP, KPCo
  - AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



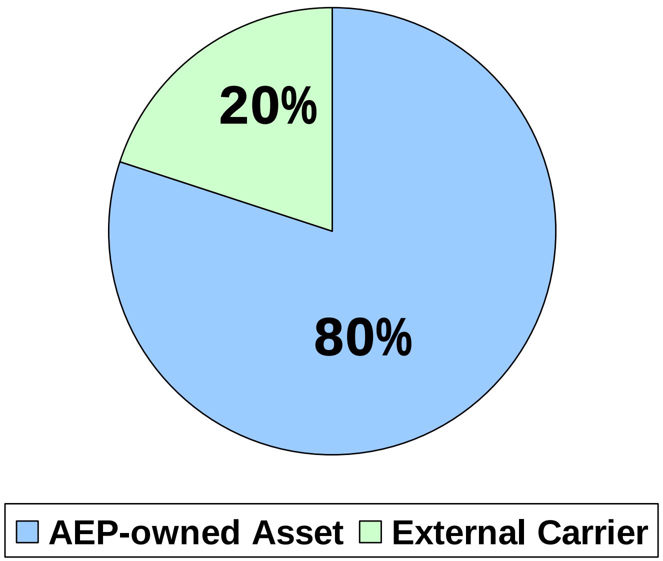
WESTERN SYSTEM



Note: Fuel Recovery percentages are based on estimates for 2006 Fiscal Year

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
2005 Actual



AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

* Represents close approximations

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

AEP AMERICAN® ELECTRIC POWER

Midwest Utilities Seminar
Chicago, IL
April 8, 2010

General James M. Gavin Plant (Ohio)

765-kV Transmission Line

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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EVP and Chief Financial Officer

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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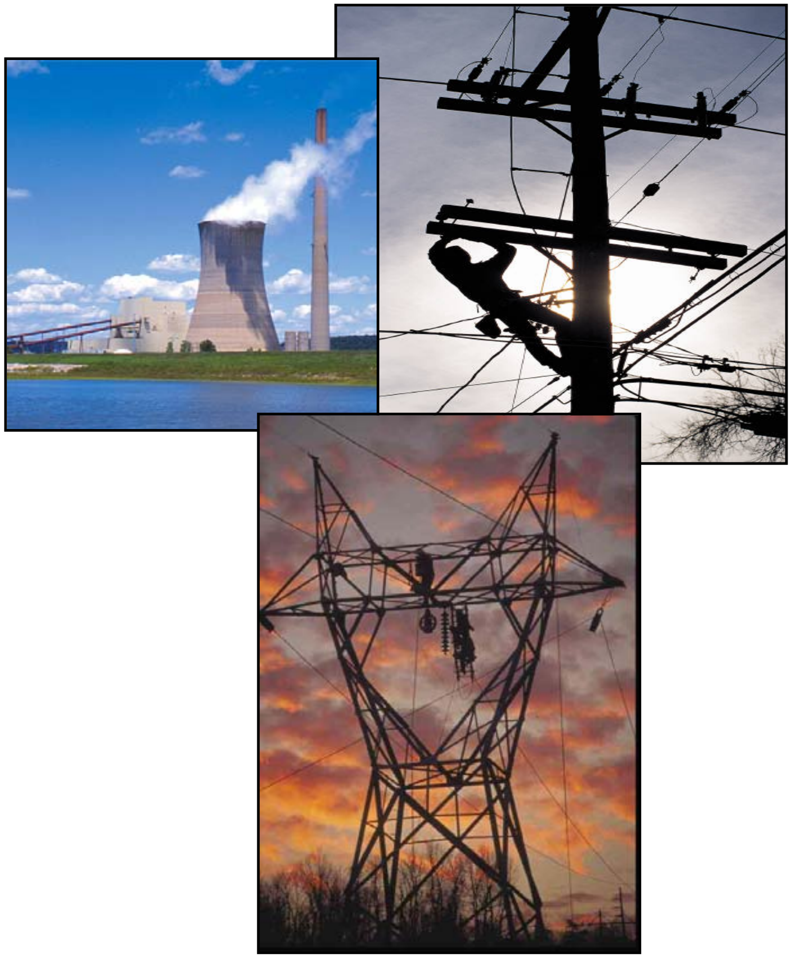
AEP Value Proposition

- **Regulated Utility Platform**
  - Diversified service territory
  - Successful regulatory track record
  - Value compared to regulated peer group

- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

- **Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders



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[1] yield percentage based on AEP closing price of $34.30 on 04/06/2010

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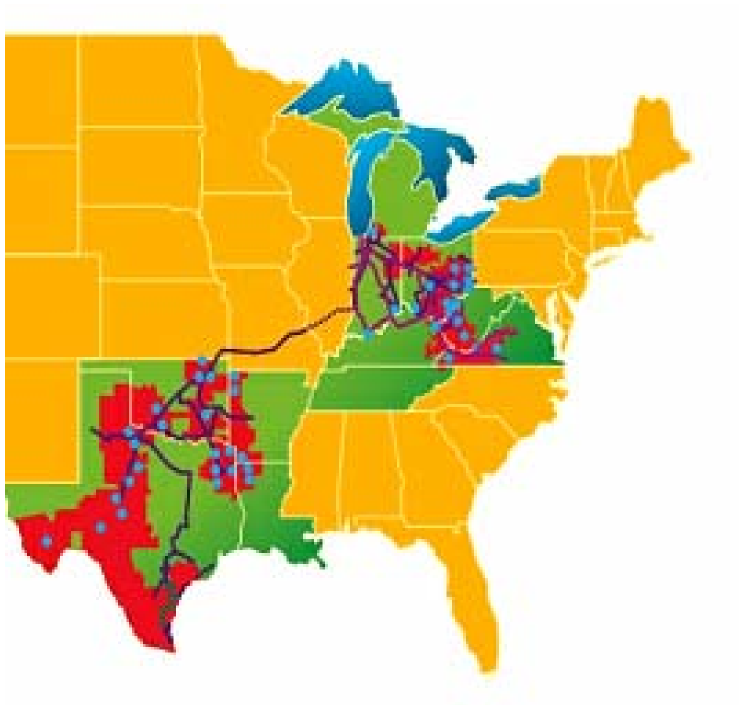
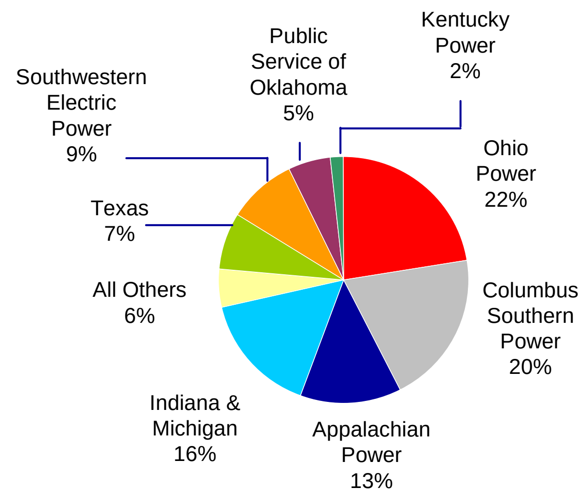
Highly Diversified Regulated Utility Platform

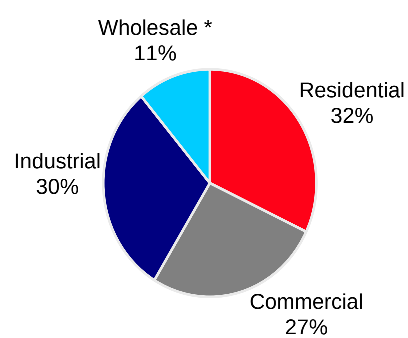


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

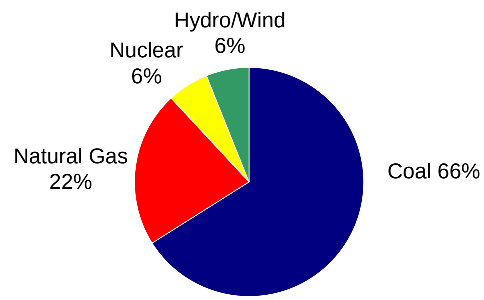


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix**



** Based on Capacity

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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
- Robust pipeline of projects up to $15B

765-kV Tower

JV Strategy - Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 765 kV
- Partners: Westar (50%) & Electric Transmission America (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & Electric Transmission America (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

ETT — COD: 2010-2017
- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

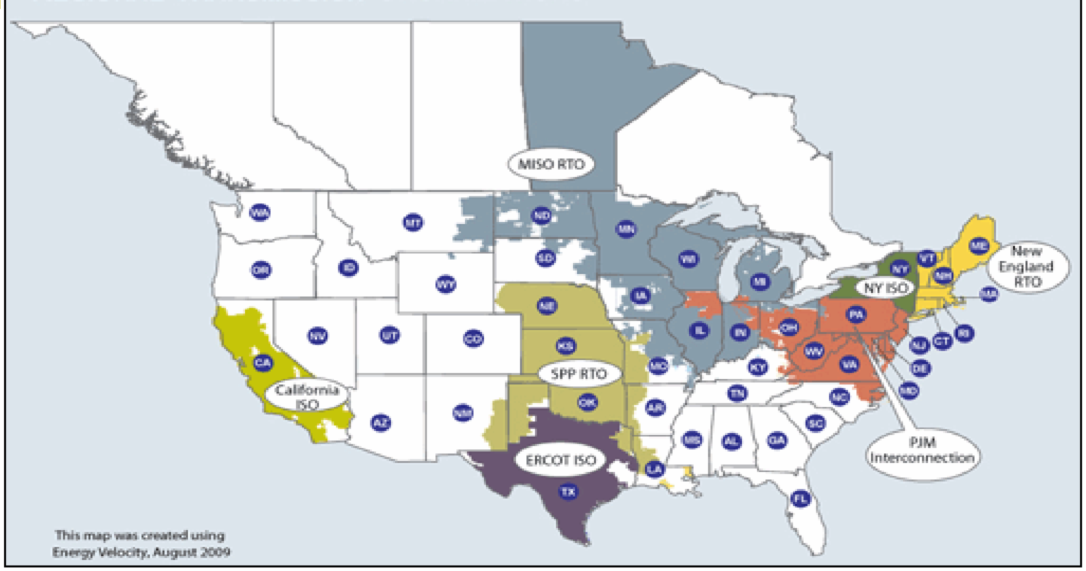
PJM

PATH-WV — COD: 2014
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

REGIONAL TRANSMISSION ORGANIZATIONS



FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Study Sponsors: ATC, ETA, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP

SPP EHV Overlay
- Regional Expansion of 765 kV Backbone

ERCOT

ETT — COD: various
- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM

PJM Expansion
- Regional Expansion of 765 kV, 500 kV and 345 kV systems

PJM/MISO

EHV Michigan/Ohio
- 700 miles of Proposed 765 kV

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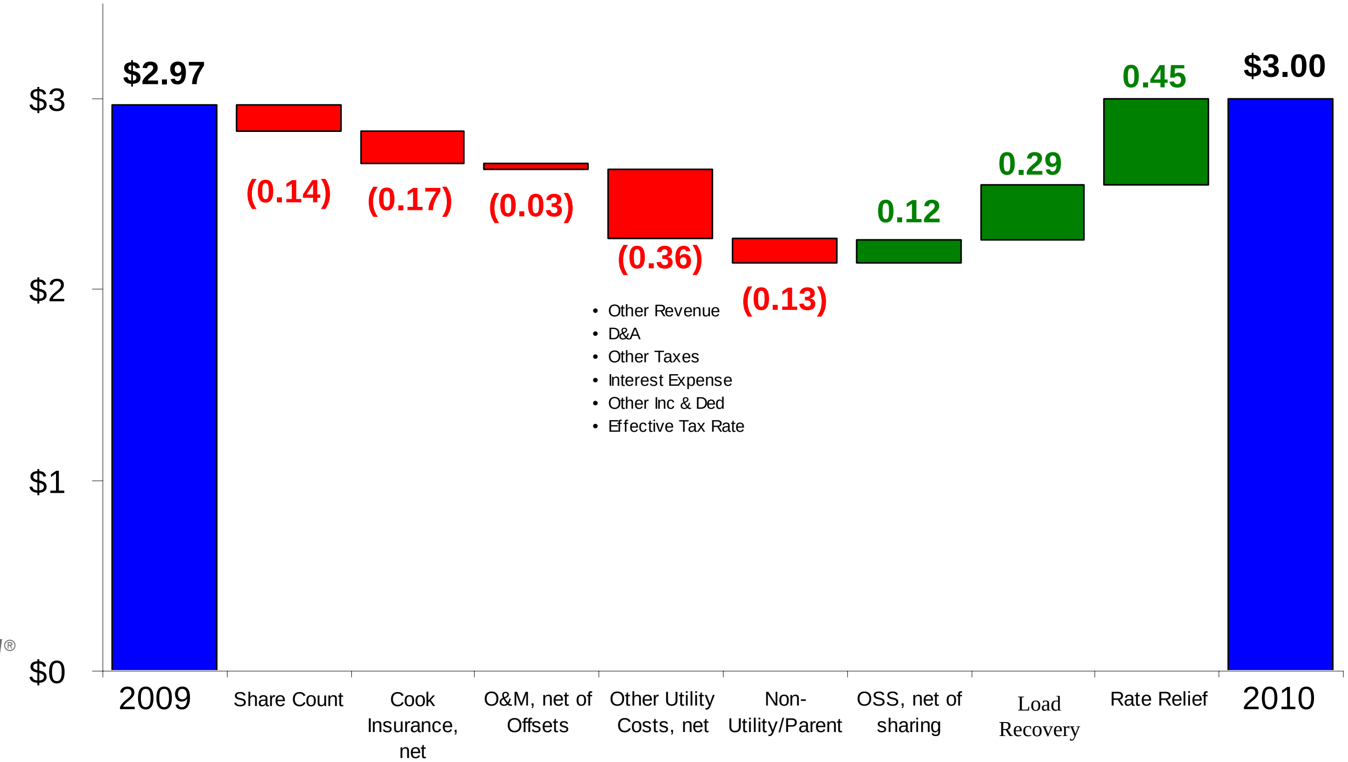
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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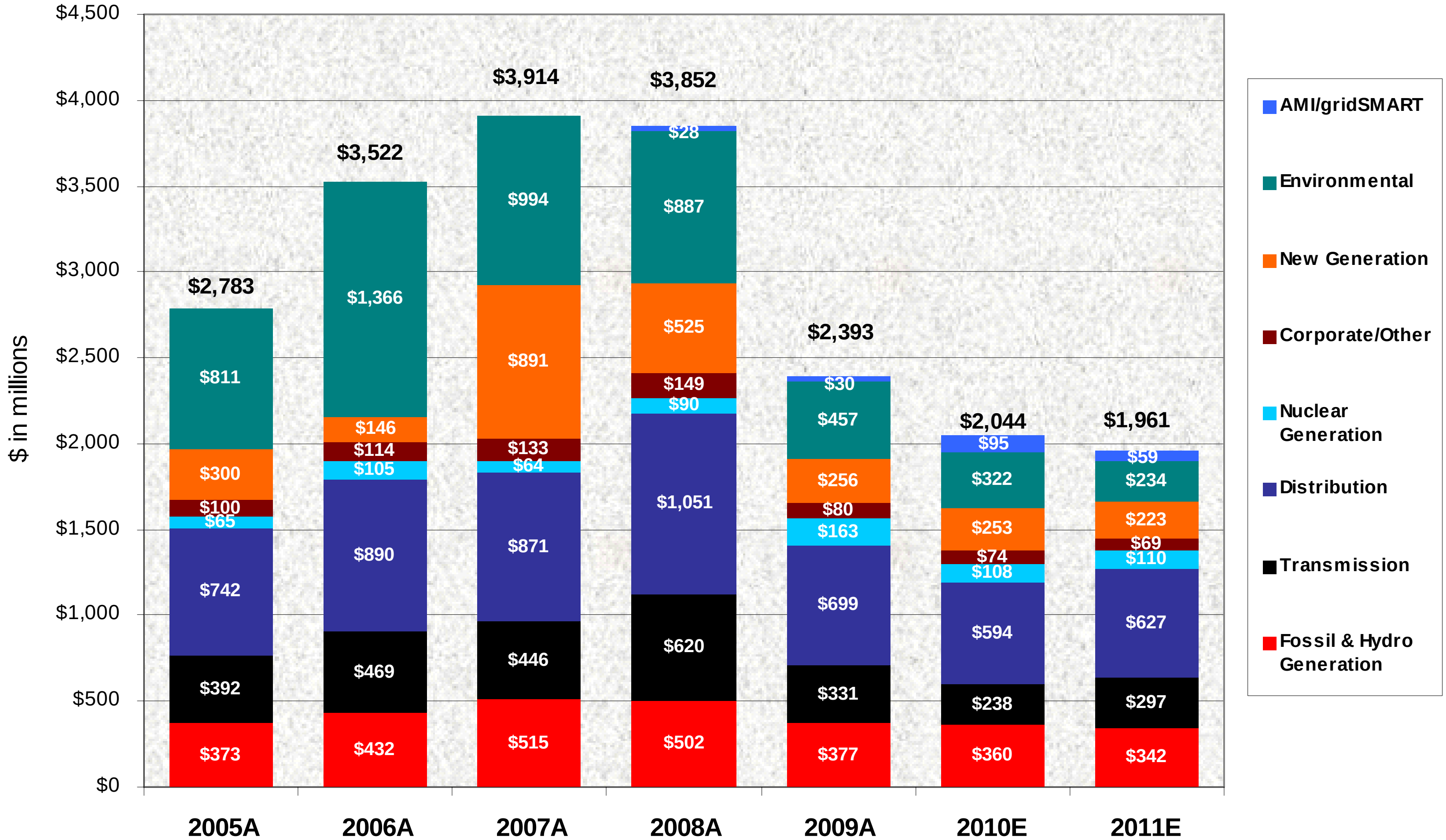
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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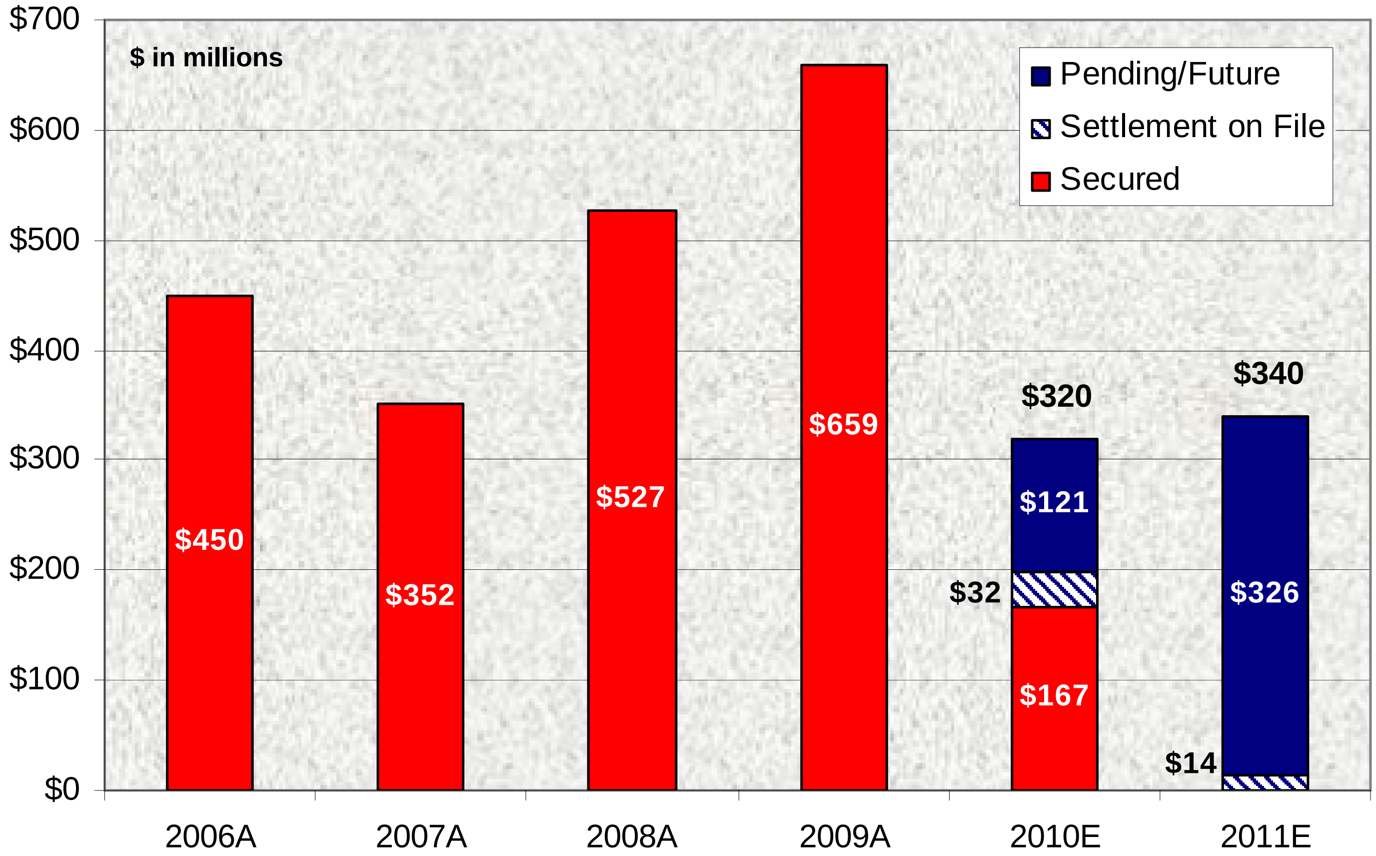
Traditional Rate Making – Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Settlement on file relates to SWEPCO Texas rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

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AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value Proposition**

Mountaineer Plant (WV)

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Appendix

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

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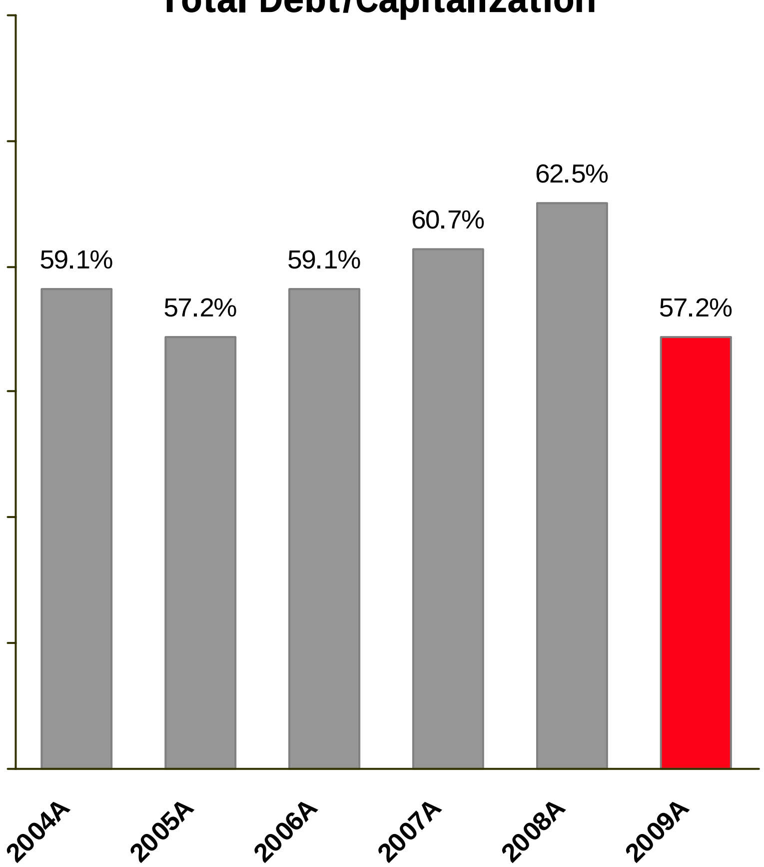
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

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AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ -	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 195
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 680	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company(1)	$ -	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,030	$ 623	$ 565

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)

Data as of March 31, 2010

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. A settlement was filed in March 2010 resulting in a revenue increase of $25MM, an ROE of 10.33%, reduced depreciation expense of $17MM and expiration of merger credits of $7MM. An order is expected in mid-April 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

AMERICAN ELECTRIC POWER

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

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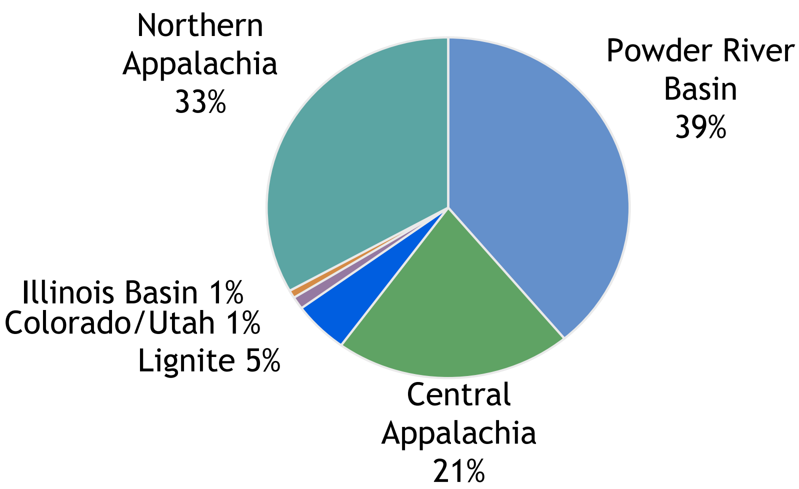
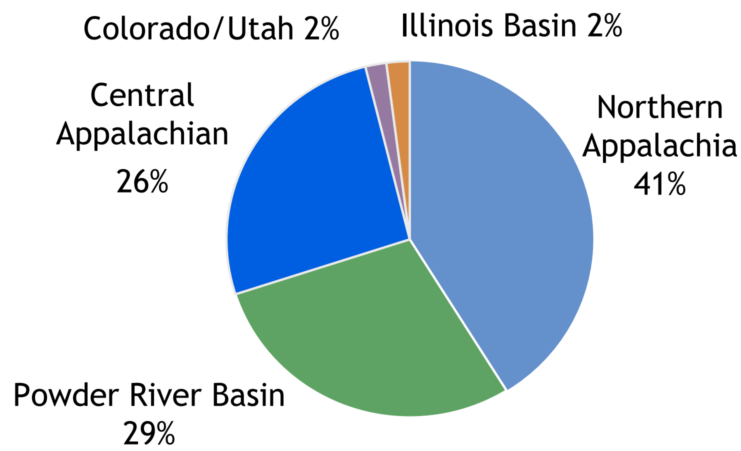
Coal Procurement - 2010 Projected

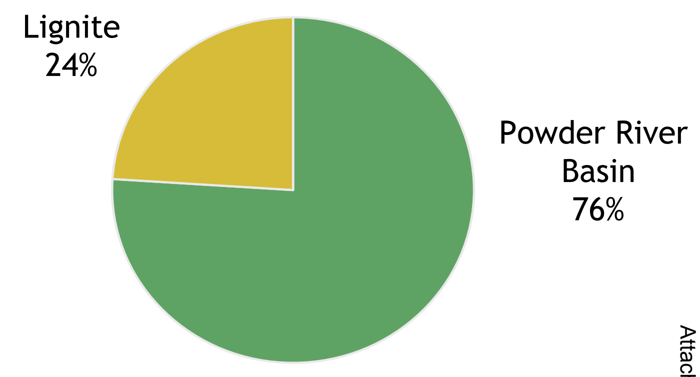
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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Midwest Utilities Conference
Chicago
April 4, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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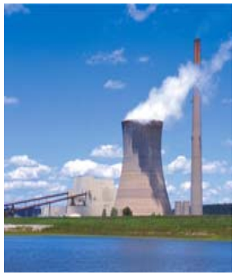
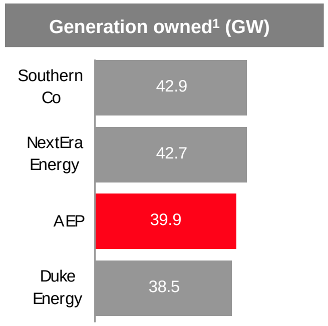
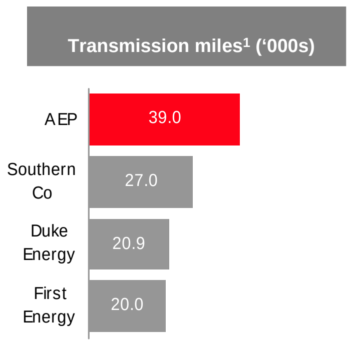
American Electric Power



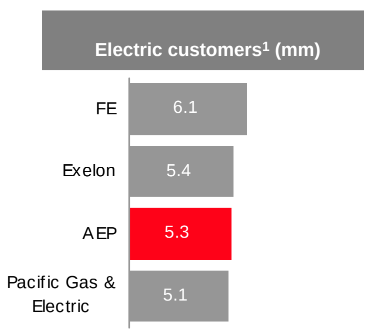
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

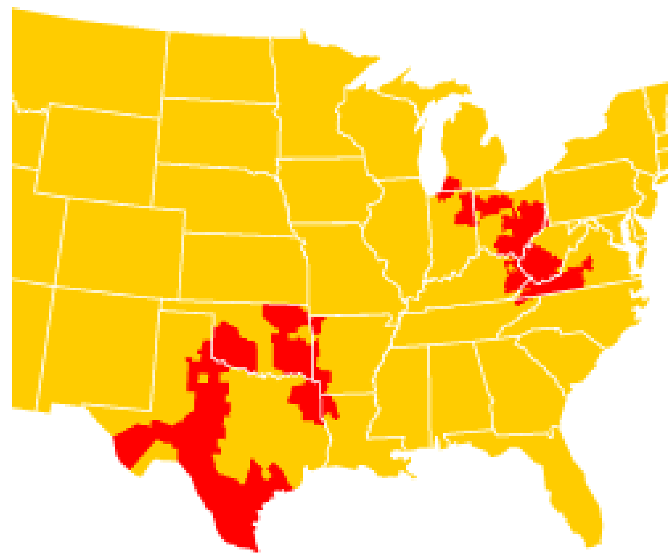


One of the largest U.S. electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

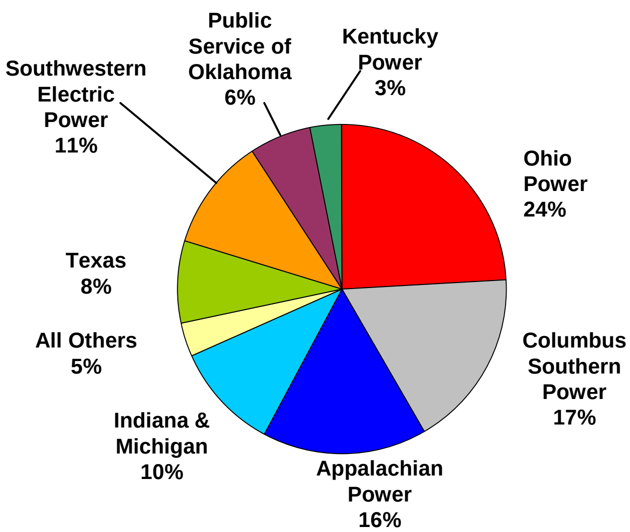
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17B Market Capitalization
BBB/Baa2/BBB credit rating

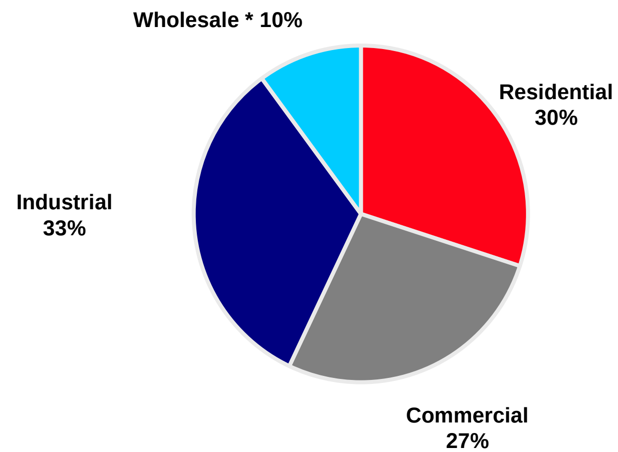
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



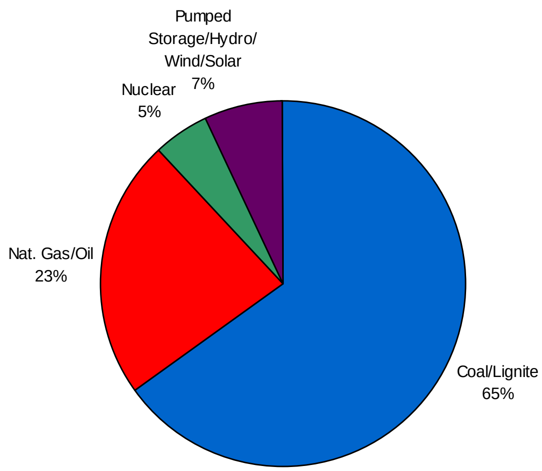
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Domestic Generation Fleet

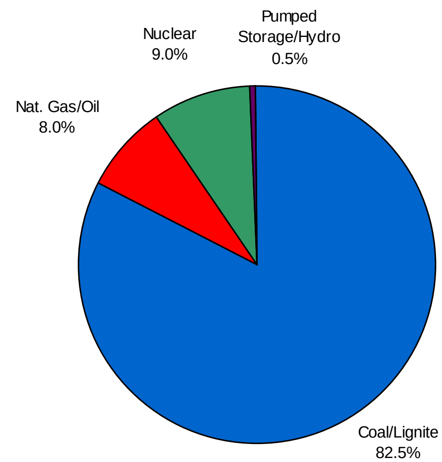
Generation Capacity by Fuel Type

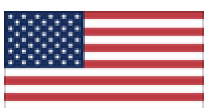
Based on 39,910 MW



2010 Generation Production by Fuel Type

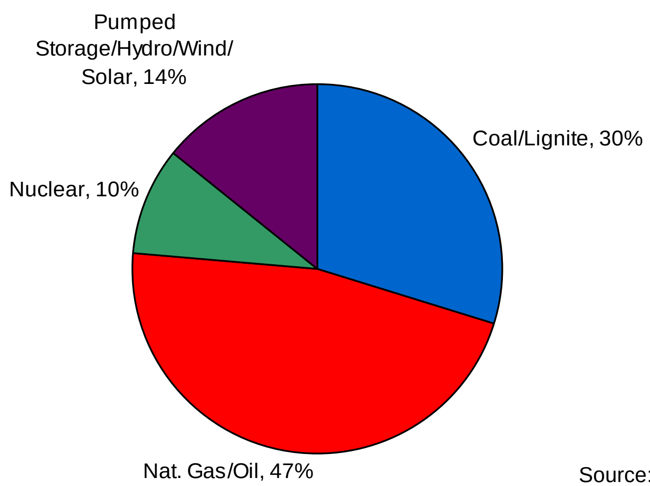
Based on 173.2 TWh





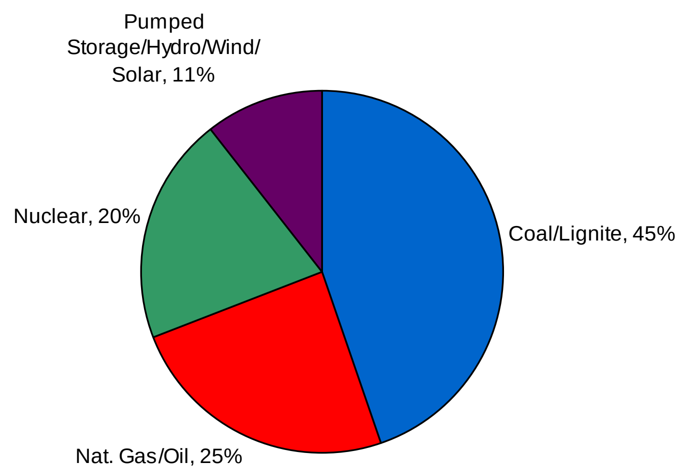
Generation Capacity by Fuel Type

Based on 1,063,848 MW



2009 Generation Production by Fuel Type

Based on 3,953.1 TWh

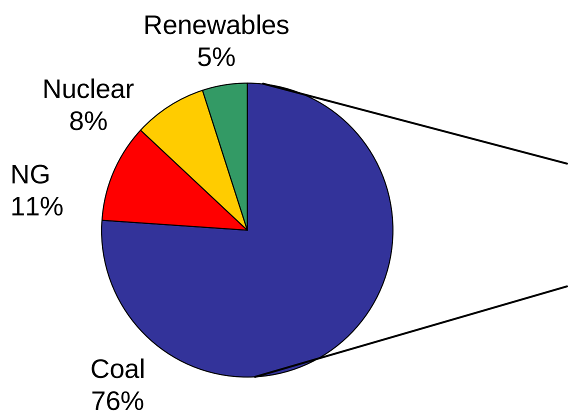


Source: www.eia.doe.gov

AEP Generation Capacity

East Capacity – 27,253 MW

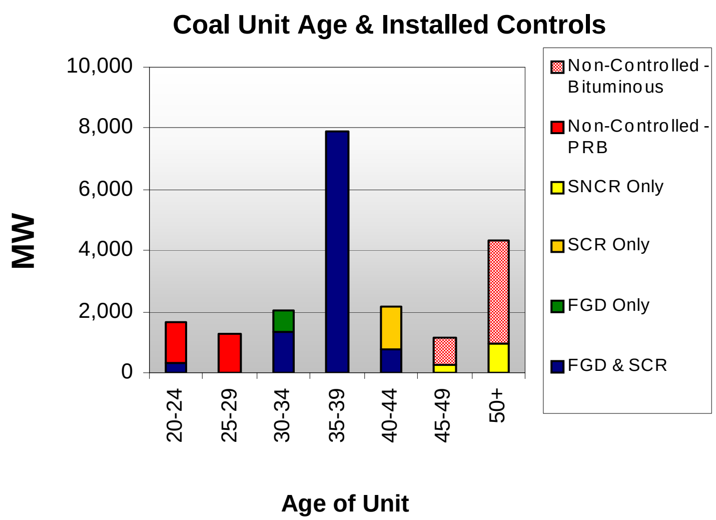
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



Coal Source

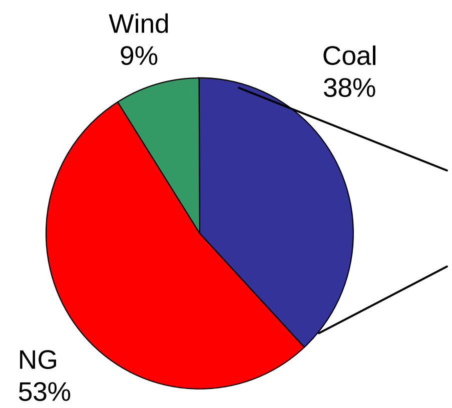
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

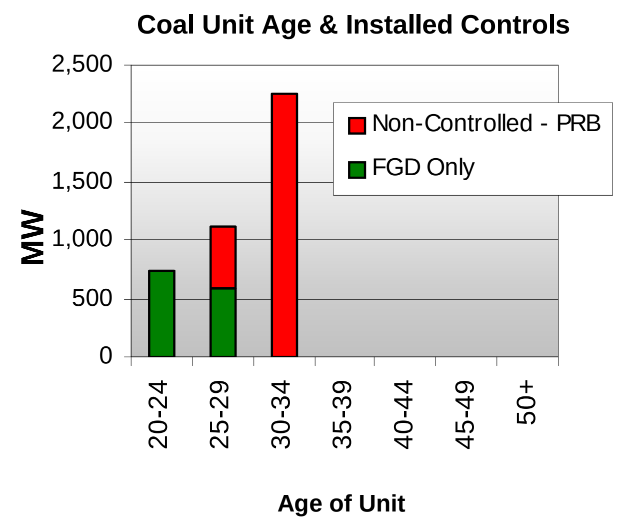
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



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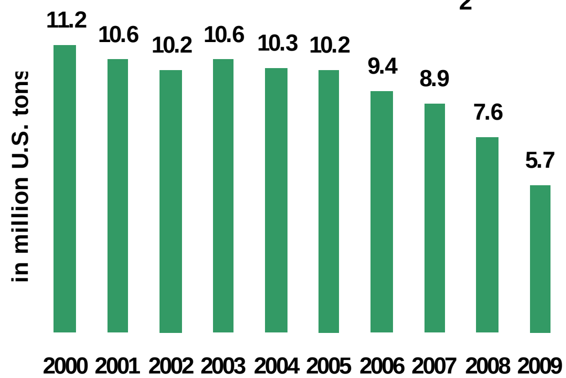
Emissions Reductions since 2000

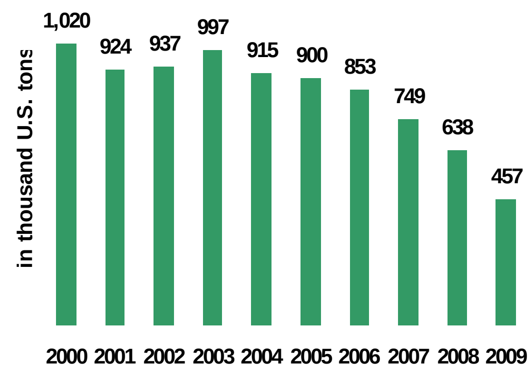
AEP®

U.S. Power Plant SO_2 Emissions



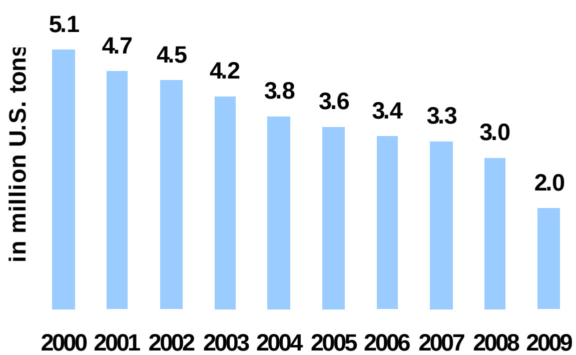
49% reduction since 2000

AEP SO_2 Emissions



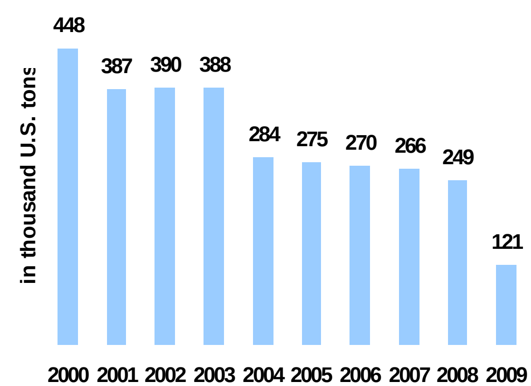
55% reduction since 2000

U.S. Power Plant NOx Emissions



61% reduction since 2000

AEP NOx Emissions



73% reduction since 2000

Source: EPA, 2010; Acid Rain Program

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

Pending EPA Regulations

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - "Non-hazardous", solid waste - action required by ~2017
  - "Special" hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- "Hazardous" option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

Transmission Investment Strategy

- **<u>Near-Term Investment</u>** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.
- **<u>Mid-Term Investment</u>** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012; Expected ROE will be in the 11.20%-11.49% range
- **<u>Long-Term Investment</u>** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

765-kV Tower

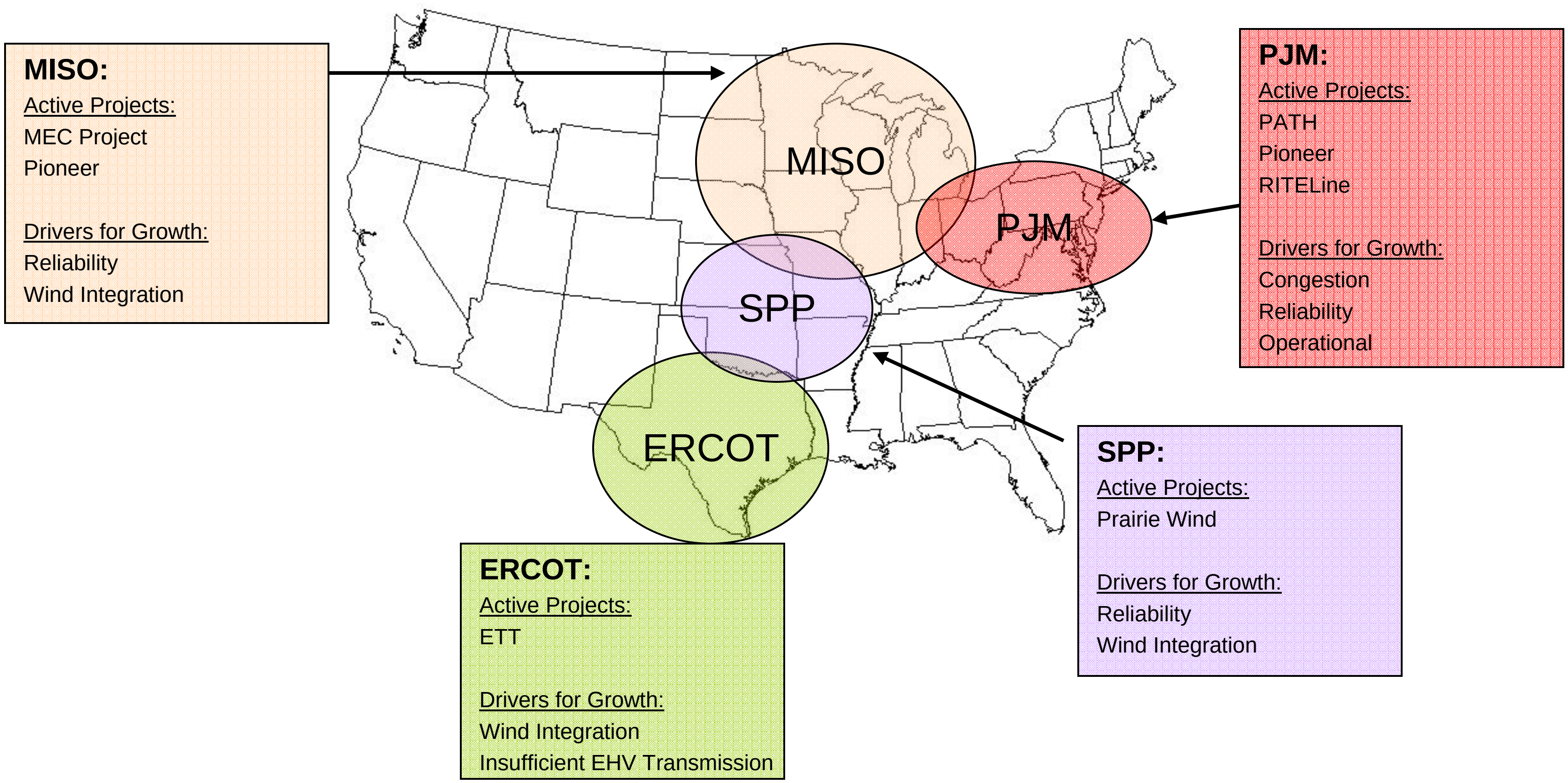
Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT



AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Capital Allocation

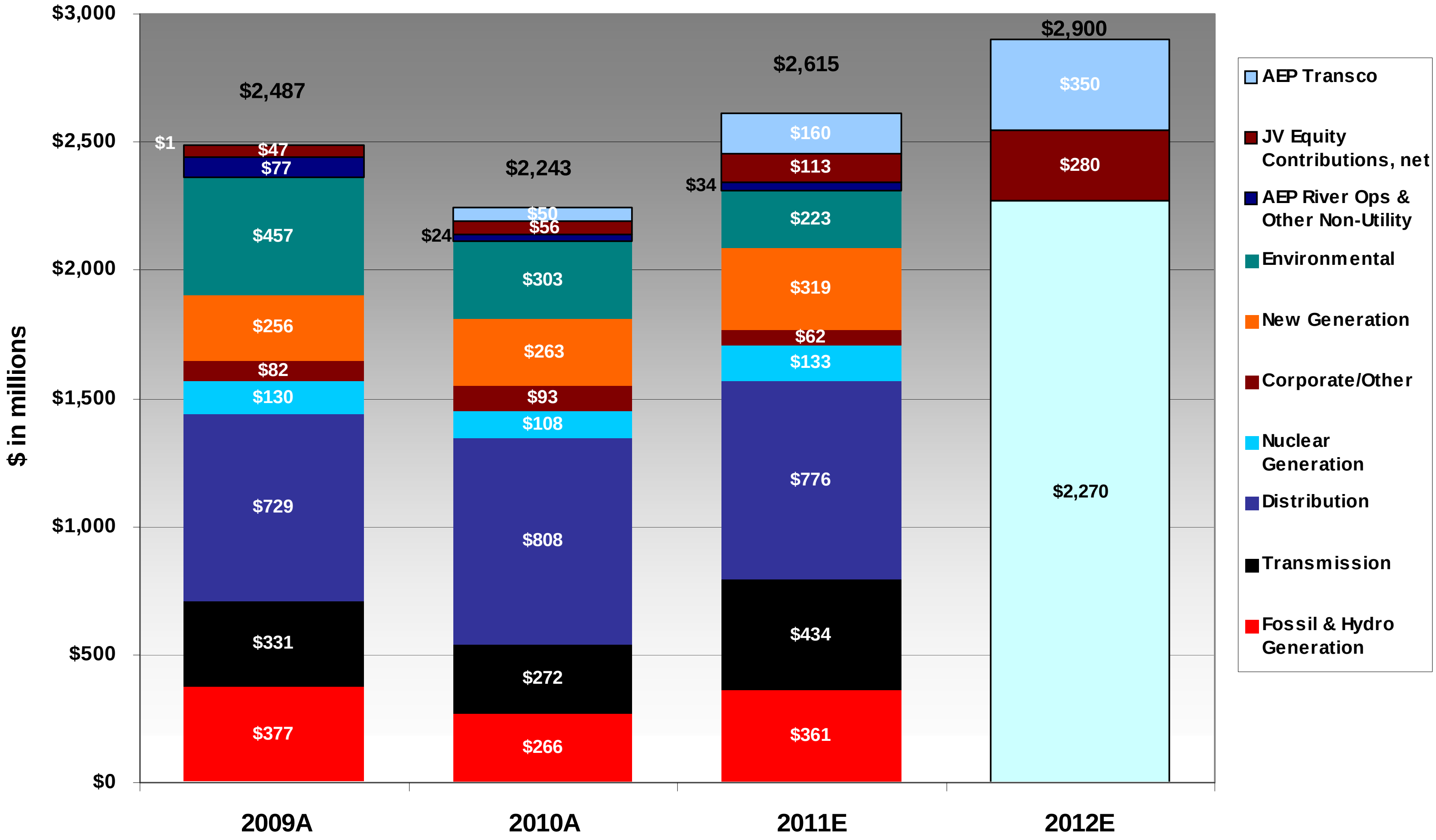
In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- **Capital for Growth**
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012

- **Return of Capital to Shareholders**
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings

- **Capital to Reduce Risk**
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

2011 Ongoing Earnings Guidance

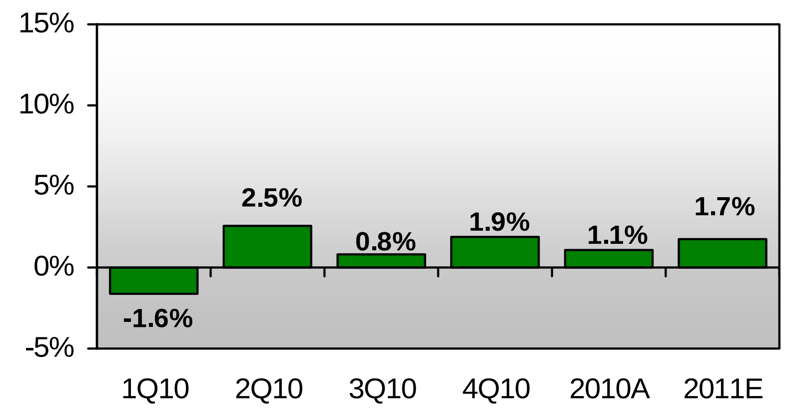
2010A: $3.03/share

2011E: $3.00-$3.20/share

Near-Term Earnings Drivers

- Recovering economy
- Rate recovery from returns on capital investment
- Continued O&M discipline

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year

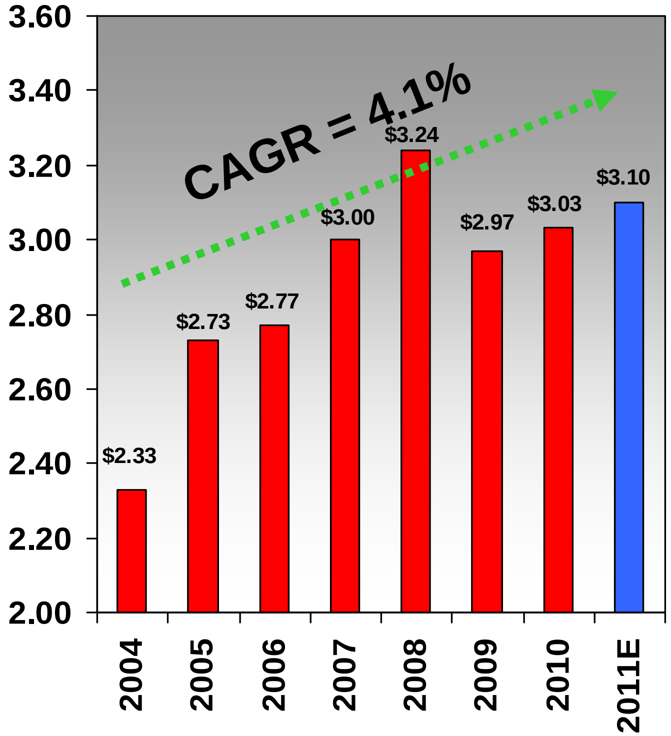


Year over Year change by segment:
Residential: 1.9%
Commercial: 0.7%
Industrial: 1.9%

Earnings and Dividends

On-Going EPS History Since 2004

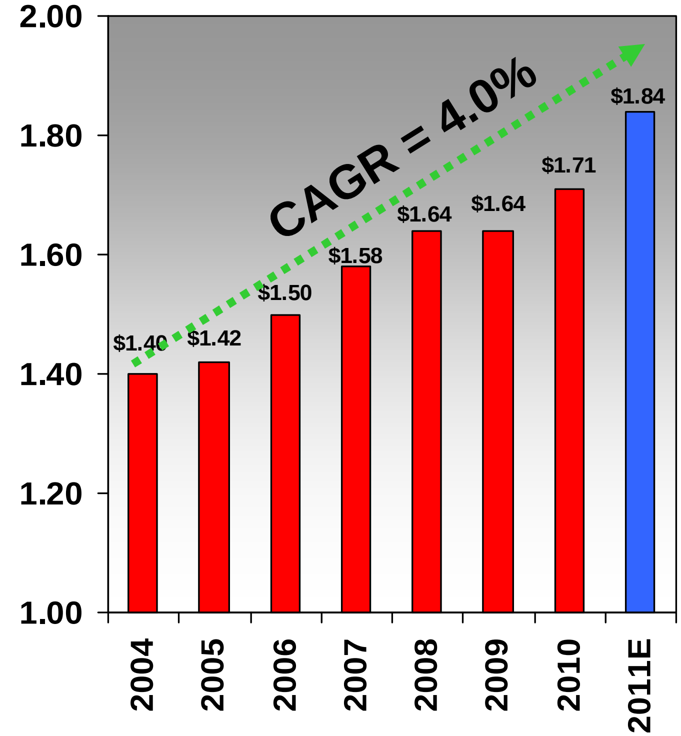
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



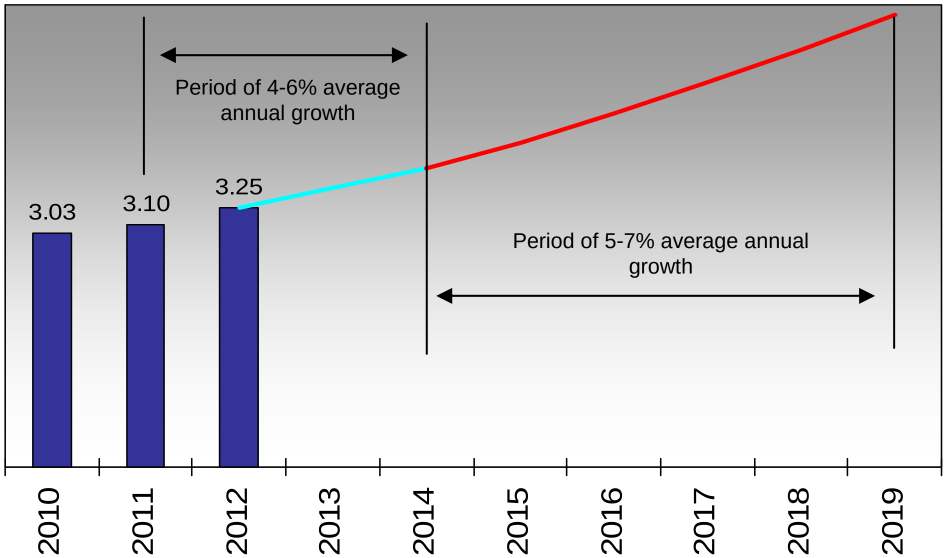
= subject to Board of Directors approval

- Dividend increased 12% in 2010
- 403rd consecutive quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Highlights

- **Regulated Electric Utility**
  - Regulatory and economic diversity
  - Operating Company Model
- **Focus on Capital Allocation**
  - Capital for Growth
  - Return of Capital to Shareholders
- **Strong Balance Sheet**
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- **Growth Opportunities**
  - Capital for utility platform
  - Transmission projects
- **Dividend yield over 5%**

Mountaineer Plant (WV)

Appendix

Detailed Ongoing Earnings Guidance

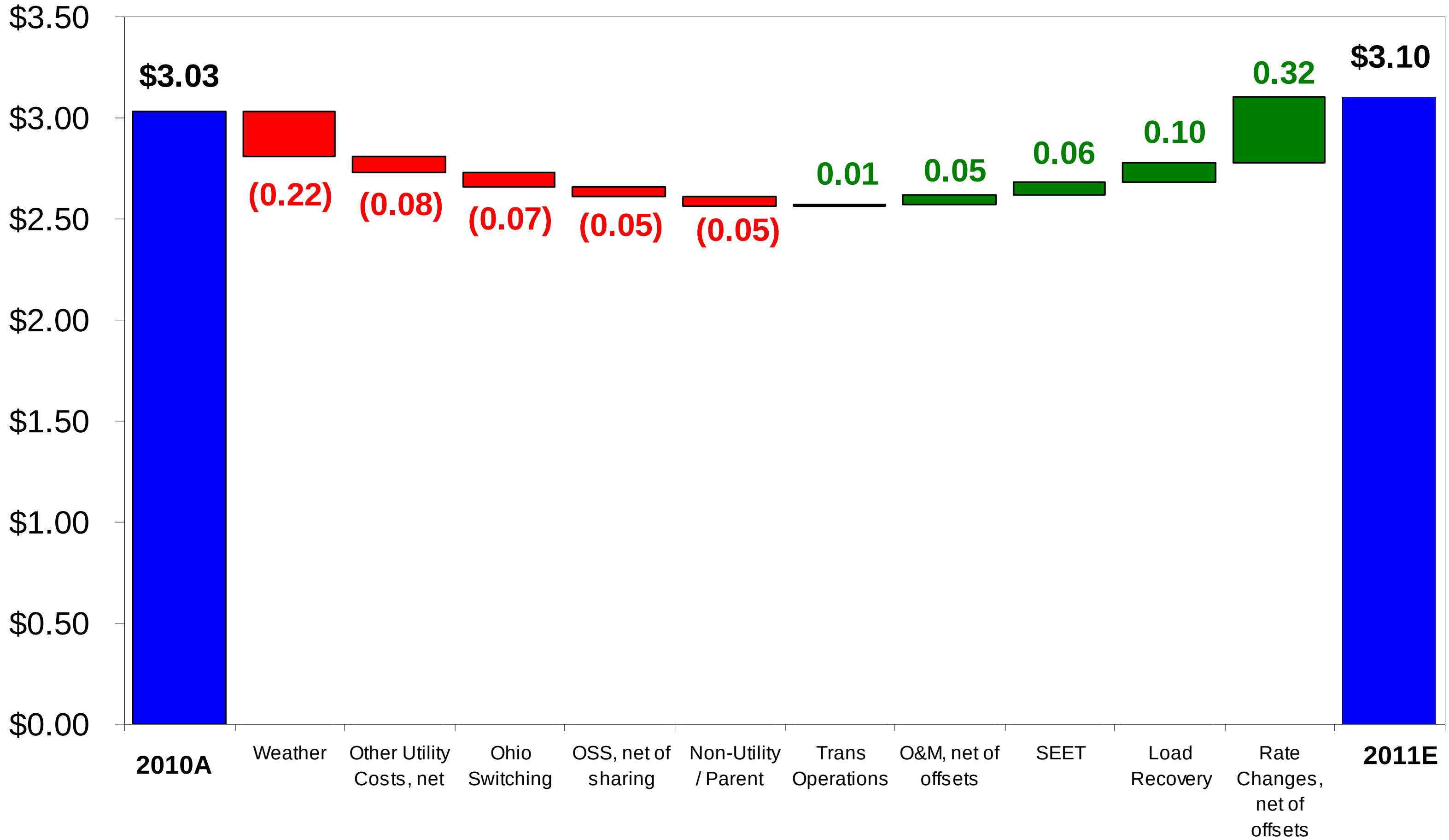
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

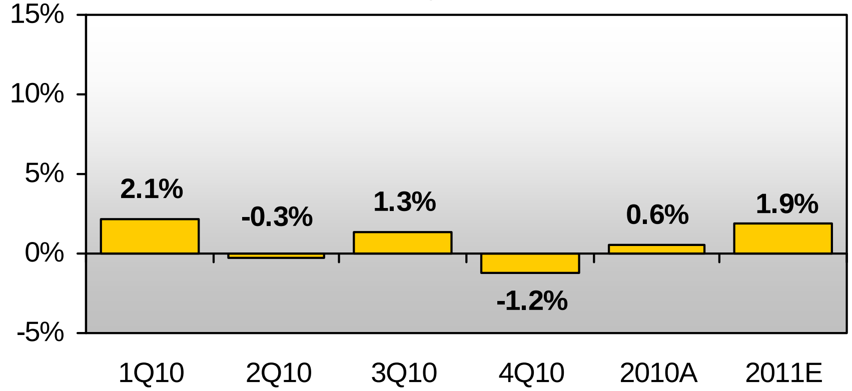


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

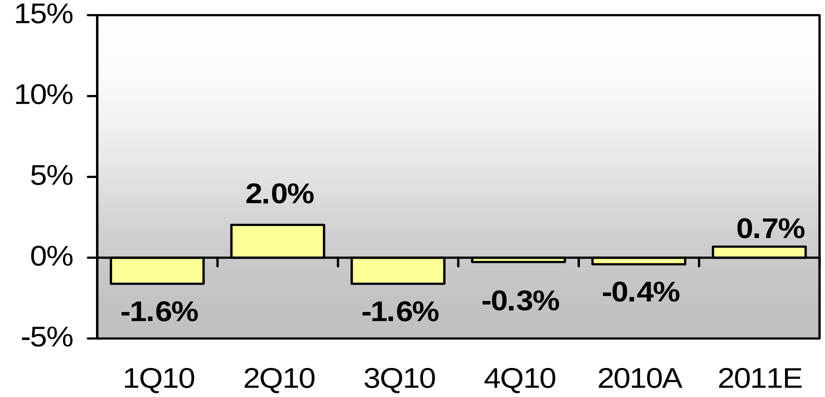
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

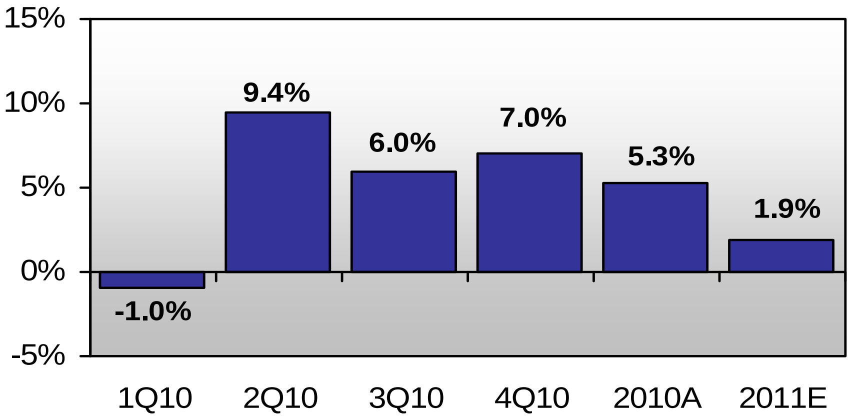
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



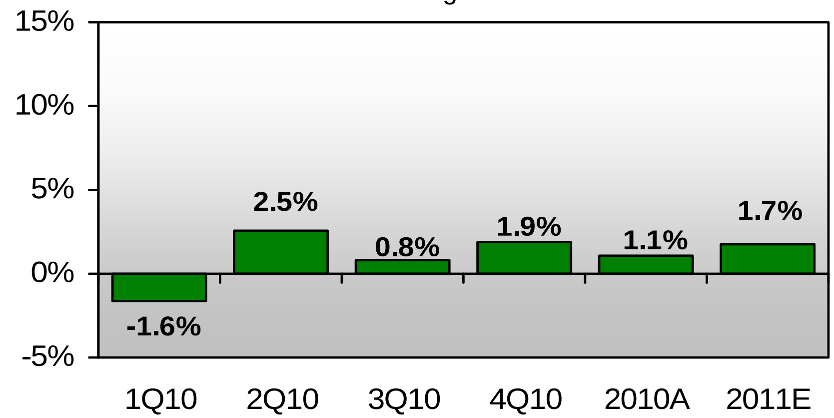
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

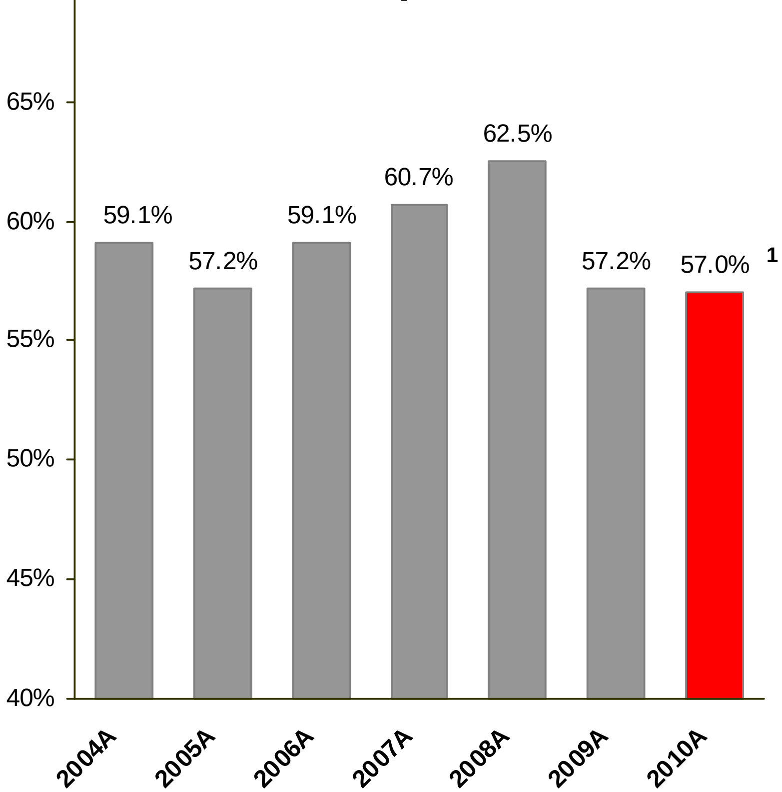
	2010A	2011E
	$ in millions	
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity

Total Debt/Capitalization



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

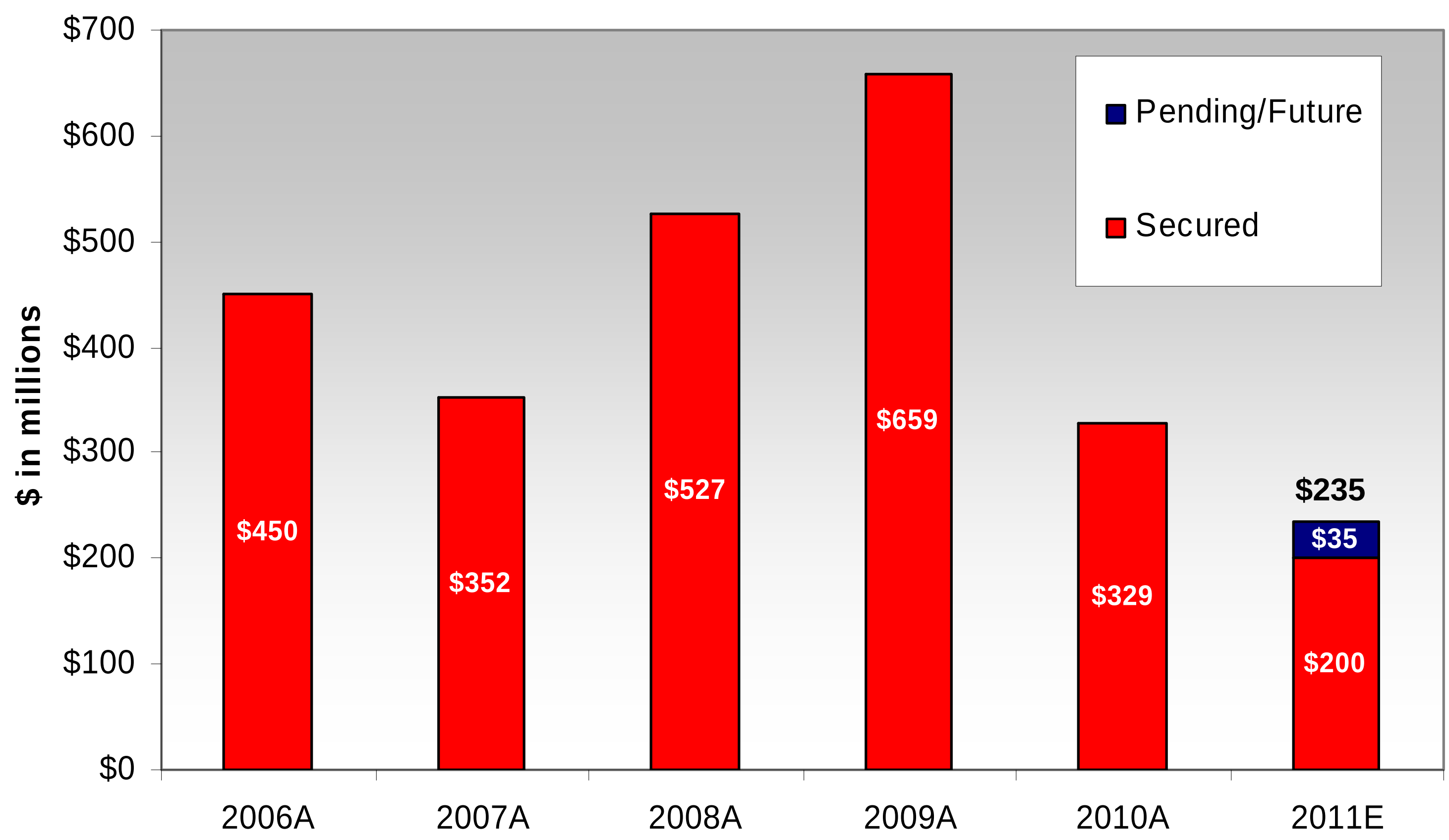
Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase). (Docket #:) A procedural schedule is pending from the VSCC. In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed . APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure - Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule - TBD

Required Rate Relief - Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

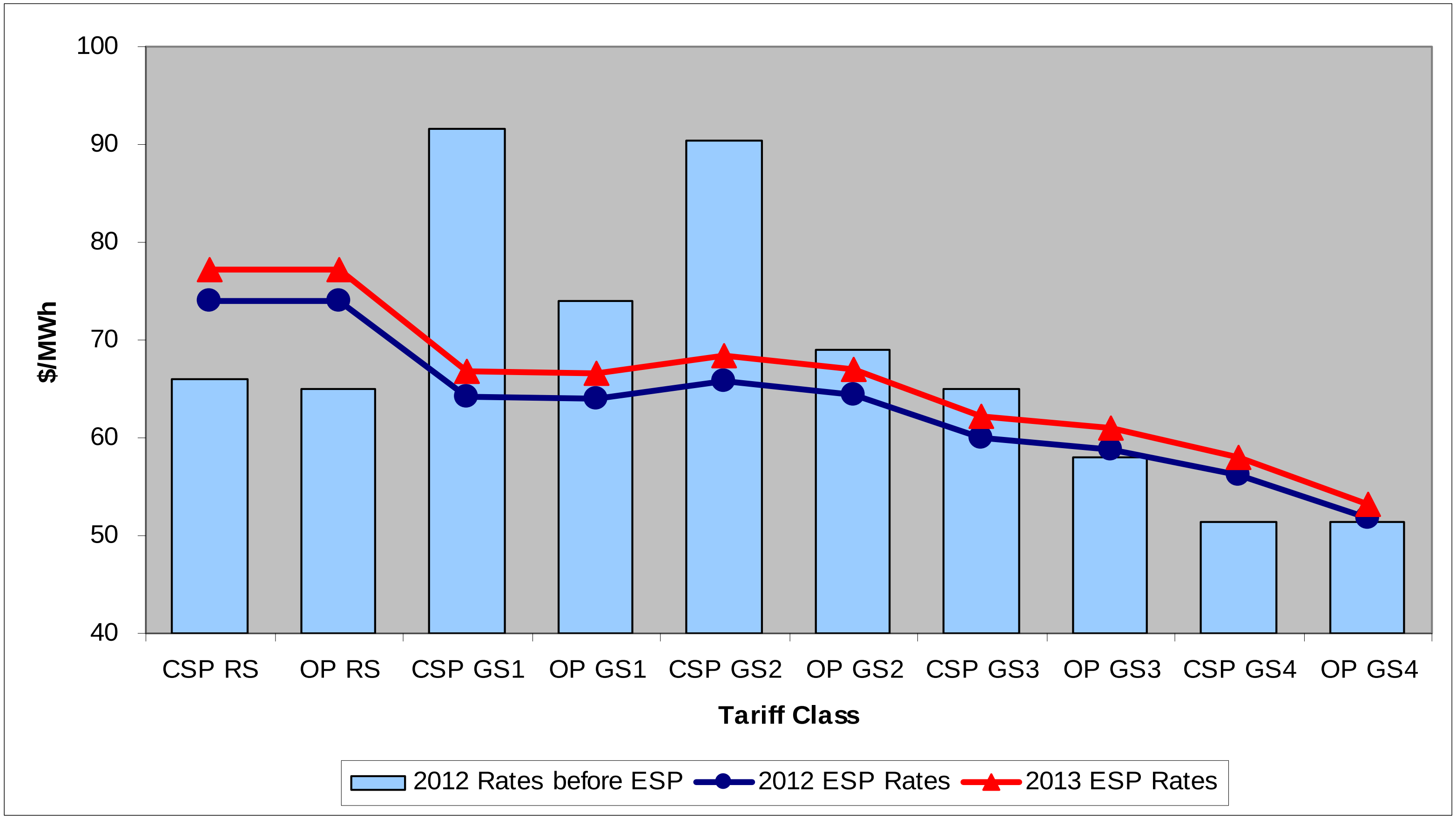
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

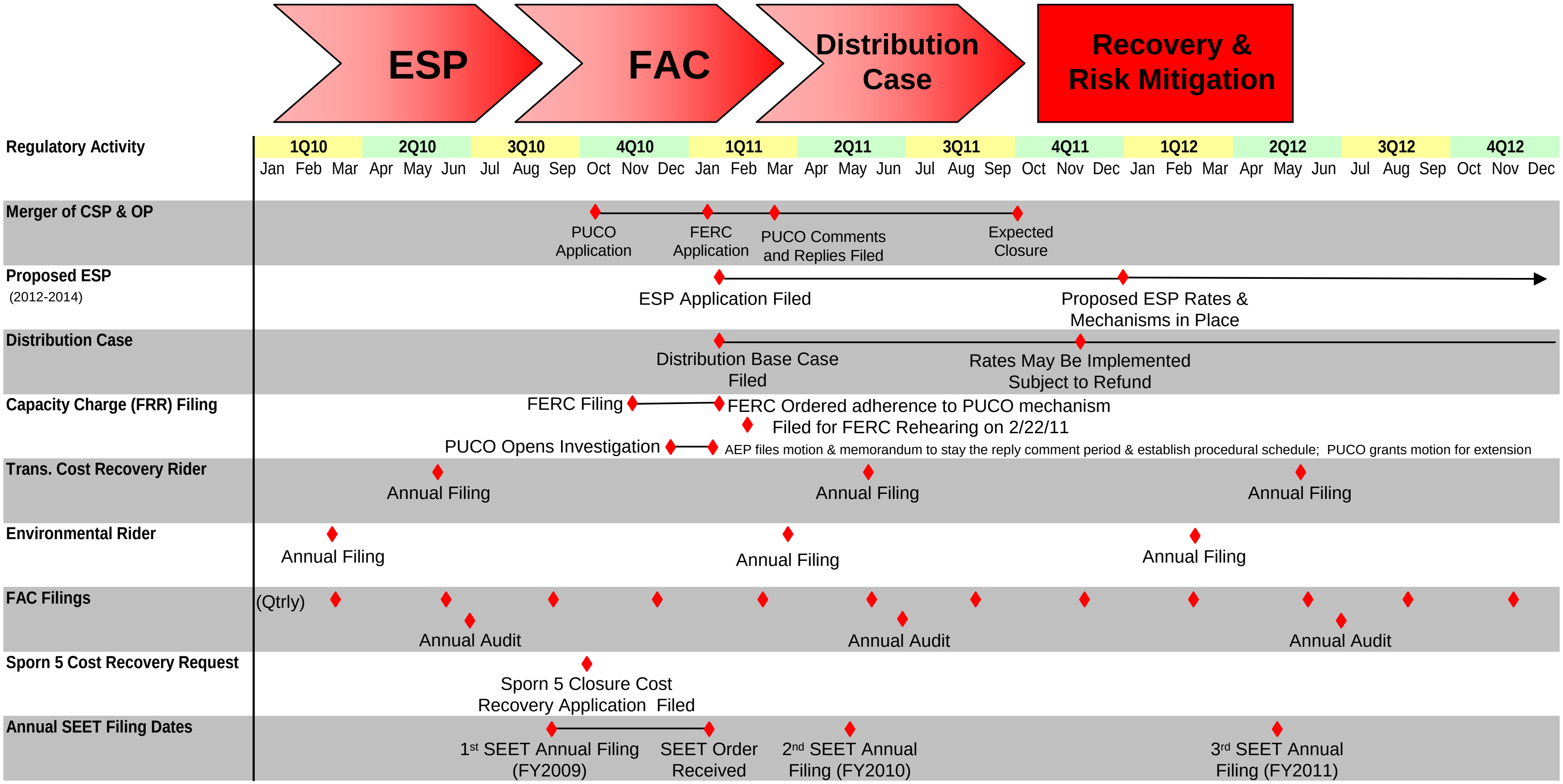
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

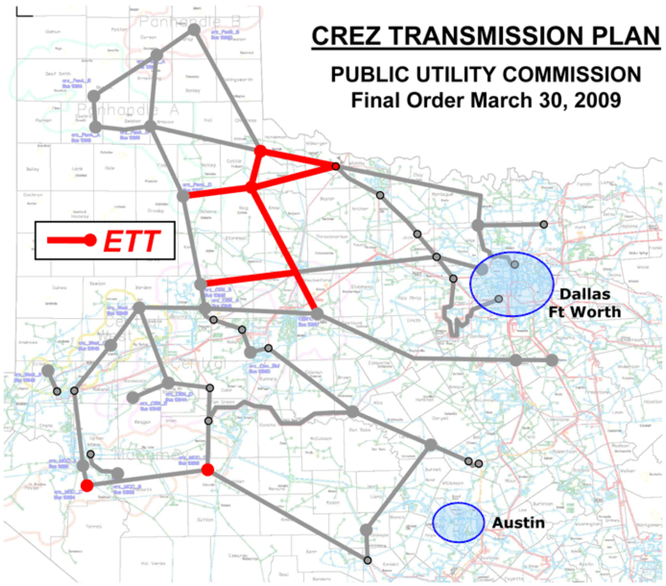
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT
Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

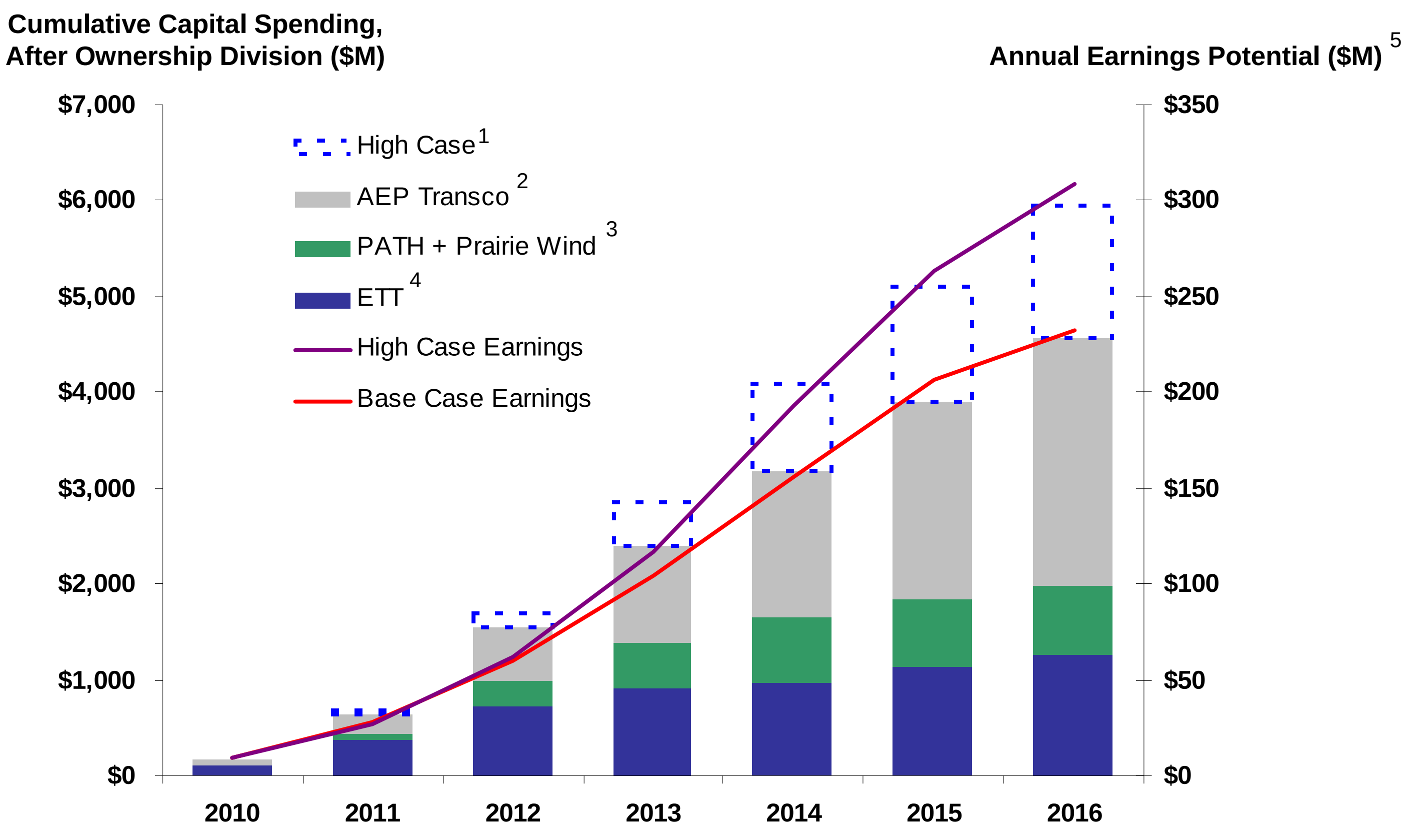
Filing Status Update:

- ***Ohio** (filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia** (filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia** (withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

$160M capital spend forecasted for 2011

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Midwest Utility Seminar

Wall Street Access and Berenson & Company

April 10, 2008

Chicago, Il

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Addressing Industry Concerns

- Rising Commodity Costs – Fuel and Transportation
- Rising Capital Costs – Environmental Retrofit and New Generation
- Declining Reserve Margins
- Need for Additional Transmission
- Regulatory Pressures Due to Rising Rates

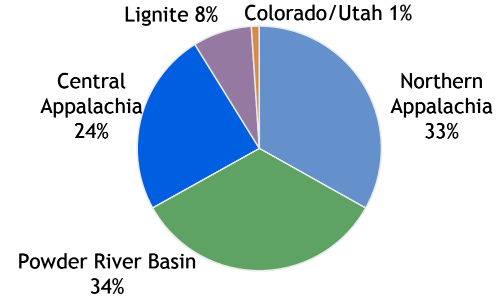
AEP is well positioned to manage each of these industry concerns.

Industry Concern: Rising Commodity Costs - Fuel and Transportation

AEP SOLUTION – FUEL PROCUREMENT STRATEGY:

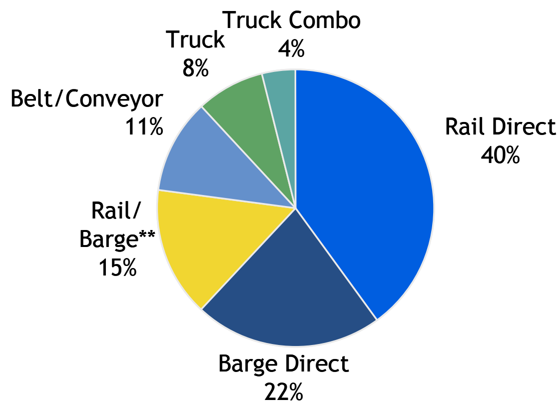
- **Portfolio of Coal Contracts**
  - Geographic and supplier diversity
  - Diversity of terms – currently ranging from 2008 to 2022
- **Portfolio of Transportation Resources**
- **Portfolio of Options to Manage the Economics of Converting BTUs to MWhs**
  - Manage emission allowance exposure
  - Blending capabilities at many plants
  - Transportation fleet to reposition coal
- **Regulatory Recovery**
  - Active fuel clauses in ten of eleven jurisdictions

AEP Supply Diversity *



* 2008 Projected

AEP Transportation Diversity *



* 2007 Actual

** Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP strategy: manage coal supply sources and transportation assets to mitigate price increases and market disruptions.

Industry Concern: Rising Capital Costs

AEP SOLUTION – Completed Environmental Retrofit

Lower Capital, Lower Operating Costs, Successful Operating Performance

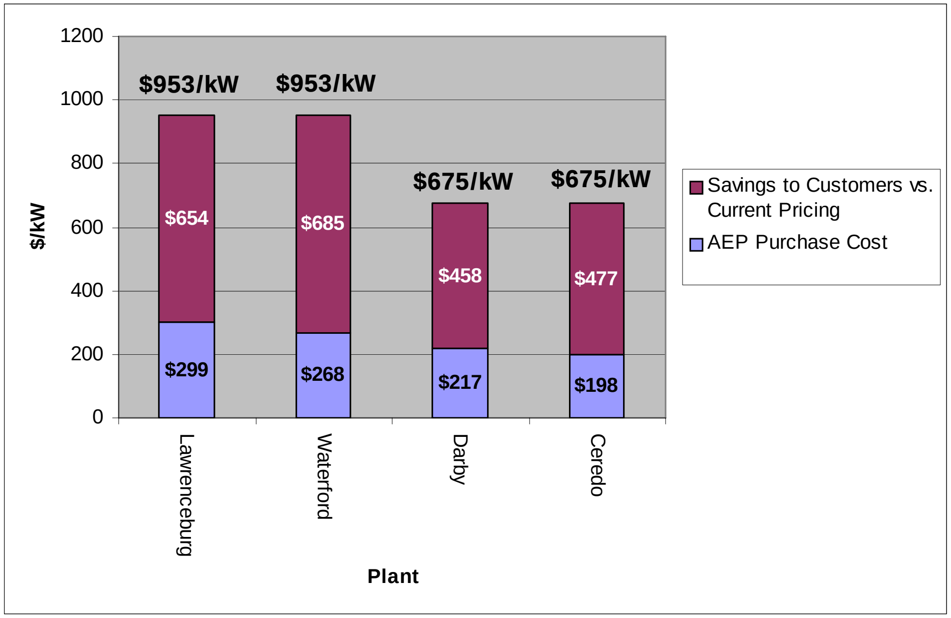
- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- Capital cost comparison for wet scrubber:
  - AEP average ~ $250/kW
  - 2007 pricing for a 600MW plant ~ $320/kW
  - 2012 forecast for a 600MW plant ~ $470/kW

- **11,076 MW FGDs currently in service or under construction equates to cost savings to rate payers based on 2007 $ of $775 million.**

AEP SOLUTION – Purchased Low-Cost Generation

Lower Capital, Successful Operating Performance, Delayed Need for Baseload

- Cost to replace plants in 2008 are estimated at $675/kW for simple-cycle and $953/kW for combined-cycle. Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections. This equates to cost savings to rate payers of $1.7 billion.



By moving early, AEP avoided approximately $2.5 billion of capital. Nearly all of these investments are currently reflected in rates.

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Add Generation:

Harry D. Mattison Plant – commercial operations achieved in 2007

Generation:

- Adequate reserves in East due to purchased generation
- Build peaking, intermediate and baseload generation in the West

Project Name	State	Fuel Type	Plant Type	MW Capacity	Original In Service Date	As Contracted Cost	Cost if Contracted in 2008	In Service if Contracted in 2008
Mattison	Arkansas	Gas	Simple-cycle	340	2007	$333/kW	$675/kW	2010
Stall	Louisiana	Gas	Combined-cycle	480	2010	$671/kW	$953/kW	2011
Turk	Arkansas	Coal	Ultra-supercritical	600	2011	$2,123/kW	$2,605/kW	2014

Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections.

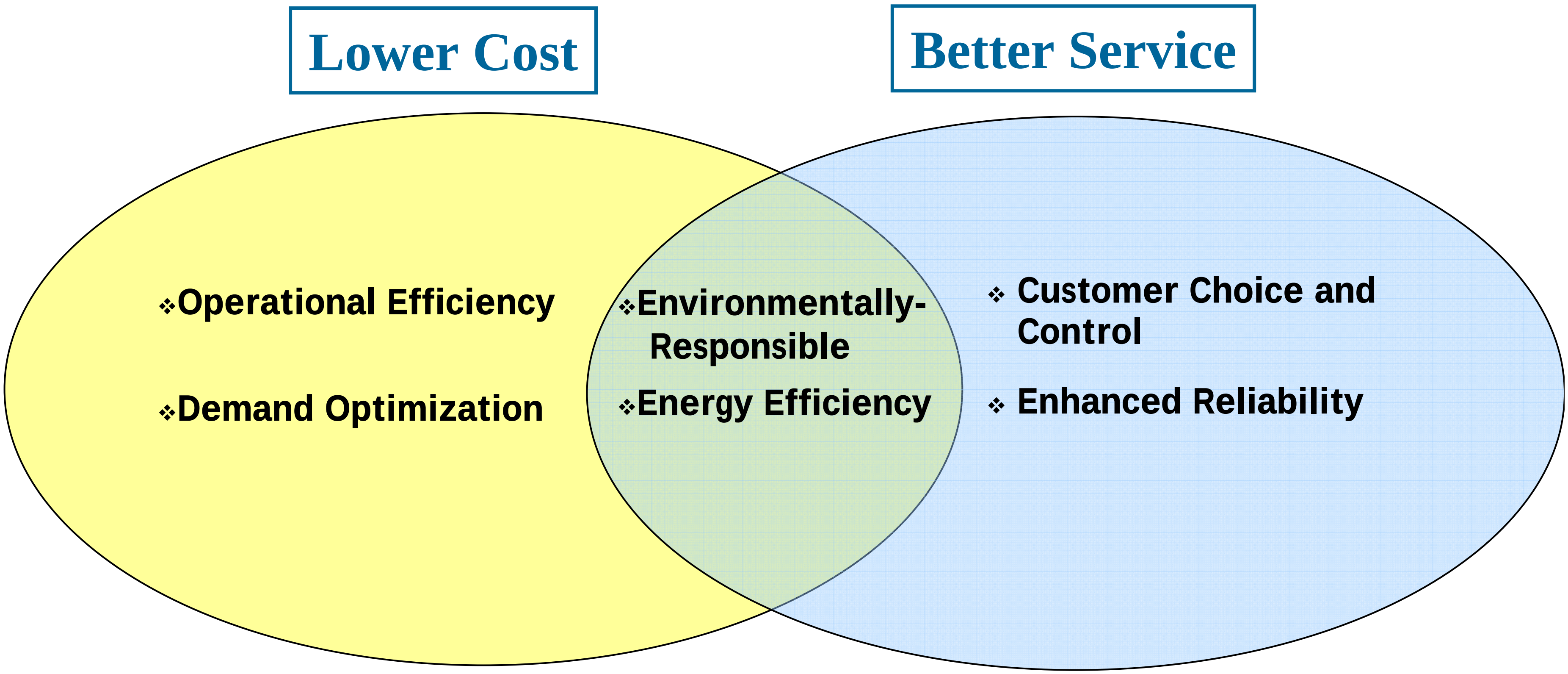
AEP's current initiatives help mitigate both the supply and demand issues facing the U.S.

AEP®

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Improve Efficiency and Demand Management:

AEP's **gridSMART**SM initiative will develop a deployment plan for new customer programs and advanced technologies to support pursuit of the following value propositions:

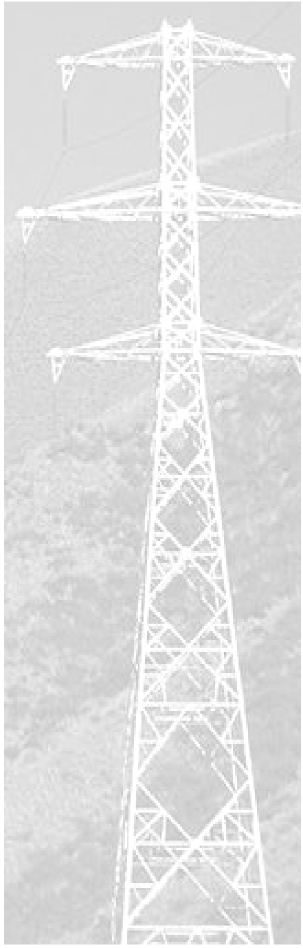


Increased efficiency reduces cost and GHG emissions. It also delays the need for new generation.

Industry Concern: Need for Additional Transmission

AEP SOLUTION:

Our status as the largest transmission owner in the U.S. affords us technical, operational and economic advantages:



- Efficient System Design - 765-kV Technology
- Advanced Technology Solutions - Laredo Variable Frequency Transformer
- Strong Supplier Relationships - Long-term Equipment and Construction Contracting
- Joint Venture Partnerships - Investment opportunities identified
  - – MidAmerican Energy Holdings Company
    - – Electric Transmission Texas - $1 billion - $7 billion opportunity
    - – Electric Transmission America - $3 billion opportunity in SPP
  - – Allegheny Energy Inc.
    - – PATH - $1.8 billion opportunity

Our customers and shareholders benefit from the scope, scale and expertise of our transmission operations.

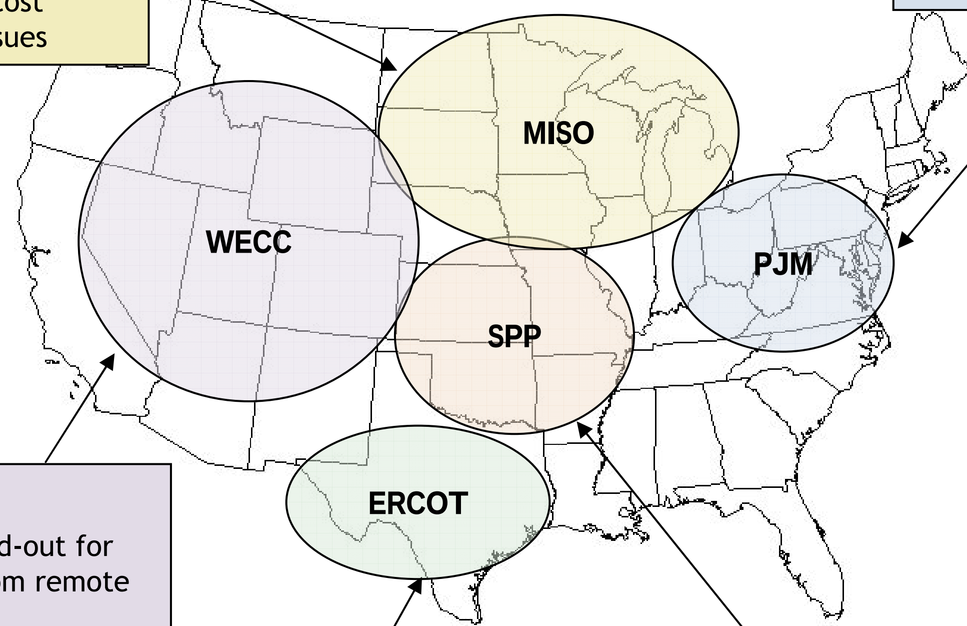
Transmission Investment Opportunities Allow Broader Market Access

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues

PJM

Congestion will be reduced and reliability will be increased



WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

ERCOT

Load growth and access to wind resources driving transmission investment

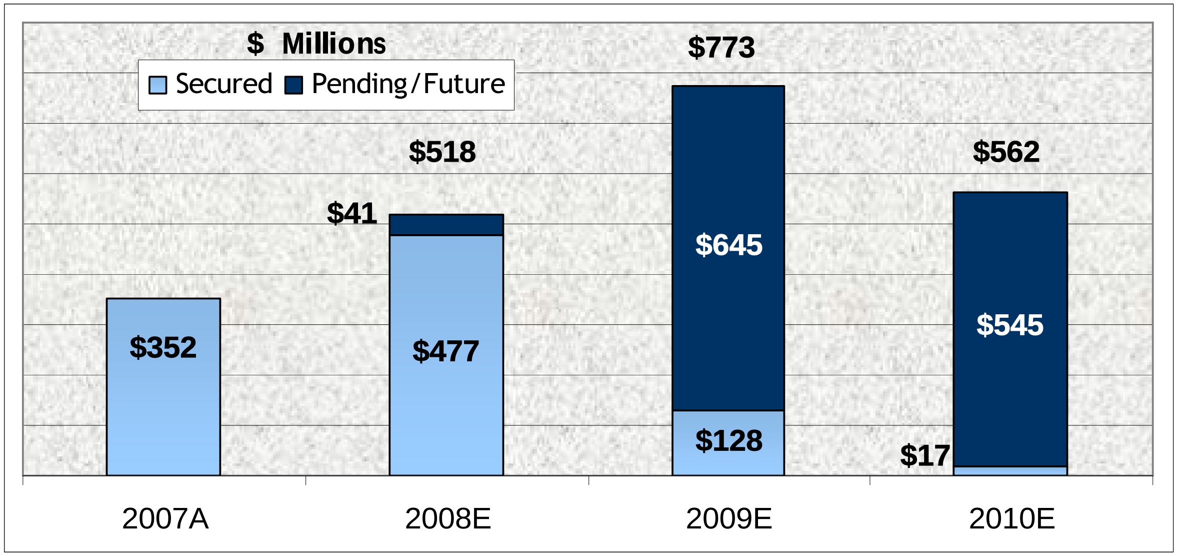
AEP's transmission initiative addresses regional supply/demand issues (congestion) and is required for more robust deployment of renewable generation sources.

AEP®

Industry Concern: Regulatory Pressures Due to Rising Rates

AEP SOLUTION:

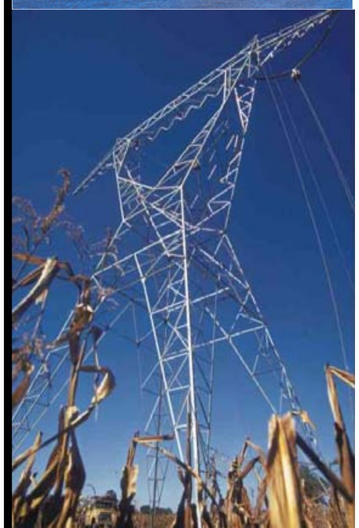
- **History of Regulatory Success/Proven Track Record**
- **Lowest Cost Provider to 93% of our customers (8 of 10 Jurisdictions)**
- **gridSMART^{SM} Initiative to reduce customer bills**
  - Benefit: more power to sell off-system creates increased sharing for retail customers, further reducing customer bills
- **AEP Track Record of Success – Anticipated 2007 rate relief of $338MM; Achieved $352MM; Already secured 92% of 2008 rate relief through the 1st quarter of 2008.**



AEP is well-positioned for continued favorable regulatory treatment.

AEP®

American Electric Power - Solid Track Record of Successful Execution



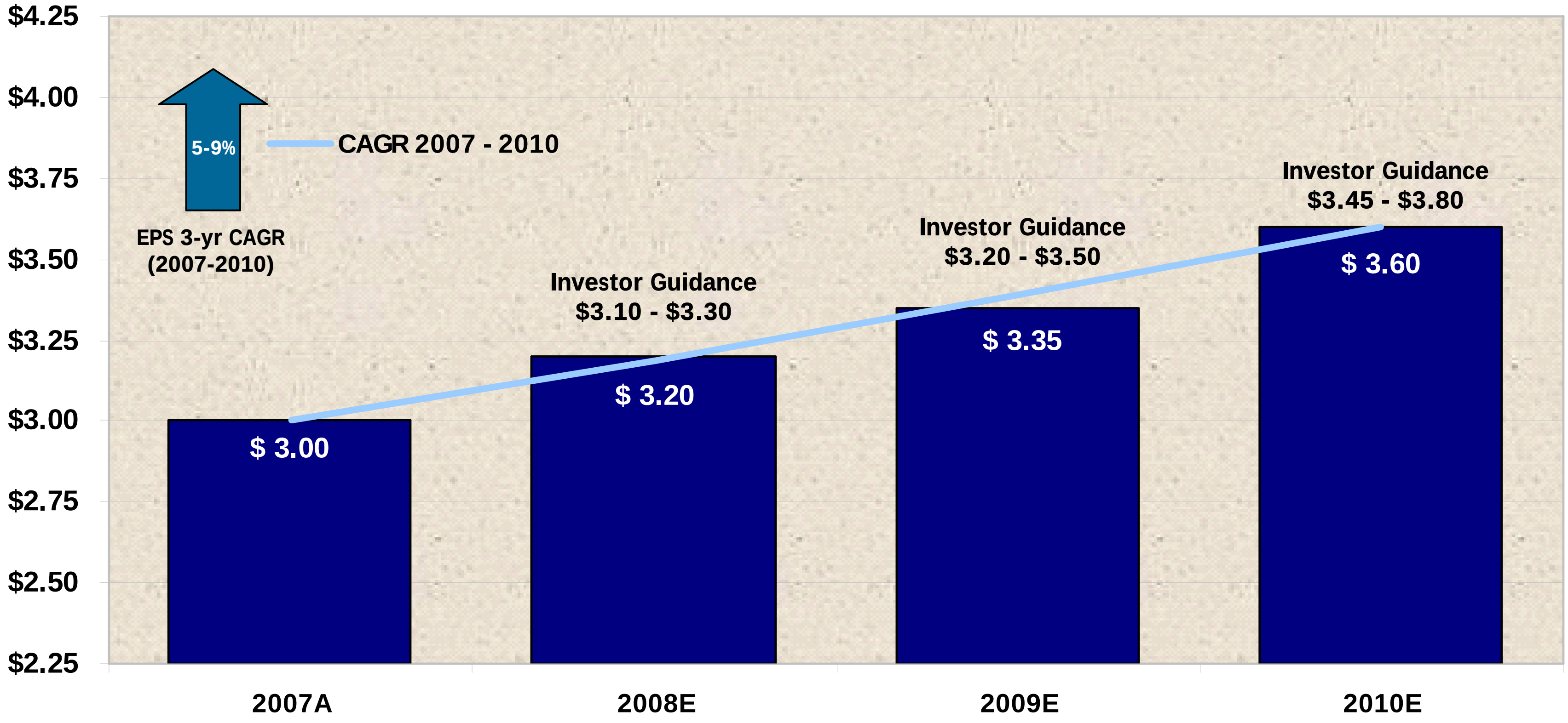
- *Economies of scope and scale in assets & operations*
  - *2nd Largest Generating Fleet in the U.S. including largest supercritical units at 1300 MW*
  - *Largest Transmission and Distribution Network in the U.S.*
- *Continued innovation and first-mover deployment of leading technology advancements*
  - *Ultra-supercritical and IGCC coal generation*
  - *765-kV leadership*
  - *gridSMART℠ initiative*

Poised for Continued Success

Questions

Appendix

4-Year Earnings Range Forecast



5% to 9% earnings growth

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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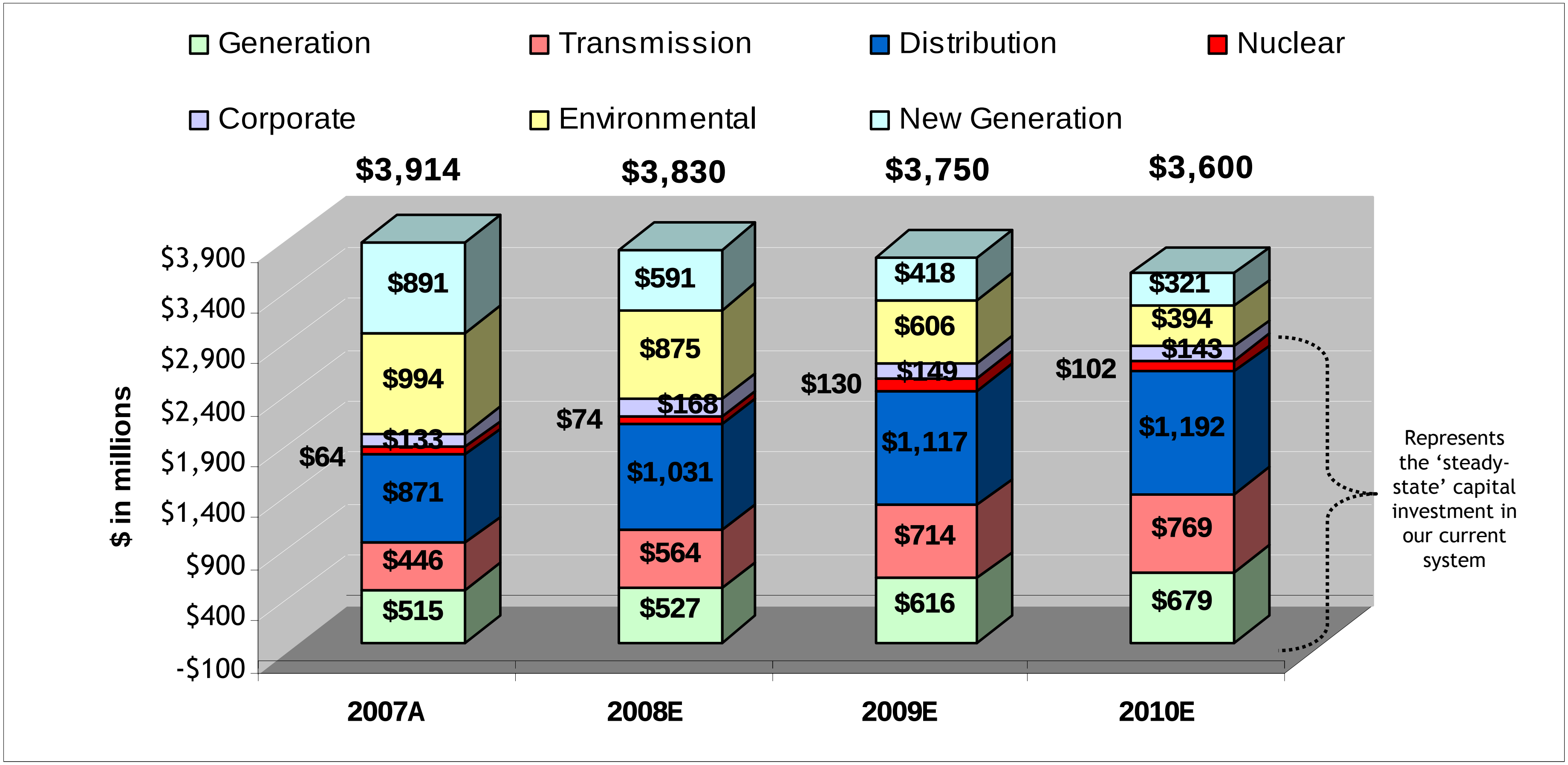
Annual Capital Investment Cycle



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects.

Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

AEP®

Capital investment is funded from cash from operations and debt issuances.

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	tbd

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $950 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the current Supreme Court of Ohio remand to the PUCO of the PUCO's April 10, 2006 Opinion and Order.

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AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Generation - Environmental Project Status Report

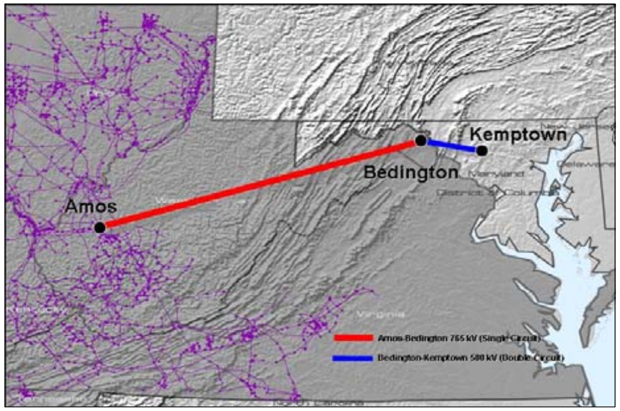
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

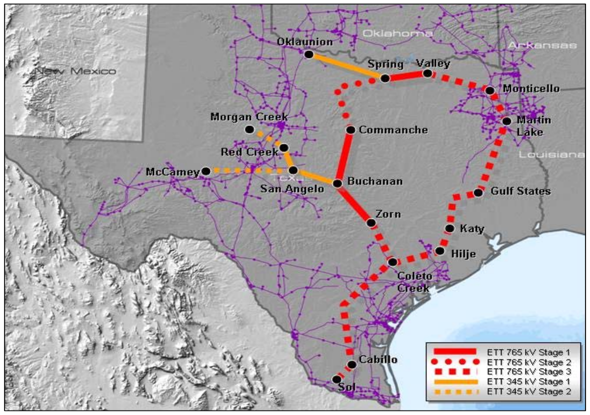
AEP

I-765™ Transmission: Investment Opportunities

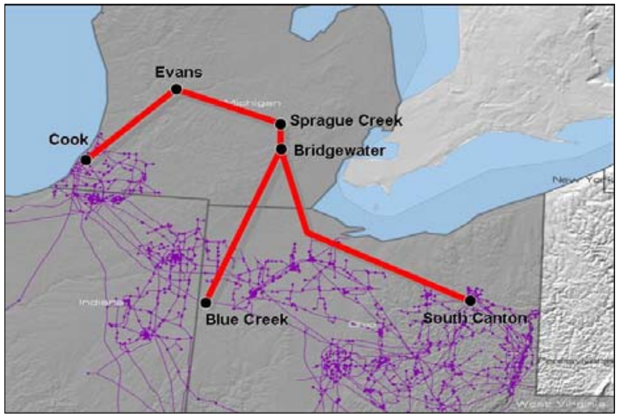
AEP is Advancing the Development of a National Interstate Today



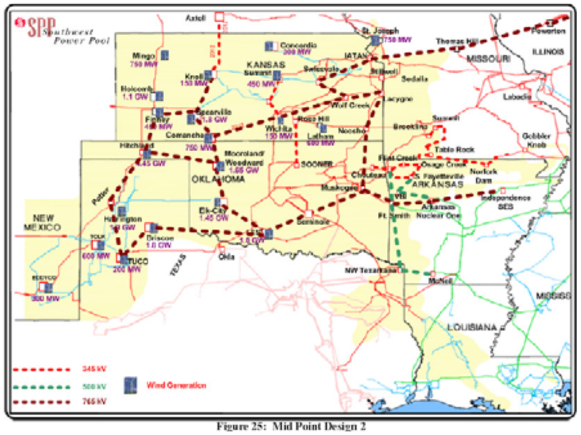
PATH Project (PJM)



ETT Proposal (ERCOT)



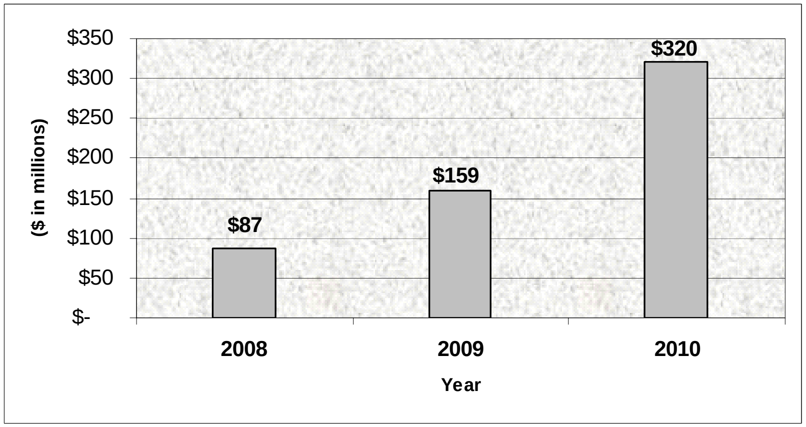
AEP-ITC Michigan Proposal (PJM/MISO)



SPP Overlay Study – Mid Design 2

Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*

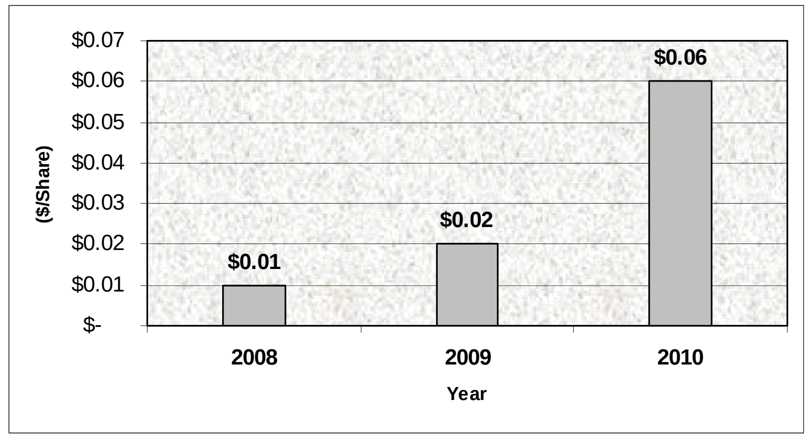


* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

PATH
Potomac-Appalachian Transmission Highline

ETT
Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

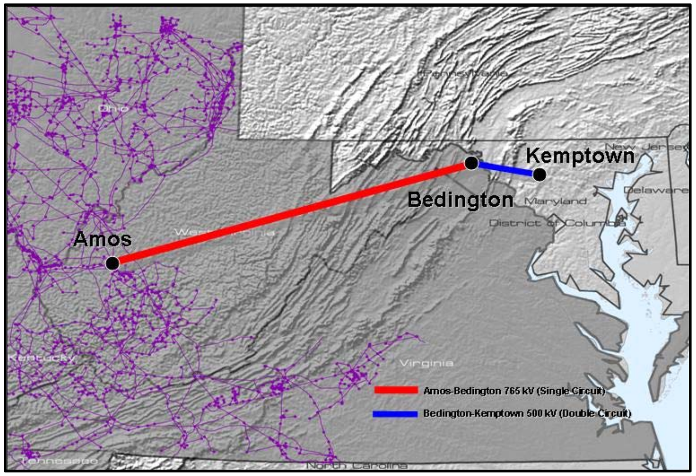
AEP®

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

AEP

I-765™ Transmission in Texas (ETT)

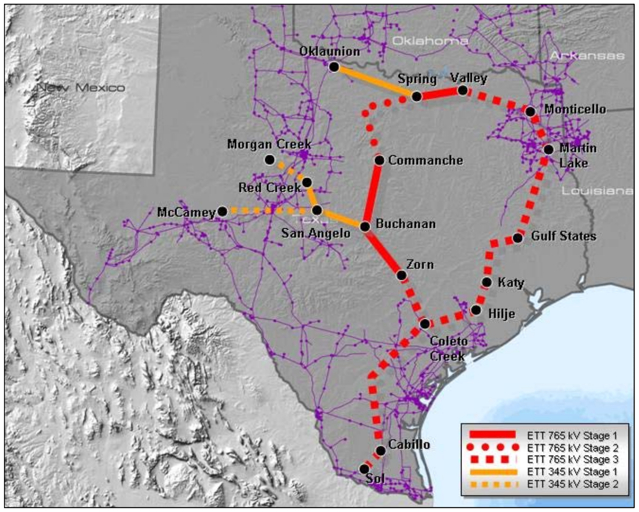
Electric Transmission Texas Update

- ### *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- ### *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- ### *ETT ERCOT Backbone Proposal*
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*

* Before ownership division.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP®

Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

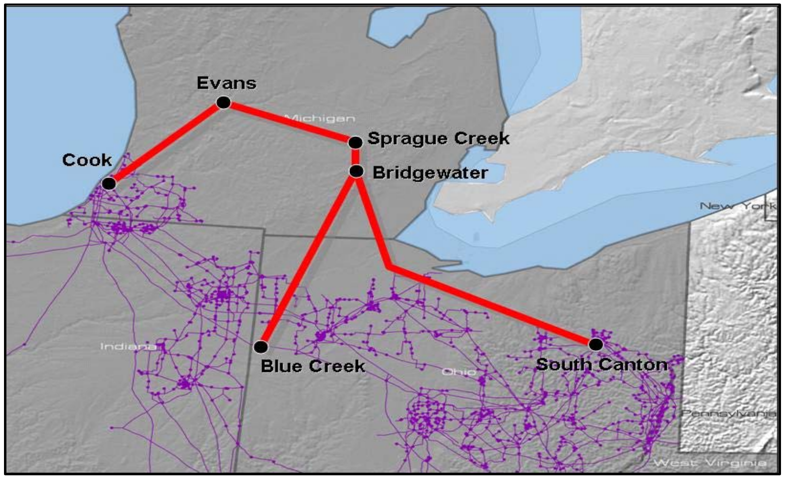
ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

AEP®

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ***Next Steps***
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

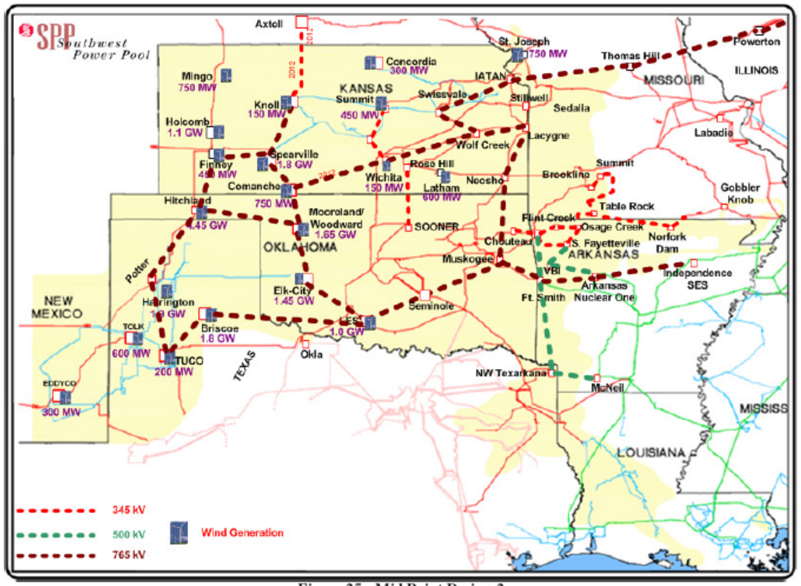


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP®

Distribution - gridSMART^{SM}

•gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

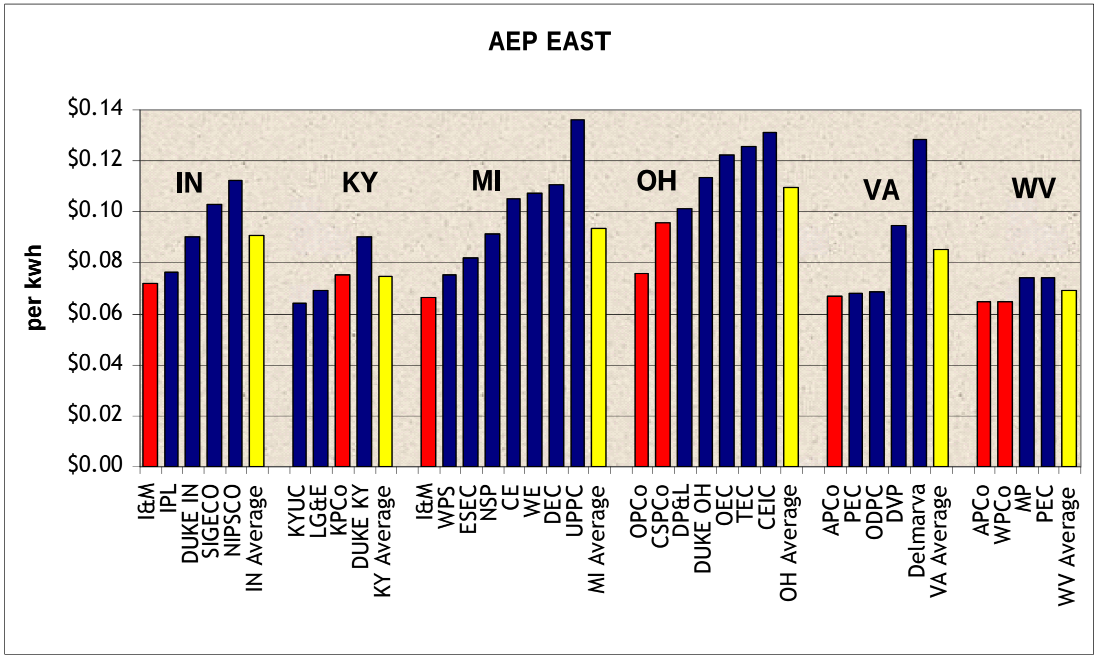
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$40**	**$ 63**	**$ 82**

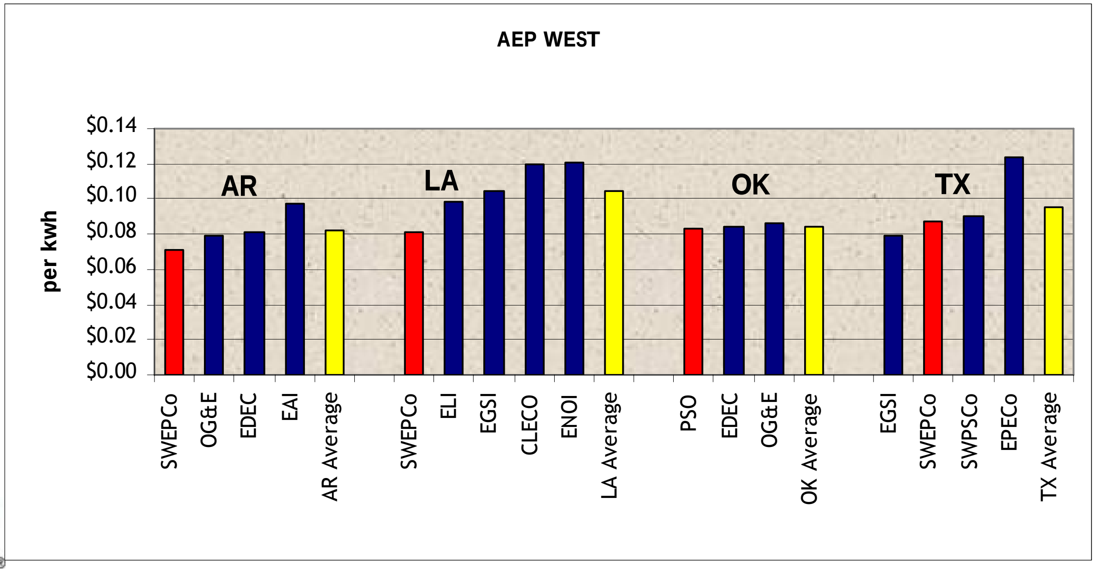
*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

AEP®

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

Our low cost provider status in most of our jurisdictions, coupled with our scale and scope, allows us the flexibility to navigate current and future macro-economic issues.

- AEP Company
- Other Company within state
- State Average

AEP®

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana - construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia - approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio - on hold pending resolution of Supreme Court remand to PUCO
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

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Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order in April 2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The PSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. A procedural schedule is being developed and the hearing most likely will occur in May or June 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings will commence on April 8, 2008. Staff testimony was favorable.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

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Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure – Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief – Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

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Mitchell Plant

Merrill Lynch Investor Visit
Mitchell Plant Tour
Moundsville, West Virginia
August 14, 2007

AEP AMERICAN ELECTRIC POWER

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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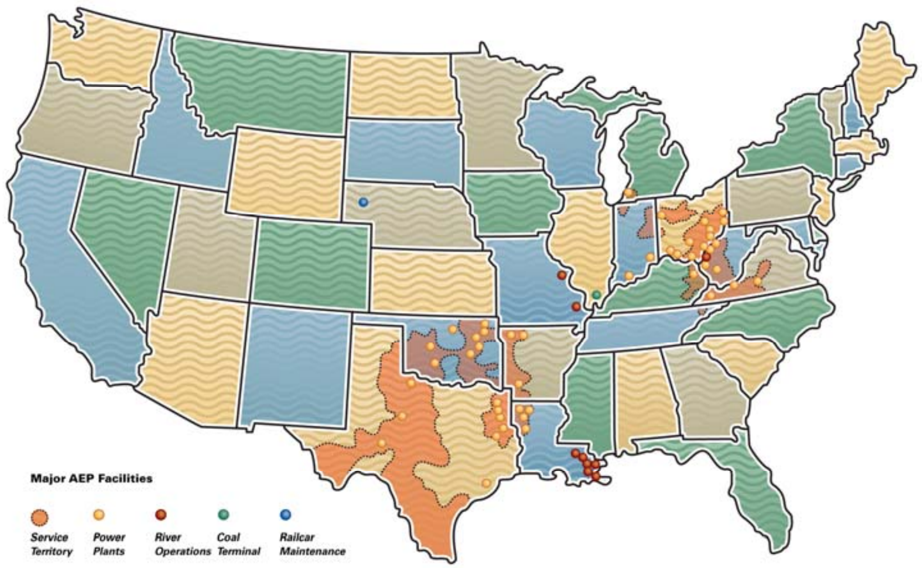
- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

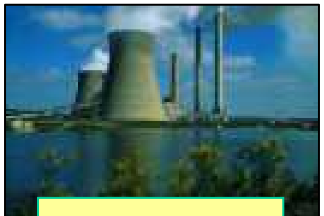


- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

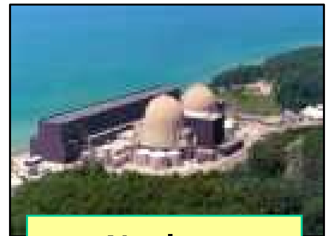
- 20,000 employees

AEP Enjoys Significant Presence Throughout The Energy Value Chain

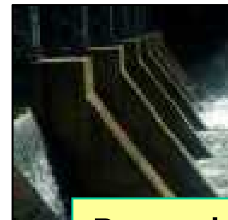
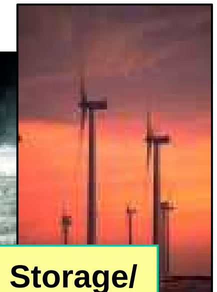


Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%
2007*	80.89%	57.73%

* - through June 30, 2007

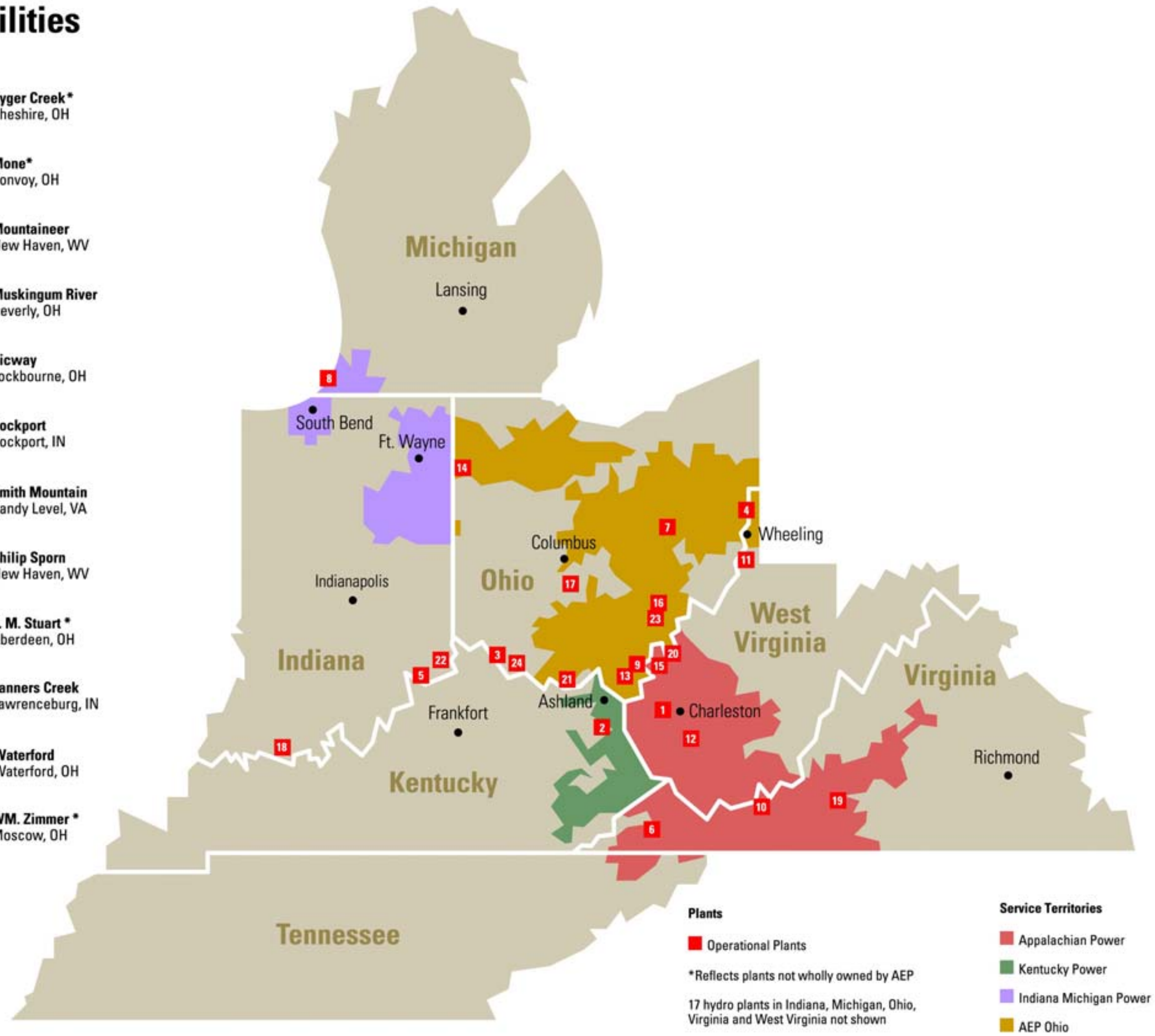
NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

AEP East Fossil Generation Fleet

Generation Facilities

1 **John E. Amos** St. Albans, WV
2 **Big Sandy** Louisa, KY
3 **Beckjord*** New Richmond, OH
4 **Cardinal*** Brilliant, OH
5 **Clifty Creek*** Madison, IN
6 **Clinch River** Cleveland, VA
7 **Conesville*** Conesville, OH
8 **Donald C. Cook** Bridgman, MI
9 **Gen. James M. Gavin** Cheshire, OH
10 **Glen Lyn** Glen Lyn, VA
11 **Kammer-Mitchell** Moundsville, WV
12 **Kanawha River** Glasgow, WV
13 **Kyger Creek*** Cheshire, OH
14 **Mone*** Convoy, OH
15 **Mountaineer** New Haven, WV
16 **Muskingum River** Beverly, OH
17 **Picway** Lockbourne, OH
18 **Rockport** Rockport, IN
19 **Smith Mountain** Sandy Level, VA
20 **Philip Sporn** New Haven, WV
21 **J. M. Stuart*** Aberdeen, OH
22 **Tanners Creek** Lawrenceburg, IN
23 **Waterford** Waterford, OH
24 **WM. Zimmer*** Moscow, OH



AEP East Coal Fleet Availability & Capacity Factor Statistics

GENERATION PERFORMANCE	2007 YTD	2006
•CAPACITY FACTOR:	69.90%	70.39%
•EQUIVALENT AVAILABILITY FACTOR:	78.95%	80.22%
•EQUIVALENT FORCED OUTAGE RATE:	10.24%	9.64%
•Net Generation (MWh)	74,228,296	134,339,449

Mitchell Plant Statistics

- Twin 800 MW Units - generating energy capacity of 9,200 GWH annually
- In service 1971
- 153 employees
- Pulverized coal fired steam generators
- Each unit to be equipped with Flue Gas Desulfurization Systems (FGD) & Selective Catalytic Reduction Systems (SCR)
- Coal yard storage capacity of 660,000 thousand tons or 60 day supply
- Consume approximately 10,000 tons of coal daily or in excess of 3.5 million tons annually
- Coal delivered by barge and rail

Mitchell Plant Fuel Statistics

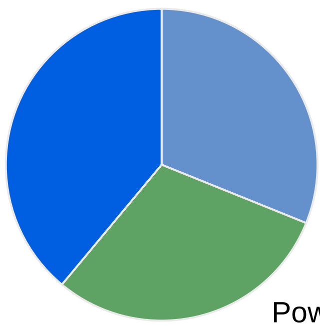
- Current Coal Deliveries
  - CAPP coal – about 12,200 Btu/lb and 1.5 lbs SO2/mmBtu
  - Consumes approximately 3.5 million tons annually
  - Coal is primarily delivered by CSX rail – in 10,000 ton unit trains – resulting in about 1 train per day
  - Some coal is delivered to Mitchell by barge
- Future Coal Deliveries
  - Plant modifications will allow for future fuel flexibility
  - Locally available high-sulfur coal use will now be possible
- Current Coal Inventory
  - Current inventory levels are higher than normal
  - Plan is to have approximately 35-40 days inventory

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7801 of 9556

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

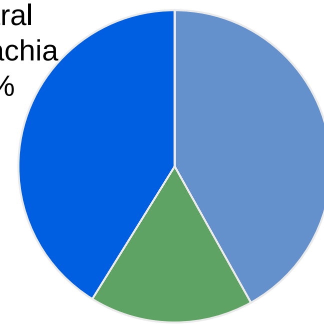
Total AEP System



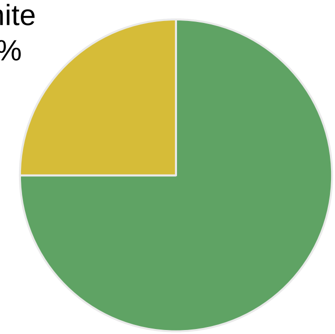
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-6% price increase in 2007 -- ($36.50 to $37.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

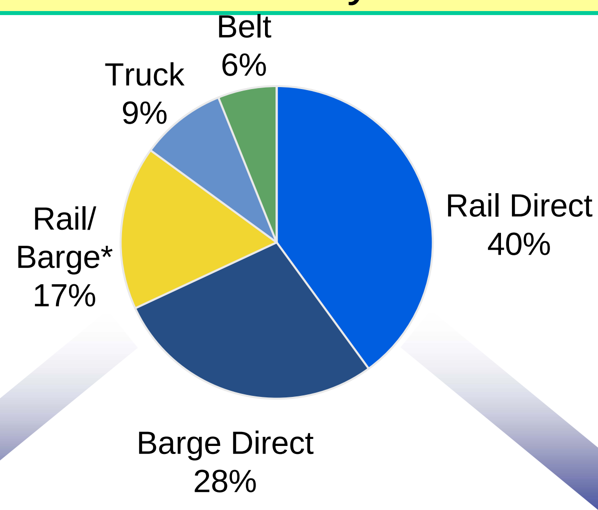


AEP West

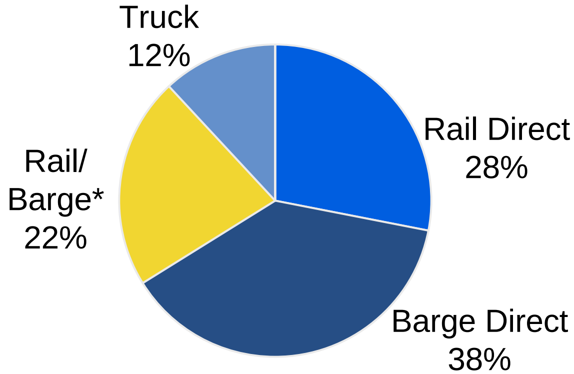


2006 Actual

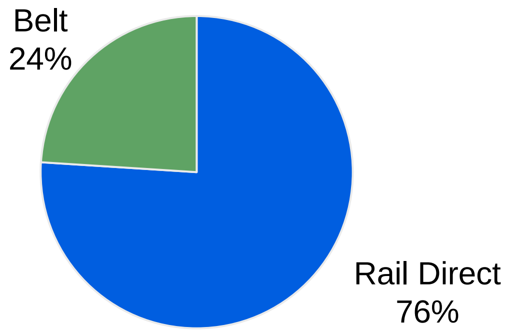
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP's Environmental Compliance Strategy

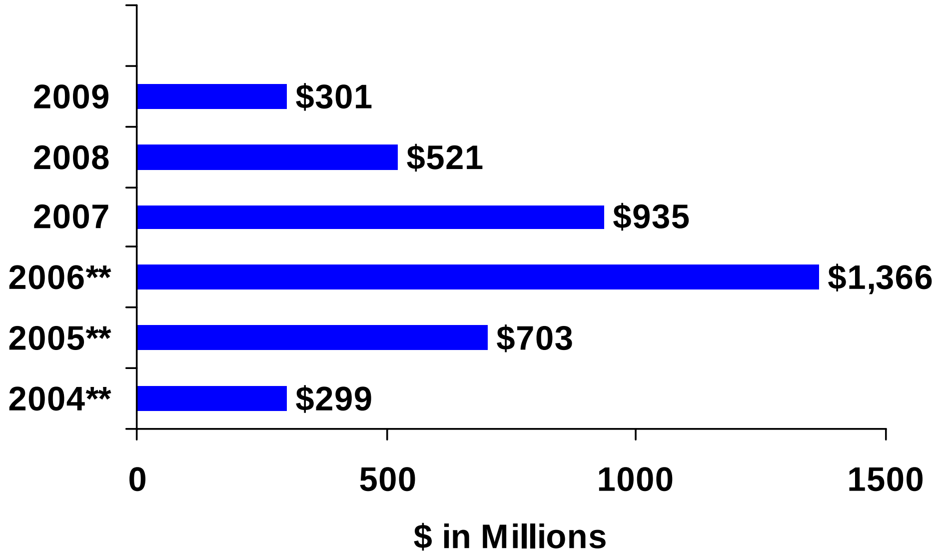
NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Much of this investment is for:**
  - **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
  - **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
  - **SCR and FGD systems together offer co-benefit of mercury capture.**
  - **Sale of gypsum (by-product) avoids future landfill costs.**
  - **Provides fuel flexibility.**

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

$4.1 Billion Environmental Investment

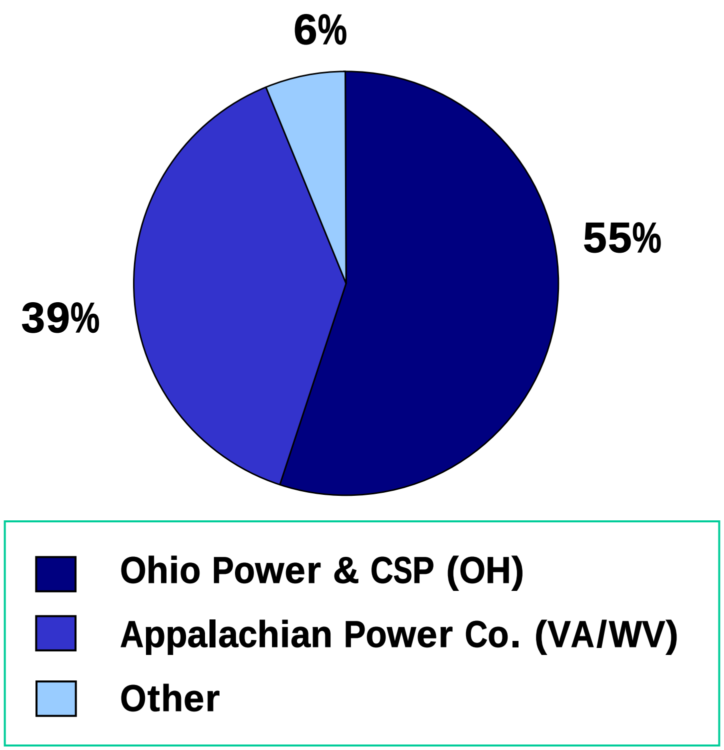
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



Majority Of 2006 & 2007 Dollars Invested In Ohio & APCo

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	130	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	262	✓	In-service	✓	In-service
Mitchell 1&2	160	✓	In-service	✓	In-service
Mountaineer	132	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
West Plants					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

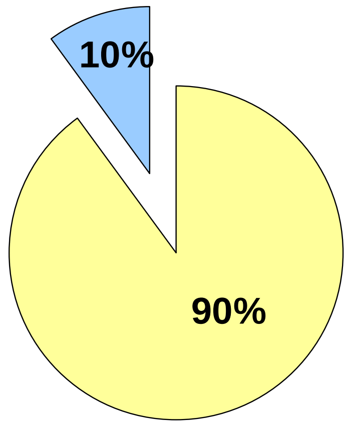
AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Materials and Vendors – AEP's Advantage

Environmental Program Costs:

Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs

Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

Typical Vendors Include:

- B&W/Alstom – FGD Spray Tower
- B&V/Chyioda – FGD Jet Bubbling Reactor
- Pullman Power – Stack Supplier
- Babcock Power – SCR
- Black & Veatch – Architect/Engineering
- Sargent & Lundy – Architect/Engineering

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

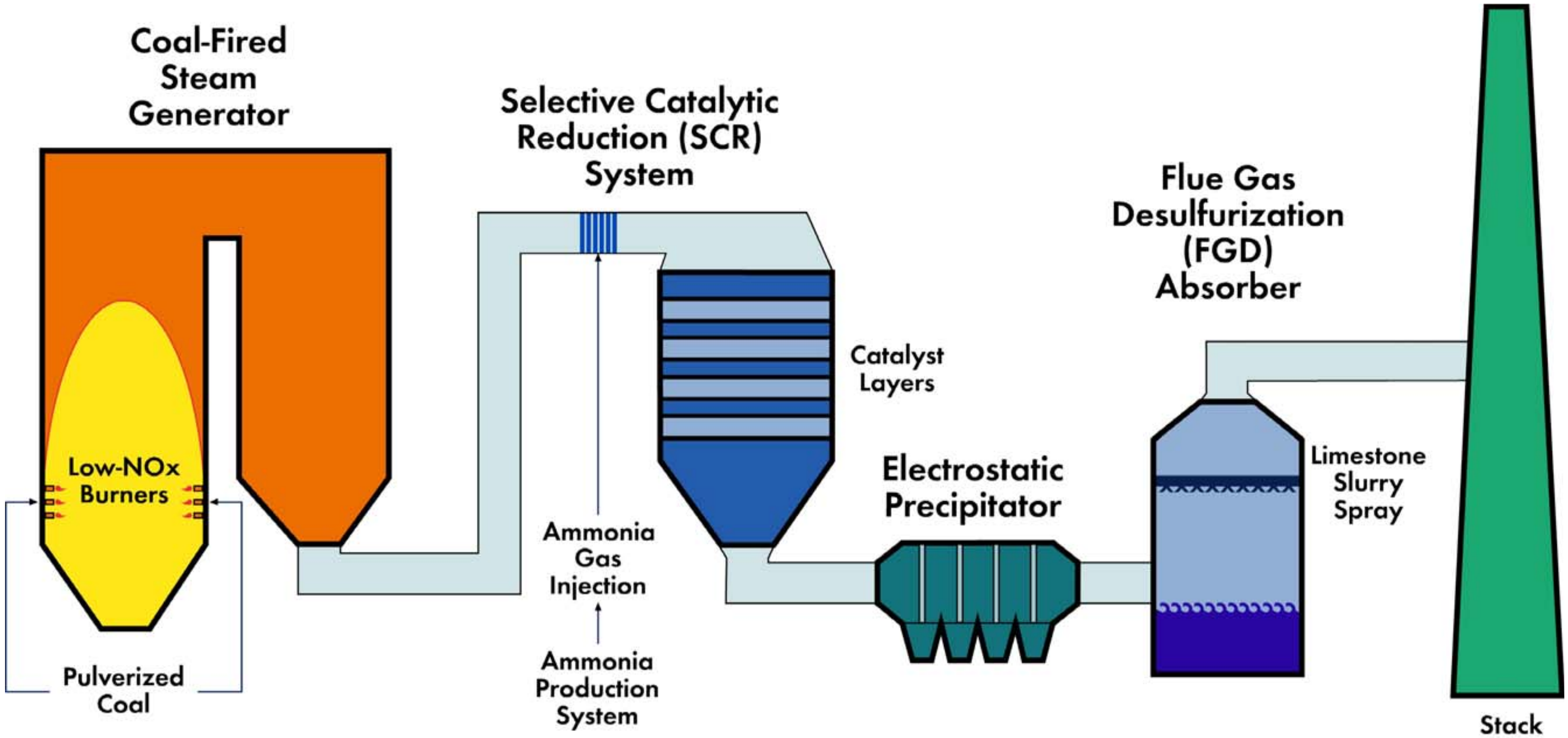
Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

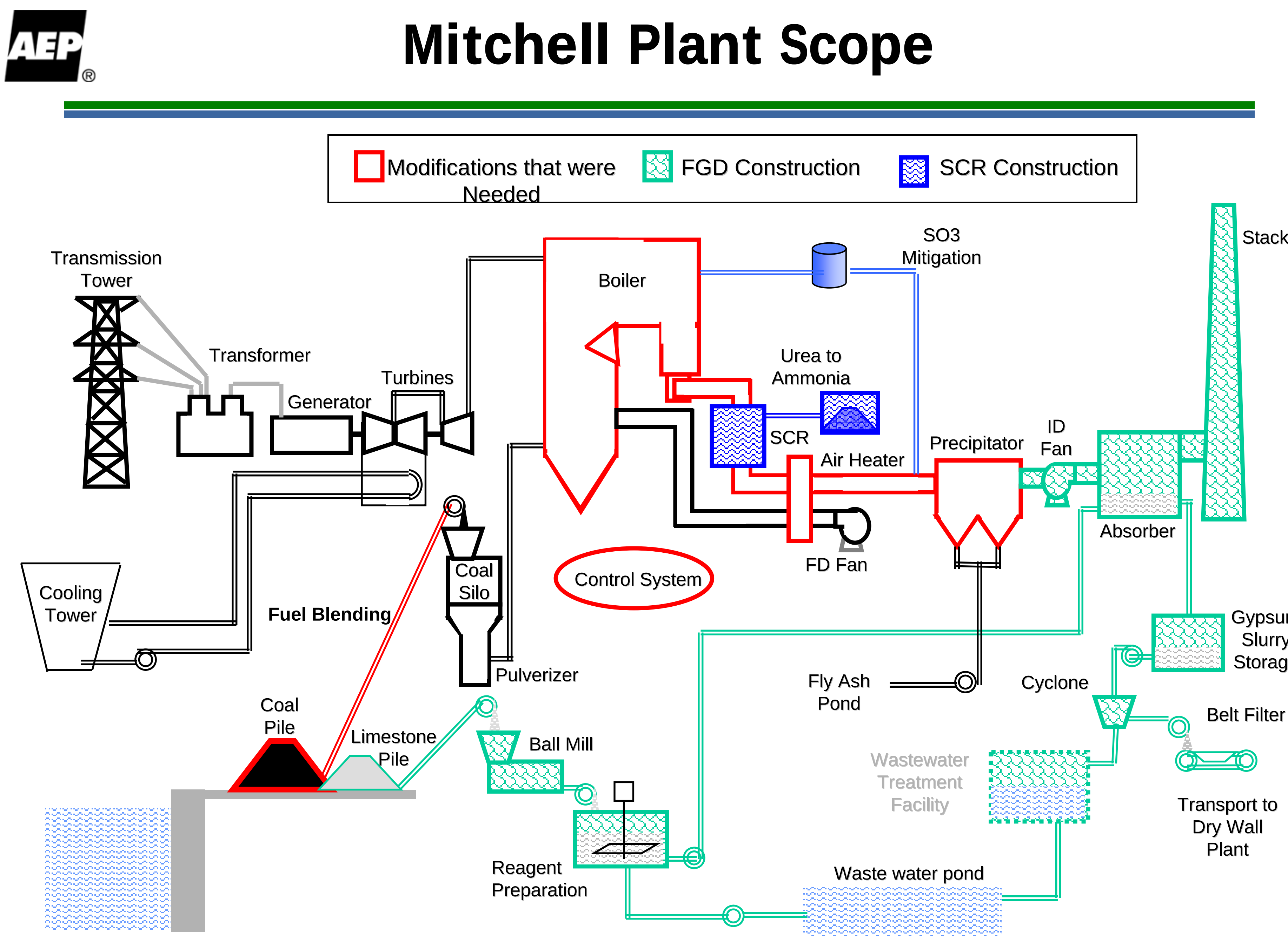
The Flue Gas Stream



SCR / FGD Installation Effect on Mitchell

- The Mitchell Plant had typically burned low sulfur bituminous coal including compliance coal.
- In the past, higher sulfur coals have produced operational inefficiencies; therefore, the steam generator underwent modifications to improve operations on higher sulfur bituminous coals.
- The FGD design accommodates the higher sulfur coal and expands the fuel flexibility of the plant. This fuel flexibility allows adaptation in changing coal markets to optimize the economic viability of the plant.

Mitchell Plant Scope



Purchased Generation

Waterford

- –821 MW combined-cycle gas plant
- –$220MM purchase price
- –Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

- –505 MW simple-cycle gas plant
- –$100MM purchase price
- –APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

- –480 MW simple-cycle gas plant
- –$102MM purchase price
- –Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

- –1140 MW combined-cycle gas plant
- –$325MM purchase price
- –AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (2)	Coal	Ultra-supercritical	600 (2)	2011
PSO	Red Rock	Oklahoma	$1.8 B (3)	Coal	Ultra-supercritical	900 (3)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (4)	Coal	IGCC	630	2017

(1) 150MW were declared in commerical operation on July 12, 2007.

(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.

(3) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.

(4) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

SWEPCo

– Mattison Plant (Tontitown, AR)

- Certificate of Need filings (LA, AR, TX) were approved in all 3 states
- Air permit received in February 2007
- Units 3 and 4 (150 MW) online on July 12, 2007; Units 1 and 2 online by January 2008

– Stall Plant (Arsenal Hill, LA)

- Certificate of Need filings (LA, AR, TX)
  - TX settled in Feb 2007
  - AR & LA decisions expected by year-end 2007
- Air permit filed on April 27, 2007 – expecting approval by March 2008
- Commercial operation date in 2010

PSO

Southwestern & Riverside Additions

- Air permit received March 22, 2007
- Commercial operation date of December 2007
- Regulatory Recovery
  - Settlement and final order in the Lawton Cogen case authorizes recovery of costs for Southwestern and Riverside peakers through a rider mechanism beginning as early as June 2008 based on the Commercial Operation date

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Mattison	$56MM	$4MM	-
Stall	$82MM	$126MM	$64MM
Southwestern	$36MM	$3MM	-
Riverside	$35MM	$2MM	-

SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

New Ultra-Supercritical Coal Facilities

SWEPCo

Turk Plant (Fulton, AR)

– Certificate of Need approvals (LA, AR, TX) expected by September/October 2007

– Air permit approval expected in August 2007

– Regulatory Recovery
  - Recovery of carrying cost requested in LA Certificate of Need filing – Hearings scheduled for September 2007
  - AR and TX rate recovery will be addressed in separate filings

– Approximately 85-90% of costs are firm
  - EPC contract for balance of plant work awarded in May 2007
  - Contracts for turbine, boiler, and environmental control equipment awarded in 2006

PSO

Red Rock Generating Facility (Red Rock, OK)

– Used and Useful Determination filed in February 2006 – Hearings concluded July 31, 2007 and order is expected in September 2007

– Air permit approval expected in October 2007

– Regulatory Recovery
  - Order expected in PSO rate case filing in July 2007 – filing included request for CWIP treatment for new projects

– Original cost estimate of $1.8 billion – revised cost estimate expected in the third quarter of 2007

2007-2009 Projected Capital Expenditures

	2007	2008	2009
Turk Plant	$211MM	$230MM	$243MM
Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- **Certificate of Public Convenience & Necessity filed Jan. 11, 2006**
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Nov. 19, 2007
  - Hearings Dec. 10-14, 2007
  - Statutory Deadline – Mar. 7, 2008
- **Air permit filed in Oct 2006**
  - A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- **Regulatory Recovery**
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- **Certificate of Environmental Compatibility & Public Need filed March 24, 2006**
  - Ohio Power Siting Board certificate issued in April 2007
- **Air permit filed in Oct 2006**
- **Regulatory Recovery**
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

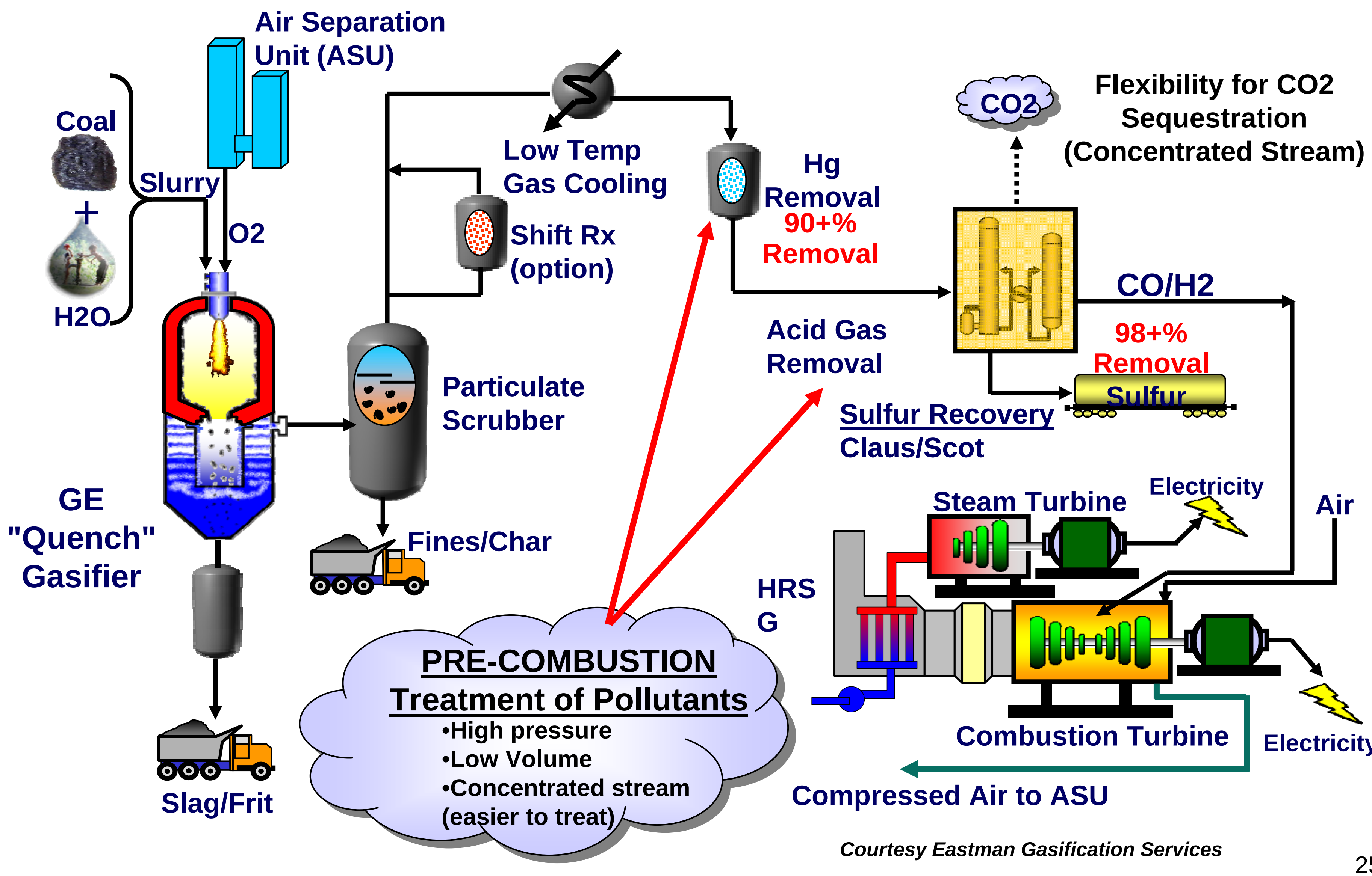
US2006$	Eastern Bituminous		
	USC	IGCC	NGCC
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC Technology Is Strategic To Keeping Coal In The Money

IGCC Technology



Courtesy Eastman Gasification Services

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP Endorses this Proposal Because It Sets Reasonable And Achievable Reduction Targets and Includes the AEP-IBEW Trade Proposal

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

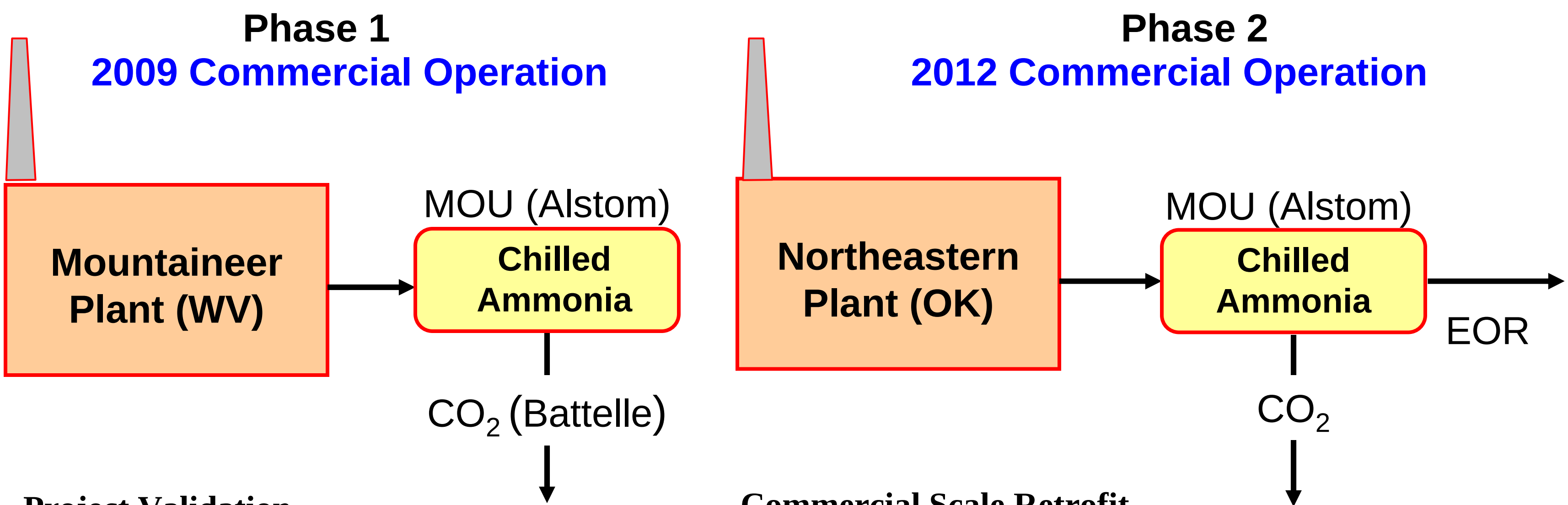
- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g., livestock methane capture deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Coal

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Technology Program



Project Validation

- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~\$225 – \$300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion Carbon Solution Provides Pure CO_2 Stream For Capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo complete 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Team with B&W
- AEP funding of ~ $1.5M for feasibility study
- Feasibility study to be completed in late 2007/early 2008

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

AEP AMERICAN® ELECTRIC POWER

Mitsubishi UFJ Securities Utility Day Handout

New York, NY
September 13, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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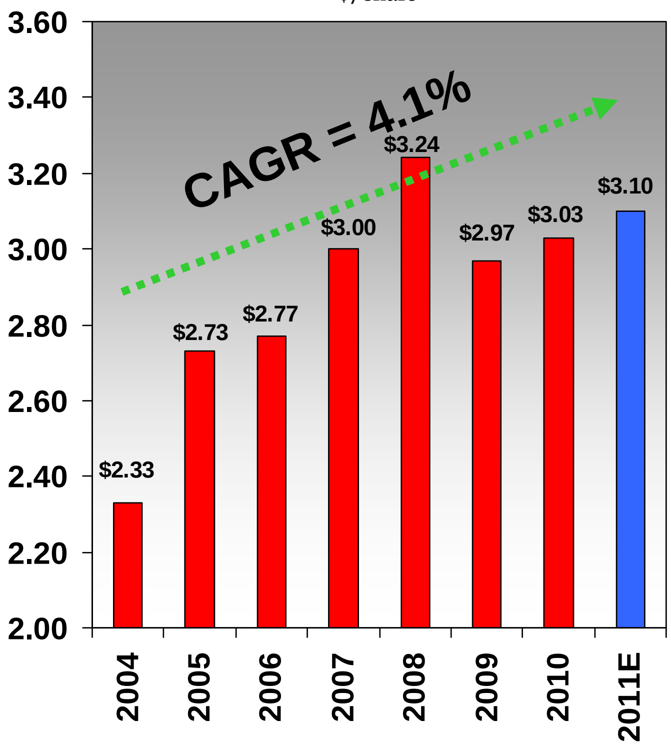
Earnings and Dividends

AEP®

On-Going EPS History Since 2004

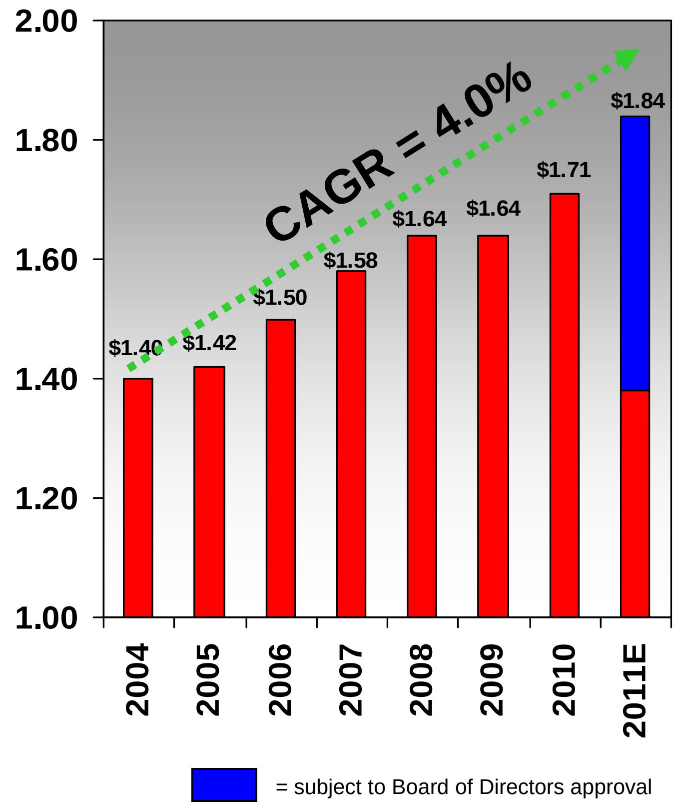
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



- Quarterly dividend increased 12% in 2010
- 405th consecutive quarterly dividend paid September 9, 2011
- 50-60% payout ratio target
- Current yield near 5%

Detailed Ongoing Earnings Guidance

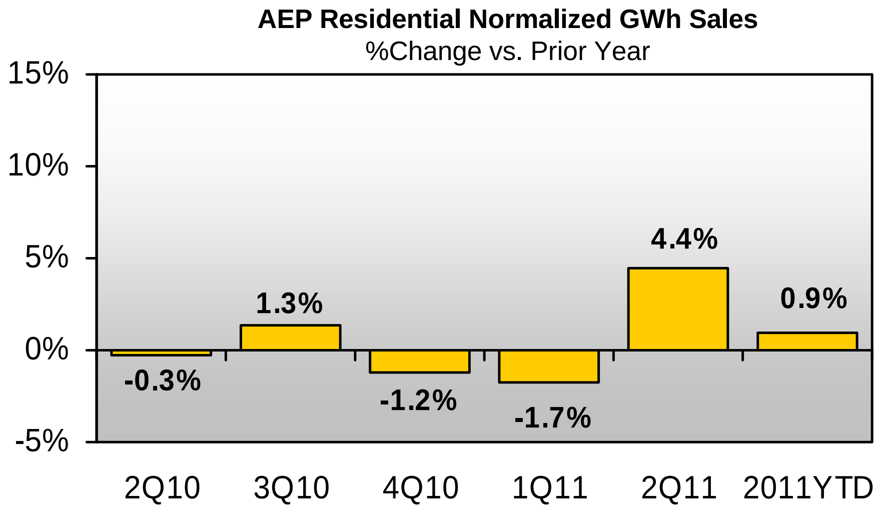
2010A: $3.03

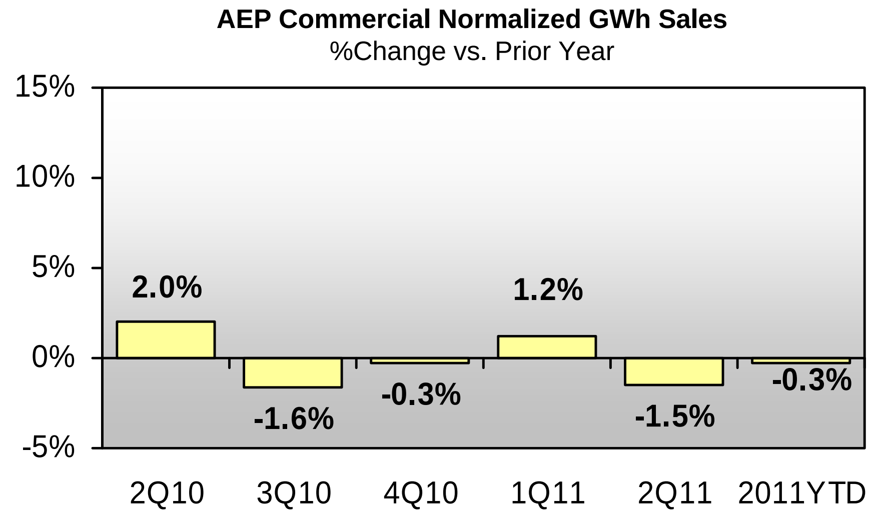
2011E: $3.00 - $3.20

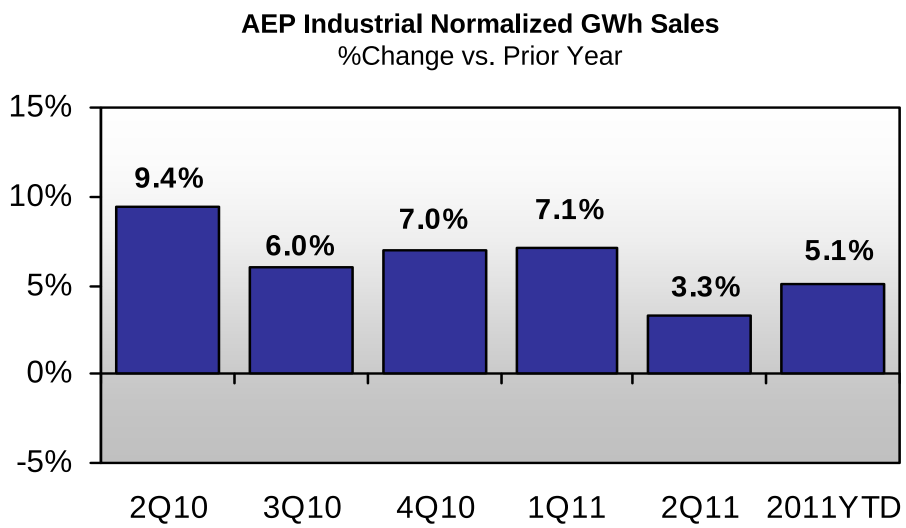
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

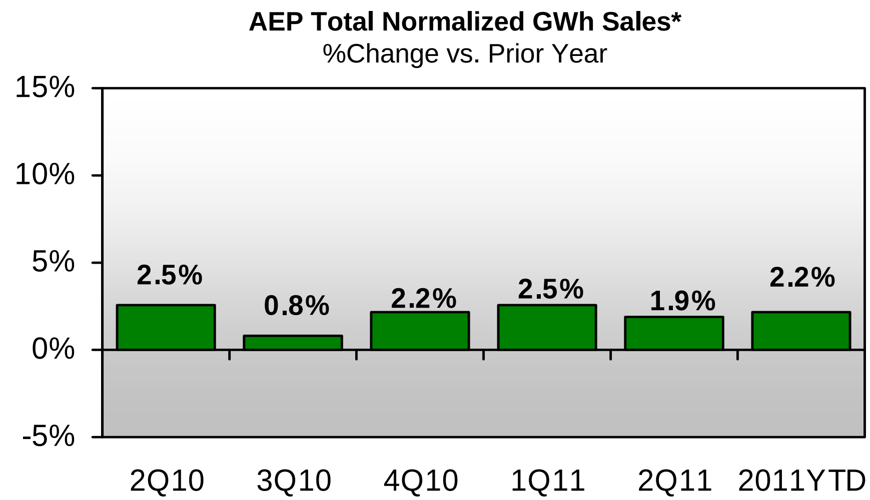
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends





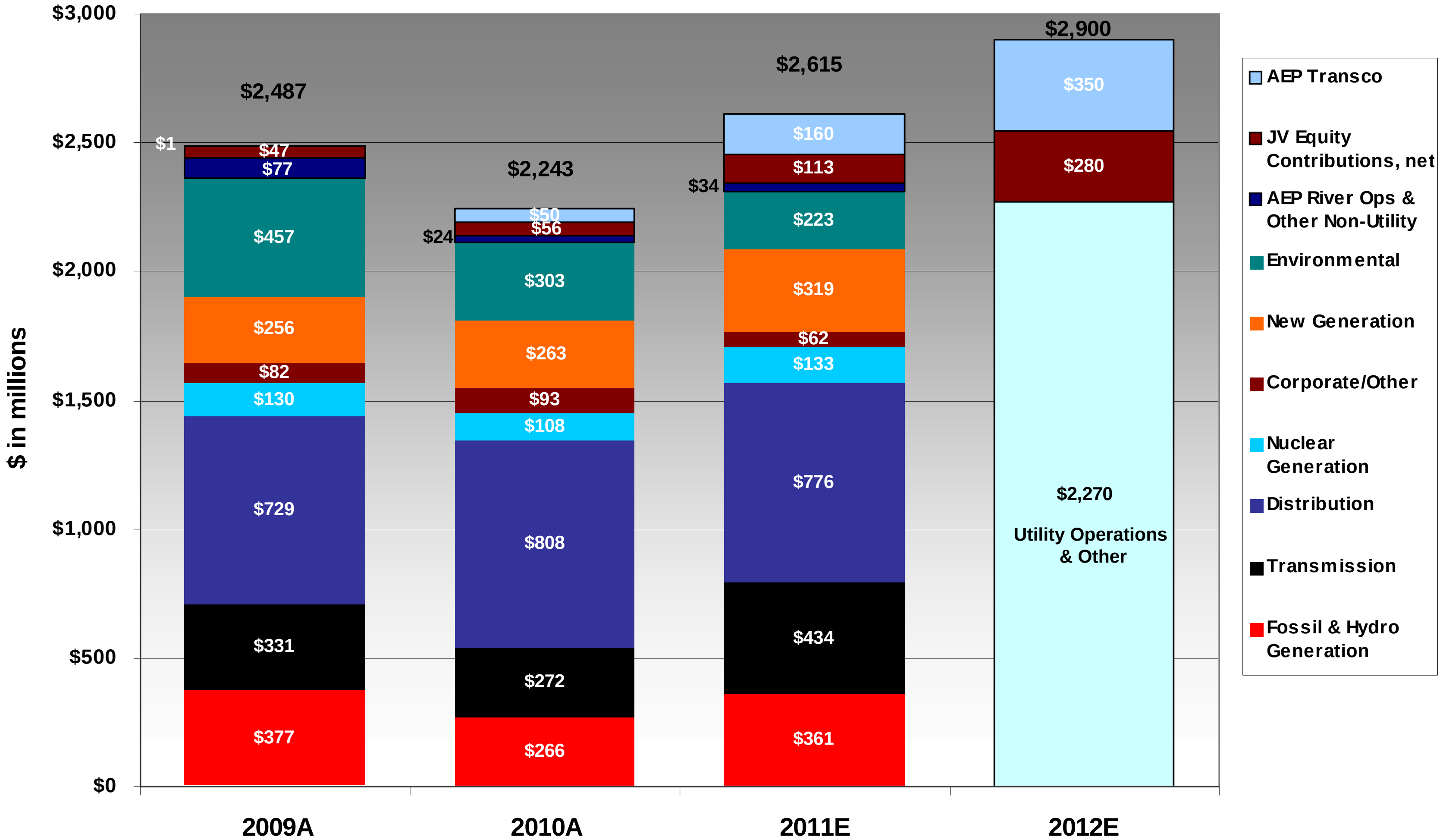




*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

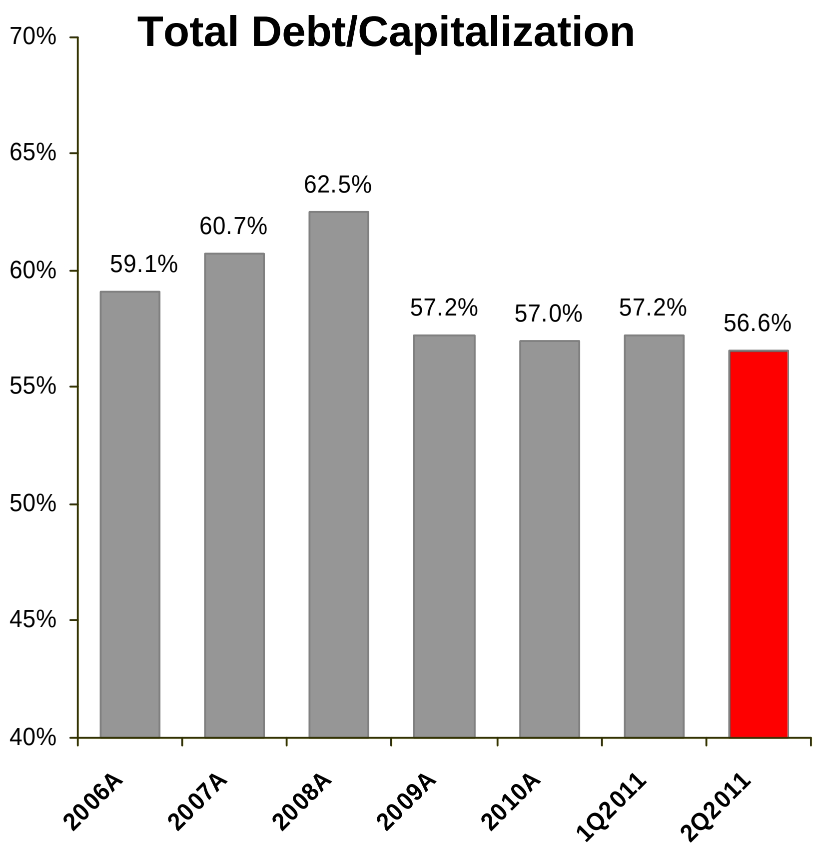
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

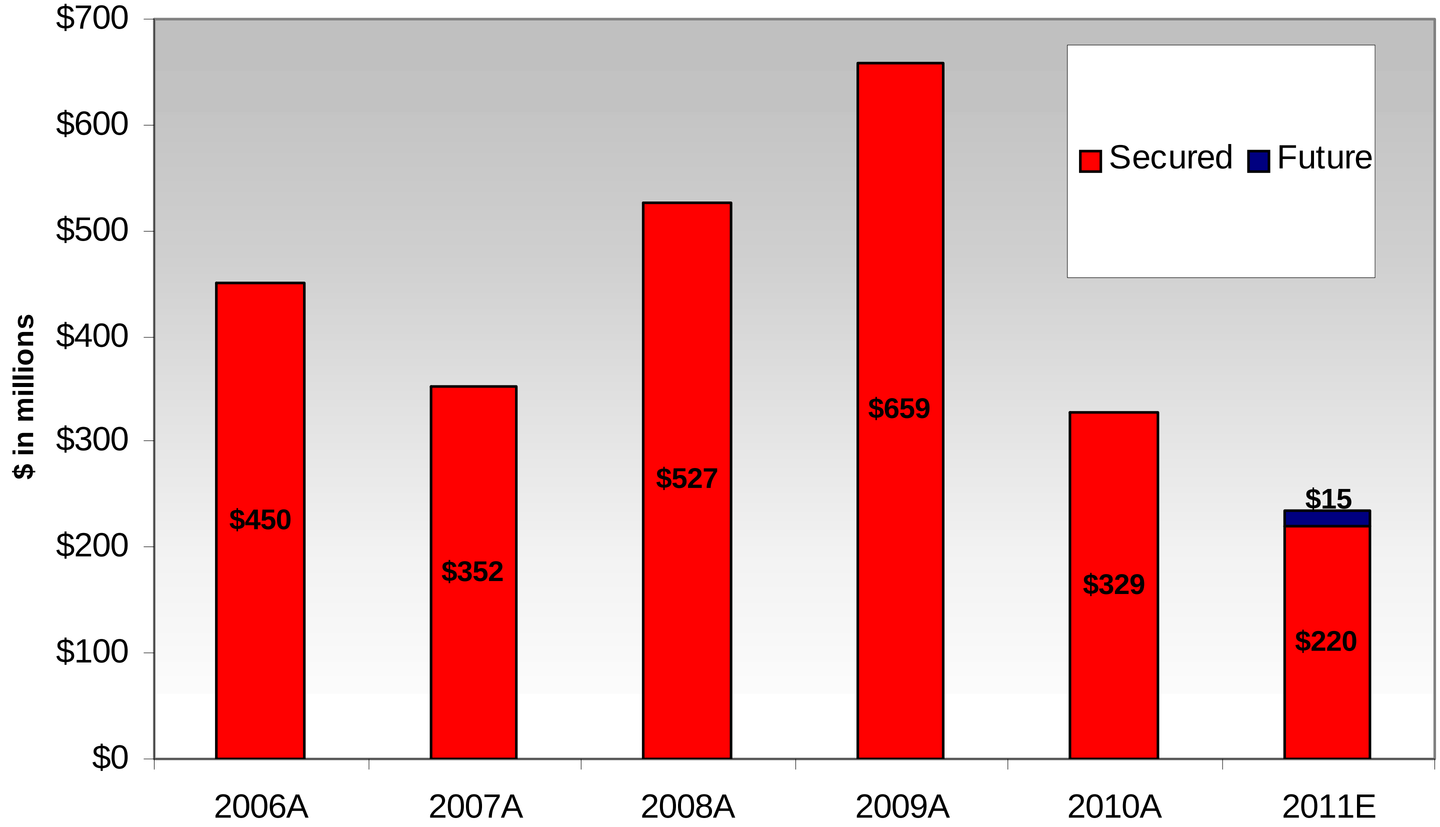
Liquidity Summary (unaudited)		Actual	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. See ESP Settlement slide for a discussion of the Distribution Investment Rider which authorizes a rate increase of $86 million in 2012.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed.   APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Rates Implemented, subject to refund	January 1, 2012
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

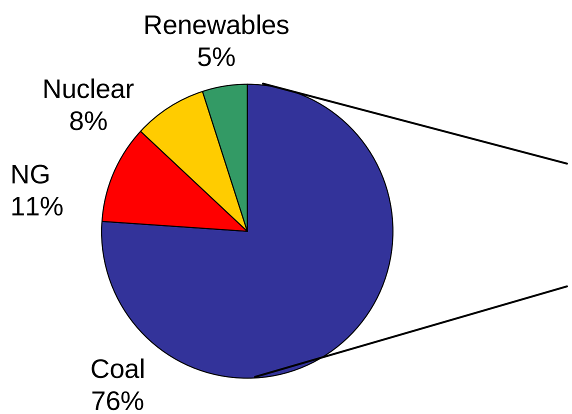
ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modifications costs greater than $50 million
- **Transition to market** - company will make a specific percentage of generation resources open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

AEP Generation Capacity

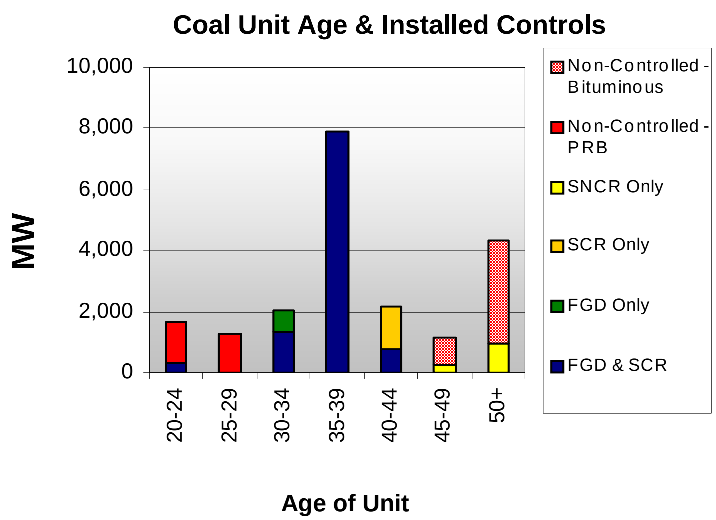
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



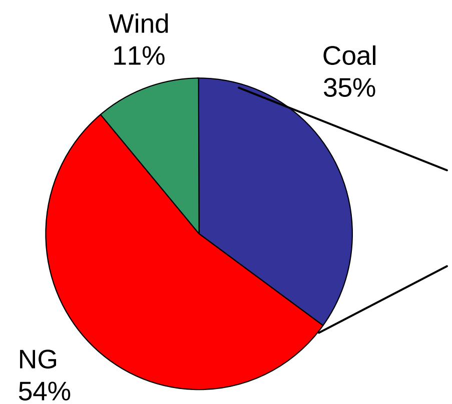
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



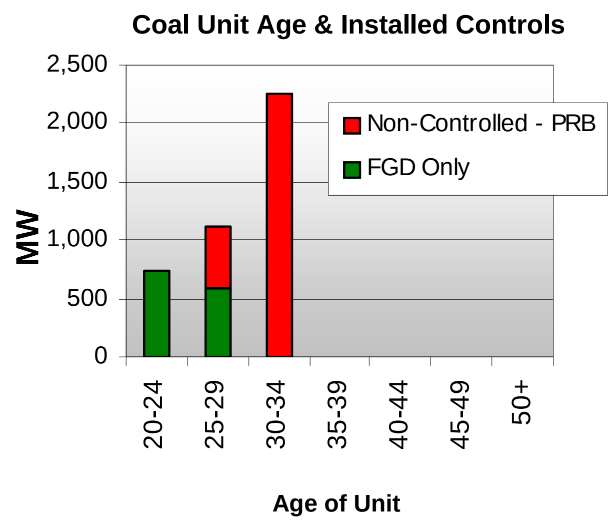
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



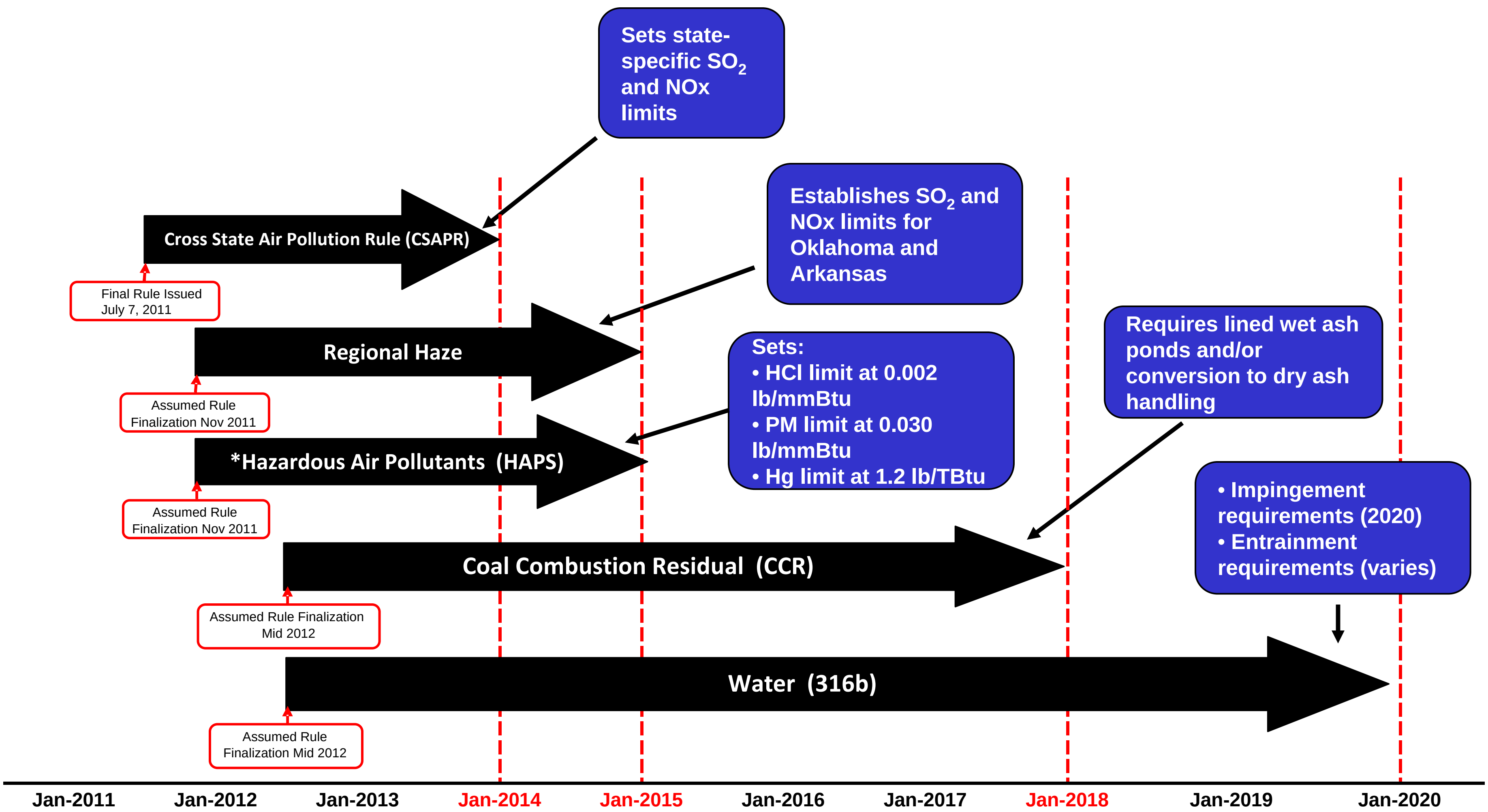
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



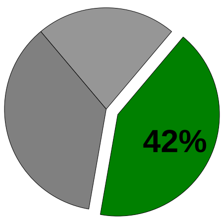
Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

AEP Coal Fleet Assessment

Least Exposed



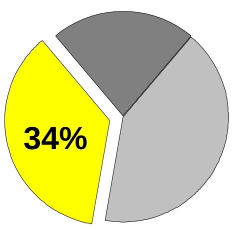
Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

2012 – 2020

Range of Capital ($ Millions) (1)

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

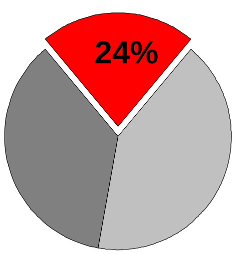
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

Retrofits/New Generation

- The tables below represent our estimated \$6 - \$8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5	510	Refuel with Natural Gas		
	Gavin 1	1320	FGD upgrade		
	Gavin 2	1320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800** *
APCO	Clinch River 1	211	Refuel with Natural Gas		
	Clinch River 2	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765** **
I&M	Rockport 1	1320	FGD, SCR		
	Rockport 2	1320	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670** ***
KPCO	Big Sandy 1	640	New Natural Gas		
	Total MW	**640**	**Total Expected Cost**		**525**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

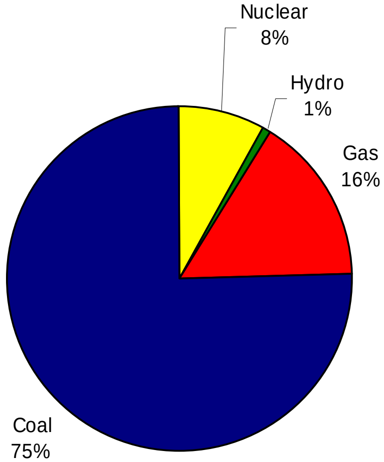
AEP®

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

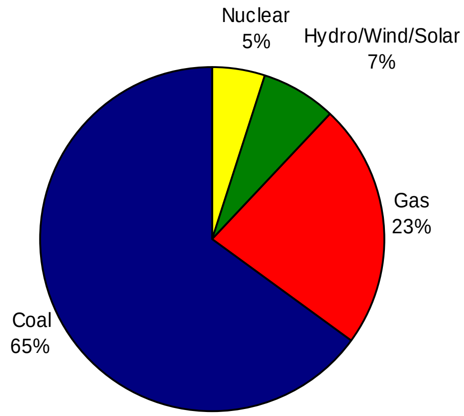
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

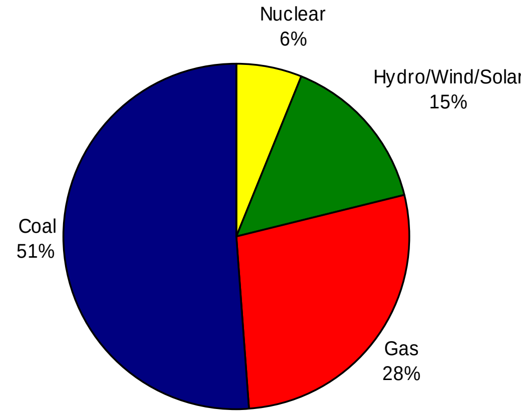
1990 AEP Generating Capacity by Fuel
37,428 total MW's



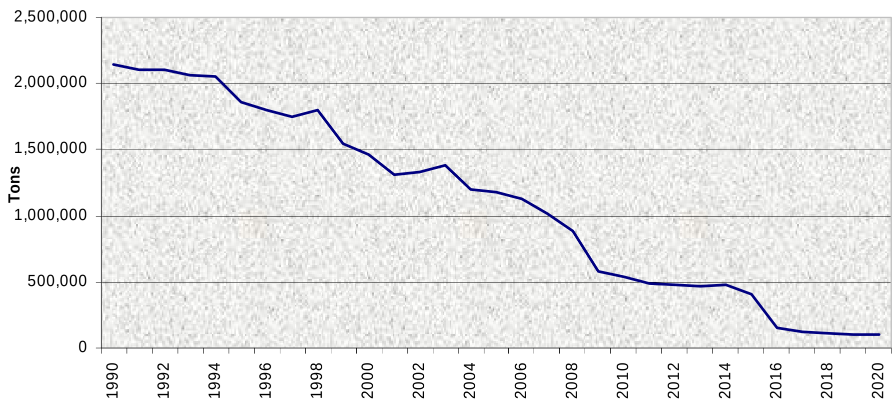
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Transmission Investment Strategy

AEP®

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $210 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

Current rate base is $412 million; expected to grow as follows:

2011: $490 million

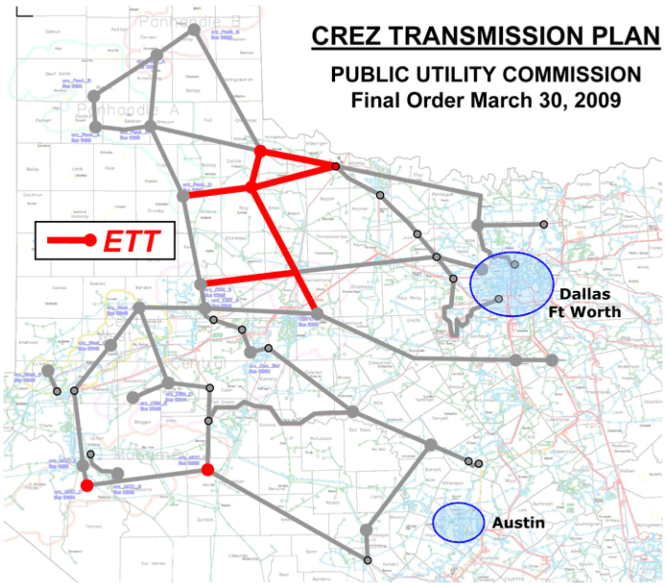
2012: $750 million

2013: $1,200 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.5 B:**
  - Approximately 500 miles of lines and 29 substations with in-service dates through 2020

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.4 B:**
  - Nine new transmission lines totaling approximately 600 miles and 16 substations
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway; 5 lines already approved

Joint Venture Strategy: Long-term

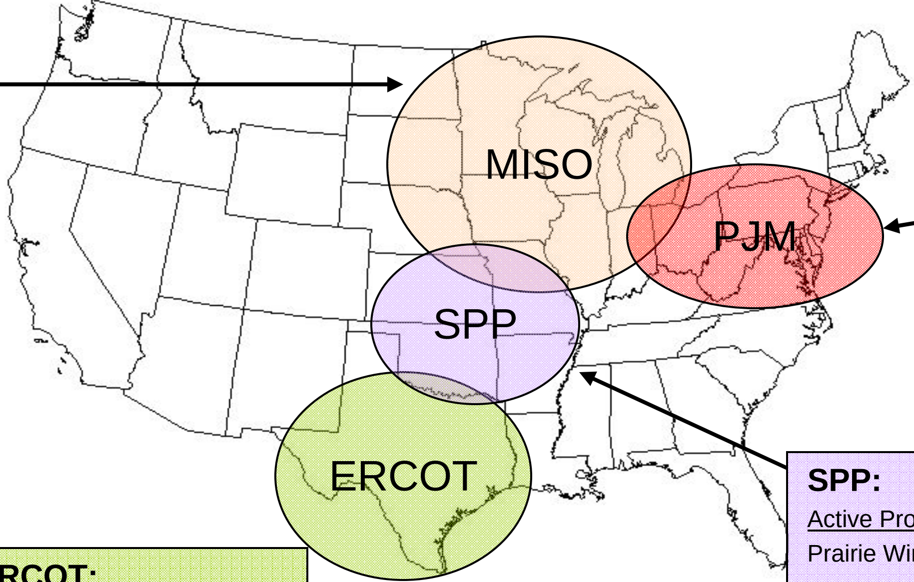
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Morgan Stanley Smith Barney Financial Advisors Presentation

Atlanta, GA

May 26, 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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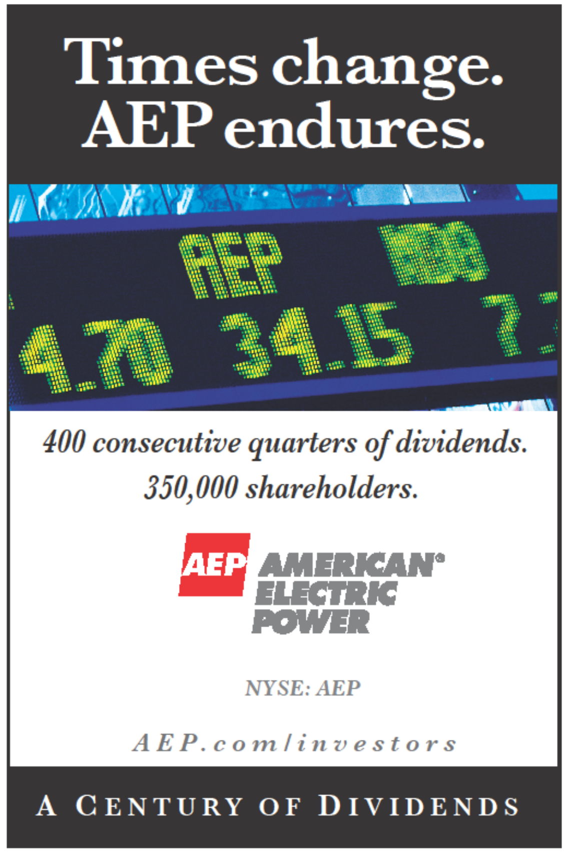
We are Proud of our Record….



Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 5.4%[1]**
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 21 analysts
- 15 Buy Ratings
- 6 Hold Ratings

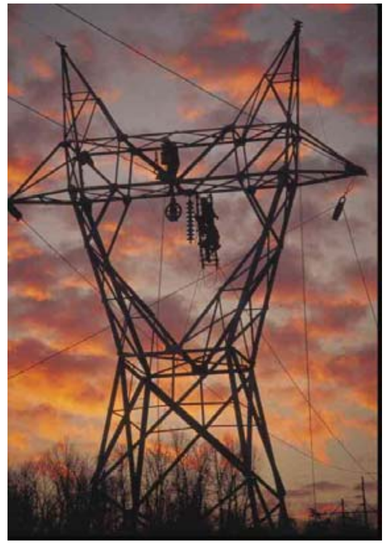
Attractive total return potential

[1] yield percentage based on AEP closing price of $31.19 on 05/24/2010

Industry Leadership

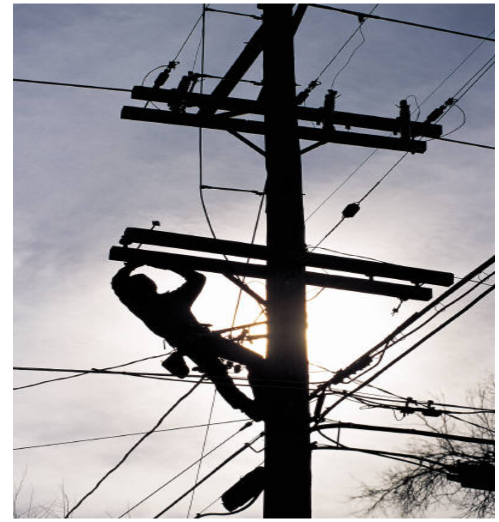
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

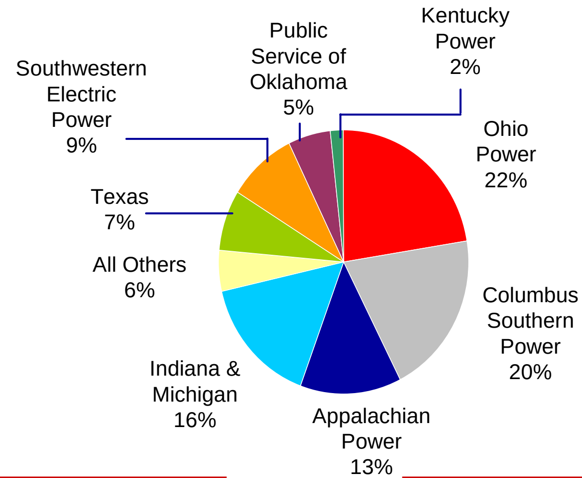
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

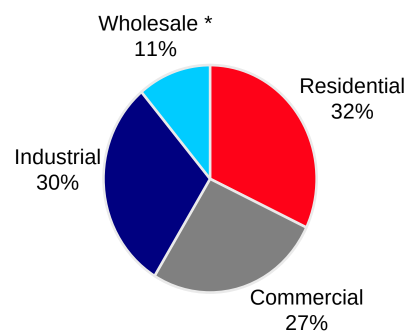
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

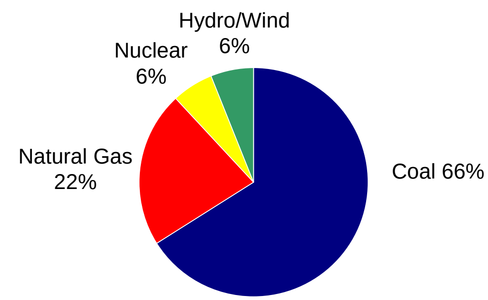


2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



2010 Ongoing Earnings Guidance

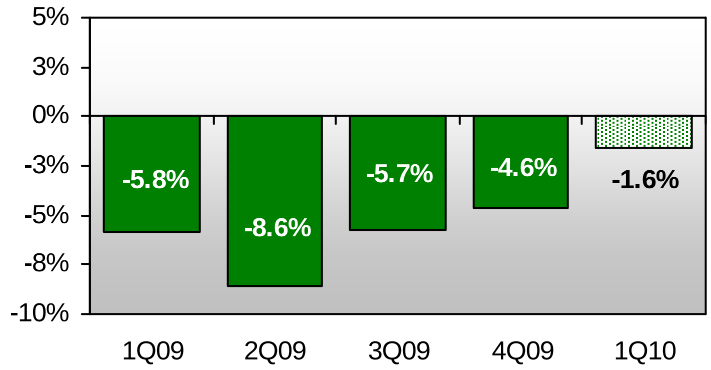
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost cutting initiatives**

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART[SM] Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- *110 miles of 765 kV*
- *Partners: Westar (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

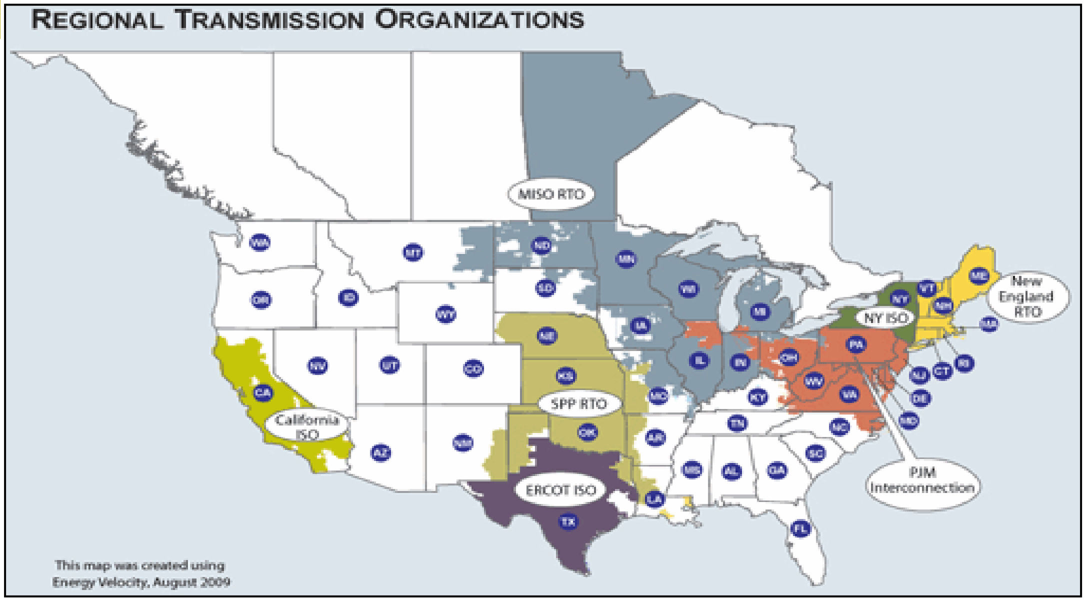
ETT — COD: 2010-2017
- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — COD: 2014
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



FUTURE DEVELOPMENT

SMARTransmission Study
- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP

SPP EHV Overlay
- *Regional Expansion of 765 kV Backbone*

ERCOT

ETT — COD: various
- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

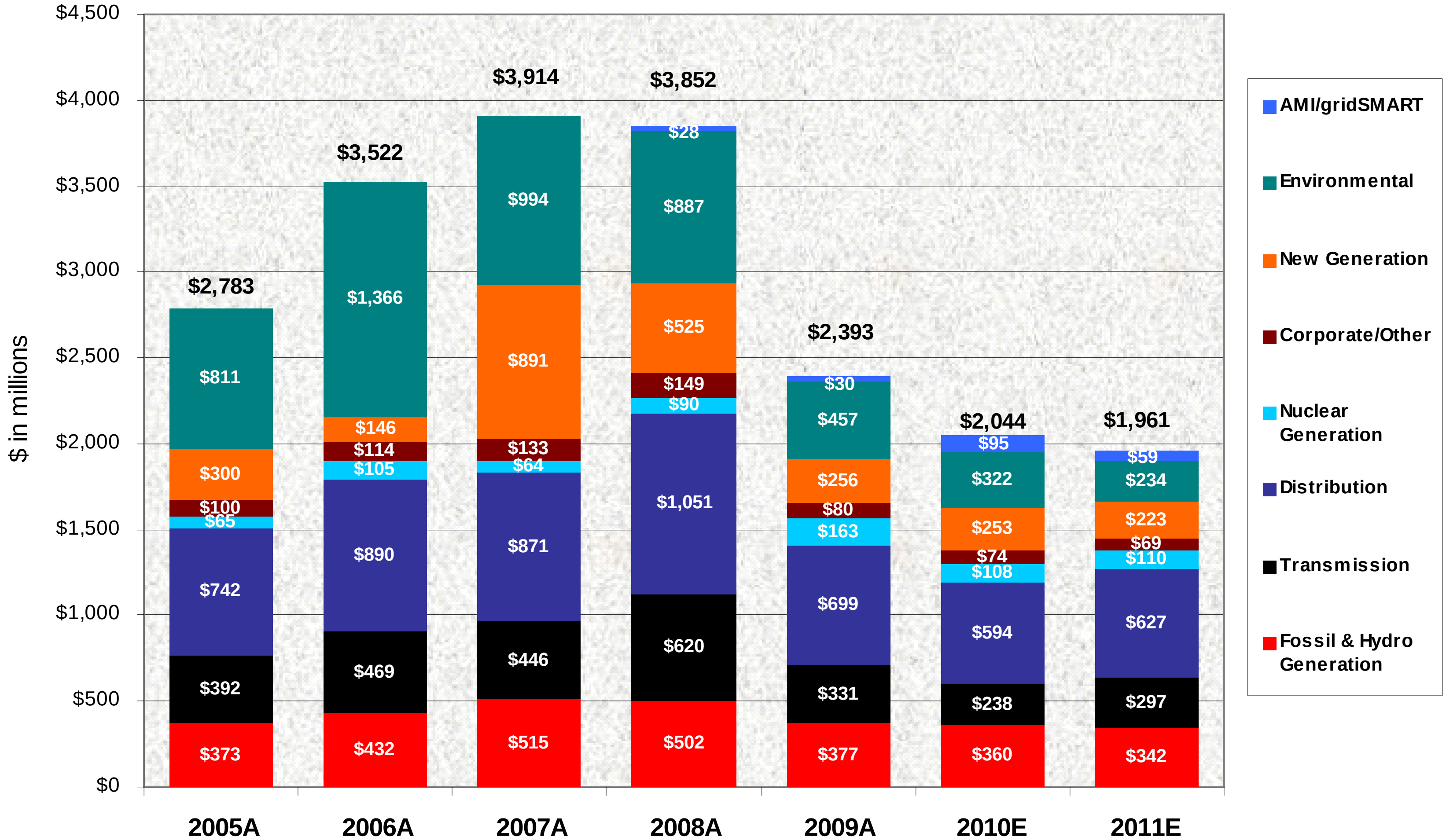
PJM

PJM Expansion
- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

PJM/MISO

EHV Michigan/Ohio
- *700 miles of Proposed 765 kV*

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Dividend Overview

- We will pay our 400th consecutive quarterly dividend to shareholders on June 10, 2010 to shareholders of record on May 10, 2010
- Annual Dividend - $1.68/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December
- Attractive yield of 5.4% as of May 24, 2010
- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value and Total Return Proposition**

Mountaineer Plant (WV)

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7861 of 9556

American Electric Power

Company Update / Overview

Morgan Stanley Corporate Access Day
Chicago
October 9, 2007

AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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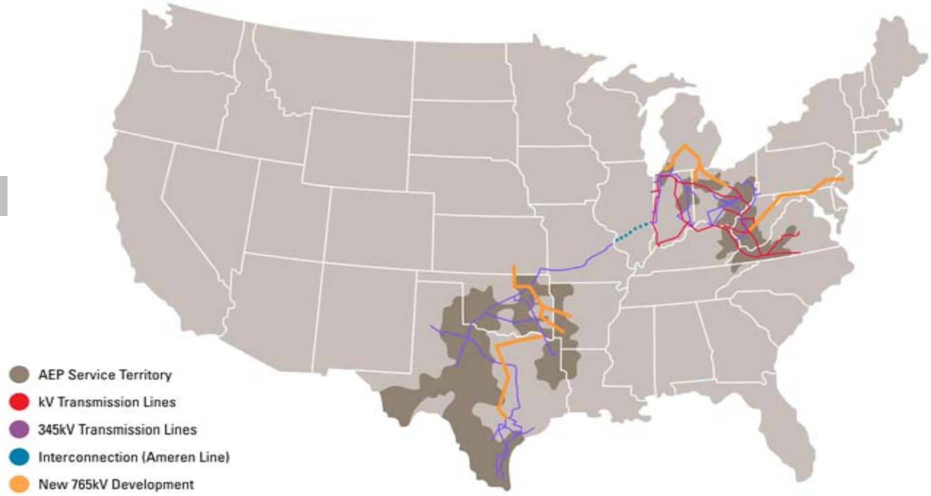
The AEP Footprint

Strength & Scale in Assets & Operations

- **5.1 million customers in 11 states**
- **Industry-leading size and scale of assets:**

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	#2
Transmission	~39,000 miles	#1
Distribution	~208,000 miles	#1

- **Coal & transportation assets:**
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

- Prepare for transition to market in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to bring economic savings to our customers while continuing to enhance shareholder value through regulatory-supported investment and operational excellence

Sustained capital investment opportunities support earnings growth.

2007 Delivered Results

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Accomplishments:

✓ **Acquisition of low-cost generation to meet capacity demand**

- Darby—480MW simple cycle ($227/kW)
- Lawrenceburg—1,140MW combined cycle ($295/kW)
- Dresden—580MW combined cycle (currently under construction); anticipated all-in cost $600-$700/kW

✓ **Brought SWEPCo's Mattison Units 3&4 (150MW) on-line July 2007 (~$380/kW)**

✓ **Completed installation of scrubbers at Mitchell & Mountaineer**

✓ **Continued progress on transmission opportunities**

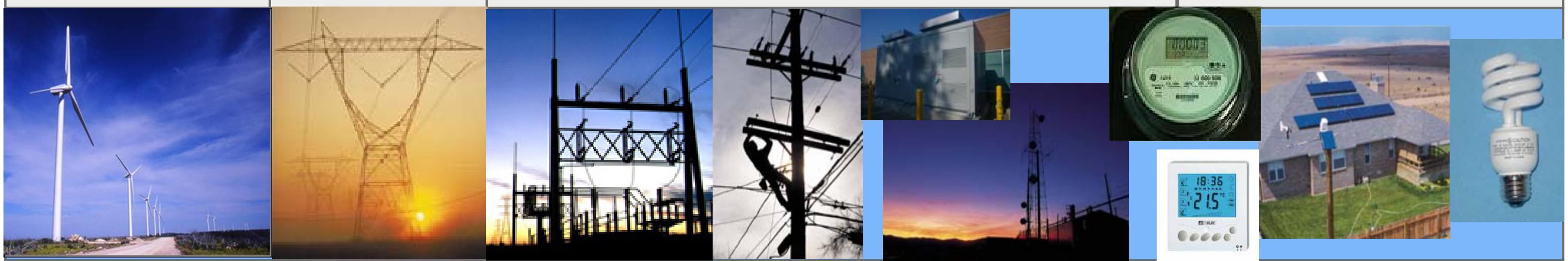
- Obtained PJM approval of Potomac-Appalachian Transmission Highline
- Formed joint venture with Allegheny Energy to construct the PATH
- Formed joint ventures with MidAmerican Energy for ETT & ETA
- Completed technical study with ITC for 765-kV in Michigan and continue to investigate the feasibility of forming a joint venture to develop the project

✓ **Secured to-date $325MM of $338MM of 2007 rate relief projections**

✓ **On track to deliver 5%-7% growth rate in 2007**

AEP continues track record of capital investment, regulatory approvals and earnings growth.

Vision for Sustainability



Generation	Transmission	Distribution	Customers

• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage
	• I-765™
	• Electric Transmission Texas JV
	• Electric Transmission America JV
	• AEP-ABB Alliance
		• Distribution automation
		• Self-healing distribution circuits
		• Advanced metering
		• Communications infrastructure
		• Mobile workforce
		• Internal energy efficiency
		• Integration platform for advanced visualization and analytics
		• Distributed generation and energy storage
			• Customer programs and incentives
			  • Energy efficiency
			  • Direct load control
			  • Peak demand reduction
			• Energy storage

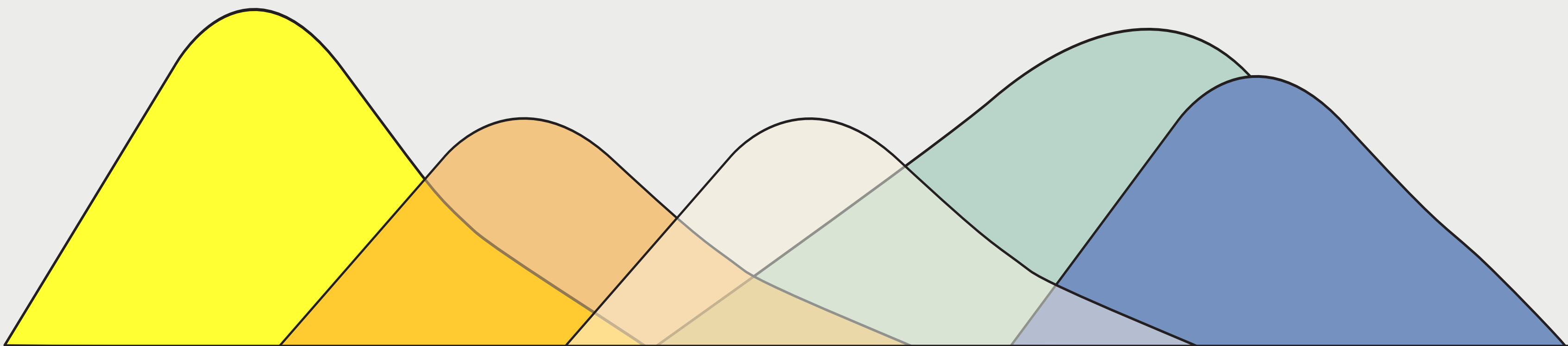
Existing generation and transmission control systems		**GridSMART**: bridging the gap to provide integrated two-way communications & control across the electricity value chain	Home energy automation

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.1B	$1.7B+	$1.5B+	$2.25B - $3.75B*	$2.0B+



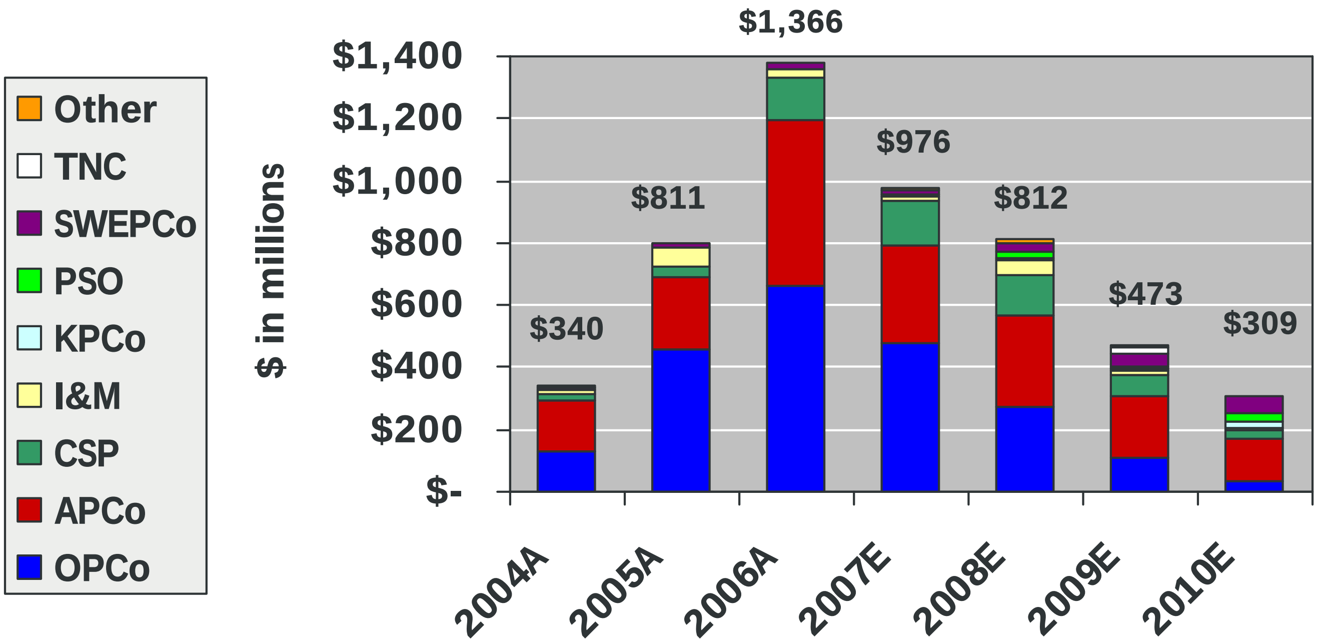
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to slide 33. *The Transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

Environmental Investments Receive Timely Rate Recovery



($ in millions)	Completed (2004-2006)	Rate Recovery
AEG	$9	partial/pending
APCo	$923	yes
I&M	$98	pending
KPCo	$3	yes
SWEPCo	$37	pending
CSP	$194	yes
OPCo	$1,253	yes
Total Capex	$2,517	

($ in millions)	Remaining (2007-2010)	Rate Recovery
AEG	$27	partial/pending
APCo	$944	yes
I&M	$77	pending
KPCo	$33	yes
PSO	$67	pending
SWEPCo	$135	pending
TNC	$22	through mkt. rates
CSP	$374	partial/pending
OPCo	$891	partial/pending
Total Capex	$2,570	

AEP®

Environmental Project Status Report

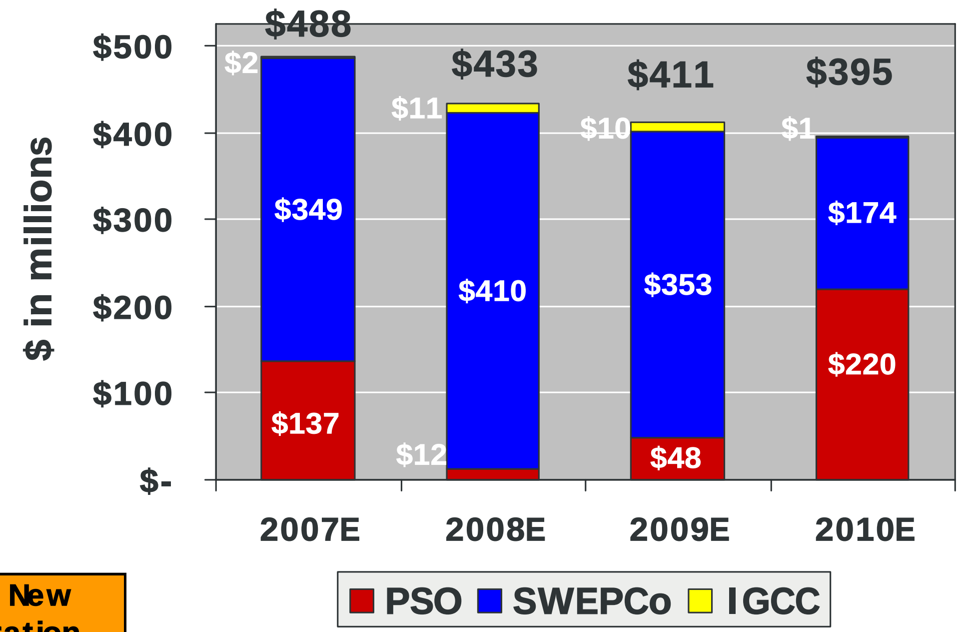
Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2009
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☐	Delayed
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5 & 6	750		N/A	☑	Unit 5 upgrade in-service; Unit 6 upgrade projected 2008
Gavin 1 & 2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR 24,630 MW COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD).

New Generation Investments and Related Recovery

Secured Recovery Mechanism

- PSO Peaking Facilities Rider



($ in millions)	Projected Construction Completion	Total New Generation Investment (2007-10)
PSO - Peaking Facilities	2008	$102
PSO - Combined Cycle *	2012	$315
SWEPCo - Mattison	2007	$66
SWEPCo - Stall	2010	$422
SWEPCo - Turk	2011	$798
APCo - IGCC	tbd	$12
CSP/OPCo - IGCC	tbd	$12
Total Capex	Total Capex	$1,727

* - intended to source requirements to be met by Red Rock Plant prior to cancellation.

Additional Recovery Mechanisms Under Consideration:

- Formula based rates
- Requests for return on CWIP
- Current and future rate cases

GridSMART

➢AEP Vision

- AEP is moving technology out of the laboratory and into real-world applications
- Aggressive goals:
  - 25 MW NaS battery installations by 2010
  - 1,000 MW demand reduction by 2012
  - 5 million smart meters by 2015

➢AEP Leadership

- **Environmental:** AEP's fleet includes hybrids
- **Efficiency and Conservation:** DOE Transformer Efficiency Initiative and participation in the Clinton Global Initiative
- **Education:** AEP Foundation's support of the National Energy Education Development (NEED) Project and Change-a-Light Program
- **Technology:** High temperature superconductors, micro grid test bed and extra-high voltage transmission advances

➢AEP's Collaboration with Others

- NGK (NaS battery) & Rolls Royce (fuel cells)
- Collaboration with GE to demonstrate the distribution/customer service business of the future

Modernization of our distribution infrastructure will change how we manage the flows of information and electricity across the energy value chain to optimize overall performance and prepare for the future.

AEP-GE Initiative

We will deploy smart meters, distribution automation and the associated enhanced technology resulting from the collaboration with GE in two regions by the end of 2008 -- representing approximately 200,000 customers.

By integrating customers and their end use technologies into the daily operation of the grid, we can collaborate to optimize supply and demand and improve energy efficiency and environmental sustainability.

Our agreement with GE is a winner for our customers, our shareholders and for the environment.

AMERICAN ELECTRIC POWER

Working Together for a Brighter Future

imagination at work

AEP and GE will collaborate to address the full energy pathway from the power plant to the home.

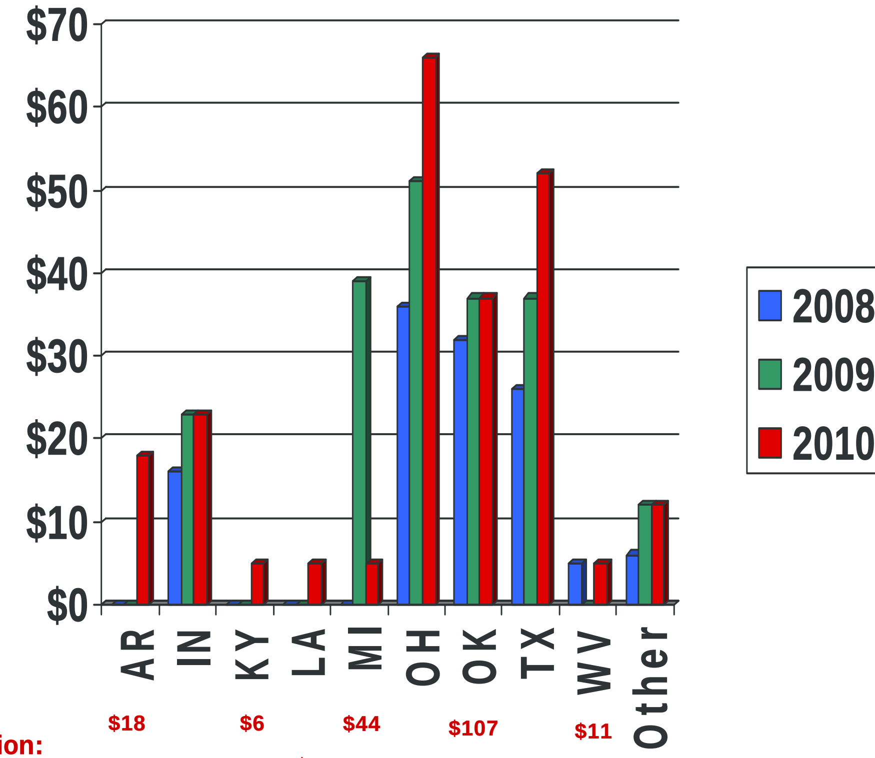
GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology	**2007**	**2008**	**2009**	**2010**
Metering & Communications	$0	$83	$138	$146
Distribution Technology Enhancements	$2	$40	$ 63	$ 82

*$452MM of the $554MM not in current forecast; spending contingent upon regulatory approval

$ in millions



3-Year Total by Jurisdiction: AR $18, IN $62, KY $6, LA $5, MI $44, OH $153, OK $107, TX $115, WV $11, Other $31

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

Pace of our GridSMART Implementation Determined by Regulators

- **Arkansas** – The Arkansas commission approved our 'quick-start' programs in September 2007, which include education, incentive to encourage use of compact florescent lights and higher efficiency appliances, weatherization for low-income housing, an emergency load management pilot and a pay-for-performance pilot that results in a payment to customers who curtail load upon request. The commission's order allows implementation on or after October 1, 2007. We will now file a revised tariff, which will seek to recover costs beginning with the first billing cycle of November 2007.

- **Indiana** - As ordered by the IURC in June 2007, I&M, in collaboration with the Office of Utility Consumer Counselor, is designing and will administer a Smart Metering Pilot Program (SMPP) for approximately 10,000 customers in South Bend, Indiana.

- **Kentucky** – Successful demand-side management programs have been in place in Kentucky since 1996. We recently filed a proposed real-time pricing pilot for which we are waiting commission approval.

- **Ohio**
  - Recent Governor remarks and draft legislation indicates modernization of Ohio's infrastructure is a high priority.
  - PUCO-sponsored series of six Smart Meter Deployment Workshops currently underway.

- **Texas**
  - Successful demand side management and energy efficiency programs have been in place in Texas since the 1990s.
  - Energy Efficiency Cost Recovery Rider currently under consideration by the PUCT in TCC's base rate case; if adopted in TCC's case, it will also apply to TNC.
  - AEP Texas Advanced Metering Project commenced July 31, 2007, which has the goal of filing with the PUCT an advanced metering deployment plan and a related surcharge recovery proposal by March 2008.

Distribution technologies and DSM/energy efficiency programs are an investment, which should be treated by regulators in the same manner as investments in generation and T&D

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7876 of 9556

Contribution of Transmission Investments

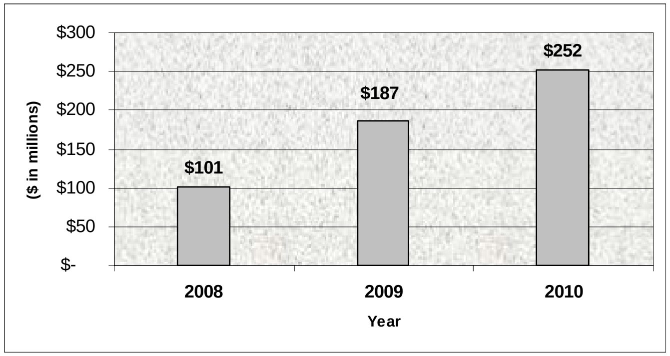
Potential Transmission Opportunities

~ $3 Billion I765[TM] Project in PJM
~ $2.6 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions

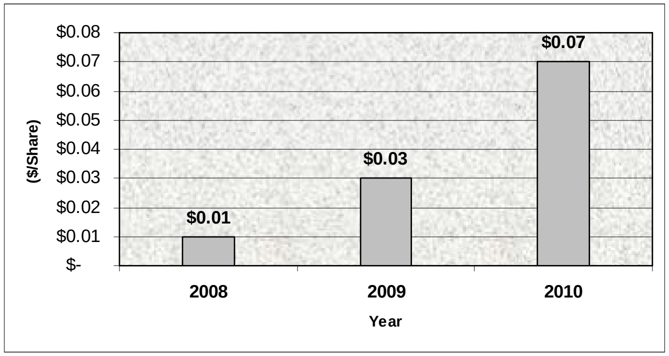
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 402 MM shares)	$0.60 - $1.00+

Projected Transmission Capital Spending*



* ~$9-$15 billion investment opportunity not included in current capital guidance forecasts, since it will be put into a JV. ETT base case and PATH projects included in above projection.

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

Electric Transmission America (ETA)

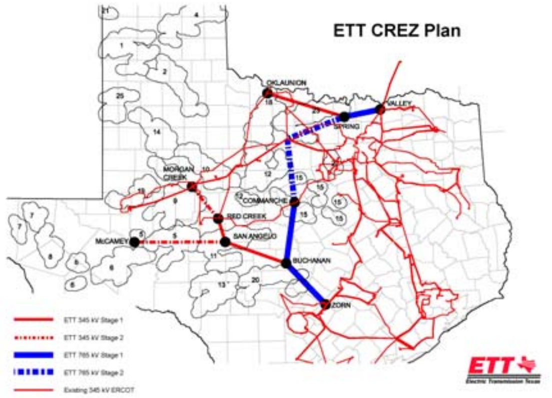
- *Electric Transmission America (ETA)*
  - AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
  - Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
  - Projects taken on by the Joint Venture would entail transmission facilities:
    - 345 kV and above
    - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
    - Greater than $100 million
  - ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
  - ETA will look to collaborate with qualified partners in each particular region.

This JV reflects a natural progression and expansion of our partnership with MidAmerican.

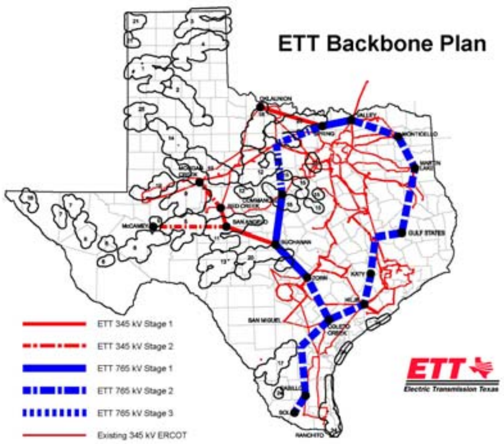
Electric Transmission Texas (ETT)

- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in the fall of 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.
- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)
- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).
- **Traditional ratemaking process through the PUCT will be utilized for investment cost recovery.**

ETT CREZ



ETT Backbone



Transmission Project Updates

PJM I-765 TM Phase I Progress to Date

- AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
- Total estimated cost of $1.8 billion
- AEP portion approximately $600 million
- Expected completion 2012

Key Next Steps

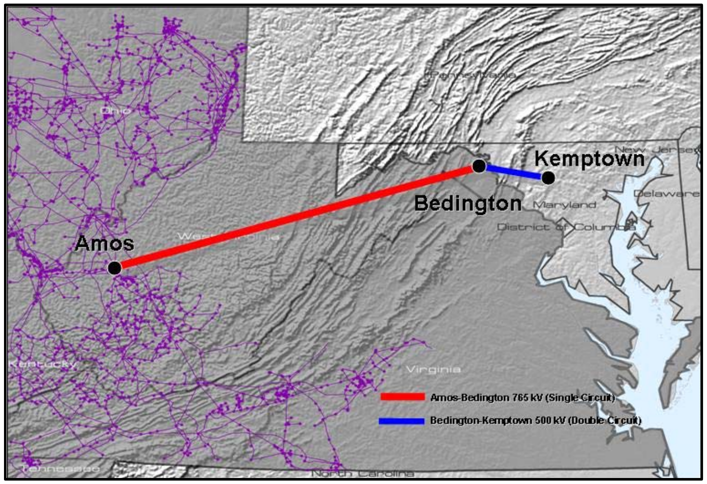
- Complete FERC Filing – Fall 2007
  - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
- Siting Approved – Fall 2009
- Completion – Fall 2012

PJM I-765 TM Phase II Update

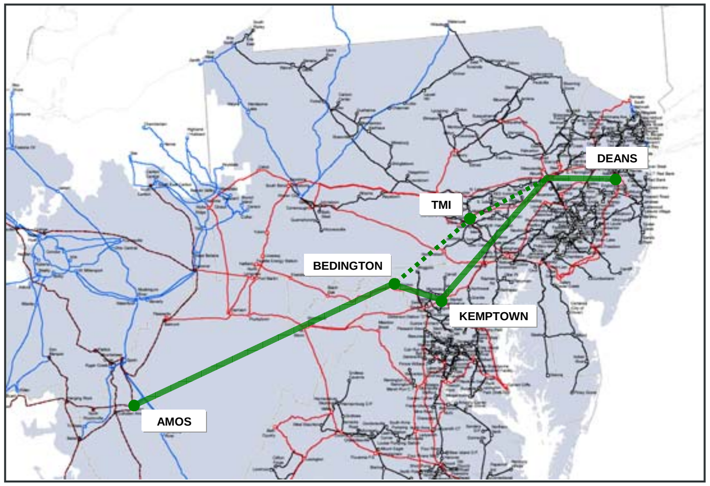
- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.

Regional Rate Design will be utilized for investment cost recovery.

PJM Phase I



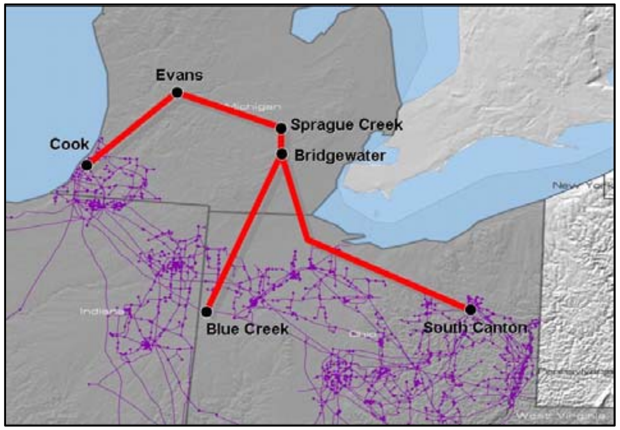
PJM Phase II



Transmission Project Updates – cont'd

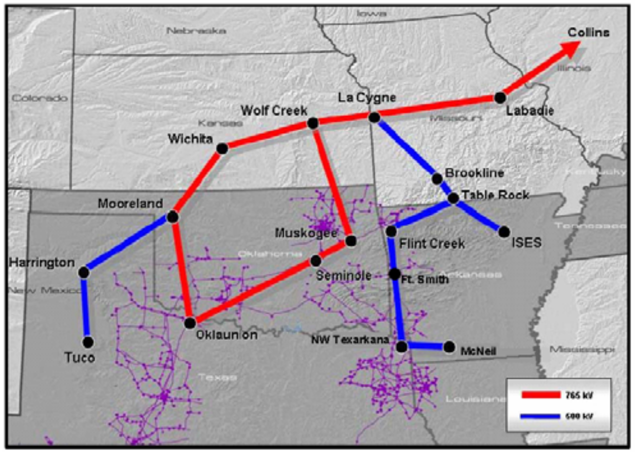
- *765 – kV in Michigan – Key Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2015

Michigan



- *765-kV in SPP – Key Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

Southwest Power Pool



- *Regional Rate Design will be utilized for investment cost recovery.*

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Advanced Generation & CO_2

Near Term:

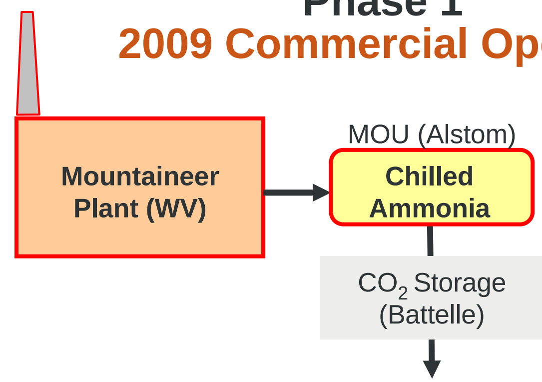
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
	2007	2008	2009	2010
Mountaineer Chilled Ammonia Project	$4	$56	$11	$0

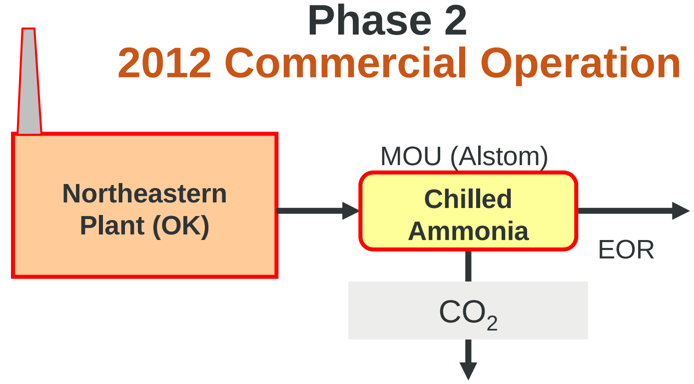
Long Term Strategy (Post 2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation

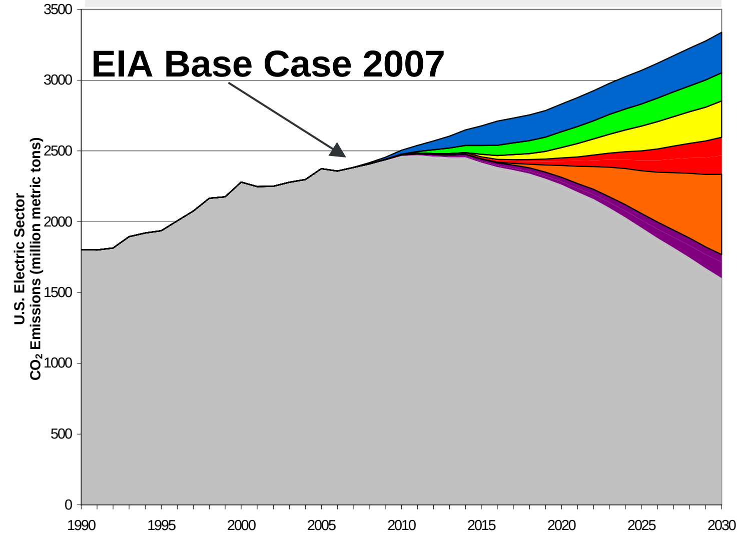


We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP is Pursuing a Portfolio of Options to Address Carbon

Technology	EIA 2007 Reference	Industry Target	AEP Plan
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr	DSM: 1000MW reduction in demand by 2012
Renewables	30 GWe by 2030	70 GWe by 2030	Wind PPAs through 2015: 1610MW nameplate or 232MW capacity for planning purposes. Also, voluntary green energy tariffs (Ohio program starting 2007)
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030	Evaluation of Nuclear COL
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030	1,246MW IGCC by 2017 447MW USC Turk plant by 2011
Carbon Capture and Storage	None	Widely Deployed After 2020	Chilled Ammonia: Mountaineer 2009 & Northeastern 2012 Oxy-coal by 2020
Plug-in Hybrid Electric Vehicles	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter	Joined Electric Drive Transportation Association (EDTA) in May 2007
Distributed Energy Resources	< 0.1% of Base Load in 2030	5% of Base Load in 2030	Pursuit of NaS® Energy Storage – 25MW of storage by 2010 and 1000MW of other storage/fuel cells by 2020

Technical Potential for CO_2 Reductions - *Achieving all targets is very aggressive, but potentially feasible.*



Technology advancement is required beyond present "state of the art" to achieve 1990 CO_2 levels by 2030. AEP is investing in a portfolio of GHG reduction initiatives. Allocation of funds will shift over time depending on technology, legislation, etc.

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Source for graphic, EIA 2007 reference and industry target data: EPRI

Investing in IGCC

Generation Technology Comparative Statistics

US2012$	Eastern Bituminous		
	USC	IGCC	NGCC
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (2012$, including: EPC+Owner's Cost+AFUDC+Transmission) ($/kW)	$2,876	$3,709	$754
Production Cost ($/MWh)	$23	$23	$57
Cost of Electricity, Without CO_2 Capture ($/MWh)	$86	$98	$111
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$137	$124	$169

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost includes cost to engineer, procure and construct plus owners direct costs, AFUDC, overheads and transmission lines.
- Assumes Northern Appalachian coal price of $2.28/mmBtu (2012$) for USC & IGCC and natural gas price of $7.73/mmBtu (2012$) for NGCC.
- Production cost includes fuel plus variable operations and maintenance costs.
- Cost of electricity represents first year estimates in 2012$ and are based on total plant cost plus fuel costs, operation and maintenance costs, and emission allowance costs.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Lag Reduction: East Regulated Utilities

Appalachian Power Co.

Customers: 949,000
Estimated Rate Base: $3.7B *
Estimated 2007 Earnings: $183MM

Indiana Michigan Power Co.

Customers: 582,000
Est. Rate Base: $2.1B *
Est. 2007 Earnings: $130MM

Kentucky Power Co.

Customers: 176,000
Estimated Rate Base: $.9B *
Estimated 2007 Earnings: $27MM

* See page 28 for rate base details

Virginia
- Opportunity for one rate case exists before 12/31/08
- E&R rider
- Post 2008 rider for DSM, renewable programs & new generation
- Fuel clause
- OSS margin sharing

West Virginia
- Special construction surcharge permitted
- Fuel clause (ENEC)

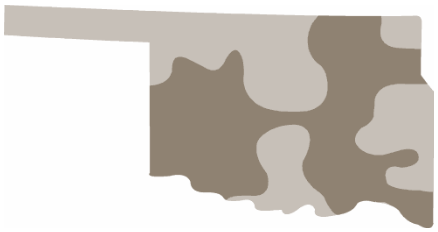
Indiana
- Riders to be requested for DSM, Environmental and RTOs
- CWIP may be approved for clean coal technology projects utilizing Indiana coal or qualified pollution control property via surcharge
- Fuel clause

Michigan
- Return on CWIP can be included in rate base
- Fuel clause

Kentucky
- Environmental surcharge
- Monthly adjustment clauses in place for DSM & fuel
- OSS margin sharing

Regulatory Lag Reduction: West Regulated Utilities

Public Service of Oklahoma

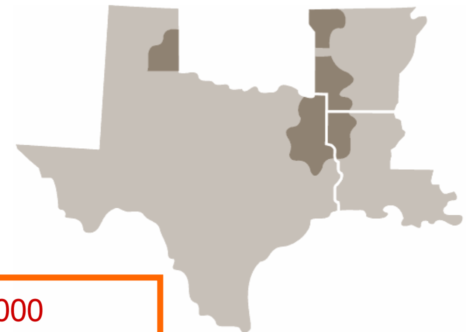


Customers: 520,000
Estimated Rate Base: $1.2B *
Estimated 2007 earnings: $35MM

* See page28 for rate base details

Oklahoma
•Rider mechanisms authorized for vegetation, Lawton Cogen & new peaking facilities after December 2007 in-service date
•Fuel clause
•OSS margin sharing

Southwestern Electric Power Co



Customers: 456,000
Est. Rate Base: $1.3B *
Est. 2007 earnings: $66MM

Arkansas
•CWIP permitted in rate base for plant that is placed in service within 6 months after the test year
•Fuel clause
•OSS margin sharing

Louisiana
•Formula rate plans permitted
•Fuel clause
•Seeking partial CWIP return on new generation projects
•OSS margin sharing

Texas
•CWIP allowed in rate base in some cases
•Fuel clause
•OSS margin sharing

Regulatory Lag Reduction: Texas Wires Business

AEP Texas Central Co & AEP Texas North Co

Customers: 927,000
Estimated Rate Base: $2.1B *
Estimated 2007 earnings: $73MM

* See page 28 for rate base details

Texas

- Transmission rider provides annual recovery dependent on the level of transmission investment and ERCOT load growth rates
- AFUDC is permitted in limited circumstances

AEP Texas will synchronize general rate requests with significant rate base changes and benefit from the flexibility of periodic transmission filings.

Rate Base by Jurisdiction

Jurisdiction	Rate Base	Approved ROE	Date	6/30/07 GAAP Earned ROE
APCo VA	$2.022MM	10.00%	5/15/2007	8.44%
APCo WV	$1.656MM	10.50%	7/26/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.89%
I&M-Indiana	$1.805MM	12.00%	11/12/1993	7.18%
I&M-Michigan	$268MM	13.00%	2/12/1991	
Ohio-CSP	$1.558MM	12.46%	5/12/1992	21.22%
Ohio-OPCo	$2.183MM	12.81%	3/23/1995	12.79%
PSO-Oklahoma (1)	$1,064MM	10.75%	5/2/2005	2.25%
SWEPCo-LA	$434MM	11.10%	12/29/1999	6.77%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1984	
Texas-TCC (2)	$862MM	10.13%	8/15/2005	6.22%
Texas-TNC (3)	$530MM	TBD	5/24/2007	8.63%

(1) PSO rate case under review. Company position is a new rate base of $1,189,422,564. Awaiting final order.

(2) TCC rate case under review. Company position is a new rate base of $1,600,487,376. Awaiting final order.

(3) PUCT approved a settlement agreement, and indicated ROE will be determined as part of TCC's rate case.

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ I&M Indiana Rate Petition
- ✓ Virginia Filings – Fuel Factor and E&R
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

The AEP Ohio Post-2008 Action Plan

Concurrent pursuit of regulatory and legislative options

- Work for a legislative outcome that:
  - Allows for market pricing or
  - Allows for new Rate Stabilization Plans that reflect a value for generation consistent with market
- If legislation is not forthcoming, work with the PUCO Staff to develop new Rate Stabilization Plans that reflect the market value of generation

Essential elements of Post-2008 Plan

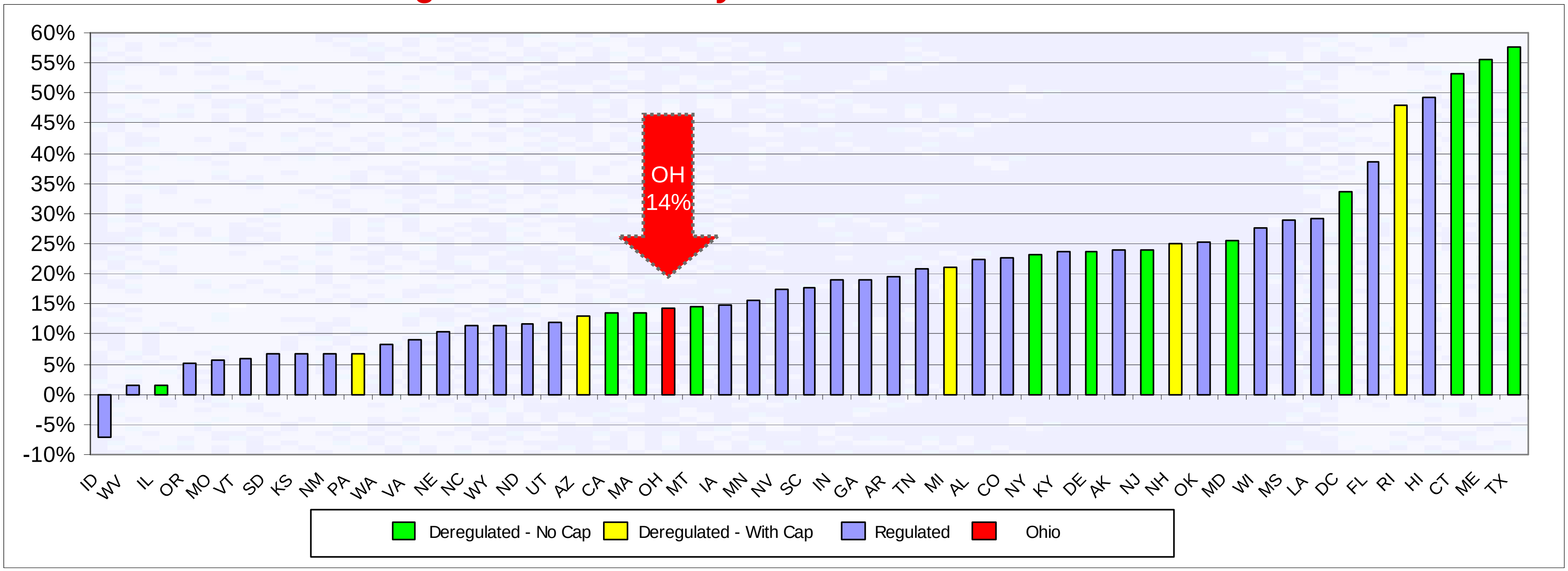
- Market-based generation pricing option
- Recovery mechanisms for new plants, fuel clause, environmental investments, GridSMART initiatives, energy efficiency projects and renewable energy investments
- Well-defined parameters for PUCO authority

Achieve a sustainable balance between shareholders and the Ohio economy.

Electricity Costs Have Increased in Both Regulated and Deregulated States

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

2002-2006 % Change in Electricity Prices



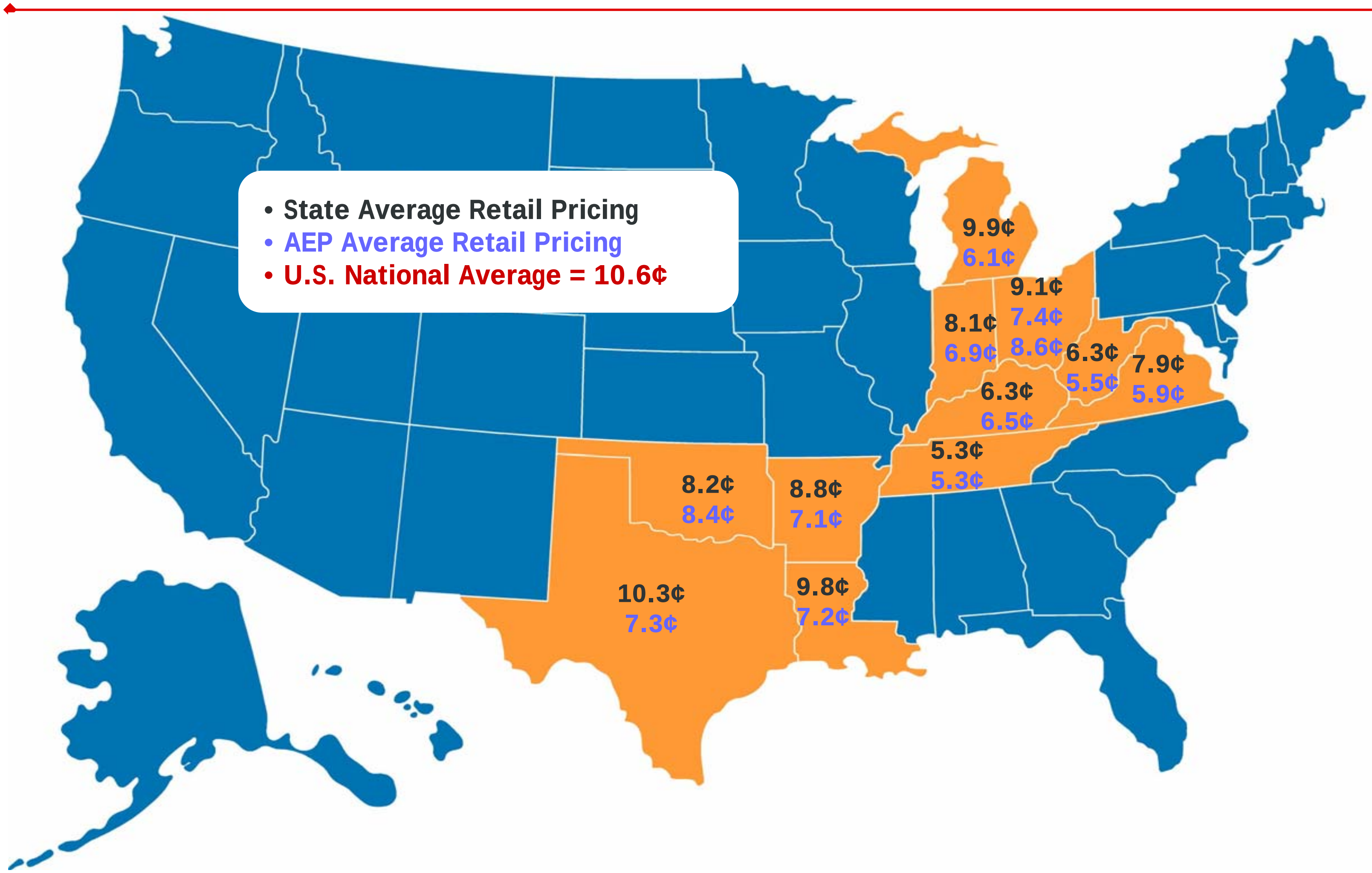
Source: USA Today, Aug. 10, 2007

- **Deregulated states median increase: 25%**
- **Regulated states average increase: 23%**
- **Ohio average increase: 14%**

Ohio increased less than the average of both regulated & deregulated states. Under any scenario, rates in Ohio will likely increase.

Average Retail Price of Electricity

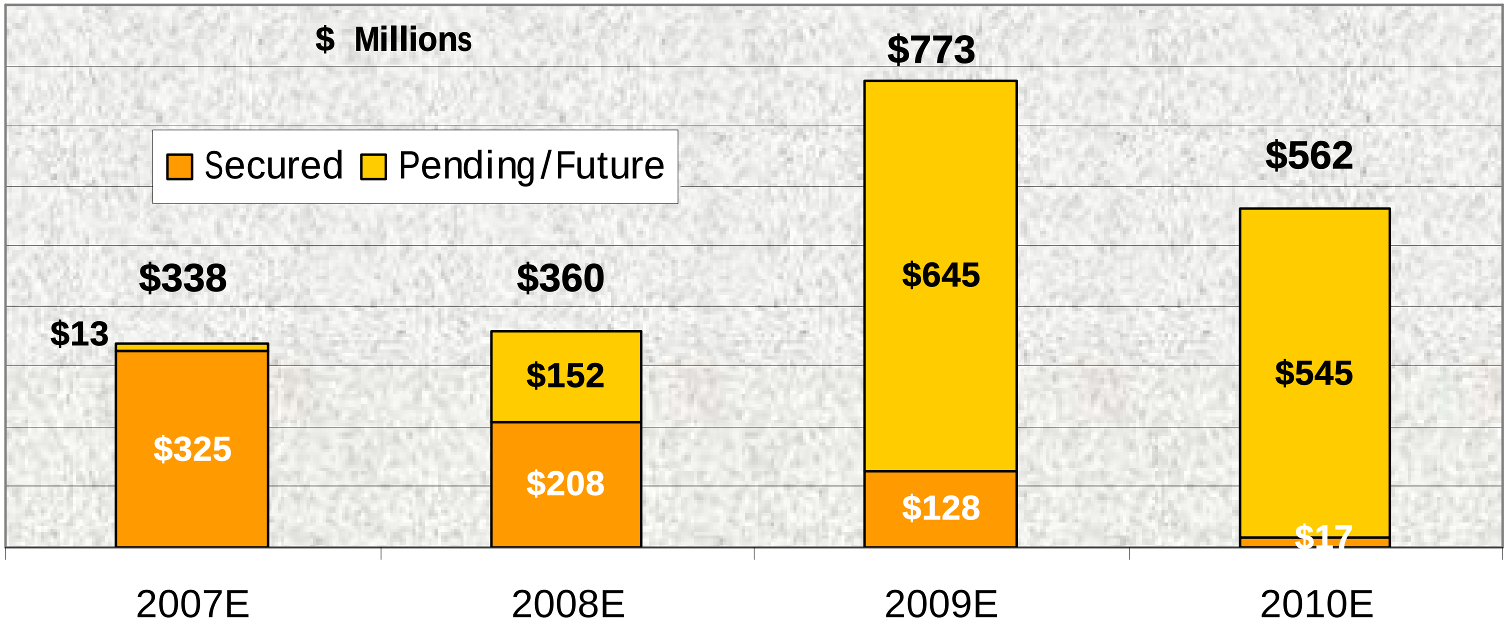
STRATEGIC DIRECTION & FINANCIAL OUTLOOK



AEP's pricing will remain competitive following anticipated rate increases.

Data source: EEI Summary of Average Realizations for the twelve months ended December 31, 2006
Ohio: OPCo = 7.4¢ / CSP = 8.6¢

Incremental Rate Relief Assumptions

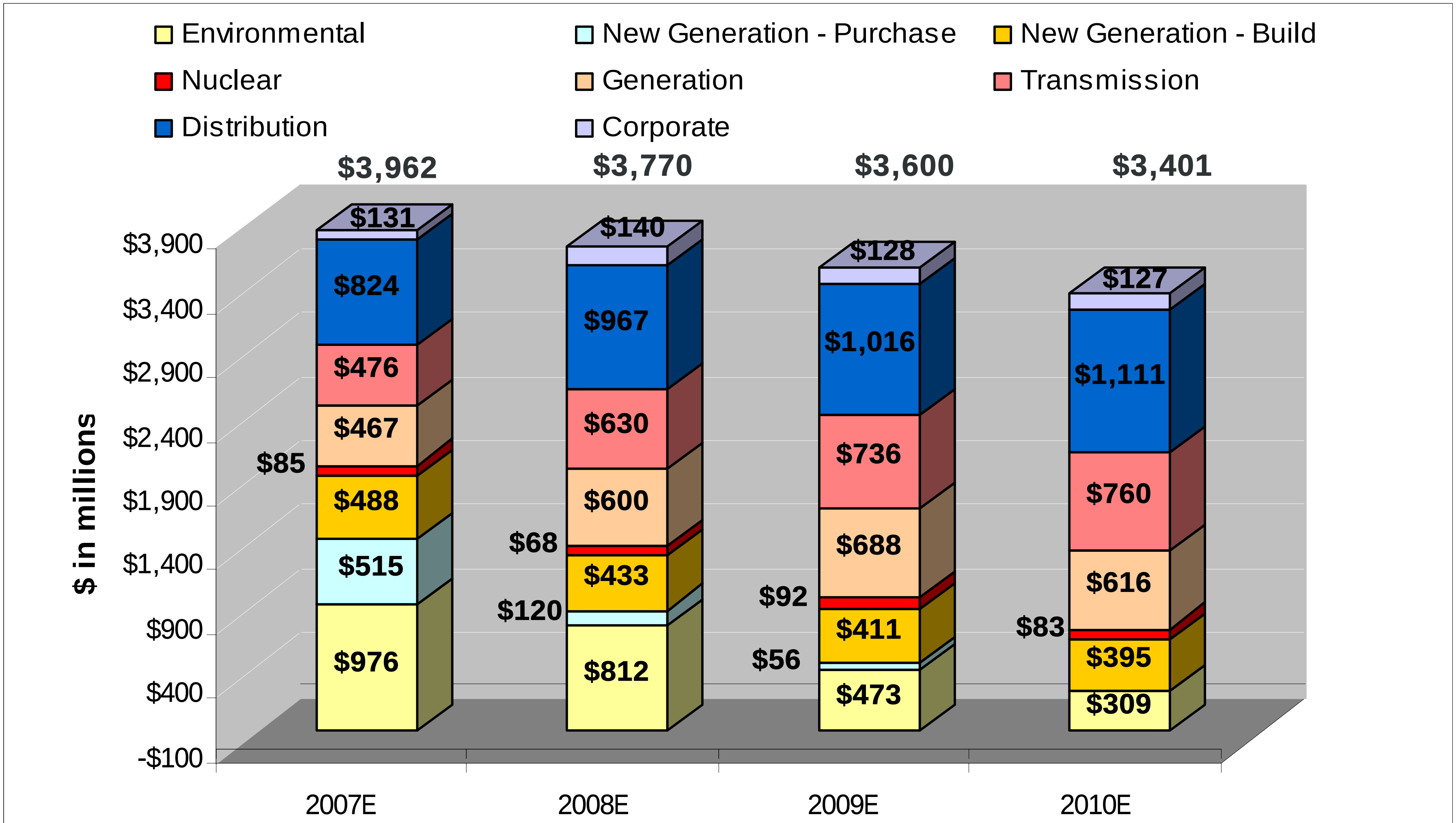


2007 Pending: PSO Rate Case
TCC Rate Case
Ohio 4%

2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation

2007 - 2010 projected annual rate increases of 5.5%

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

Multi-Year Capital Investment Funding Plan

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Capital investment is funded from cash from operations and debt issuances

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Credit Quality Parameters

Forecast Parameters:

- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCO	42-44%
CSP	45-47%
I&M	40-42%
KPCO	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings
  - FFO to Interest range of 3.7x to 4.2x
  - FFO/Total Debt range of 16% to 19%

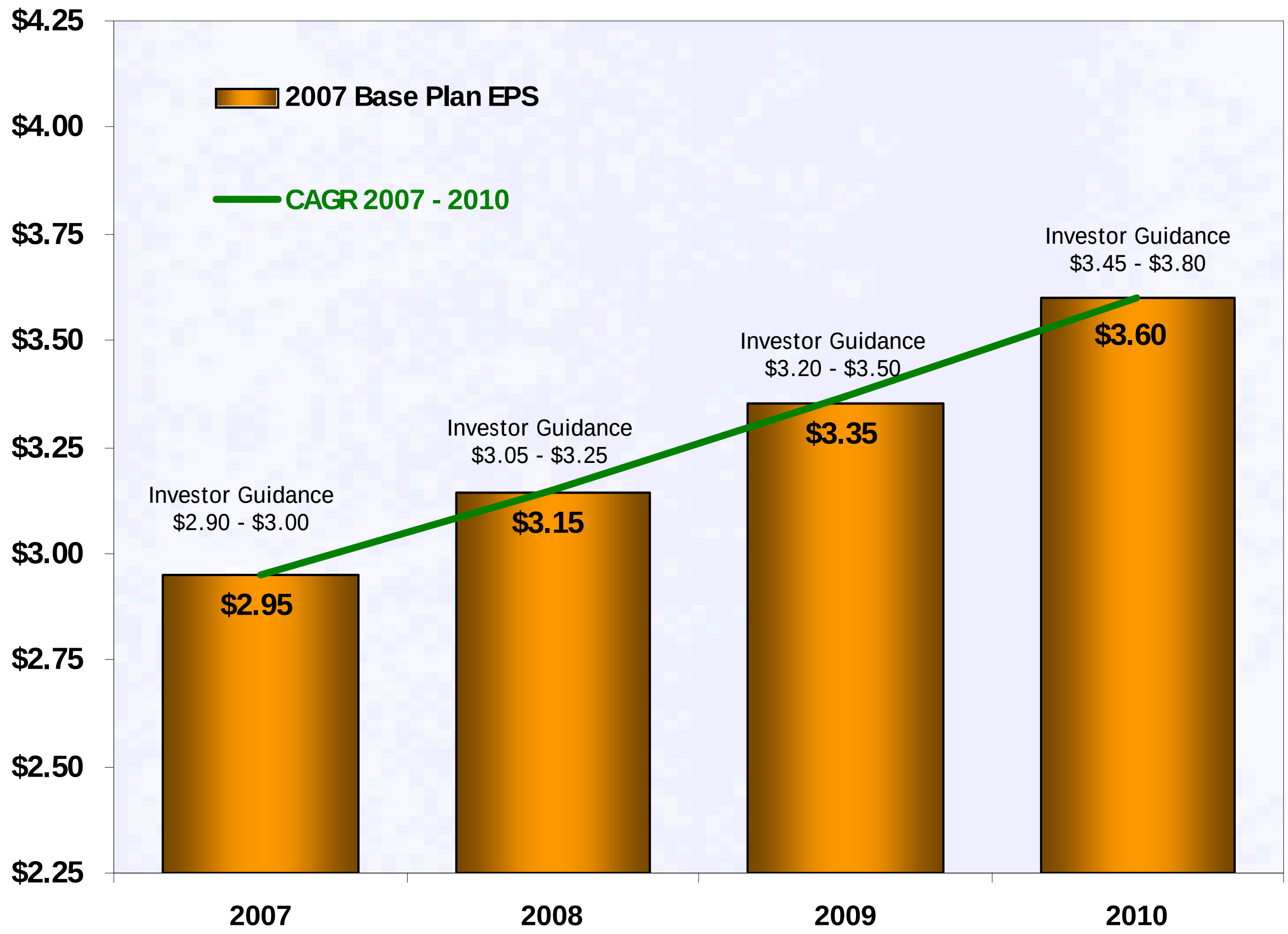
2008 Projected Cash Flow

	2007 Estimate	2008 Estimate
Beginning Cash Balance	$ 301	$ 102
Cash from Operations:		
Income from Continuing Operations	1,173	1,269
Depreciation and Amortization	1,535	1,511
Other	(655)	45
Total from Operations	2,053	2,825
Cash from Investing:		
Construction Expenditures	(3,604)	(3,860)
Asset Sales	228	-
Distressed Generation Purchases	(515)	-
Investment in Non-Consolidating Subsidiaries	(13)	(34)
Other	138	(69)
Total from Investing	(3,766)	(3,963)
Cash from Financing:		
Common Equity	150	150
Long-Term Debt Issued/(Retired)	1,334	1,789
Short-Term Debt Change, Net	529	(111)
Common Dividends	(631)	(659)
Other Financing Activities	132	(28)
Total from Financing	1,514	1,141
Net Change in Cash	$ (199)	$ 3
Ending Cash Balance	$ 102	$ 105

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation. In addition, construction expenditures include AFUDC.

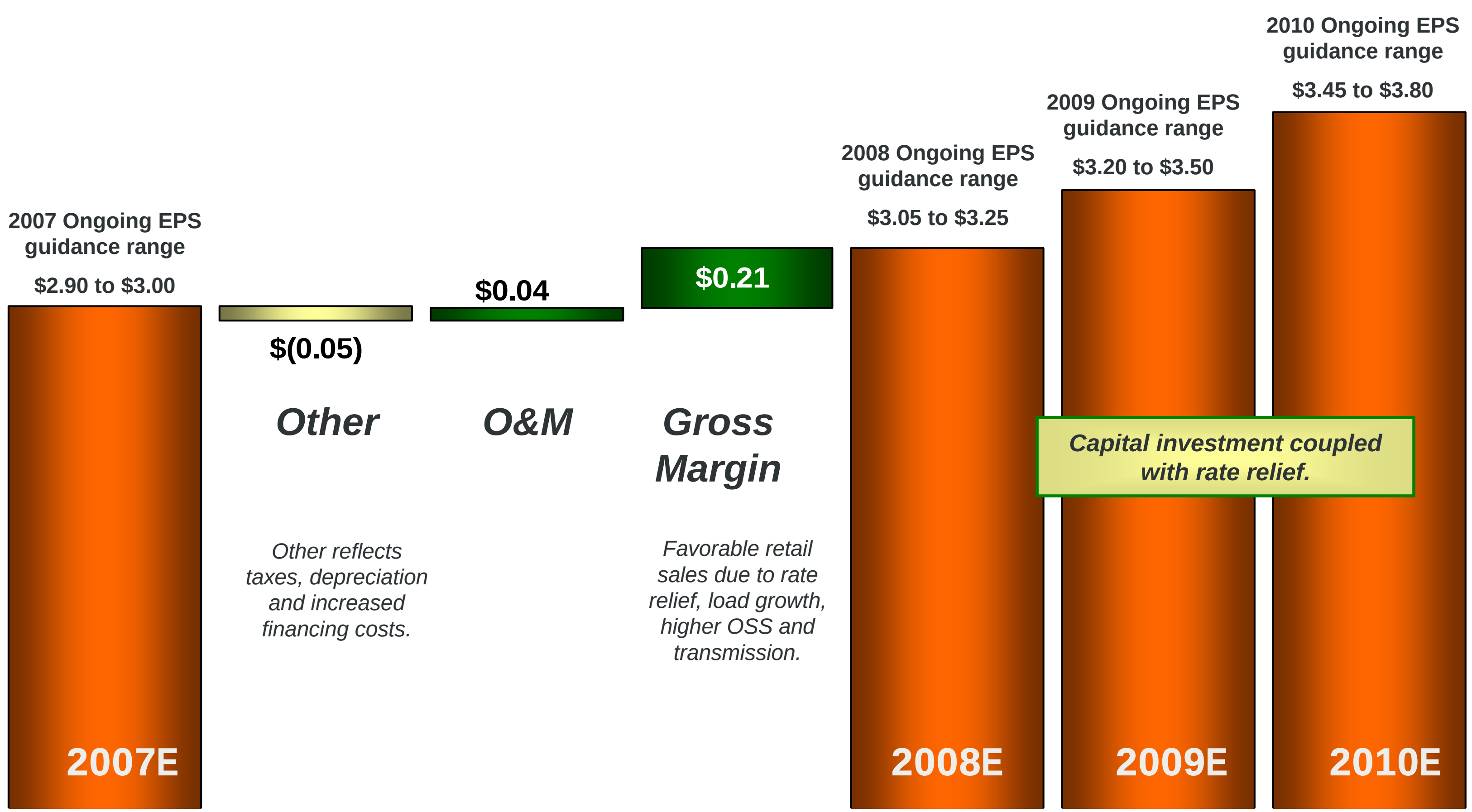
4-Year Earnings Range Forecast

STRATEGIC DIRECTION & FINANCIAL OUTLOOK



5% to 9% earnings growth and recommendation of a 4Q07 dividend increase.

Long-Range Earnings Drivers



Traditional utility factors will drive earnings

AEP®

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Transmission Revenue - 3rd Party		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

2008 Earnings Guidance

STRATEGIC DIRECTION & FINANCIAL OUTLOOK

		2007 Guidance ($ millions)	2008 Guidance ($ millions)
	UTILITY OPERATIONS:		
	Gross Margin:		
1	East Regulated Integrated Utilities	2,440	2,425
2	Ohio Companies	2,433	2,497
3	West Regulated Integrated Utilities	1,046	1,111
4	Texas Wires	520	536
5	Off-System Sales	617	642
6	Transmission Revenue - 3rd Party	276	331
7	Other Operating Revenue	627	545
8	Utility Gross Margin	7,959	8,087
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12	Interest Exp & Preferred Dividend	(773)	(864)
13	Other Income & Deductions	101	191
14	Income Taxes	(566)	(582)
15	Utility Operations On-Going Earnings	1,117	1,237

Performance Drivers

Retail Sales (lines 1-4):
- Positive load growth - $132MM
- Continued rate relief - $228MM
- Offset by fuel and PJM costs - $(186)MM

Off-System Sales (line 5):
- Increase due to slightly higher margins

Transmission Revenue (line 6):
- Higher rates in ERCOT, PJM and SPP

Other Operating Revenue (line 7):
- Lower revenues from third party work, primarily offset in line 9 - O&M

Operations & Maintenance (line 9):
- Continued emphasis on cost control

Interest Expense (line 12):
- Increased long term debt outstanding

Other Income & Deductions (line 13):
- Additional 2008 APCo E&R carrying charges & AFUDC, offset by elimination of Centrica earnings sharing mechanism in 2008

Income Taxes (line 14):
- Higher pre-tax income, offset by change in effective tax rate. Effective tax rate for utility operations is 33.6% in 2007 and 32.0% in 2008.

2008 Earnings Guidance

	2007 Guidance ($ millions)	2008 Guidance ($ millions)
TRANSMISSION OPERATIONS	-	5
NON-UTILITY OPERATIONS:		
MEMCO	67	57
Generation & Marketing	29	21
Non-Utility Operations On-Going Earnings	96	78
Parent and Other On-Going Earnings	(40)	(51)

Performance Drivers

Transmission Operations:

- Equity earnings contribution from Electric Transmission Texas LLC

MEMCO:

- Decrease due to increasing costs and reduced import/northbound river traffic

Generation & Marketing:

- Decrease due to divestiture of Sweeny in 4Q07

Parent & Other:

- Increase loss due primarily to interest expense related to hybrid securities issued at the parent

Performance Sensitivities

Driver	Change	Effect
EPS Sensitivities		
Load Growth (MWh)	1%	$0.10 EPS
Utility O&M	1%	$0.05 EPS
Capital Spending	$250M	$0.03 EPS
Unit Availability	1%	$0.04 EPS
ECAR Power Price	$1/MWh	$0.04 EPS
Fuel and Purchased Power	1%	$0.03 EPS
Henry Hub Gas Price	5%	$0.07 EPS
Interest Rate (20% floating debt)	100 BPs	$0.05 EPS
Authorized ROE	**1%**	**$0.24 EPS**

Longer term performance can be substantially enhanced by achieving a higher authorized return.

Financial Forecast Highlights

- **Updated 2008 & 2009 earnings guidance ranges and introduction of 2010**

2007 Range $2.90 to $3.00	**2008 Range $3.05 to $3.25**
2009 Range $3.20 to $3.50	**2010 Range $3.45 to $3.80**

- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Ohio: Continue momentum toward market
  - Cost management
- Commitment to recommend an 8-cent/share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Refined capital investment forecast and introduction of 2010 level

2007E: $3,962 MM	**2008E: $3,770 MM**
2009E: $3,600 MM	**2010E: $3,401 MM**

- Maintain credit ratings: BBB/Baa2/BBB

Value Proposition

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Sustainable Business Model

AEP AMERICAN ELECTRIC POWER®

Morgan Stanley Utilities Conference
New York, NY
March 11, 2010

Mountaineer Plant (WV)

345-kV Transmission Line

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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Lisa Barton – VP, Transmission Strategy & Business Development

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AEP Value Proposition

Regulated Utility Platform

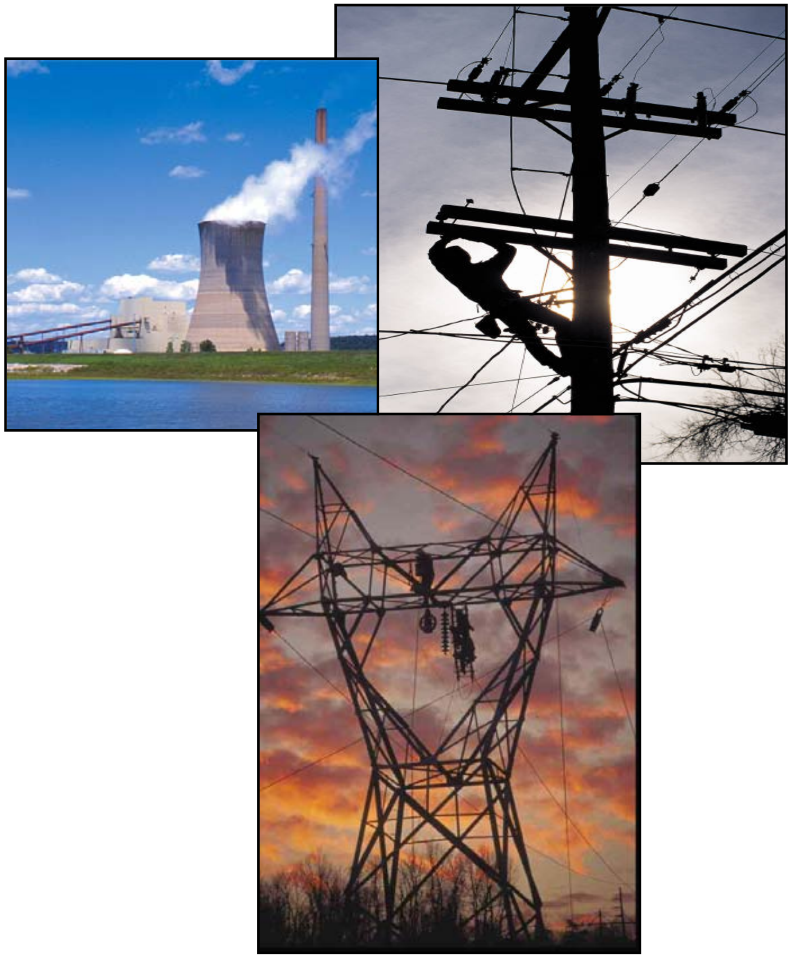
- Diversified service territory
- Successful regulatory track record
- Value compared to regulated peer group

Earnings Growth Prospects

- Investment in utility platform greater than depreciation level (2 - 4%)
- With transmission opportunities (4 - 8%)

Attractive Yield Opportunity of 4.8%[1]

- 50-60% payout ratio targeted
- Nearly a century of dividend payments to shareholders



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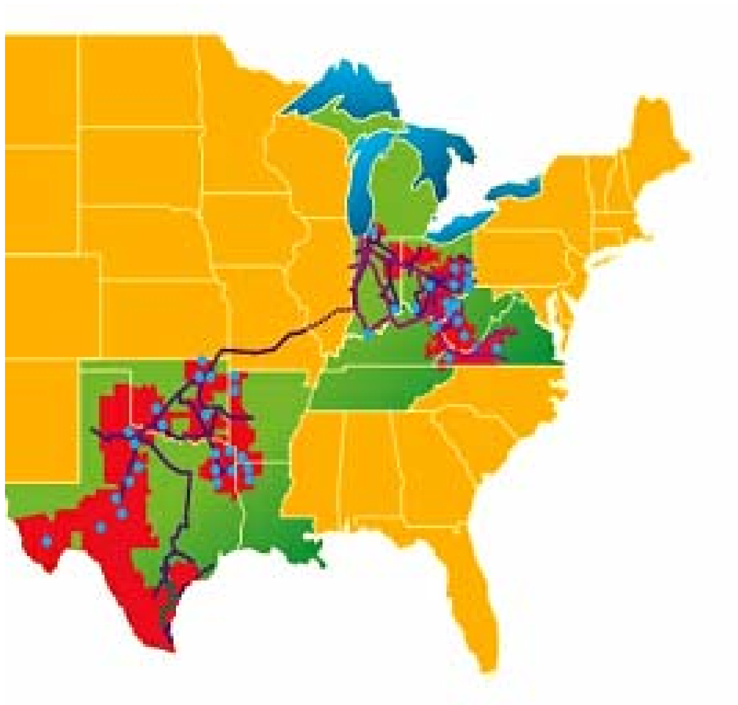
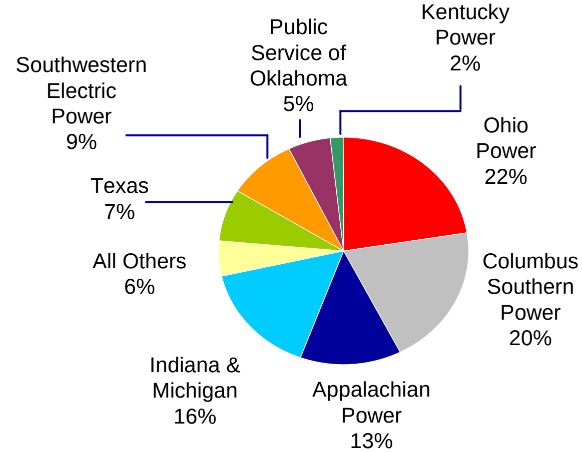
[1] yield percentage based on AEP closing price of $34.12 on 03/09/2010

Highly Diversified Regulated Utility Platform

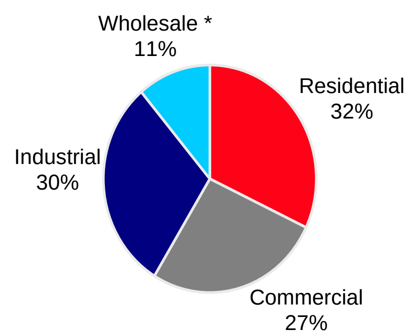


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

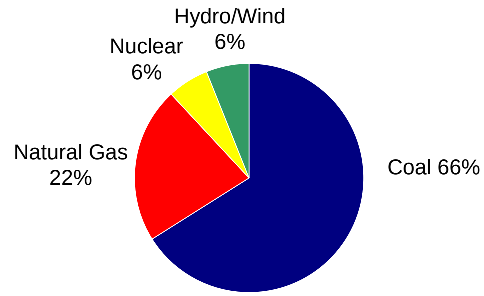


2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
- Robust pipeline of projects up to $15B

765-kV Tower

AEP AMERICAN ELECTRIC POWER

JV Strategy – Nationwide Grid Expansion

SPP

Prairie Wind — COD: 2013-14
- 110 miles of 765 kV
- Partners: Westar (50%) & Electric Transmission America (50%)
- Estimated Cost: $400 million
- ROE: 12.8%

Tallgrass — COD: 2013-14
- 170 miles of 765 kV
- Partners: OG&E (50%) & Electric Transmission America (50%)
- Estimated Cost: $500 million
- ROE: 12.8%

ERCOT

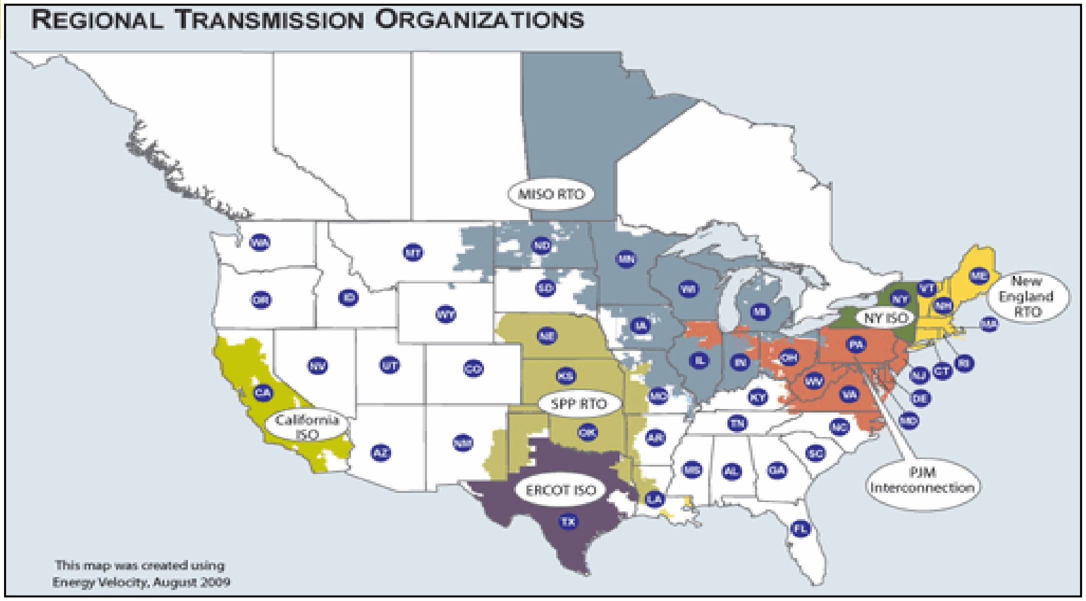
ETT — COD: 2010-2017
- 345 kV ERCOT Expansion
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $1.4 billion
- ROE: 9.96%

PJM

PATH-WV — COD: 2014
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

PJM/MISO

Pioneer — COD: 2015
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%



ACTIVE PROJECTS

FUTURE DEVELOPMENT

SMARTransmission Study
- Interregional EHV & Wind Integration Study
- Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy

SPP EHV Overlay
- Regional Expansion of 765 kV Backbone

ETT — COD: various
- Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)
- Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)

PJM Expansion
- Regional Expansion of 765 kV, 500 kV and 345 kV systems

EHV Michigan/Ohio
- 700 miles of Proposed 765 kV

SPP | ERCOT | PJM | PJM/MISO

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Electric Transmission Texas, LLC

Overview:

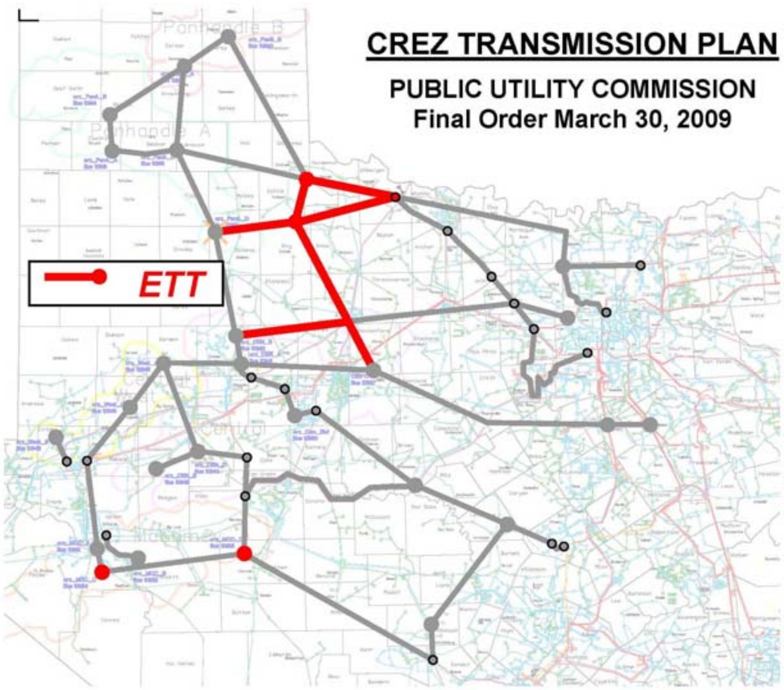
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2017: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects pending transfer in service 2010-2013: $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

AEP AMERICAN® ELECTRIC POWER

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

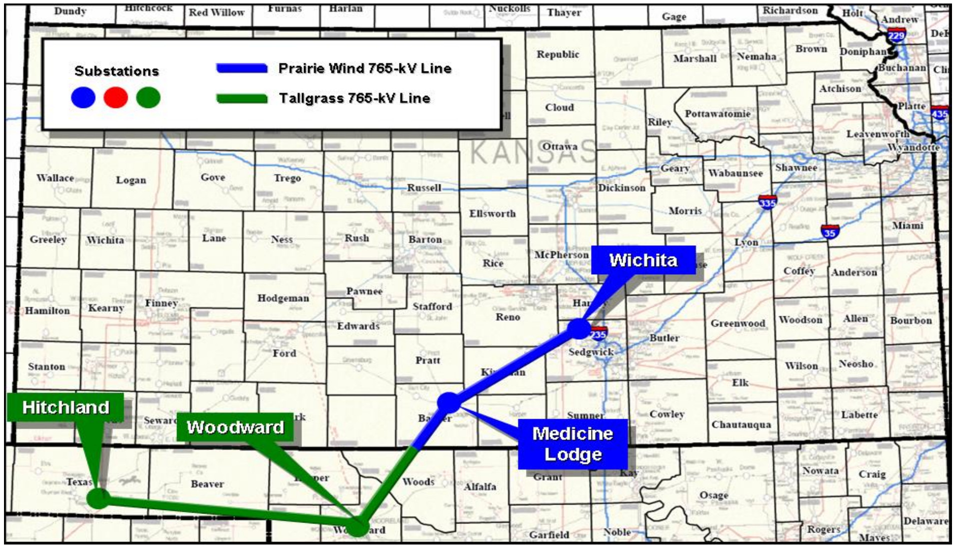
PATH
Potomac-Appalachian Transmission Highline

AEP AMERICAN® ELECTRIC POWER

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

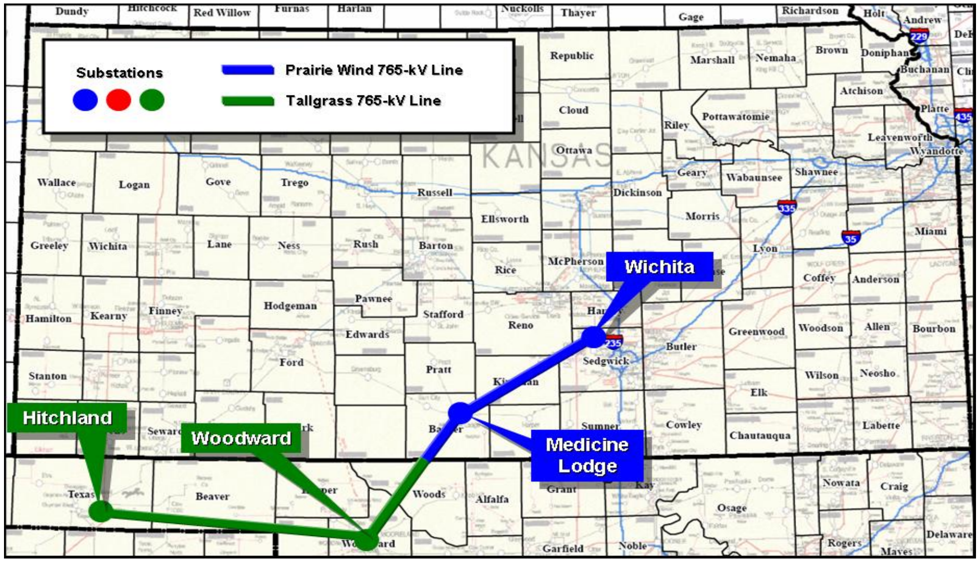
Key Challenges:

- RTO Approval
- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

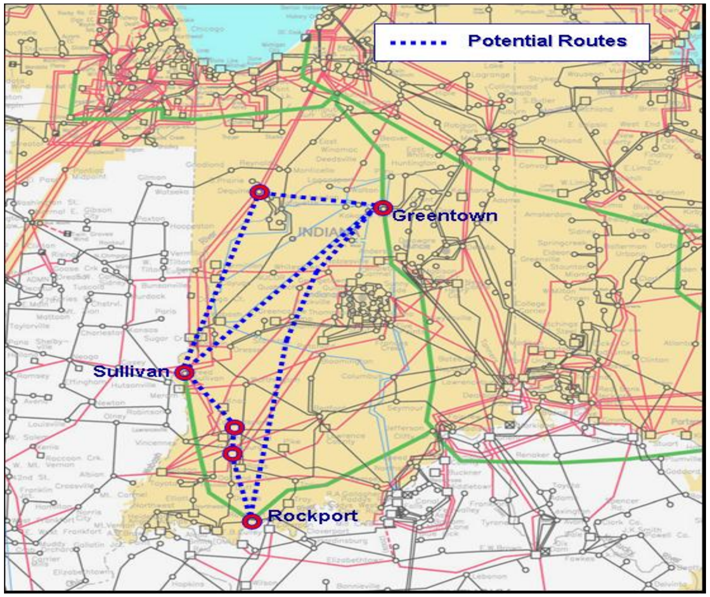
- RTO Approval
- Siting

AEP AMERICAN ELECTRIC POWER

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

AEP AMERICAN ELECTRIC POWER®

Upper Midwest EHV Development—SMART Study

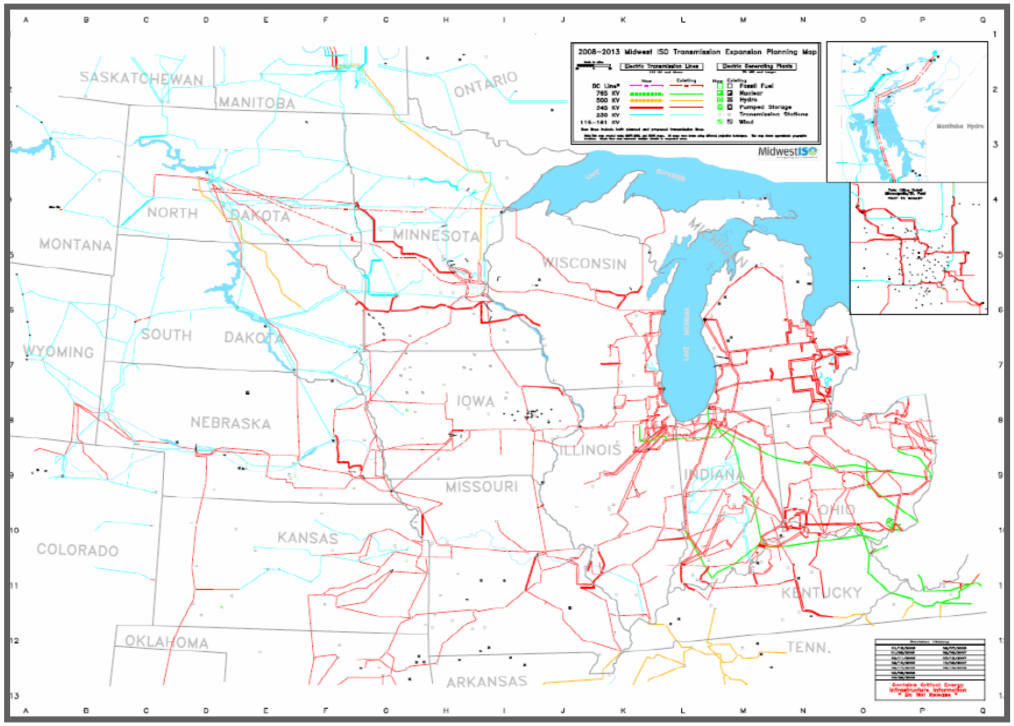
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2nd Qtr 2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives

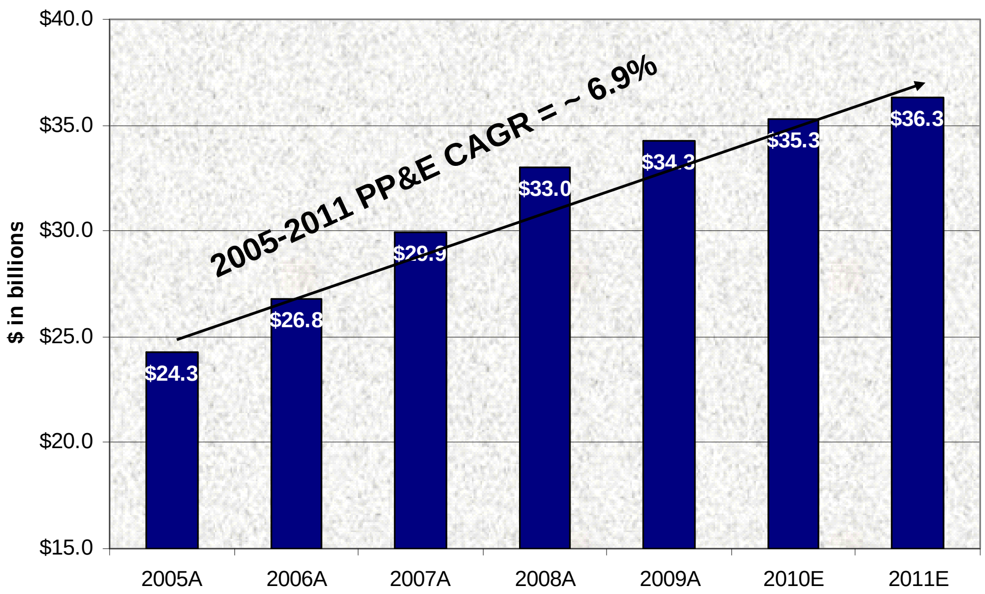


Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

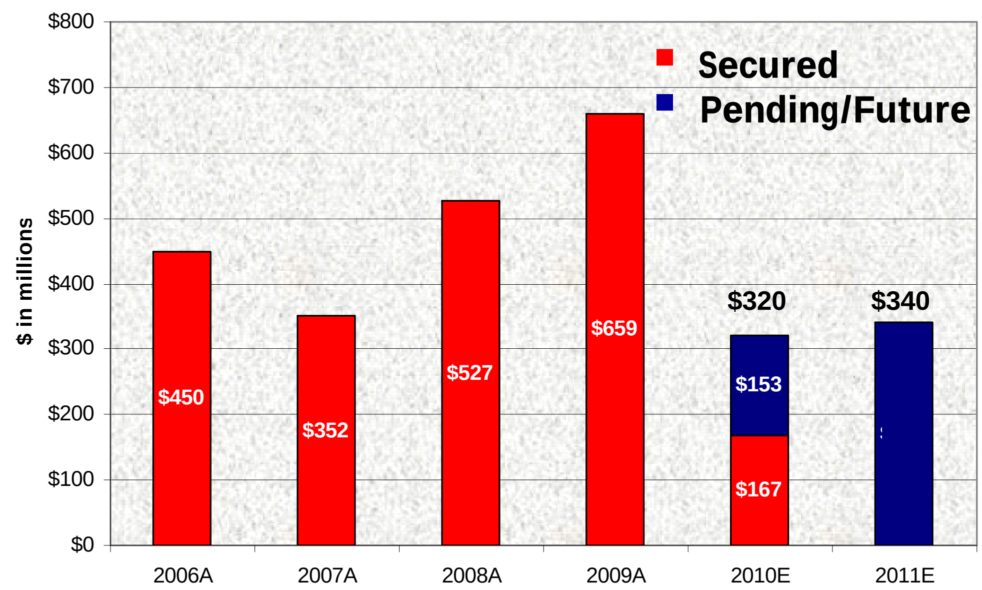
AEP AMERICAN ELECTRIC POWER

Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

AEP AMERICAN® ELECTRIC POWER

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

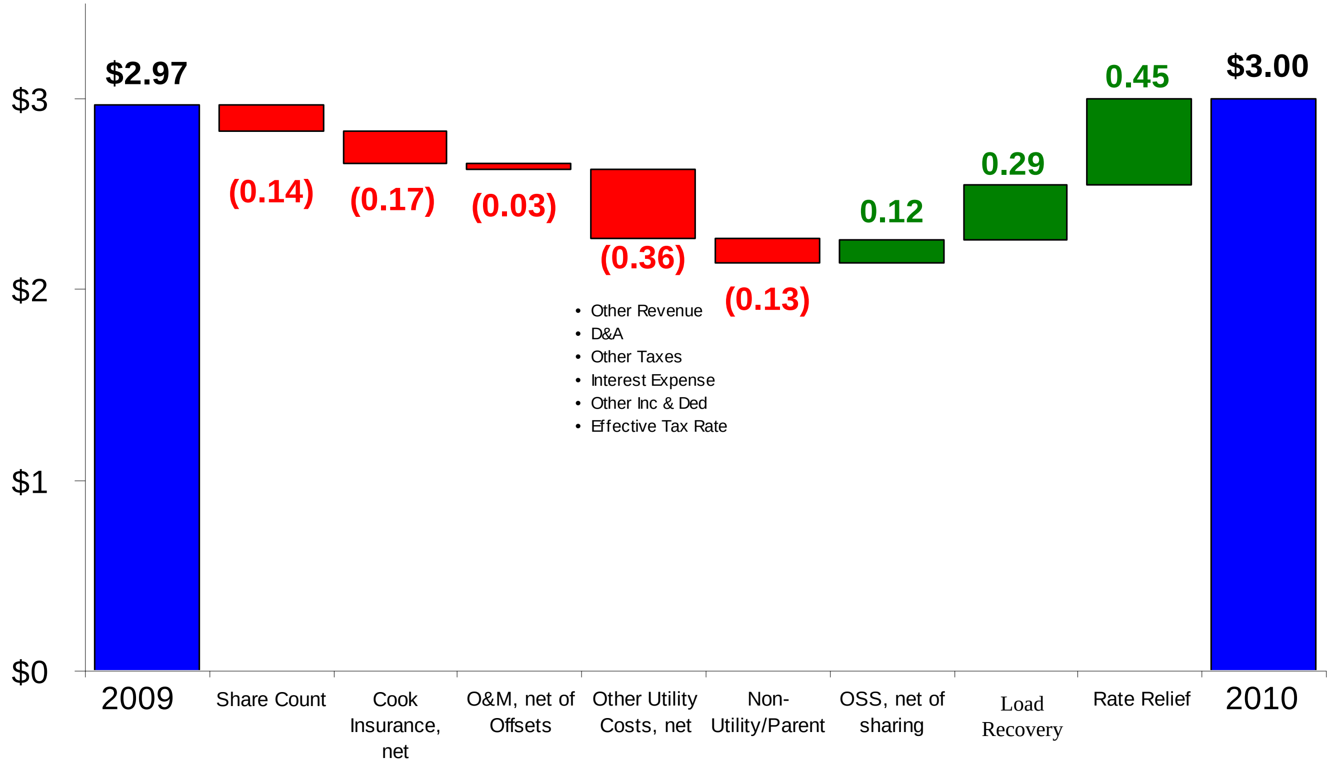
($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

AEP AMERICAN® ELECTRIC POWER

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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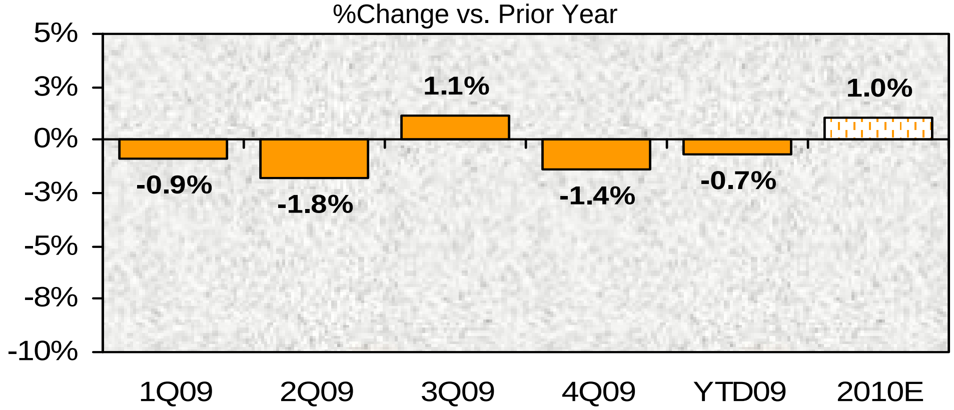
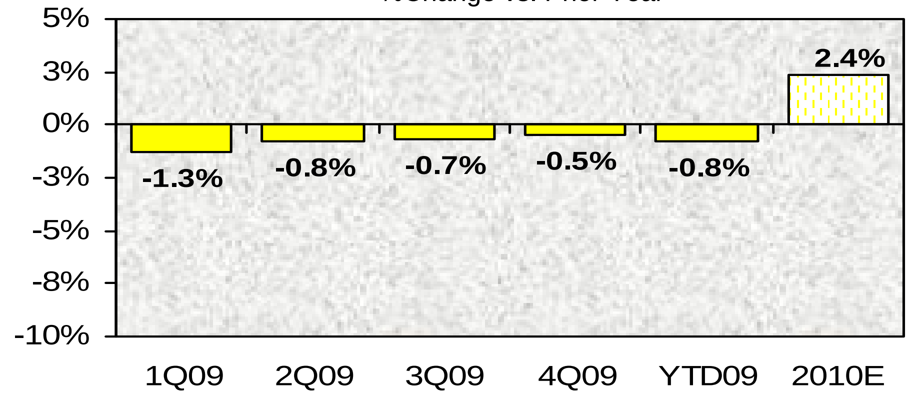
Normalized Load Trends

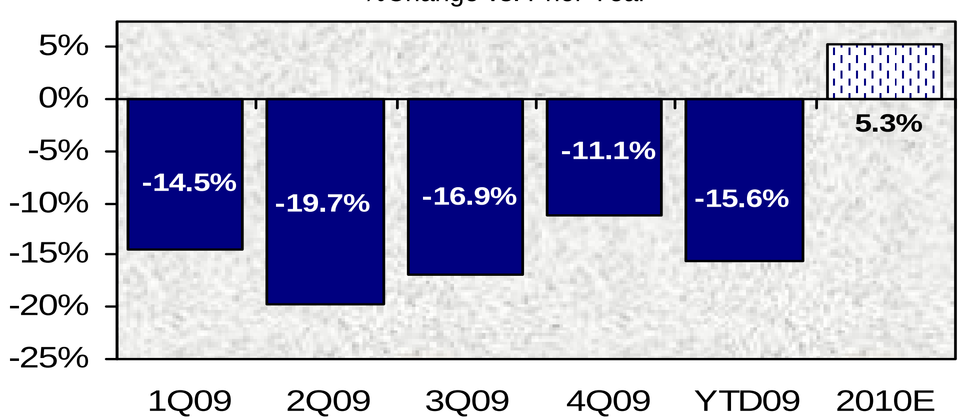
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



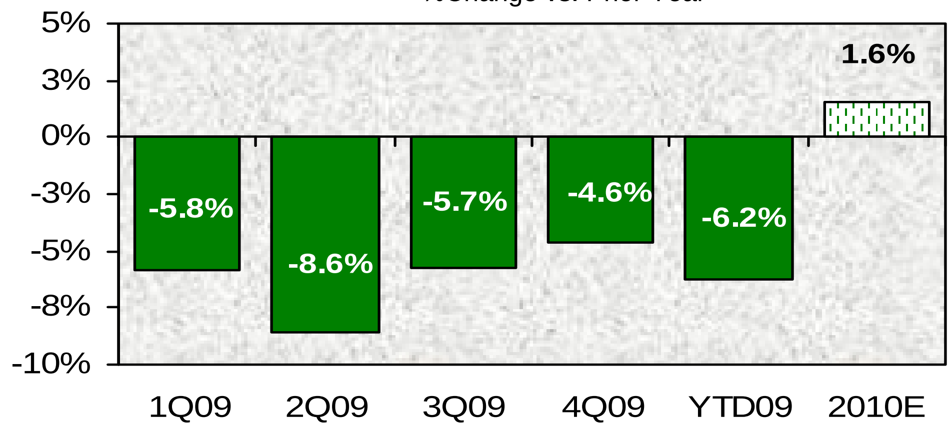
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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Additional 2010 Earnings Drivers

O&M Assumptions

- **$23MM increase over 2009, net of revenue offsets**
- **Includes $80MM increase in employee and operational expenses**

Rate Relief Assumptions

- **$320MM, net of trackers**
- **$167MM secured**
  - **AR, OH, OK, VA, WV**
- **Active or pending rate cases include KY, MI, TX, VA, WV and others**

AEP AMERICAN® ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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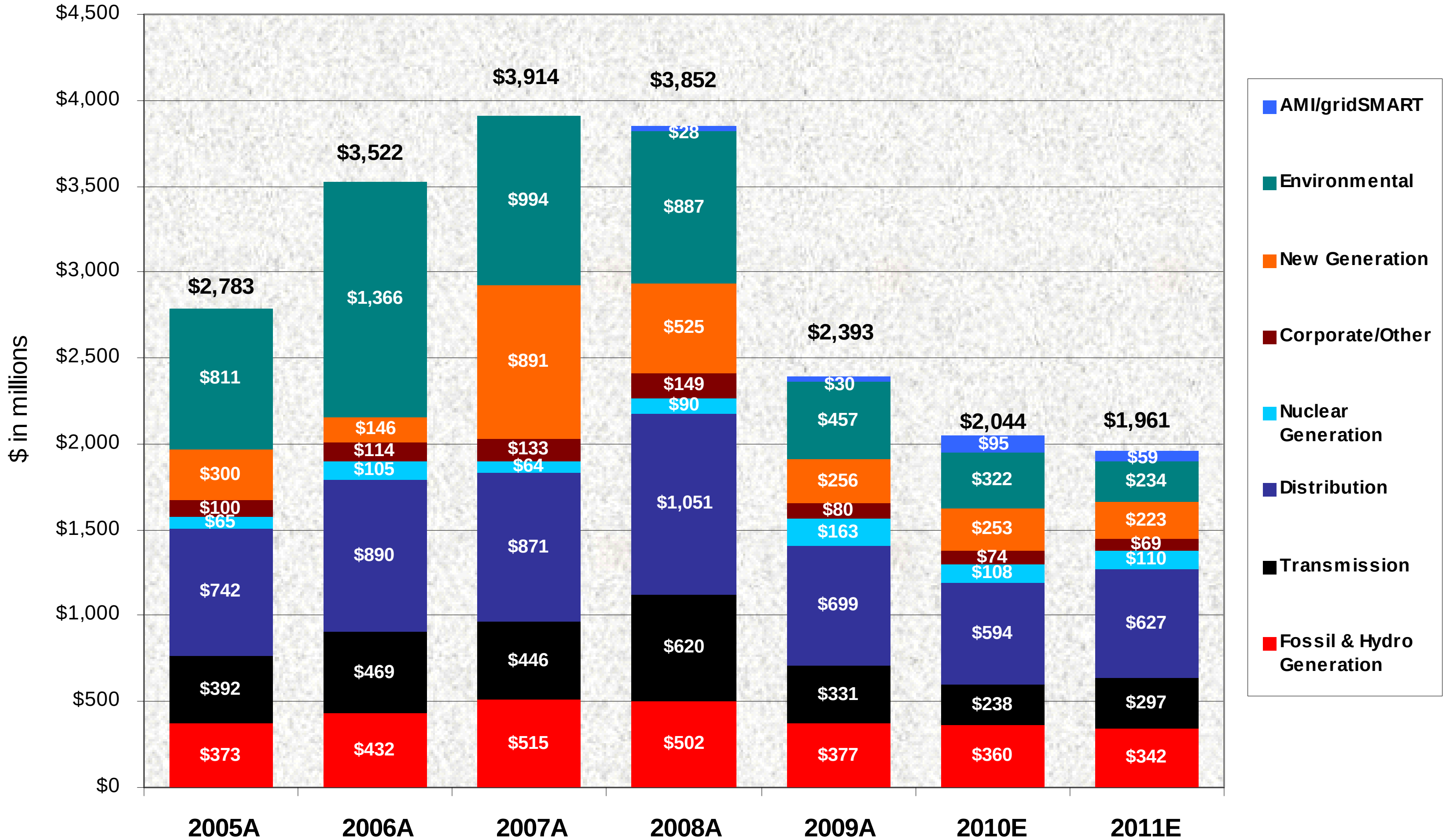
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

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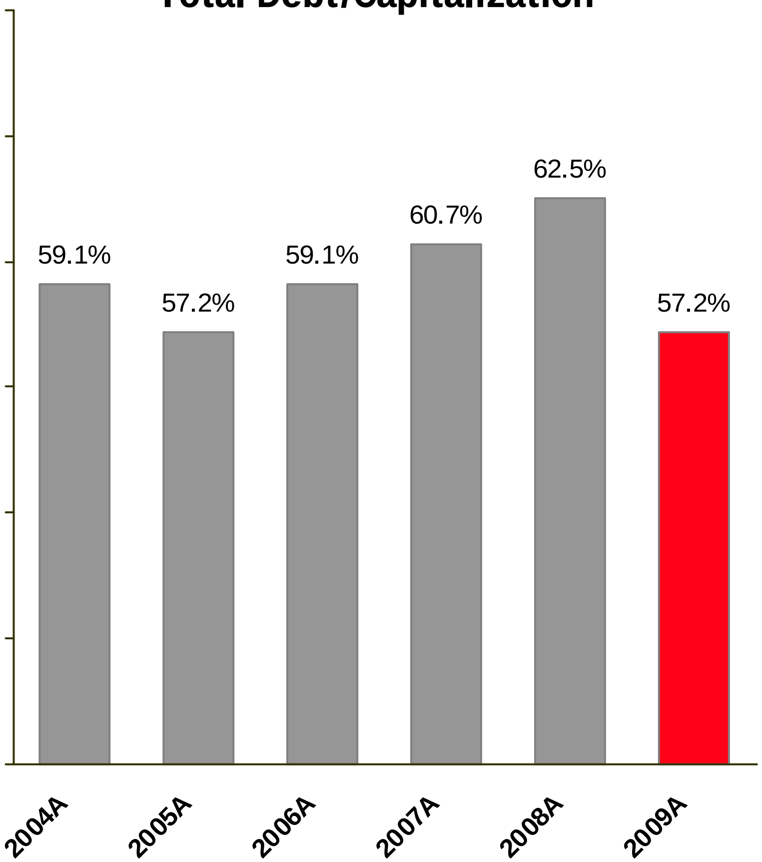
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN ELECTRIC POWER®

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

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Long-term Debt Maturity Profile

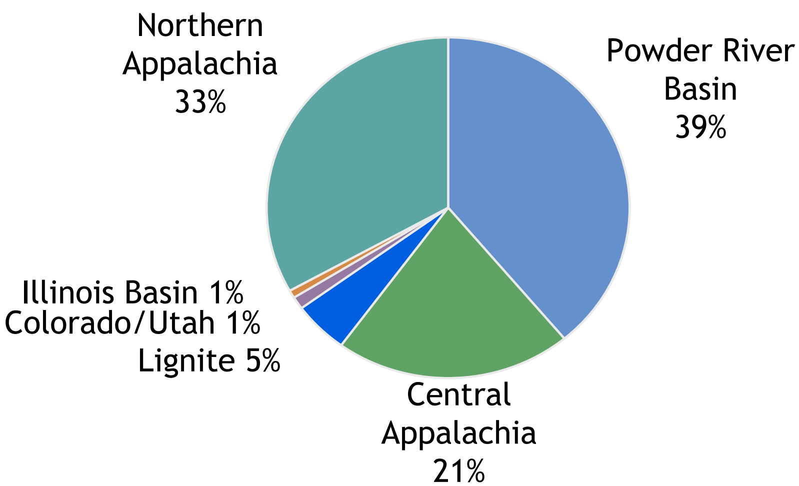
($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ 490	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 45
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 679	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company(1)	$ 66	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,585	$ 623	$ 415

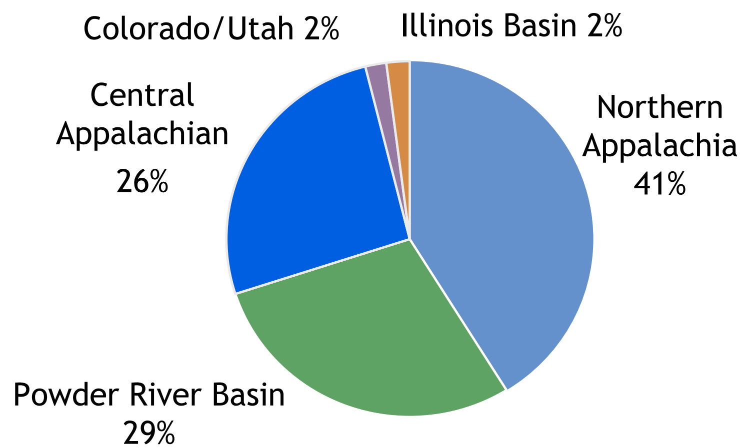
(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

Coal Procurement - 2010 Projected

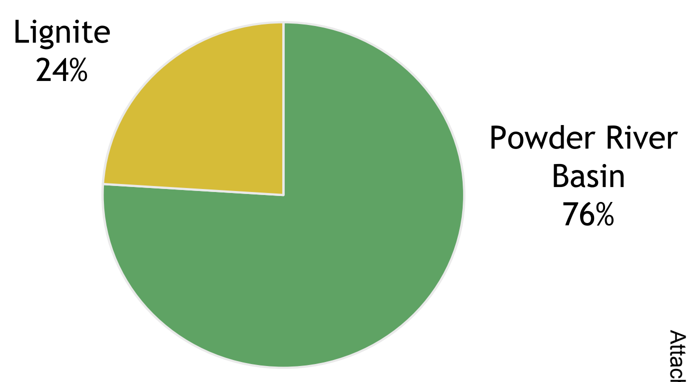
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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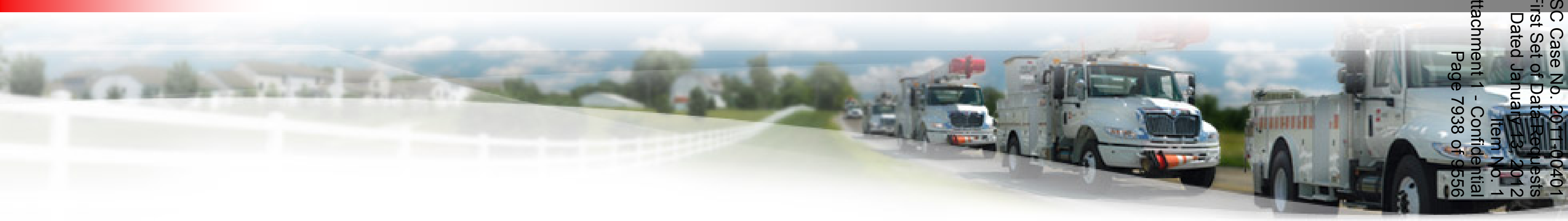
Morgan Stanley Office Visit February 28, 2011



“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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  - Operating Company Model
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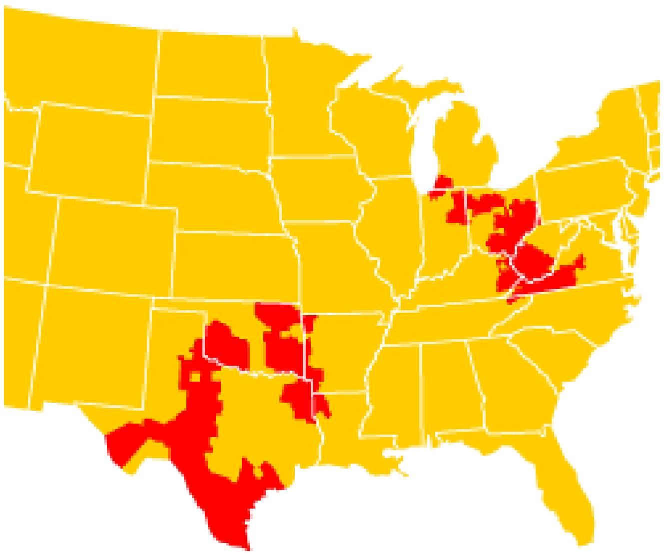
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- **Strong Balance Sheet**
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- **Growth Opportunities**
  - Capital for utility platform
  - Transmission projects
- **Dividend yield of 5%**

Serving electric customers in 11 states



AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$17.7B Market Capitalization
BBB/Baa2/BBB credit rating

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Capital for Growth
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012

- Return of Capital to Shareholders
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings

- Capital to Reduce Risk
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Managing Operations and Investment

AEP®

Challenges:

Required refinement of the operating company model and improved line-of-sight management due to decreased load growth, regulatory lag, reduced rate headroom, and environmental challenges

Actions:

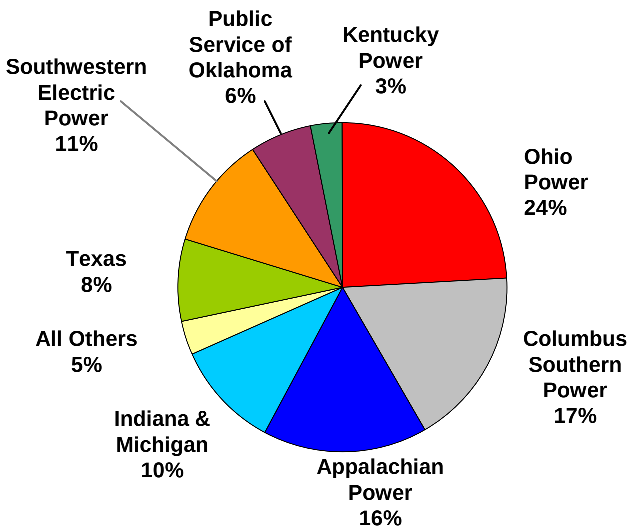
- Empower operating company employees to drive results
- Efficiently allocate capital
- Demonstrate O&M and capital expenditure discipline
- Identify asset renewal strategy for investing in traditional distribution and transmission assets that enhance reliability and customer satisfaction
- Enable long-term planning discussions with regulators and legislators

Expected Outcomes:
Optimize spending for more efficient return on investment
Improve dialogue with customers and regulators
Minimize lag in rate recovery

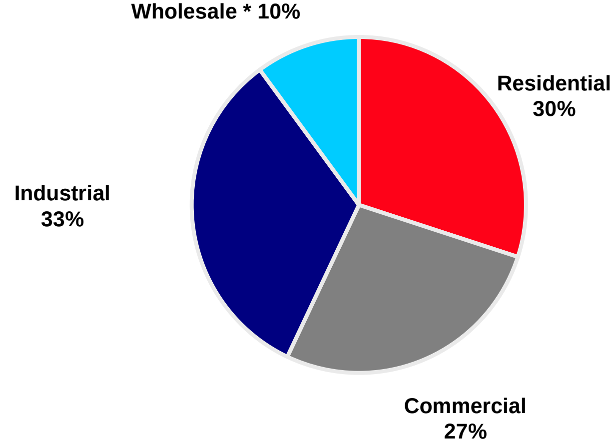
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



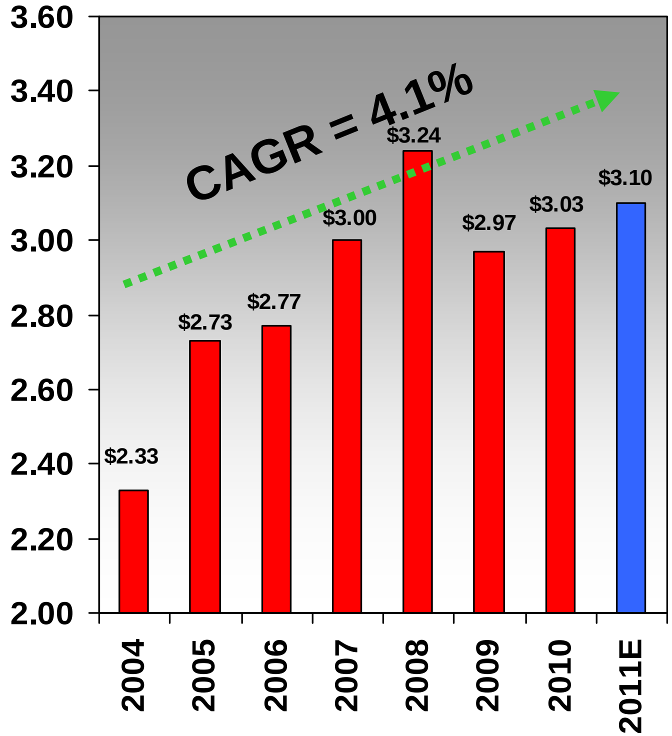
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

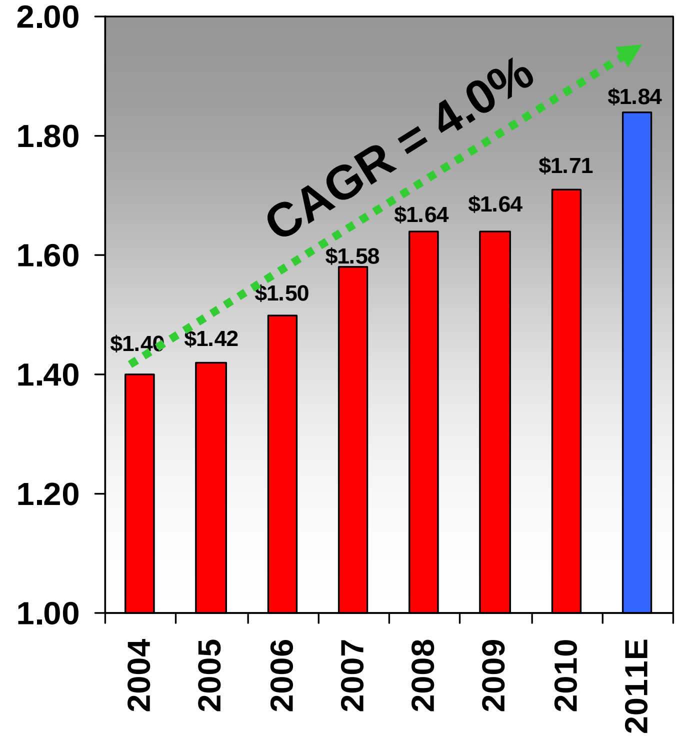
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



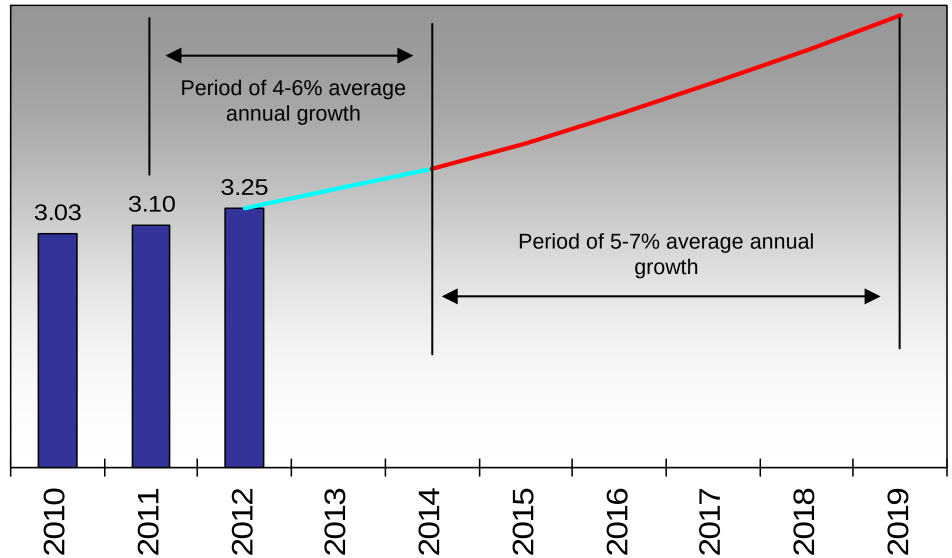
= subject to Board of Directors approval

- Dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend declared in January 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

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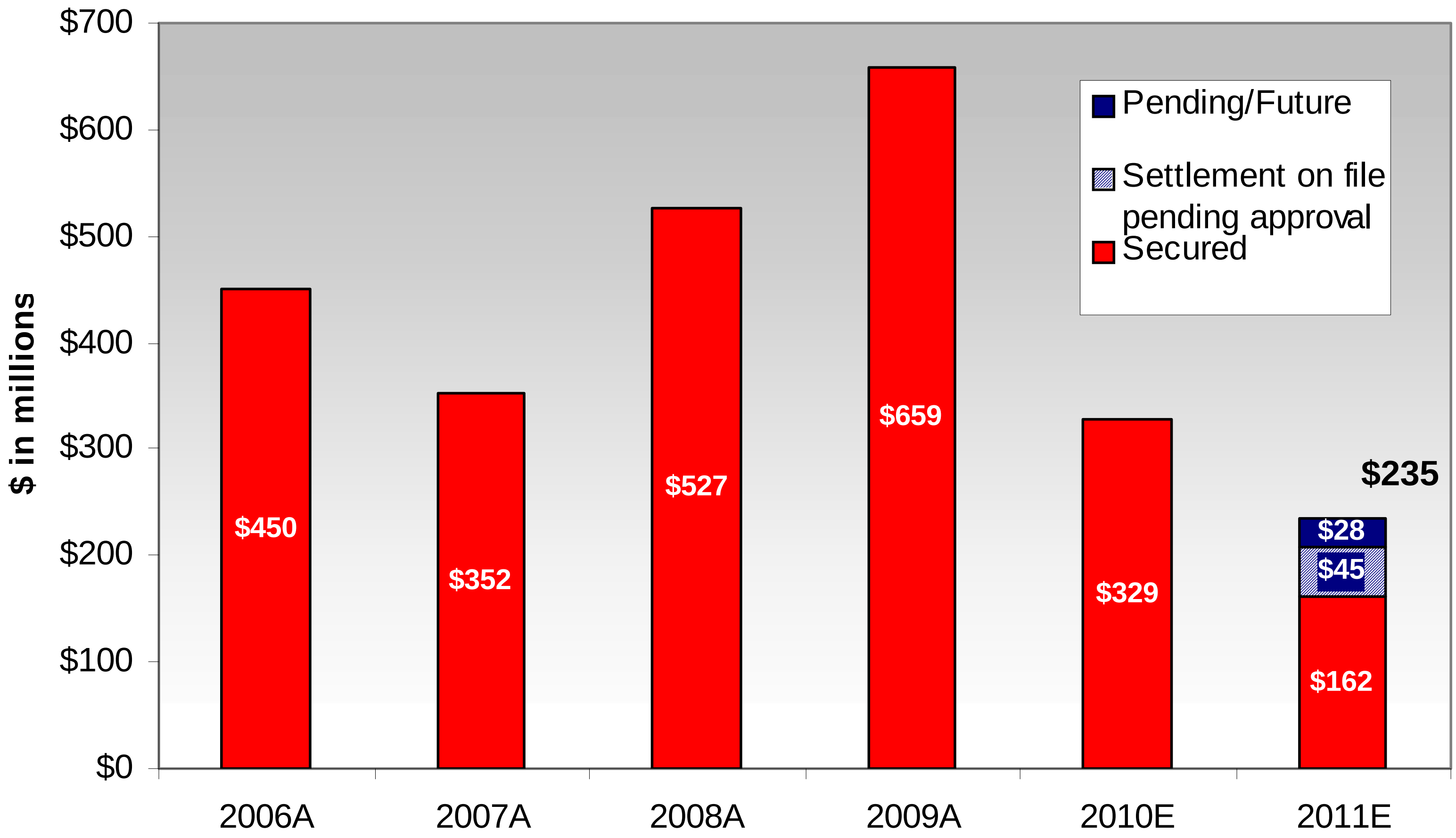
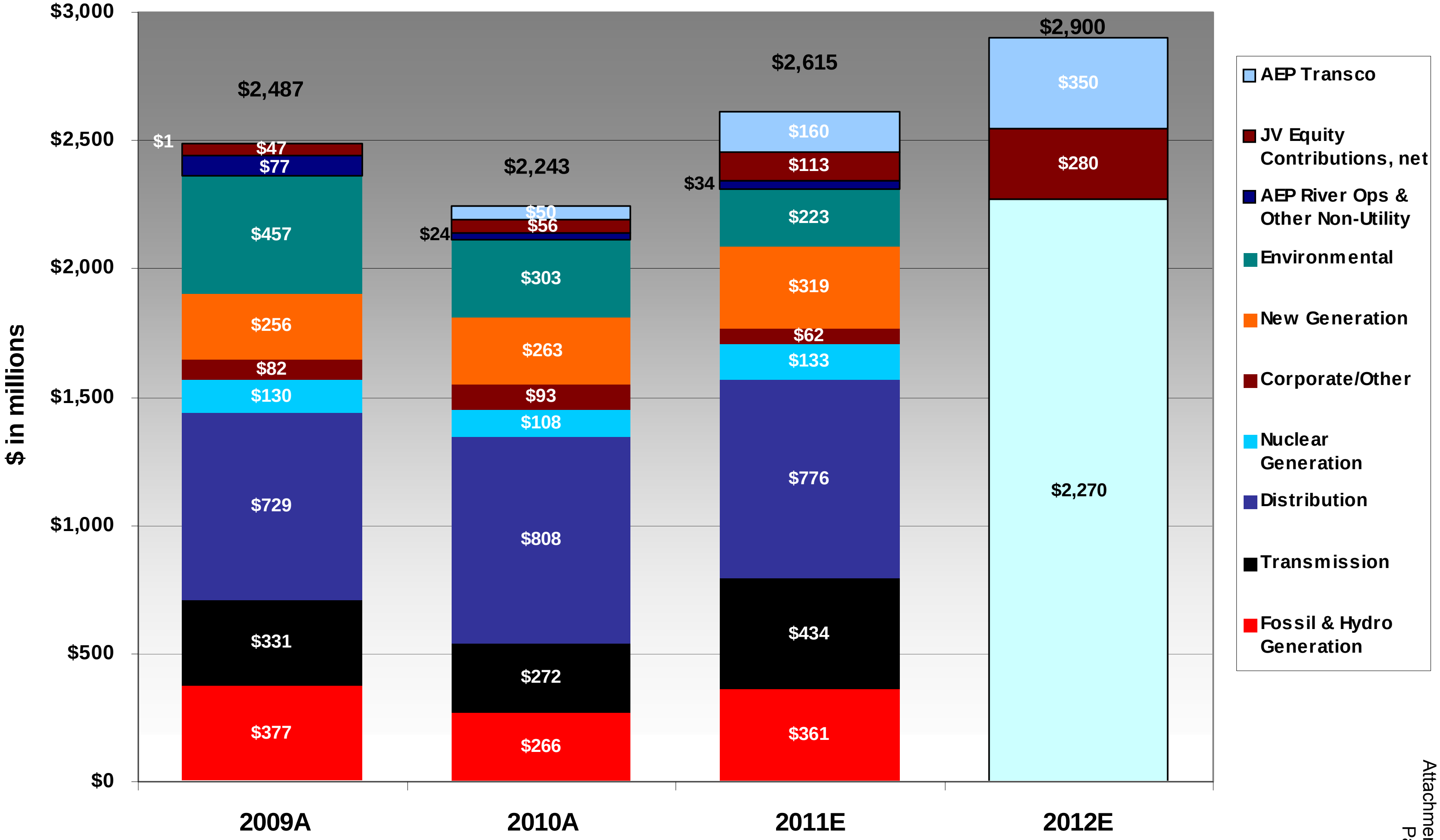
Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Active or pending rate cases include West Virginia and others yet to be filed

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Cash Flow Guidance

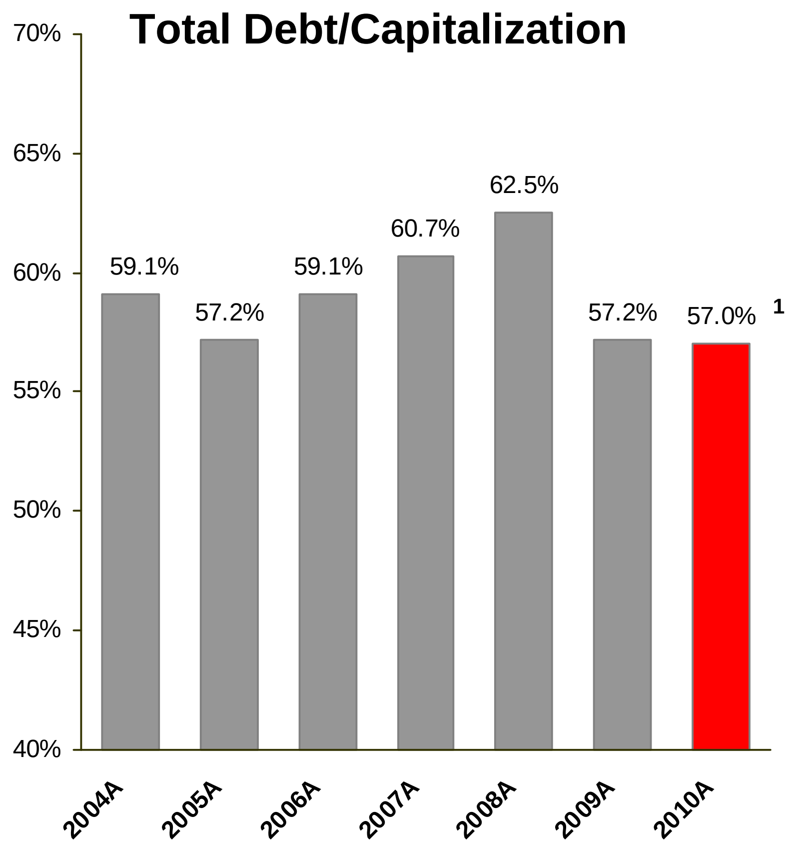
AEP®

	2010A	2011E
	$ in millions	
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to September 30, 2010 10Q *Enron Bankruptcy* pages 56-57 for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Detailed Ongoing Earnings Guidance

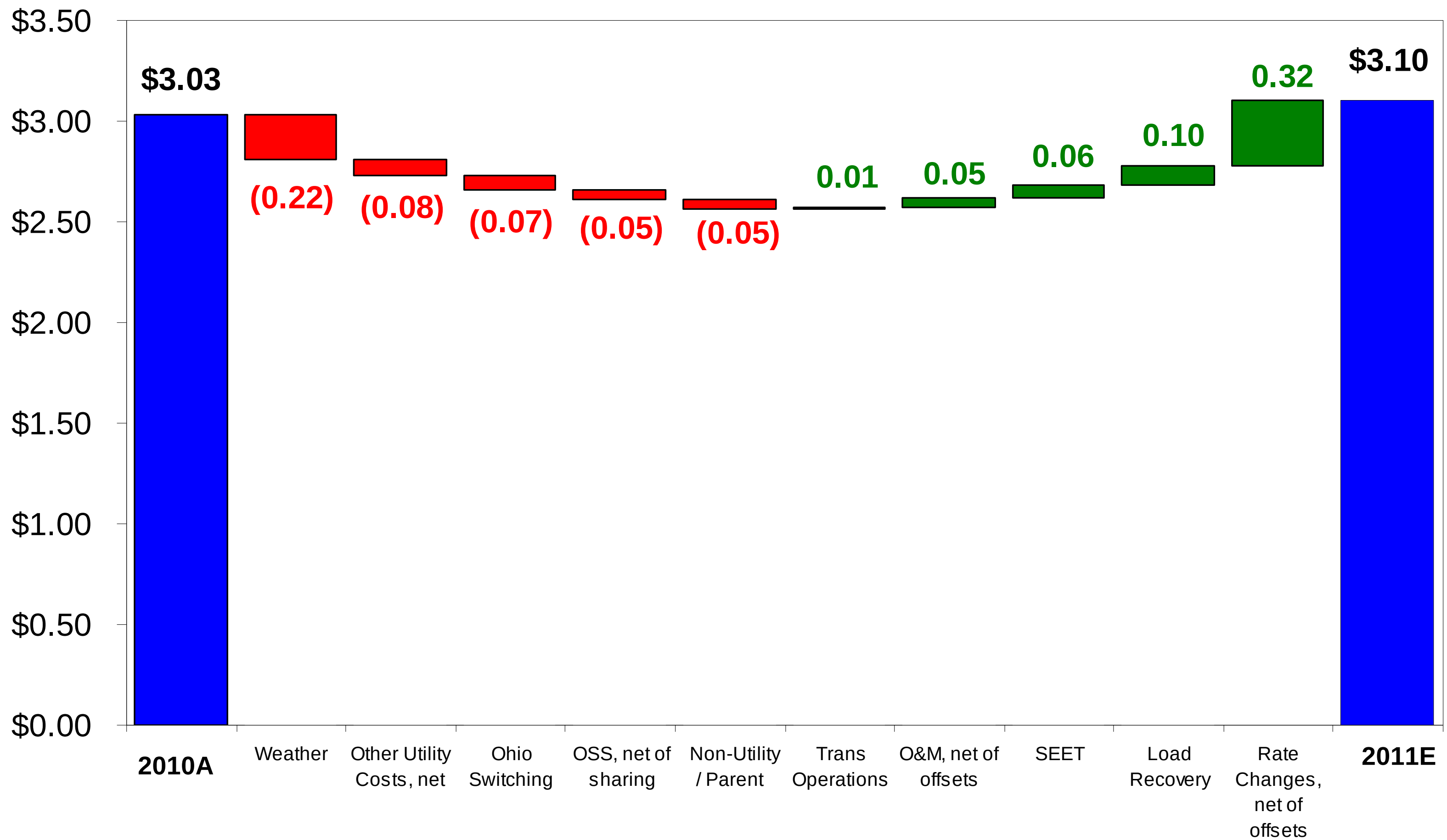
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

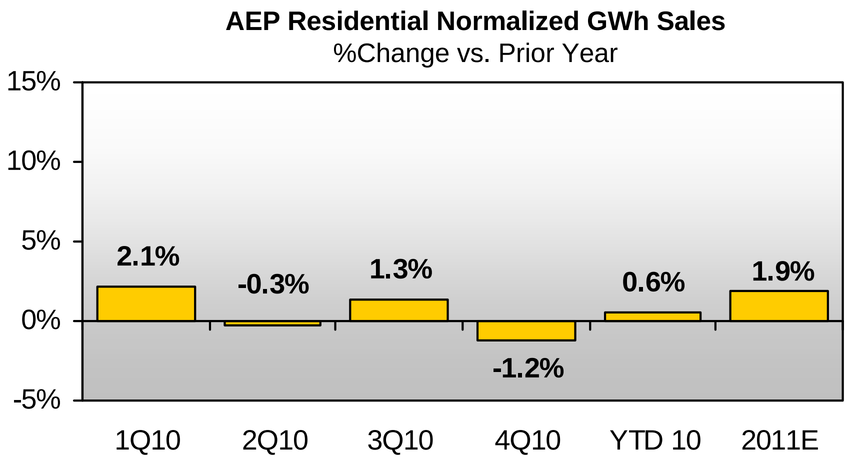
2011 Earnings Drivers

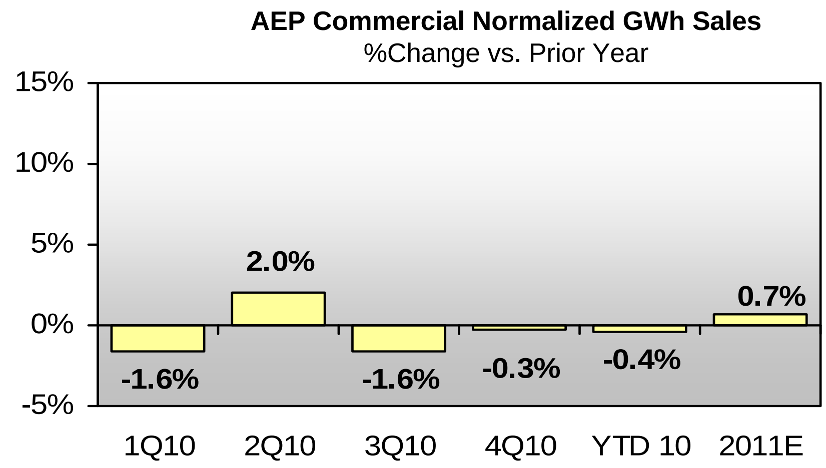


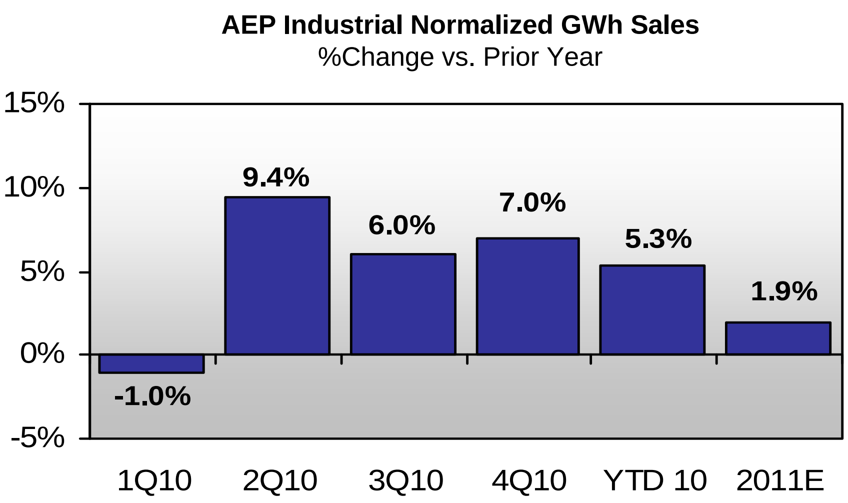
- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

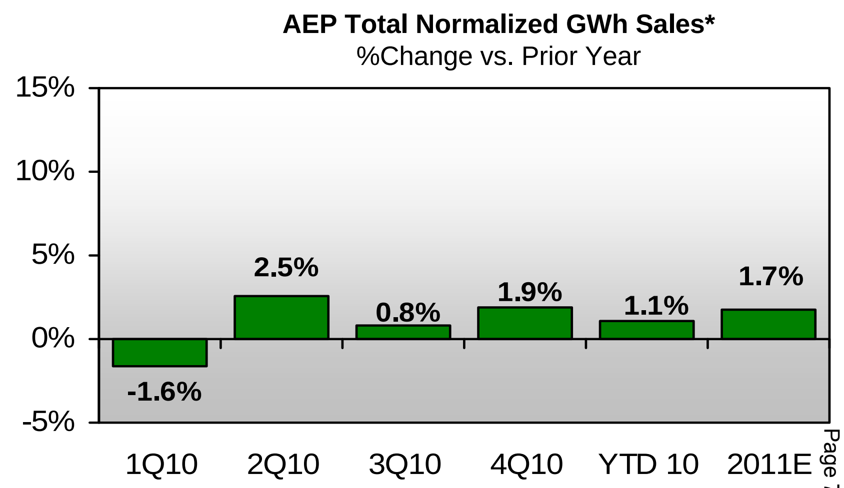
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends









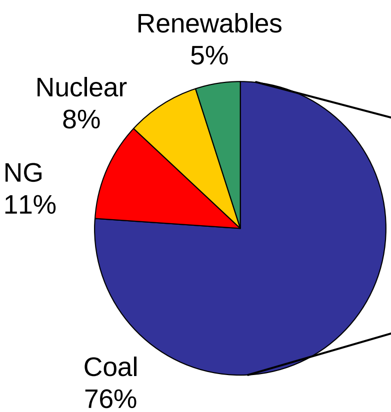
*includes firm wholesale load

Note: Chart represents connected load

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



Coal Source

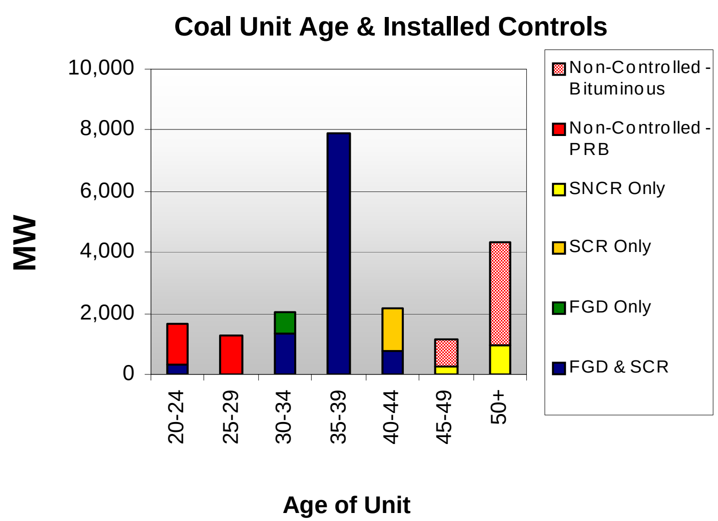
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost

2009A - $56/ton

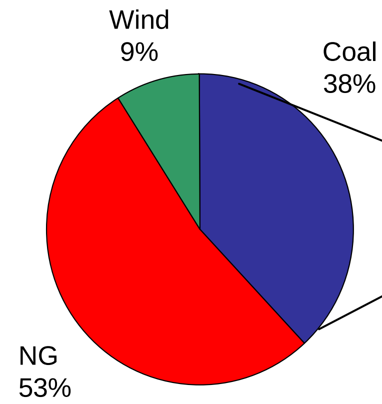
2010A - $52/ton

2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind



Coal Source

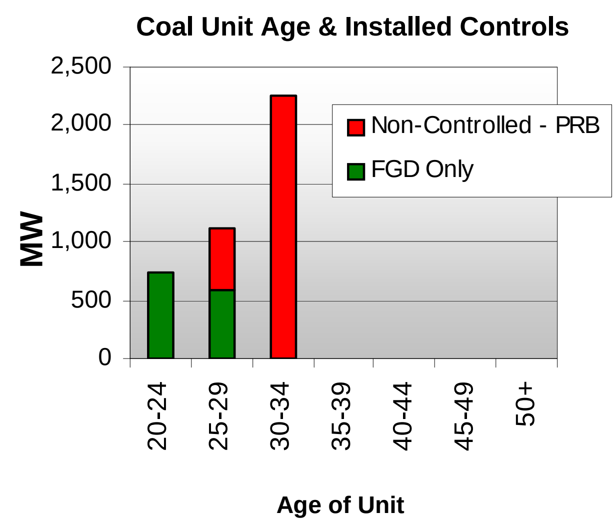
PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton

2010A - $29/ton

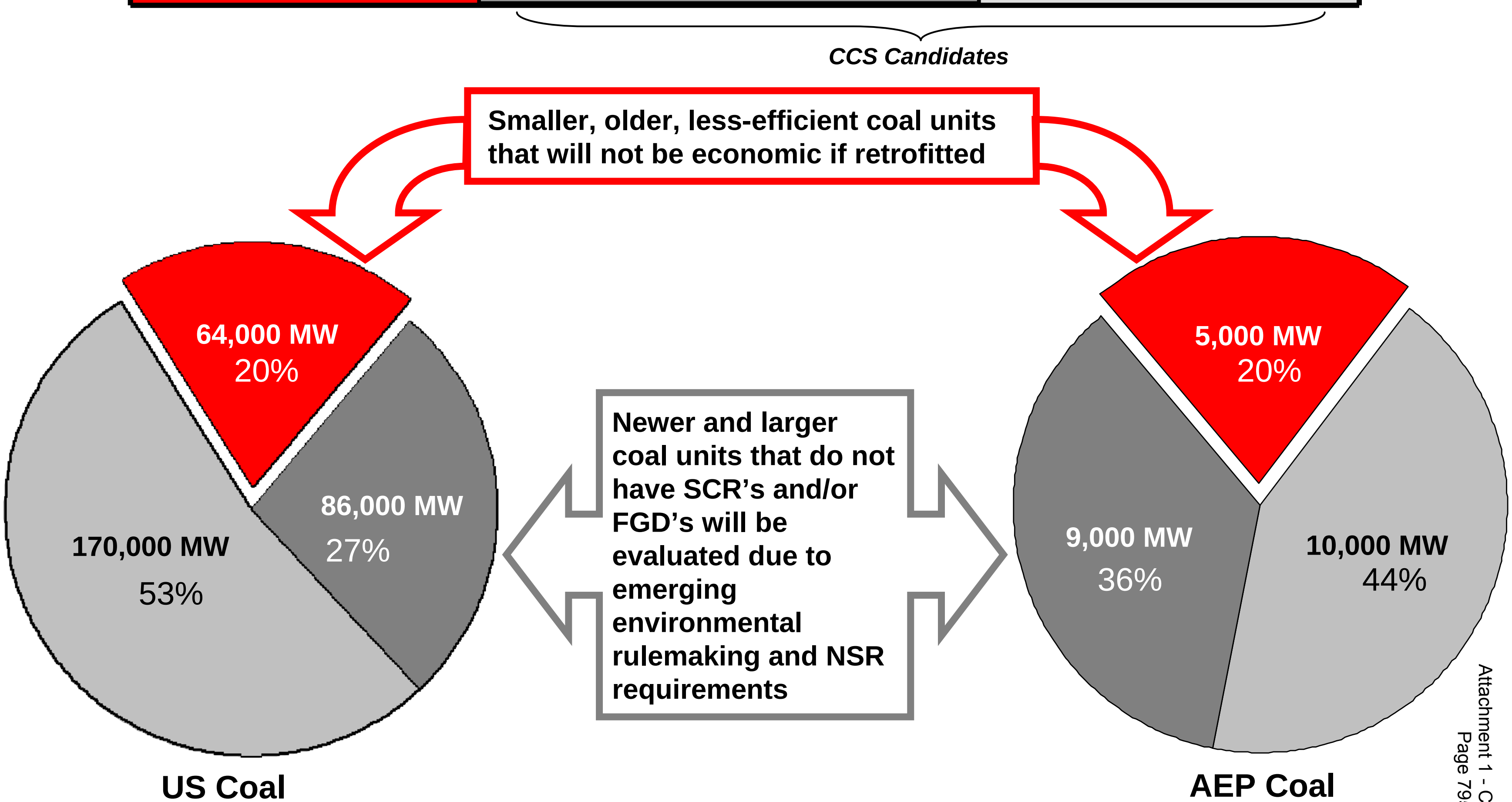
2011E - $29/ton



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7956 of 9556

Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

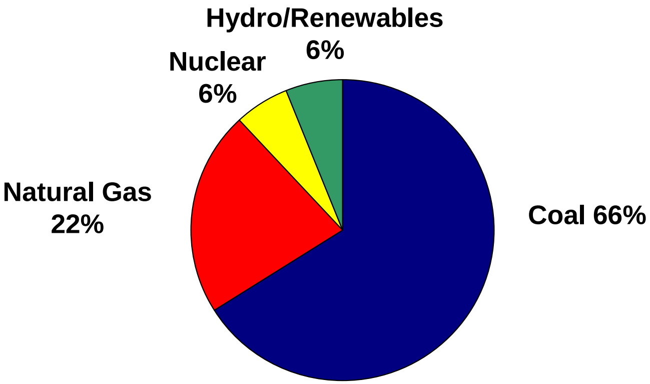


Nearly 50% of U.S. coal plants are exposed

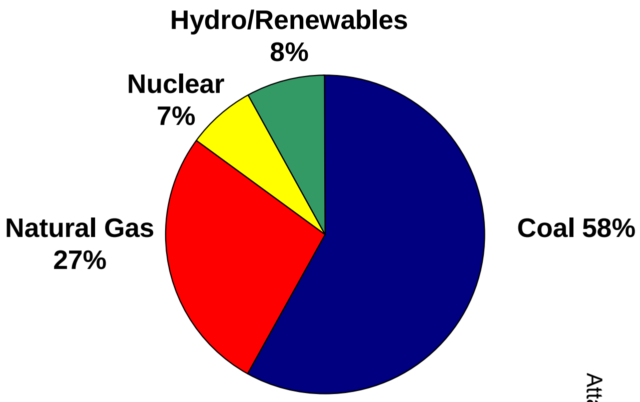
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7957 of 9556

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

AEP®

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

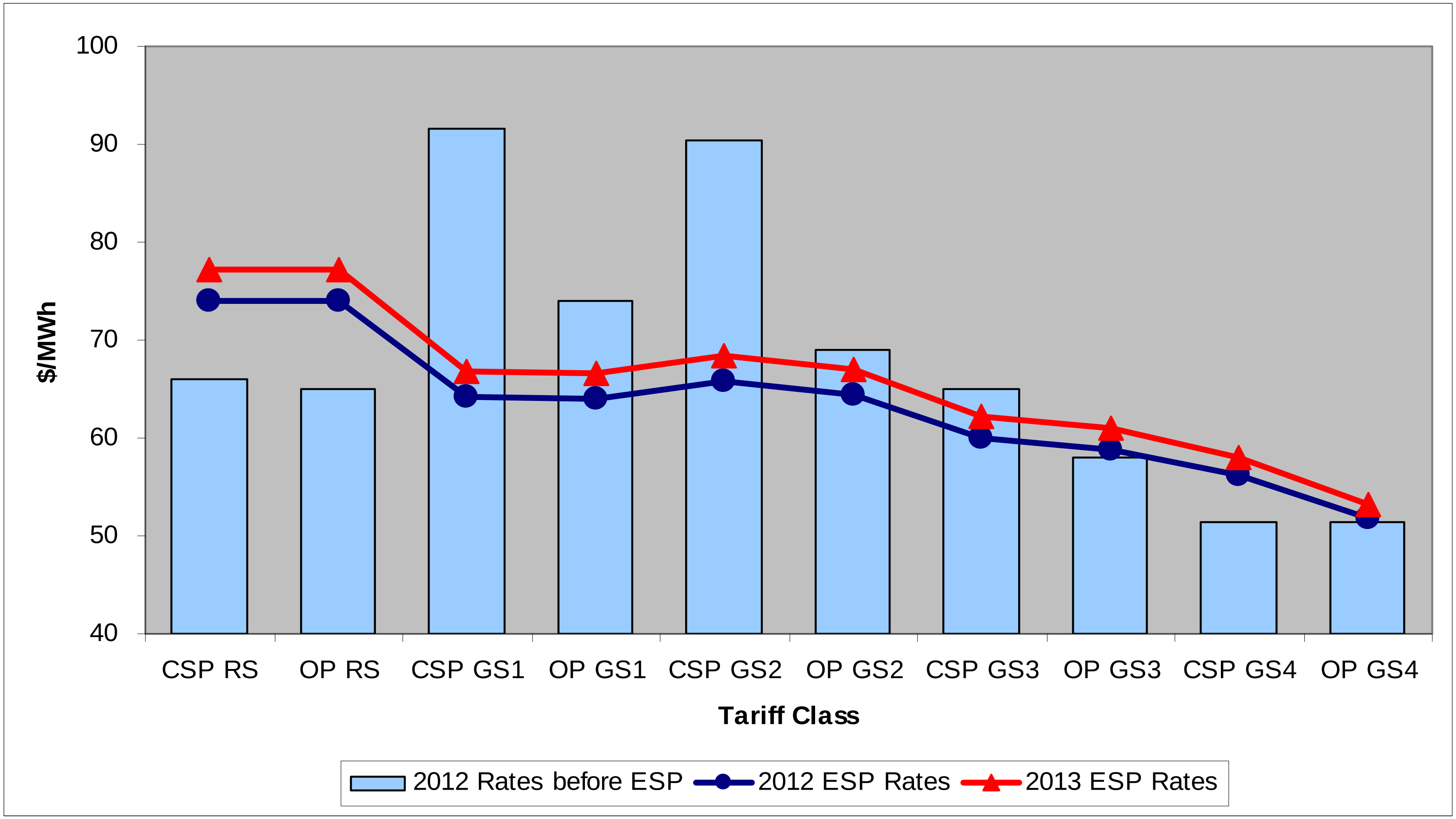
	2012			2013			2014		
	Revenue	$/MWh	%	Revenue	$/MWh	%	Revenue	$/MWh	%
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2	GS Demand	(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3		(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2	GS Demand	0.1%	(0.7%)	(3.5%)	(4.1%)
GS3		(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

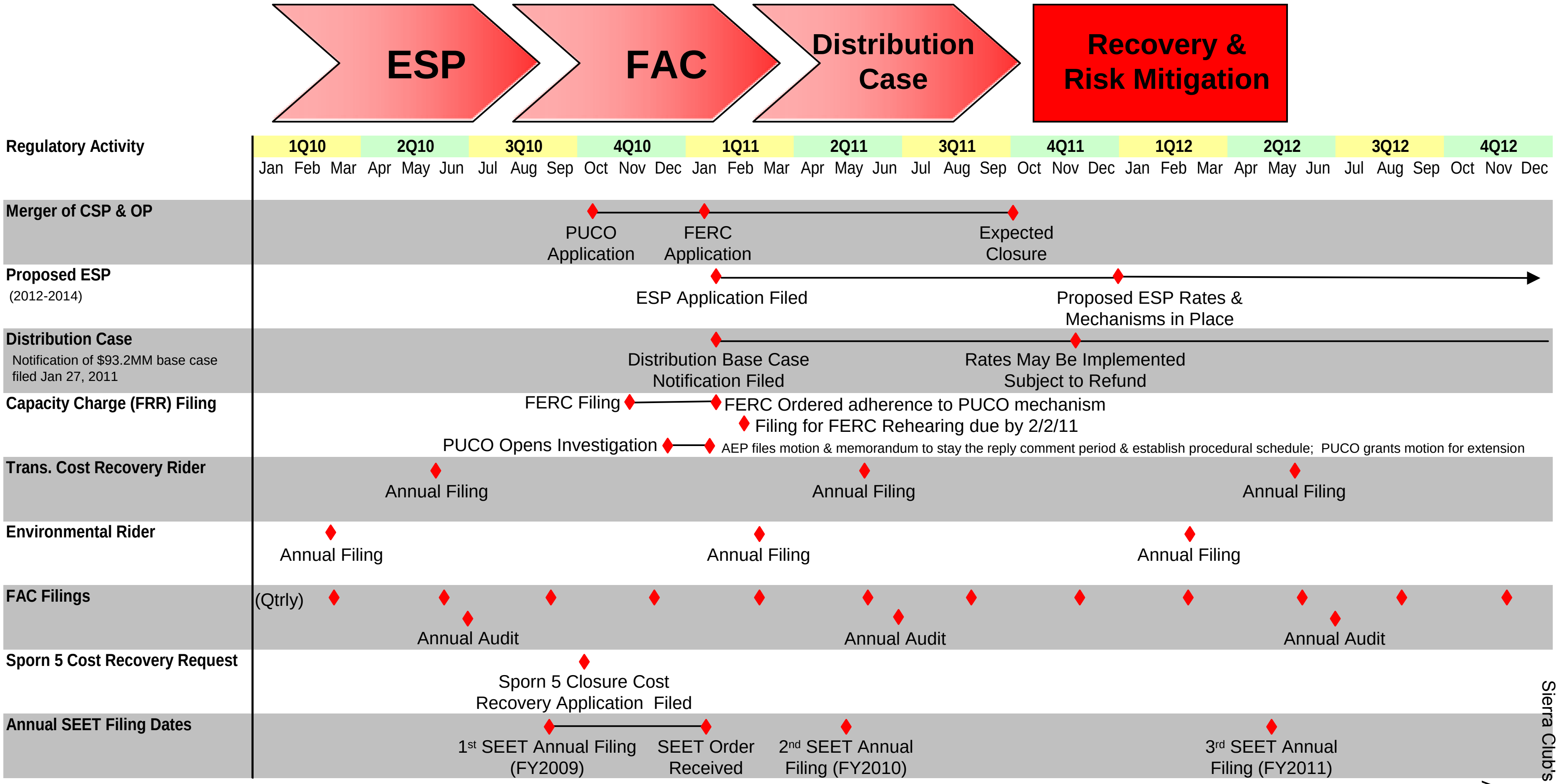
List of ESP Riders – Existing and Proposed

AEP®

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline

AEP®



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

AEP AMERICAN ELECTRIC POWER®

Morgan Stanley Smith Barney Financial Advisors Meeting
Cincinnati, OH
February 24, 2010


Hurricane Ike Restoration


765-kV Transmission Line (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Value Proposition to Retail Investors

AEP®

- **Attractive Yield Opportunity of 4.9%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

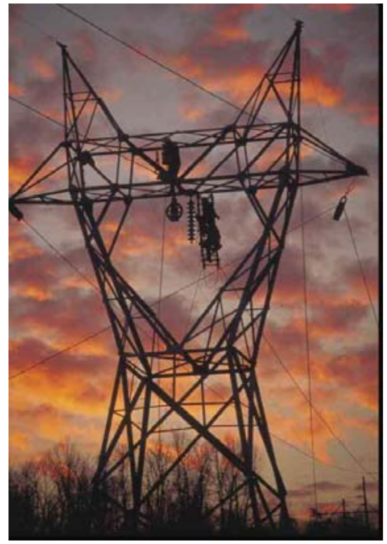
Current Wall Street Analyst Coverage:

- 21 analysts
- 14 Buy Ratings
- 7 Hold Ratings

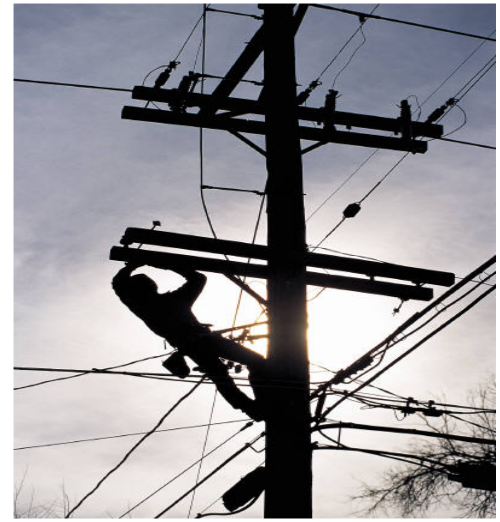
[1] yield percentage based on AEP closing price of $33.65 on 02/22/2010

Industry Leadership

One of the largest U.S. electricity generators



The largest U.S. electricity transmitter



One of the largest U.S. electricity distributors serving 5.2MM customers

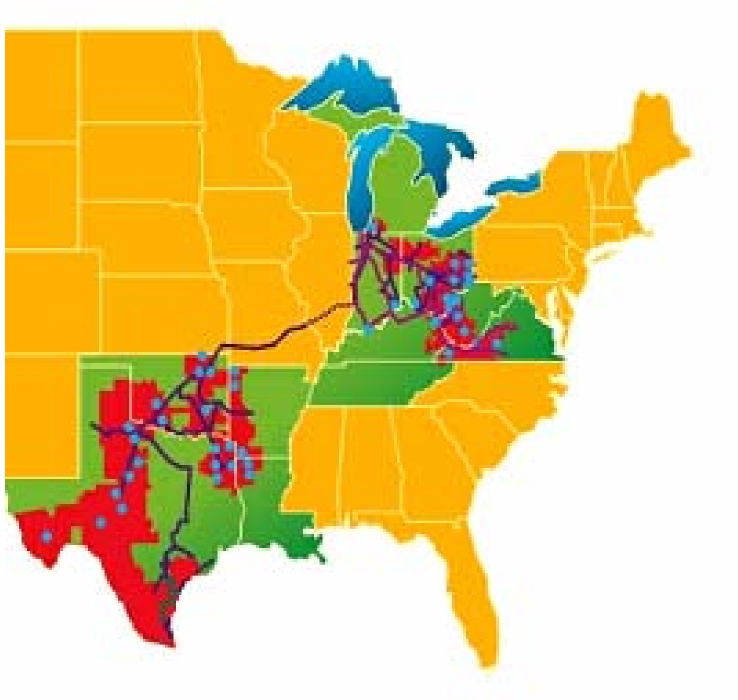
Generation owned[1] (GW)	
SO	42.6
AEP	40.6
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
PGN	21.8

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.7
MidA	17.9
ITC	15.1
FE	15.1
Oncor	14.9
EIX	12.0
PGN	11.0

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

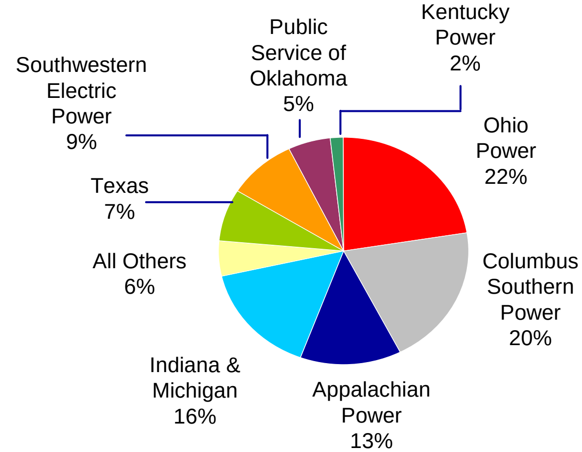
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

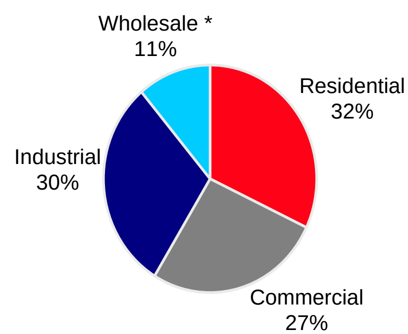


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

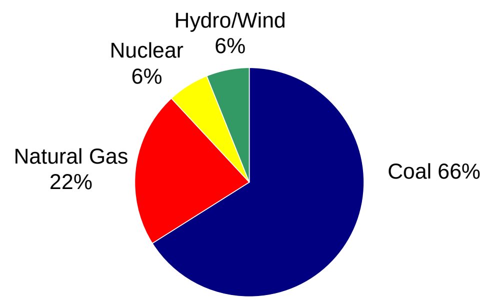


2009 Retail Load



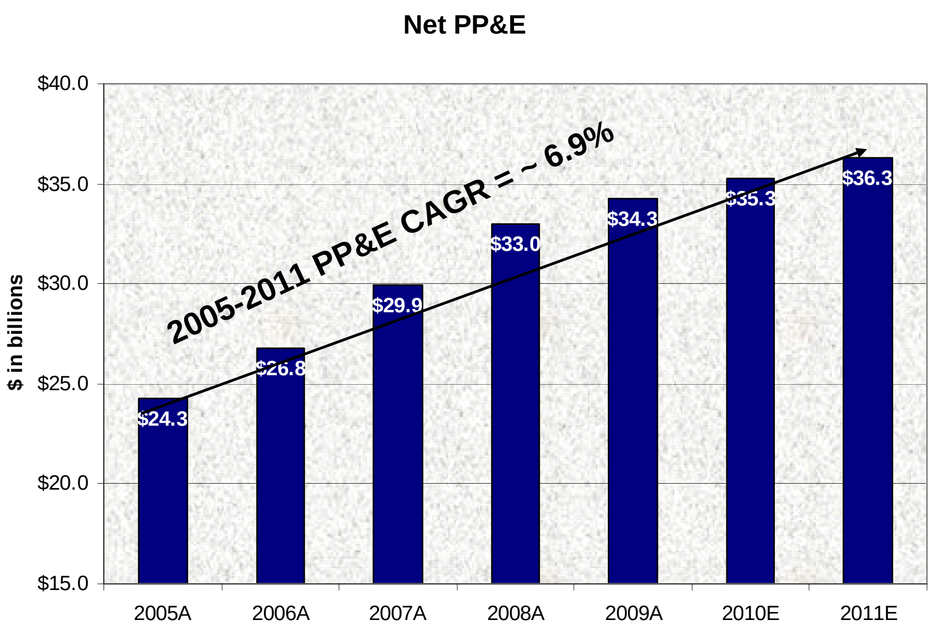
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



Traditional Ratemaking Environment

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

- **Base Rates**
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- **Recovery of Fuel Costs**
  - Active fuel clauses in all jurisdictions
- **Opportunities to Reduce Regulatory Lag**
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- **Ohio Generation Rates set by PUCO according to SB221 (non-cost based)**

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Carbon Capture and Storage Project – Mountaineer Plant (WV)

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

AEP®

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- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.1B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

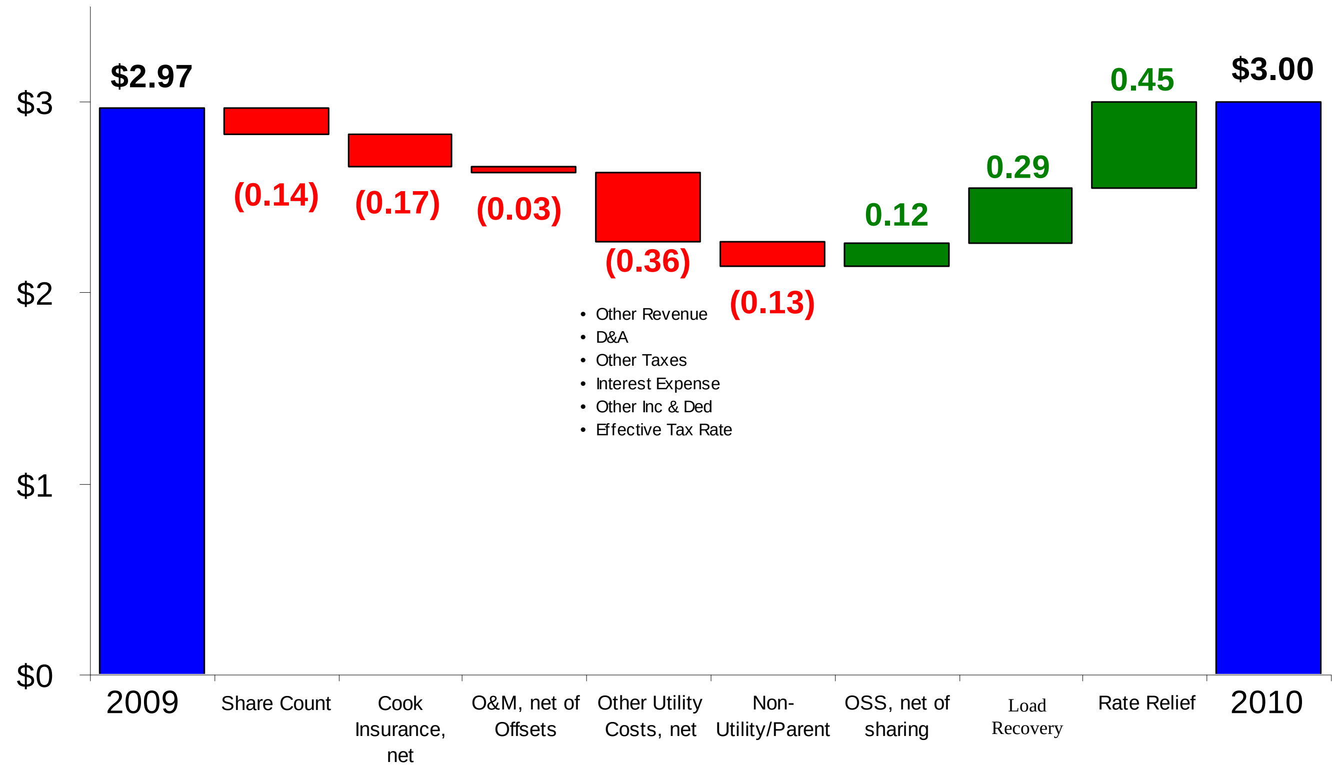
Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

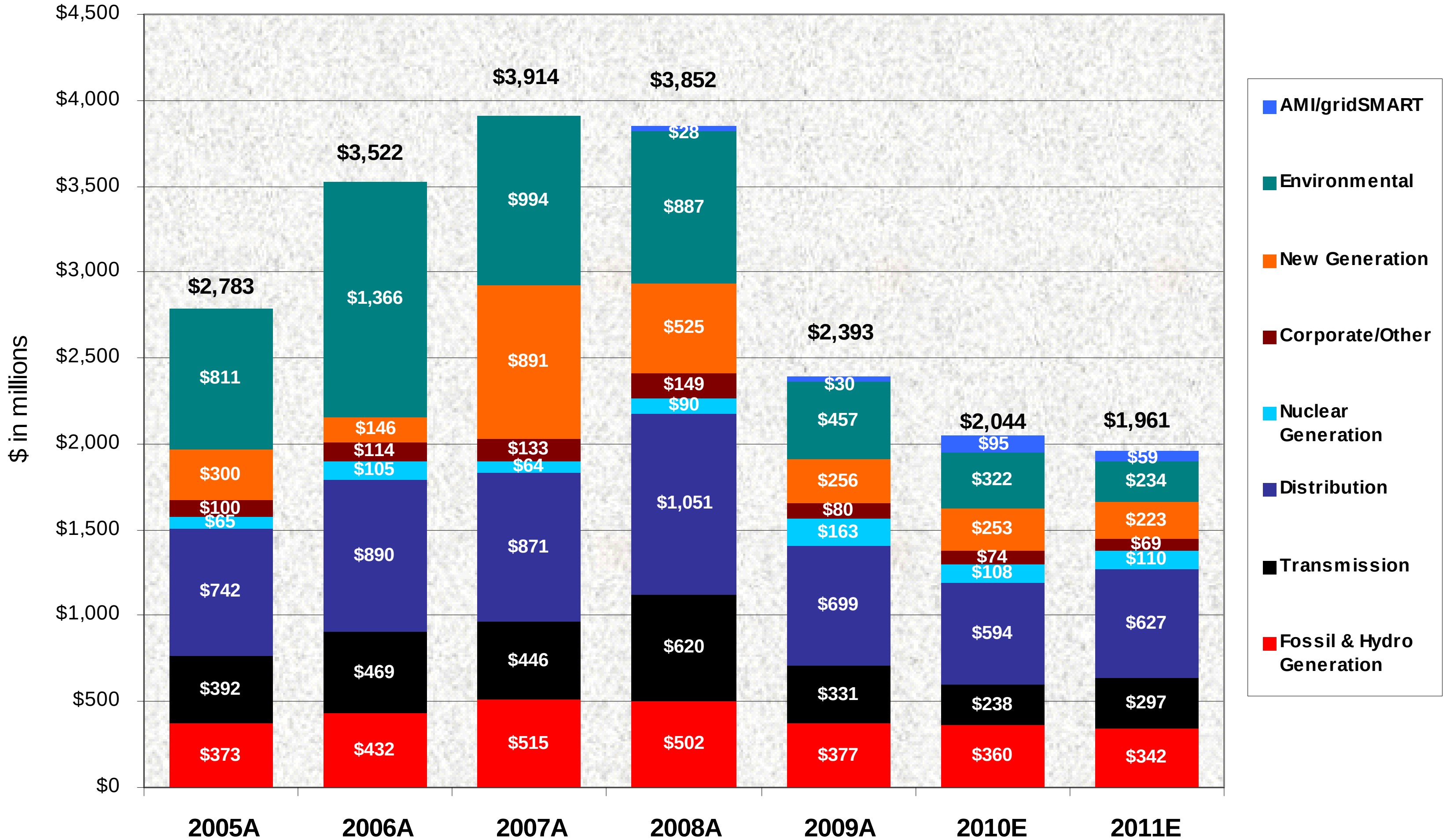
765-kV Tower

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



Utility Operations Capital Expenditures



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$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
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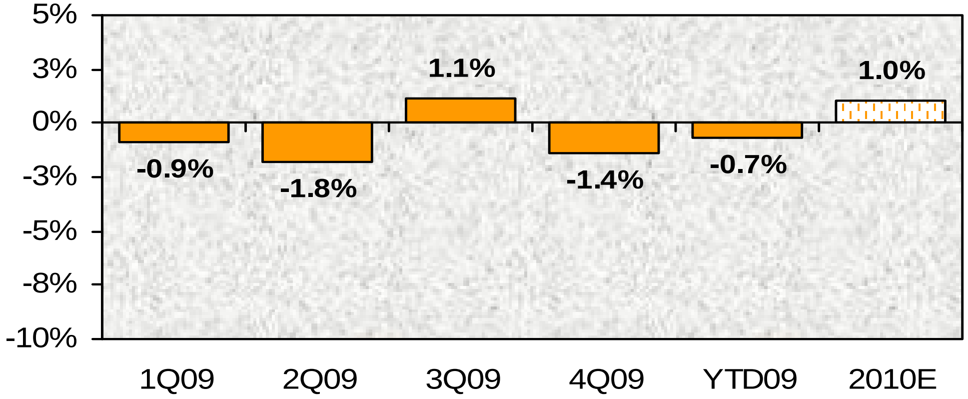
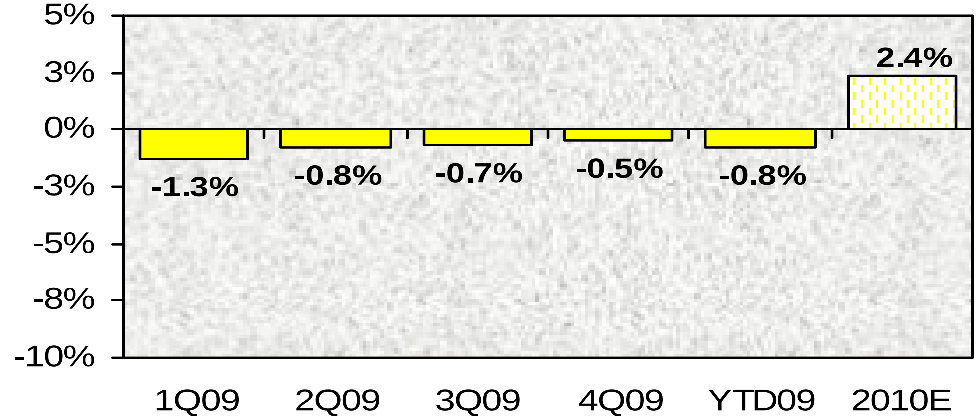
Normalized Load Trends

AEP®

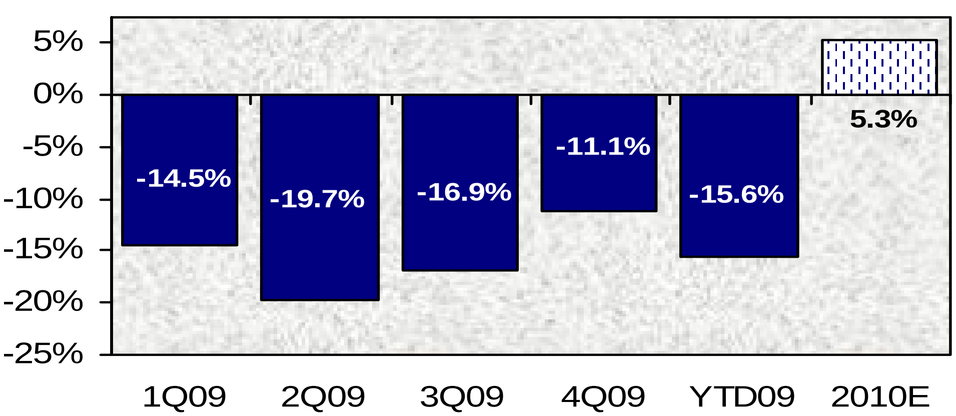
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



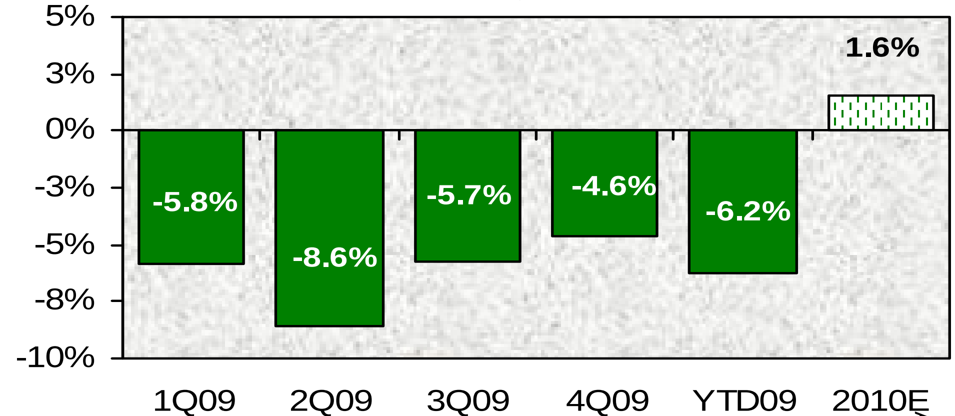
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 7976 of 9556

Dividend Overview

- We have declared 399 consecutive quarterly dividends to shareholders

- Annual Dividend - $1.64/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December

- Attractive yield of 4.9% as of February 22, 2010

- Conservative target dividend payout ratio of 50 – 60%

- Dividend Reinvestment Program Available

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value Proposition**

Mountaineer Plant (WV)

AEP AMERICAN® ELECTRIC POWER

Morgan Stanley Smith Barney
Financial Advisors Meeting
Washington, DC
March 23, 2010

Hurricane Ike Restoration

765-kV Transmission Line (WV)

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Chuck Zebula
Treasurer and SVP of Investor Relations

Value Proposition to Retail Investors

AEP®

- **Attractive Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

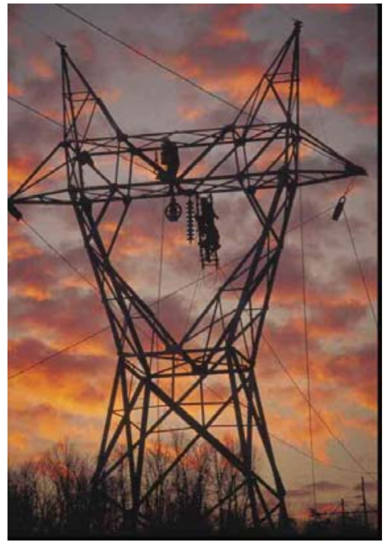
- 21 analysts
- 14 Buy Ratings
- 7 Hold Ratings

[1] yield percentage based on AEP closing price of $34.52 on 03/19/2010

Industry Leadership

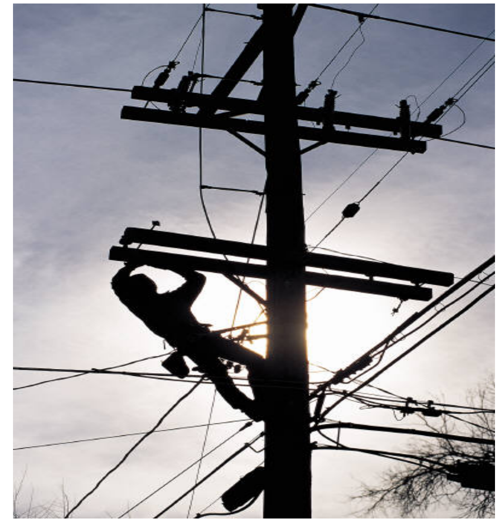
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



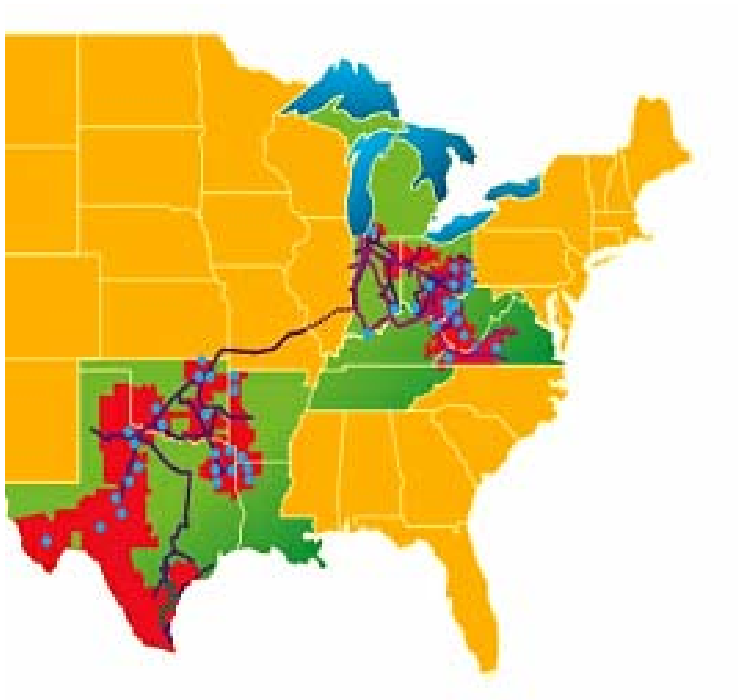
One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

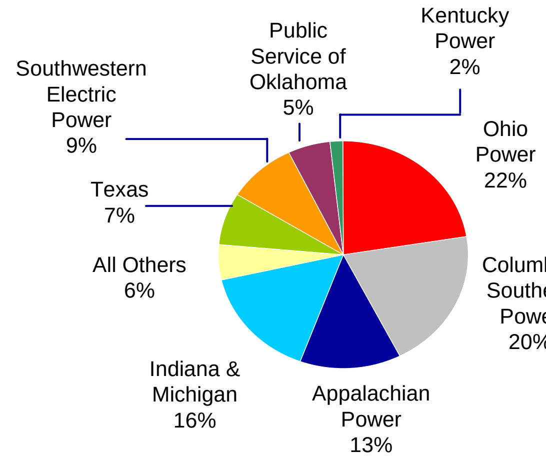
Highly Diversified Regulated Utility Platform

AEP®

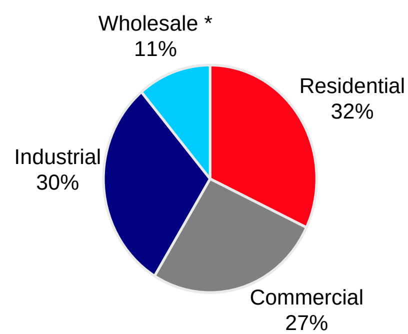


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

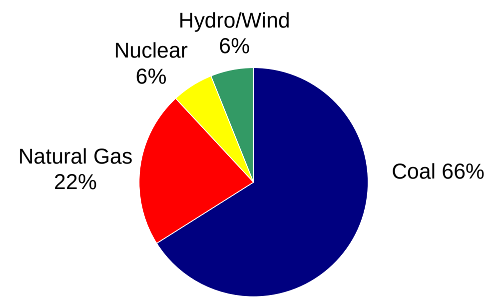


2009 Retail Load



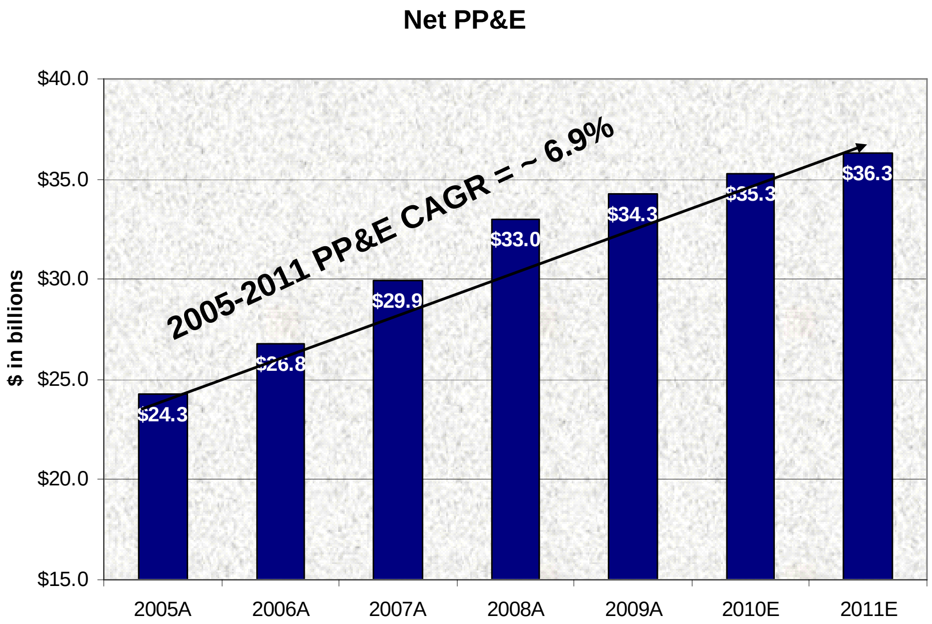
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



Traditional Ratemaking Environment

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

- **Base Rates**
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- **Recovery of Fuel Costs**
  - Active fuel clauses in all jurisdictions
- **Opportunities to Reduce Regulatory Lag**
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.

Energy Policy Initiatives = Opportunities

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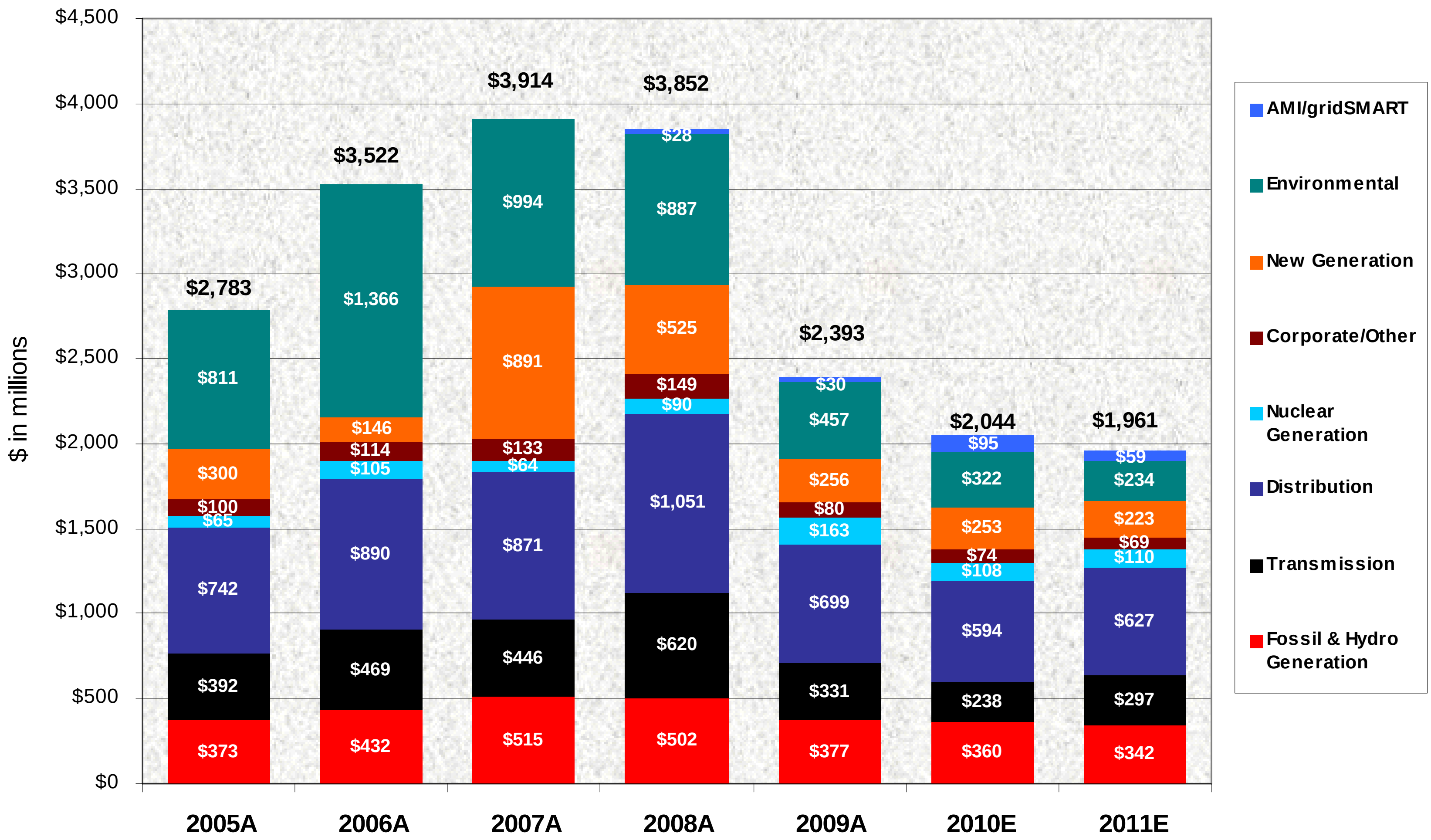
EARNINGS DRIVERS

- ↑ $320MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $23MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

Utility Operations Capital Expenditures



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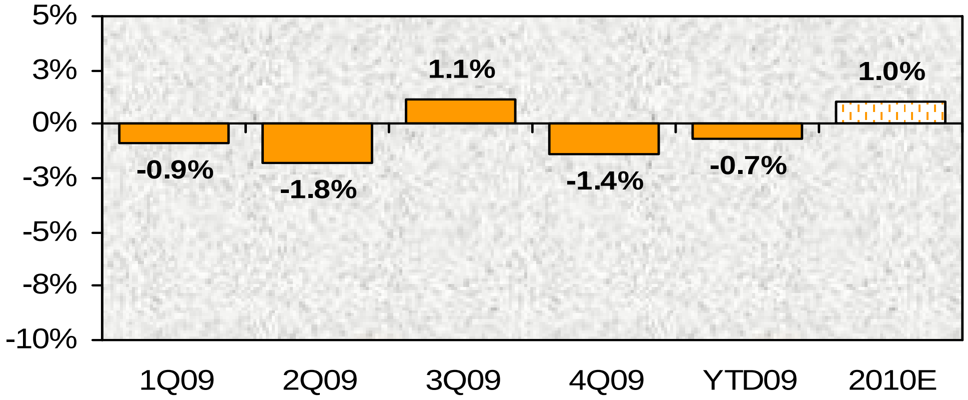

AEP Commercial Normalized GWh Growth
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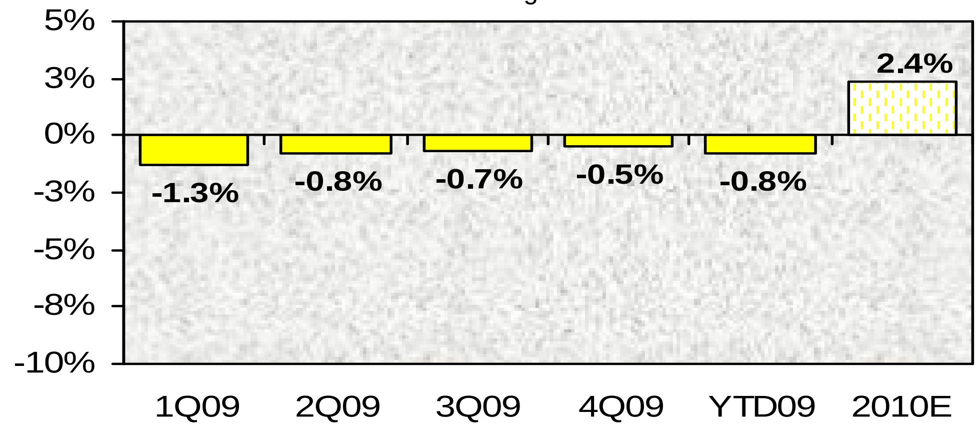

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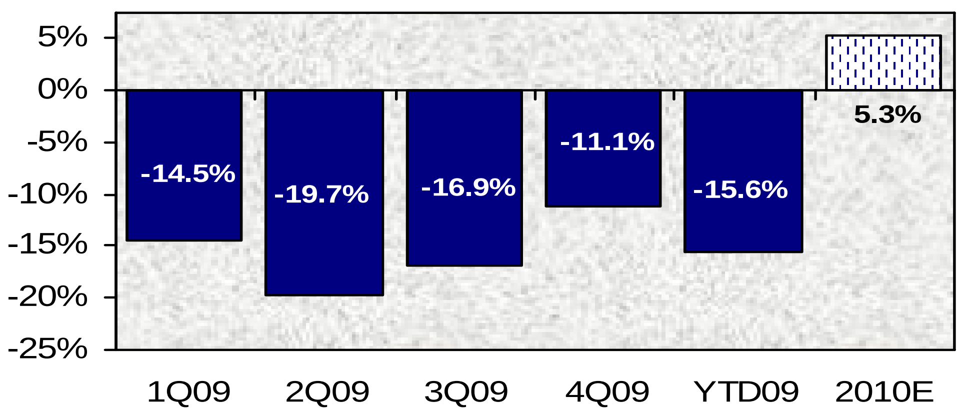
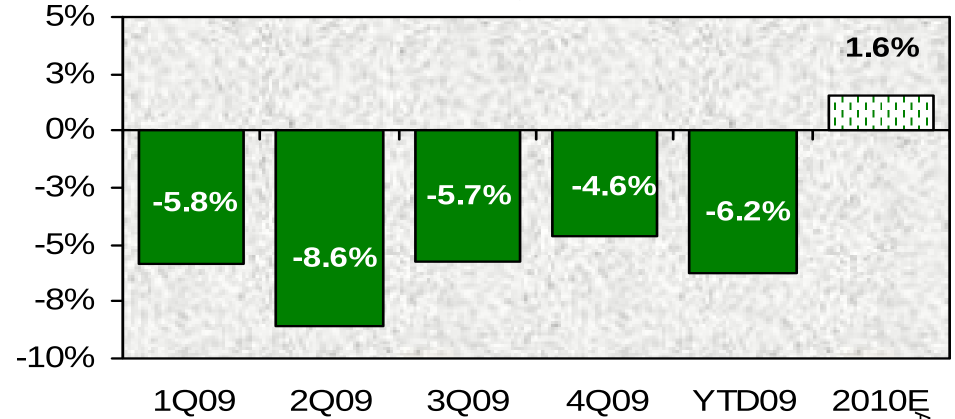


AEP Normalized GWh Growth*
%Change vs. Prior Year



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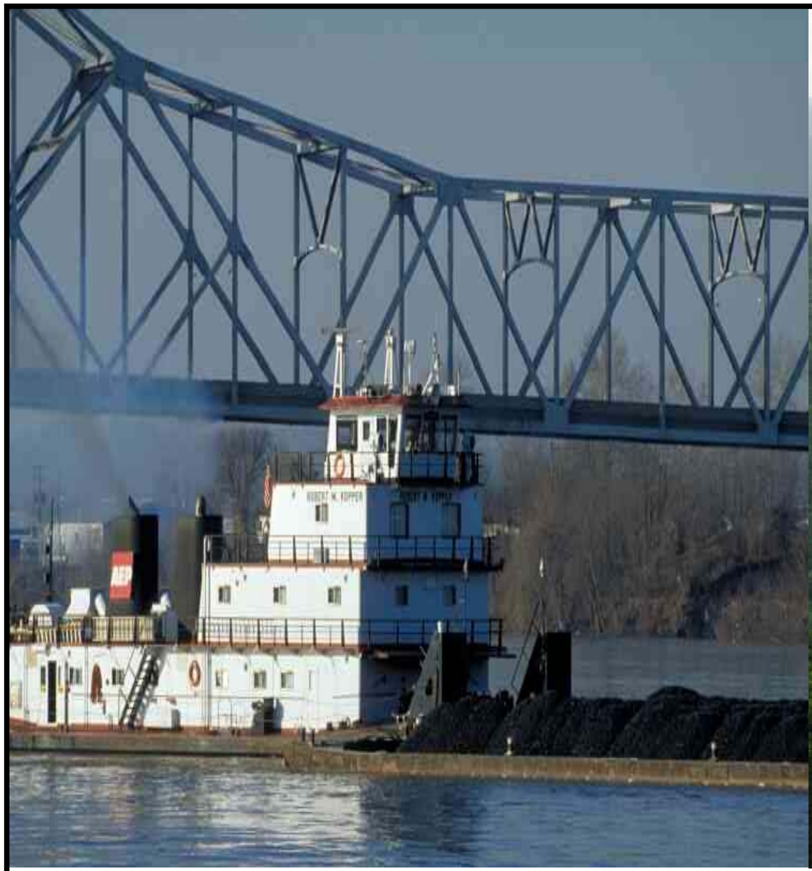

Morgan Stanley

Global Electricity & Energy Conference

April 3, 2008

New York, NY

AEP AMERICAN® ELECTRIC POWER

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Chairman, President & CEO

AEP Addressing Industry Concerns

- Rising Commodity Costs – Fuel and Transportation
- Rising Capital Costs – Environmental Retrofit and New Generation
- Declining Reserve Margins
- Need for Additional Transmission
- Regulatory Pressures Due to Rising Rates

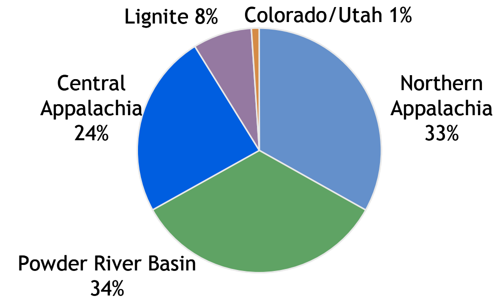
AEP is well positioned to manage each of these industry concerns.

Industry Concern: Rising Commodity Costs – Fuel and Transportation

AEP SOLUTION – FUEL PROCUREMENT STRATEGY:

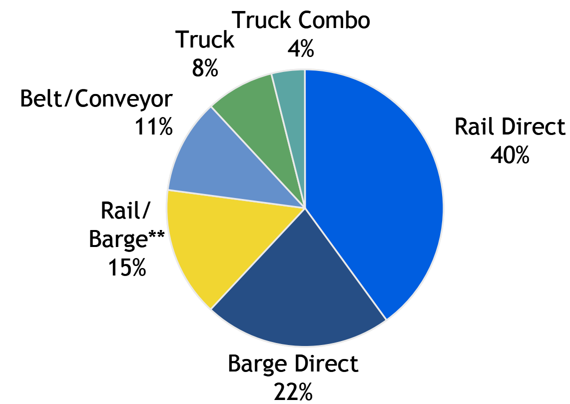
- **Portfolio of Coal Contracts**
  - Geographic and supplier diversity
  - Diversity of terms – currently ranging from 2008 to 2022
- **Portfolio of Transportation Resources**
- **Portfolio of Options to Manage the Economics of Converting BTUs to MWhs**
  - Manage emission allowance exposure
  - Blending capabilities at many plants
  - Transportation fleet to reposition coal
- **Regulatory Recovery**
  - Active fuel clauses in ten of eleven jurisdictions

AEP Supply Diversity *



* 2008 Projected

AEP Transportation Diversity *



* 2007 Actual

** Reflects coal delivered to AEP plants transported through a combination of rail and barge

AEP strategy: manage coal supply sources and transportation assets to mitigate price increases and market disruptions.

Industry Concern: Rising Capital Costs

AEP SOLUTION – Completed Environmental Retrofit

Lower Capital, Lower Operating Costs, Successful Operating Performance

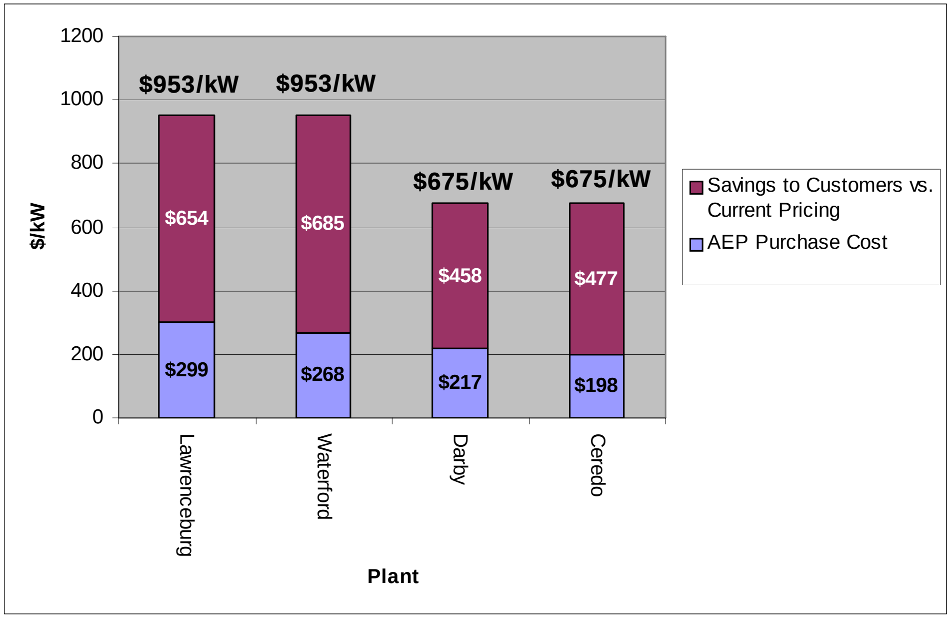
- By locking in our environmental program costs in the early portion of this decade, AEP has a clear 'first-mover' advantage
- Capital cost comparison for wet scrubber:
  - AEP average ~ $250/kW
  - 2007 pricing for a 600MW plant ~ $320/kW
  - 2012 forecast for a 600MW plant ~ $470/kW

- **11,076 MW FGDs currently in service or under construction equates to cost savings to rate payers based on 2007 $ of $775 million.**

AEP SOLUTION – Purchased Low-Cost Generation

Lower Capital, Successful Operating Performance, Delayed Need for Baseload

- Cost to replace plants in 2008 are estimated at $675/kW for simple-cycle and $953/kW for combined-cycle. Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections. This equates to cost savings to rate payers of $1.7 billion.



By moving early, AEP avoided approximately $2.5 billion of capital. Nearly all of these investments are currently reflected in rates.

AEP®

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Add Generation:

Harry D. Mattison Plant – commercial operations achieved in 2007

Generation:

- **Adequate reserves in East due to purchased generation**
- **Build peaking, intermediate and baseload generation in the West**

Project Name	State	Fuel Type	Plant Type	MW Capacity	Original In Service Date	As Contracted Cost	Cost if Contracted in 2008	In Service if Contracted in 2008
Mattison	Arkansas	Gas	Simple-cycle	340	2007	$333/kW	$675/kW	2010
Stall	Louisiana	Gas	Combined-cycle	480	2010	$671/kW	$953/kW	2011
Turk	Arkansas	Coal	Ultra-supercritical	600	2011	$2,123/kW	$2,605/kW	2014

Costs include as-spent direct plant costs only. Excluded are AFUDC, land, transmission and gas pipeline interconnections.

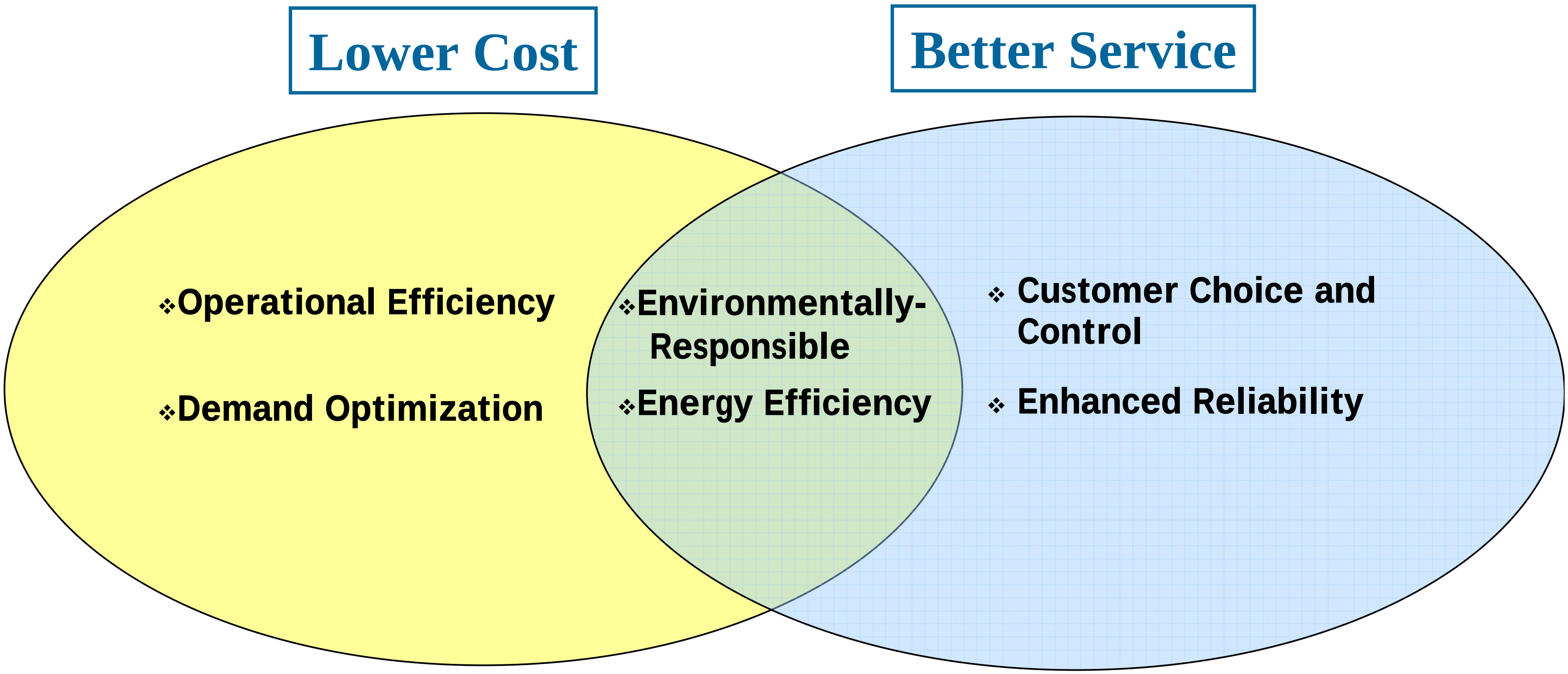
AEP's current initiatives help mitigate both the supply and demand issues facing the U.S.

AEP®

Industry Concern: Declining Reserve Margins

AEP SOLUTION – Improve Efficiency and Demand Management:

AEP's **gridSMART**^SM initiative will develop a deployment plan for new customer programs and advanced technologies to support pursuit of the following value propositions:



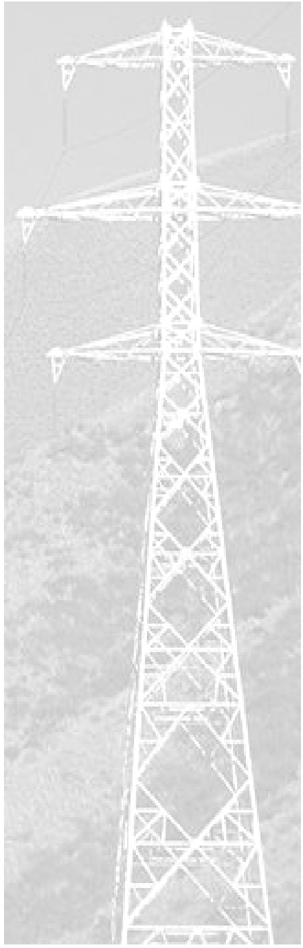
Increased efficiency reduces cost and GHG emissions. It also delays the need for new generation.

Industry Concern: Need for Additional Transmission

AEP SOLUTION:

Our status as the largest transmission owner in the U.S. affords us technical, operational and economic advantages:

- Efficient System Design - 765-kV Technology
- Advanced Technology Solutions - Laredo Variable Frequency Transformer
- Strong Supplier Relationships - Long-term Equipment and Construction Contracting
- Joint Venture Partnerships - Investment opportunities identified
  - MidAmerican Energy Holdings Company
    - Electric Transmission Texas - $1 billion - $7 billion opportunity
    - Electric Transmission America - $3 billion opportunity in SPP
  - Allegheny Energy Inc.
    - PATH - $1.8 billion opportunity



Our customers and shareholders benefit from the scope, scale and expertise of our transmission operations.

AEP®

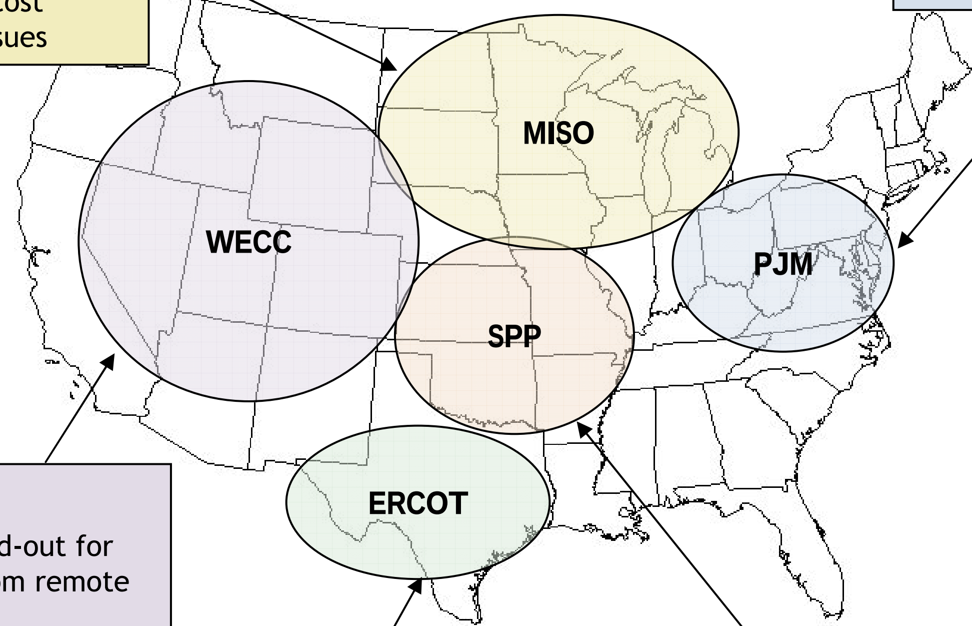
Transmission Investment Opportunities Allow Broader Market Access

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues

PJM

Congestion will be reduced and reliability will be increased



WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

ERCOT

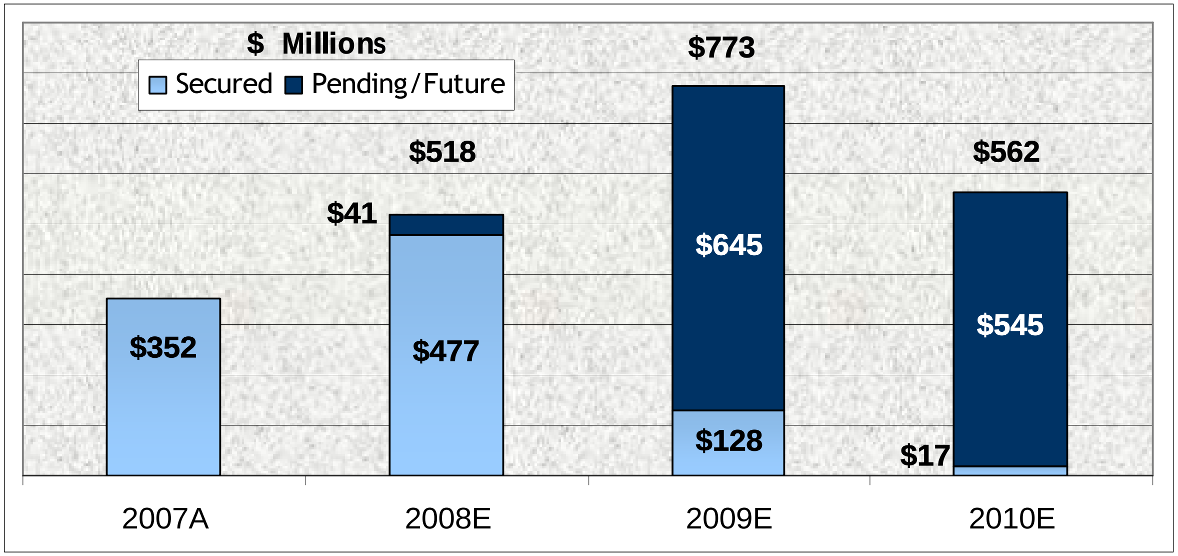
Load growth and access to wind resources driving transmission investment

AEP's transmission initiative addresses regional supply/demand issues (congestion) and is required for more robust deployment of renewable generation sources.

Industry Concern: Regulatory Pressures Due to Rising Rates

AEP SOLUTION:

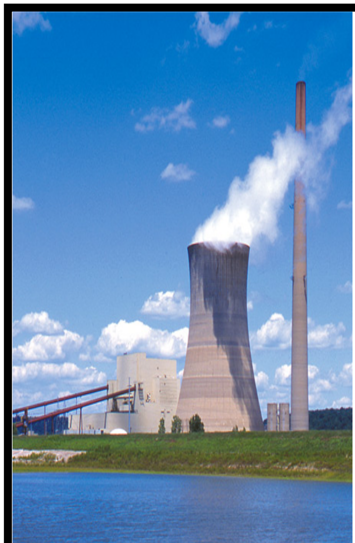
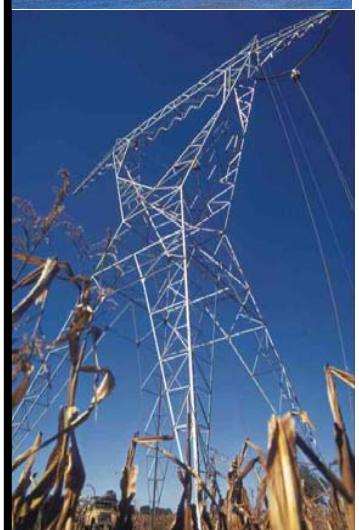
- **History of Regulatory Success/Proven Track Record**
- **Lowest Cost Provider to 93% of our customers (8 of 10 Jurisdictions)**
- **gridSMART℠ Initiative to reduce customer bills**
  - Benefit: more power to sell off-system creates increased sharing for retail customers, further reducing customer bills
- **AEP Track Record of Success – Anticipated 2007 rate relief of \$338MM; Achieved \$352MM; Already secured 92% of 2008 rate relief through the 1st quarter of 2008.**



AEP is well-positioned for continued favorable regulatory treatment.

AEP®

American Electric Power - Solid Track Record of Successful Execution

- *Economies of scope and scale in assets & operations*
  - *2nd Largest Generating Fleet in the U.S. including largest supercritical units at 1300 MW*
  - *Largest Transmission and Distribution Network in the U.S.*

- *Continued innovation and first-mover deployment of leading technology advancements*
  - *Ultra-supercritical and IGCC coal generation*
  - *765-kV leadership*
  - *gridSMART^{SM} initiative*

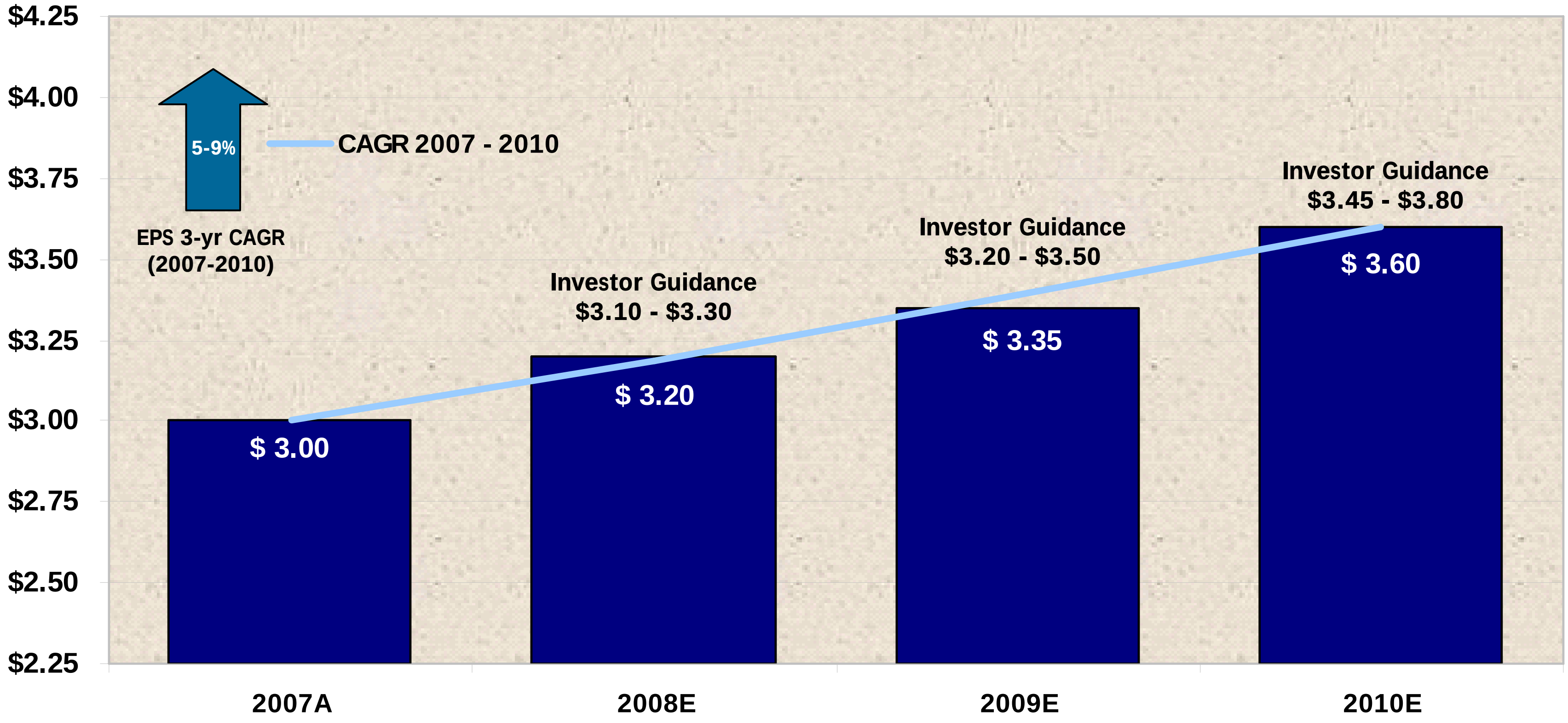

AEP®

Poised for Continued Success

Questions

Appendix

4-Year Earnings Range Forecast



5% to 9% earnings growth

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		2007 Performance Driver	2007 Actual ($ millions)	2008 Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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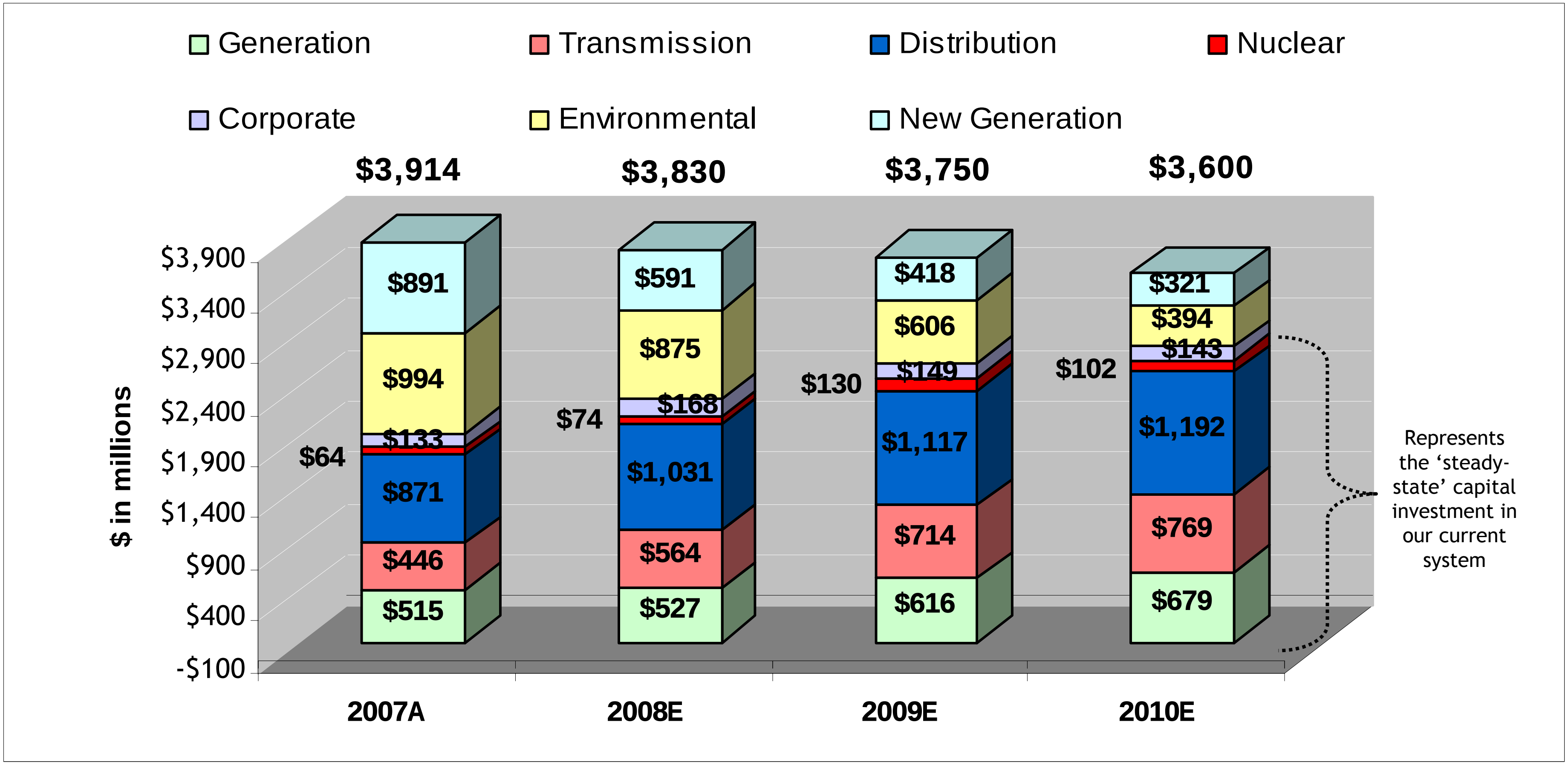
Annual Capital Investment Cycle



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects.

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Capital Investment + Rate Relief = Earnings Growth

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

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Capital investment is funded from cash from operations and debt issuances.

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	tbd

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $950 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the current Supreme Court of Ohio remand to the PUCO of the PUCO's April 10, 2006 Opinion and Order.

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AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

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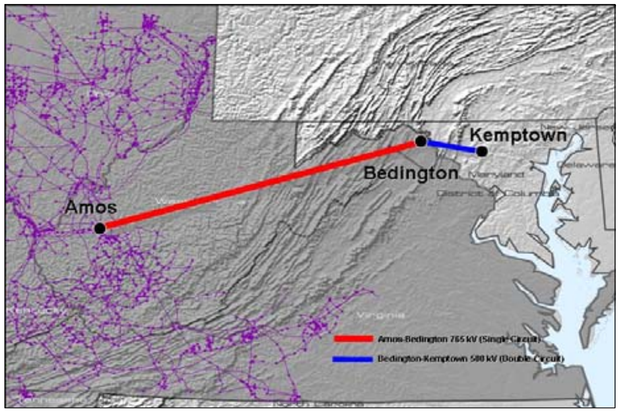
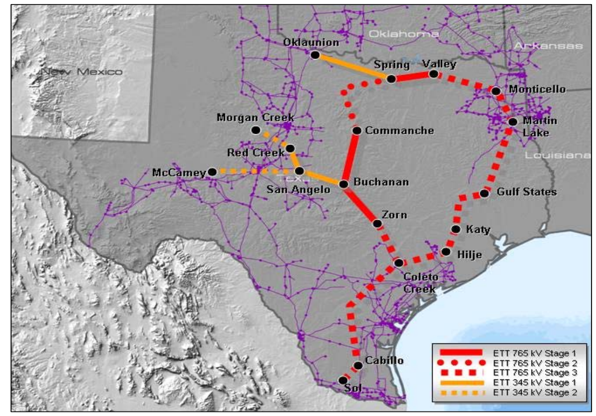
At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

I-765™ Transmission: Investment Opportunities

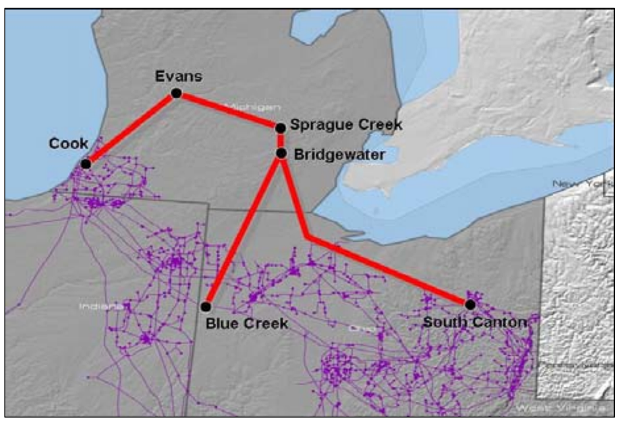
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

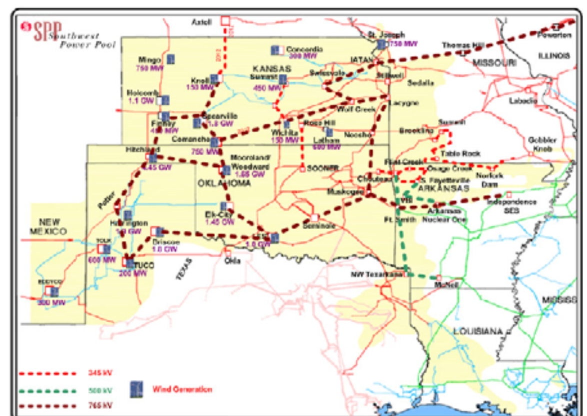


Figure 25: Mid Point Design 2

SPP Overlay Study - Mid Design 2

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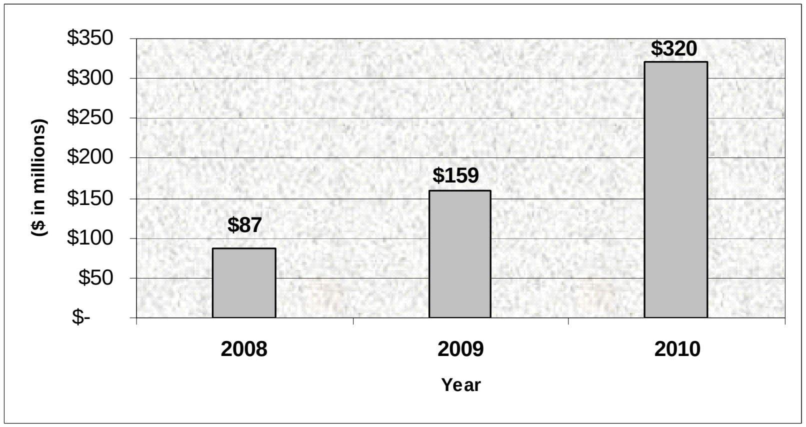
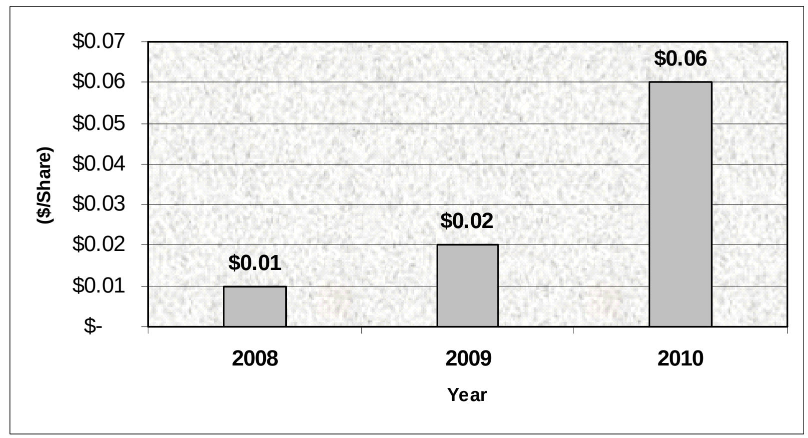
Transmission – Investments and Earnings Contributions

Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

Projected Transmission EPS Contributions*



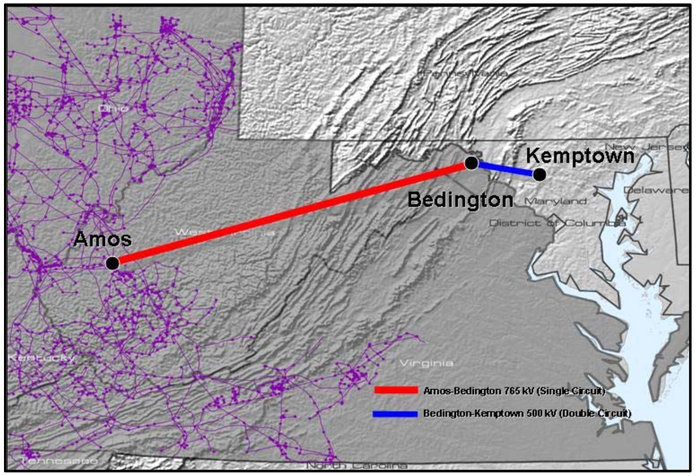
* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

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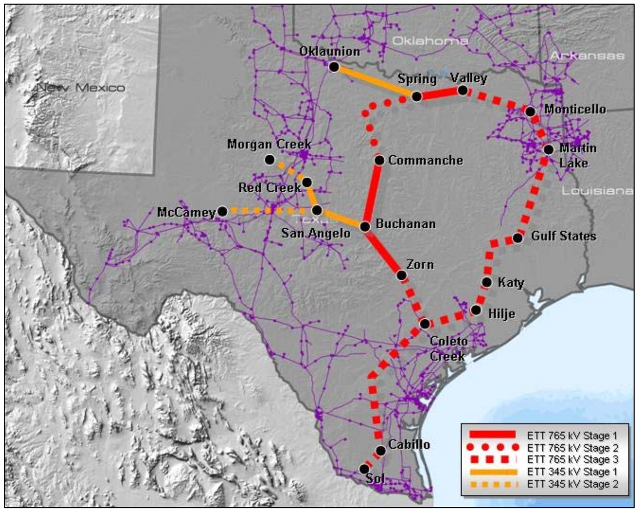
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- *ETT ERCOT Backbone Proposal*
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

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Electric Transmission America (ETA)

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

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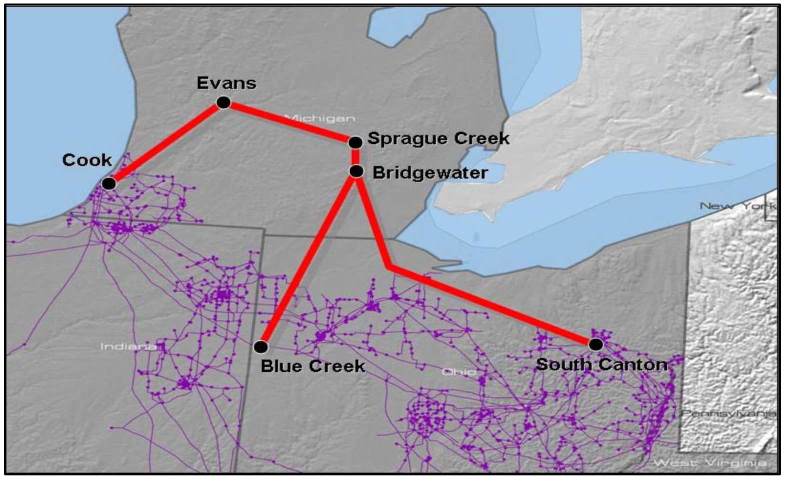
I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765TM Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

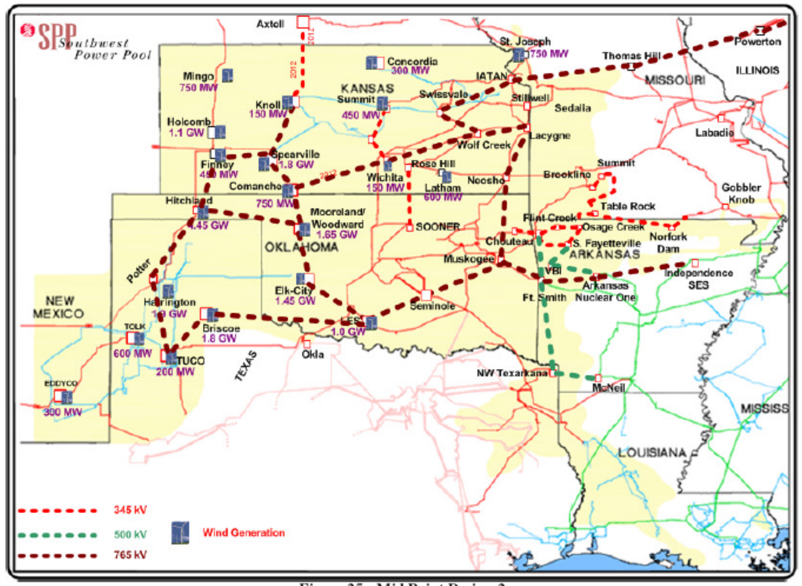


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP®

Distribution - gridSMART℠

•gridSMART℠: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

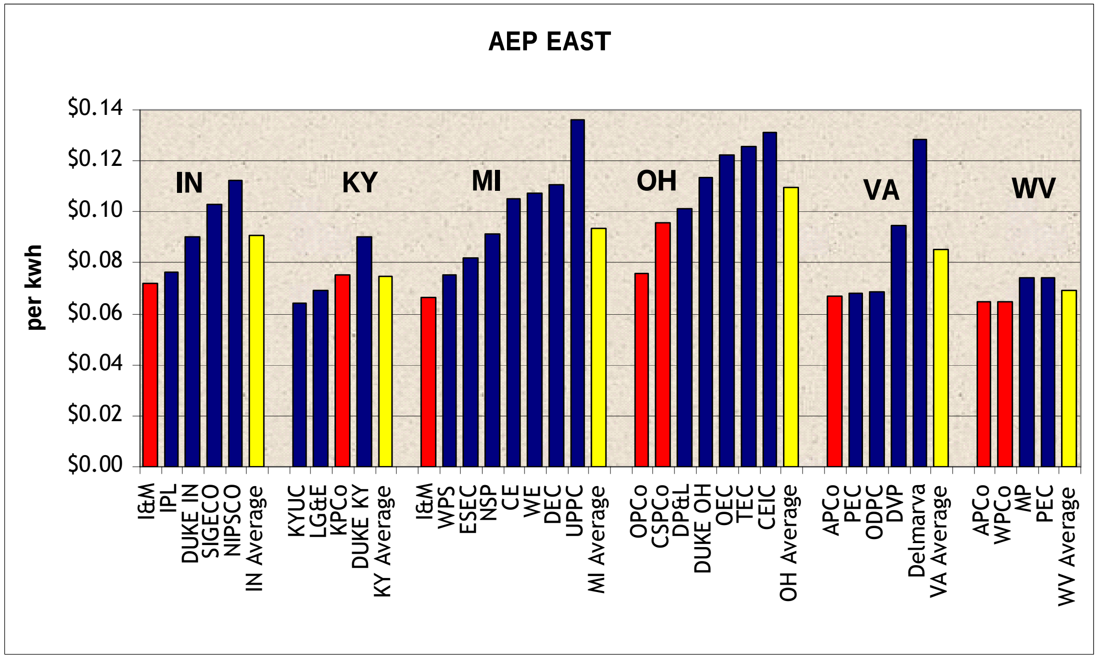
- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

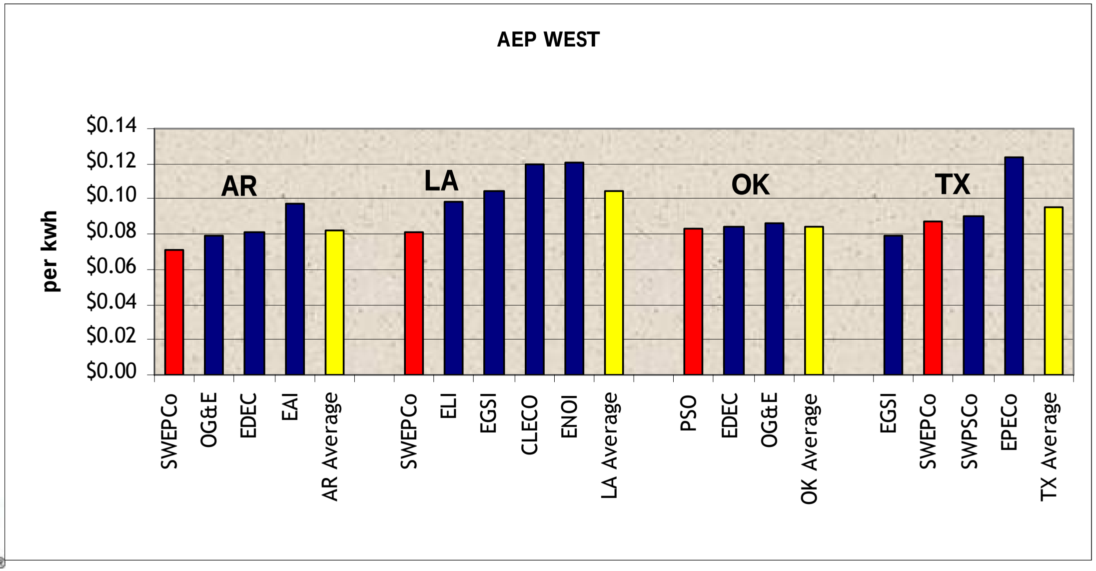
Capital Investment, Subject to Regulatory Approval * $ in millions			
Technology	**2008**	**2009**	**2010**
Metering & Communications	**$83**	**$138**	**$146**
Distribution Technology Enhancements	**$40**	**$ 63**	**$ 82**

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

Our low cost provider status in most of our jurisdictions, coupled with our scale and scope, allows us the flexibility to navigate current and future macro-economic issues.

- AEP Company
- Other Company within state
- State Average

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8021 of 9556

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
  - SWEPCo Turk Plant Filing in Louisiana - construction approval

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Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia - approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio - on hold pending resolution of Supreme Court remand to PUCO
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC.

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Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

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Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Intervenor testimony was received December 10, 2007 and Staff testimony was received on January 18, 2008. Public hearings commenced February 12, 2008. We expect an order in April 2008.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

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Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The PSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. A procedural schedule is being developed and the hearing most likely will occur in May or June 2008.

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Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings will commence on April 8, 2008. Staff testimony was favorable.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure – Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief – Company Position (9/30/07)

($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Morgan Stanley Global Electricity & Energy Conference


AEP AMERICAN ELECTRIC POWER®


March 15, 2007

New York, NY

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Upcoming Investor Communication Activities*

April 24, 2007	Annual Meeting of Shareholders – Shreveport, LA
April 26, 2007	1Q07 Earnings Call
June 7, 2007	Citigroup Power, Gas & Utilities Conference

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*Note: Events at which Mike Morris is scheduled to speak with investors/analysts.

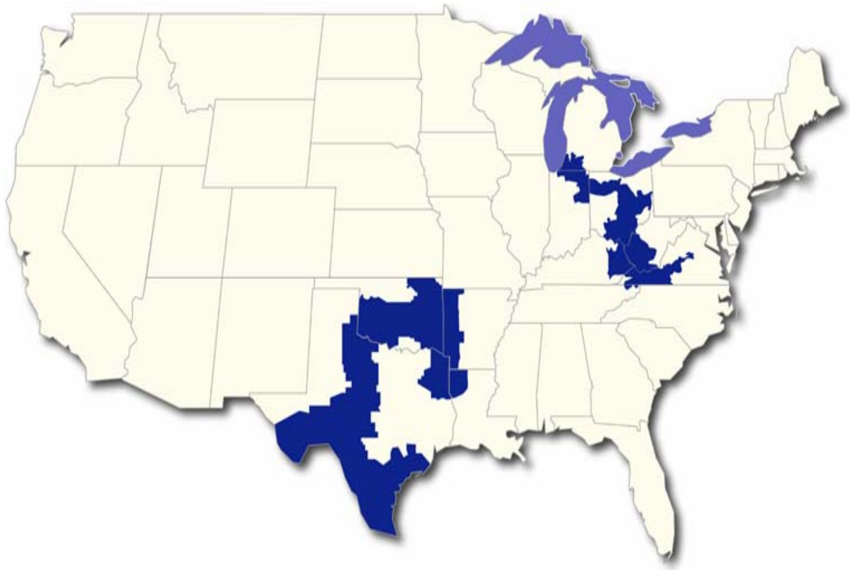
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

Strategic Direction

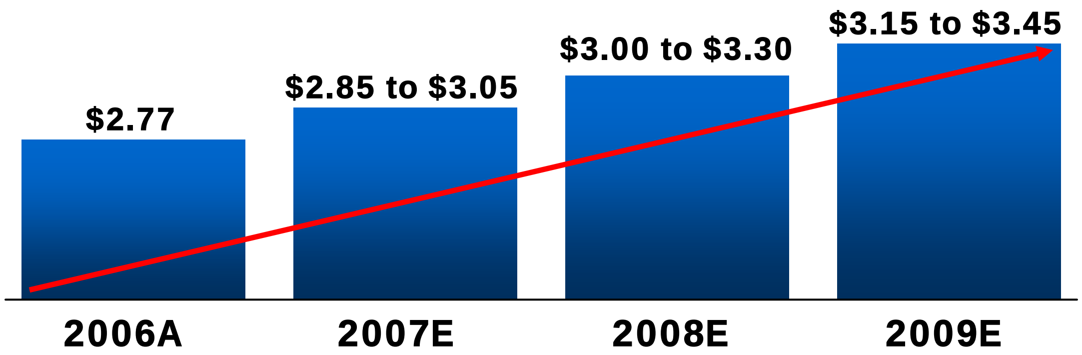
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

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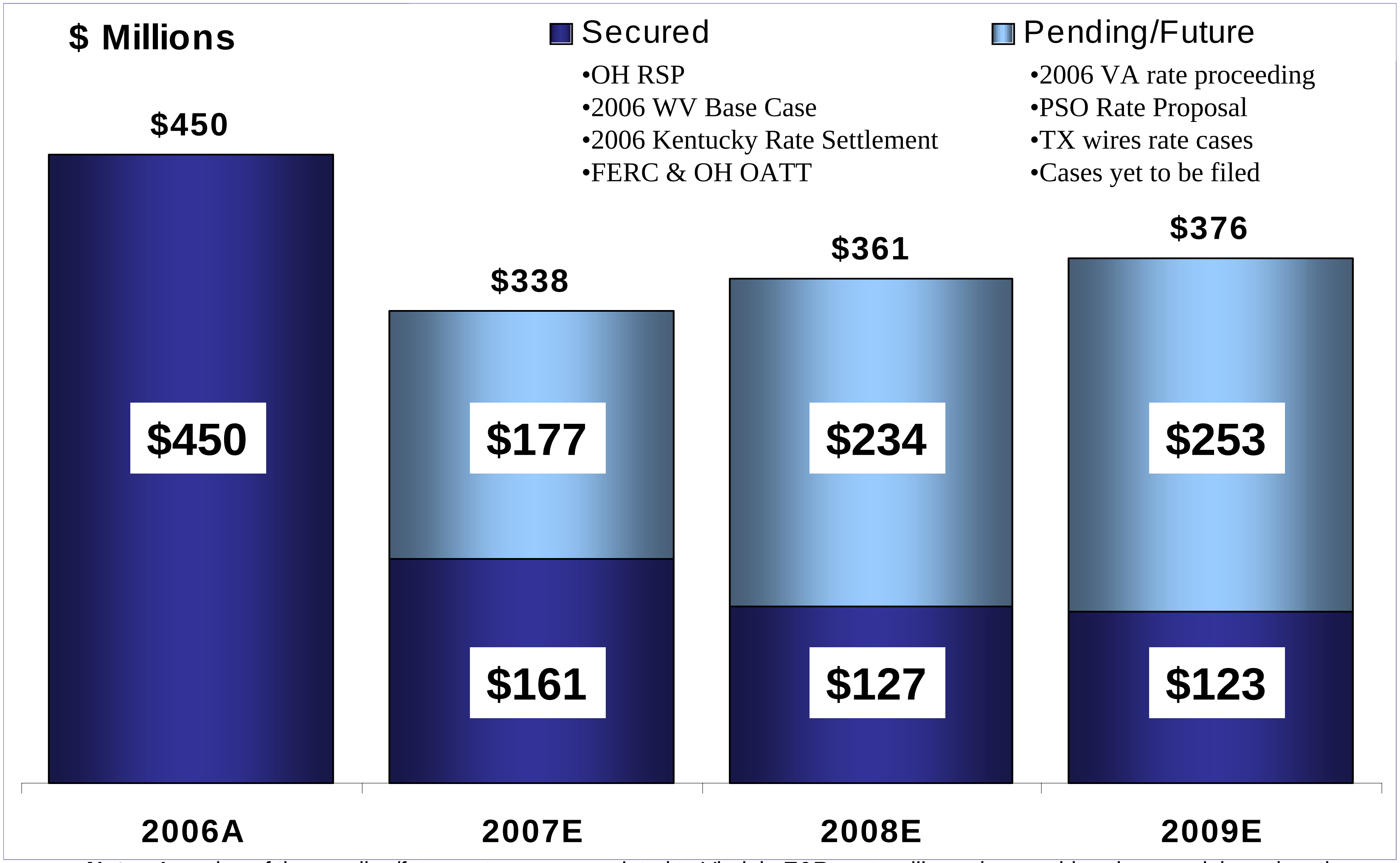
OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

Incremental Rate Relief Composition



Note: A portion of the pending/future rate recovery related to Virginia E&R costs will now be considered secured, based on the Virginia SCC's Nov. 20, 2006 order in our E&R case. Further analysis is required to quantify these amounts.

RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Utility Investment Drives Growth

Updated Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443** *
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase $325

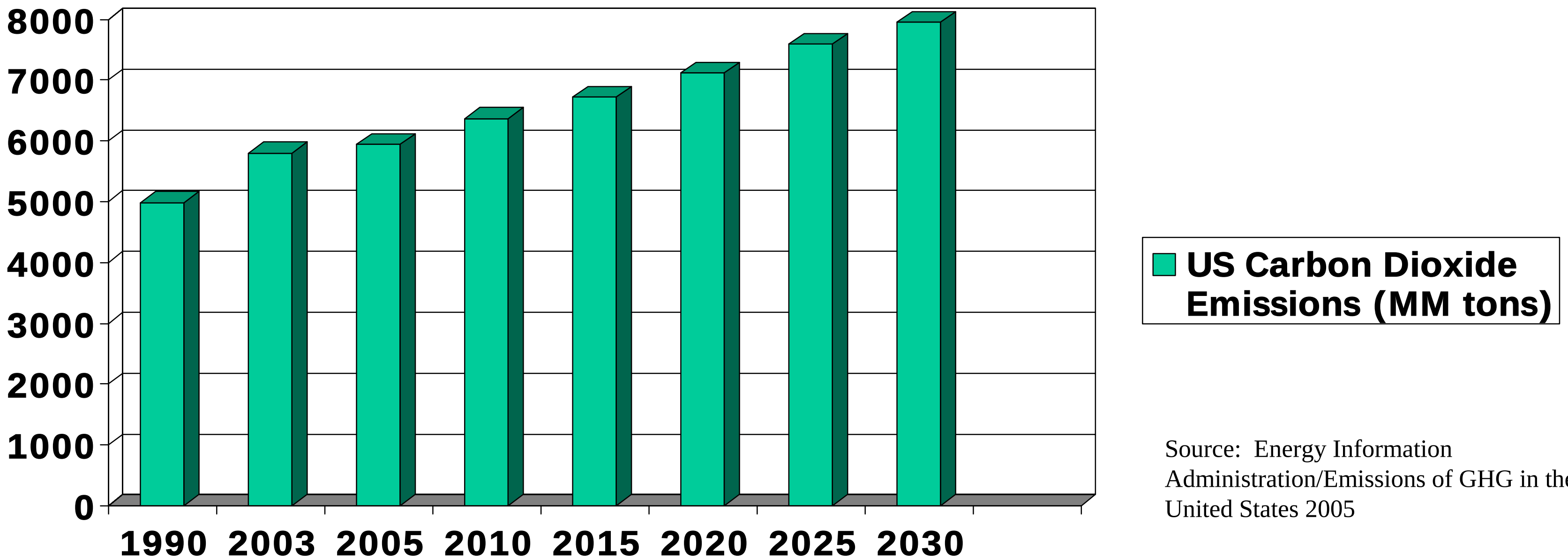
2007 Including Lawrenceburg **$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

Investment Decisions Today Must Consider Likelihood of Future CO_2 Emission Limits



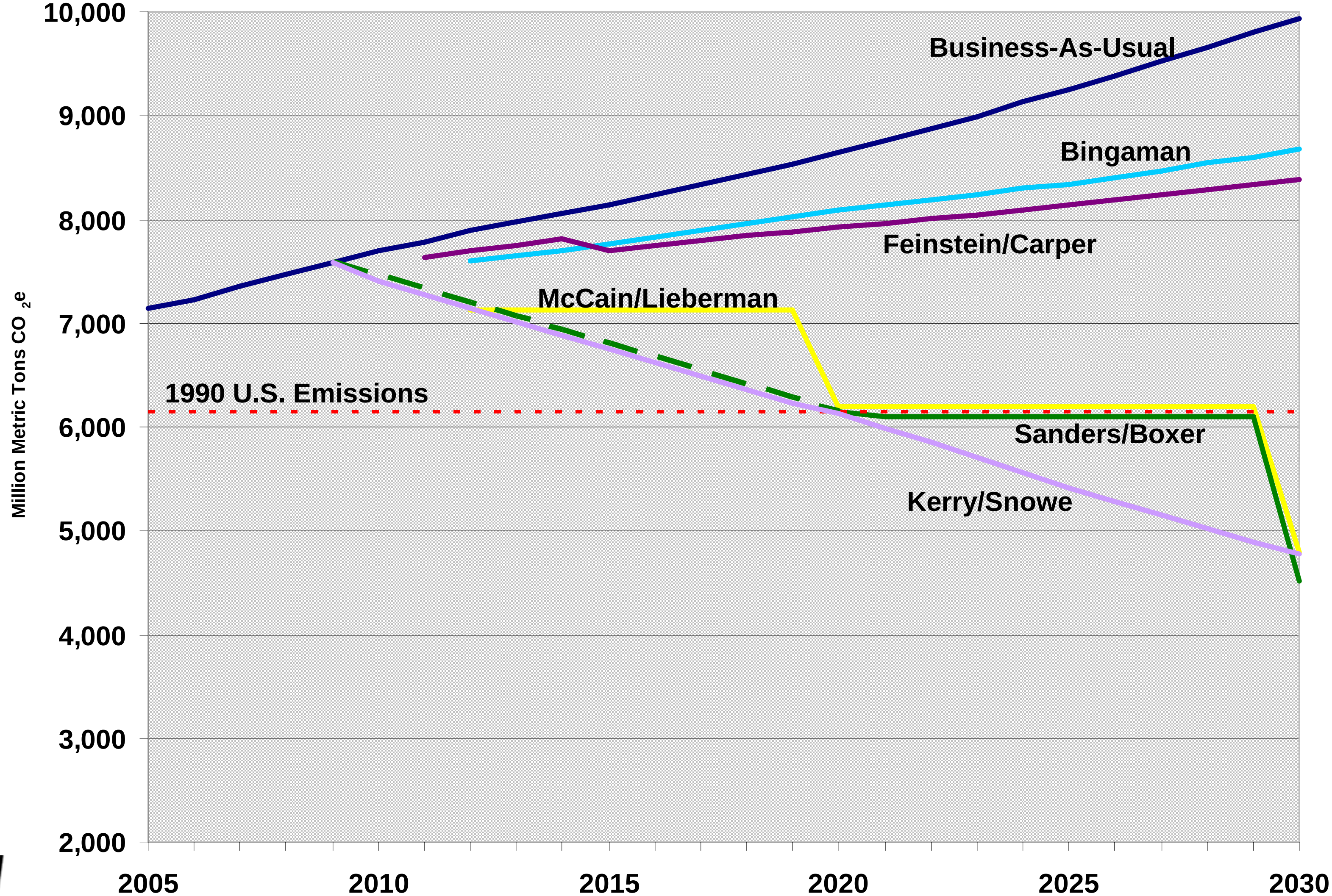
Source: Energy Information Administration/Emissions of GHG in the United States 2005

Note: Chart above assumes no mandatory limits imposed on CO_2 emissions

- Absent federal policies, long-term CO_2 growth is likely to be significant, driven by:
  - Population and economic growth
  - Increased penetration of computers, electronics and appliances
  - Increases in commercial floor space
  - Increases in highway, rail and air travel
- Likelihood of US GHG legislation is growing
  - Climate change science
  - Public perceptions
  - Political shifts in Congress

INCLUSION OF CLIMATE CHANGE IN INVESTMENT DECISIONS AND TAKING VOLUNTARY ACTIONS TO REDUCE CO_2 FOOTPRINT WILL ENHANCE SHAREHOLDER RETURN PROSPECTS

Initial Greenhouse Gas Regulatory Proposals
110th Congress



Sources: EIA & EPA data/forecasts

Note: Most proposals are still in "draft" stage

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

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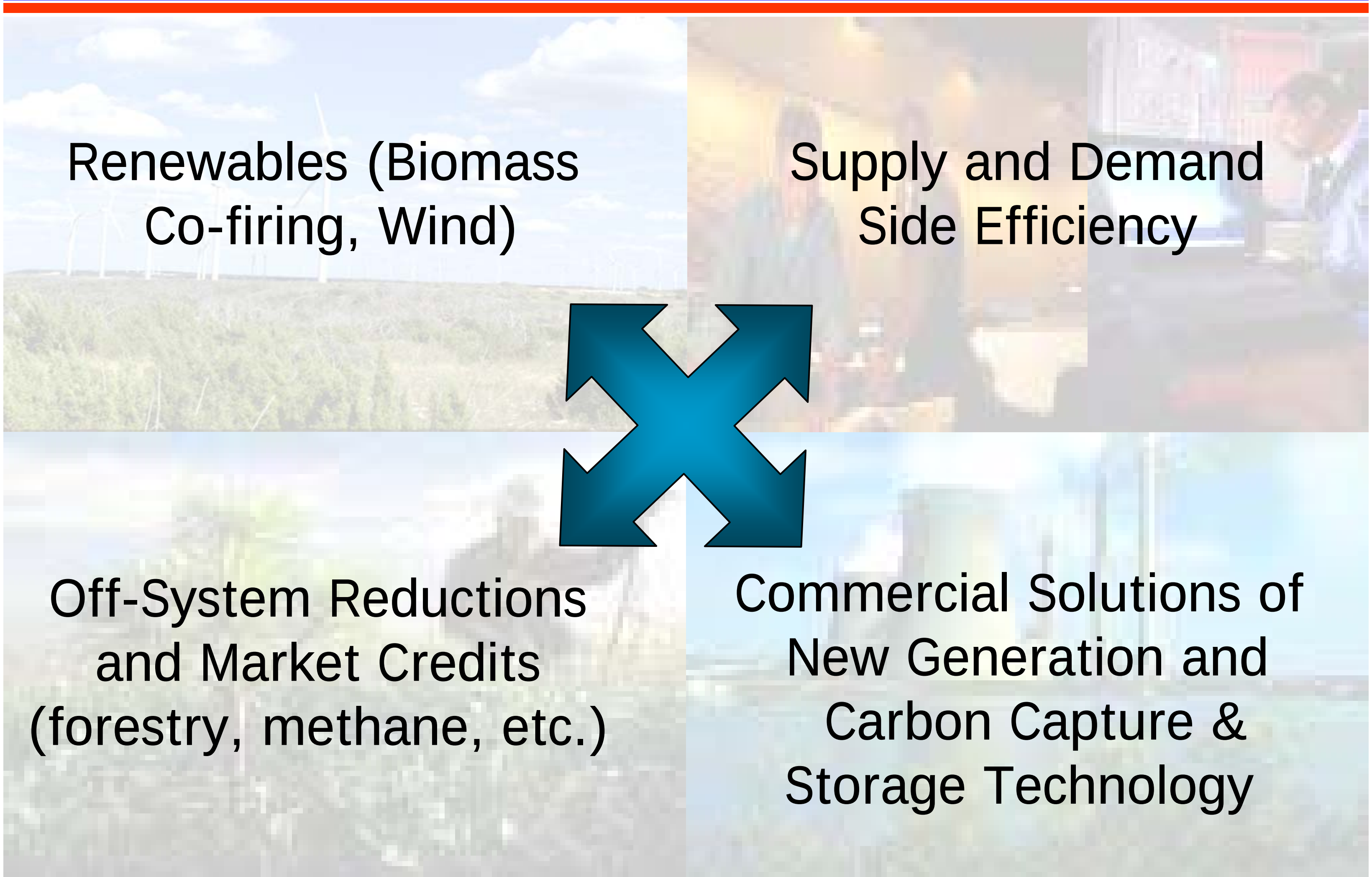
A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio



AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Strategic Emission Reduction Initiatives

- **Environmental Retrofit Program**
- **Power Plant Efficiency Improvements**
- **New Generation Technology**
  - IGCC
  - Ultra-supercritical
  - FutureGen
- **Carbon Reduction and Offset Program**
- **Carbon Capture and Storage**

AEP HAS A PLAN TO OFFSET THE GROWTH OF ITS FUTURE CO_2 EMISSIONS

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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KPSC Case No. 2011-00401
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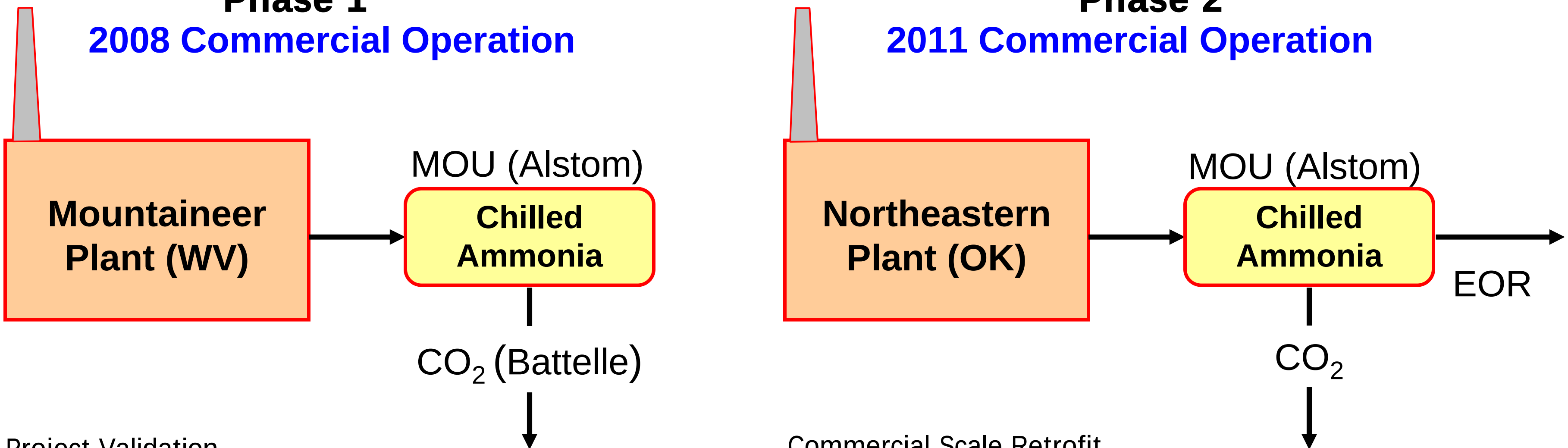
Attachment 1 - Confidential
Page 8045 of 9556

Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



<u>Project Validation</u>

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

<u>Commercial Scale Retrofit</u>

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

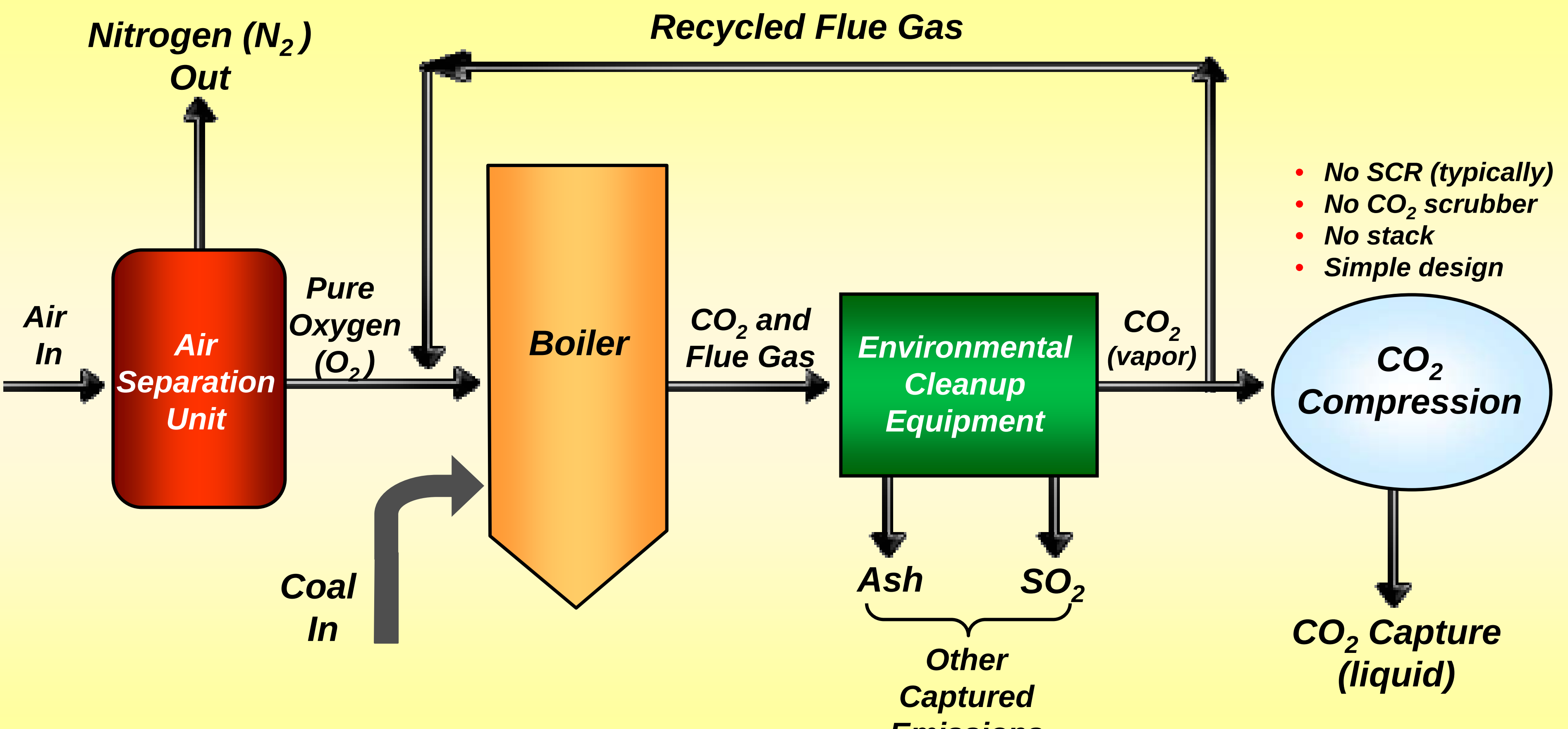

Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

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Coming Soon – AEP's 2006 Corporate Responsibility Report

Our Vision for Sustainability

AEP enters its second century committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities. We will safely provide reliable, reasonably priced electric power while actively working to protect people and the environment. We will engage stakeholders and continue our role in making people's lives better today and for generations to come.

Our Challenges & Opportunities

- Leadership, management and strategy
- Climate Change
- Energy security, reliability and growth
- Environmental performance
- Workforce issues
- Stakeholder engagement
- Public Policy

WE WILL CONTINUE TO WORK AS INNOVATIVELY, EFFICIENTLY, DILIGENTLY AND RESPONSIBLY AS WE DID DURING OUR FIRST CENTURY. SUSTAINABILITY IS A JOURNEY, NOT A DESTINATION.

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Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

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Appendix

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 38,300 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

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Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

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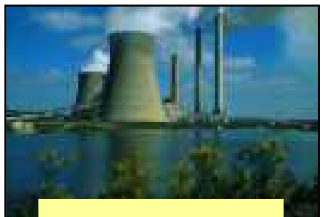
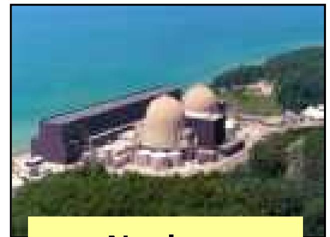
RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
38,292 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

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New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	1Q07[(1)]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[(2)]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[(3)]	Coal	Ultra-supercritical	600[(3)]	2011
PSO	Red Rock	Oklahoma	$1.8 B[(4)]	Coal	Ultra-supercritical	950[(4)]	2011
CSP/OP	Great Bend	Ohio	Under Review[(5)]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[(5)]	Coal	IGCC	600	TBD

(1) Sale expected to close 1Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

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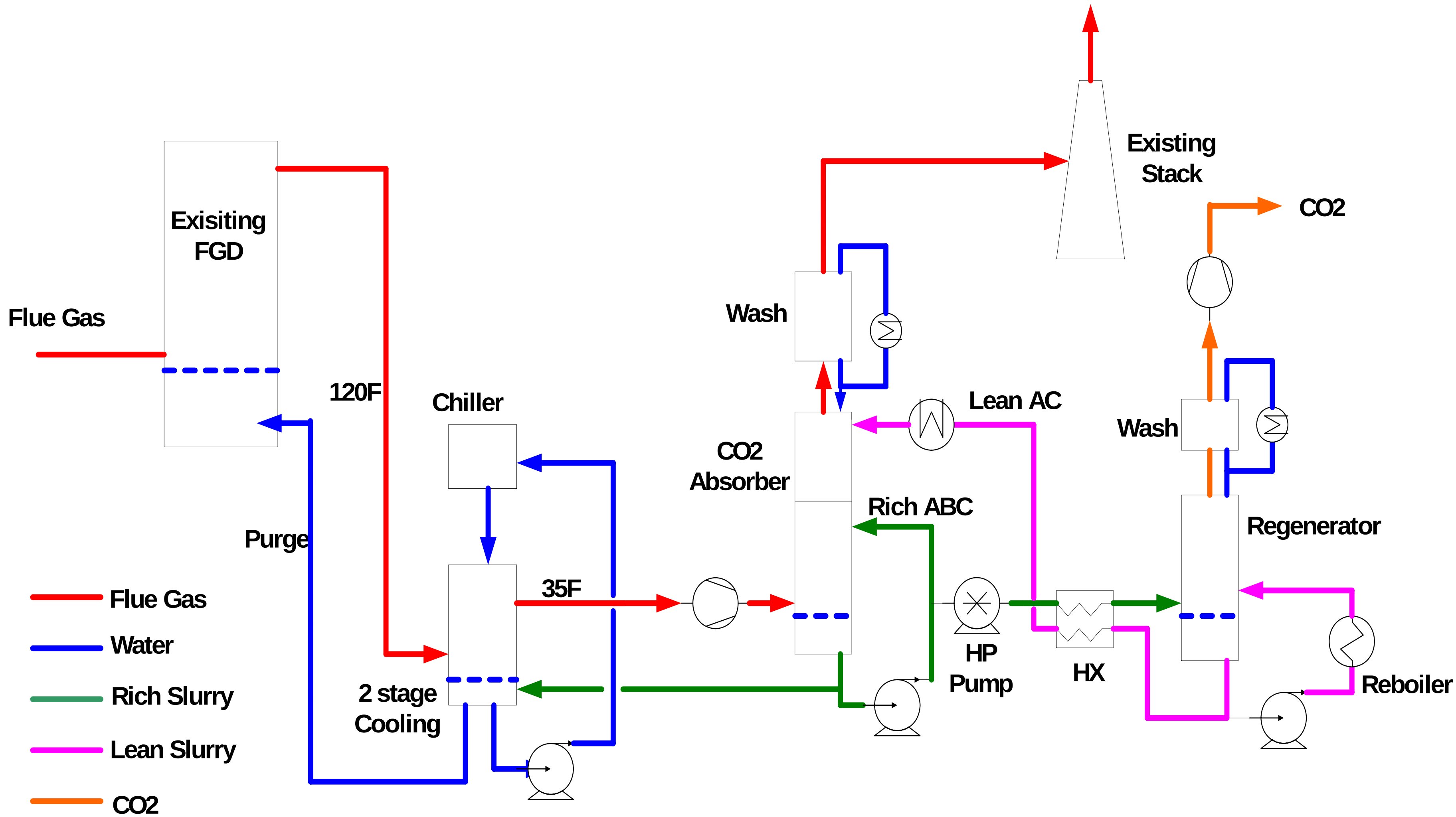
Schematic of the Chilled Ammonia Process

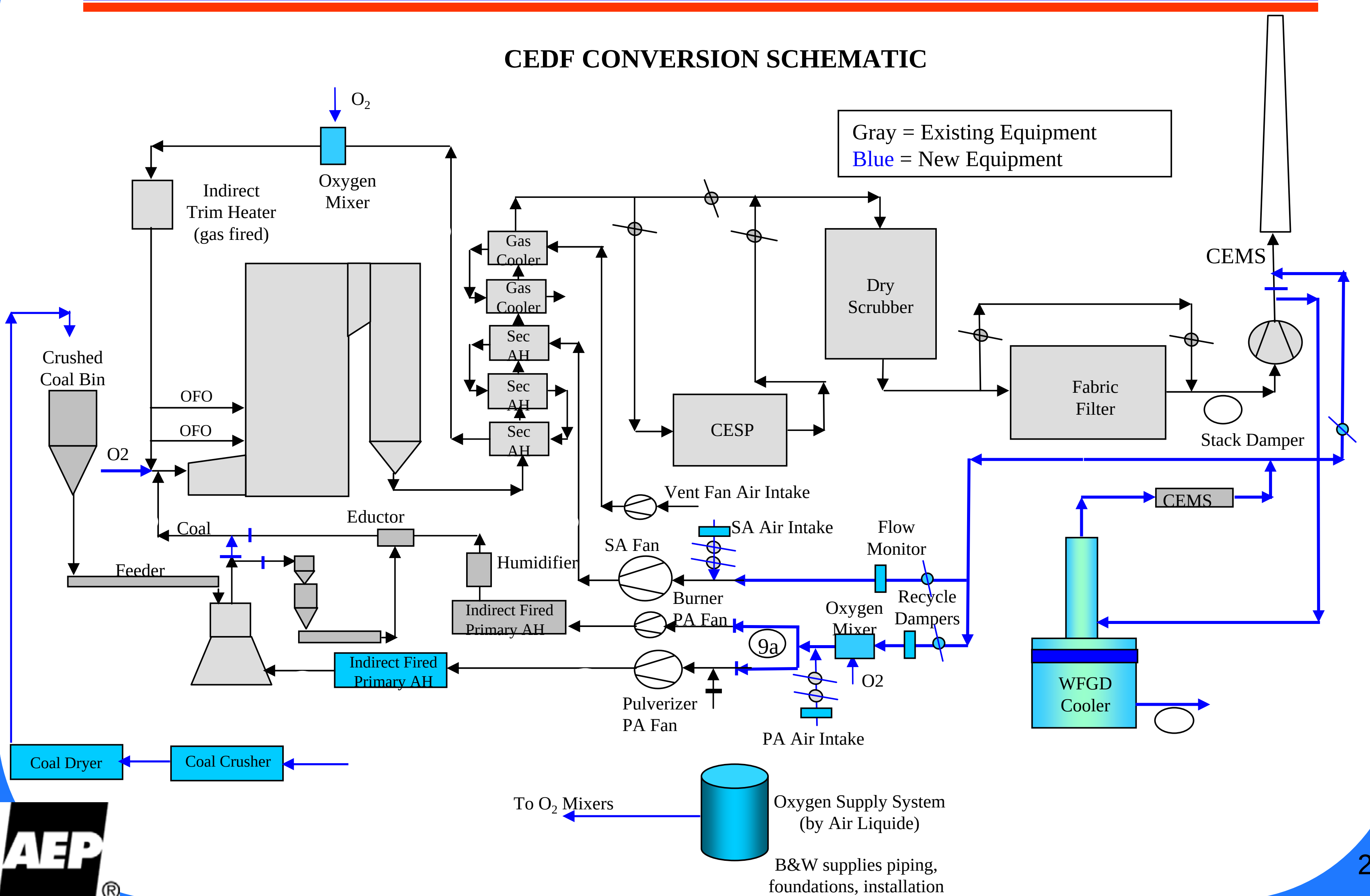


Cooling & Cleaning of FG

CO2 Absorption

CO2 Regeneration

Schematic of the Oxy-Fuel Process



Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval 1) to operate as an electric transmission utility in Texas; 2) to contribute transmission assets currently under construction by AEP subsidiary TCC to the joint venture company; and 3) establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%
  - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in early to mid-2007.

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 6, 2006	Hearings commenced
February 5, 2007	Briefs filed

Next Steps

APCo is now awaiting an initial recommendation from the Hearing Examiner (HE). APCo will have an opportunity to respond to the HE recommendation after it has been issued. Following this action, we then await an order from the SCC. No statutory deadline.

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. TCC and TNC requested rate increases of $81.1MM and $24.8MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony filed
March 23, 2007	Staff testimony due
Mid-April 2007	Hearings to commence
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	11.25%	4.50%
Total	100%		8.02%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	11.25%	4.50%
Total	100%		7.97%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$588,170,858	$ 1,012,316,518
Cost of Capital	8.02%	8.02%
Return on Rate Base	$ 47,144,247	$ 81,141,219
Operation & Maintenance	$ 24,953,569	$ 234,900,166
Depreciation & Amortization	$ 16,050,664	$ 61,560,580
Income Taxes	$ 13,127,245	$ 21,909,492
Taxes other than Income	$ 14,691,850	$ 65,648,324
Total Cost of Service	$115,967,575	$ 465,159,781
Miscellaneous Revenues	$ (4,557,543)	$ (33,982,023)
Base Rate Revenue Requirement	$111,410,032	$ 431,177,758
Test Year Adjusted Base Rate Rev.	$ 90,790,725	$ 390,700,744
Requested Base Rate Increase	$ 20,619,307	$ 40,477,014

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$171,049,145	$ 288,872,851
Cost of Capital	7.97%	7.97%
Return on Rate Base	$ 13,639,241	$ 23,034,353
Operation & Maintenance	$ 12,775,116	$ 60,434,214
Depreciation & Amortization	$ 12,206,069	$ 28,670,726
Income Taxes	$ 3,126,651	$ 5,279,031
Taxes other than Income	$ 3,661,924	$ 12,093,639
Total Cost of Service	$ 45,409,001	$ 129,511,963
Miscellaneous Revenues	$ (365,848)	$ (7,216,050)
Base Rate Revenue Requirement	$ 45,043,153	$ 122,295,913
Test Year Adjusted Base Rate Rev.	$ 36,025,589	$ 112,706,901
Requested Base Rate Increase	$ 9,017,564	$ 9,589,012

Note: O&M expenses and test year adjusted base rate revenues for distribution include TCOS billings

Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor testimony due
April 9, 2007	Rebuttal testimony due
May 1, 2007	Hearings to commence
June 20, 2007	Final order expected

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP®

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

AEP®

AEP AMERICAN ELECTRIC POWER®

Morgan Stanley Smith Barney Financial Advisors Meeting

Dallas, TX

March 4, 2010

Hurricane Ike Restoration

765-kV Transmission Line (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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Brian Tierney, EVP and CFO

Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 21 analysts
- 14 Buy Ratings
- 7 Hold Ratings

[1] yield percentage based on AEP closing price of $33.94 on 03/01/2010

Industry Leadership

One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.6
AEP	40.6
DUK	39.1
FPL	35.5
ETR	30.0
D	27.1
EXC	24.8
CPN	24.2
NRG	24.0
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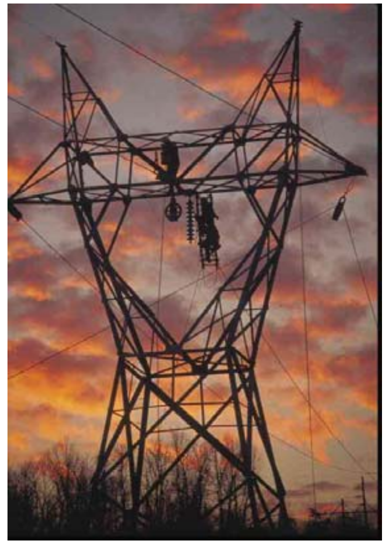

The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
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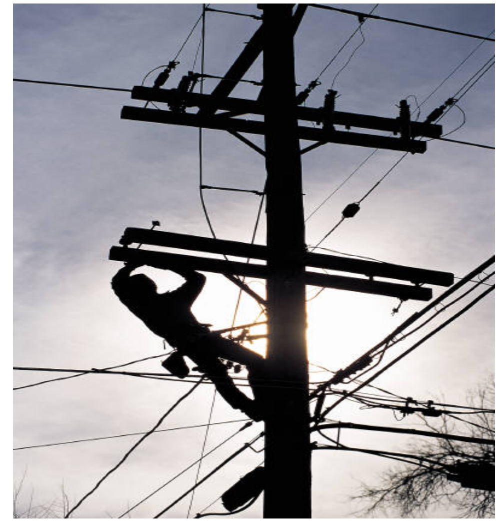


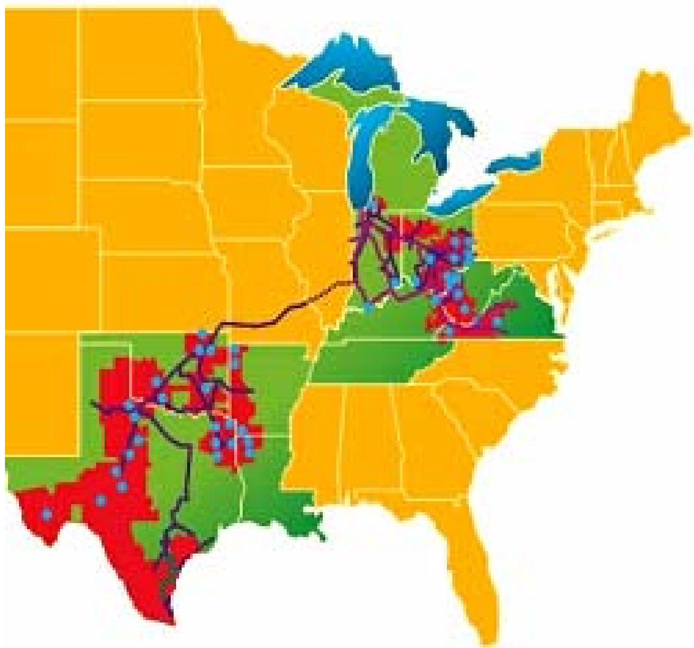
One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

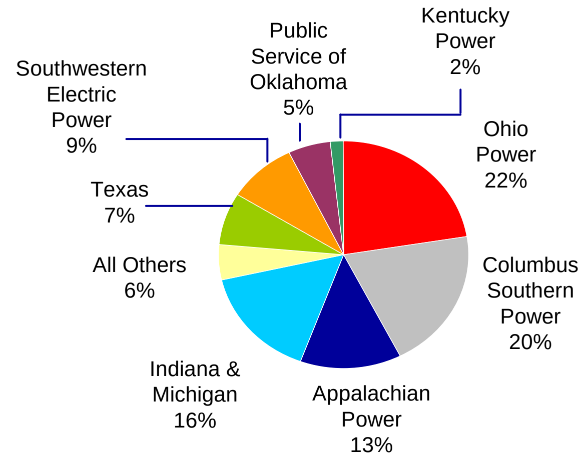
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8071 of 9556

Highly Diversified Regulated Utility Platform

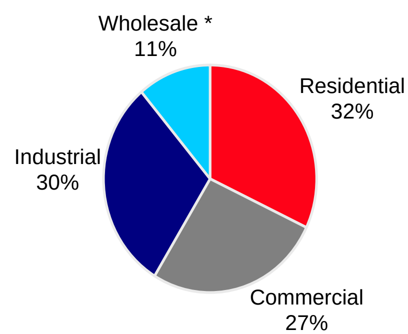


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

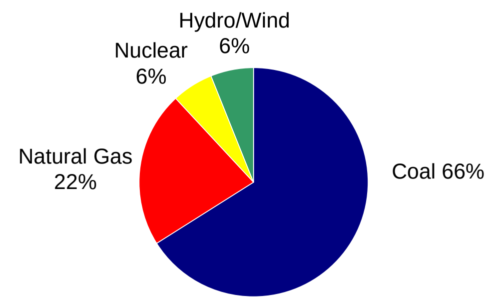


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

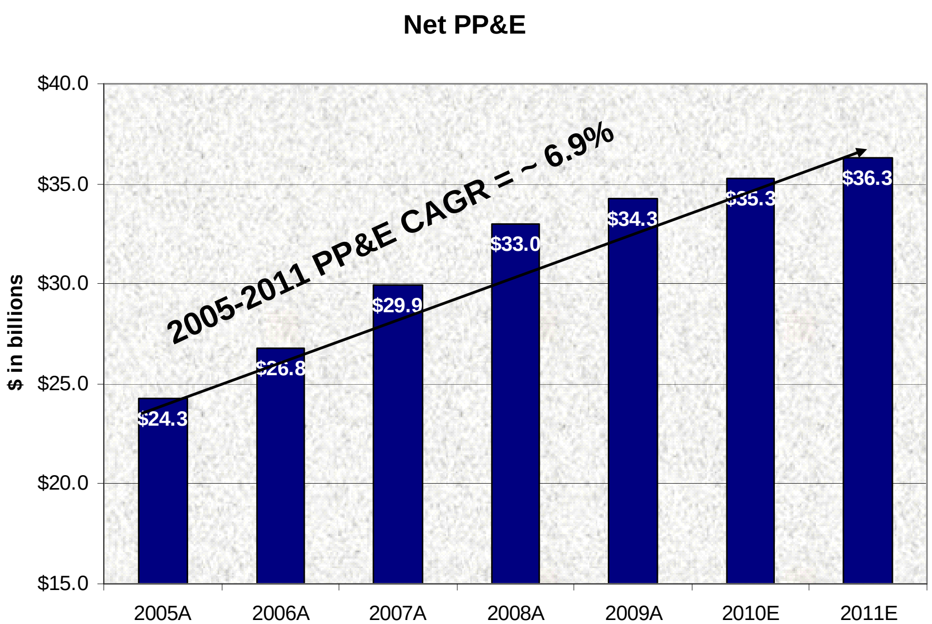
Fuel Mix



Traditional Ratemaking Environment

AEP®

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

- **Base Rates**
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- **Recovery of Fuel Costs**
  - Active fuel clauses in all jurisdictions
- **Opportunities to Reduce Regulatory Lag**
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- **Primarily wires-only business in Texas (transmission and distribution)**

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Carbon Capture and Storage Project – Mountaineer Plant (WV)

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

<u>ETT</u>: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.1B in this decade

<u>Transco</u>: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

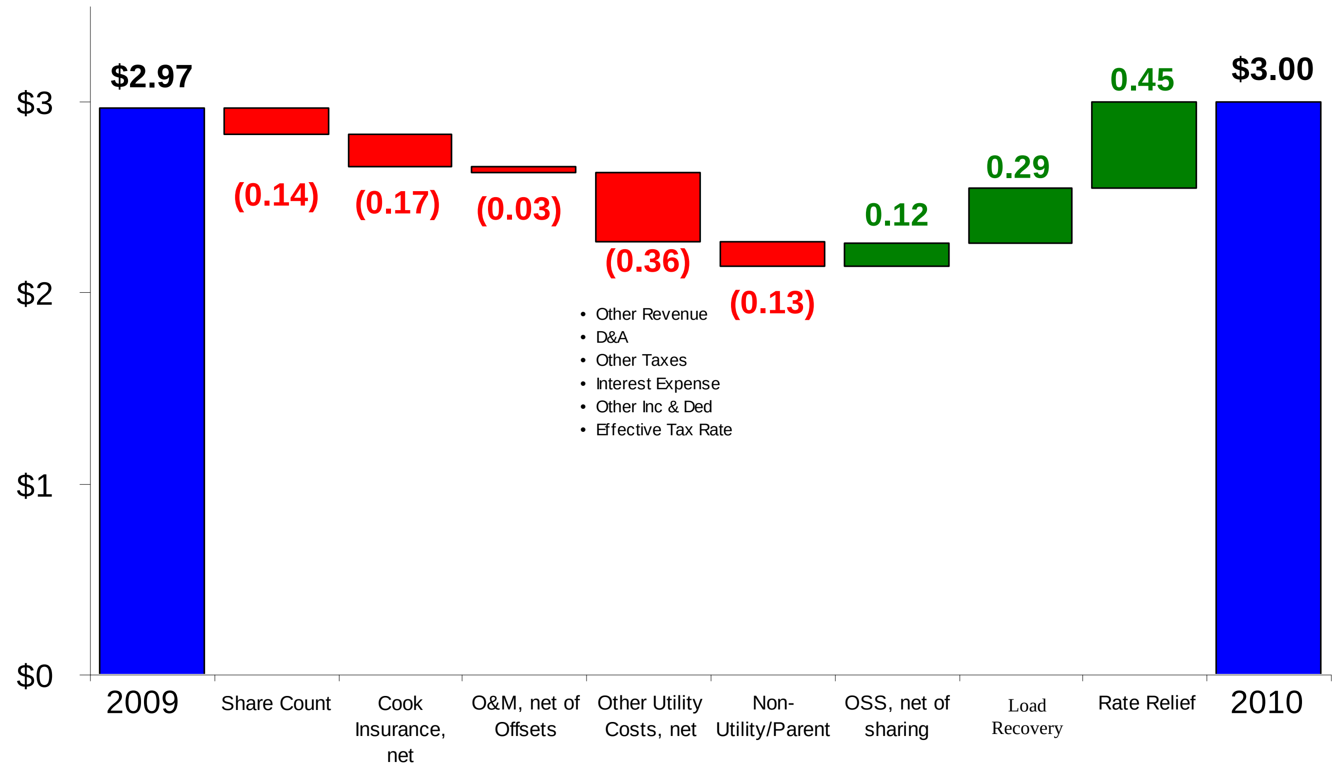
<u>Joint Ventures</u>: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

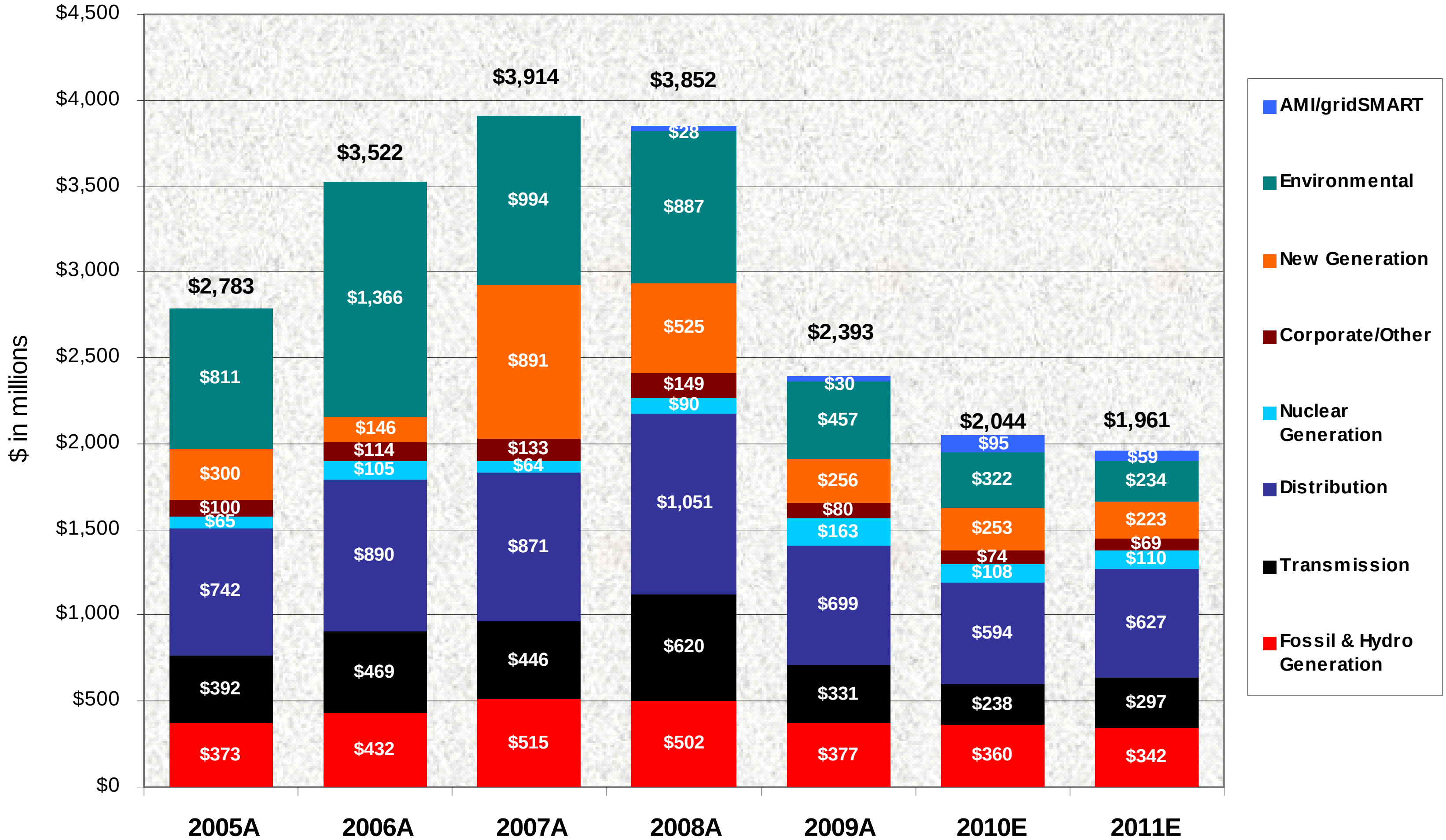
765-kV Tower

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



Utility Operations Capital Expenditures

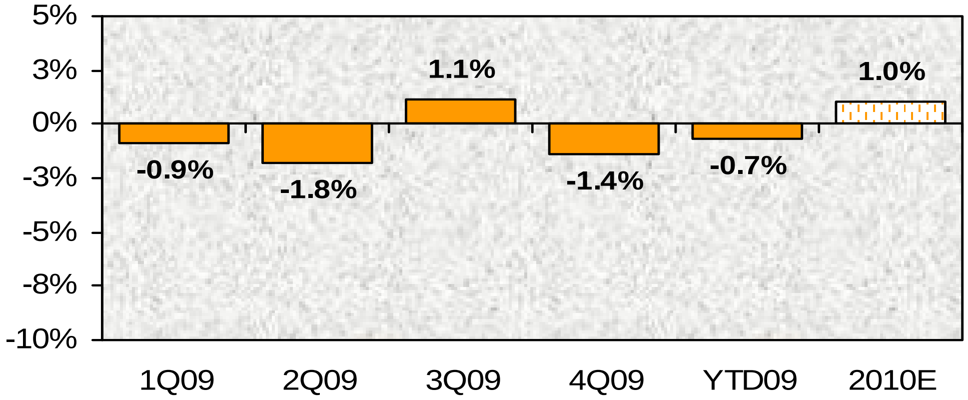


Non-Utility Operations Capital (not included above)

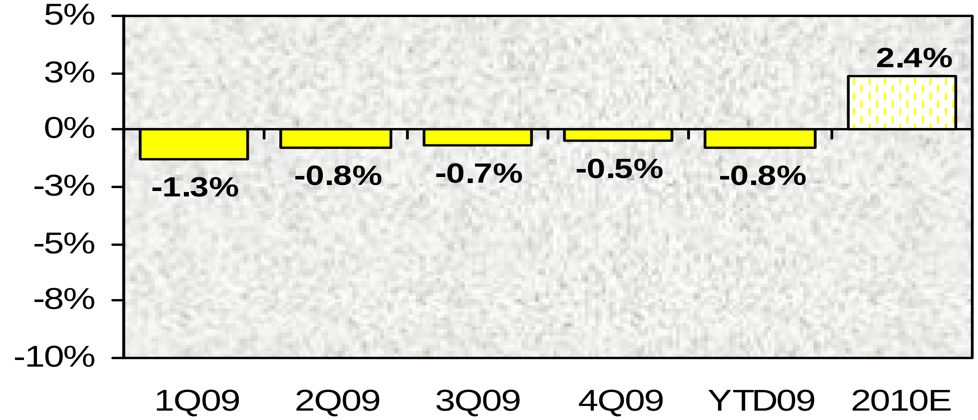
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Normalized Load Trends

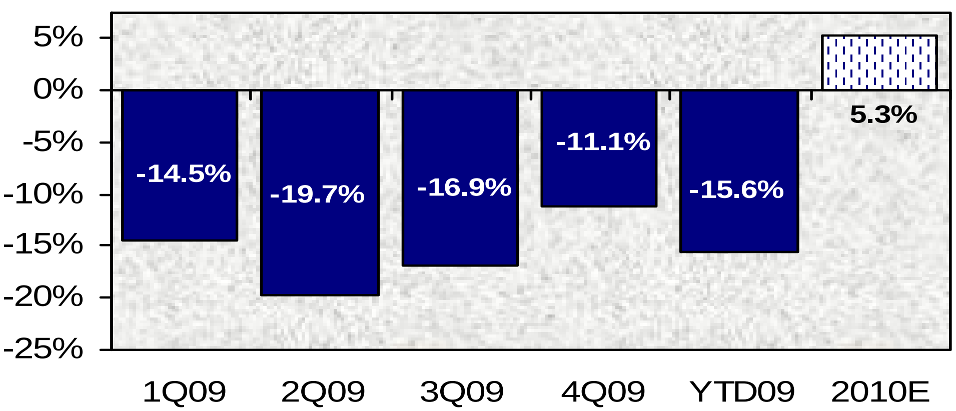
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



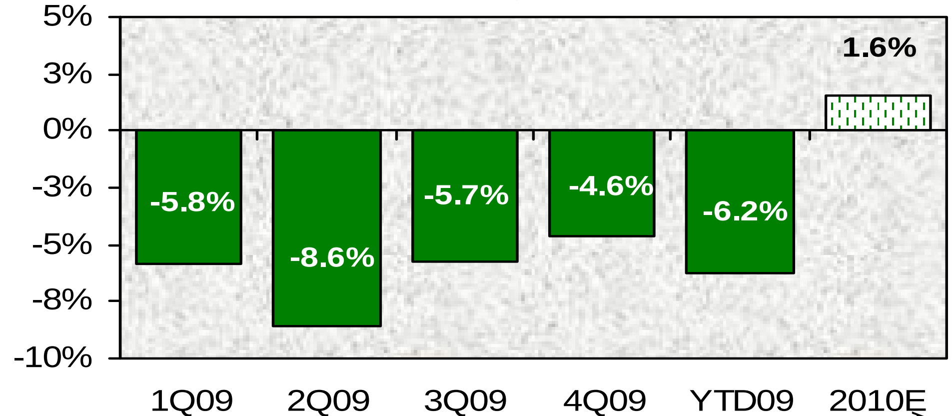
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

Dividend Overview

- We have declared 399 consecutive quarterly dividends to shareholders

- Annual Dividend - $1.64/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December

- Attractive yield of 4.8% as of March 1, 2010

- Conservative target dividend payout ratio of 50 – 60%

- Dividend Reinvestment Program Available

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- Strong Value Proposition

Mountaineer Plant (WV)

Morgan Stanley Smith Barney Financial Advisors Presentation

New York, NY

May 2010

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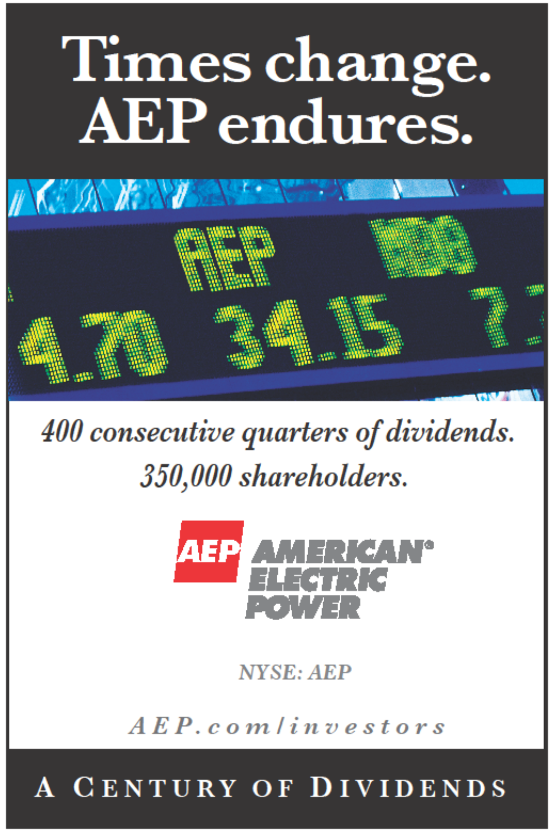
We are Proud of our Record….



Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 5.0%[1]**
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 21 analysts
- 15 Buy Ratings
- 6 Hold Ratings

Attractive total return potential

[1] yield percentage based on AEP closing price of $33.84 on 04/29/2010

Industry Leadership

One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
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AEP	40.6
DUK	38.9
EXC	31.2
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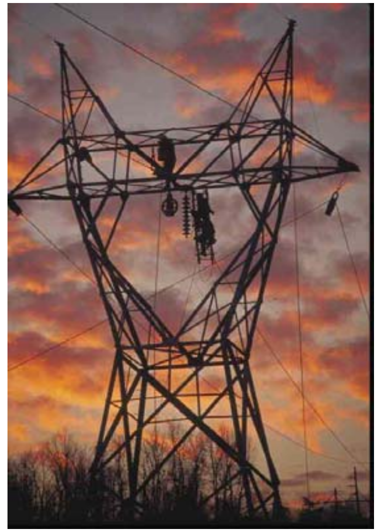

The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
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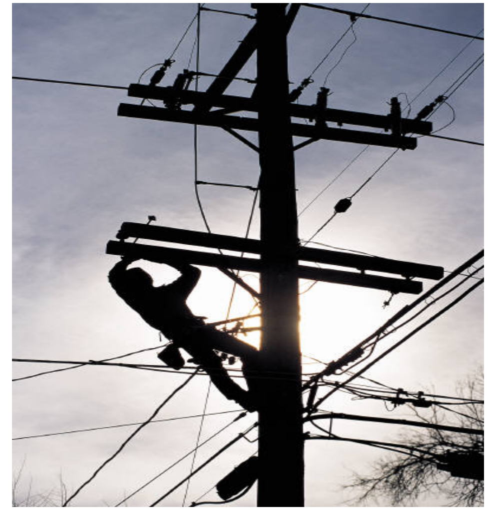
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

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PGN	3.1

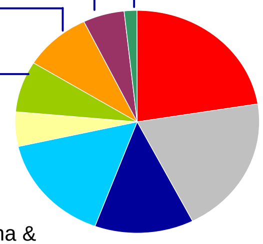
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

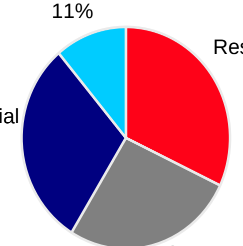
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



2009 Retail Load



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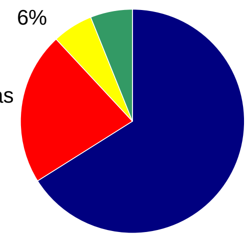
Fuel Mix



2010 Ongoing Earnings Guidance

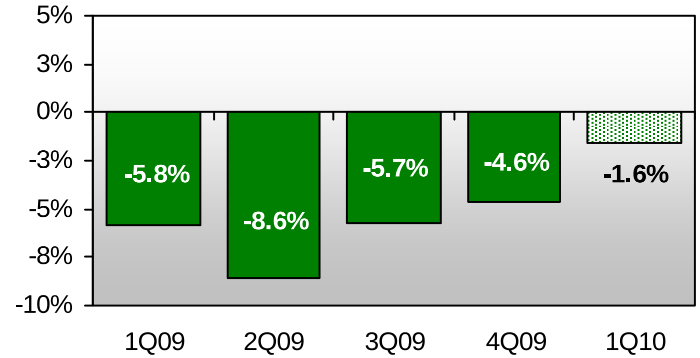
2009A: $2.97/share

2010E: $2.80-$3.20/share

Potential Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes/prices**
- **O&M discipline**
- **Longer term—Transmission investment**

AEP Total Normalized GWh Sales*
Quarter %Change vs. Prior Year



2-4% EPS growth rate with 4% upside from Transmission

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

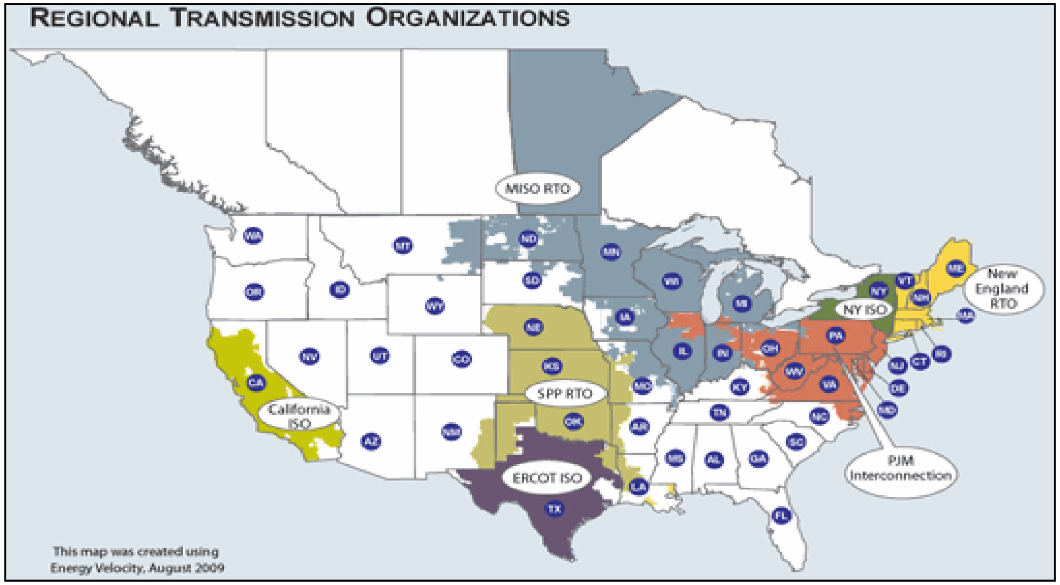
JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind — COD: 2013-14	**ETT** — COD: 2010-2017	**PATH-WV** — COD: 2014	**Pioneer** — COD: 2015
❑ *110 miles of 765 kV* ❑ *Partners: Westar (50%) & MidAmerican Energy (50%)* ❑ *Estimated Cost: $400 million* ❑ *ROE: 12.8%*	❑ *345 kV ERCOT Expansion* ❑ *Partner: MidAmerican Energy (50%)* ❑ *Estimated Cost: $1.4 billion* ❑ *ROE: 9.96%*	❑ *275 miles of 765 kV* ❑ *Partner: Allegheny Energy (50%)* ❑ *Estimated Cost: $1.2 billion* ❑ *ROE: 14.3%*	❑ *240 miles of 765 kV* ❑ *Partner: Duke Energy (50%)* ❑ *Estimated Cost: $1 billion* ❑ *ROE: 12.54%*

Tallgrass — COD: 2013-14

- ❑ *170 miles of 765 kV*
- ❑ *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- ❑ *Estimated Cost: $500 million*
- ❑ *ROE: 12.8%*



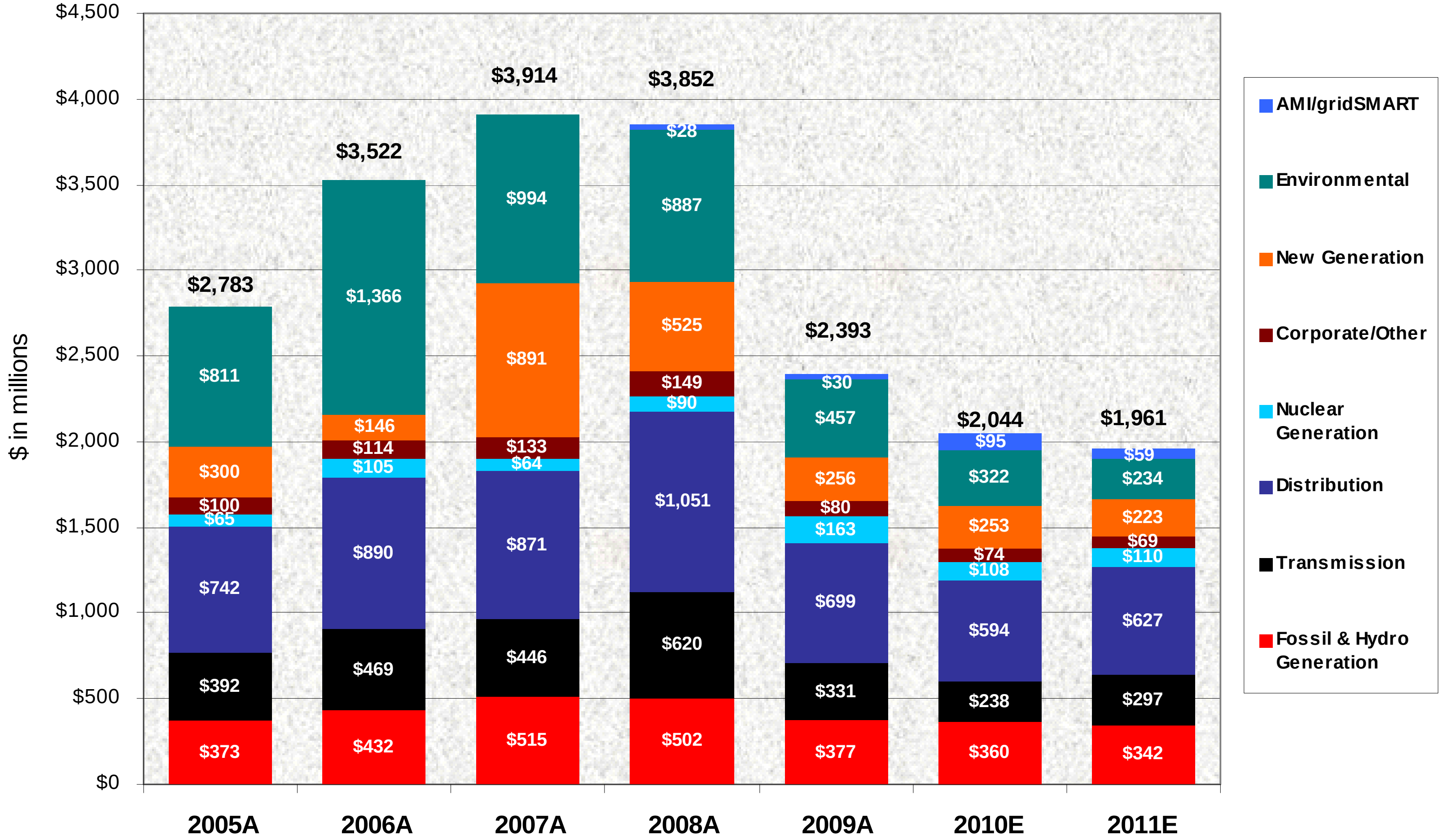
FUTURE DEVELOPMENT

SMARTransmission Study

- ❑ *Interregional EHV & Wind Integration Study*
- ❑ *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** — COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
❑ *Regional Expansion of 765 kV Backbone*	❑ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ❑ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	❑ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	❑ *700 miles of Proposed 765 kV*

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Dividend Overview

- **We will pay our 400th consecutive quarterly dividend to shareholders on June 10, 2010 to shareholders of record on May 10th**
- **Annual Dividend - $1.68/share**
  - **Declared in January, April, July and October**
  - **Paid in March, June, September and December**
- **Attractive yield of 5.0% as of April 29, 2010**
- **Conservative target dividend payout ratio of 50 – 60%**

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value and Total Return Proposition**

Mountaineer Plant (WV)

Mountaineer Plant

Investor Field Trip
New Haven, West Virginia
June 29, 2006

AEP AMERICAN ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Welcome to Mountaineer

Michael G. Morris
Chairman, President & CEO

Bill Sigmon

SVP – Fossil & Hydro Generation

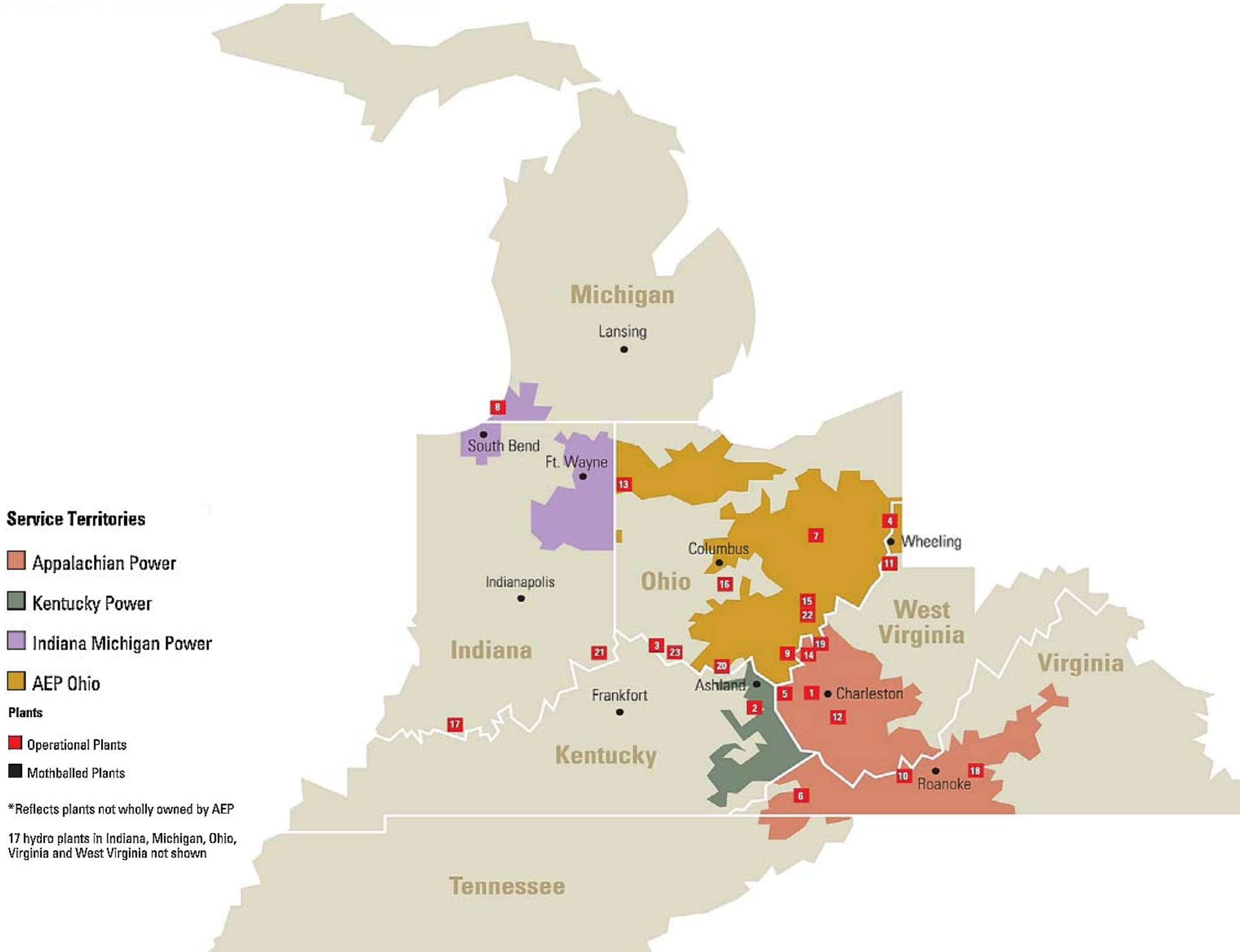
Fossil & Hydro Generation Fleet Recordable Incidents by Year

Year	Recordable Rate*	Severity Rate
2003	2.24	52.94
2004	2.01	67.91
2005	2.06	58.40
2006 Thru 1st Quarter	1.44	18.25

- *Without hearing losses
- Recordable Rate = Recordable cases x 200,000/hours worked
- Severity Rate = Lost worked days + Restricted activity days x 200,000/hours worked

AEP East Power Plants

1 **John E. Amos** St. Albans, WV
2 **Big Sandy** Louisa, KY
3 **Beckjord *** New Richmond, OH
4 **Cardinal *** Brilliant, OH
5 **Ceredo** Ceredo, WV
6 **Clinch River** Cleveland, VA
7 **Conesville *** Conesville, OH
8 **Donald C. Cook** Bridgman, MI
9 **Gen. James M. Gavin** Cheshire, OH
10 **Glen Lyn** Glen Lyn, VA
11 **Kammer-Mitchell** Moundsville, WV
12 **Kanawha River** Glasgow, WV
13 **Mone*** Convoy, OH
14 **Mountaineer** New Haven, WV
15 **Muskingum River** Beverly, OH
16 **Picway** Lockbourne, OH
17 **Rockport** Rockport, IN
18 **Smith Mountain** Sandy Level, VA
19 **Philip Sporn** New Haven, WV
20 **J. M. Stuart *** Aberdeen, OH
21 **Tanners Creek** Lawrenceburg, IN
22 **Waterford** Waterford, OH
23 **WM. Zimmer *** Moscow, OH



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AEP West Power Plants

24 **Arsenal Hill**
Shreveport, LA

25 **Comanche**
Lawton, OK

26 **Desert Sky**
Iraan, TX

27 **Dolet Hills** *
Mansfield, LA

28 **Flint Creek** *
Gentry, AR

29 **Fort Phantom**
Abilene, TX

30 **Knox Lee**
Longview, TX

31 **Lieberman**
Mooringsport, LA

32 **Lone Star**
Lone Star, TX

33 **Northeastern 1 & 2**
Oologah, OK

34 **Northeastern 3 & 4**
Oologah, OK

35 **Oklaunion** *
Vernon, TX

36 **Pirkey** *
Hallsville, TX

37 **Plaquemine***
Baton Rouge, LA

38 **Riverside**
Jenks, OK

39 **San Angelo**
San Angelo, TX

40 **Southwestern**
Anadarko, OK

41 **Sweeny** *
Old Ocean, TX

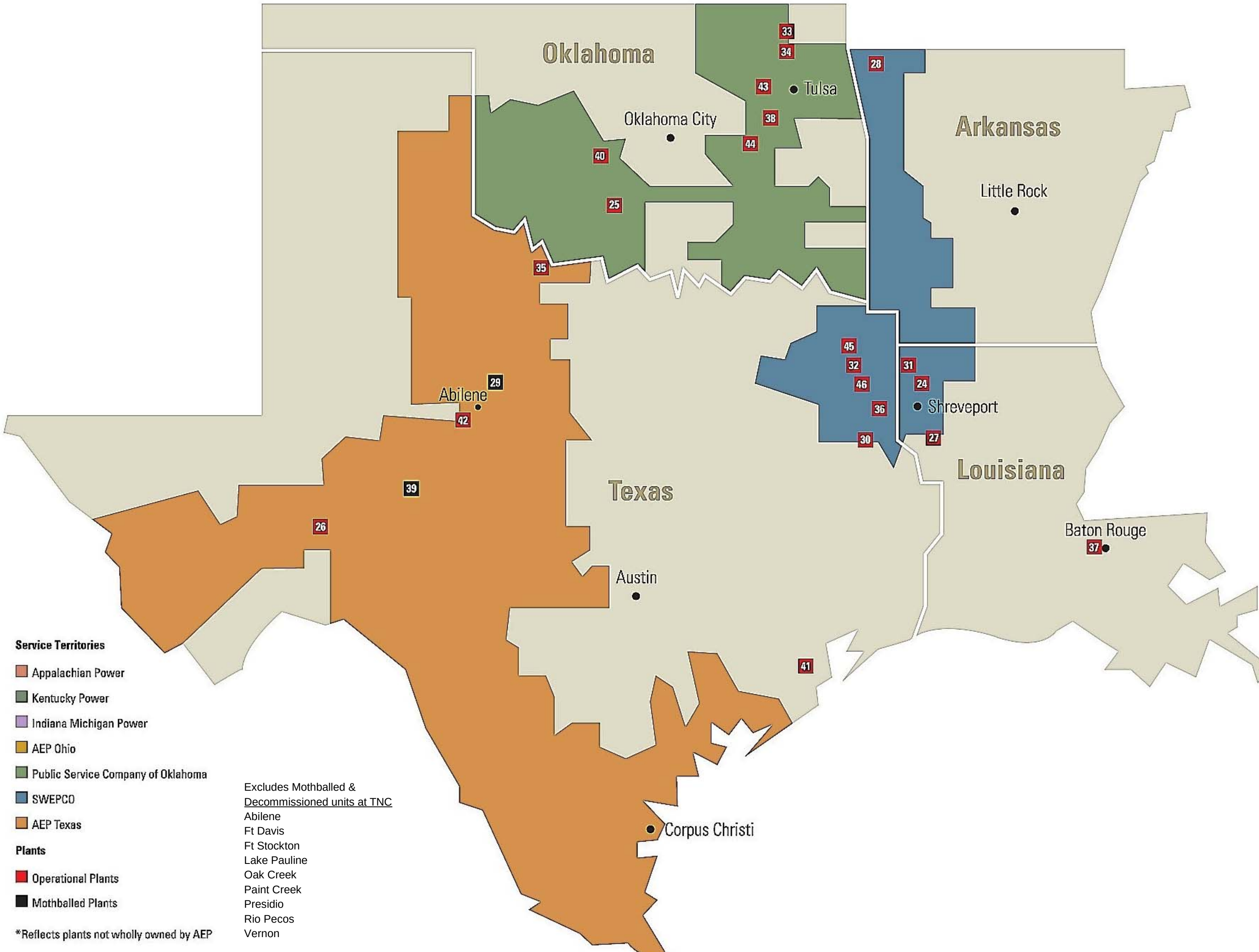
42 **Trent Mesa**
Trent, TX

43 **Tulsa**
Tulsa, OK

44 **Weleetka**
Weleetka, OK

45 **Welsh**
Pittsburg, TX

46 **Wilkes**
Avinger, TX



Excludes Mothballed &
Decommissioned units at TNC
Abilene
Ft Davis
Ft Stockton
Lake Pauline
Oak Creek
Paint Creek
Presidio
Rio Pecos
Vernon

AEP Fossil & Hydro Fleet Availability & Capacity Factor Statistics

Generation Performance	2006*	2005	2004
• Capacity Factor:	61.05%	62.1%	59.8%
• Equivalent Availability Factor:	79.92%	84.11%	82.09%
• Equivalent Forced Outage Rate:	6.62%	7.28%	7.85%

* Thru 1st Quarter

Region 1 Availability & Capacity Factor Statistics

Generation Performance	2006*	2005	2004
• Capacity Factor:	82.32%	80.53%	73.04%
• Equivalent Availability Factor:	86.85%	86.60%	82.33%
• Equivalent Forced Outage Rate:	3.71%	5.71%	7.37%

Region 1 Plants:

• Amos	2900 MW
• Gavin	2600 MW
• Mountaineer	1300 MW
• Rockport	2600 MW
	9400 MW

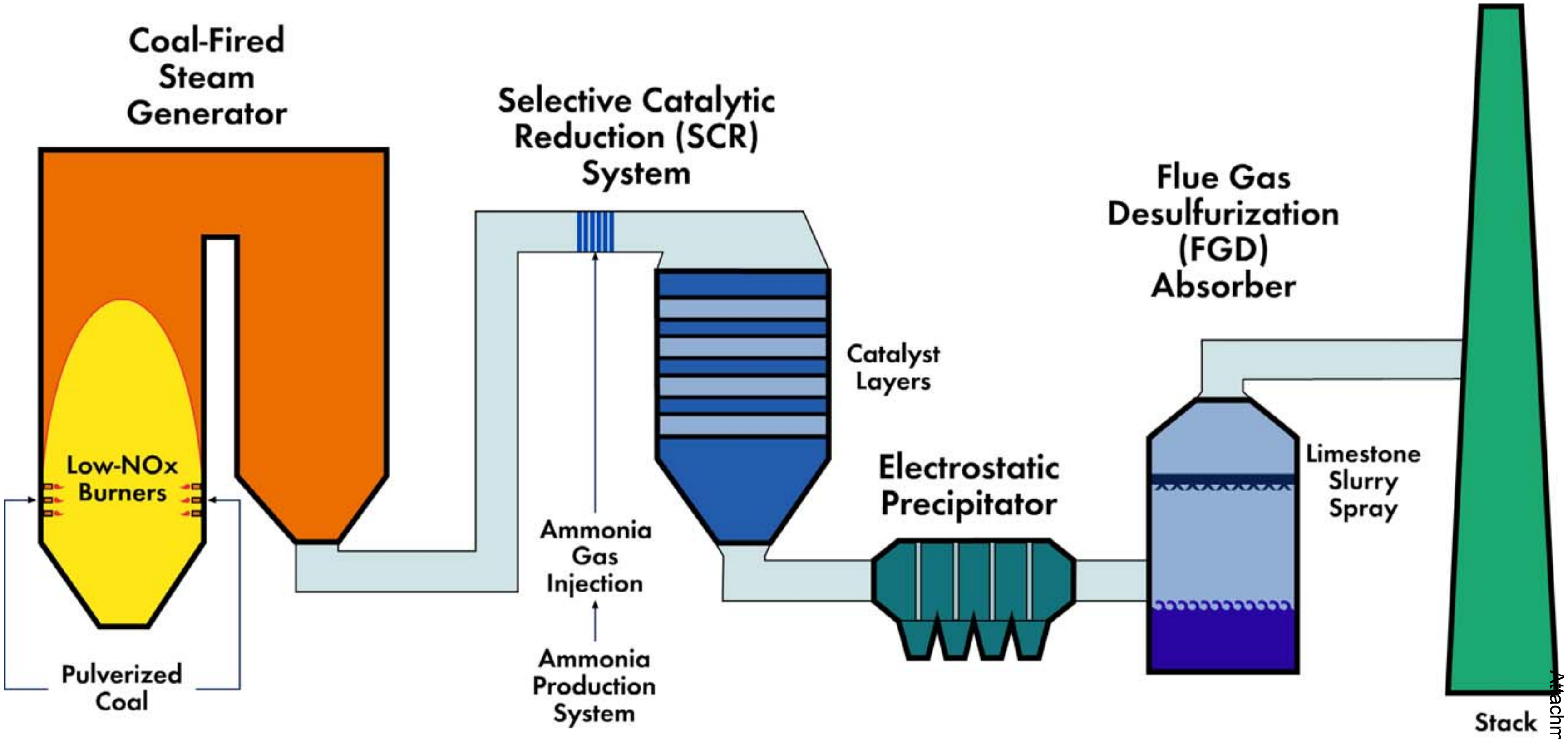
* Thru 1st Quarter

Mountaineer Plant Availability & Capacity Factor Statistics

Generation Performance	2006*	2005
• Capacity Factor:	96.61%	92.41%
• Equivalent Availability Factor:	99.47%	97.61%
• Equivalent Forced Outage Rate:	0%	1.46%

* Thru 1st Quarter

Mountaineer Basic Operation



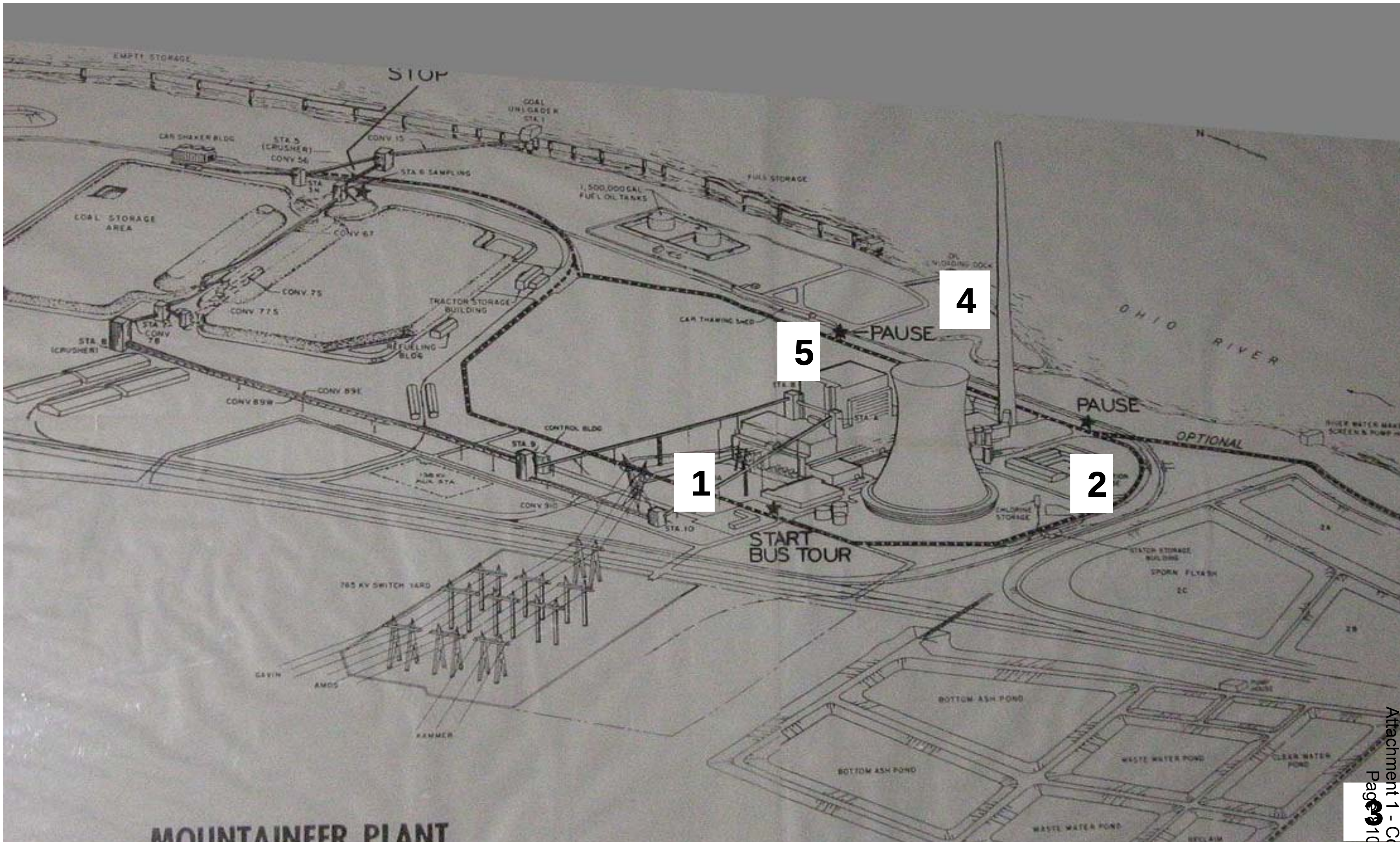
Mountaineer Plant Statistics

- One 1300 MW Unit - generating energy capacity of 10,500 GWH annually
- In service 1980
- 150 employees (excluding contractors)
- Pulverized coal fired steam generators
- Unit to be equipped with Flue Gas Desulfurization Systems (FGD) in Jan 07
- Selective Catalytic Reduction Systems (SCR) in-service 2002
  - NOx Emissions non-ozone season < 0.50 LB/MBTU
  - NOx Emissions ozone season (May-Sept) 0.05 LB/MBTU (90% reduction)
- Average coal yard storage capacity 420,000 thousand tons or 35 day supply
- Consume approximately 12,000 tons of coal daily or in excess of 4.0 million tons annually
- Coal delivered by barge (95%) and rail (5%)

Driving Toward Mountaineer Performance Levels at Other Large AEP Plants

- Fossil & Hydro Generation Organized in Regions by series (1300, 800, 600, etc.)
- Internal Benchmarking
- GAPs – applying learning at all applicable facilities
- Focused, correctly prioritized capital investment (2004 – 2008)
  - All pendant reheaters replaced approx. $70 MM
  - Superheater for Amos 3, Gavin 1, Gavin 2, Mountaineer, Rockport 1 approx. $125 MM
  - Other steam generators upgrade approx. $50 MM
  - Turbine and valve upgrade approx. $50 MM

PLANT TOUR ROUTE



Tour Layout

- Phase 1 – Bus Tour (begin at area 1 on map)
  - FGD construction site (area 2)
  - New mine location, gypsum landfill, waste water and bottom ash ponds (area 3)
  - New construction – E Crane to unload limestone from barge (area 4)

Phase 2 – Walking Tour Inside Plant (area 5)
  - Boiler
  - 18th Floor view
  - Control Room

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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TOUR SAFETY INSTRUCTIONS

KPSC Case No. 2011-00401
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Mike Rencheck

SVP – Engineering, Projects & Field Services

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

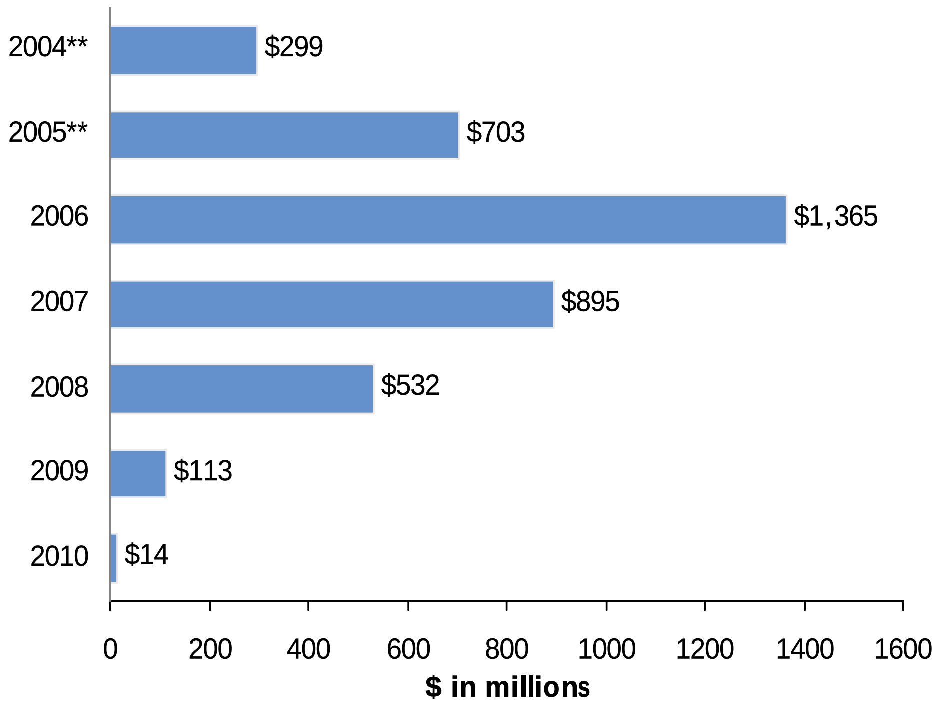
Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Environmental Investment: $3.9 Billion Through 2010

Environmental Capital Investment*

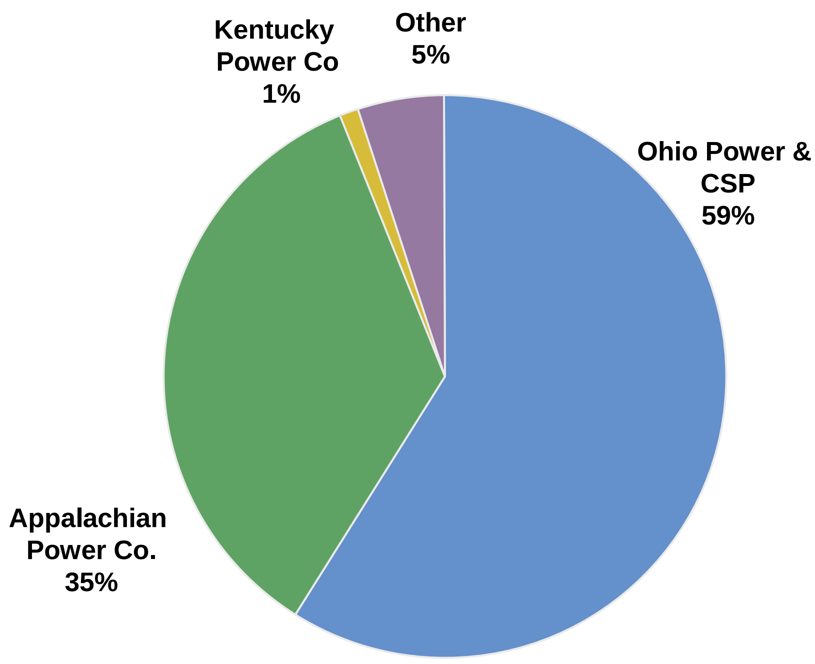


*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

($3.9 billion figure reflects delay of Big Sandy 2 investment)

Projected Environmental Investment Allocation



Majority of 2006 & 2007 dollars will be invested in Ohio & APCo

Environmental Investment

FGD – Reduces SO_2 by 95% to 98%

Co-Benefit Hg Capture

SCR - Reduces NOx by 90%

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1300	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	627	2009
Muskingum 5	585	2008
Conesville 4	339	2009
Total	**7951**	

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Cost of Control Technology

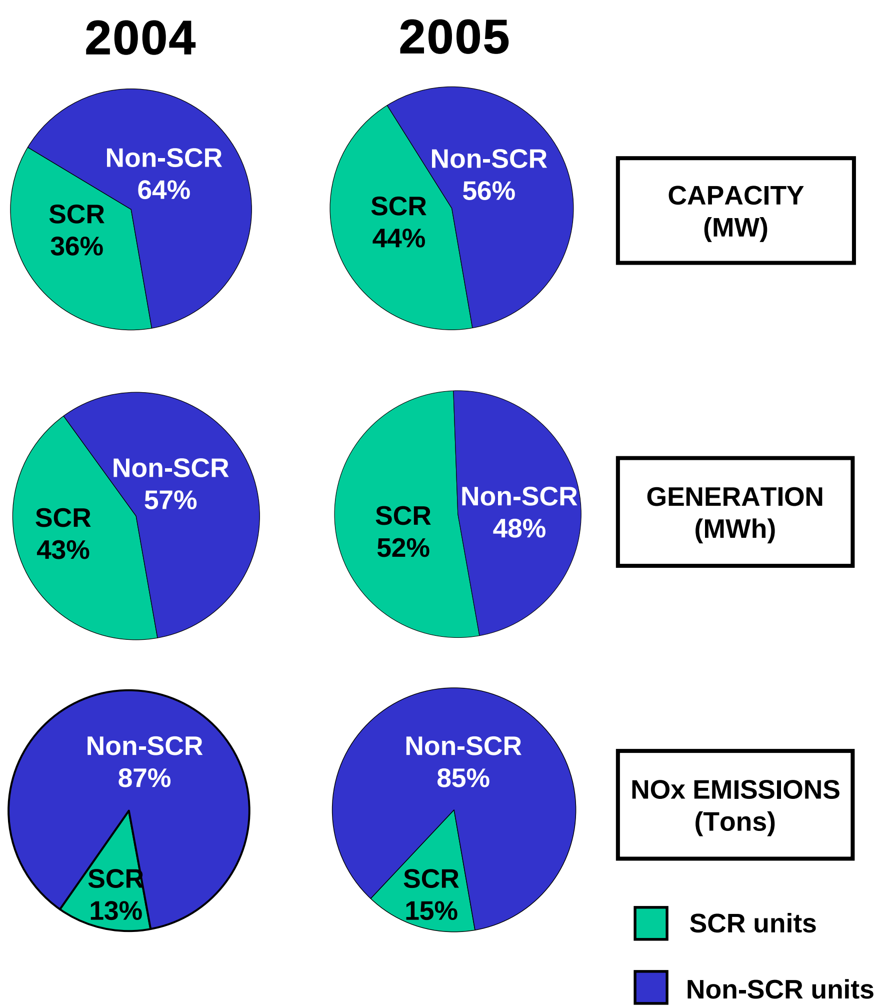
AEP's compliance plan largely relies on SCR & FGD technology to meet the requirements of CAIR and CAMR. AEP also deployed other combustion related controls, such as low NOx burners and optimized boiler controls throughout the system.

Conventional Technology

	SCR	**FGD**
AEP Capital Cost	~$121/kW avg.	~$250/kW avg.
Pollutant(s)	NO_x	SO_2 (& Hg as co-benefit)
Removal Efficiency	85 to 93%	95%-98% (&~80%)
Aux. Power	Approx. 1%	1.5% to 3.0%

SCR Performance and NOx Removal

OPERATED FOSSIL CAPACITY in OZONE SEASON



AEP has demonstrated the ability to achieve high NOx removals from units with SCR. Beginning in 2001 through the past two full ozone seasons, our operating experience has proven to be valuable as we continue to strive for consistently high NOx removals and increased boiler availabilities at these low NOx emitting plants.

Why scrub Mountaineer?

- Limitations on current coal supply due to current federal SO_2 limitations
- Access to competitive high sulfur coal supply
- Landfill readily available
- Age of unit
- Easy to retrofit & attractive economies of scale
- Unit has SCR installed – co-benefit of mercury reduction

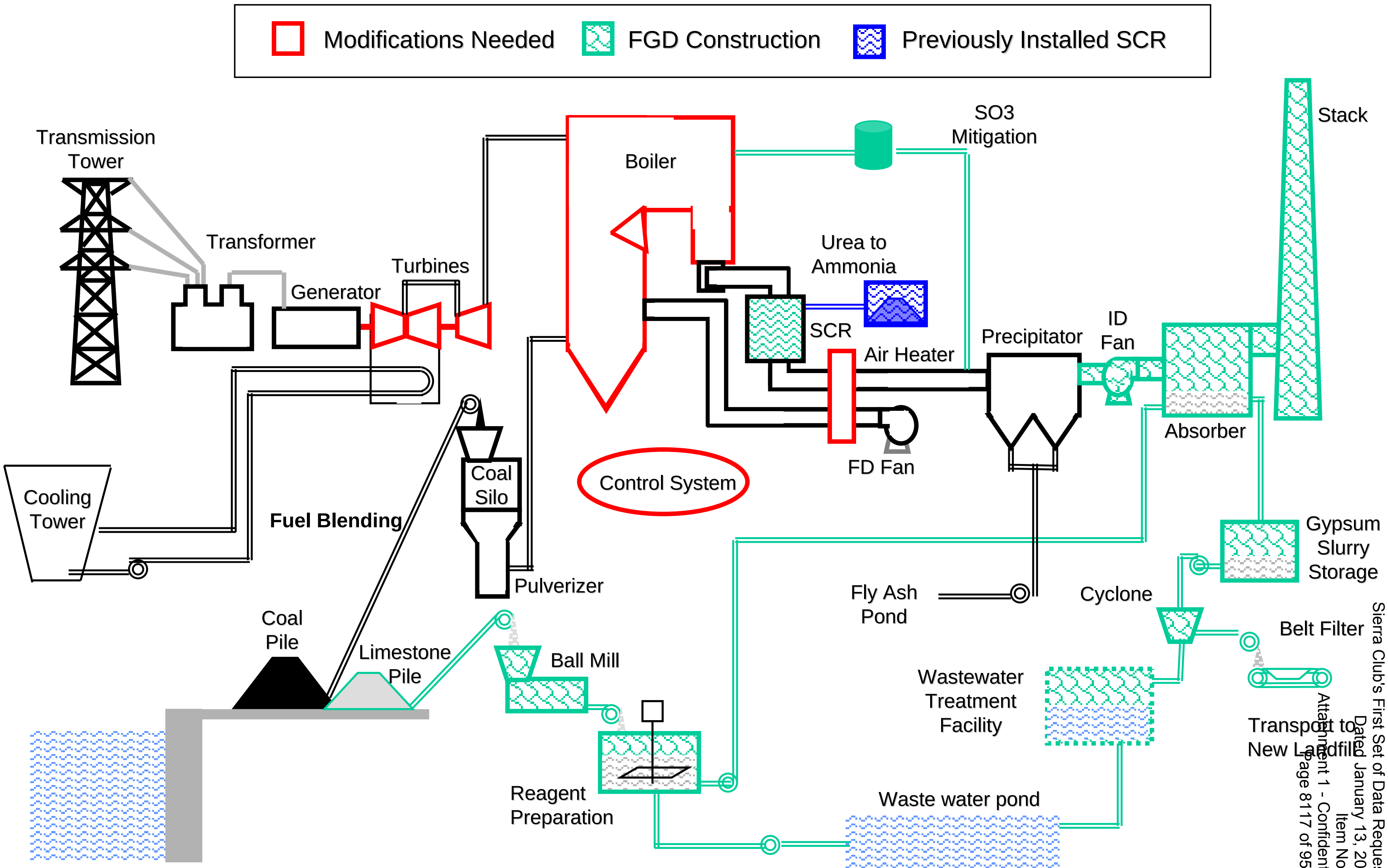
Typical FGD Installation Effect

The FGD design will accommodate higher sulfur coal and expand the fuel flexibility of the plant, while maintaining reduced SO_2 emissions. This fuel flexibility will permit adaptation in changing coal markets to optimize the economic viability of the plant.

The Process -

- **Higher sulfur coal requires boiler upgrades to maintain reliable operation**
- **Creates byproduct (gypsum) that must be disposed via wallboard plant or landfill**
- **High sulfur coal promotes SO_3 formation that must be mitigated**
- **Water vapor from FGD requires a new “wet” chimney**
- **Auxillary power consumption 1.5-3%**

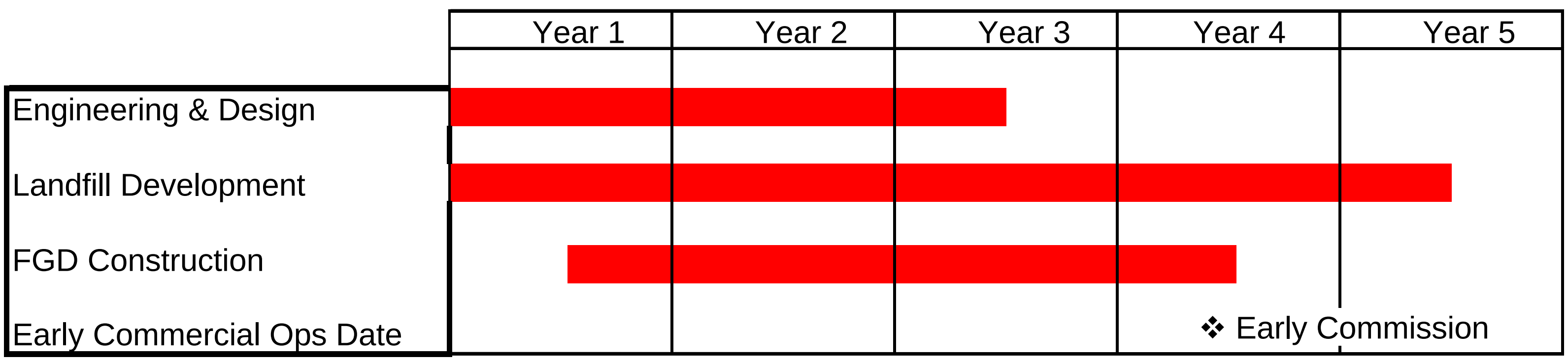
Mountaineer Plant Scope



Typical FGD Project Milestone Schedule

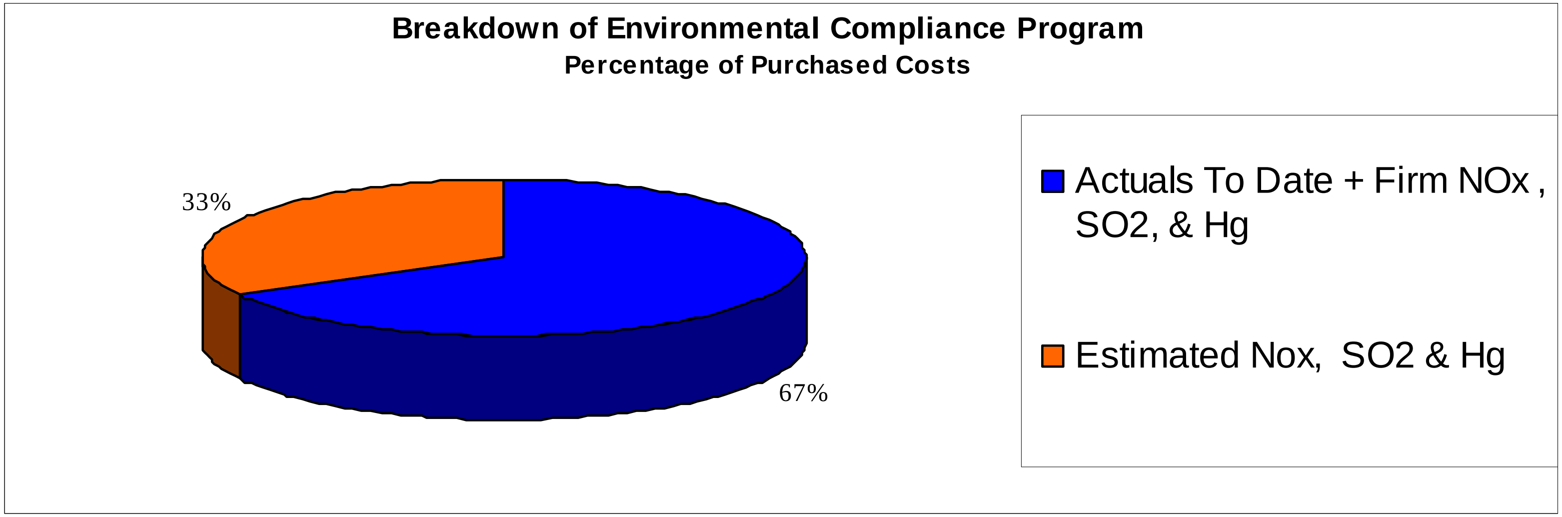
- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, Phase 3 Bid Construction at 30 – 60 % design complete

- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path



Materials and Vendors

Cost Management of Materials



Typical Vendors

- FGD
  - Spray Tower – B&W/Alstom
  - Jet Bubbling Reactor – B&V Chyioda
- Stack Supplier
  - Pullman Power Inc.
- SCR
  - Babcock Power
- Architect Engineering Firms
  - Black & Veatch
  - Sargent & Lundy
  - Shaw – Stone & Webster
  - Worley Parsons

Impact of SCR and FGD on Net Generation

- The overall generation loss in capacity associated with SCR and FGD for the entire AEP fleet is roughly 600MW.
- Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.
- Plant modifications increasing unit MW ratings are being implemented as part of the retrofit program
  - For example, Mountaineer turbine valve upgrades will increase unit output by ~30-45 MW
  - Similar upgrades will be implemented on other units

PLANT MODIFICATIONS WILL MITIGATE FGD AND SCR CAPACITY CONSUMPTION

IGCC Opportunity at Mountaineer Site

- Two sites under primary consideration
  - Great Bend (Ohio)
  - Mountaineer (West Virginia)
- IGCC footprint for 2-600 MW IGCC at either site
- Mountaineer offers advantages of existing infrastructure
  - Site preparation
  - River frontage development
  - Coal handling
  - Transmission
  - Landfill

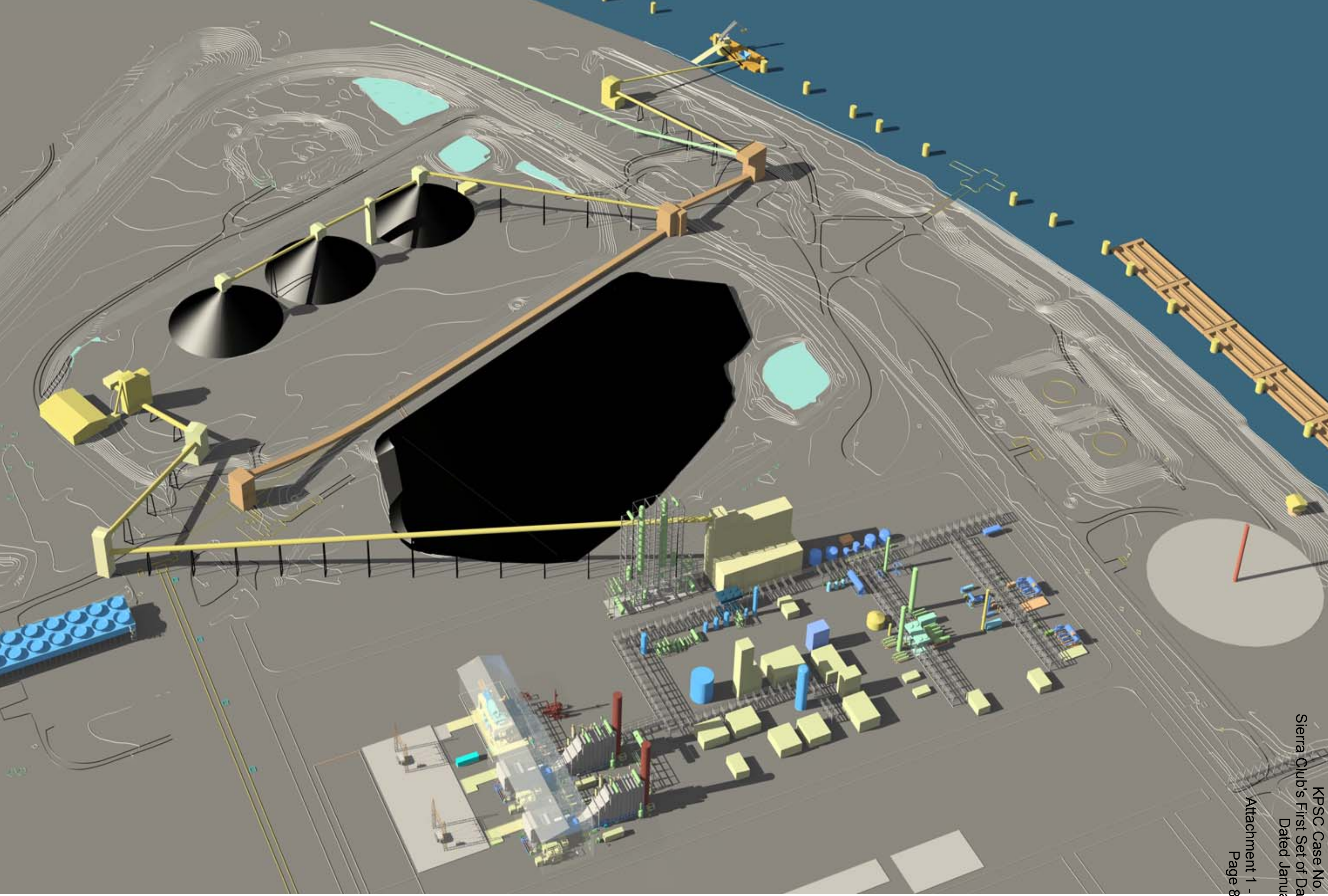
IGCC Opportunity at Mountaineer Site

- **Status**
  - **Concurrent FEED (Front End Engineering and Design) on both Mountaineer and Great Bend Sites with GE/Bechtel**
  - **Applications made to PJM on both sites for Facilities Studies**
  - **Air permit applications by 3Q06**
  - **Wastewater and U.S. Corps of Engineers permit applications in progress**

IGCC Opportunity at Mountaineer Site

- **Key Elements of Plant Design**
  - **2-GE 7FB Combustion Turbines**
  - **2-Radiant+Quench Gasifiers**
  - **SO_2 Removal > 99%**
  - **Mercury Removal > 90%**

- **Fuel Envelope**
  - **Chlorides to 3500 ppm (Illinois Basin)**
  - **Sulfur to 7.5 lb/MMBtu (Northern Appalachian)**
  - **Ash to 12%**
  - **Ability to blend up to 30% petroleum coke**



AEP AMERICAN ELECTRIC POWER

Mountaineer IGCC Plant Opportunity

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Chuck Zebula

SVP - Fuel, Emissions & Logistics

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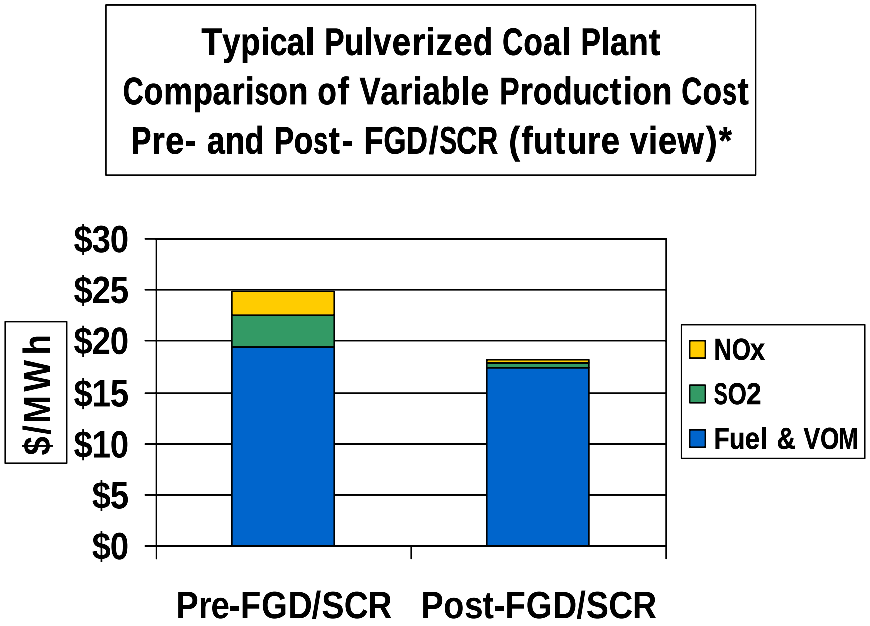
Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low



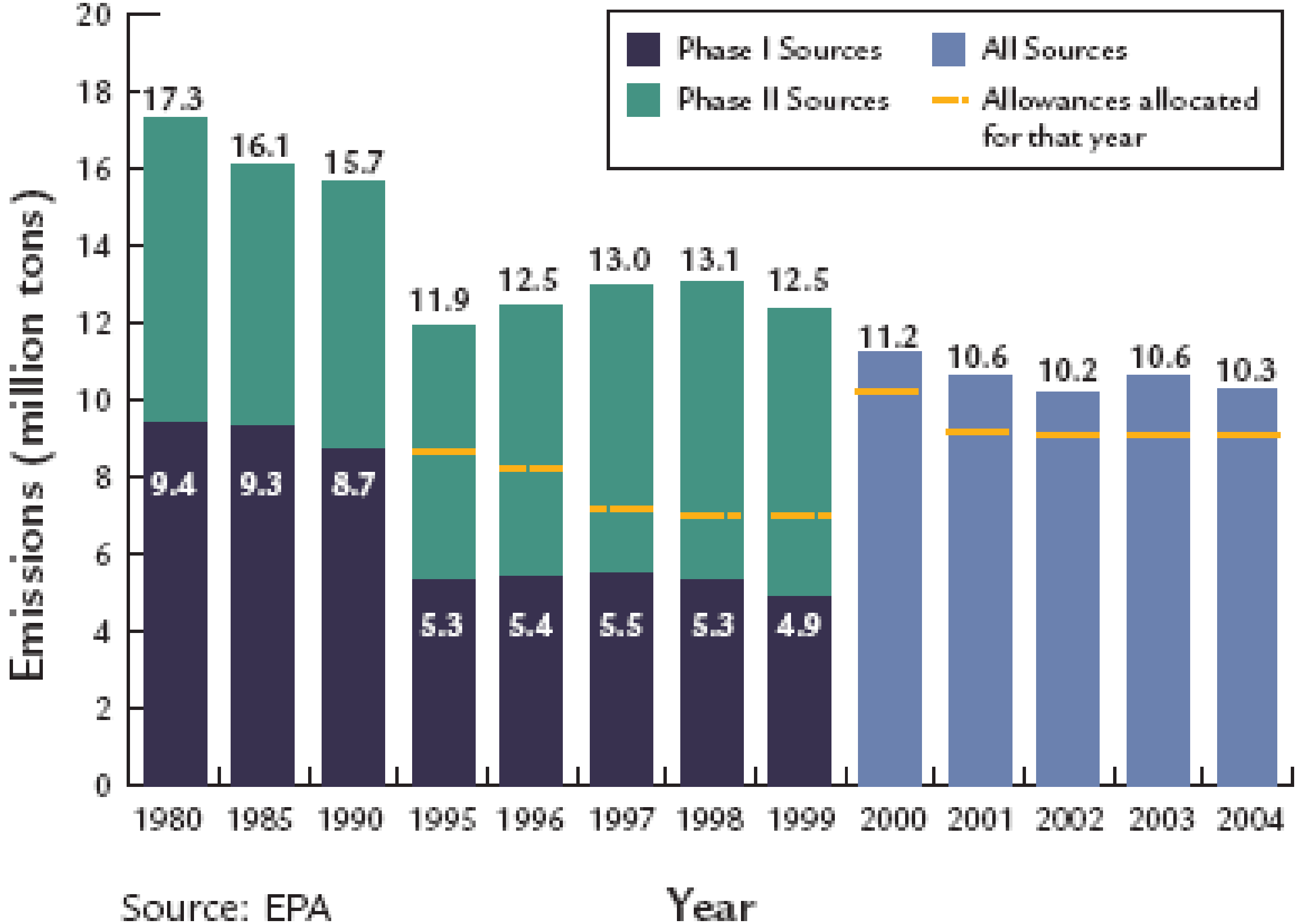
* Assumes annual NOx program

AEP will remain the low cost producer following completion of environmental retrofit projects

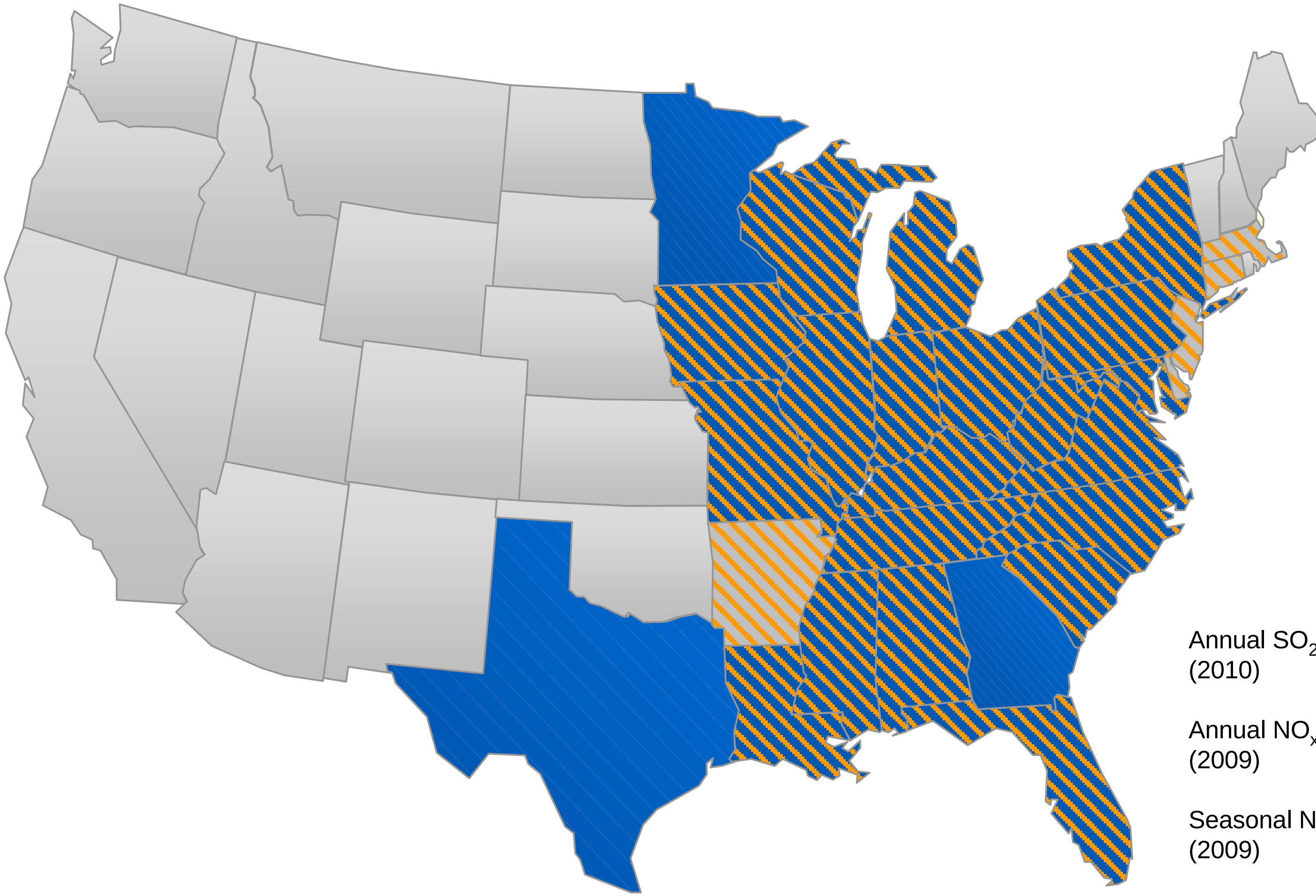
Coal Requirements - Mountaineer

- Federal NSPS limit – 1.2 lbs SO_2/mmBtu
- Current Coal Deliveries
  - Blend of CAPP and PRB coal
  - Consumes approximately 4.0 million tons annually
  - Delivery primarily by barge; some by rail
- Future Coal Deliveries
  - Plant modifications will allow for future fuel flexibility
  - Locally available high-sulfur coal use will now be possible
  - Mine development near Mountaineer property – which will deliver coal via conveyor
- Current Coal Inventory
  - Current inventory levels are near normal levels
  - Plan is to have approximately 35 days of inventory

Title IV SO_2 Compliance



Clean Air Interstate Rule



Emission Caps*

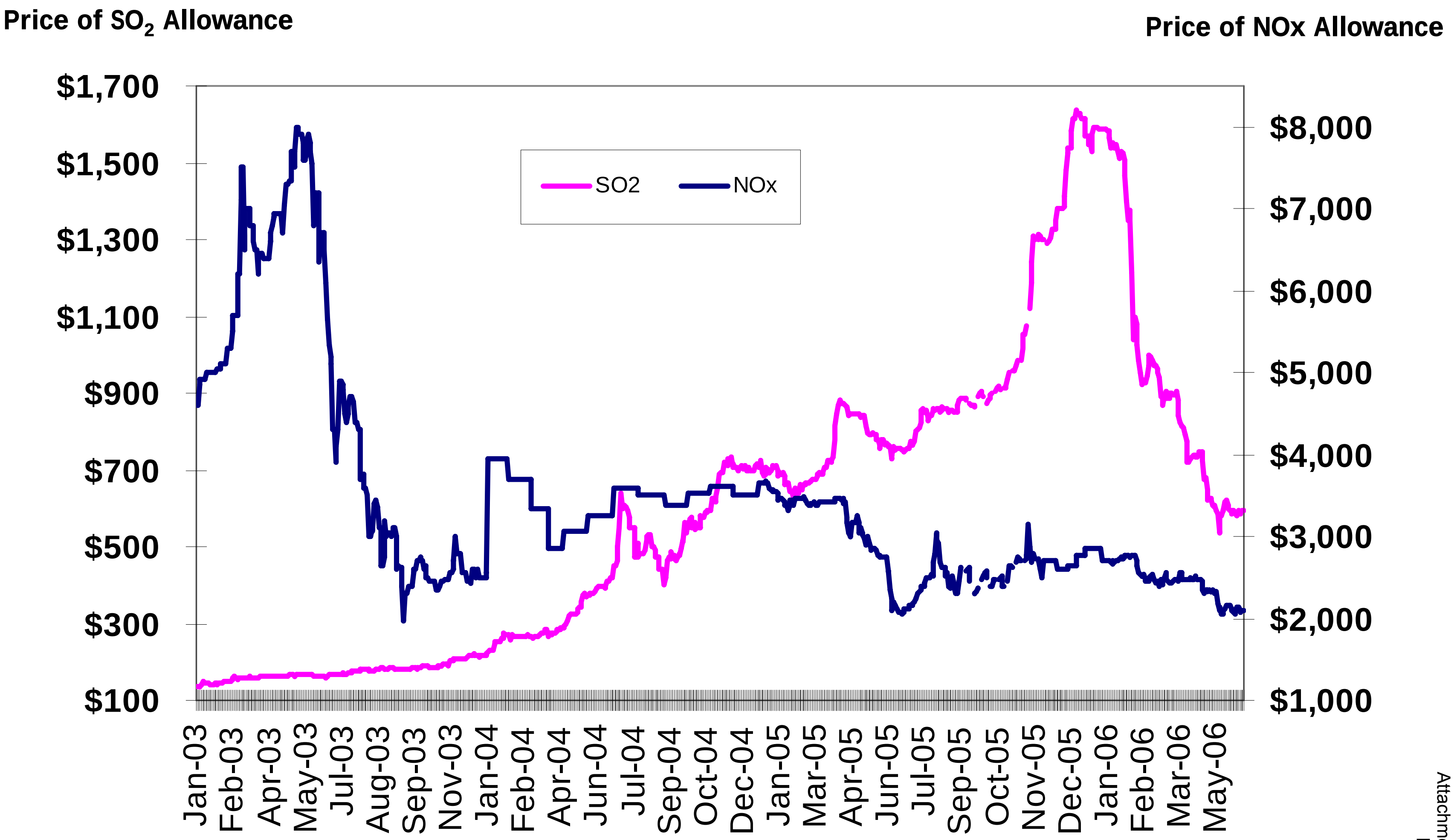
(million tons)

	2009/2010	2015
Annual SO_2 (2010)	3.6	2.5
Annual NO_x (2009)	1.5	1.3
Seasonal NO_x (2009)	.58	.48

*For the affected region.

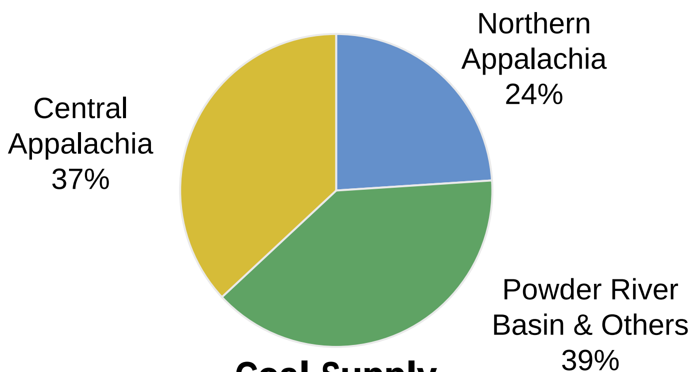
- States controlled for fine particles (annual SO_2 and NO_x)
- States controlled for ozone (ozone season NO_x)
- States controlled for both fine particles (annual SO_2 and NO_x) and ozone (ozone season NO_x)
- States not covered by CAIR

Allowance Markets for SO_2 and NOx



Coal Procurement

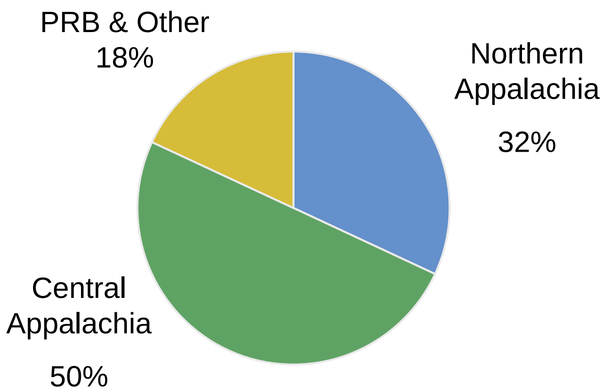
Total AEP System



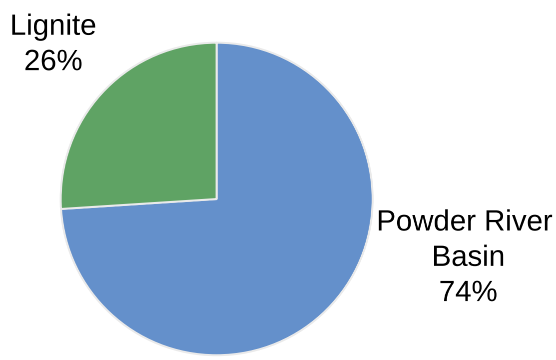
Coal Supply (on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 90%+ contracted for 2007
- Approximate 11%-13% price increase in 2006

AEP Eastern System

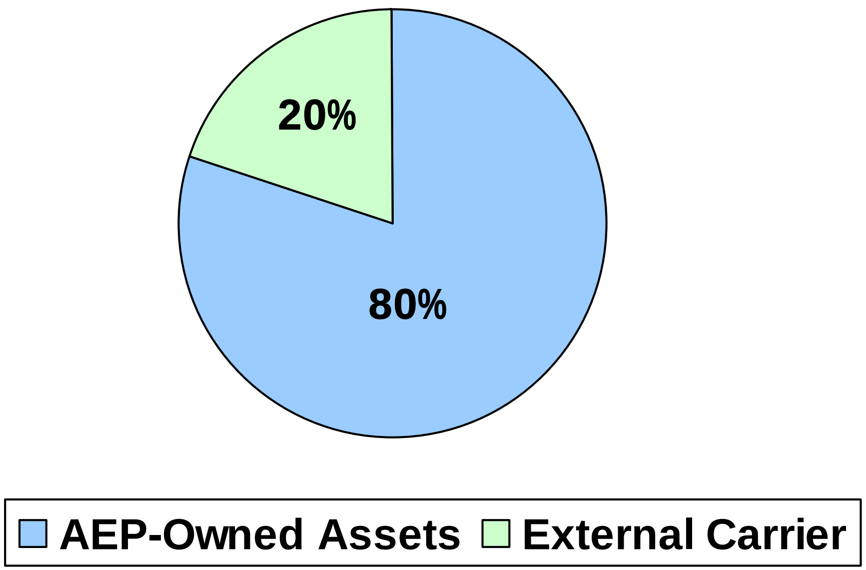


AEP Western System



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

AEP River Operations - Memco

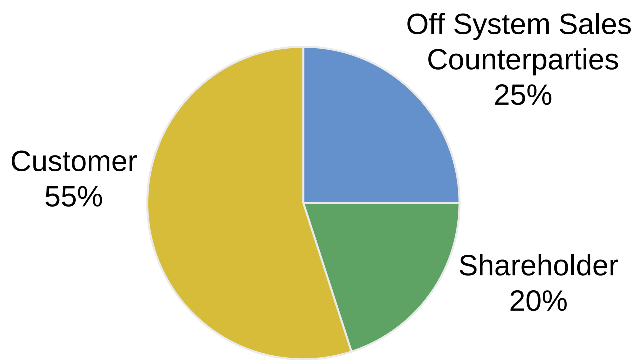
2006 Performance Drivers

- Favorable supply/demand levels of barges
- Strong market for transportation
- Efficiency of operations
- Good operating conditions
- Strong management team

APPENDIX

Fuel Recovery

AEP System



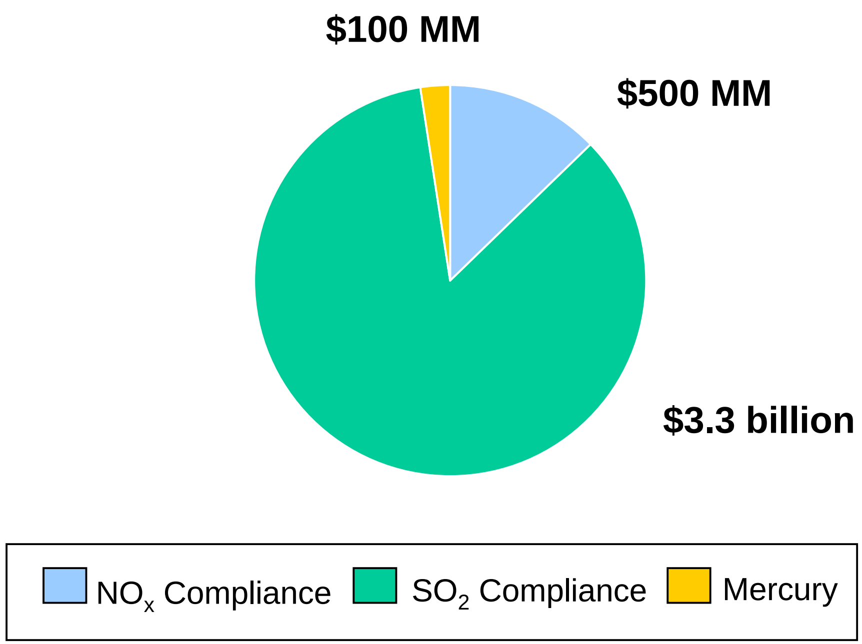
Fuel Cost Recovery (on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M - MI, KGP, KP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$1.9 Billion:

$1.8 Billion for SO_2

$0.1 Billion for Other

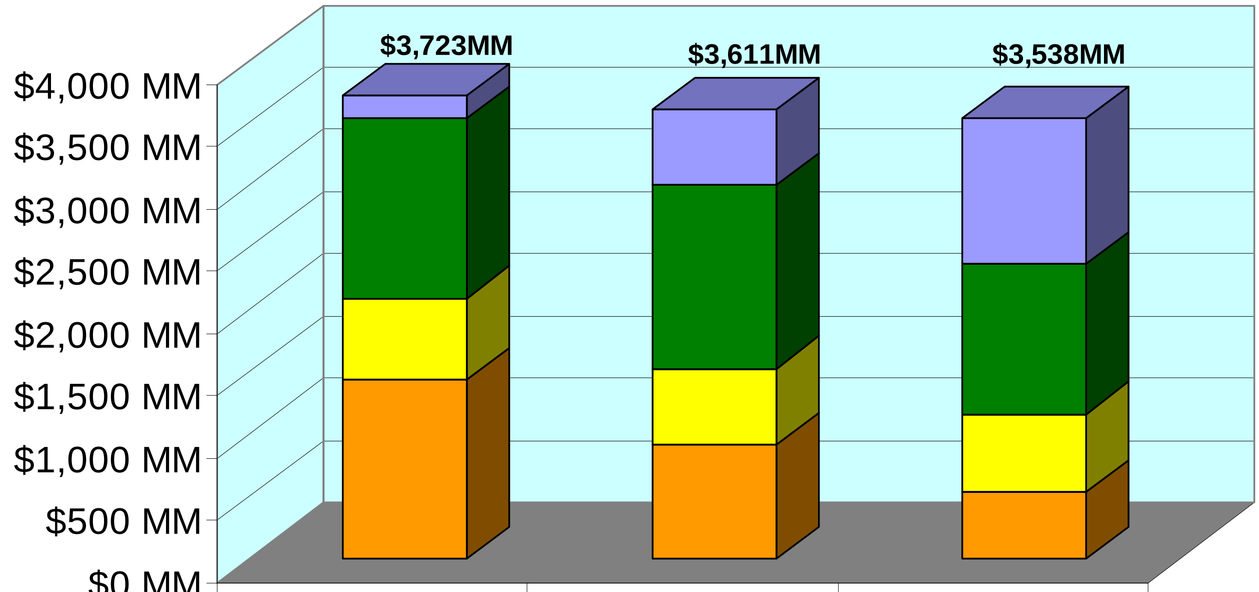
$3.9 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC; $3.9 billion figure reflects delay of Big Sandy 2 investment

Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,441	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE - INVESTMENT LEVEL WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,091)	$ (1,527)	$ (1,161)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,632)	$ (2,084)	$ (2,377)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

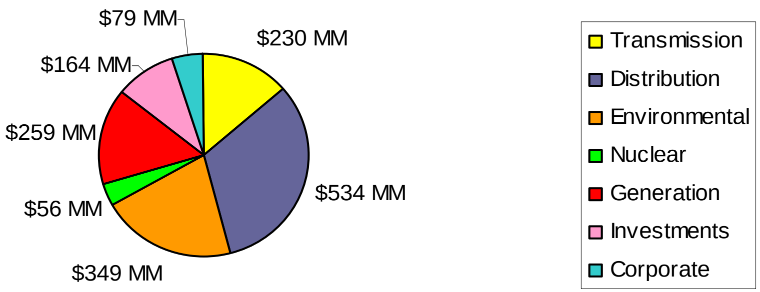
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

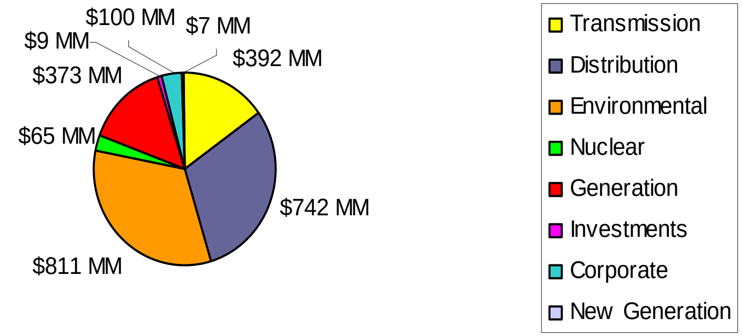
REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

Capital Investment 2004 - 2006

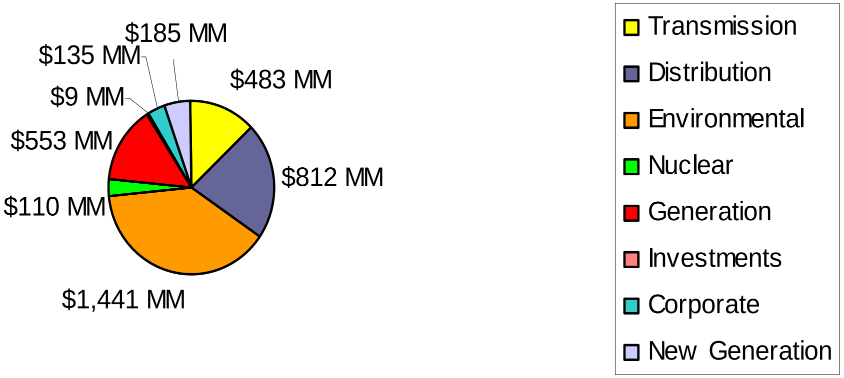
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Morgan Stanley Smith Barney
Financial Advisors Presentation
Boston, MA
August 11, 2010

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

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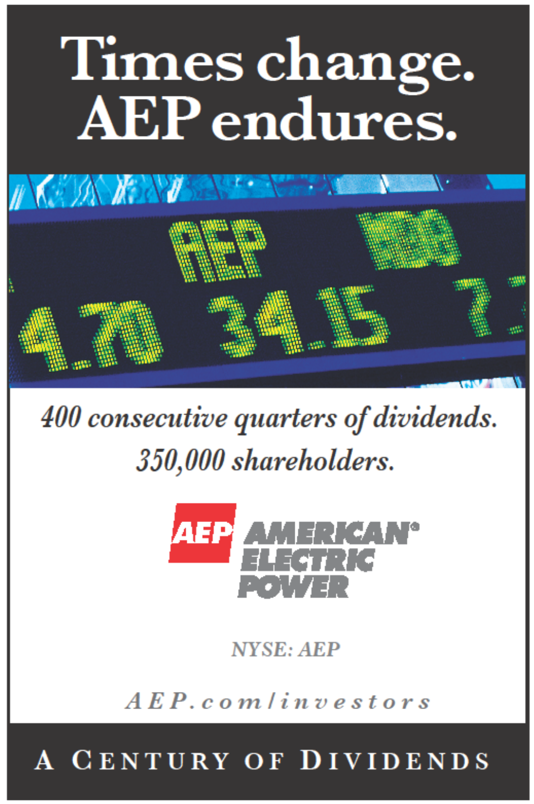
We are Proud of our Record….



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- **Attractive Yield Opportunity of 4.7%[1]**
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- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 22 analysts
- 13 Buy Ratings
- 8 Hold Ratings
- 1 Sell Rating

Attractive total return potential

[1] yield percentage based on AEP closing price of $35.85 on 08/09/2010

Industry Leadership

One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
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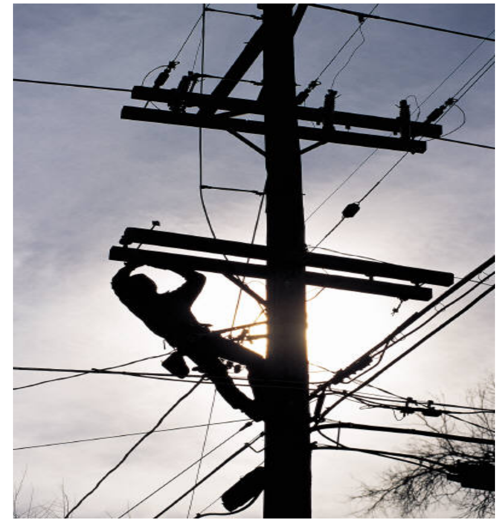

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5.2 million customers in 11 states

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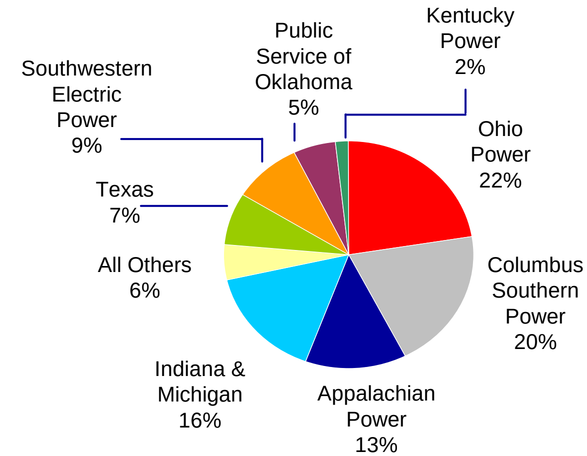

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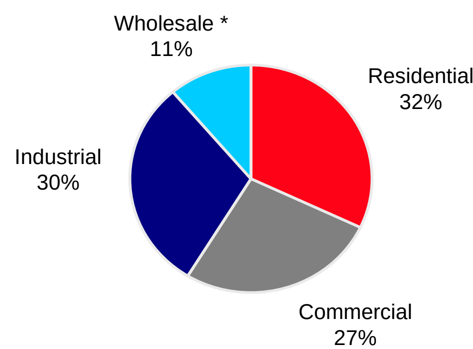

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2010 Ongoing Earnings Guidance

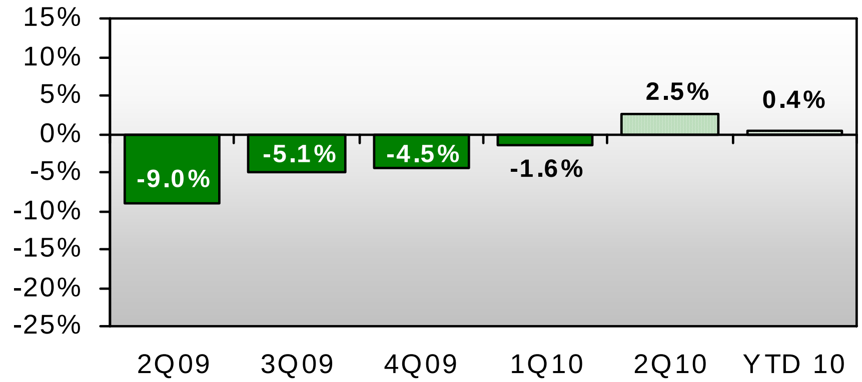
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load recovery**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost cutting initiatives**

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: -0.3%
Commercial: 2.0%
Industrial: 9.4%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

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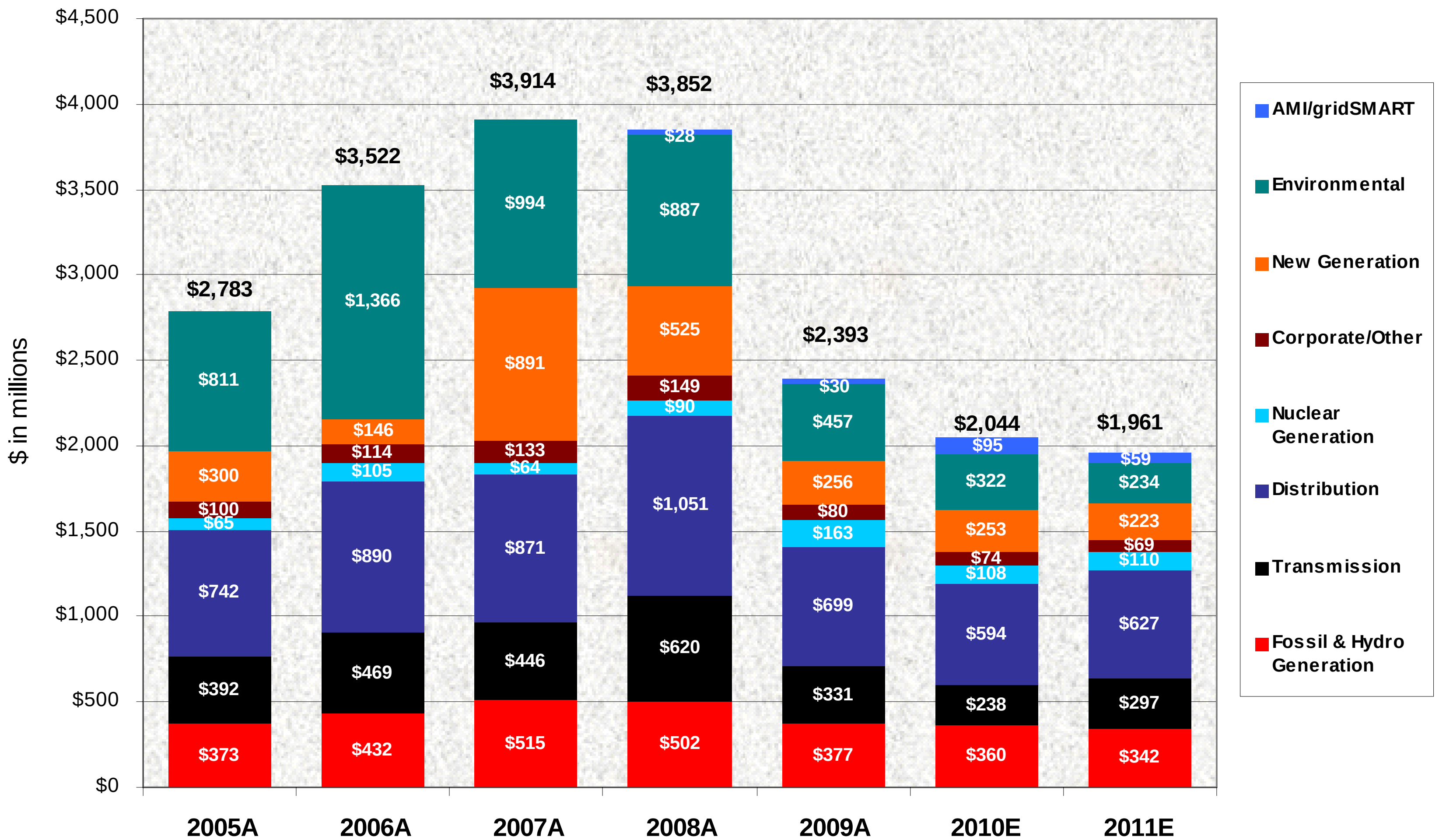
765-kV Tower

Utility Operations Capital Expenditures



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AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

10

Dividend Overview

- We paid our 400th consecutive quarterly dividend to shareholders on June 10, 2010
- Annual Dividend - $1.68/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December
- Attractive yield of 4.7% as of August 9, 2010
- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- Strong Value and Total Return Proposition

Mountaineer Plant (WV)

AEP AMERICAN ELECTRIC POWER®

Morgan Stanley Smith Barney Financial Advisors Presentation

Chicago, IL

June 17, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

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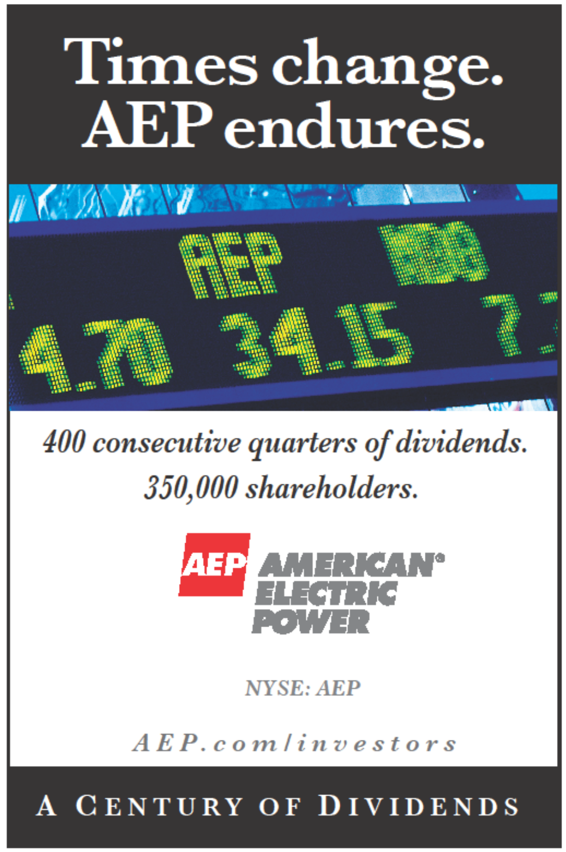

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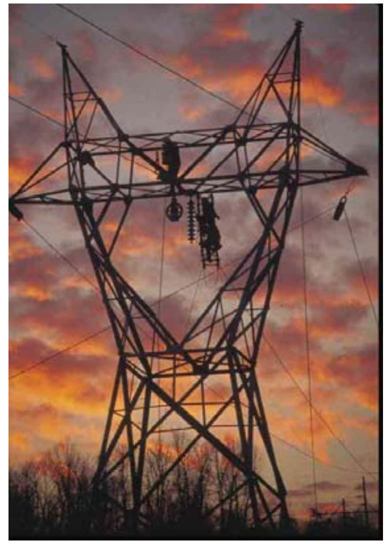

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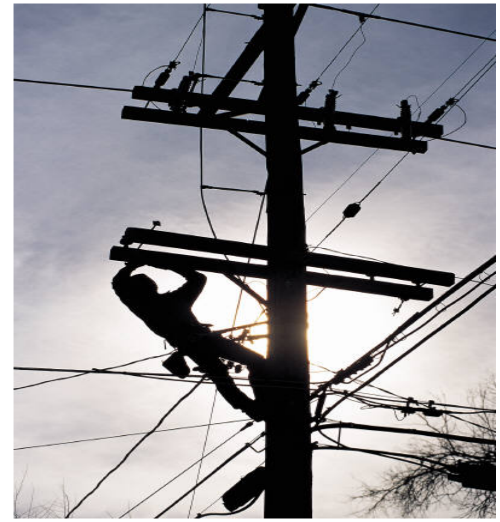

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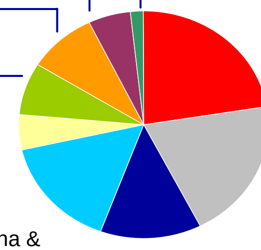

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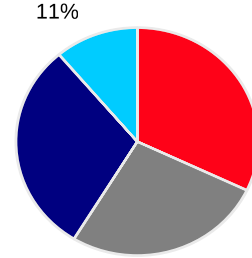

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8158 of 9556

2010 Ongoing Earnings Guidance

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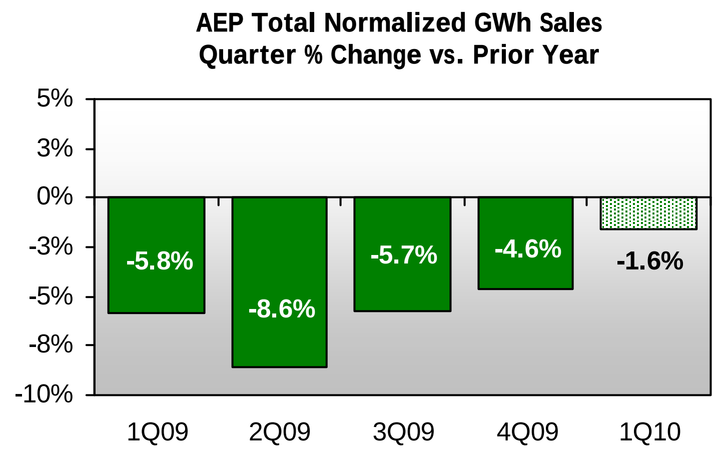

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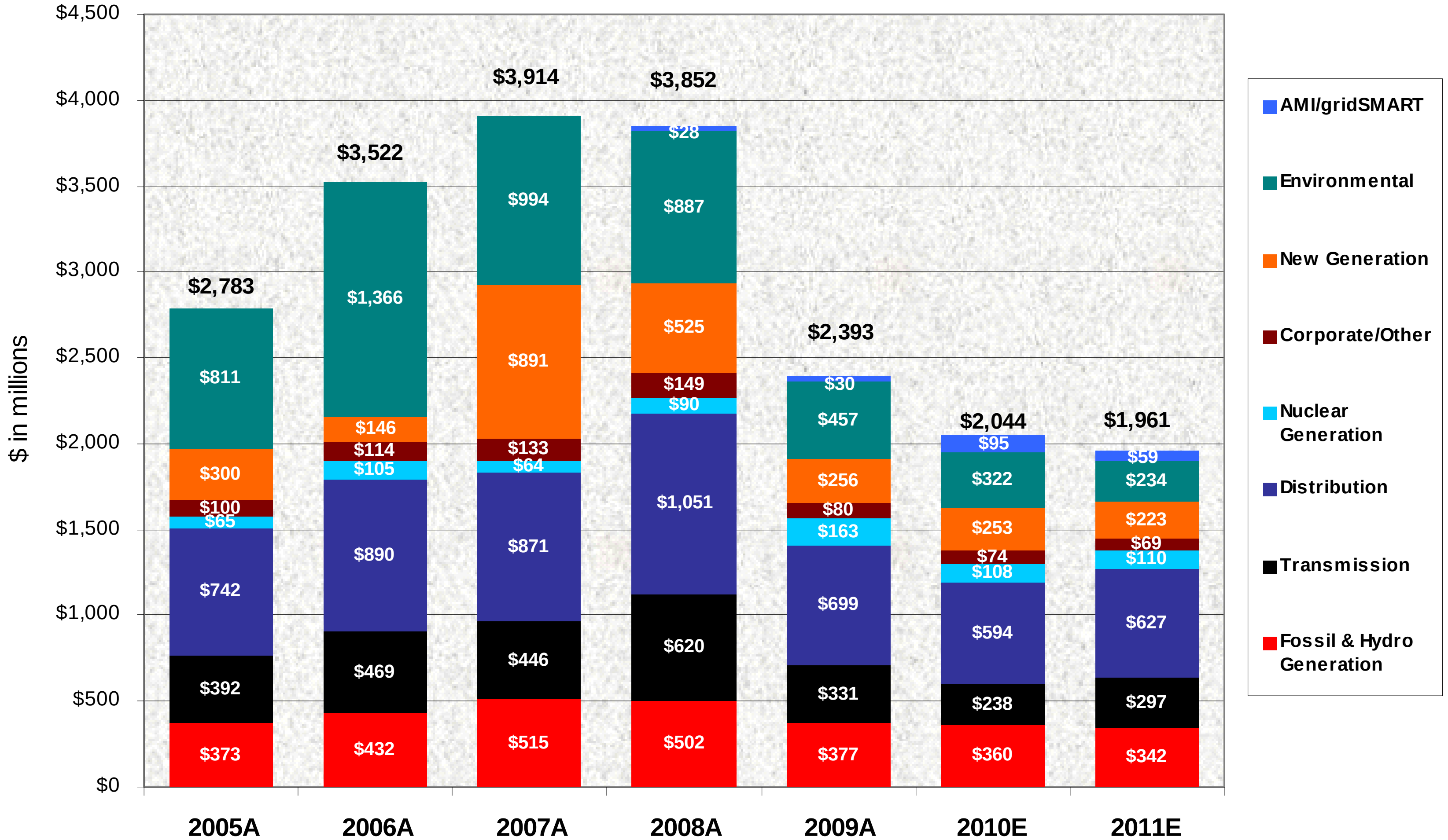

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  - Paid in March, June, September and December
- Attractive yield of 5.0% as of June 15, 2010
- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value and Total Return Proposition**

Mountaineer Plant (WV)

AEP AMERICAN® ELECTRIC POWER

Morgan Stanley Smith Barney Financial Advisors Presentation

Bloomington, MN

October 4, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

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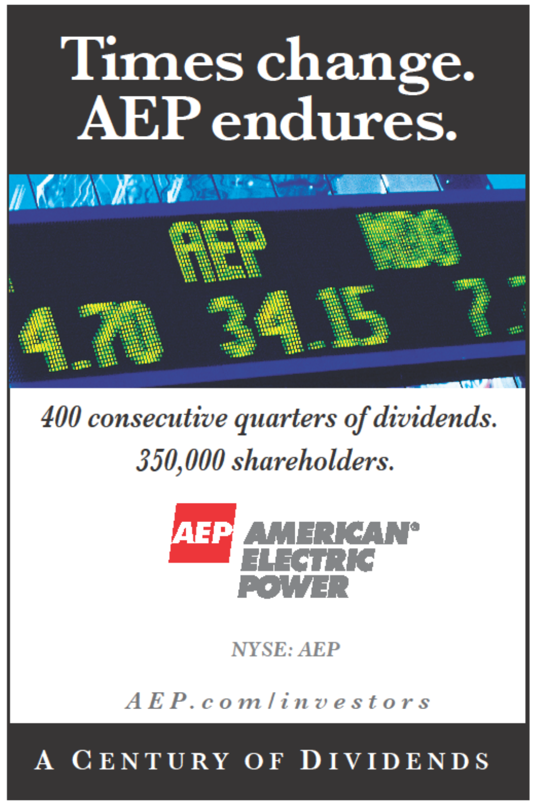


Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 4.6%[1]**
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

- 22 analysts
- 13 Buy Ratings
- 8 Hold Ratings
- 1 Sell Rating

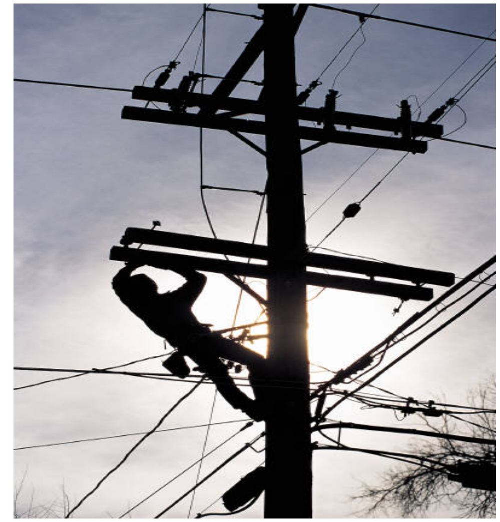
Attractive total return potential

[1] yield percentage based on AEP closing price of $36.23 on 09/30/2010

Industry Leadership

One of the largest U.S. electricity generators

The largest U.S. electricity transmitter



One of the largest U.S. electricity distributors serving 5.2MM customers

Generation owned[1] (GW)	
SO	42.9
NEE	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
NEE	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
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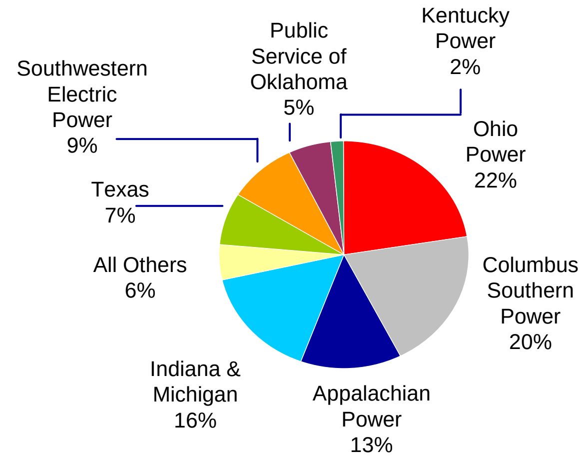
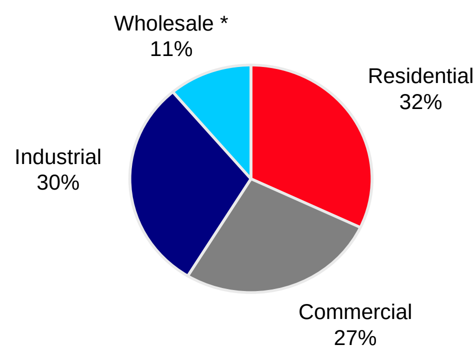
2009 Earnings Contribution



2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

2010 Ongoing Earnings Guidance

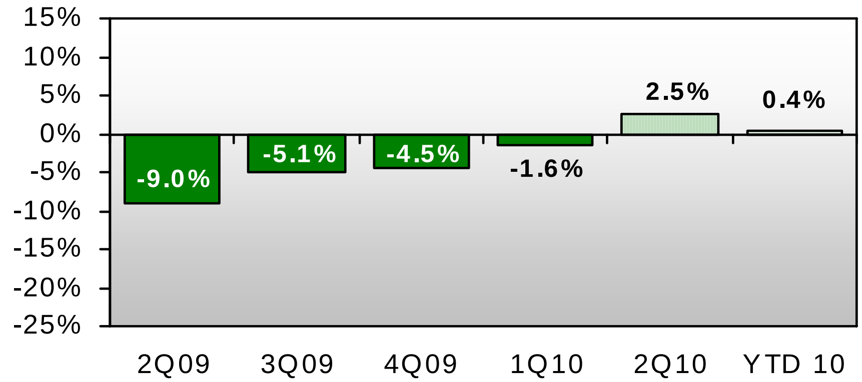
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load recovery**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost cutting initiatives**

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: -0.3%
Commercial: 2.0%
Industrial: 9.4%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

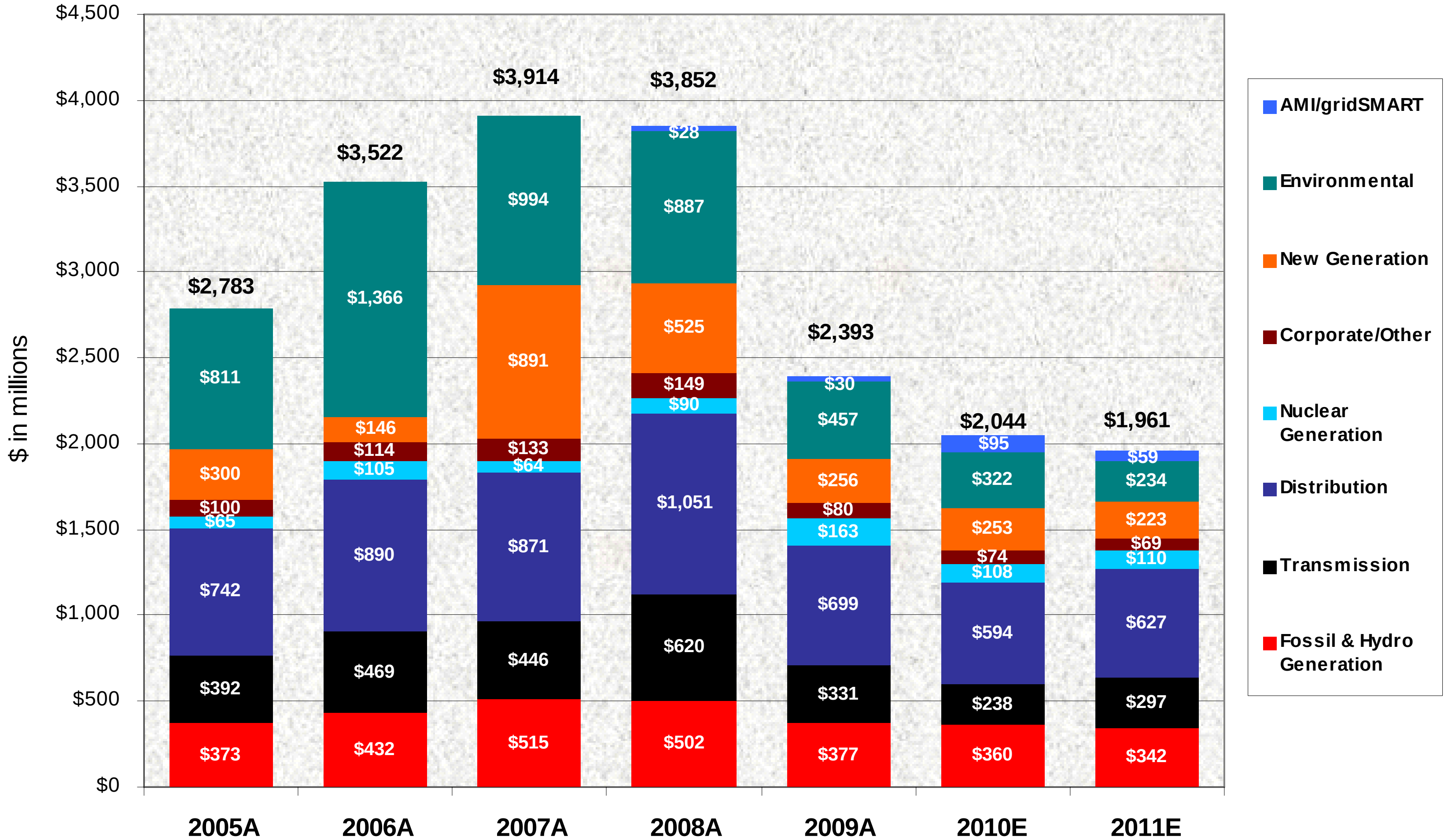
- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - In service assets $0.4 billion
  - CREZ opportunity $1.1 billion est. in service 2010-2013
  - Other ETT projects $1.6 billion est. in service 2010-2017

- **AEP Transmission Company (Transco): Within our existing footprint**
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually

- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

10

Dividend Overview

- **We paid our 401st consecutive quarterly dividend to shareholders on September 10, 2010**
- **Annual Dividend - $1.68/share**
  - **Declared in January, April, July and October**
  - **Paid in March, June, September and December**
- **Attractive yield of 4.6% as of September 30, 2010**
- **Conservative target dividend payout ratio of 50 – 60%**

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
- **Strong Value and Total Return Proposition**

Mountaineer Plant (WV)

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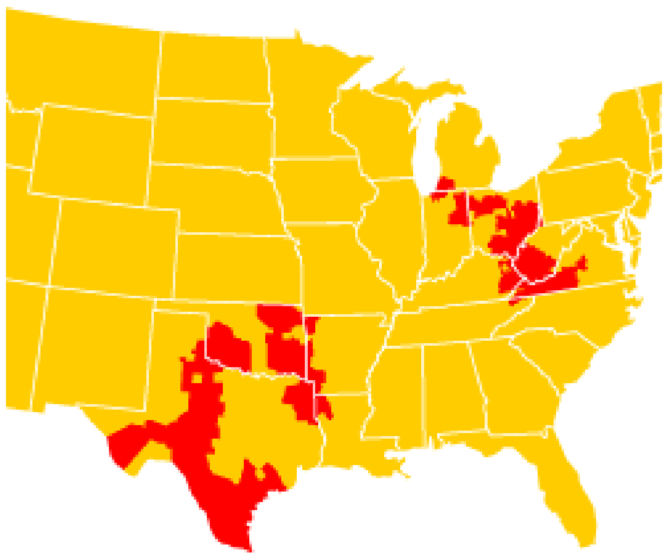
American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for growth
  - Return of capital to shareholders
  - Pension funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



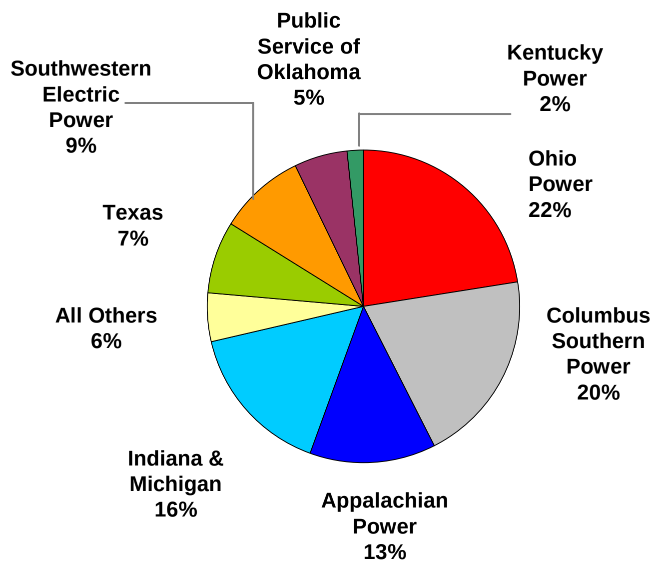
AEP Fast Facts

5.2 million customers
40 GW of generation capacity
39,000 miles of transmission lines

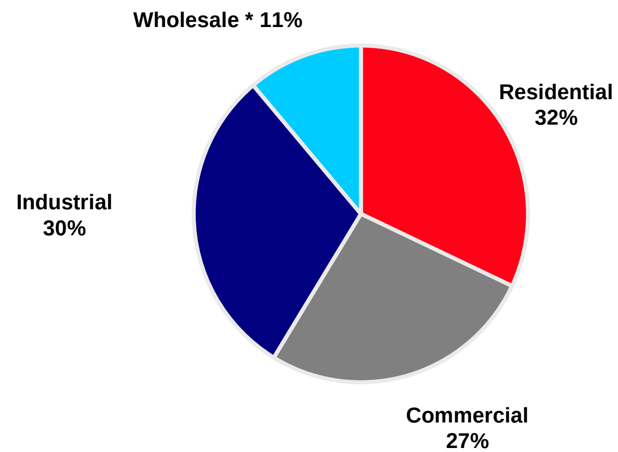
$17B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2009 Earnings Contribution



2009 Retail Load



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Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

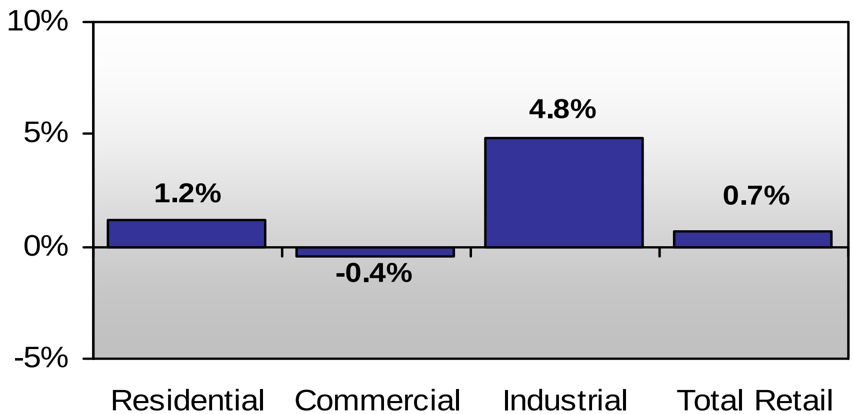
2010 & 2011 Ongoing Earnings Guidance

2010E: $2.95-$3.05/share

2010 Earnings Drivers

- $331M in rate recovery secured
- Retail load recovery of 1.1%
- Increase in off-system sales volumes
- Cost cutting initiatives and continued discipline in O&M

AEP YTD 9/30/2010 Normalized GWh Sales
%Change vs. YTD2009

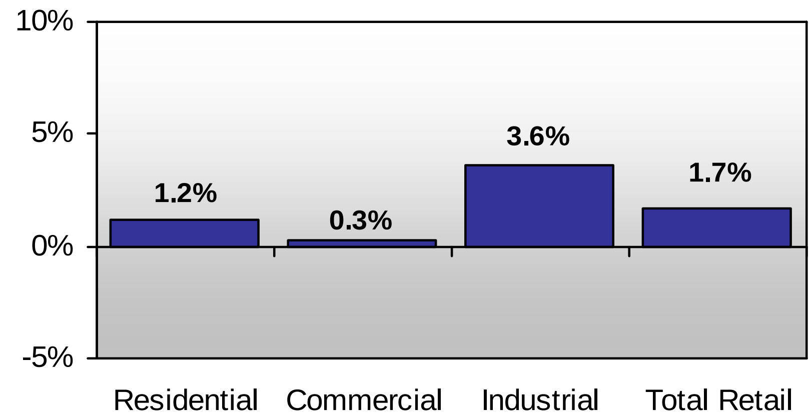


2011E: $3.00-$3.20/share

2011 Earnings Drivers

- $235M in rate recovery (67% already secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $23M
- Continued discipline in O&M

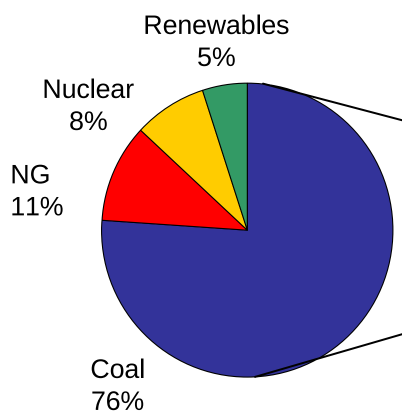
AEP Forecasted 2011 Normalized GWh Sales
%Change vs. 2010E



AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



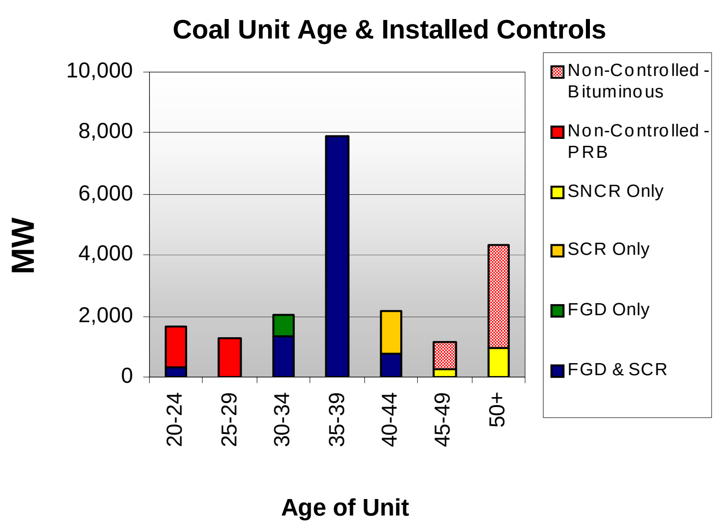
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost

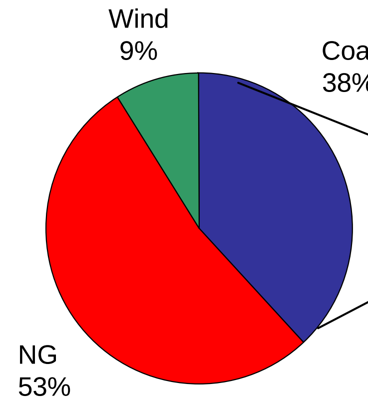
2009A - $56/ton
2010E - $52/ton
2011E[1] - $51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind



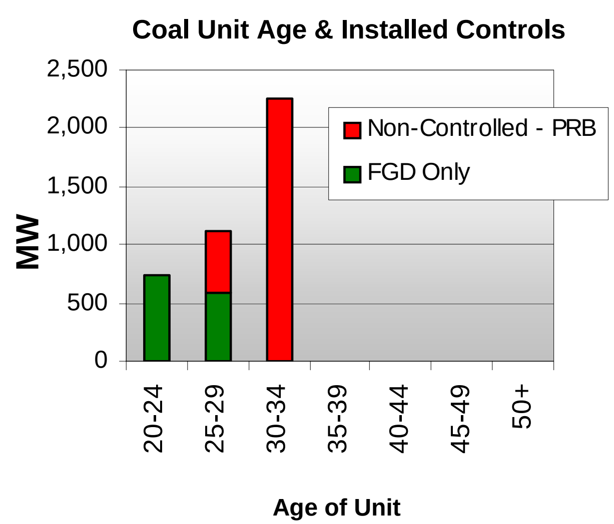
Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010E - $29/ton
2011E[1] - $29/ton

[1] Represents cost of committed position (90%)



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Transmission as a Growth Engine

- **Electric Transmission Texas (ETT)**
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- **AEP Transmission Company (AEP Transco)**
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- **Progress on Joint Ventures in 2010**
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

Electric Transmission Texas

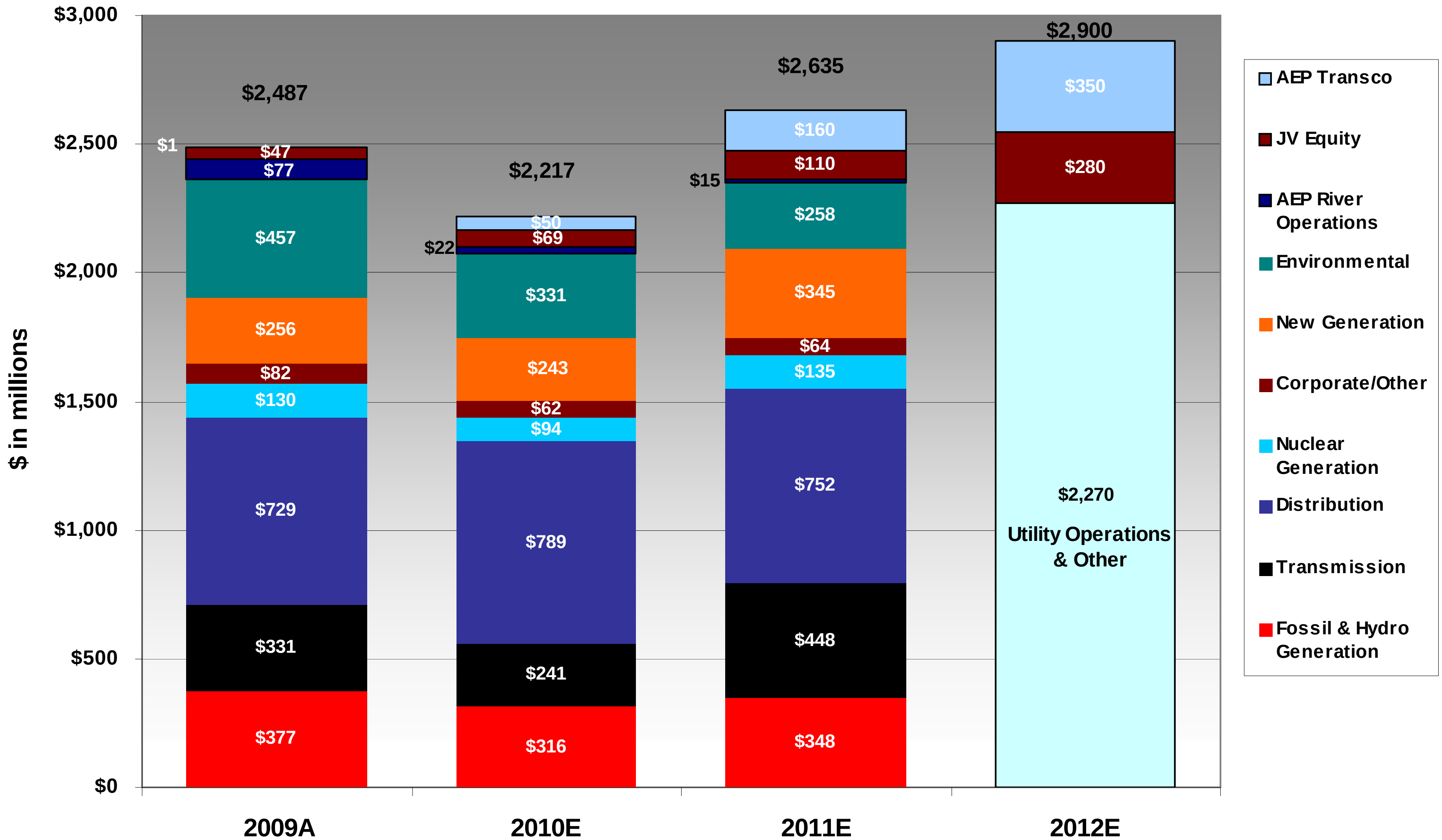
ELECTRIC TRANSMISSION AMERICA, LLC

Potomac-Appalachian Transmission Highline

Prairie Wind Transmission

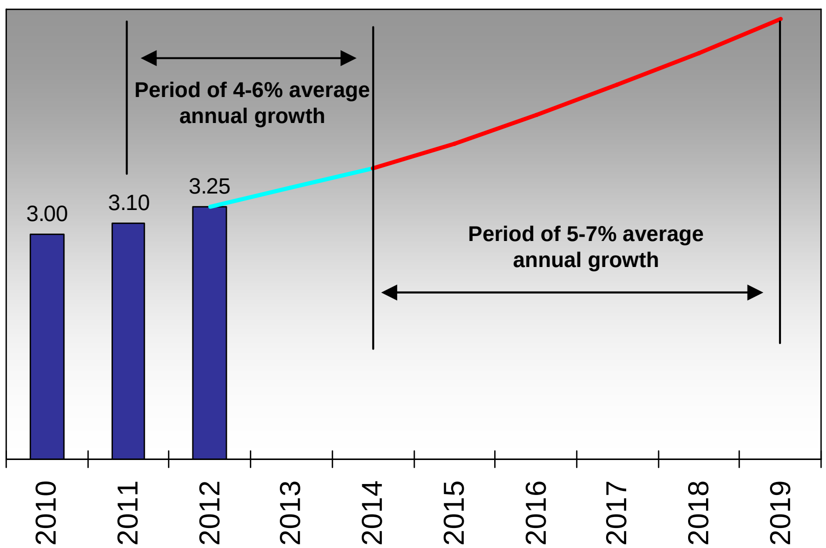
Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

Capital Expenditures



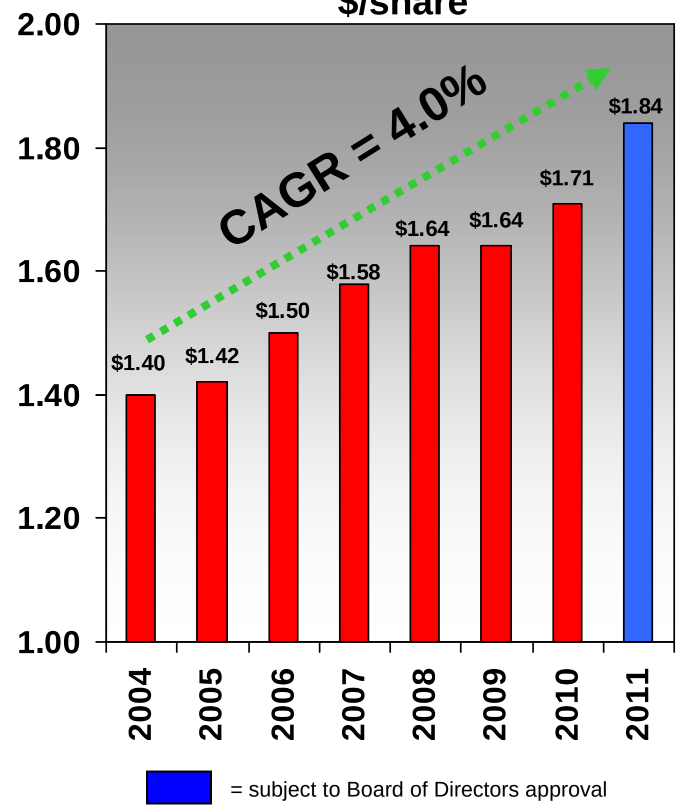
AEP – Income and Growth Opportunity

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004
$/share



- 9.5% increase in quarterly dividend to $0.46/share declared on October 26th
- 402nd consecutive quarterly dividend paid in December
- 50-60% payout ratio target
- Current yield over 5%

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- Premier Utility Platform
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- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
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Mountaineer Plant (WV)

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Morgan Stanley Smith Barney Financial Advisors Presentation

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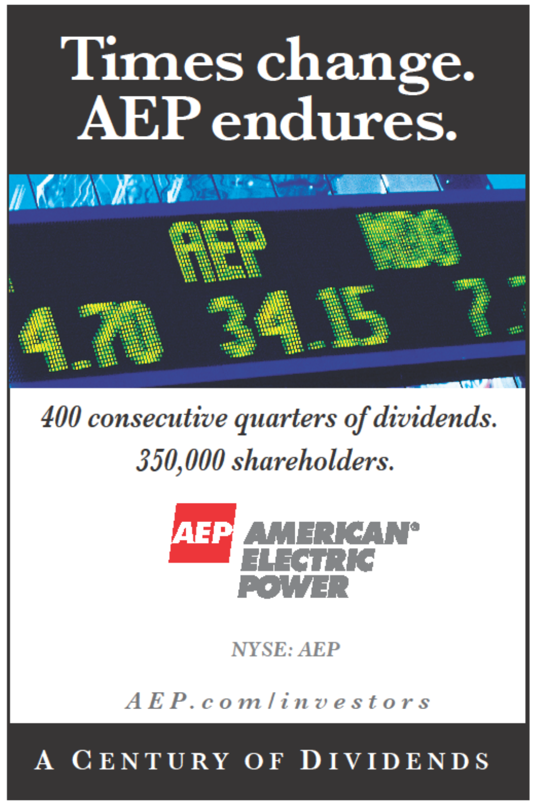

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Value Proposition to Retail Investors

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  - Investment in utility platform greater than depreciation level (2 - 4%)
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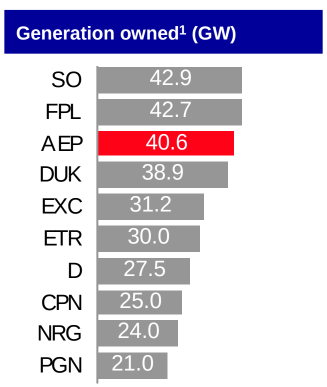
Attractive total return potential

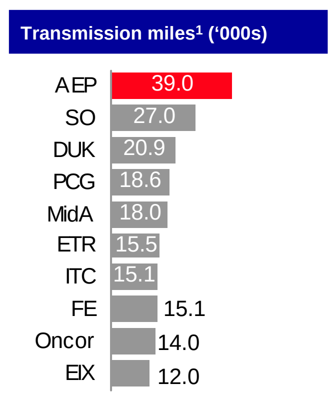
[1] yield percentage based on AEP closing price of $35.98 on 07/30/2010

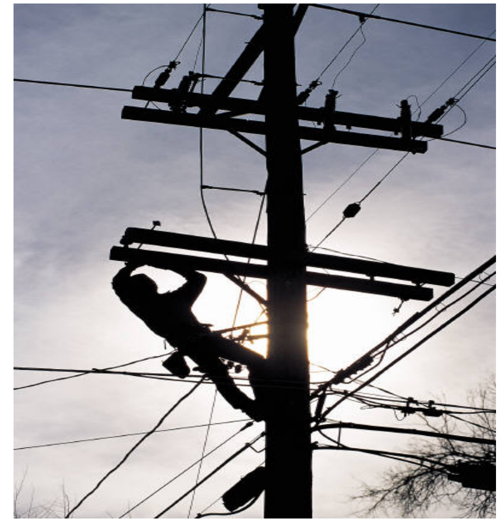
Industry Leadership

One of the largest U.S. electricity generators

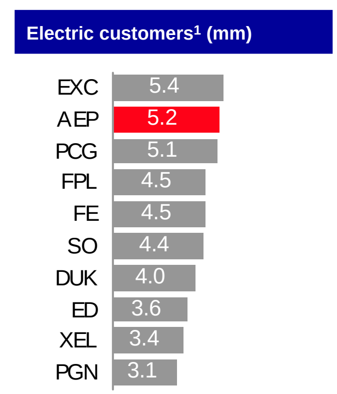


The largest U.S. electricity transmitter





One of the largest U.S. electricity distributors serving 5.2MM customers



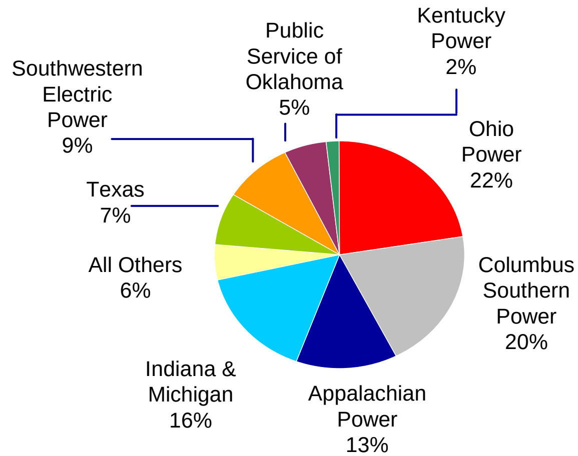
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

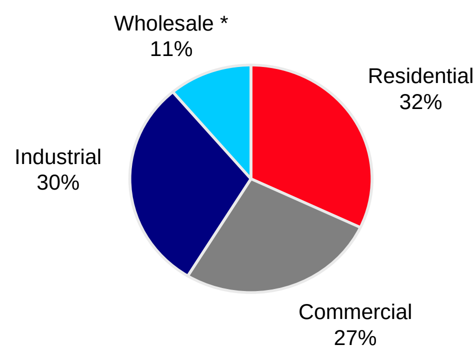
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

2010 Ongoing Earnings Guidance

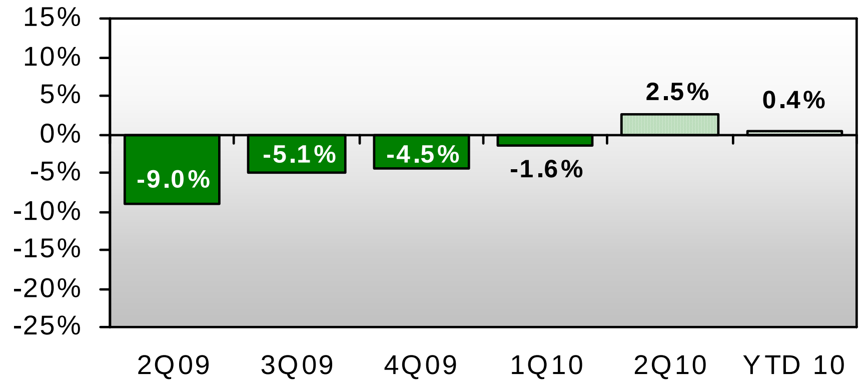
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-Term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load recovery**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost cutting initiatives**

AEP Total Normalized GWh Sales
Quarter % Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: -0.3%
Commercial: 2.0%
Industrial: 9.4%

Energy Policy Initiatives = Opportunities

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Carbon Capture and Storage Project – Mountaineer Plant (WV)

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

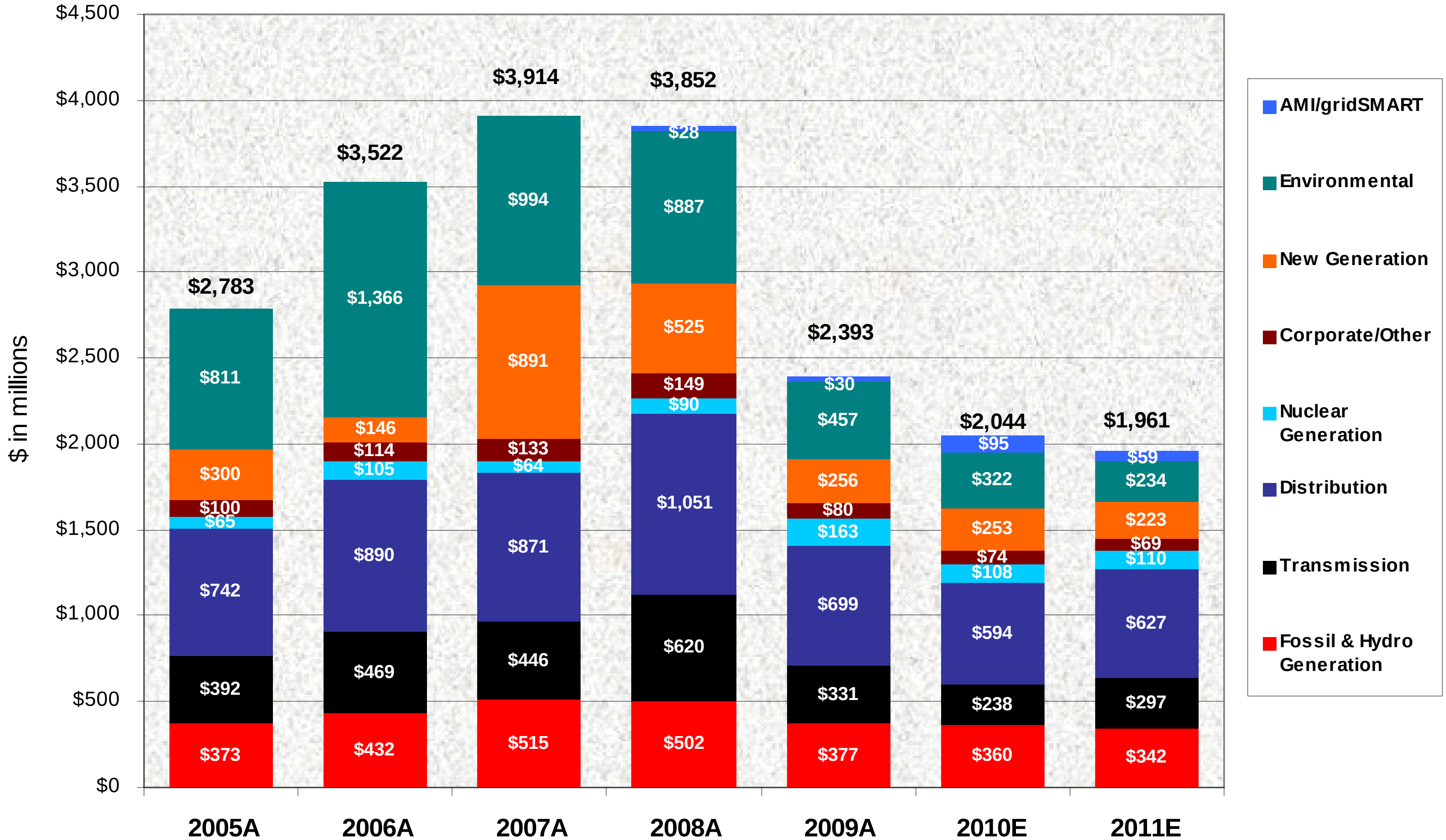
765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

- **AEP Transmission Company (Transco): Within our existing footprint**
  - Develop new AEP-only projects within AEP's footprint
  - Reduce regulatory lag through FERC formula rates adjusted annually
- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B within this decade
- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Dividend Overview

- We paid our 400th consecutive quarterly dividend to shareholders on June 10, 2010
- Annual Dividend - $1.68/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December
- Attractive yield of 4.7% as of July 30, 2010
- Conservative target dividend payout ratio of 50 – 60%

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- Strong Value and Total Return Proposition


Mountaineer Plant (WV)

American Electric Power

Mountaineer CO_2 Capture and Storage Project

Citigroup Investor Visit
New Haven, West Virginia

June 25, 2009

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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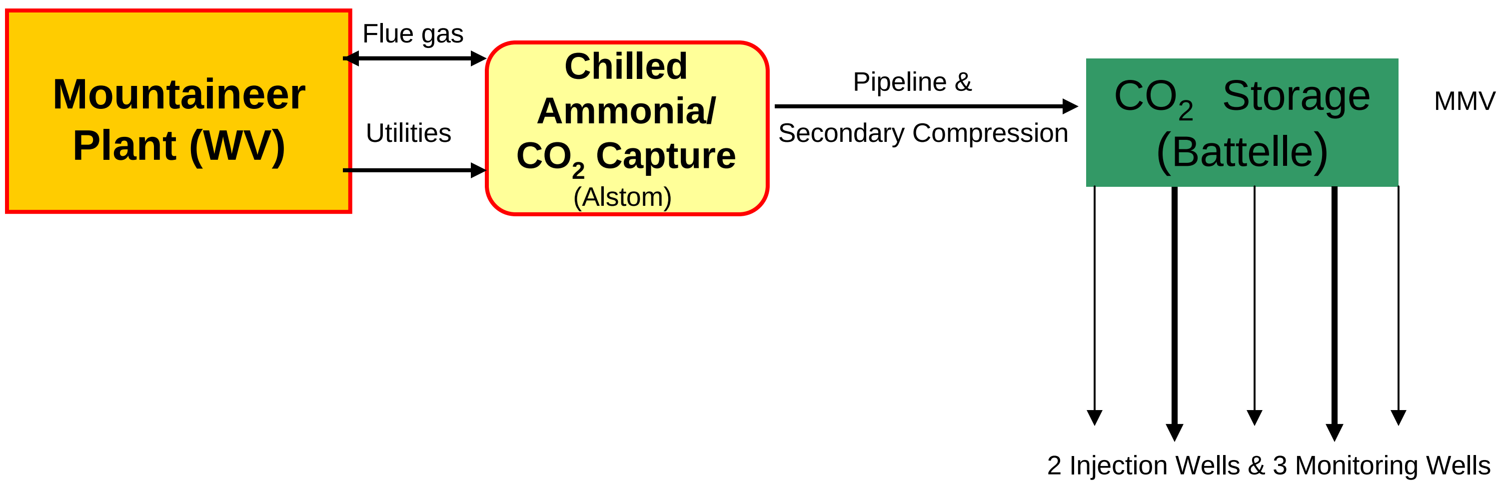
Presentation Outline

- Project Overview
- Geologic Characterization
- CO_2 Handling and Storage
- Permits, Legal Approval, & Outreach
- Questions and Answers

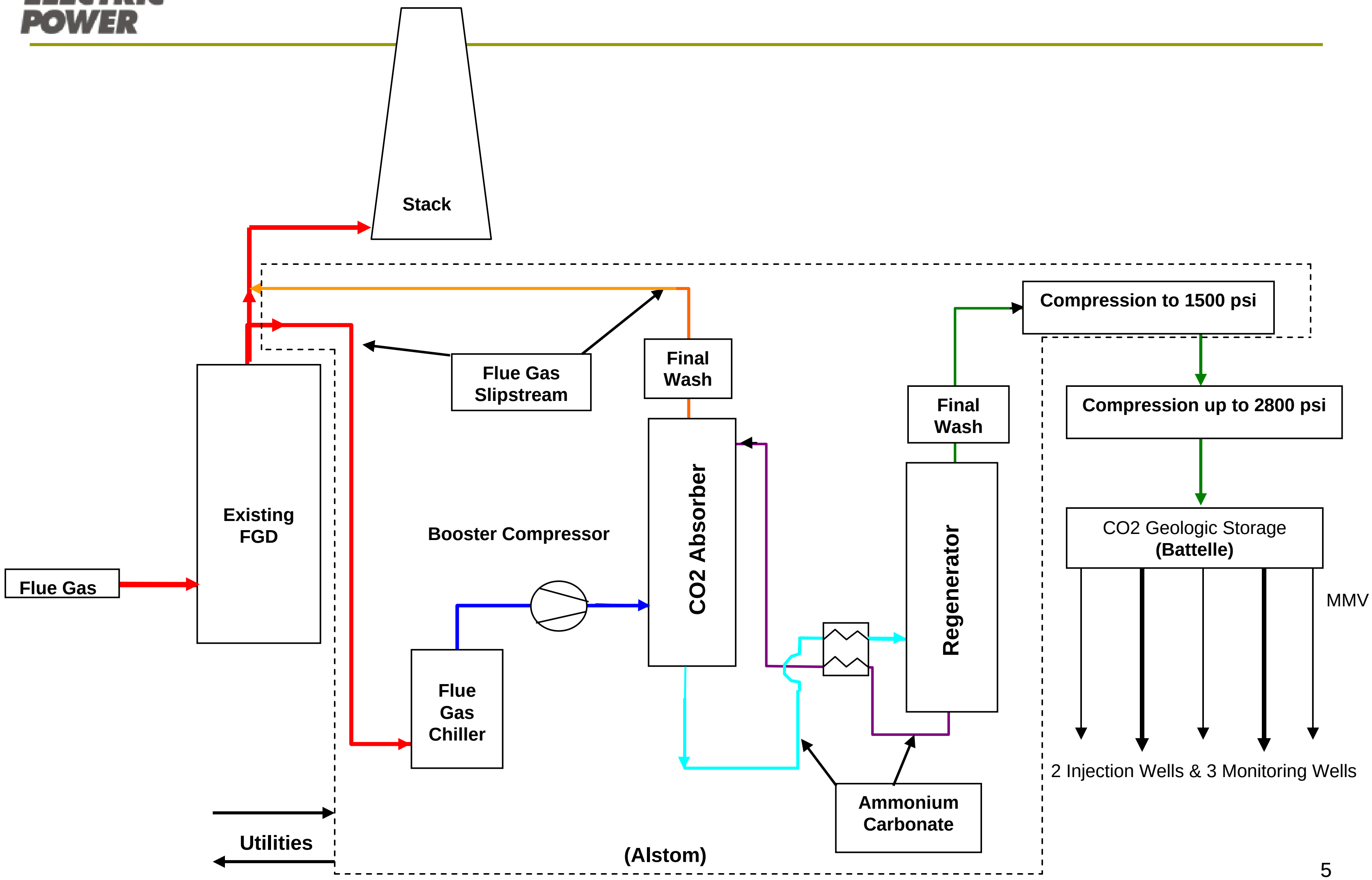
Mountaineer CCS Project

2009 Startup



- 20 MW (electric) slip stream from FGD outlet
- Capture and store ~100k–165k tonnes of CO_2 per year
- Started engineering, planning, and permitting in Sep 07
- Started construction 2Q 2008, in operation 3Q 2009
- Alstom responsible for CAP island, AEP responsible for utilities to/from CAP island and CO_2 storage (Battelle as contractor)

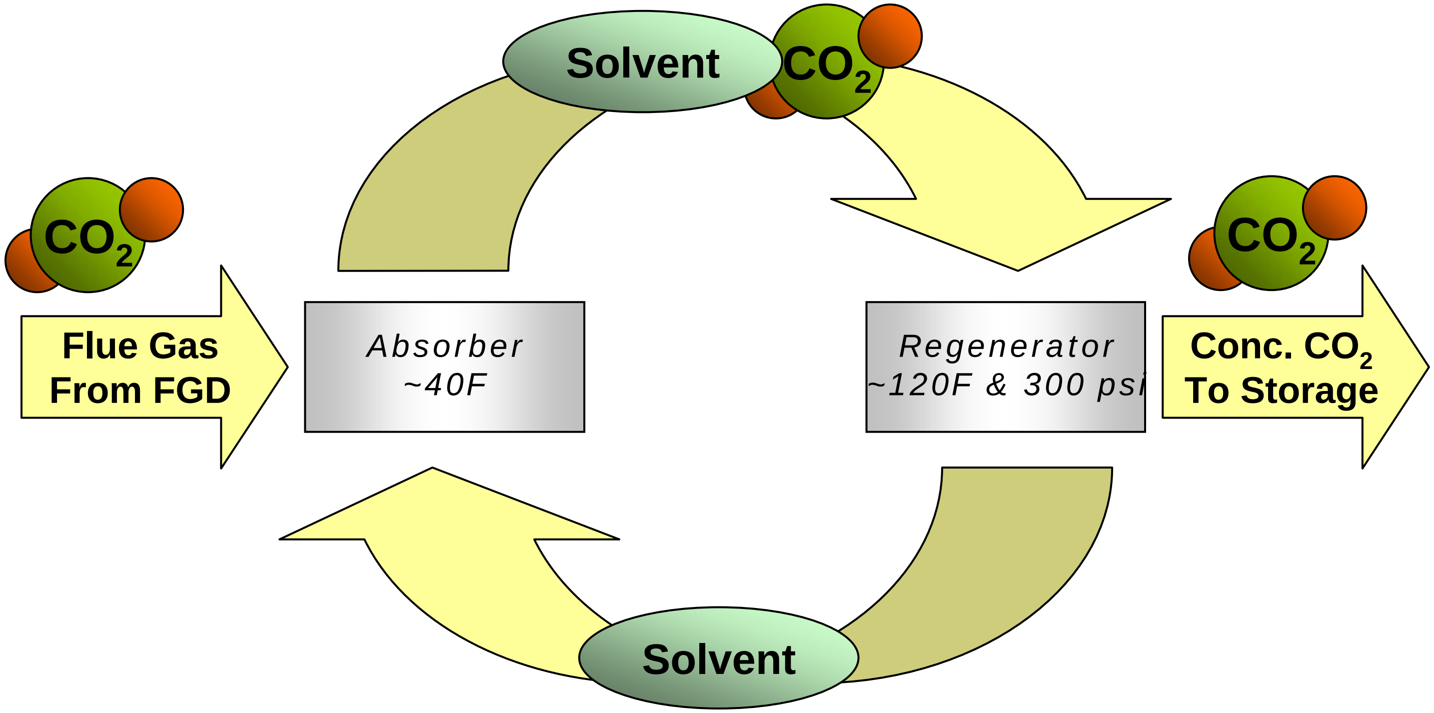
Schematic of the Alstom Chilled Ammonia Process



June 25, 2009

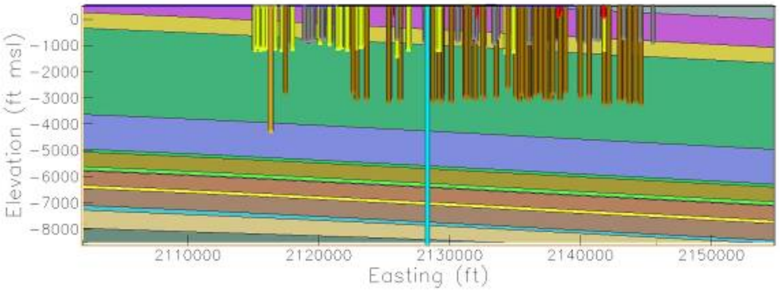
Alstom Chilled Ammonia Process

- Selected the chilled ammonia technology for CO_2 capture due to its lower steam consumption and higher energy efficiency.
- Ammonia solution (Ammonium Carbonate) absorbs CO_2 at low temperature and releases the CO_2 at moderately elevated temperature and high pressure.



Site Characterization

- Site characterization work at the site funded by DOE, AEP, Battelle, and others – MRCSP Ohio River Valley Project
- Preliminary geology report prepared in 2003
- Seismic survey in 2003
- Drilling and testing AEP#1 deep well during 2003-05
- Design, feasibility study for integrated CCS pilot 2005 -07
- Few deep wells (>5,000 ft) nearby



Battelle Graphic

Site Characterization and Feasibility Study

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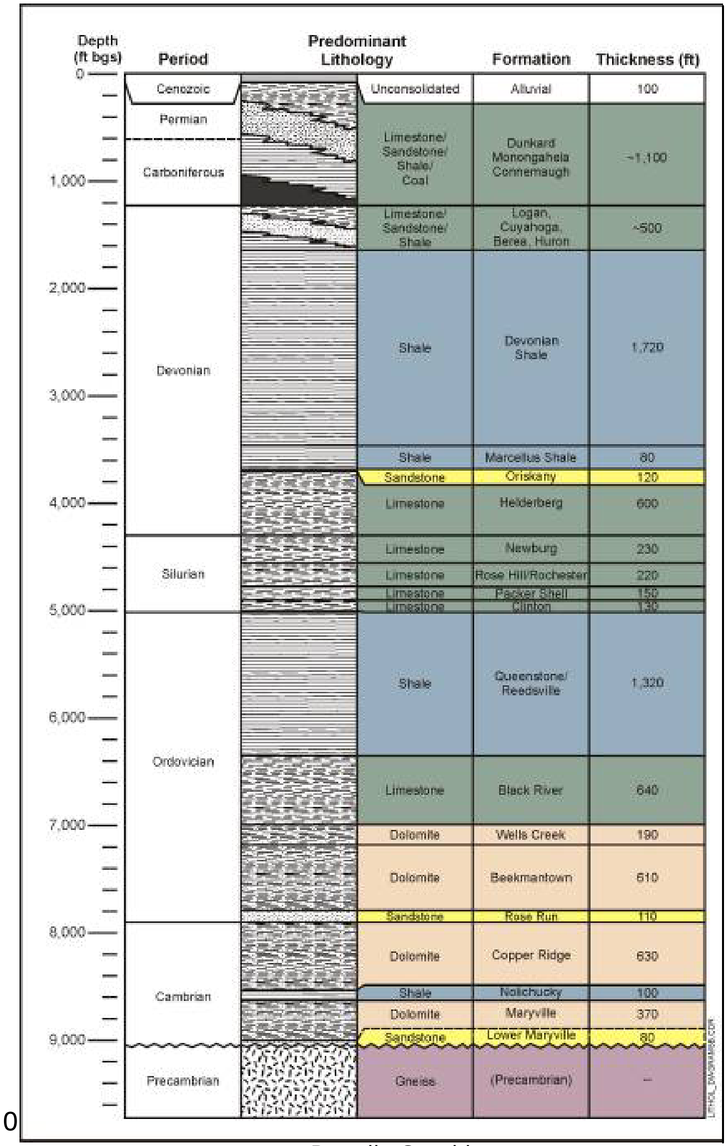
Site characterization study identified two feasible injection reservoirs with several thousand feet of excellent caprock

- Rose Run Sandstone
- Copper Ridge B-Zone



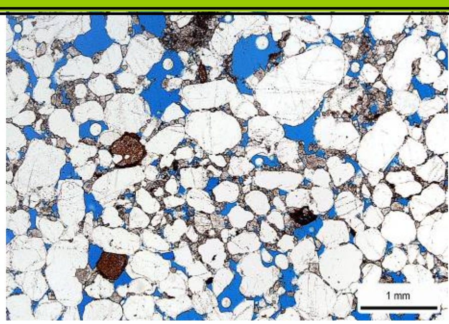
Battelle Graphic

Upper Injection Zone Cores from AEP#1 Test Well

Rose Run Sandstone- 116 ft total thickness, 30 ft porous sandstone

<u>Hydraulic Core Tests 7763.5 ft</u>

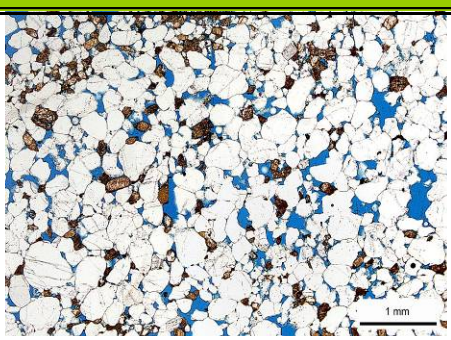
Lithology	**= Sandstone**
Density	**= 2.68 g/mL**
Porosity	**= 9.1%**
Permeability	**= 36 mD**



Data from Battelle

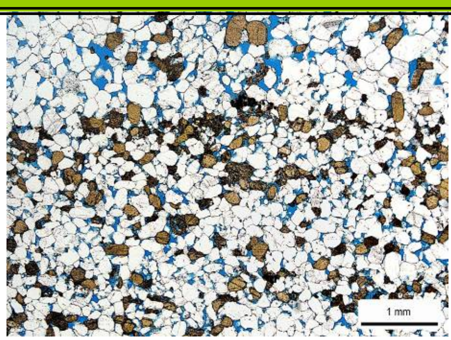
<u>Hydraulic Core Tests 7775 ft</u>

Lithology	**= Sandstone**
Density	**= 2.64 g/mL**
Porosity	**= 10.4%**
Permeability	**= 49 mD**



<u>Hydraulic Core Tests 7819 ft</u>

Lithology	**= Sandstone**
Density	**= 2.63 g/mL**
Porosity	**= 11.5%**
Permeability	**= 36 mD**



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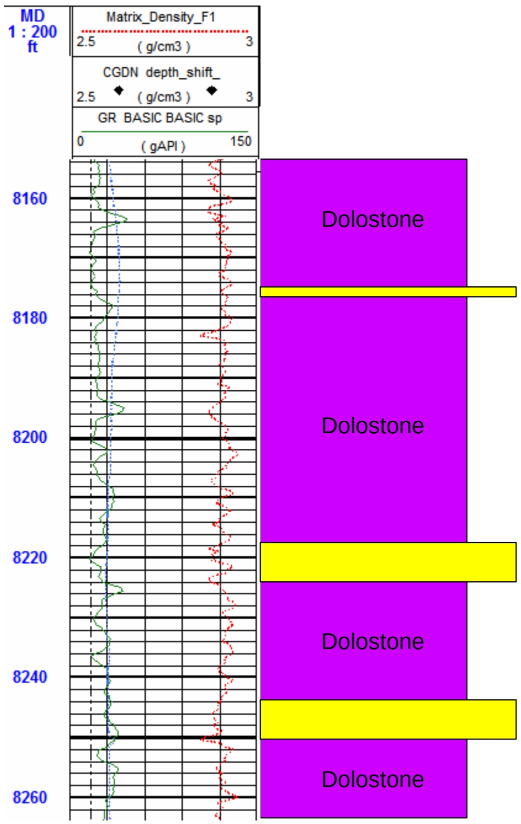
Copper Ridge "B-zone"

- -Reservoir tests suggest significant storage potential in "B-zone"
- -Carbonate unit, nature of porosity/permeability uncertain
- -Few core samples collected from interval



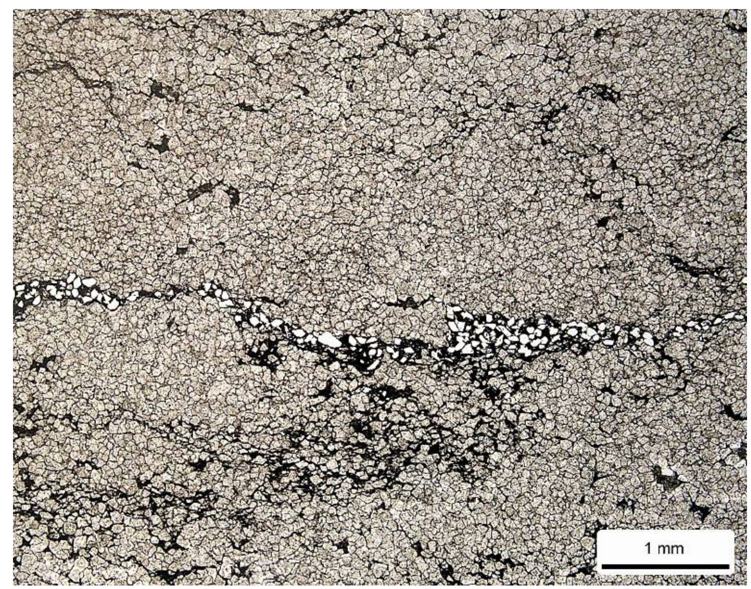
Sandy Dolostone ?, High Porosity

Sandy Dolostone ?, High Porosity

"B" Zone, Sandstone / Sandy Dolostone,
- High Porosity
- Sidewall core

Battelle Graphic

Copper Ridge Sidewall Core 7930 ft



Battelle Graphic

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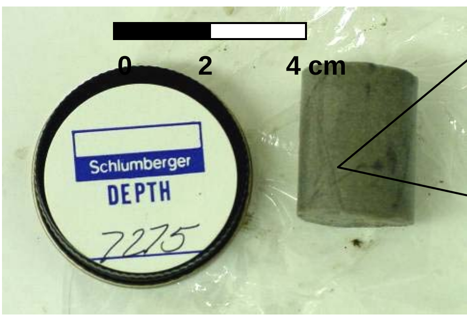
Immediate Caprock above Injection Zone

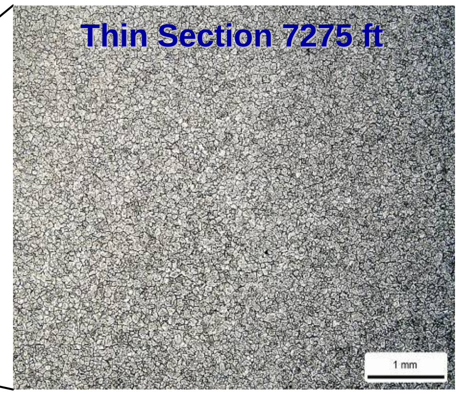
Beekmantown Dolomite 7210-7755 ft

Rotary Sidewall Core 7275 ft

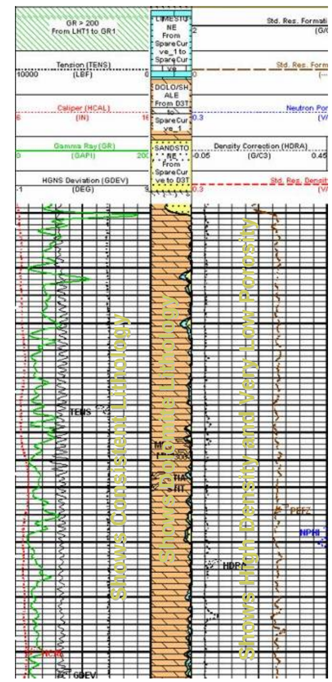


X100

Thin Section 7275 ft



Wireline Log 7100-7300 ft



Hydraulic Core Tests 7275 ft	
Lithology	= Dolomite
Density	= 2.82 g/mL
Porosity	= 0.38%
Permeability	= <0.001 mD

Battelle Graphic

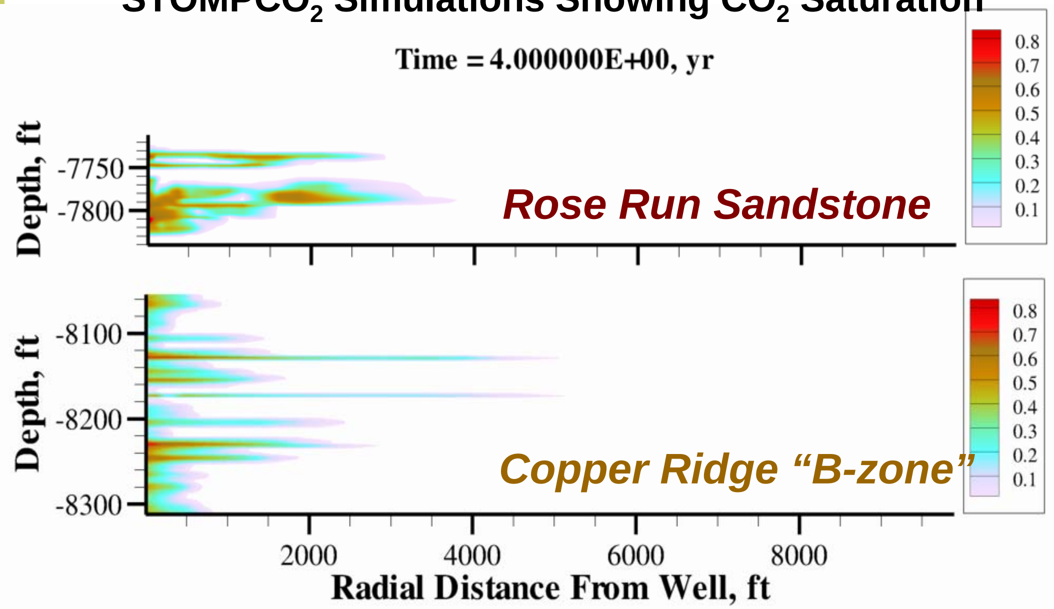
- Presence of multiple, thick, low- permeability containment zones has been established through wellbore observations and seismic survey

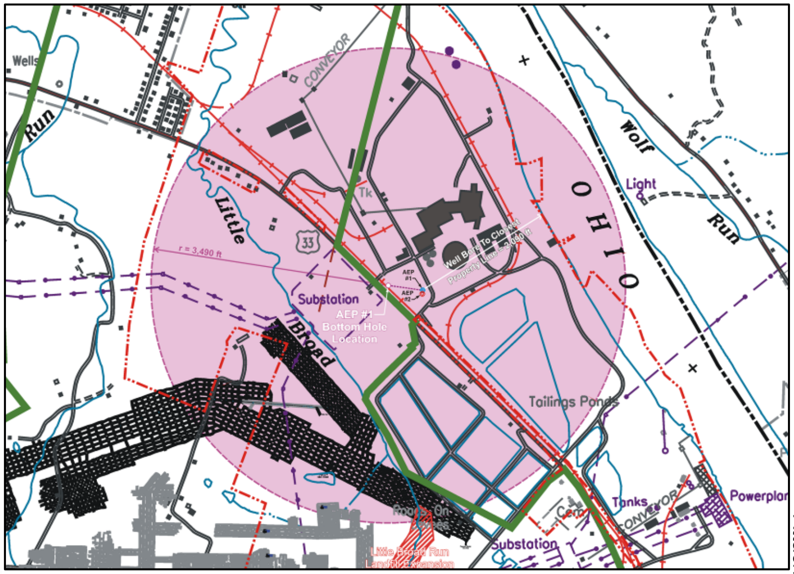
Data from Battelle

Area of Review

- "The Area of Review (AOR) is to be, at a minimum, the anticipated size of the CO_2 plume as modeled or calculated from the injection volume and the characteristics of the injection zone."
- Based on modeling of ~165,000 tonnes/yr of CO_2 into a single formation, an AOR at 3,490 ft from injection well (area containing 90% CO_2) has been proposed.

STOMPCO$_2$ Simulations Showing CO_2 Saturation





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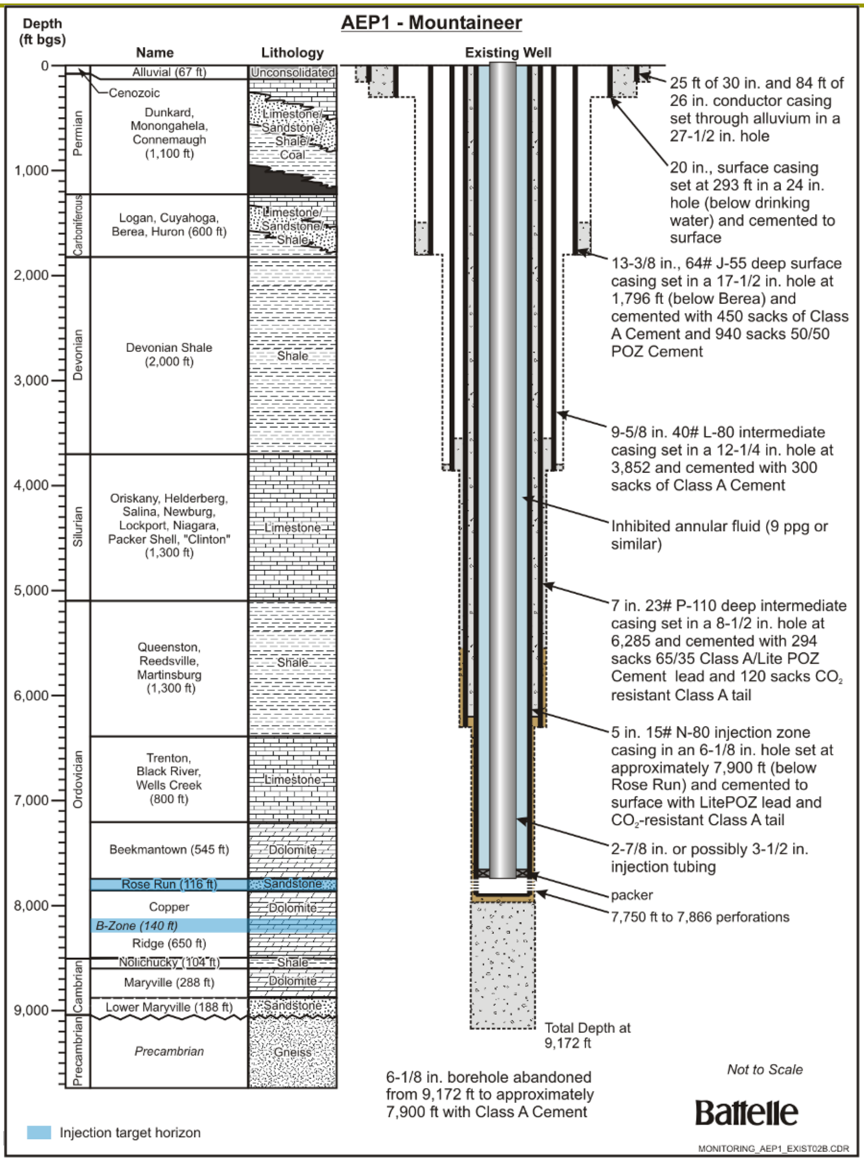
Injection Well Design Example

- Proposed well design for injection well AEP#1 for completion in Rose Run Sandstone
- Multiple well casings isolate shallow freshwater and intermediate zones from injection
- Stainless steel casing and CO_2-resistant cement used in deep injection well casing



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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8211 of 9556

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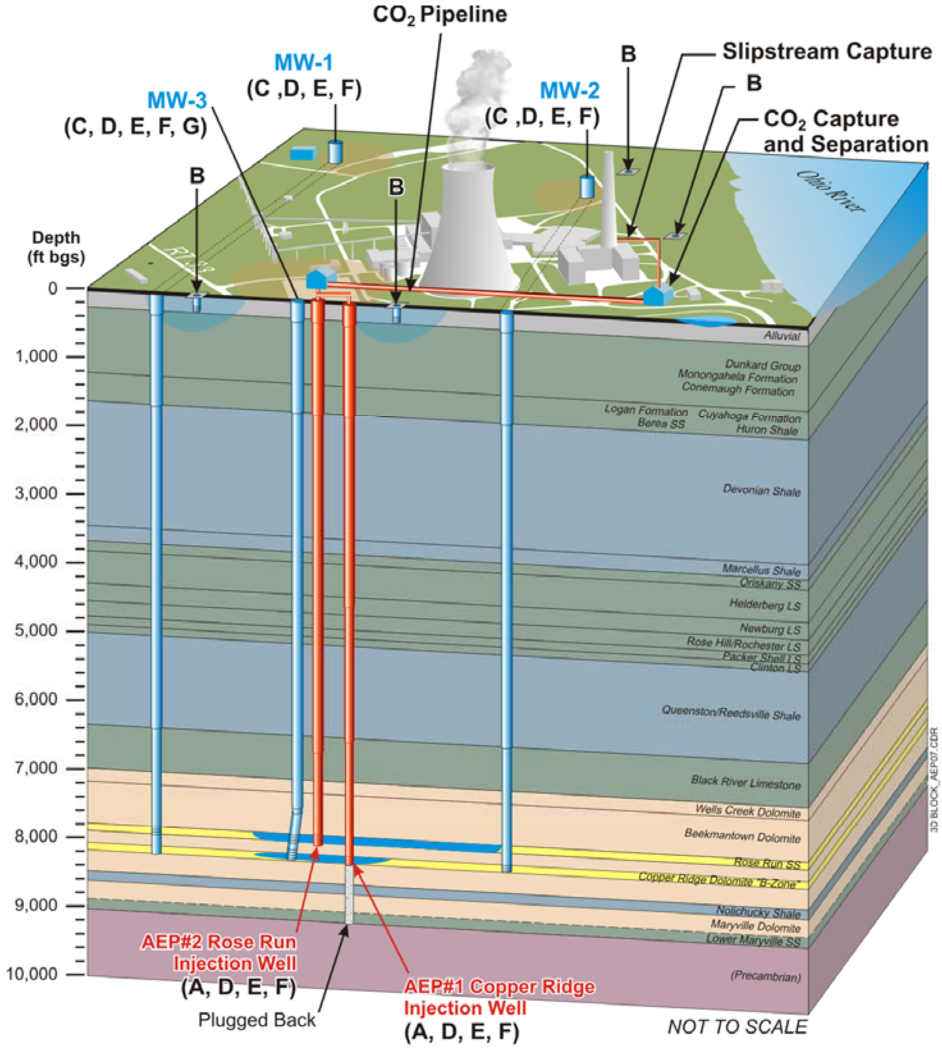
Monitoring System Design



Injection Well Monitoring

- **A** Injection Flow Rate, Injection Pressure /Temperature, Annulus Pressure, Corrosion Monitoring, CO_2 Injectate Analysis

Surface Leak Detection Methods

- **B** Shallow Groundwater Monitoring

CO_2 Tracking Methods

- **C** Fluid Sampling
- **D** Wireline Logging for CO_2 Detection
- **E** Pressure Monitoring
- **F** Cross-Well Seismic Surveys

Caprock/Confining Layer Monitoring

- **G** Microseismic Monitoring

Battelle Graphi

Permits & Outreach

- Known or anticipated permits:
  - Underground Injection Control (UIC) – WV DEP
  - Monitoring well work permit – WV DEP
  - NPDES permit modification – WV DEP
  - Storm Water Construction Permit – WV DEP
  - Public Lands Permit – WV DNR
  - Corps permit notification – Corps of Engineers
  - Periodic seismic survey – Local/county engineer

- Communication and outreach
  - WV DEP and EPA Meetings
  - AEP informational presentations
  - Local town hall and community leader meetings
  - Outside stakeholders

CCS Development Challenges

Biggest challenges for large scale CCS projects:

1. Pore space ownership & legal approval
2. Parasitic load
3. Capital and O&M costs

AEP AMERICAN ELECTRIC POWER

National Association of Stockbrokers
Chicago, IL
April 8, 2010

Hurricane Dolly Storm Restoration

765-kV Transmission Line

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms and our ability to recover significant restoration costs through applicable rate activities, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through rates, insurance or warranty, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Brian Tierney
EVP and Chief Financial Officer

3

Value Proposition to Retail Investors

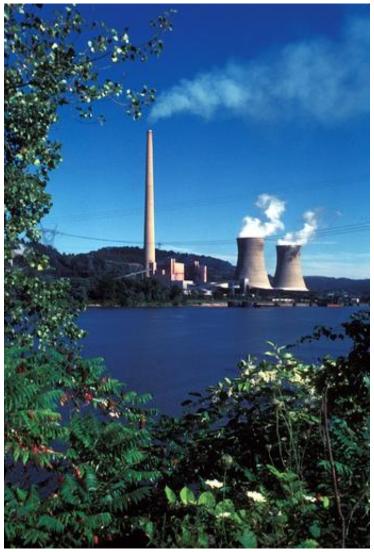
- **Attractive Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

Current Wall Street Analyst Coverage:

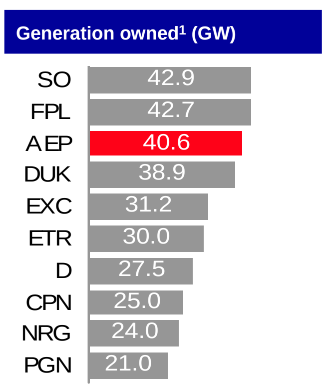
- 21 analysts
- 14 Buy Ratings
- 7 Hold Ratings

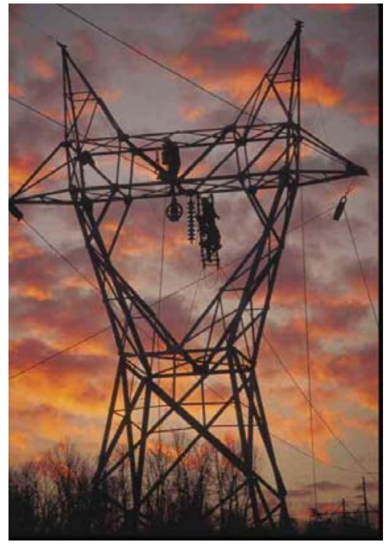
[1] yield percentage based on AEP closing price of $34.30 on 04/06/2010

Industry Leadership



One of the largest U.S. electricity generators





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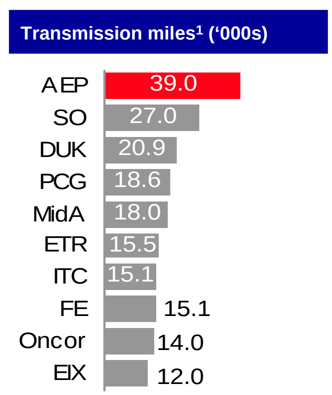

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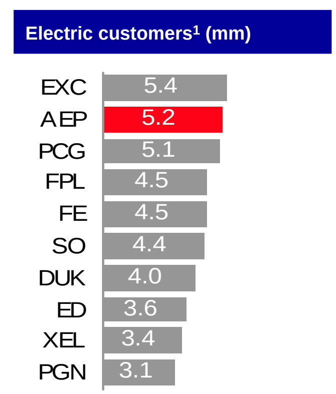

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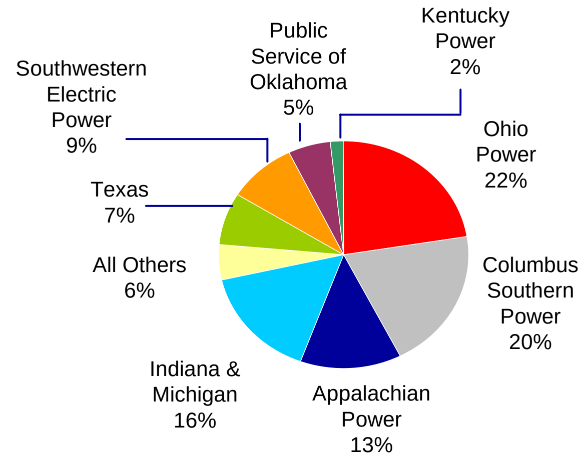

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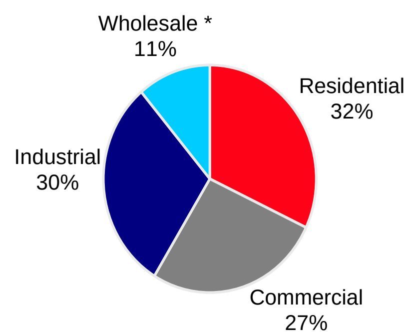

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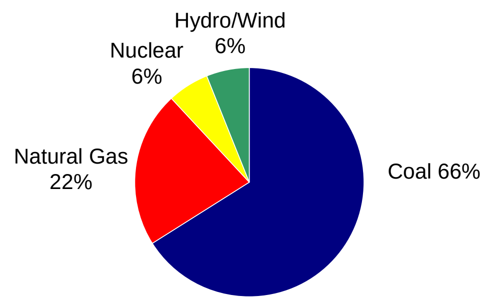
Fuel Mix



Traditional Ratemaking Environment

- **Base Rates**
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs

- **Recovery of Fuel Costs**
  - Active fuel clauses in all jurisdictions

- **Opportunities to Reduce Regulatory Lag**
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Energy Policy Initiatives = Opportunities

AEP®

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- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.1B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
- Robust pipeline of projects up to $15B

765-kV Tower

2010 Ongoing Earnings Guidance

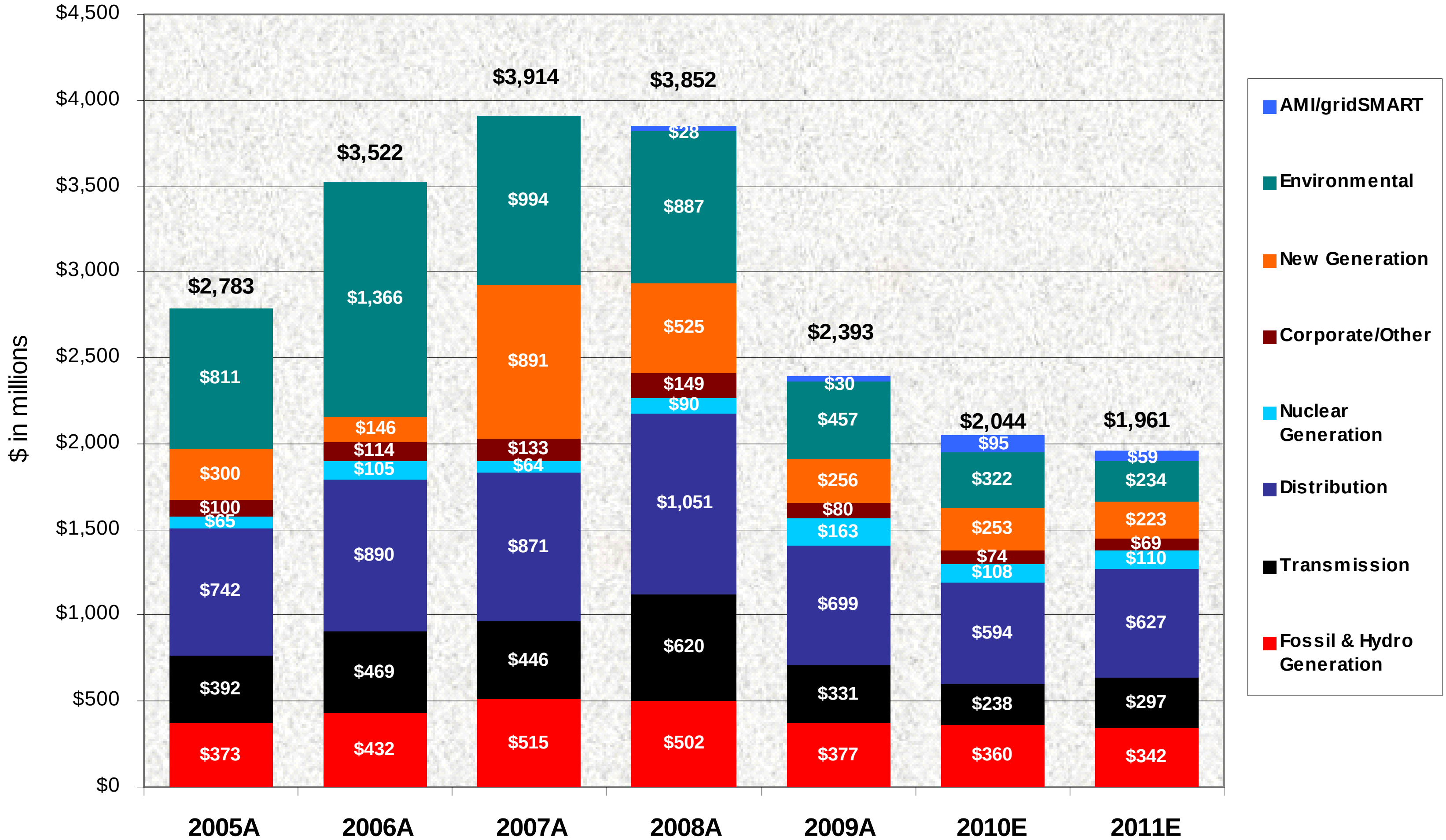
	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)

EARNINGS DRIVERS

- ↑ $320MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $23MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Dividend Overview

- We have paid 399 consecutive quarterly dividends to shareholders
- Annual Dividend - $1.64/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December
- Yield of 4.8% as of April 6, 2010
- Conservative target dividend payout ratio of 50 – 60%
- Dividend Reinvestment Program Available

AEP Highlights

- **Premier Utility Platform**
- **Traditional and Effective Regulatory Relationships**
- **Energy Policy Initiatives Create Technology Deployment and Investment Opportunity**
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- **Strong Value Proposition**

Mountaineer Plant (WV)

AEP and Climate Legislation

Mountaineer Plant - New Haven, WV

AEP AMERICAN ELECTRIC POWER

Northeastern Plant - Oologah, OK

NBIM Roundtable Carbon Discussion

February 12 & 13, 2008

Washington DC

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Tony Kavanagh – VP Washington Office

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Topics for Discussion

- **AEP Climate Strategy:**
  - How is AEP preparing for ultimate climate legislation?
  - What specific voluntary actions and proactive investments is the company undertaking?

- **Federal Legislation:**
  - What type of climate legislation is likely?
  - When will it become effective?
  - How will climate legislation affect operations, capital investment, choice of generation, operations and earnings?
  - What constitutes "reasonable" climate legislation?

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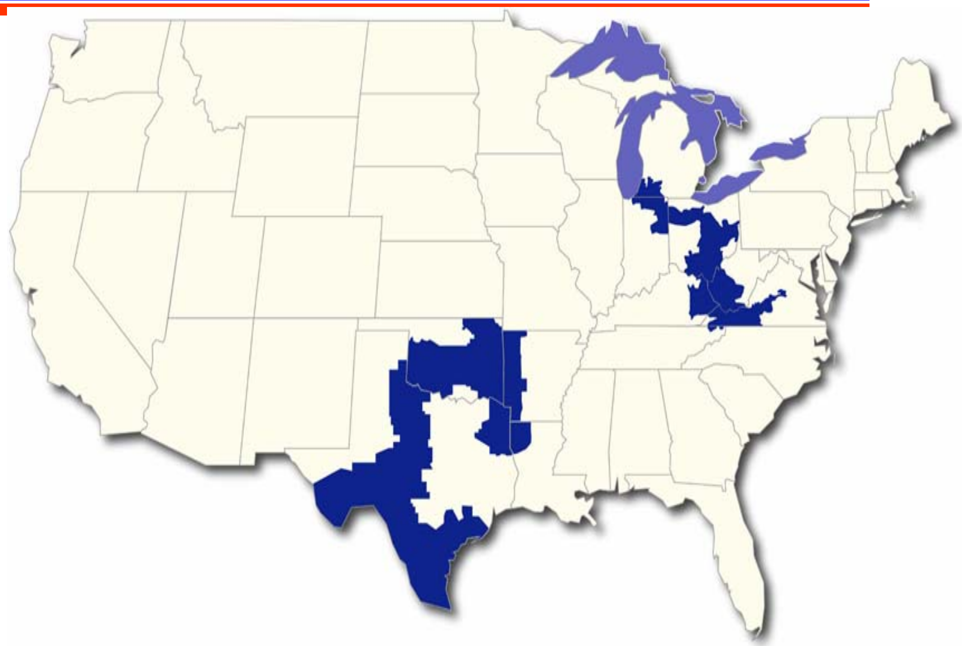
Company Overview

- 5.2 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,300 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~212,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees



AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
67%	**24%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain

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Vision for Sustainability

<table>
<tr><th>Generation</th><th>Transmission</th><th>Distribution</th><th>Customers</th></tr>
<tr><td colspan="4"></td></tr>
<tr>
<td>• Environmental Projects
• Wind
• IGCC
• Carbon Capture & Storage</td>
<td>• I-765™
• Electric Transmission Texas JV
• Electric Transmission America JV
• AEP-ABB Alliance</td>
<td>• Distribution automation
• Self-healing distribution circuits
• Advanced metering
• Communications infrastructure
• Mobile workforce
• Internal energy efficiency
• Integration platform for advanced visualization and analytics
• Distributed generation and energy storage</td>
<td>• Customer programs and incentives
  • Energy efficiency
  • Direct load control
  • Peak demand reduction
• Energy storage</td>
</tr>
<tr>
<td colspan="2">Existing generation and transmission control systems</td>
<td>gridSMART℠: bridging the gap to provide integrated two-way communications & control across the electricity value chain</td>
<td>Home energy automation</td>
</tr>
</table>

AEP is committed to operating responsibly, efficiently and profitably for customers, shareholders, employees and communities.

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AEP Climate Strategy

AEP's Climate Strategy

GLOBAL ROUNDTABLE ON CLIMATE CHANGE

CLIMATE LEADERS®
U.S. Environmental Protection Agency

CCX™ Chicago Climate Exchange

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Coal
- **Taking voluntary, proactive action now, making real reductions and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders and SF-6 Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Investing in longer term technology solutions--new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical PC)**

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AEP must be a leader in addressing climate change

AEP's Climate Position

- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment

- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable & reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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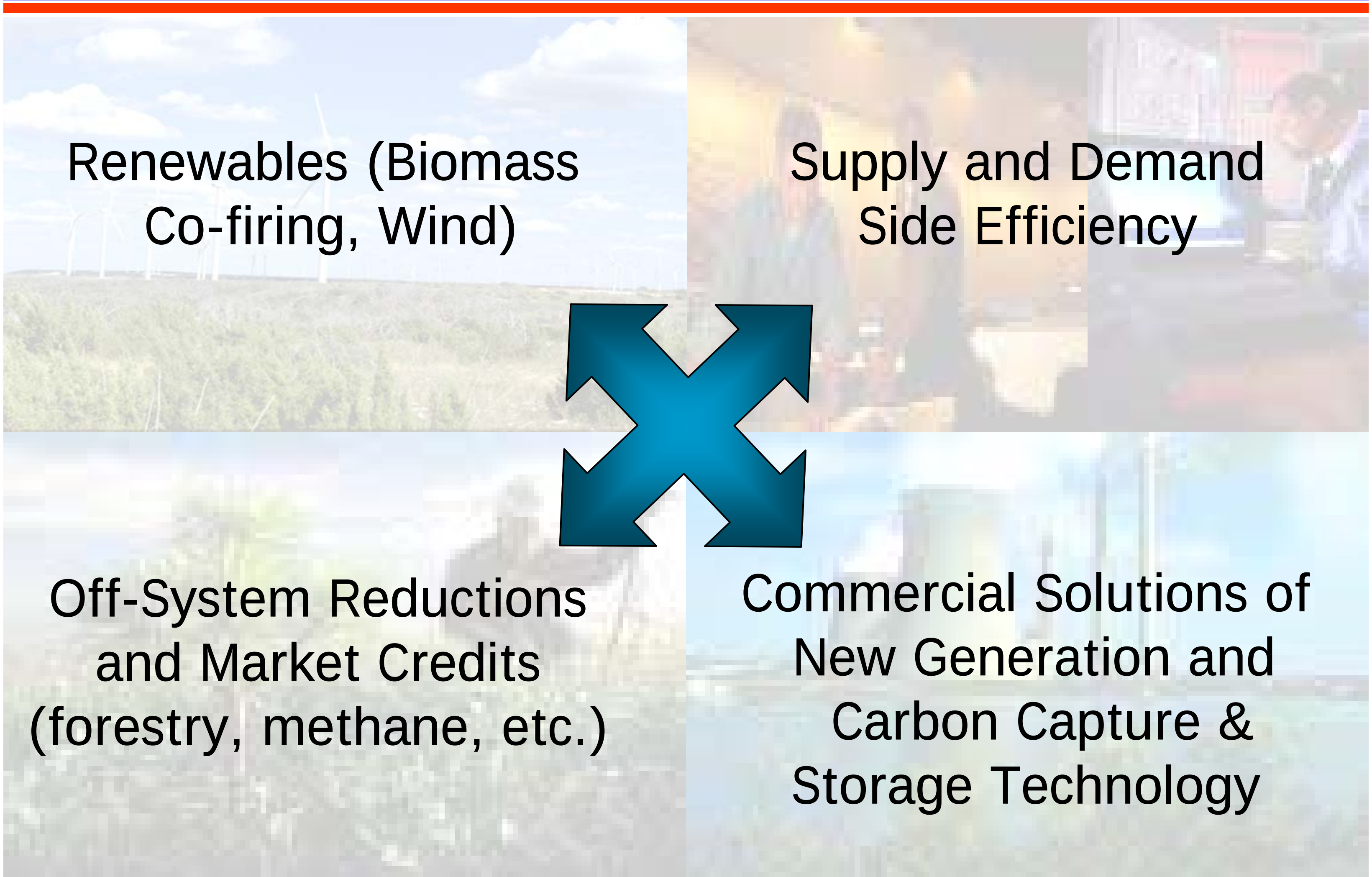
AEP's Long-Term GHG Reduction Portfolio



AEP is investing in a portfolio of GHG reduction alternatives

A Portfolio Approach: AEP Long-Term CO_2 Reduction Commitment

Existing Programs

- **Existing plant efficiency improvements**
- **Renewable Energy**
  - 800 MWs of Wind
  - 300 MWs of Hydro
- **Domestic Offsets**
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - **1.2MM tons of carbon sequestered**
- **International Offsets**
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- **Chicago Climate Exchange**

AEP's reductions/offsets of CO_2:
- **2003-2005: 31 MMT**
- **2006-2010 (proj.): Additional 15 MMT**

New Program Additions (by 2011)

- **1000 MWs of Wind PPAs: 2MM tons/yr**
- **Domestic Offsets (methane): 2MM tons/yr**
- **Forestry: Tripling annual investment to increase to 0.5MM tons/yr by 2015**
- **Fleet Vehicle/Aviation Offsets: 0.2MM tons/yr**
- **Additional actions--end use and supply efficiency and biomass: 0.2MM tons/yr**

New Technology Additions

- **New Technology Generation – IGCC and USC**
- **Commercial solutions for existing fleet**
  - Chilled Ammonia
  - Oxy-Coal

AEP's reductions/offsets of CO_2:
2011+: 5 MMT/YEAR
Longer Term—New Technology

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AEP Wind Operations/Purchases

Trent Mesa (2001)

- **150 MW** (100 - 1.5 MW turbines)
- Abilene/Sweetwater, TX

Southwest Mesa (1999)

- **75 MW** (107 – 700kW turbines)
- McCarney, TX
- Power Purchaser

Desert Sky (2002)

- **160 MW** (107 - 1.5 MW turbines)
- Bakersfield, TX

Summary

•Owned/Operated 385 MW

•Wind Purchases 392 MW

•Total Existing Wind at end of 2006: 777 MW

•**New Wind Purchases in 2007: 275 MW**

Will acquire an additional 725 MW of new wind to attain goal of 1,000 MW by 2011

Off-System Reductions

Existing AEP Programs:

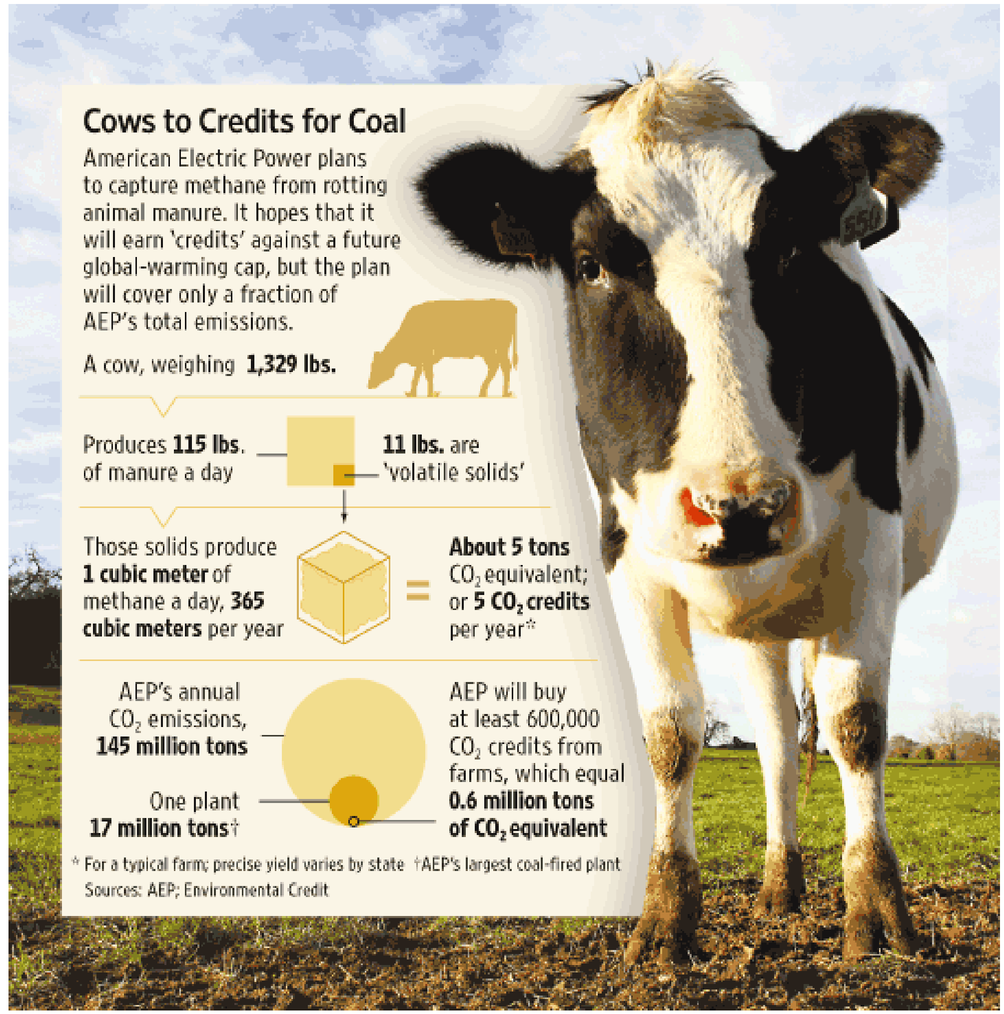
- Forestry - Domestic
  - 350,000 tons / yr
  - 63 MM trees planted
- Forestry – International
- Chicago Climate Exchange

New AEP Commitment by 2011:

- 2 M tons per year of additional CO_2 offsets

Latest Announcement:

- Methane Capture Deal with Environmental Credit Corp.
  - 600,000 CCX carbon credits per year
  - Begins 2010
  - Runs through 2017
  - 51% of credits sourced from "AEP States"

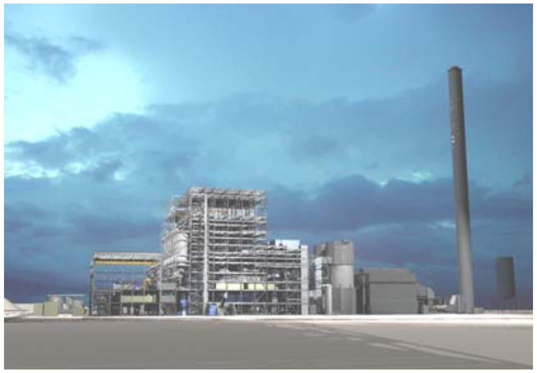


Source: Wall Street Journal June 14, 2007

AEP Leadership in Technology: IGCC and USC

NEW ADVANCED GENERATION

- **IGCC -- AEP first to announce plans to build two 600+ MW IGCC commercial size facilities in US (OH and WV) by mid next decade**



- **USC -- AEP will be first to employ new generation ultra-supercritical (steam temperatures >1100ºF) coal plant in U.S (AR)**

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AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

- **Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.**
  - **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009**
  - **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**
- **Oxy-Coal--AEP will also demonstrate (10MWe) and then install oxy-coal CO_2 capture & storage at a commercial sized coal unit (about 200 MWe)—feasibility study to be completed in 2008.**

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AEP Leadership in New Technology: Chilled Ammonia CCS

Phase 1

2009 Commercial Validation

1300 MW Mountaineer Plant (WV) → MOU (Alstom) **Chilled Ammonia 20MWe scale**

CO_2 Storage (Battelle)

Captures and sequesters 100,000 metric tons of CO_2 /yr.

Phase 2

2012 Commercial Operation

450 MW Northeastern Plant (OK) → MOU (Alstom) **Chilled Ammonia 200MWe scale** → EOR

CO_2 Storage

Captures and sequesters 1.5 Million metric tons of CO_2 /yr.

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Examples of Relative GHG Mitigation Costs for Power Sector

$40+

\$/ton CO_2e

$0

- **Carbon Capture w/ Geologic Sequestration**
- **Other renewable, advanced geothermal and/or solar**
- **Carbon Capture for Enhanced Oil Recovery**
- **New Biomass Generation**
- **Dispatch of additional gas vs. inefficient coal**
- **Biomass Co-firing**
- **Biological Sequestration (e.g. Forestry)**
- **New Wind**
- **Energy Efficiency**
- **Methane Offsets**

Nuclear?

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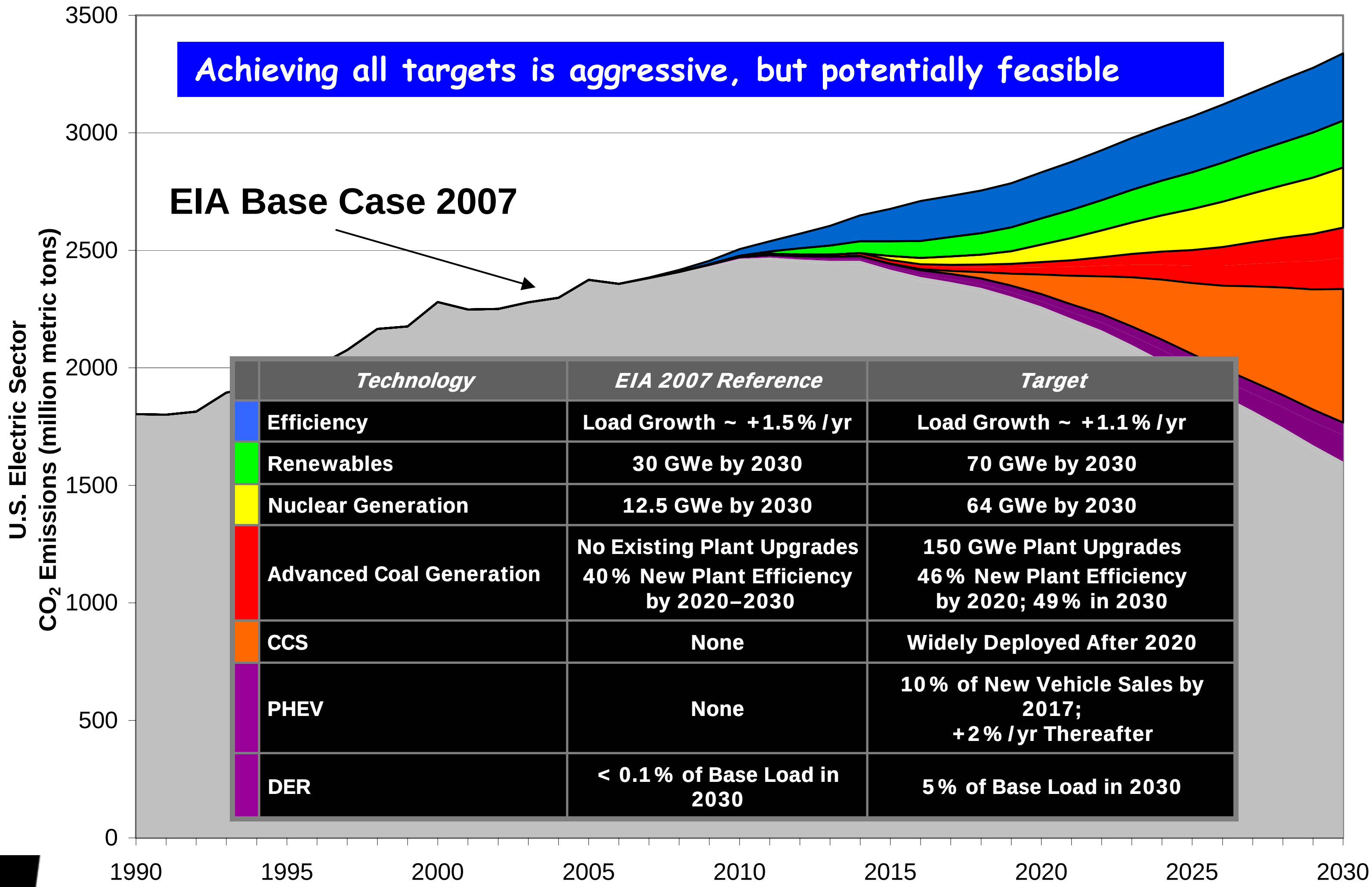
EPRI CO_2 Reduction "Prism"



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

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Key Issues for CCS Development in U.S.

- Overcoming the "Economic" Hurdle
- High Up-Front Capital Investment—Getting Adequate Financing and Recovery in Rates
- Commercial Demonstrations of CCS at Large Coal-Fired Power Plants
- National Standards for Permitting of Storage Reservoirs
- Potential Institutional, Legal and Regulatory Barriers to Carbon Storage

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Federal Legislation and AEP Position

Prospects for US Federal Legislation—The Crystal Ball

- With Democratic majorities in the House and Senate, prospects during the 110th Congress for mandatory climate legislation have increased.
- Nonetheless, the Senate and House have just begun introducing/developing legislation and there are many contentious issues, particularly allocation.
- In the 2009 and after period, passage of legislation is more likely, with a new President in office.
- A general timeline for passage of Clean Air Legislation has typically been 5-8 years after the initial “serious” proposals.

We are at the “end of the beginning” NOT the “beginning of the end.”

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Potential for Federal Climate Legislation

- Legislation could pass as early as 2009-10 with limits taking effect as early as 2015. Any earlier reduction requirements are unlikely.
- Moderate approach probably has best chance of passage, which means offsetting emissions growth initially (during next decade) with significant reductions thereafter.
- Impacts in terms of utility operations, capital and earnings won't be until the 2015-20 period. With more substantial impacts probably not beginning until 2020 and after.

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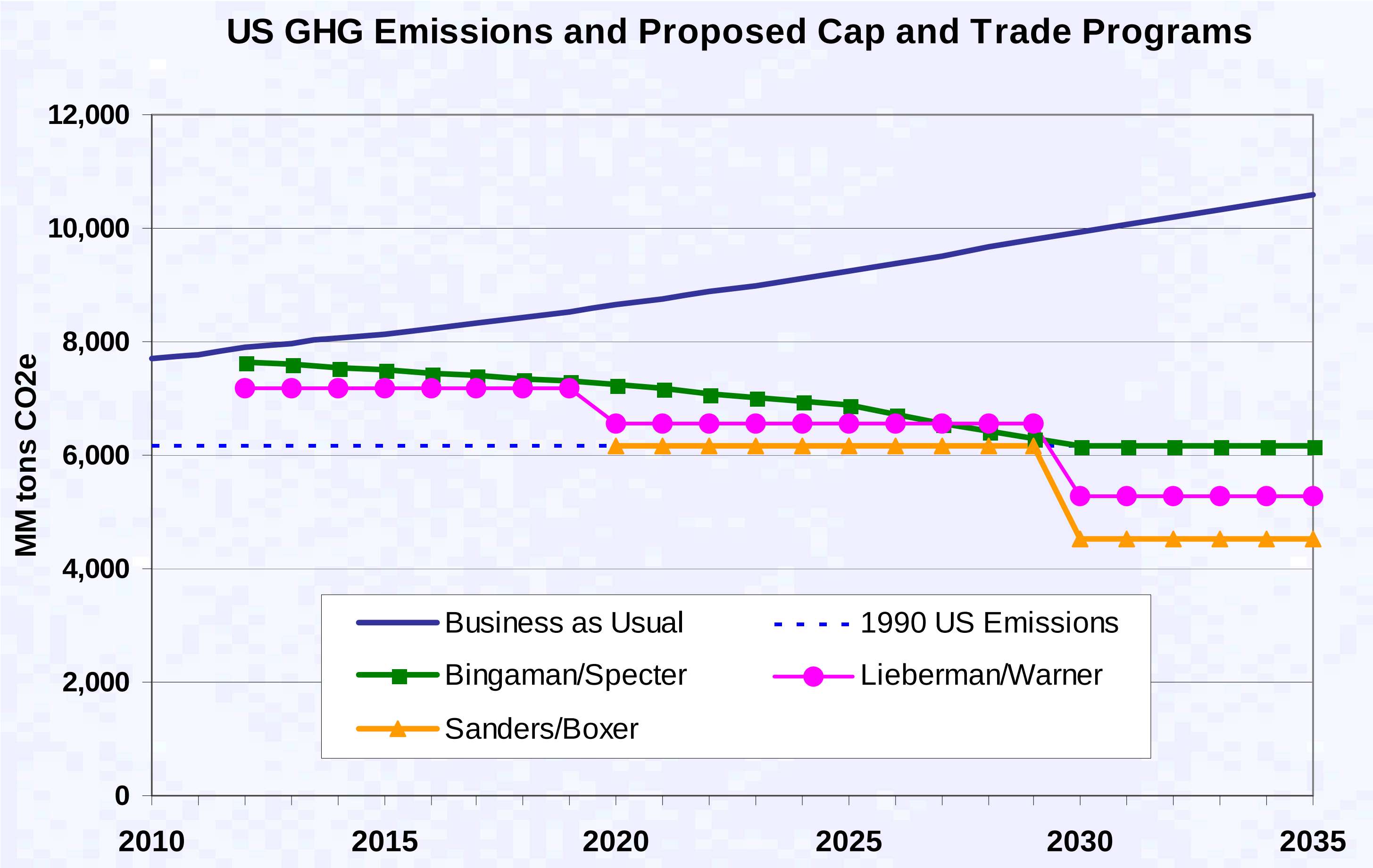
Emission Reductions Under Selected Bills



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AEP Supports Bingaman-Specter Bill

"Low Carbon Economy Act of 2007"

- Economy wide cap-and-trade program to limit Greenhouse Gas Emissions
  - Caps and Dates
    - 2006 Levels by 2020
    - 1990 levels by 2030
  - Industry Sectors "Regulated" under bill
    - Natural Gas and Petroleum regulated "upstream"
    - Coal regulated "downstream" at the power plant level
  - Allocations to Electricity Generators
    - Only fossil-fired electric generators receive allowances
  - Safety Valve (TAP)
  - Bonus Allowances for Carbon Capture and Sequestration
  - Early Reduction Credits and Offsets Included
  - Congressional Review of International Action (e.g. AEP-IBEW Proposal)

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AEP Supports Reasonable Legislation on GHG

Background on Allowance Allocations and Auctions

- **"Allowance" = Right to emit a ton of emissions.** Each year allowances are surrendered to cover annual emissions.
- **Most programs (e.g. EPA's SO_2 and NOx, CAIR and CAMR) allocate allowances (at "no cost") to generators (primarily based on historic emissions) with little or no auction.** The EPA SO_2 program has been hailed as a success because of its AFFORDABILITY due in part to a small (2.8%) auction.
- **Allowance allocation to emitters does NOT result in a "windfall." CO_2 cap means ALLOWANCES <EMISSIONS. So reductions must be made at a NET COST.**
- **Importantly, whether allowances are allocated at "no cost" or auctioned has NO environmental impact, it is the overall CO_2 cap that determines the amount of reductions.**

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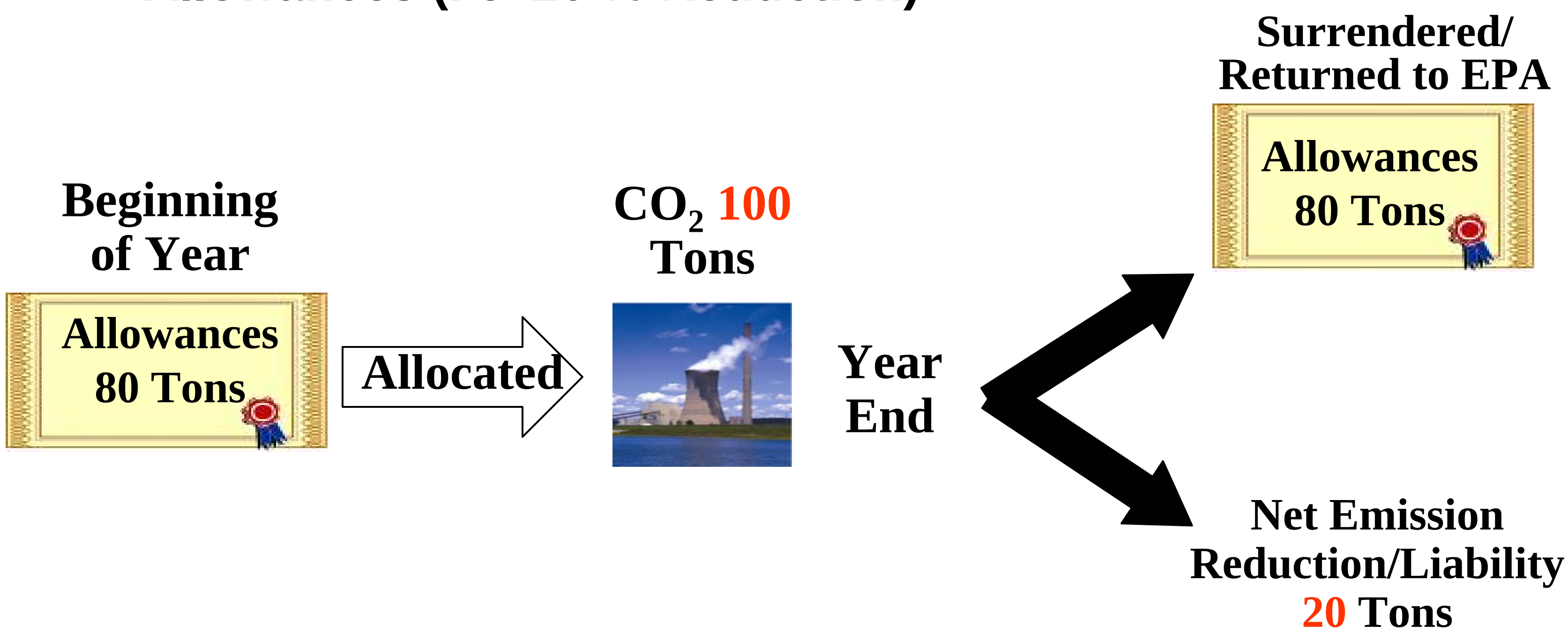
“Free” Allocation To Emitters Does Not Increase Profits

- Example: Company Emits 100 Tons, Receives 80 “No-Cost” Allowances (i.e. 20 % Reduction).



- Full Allocation to Emitters Does NOT Create a “Net Asset” or Windfall because of the Liability of Complying with the CO_2 Cap. In fact, it is a NET LIABILITY.

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Technical Appendix

Carbon Capture and Storage

CO_2 Capture Techniques

- **Post-Combustion Capture**
  - Conventional or Advanced Amines, Chilled Ammonia
  - *Key Points*
    - Amine technologies commercially available in other industrial applications
    - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
    - High parasitic demand
      - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
    - Amines require **very** clean flue gas
- **Modified-Combustion Capture**
  - Oxy-Coal
  - *Key Points*
    - Technology not yet proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - High parasitic demand, >25%
- **Pre-Combustion Capture**
  - IGCC with Water-Gas Shift – FutureGen
  - *Key Points*
    - Most of the processes commercially available in other industrial applications
      - Have never been integrated together
    - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
    - Creates stream of very high CO_2 concentration
    - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

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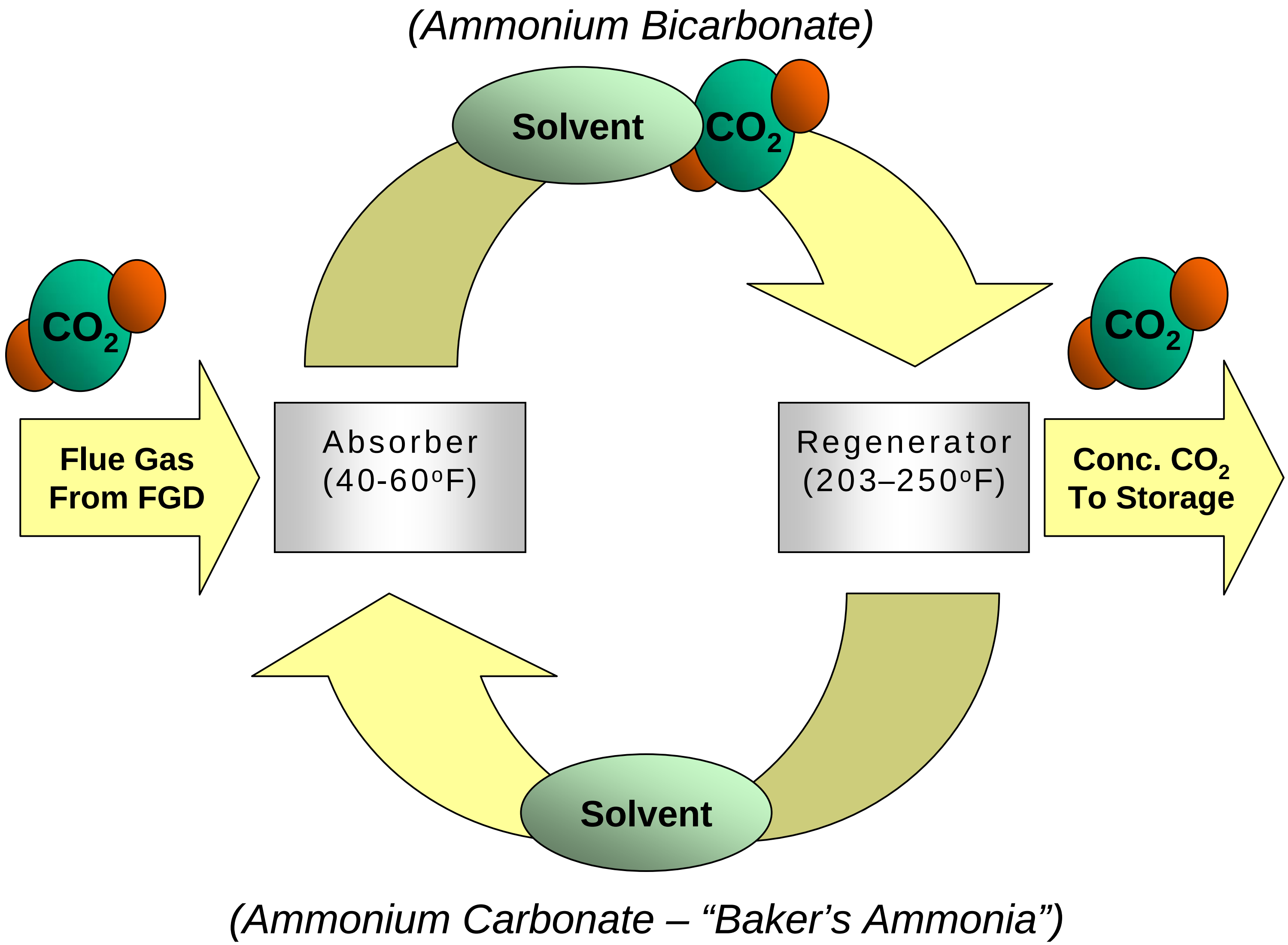
Alstom Chilled Ammonia Process
Post-Combustion Capture



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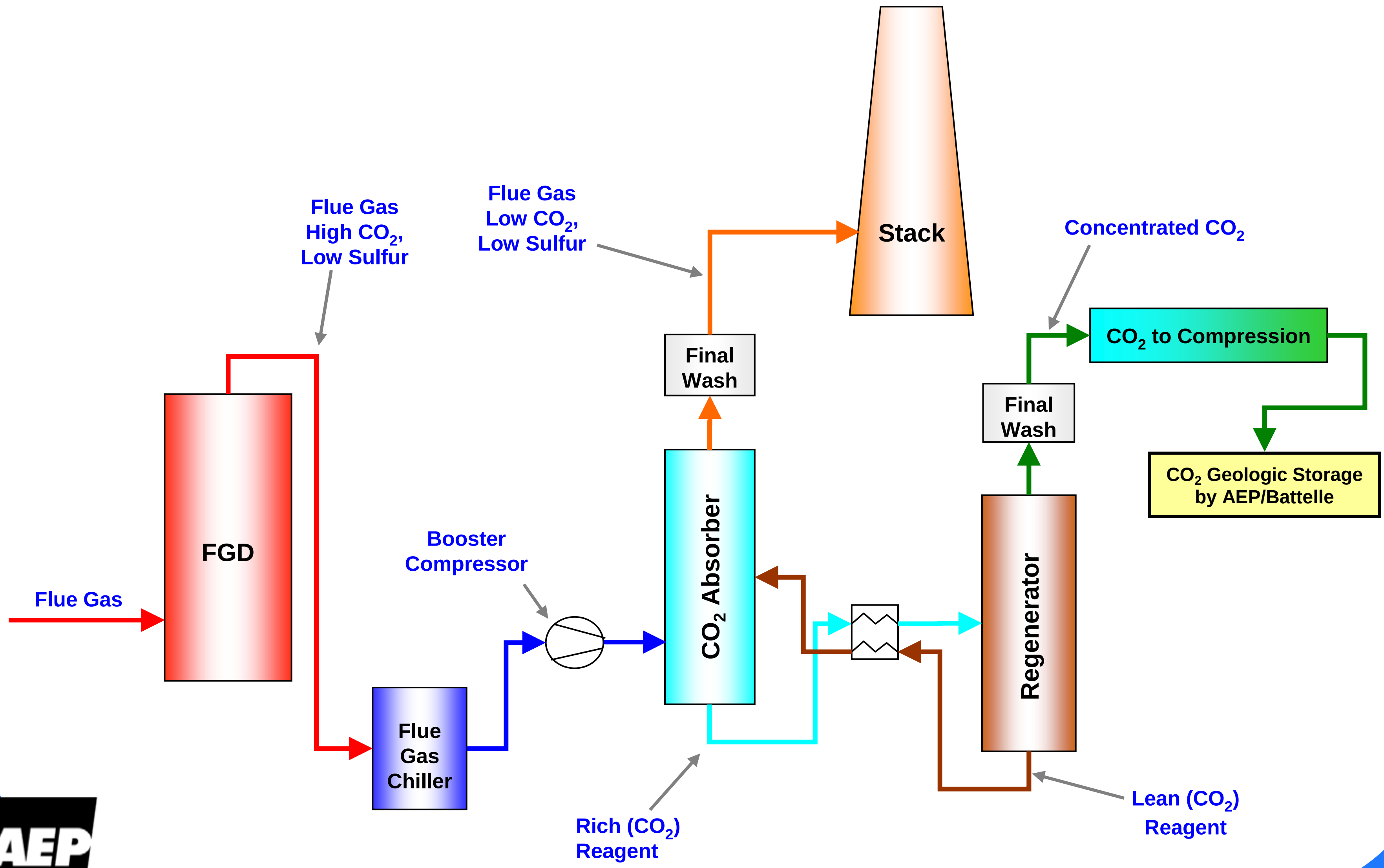
Alstom's Chilled Ammonia Process

Post-Combustion Capture



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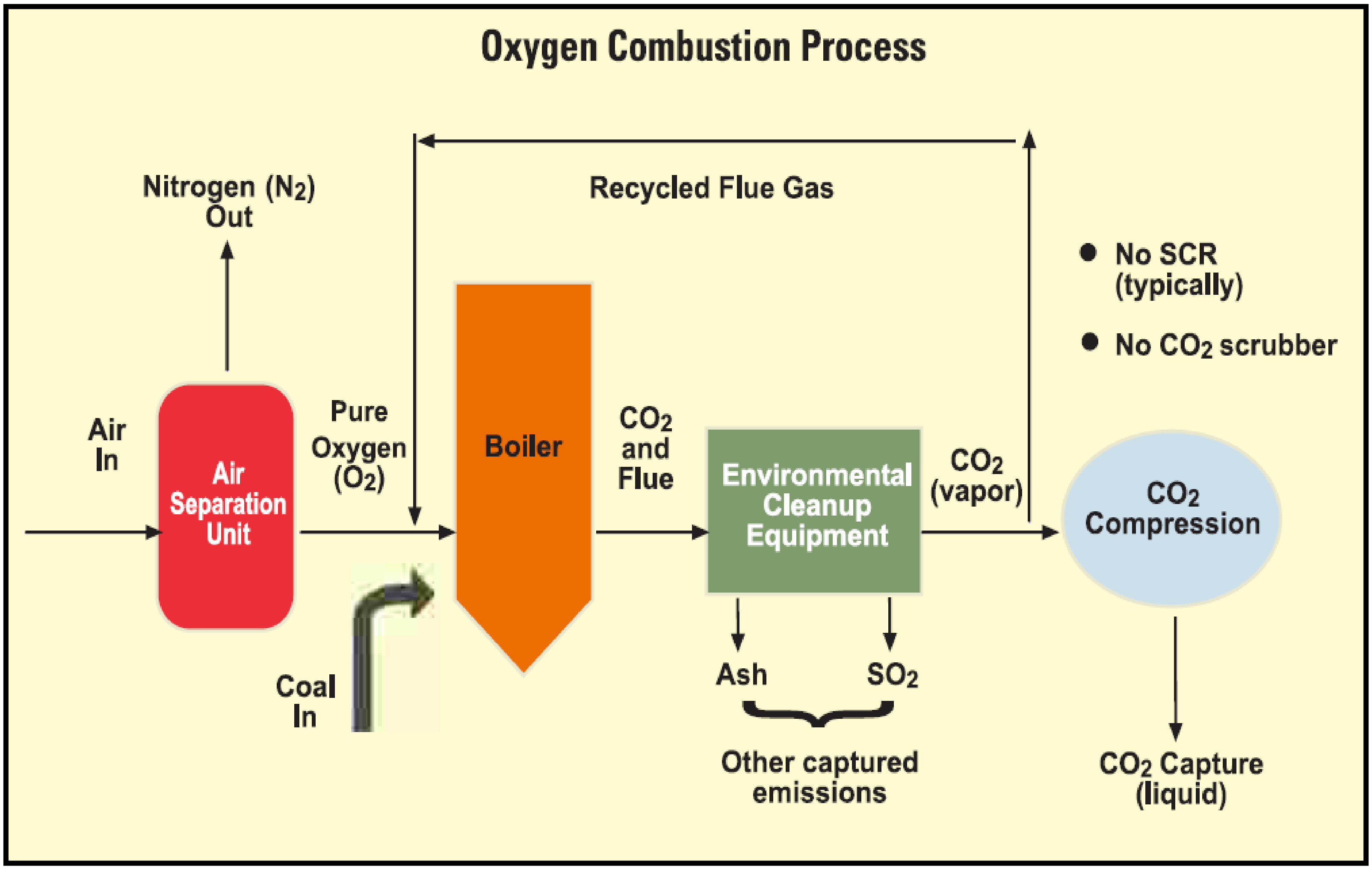
Babcock & Wilcox Oxy-Coal Process

Modified Combustion Capture



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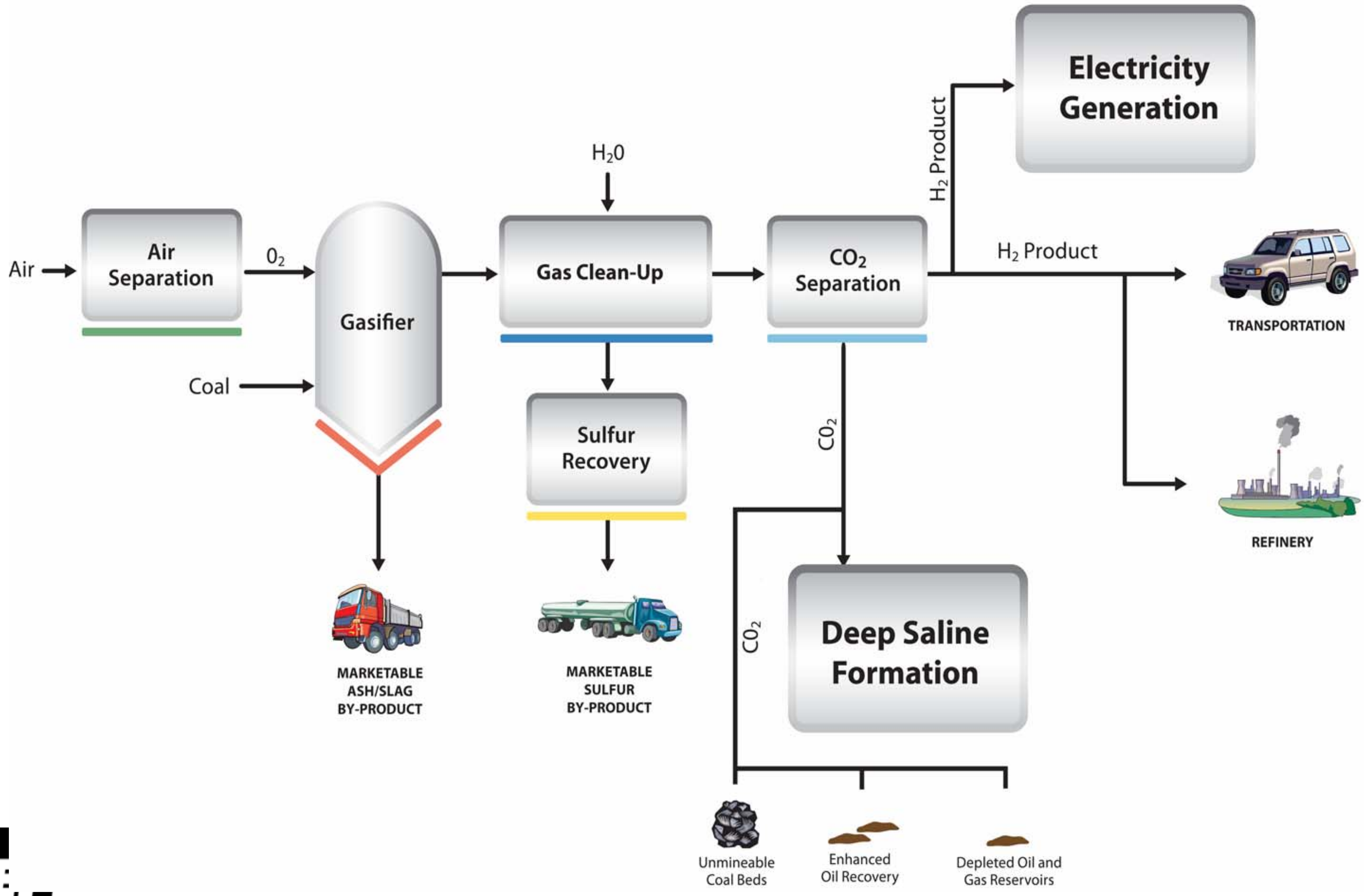
FutureGen Water-Gas Shift Process
Pre-Combustion Capture



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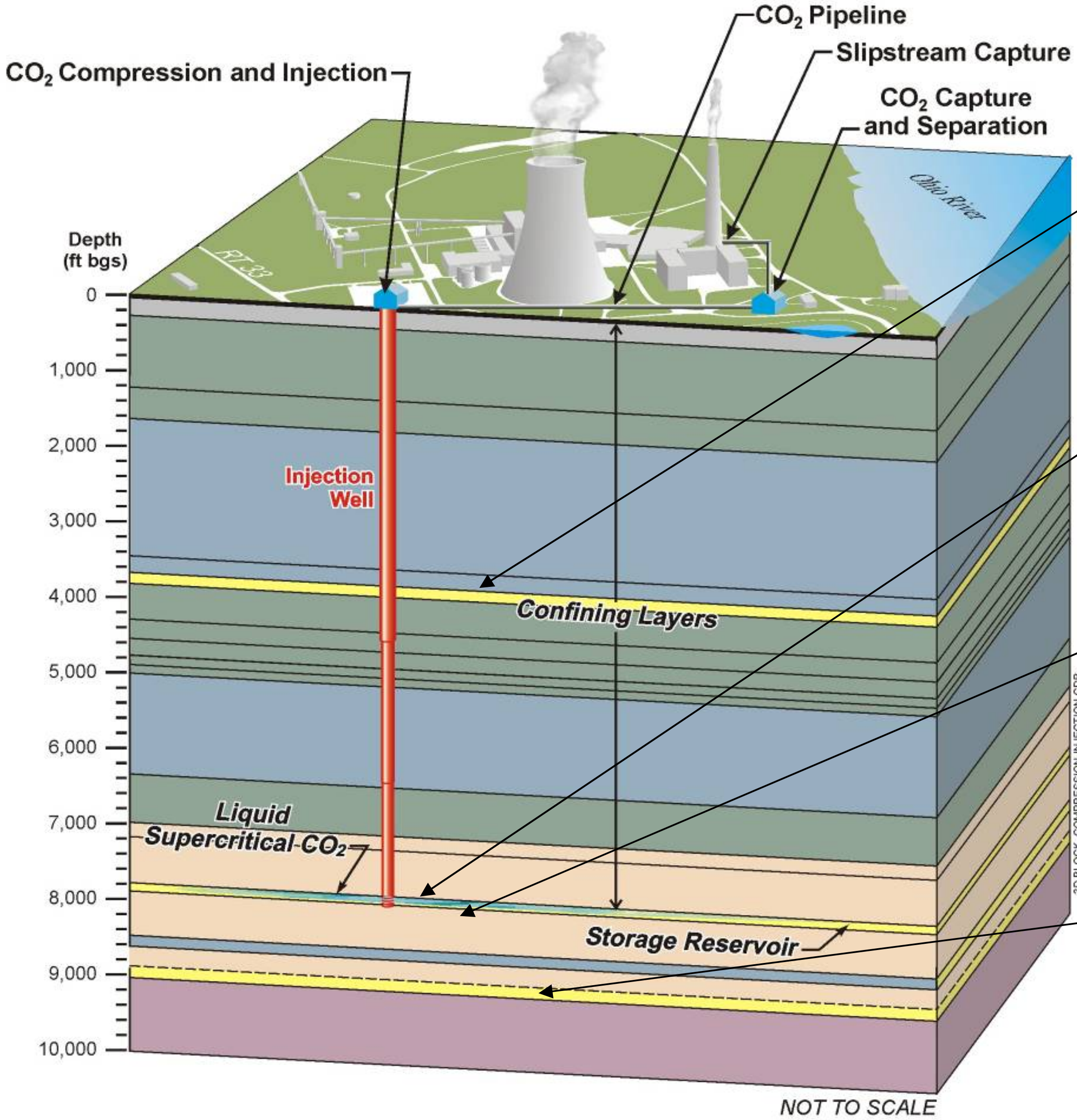
CO_2 Injectivity in the Mountaineer Area



CO_2 injection should also be possible in shallower sandstone and carbonate layers in the region

Rose Run Sandstone (~7800 feet) is a regional candidate zone in Appalachian Basin

A high permeability zone called the “B zone” within Copper Ridge Dolomite has been identified as a new injection zone in the region

Mount Simon Sandstone/Basal Sand - the most prominent reservoir in most of the Midwest but not desirable beneath Mountaineer site

AEP's Carbon Capture & Storage Project

CCS Clean Energy for A Clean Environment
AEP's Carbon Capture & Storage Project

Leading the Way

AEP and Carbon Capture and Storage

AEP continues its heritage of advancing technology for the electric utility industry with leading-edge carbon capture and storage initiatives.

As an industry leader in climate action, AEP recognized more than a decade ago that the emissions of its coal-fueled fleet of power plants -- including carbon, a greenhouse gas emission associated with global climate change -- would have a significant impact on the future of the company.

AEP has faced the challenge with innovative, first-of-a-kind approaches designed to allow the continued use of coal to generate electricity in a carbon-constrained world.

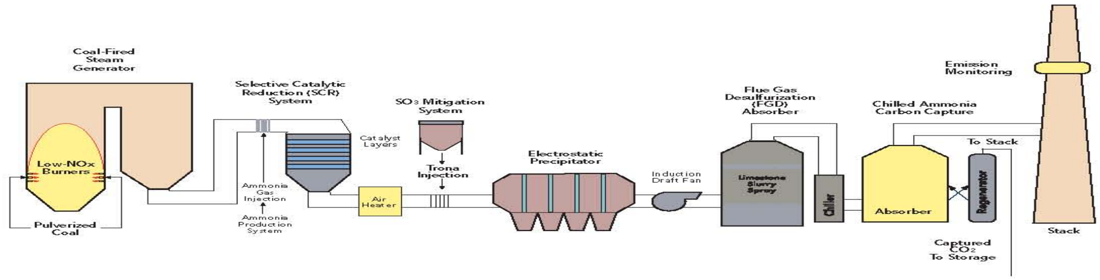
AEP and Carbon Capture and Storage

AEP's goal is to address the issue of climate change while maintaining a supply of affordable, reliable energy for customers that helps keep our economy and our nation secure and strong.

AEP will install Alstom's chilled ammonia process, a post-combustion technology, on two coal-fired power plants

- A technology validation project at Mountaineer Plant in West Virginia and
- Commercial scale installation at Northeastern Station in Oklahoma

The carbon capture project at Mountaineer Plant will be operational in early 2009. In addition, AEP will capture, compress and store underground at least 100,000 metric tons of carbon dioxide (CO_2) per year in deep geologic formations. The estimated $70 million project will operate three to five years.



CCS process occur after the flue gas exits the FGD system and before it enters the stack.

Commercial scale application of Alstom's chilled ammonia process at Northeastern will enter commercial operation in 2011. The installation will capture approximately 1.5 million metric tons of CO_2 per year. At Northeastern, AEP intends that the CO_2 will be used for enhanced oil recovery (EOR).

With these projects, AEP continues its leadership position with significant scale-up of technology to capture and store CO_2 emissions from a coal-fired plant.

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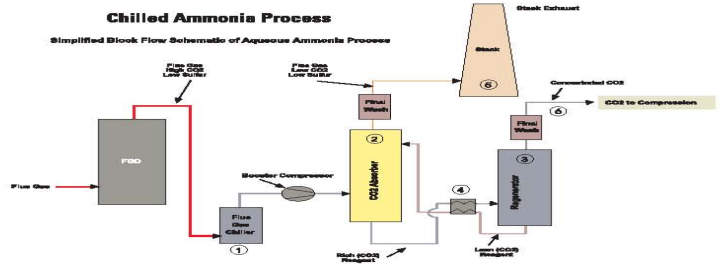
AEP's Carbon Capture & Storage Project

Carbon Capture

With Alstom's chilled ammonia process

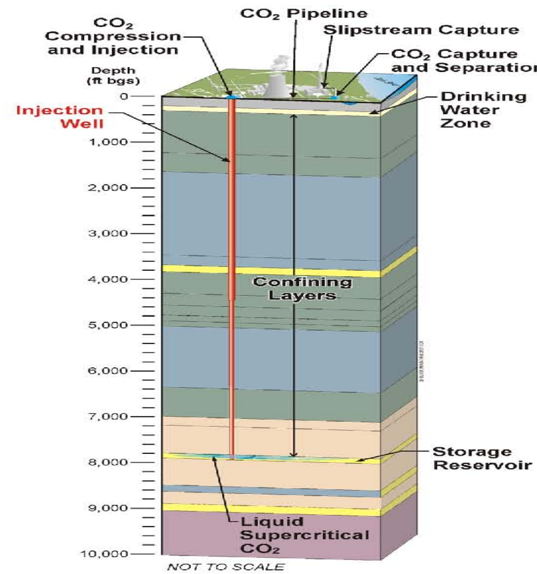
1. The flue gas is chilled to ~ 35°F
2. Ammonium carbonate absorbs CO_2 to make ammonium bicarbonate
3. Ammonium bicarbonate slurry is pumped to a regenerator for CO_2 removal, where the ammonium bicarbonate is converted back to ammonium carbonate and is reused to repeat the process.
4. Heat recovery ensures efficient operation of process.
5. The clean flue gas -- containing mainly nitrogen, excess oxygen and low concentration of CO_2 -- flows to the stack
6. CO_2 is sent to geologic storage in deep saline aquifers or EOR fields.



Carbon Storage

AEP will work with Battelle Memorial Institute to store captured carbon in deep saline aquifers on the Mountaineer Plant site. A characterization study was conducted here in 2003 - 04 and one well already exists. That study indicated that the geologic formations in this area are favorable for carbon storage.

For storage, the captured CO_2 is compressed into a liquid-like state and injected under pressure into saline aquifers in carefully chosen deep geologic formations of pourous sandstone or dolamite. The CO_2 is injected more than a mile underground and spreads through the pore space in the rock where it is effectively trapped from moving upward by layers of impermeable rock above the porous rock, much like oil and gas deposits are trapped for millions of years.



Other technologies – Oxy-coal

AEP also will conduct a retrofit feasibility study with Babcock & Wilcox of its Oxy-coal technology. Plans to retrofit an existing AEP plant for commercial-scale CO_2 capture using this pre-combustion technology will follow.

Oxy-coal combustion creates a flue gas that is primarily a concentrated stream of CO_2. In the Oxy-coal combustion process

- Combustion air is replaced with relatively pure oxygen.
- A portion of the CO_2-rich flue gas is returned to the burners, essentially substituting CO_2 for the nitrogen in the furnace.
- The fraction of the flue gas that is not re-circulated to the burners leaves the plant and is available for subsequent use or storage.
- A secondary benefit of Oxy-coal firing is the reduction of nitrogen oxide (NOx) emissions.

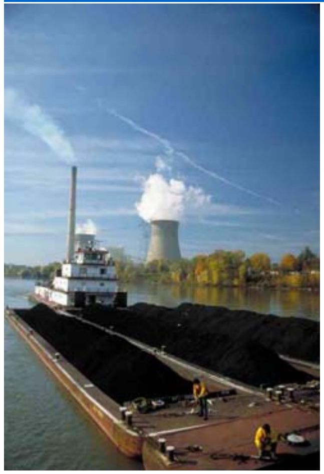
AEP AMERICAN ELECTRIC POWER

AEP

Fixed Income Luncheon

New York City

April 17, 2007



AEP AMERICAN® ELECTRIC POWER

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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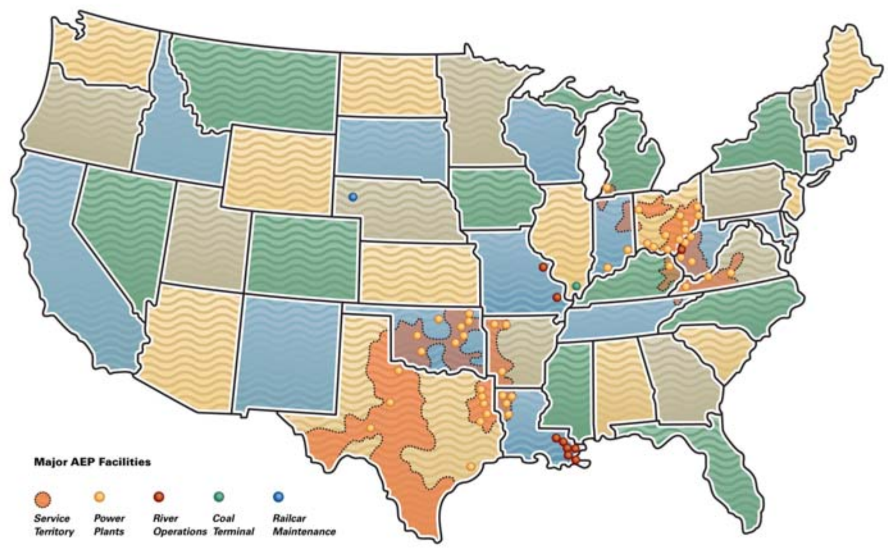
Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



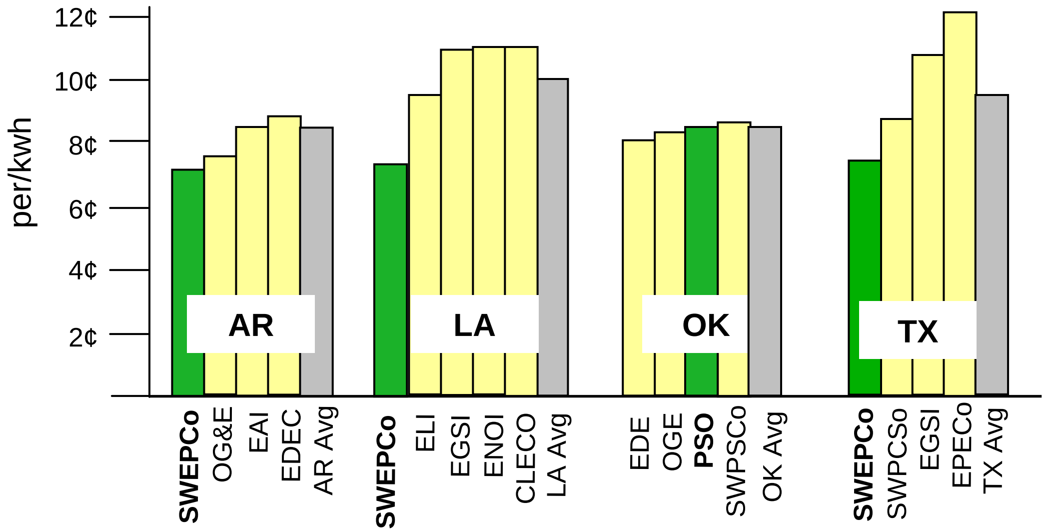
- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

AEP Provides Low Cost Electric Service

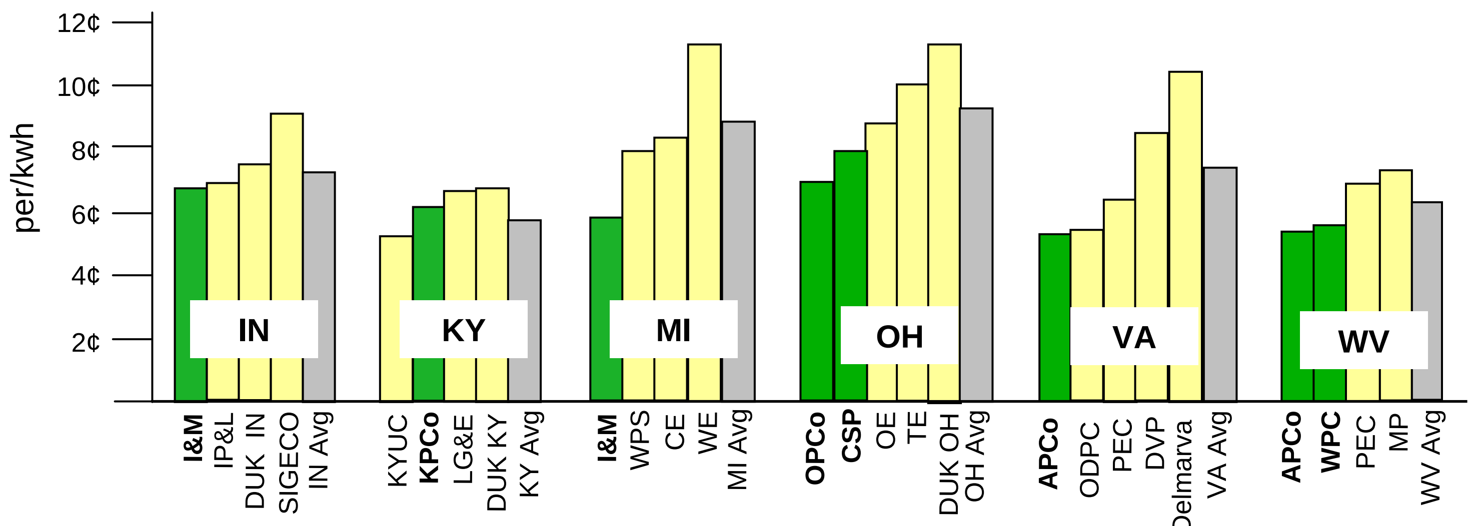
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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KPSC Case No. 2011-00401
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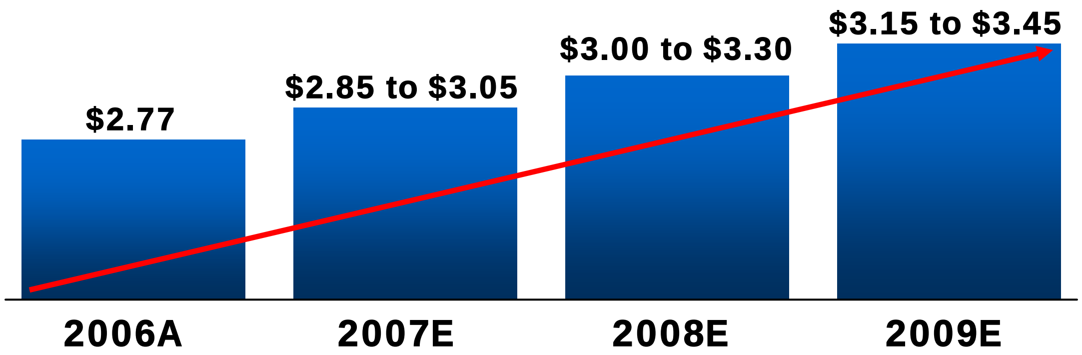
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Our Strategy Remains Focused On Regulated Operations

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Build	$474	$485	$573	**$1,532**
New Generation - Purchase	$118	$0	$0	**$443 ***
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC

*Includes Lawrenceburg purchase $325MM in 2007

GROWTH INVESTMENT TO BE FUNDED BY CASH FROM OPERATIONS VIA RATE RELIEF AND DEBT ISSUANCES

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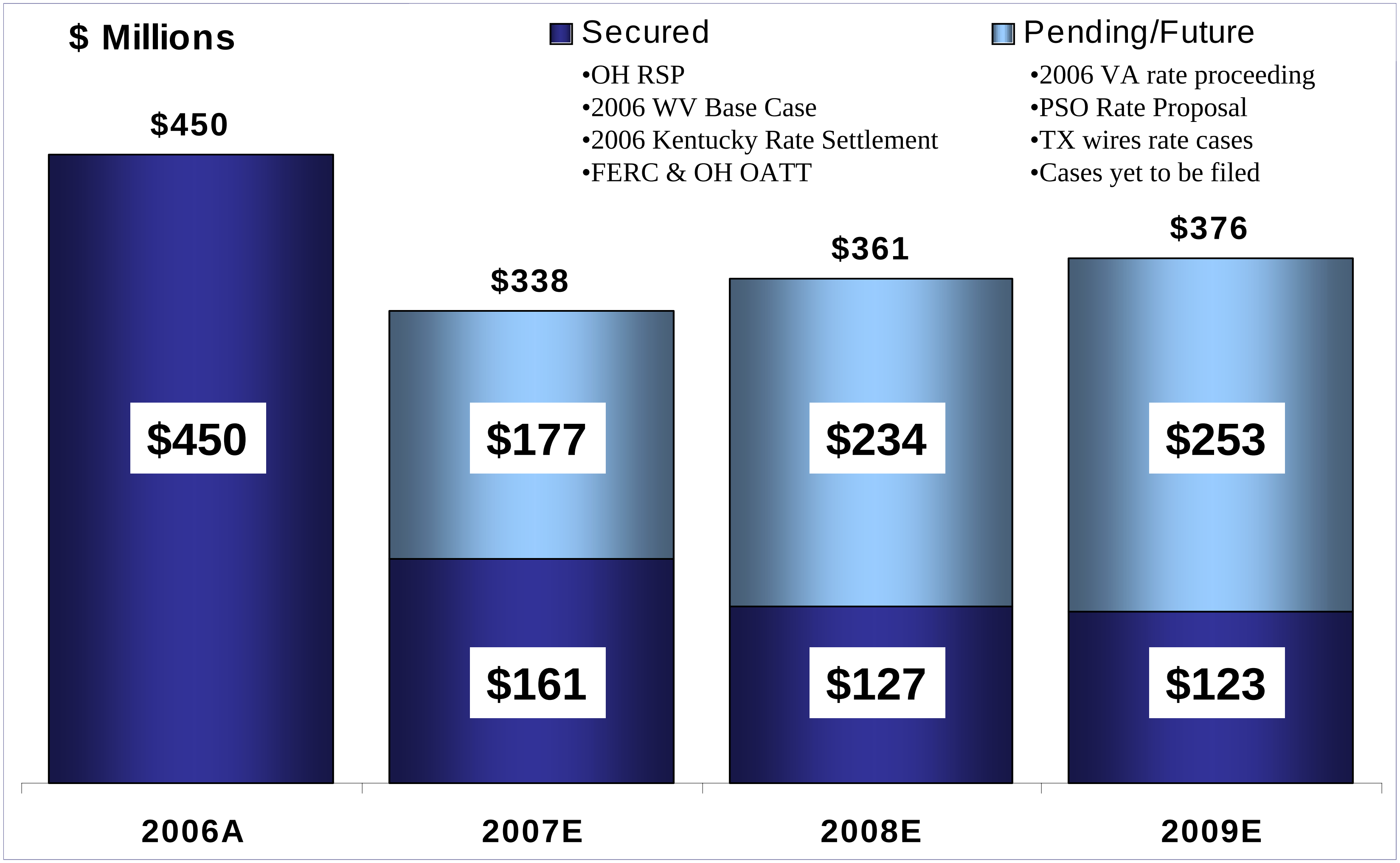
Incremental Rate Relief Composition

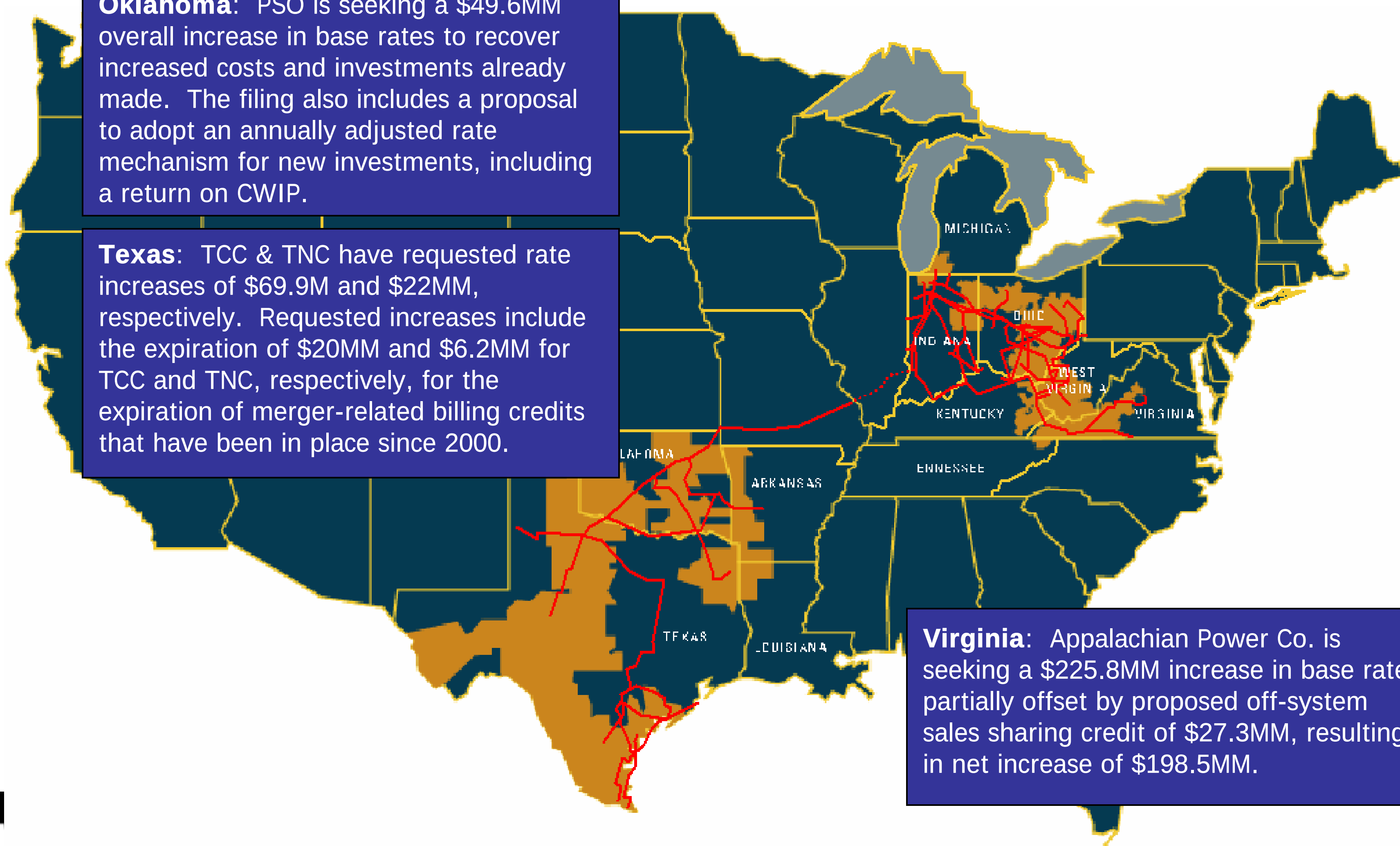


RATE RELIEF IS A CRITICAL ELEMENT TO AEP'S FINANCIAL SUCCESS

Base Case Regulatory Summary

Oklahoma: PSO is seeking a $49.6MM overall increase in base rates to recover increased costs and investments already made. The filing also includes a proposal to adopt an annually adjusted rate mechanism for new investments, including a return on CWIP.

Texas: TCC & TNC have requested rate increases of $69.9M and $22MM, respectively. Requested increases include the expiration of $20MM and $6.2MM for TCC and TNC, respectively, for the expiration of merger-related billing credits that have been in place since 2000.



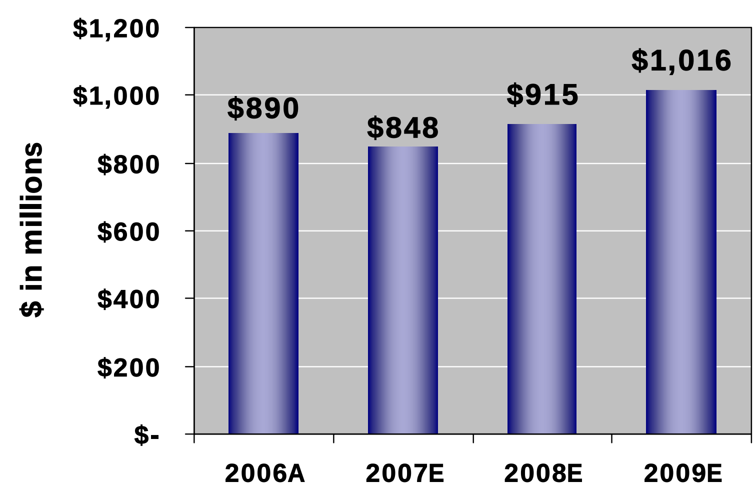
Virginia: Appalachian Power Co. is seeking a $225.8MM increase in base rates, partially offset by proposed off-system sales sharing credit of $27.3MM, resulting in net increase of $198.5MM.

Rate Relief & Enhanced Distribution Investment

- AEP Ohio Reliability Plan (Filed Oct. 6, 2006)
  - Plan will enhance distribution system reliability
  - Proposing an average annual investment of $130MM over 5-year period
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Public Service of Oklahoma Rate Rider
  - $24MM annual vegetation management rider approved in Nov. 2005
- Texas Wires Rate Cases (Filed Nov. 9, 2006)
  - TCC & TNC seeking to increase rates for distribution & transmission services
  - Requested increases total $69.9MM and $20MM for TCC & TNC transmission & distribution revenues, respectively.

	2005	2006
Line Miles	201,666	207,632
Net PP&E-Distribution	$7,617MM	$8,241MM

Total Projected Distribution Investment



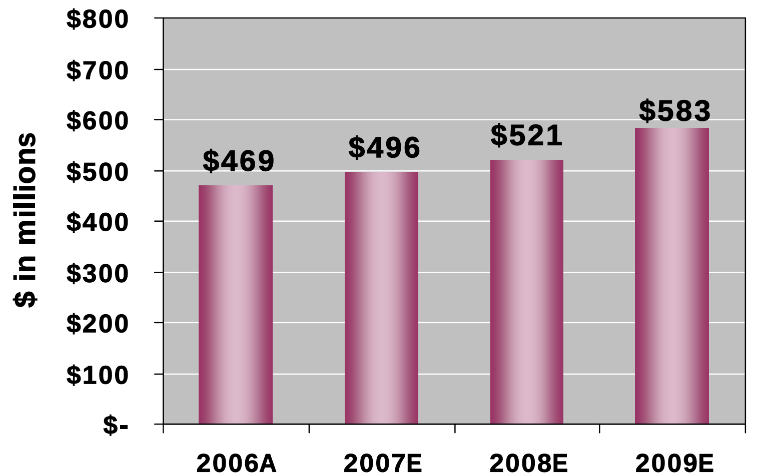
Rate Relief For Distribution Enhancement Will Be Sought Through Innovative Recovery Methods, Such As Rate Riders

Transmission Investment Forecast

- FERC PJM Regional Transmission Rate Design
  - FERC ALJ recommended adoption of "postage stamp" rate
  - Final order expected in mid-2007
- Ohio Annual Transmission Rate Filing
  - Ohio companies transmission rates annually adjusted for FERC-approved open access rates, net congestion & ancillary services
- PUCT & FERC Filings to establish Electric Transmission Texas LLC (ETT)
  - Certificate of Convenience & Necessity filed Jan. 22, 2007 to establish ETT as a regulated utility company and to set initial rates
  - FERC filing to transfer transmission assets to ETT submitted Feb. 15, 2007
  - Approvals and asset transfer expected mid-2007

	2005	2006
Circuit Miles	38,879	39,158
Net PP&E-Transmission	$4,153MM	$4,686MM

Total Projected Transmission Investment



The AEP Advantage: 100 Years Of Transmission Leadership Experience In The United States

Transmission ~ $9 Billion Opportunity*

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $1 billion+ in ERCOT via Electric Transmission Texas, LLC (ETT)
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion I-765 Project in PJM
- ~ $3 billion project filed with SPP

Assumptions	
Estimated Investment Opportunity	$9 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%
Potential EPS Impact (based on 396 MM shares)	+ $0.60**

* ~$9 billion investment opportunity not included in current capital guidance forecasts

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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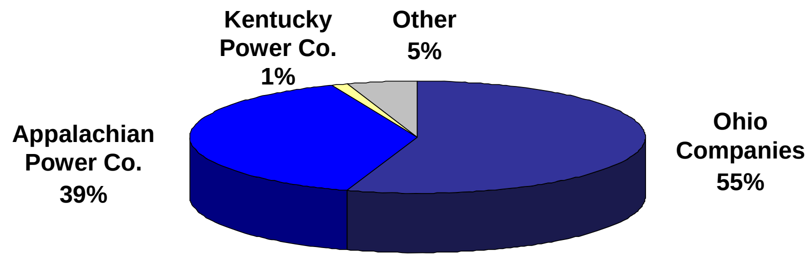
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

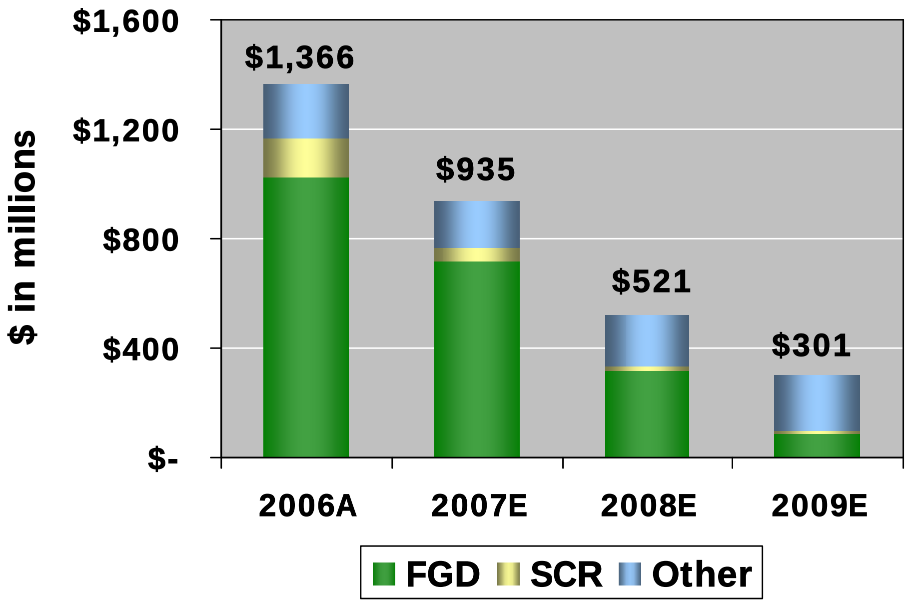
Environmental Investment Forecast

- Ohio Rate Stabilization Plan
  - Annual 3% and 7% generation rate increases at CSP & OP, respectively for 2006-2008
  - Filing made on Jan. 23 for recovery of 2007 costs associated with additional generation-related expenditures, pursuant to the 4% provision of the RSP
- West Virginia Rate Settlement
  - Mechanism in place to provide for rate increases through 2009 for ongoing environmental investments
- Virginia E&R Mechanism
  - Allows APCo-VA to recover incremental environmental & reliability costs
  - Order issued Nov. 20, 2006 granting $21.4MM of recovery for costs incurred thru Sept. 30, 2005
- Kentucky Environmental Surcharge
  - Monthly surcharge mechanism allows for recovery of pollution-control projects required by the Federal Clean Air Act

Projected Environmental Investment Allocation (2006A – 2009E)



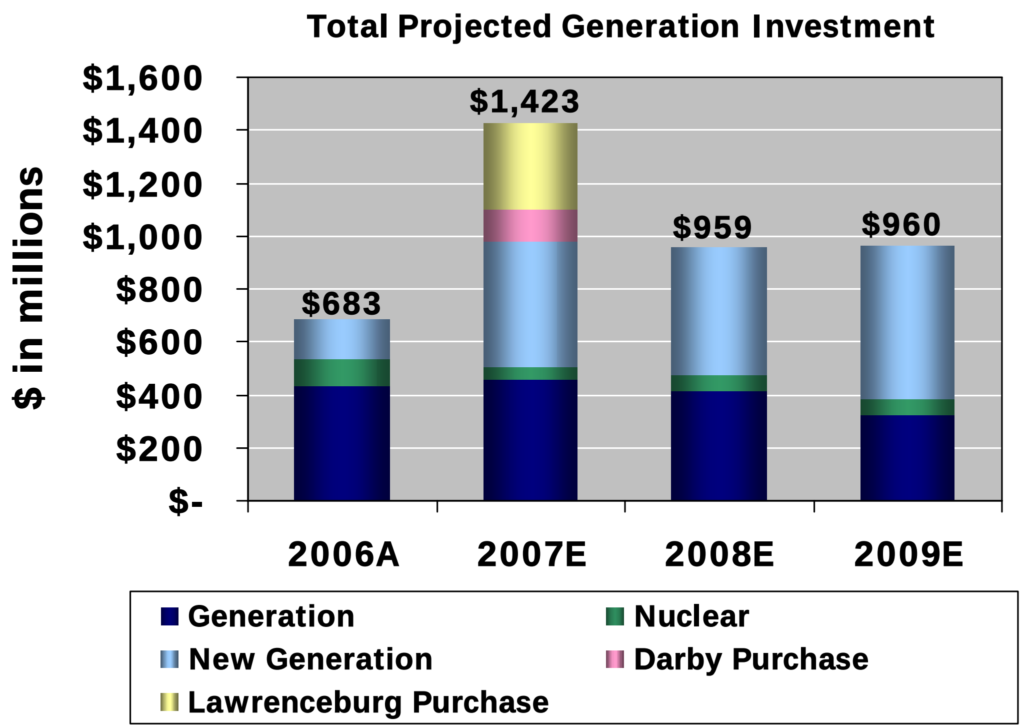
Total Projected Environmental Investment



AEP Benefits From First-Mover Advantage Through Lower Contracted Pricing & Reduced Market Escalation Exposure

Generation Investment Forecast

- Public Service Oklahoma Rate Proposal
  - Proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP
- Purchased Generation Initiative
  - New generation resources required to meet growing electricity needs of our customers
  - Completed purchase of 1,368 MW of gas-fired generating capacity in 2005 -- purchase pending for additional 1,620 MW
- Ohio Phase I IGCC Approval
  - PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006



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Investing In Generation To Meet The Growing Electricity Demands Of Our Customers At An Attractive Price

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
CSP	Darby	Ohio	$102 MM	Gas	Simple-cycle	480	2Q07[1]
AEG	Lawrenceburg	Indiana	$325 MM	Gas	Combined-cycle	1140	2Q07[2]
SWEPCo	Tontitown	Arkansas	$130 MM	Gas	Simple-cycle	320	2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Arsenal Hill	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Hempstead	Arkansas	$1.3 B[3]	Coal	Ultra-supercritical	600[3]	2011
PSO	Red Rock	Oklahoma	$1.8 B[4]	Coal	Ultra-supercritical	950[4]	2011
CSP/OP	Great Bend	Ohio	Under Review[5]	Coal	IGCC	600	TBD
APCo	Mountaineer	West Virginia	Under Review[5]	Coal	IGCC	600	TBD

(1) Sale expected to close 2Q07 - Plant began commercial operation in 2001
(2) Sale expected to close 2Q07 - Plant began commercial operation in 2004
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment
(4) PSO will own 50%, or 425 megawatts, totaling approximately $900MM in capital investment
(5) AEP is currently working with GE and Bechtel on a FEED (front-end engineering and design) study. When completed (expected mid-year 2007), a cost estimate will be available.

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.2%
- Positive dividend outlook
- Stable credit profile

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Appendix

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8280 of 9556

Company Overview

SIGNIFICANT PRESENCE THROUGHOUT THE DOMESTIC VALUE CHAIN

Our US electric assets include:

- Nearly 38,240 megawatts of generating capacity in 3 power pools (one of the largest US generation portfolios with a significant cost advantage in many of our market areas)
- Approximately 39,000 circuit miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Nearly 208,000 miles of overhead and underground distribution lines

With our coal and transportation assets we:

- control over 8,000 railcars
- own and/or operate over 2,600 hopper barges and 51 towboats
- operate one active coal-handling terminal with 20 million tons of capacity

We consume approximately 76 million tons of coal annually.

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Summary of 5-7% Long-Range Growth Components

- Energy sales growth of 1.5%
- Rate base investment
  - Generation plant purchases & build
  - Transmission – interstate & intrastate
  - Distribution
  - Reliability
- Transmission company
- Commercial operations
- Regulatory strategy
  - Achieve timely returns
  - Seek cash returns on investment during construction
  - Create & secure innovative rate plans
    - Pursue post-2008 solution in Ohio
    - Expand use of trackers
    - Formula rates

RATE BASE INVESTMENT COUPLED WITH INNOVATIVE REGULATORY PLANS WILL REDUCE LAG AND DRIVE EARNINGS GROWTH

AEP's Expansive Distribution Network

By State	Line Miles*	By Operating Company	Line Miles*
Tennessee	1,496	KGPCO	1,496
Virginia	29,499	KYPCO	9,730
W. Virginia	20,993	APCO	49,024
Kentucky	9,730	OPCO	26,159
Ohio	43,336	CSP	17,177
Michigan	5,133	I&M	19,705
Indiana	14,572	WPC	1,468
Texas	50,028	TCC	27,958
Oklahoma	21,208	TNC	14,378
Arkansas	4,322	PSO	21,208
Louisiana	7,315	SWEPCO	19,329
Total	**207,632**	**Total**	**207,632**

* Includes approximately 26,000 of underground circuit miles

AEP Currently Serves Over 5.1 Million Customers; Customer Additions Totaled 63,000 In 2006

AEP Transmission Network – Largest in the Country

Operating Company Level

(Circuit Miles)

Operating Company	765 kV	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	<100 kV	Total
APCo	734	97	383	106	0	3,288	0	2,142	6,750
CSP	0	0	884	0	0	887	0	635	2,406
I&M	615	0	1,614	0	0	1,664	0	1,448	5,341
KGPCo	0	0	0	0	0	0	0	30	30
KPCo	258	0	8	0	46	320	0	602	1,234
OPCo	509	0	909	0	0	2,463	0	2,645	6,526
PSO	0	0	579	34	8	2,123	10	812	3,566
SWEPCo	0	0	660	0	228	1,171	42	1,402	3,503
TCC	0	0	641	0	0	2,610	0	1,740	4,991
TNC	0	0	222	0	0	1,586	14	2,699	4,521
WPCo	0	16	9	0	0	175	0	88	288
Total	**2,116**	**113**	**5,909**	**140**	**282**	**16,287**	**67**	**14,244**	**39,158**

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AEP Is The Leader In Transmission Expertise

New Transmission Investment Funding Plans

- Electric Transmission Texas
  - 40% equity / 60% debt capital structure requested in PUCT follows Texas precedent for T&D companies' filings
  - Equity – 50% AEP / 50% Mid-American Energy
  - Debt – Initially bank financing
  - Initial funding in 3Q07 after regulatory approvals

- Other Transmission Projects
  - Equity percentage of capital structure will target FERC precedents
  - Equity ownership percentage will vary by project
  - Will seek FERC transmission incentives
    - Incentive ROE
    - Return on CWIP
    - Abandonment recovery
    - Expensing pre-construction expenses

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Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	☑	In-service	☑	Projected 2008-09
Gavin 1 & 2	2620	☑	In-service	☑	In-service
Mitchell 1	800	☑	Projected 2007	☑	Projected 2007
Mitchell 2	800	☑	Projected 2007	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	☑	In-service
Stuart 1-4	620	☑	In-service	☑	Projected 2009
Cardinal 1	600	☑	In-service	☑	Projected 2007
Muskingum River 5	585	☑	In-service	☐	Delayed
Pirkey	580	☐	N/A	☑	In-service
Oklaunion	485	☐	N/A	☑	In-service
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Zimmer	330	☑	In-service	☑	In-service
Dolet Hills	262	☐	N/A	☑	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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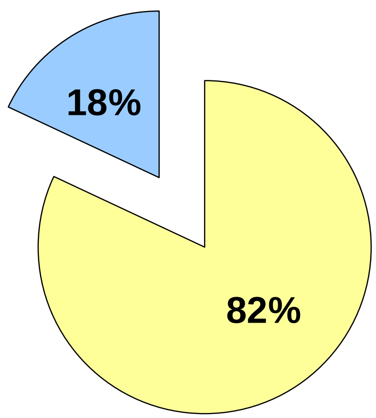
Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



- Actuals To Date & Firm Costs
- Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

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AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region.   AEP intends to seek regulatory recovery approvals in advance of building the plant.

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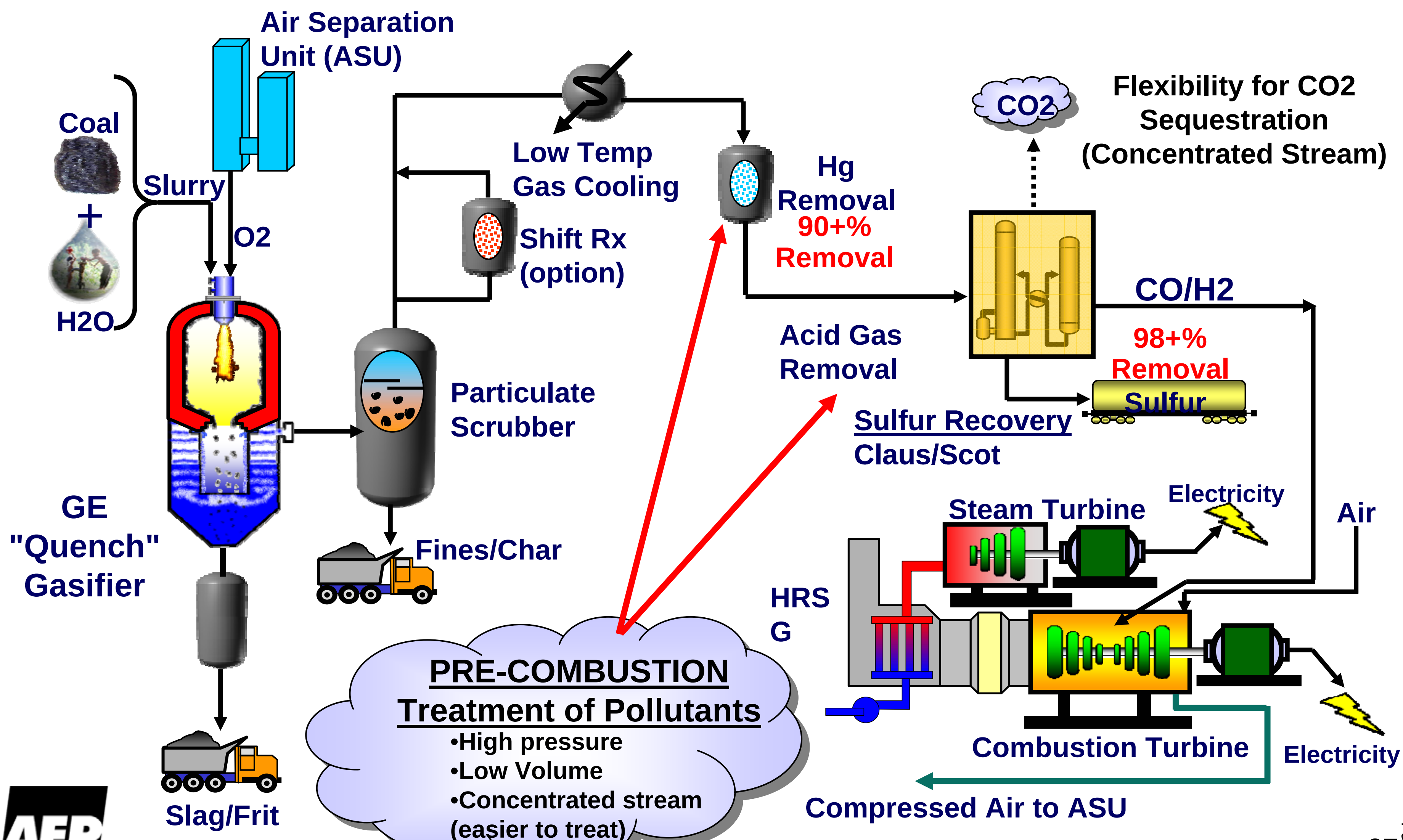
AEP Is Committed To IGCC Technology

IGCC Technology



Courtesy Eastman Gasification Services

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IGCC Permitting Process

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act) – Environmental site studies addressing wetlands, endangered species, historical artifacts

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Permitting Process Will Take 1 – 2 Years

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

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A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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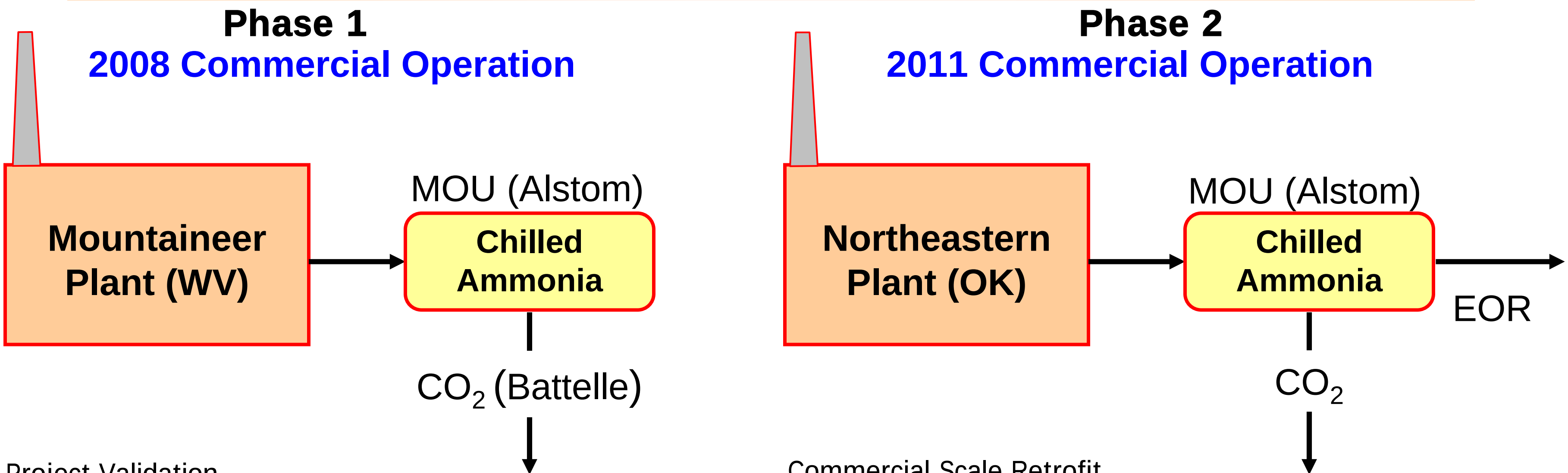
Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program



<u>Project Validation</u>

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

<u>Commercial Scale Retrofit</u>

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative

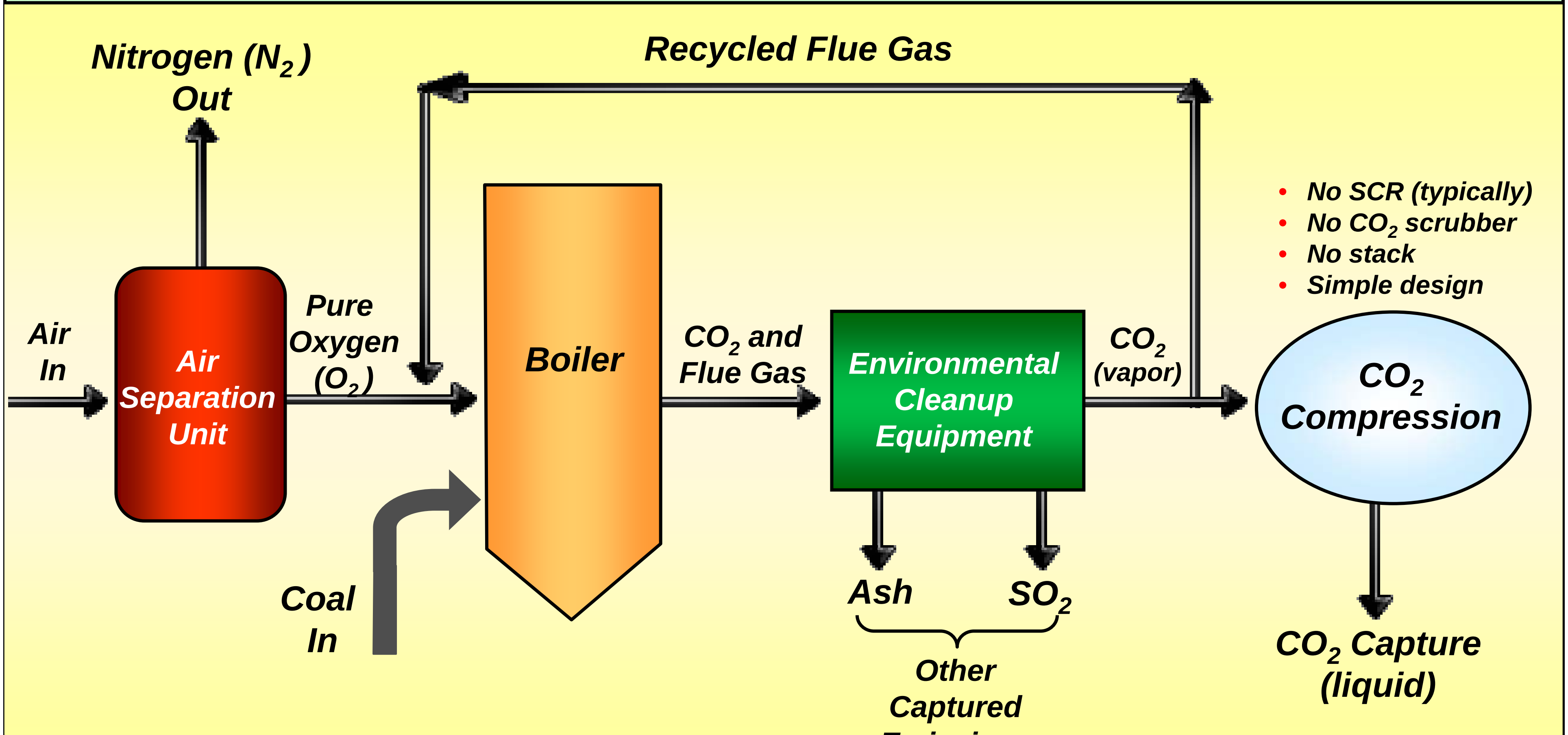

Illustration supplied courtesy of The Babcock & Wilcox Company.

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

<u>Pilot Scale Demonstration</u>

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

<u>Commercial Scale Retrofit</u>

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

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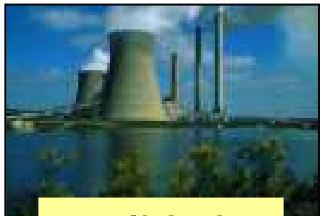
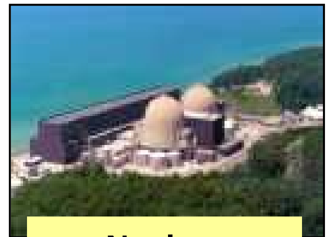
Domestic Generation Fleet

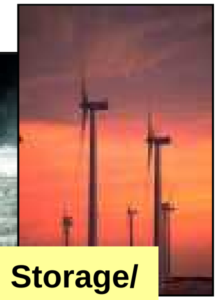


Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%



Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Note: Figures include Darby & Lawrenceburg plants

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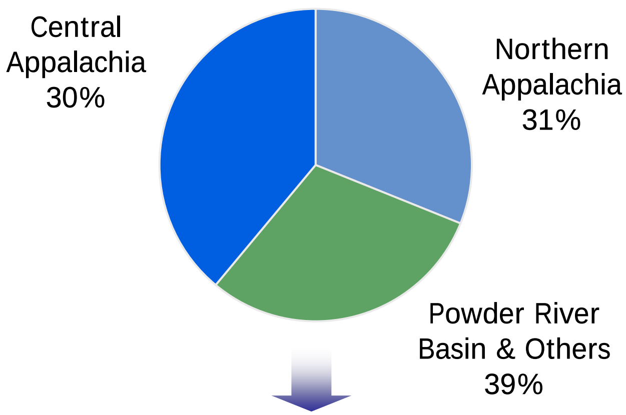
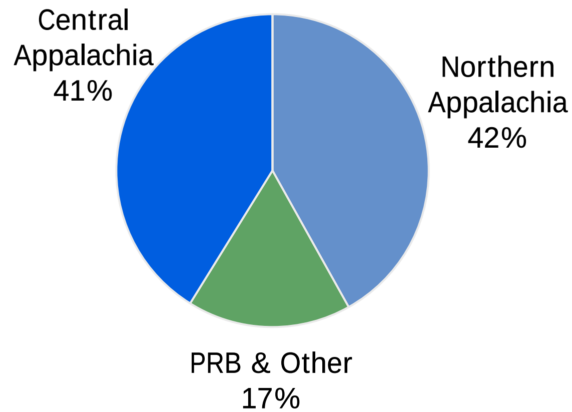
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

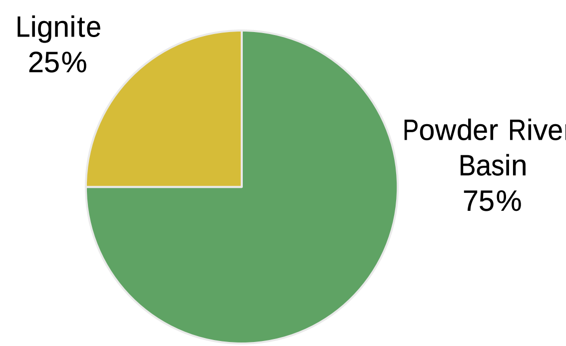
Total AEP System



AEP East



AEP West



Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

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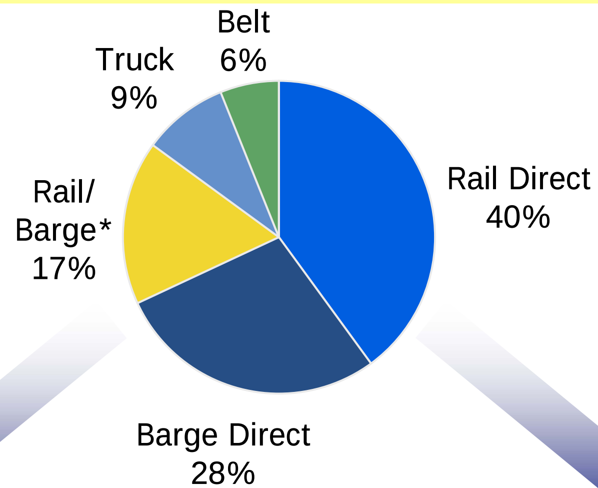
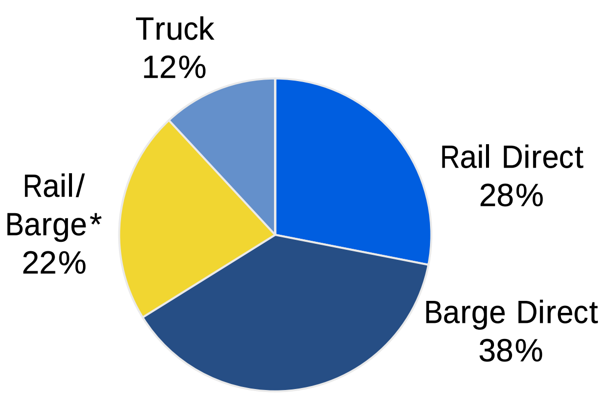
Coal Delivery

2006 Actual

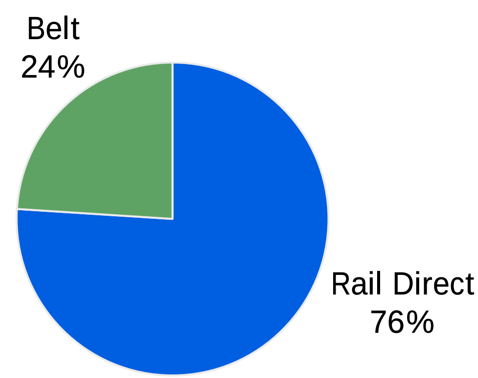
Total AEP System



AEP East



AEP West



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* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Regulatory Activity

AEP Ohio Distribution Reliability Filing

Filed Oct. 6, 2006 – AEP Ohio proposes an additional annual average investment of approximately $130MM over the next 5 years on vegetation management, equipment replacement, infrastructure upgrades & improved use of technology, to help reduce outages and improve service reliability.

- We are requesting implementation of a Reliability Cost Recovery Rider for recovery of the incremental O&M expenses and a return on and of the capital investments made under the plan. The requested ROE is 10.5%.
  - If approved, the rider would be implemented July 1, 2007 through December 31, 2008 and would be effective until new distribution rates are placed in effect. We anticipate that new base distribution rates would be effective after the expiration of the RSP on Dec. 31, 2008.
- Requested recovery amounts total $20MM in 2007 and $51MM in 2008.
- Staff testimony due April 17, 2007; Evidentiary hearing to commence April 30, 2007.

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony due May 7, 2007; Evidentiary hearing to commence May 22, 2007.

Regulatory Activity

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
    - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
    - Intervenor testimony is due May 30, 2007. Staff testimony is due June 7, 2007. Hearings are scheduled for June 26-29, 2007.
        - An order is expected Mid-2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
    - Up to $96MM of SECA revenues could be disallowed, net of unused provisions
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007

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Regulatory Activity

FERC Regional Rate Design

- The FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service provided by high voltage facilities they own that benefit customers throughout PJM
- July 2006 ALJ-rendered initial decision:
  - License plate rates for existing facilities are not just and reasonable, and must be replaced (effective April 1, 2006, when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year as the best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, if not phased in.
  - Briefs on Exceptions to the initial decision by all parties have been filed; An order is expected by the Commission in mid-2007.

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Summary Rate Case Information

APCo Virginia General Rate Case

On May 4, 2006, Appalachian Power Co. filed a general base rate case with the Virginia State Corporation Commission (VSCC) requesting an increase of $198.5 million ($225.8 million in base revenues offset by an off-system sales credit of $27.3 million). (Docket #: PUE-2006-00065)

Projected Capital Structure – Company Position (9/30/07)

(in thousands)		Amount Outstanding	% of Capitalization	Cost Rate	Weighted Cost
Long-term debt	$	2,789,504	53.36%	5.67%	3.02%
Short-term debt	$	120,995	2.31%	5.11%	0.12%
Preferred Stock	$	17,624	0.34%	4.35%	0.02%
Common Stock	$	2,286,397	43.74%	11.50%	5.03%
Investment Tax Credit	$	13,184	0.25%	8.29%	0.02%
Total	$	5,227,704	100.00%		8.21%

Procedural Schedule

May 4, 2006	Case filed
October 2, 2006	Rates went into effect, subject to refund
October 24, 2006	Staff testimony filed
December 7, 2006	Hearings commenced
February 5, 2007	Briefs filed
March 28, 2007	Hearing Examiner Recommendation filed

APCo has until April 18, 2007 to comment on the Hearing Examiner's report. Following this action, we will await an order from the SCC. No statutory deadline.

Projected Rate Base – Company Position (9/30/07)

Pro-forma Rate Base	$2.3 billion

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Summary Rate Case Information

Texas Central & Texas North Companies Wires Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310)

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Cap. Structure Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.79%	3.47%
Common Equity	40%	10.75%	4.30%
Total	100%		7.77%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

TNC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 171,049,145	$ 288,872,851

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Summary Rate Case Information

PSO Rate Proposal

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor & Staff testimony
April 9, 2007	Rebuttal testimony
May 1, 2007	Hearings
June 20, 2007	Final order expected

* Figures are rounded

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$ 1,420	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 Credit Metric Ranges

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.5x to 4.0x

FFO/Total Debt range of 15% to 17%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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Forecasted Capital Expenditures

($ IN THOUSANDS)

Company	2007	2008	2009
AEP System*	**$ 3,867,000**	**$ 3,026,000**	**$ 2,974,000**
AEG	$ 343,000	$ 28,000	$ 34,000
APCo	$ 664,000	$ 531,000	$ 461,000
CSPCo	$ 439,000	$ 354,000	$ 233,000
I&M	$ 252,000	$ 264,000	$ 294,000
KPCo	$ 70,000	$ 114,000	$ 100,000
OPCo	$ 832,000	$ 368,000	$ 389,000
PSO	$ 319,000	$ 330,000	$ 466,000
SWEPCo	$ 537,000	$ 605,000	$ 540,000
TCC	$ 241,000	$ 214,000	$ 273,000
TNC	$ 143,000	$ 188,000	$ 149,000

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Figures exclude AFUDC.

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Long-Term Debt Maturity Profile

Year		2007		2008		2009
AEP Service Corp.	$	-	$	36,000,000	$	-
AEP, Inc.	$	345,000,000	$	-	$	-
AEP Generating Company	$	-	$	-	$	-
Appalachian Power	$	325,000,000	$	200,000,000	$	150,000,000
Columbus Southern Power	$	-	$	112,000,000	$	-
Kentucky Power	$	322,964,000	$	30,000,000	$	-
Indiana Michigan	$	-	$	50,000,000	$	45,000,000
Ohio Power Company	$	-	$	44,542,074	$	106,000,000
Public Service of Oklahoma	$	-	$	-	$	50,000,000
Southwestern Electric Power	$	90,000,000	$	117,903,000	$	-
Texas Central Company	$	-	$	68,104,803	$	-
Texas North Company	$	8,151,000	$	-	$	-
Total	$	1,091,115,000	$	658,549,877	$	351,000,000

Note: Maturities remaining as of March 31, 2007

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2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEG	$343	$200-$225	40%
APCo	$664	$350-$450	43-45%
CSP	$439	$0-$50	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$350-$450	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$150-$200	40%

(a) Includes tax exempt issuances
(b) Ratios include impact of Rockport 2 lease
(c) Excludes impact of securitization on the equity ratio

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Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

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Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

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Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated debt/cap ratio
- Target utility company capitalization structures

Company	Target Equity Ratio
AEG	40%
APCO	43-45%
CSP	44-46%
I&M	40-42%
KPCO	42-44%
OPCo	44-46%
PSO	44-46%
SWEPCo	44-46%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios

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We Are Committed To Maintaining Our Current Credit Ratings
BBB / Baa2 / BBB

AEP AMERICAN® ELECTRIC POWER

Bank of America Merrill Lynch 2011 Power & Gas Leaders Conference

New York, NY
September 20, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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Diversified Regulated Utility Platform

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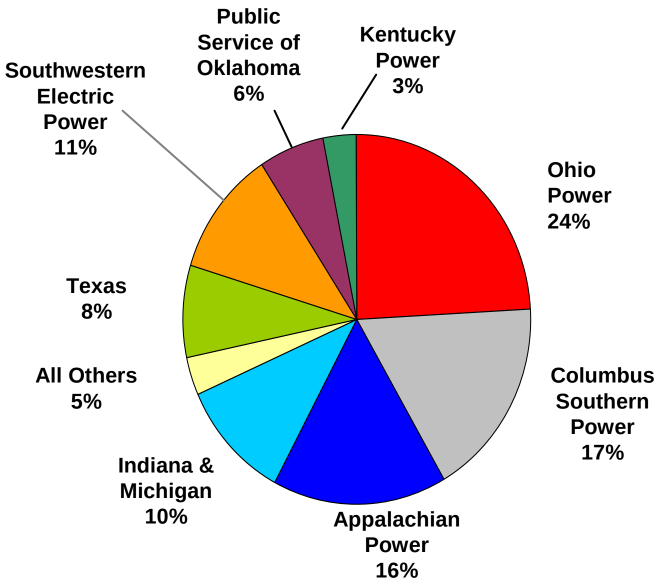
2010 On-Going Earnings Contribution



Items to Watch

- Economic Recovery
- Ohio ESP and Other Filings
- EPA Regulations
- ETT and Transcos
- On-going Rate Cases and ROEs
  - Virginia
  - Michigan
  - Ohio

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8319 of 9556

ESP Settlement

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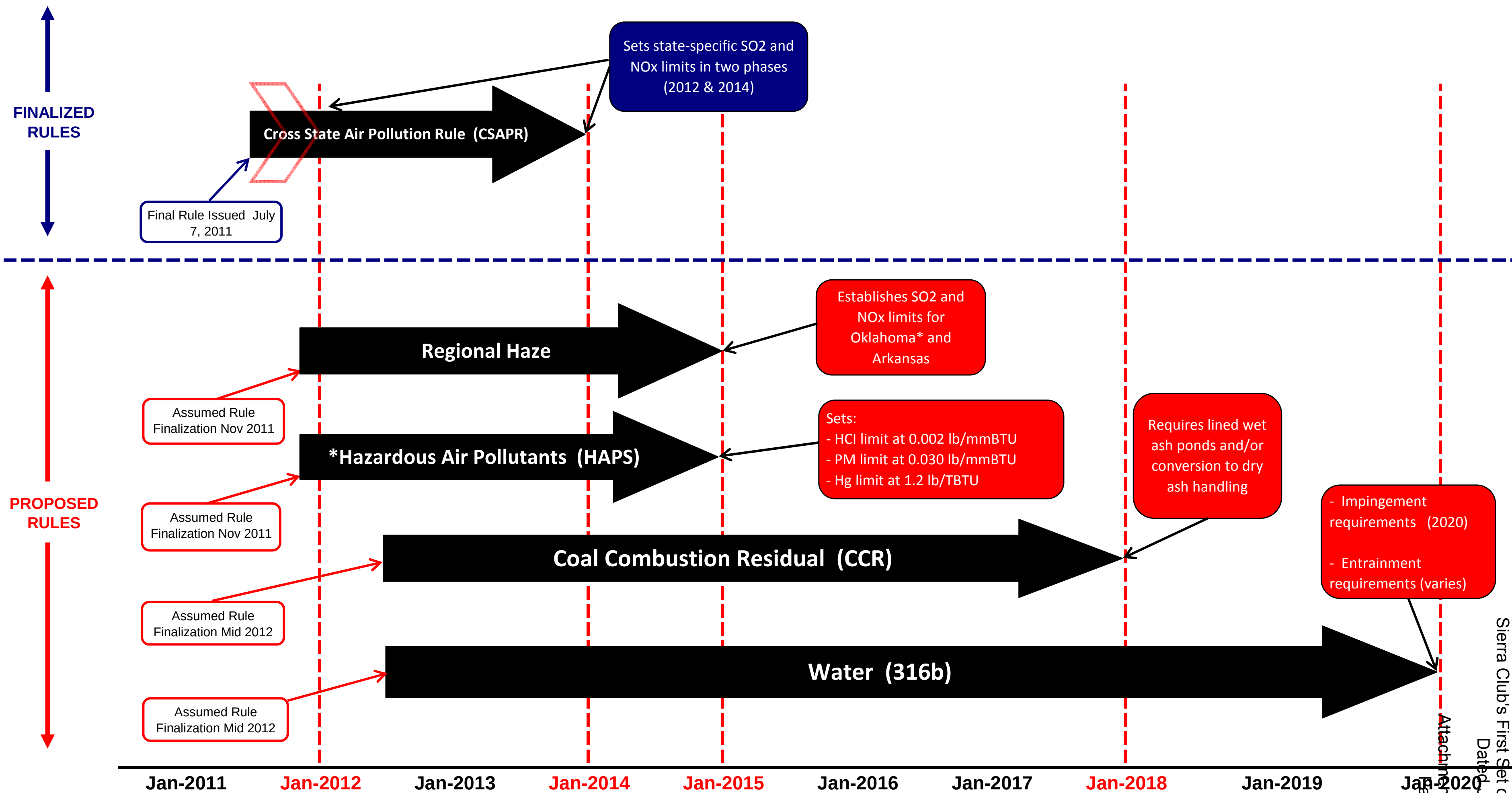
Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available,
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

EPA Regulatory Deadlines



*** Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.**

AEP Coal Fleet Assessment

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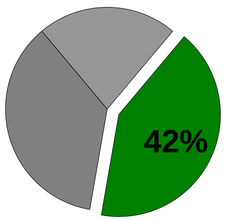
2012 – 2020

Range of Capital ($ Millions) (1)

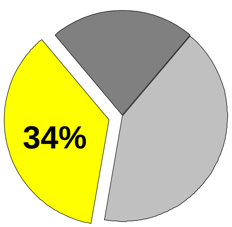
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

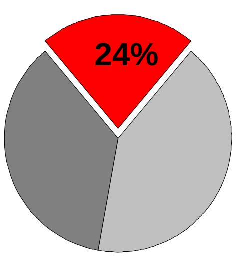
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

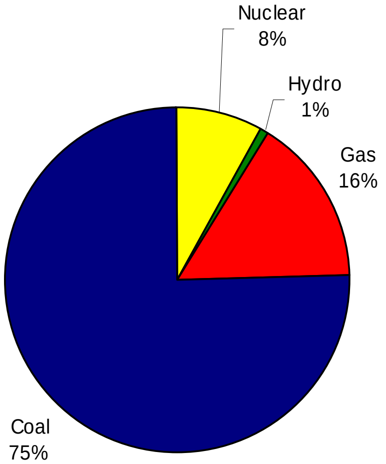
(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

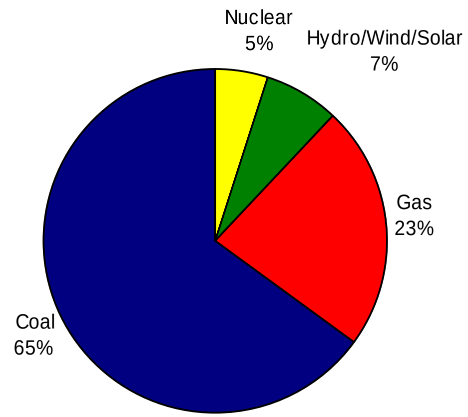
(4) Includes NSR Compliance.

Generation Transformation

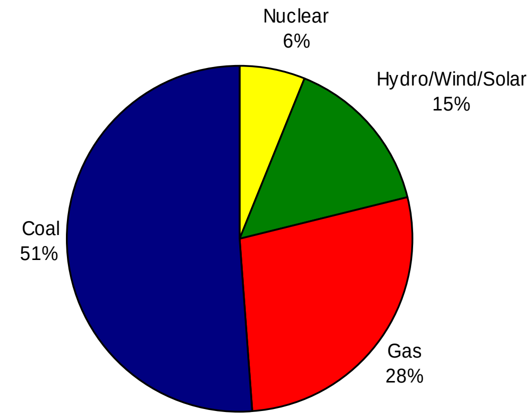
1990 AEP Generating Capacity by Fuel
37,428 total MW's



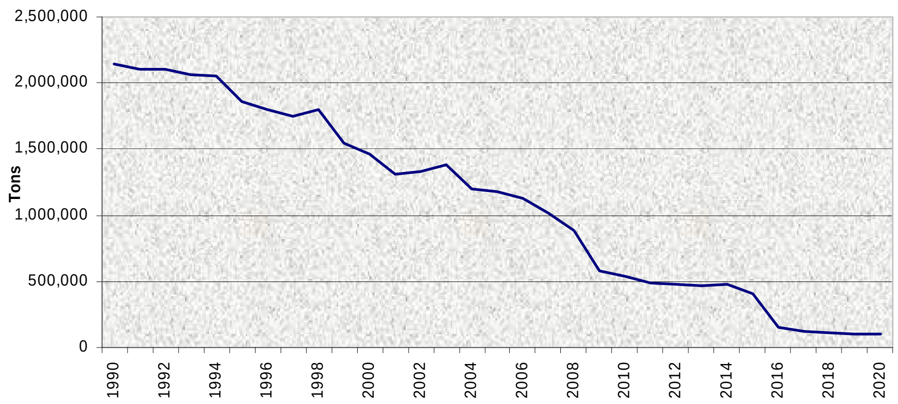
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $210 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Significant Investment Opportunities in Environmental Retrofits and Transmission
- Strong Value and Total Return Proposition

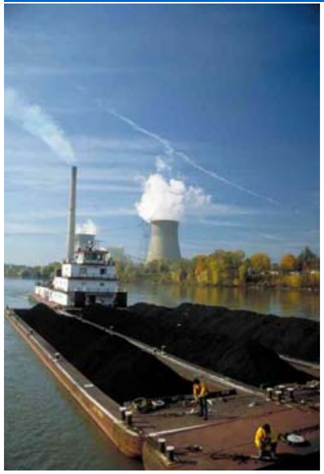
Mountaineer Plant (WV)

Norges Bank Investment Management

AEP Headquarters

Columbus, OH

May 21, 2007



AEP AMERICAN ELECTRIC POWER®

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and/or Virginia, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Participants

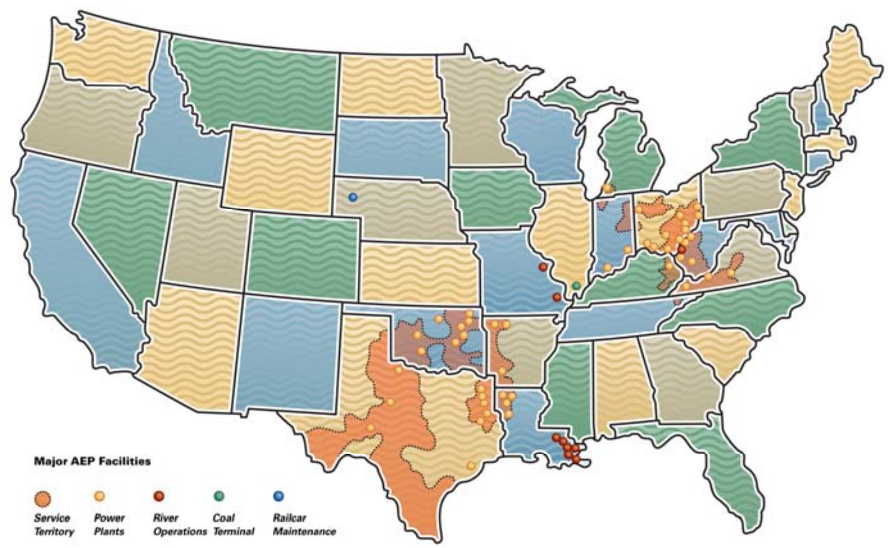
Mike Morris	*Chairman, President & CEO*
Dennis Welch	*SVP, Environment Safety & Health*

Company Overview

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,200 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005

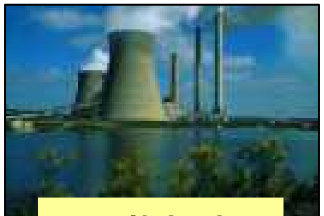


- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP ENJOYS SIGNIFICANT PRESENCE THROUGHOUT THE ENERGY VALUE CHAIN

Domestic Generation Fleet



Coal/Lignite

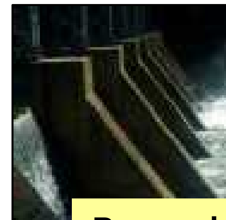
67%

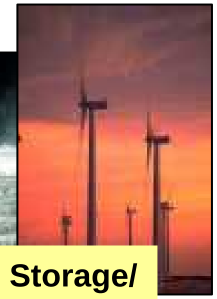
Nat. Gas/Oil

24%

Nuclear

6%





Pumped Storage/
Hydro/Wind

3%

AEP's Generation Fleet

38,238 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

CONTINUED COMMITMENT TO OUR CORE UTILITY MISSION: BRING REASONABLY PRICED ELECTRIC SERVICE TO OUR CUSTOMERS, THEREBY STRENGTHENING OUR COMMUNITIES AND REWARDING OUR INVESTORS

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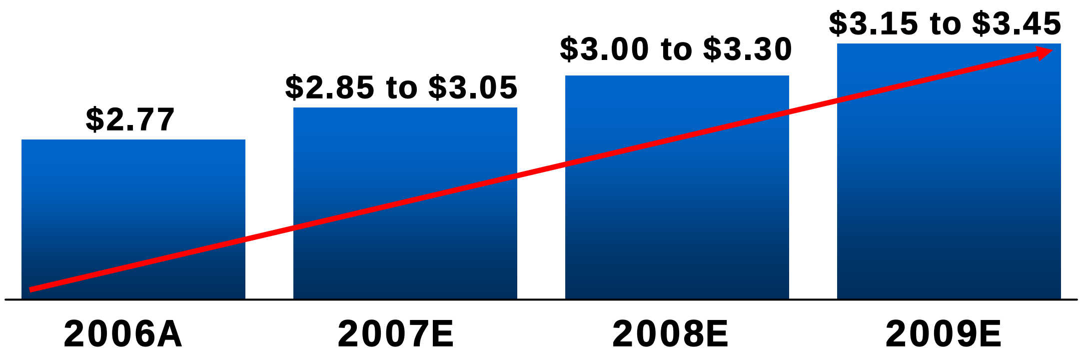
Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

OUR STRATEGY REMAINS FOCUSED ON REGULATED OPERATIONS

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AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

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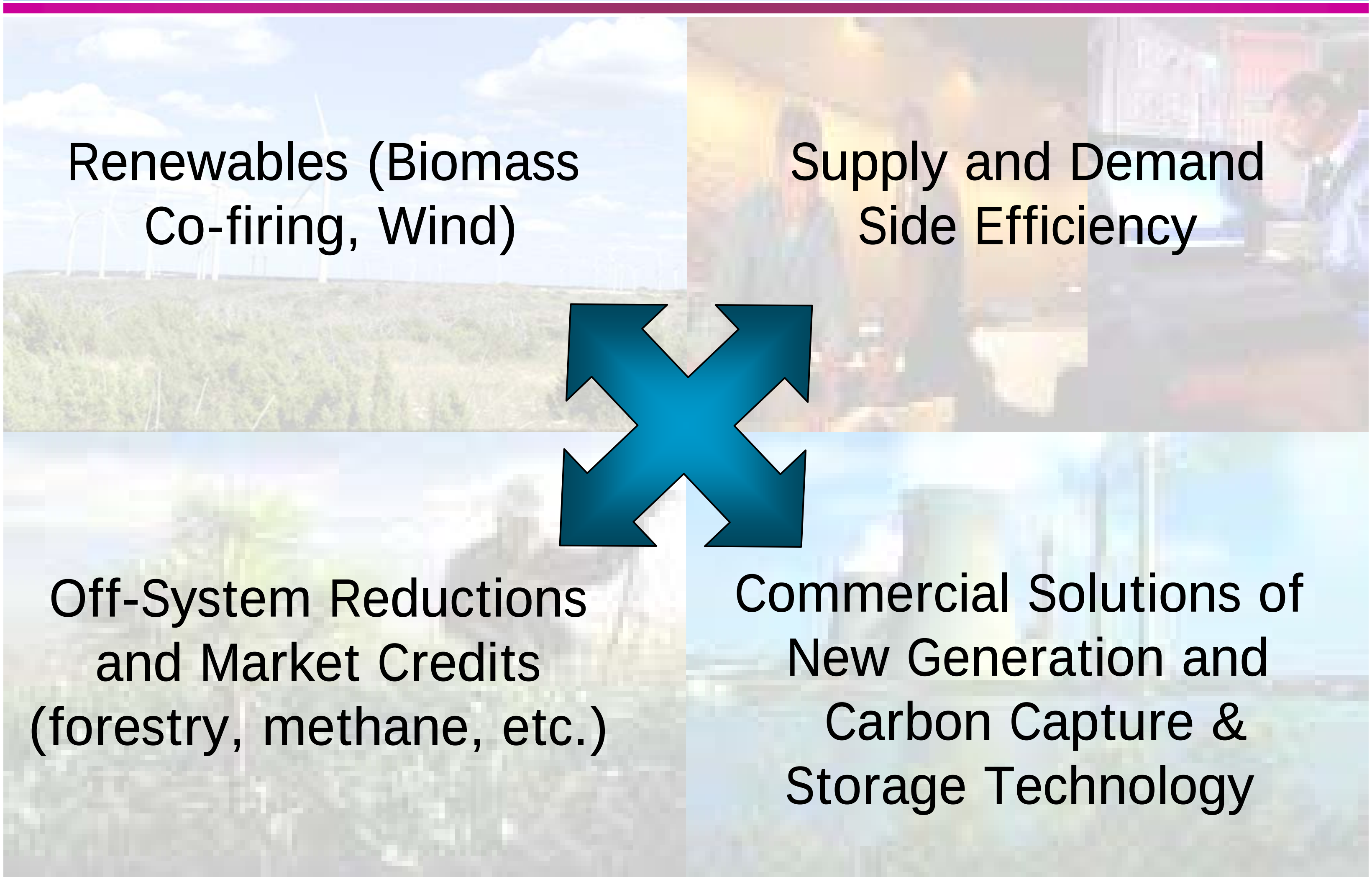
A RELIABLE & REASONABLY-PRICED ELECTRIC SUPPLY IS NECESSARY TO SUPPORT THE ECONOMIC WELL-BEING OF THE AREAS WE SERVE

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP MUST BE A LEADER IN ADDRESSING CLIMATE CHANGE

AEP's Long-term GHG Reduction Portfolio



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AEP IS INVESTING IN A PORTFOLIO OF GHG REDUCTION ALTERNATIVES

IGCC Overview

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2 , mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

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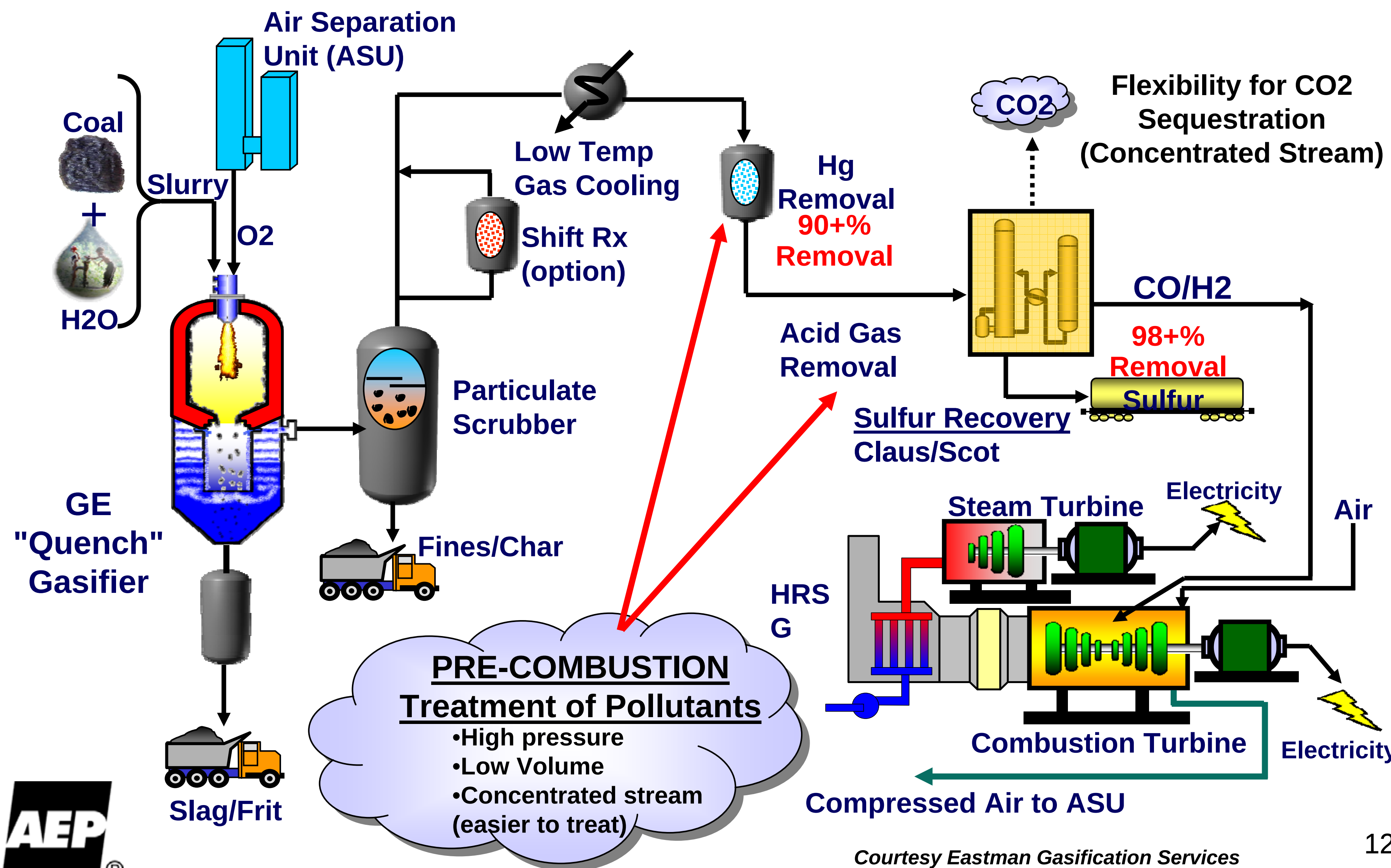
AEP IS COMMITTED TO IGCC TECHNOLOGY

IGCC Technology



Courtesy Eastman Gasification Services

IGCC Permitting Process

IGCC Permitting Issues

- **Air**
  - ✓ Identify best available control technology (BACT)
  - ✓ Determine how start-up and shut-down emissions should be addressed
- **Wastewater**
  - ✓ understand nature of wastewater streams
  - ✓ Determine treatability and permitting scopes
- **US ACE (US Army Corp of Engineers**)
  - ✓ Conduct all necessary site studies per NEPA (National Environmental Policy Act) requirements (Wetlands, endangered species, archaeology)
  - ✓ Obtain permit to construct river facilities

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PERMITTING PROCESS TAKES 1 – 2 YEARS AND IS WELL UNDER WAY

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2009-10
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	In-service	✓	In service
Mitchell 2	800	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service		Delayed
Conesville 5 & 6	750		N/A	✓	In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected Q3 2007
Muskingum River 5	585	✓	In-service		Delayed
Pirkey	580		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262		N/A	✓	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

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Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: Implement during 2007 to take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP IS COMMITTED TO A 5MM TON/YR REDUCTION IN CO_2 EMISSIONS WHICH OFFSETS APPROXIMATELY HALF OF THE EMISSIONS PROJECTED FROM NEW GENERATION PROJECTS PREVIOUSLY ANNOUNCED

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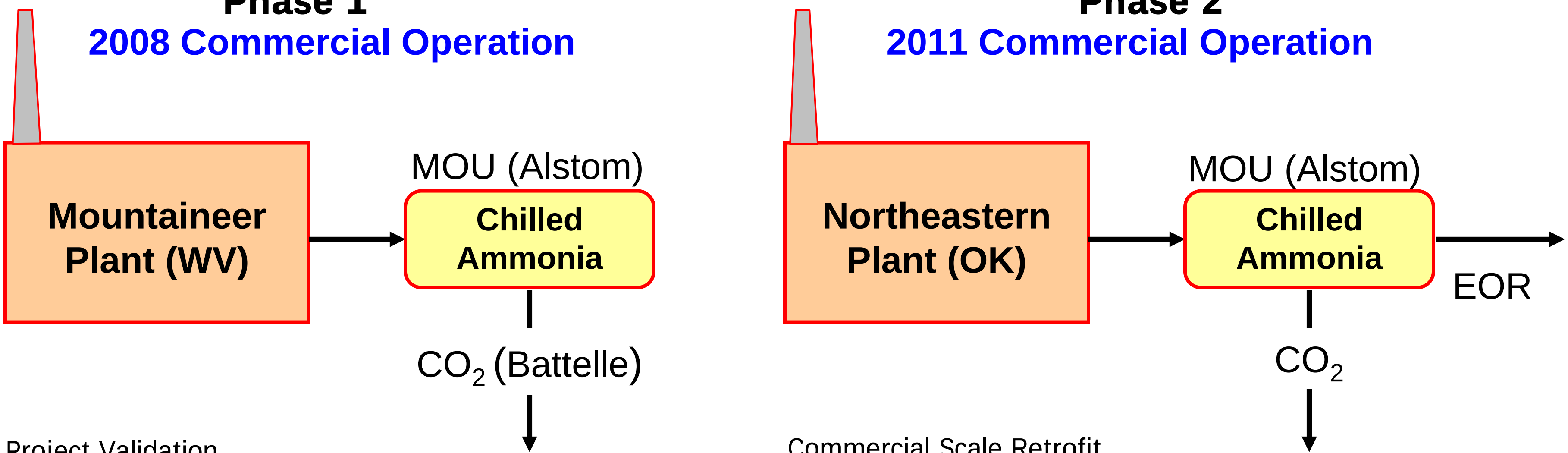
Chilled Ammonia Process Plant Footprint

Chilled Ammonia Technology Program

Phase 1
2008 Commercial Operation

Phase 2
2011 Commercial Operation



Project Validation

- 30 MW_t (megawatts thermal) scale (a scale up of Alstom/EPRI 5 MW_t field pilot, under construction at WE Energies)
- <0.1MM tonnes CO_2 per year
- In operation 4Q 2008
- Approximate total cost \$50 – \$80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital \$250 – \$300M (CO_2 capture & compression)
- Approx. O&M cost \$12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit SCR & Wet FGD Required: ~\$225 – \$300M (required for CO_2 capture equipment)
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR) or geologic storage

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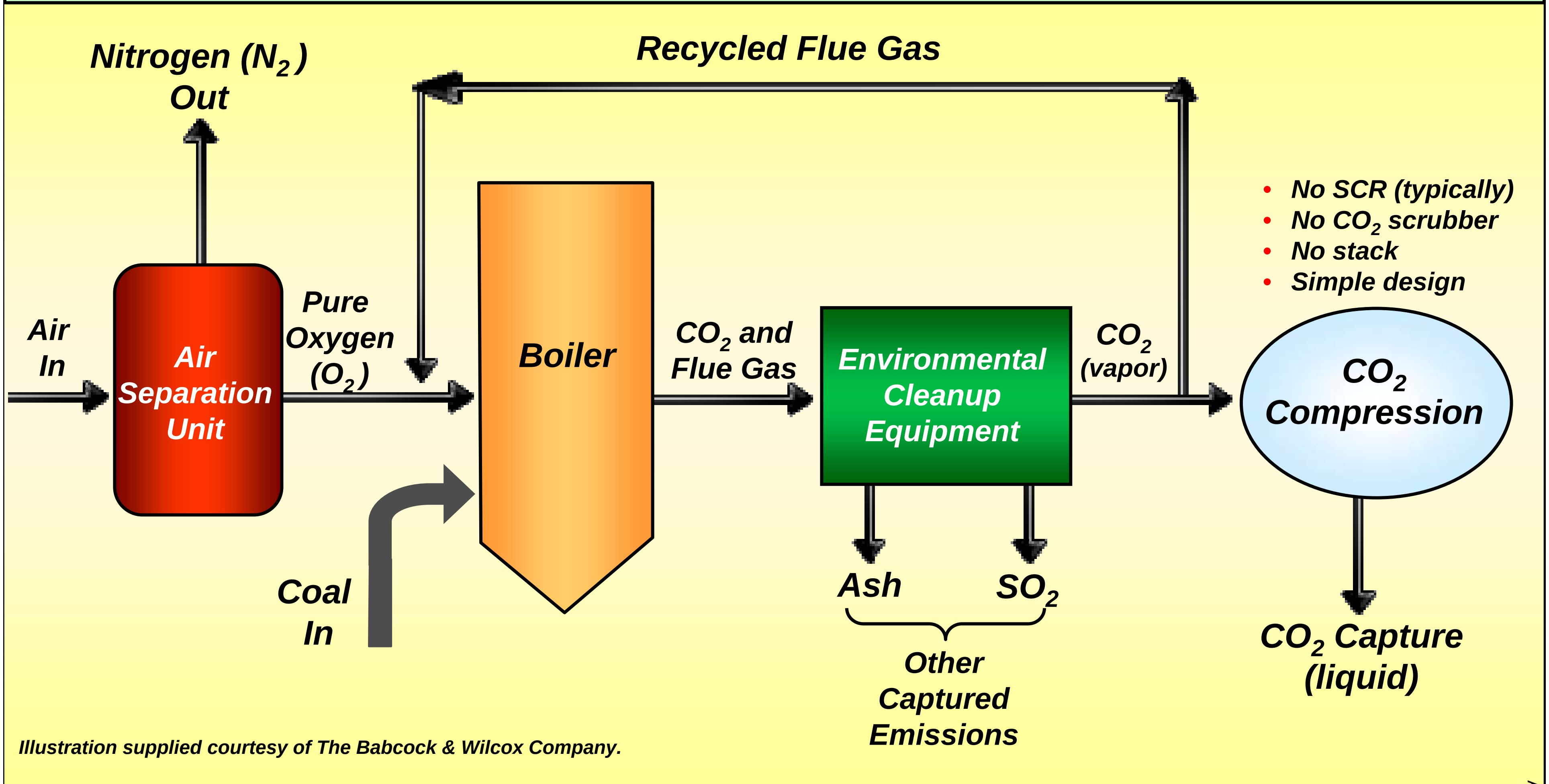
POST-COMBUSTION CARBON SOLUTION PROVIDES PURE CO_2 STREAM FOR CAPTURE

Oxy-Fuel Technology Initiative



- *No SCR (typically)*
- *No CO_2 scrubber*
- *No stack*
- *Simple design*

NEAR-ZERO EMISSIONS USING OXY-FUEL COMBUSTION TECHNOLOGY

Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed 2Q 2008

COMBUSTION CONVERSION TECHNOLOGY FOR EXISTING COAL FLEET – LONGER LEAD TIME WITH ENHANCED VIABILITY AND LONG-TERM POTENTIAL

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2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

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CASH ON HAND EXPECTED TO BE $205 MILLION AT YEAR END 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:
Debt to total capital (adjusted - rating agency view) range of 58% to 60%
FFO to Interest range of 3.6x to 4.0x
FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

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Capital Structure

Capital Structure	Actual 12/31/2006			Actual 3/31/2007		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	13,902	-	13,902
Short-term Debt	18	-	18	175	-	175
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,540	9,540
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**14,077**	**9,601**	**23,678**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***59.5%***	***40.5%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(27)	-	(27)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,183	-	1,183
Securitization Bonds	(2,335)	-	(2,335)	(2,303)	-	(2,303)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(251)	-	(251)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**12,679**	**9,601**	**22,280**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***56.9%***	***43.1%***	***100.0%***

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ADJUSTED DEBT/CAPITALIZATION: 56.90%

New York Investor Meetings
Hosted by Jefferies & Co.
August 17, 2010

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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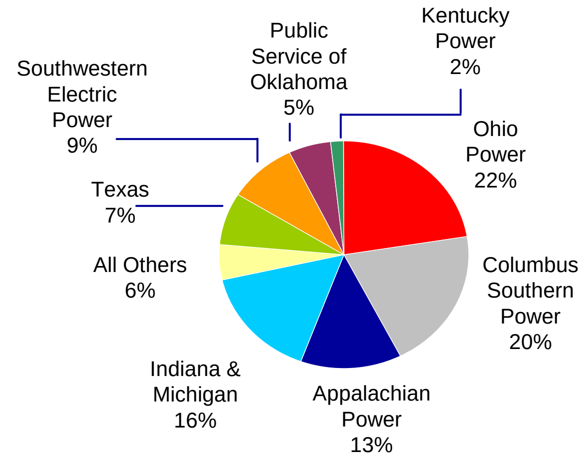
Highly Diversified Regulated Utility Platform

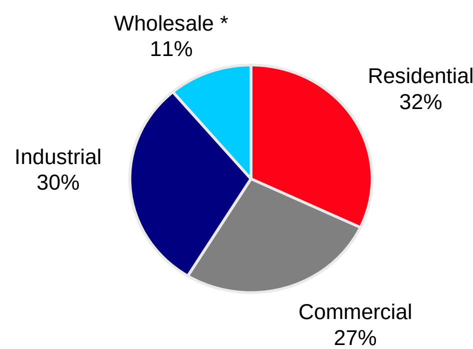
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution

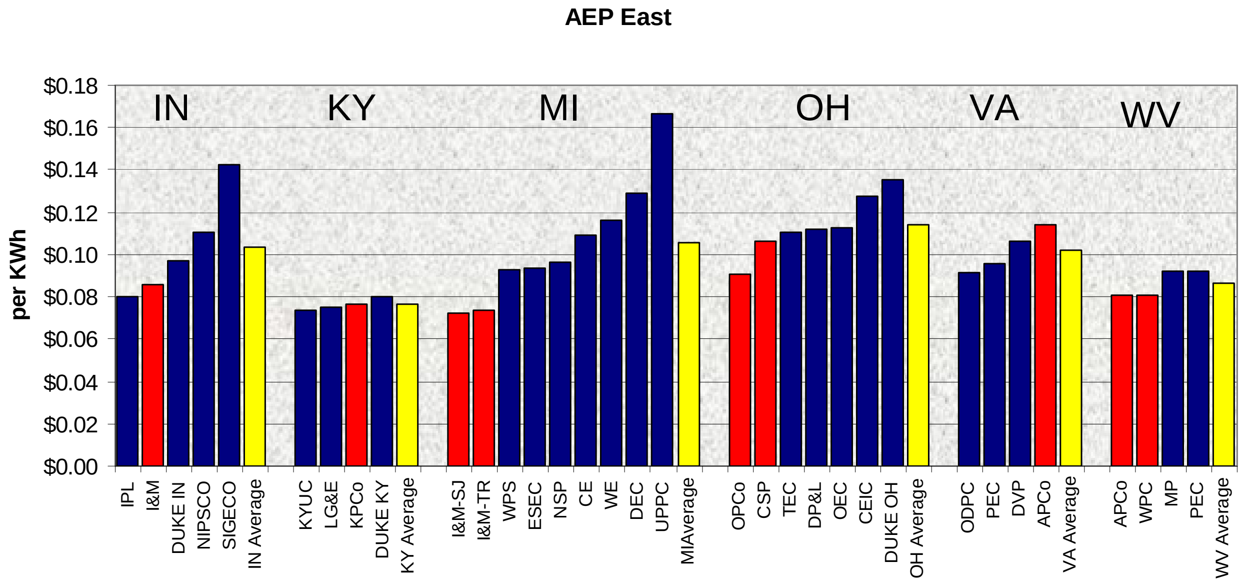


2009 Retail Load



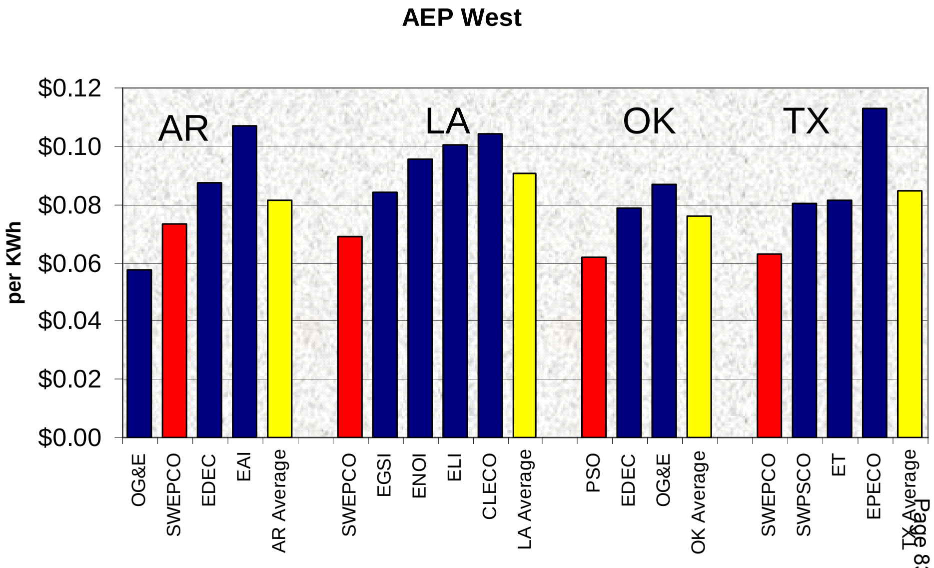
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Residential Rates Comparison



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP Company
Other Utilities within state
State Average



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

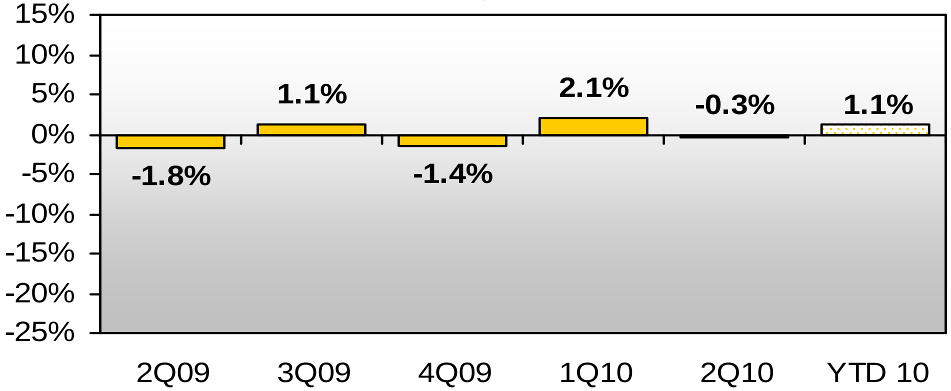
2010E: $2.80-$3.20

		2009 Performance Driver	2009 Actual ($ millions)	2010 Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

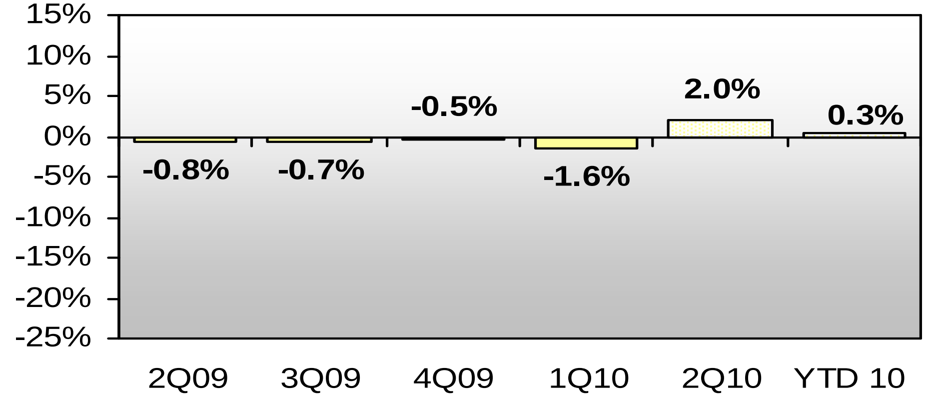
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Normalized Load Trends

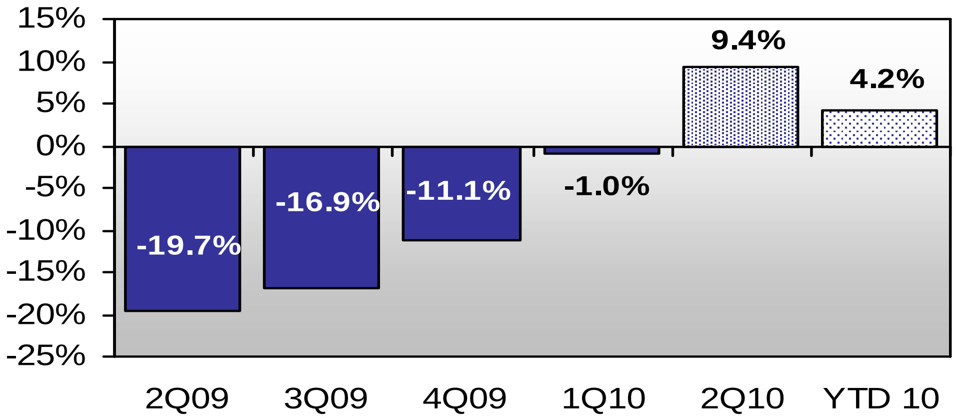
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



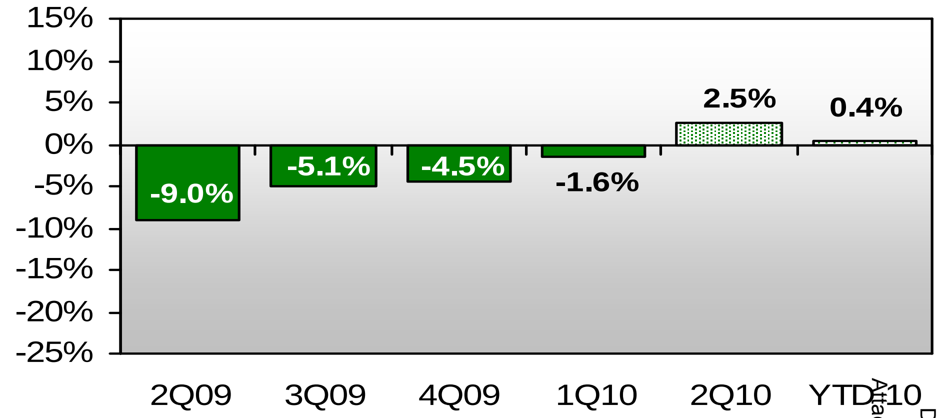
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



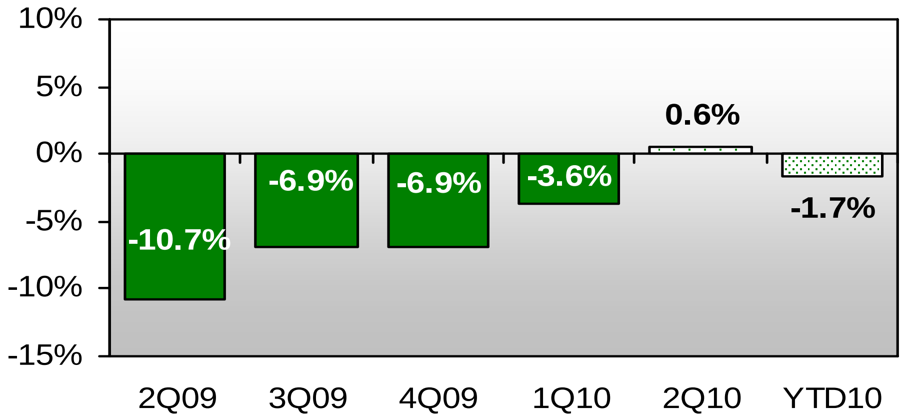
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



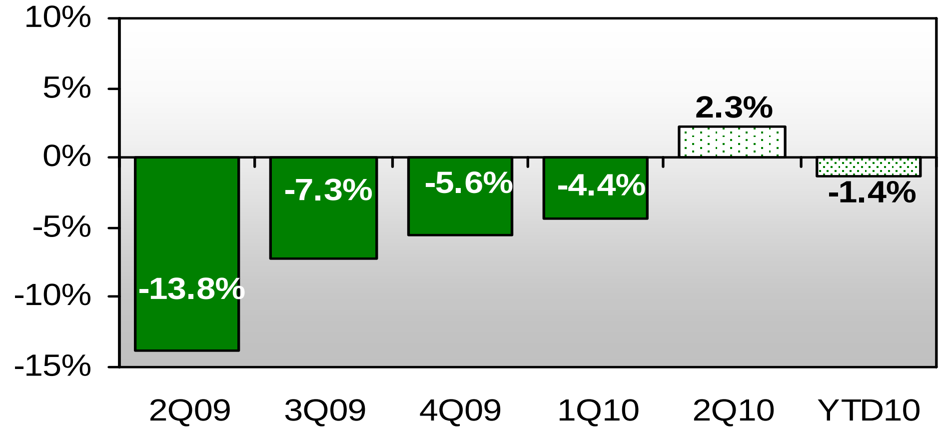
*includes firm wholesale load

Normalized Load Trends by Region

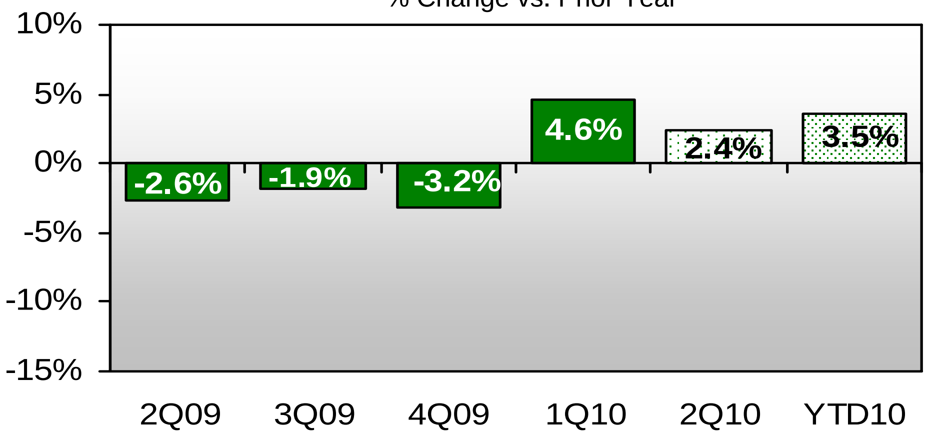
Reg East Total Normalized GWh Sales*
% Change vs. Prior Year



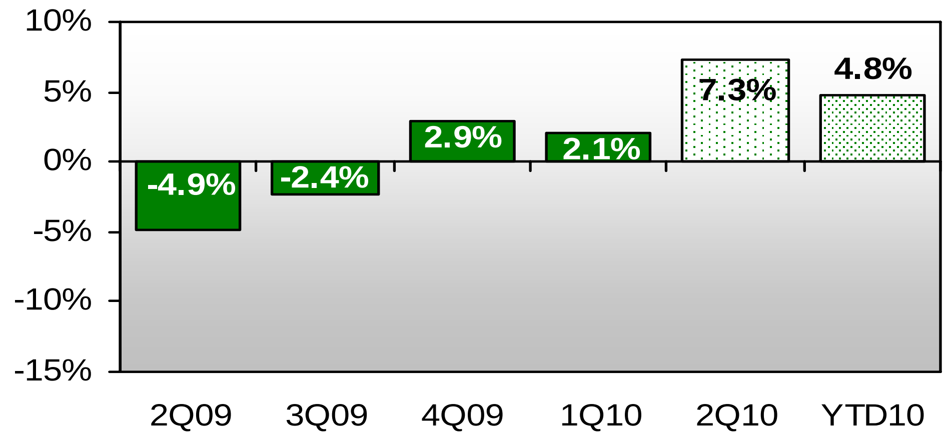
Ohio Total Normalized GWh Sales*
% Change vs. Prior Year



Reg West Total Normalized GWh Sales*
% Change vs. Prior Year



Texas Wires Total Normalized GWh Sales*
% Change vs. Prior Year



*includes firm wholesale load

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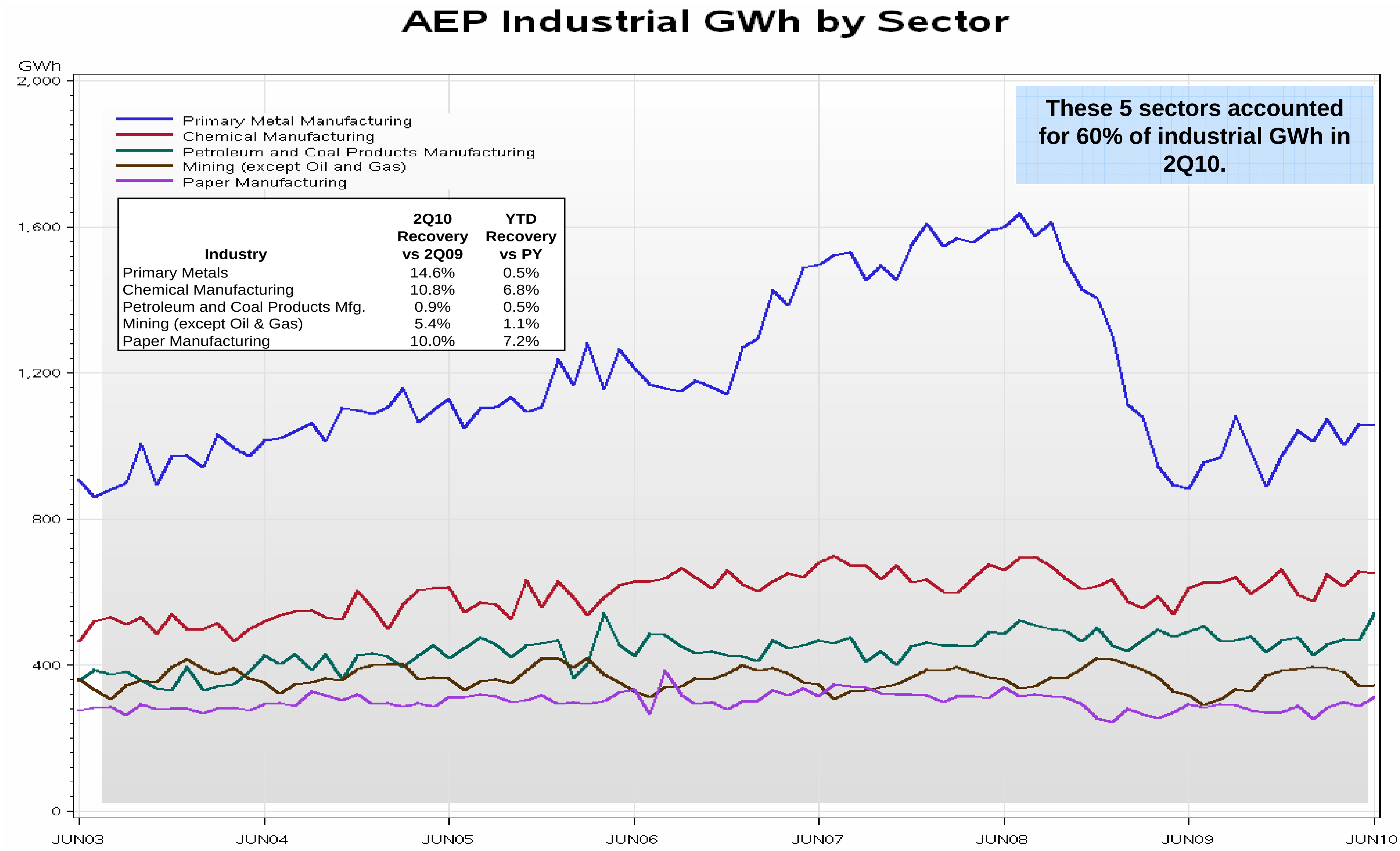
Industrial Sales



Industry	2Q10 Recovery vs 2Q09	YTD Recovery vs PY
Primary Metals	14.6%	0.5%
Chemical Manufacturing	10.8%	6.8%
Petroleum and Coal Products Mfg.	0.9%	0.5%
Mining (except Oil & Gas)	5.4%	1.1%
Paper Manufacturing	10.0%	7.2%

Off System Sales Gross Margin Detail

2Q10

	2Q09 GWh	2Q09 Realization	2Q09 ($millions)	2Q10 GWh	2Q10 Realization	2Q10 ($millions)
OSS Physical Sales	3,622	$ 10.13	$ 37	3,980	$ 11.21	$ 45
Marketing/Trading	-		$ 52	-		$ 31
Pre-Sharing Gross Margin	3,622		$ 88	3,980		$ 76
Margin Shared			$ (19)			$ (18)
Net OSS			$ 70			$ 58

- Physical off-system sales margins exceeded last year by $8M
- Volumes up 10% versus last year led by a 37% increase in June
- Improved AEP/Dayton Hub pricing: 13% increase in liquidation prices
- Lower Trading & Marketing results by $20M

YTD10

	YTD09 GWh	YTD09 Realization	YTD09 ($millions)	YTD10 GWh	YTD10 Realization	YTD10 ($millions)
OSS Physical Sales	6,213	$ 12.91	$ 80	8,724	$ 12.24	$ 107
Marketing/Trading	-		$ 93	-		$ 69
Pre-Sharing Gross Margin	6,213		$ 173	8,724		$ 176
Margin Shared			$ (42)			$ (44)
Net OSS			$ 131			$ 132

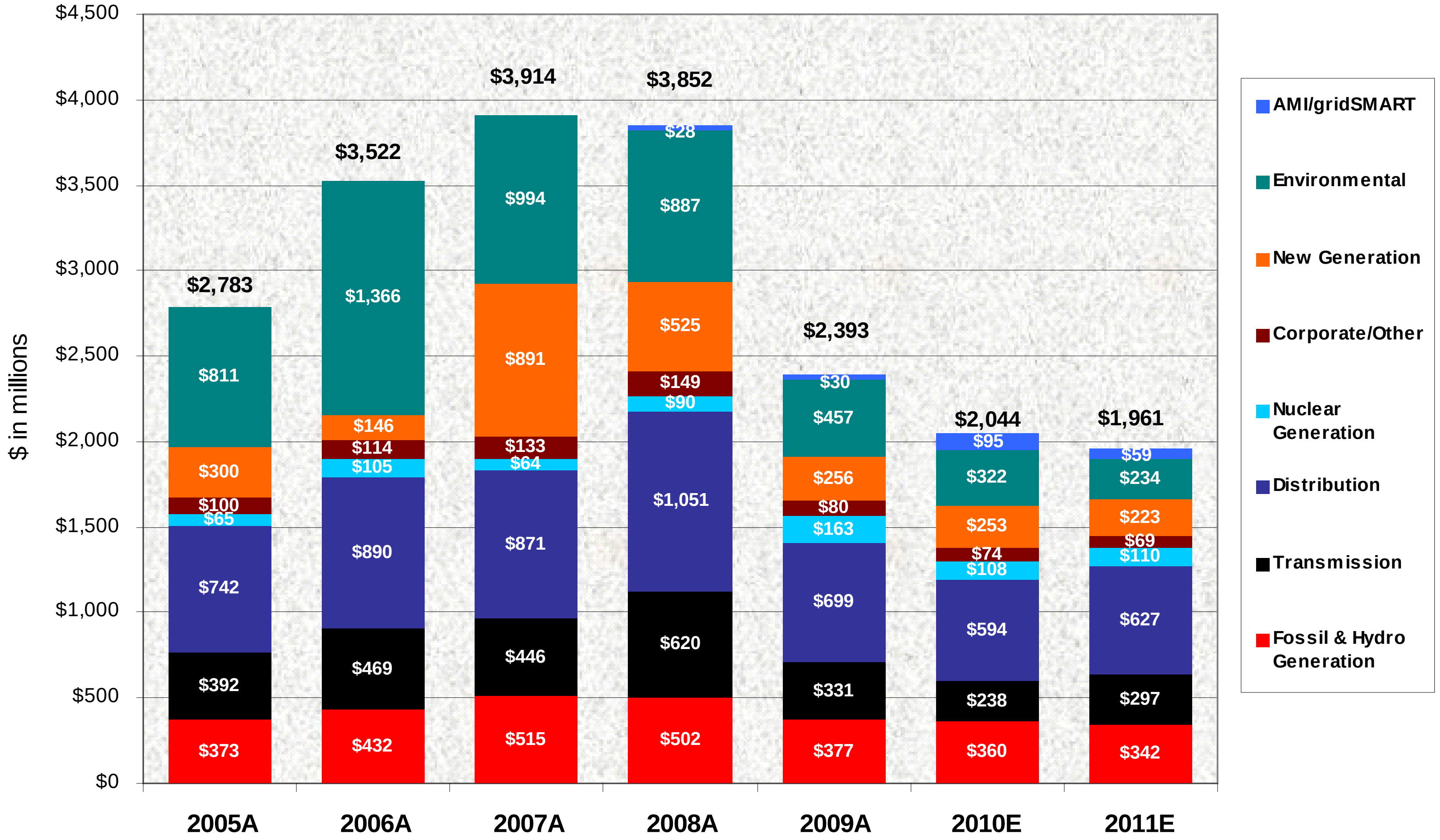
- Physical off-system sales margins exceeded last year by $27M
- Volumes up 40% versus last year
- Improved AEP/Dayton Hub pricing: 5% increase in liquidation prices
- Lower Trading & Marketing results by $24M

* May not foot due to rounding

Outlook

- Retail Load Volume & Margin recovery slower than previously anticipated
- Off-System Sales margin challenged by market prices
- Rate Changes on target for remainder of the year
- O&M Cost Reduction & Restructuring Program
  - Severance of 2,461 employees
- Operating Company Refinements
- 2010 Earnings Guidance $2.80 - $3.20 per share

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

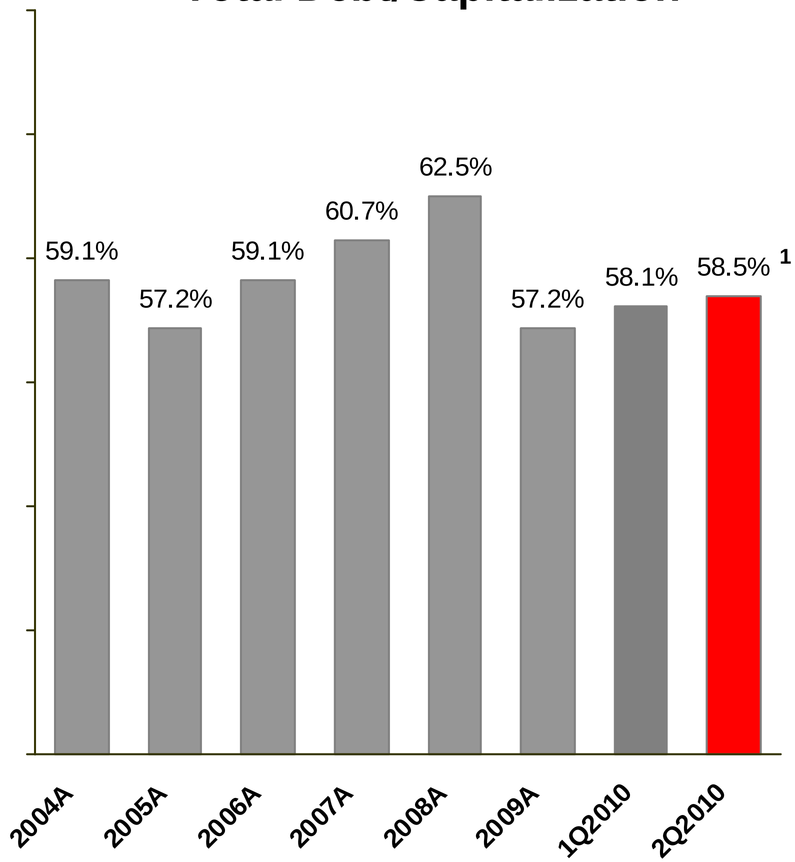
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $677 million are classified as short-term debt; The 2Q2010 debt/capitalization ratio would be 57.6%, excluding AEP Credit.

Current Liquidity Summary
As of June 30, 2010

Liquidity Summary (unaudited)	**Actual 06/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	838	
Less		
Commercial Paper Outstanding	(787)	
Letters of credit issued	(626)	
Net Available Liquidity	**$2,857**	

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)

Data as of June 30, 2010

AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

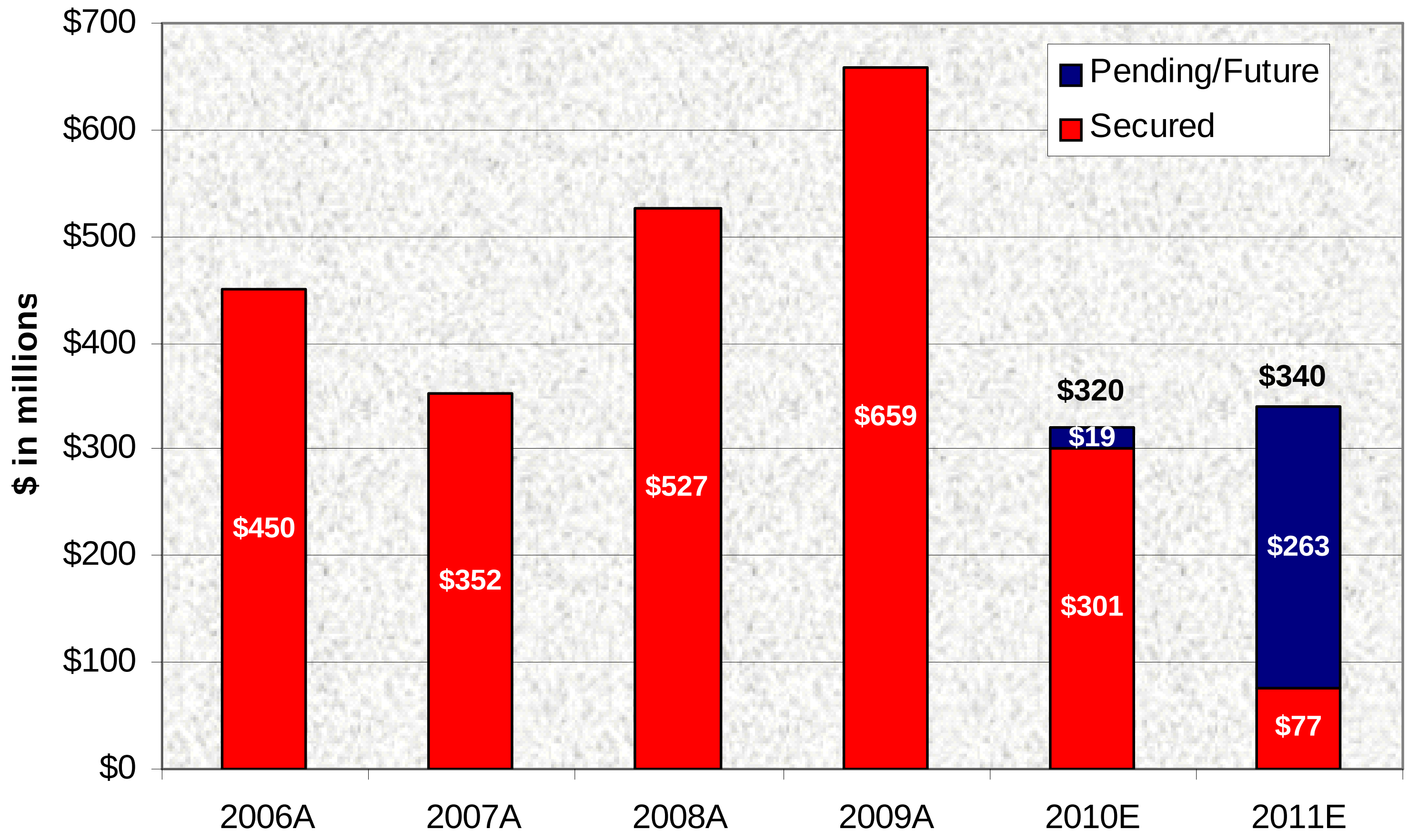
S=Stable

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires (1)	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Oklahoma, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Recent Rate Case Outcomes

APCo – Virginia Base Rate Case

	(Millions)
Company's Proposed Request	$ 167.0
Adjustments:	
Rate Base/Revenue Adj.	$ 3.5
Return on Equity 10.53% vs. 13.35%	$ (41.0)
Member Load Ratio	$ (15.0)
Capacity Rate	$ (12.8)
CCS Project	$ (9.8)
PJM Ancillaries	$ (7.4)
Environmental	$ (5.3)
ICP @ 50%	$ (4.2)
ADITC	$ (3.6)
Deferred Fuel Balance	$ (2.4)
Umbrella Trust	$ (1.3)
Deferred Wind Balance	$ (1.2)
Other Miscellaneous	$ (5.0)
Total Adjustments	$ (105.5)
Commission Order	$ 61.5

KPCo – Kentucky Base Rate Case

	(Millions)
Company's Proposed Request	$ 123.6
Adjustments:	
Wind Purchased Power Agreements	$ (14.5)
Depreciation	$ (10.7)
Return on Equity 10.5% vs. 11.75%	$ (8.5)
System Sales	$ (7.5)
Capacity Payments	$ (7.2)
Reliability Expenditures	$ (6.3)
Storm Adjustments	$ (5.6)
OATT Transmission	$ (2.2)
Other Miscellaneous	$ 2.6
Total Adjustments	$ (59.9)
Approved Settlement	$ 63.7

Current Base Rate Cases

$ in millions

I&M - Michigan	Company Filing	Staff Testimony
Rate increase	**$63**	$34
Rate base/investment	$601	$585
Return on equity	11.75%	10.35%
Equity component	44.19%	44.14%
Riders requested	Numerous	Denied except Net Lost Revenues

Status: Case filed on January 27, 2010. Hearing held August 9-10, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Order due January 25, 2011.

APCo - West Virginia	Company Filing	Staff Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

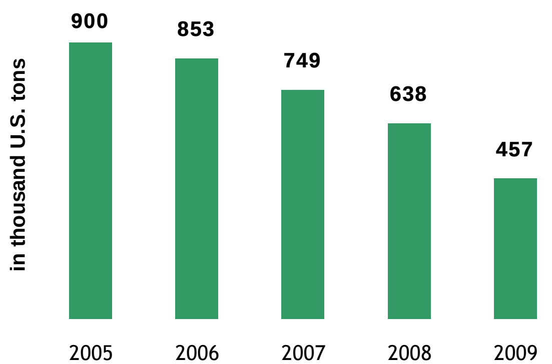
PSO - Oklahoma	Company Filing	Staff Testimony
Rate increase	**$83**	n/a
Rate base/investment	$1,687	
Return on equity	11.50%	
Equity component	45.84%	
Tracker requested	SPP Transmission Service Costs	

Status: Case filed on July 9, 2010. Procedural schedule pending.

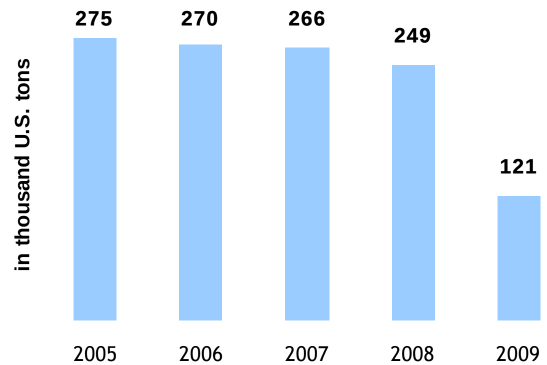
$370 million total base rate increase requests on file

Our Fleet Will Continue to Transform

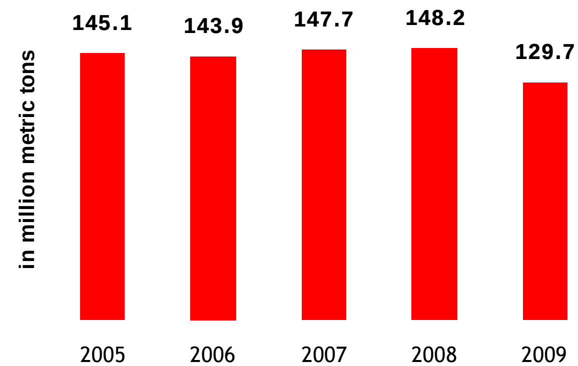
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



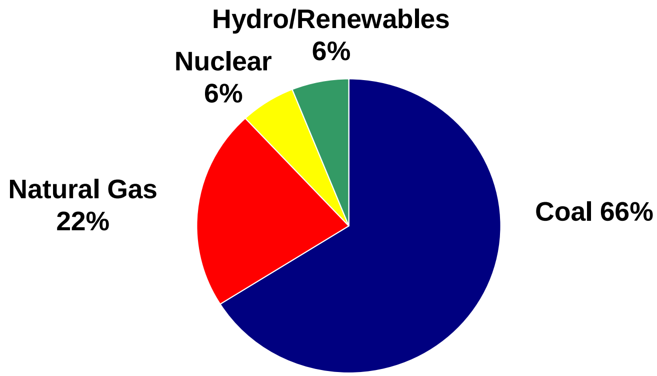
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



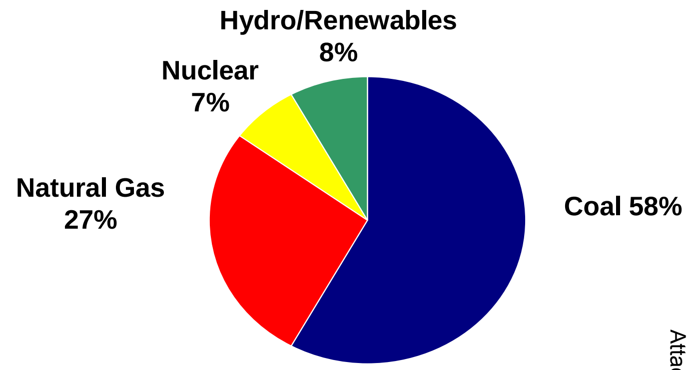
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ $5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The final estimated cost of the plant is $433 million including $49MM of AFUDC.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009

Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2017

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

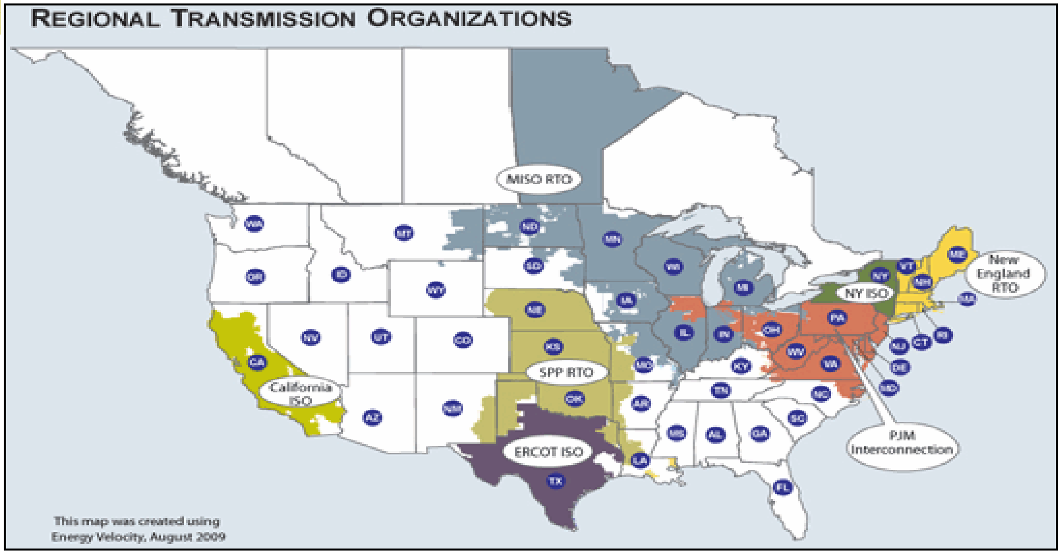
PATH-WV — COD: 2015

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2016

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ERCOT

ETT — COD: various

- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

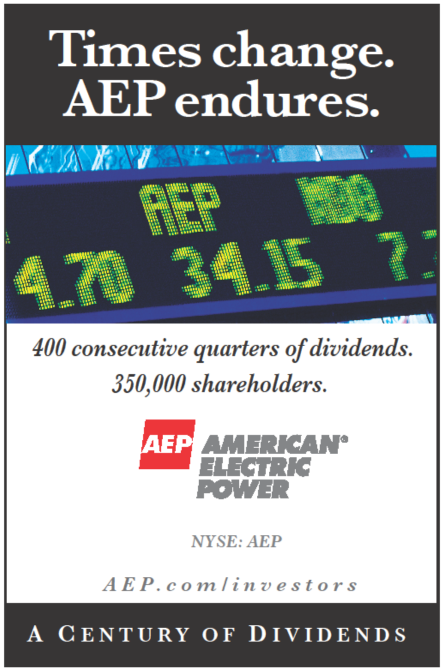
PJM/MISO

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

Value Proposition

- **Current Yield Opportunity of 4.8%[1]**
  - **June 10th – 400th consecutive quarterly dividend was paid to shareholders**
  - **50-60% payout ratio targeted**
  - **Dividend increased 2.44% on April 27th**
- **Earnings Growth Prospects**
  - **Investment in utility platform greater than depreciation level (2 - 4%)**
  - **With transmission opportunities (4 - 8%)**



Attractive total return potential

[1] yield percentage based on AEP closing price of $35.35 on 08/12/2010

American Electric Power, Inc. Operating Company Detail

Los Angeles Road Show

Hosted by UBS Investment Bank

August 6-7, 2007

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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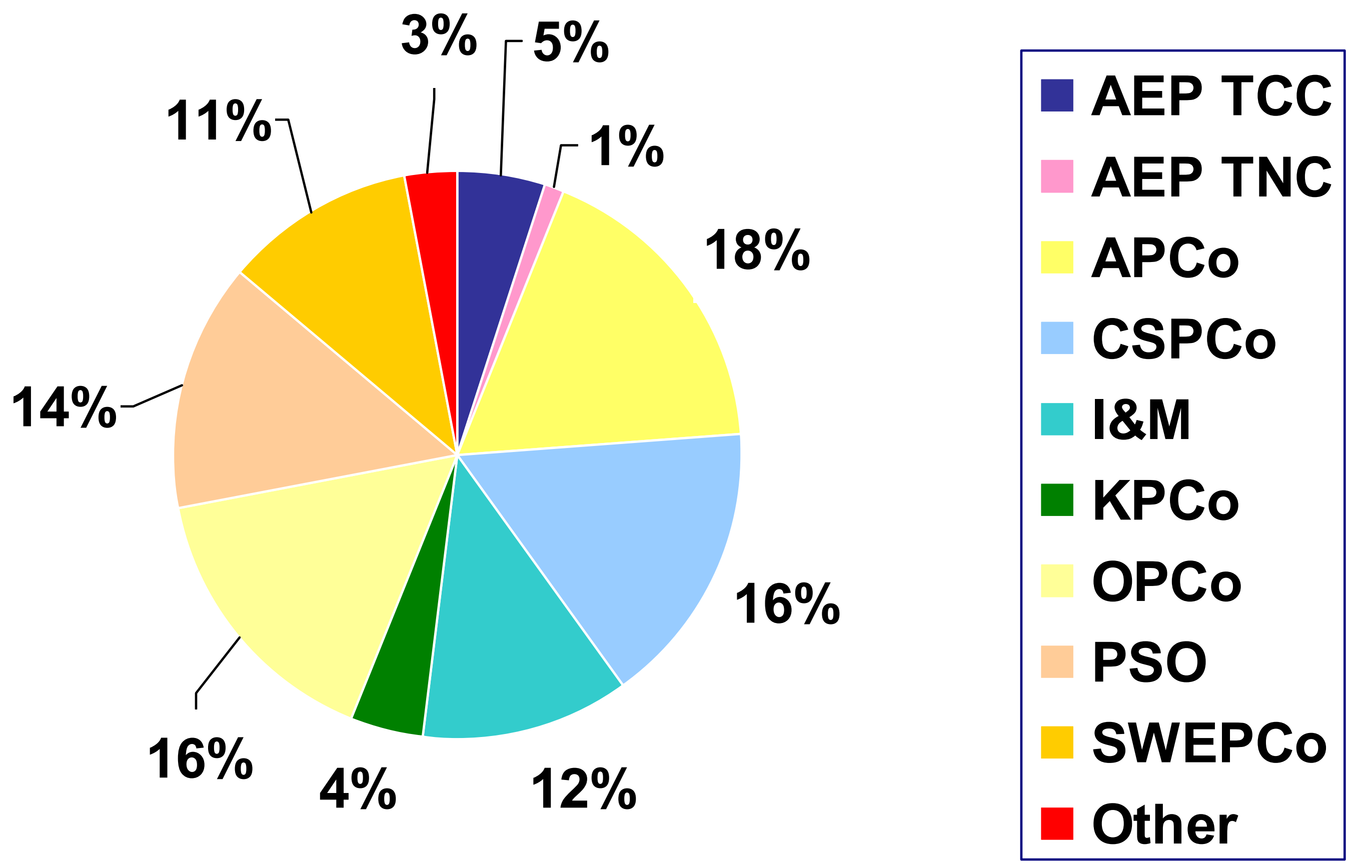
2006 Retail Revenue

Retail Revenue Composition by Operating Company



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Earned ROEs

Company	6/30/07 Earned ROE
AEP Texas Central Company	**6.22%**
AEP Texas North Company	**8.63%**
Appalachian Power Company	**4.56%**
Columbus Southern Power Company	**21.22%**
Indiana Michigan Power Company	**7.18%**
Kentucky Power Company	**9.89%**
Ohio Power Company	**12.79%**
Public Service Company of Oklahoma	**2.25%**
Southwestern Electric Power Company	**6.77%**

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ROEs Calculated on a GAAP Basis

Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Semi-annually
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	n/a
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annually

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	No	There is $17 million built into Indiana's base rates
Kentucky	Yes, above and below base levels	Sharing only occurs after annual profits exceed $24,855,326. Between that amount and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 67% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	Factored into base rates at a fixed rate. Effective 7/1/07, legislation was enacted to allow company retention of at least 25% of OSS margins. We have a filing pending before the VA SCC to initiate this sharing.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

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Forecasted Capital Expenditures

($ IN MILLIONS)

Company	2007	2008	2009
AEP System*	**$ 3,867**	**$ 3,026**	**$ 2,974**
AEG	$ 343	$ 28	$ 34
APCo	$ 664	$ 531	$ 461
CSPCo	$ 439	$ 354	$ 233
I&M	$ 252	$ 264	$ 294
KPCo	$ 70	$ 114	$ 100
OPCo	$ 832	$ 368	$ 389
PSO	$ 319	$ 330	$ 466
SWEPCo	$ 537	$ 605	$ 540
TCC	$ 241	$ 214	$ 273
TNC	$ 143	$ 188	$ 149

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2007 Key Operating Company Highlights

Dependent on Actual Capital Investment (in millions $)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Adjusted Equity Ratio
AEG	$343	$220	40%
APCo	$664	$600-$700	43-45%
CSP	$439	$50-$100	44-46%
I&M	$252	$50	40-42% (b)
KPCo	$70	$300-$400	42-44%
OPCo	$832	$450-$550	44-46%
PSO	$319	$150-$250	44-46%
SWEPCo	$537	$250-$550	44-46%
TCC (c)	$241	$0	40%
TNC	$143	$0	40%

(a) Includes tax exempt issuances

(b) Ratios include impact of Rockport 2 lease

(c) Excludes impact of securitization on the equity ratio

Maintain Financial Strength Of Utility Companies By Retaining And/Or Infusing Equity Capital Depending On Their Credit Ratios And Free Cash Flow

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Managing Subsidiary Cash Flows

- We monitor:
  - AEP consolidated cash requirements
  - Utility expected rates of return and potential regulatory lags
  - Amount of capital spending and internal cash needs
  - Free cash flow – cash available after construction
  - Credit ratios

- Dividends and equity:
  - We pay dividends based on free cash flow and credit metrics
  - When additional equity/cash is needed at the subsidiary level, the first option is dividend reductions, then capital infusions
  - We are currently evaluating hybrid securities as a source of equity

Our Objective Is To Maintain The Financial Strength And Capital Markets Access Of The AEP Operating Companies

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Commitment To Credit Quality

- Maintain adequate liquidity
- Target 60% consolidated AEP debt/cap ratio
- Target long term AEP dividend payout ratio range of 55-60%

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's	S&P		Fitch
Company	Senior Unsecured	Business Profile	Senior Unsecured	Senior Unsecured
AEP, Inc. [1]	Baa2	5	BBB	BBB
AEP, Inc. Short Term Rating	P2	N/A	A2	F2
APCo	Baa2	5	BBB	BBB+
CSPCo	A3	4	BBB	A-
I&M	Baa2	6	BBB	BBB
KPCo	Baa2	5	BBB	BBB
OPCo	A3	4	BBB	BBB+
PSO	Baa1	5	BBB	A-
SWEPCo	Baa1	5	BBB	A-
TCC	Baa2	3	BBB	BBB+
TNC	Baa1	3	BBB	A-

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

Note: All rating agencies have each company on stable outlook with the exception of Fitch, which has a negative outlook on TCC.

We Are Committed To Maintaining Our Current Credit Ratings

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Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Long-Term Debt Maturity Profile

($ in millions)

Year		2007		2008		2009
AEP, Inc.	$	345	$	-	$	-
Appalachian Power	$	200	$	200	$	150
Columbus Southern Power	$	-	$	112	$	-
Kentucky Power	$	323	$	30	$	-
Indiana Michigan	$	-	$	50	$	45
Ohio Power Company	$	-	$	42	$	100
Public Service of Oklahoma	$	-	$	-	$	50
Southwestern Electric Power	$	90	$	116	$	-
Texas Central Company *	$	-	$	68	$	-
Total	$	958	$	618	$	345

Note: Maturities remaining as of June 30, 2007

* - 2008 maturities include $19 million in first mortgage bonds that were defeased in May 2004

Debt Schedules – as of 6/30/07

American Electric Power, Inc.

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.102%		$1,077,775,000

American Electric Power Service Corp.

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$36,000,000

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Debt Schedules – as of 6/30/07

AEP Texas Central

Series	Interest	Maturity	Amount
First Mortgage Bond *	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	4.400%	05/01/2030	$111,700,000
Pollution Control Bond	4.550%	05/01/2030	$50,000,000
Pollution Control Bond	4.450%	06/01/2020	$6,330,000
Preferred Stock	4.000%	N/A	$4,191,200
Preferred Stock	4.200%	N/A	$1,730,100
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	5.898%		$695,017,300
Securitization Bond	5.010%	1/15/2008 **	$49,523,804
Securitization Bond	5.560%	1/15/2010 **	$107,094,258
Securitization Bond	5.960%	7/15/2013 **	$214,926,738
Securitization Bond	6.250%	1/15/2016 **	$191,856,858
Securitization Bond	4.980%	1/1/2010 **	$217,000,000
Securitization Bond	4.980%	7/1/2013 **	$341,000,000
Securitization Bond	5.090%	7/1/2015 **	$250,000,000
Securitization Bond	5.170%	1/1/2018 **	$437,000,000
Securitization Bond	5.306%	7/1/2020 **	$494,700,000
Weighted Average or Total	5.323%		$2,303,101,658

AEP Texas North

Series	Interest	Maturity	Amount
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Pollution Control Bond	4.450%	06/01/2020	$44,310,000
Preferred Stock	4.400%	N/A	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.420%		$315,968,600

* TCC's First Mortgage Bond was defeased in May 2004

** represents scheduled final payment date, no ultimate maturity date

AEP®

Debt Schedules – as of 6/30/07

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	05/01/2019	$30,000,000
Pollution Control Bond	Floating	11/01/2021	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Pollution Control Bond	Floating	05/01/2037	$75,000,000
Preferred Stock	4.500%	N/A	$17,763,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	5.294%		$2,480,038,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	12/01/2038	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

AEP®

Debt Schedules – as of 6/30/07

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	10/01/2019	$25,000,000
Pollution Control Bond	Floating	04/01/2025	$40,000,000
Pollution Control Bond	4.625%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	N/A	$5,533,500
Preferred Stock	4.120%	N/A	$1,105,500
Preferred Stock	4.560%	N/A	$1,441,200
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Senior Notes	6.050%	03/15/2037	$400,000,000
Weighted Average or Total	5.811%		$1,320,080,200

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/10/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Debt Schedules – as of 6/30/07

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.563%	10/01/2022	$19,565,000
Pollution Control Bond	5.563%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Pollution Control Bond	4.900%	06/01/2037	$65,000,000
Notes Payable	6.810%	03/31/2008	$4,390,244
Notes Payable	6.270%	03/31/2009	$19,000,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	N/A	$1,459,500
Preferred Stock	4.200%	N/A	$2,282,400
Preferred Stock	4.400%	N/A	$3,148,200
Preferred Stock	4.500%	N/A	$9,737,300

Ohio Power Company (continued)

Series	Interest	Maturity	Amount
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2010	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Senior Notes	Floating	04/05/2010	$400,000,000
Weighted Average or Total	5.841%		$2,680,372,644

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Debt Schedules – as of 6/30/07

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Pollution Control Bond	4.450%	06/01/2020	$12,660,000
Preferred Stock	4.000%	N/A	$4,454,800
Preferred Stock	4.240%	N/A	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Senior Notes	6.150%	08/01/2016	$150,000,000
Weighted Average or Total	5.489%		$689,281,700

Southwestern Electric Power Company

Series	Interest	Maturity	Amount
Notes Payable	4.470%	05/16/2011	$16,888,366
Notes Payable	Floating	06/30/2008	$3,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	N/A	$3,767,300
Preferred Stock	4.650%	N/A	$190,700
Preferred Stock	4.280%	N/A	$738,600
Senior Notes	5.380%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Senior Notes	5.550%	01/15/2017	$250,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	5.541%		$924,322,966

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AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC completed its exit from the generation business through the sale of all of its generation assets. At December 31, 2006, TCC had 1,224 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

MAJOR CUSTOMERS:

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
TXC
Javelina Refinery
Citgo Petroleum Corporation
Formosa Utl Ven Ltd.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Food processing
Petroleum refining
Chemicals

- **Top 10 customers = 47% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **57 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**630,000**
• **Commercial**	**102,000**
• **Industrial**	**5,000**
• **Other**	**1,000**
Total	**738,000**

Transmission Miles	**5,000**
Distribution Miles	**28,000**

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AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004 Debt	2004 Equity	2004 Total	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total
Capitalization Per Balance Sheet	1,907,501	1,274,583	3,182,084	1,935,576	953,570	2,889,146	3,015,614	411,037	3,426,651
% of Capitalization Per Balance Sheet	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%	88.0%	12.0%	100.0%
Adjusted Capitalization	1,125,386	1,274,583	2,399,969	1,269,995	953,570	2,223,565	661,806	411,037	1,072,843
% of Adjusted Capitalization	46.9%	53.1%	100.0%	57.1%	42.9%	100.0%	61.7%	38.3%	100.0%
FFO Interest Coverage			2.9			1.4			2.0
FFO to Total Debt			14.3%			2.6%			13.0%

2006 Financial Data (in thousands)

Revenue	$	665,000
% of AEP Retail		5%
Net Income (Loss)	$	42,000
Capital Expenditure	$	270,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 5,324,000
Net Plant Assets	$ 2,240,000

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 241,000	$ 247,000	$ 222,100

AEP®

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, TNC had 386 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

MAJOR CUSTOMERS:
Zoltec Corporation
Kinder Morgan
Occidental Permian Ltd.
EBAA Iron, Inc.
Rhodia Inc.
D&S Pipeline Corporation
Georgia-Pacific Corporation
Aethon I LP
Texas Instruments
Tyson Foods Inc. (Wright Brand)

PRINCIPAL INDUSTRIES SERVED:
Pipelines, except natural gas
Oil and gas extraction
Food processing
Electric equipment
Stone, clay and glass production

- **Top 10 customers = 27% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**
- * Industrial % is in terms of wires revenues

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
• **Other**	**6,000**
Total	**189,000**

Generating Capacity 377 MW

Oklaunion Plant – Vernon, TX
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal: 100%**

Transmission Miles 4,500

Distribution Miles 14,000

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	314,357	312,778	627,135	276,845	316,276	593,121	276,936	308,705	585,641
% of Capitalization Per Balance Sheet	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	47.3%	52.7%	100.0%
Adjusted Capitalization	314,357	312,778	627,135	276,845	316,276	593,121	268,785	308,705	577,490
% of Adjusted Capitalization	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%	46.5%	53.5%	100.0%
FFO Interest Coverage			5.8			5.0			3.7
FFO Total Debt			33.4%			29.8%			17.4%

2006 Financial Data (in thousands)

Revenue	$ 329,000
% of AEP Retail	1%
Net Income	$ 15,000
Capital Expenditure	$ 70,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 968,000
Net Plant Assets	$ 842,000
Cash	$ 84

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 143,000	$ 188,000	$ 149,000

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Appalachian Power

President and Chief Operating Officer:
Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:
Coal mining
Primary metals
Chemicals
Textile mill products
Paper products

Total Customers:

• **Residential**	**810,000**
• **Commercial**	**128,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**949,000**

Generating Capacity **6,282 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **80.8%**
- **Hydro/Pump:** **10.8%**
- **Nat Gas** **8.4%**

Transmission Miles	**6,750**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	1,995,658	1,427,502	3,423,160	2,345,511	1,821,485	4,166,996	2,633,639	2,053,937	4,687,576
% of Adjusted Capitalization	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			5.0			3.7			3.9
FFO Total Debt			19.7%			12.4%			14.4%

2006 Financial Data (in thousands)

Revenue	$ 2,394,000
% of AEP Retail	18%
Net Income	$ 180,000
Capital Expenditure	$ 893,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 7,016,000
Net Plant Assets	$ 5,524,000
Cash	$ 2,318

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 664,000	$ 531,000	$ 461,000

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Appalachian Power

APCo Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	29,551,752	32,949,364	31,494,581	31,331,899
Coal Consumption (tons burned)	11,604,352	13,187,986	12,619,910	12,470,749

Operating Information

2006 retail electric sales in megawatt-hours	32,448,331	2006 firm wholesale sales in megawatt-hours	2,821,450
Average cost per kilowatt-hour (residential)	5.85 cents	2006 System Peak - December 8	6,990 MW

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	5	Hydro
Byllesby #1, 2, 3, 4	Byllesby, Virginia	8	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	528	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	28	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lyn #1, 2	Glen Lyn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	9	Hydro
Niagara #1, 2	Roanoke, Virginia	1	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	6	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2 *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	12	Hydro
Marmet #1, 2, 3	Marmet, West Virginia	11	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES *

West Virginia	Customers
APCo	**434,504**
Allegheny	492,354

Virginia	Customers
APCo	**503,525**
Dominion Virginia	2,171,253
Allegheny	95,665
Kentucky Utilities	29,900
Conectiv	21,930

Tennessee	Customers
APCo	**45,960**

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- **Top 10 Customers = 49% of industrial sales**
- **Metropolitan areas account for 34% of ultimate sales**
- **110 persons per square mile (U.S. = 95)**

TYPICAL BILL COMPARISON **

West Virginia	
APCo	**58.87**
AEP – Wheeling	**58.87**
Allegheny	70.46

Virginia	
ODPCo	64.69
APCo	**66.72 *** **
Dominion Virginia	85.28
Conectiv	126.82

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

*** APCo Virginia rate adjusted for effect of rate case order received in May 2007.

MAJOR CUSTOMERS:
Century Aluminum of WV, Inc. (WV)
CONSOL Energy (VA)
Roanoke Electric Steel Corporation (VA)
Georgia-Pacific Corporation (VA)
Alcan Rolled Products (WV)
Greif Brothers Corporation (VA)
West Virginia Alloys, Inc. (WV)
Dickenson-Russell Coal Co, LLC (VA)
Steel of WV, Inc. (WV)
Toyota Motor Manufacturing (WV)

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSPCo covers a service territory of 3,701 miles and at December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Food processing
Chemicals
Primary metals
Fabricated metals
Rubber and plastic products

Total Customers:

• **Residential**	**662,000**
• **Commercial**	**76,000**
• **Industrial**	**4,000**
Total	**742,000**

Generating Cap	**3,708 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**63.2%**
• **Natural Gas**	**36.1%**
• **Hydro:**	**0.7%**

Transmission Miles	**2,400**
Distribution Miles	**17,200**

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Capitalization Per Balance Sheet	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075	1,198,018	1,056,017	2,254,035
% of Adjusted Capitalization	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			6.2			5.8			6.2
FFO Total Debt			28.7%			24.3%			28.8%

2006 Financial Data (in thousands)

Revenue	$ 1,807,000
% of AEP Retail	16%
Net Income	$ 185,000
Capital Expenditure	$ 307,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,521,000
Net Plant Assets	$ 2,725,000
Cash	$ 1,319

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 439,000	$ 354,000	$ 233,000

AEP®

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	14,049,095	14,038,045	14,134,232	14,073,791
Coal Consumption (tons burned)	6,121,275	6,048,060	5,953,084	6,040,806

Operating Information

2006 retail sales in megawatt-hours	19,567,156
2006 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	8.70 cents
2006 System Peak – August 2	4,425 MW

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,254	Coal
J. M. Stuart *#1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	608	Coal
Wm. H. Zimmer *#1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Racine #1	Racine, Ohio	26	Hydro
Waterford # 1,2,3,4	Washington County, Ohio	857	Nat Gas
Darby # 1,2,3,4,5,6	Mount Sterling, Ohio	480	Nat Gas

AEP®

Columbus Southern Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

*** First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:
Eramet Marietta, Inc.
Kraton Polymers
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
Glatfelter Company
Columbus Steel Castings Co.
General Mills
Griffin Wheel Company
Mill's Pride LP
Ross Products

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 85% of ultimate sales**
- **234 persons per square mile (U.S. = 95)**

Indiana Michigan Power

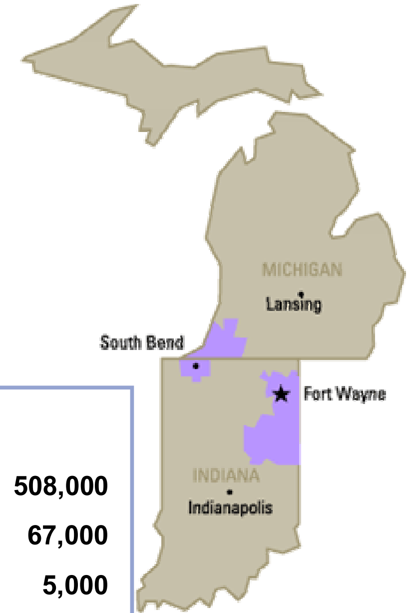
President and Chief Operating Officer: Helen Murray

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2006, I&M had 2,643 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Transportation equipment
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products



Total Customers:	
• **Residential**	**508,000**
• **Commercial**	**67,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**582,000**
Generating Capacity	**5,753 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.2%**
• **Hydro:**	**0.3%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana Michigan Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818	1,646,308	1,297,521	2,943,829
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.9%	44.1%	100.0%
Adjusted Capitalization	1,757,390	1,099,582	2,856,972	1,909,337	1,228,176	3,137,513	1,991,717	1,297,521	3,289,238
% of Adjusted Capitalization	61.5%	38.5%	100.0%	60.9%	39.1%	100.0%	60.6%	39.4%	100.0%
FFO Interest Coverage			4.1			4.7			4.8
FFO Total Debt			23.2%			22.8%			23.9%

2006 Financial Data (in thousands)

Revenue	$ 1,977,000
% of AEP Retail	12%
Net Income	$ 121,000
Capital Expenditure	$ 325,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 5,546,000
Net Plant Assets	$ 3,313,000
Cash	$ 1,369

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 252,000	$ 264,000	$ 294,000

Indiana Michigan Power

I&M Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Avg.**
MWh Produced	21,258,001	31,535,226	31,950,768	28,247,998
Coal Consumption (tons burned)	7,186,066	7,011,370	7,947,666	22,145,102

Operating Information

2006 retail electric sales in megawatt-hours	18,982,744
2006 firm wholesale sales in megawatt-hours	3,497,758
Average cost per kilowatt-hour (residential)	6.73 cents
2006 System Peak – July 31	4,650 MW

Indiana Michigan Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,600	Coal
Berrien Springs #1 , 2 , 3	Berrien Springs, Michigan	5	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	2	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	2	Hydro
Mottville #1, 2, 3, 4	Mottville, Michigan	1	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	4	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES *

Indiana	Customers
I & M	**453,788**
IP & L	462,831
NIPSCO	447,831
Duke Indiana (PSI)	758,912
SIGECo	144,632

Michigan	Customers
I & M	**125,588**
Consumers Energy	1,779,184
Detroit Edison	2,156,214

TYPICAL BILL COMPARISON **

Indiana	
I & M	**69.64**
IP & L	76.00
Duke Indiana (PSI)	78.82
SIGECo	94.62

Michigan	
I & M	**66.65**
Consumers Energy	101.43
Detroit Edison	111.93

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

MAJOR CUSTOMERS:
Steel Dynamics Inc. (IN)
American Axle and Mfg. Co, Inc. (MI)
Air Products & Chemicals, Inc. (IN)
Boc Gases (IN)
Saint Gobain Corporation USA (IN)
Whirlpool Corp (MI)
New Energy Corp (IN)
Dock Foundry (MI)
Bosch Braking Systems Corp. (MI)
IN TEK (IN)

- **Top 10 Customers = 46% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

AEP®

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,600**
• **Other**	**400**
Total	**176,000**

Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,200**
Distribution Miles	**9,700**

PRINCIPAL INDUSTRIES SERVED:

Petroleum refining
Coal mining
Primary metals
Chemicals
Electric/gas/sanitary services

AEP®

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Capitalization Per Balance Sheet	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
Adjusted Capitalization	508,310	320,980	829,290	493,030	347,841	840,871	477,604	369,651	847,255
% of Adjusted Capitalization	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%	56.4%	43.6%	100.0%
FFO Interest Coverage			3.9			3.4			3.9
FFO Total Debt			16.6%			14.0%			17.7%

2006 Financial Data (in thousands)

Revenue	$ 586,000
% of AEP Retail	4%
Net Income	$ 35,000
Capital Expenditure	$ 78,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 1,311,000
Net Plant Assets	$ 1,002,000
Cash	$ 702

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 70,000	$ 114,000	$ 100,000

AEP®

Kentucky Power

Kentucky Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	6,550,509	7,345,624	7,171,505	7,022,546
Coal Consumption (tons burned)	2,607,559	2,926,253	2,854,537	2,796,116

Operating Information

2006 retail electric sales in megawatt-hours	7,122,459
2006 firm wholesale sales in megawatt-hours	97,405
2006 average cost per kilowatt-hour (residential)	6.50 cents
2006 System Peak – December 8	1,636 MW

Kentucky Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Big Sandy #1, 2	Louisa, Kentucky	1,060	Coal

Kentucky Power

KENTUCKY UTILITIES *

Kentucky	Customers
KPCo	**175,255**
Kentucky Utilities	491,314
LG & E	392,998

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Kentucky	
Kentucky Utilities	58.57
LG&E	65.40
KPCo	**69.40**
Duke Kentucky	76.70

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Catlettsburg Refining LLC
AK Steel Holding Corporation
Sidney Coal Company, Inc.
Blue Diamond Coal Co.
CONSOL of Kentucky, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC
McCoy Elkhorn Coal Corporation
Perry County Coal Corp.
Shamrock Coal Company

- **Top 10 customers = 63% of industrial sales**
- **Metropolitan areas account for 41% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2006, OPCo had 2,330 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

Total Customers:

• **Residential**	**611,000**
• **Commercial**	**91,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**712,000**

Generating Capacity **8,498 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **99.9%**
- **Hydro:** **0.1%**

Transmission Miles **6,500**

Distribution Miles **26,200**

PRINCIPAL INDUSTRIES SERVED:

Primary metals
Rubber and plastic products
Stone, clay and glass products
Petroleum refining
Chemicals

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004 Debt	2004 Equity	2004 Total	2005 Debt	2005 Equity	2005 Total	2006 Debt	2006 Equity	2006 Total
Capitalization Per Balance Sheet	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Capitalization Per Balance Sheet	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
Adjusted Capitalization	2,053,641	1,490,479	3,544,120	2,291,409	1,784,586	4,075,995	2,600,050	2,024,972	4,625,022
% of Adjusted Capitalization	57.9%	42.1%	100.0%	56.2%	43.8%	100.0%	56.2%	43.8%	100.0%
FFO Interest Coverage			4.9			6.2			6.2
FFO Total Debt			22.6%			23.8%			19.7%

2006 Financial Data (in thousands)

Revenue	$ 2,725,000
% of AEP Retail	16%
Net Income	$ 229,000
Capital Expenditure	$ 1,000,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 6,819,000
Net Plant Assets	$ 5,569,000
Cash	$ 1,625

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 832,000	$ 368,000	$ 38[illegible],000

AEP®

Ohio Power

Ohio Power Generation Production Statistics – 2004 – 2006				
Production Stat	**2004**	**2005**	**2006**	**Three Year Average**
MWh Produced	52,156,749	52,080,585	49,341,134	51,192,823
Coal Consumption (tons burned)	20,534,361	20,382,116	19,111,071	20,009,183

Operating Information

2006 retail sales in megawatt-hours	25,262,084
2006 firm wholesale sales in megawatt-hours	2,125,426
Average cost per kilowatt-hour (residential)	7.53 cents
2006 System Peak – August 2nd	5,260 MW

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	26	Hydro

Ohio Power

OHIO UTILITIES *

Ohio	Customers
AEP Ohio **	**1,416,992**
First Energy ***	1,171,438
Duke Ohio (CG&E)	658,983
DP&L	510,295

** AEP Ohio - CSPCo = 708,169
OPCo = 708,823

***First Energy - Toledo Edison = 163,719
CEI = 310,022
Ohio Edison = 697,697

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON ****

Ohio	
AEP (OPCo)	**75.39**
AEP (CSP)	**85.02**
DP&L	95.87
Duke Ohio (CG&E)	100.75
FE (CEI)	108.68
FE (Toledo Edison)	113.40
FE (Ohio Edison)	116.09

**** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007. Ohio rates represent POLR bundled residential rates.

MAJOR CUSTOMERS:

Wheeling-Pittsburgh Steel Corp.
The Timken Company
Republic Engineered Products, LLC
Premcor Refining Group, Inc.
Globe Metallurgical, Inc
Owens Corning Fiberglas Corp.
Linde Gas
Marathon Ashland Petroleum LLC
Aristech Chemical Corp.
Armco Inc.

- **Top 10 customers = 45% of industrial sales**
- **Metropolitan areas account for 58% of ultimate sales**
- **138 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2006, PSO had 1,233 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Stone, clay and glass products
Primary metals
Transportation equipment

Total Customers:

• Residential	447,000
• Commercial	58,000
• Industrial	7,000
• Other	8,000
Total	520,000

Generating Capacity		**4,219 MW**
Generating Capacity by Fuel Mix:		
• Coal:	25%	
• Natural Gas:	75%	
Transmission Miles		**3,600**
Distribution Miles		**21,200**

AEP®

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Capitalization Per Balance Sheet	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
Adjusted Capitalization	601,094	534,518	1,135,612	646,954	553,859	1,200,813	746,321	590,700	1,337,021
% of Adjusted Capitalization	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%	55.8%	44.2%	100.0%
FFO Interest Coverage			5.5			2.8			6.0
FFO Total Debt			28.2%			9.5%			27.2%

2006 Financial Data (in thousands)

Revenue	$ 1,442,000
% of AEP Retail	14%
Net Income	$ 37,000
Capital Expenditure	$ 240,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 2,579,000
Net Plant Assets	$ 1,999,000
Cash	$ 1,651

Estimated Capital Expenditures
(in thousands)

2007	2008	2009
$ 319,000	$ 330,000	$ 466,000

AEP®

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8418 of 9556

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	12,512,486	15,375,848	15,139,848	14,342,727
Coal Consumption (tons burned)	4,093,436	4,353,364	4,421,396	4,289,399

Operating Information

2006 retail electric sales in megawatt-hours	17,845,471
2006 firm wholesale sales in megawatt-hours	9,916
Average cost per kilowatt-hour (residential)	8.41 cents
2006 System Peak – August 9	4,169 MW

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	404	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

OKLAHOMA UTILITIES *

Oklahoma	Customers
PSO	**511,924**
OG&E	678,126

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Oklahoma	
Empire District	70.73
PSO	**73.67**
OG&E	74.60

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Sun Refining
AMR Corporation
Sinclair
Terra Nitrogen Limited Partner
Republic Paperboard
Explorer Pipeline Co.

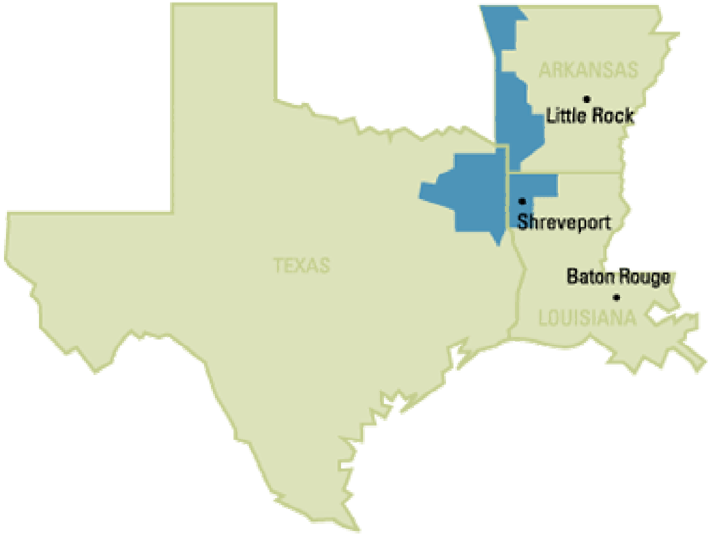
- **Top 10 customers = 46% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **47 persons per square mile (U.S. = 95)**

Southwestern Electric Power

President and Chief Operating Officer: Venita McCellon-Allen

Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2006, SWEPCo had 1,545 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.



Total Customers:

• **Residential**	**386,000**
• **Commercial**	**62,000**
• **Industrial**	**7,000**
• **Other**	**1,000**
Total	**456,000**

Generating Capacity	**4,637 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite:** **58%**
- **Natural Gas:** **42%**

Transmission Miles	**3,500**
Distribution Miles	**19,300**

PRINCIPAL INDUSTRIES SERVED:

Oil and gas extraction
Paper products
Chemicals
Food processing
Primary metals

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2004			2005			2006		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Capitalization Per Balance Sheet	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
Adjusted Capitalization	806,494	773,318	1,579,812	776,529	787,078	1,563,607	936,929	825,899	1,762,828
% of Adjusted Capitalization	51.0%	49.0%	100.0%	49.7%	50.3%	100.0%	53.1%	46.9%	100.0%
FFO Interest Coverage			5.7			3.8			5.9
FFO Total Debt			31.4%			18.1%			28.9%

2006 Financial Data (in thousands)

Revenue	$ 1,432,000
% of AEP Retail	11%
Net Income	$ 92,000
Capital Expenditure	$ 323,000

2006 Asset Data (in thousands)

	As of 12/31/06
Total Assets	$ 3,191,000
Net Plant Assets	$ 2,494,000
Cash	$ 2,618

Estimated Capital Expenditures

(in thousands)

2007	2008	2009
$ 537,000	$ 605,000	$ 540,000

AEP®

Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2004 - 2006				
Production Stat	**2004**	**2005**	**2006**	**Three-Year Average**
MWh Produced	20,071,578	20,167,754	19,961,798	20,067,043
Coal Consumption (tons burned)	13,032,475	12,420,979	12,180,786	12,544,747

Operating Information

2006 retail electric sales in megawatt-hours	16,992,647
2006 firm wholesale sales in megawatt-hours	5,658,514
Average cost per kilowatt-hour (residential)	7.22 cents
2006 System Peak – August 16	4,912 MW

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas
Mattison #3, 4	Tontitown, Arkansas	150	Gas

Southwestern Electric Power

SOUTHWESTERN UTILITIES *

Arkansas	Customers
SWEPCo	**109,760**
Entergy AR	672,890

Louisiana	Customers
SWEPCo	**171,564**
Entergy	1,189,038
CLECO	263,797

Texas	Customers
SWEPCo	**166,906**
Entergy	377,143
SPSCo	277,203
El Paso	256,384

* Customer counts are as of December 31, 2005 and were sourced from table 10 at http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

TYPICAL BILL COMPARISON **

Arkansas	
SWEPCo	**74.63**
OG&E	77.70
Empire District	86.30
ETR	102.43

Louisiana	
SWEPCo	**63.91**
Entergy LA	99.63
Entergy Gulf St	100.81
Entergy NO	104.20
CLECO	110.19

Texas	
SWEPCo	**60.80**
SPSCo	80.91
ETR	114.79
EP	128.32
TXU	144.11

** Typical bills are displayed in $/month, based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI 2007 Typical Bills and Average Rates Report as of January 1, 2007.

MAJOR CUSTOMERS:
Lone Star Steel Company (TX)
Tyson Foods Inc. (AR & TX)
Domtar, Inc (AR)
International Paper Company (TX)
Pilgrim Pride Corporation (TX)
Calumet Lubricants (LA)
General Motors Corporation (LA)
Libbey Glass Inc. (LA)
Cooper Tire & Rubber Company (AR)
Glad Manufacturing (AR)

- **Top 10 customers = 55% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **79 persons per square mile (U.S. = 95)**

AEP®

AMERICAN ELECTRIC POWER

Oppenheimer Office Visit

September 2, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

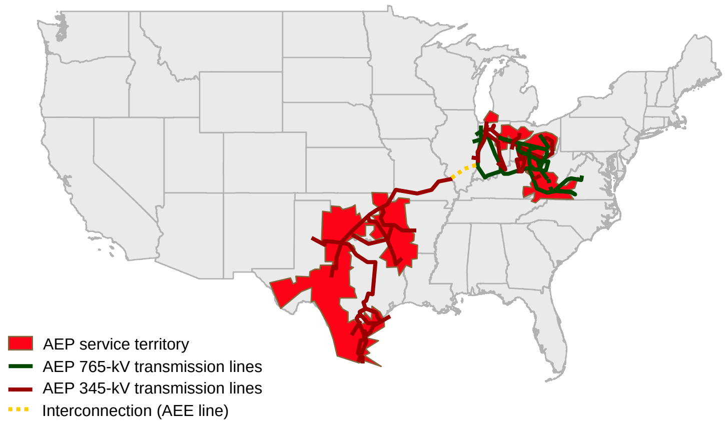
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

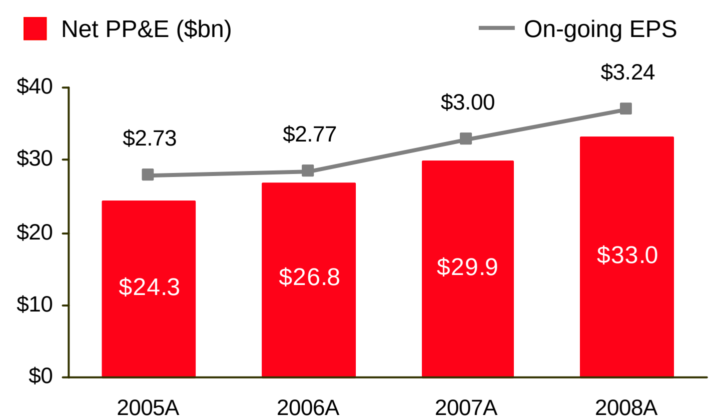


AEP's Leadership Position

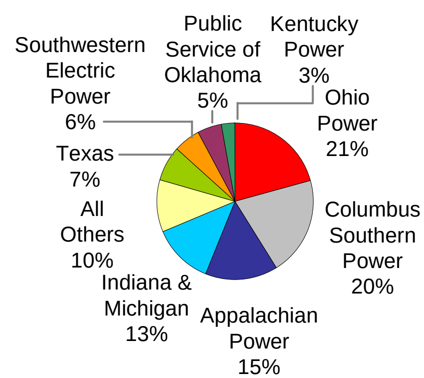
Transmission miles[1] ('000s)		Generation owned[1] (GW)		Electric customers[1] (mm)	
AEP	39.0	SO	42.6	EXC	5.4
SO	27.0	AEP	40.6 *	AEP	5.2
DUK	20.9	DUK	39.1	PCG	5.1
PCG	18.7	FPL	35.5	FPL	4.5
MidA	17.9	ETR	30.0	FE	4.5
ITC	15.1	D	27.1	SO	4.4
FE	15.1	EXC	24.8	DUK	4.0
Oncor	14.9	CPN	24.2	ED	3.6
EIX	12.0	NRG	24.0	XEL	3.4
PGN	11.0	PGN	21.8	PGN	3.1

* - AEP generation includes long-term PPAs and generation under construction

Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn

- *Highly diversified regulated utility earnings contribution*

[1] *Source: Company filings*
[2] *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8429 of 9556

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

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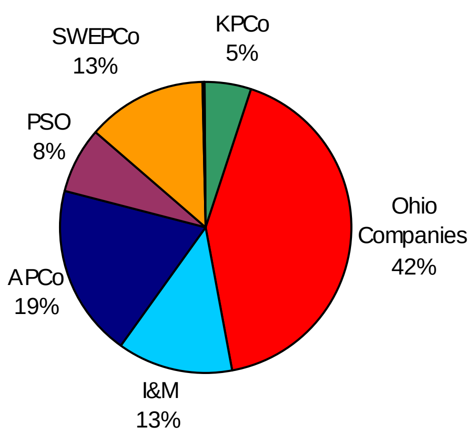
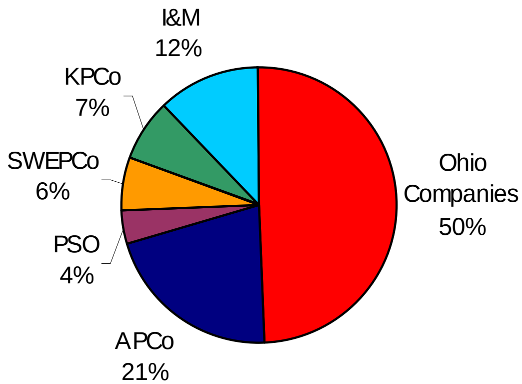
CO_2 Cost Recovery – Should Follow SO_2 & NOx

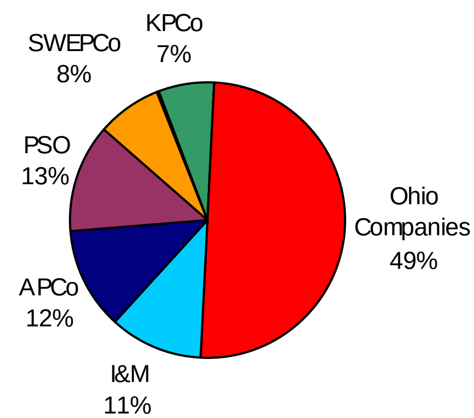
2008 AEP System CO_2 Emissions
163M tons



2008 AEP System SO_2 Emissions
637k tons



2008 AEP System NOx Emissions
248k tons



- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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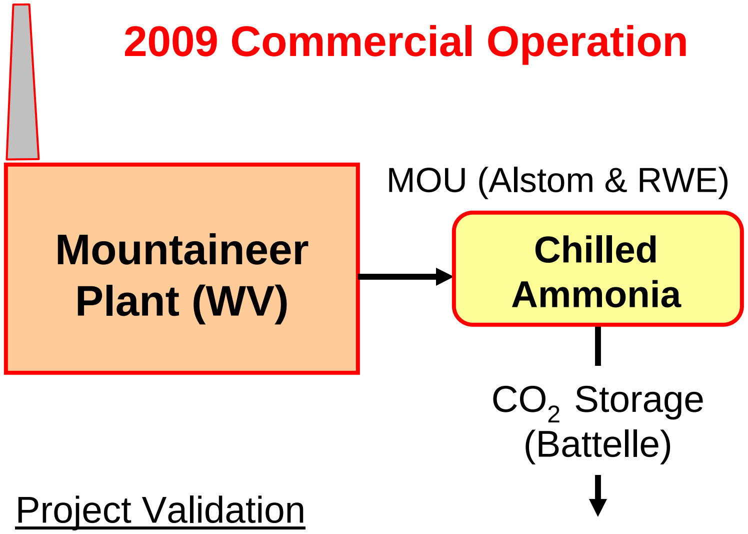
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- **Alstom "Chilled Ammonia" Technology**
- **20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)**
- **Located at the AEP Mountaineer Plant in WV**
- **100,000 - 300,000 tonnes CO_2 per year**
- **In operation 3Q 2009**
- **Geologic storage for CO_2**
- **Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection**

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - **Amine technologies are currently available in other industrial applications**
  - **Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches**
  - **High parasitic demand**
    - **Conventional Amine ~ 25-30%**
    - **Chilled Ammonia target ~ 10-15%**

Key Issues for CCS Development in the U.S.

- **Overcoming the 'economic' hurdle**
- **High up-front capital investment**
- **Commercial demonstration at large coal-fired power plants**
- **National standards for permitting of storage reservoirs**
- **Potential institutional, legal and regulatory barriers to carbon storage**

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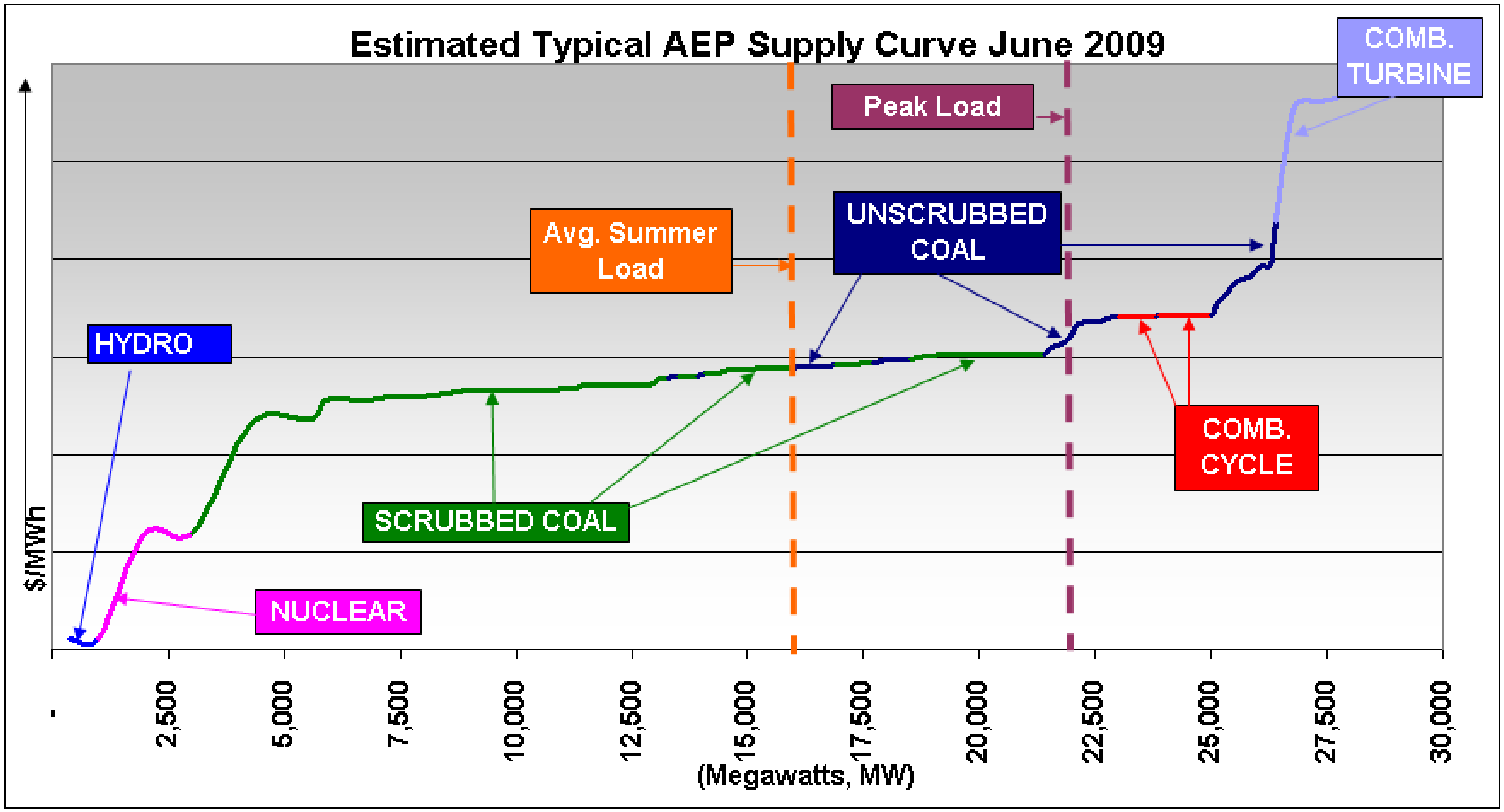
AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



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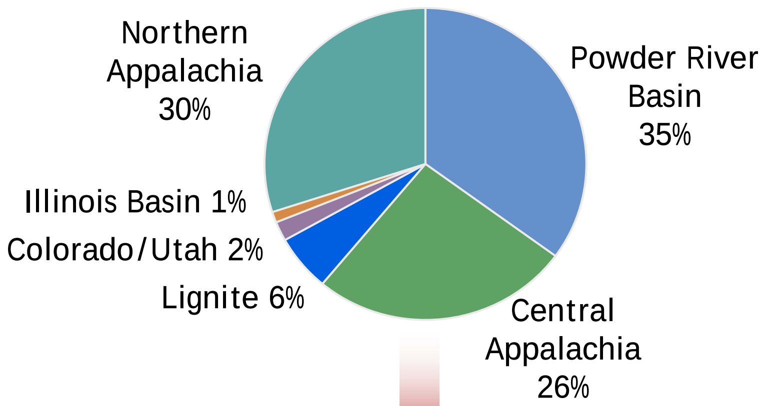
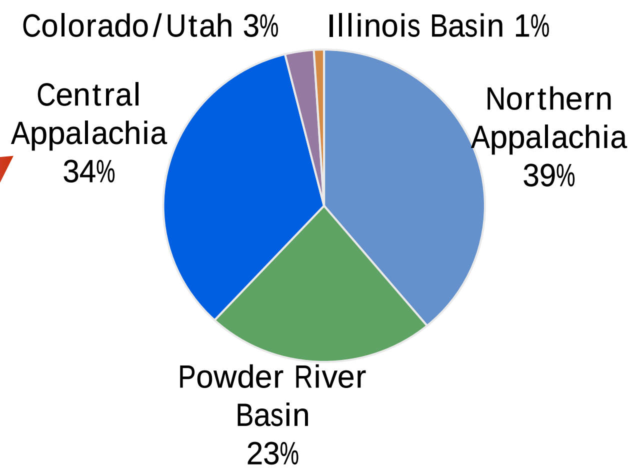
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

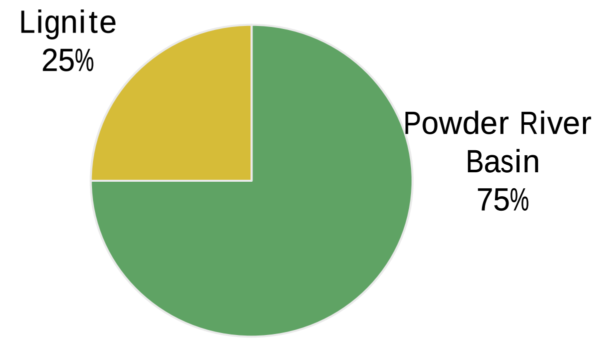
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

p.20

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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Overview of 2009 Guidance

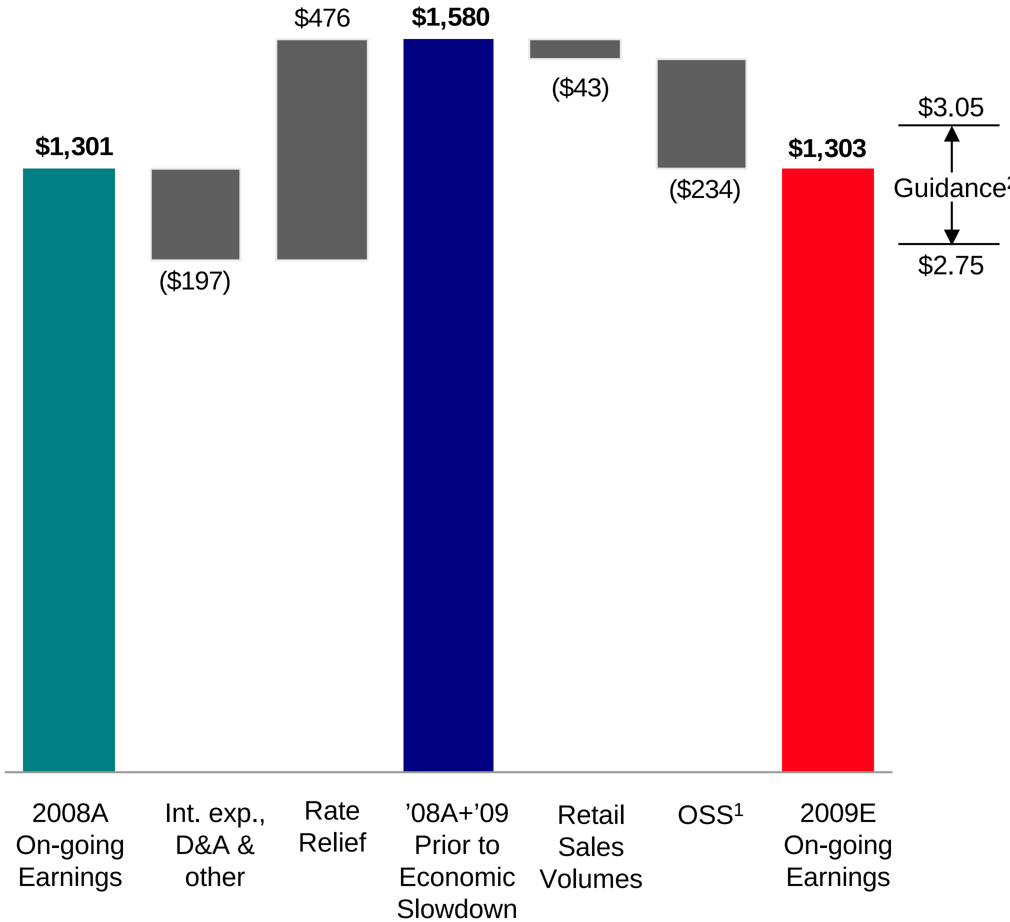
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax
[1] Net of sharing
[2] Assumes 2009 average shares outstanding ~ 450 million

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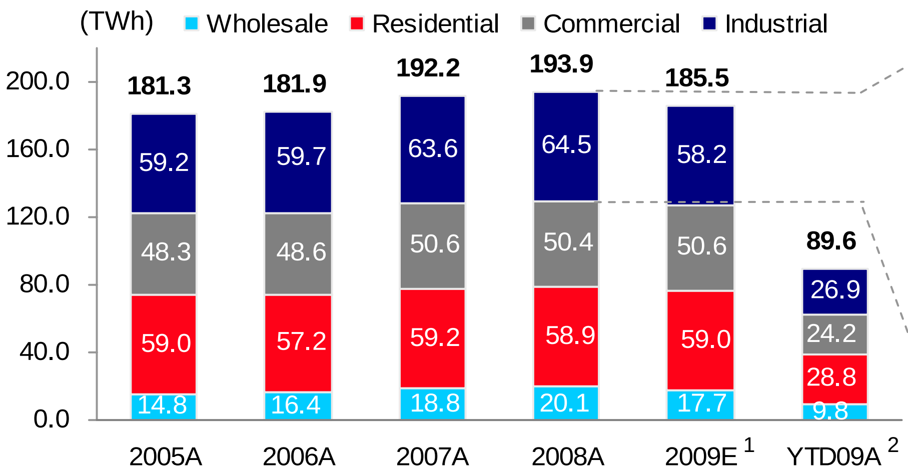
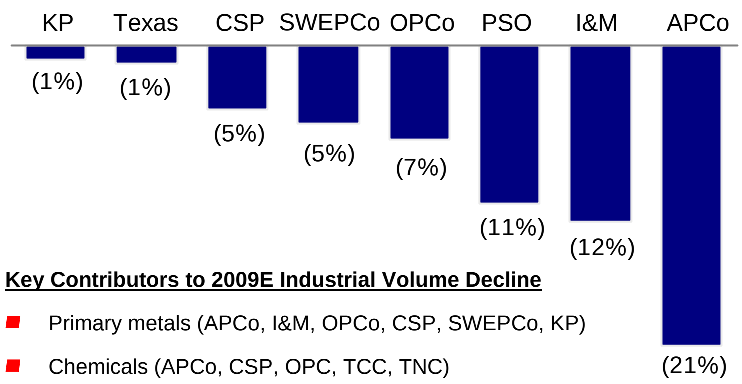
Key Drivers of 2009 Guidance: Retail Sales

Retail Load by Customer Class



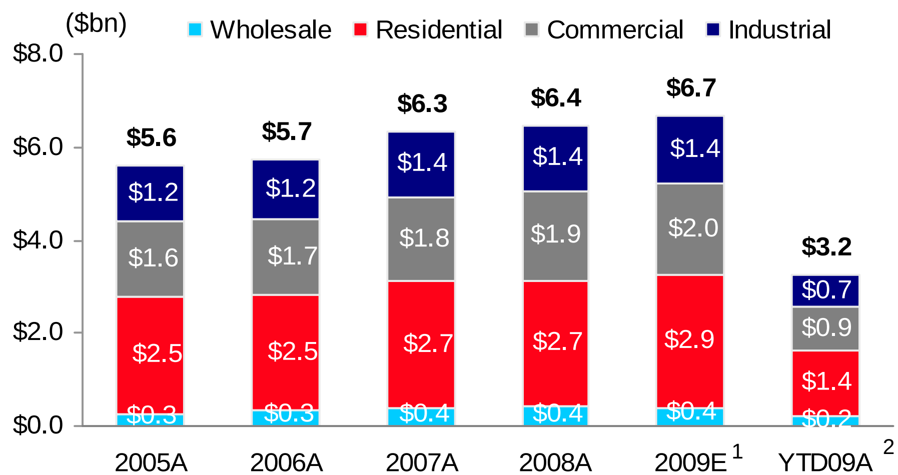
Forecast Drop in 2009 Industrial Sales

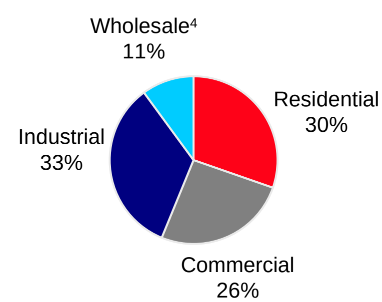


Key Contributors to 2009E Industrial Volume Decline

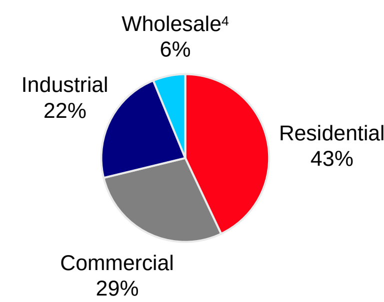
- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Chemicals (APCo, CSP, OPC, TCC, TNC)
- Paper (APCo, PSO, SWEPCo)
- Plastics & Rubber (APCo, CSP, OPCo, I&M)

Retail Base Revenue[3] by Customer Class





2008 Retail Load = 193.9 TWh



2008 Retail Base Revenue [3] = $6.4bn

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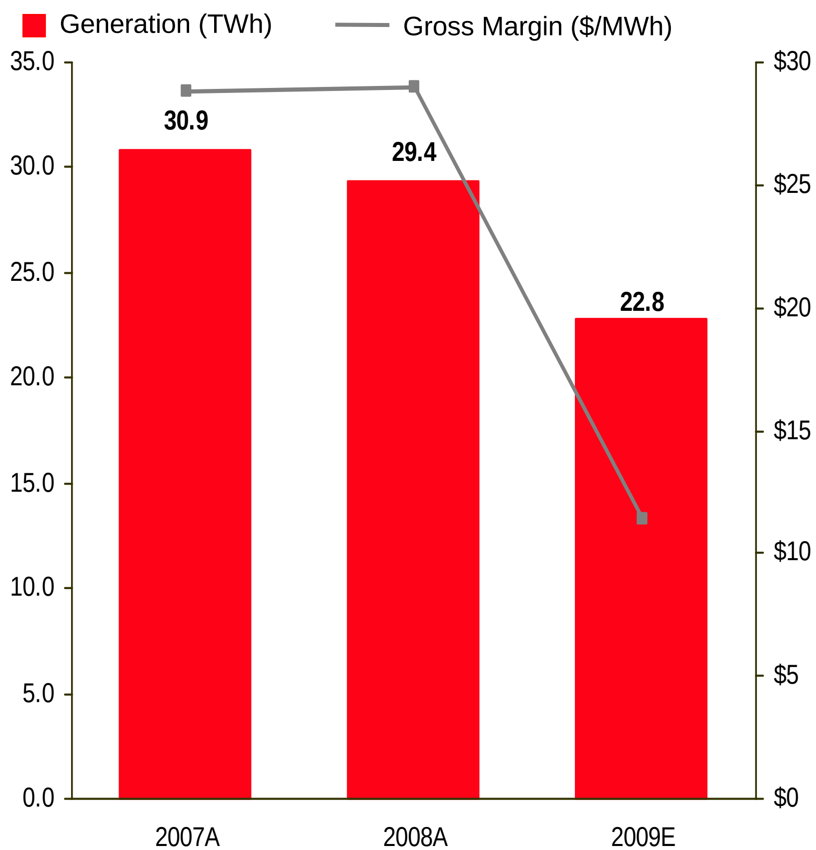
[1] 2009E assumes normalized weather
[2] YTD09A represents actual results through June 30, 2009

[3] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables
[4] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

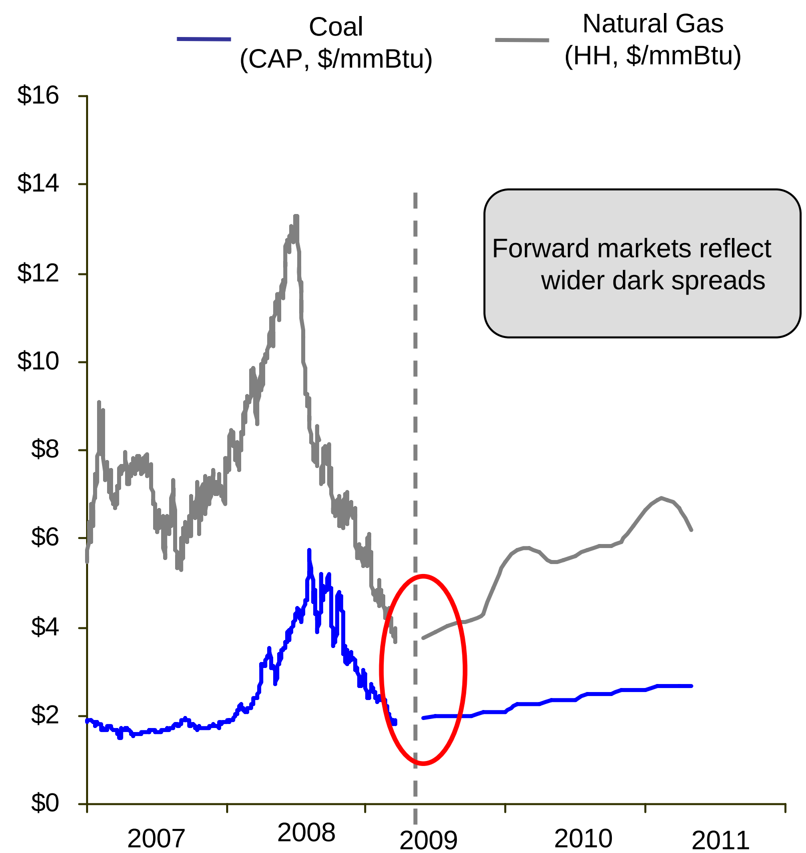
Key Drivers of 2009 Guidance: Off-System Sales

Off-System Sales Metrics



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260

Natural Gas and Central Appalachian Coal Prices



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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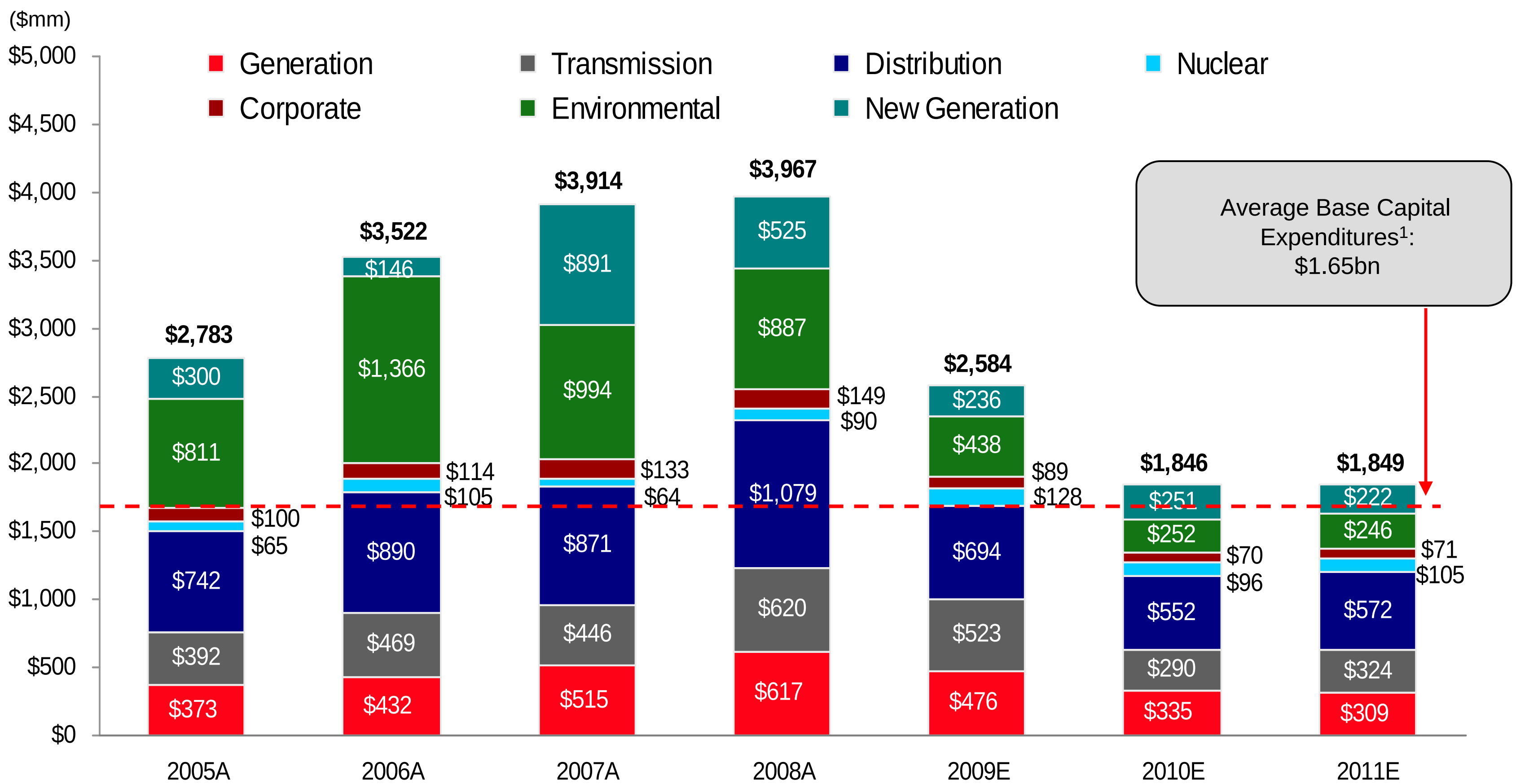
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

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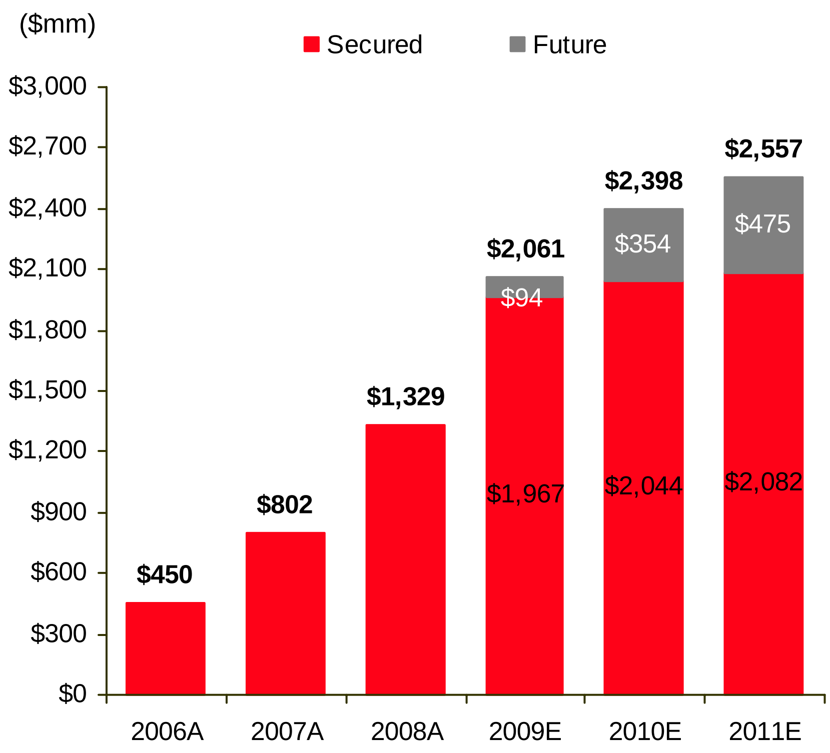
Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $77mm and $38mm was secured for 2010 and 2011, respectively, as of July 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ SWEPCo (AR) ($54MM) TX($75MM)
  - ✓ APCo VA ($169MM)
  - ✓ PSO ($30MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Rehearing Order	2010 ESP Appl.	2010 PUCO Rehearing Order	2011 ESP Appl.	2011 PUCO Rehearing Order	Cumulative ESP Appl.	Cumulative PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
(Incl. OVEC of $68.8M)								
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

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Summary Rate Case Information

APCo Virginia General Rate Case

On August 14, 2009 APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. (Docket #: PUE-2009-00030) A procedural schedule is pending from the VSCC. A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure - Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule TBD

Required Rate Relief - Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

SWEPCo Texas General Rate Case

On August 28, 2009 SWEPCo filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to recover concurrent financing costs related to the construction of the Stall and Turk plants as well as increased operating costs and enhanced distribution reliability spending. (Docket# 37364) An order is expected in 2010.

Projected Capital Structure - Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule TBD

Required Rate Relief - Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

Capital Investment Funding Plan

$ in millions

	Actual 2008	Projection 2009
Planned Capital Investment (Excluding AFUDC)	$ (3,967)	$ (2,584)
Planned Transmission Initiatives (JV Equity Contributions)	0	(49)
Dividend on Common Stock	(660)	(755)
Cash Sources (Uses)		
Cash from Operations	2,576	2,514
Proceeds from Sale of Assets	90	172
Common Stock Issued	159	1,763
Change in Debt, Net	2,266	(773)
Other	(231)	(498)
Change in Cash	233	(210)
Ending Cash Balance	$ 411	$ 201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

AEP AMERICAN ELECTRIC POWER

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

Long-term Debt Maturity Profile

($ in millions)
(as of June 30, 2009)

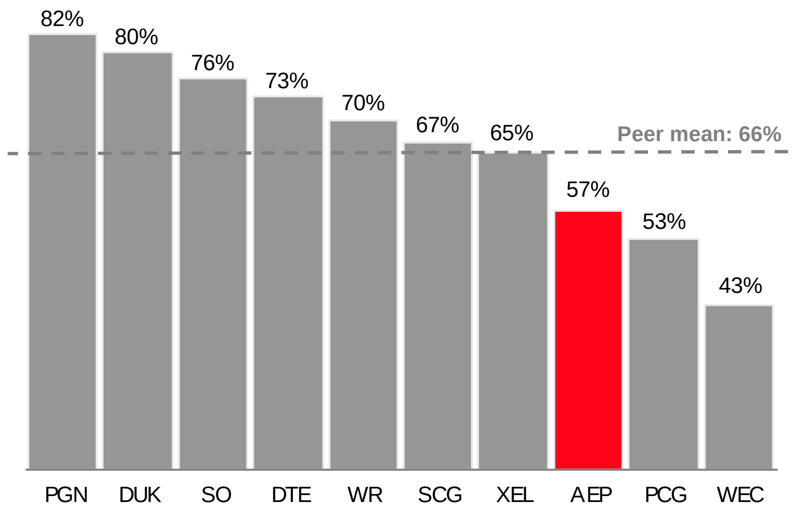
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

AEP AMERICAN® ELECTRIC POWER

Dividend Overview

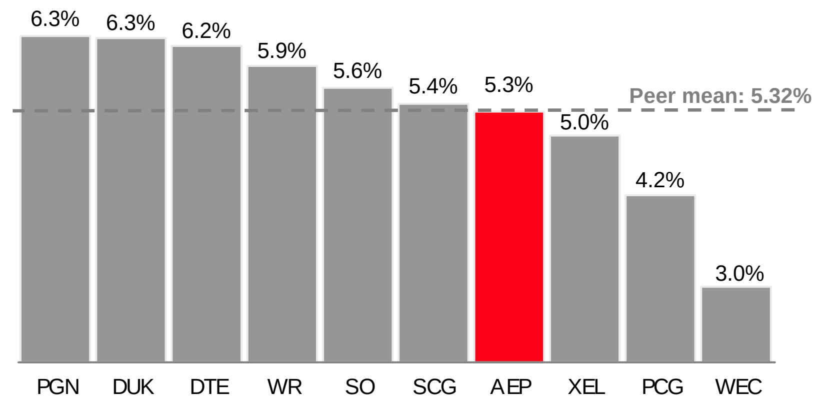
- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate
Source: Bloomberg & First Call earnings estimates as of 9/1/09

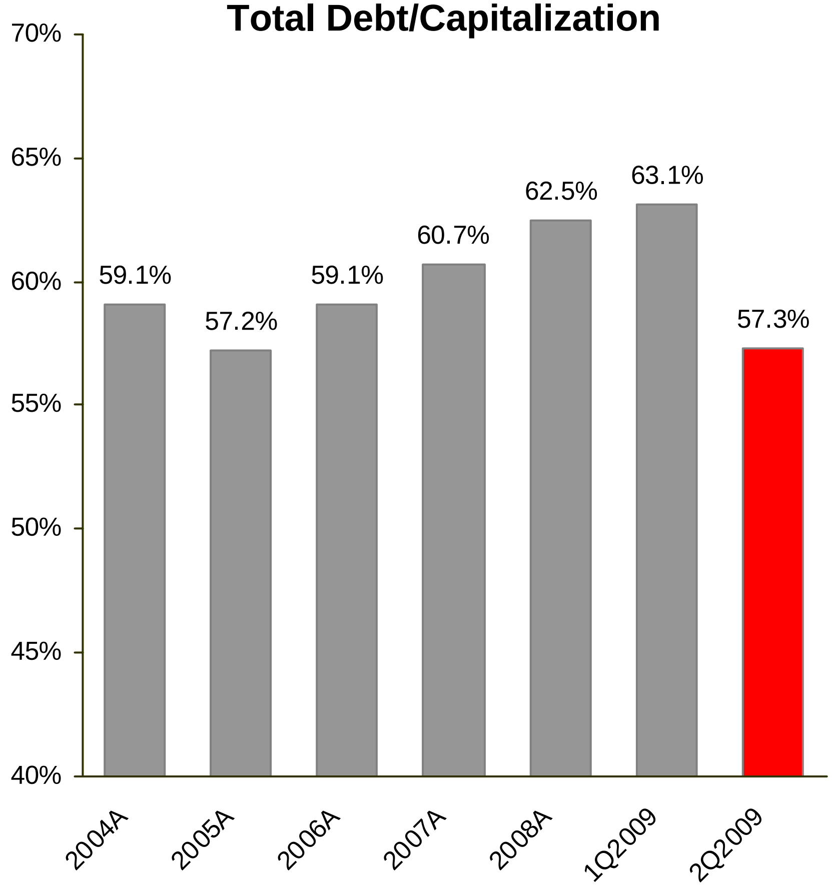
Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price
Source: ThomsonONE as of 9/1/09

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 6/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

AEP AMERICAN® ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

Pioneer — **COD: 2015**

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**

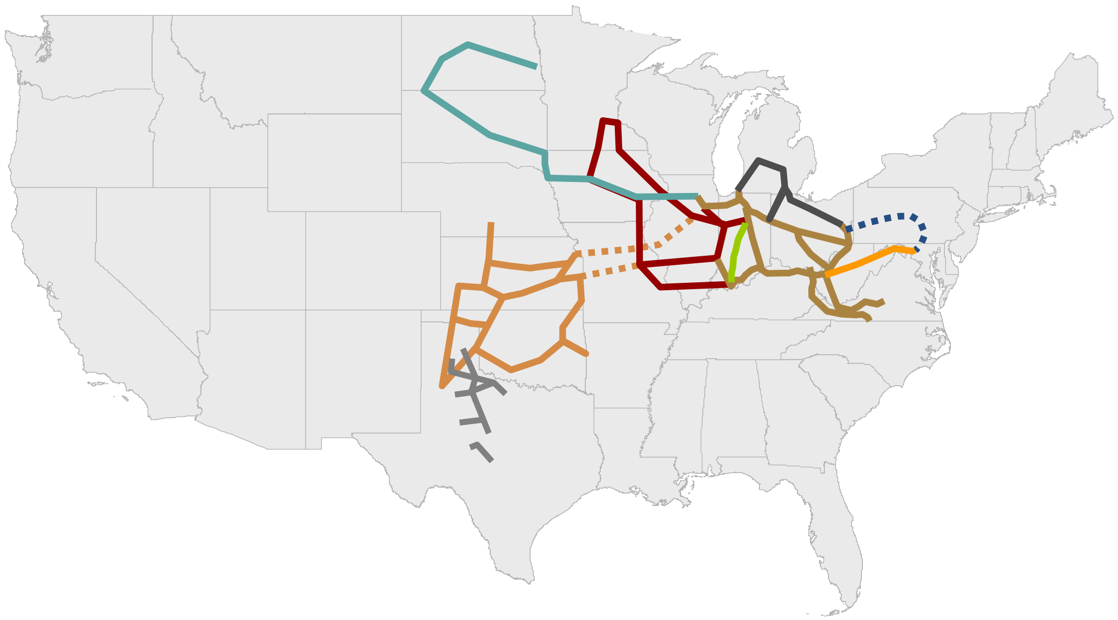
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013**

- *110 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

ETT — **COD: 2013**

- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**

- *700 miles of 765 kV*

PJM Projects

- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**

- *1000+ miles of 765 kV*

MISO Vision Plan

- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**

- *765 kV Backbone*

ETT — **COD: ~2018**

- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

AEP AMERICAN ELECTRIC POWER

Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

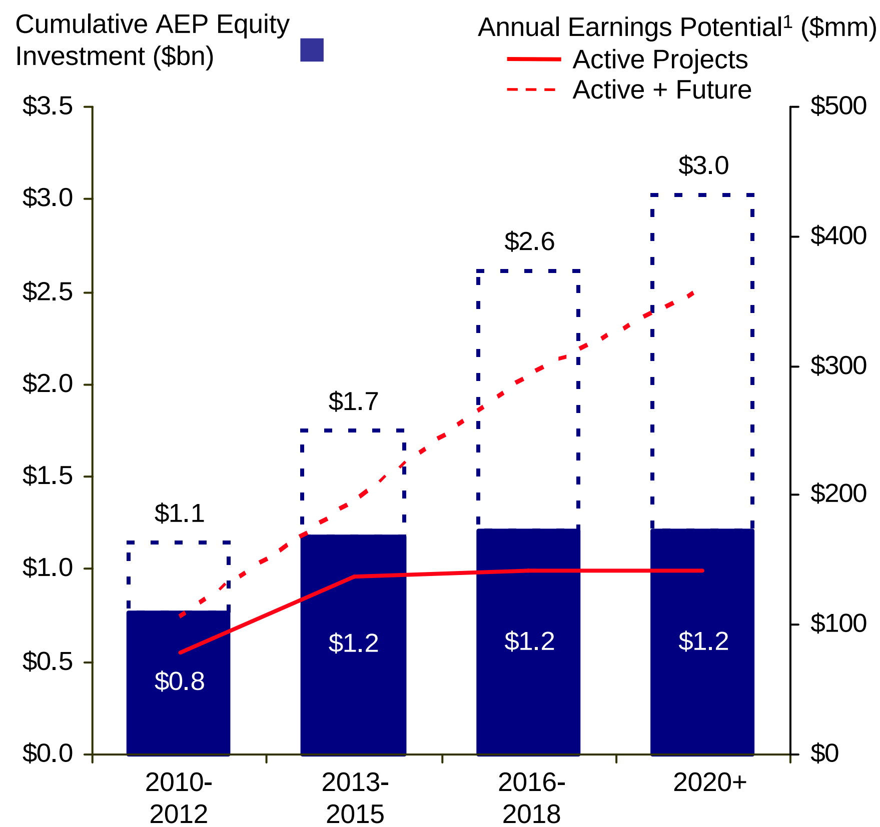
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

AEP AMERICAN ELECTRIC POWER

PENN Capital Management Office Visit

Columbus, OH

September 11, 2008

AEP AMERICAN ELECTRIC POWER®

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are canceled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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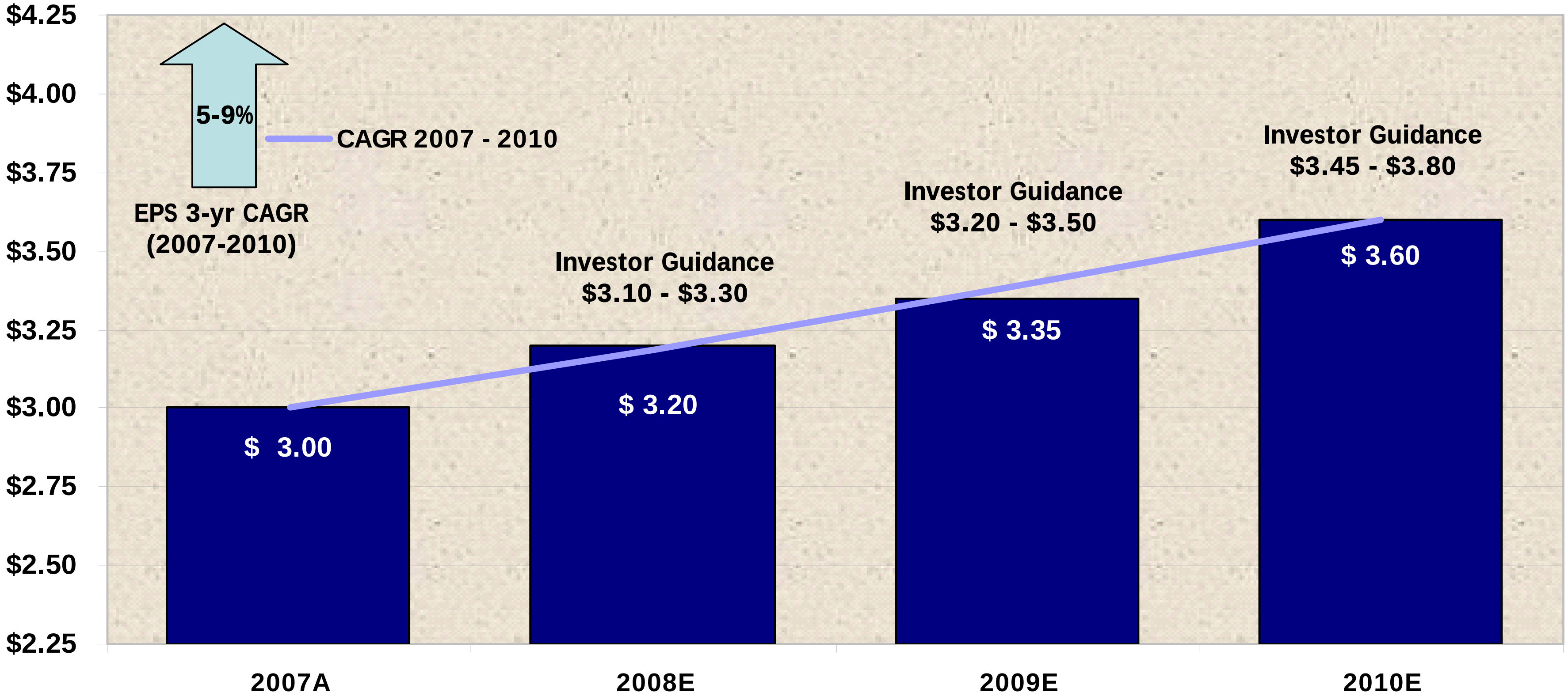
The AEP Value Proposition

Leveraging our vast energy platform with low-risk investments in infrastructure to enable sustainable growth.



AEP's ability to ensure a disciplined approach to capital investment allows us to sustainably grow earnings and shareholder value.

Detailed Ongoing Earnings Guidance

2007A: $3.00

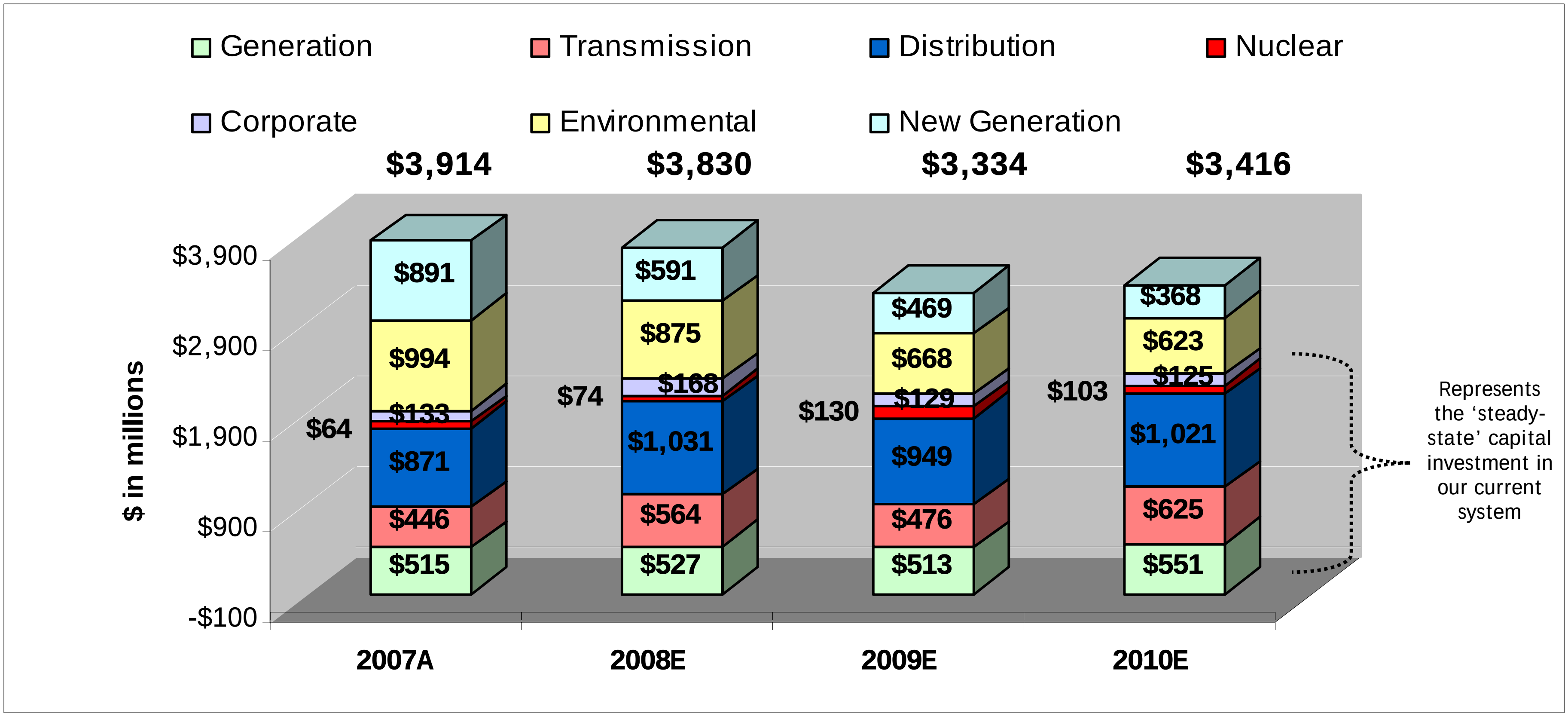
2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

4-Year Capital Investment Forecast



Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$583	$474	**$2,495**
I&M	$282	$386	$458	$497	**$1,623**
KPCo	$76	$127	$89	$106	**$398**
TCC	$212	$208	$186	$282	**$888**
TNC	$93	$120	$87	$91	**$391**
PSO	$303	$277	$257	$419	**$1,256**
SWEPCo	$511	$741	$710	$681	**$2,643**
CSP	$432	$404	$312	$308	**$1,456**
OPCo	$805	$635	$441	$411	**$2,292**
Other Companies	$488	$206	$211	$147	**$1,052**
Total Capex	**$3,914**	**$3,830**	**$3,334**	**$3,416**	**$14,494**

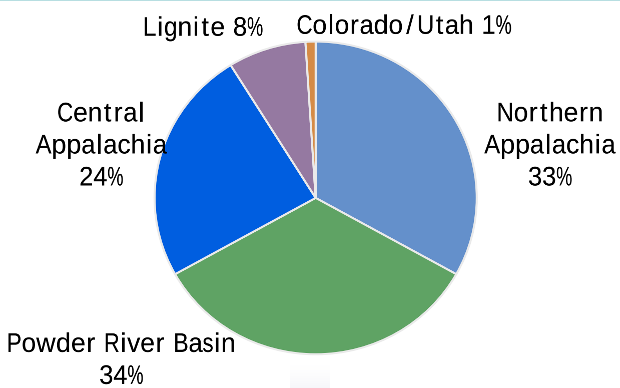
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

Coal Procurement – 2008 Projected

AEP burns approx. 76 million tons of coal per year

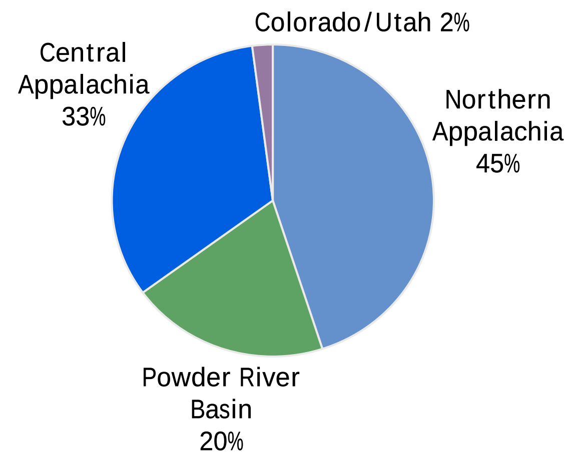
Total AEP System



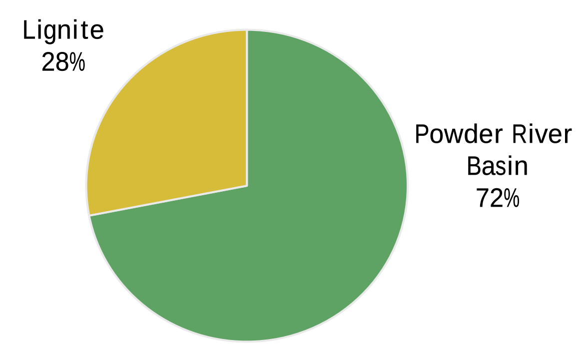
Coal Stats:

- > 95% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 20% price increase in 2008 based on 2007 actual results.

AEP East

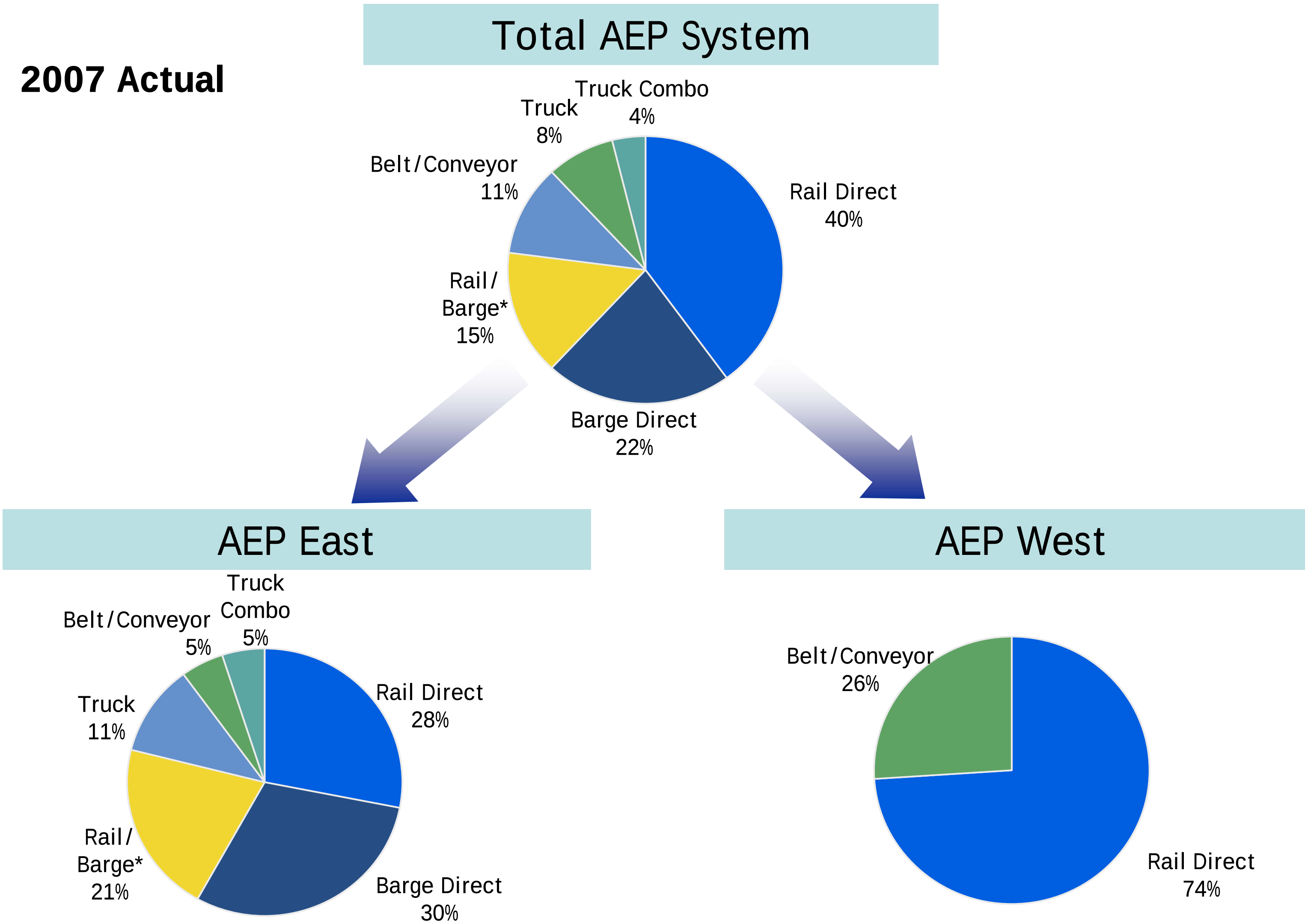


AEP West



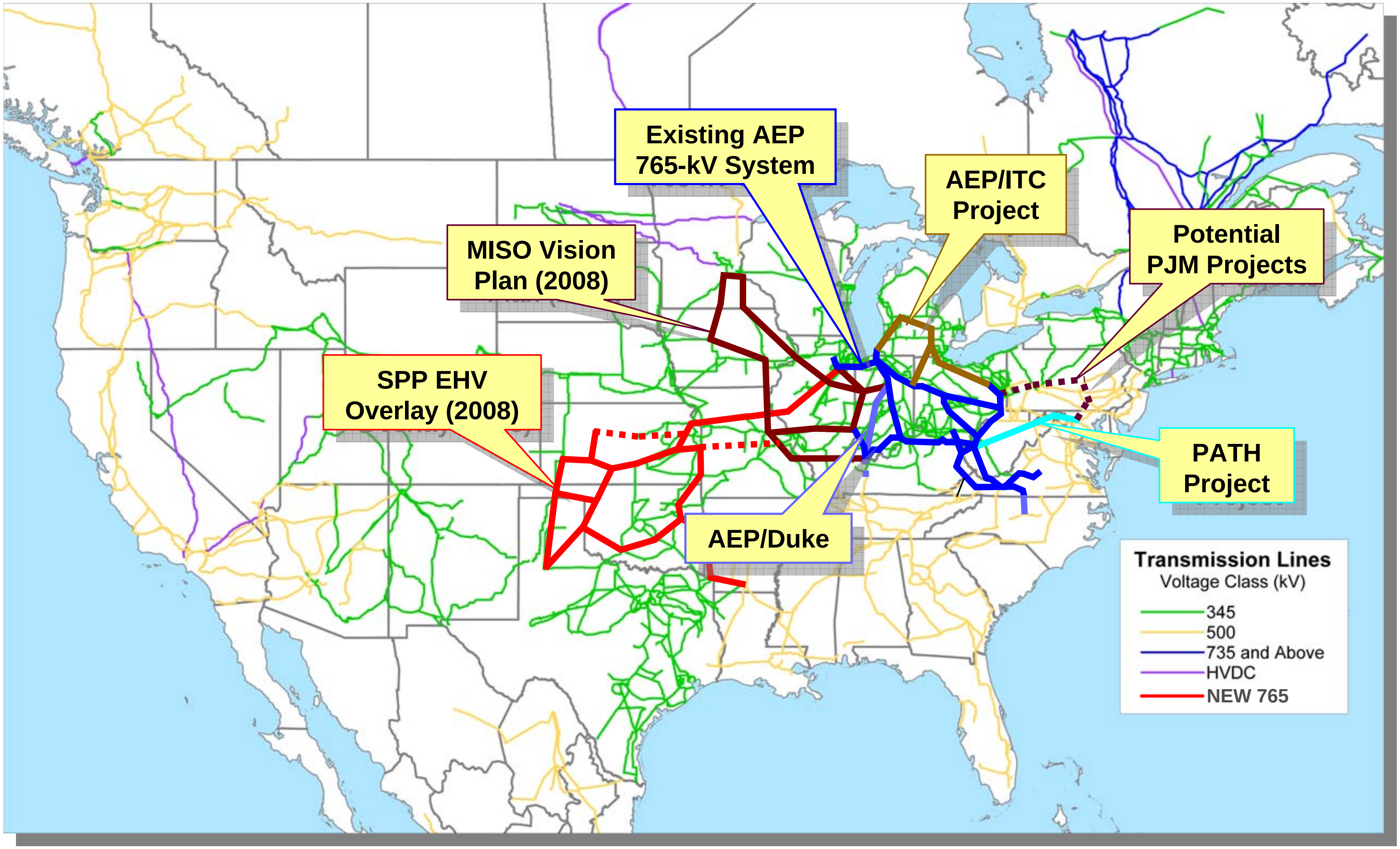
Coal Delivery

2007 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

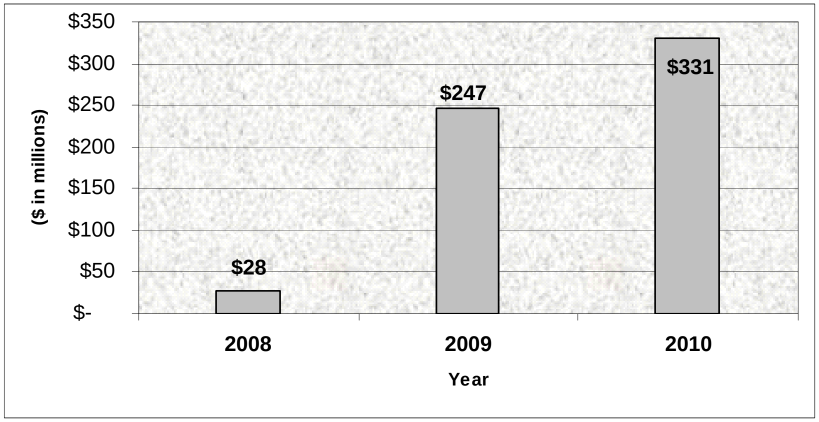
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Transmission – Investments and Earnings Contributions

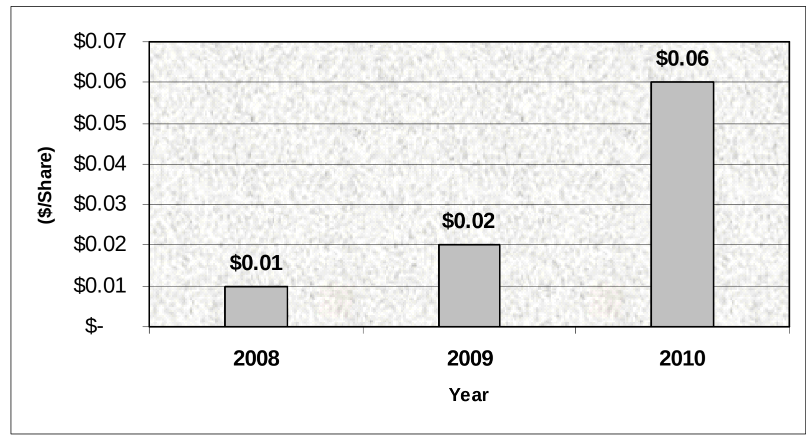
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

ETT Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

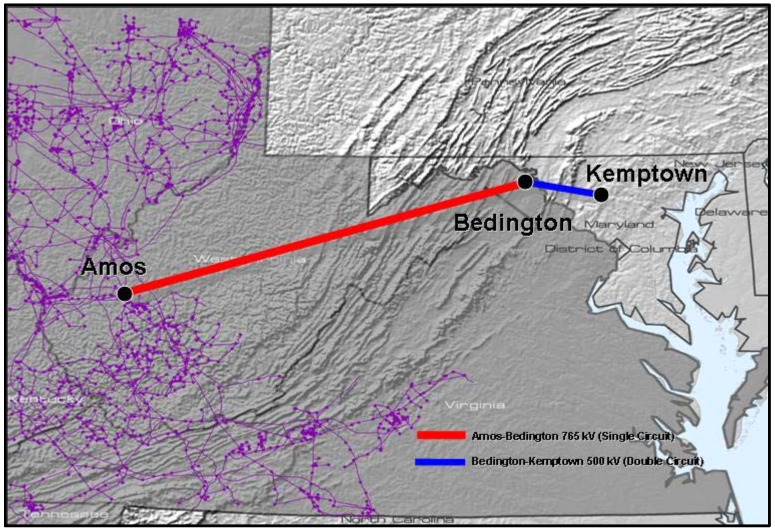
PATH Potomac-Appalachian Transmission Highline

Transmission will provide a near and long-term catalyst for earnings growth.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8461 of 9556

I-765™ Transmission in PJM: PATH

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Key Next Steps*
  - Siting Approval from WV and MD - 2010
  - Targeted Completion - 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MEHC

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner
  - Total initial investment of $70 million before ownership division
- *Next Steps*
  - Await PUCT approval of consortium proposal, which includes ETT's portion of 710 miles of new transmission at an estimated cost of between $1.5 billion and $1.7 billion
  - Anticipate transferring some project opportunities in 2008 after regulatory approvals obtained.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - ETA recently signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

I-765™ Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- *Overview*
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- *Benefits*
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- *Next Steps*
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2013-2017

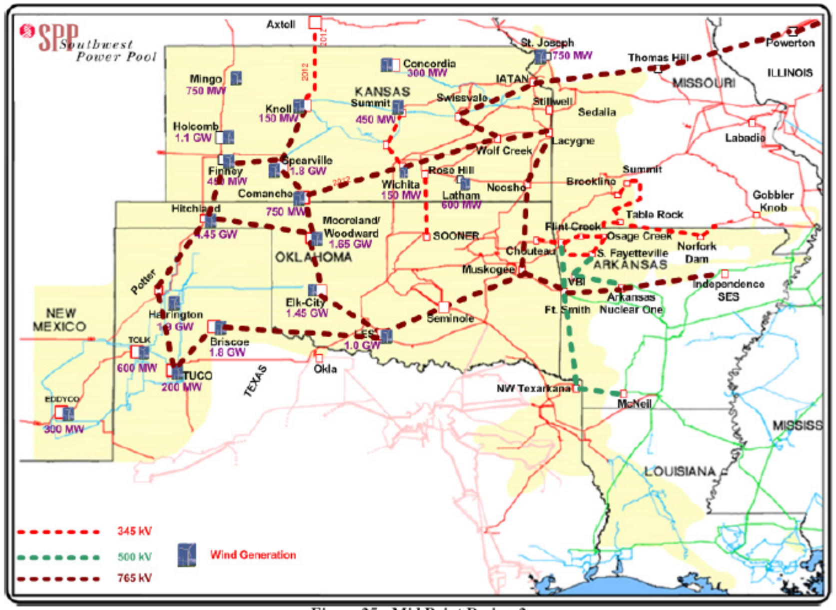


Figure 25: Mid Point Design 2

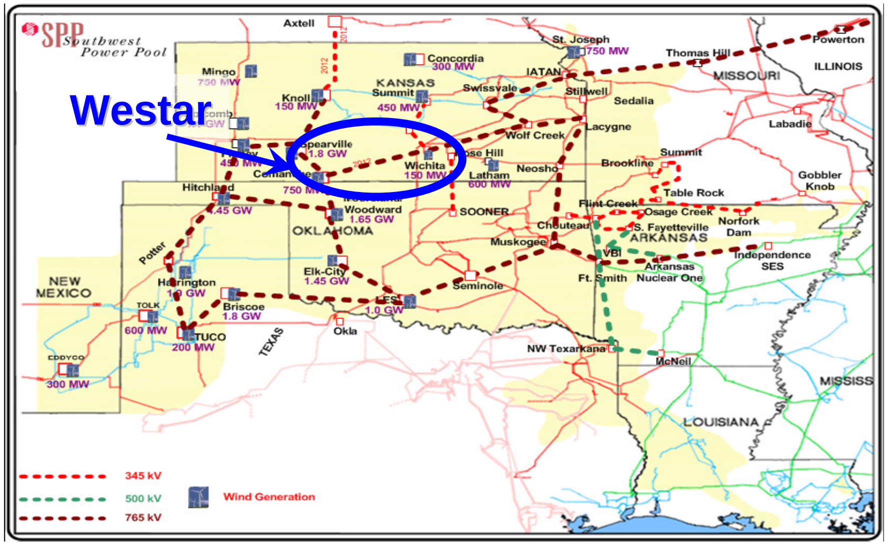
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ## *Overview*
  - On May 19, 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT)
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, Kan., west to a substation northeast of Dodge City, Kan., and then south to the Kansas border from Medicine Lodge, Kan.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013
  - AEP's ownership of the joint venture is 25%
  - AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - Other responsibilities will be handled by the partners or outsourced
- ## *Next Steps*
  - Filed CPCN – 2Q2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate Filing (postage stamp) – Fall 2008
  - SPP Cost Allocation Filing - 2009
  - Siting Approval – 2009
  - Estimated Completion – 2013



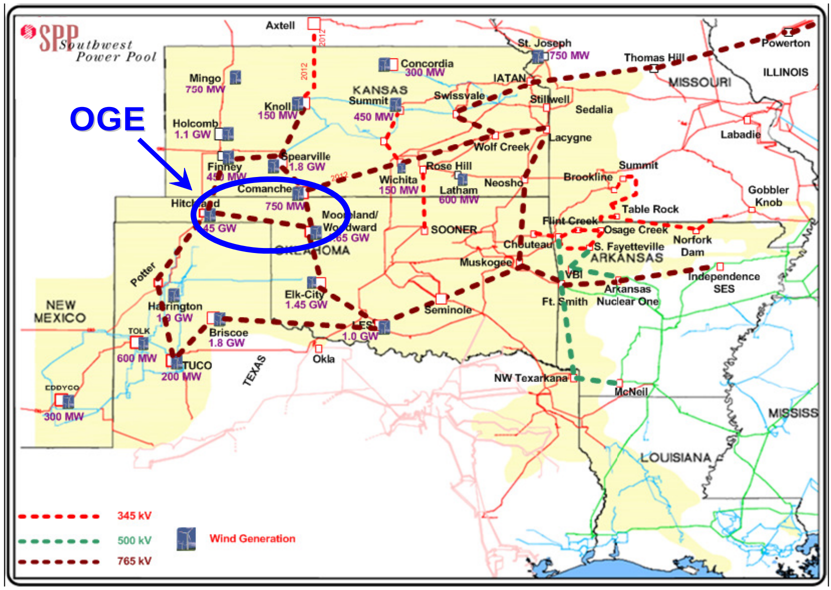
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETA JV with OGE

JV to build second segment of 765-kV transmission in SPP

- ❑ *Overview*
  - ❑ On July 15, 2008, ETA signed an agreement with OGE Energy Corp. to form a joint venture
  - ❑ The JV is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, that will link into OGE's station at Woodward and then extend west to a new station that will be built near Guymon, OK.
  - ❑ The project will provide enhanced electricity transport in Oklahoma and support expansion of renewable electricity generation in the region
  - ❑ Project is expected to cost approximately $500 million (based on SPP estimates) and be in-service by 2013
  - ❑ AEP's ownership of the joint venture is 25%
  - ❑ AEP obligations include oversight of 765-kV Engineering, 765-kV Technology and Project Management
  - ❑ Other responsibilities will be handled by the partners or outsourced
- ❑ *Next Steps*
  - ❑ File CPCN –2008
  - ❑ SPP RTO EHV Overlay Approval – 2009
  - ❑ FERC Formula Rate – Fall 2008
  - ❑ SPP Cost Allocation Filing – 2009
  - ❑ Siting Approval – 2009
  - ❑ Estimated Completion – 2013

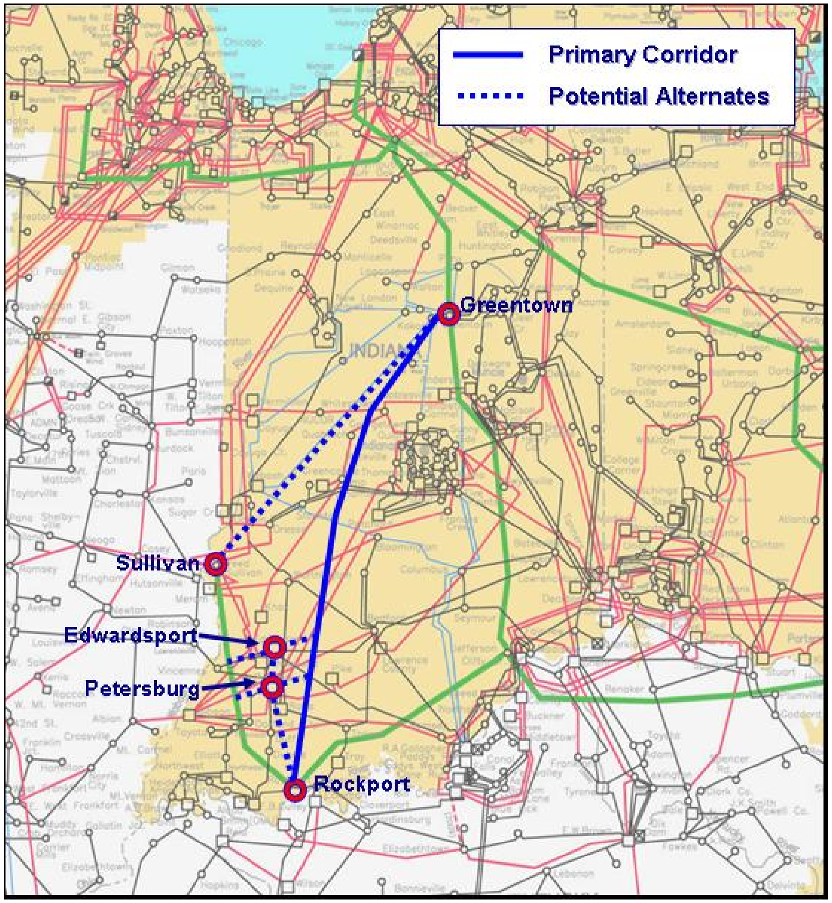


Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Pioneer Transmission, LLC

- *Overview*
  - On August 11, 2008, AEP & Duke formed a joint venture to build and own a 765-kV transmission line. Pioneer Transmission LLC is a 50/50 joint venture between the two companies.
  - The primary project involves the construction of approximately 240 miles of 765-kV lines extending from AEP's Rockport substation east of Evansville, Indiana with Duke's Greentown substation near Kokomo, Indiana.
  - Project is expected to cost approximately $1 billion, but final costs will depend on the routing of the line, equipment and commodity costs. AEP's share of the costs will be 50% of the total.
  - In-service date will be determined by the MISO and PJM planning process, with earliest possible completion in the 2014-2015 timeframe.
- *Next Steps*
  - Submit proposal to PJM & MISO for consideration in their transmission expansion plans
  - FERC filing for rate approval – 2008
  - Estimated Completion – 2014-2015



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

I-765TM Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

Overview

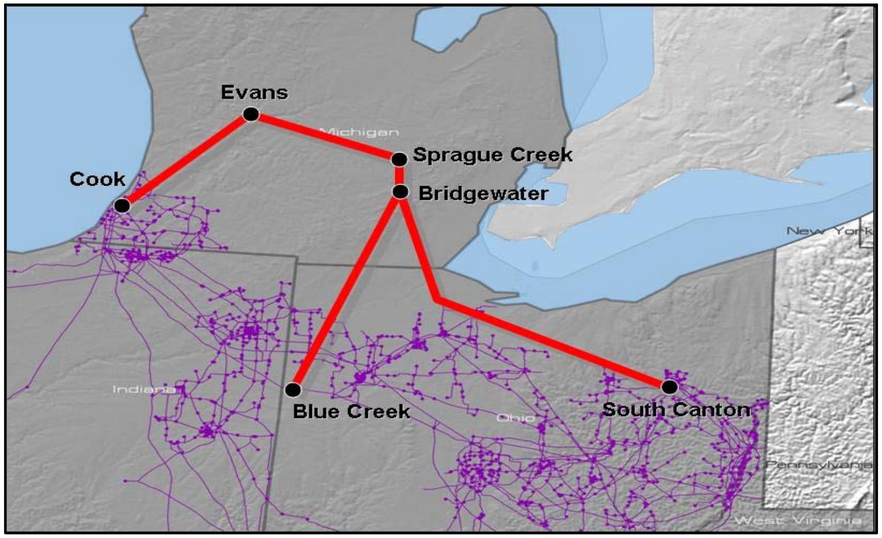
- ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
- Study was released Q3 2007
- 700 miles of 765-kV line in Ohio and Michigan
- $2.6 billion investment (before ownership division)
- AEP and ITC are in discussions to form a Joint Venture

Benefits

- Up to 5,000 MW improved transfer capability
- Reduces network line losses by 250 MW

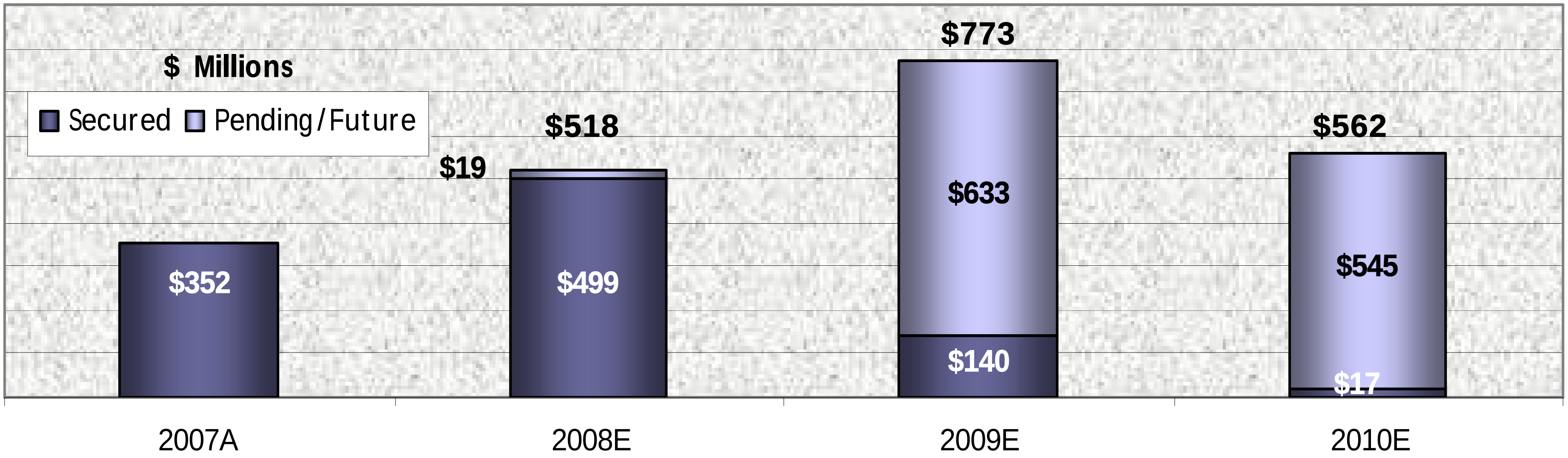
Next Steps

- Agreement on JV (AEP/ITC) - Summer 2008
- JV Formation - 2008
- MISO and PJM Review/Approval - 2009
- FERC Formula Rate & Cost Allocation Filing - 2009
- Siting Approval – 2011-2012
- Estimated Completion – 2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Incremental Rate Relief



- 96% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Construction Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo – Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery, SWEPCo - LA Formula Rate Plan, KPCo Marginal Loss Recovery, TCC/TNC TCOS and Rate Case Expense Recovery.
- 2008 Pending: Virginia base case rates subject to refund ($208MM requested).
- 2009 Pending: Virginia base case ($208MM requested), Indiana base case ($129MM requested), Oklahoma base case ($132.6MM requested), Ohio ESP, other cases yet to be filed.

Secured $499MM of $518MM for 2008

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Virginia - Fuel Factor												
Intervenor Testimony		08/28/08										
Interim Rates Effective			09/01/08									
Staff Testimony			09/09/08									
Rebuttal Testimony			09/16/08									
Hearing			09/23/08									
Expected Order					Expected Order							
Virginia - E&R Filing												
Intervenor Testimony		08/13/08										
Staff Testimony		08/27/08										
Rebuttal Testimony			09/03/08									
Hearing			09/17/08									
Expected Order						Order						
Virginia - Base Rate Case												
Intervenor Testimony			09/26/08									
Staff Testimony				10/10/08								
Rebuttal Testimony				10/20/08								
Rates Effective *				10/28/08								
Hearing				10/29/08								
Expected Order							Expected Order					

* Subject to refund, with interest

Current Regulatory Calendar

	2008						2009					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Indiana - Base Rate Case												
Staff/Intervenor Testimony			09/02/08									
Rebuttal Testimony				10/15/08								
Hearing Begins						12/1/08						
Expected Order												Expected Order
Ohio - ESP Filing												
Company Testimony Filed	07/31/08											
Intervenor Testimony				10/17/08								
Staff Testimony				10/24/08								
Hearing Begins					11/03/08							
Expected Order						Order						
Oklahoma - Base Rate Case												
Company Testimony Filed	07/11/08											
Staff/Intervenor Testimony				10/29/08								
Rebuttal Testimony					11/19/08							
Settlement Conference						12/01/08						
Hearing Begins						12/08/08						
Rates Effective *							01/08/09					

* Subject to refund, with interest

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery
- PSO Red Rock Cost Recovery
- SWEPCo Turk Plant Filing in Louisiana and Texas – construction approval
- SWEPCo Stall Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- AEP Ohio ESP Filing
- I&M - Indiana Base Rate Case
- PSO – Oklahoma Base Rate Case
- APCo - Virginia Base Rate Case
- APCo – Virginia E&R Surcharge Filing
- SPP OATT Formula Rate Filing
- PJM OATT Formula Rate Filing
- SWEPCo Stall Plant Filing in Arkansas

AEP Ohio Electric Security Plan

- On July 31, 2008, in conjunction with the requirements of SB221, AEP Ohio filed an Electric Security Plan with the PUCO on behalf of CSPCo and OPCo.
- The filing includes the following key components:
  - Energy Efficiency and Demand Response
  - Renewable Energy
  - gridSMART℠ Phase 1
  - Distribution Reliability Enhancement
  - Economic Development
  - Provider of Last Resort
- The proposed rate plan results in an annual increase of approximately 15 percent on customers' total bills.
- The filing seeks to recover changes in fuel and environmental expenses relative to levels reflected in current rates.
- Intervenor testimony is due October 17, Staff testimony is due October 24 and the public hearing commences on November 3, 2008. We anticipate an order at the end of 2008.

Highlights of AEP Ohio's ESP Filing

		2009 CSP	2009 OPCo	2010 CSP	2010 OPCo	2011 CSP	2011 OPCo	Source
		Incremental Proposed Revenue		Incremental Proposed Revenue		Incremental Proposed Revenue		
Note 1	**Total FAC**	**147.9M**	**66.6M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
	Non-FAC							
Note 2	Environmental Capital	26.0M	84.0M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 3	Non-FAC Generation	14.2M	41.8M	14.6M	44.7M	15.0M	47.8M	Exhibit DMR-1
Note 4	POLR	93.6M	21.2M	0.0M	0.0M	0.0M	0.0M	Exhibit DMR-1
Note 5	Distribution	23.8M	21.2M	25.5M	22.6M	27.3M	24.1M	Exhibit DMR-1
Note 6	EE/DR	13.6M	16.8M	14.8M	17.8M	9.6M	11.8M	Exhibit DMR-1
Note 7	Other	-80.7M	-27.1M	0.0M	0.0M	22.8M	15.2M	Exhibit DMR-1
	Total Non-FAC	**90.5M**	**157.8M**	**54.9M**	**85.1M**	**74.7M**	**98.9M**	Exhibit DMR-1
	Total Increase	**238.4M**	**224.4M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit DMR-1
		Other Components		**Other Components**		**Other Components**		
Note 1	**Deferred Fuel**	**111.7M**	**300.1M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
	Carrying Charges on Dfd Fuel	**6.2M**	**16.7M**	**TBD**	**TBD**	**TBD**	**TBD**	Exhibit LVA-1
Note 8	**Economic Development**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	**25.0M**	**0.0M**	JH Test P16

Note 1: AEP Ohio requested phase-in of proposed incremental FAC expenses during the three-year ESP period. Additionally, there will be a periodic true-up of the current period actual FAC to what was recovered in rates for that period. This will produce on-going periodic under/over recoveries of FAC costs for the period that have not been estimated for 2010 or 2011.

Note 2: Represents capital carrying cost on environmental facilities not currently reflected in rates. Exhibits PJN-8 &PJN-10 provides calculation of environmental carrying cost and components of the carrying cost rate applied to the capital expenditures, respectively.

Note 3: We requested a 3% & 7% per year increase in non-FAC generation for CSP & OPCo, respectively, consistent with the RSP increases. Exhibit PJN-8 shows the capital carrying cost on incremental environmental facilities forecasted for 2009. Exhibit PJN-10 provides the calculation and components of the carrying cost rate applied to the capital expenditures.

Note 4: Represents the Provider of Last Resort charge which is addressed in the testimony of Craig Baker starting on page 25.

Note 5: Requested an annual 7% & 6.5% per year increase in Distribution for CSP & OPCo, respectively. Exhibit DMR-4 shows expected O&M & carrying charge cost of capital for reliability and in the case of CSP, gridSMART, for the 2009-2011 time period. The carrying charge costs are provided on Exhibit PJN-10.

Note 6: Represents estimated costs to provide AEP-sponsored customer demand response & energy efficiency programs. These costs are discussed in the Sloneker testimony starting on page 18.

Note 7:

	2009 CSP	2009 OPCo	2011 CSP	2011 OPCo
Expiration of Special Contract	-$22.7M	-$27.1M		
Reg Asset Surcharge	-$54.2M		22.8M	15.2M
Other	-$3.8M	$0.0M		
Total Other	-$80.7M	-$27.1M	$22.8M	$15.2M

A special contract expires 12/31/08 and the customer will go on the standard tariff.
The revenue reduction associated with the elimination of the reg asset surcharge in 2009 will be offset by the reduction in related amortization.
Other of $3.8M represents the expiration of monthly line extension surcharges.

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306). Order is expected in June 2009.

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1	*
Rate of Return		8.10%	
Operating Income Requirement	$	162.6	
Pro-Forma Operating Income	$	112.3	
Difference	$	50.2	
Revenue Conversion Factor		1.64	
Revenue Deficiency	$	82.4	
Reliability Enhancement Tracker	$	28.9	
DSM / EE Tracker	$	3.8	
Off-System Sales Margins Tracker	$	(48.0)	
PJM Tracker	$	45.1	
Environmental Compliance Tracker	$	16.3	
Total Required Rate Relief	$	128.5	

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Procedural Schedule

January 31, 2008	Case filed
May-June 2008	Hearing presenting I&M Case-In-Chief
September 2, 2008	Public & Intervenors' filing of Cases-In-Chief
October 15, 2008	Filing of rebuttal by I&M
December 1, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Summary Rate Case Information

PSO Oklahoma General Rate Case

On July 11, 2008, PSO filed a general base rate case with the Oklahoma Corporation Commission (OCC) requesting an increase of $132.6 million. (Docket #: PUD 200800144). Order is expected in 1Q2009.

Projected Capital Structure - Company Position (2/29/08)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	55.57%	6.60%	3.67%
Preferred Stock	0.33%	4.02%	0.01%
Common Equity	44.10%	11.25%	4.96%
Total	100%		8.64%

Procedural Schedule

July 11, 2008	Case filed
October 29, 2008	Staff and intervenor testimony
November 19, 2008	PSO rebuttal testimony
December 8, 2008	Hearing commences
January 8, 2009	Interim rates effective, subject to refund
1Q 2009	Final order

Required Rate Relief - Company Position (2/29/08)

($ in millions)

Rate Base	$	1,545.2 *
Rate of Return		8.64%
Operating Income Requirement	$	133.5
Pro-Forma Operating Income	$	53.0
Difference	$	80.5
Revenue Conversion Factor		1.647045
Total Required Rate Relief	$	132.6

* - rate base as of February 29, 2008, updated for known and measurable adjustment through August 31, 2008

Summary Rate Case Information

APCo Virginia General Rate Case

On May 30, 2008, Appalachian Power filed a general base rate case with the SCC requesting an increase of $207.9 million. Interim rates can go into effect on October 28, 2008, subject to refund with interest. (Docket #: PUE-2008-00046)

Projected Capital Structure - Company Position (6/30/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	2.97%	4.79%	0.14%
Long-Term Debt	55.52%	6.35%	3.53%
Preferred Stock	0.32%	4.35%	0.01%
Common Equity	41.02%	11.75%	4.82%
Other Items	0.17%	8.63%	0.02%
Total	100%		8.52%

Procedural Schedule

May 30, 2008	Case Filed
September 26, 2008	Respondents Testimony
October 10, 2008	Staff Testimony
October 20, 2008	APCo Rebuttal Testimony
October 28, 2008	Rates Effective, Subject to Refund
October 29, 2008	Hearings

Required Rate Relief - Company Position (12/31/07)

($ in millions)

Rate Base	$	2,415.1 *
Rate of Return		8.52%
Operating Income Requirement	$	205.7
Adjusted Operating Income	$	79.2
Difference	$	126.5
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	207.9

* - rate base as of December 31, 2007, updated for known and measurable changes through June 30, 2008

Regulatory Activity Underway

APCo-Virginia E&R Filing

On May 30, 2008, Appalachian Power filed the third tranche of E&R surcharge filings with the SCC, requesting a $66.5 MM increase for environmental and reliability costs incurred during the period October 1, 2006 through December 31, 2007, with a proposed one year recovery period commencing January 1, 2009. Respondent testimony was received August 13, Staff testimony was received August 27, Rebuttal testimony is due September 3 and a hearing will commence on September 17.

Summary of APCo's E&R filings:

E&R Tranche:	Case Number	Cost Incurred :	Recovery Period:	Amount:
I	PUE-2005-00056	7/1/2004 thru 9/30/2005	12/1/2006 thru 11/30/2007	$21.3 million
II	PUE-2007-00069	10/1/2005 thru 9/30/2006	1/1/2008 thru 12/31/2008	$48.9 million
III	PUE-2008-00045	10/1/2006 thru 12/31/2007	Proposed 1/1/09 thru 12/31/09	$66.5 million

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

PJM OATT Formula Rate Filing

- On July 31, 2008, the seven AEP East companies filed with the FERC to update the Open Access Transmission Tariff (OATT) rate and implement a formula transmission rate that will be updated annually to keep rates current with transmission investment.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is \$507MM and the new revenue requirement requested is \$606MM. Approximately \$31MM of the increase relates to 3rd party and Ohio and the rest, if approved, would be recovered through retail jurisdictional filings in the other east jurisdictions.
- We requested an effective date of October 1, 2008 for the revised tariff, which the FERC may suspend for an additional five months.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008. A draft air permit approval was released for public comment on August 11, 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on April 29, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- The PUCT issued a written order approving construction of the plant on August 12, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding was suspended pending outcome in Louisiana. Now that Louisiana approval has been received, we will seek an expedited ruling from Arkansas.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- The Louisiana PSC approved the plant on September 10, 2008.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Commitment to Credit Quality

- ❑ Maintain adequate liquidity
- ❑ $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- ❑ Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- ❑ Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- ❑ Target long term dividend payout ratio range of 55-60%
- ❑ Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

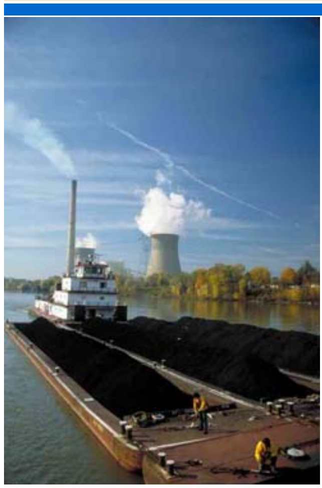
Philadelphia Securities Association

Luncheon Meeting

Union League of Philadelphia

Philadelphia, PA

July 17, 2007



AEP AMERICAN® ELECTRIC POWER

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP®

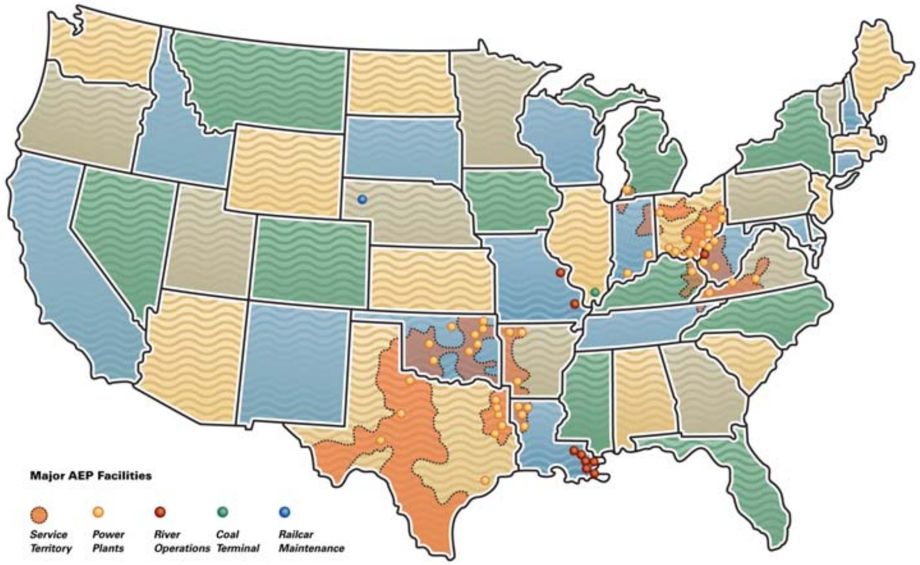
Mike Morris
Chairman, President & Chief Executive Officer

Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity

20,000 employees

AEP®

Strategic Direction

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:

- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

AEP®

Purchased Generation

Waterford

– 821 MW combined-cycle gas plant
– $220MM purchase price
– Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

– 505 MW simple-cycle gas plant
– $100MM purchase price
– APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

– 480 MW simple-cycle gas plant
– $102MM purchase price
– Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

– 1140 MW combined-cycle gas plant
– $325MM purchase price
– AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

AEP®

New Generation Facilities

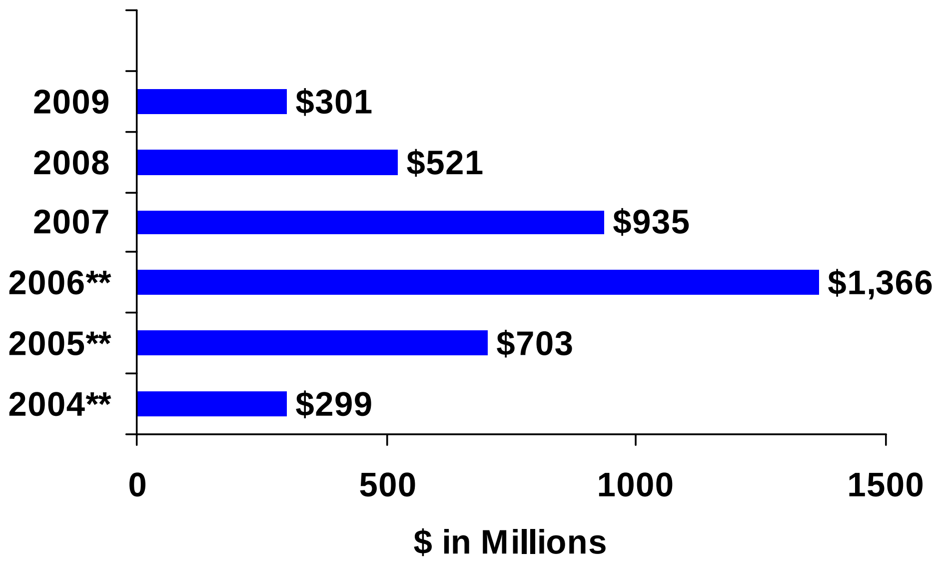
Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B[1]	Coal	Ultra-supercritical	600[1]	2011
PSO	Red Rock	Oklahoma	$1.8 B[2]	Coal	Ultra-supercritical	950[2]	2012
CSP/OP	Great Bend	Ohio	$2.23 B	Coal	IGCC	600	2012
APCo	Mountaineer	West Virginia	Under Review[3]	Coal	IGCC	600	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) PSO will own 50%, or 475 megawatts, totaling approximately $900MM in capital investment.
(3) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

$4.1 Billion Environmental Investment

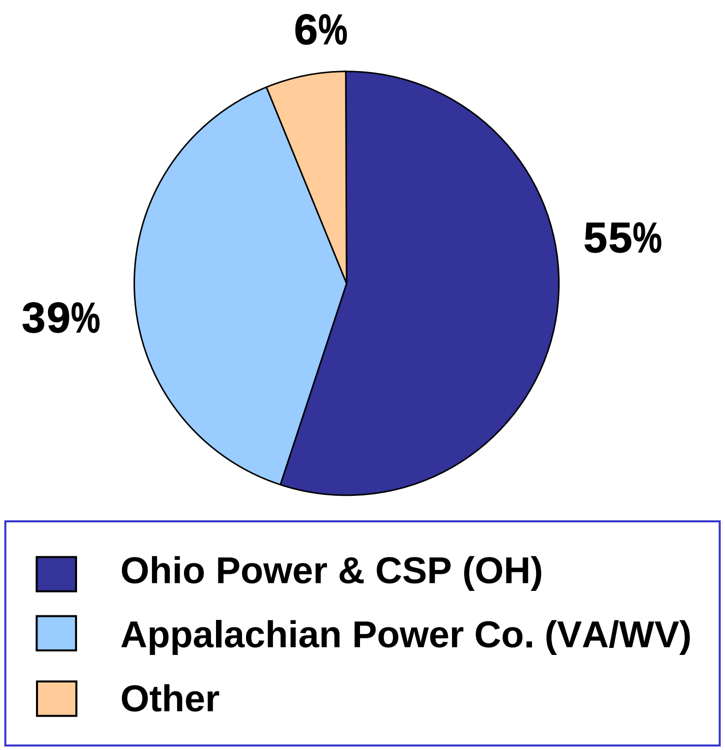
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



AEP®

Majority Of 2006 & 2007 Dollars Are Invested In Ohio & APCo

Integrated Gasification Combined Cycle Facilities

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- Regulatory Recovery Filing
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO2 capture provides pressurized CO2 at the fence line and does not include transportation, storage and monitoring costs.

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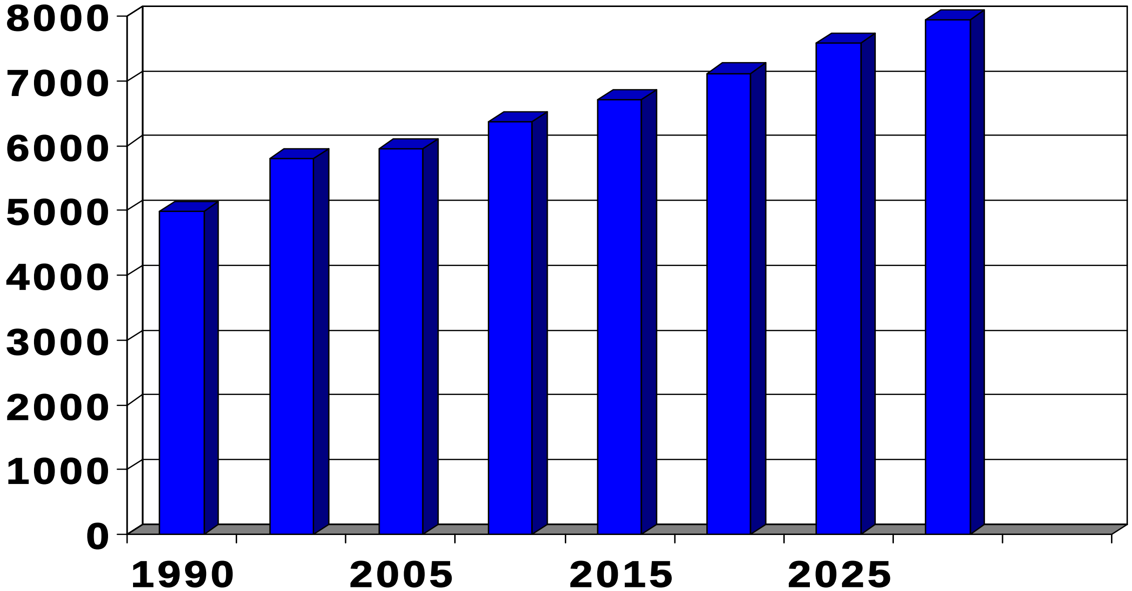
IGCC Technology Is Strategic To Keeping Coal In The Money

Investment Decisions Today Must Consider Likely Future CO_2 Emission Limits



Source: Energy Information Administration/Emissions of GHG in the United States 2005

Note: Chart above assumes no mandatory limits imposed on CO_2 emissions

- **Absent federal policies, long-term CO_2 growth is likely to be significant, driven by population and economic growth, electrification, transportation**

- **Likelihood of US GHG legislation is growing**
  - ✓ **Climate change science**
  - ✓ **Public perceptions**
  - ✓ **Political shifts in Congress**

Inclusion Of Climate Change In Investment Decisions And Taking Voluntary Actions To Reduce CO2 Footprint Will Enhance Shareholder Return Prospects

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AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

AEP®

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for Allowance Allocations
- International Action

AEP endorses this proposal because it is manageable

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AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g. livestock methane deal of 0.6 MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

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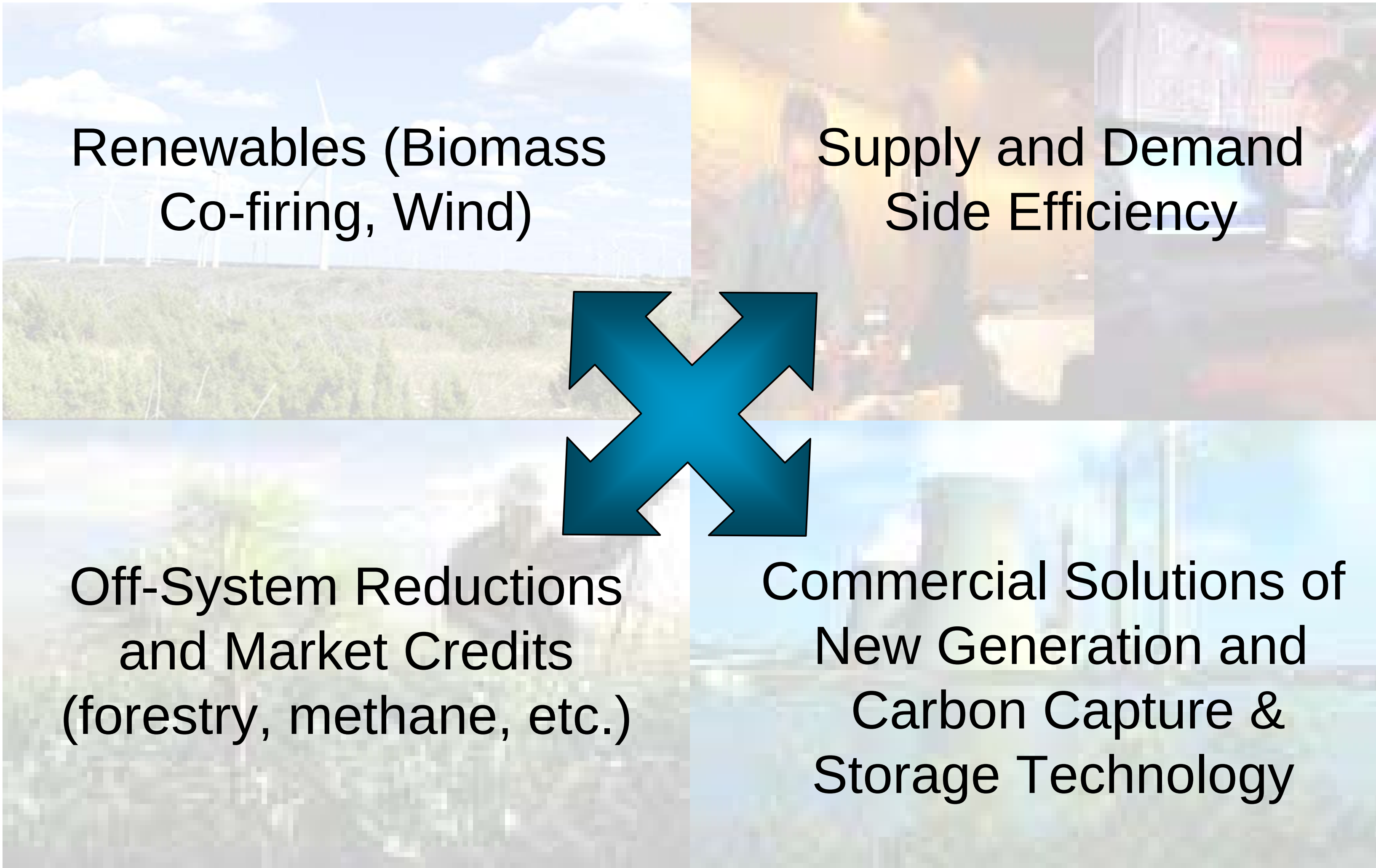
AEP's Long-term GHG Reduction Portfolio



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AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP and New Clean Coal Technology

Phase 1—CO2 Capture / Storage
2008 Commercial Validation

Mountaineer Plant (WV) @ 30 MW → MOU (Alstom) **Chilled Ammonia** → CO_2 (Battelle) → **0.1 MM tons CO_2 / yr**

Phase 2—CO2 Capture / Storage
2011 Commercial Operation

Northeastern Plant (OK)- 600 MW → MOU (Alstom) **Chilled Ammonia** → CO_2 EOR → **1.5 MM tons CO_2 / yr**

***FUTUREGEN** - First Near Zero Emissions Hydrogen/ Electric-AEP and Alliance members*

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Oxy-Fuel CO_2 Capture & Storage Project

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8502 of 9556

Transmission Investment Opportunity *

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

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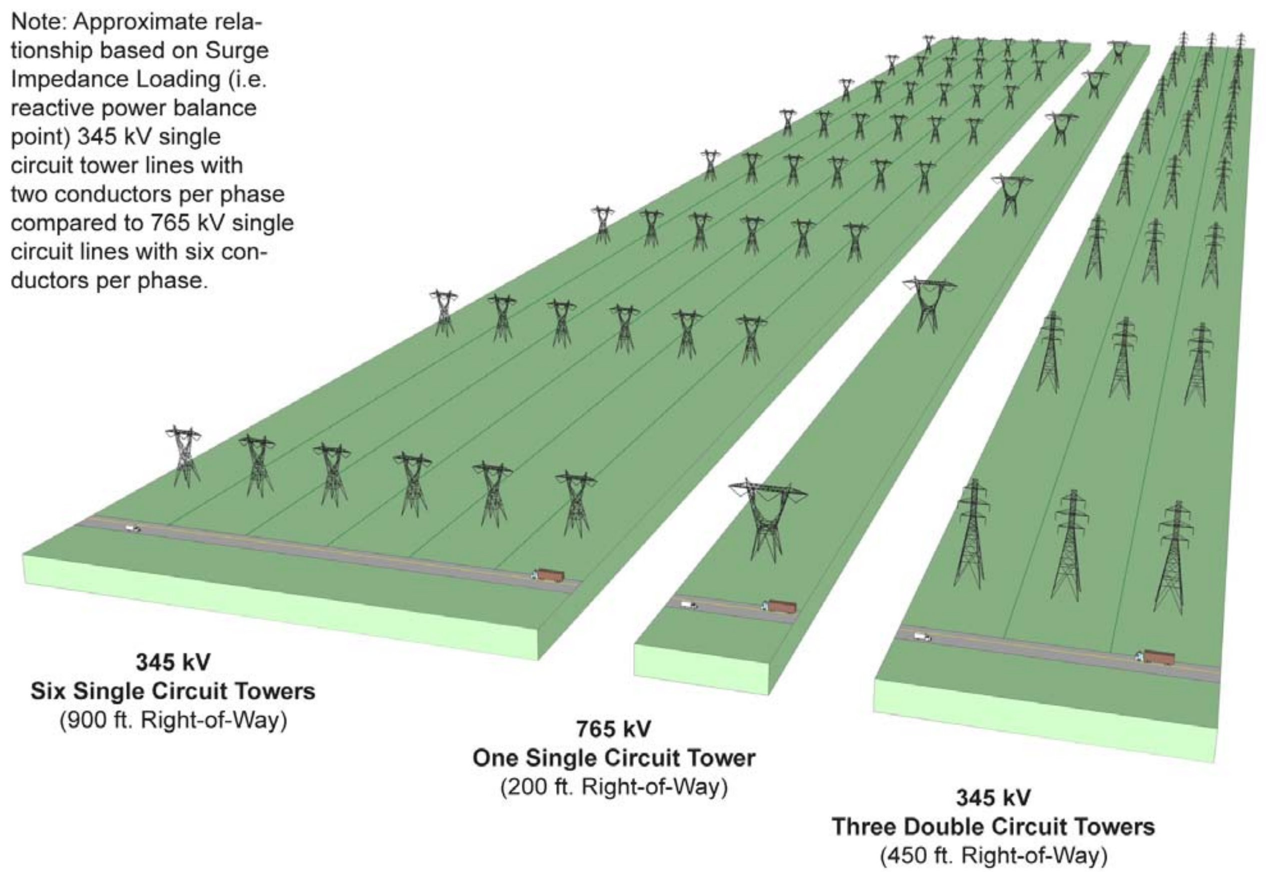
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765 Right-of-Way Comparison



765-kV maximizes land use, providing the most efficient, highest capacity transmission in less right-of-way.

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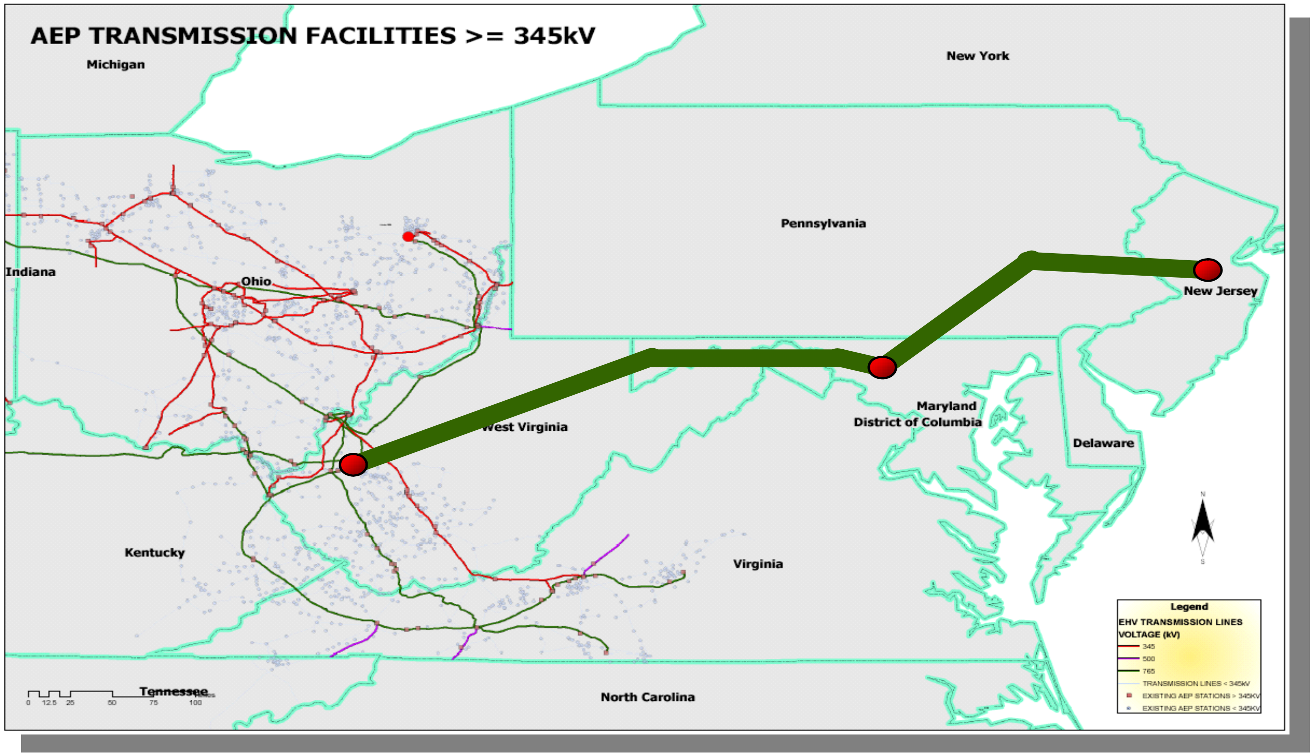
765 PJM



• JV with Allegheny to build a 290 mile West Virginia – Maryland line (Approved by PJM in June 2007). Total estimated cost of $1.8 billion (AEP portion appprox. $600 million). (Second leg which would continue to New Jersey still under consideration by PJM.)

• Enhances Midwest-Mid-Atlantic reliability and improves power transfer capability by 5000 MW.

• Reduces network line losses by 280 MW.

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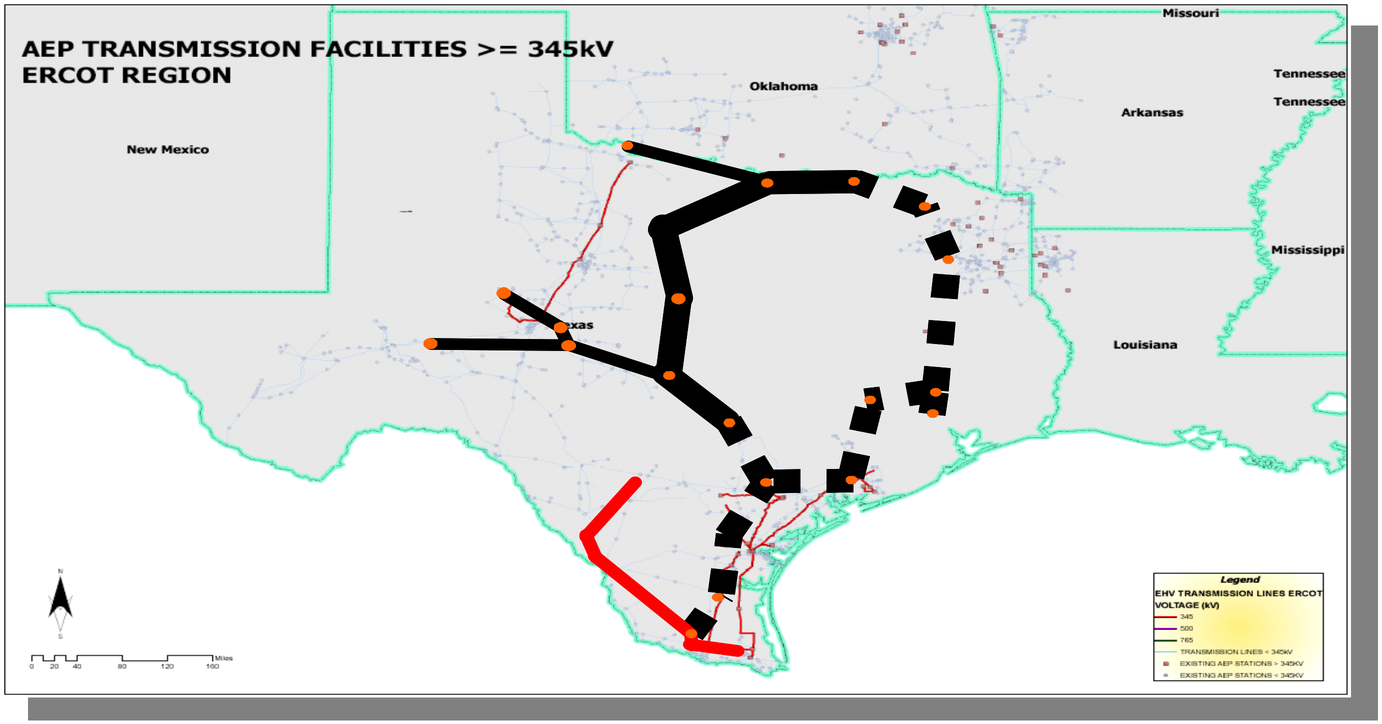
765-ERCOT



• Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets.

• AEP exploring ERCOT transmission investment opportunity, including 420 miles of 765-kV initially.

• Up to 4000MW improved transfer capability.

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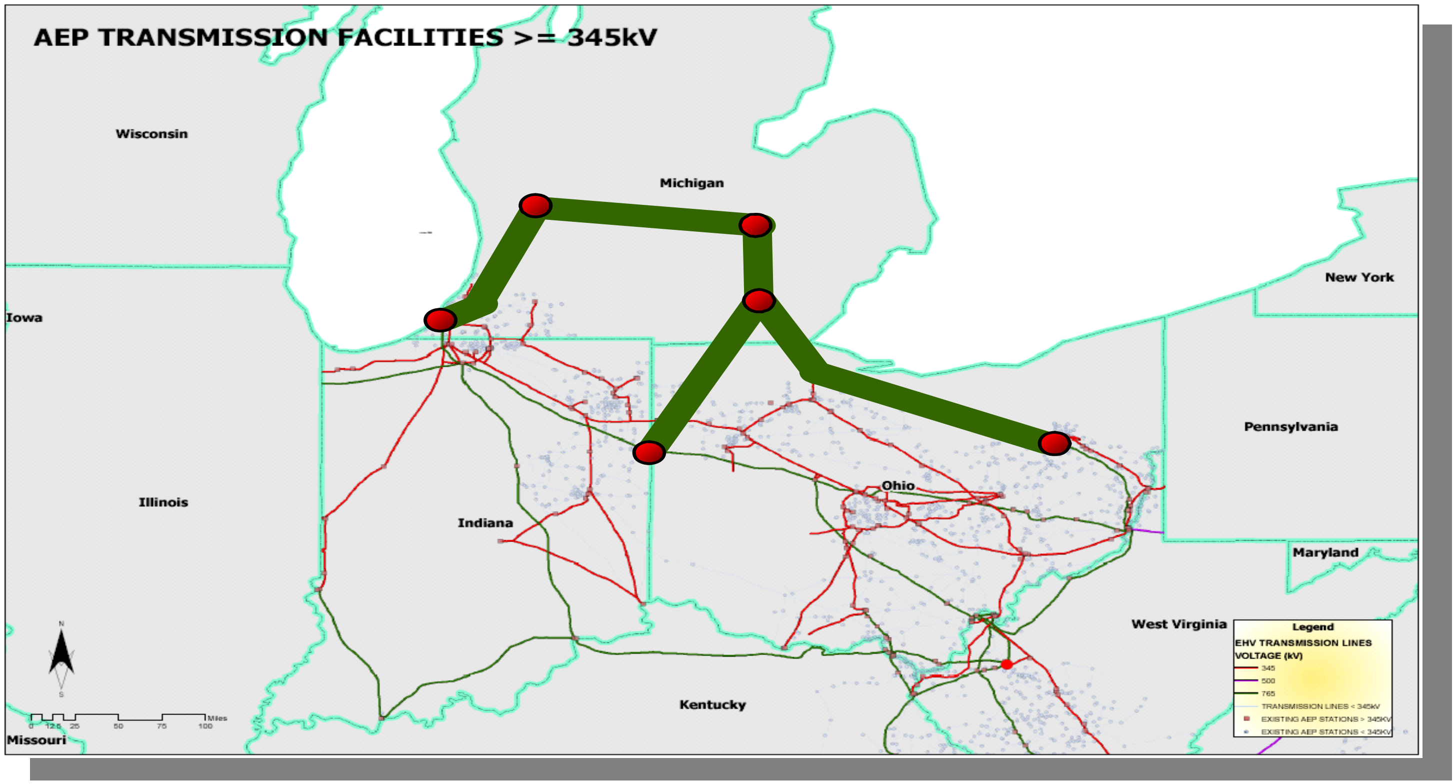
765-Michigan

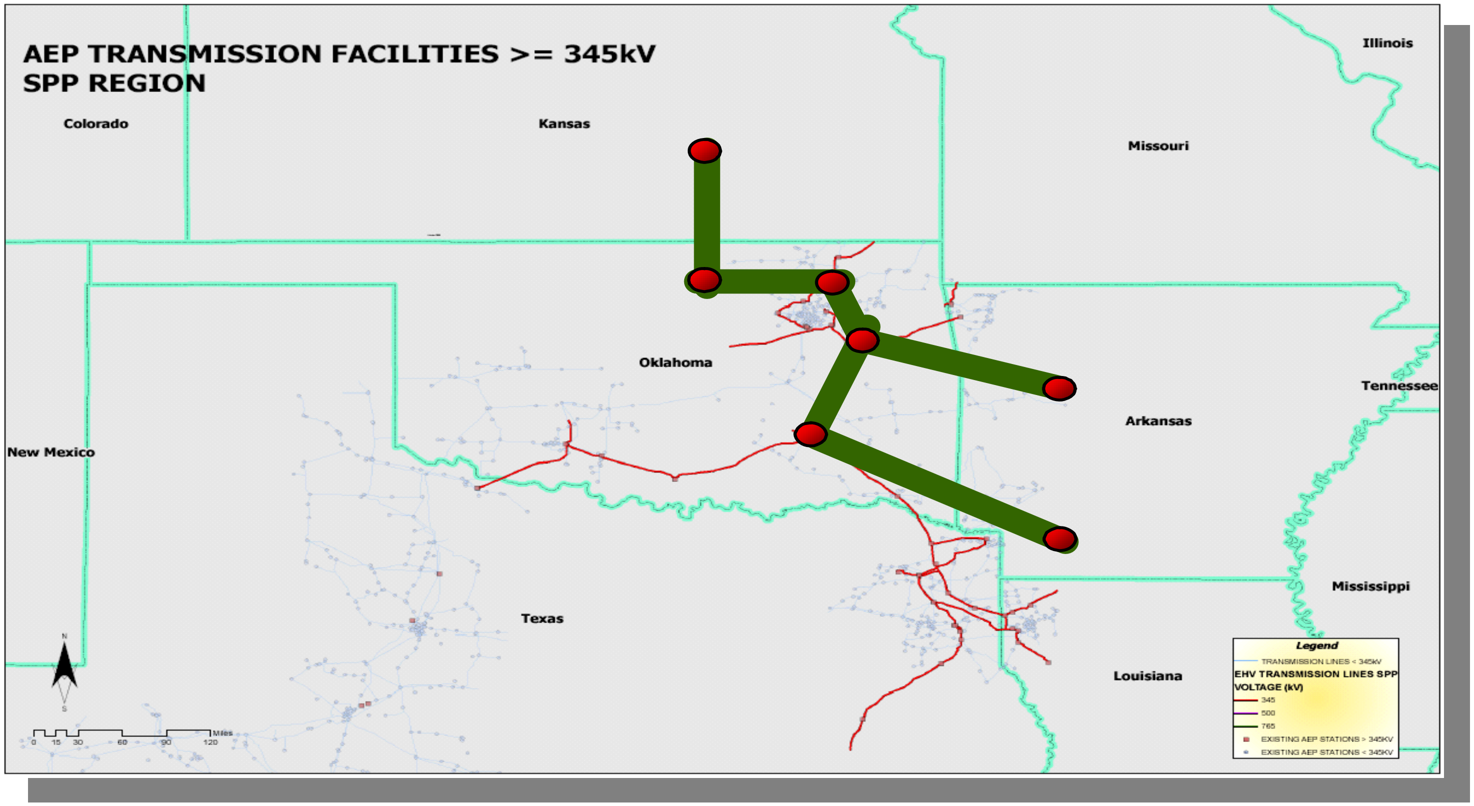


• Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of 700 miles of 765-kV lines in Ohio and Michigan. Study to be completed by August 2007.

• Over 3000MW improved transfer capability.

• Reduces network line losses by 250 MW.

765-SPP



• In July '06 AEP submitted conceptual project to SPP for six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, proposed construction period 2012-17.

• SPP issued EHV Overlay Study in June 2007 reviewing 345 kV, 500 kV, and 765 kV potential projects in SPP. An alternative which includes a 765-kV in Oklahoma and Kansas connecting east to PJM was chosen as the preferred alternative.

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2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ **Results in $24 Million annual increase in base rates**
- ✓ **10.0% approved ROE**

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ **Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)**
- ✓ **No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.**

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ **Results in $85.5 million net increase in revenues effective July 1, 2007**
  - ✓ **$54.8 million covers increased costs related to coal and purchased power**
  - ✓ **$28.5 million covers environmental construction costs, primarily related to installation of scrubbers**
  - ✓ **Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1**

Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ **Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year**
- ✓ **Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding**
- ✓ **Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.**

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In Hand to Date - $282MM of the $338MM Rate Recovery in 2007 Guidance

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - ✓ SWEPCo Turk Plant Filings in Arkansas and Louisiana for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

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Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

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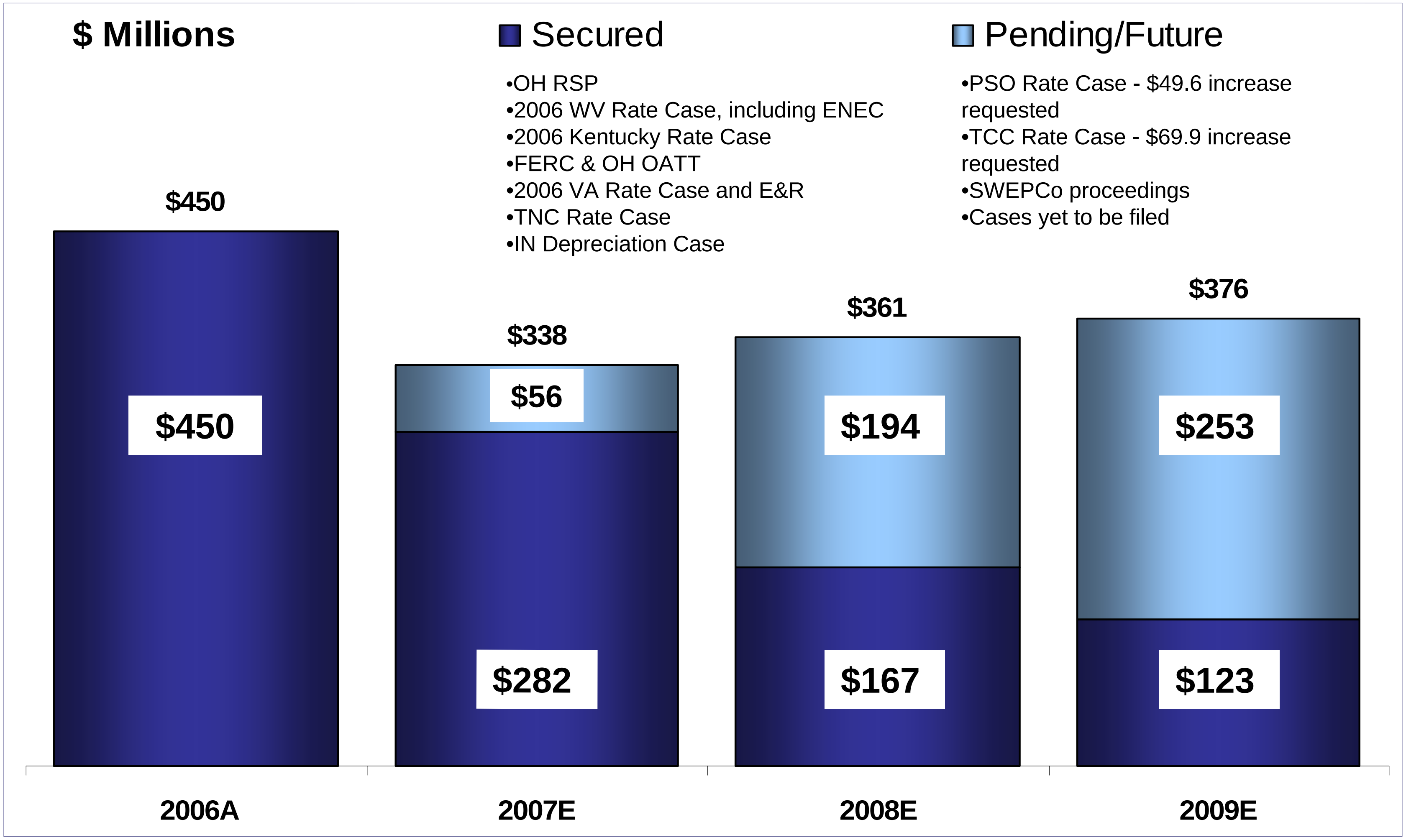
Appendix

Incremental Rate Relief Composition



Rate Relief Is A Critical Element To AEP's Financial Success

Regulatory Activity Underway

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

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Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

* Figures are rounded

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
July 2007	Final order expected

July 6, 2007—implemented interim rates of $8.6MM for a key provision on which there seemed to be agreement.

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Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- I&M requested a test year of the twelve months ended September 30, 2007 but it is up to the IURC to determine the test year to be used.
- I&M will file its revenue requirement in approximately 2-3 months after the end of the stipulated test year.

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Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings are scheduled for July 16-19, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

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Regulatory Activity Underway

West Virginia Mountaineer IGCC Filing

- Testimony filed on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for September 10-14, 2007 with an order on or before December 2, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

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Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for the Used and Useful Determination commenced July 9, 2007.
- Hearings for OG&E's cost recovery commence July 19, 2007.

SWEPCo Turk Plant Filings

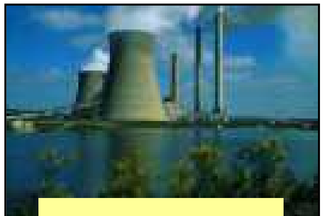
Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Depending on contested issues, public hearings will begin either July 19, 2007 or August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%

Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

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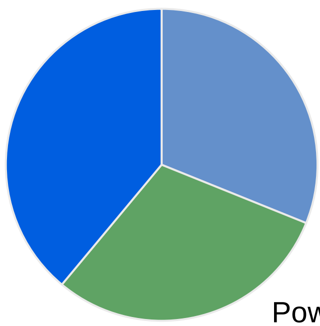
Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

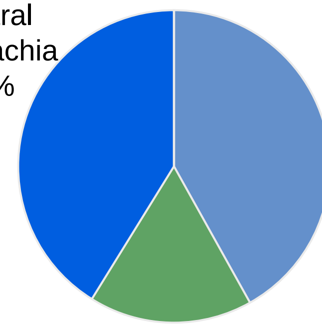
Total AEP System



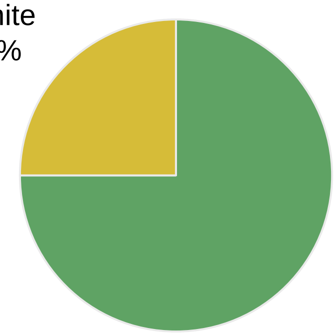
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



AEP West



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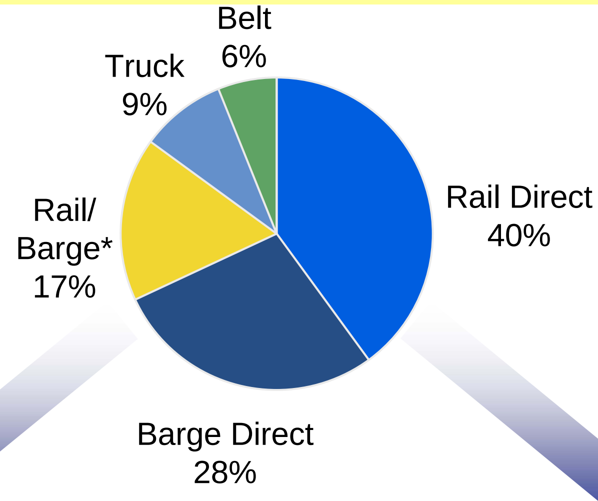
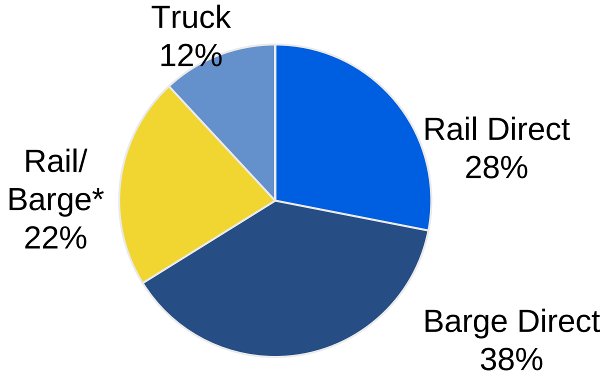
Coal Delivery

2006 Actual

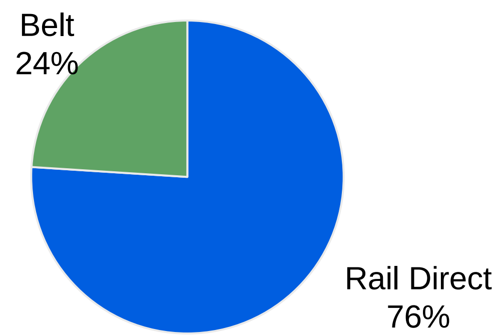
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Environmental Investment

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008 -10
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	In-service	✓	In-service
Mitchell 2	800	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	✓	Upgrade In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2008
Muskingum River 5	585	✓	In-service	☐	Delayed
Pirkey	580	☐	N/A	✓	Upgrade In-service
Oklaunion	485	☐	N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262	☐	N/A	✓	In-service

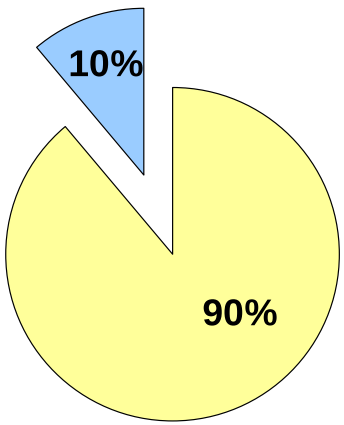
*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

AEP®

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



Actuals To Date & Firm Costs
Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

New Gas-Fired Generation Facilities

SWEPCo

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PSO

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SWEPCo's and PSO's Short-Term and Intermediate Power Needs Will Be Met With Newly Constructed Gas-Fired Facilities

AEP®

New Ultra-Supercritical Coal Facilities

SWEPCo	PSO

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- Certificate of Need approvals (LA, AR, TX) expected by September/October 2007
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Red Rock Generating Facility	$54MM	$120MM	$236MM

Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

AEP®

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating/making longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

Chilled Ammonia Process Plant Footprint

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8528 of 9556

Oxy-Fuel Technology Initiative

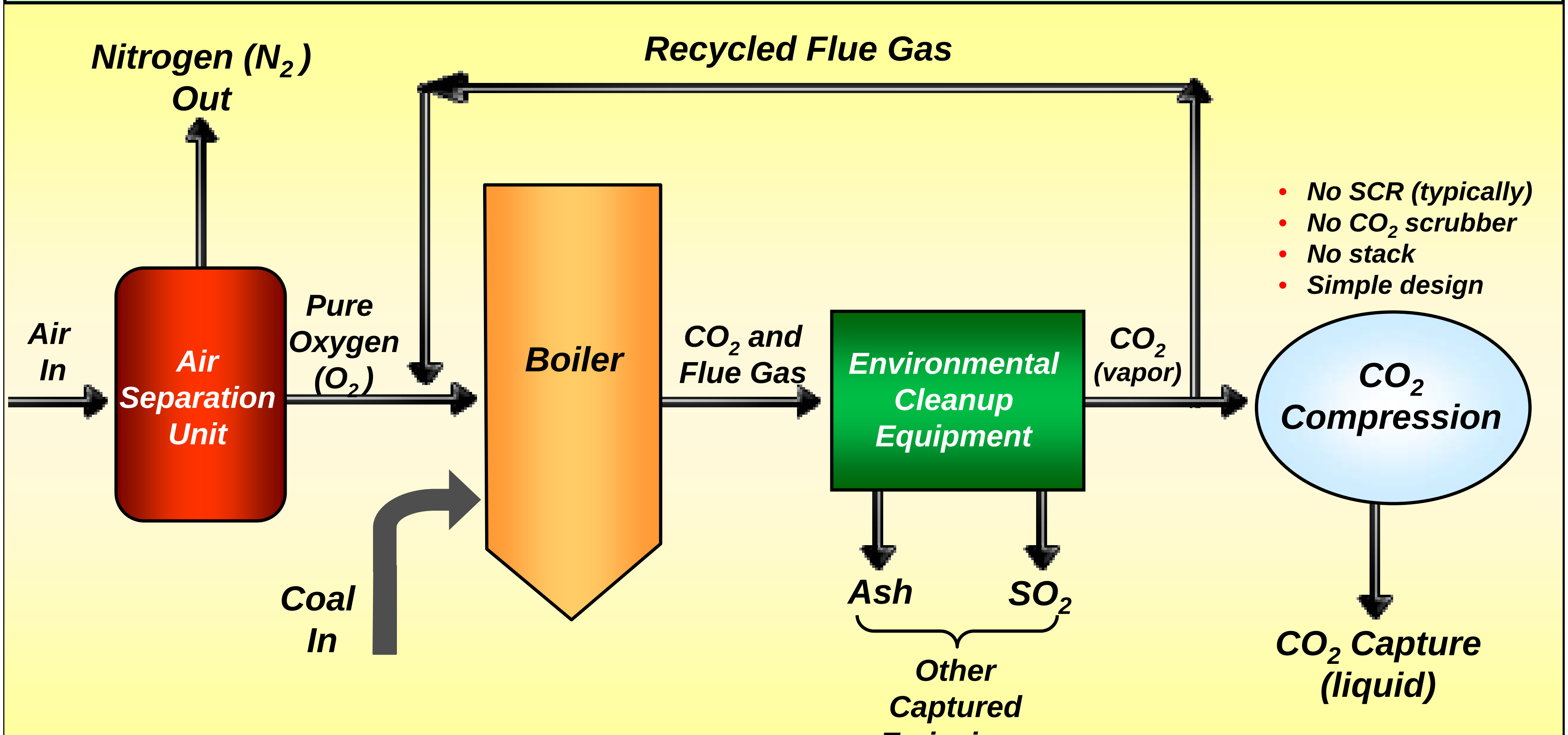


Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-zero Emissions Using Oxy-fuel Combustion Technology

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc. [1]	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
AEP Texas North Company [2]	Baa1	A3	S	3	BBB	BBB	S	A-	A	N
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) In September 2006, S&P upgraded AEP's consolidated business profile score from 6 to 5.

(2) AEP Texas North Company was placed on negative outlook by Fitch in April 2006.

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase	$325
2007 Including Lawrenceburg	**$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash
From Operations Via Rate Relief And Debt Issuances

AEP®

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP®

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

CASH ON HAND EXPECTED TO BE $205 MILLION AT YEAR END 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	**2007**	**2008**	**2009**
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

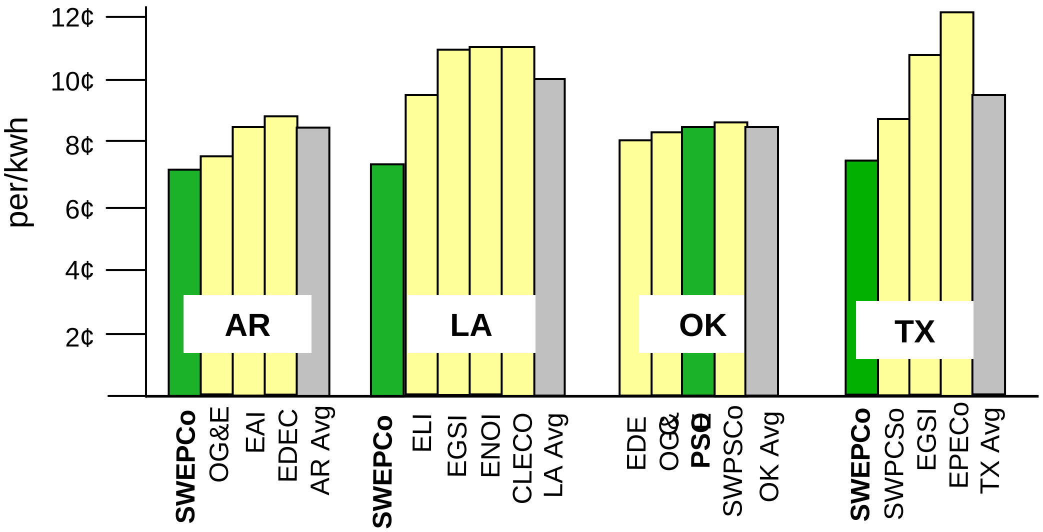
* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

CAPITAL INVESTMENT IS FUNDED BY CASH FROM OPERATIONS AND DEBT ISSUANCES

AEP®

AEP Provides Low Cost Electric Service

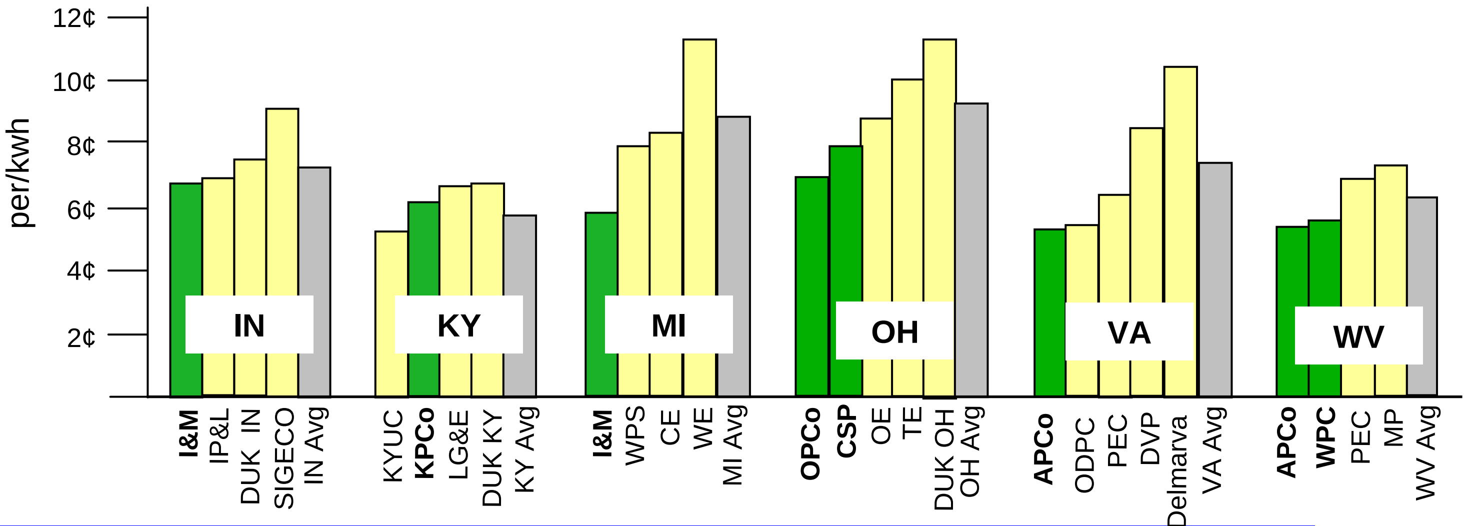
AEP West



Residential Average rates 12 months ended 6/30/2006

Source: Summer 2006 EEI Typical Bills and Average Rates Report.

AEP East



2006-2009 Projected Annual Rate Increase Of 3.8%

American Electric Power, Inc.

Philadelphia/Baltimore

Road Show

Hosted by Banc of America

July 16-17, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio, and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Mike Morris
Chairman, President, & CEO

Table of Contents

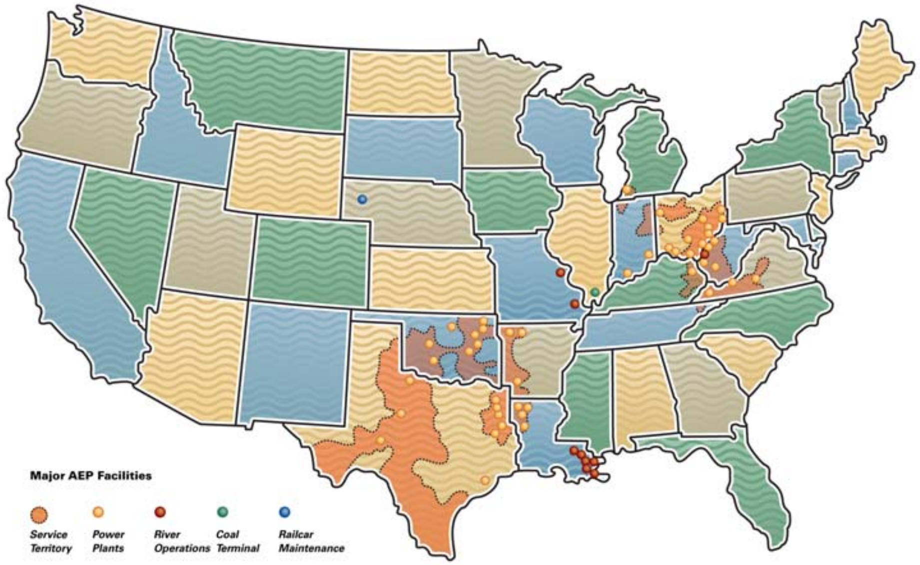
Strength & Scale in Assets & Operations

AEP®

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~208,000 miles	# 1

Source: Company research & Resource Data International Platts, PowerDat 2005



- Coal & transportation assets
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,000 employees

AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP Enjoys Significant Presence Throughout The Energy Value Chain

Strategic Direction

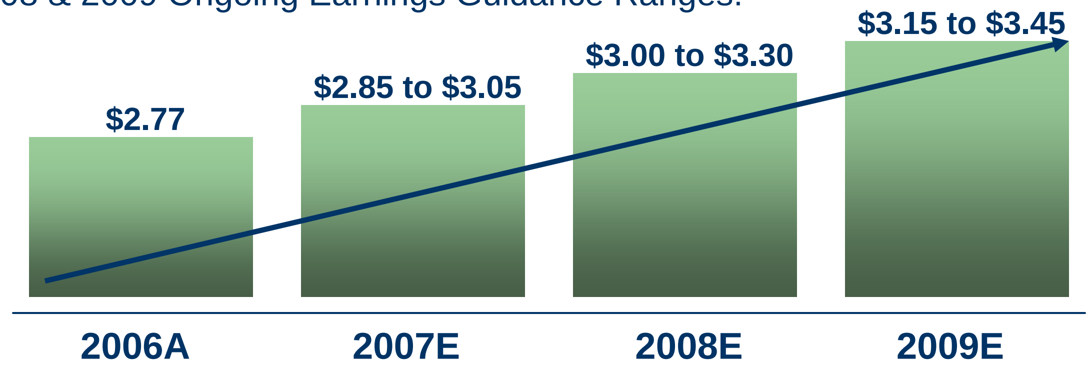
- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- Develop our transmission business
- Achieve adequate returns on all assets

Deliver value to investors and cost effective service to our customers

Continued Commitment To Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Framework For Long-Range Performance

- 2007, 2008 & 2009 Ongoing Earnings Guidance Ranges:



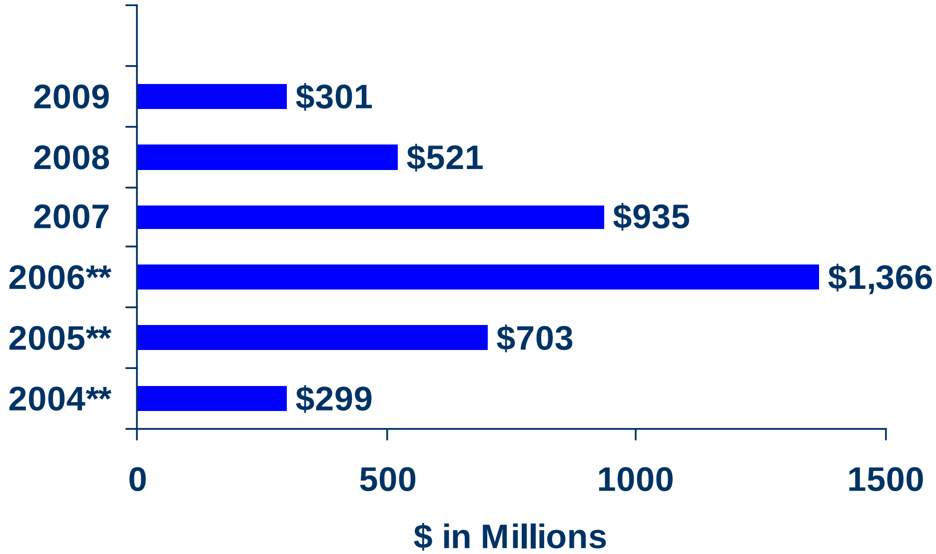
- EPS Growth Range: 5-7% (2006-2009)
  - Continued disciplined investment in existing utility operations
    - Reliability
    - Environmental
    - New Generation & Distribution Infrastructure
  - Investment in new transmission opportunities
  - Seek rate recovery for new investments
  - Control costs & achieve timely rate relief
- Maintain credit ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

$4.1 Billion Environmental Investment

AEP®

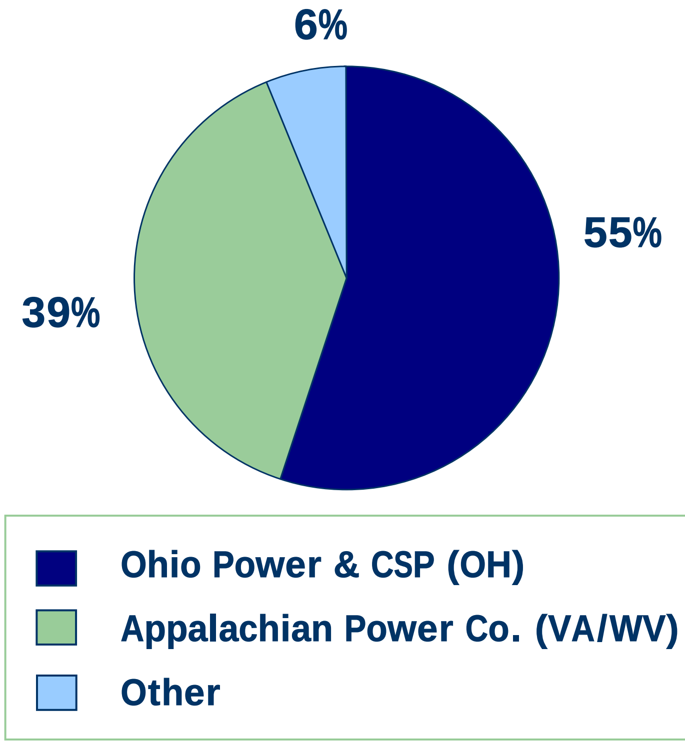
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004, 2005 and 2006

Projected Environmental Investment Allocation



Majority Of 2006 & 2007 Dollars Are Invested In Ohio & APCo

Environmental Investment

AEP®

AT THE CONCLUSION OF OUR CURRENT ENVIRONMENTAL RETROFIT PROGRAM, OVER 47% OF OUR COAL-FIRED GENERATION FLEET WILL BE EQUIPPED WITH SCRs AND OVER 50% WILL BE SCRUBBED (FGD). AEP's TOTAL COAL FLEET CAPACITY = 24,710 MEGAWATTS*

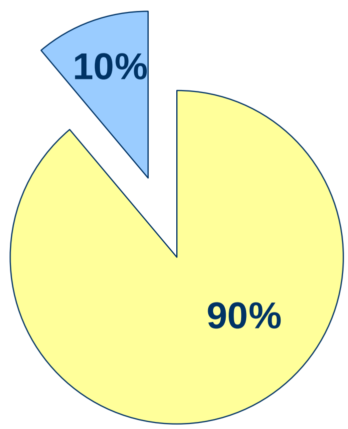
Plant Name	MW Capacity	SCR	Status	FGD	Status
Amos 1-3	2900	✓	In-service	✓	Projected 2008 -10
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1	800	✓	In-service	✓	In-service
Mitchell 2	800	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Big Sandy 2	800	✓	In-service	☐	Delayed
Conesville 5 & 6	750	☐	N/A	✓	Upgrade In-service
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Cardinal 1	600	✓	In-service	✓	Projected 2008
Muskingum River 5	585	✓	In-service	☐	Delayed
Pirkey	580	☐	N/A	✓	Upgrade In-service
Oklaunion	485	☐	N/A	✓	In-service
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
Dolet Hills	262	☐	N/A	✓	In-service

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Installation Of SCR And FGD Equipment Will Allow Our Coal Fleet To Remain Extremely Cost Competitive

Materials and Vendors – AEP's Advantage

Environmental Program Costs:
Active/Firm Costs to Remaining Estimated Costs



- Actuals To Date & Firm Costs
- Remaining Estimated Costs*

* Primarily labor and activated carbon injection systems

SCR Technology

- Removes 90 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kw avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~80% removal efficiency

FGD Technology

- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kw avg.**

AEP Benefits From First-mover Advantage Through Lower Contracted Pricing and Reduced Market Escalation Exposure

Purchased Generation

Waterford

– 821 MW combined-cycle gas plant
– $220MM purchase price
– Columbus Southern Power completed purchase on Sept. 28, 2005

Ceredo

– 505 MW simple-cycle gas plant
– $100MM purchase price
– APCo completed purchase on Dec. 15, 2005

2,946 MW of gas-fired generation added since 2005

Darby

– 480 MW simple-cycle gas plant
– $102MM purchase price
– Columbus Southern Power completed purchase on April 25, 2007

Lawrenceburg

– 1140 MW combined-cycle gas plant
– $325MM purchase price
– AEG completed purchase on May 16, 2007

Additional Gas-fired Generation Allows Us To Meet The Growing Needs Of Our Customers And Provides The Company With Greater Fuel Flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340	2007/2008
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B[1]	Coal	Ultra-supercritical	600[1]	2011
PSO	Red Rock	Oklahoma	$1.8 B[2]	Coal	Ultra-supercritical	950[2]	2012
CSP/OP	Great Bend	Ohio	$2.23 B	Coal	IGCC	600	2012
APCo	Mountaineer	West Virginia	Under Review[3]	Coal	IGCC	600	2017

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(2) PSO will own 50%, or 475 megawatts, totaling approximately $900MM in capital investment.
(3) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP Is Meeting The Growing Electricity Needs Of Customers Through The Pursuit Of New Economic Generation Facilities

New Gas-Fired Generation Facilities

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  - Air permit filed and approved in February 2007
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New Ultra-Supercritical Coal Facilities

AEP®

SWEPCo	PSO

SWEPCo

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Ultra-Supercritical Coal-Fired Generation Is The Most Economical Choice For New Baseload Plants In AEP's Western Service Territory

Integrated Gasification Combined Cycle Facilities

AEP®

Front-End Engineering & Design (FEED) results complete. Results were filed in June 2007. Cost estimates in target range of 20-30% premium over new ultra-supercritical coal-fired facilities of equal capacity.

West Virginia

- Certificate of Public Convenience & Necessity filed Jan. 11, 2006
  - APCo testimony filed June 18, 2007
  - Intervenor & Staff testimony due Aug. 17, 2007
  - Hearings Sept. 10-14, 2007
  - Statutory Deadline – Dec. 2, 2007
- Air permit filed in Oct 2006 – A technical review of the application and development of a draft permit is ongoing by the WV Dept. of Environmental Protection
- Regulatory Recovery Filing
  - Filing made in June 2007 –included request for cash recovery mechanism

Ohio

- Certificate of Environmental Compatibility & Public Need filed on March 24, 2006
  - Ohio Power Siting Board approved application on March 9, 2007
- Air permit filed in Oct 2006
- Regulatory Recovery Filing
  - Phase 1 – June 2006 – PUCO approved tariff to recover pre-construction costs ($24MM) over 12-month period effective July 1, 2006
  - Phase 2 – filing likely to be withheld until resolution of Ohio Supreme Court action
  - Informational filing made on June 18, 2007 to inform PUCO of the West Virginia filing

Construction Period Of 48-50 Months Following Receipt Of Major Regulatory And Permit Approvals

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		
	USC	**IGCC**	**NGCC**
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO2 capture provides pressurized CO2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC Technology Is Strategic To Keeping Coal In The Money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A Reliable & Reasonably-priced Electric Supply Is Necessary To Support The Economic Well-being Of The Areas We Serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for Allowance Allocations
- International Action

AEP endorses this proposal because it is manageable

AEP's Climate Strategy

- **Being proactive and engaged in the development of climate policy**
  - International Emissions Trading Association (IETA)
  - Electric Power Research Institute (EPRI)
  - Pew Center on Global Climate Change
  - e8
  - Global Roundtable on Climate Change
- **Investing in science/technology R&D**
  - FutureGen Alliance
  - US DOE research on carbon capture and sequestration at our Mountaineer Plant
  - EPRI – combustion technologies
  - MIT Energy Laboratory
  - B&W – Oxy-Fuel
- **Taking voluntary, proactive action now, demonstrating voluntary programs can work and setting policy precedents thru CCX**
  - Chicago Climate Exchange (CCX)
  - EPA Climate Leaders
  - EPA SF-6 Emission Reduction Partnership for Electric Power Systems Program
  - Asia-Pacific Partnership
  - DOE 1605B- voluntary reporting of GHGs Program
  - Business Roundtable Climate Resolve
  - Numerous forestry activities
- **Evaluating longer term investment decisions such as new generation and carbon capture and storage (e.g., IGCC, Ultra-supercritical)**

AEP Must Be A Leader In Addressing Climate Change

AEP's Long-term GHG Reduction Portfolio

AEP®

Renewables (Biomass Co-firing, Wind)

Supply and Demand Side Efficiency

Off-System Reductions and Market Credits (forestry, methane, etc.)

Commercial Solutions of New Generation and Carbon Capture & Storage Technology

AEP Is Investing In A Portfolio Of GHG Reduction Alternatives

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

- Incremental Reduction quantity: 5MM tons/yr
- Timing: To take effect/receive credits by 2011
- Methods
  - +1000 MWs of Wind PPAs – 2MM tons/yr
  - Domestic Offsets (methane) – 2MM tons/yr (e.g. livestock methane deal of 0.6MM tons/yr)
  - Forestry – Tripling annual investment to increase to 0.5MM tons/yr by 2015
  - Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
  - Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

- Commercial solutions for existing fleet
  - Chilled Ammonia
  - Oxy-Fuel

AEP Is Committed To A 5mm Ton/Yr Reduction In Co_2 Emissions Which Offsets Approximately Half Of The Emissions Projected From New Generation Projects Previously Announced

Chilled Ammonia Process Plant Footprint

AEP and New Clean Coal Technology

AEP®

Phase 1—CO2 Capture/Storage
2008 Commercial Validation

Mountaineer Plant (WV) @ 30 MW

MOU (Alstom)

Chilled Ammonia

CO_2 (Battelle)

0.1 MM tons CO_2 /yr

Phase 2—CO2 Capture/Storage
2011 Commercial Operation

Northeastern Plant (OK)- 600 MW

MOU (Alstom)

Chilled Ammonia

CO_2 EOR

1.5 MM tons CO_2/yr

FUTUREGEN - First Near Zero Emissions Hydrogen/ Electric-AEP and Alliance members

Oxy-Fuel Technology Initiative

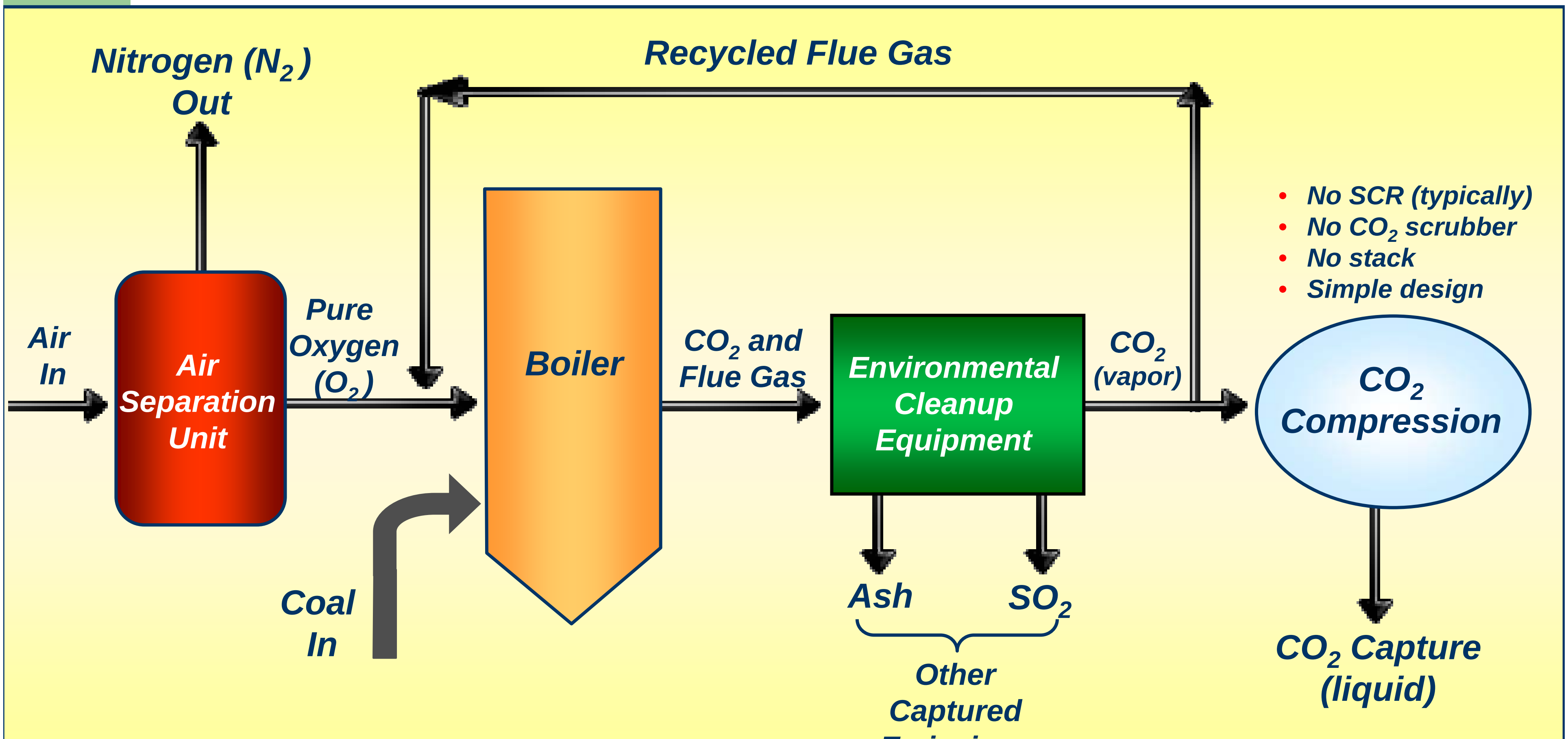


Illustration supplied courtesy of The Babcock & Wilcox Company.

Near-zero Emissions Using Oxy-fuel Combustion Technology

Oxy-Fuel CO_2 Capture & Storage Project

AEP®

Pilot Scale Demonstration

- 10 MW_e scale
- Teamed with B&W at its Alliance Research Center and 16 other utilities
- Demo completed 3Q 2007
- AEP funding of $50k

Commercial Scale Retrofit

- Retrofit on existing AEP sub-critical unit (several available)
- 150 – 230 MW_e scale retrofit
- 4,000 – 5,000 tons CO_2 per day
- Teamed with B&W
- AEP funding of ~ $200k – $3M for feasibility study
- Feasibility study to be completed in late 2008/early 2009

Combustion Conversion Technology For Existing Coal Fleet – Longer Lead Time With Enhanced Viability And Long-term Potential

Transmission Investment Opportunity *

AEP®

Creating a business model to manage capital requirements for enhanced returns with partners

- ~ $3 billion I-765 Project in PJM
- ~ $2 billion 765-kV study with ITC in Michigan
- ~ $3 billion project filed with SPP
- ~ $1- $7 billion in ERCOT via Electric Transmission Texas, LLC (ETT)

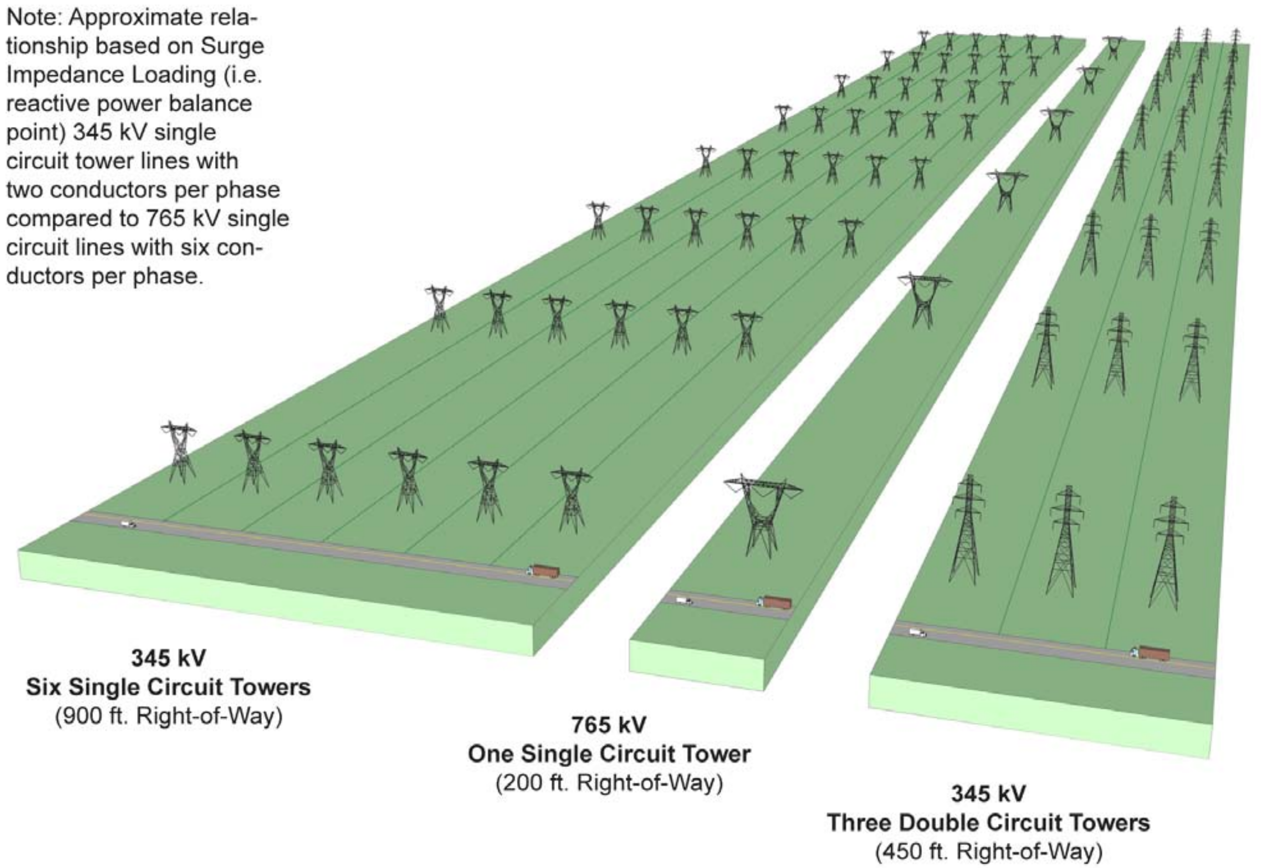
Assumptions	
Estimated Investment Opportunity	$15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt/Equity Ratio	50% debt / 50% equity
Return on Equity	11.00%-13.00%
Potential EPS Impact (based on 396 MM shares)	$0.60+ **

* This identified transmission opportunity is not included in current capex guidance

** Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion

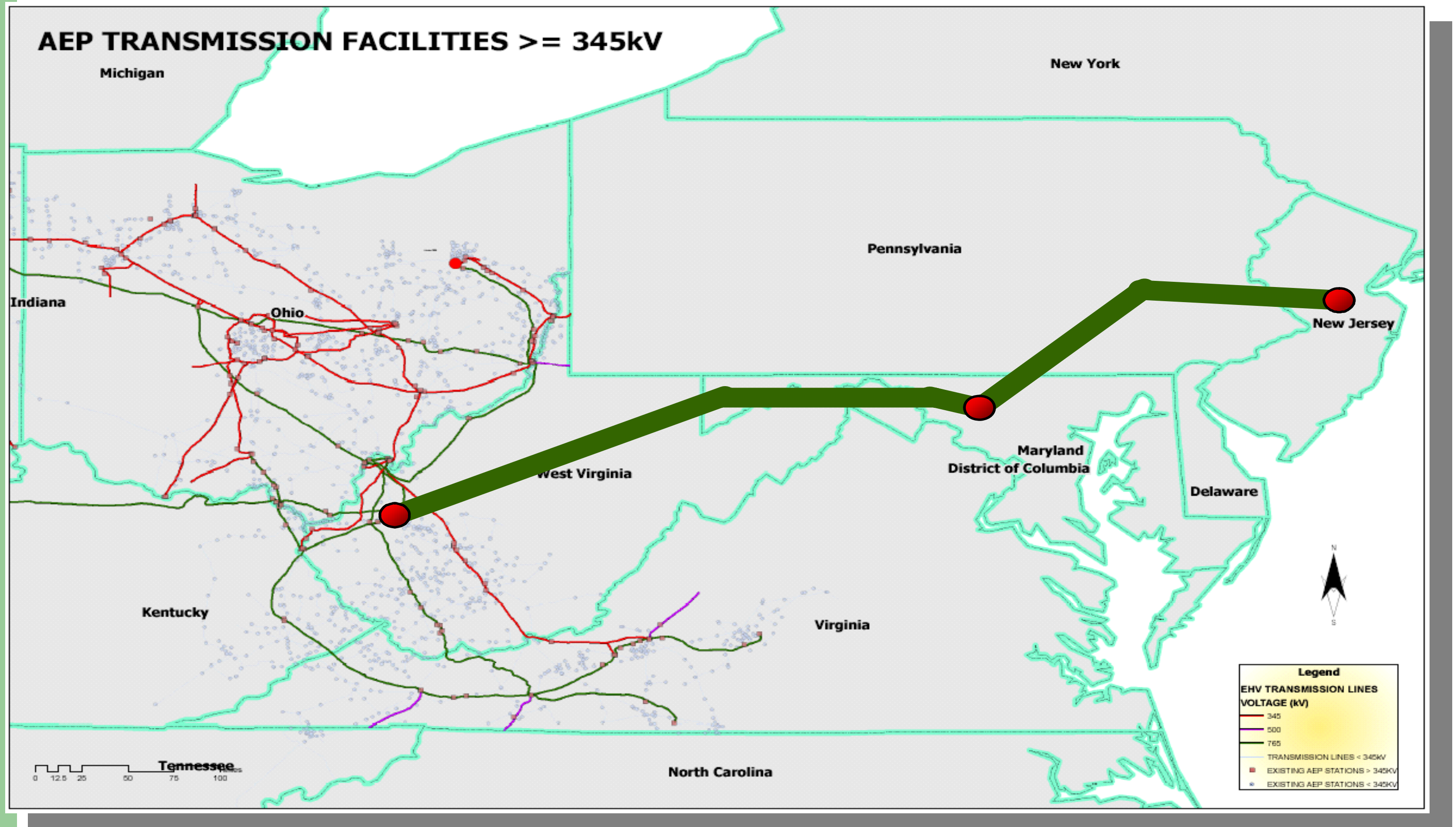
Building The Next US Interstate System For Enhanced Reliability And Market Efficiency Could Have Significant EPS Implications

765 Right-of-Way Comparison



765-kV maximizes land use, providing the most efficient, highest capacity transmission in less right-of-way.

765-kV PJM

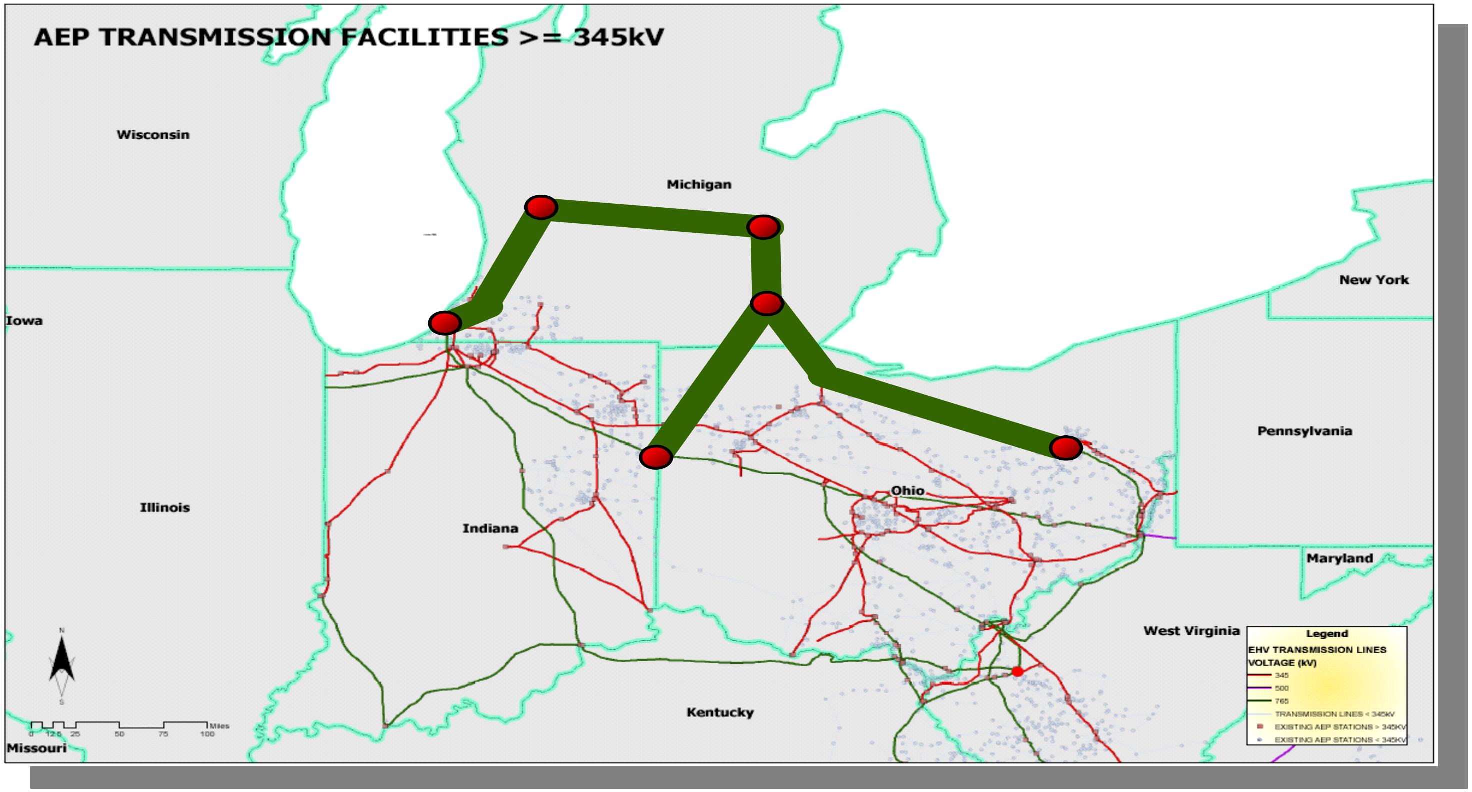


- **JV with Allegheny to build a 290 mile West Virginia – Maryland line (Approved by PJM in June 2007). Total estimated cost of $1.8 billion (AEP portion approximately $600 million). (Second leg which would continue to New Jersey still under consideration by PJM.)**

- **Enhances Midwest-Mid-Atlantic reliability and improves power transfer capability by 5000 MW.**

- **Reduces network line losses by 280 MW.**

765-kV Michigan

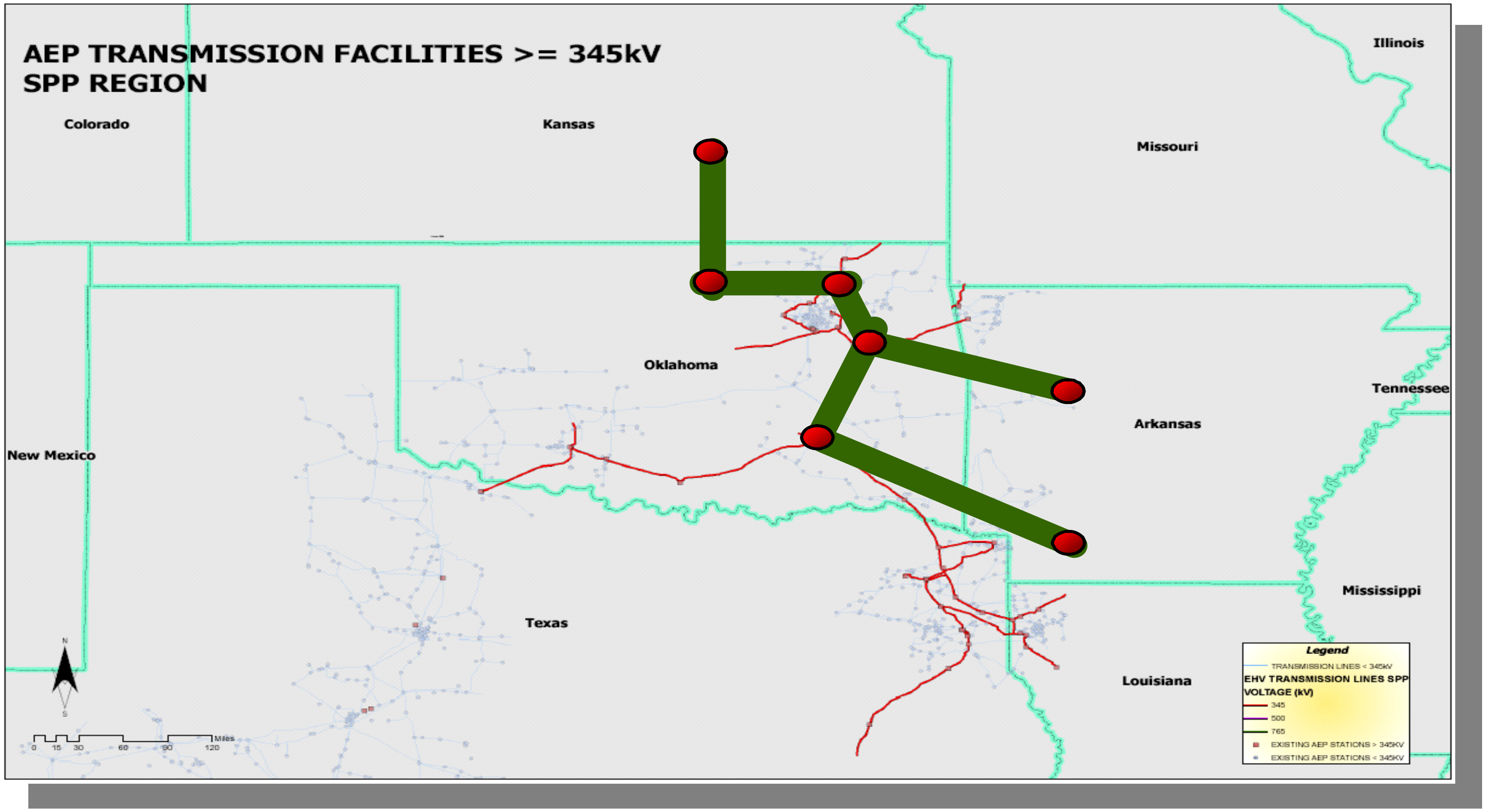


➢**Agreement with ITC Transmission for Michigan 765-kV to study the feasibility of 700 miles of 765-kV lines in Ohio and Michigan. Study to be completed by August 2007.**

➢**Over 3000MW improved transfer capability.**

➢**Reduces network line losses by 250 MW.**

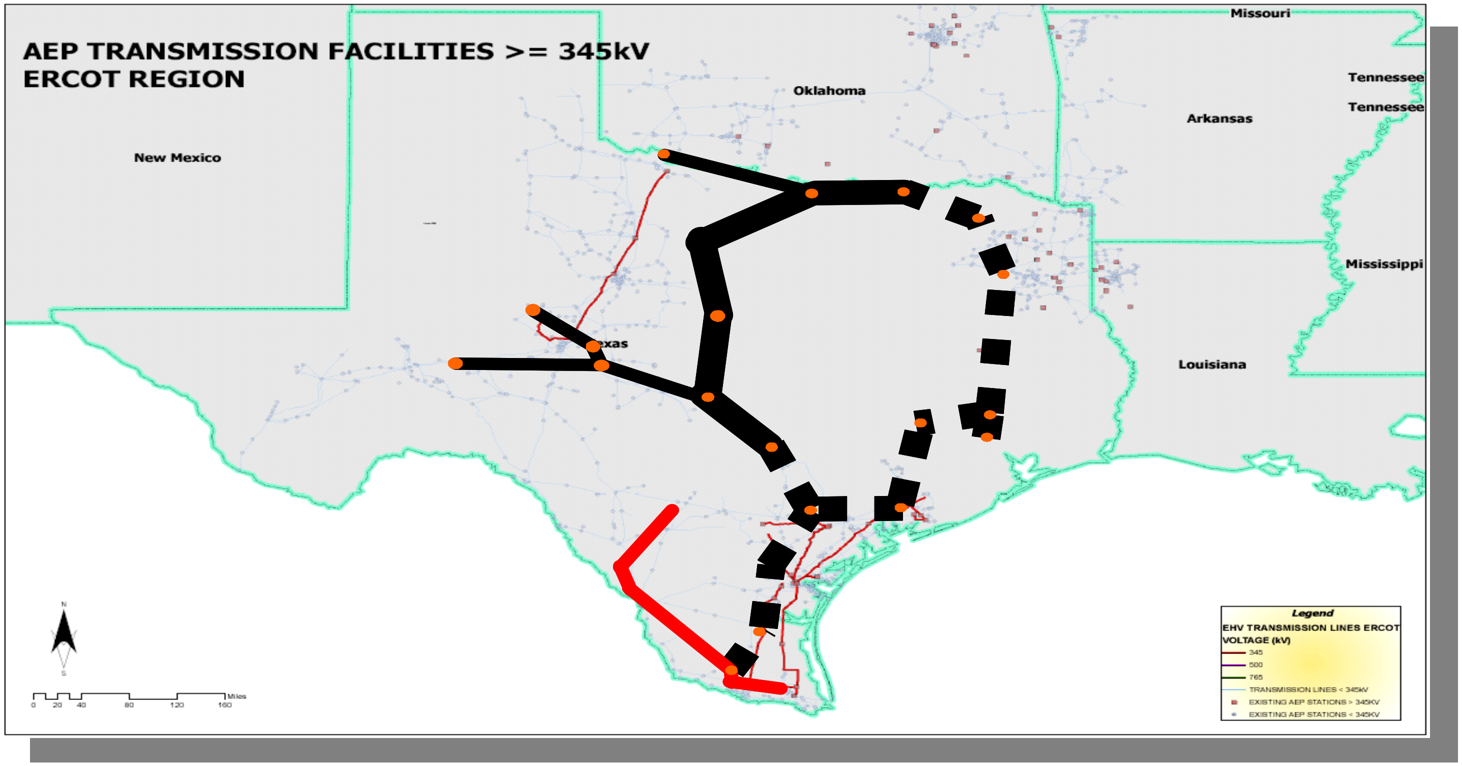
765-kV SPP



➢**In July '06 AEP submitted conceptual project to SPP for six 765-kV lines, 610 line miles from Arkansas to Wichita, KS, proposed construction period 2012-17.**

➢**SPP issued EHV Overlay Study in June 2007 reviewing 345 kV, 500 kV, and 765 kV potential projects in SPP. An alternative which includes a 765-kV in Oklahoma and Kansas connecting east to PJM was chosen as the preferred alternative.**

765-kV ERCOT



- Jointly-owned utility company (AEP and Mid American) will design, construct & operate ERCOT transmission assets
- AEP exploring 765-kV ERCOT transmission investment opportunity
- 420 line miles
- Up to 4000MW improved transfer capability

Incremental Rate Relief Composition

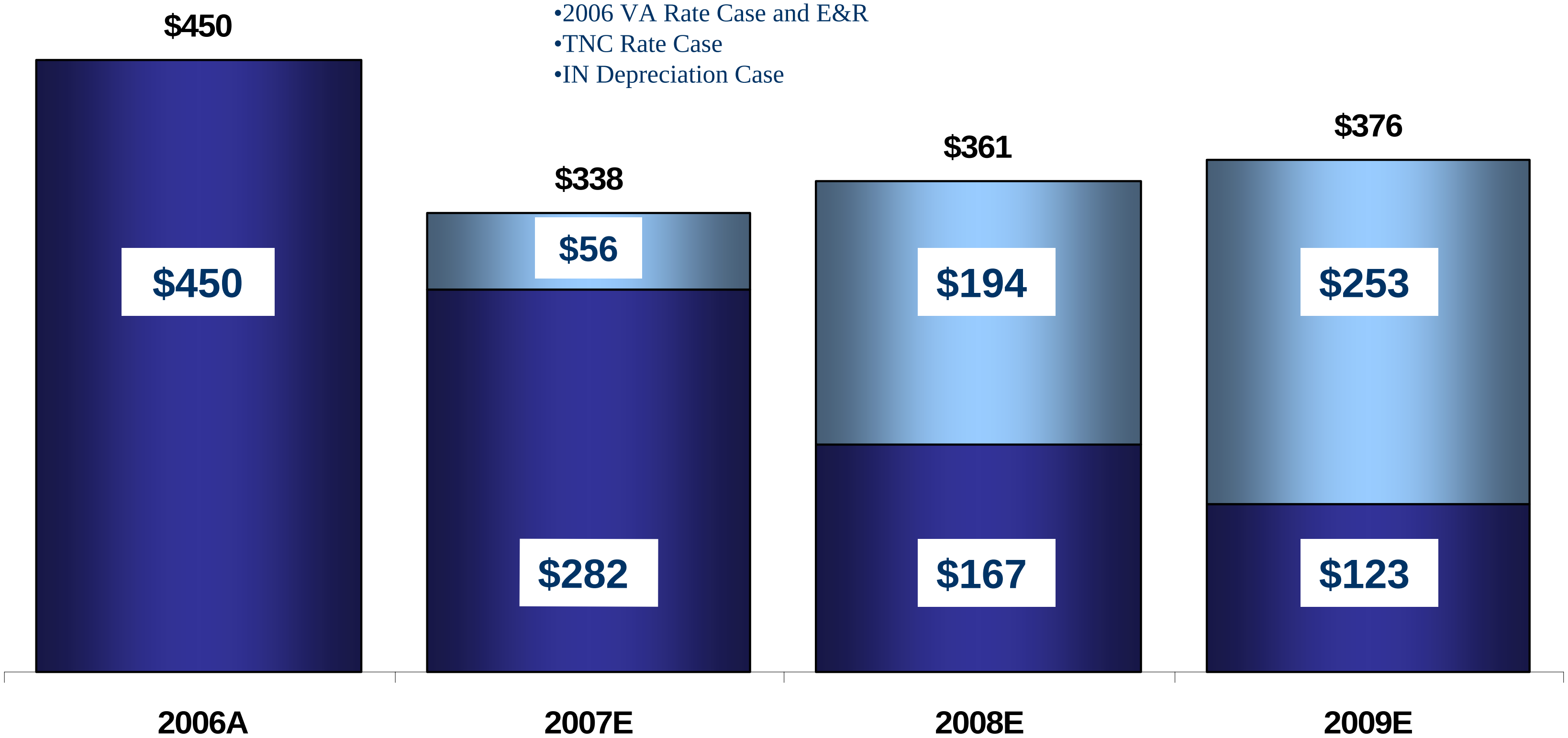
$ Millions

Secured

- OH RSP
- 2006 WV Rate Case, including ENEC
- 2006 Kentucky Rate Case
- FERC & OH OATT
- 2006 VA Rate Case and E&R
- TNC Rate Case
- IN Depreciation Case

Pending/Future

- PSO Rate Case - $49.6 increase requested
- TCC Rate Case - $69.9 increase requested
- SWEPCo proceedings
- Cases yet to be filed



Rate Relief Is A Critical Element To AEP's Financial Success

Regulatory Activity Underway

- ✓ AEP Texas Central Company General Rate Case
- ✓ PSO General Rate Case
- ✓ CSP and OPCo Filing for 4% Increase Provision on Generation Rates
- ✓ I&M Indiana Rate Petition
- ✓ Electric Transmission Texas LLC Request for Certificate of Convenience and Necessity and Initial Rates
- ✓ FERC Seams Elimination Cost Adjustment Proceedings
- ✓ SPP OATT Formula Rate Filing
- ✓ New Generation
  - ✓ IGCC Filing in West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - ✓ IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - ✓ PSO Red Rock Generating Facility Filing in Oklahoma for a Used and Useful Determination
  - ✓ SWEPCo Turk Plant Filings in Arkansas and Louisiana for Certificates of Need

Level Of Capital Investment Will Be Adjusted Based On Rate Recovery And/Or Cash Generation

Regulatory Activity Underway

AEP

AEP Texas Central Company General Rate Case

On November 9, 2006, TCC & TNC filed applications with the PUCT to raise base rates they charge to Retail Electric Providers (REP) serving end-use electricity customers in their service territories. On April 3, 2007, TCC and TNC submitted revised rate increase requests of $69.9MM and $22MM, respectively. Requested increases include the expiration of merger-related billing credits that have been in place since 2000, totaling $20MM and $6.2MM for TCC and TNC, respectively. (TCC Docket #33309, TNC Docket #33310). TNC reached settlement on May 4, 2007 for a $13.7MM increase in revenues and a $2MM increase in depreciation, resulting in an annual increase of $11.7MM. The settlement was approved by the PUCT on May 24, 2007.

Procedural Schedule

March 13, 2007	Intervenor testimony
March 23, 2007	Staff testimony
April 3, 2007	Rebuttal testimony
April 12, 2007	Hearings
May 14, 2007	Rates effective under bond, subject to refund

Final Order expected in September-October 2007

TNC Approved Rate Base

Description	Transmission	Distribution
Total Rate Base	$ 188,152,535	$ 341,375,118

TCC Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	60%	5.86%	3.52%
Common Equity	40%	10.75%	4.30%
Total	100%		7.82%

TCC Rate Base – Company Position (Test Year ended 6/30/06)

Description	Transmission	Distribution
Total Rate Base	$ 588,170,858	$ 1,012,316,518

Regulatory Activity Underway

PSO General Rate Case

On November 21, 2006, Public Service Oklahoma filed an application with the Oklahoma Corporation Commission to increase base rates by $49.6 million to recovery investments already made and costs incurred. The request represents a 4% overall increase (including fuel). The filing also includes a proposal to adopt an annually adjusted rate mechanism, which includes a return on CWIP. The formula rate would adjust rates, up or down, if PSO earns above or below an approved bandwidth around the authorized ROE. (Case #200600285)

Pro-forma Capital Structure – Company Position (Test Year ended 6/30/06)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	53.55%	6.32%	3.39%
Preferred Stock	0.43%	4.02%	0.02%
Common Equity	46.02%	11.75%	5.41%
Total	100%		8.82%

Procedural Schedule

November 21, 2006	Case filed
March 20, 2007	Intervenor and staff testimony filed
April 9, 2007	Rebuttal testimony filed
May 1, 2007	Hearings to commence
May 30, 2007	ALJ report issued
June 13, 2007	Oral closing arguments
July 2007	Final order expected

Pro-forma Rate Base – Company Position (Test Year ended 6/30/06)*

($ in millions)

Rate Base	$ 1,189.4
Rate of Return	8.82%
Operating Income Requirement	$ 104.9
Pro-Forma Operating Income	$ 74.8
Difference	$ 30.1
Revenue Conversion Factor	1.65
Change in Revenues	$ 49.6

July 6, 2007—Implemented Interim rates of $8.6MM for a key provision on which there seems to be agreement.

* Figures are rounded

Regulatory Activity Underway

AEP Ohio Application For 4% Provision On Generation Rate

- On Jan. 23, 2007, CSP and OP filed an application at the PUCO to recover 2007 costs associated with additional generation-related expenditures the companies are encountering related to environmental, security and other new generation-related costs pursuant to the RSP.
- CSP and OP are requesting to implement the provision to recover $24.5MM and $8.2MM, respectively, from May 2007 through December 2007.
- Staff & Intervenor testimony filed May 11, 2007; Staff recommended a $15MM increase at CSP and a $3.7MM increase at OP; OCC recommended a $19.9MM increase for CSP and a $3.7MM increase for OP.
- Hearings were held in May and June and we expect an order in September or October 2007.
- Because there was no specific action by the PUCO within the required time frame, we were allowed to implement these increases, subject to refund, in May 2007.

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM, environmental compliance and capacity equalization settlement.
- I&M requested a test year of the twelve months ended September 30, 2007 but it is up to the IURC to determine the test year to be used.
- I&M will file its revenue requirement in approximately 2-3 months after the end of the stipulated test year.

Regulatory Activity Underway

Electric Transmission Texas (ETT) Rate Filing

- Jan. 22, 2007 – ETT filed with the PUCT for approval to operate as an electric transmission utility in Texas and to establish initial rates for ETT.
  - Requested capital structure of 60% debt / 40% equity; requested ROE of 11.25%.
  - Intervenor testimony filed June 8, 2007; Staff testimony filed June 18, 2007; Staff recommended a 10.50% ROE – 10.0% with a 50 bps addition for start-up risk; Hearings are scheduled for July 16-19, 2007.
  - An order is expected in the third quarter of 2007 and operations are expected to commence in the 2nd half of 2007. Upon receipt of approvals, AEP and MidAmerican will each own a 50% interest in the joint venture.

Seams Elimination Cost Adjustment Revenues

- August 2006 – ALJ rendered initial decision finding SECA rates charged were unfair, unjust & discriminatory.
  - Up to $96MM of SECA revenues could be disallowed, net of unused provisions.
- We believe that major portions of the ALJ's findings either conflict with previous FERC decisions or are without merit or both.
- Exceptions to initial decision filed Sept. 11, 2006; Replies to exceptions filed Oct. 11, 2006; Order expected by the Commission in 2007.

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission serves over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1st.
- The current revenue requirement is $88.7MM and the new total revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff and FERC can suspend for an additional five months, which would push the effective date to February 1, 2008.

Regulatory Activity Underway

West Virginia Mountaineer IGCC Filing

- Testimony filed on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Public hearings are scheduled for September 10-14, 2007 with an order on or before December 2, 2007.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- Oral arguments regarding this matter are scheduled on the Ohio Supreme Court's agenda for October 9, 2007.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.

Regulatory Activity Underway

Oklahoma Red Rock Generating Facility

- Testimony filed on February 1, 2006 in support of PSO's application for a determination that additional baseload electric generating capacity will be used and useful.
- The Oklahoma Corporation Commission consolidated this cause with Oklahoma Gas and Electric's application for an order granting pre-approval to construct Red Rock Generating Facility and authorize a recovery rider.
- Initial staff and intervenor testimony agrees that PSO needs baseload capacity and staff recommends that the OCC find Red Rock used and useful. The biggest challenges related to the RFP process and the debt equivalence issue in evaluating the PPA bids.
- Hearings for the Used and Useful Determination commenced July 9, 2007.
- Hearings for OG&E's cost recovery commence July 19, 2007.

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Depending on contested issues, public hearings will begin either July 19, 2007 or August 9, 2007.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to Purchase, Operate, Own and Install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings are scheduled for September 11-14, 2007.

2007 Regulatory Activity Completed

Appalachian Power – Virginia Base Rate Case

Final order approved on May 15, 2007

- ✓ Results in $24 Million annual increase in base rates
- ✓ 10.0% approved ROE

Texas North Base Rate Case

Final settlement order approved on May 24, 2007

- ✓ Results in $11.7 million increase in pre-tax earnings ($13.7 million increase in revenues offset by $2 million increase in depreciation expense)
- ✓ No stipulated ROE in the settlement. For AFUDC purposes, Texas North will utilize the ROE that comes out of the Texas Central rate case.

Appalachian Power – West Virginia Expanded Net Energy Cost (ENEC) Filing

Final settlement order approved on June 22, 2007

- ✓ Results in $85.5 million net increase in revenues effective July 1, 2007
  - ✓$54.8 million covers increased costs related to coal and purchased power
  - ✓$28.5 million covers environmental construction costs, primarily related to installation of scrubbers
  - ✓Remainder ($2.2 million) recovers first year costs of rehabilitating four small electric utilities acquired as of July 1

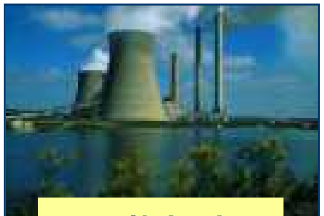
Indiana Michigan Power – Indiana Depreciation Study

Interim settlement order approved on June 13, 2007

- ✓ Allowed a change in depreciation rates effective July 1, 2007, resulting in a pretax earnings increase of approximately $69 million per year
- ✓ Stipulated a $5 million credit to customers in the next fuel adjustment clause proceeding
- ✓ Required I&M to file a rate petition on or before July 1. Petition was filed on June 19.

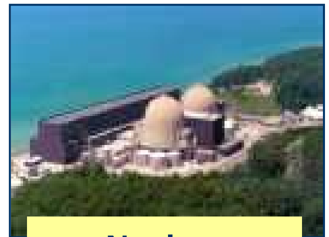
In Hand to Date - $282MM of the $338MM Rate Recovery in 2007 Guidance

Domestic Generation Fleet



Coal/Lignite
67%

Nat. Gas/Oil
24%



Nuclear
6%

Pumped Storage/
Hydro/Wind
3%

AEP's Generation Fleet
38,388 MW Capacity

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2004	85.19%	62.43%
2005	84.52%	62.04%
2006	82.87%	60.98%

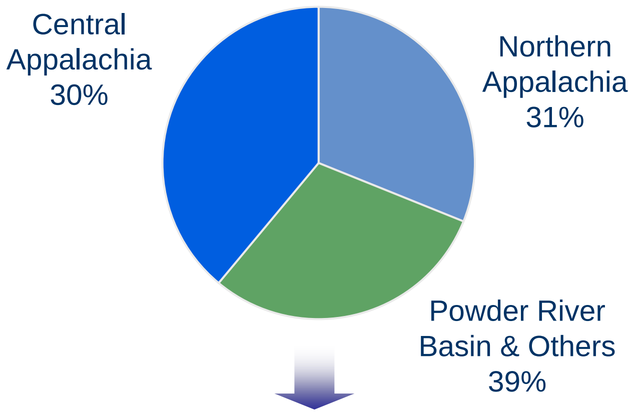
NERC Regional Presence

RFC (formerly ECAR)	72%
SPP	23%
ERCOT	5%

Coal Procurement – 2007 Projected

AEP purchases approx. 76 million tons of coal per year

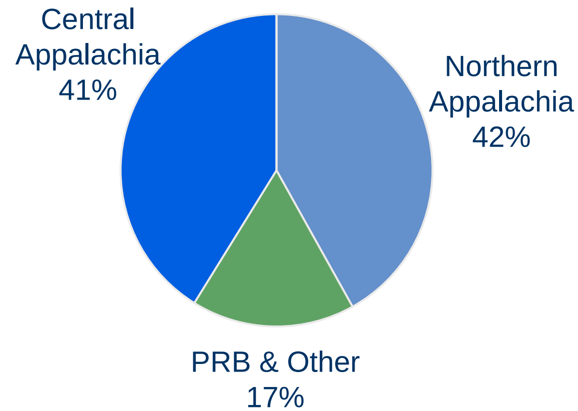
Total AEP System



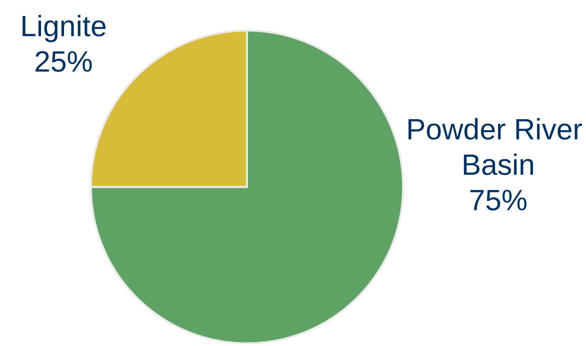
Coal Stats:

- 95% contracted for 2007
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 7-9% price increase in 2007 -- ($37.50 to $38.50/ton)
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East

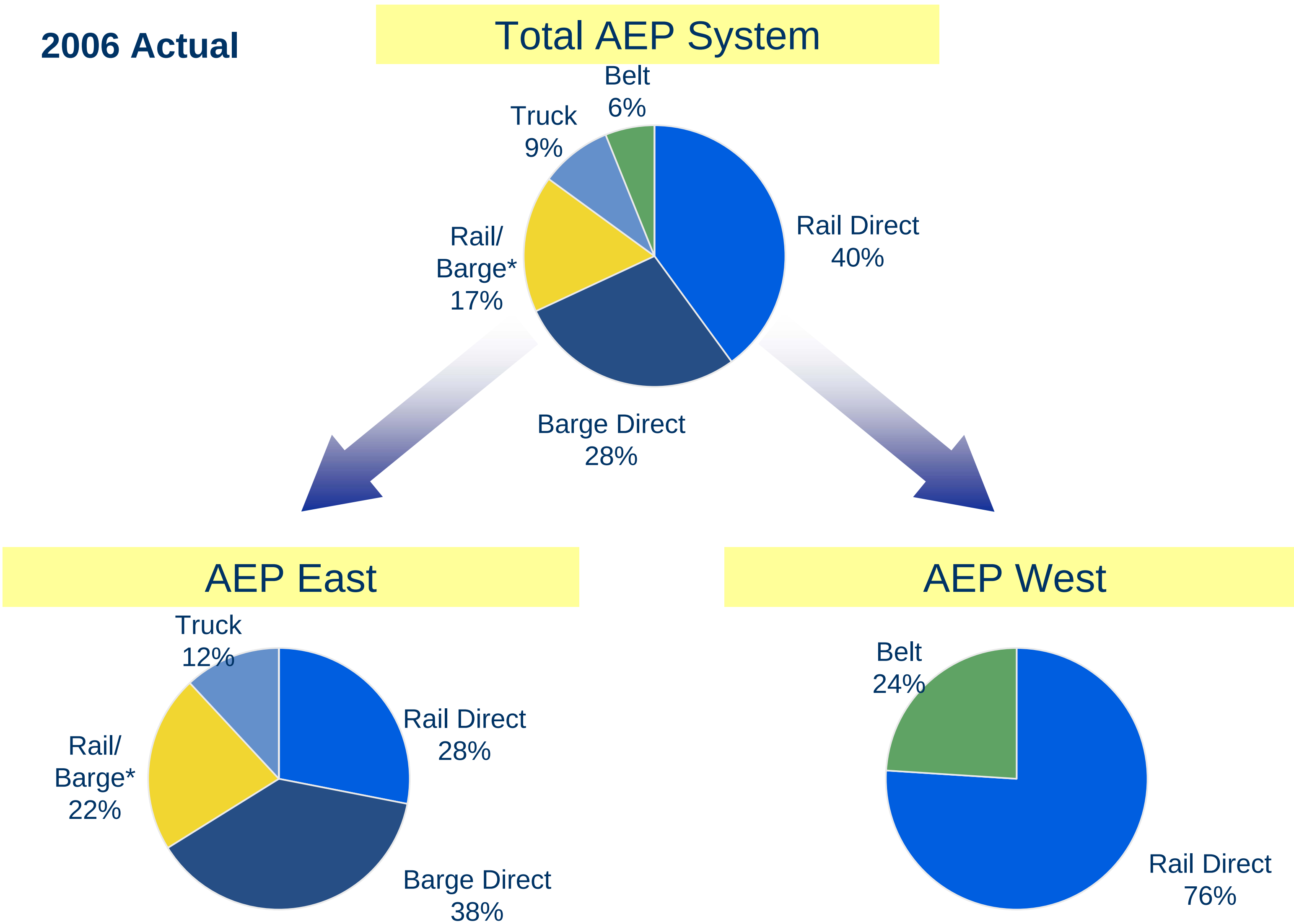


AEP West



Coal Delivery

2006 Actual



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$443***
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,867**

Add: Lawrenceburg Plant Purchase $325

2007 Including Lawrenceburg **$3,867**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

*Includes Lawrenceburg purchase $325MM in 2007

Growth Investment To Be Funded By Cash From Operations Via Rate Relief And Debt Issuances

2007 Ongoing Guidance: $2.85 to $3.05 Per Share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		2006 Performance Driver	2006 Actual ($ millions)	2007 Performance Driver	2007 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,440
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,433
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,046
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	520
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	617
6	Transmission Revenue - 3rd Party		271		276
7	Other Operating Revenue		527		627
8	**Utility Gross Margin**		7,342		7,959
9	Operations & Maintenance		(3,201)		(3,353)
10	Depreciation & Amortization		(1,411)		(1,476)
11	Taxes Other than Income Taxes		(735)		(775)
12	Interest Exp & Preferred Dividend		(670)		(773)
13	Other Income & Deductions		246		101
14	Income Taxes		(543)		(566)
15	**Utility Operations On-Going Earnings**		1,028		1,117
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		67
17	Generation & Marketing		12		29
18	**Non-Utility Operations On-Going Earnings**		92		96
19	**Parent & Other On-Going Earnings**		(27)		(40)
20	**ON-GOING EARNINGS**		1,093		1,173

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance*
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of the $2.85 to $3.05 per share guidance range.

Cash On Hand Expected To Be $205 Million At Year End 2007

Multi-Year Capital Investment Funding Plan

	Actual 2006	Projection 2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

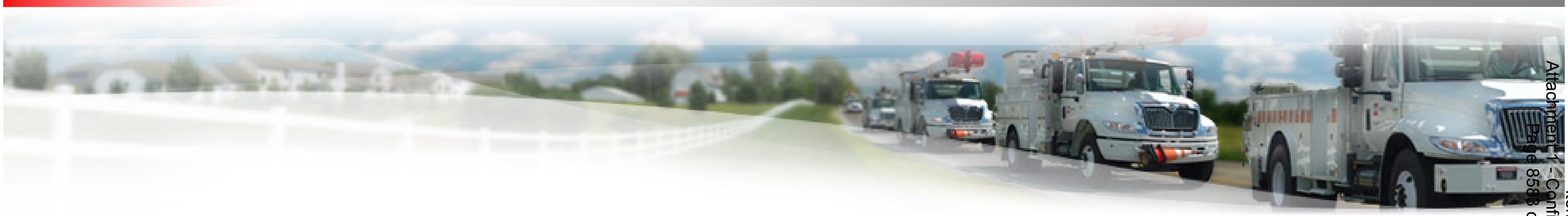
* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital Investment Is Funded By Cash From Operations And Debt Issuances

AEP AMERICAN ELECTRIC POWER®

Philadelphia Securities Association Presentation

Philadelphia, PA
August 17, 2011



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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Value Proposition to Retail Investors

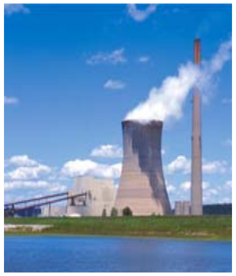
- **Attractive Yield Opportunity near 5.0%**
  - 50-60% payout ratio targeted
  - Quarterly dividend increased 12% in 2010
  - 404 consecutive quarters of dividend payments to our shareholders
- **Earnings Growth Prospects**
  - 4 – 6% in the 2012 to 2014 time frame
  - 5 – 7% beyond 2014

Current Wall Street Analyst Coverage:

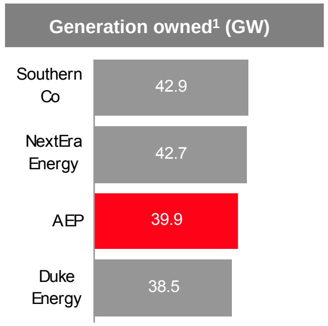
- **24 analysts**
- **12 Buy Ratings**
- **11 Hold Ratings**
- **1 Sell Rating**

Attractive total return potential

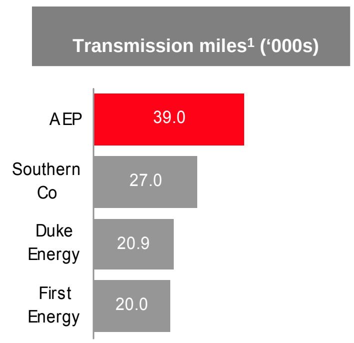
American Electric Power



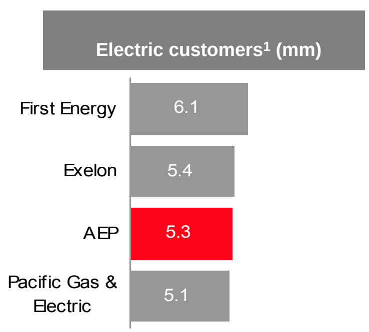
One of the largest
U.S. electricity generators



The largest U.S. electricity
transmitter

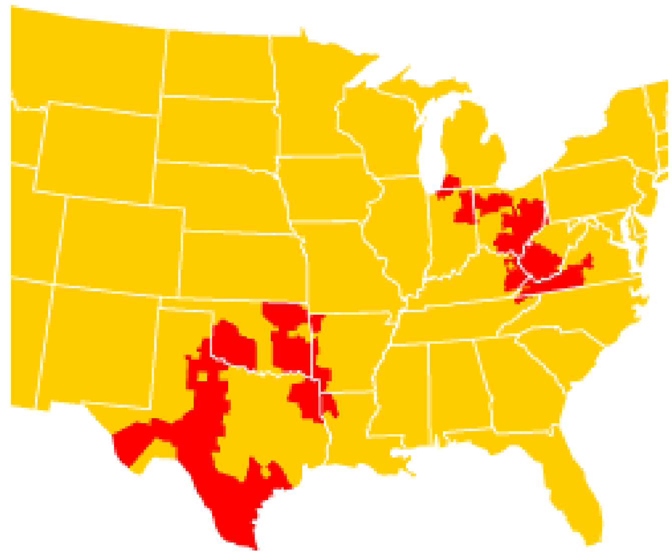


One of the largest U.S.
electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

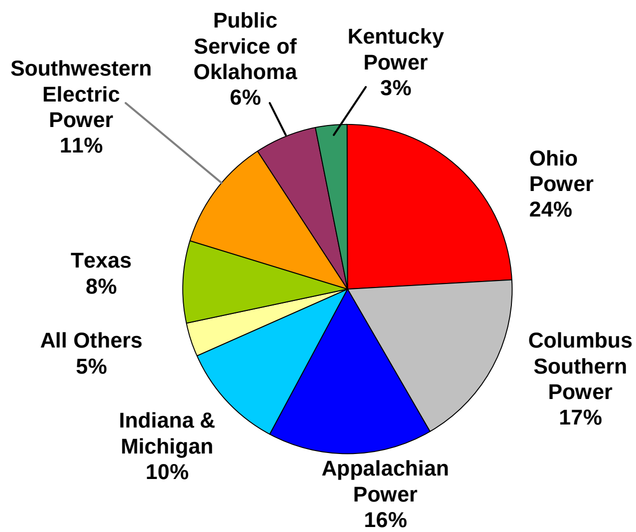
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.2B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

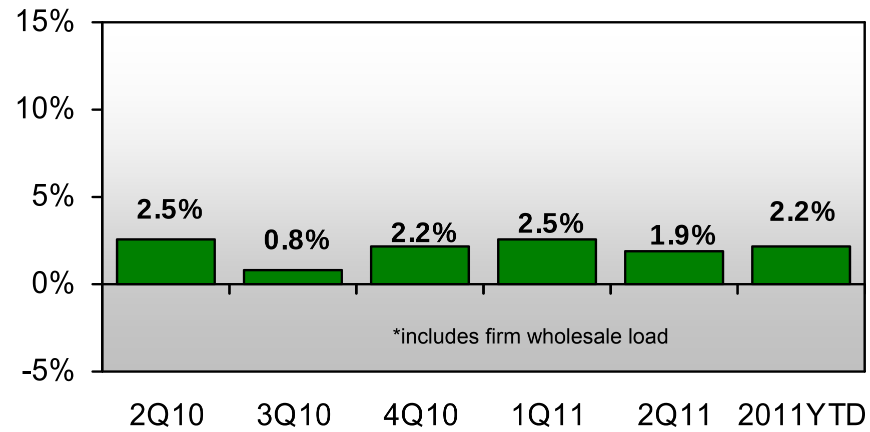
Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



AEP Total Normalized GWh Sales*

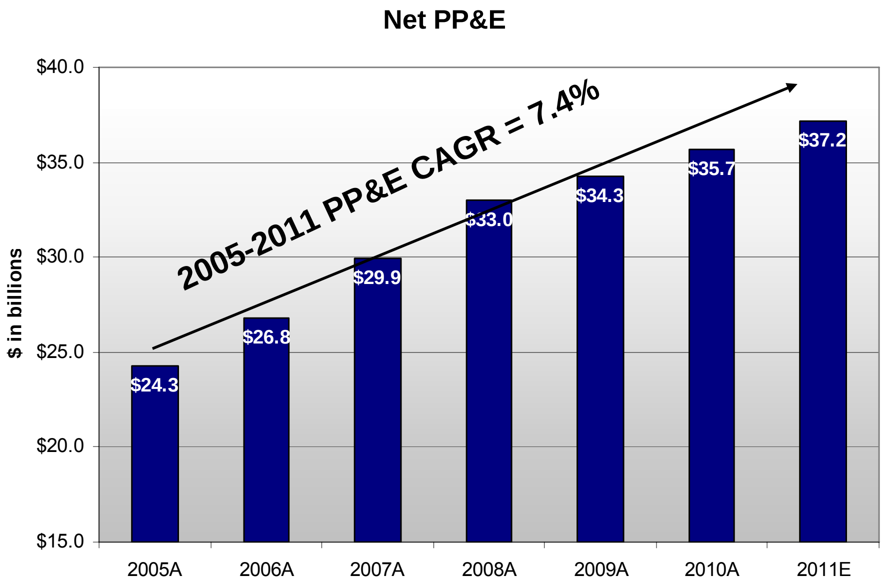
%Change vs. Prior Year



Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Ratemaking Environment

Growth in Net PP&E



Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

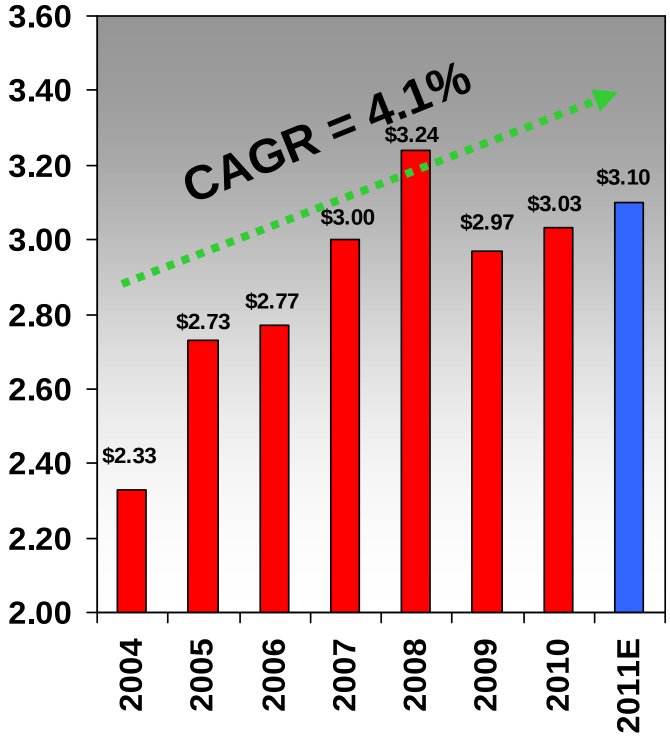
Regulatory Framework

- Base Rates
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- Recovery of Fuel Costs
  - Active fuel clauses in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)
  - Current generation rates set for 2009 – 2011
  - New filing currently with PUCO to set generation rates for 2012 – 2014; outcome expected in 4Q11
  - Customers have choice for generation service

Earnings and Dividends

On-Going EPS History Since 2004

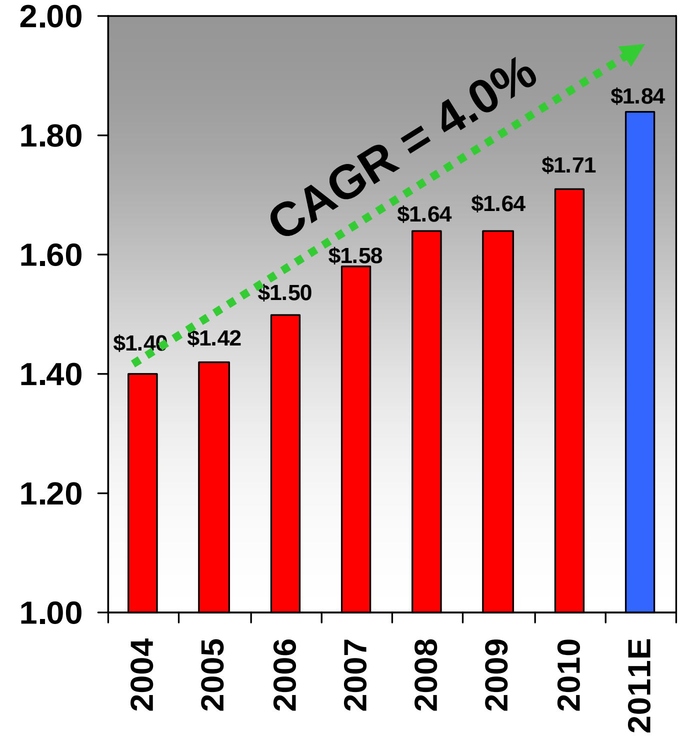
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

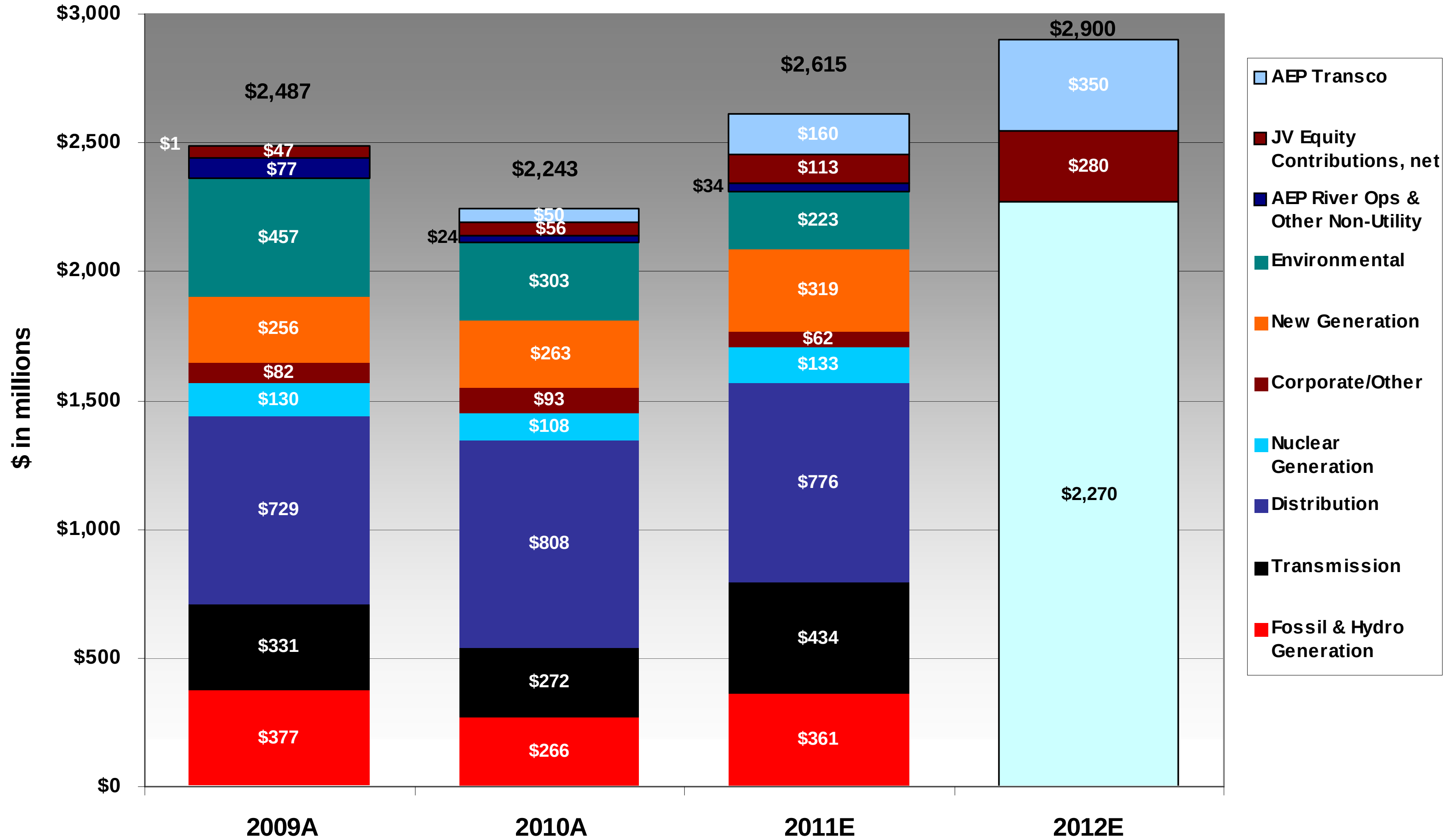
$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend declared in July 2011
- 50-60% payout ratio target
- Current yield near 5%

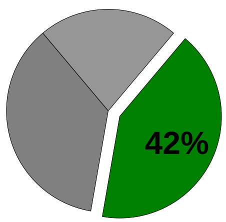
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

AEP Coal Fleet Assessment

Least Exposed



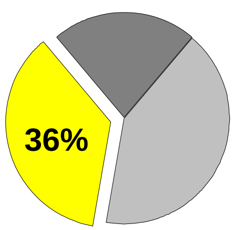
Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

2012 – 2020

Range of Capital ($Millions) [1]

Proposed Rules		Low		High
Water Rules [2]	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules [3]	$	1,425	$	1,900

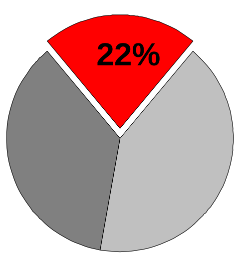
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High
Water Rules [2]	$	55	$	85
CCR Rules	$	385	$	520
Air Rules [3] [4]	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

Proposed Rules		Low		High
Water Rules [2]	$	-	$	5
CCR Rules	$	30	$	45
Air Rules [3] [4]	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CSAPR and Regional Haze Federal Implementation Plans in OK & AR.

(4) Includes NSR Compliance.

Additional Investment Opportunities

ETT Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:**
  Current rate base is $412 million; expected to grow as follows:
  2011: $482 million
  2012: $778 million
  2013: $1,352 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

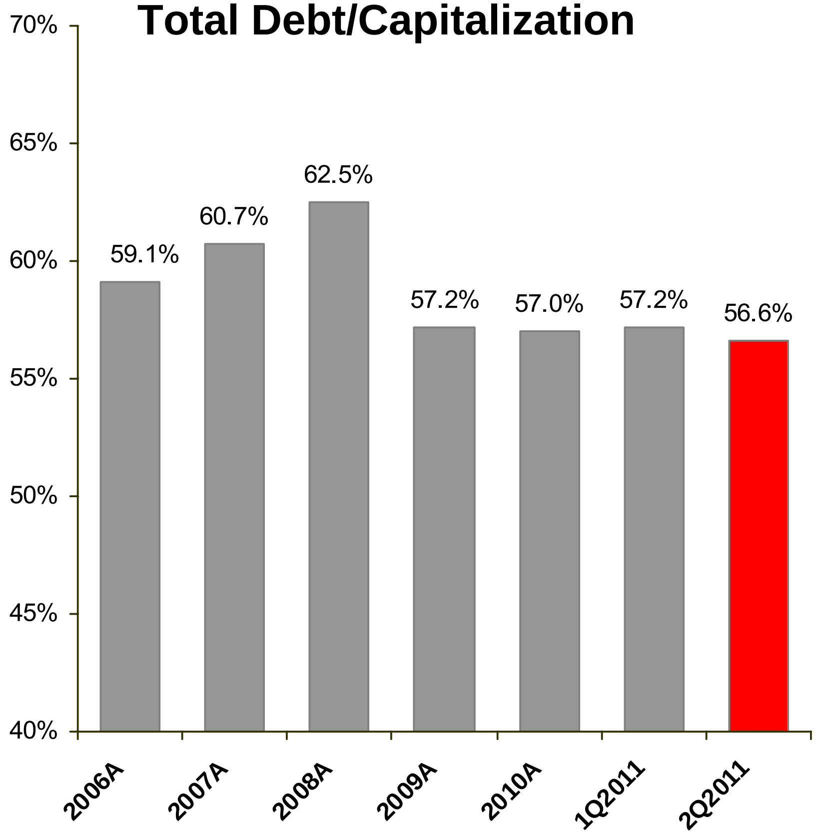
AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $160 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

Additional joint ventures diversify AEP's investment outside the traditional footprint while providing longer-term incremental earnings.

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

AEP Highlights

- Large, Diverse Electric Utility
- Focus on Capital Allocation
- Strong Balance Sheet
- Growth Opportunities
- Dividend yield near 5%

Mountaineer Plant (WV)

AMERICAN ELECTRIC POWER

Renewable Energy Finance Forum

New York, NY

June 24, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company's Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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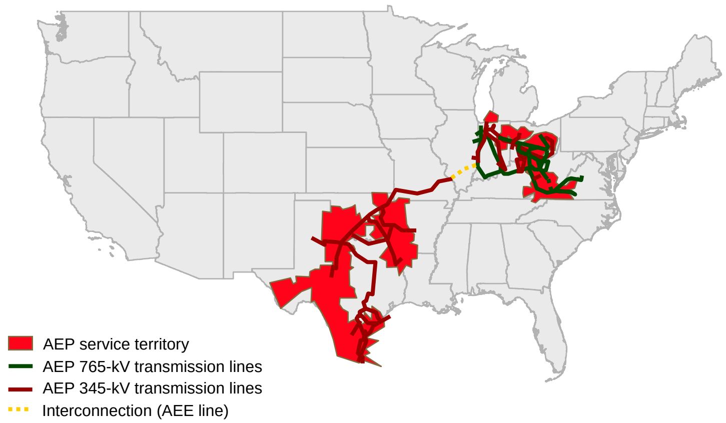
AEP AMERICAN ELECTRIC POWER

Holly Koeppel
EVP and Chief Financial Officer

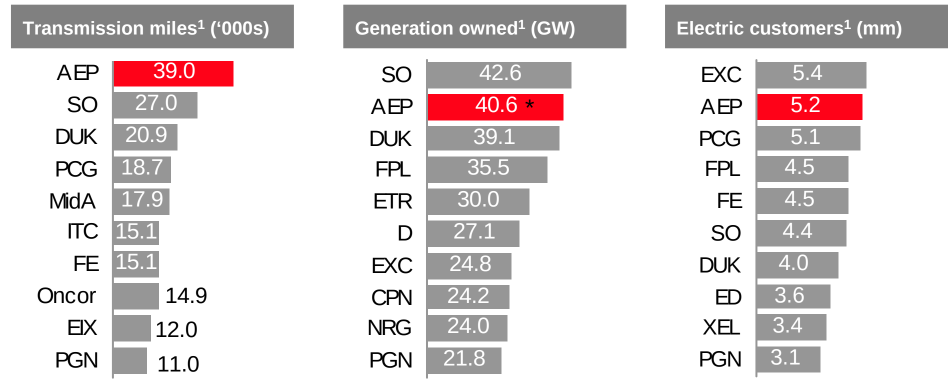
AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

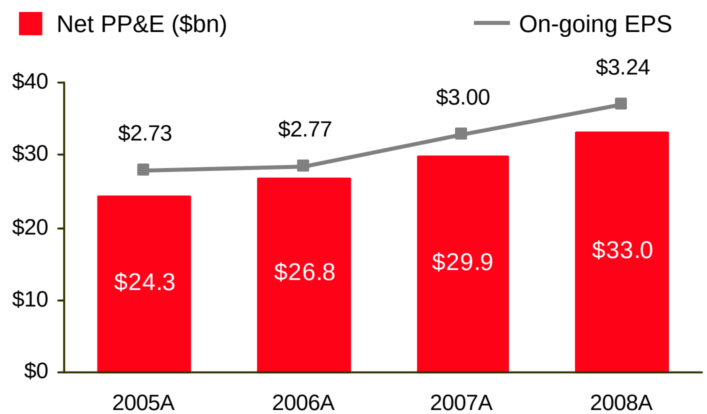


AEP's Leadership Position

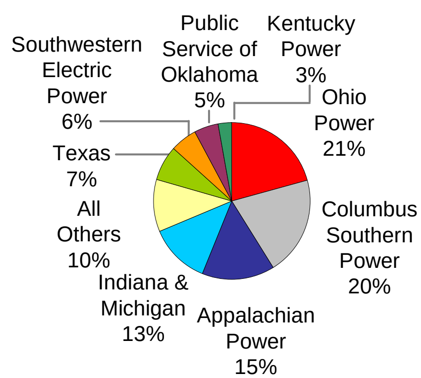


* - AEP generation includes long-term PPAs and generation under construction

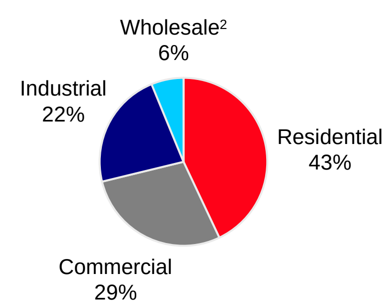
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

[1] Source: Company filings
[2] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8599 of 9556

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

AEP AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

Renewable Energy

- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of new renewables capacity via long-term PPAs – 903MW achieved to-date

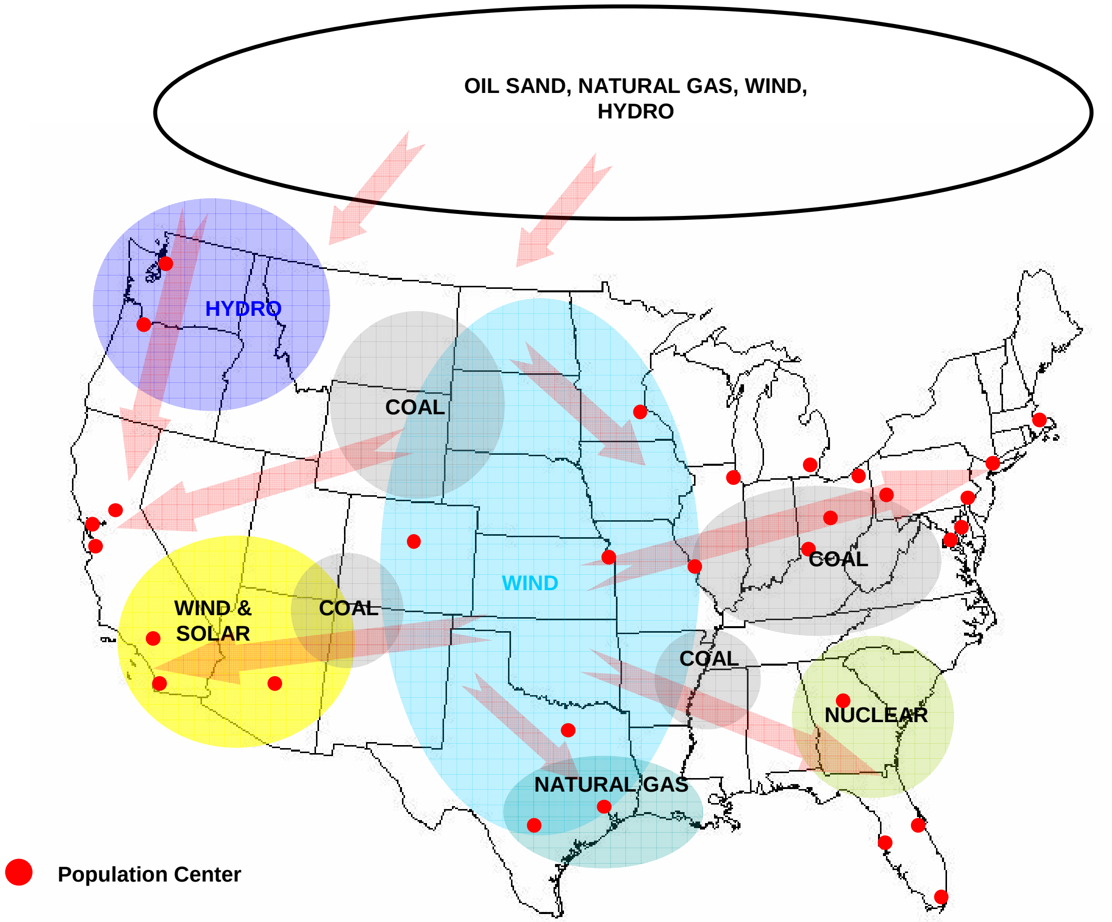
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

AEP AMERICAN ELECTRIC POWER

US Renewable Opportunities

- The U.S. has a large renewable resource base distant from major load centers
- State level mandates may provide some opportunity – utilities are more likely to contract with PPAs based on the current regulatory framework
- "Many of our resources, whether it's wind or sun or geothermal, they're out in rural areas…and we just don't have any infrastructure. If we're going to take this whole energy piece on the renewable side seriously ... we've got to get the transmission and infrastructure piece right" ***Utah Gov. Jon Huntsman - AP Western Governors, Utility Heads Seeks Energy Solutions July 1, 2008***



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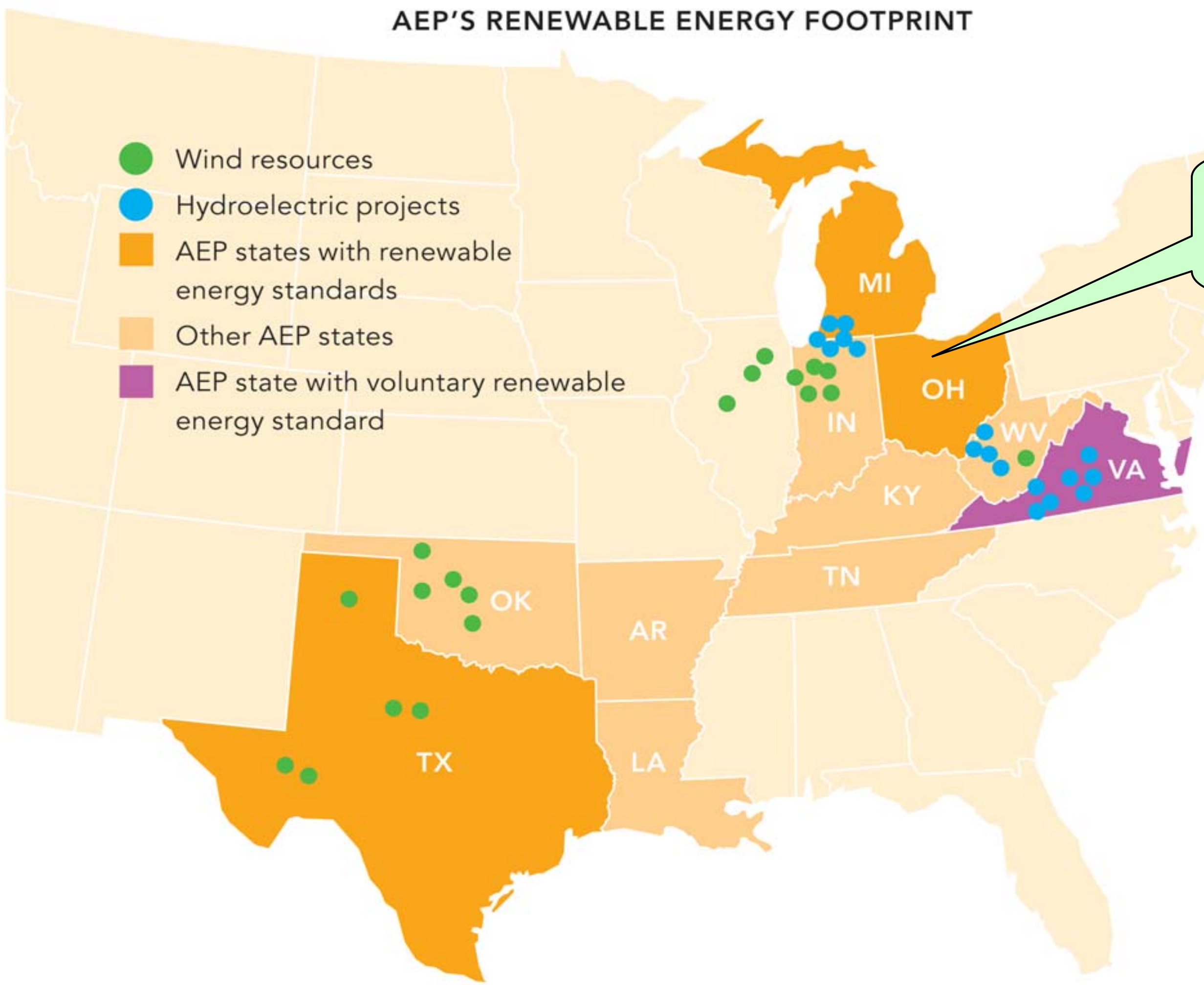
AEP Renewable Footprint



New 10 MW Solar PPA with juwi Solar Inc.

Renewables Portfolio*

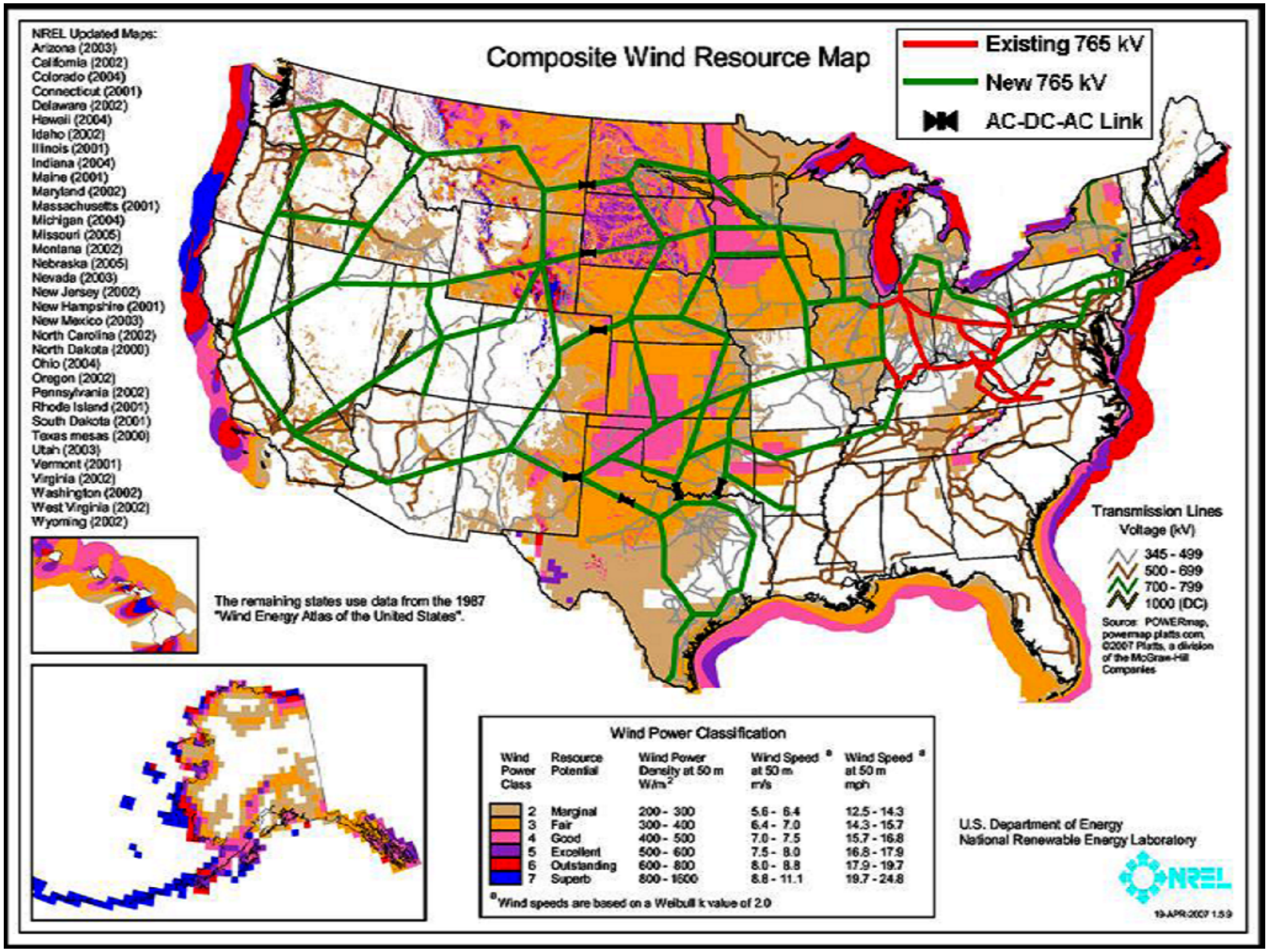
Wind	
PSO – 5 PPAs	591MW
SWEPCo – 1 PPA	79MW
APCo – 4 PPAs	376MW
I&M – 2 PPAs	150MW
AEP Ohio – 2 PPAs	100MW
Total Regulated	**1,296MW**
AEPEP – owned	310MW
AEPEP – 2 PPAs	177MW
Non-regulated	**487 MW**
Hydro (run-of-river)	
Regulated – owned / PPA	**364MW**
Solar	
Regulated - PPA	**10MW**

*** Includes owned assets and long-term purchased power agreements (PPA)**

AEP AMERICAN ELECTRIC POWER

AEP's HV Transmission Vision

- 765 kV backbone system that provides cost-effective connections from areas of high wind potential to major load centers
- Approximately 19,000 miles of new 765 kV transmission lines
- Plan is estimated to cost $60 billion in 2007 dollars



Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m²	Wind Speed at 50 m m/s	Wind Speed at 50 m mph
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

Wind speeds are based on a Weibull k value of 2.0

http://www.aep.com/about/i765project/docs/WindTransmissionVisionWhitePaper.pdf

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

Pioneer — **COD: 2015**

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

PATH-WV — **COD: 2014**

- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

Tallgrass — **COD: 2013-14**

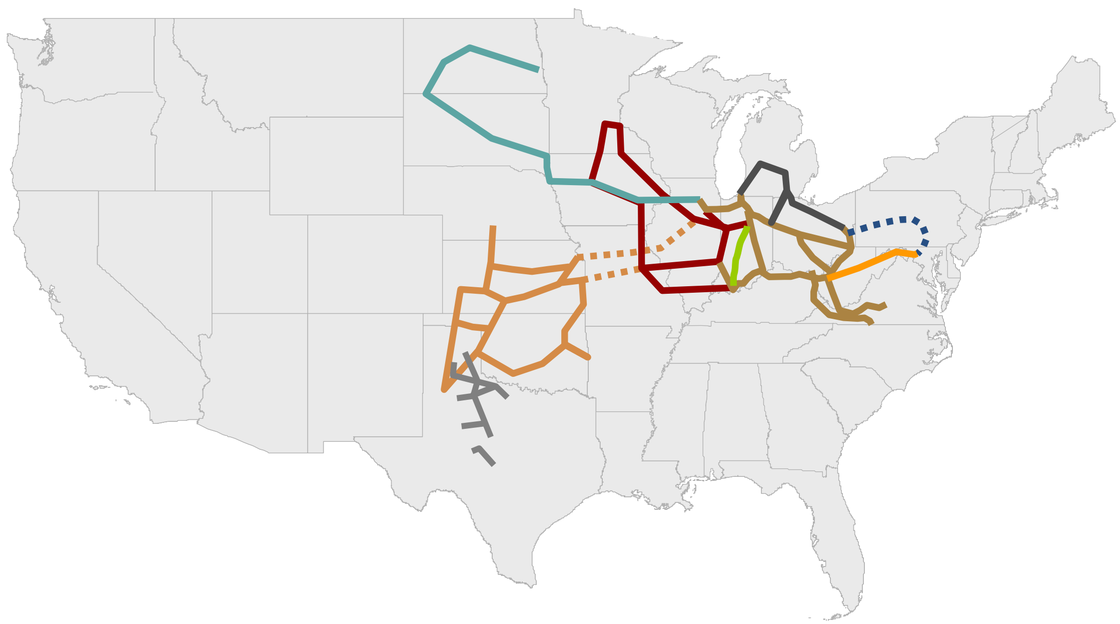
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

Prairie Wind — **COD: 2013**

- *110 miles of 765 kV*
- *Partners: Westar Energy (50%) & MidAmerican Energy (25%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

ETT — **COD: 2013**

- *345 kV in ERCOT*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 9.96%*



Future Projects:

EHV Michigan — **COD: ~2020**

- *700 miles of 765 kV*

PJM Projects

- *Enhance existing 765/345 kV*

Hartland — **COD: ~2020**

- *1000+ miles of 765 kV*

MISO Vision Plan

- *765 kV Backbone*

SPP Overlay — **COD: 2013-14**

- *765 kV Backbone*

ETT — **COD: ~2018**

- *345 kV in ERCOT*
- *Additional CREZ spend of $750-$850 million*

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

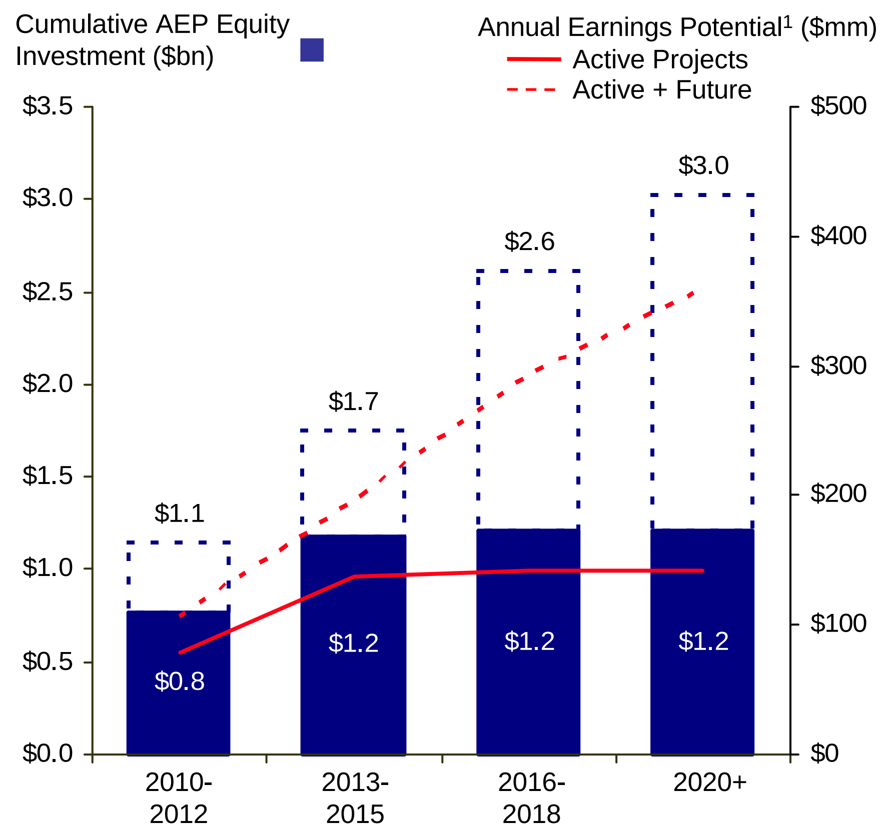
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

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Policy Changes Will Clear the Way for Interconnection of Renewable Resources

- To achieve good public policy while advancing our transmission business strategy, AEP took a leadership role in national and regional public policy debates
- Emerging policies must directly support and encourage development of new transmission investment to interconnect renewable resources and meet our nation's future energy needs, since a Federal mandate to use renewable energy resources alone will not suffice
- Today, our nation lacks a workable Federal process for coordinating the development of transmission across regions and ensuring timely siting of an extra high voltage multi-state transmission system
- AEP's goal is to remove barriers to timely transmission investment through clear and improved rules that encourage transmission investment
- We are vigorously pursuing comprehensive Federal legislation to create Federal siting authority, broad cost allocation, and expedited planning
- Within the current regional framework, we are seeking to expedite planning for EHV systems and establish broad cost allocation principles within and across RTOs
- We continue to strongly support Federal incentives for capital investment in transmission infrastructure

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Smart Grids Enabled with Energy Storage Can Accommodate Intermittent Renewables

- ❑ Advanced monitoring communications and control, integrated into the distribution system, is a major element of the emerging Smart Grid.

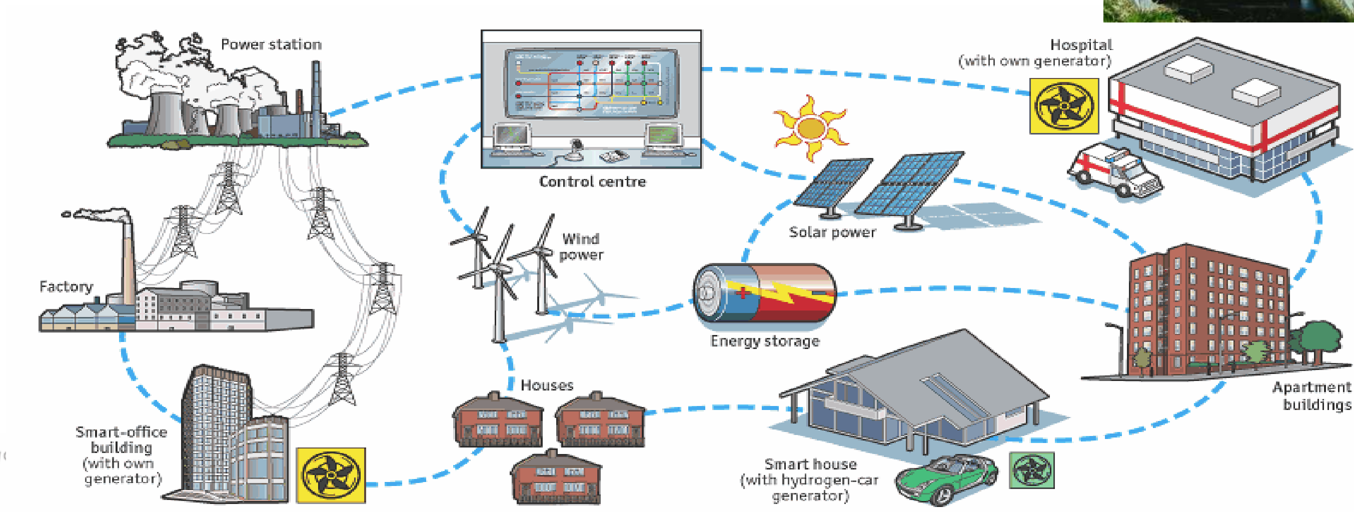
- ❑ Energy storage can decouple load from generation, as well as, accommodate the variability in customer-owned distributed generation.

- ❑ Smart Grids enhanced with broadly distributed energy storage can buffer the grid from the intermittency of supply inherent in some types of renewable generation.

  - After a successful deployment of substation NaS batteries, AEP is expanding its storage experience to a new game-changing platform, ***Community Energy Storage*** (CES).

    – ***Uses new or used batteries from electric cars***

    – ***Functions as a substation battery when aggregated***



Sources: *The Economist*; ABB

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Questions

AEP AMERICAN ELECTRIC POWER®

Ohio Retail Brokers Luncheon
Columbus, OH
January 11, 2010

General JM Gavin Coal Plant (OH)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants including our ability to restore I&M’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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Mike Morris, Chairman and CEO

Value Proposition to Retail Investors

- **Attractive Yield Opportunity of 4.7%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)

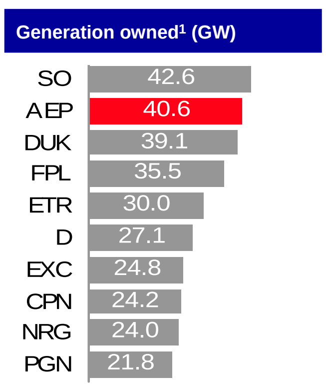
Current Wall Street Analyst Coverage:

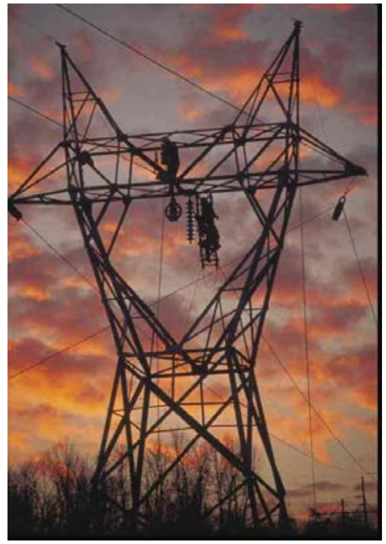
- 20 analysts
- 13 Buy Ratings
- 7 Hold Ratings

[1] yield percentage based on AEP closing price of $35.19 on 01/07/2010

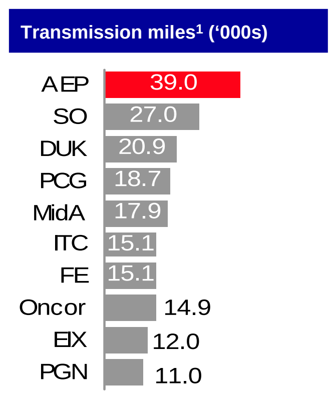
Industry Leadership

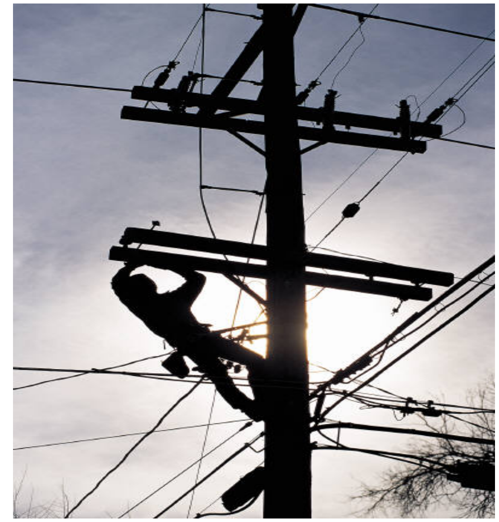
One of the largest U.S. electricity generators



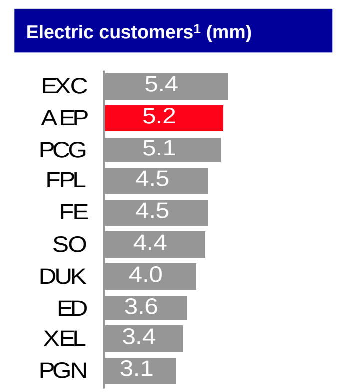


The largest U.S. electricity transmitter



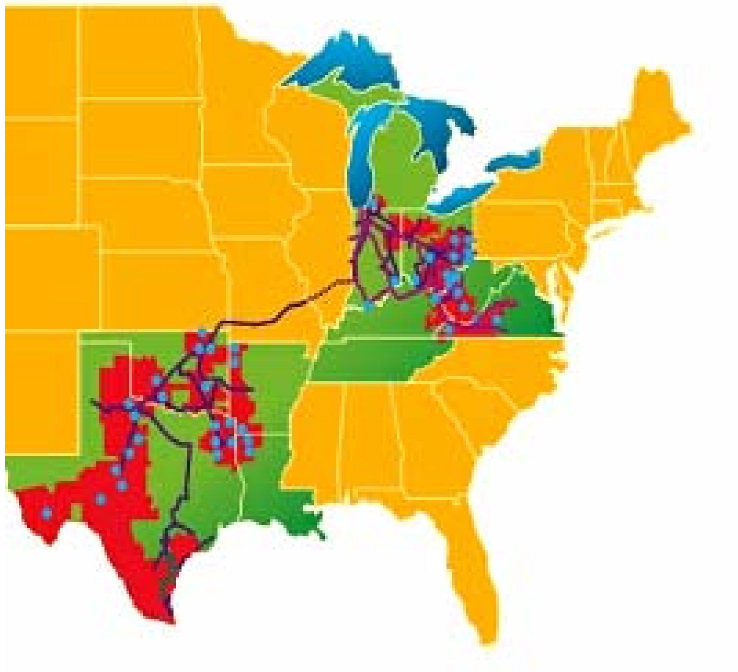


One of the largest U.S. electricity distributors serving 5.2MM customers



[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

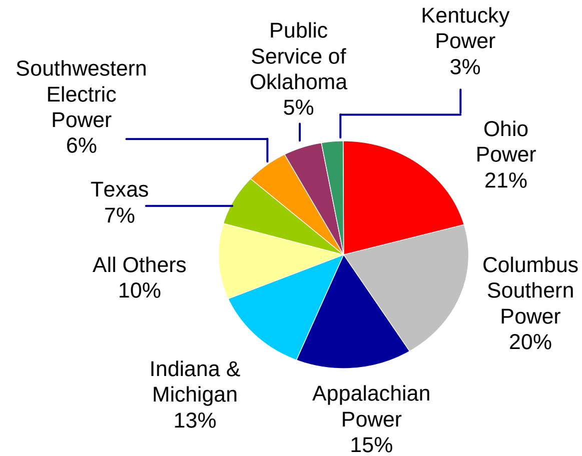
Highly Diversified Regulated Utility



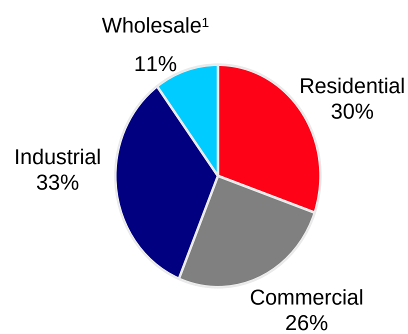
Serving customers in 11 states as:

- AEP Ohio
- AEP Texas
- Appalachian Power
- Indiana Michigan Power
- Kentucky Power
- Public Service Co of Oklahoma
- Southwestern Electric Power

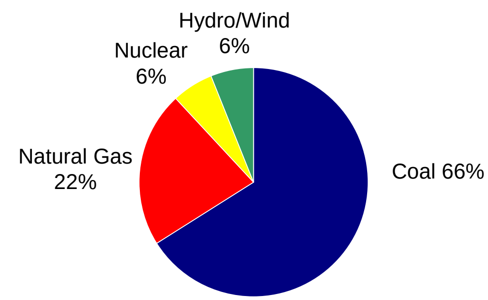
2008 Earnings Contribution



2008 Retail Load



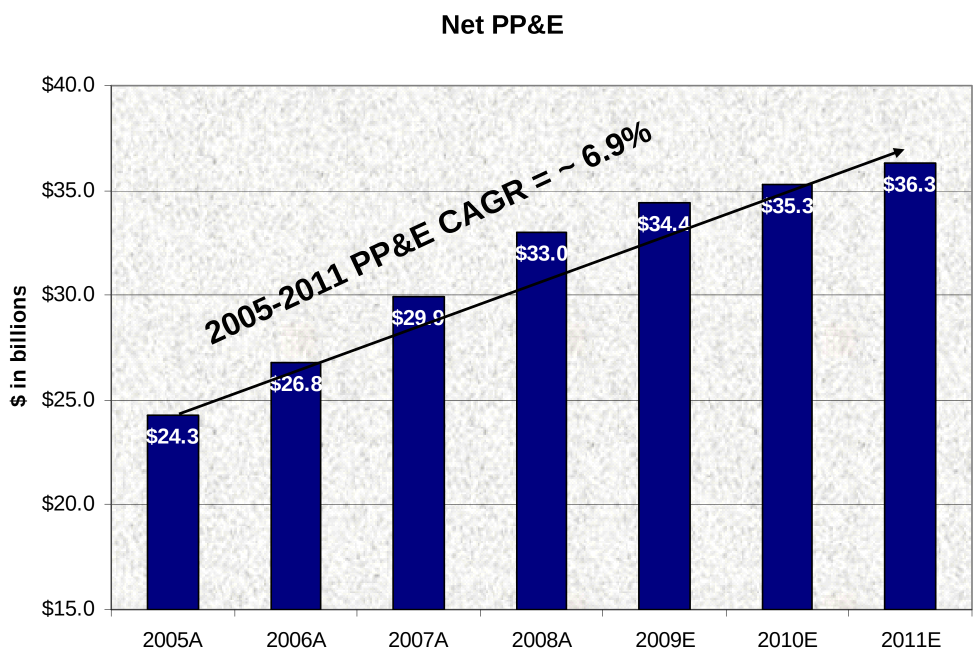
Fuel Mix



[1] Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales

Traditional Ratemaking Environment

Growth in Net PP&E



Growth in rate base resulting in $2 billion of rate relief secured from 2006 through 2009

- **Base Rates**
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- **Recovery of Fuel Costs**
  - Active fuel clauses in all jurisdictions
- **Opportunities to Reduce Regulatory Lag**
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- **Ohio Generation Rates set by PUCO according to SB221 (non-cost based)**

Energy Policy Initiatives = Opportunities

AEP®

Policy: Greenhouse Gas Emissions Reductions

Technology: Mountaineer Carbon Capture and Storage Project

Policy: Renewable Energy Standards; Energy Efficiency, Security and Reliability

Technology: Industry Leading High Voltage Transmission and gridSMART℠ Projects

Carbon Capture and Storage Project – Mountaineer Plant (WV)

765-kV Transmission Line – Wyoming-Jacksons Ferry (WV)

Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.1B in the next decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Energy Policy Initiatives Create Technology Deployment and Investment Opportunity
  - Greenhouse Gas Emissions Reductions
  - Energy Efficiency, Security and Reliability
- Strong Value Proposition

Brian Tierney, EVP and Chief Financial Officer

2010 Ongoing Earnings Guidance

AEP®

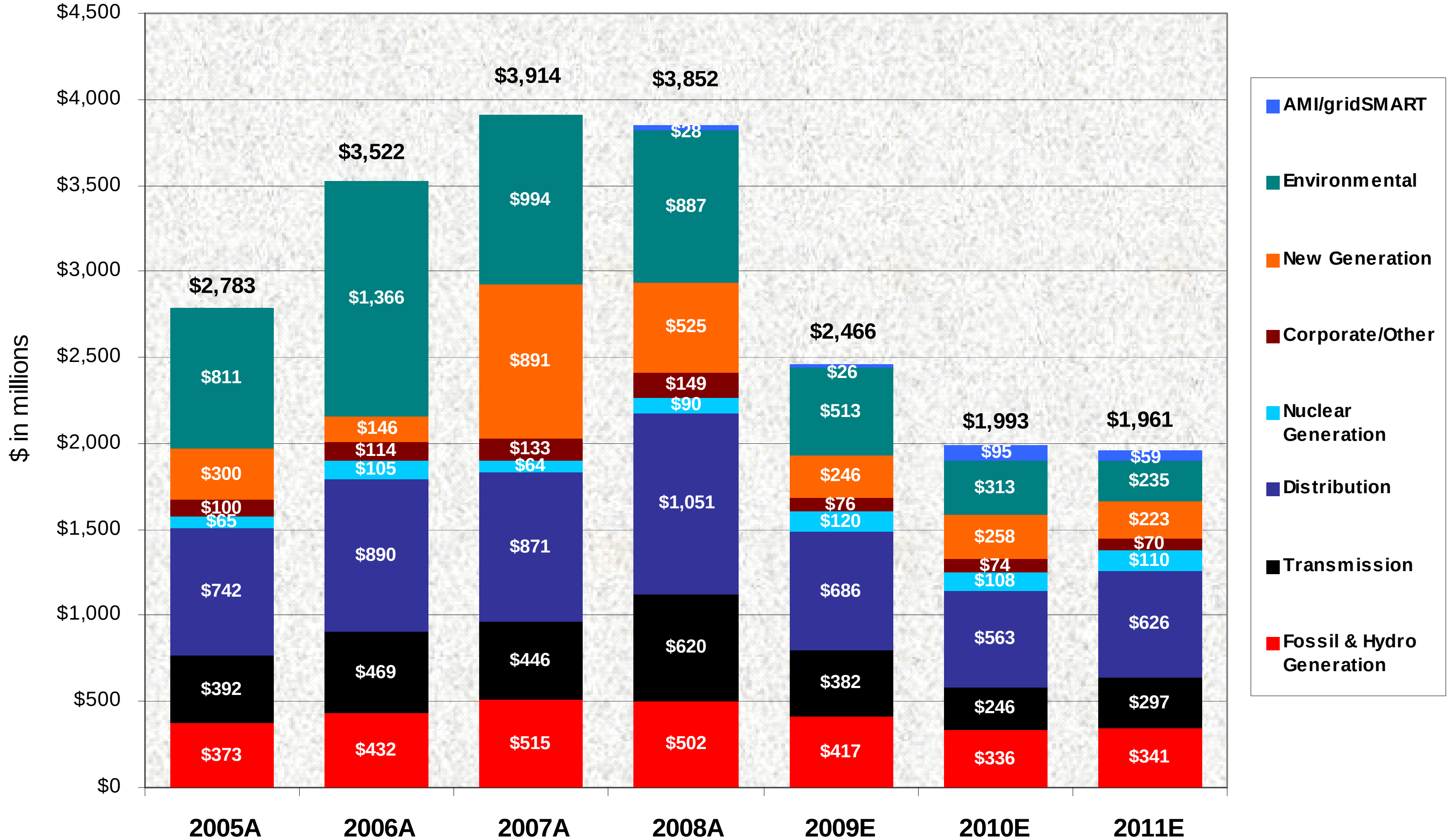
	2009E: $2.90-$3.05	2010E: $2.80-$3.20
Utility Operations	$ 2.92	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.18	$ 0.09
Parent & Other	$(0.14)	$(0.12)

EARNINGS DRIVERS

- ↑ $317MM in rate relief
- ↑ Increase in off-system sales volumes
- ↑ Load growth

- ↓ Net increase in utility operations O&M of $72MM
- ↓ Elimination of Cook accidental outage insurance proceeds
- ↓ Increase in average shares outstanding

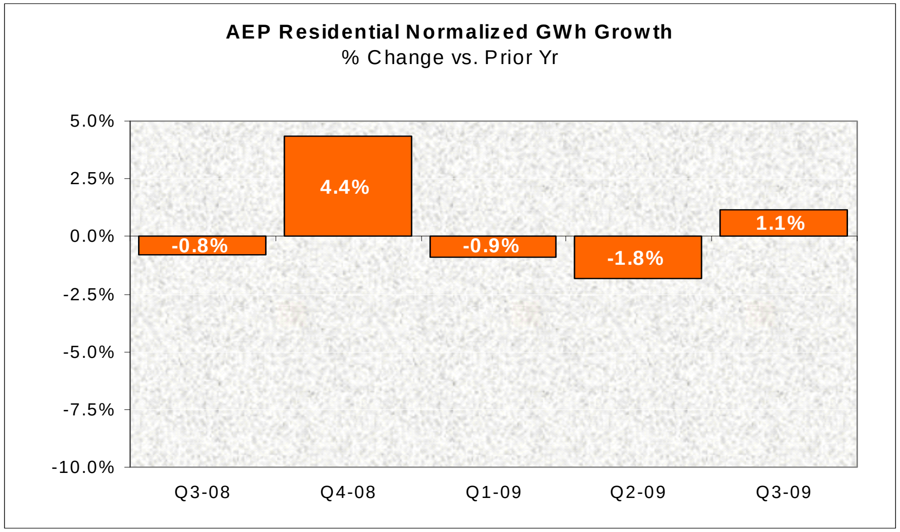
Utility Operations Capital Expenditures

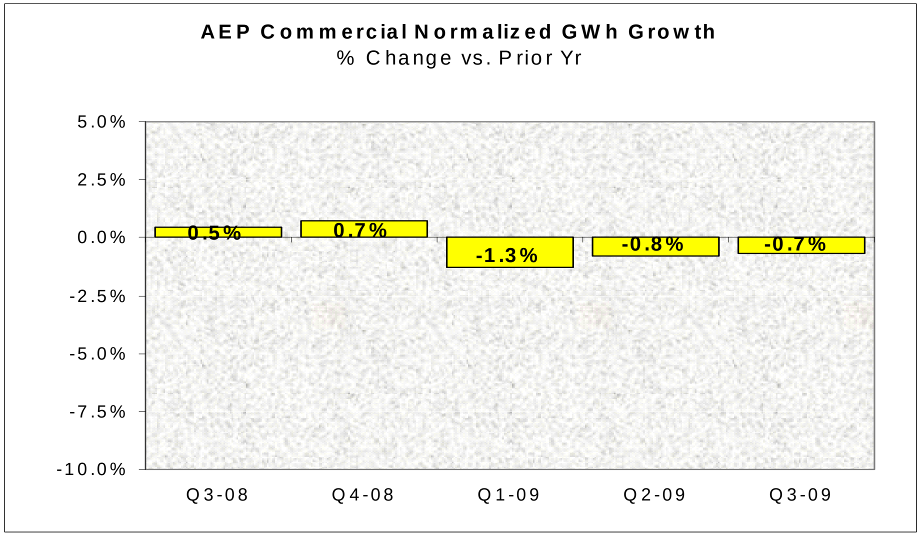


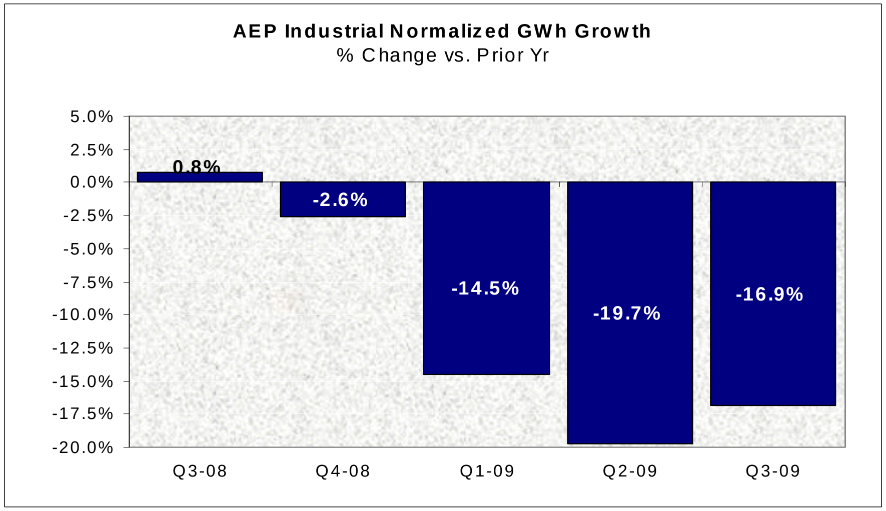
Non-Utility Operations Capital (not included above)

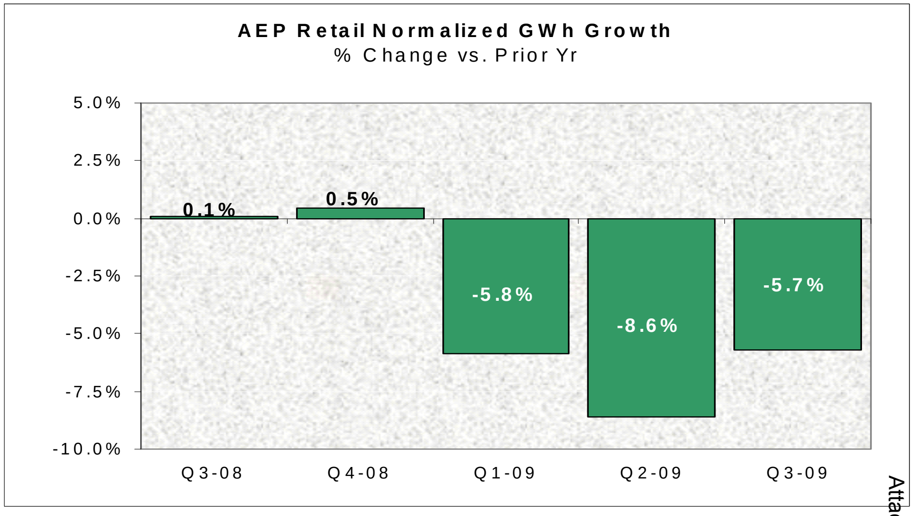
$ in millions	2008A	2009E	2010E	2011E
AEP River Operations	$115	$79	$16	$20
AEP Transco	0	0	$118	$175 - $325
Joint Venture Equity	$5	$49	$93	$155 - $355

12-Month Normalized Retail Load Trends









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Dividend Overview

- We have paid 398 consecutive quarterly dividends to shareholders
- Annual Dividend - $1.64/share
  - Declared in January, April, July and October
  - Paid in March, June, September and December
- Attractive yield of 4.7% as of January 7, 2010
- Conservative target dividend payout ratio of 50 – 60%
- Dividend Reinvestment Program Available

Investment Attributes

- **Strong utility platform**
  - Consistent regulatory outcomes
  - Active fuel recovery
  - Geographic and regulatory diversity
  - Growth through capital investment

- **Total Return Opportunity**
  - Consistent dividend policy
  - Growth Opportunities

Mountaineer Plant (WV)

American Electric Power

San Francisco Road Show

Hosted by UBS Investment Bank
November 28, 2007

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

SAN FRANCISCO ROAD SHOW

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate relief or other recovery for new investments transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting setting bodies; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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AEP Strategy

Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

Financial Forecast Highlights

- Updated 2008 & 2009 earnings guidance ranges and introduction of 2010

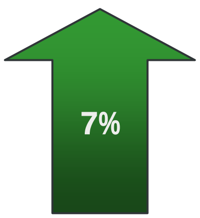
2007 Range $2.90 to $3.00	**2008 Range $3.05 to $3.25**
2009 Range $3.20 to $3.50	**2010 Range $3.45 to $3.80**

- Increased EPS growth range: 5-9% (2007-2010)
  - Disciplined investment in utility operations
  - Innovative rate recovery for new investments
  - Continued pursuit of Ohio post-2008 solution
  - Cost management
- 8-cent/share increase in annual dividend effective 4Q07 (from $1.56/share to $1.64/share annually)
- Refined capital investment forecast and introduction of 2010 level

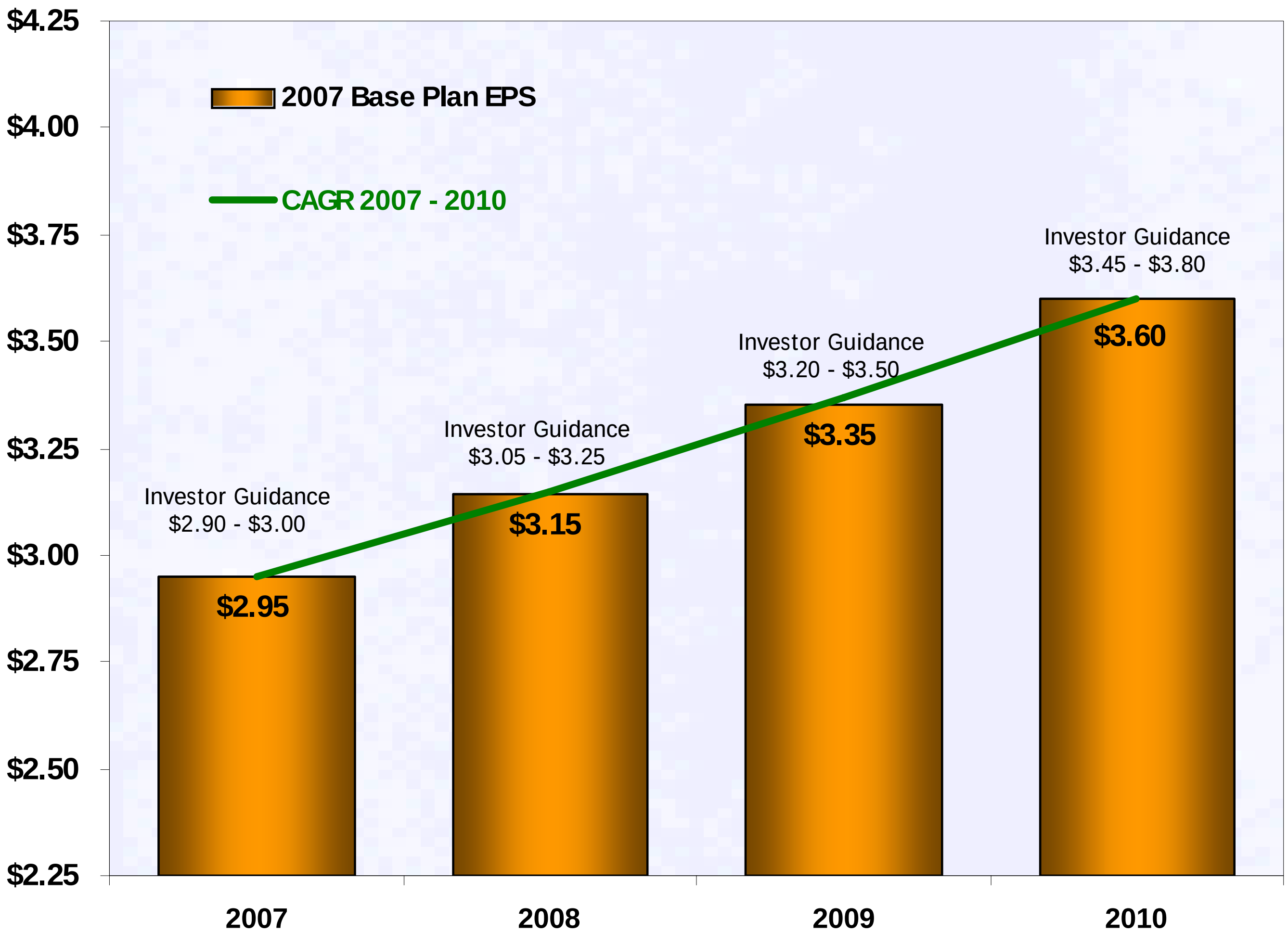
2007E: $3,962 MM	**2008E: $3,770 MM**
2009E: $3,600 MM	**2010E: $3,401 MM**

- Maintain credit ratings: BBB/Baa2/BBB

4-Year Earnings Range Forecast

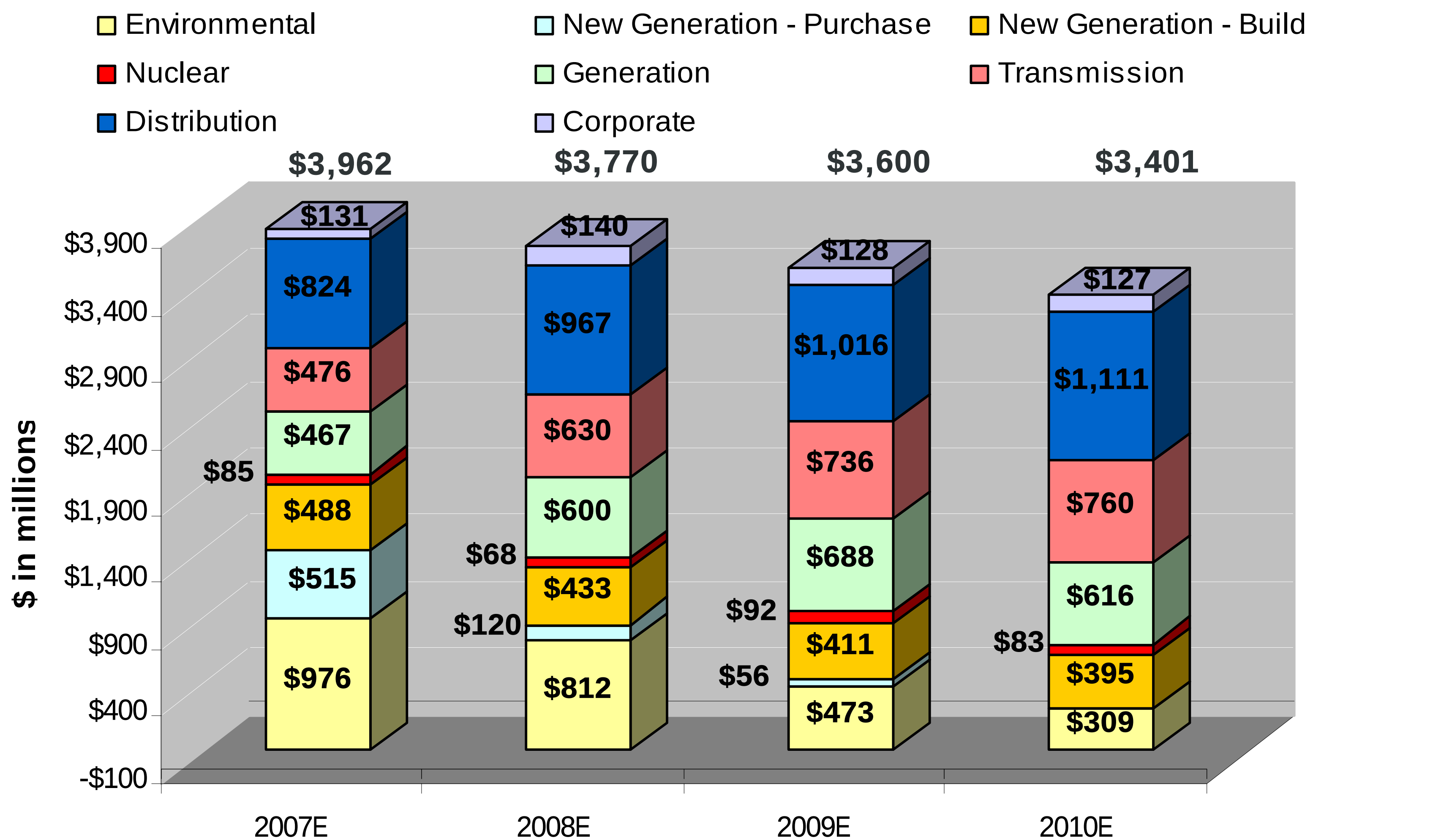


EPS 3-yr CAGR (2007-2010)



5% to 9% earnings growth and a 4Q07 dividend increase.

4-Year Capital Investment Forecast

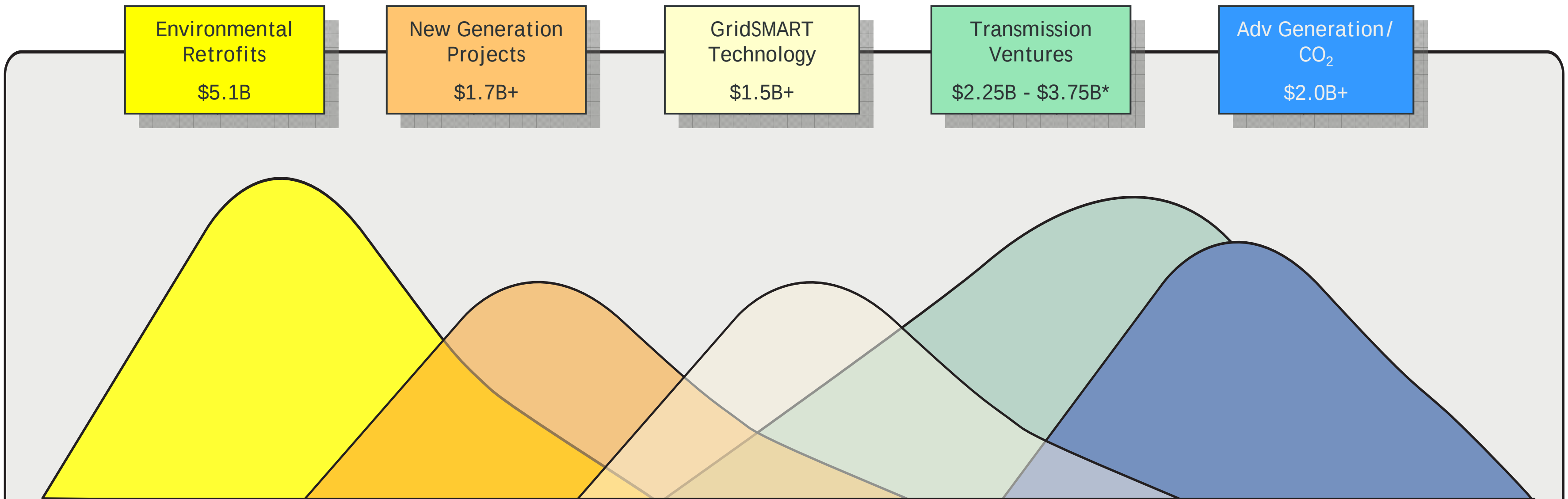


Note: amounts exclude AFUDC, $452MM related to GridSMART and $540MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Earnings Catalysts

Capital Investment – Consistent Waves of Opportunity



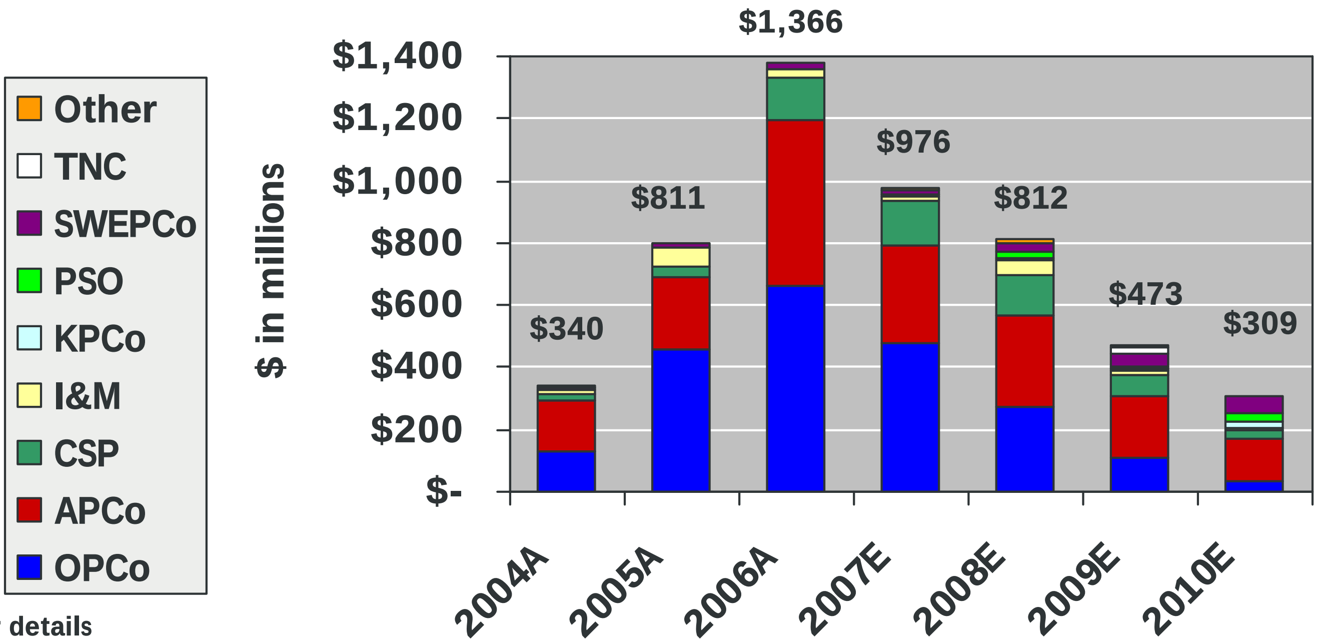
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 8. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

Environmental Investments Receive Timely Rate Recovery



See page 11 for details

($ in millions)	Completed (2004-2006)	Rate Recovery
AEG	$9	partial/pending
APCo	$923	yes
I&M	$98	pending
KPCo	$3	yes
SWEPCo	$37	pending
CSP	$194	yes
OPCo	$1,253	yes
Total Capex	$2,517	

($ in millions)	Remaining (2007-2010)	Rate Recovery
AEG	$27	partial/pending
APCo	$944	yes
I&M	$77	pending
KPCo	$33	yes
PSO	$67	pending
SWEPCo	$135	pending
TNC	$22	through mkt. rates
CSP	$374	partial/pending
OPCo	$891	partial/pending
Total Capex	$2,570	

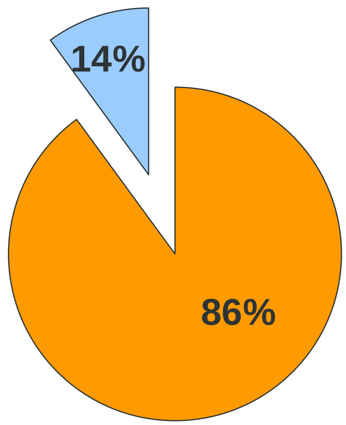
Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	Projected 2008
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

Materials and Vendors – AEP's Advantage

Breakdown of Environmental Compliance Program
(% of Purchased Costs)



Actuals To Date & Firm Costs
Estimated Cost Exposure*

Note: these percentages relate to the environmental program through 2010

* Primarily labor costs

SCR Technology

- Removes 85 – 93% of NOx emissions
- Requires ~ 1% use of auxiliary power
- **AEP Capital Cost ~ $121/kW avg.**

Combination of SCR & FGD technology results in co-benefit of Hg removal ~ 80% removal efficiency

FGD Technology

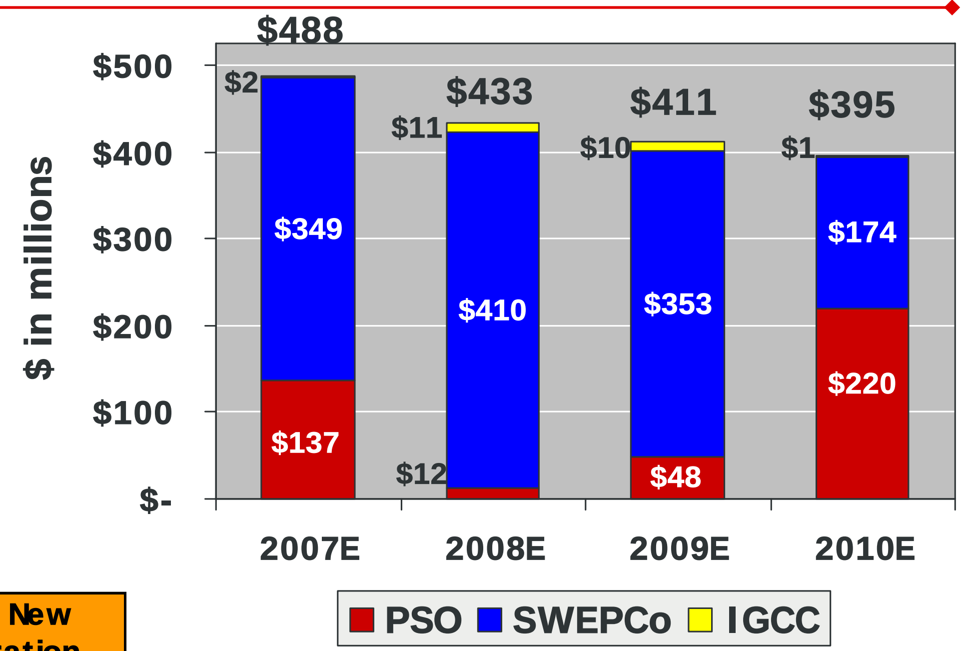
- Removes 95 – 98% of SO_2 emissions
- Requires ~1.5% to 3.0% use of auxiliary power
- **AEP Capital Cost ~ $250/kW avg.**

AEP benefits from first-mover advantage through lower contracted prices compared to industry.

New Generation Investments and Related Recovery

Secured Recovery Mechanism

- PSO Peaking Facilities Rider



($ in millions)	Projected Construction Completion	Total New Generation Investment (2007-10)
PSO - Peaking Facilities	2008	$102
PSO - Combined Cycle *	2012	$315
SWEPCo - Mattison	2007	$66
SWEPCo - Stall	2010	$422
SWEPCo - Turk	2011	$798
APCo - IGCC	tbd	$12
CSP/OPCo - IGCC	tbd	$12
Total Capex	Total Capex	$1,727

* - intended to source requirements to be met by Red Rock Plant prior to cancellation.

Additional Recovery Mechanisms Under Consideration:

- Formula based rates
- Requests for return on CWIP
- Current and future rate cases

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	$122 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$59 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$58 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$265 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$375 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (2)	Coal	Ultra-supercritical	600 (3)	2011
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	TBD
CSP/OP	Great Bend	Ohio	Under Review (3)	Coal	IGCC	630	TBD

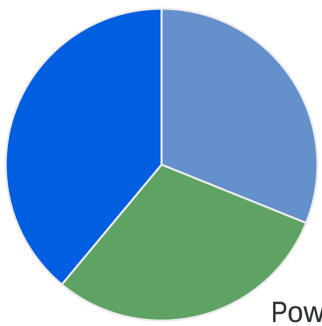
(1) 150MW declared in commercial operation on July 12, 2007.
(2) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(3) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

SAN FRANCISCO ROAD SHOW

Coal Procurement

AEP burns approx. 76 million tons of coal per year

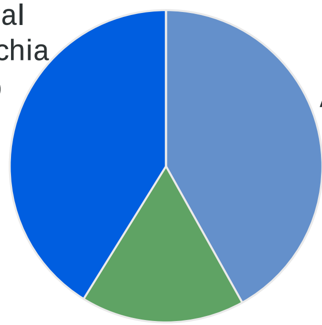
Total AEP System



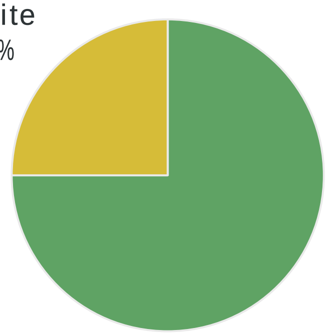
Coal Stats:

- Fully contracted for 2007; >93% for 2008
- Avg. delivered price ~ $35.10/ton in 2006
- Approximate 4-5% price increase in 2007 -- ($36.50 to $37.50/ton); 13% increase in 2008 based on anticipated 2007 actual results.
  - Addition of Mountaineer & Mitchell scrubbers allows for a greater mix of Northern Appalachian coal in 2007

AEP East



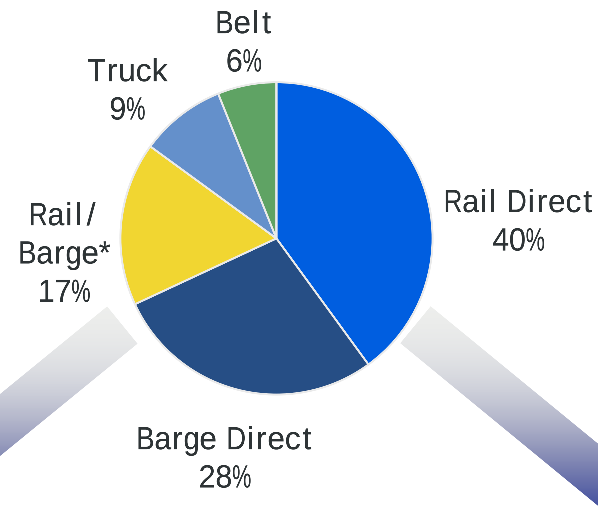
AEP West



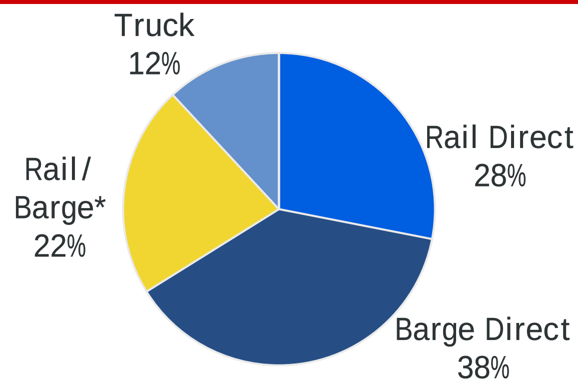
Coal Delivery

2006 Actual

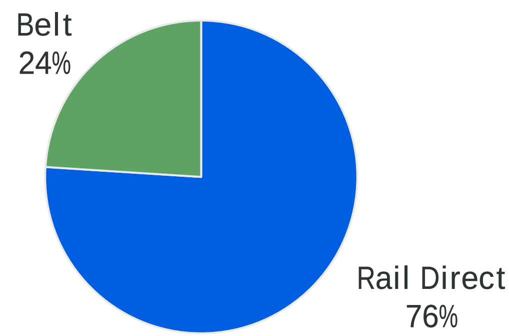
Total AEP System



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

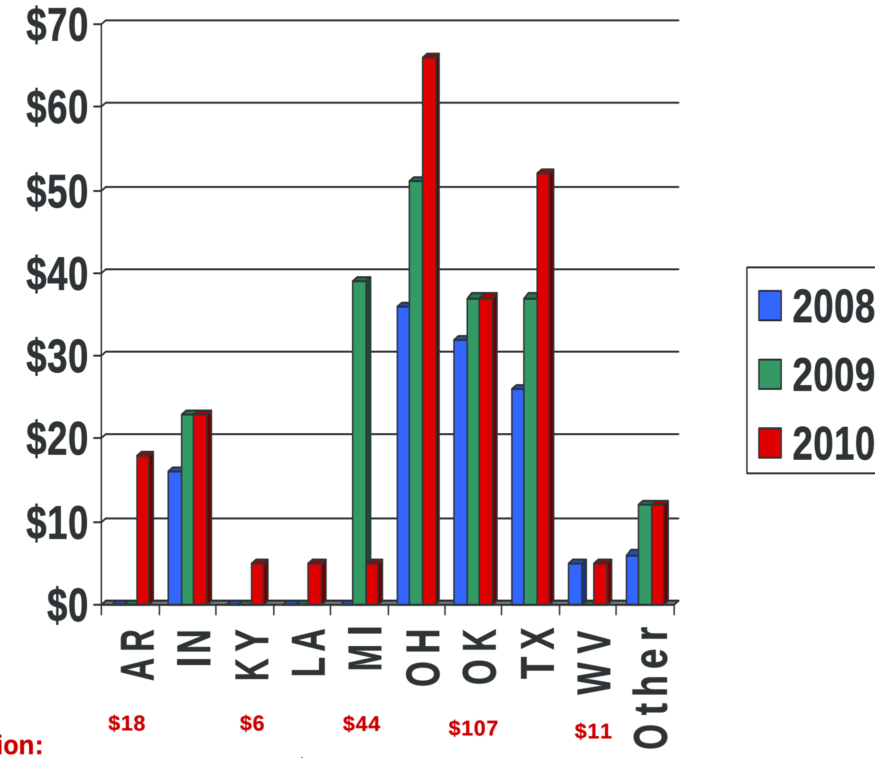
GridSMART

GridSMART: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

Capital Investment, Subject to Regulatory Approval * $ in millions				
Technology	**2007**	**2008**	**2009**	**2010**
Metering & Communications	$0	$83	$138	$146
Distribution Technology Enhancements	$2	$40	$ 63	$ 82

*$452MM of the $554MM not in current forecast; spending contingent upon regulatory approval

$ in millions



3-Year Total by Jurisdiction: $18 $62 $6 $5 $44 $153 $107 $115 $11 $31

AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $554MM capital investment by 2010, subject to regulatory approval.

Contribution of Transmission Investments

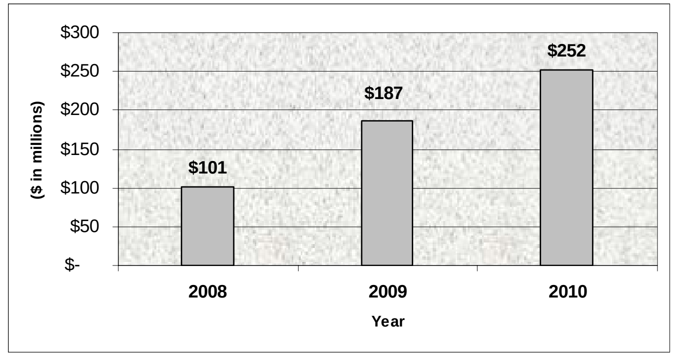
Potential Transmission Opportunities

~ $3 Billion I765™ Project in PJM
~ $2.6 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

Assumptions

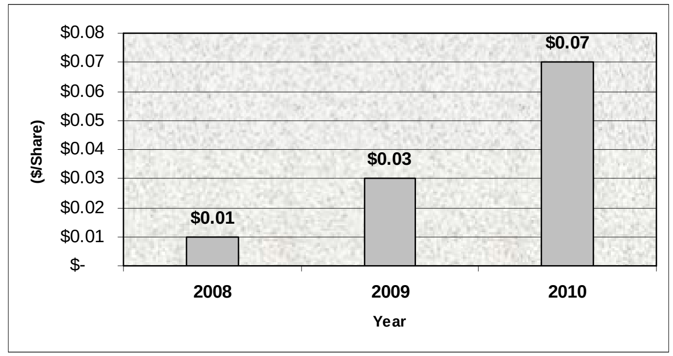
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 402 MM shares)	$0.60 - $1.00+

Projected Transmission Capital Spending*



* ~$9-$15 billion investment opportunity not included in current capital guidance forecasts, since it will be put into a JV. ETT base case and PATH projects included in above projection.

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Transmission will provide a near and long term catalyst for growth.

Electric Transmission Texas (ETT)

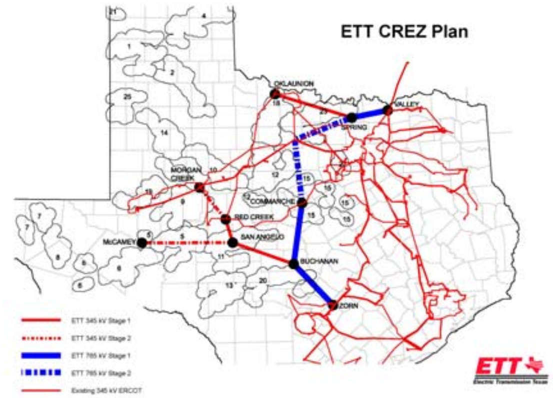
- **Electric Transmission Texas (ETT) Transaction Status**
  - Participation Agreement signed Jan. 9, 2007
  - PUCT Recently Approved:
    - ROE of 9.96%
    - Establishment of Transmission Utility Status
  - Received FERC/PUCT approvals:
    - Asset transfer for TCC to ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)

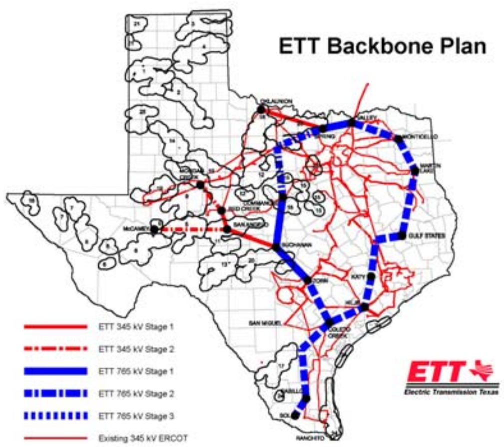
- **ETT ERCOT Backbone Proposal**
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).

- **Traditional ratemaking process through the PUCT will be utilized for investment cost recovery.**

ETT CREZ



ETT Backbone



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8644 of 9556

Electric Transmission America (ETA)

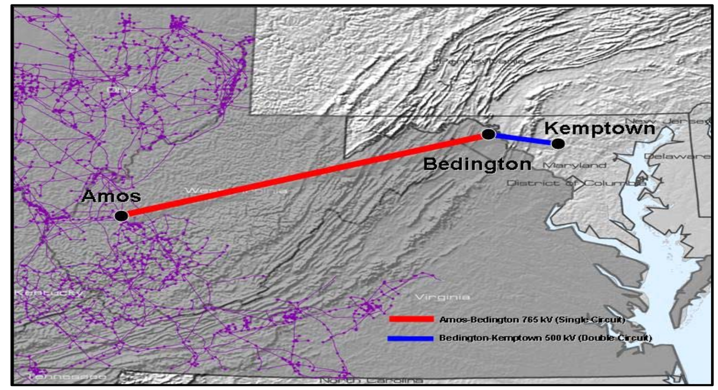
- ***Electric Transmission America (ETA)***
  - AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 Joint Venture.
  - Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
  - Projects taken on by the Joint Venture would entail transmission facilities:
    - 345-kV and above
    - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
    - Greater than $100 million
  - ETA will hope to identify and initiate the approval process for the first project during the first half of 2008.
  - ETA will look to collaborate with qualified partners in each particular region.

This JV reflects a natural progression and expansion of our partnership with MidAmerican.

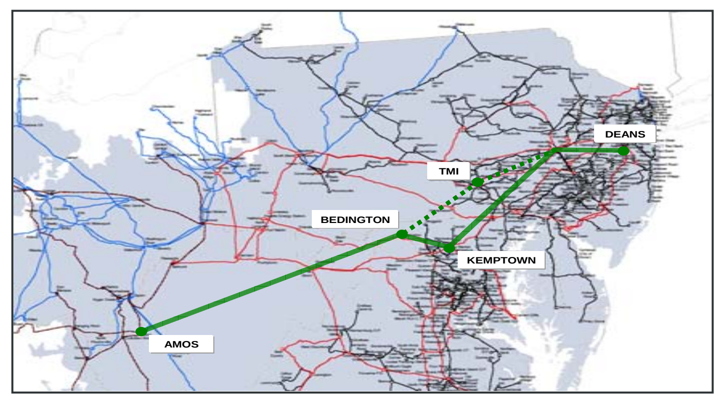
Transmission Project Updates - PJM

- *I-765 TM in PJM Phase I Update*
  - AEP and Allegheny entered into the PATH (Potomac-Appalachian Transmission Highline) JV to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012
- *Key Next Steps*
  - Complete FERC Filing – December 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Begin Routing Study – Fall 2007
  - State Filings – Fall 2008
  - Construction – Early 2010
  - Completion – Fall 2012
- *I-765 TM in PJM Phase II Update*
  - Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
  - Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
  - Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.
- *Regional Rate Design will be utilized for investment cost recovery.*

Phase I in PJM



Phase II in PJM



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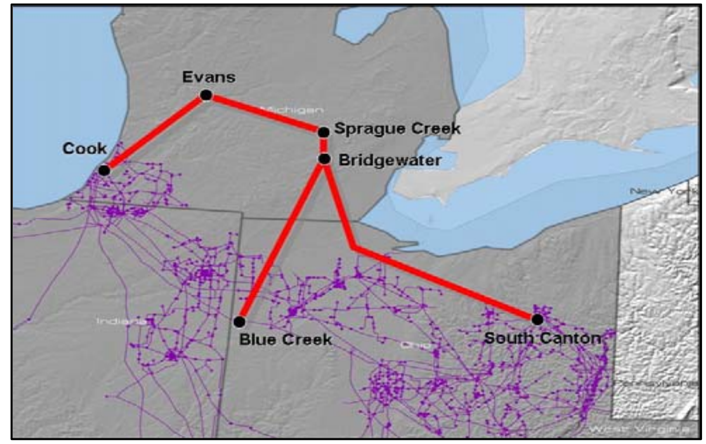
Transmission Project Updates – cont’d

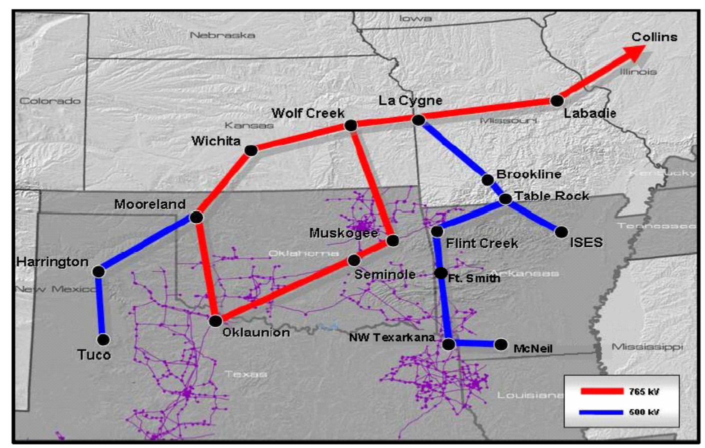
- *765 – kV in Michigan – Key Next Steps*
  - Study results shared with PJM/MISO– Summer 2007
  - Public release of study results – Fall 2007
  - Potential JV formation – Fall 2007
  - PJM/MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2015

Michigan



- *765-kV in SPP – Key Next Steps*
  - Study disclosure – Fall 2007
  - JV formation (Partner-TBD) – Fall 2007
  - SPP RTO/BOD EHV Overlay approval – Summer 2009
  - SPP RTO FERC Filing – Fall 2009
  - Siting approval – Fall 2011
  - Estimated completion – Summer 2017

Southwest Power Pool



- *Regional Rate Design will be utilized for investment cost recovery.*

SAN FRANCISCO ROAD SHOW

Advanced Generation & CO_2

Near Term:

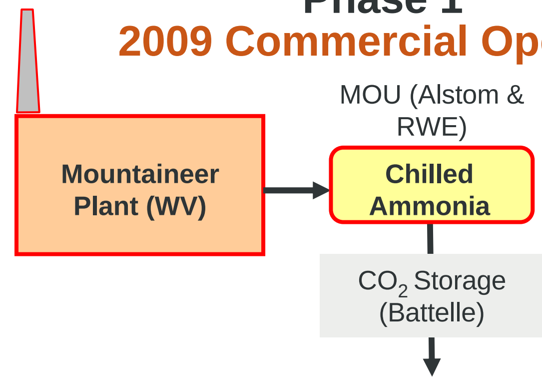
- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
	2007	2008	2009	2010
Mountaineer Chilled Ammonia Project	$4	$56	$11	$0

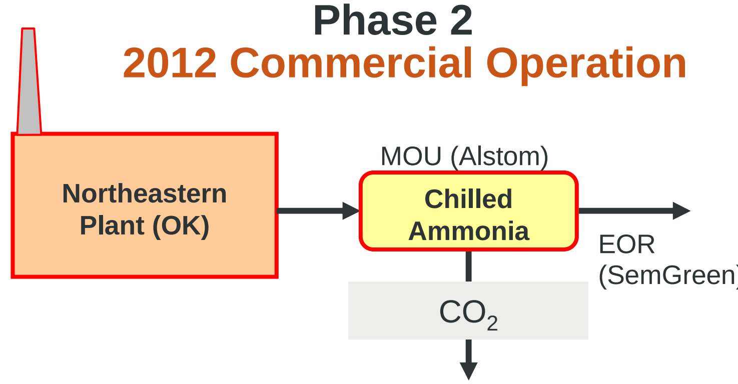
Long Term Strategy (Post 2010):

- IGCC
- Oxy Coal Technology
- Chilled Ammonia
- Nuclear COL

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

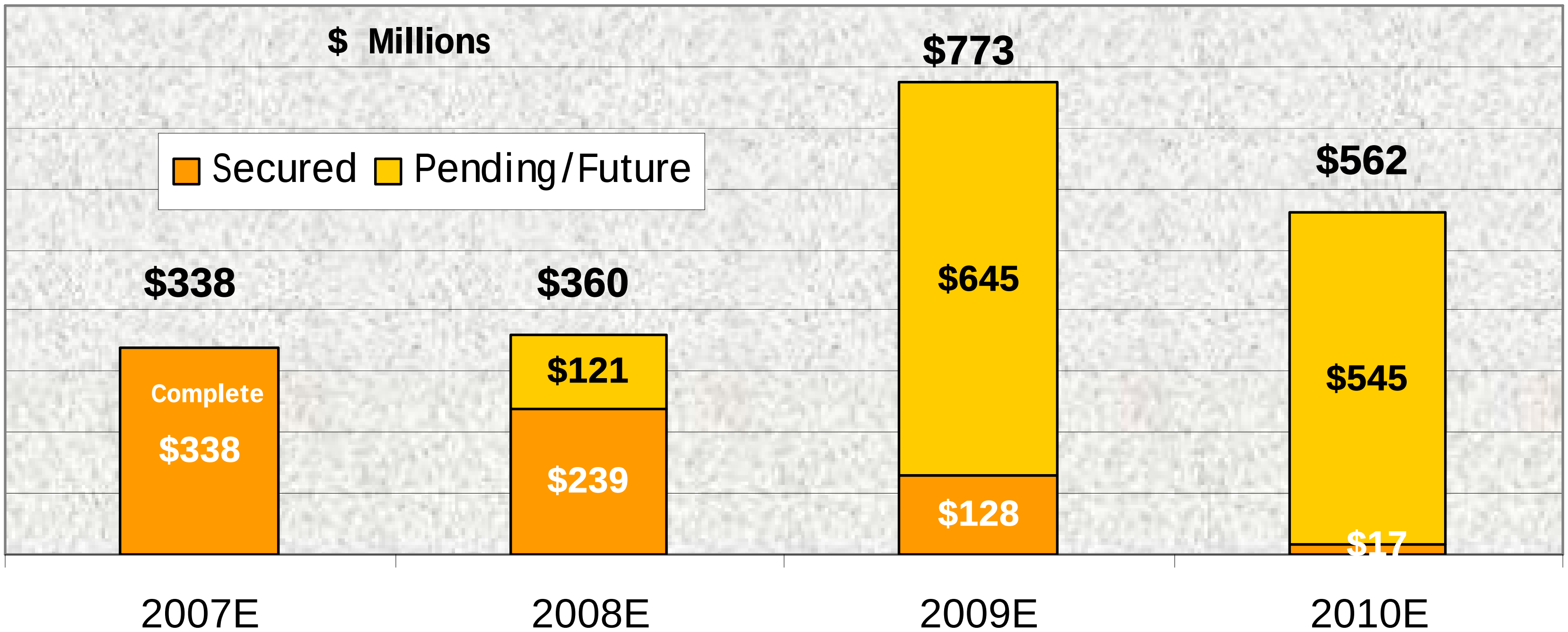
Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

- Key Components:
  - Start date for greenhouse-gas reductions is 2012
  - Goals: 2006 levels by 2020; 1990 levels by 2030
  - Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
  - Support for allowance allocations
  - International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

Incremental Rate Relief Assumptions



2008 Secured: Ohio 3% & 7%
I&M Depreciation
APCo-WV Construction Surcharge
PSO Peaking Generation and General Rate Case
TCC and TNC General Rate Cases

2007 - 2010 projected annual rate increases of 5.5%.

Regulatory Strategy: Reduce Lag

The strategy: reduce the time between in-service dates and rate recovery

- Maximize frequency of filings
  - Seek ability to pro-forma both capital and O&M through date which rates are effective
- Single-issue cost recovery
  - Reliability
  - Vegetation
  - Environmental
- Trackers
  - Federally-approved transmission costs
  - Fuel and emissions
  - ERO compliance costs
  - Off-system sales margin sharing
- Formula rates
- Return on CWIP

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

Regulatory Activity Completed

Company	Case	Order Date	Dollar Amount	ROE
APCo - Virginia	Base Rate Case	May 15, 2007	$24MM increase in annual base rates	10.0%
APCo - West Virginia	ENEC Filing	June 22, 2007	$29MM increase in annual revenues	10.5%
I&M - Indiana	Depreciation Study	June 13, 2007	$69MM estimated decrease in annual depreciation expense	N/A
I&M - Michigan	Depreciation Study	September 25, 2007	$10MM estimated decrease in annual depreciation expense	N/A
CSP/OPCo	4% RSP	October 3, 2007	$23MM increase in annual generation rates	N/A
TNC	Base Rate Case	May 24, 2007	$12MM increase in annual pre-tax earnings	9.96%
TCC	Base Rate Case	October 17, 2007	$50MM increase in annual pre-tax earnings	9.96%
ETT	Utility Status/ROE	October 17, 2007	N/A	9.96%
PSO	Base Rate Case	October 9, 2007	$20MM increase in annual pre-tax earnings	10.0%

Incremental rate relief requirements for 2007 have been satisfied.

Regulatory Activity Underway

- Ohio Post 2008
- CSPCo and OPCo Filing for 4% Provision on Generation Rates
- I&M - Indiana Rate Petition
- APCo Filings – E&R and Fuel Factor Adjustments
- SPP OATT Formula Rate Filing
- PSO Storm Cost Recovery Filing
- New Generation:
  - IGCC Filing in Virginia and West Virginia for Certificate of Need and approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio on Hold Pending Resolution of Supreme Court Challenge of PUCO's authority
  - SWEPCo Turk Plant Filings in Arkansas, Louisiana and Texas for Certificates of Need

Regulatory Activity Underway

Ohio Post 2008

- On August 29, 2007, the Ohio Governor submitted legislation (SB221) that would restructure the regulation of Ohio's electric industry. The bill also includes several efficiency and renewable energy standards.
- Hearings on the legislation began on September 26, 2007 in the Ohio Senate and continued through the end of October.
- On October 25, 2007, the substitute version and associated amendments were incorporated into SB221.
- Full Senate vote occurred October 31, 2007. SB221 passed 32-0.
- Presented to House Public Utilities Committee on November 7, 2007; Hearing schedule extends to the end of January 2008.

AEP Ohio Application For 4% Provision On Generation Rate

- On October 24, 2007, CSPCo and OPCo filed an application pursuant to the RSP at the PUCO to recover costs associated with additional generation-related expenditures the companies are encountering related to environmental (CAIR, CAMR and NPDES – Clean Water Act) and PJM marginal losses.
- CSPCo and OPCo are requesting to implement the provision to recover \$37.4MM and \$12.6MM, respectively, from January through December 2008. These amounts represent actual costs incurred, plus carrying costs, through October 31, 2007.

Regulatory Activity Underway

I&M Indiana Rate Petition

- On June 19, 2007, I&M filed a petition with the Indiana Utility Regulatory Commission (IURC) for authority to increase its rates and charges for electric utility service and to establish and implement rate adjustment mechanisms to track certain matters.
- Requested trackers relate to reliability enhancement, demand-side management/energy efficiency programs, off-system sales margins, PJM costs and environmental compliance.
- Parties have agreed to a historic test year ended September 30, 2007, with a rate case filing date of January 31, 2008. This schedule has been approved by the IURC.
- Hearings are expected in May 2008, and an order in the first quarter of 2009.

APCo E&R and Fuel Factor Adjustments

E&R:

- On July 16, 2007 a filing was made with the VA SCC requesting an additional $39MM be added to the current rider of $21MM. Therefore, at December 1, 2007, we will begin collecting $60MM.
- Intervenor testimony was filed on October 3, 2007, staff testimony filed on October 17, 2007, rebuttal testimony filed on October 24, 2007 and public hearings are were held on November 5 & 6, 2007.

Fuel Factor:

- On July 16, 2007, a filing was made with the VA SCC requesting the termination of the OSS base credit and reflected 75% of OSS margins as a credit to fuel expense, consistent with new Virginia legislation. Implementation of the fuel factor was approved effective September 1, 2007, subject to review/refund.
- Intervenor testimony was filed on October 5, 2007, staff testimony filed on October 15, 2007 and rebuttal testimony filed on October 22, 2007.
- Based on the addition of PJM marginal losses to the filing in October 2007, a new procedural schedule was agreed upon which stipulates staff and intervenor testimony due December 3, 2007, rebuttal testimony due December 10, 2007 and public hearings are expected to commence on December 18, 2007.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $161MM.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extends the effective date to February 1, 2008. A request for rehearing was submitted on October 1, 2007.
- A technical conference was held on October 18, 2007. The purpose was to review and clarify the company's responses to discovery. A second technical conference was held November 6, 2007 with a settlement meeting held November 15, 2007 and another scheduled for December 4, 2007.

PSO Storm Cost Recovery Filing

- On October 24, 2007, Public Service Company of Oklahoma filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to a severe January 2007 winter storm. PSO requests the Commission to direct it to establish a regulatory asset of approximately $13 million reflecting the future recovery of these costs, and to amortize the regulatory asset as PSO realizes proceeds from the sale of sulfur dioxide (SO_2) emission allowances.
- Hearings are tentatively scheduled for February 27-28, 2008.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

West Virginia

- Testimony filed with the West Virginia Public Service Commission on June 18, 2007 in support of APCo's application for a Certificate of Public Convenience and Necessity to construct a 600MW IGCC plant in WV at a cost of approximately $2.23 billion.
  - Testimony includes a proposal for the Commission to approve a cost recovery mechanism through the existing Expanded Net Energy Cost (ENEC) mechanism. The filing is not a formal proposal to adjust rates.
  - Actual requests for increased rates will be included in future filings, once construction of the plant has commenced and actual Construction Work In Progress data is known.
- Staff and Intervenor testimony filed November 19, 2007.
- Public hearings are scheduled for December 10-14, 2007 with an order on or before March 7, 2008.

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- Public hearings are scheduled for February 12, 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- Oral arguments regarding this matter were conducted at the Ohio Supreme Court on October 9, 2007. It is likely the court's decision will not be announced until some time in the first quarter of 2008.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- Public hearings commenced August 20, 2007 and final briefs were filed in October 2007.
- The PSC issued its order on November 21, 2007, approving construction of the plant.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. Peaking and intermediate facilities have been addressed. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- Public hearings commenced September 11, 2007. Decision expected by year end.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. Decision expected in early 2008.

Rate Base & September 2007 Earned ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date	9/30/07 GAAP Earned ROE
APCo-VA	$2,022MM	10.00%	10/2/2006	8.93%
APCo-WV	$1,656MM	10.50%	7/28/2006	
Kentucky	$858MM	10.50%	3/31/2006	9.87%
I&M-Indiana	$1,805MM	12.00%	11/19/1993	9.00%
I&M-Michigan	$268MM	13.00%	4/1/1991	
Ohio-CSPCo	$1,558MM	12.46%	5/12/1992	21.77%
Ohio-OPCo	$2,183MM	12.81%	3/23/1995	12.70%
PSO-Oklahoma	$1,120MM	10.00%	10/9/2007	1.28%
SWEPCo-LA	$434MM	11.10%	12/29/1999	5.97%
SWEPCo-AR	$408MM	10.75%	9/23/1999	
SWEPCo-Texas	$474MM	15.70%	2/15/1983	
Texas-TCC	$1,566MM	9.96%	6/1/2007	8.10%
Texas-TNC	$530MM	9.96%	6/1/2007	10.71%

Detailed Ongoing Earnings Guidance

2007E: $2.90 - $3.00

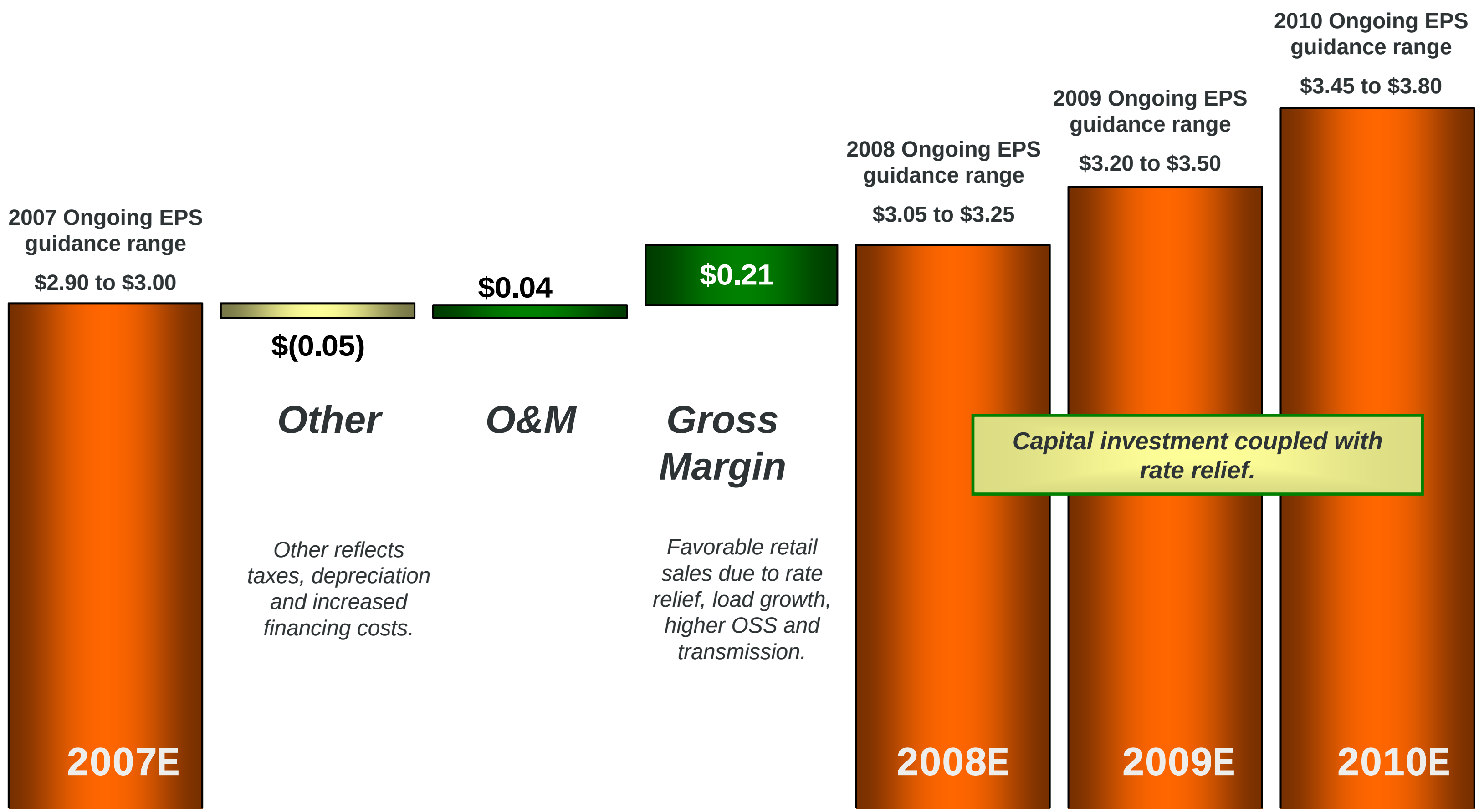
2008E: $3.05 - $3.25

American Electric Power
2007 Guidance vs. 2008 Estimate

		Performance Driver	2007 Guidance ($ millions)	Performance Driver	2008 Estimate ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	73,325 GWh @ $ 33.3 /MWhr =	2,440	75,163 GWh @ $ 32.3 /MWhr =	2,425
2	Ohio Companies	50,452 GWh @ $ 48.2 /MWhr =	2,433	51,492 GWh @ $ 48.5 /MWhr =	2,497
3	West Regulated Integrated Utilities	41,927 GWh @ $ 24.9 /MWhr =	1,046	42,859 GWh @ $ 25.9 /MWhr =	1,111
4	Texas Wires	26,628 GWh @ $ 19.5 /MWhr =	520	26,964 GWh @ $ 19.9 /MWhr =	536
5	Off-System Sales	30,289 GWh @ $ 20.4 /MWhr =	617	30,085 GWh @ $ 21.3 /MWhr =	642
6	Transmission Revenue - 3rd Party		276		331
7	Other Operating Revenue		627		545
8	**Utility Gross Margin**		**7,959**		**8,087**
9	Operations & Maintenance		(3,353)		(3,328)
10	Depreciation & Amortization		(1,476)		(1,479)
11	Taxes Other than Income Taxes		(775)		(788)
12	Interest Exp & Preferred Dividend		(773)		(864)
13	Other Income & Deductions		101		191
14	Income Taxes		(566)		(582)
15	**Utility Operations On-Going Earnings**		**1,117**		**1,237**
16	**TRANSMISSION OPERATIONS**		-		5
	NON-UTILITY OPERATIONS:				
17	MEMCo		67		57
18	Generation & Marketing		29		21
19	**Non-Utility Operations On-Going Earnings**		96		78
20	**Parent Company & Other On-Going Earnings**		(40)		(51)
21	**ON-GOING EARNINGS**		**1,173**		**1,269**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.
May not foot due to rounding.

Long-Range Earnings Drivers



Traditional utility factors will drive earnings.

Multi-Year Capital Investment Funding Plan

	Actual	Projection			
	2006	2007	2008	2009	2010
Planned Capital Investment (Excluding AFUDC) *	$ (3,448)	$ (3,962)	$ (3,770)	$ (3,600)	$ (3,401)
Investment in Non-Consolidating Subsidiaries	$ -	$ (13)	$ (34)	$ (66)	$ (114)
Dividend on Common Stock	(591)	(631)	(659)	(664)	(669)
Cash Sources					
Cash from Operations	2,732	2,053	2,825	3,028	3,292
Proceeds from Sale of Assets	186	228	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	99	150	150	150	150
Change in Debt, Net	(320)	1,863	1,678	1,432	989
TCC Securitization Bond Issuance	1,740	-	-	-	-
Other	(498)	113	(187)	(284)	(247)
Change in Cash	(100)	(199)	3	(4)	-
Ending Cash Balance	$ 301	$ 102	$ 105	$ 101	$ 101

* Includes Distressed Generation Purchases in 2007

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Capital investment is funded from cash from operations and debt issuances.

2008 Projected Cash Flow

	2007 Estimate	2008 Estimate
Beginning Cash Balance	$ 301	$ 102
Cash from Operations:		
Income from Continuing Operations	1,173	1,269
Depreciation and Amortization	1,535	1,511
Other	(655)	45
Total from Operations	2,053	2,825
Cash from Investing:		
Construction Expenditures	(3,604)	(3,860)
Asset Sales	228	-
Distressed Generation Purchases	(515)	-
Investment in Non-Consolidating Subsidiaries	(13)	(34)
Other	138	(69)
Total from Investing	(3,766)	(3,963)
Cash from Financing:		
Common Equity	150	150
Long-Term Debt Issued/(Retired)	1,334	1,789
Short-Term Debt Change, Net	529	(111)
Common Dividends	(631)	(659)
Other Financing Activities	132	(28)
Total from Financing	1,514	1,141
Net Change in Cash	$ (199)	$ 3
Ending Cash Balance	$ 102	$ 105

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation. In addition, construction expenditures include AFUDC.

SAN FRANCISCO ROAD SHOW

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Sierra Club's First Set of Data Requests
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Capital Investment Drives Operating Company Growth

($ in millions)	2007E	2008E	2009E	2010E	Total
APCo	$658	$720	$749	$579	**$2,706**
I&M	$305	$341	$405	$341	**$1,392**
KPCo	$70	$122	$100	$119	**$411**
TCC	$247	$197	$245	$234	**$923**
TNC	$106	$171	$134	$132	**$543**
PSO	$280	$266	$318	$511	**$1,375**
SWEPCo	$582	$694	$651	$563	**$2,490**
CSP	$449	$393	$303	$262	**$1,407**
OPCo	$799	$666	$525	$544	**$2,534**
Other Companies	$466	$200	$170	$116	**$952**
Total Capex	**$3,962**	**$3,770**	**$3,600**	**$3,401**	**$14,733**

Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

2008 Key Operating Company Highlights

Dependent on Actual Capital Investment ($ in millions)

Company	Projected Capital Expenditures	Projected Issuances (a)	Target Equity Ratio
AEP, Inc.	$0	$500-600 (b)	n/a
AEG	$138	$100-150	40%
APCo	$720	$500-600	42-44%
CSP	$393	$250-350	45-47%
I&M	$341	$0	40-42% (c)
KPCo	$122	$100-200	41-43%
OPCo	$666	$100-200	44-46%
PSO	$266	$0	43-45%
SWEPCo	$694	$300-500	43-45%
TCC	$197	$0	40% (d)
TNC	$171	$100-150	40%

(a) Includes tax-exempt issuances

(b) Represents hybrid securities

(c) Ratios include impact of Rockport 2 lease

(d) Excludes impact of securitization on the equity ratio

AEP will maintain the financial strength of its subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow.

AEP®

Long-term Debt Maturity Profile

($ in millions)

Year	2007 [1]	2008	2009
AEP Service Corp.	$ -	$ 36	$ -
AEP, Inc.	$ -	$ -	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ 200	$ 200	$ 150
Columbus Southern Power	$ -	$ 112	$ -
Kentucky Power	$ 198	$ 30	$ -
Indiana Michigan Power	$ -	$ 50	$ 45
Ohio Power Company	$ -	$ 42	$ 100
Public Service of Oklahoma	$ -	$ -	$ 50
Southwestern Electric Power	$ -	$ 2	$ -
Texas Central Company	$ -	$ 48	$ -
Texas North Company	$ -	$ -	$ -
Total	$ 398	$ 520	$ 345

(1) Maturities remaining as of September 30, 2007

Credit Quality Parameters

Forecast Parameters:

- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings
    - FFO to Interest range of 3.7x to 4.2x
    - FFO/Total Debt range of 16% to 19%

Capitalization

Capital Structure	Actual 12/31/2006 Debt	Actual 12/31/2006 Equity	Actual 12/31/2006 Total	Actual 9/30/2007 Debt	Actual 9/30/2007 Equity	Actual 9/30/2007 Total
Balance Sheet Capitalization						
Long-term Debt	13,698	-	13,698	14,777	-	14,777
Short-term Debt	18	-	18	587	-	587
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,412	9,412	-	9,908	9,908
Total Capitalization per Balance Sheet	**13,716**	**9,473**	**23,189**	**15,364**	**9,969**	**25,333**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***60.6%***	***39.4%***	***100.0%***
Adjustments						
Defeased First Mortgage Bonds	(21)	-	(21)	(19)	-	(19)
Rockport Plant Unit 2 Off-Balance Sheet Lease	1,183	-	1,183	1,163	-	1,163
Securitization Bonds	(2,335)	-	(2,335)	(2,257)	-	(2,257)
Spent Nuclear Fuel Disposal Liability	(247)	-	(247)	(256)	-	(256)
Total Adjusted Capitalization	**12,296**	**9,473**	**21,769**	**13,995**	**9,969**	**23,964**
% of Adjusted Capitalization	***56.5%***	***43.5%***	***100.0%***	***58.4%***	***41.6%***	***100.0%***

Adjusted debt-to-capital ratio was 58.4% as of 9/30/07.

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's			S&P				Fitch		
	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
American Electric Power Company, Inc.	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
AEP, Inc. Short Term Rating	P2	NR	S	N/A	A2	NR	S	F2	NR	S
AEP Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	BBB+	A-	N
AEP Texas North Company [1]	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

(1) AEP Texas Central Company was downgraded and placed on negative outlook by Fitch in April 2007.

AEP is committed to maintaining current credit ratings.

SAN FRANCISCO ROAD SHOW

Value Proposition

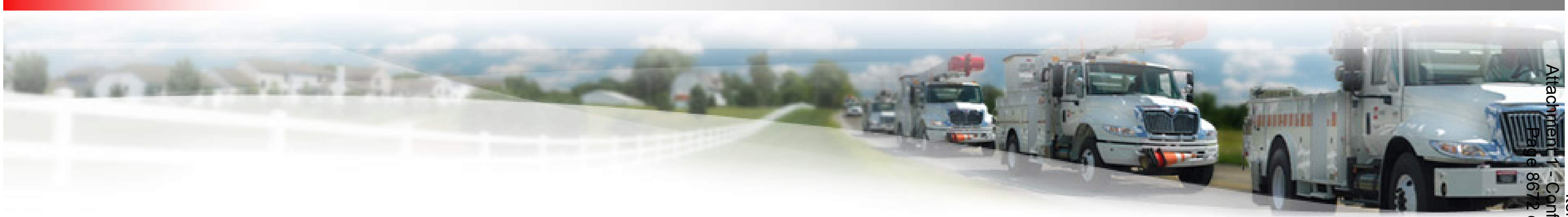
- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

Sustainable Business Model

AEP AMERICAN ELECTRIC POWER®

Sanford Bernstein Strategic Decisions Investor Conference

New York, NY
June 1, 2011



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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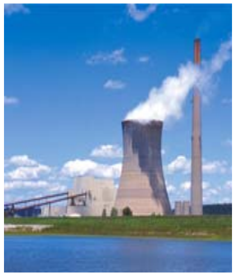
American Electric Power



One of the largest U.S. electricity generators

Generation owned[1] (GW)	
Southern Co	42.9
NextEra Energy	42.7
AEP	39.9
Duke Energy	38.5

The largest U.S. electricity transmitter

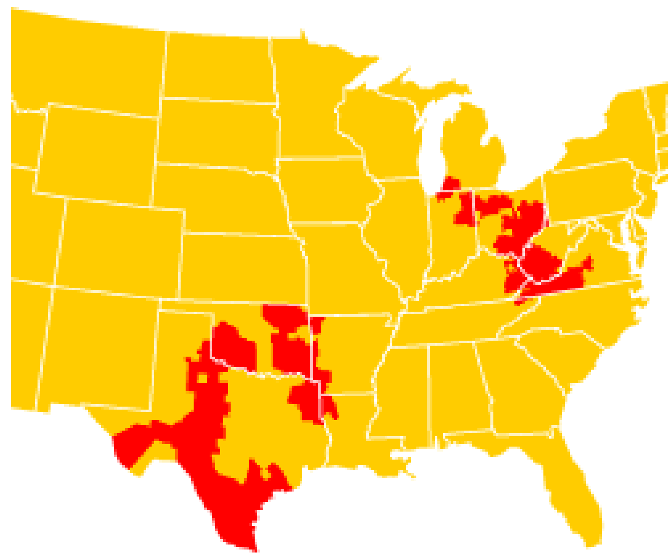
Transmission miles[1] ('000s)	
AEP	39.0
Southern Co	27.0
Duke Energy	20.9
First Energy	20.0

One of the largest U.S. electricity distributors

Electric customers[1] (mm)	
FE	6.1
Exelon	5.4
AEP	5.3
Pacific Gas & Electric	5.1

[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

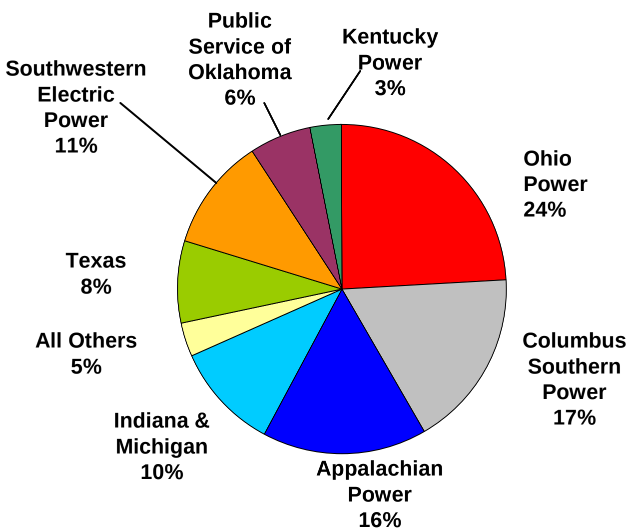
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$18.6B Market Capitalization
BBB/Baa2/BBB credit rating

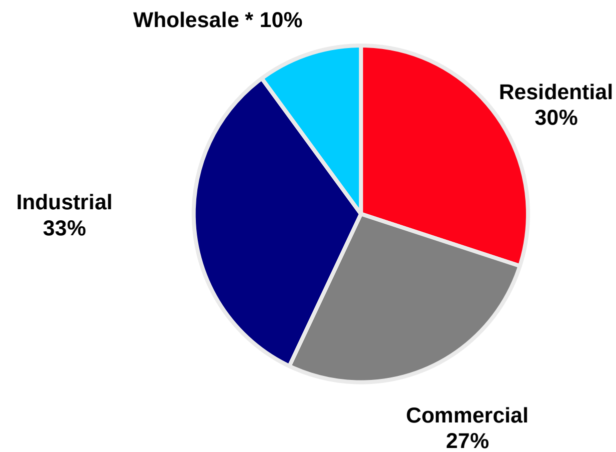
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Maintenance Capital
- Capital for Growth
  - Spending in excess of depreciation levels
  - Capital allocated to higher return areas
  - Continued capital prioritization and discipline
  - Optimization of portfolio of assets
- Capital to Reduce Risk
- Return of Capital to Shareholders

Managing Operations and Investment

Challenges:

Required refinement of the operating company model and improved line-of-sight management due to economic conditions, regulatory lag, reduced rate headroom, environmental challenges and resource preferences

Actions:

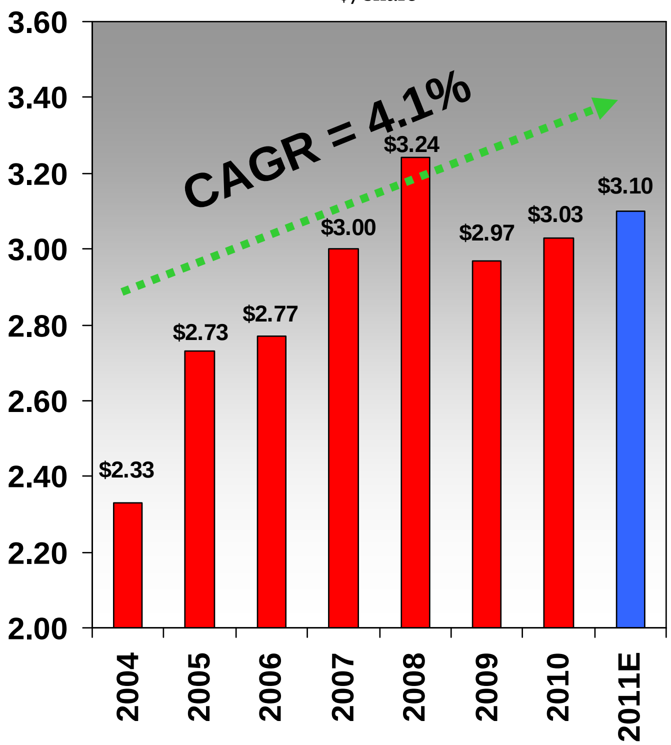
- Empower operating company employees to drive results
- Efficiently allocate capital
- Demonstrate O&M and capital expenditure discipline
- Identify asset renewal strategy for investing in traditional distribution and transmission assets that enhance reliability and customer satisfaction
- Enable long-term planning discussions with regulators and legislators

Expected Outcomes:
Optimize spending for more efficient return on investment
Improve dialogue with customers and regulators
Minimize lag in rate recovery

Earnings and Dividends

On-Going EPS History Since 2004

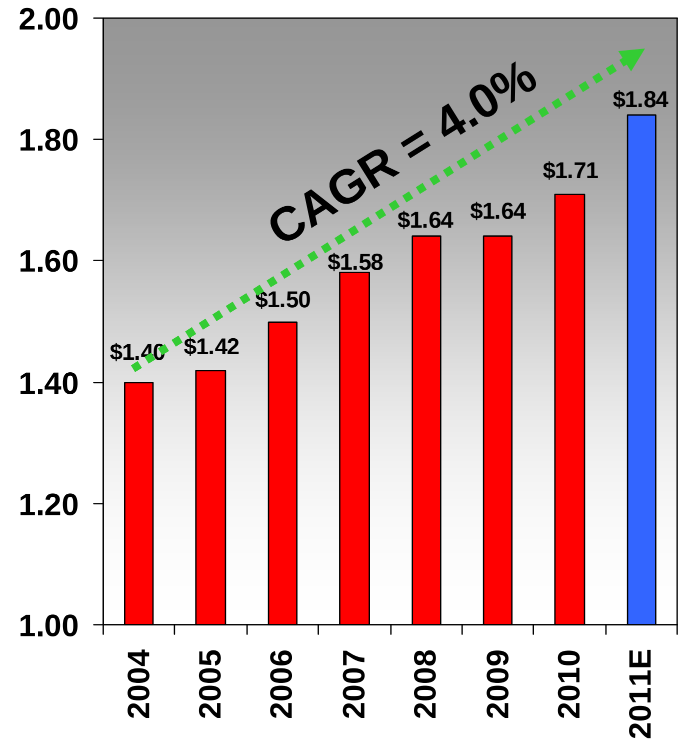
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend will be paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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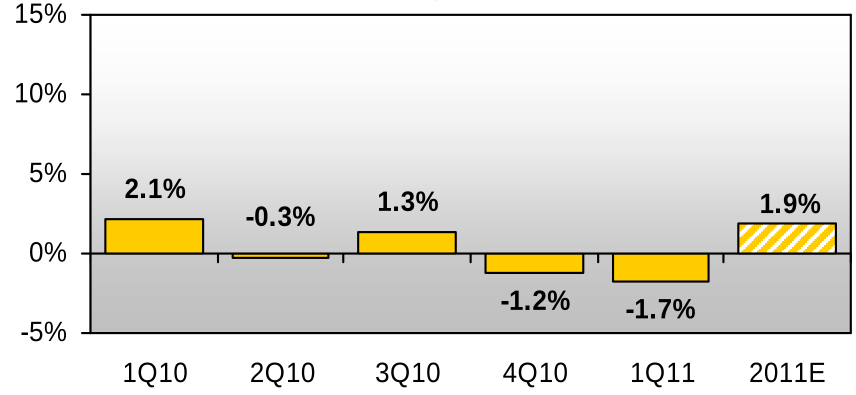
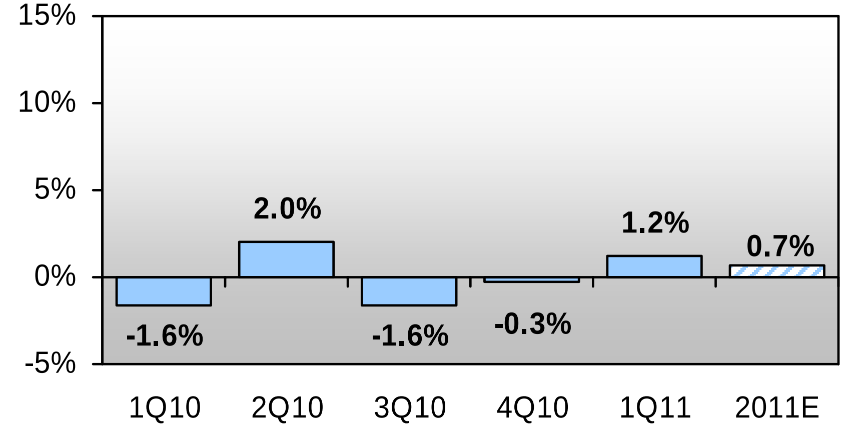
Normalized Load Trends

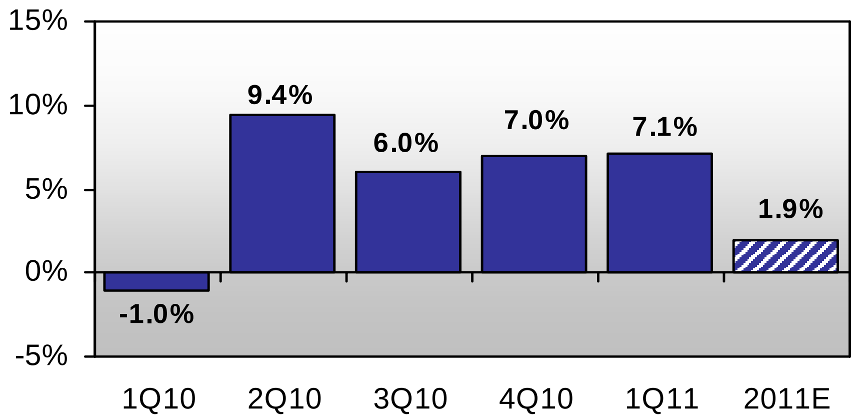
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



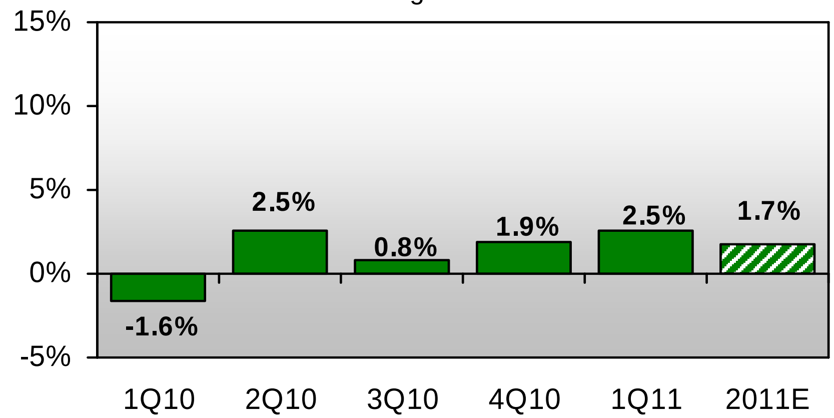
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



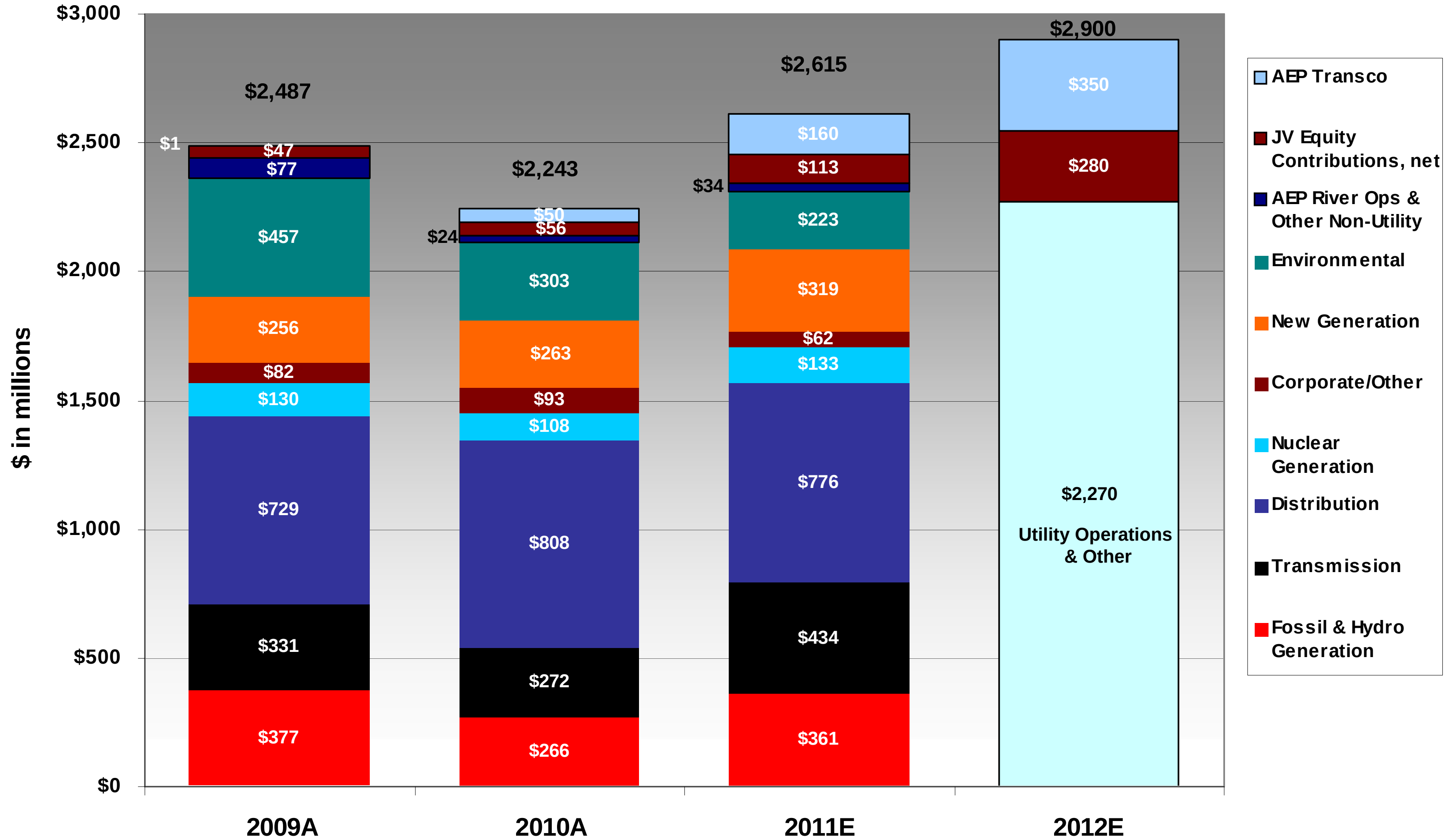
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[1]	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

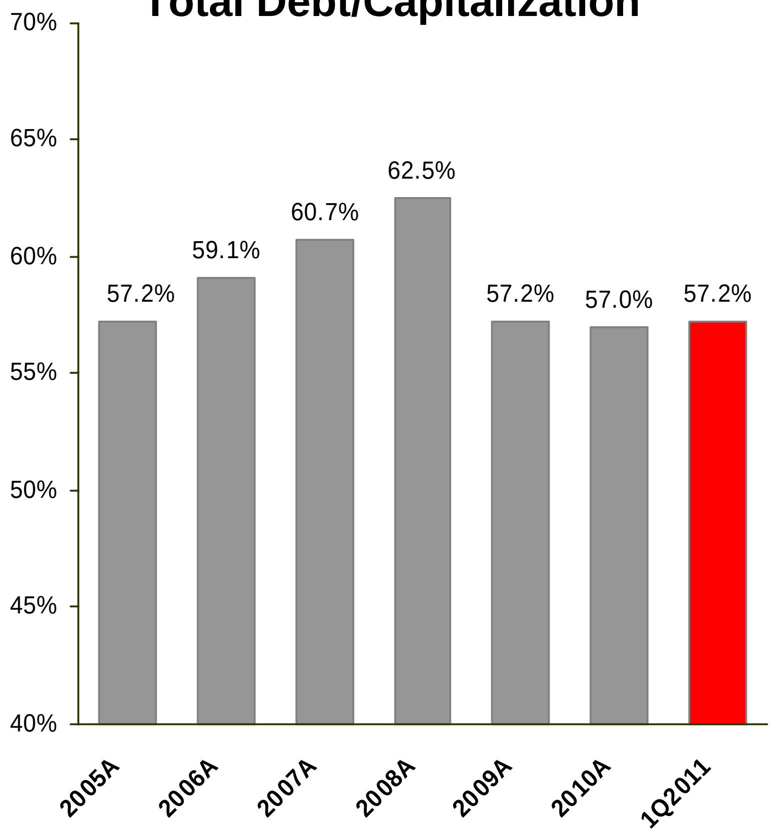
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

Total Debt/Capitalization

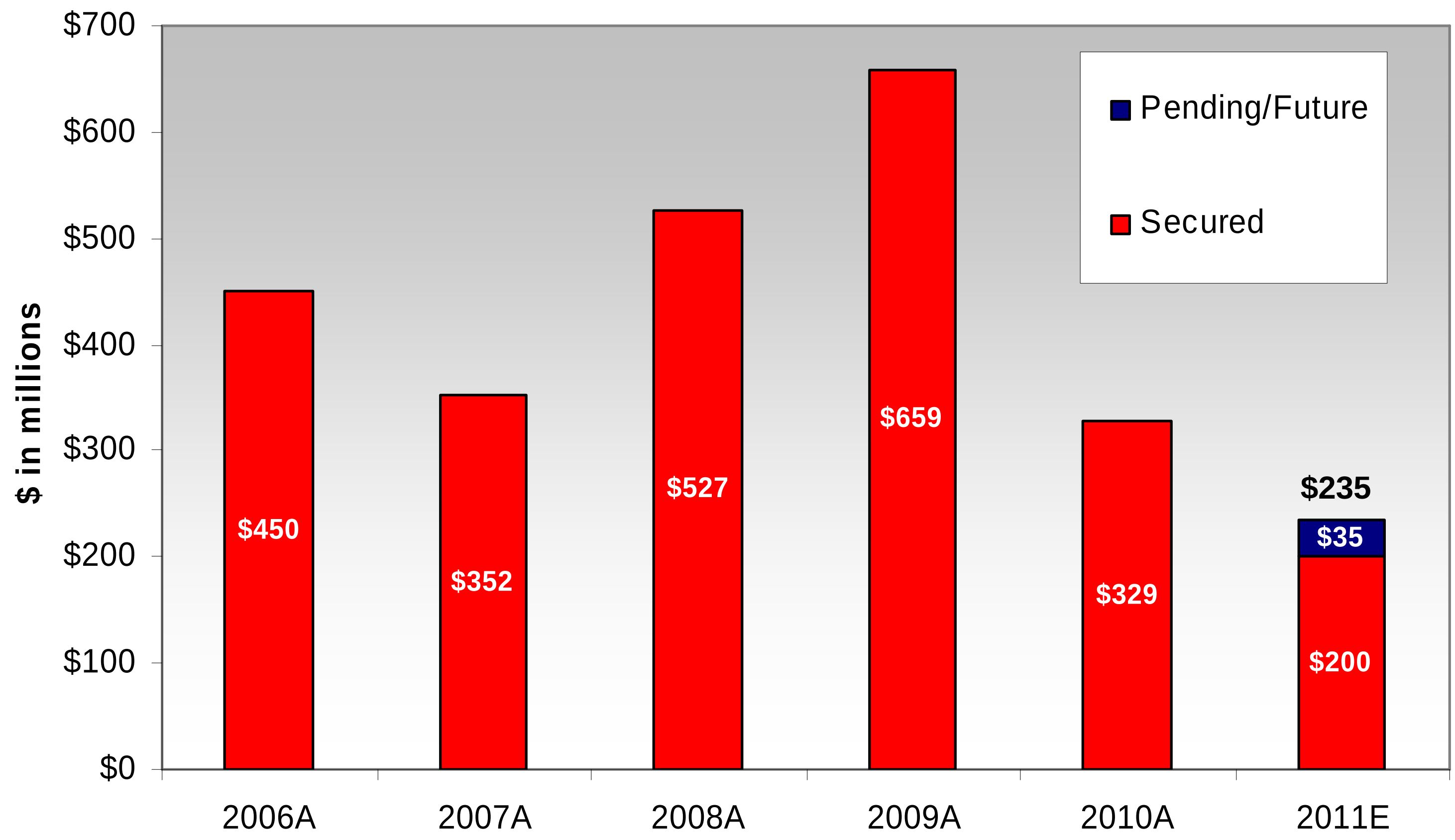


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 03/31/11	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – June 13; Staff testimony – June 27; Hearing July 20**

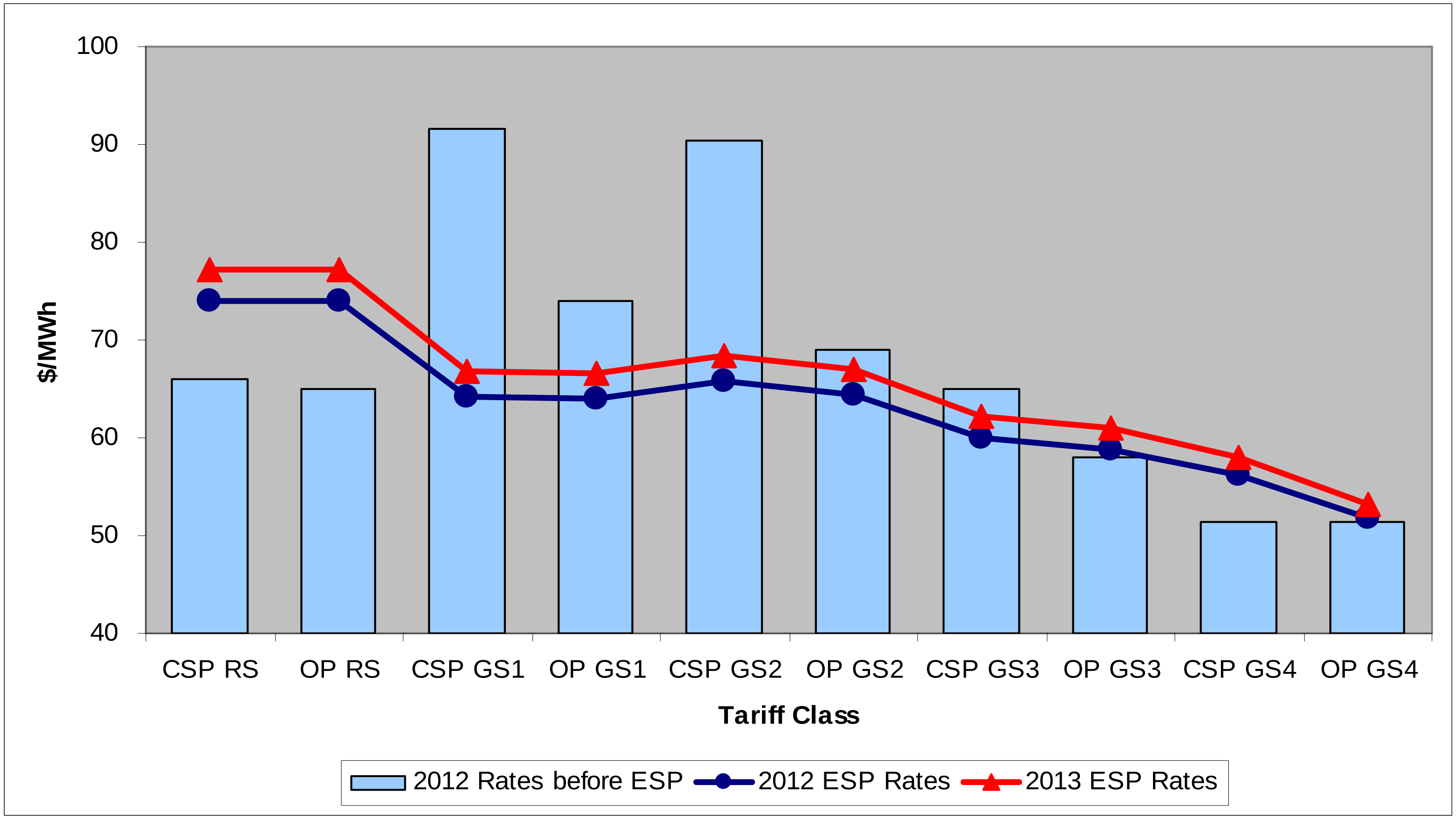
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

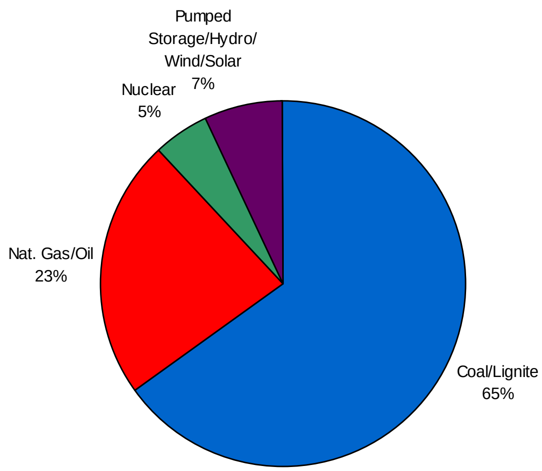
List of ESP Riders – Existing and Proposed

AEP®

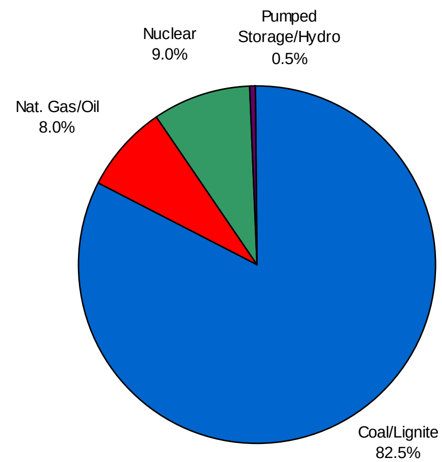
Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Domestic Generation Fleet

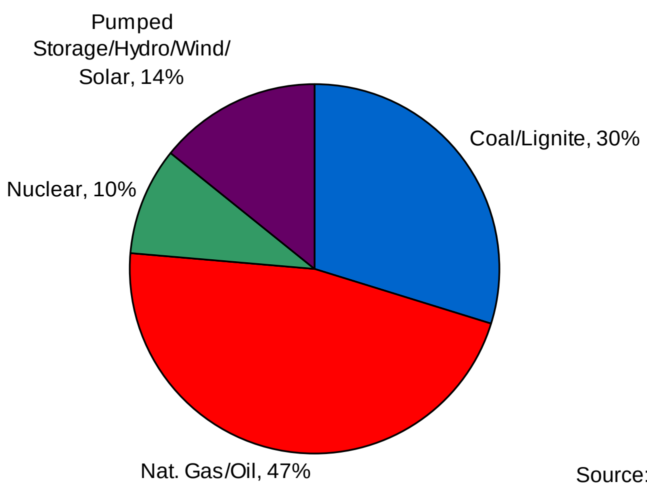
Generation Capacity by Fuel Type
Based on 39,910 MW



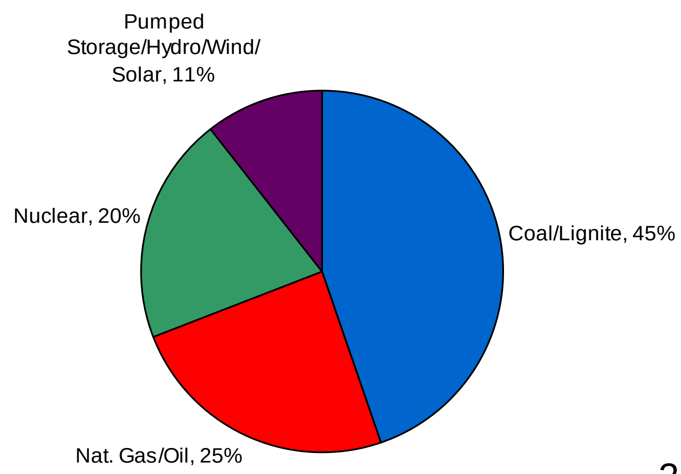
2010 Generation Production by Fuel Type
Based on 173.2 TWh



Generation Capacity by Fuel Type
Based on 1,063,848 MW



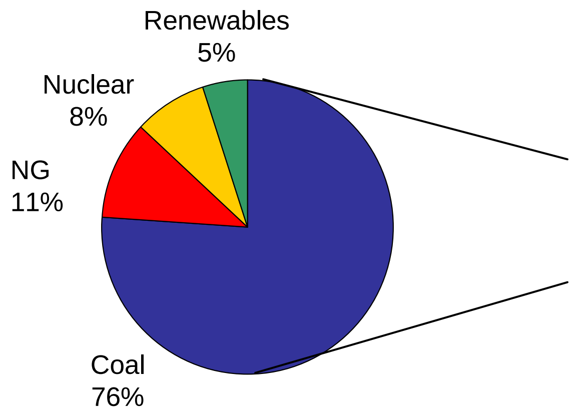
2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

AEP Generation Capacity

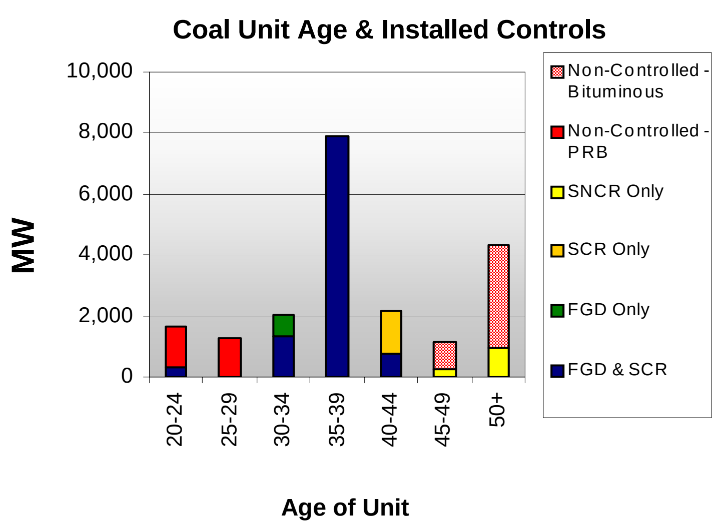
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



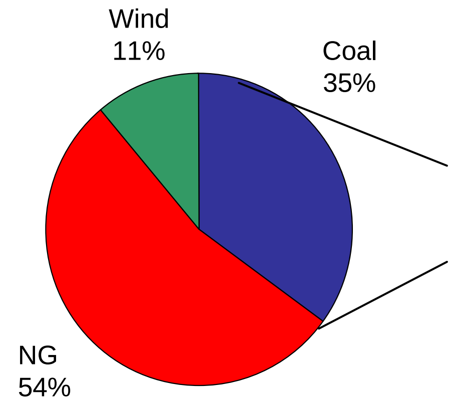
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



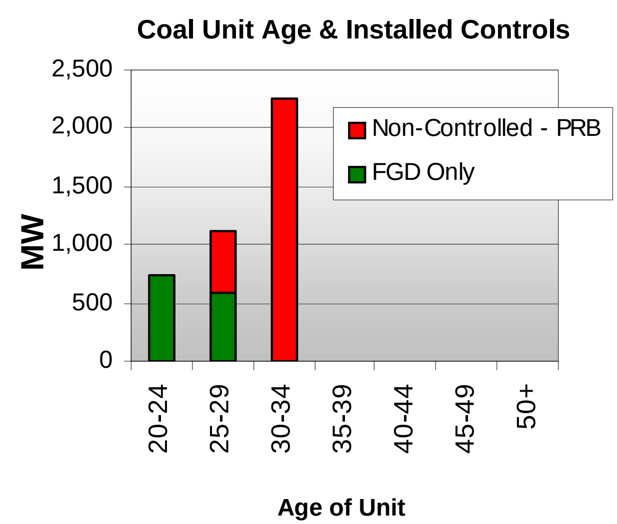
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Pending EPA Regulations

AEP®

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion (including AFUDC) for solid waste option
- “Hazardous” option could cost DOUBLE this amount

316b RULE

- EPA issued proposal March 28, 2011
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

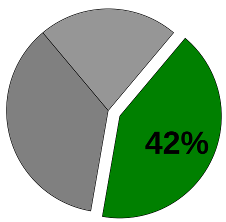
The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($Millions) [1]

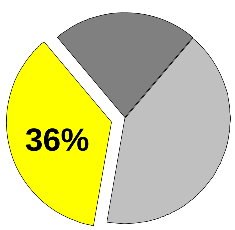
Least Exposed



Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

Proposed Rules		Low		High
Water Rules [2]	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules [3]	$	766	$	1,046

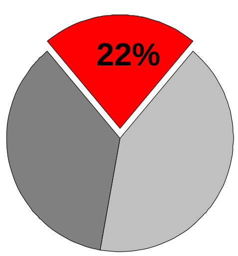
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High [4]
Water Rules [2]	$	26	$	46
CCR Rules	$	357	$	726
Air Rules [3] [5]	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

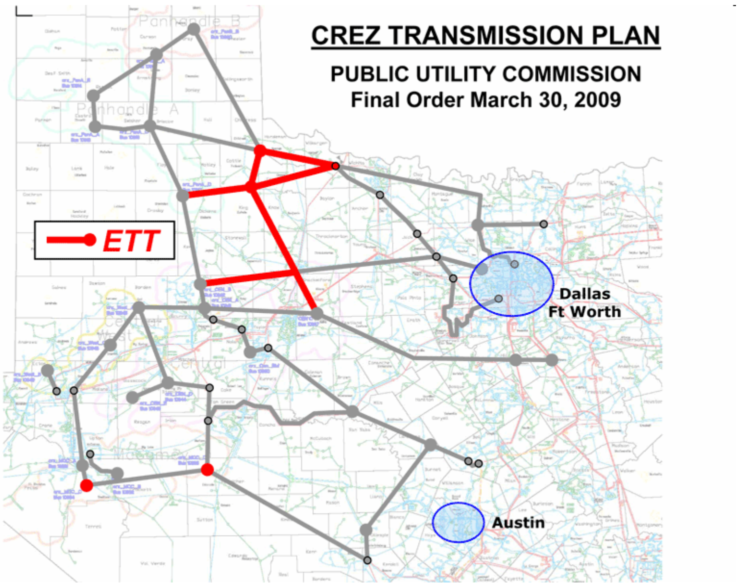
Growing Rate Base:

Current rate base is $412 million; expected to grow as follows:

- 2011: $473 million
- 2012: $778 million
- 2013: $1,352 million

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transcos is 11.49%
  - ROE order for West Transcos is 11.20%

State Filing Status Update:

- **Ohio** – PUCO approved the Ohio Transco December 29, 2010
- **West Virginia** – Filing made January 6, 2011; Hearings in June
- **Arkansas** – Filing in Arkansas made May 6, 2011
- **Louisiana –** Expecting LA filing in 3Q 2011
- **Texas-SPP** – Expecting TX filing in mid 2011
- **Kentucky** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- **Indiana** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- **Virginia** – Filing withdrawn to give additional time to resolve issues with Staff
- **Michigan and Oklahoma** – Do not require state filing

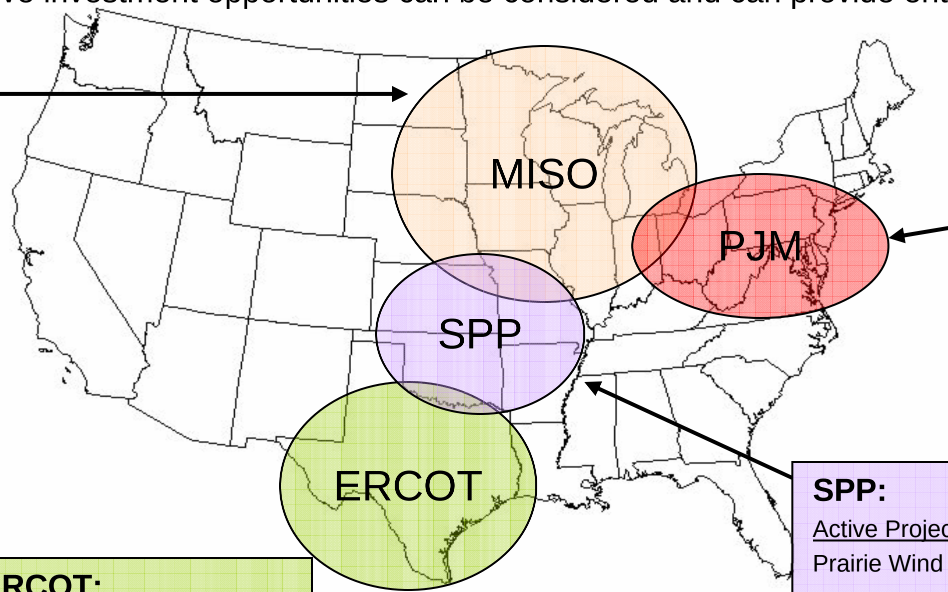
$160M capital spend forecasted for 2011; $350MM for 2012

Joint Venture Strategy: Long-term

- **Strategy:** JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility:** Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

AMERICAN ELECTRIC POWER

Sanford Bernstein & Clients Office Visit

Monday, December 15, 2008

Columbus, OH

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"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas coal, nuclear fuel and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Table of Contents

2008 & 2009 Ongoing Earnings Guidance

2008 EPS: $3.15 - $3.25

2009 EPS: $3.00 - $3.40

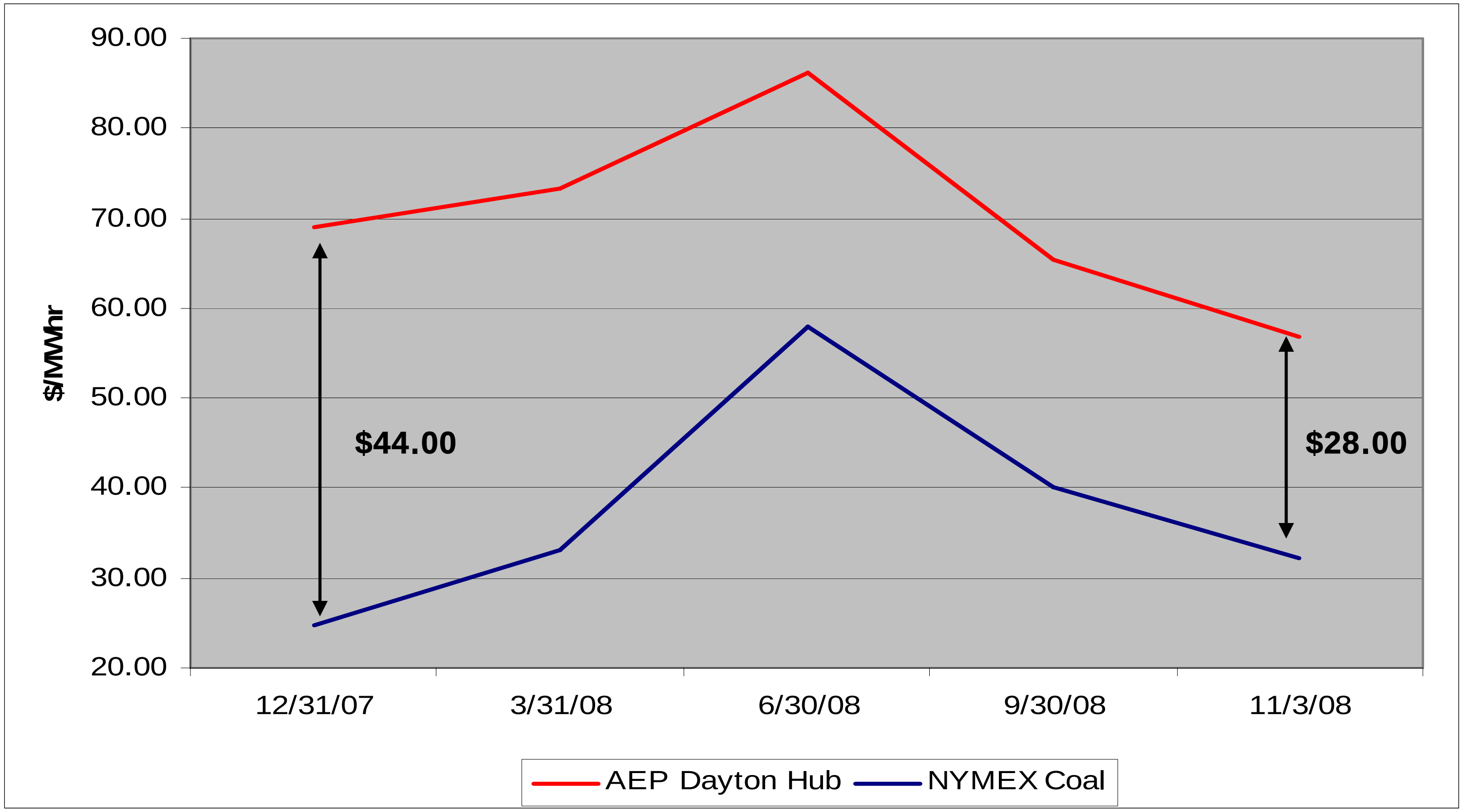
American Electric Power
Earnings Guidance for 2008 and 2009

	2008 Original Guidance ($ millions)	2008 Original Guidance EPS	2009 Guidance ($ millions)	2009 Guidance EPS
Utility Gross Margin	**8,148**		**8,433**	
Operations & Maintenance	(3,337)		(3,337)	
Depreciation & Amortization	(1,451)		(1,546)	
Taxes Other than Income Taxes	(779)		(790)	
Interest Exp & Preferred Dividend	(839)		(929)	
Other Income & Deductions	127		120	
Income Taxes	(602)		(641)	
Utility Operations	**1,267**	**3.15**	**1,310**	**3.23**
Transmission Operations	2	0.01	5	0.01
Non-Utility Operations:				
AEP River Operations	57	0.14	62	0.15
Generation & Marketing	20	0.05	13	0.03
Parent & Other	(61)	(0.15)	(91)	(0.22)
ON-GOING EARNINGS	**1,285**	**3.20**	**1,299**	**3.20**

2009 guidance provides range for a reasonable Ohio outcome, holds O&M flat and reflects higher interest expense.

Dark Spread Comparison

NYMEX Coal vs. AEP-Dayton Hub Peak Electricity



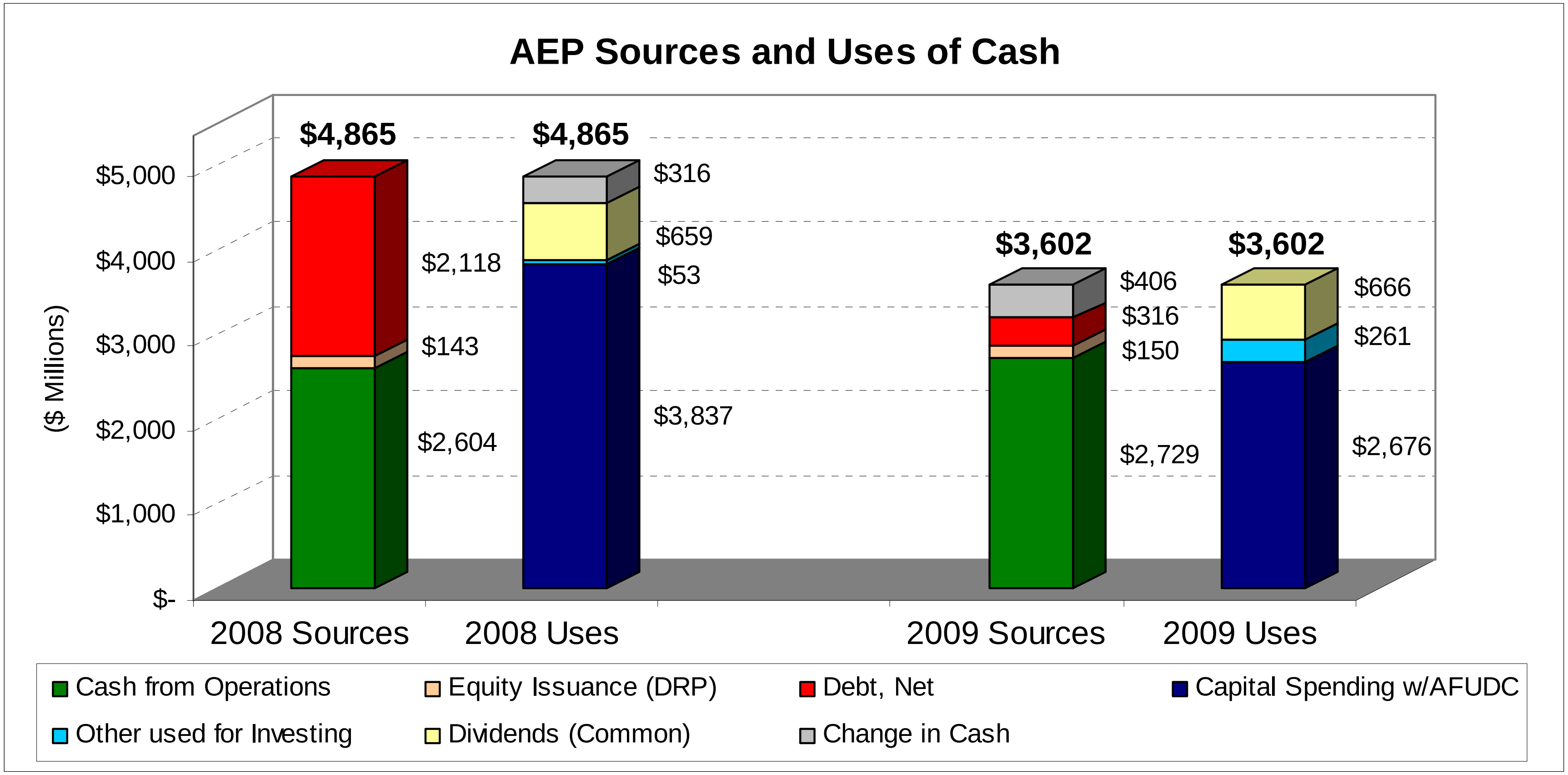
Coal Purchases:
2009: 95+%
2010: 85+%

Del. Coal Prices:
2007A: $36.58/ton
2008E: $46.82/ton

2009 estimated
increase: 12%-15%

- Coal price represents standard NYMEX contract specifications with a heat content of 12,000 Btus/lb
- 10,000 heat rate used for conversion
- Coal and peak electricity prices reflect market prices for calendar year 2009 delivery on the business dates given above

2008 & 2009 Cash Flow Forecast



Capital spending closely matches cash flow from operations in 2009.

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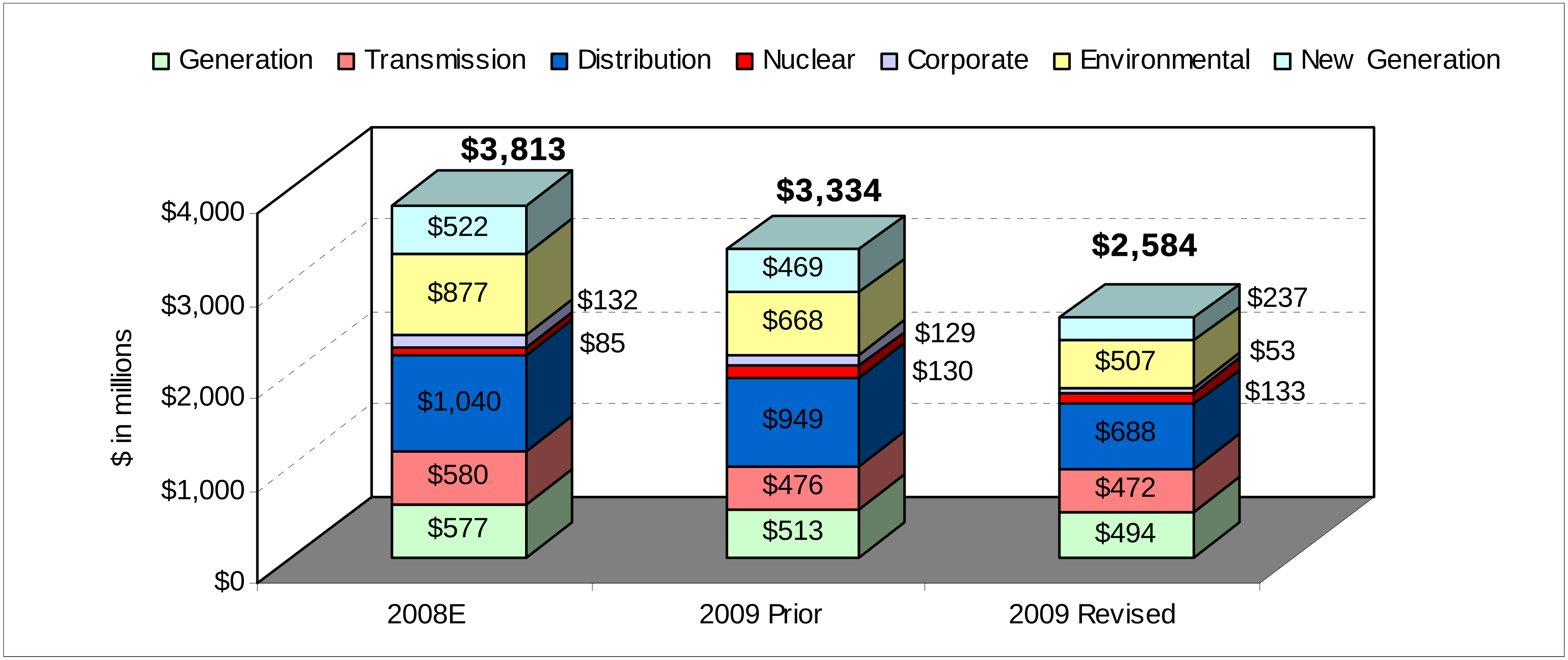
2008 & 2009 Capital Spending

- Capital expenditures for 2009 will be cut by $750 million from previous guidance.



The reduction in capital spending will significantly reduce our need to access capital markets in 2009.

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Liquidity

Liquidity Summary (unaudited)	Actual 10/28/08	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Revolving Credit Facility	338	Apr-09
Total Credit Facilities	**3,919**	
Plus		
AEP, Inc. Cash and Investments	1,366	
Less		
Draw on Credit Facilities	(1,969)	
Commercial Paper Outstanding	(178)	
Letters of Credit Issued	(439)	
Net Available Liquidity	**$2,699**	

AEP's liquidity position is $2.7 billion as of 10/28/08.

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Pension and OPEB Estimate

- The Pension plan and OPEB funds investment returns are each down about 25% YTD as of October 16, 2008. The drop in assets is mitigated slightly by a corresponding decrease in plan liability caused by a higher discount rate (from 6% to 7% for pensions and from 6.25% to 7.25% for OPEB).
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- As of October 16, 2008, we expect 2009 pension expense to increase $10MM over 2008 and the estimated OPEB expense to increase $30MM year over year.
- These increases are reflected in our current guidance.
- We are currently not expecting any mandatory contributions to pension in 2009.

Regulatory Activity Underway

- ❑ AEP Ohio ESP Filing
- ❑ I&M – Indiana Base Rate Case
- ❑ PSO – Oklahoma Base Rate Case
- ❑ SWEPCo Stall Plant Filing in Arkansas
- ❑ SPP OATT Formula Rate Filing
- ❑ PJM OATT Formula Rate Filing

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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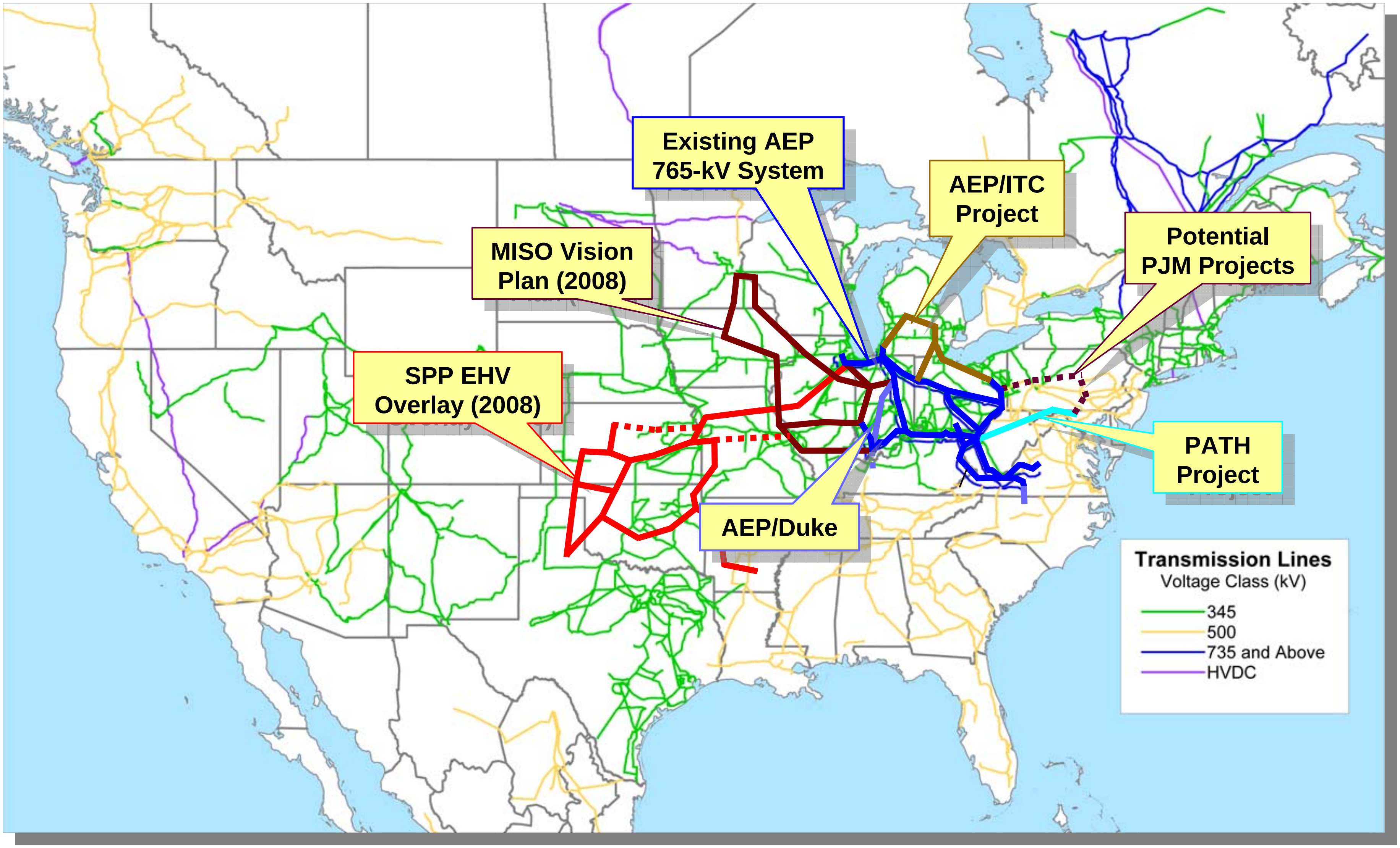
Making it Happen: EHV Projects Under Development



NOTE: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

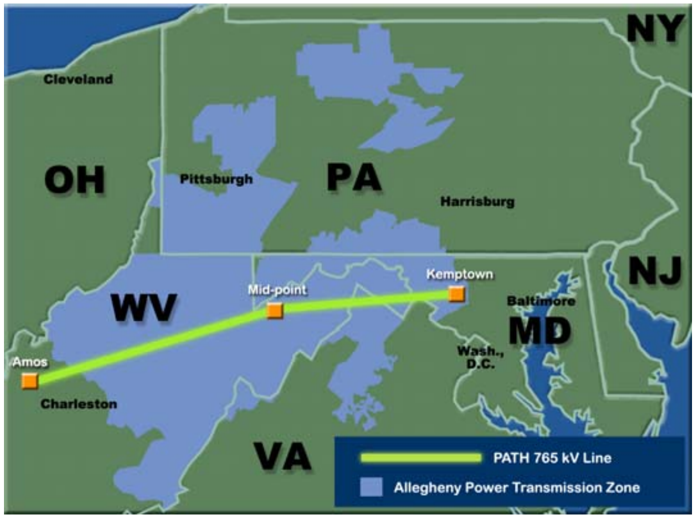
EHV Transmission in PJM: PATH

PATH Progress to Date

- PJM approved project in its Regional Transmission Expansion Plan in June 2007
- On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries
- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
- FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- In October 2008, PJM announced a reconfiguration of the PATH line which will eliminate the connection with the Bedington substation and the twin-circuit 500-kV lines from Bedington to Kemptown, and include a new mid-point substation near existing PATH alternative routes
  - The reconfiguration is a result of constraints identified as a result of comprehensive siting studies; interaction with government agencies; public input; and a desire to identify a solution that reduces line mileage and minimizes the impact on communities and the environment.
- Total estimated cost of $1.8 billion; AEP portion approximately $600 million

Key Challenges

- CPCN and Siting Approval from WV and MD



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

Joint Ventures with MidAmerican Energy Holdings Company

Electric Transmission Texas Update

- 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
- ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
- Services provided by AEP and investment opportunities can be offered by either partner
- Total initial investment of $70 million before ownership division
- In October 2008, the District Court found that the PUCT exceeded its authority by granting ETT a CCN. This decision is currently under appeal and ETT believes the ultimate outcome will validate its utility status.

Electric Transmission America Update

- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.
  - In 2008, ETA signed agreements with Westar Energy and OGE proposing to build the first and second segments of the 765-kV Overlay Plan in SPP

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Texas CREZ Project

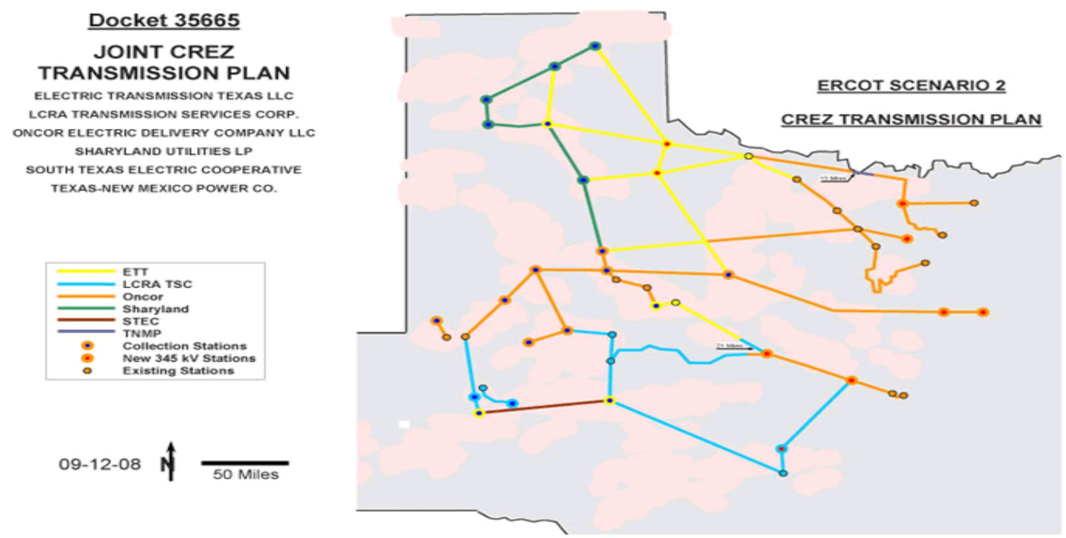
Strengthening the ERCOT grid to collect and deliver wind generation to load

❑ *Overview*

- ❑ In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the CREZ facilities approved by the Commission.
- ❑ ETT's requested share of the coordinated plan is approximately $1.5 billion. Staff testimony in October 2008 recommended ETT's share at $1.2 billion.
- ❑ The filing calls for completion of the plan by 2012.

❑ *Next Steps*

- ❑ Selection of transmission providers – 1Q 2009



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ETT
Electric Transmission Texas

EHV Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development

Figure 25: Mid Point Design 2

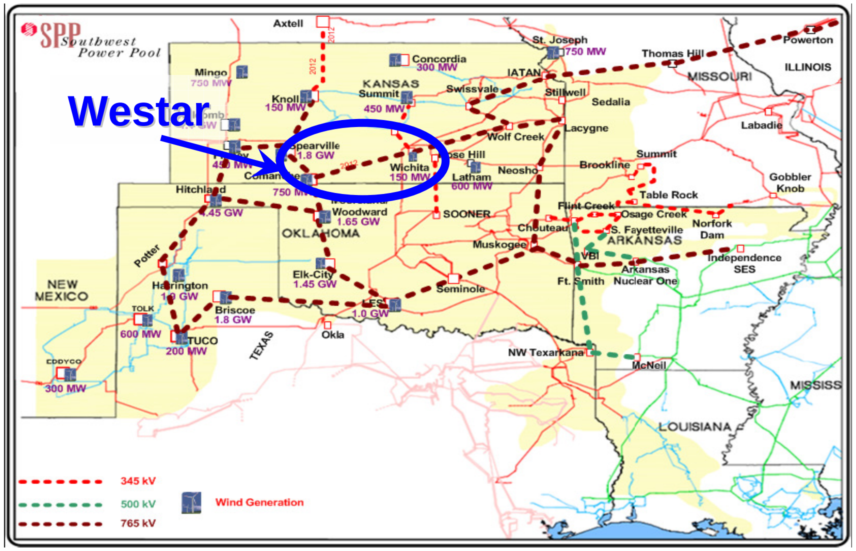
Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - PWT is a 50/50 JV that is proposing to build approximately 230 miles of 765-kV lines extending from Wichita, KS, west to a substation northeast of Dodge City, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - Project is expected to cost approximately $600 million (based on SPP estimates) and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Kansas CPC filing submitted in May 2008.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

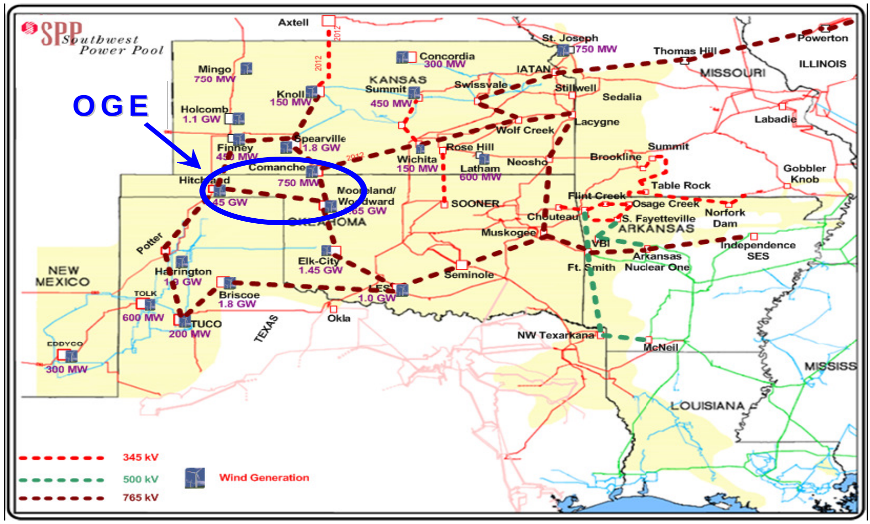
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

❑ *Overview*

- ❑ In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- ❑ TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
- ❑ The project will promote wind development in the western half of Oklahoma.
- ❑ Project is expected to cost approximately $500 million and be in-service by 2013.
- ❑ AEP's ownership of the joint venture is 25%.
- ❑ Other responsibilities will be handled by the partners or outsourced.
- ❑ FERC order received in December 2008:
  - ❑ Cash return on CWIP and 12.8% incentive ROE
  - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
  - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

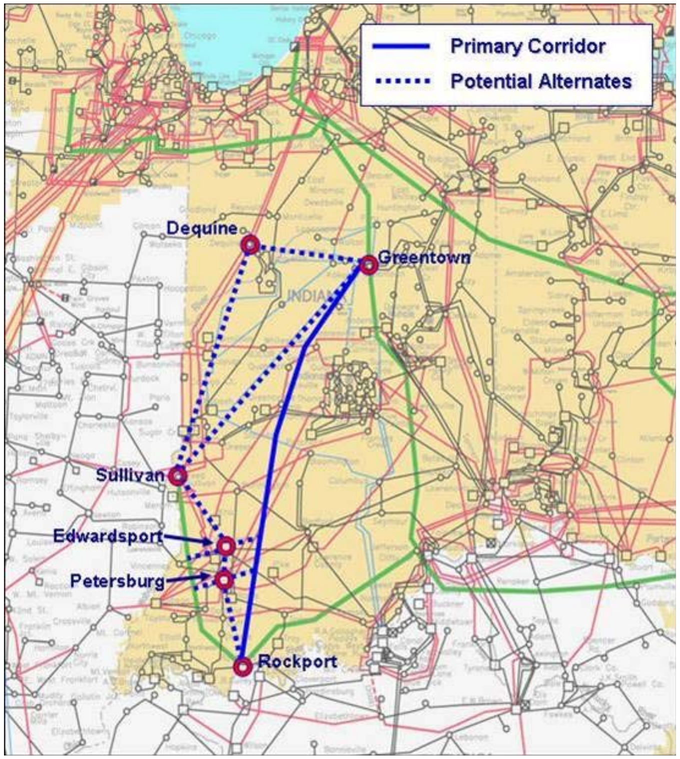
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

❑ *Key Challenges*

- ❑ Cost allocation which enables the development of "system solutions"
- ❑ RTO Approval

Pioneer Transmission, LLC

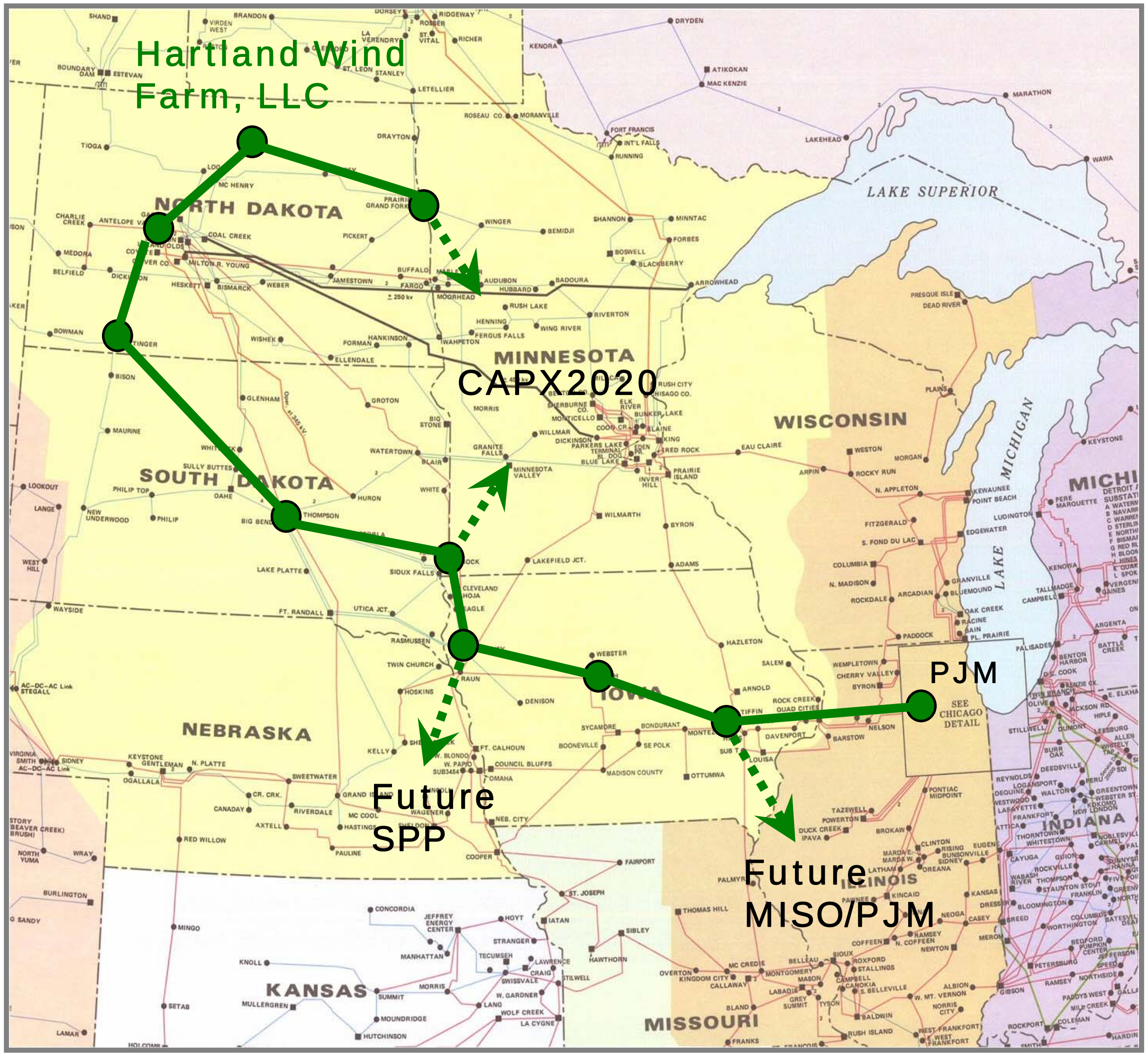
- ***Overview***
  - In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
  - PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
  - The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
  - Project is expected to cost approximately $1 billion and be in-service by 2015.
  - AEP's ownership of the joint venture is 50%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC formula rate filing submitted in October 2008 requesting:
    - Cash return on CWIP and 13.5% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected.

- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval
  - Siting

EHV Dakota Project – Conceptual View



- ❑ ~1,200 miles of 765-kV line
- ❑ ~10 stations
- ❑ ~$5-10 billion

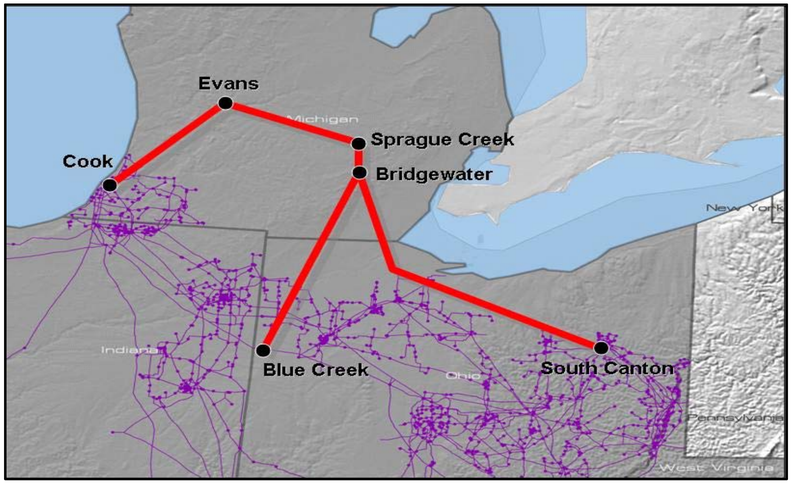
Next Steps:

- ❑ Public outreach and advocacy in the Dakotas and Iowa beginning January 2009.
- ❑ Assess project feasibility and integration with MISO long-term plans.
- ❑ Continue discussions with interested utility & renewable parties on potential partner agreements.

EHV Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- ***Overview***
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (in 2007, before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- ***Benefits***
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTOs Approvals



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The Next Administration—Energy and the Environment

- ❑ **Energy Legislation -- A First Priority**
  - For Electric Utilities: Federal RPS Likely

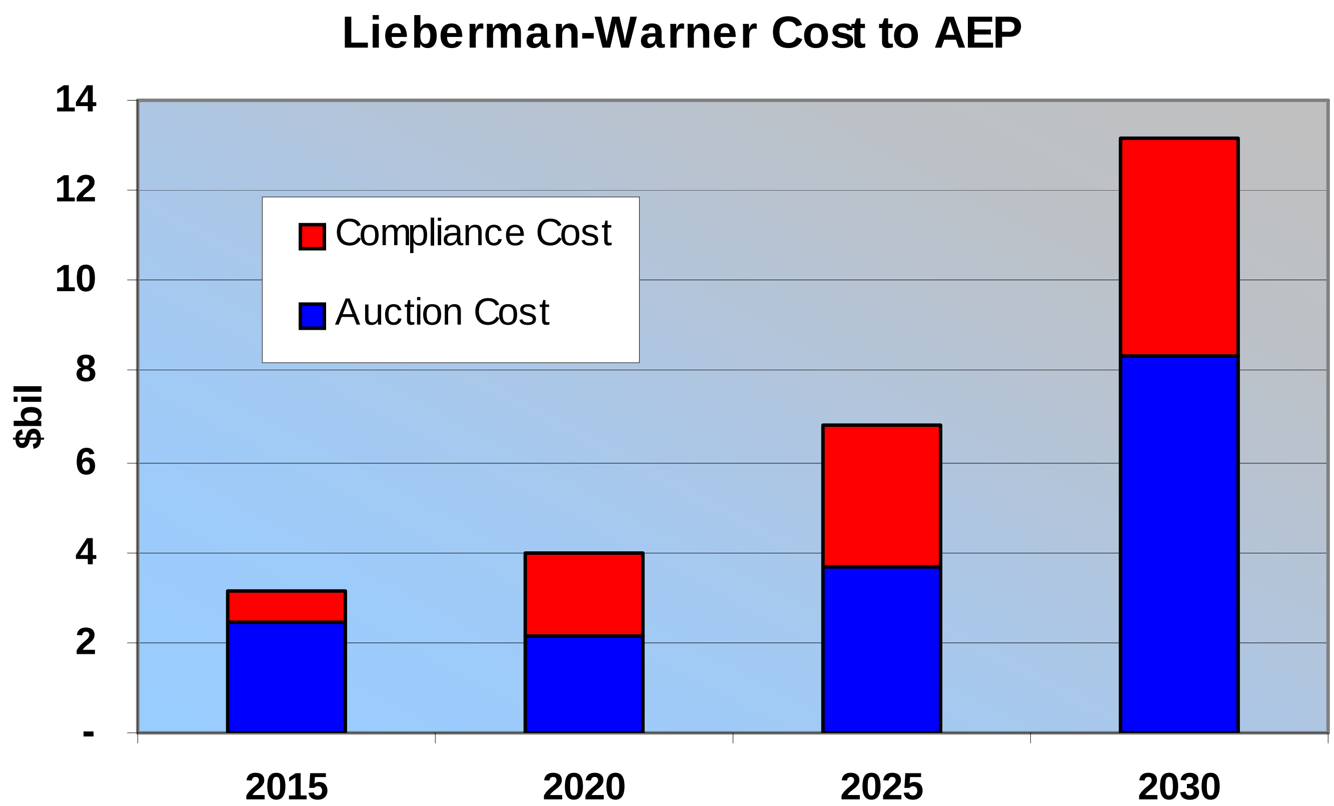
- ❑ **Climate Legislation -- Also a Priority**
  - Passage Complex

- ❑ **Further Air Emissions Requirements --SO_2, NOx, and Mercury???**

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2010
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade in-service
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2013
Northeastern 3	450		N/A	☑	Projected 2014
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

Annual AEP Cost Increases



The cost and rate impacts of Lieberman-Warner are very large, particularly due to increasing levels of auctions over time. <u>Auction purchases account for more than two-thirds of total costs.</u>

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Investor Meeting

September 23, 2005

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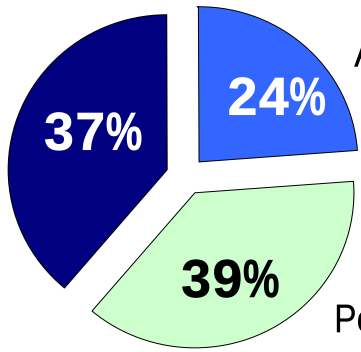
Fuel, Emissions & Logistics

Chuck Zebula
SVP-Fuel Emissions & Logistics

Coal Procurement

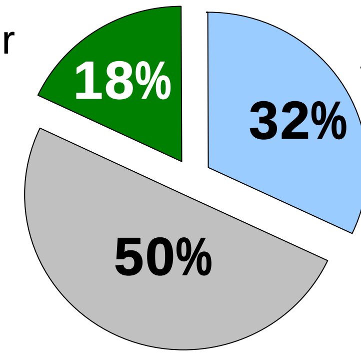
AEP SYSTEM



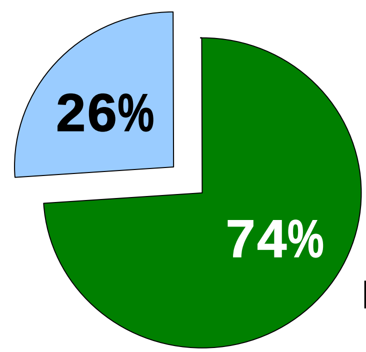
Coal Supply
(on average)

- ➢ Purchase 75 MM tons per year
- ➢ Avg. delivered price ~ $28.50/ton in 2004
- ➢ Essentially 100% purchased for 2005
- ➢ Approximately 12%-14% price increase in 2005
  - Increase being pressured by strong burn
  - PRB deliveries will impact results

EASTERN SYSTEM

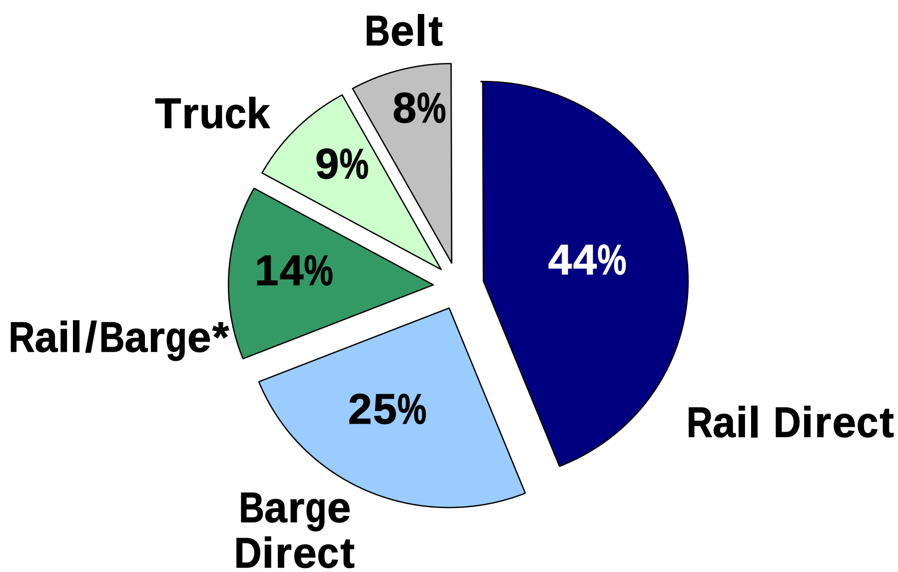


WESTERN SYSTEM

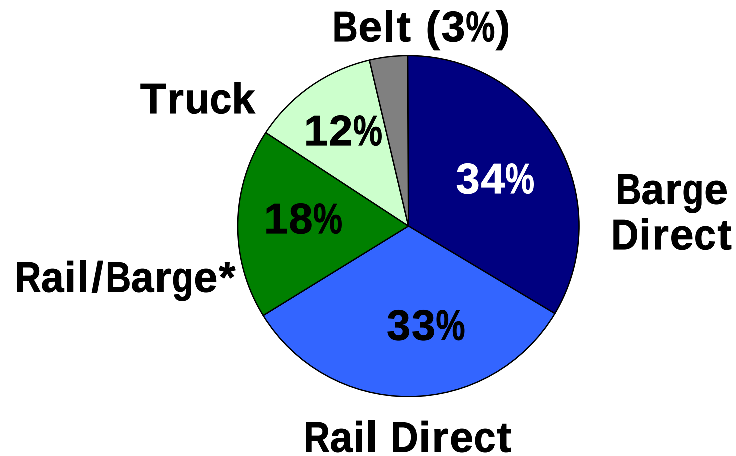


Coal Delivery Mix

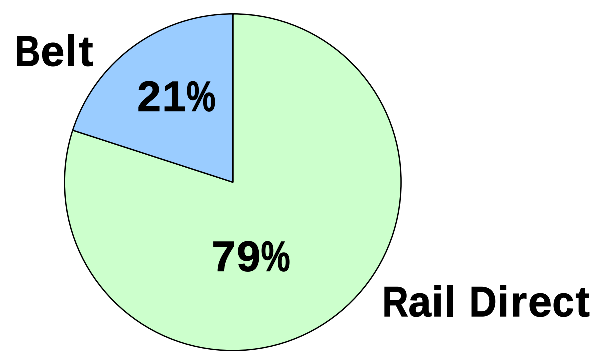
AEP SYSTEM DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



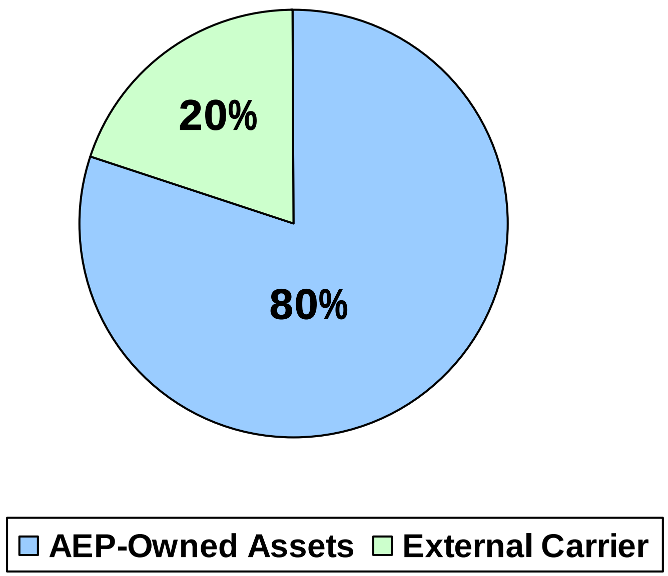
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

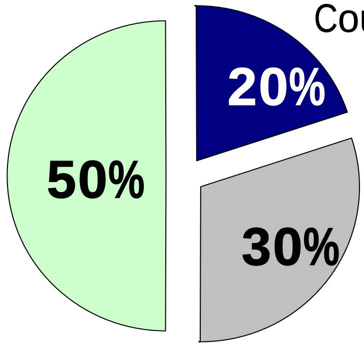
AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Fuel Recovery

AEP SYSTEM

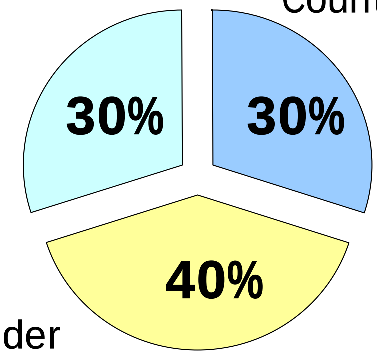


Fuel Cost Recovery
(on average)

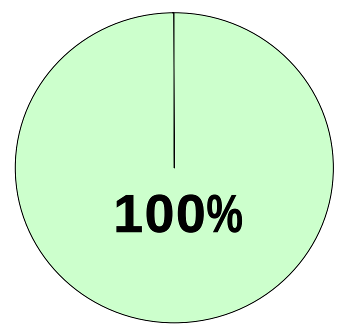
- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



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Investing in IGCC

Bruce Braine
VP-Strategic Policy Analysis

Investing in IGCC

Ohio IGCC Procedural Schedule

- **August 16, 2005: Evidentiary Hearings Concluded**
- **September 20, 2005: Initial Briefs Due**
- **October 11, 2005: Reply Briefs Due**

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

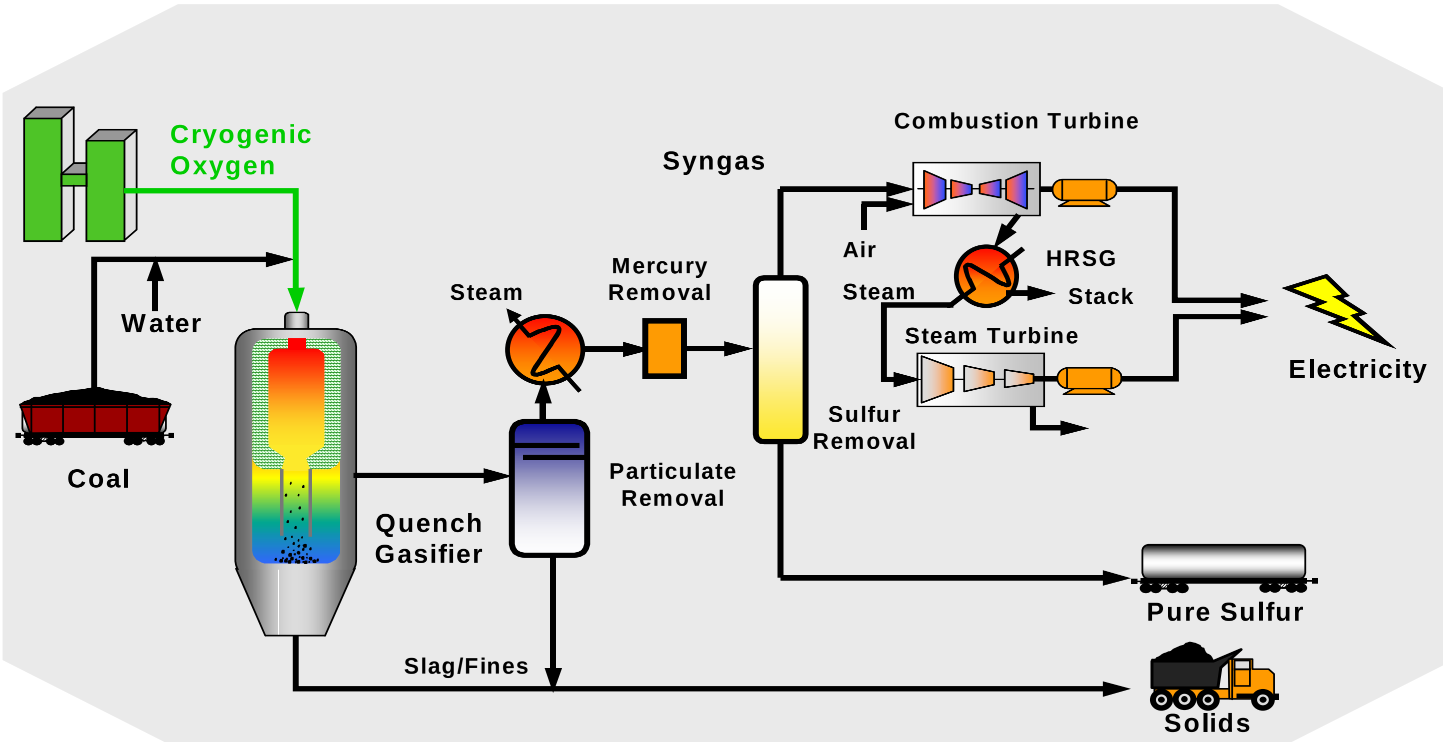
Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.

** Total plant cost include land, overheads, AFUDC, etc.

*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- Air – to evaluate best available control technology (BACT)
- Wastewater – to understand wastewater streams
- US COE (Corp of Engineers) – to obtain permits for construction of river facilities
- NEPA Process – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- ➢ Secure cost recovery plan – Summer
- ➢ Finalize site selection - Fall
- ➢ Negotiate with suppliers – Throughout 2005

- ➢ 2005—2007: Obtain permits and finalize engineering and procurement

- ➢ 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

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Environmental Rules

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:
  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to <u>all</u> three trading programs
- Arkansas subject <u>only</u> to the Ozone-Season trading program
- Texas subject to <u>only</u> the Annual NO_x & SO_2 trading programs
- CAIR does <u>not</u> apply to Oklahoma

AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Environmental Investment

AEP's Environmental Compliance Strategy

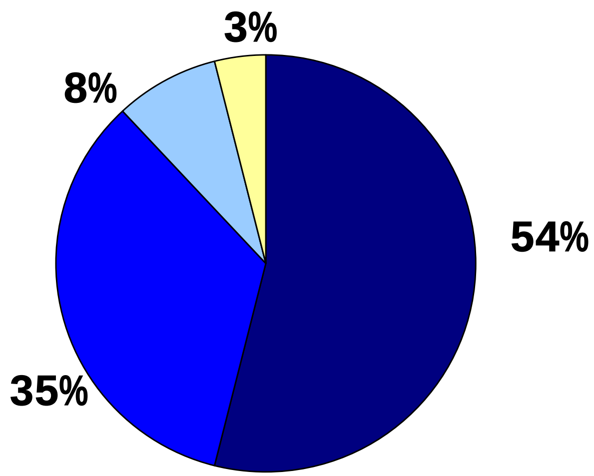
NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

- **Much of this investment will be for:**
  - **Selective catalytic reduction (SCR) systems to reduce nitrogen oxide emissions by 90%.**
  - **Flue gas desulfurization (FGD) systems (scrubbers) to reduce sulfur dioxide emissions by 98+%.**
  - **SCR and FGD systems together offer co-benefit of mercury capture.**
  - **Sale of gypsum (by-product) avoids future landfill costs.**
  - **Provides fuel flexibility.**

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

$4.1 Billion Environmental Investment: Spending by Company

Projected Environmental Investment Allocation



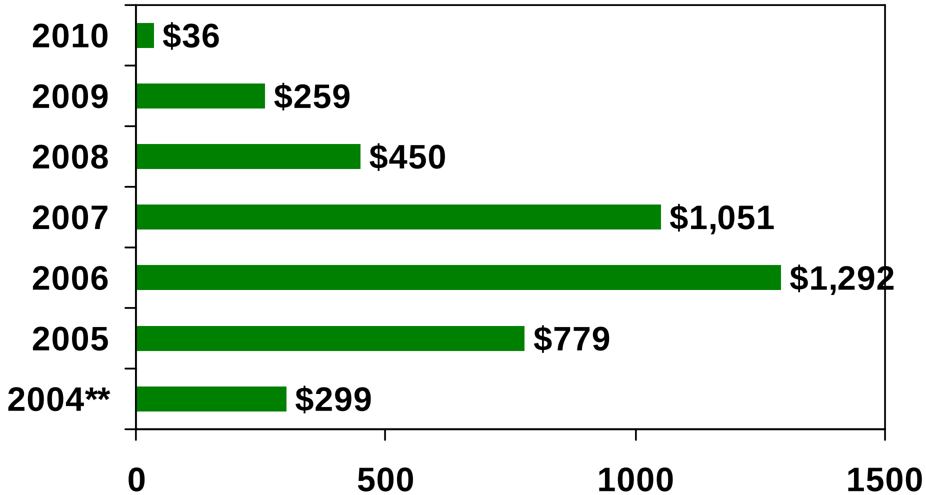
- Ohio Power & CSP (OH)
- Appalachian Power Co. (VA/WV)
- Kentucky Power Co. (KY)
- Other

Funding the Environmental Investments

- **Ohio**: 54% ($2.2 billion)
  - Approved annual increases 2006-2008
    - CSP – 3% annually
    - OP – 7% annually
- **Virginia/West Virginia**: 35% ($1.4 billion)
  - VA: Annual rate relief through Environmental & Reliability cost recovery mechanism; Two rate case opportunities through 2010
  - WV: General rate increase filed 8/26/05 including environmental, reliability & fuel recovery
- **Kentucky**: 8% ($319 million)
  - Automatic surcharge mechanism

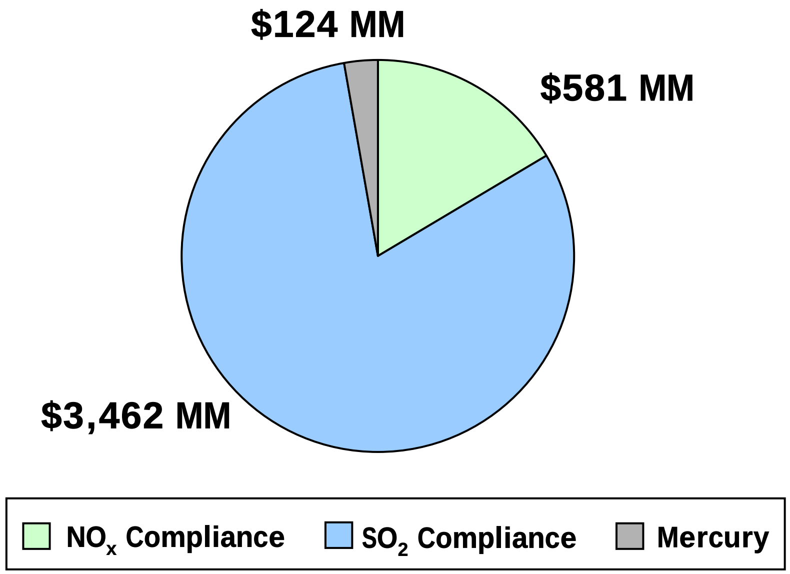
Environmental Investment: $4.1 Billion Through 2010

Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Compliance Allocation



Current Programs
$2.0 Billion:
$0.5 billion for NOx
$1.5 billion for SO_2

Future Programs
$2.1 Billion:
$1.9 billion for SO_2
$0.2 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

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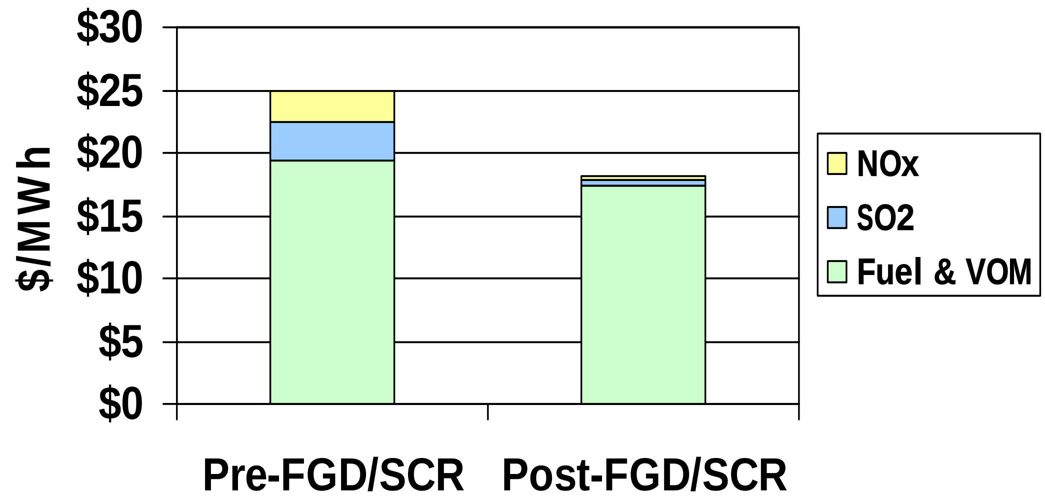
Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Environmental Investment

	FGD	SCR

Completed

FGD:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR:

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

FGD:

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

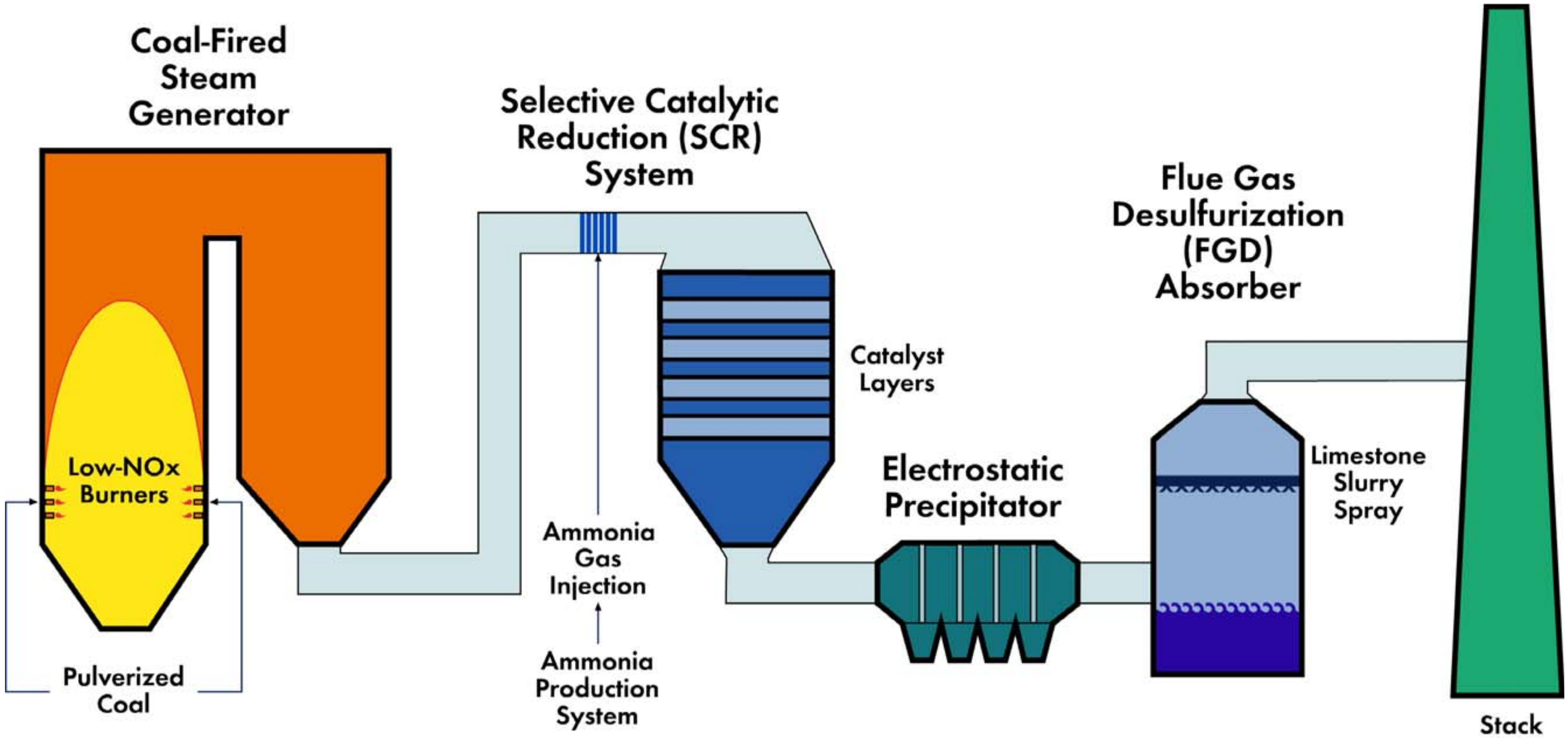
SCR:

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2006 - 2009

Note: MW capacity shown represents AEP's owned capacity only

The Flue Gas Stream



Materials and Vendors

Material Costs

- **The primary materials used during construction are steel and alloys, the cost of which is volatile. We closely monitor the cost of such materials and strive to proactively manage our cost exposure.**

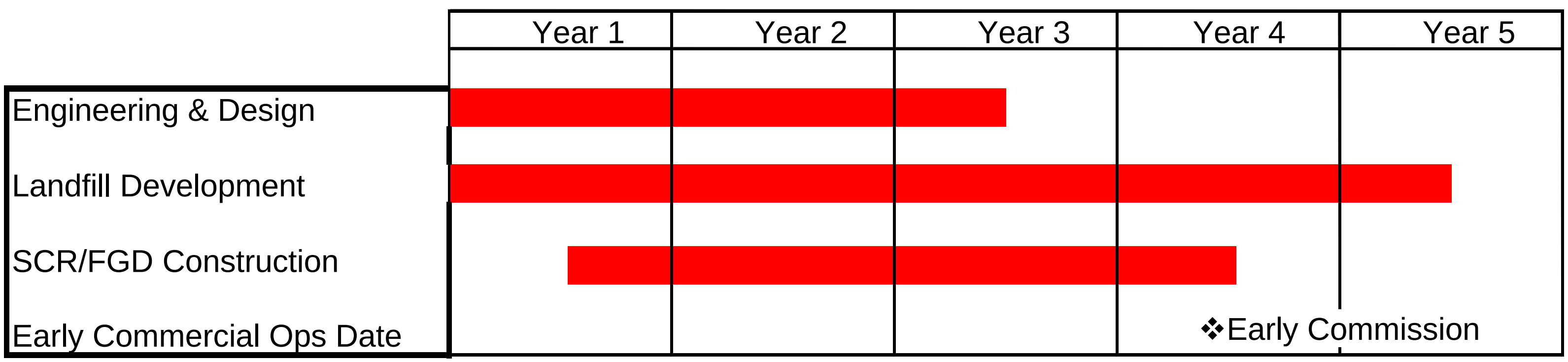
Typical Vendors

- **FGD**
  - **B&W**
  - **Alstom**
  - **B & V Chyioda**
- **SCR**
  - **Babcock-Riley Power**
- **Stack Supplier**
  - **Pullman Power Inc.**

Typical FGD/SCR Project Milestone Schedule

- **Phased Execution**
  - Lessons Learned: Focus on performance/risk management/cost
  - Phase 1 Feasibility Study, Phase 2a Conceptual design, Phase 2b Detailed design, bid Phase 3 Construction At 30 – 60 % design complete

- **Typical Plant and Landfill Schedule for Engineering, Procurement, Permitting, and Construction**
  - A new landfill requirement can be the critical path



Impact of SCR and FGD on Net Generation

- **The overall generation loss in capacity associated with SCR and FGD for the entire AEP fleet is roughly 600MW.**
- **Typically, an SCR consumes approximately 1% whereas an FGD consumes from 1.5% to 3.0% of the plant electricity output.**

PLANT MODIFICATIONS WILL MITIGATE FGD AND SCR CAPACITY CONSUMPTION

AEP AMERICAN® ELECTRIC POWER

Soleil Securities Diversified Utility & Energy Conference
New York, NY
April 1, 2010

765-kV Transmission Line

345-kV Transmission Line

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This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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Susan Tomasky, President AEP Transmission

A Changing Landscape

- National energy policy will inevitably drive significant changes in the nation's supply portfolio.
- A national Renewable Energy Standard and CO_2 legislation will impact all states, and the ability to effectively comply with these policies is reliant on a transmission system built to adapt to changes.
- Renewable resources pose significant operational challenges. A robust and flexible transmission system is critical to making sure those challenges do not jeopardize reliability to customers.
- Large scale "backbone" transmission takes several years to permit and construct – without transmission being built <u>first</u>, much of the planned renewable generation will not be developed.
- AEP believes that development of an interstate backbone transmission grid – analogous to the interstate highway system – is necessary to meet our nation's energy goals.

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Today’s Challenge

- Why Change Now?
  - Dramatic shifts in generation profile.
  - Electrically isolated large scale renewables need to be interconnected and efficiently delivered.
  - Environmental requirements are likely to force retirement of large fossil units, potentially at a magnitude never before faced in this country.
  - The search for a “bright line” between reliability and economic transmission projects is increasingly artificial.
- What Needs to Change?
  - Planning for a new energy supply paradigm.
  - Cost allocation principles to encompass a strategic expansion of transmission.
  - Siting processes which are aligned with state, regional and national energy policy objectives.
- “What got us here won’t get us there.”

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Planning & Building Smarter

- Advance a long-term, strategic "system-based" approach to transmission planning.

- Transmission grid should be adaptable to address:
  - Policy driven goals to interconnect and ensure efficient deliverability of renewables.
  - Facilitate the retirement of aging and expensive resources.
  - Regional availability of resources and operational requirements of the grid.

- Extra-high voltage (EHV) planning is needed both "within and between" traditional planning regions with:
  - Consistent planning criteria applied to EHV transmission.
  - Regional and inter-regional planning efforts and consensus on transmission development goals.
  - Longer time horizons to ensure development of strategic as opposed to "band-aid" solutions.

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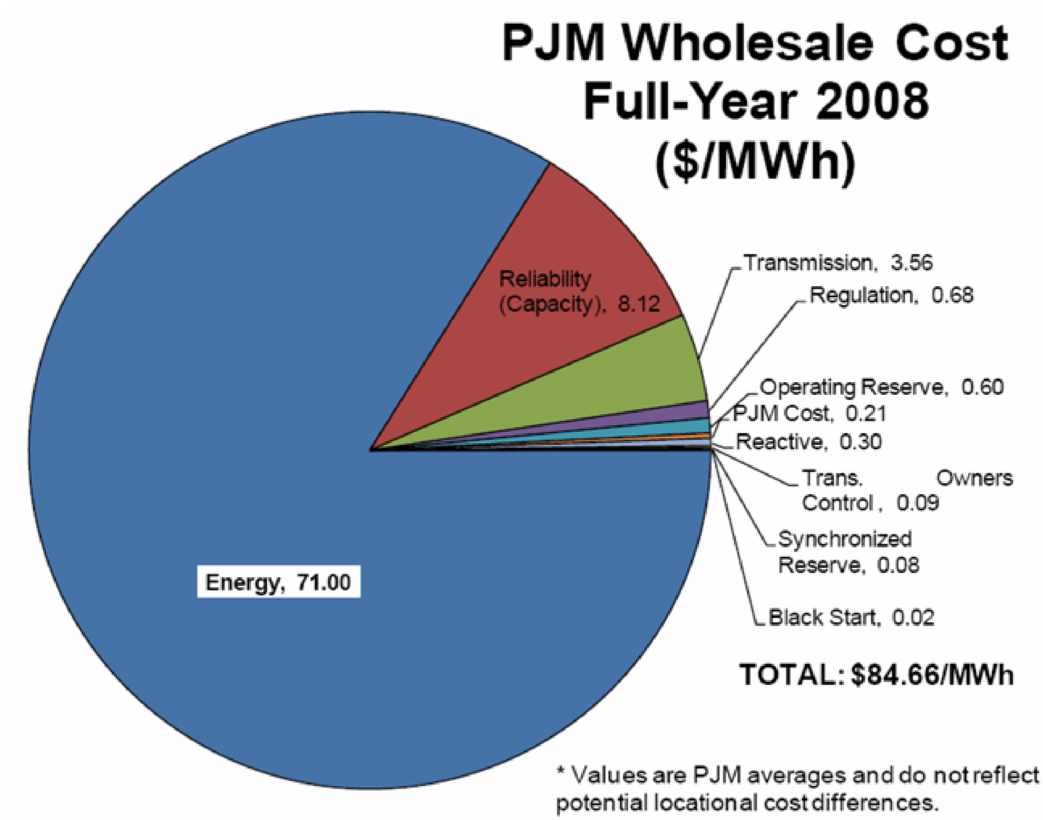
Fair Allocation of Costs & Benefits

- Transmission represents a very small part of the customer bill.
- Substantial investments in transmission have a small impact on customer bills.
- Transmission expansion facilitates lower delivered energy costs due to:
  - Increased competition and less constrained markets.
  - Reduced energy losses.
- Studies often show transmission can pay for itself, provided costs are broadly allocated.



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Development Needs

To make significant strides in developing clean, domestic energy and reducing emissions, we as a nation need:

- National energy policy with specific goals and guidelines, particularly as it relates to renewables and CO_2.
- Federal planning authorities that can mandate RTOs, utilities, or other planning entities to develop long-term, interconnection-wide transmission plans that will facilitate national energy goals.
- Mandates to develop reasonable regional and interregional cost allocation methodologies to support EHV transmission that is in the national interest.
- Support for the siting of national-interest transmission lines where necessary.
- Benchmarks to check progress of plans and ensure timely construction.

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AEP's Transmission Investment Opportunities

- **AEP Transmission Company (Transco): Within our existing footprint**
  - Provides opportunity to:
    - Develop new AEP-only projects within AEP's footprint
    - Reduce regulatory lag through FERC formula rates adjusted annually
    - Enhance access to capital
    - First year investment opportunity--$121MM
- **Electric Transmission Texas (ETT): Projects in Texas ERCOT jurisdiction**
  - Framework in Texas allows for more expeditious siting and recovery
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B within this decade
- **Joint Ventures (JVs): Outside of our footprint, with Electric Transmission America (ETA) or others**
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - State and future Federal RES will provide enhanced investment opportunities
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2016
  - Robust pipeline of projects up to $15B

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AEP Transmission Company (Transco)

- Transco will be used to develop significant new on-system, AEP-owned investments
  - Greenfield Projects
  - Station Additions
  - System Upgrades
- Seven companies have been established under the AEP Transco holding company
- Next steps:
  - Obtain state utility status where required
    - No filing required in Michigan or Oklahoma
    - Filing made in Ohio
  - FERC tariff for Transco filed December 1, 2009 with rates effective and first projects in-service in 2010; Settlement discussions on-going
  - Seek retail tracking mechanisms at the state level (OH, LA, VA, TX-ERCOT already secured)

765-kV Tower

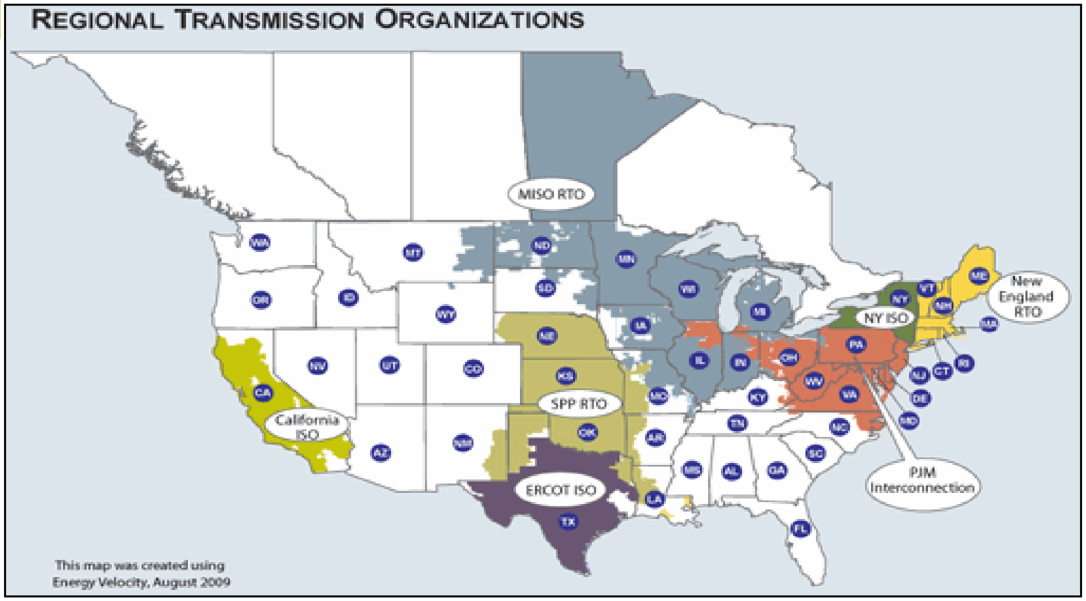
JV Strategy – Nationwide Grid Expansion

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind COD: 2013-14	**ETT** COD: 2010-2017	**PATH-WV** COD: 2014	**Pioneer** COD: 2015
▪ *110 miles of 765 kV* ▪ *Partners: Westar (50%) & Electric Transmission America (50%)* ▪ *Estimated Cost: $400 million* ▪ *ROE: 12.8%*	▪ *345 kV ERCOT Expansion* ▪ *Partner: MidAmerican Energy (50%)* ▪ *Estimated Cost: $1.4 billion* ▪ *ROE: 9.96%*	▪ *275 miles of 765 kV* ▪ *Partner: Allegheny Energy (50%)* ▪ *Estimated Cost: $1.2 billion* ▪ *ROE: 14.3%*	▪ *240 miles of 765 kV* ▪ *Partner: Duke Energy (50%)* ▪ *Estimated Cost: $1 billion* ▪ *ROE: 12.54%*

Tallgrass COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
▪ *Regional Expansion of 765 kV Backbone*	▪ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ▪ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	▪ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	▪ *700 miles of Proposed 765 kV*

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Key Investment Attributes

AEP is the Leader

- Largest US transmission footprint
- Interstate EHV transmission highway vision
- National renewables transmission strategy

Quality Investments

- 4 FERC-approved ($3.3 billion)
- AEP Transco (2010 Investment: $121 million)
- Independent ERCOT transmission JV company (up to $3.0 billion)
- Robust pipeline of future high-voltage transmission projects (up to $15 billion)

Attractive Returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Robust long-term annual earnings growth potential

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Appendix

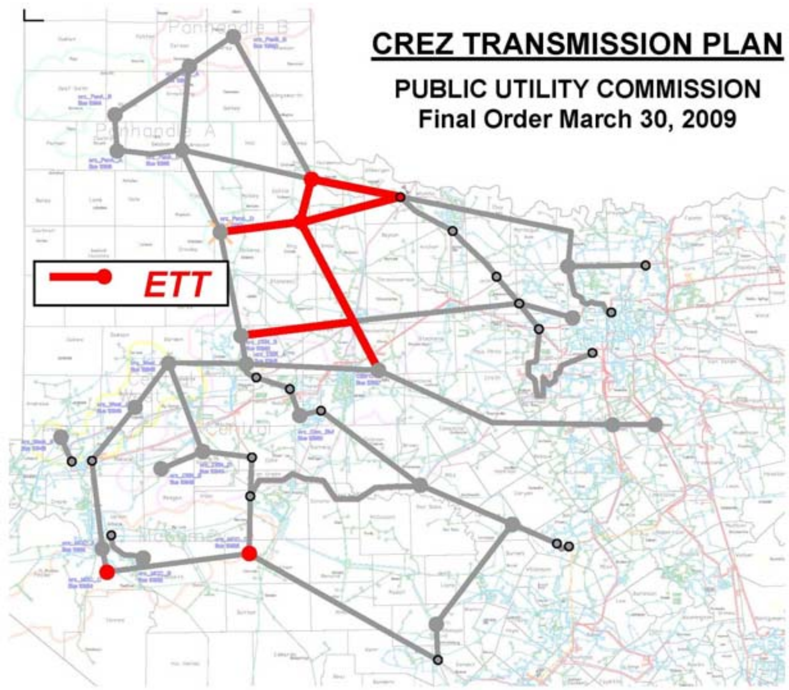
Electric Transmission Texas, LLC

Overview:

- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

- **Opportunities:**
  - Projects in service 2010-2017: $1.4 billion
  - CREZ projects in service 2012-2013: $1.1 billion
  - Other projects pending transfer in service 2010-2013: $600 million

- **Next Steps:**
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT Electric Transmission Texas

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EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

PATH
Potomac-Appalachian Transmission Highline

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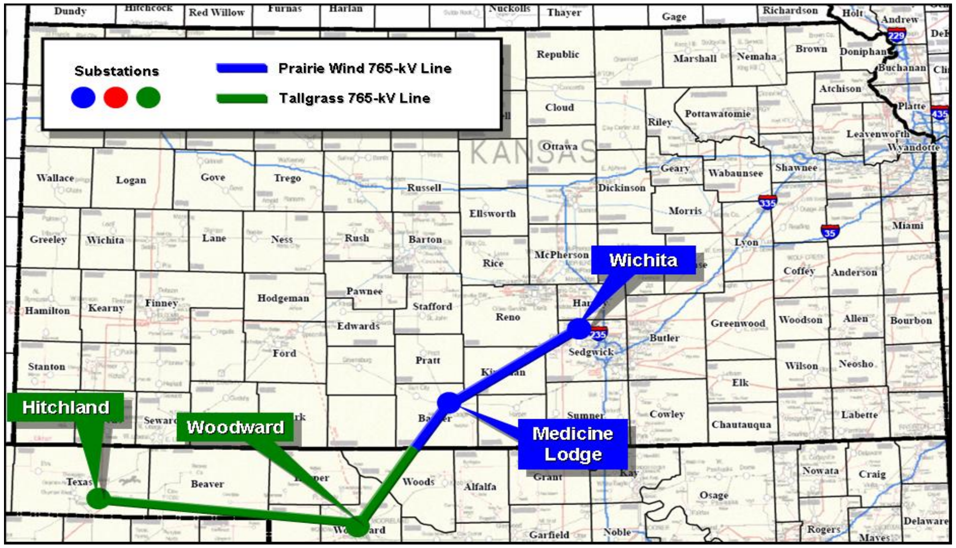
Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP’s ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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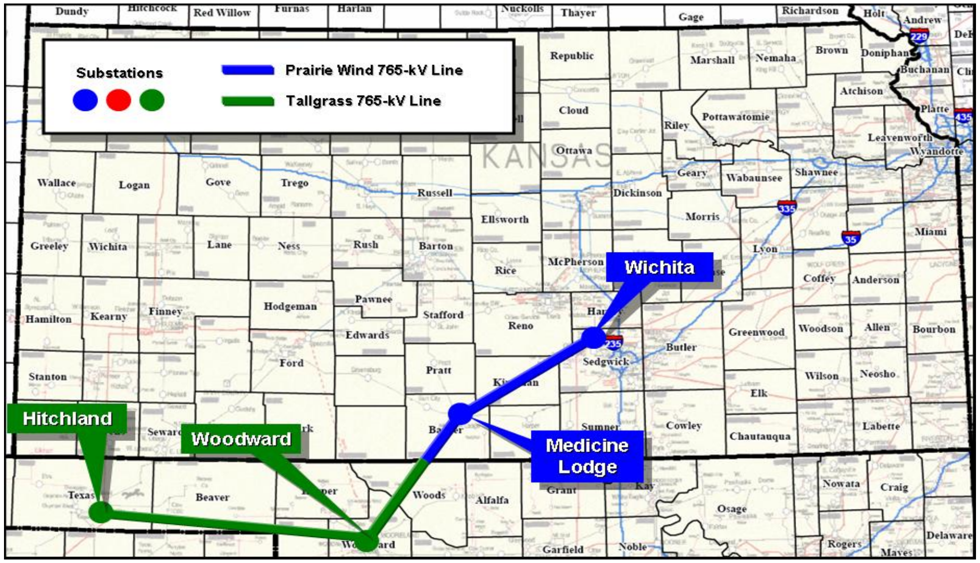
Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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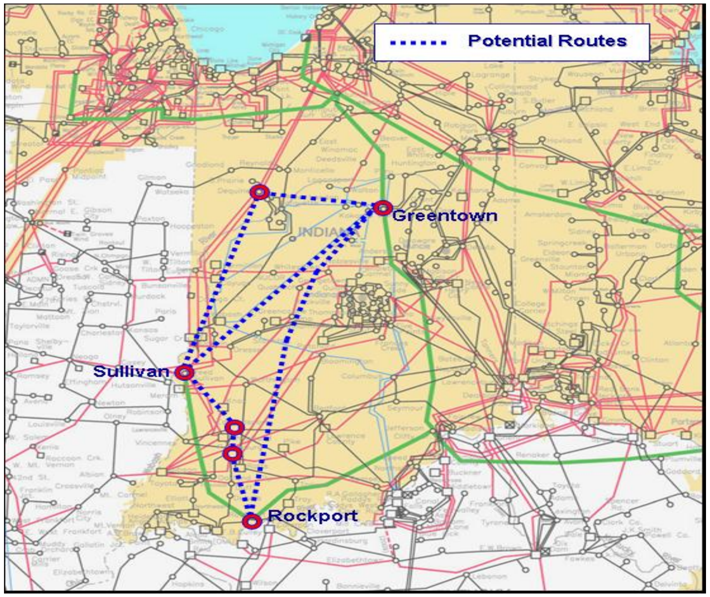
Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

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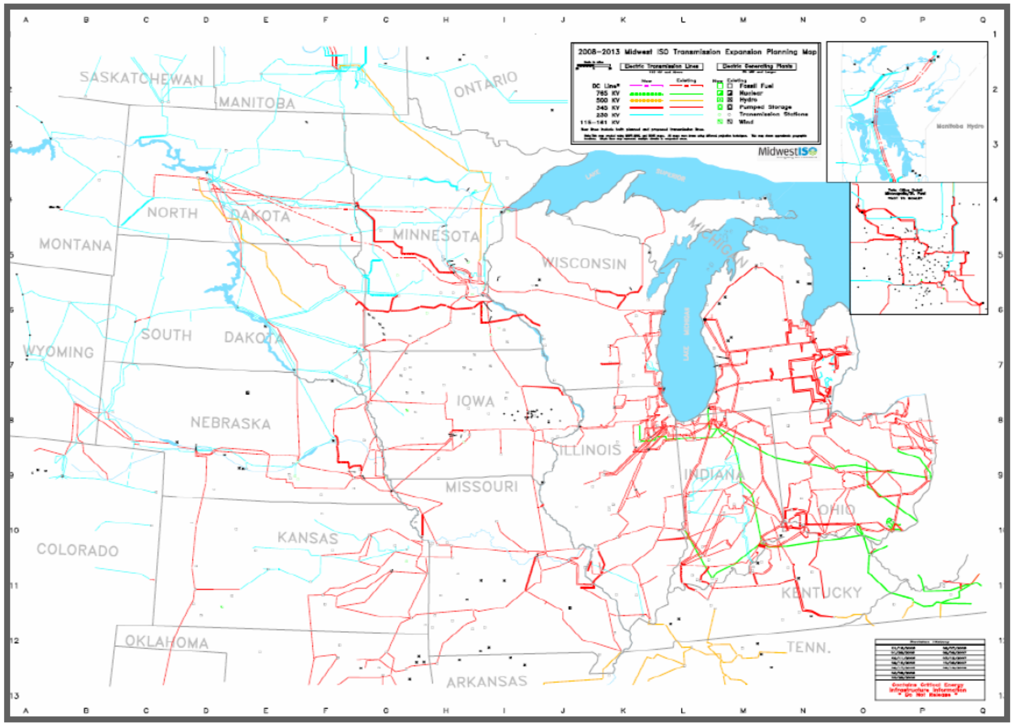
Upper Midwest EHV Development—SMART Study

Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2Q2010 and will include "overlay" options and quantification of economic benefits



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives

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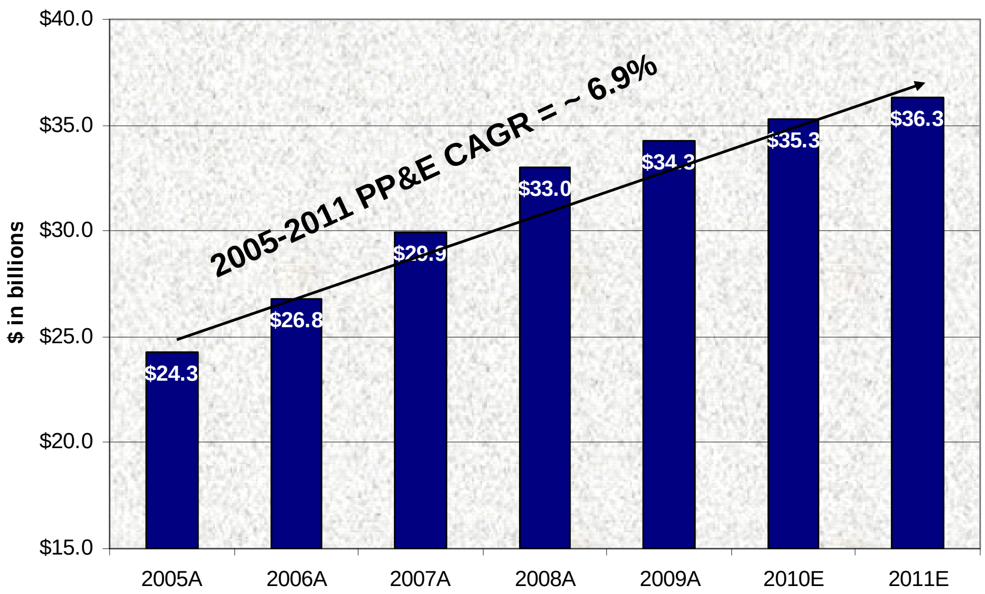
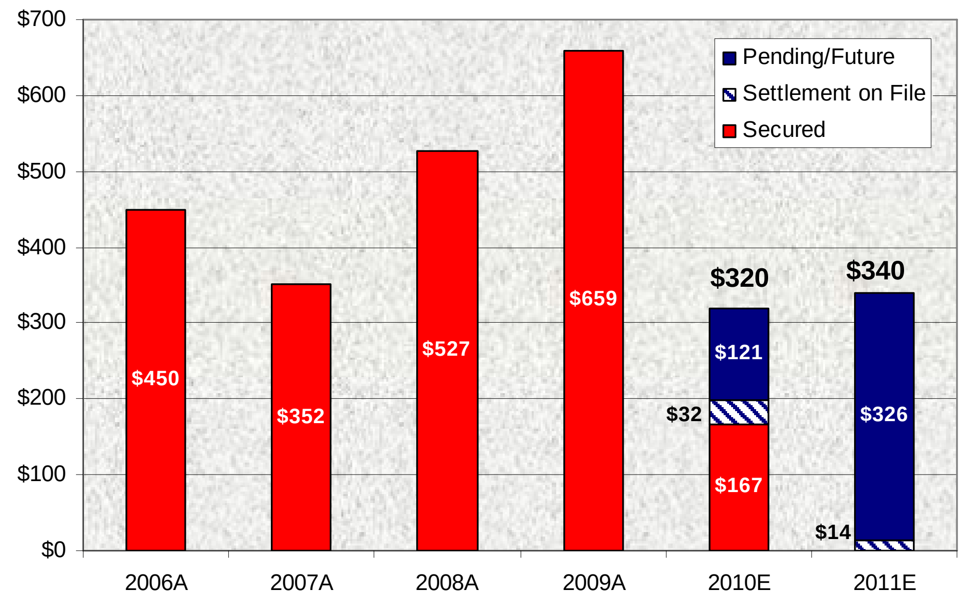
Traditional Rate Making Environment

Growth in Net PP&E



Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Kentucky, Michigan, Virginia, West Virginia and others

Settlement on file relates to SWEPCO Texas rate case

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Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. A settlement was filed in March 2010 resulting in a revenue increase of $25MM, an ROE of 10.33%, reduced depreciation expense of $17MM and expiration of merger credits of $7MM. An order is expected in mid-April 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

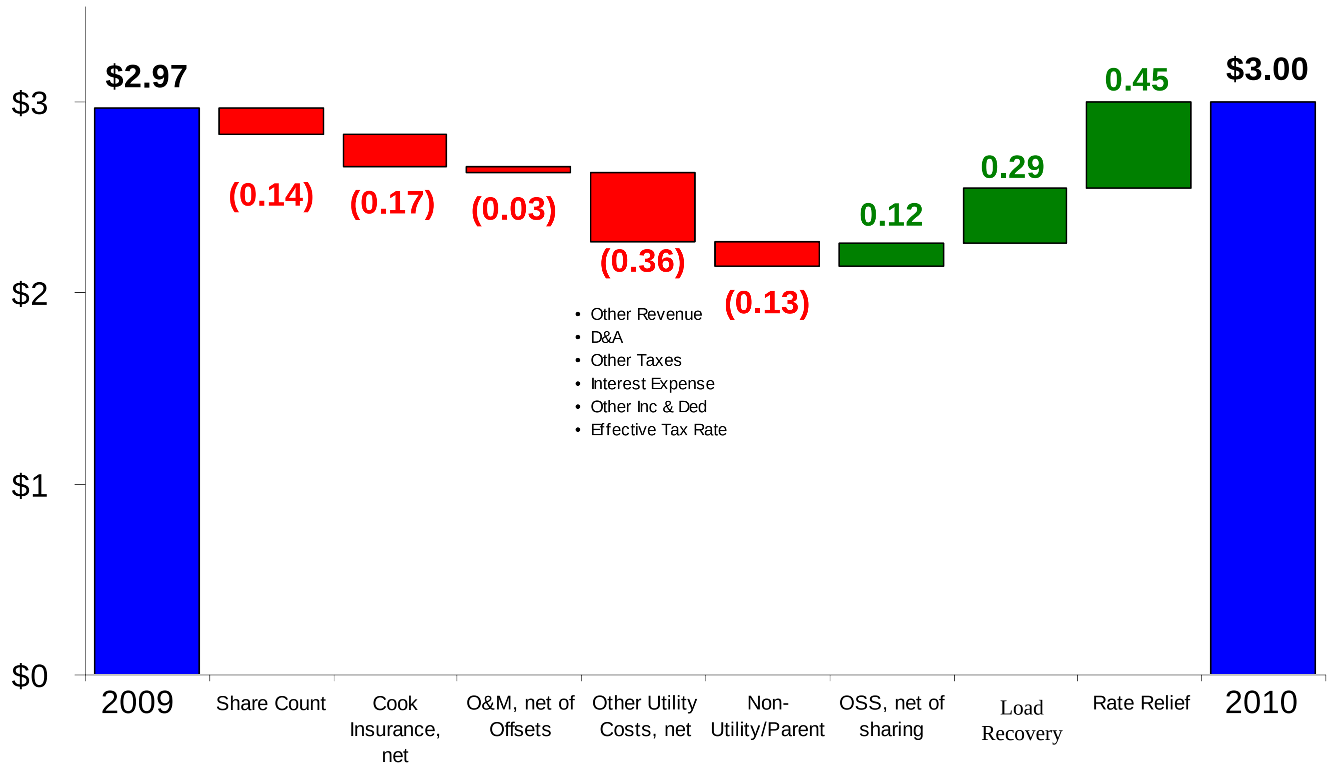
Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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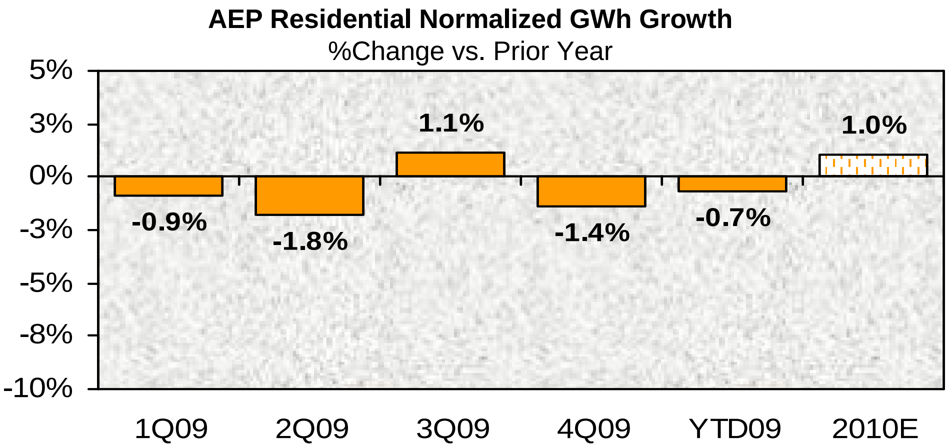
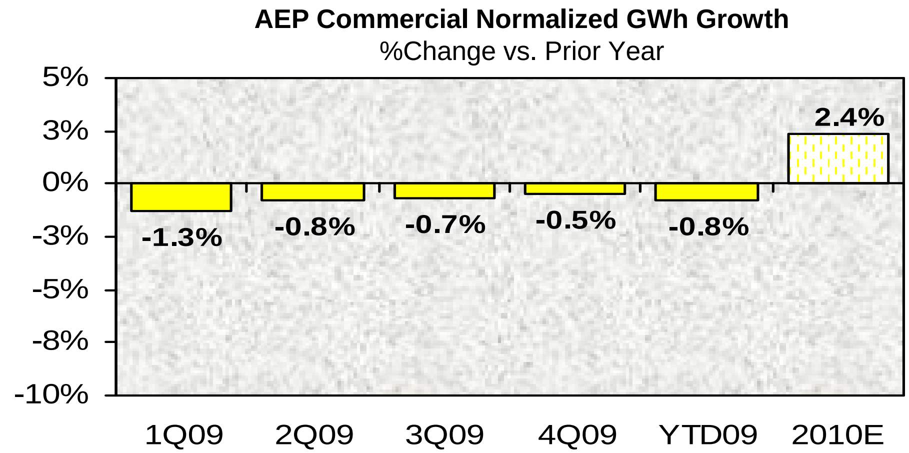
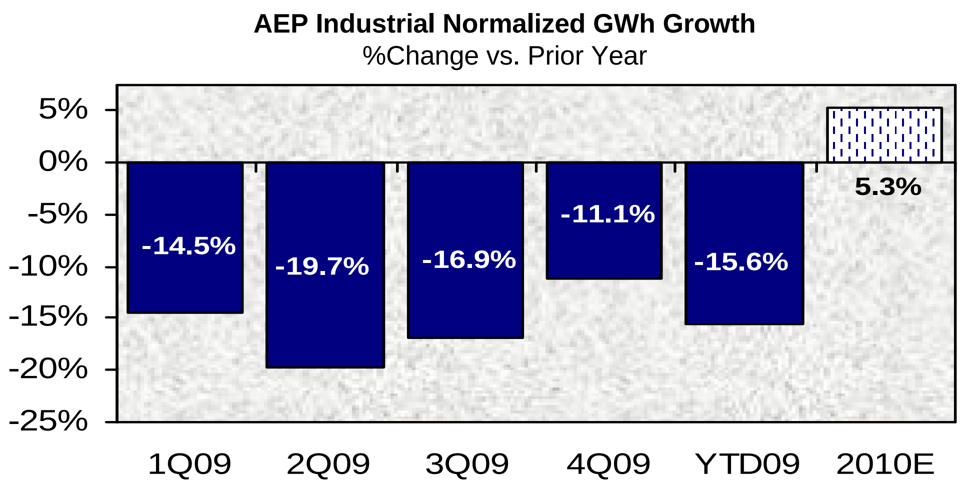
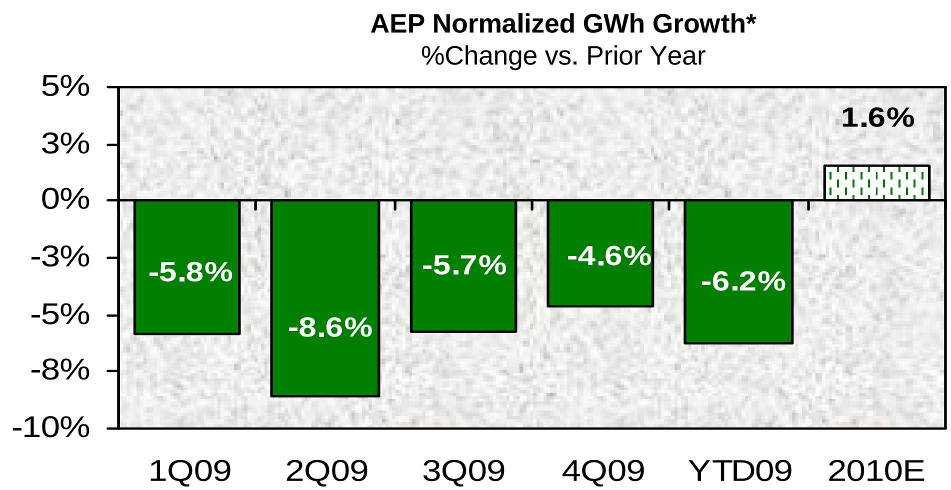
Normalized Load Trends









*includes firm wholesale load

Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

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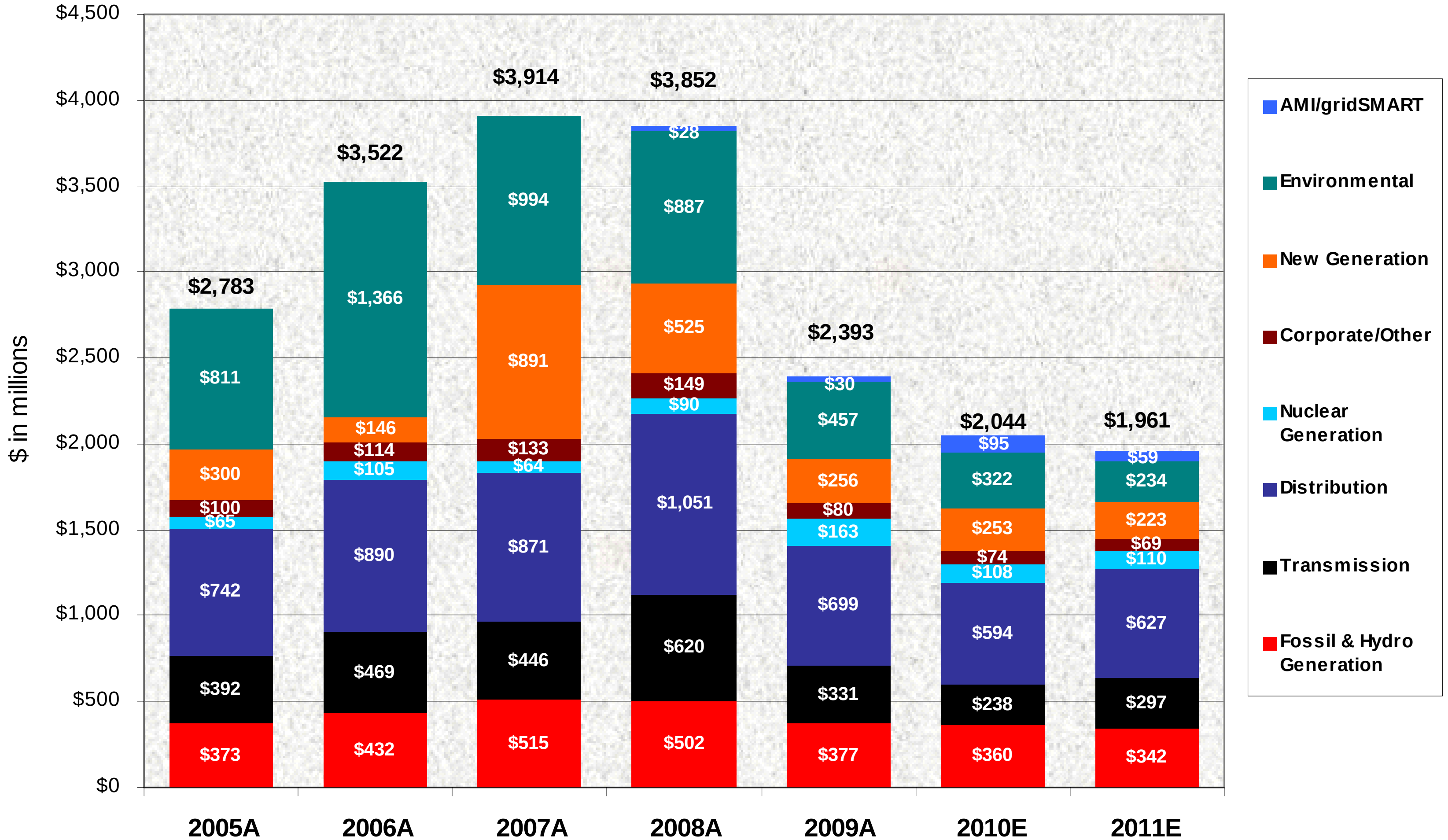
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

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Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

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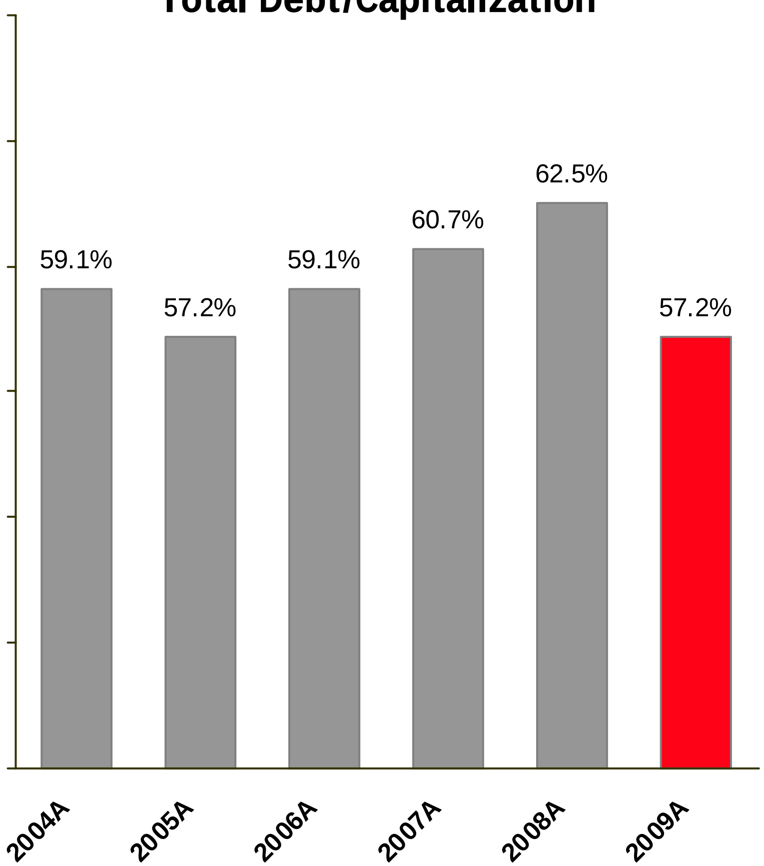
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP AMERICAN® ELECTRIC POWER

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012
AEP, Inc.	$ -	$ -	$ -
AEP Generating Company	$ -	$ 130	$ -
Appalachian Power	$ 200	$ 250	$ 250
Columbus Southern Power	$ 150	$ -	$ 195
Indiana Michigan Power	$ -	$ -	$ 100
Kentucky Power	$ -	$ -	$ -
Ohio Power	$ 680	$ -	$ -
Public Service of Oklahoma	$ -	$ 75	$ -
Southwestern Electric Power	$ -	$ 48	$ -
Texas Central Company(1)	$ -	$ 120	$ 20
Texas North Company	$ -	$ -	$ -
Total	$ 1,030	$ 623	$ 565

(1) Includes Texas Securitization Bonds Based upon Scheduled Final Payment Date
Includes mandatory tenders (put bonds)

Data as of March 31, 2010

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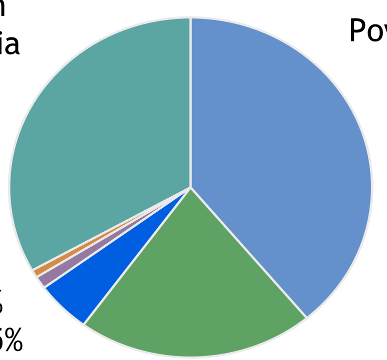
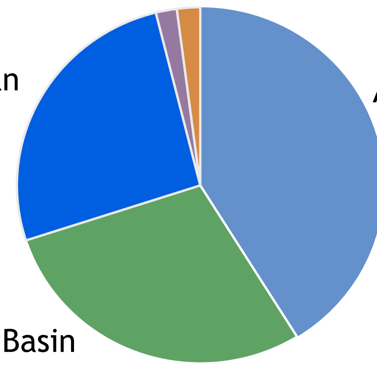
Coal Procurement - 2010 Projected

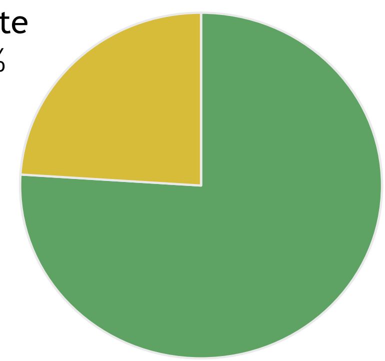
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

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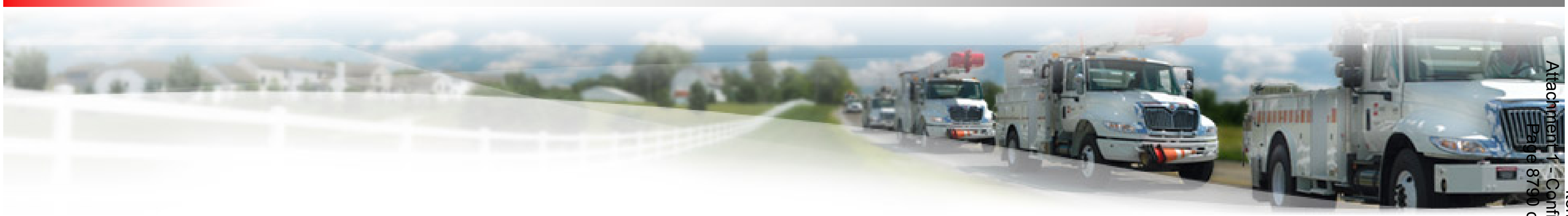
Soleil Securities Diversified Utility & Energy Conference

New York, NY
April 6, 2011



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclea fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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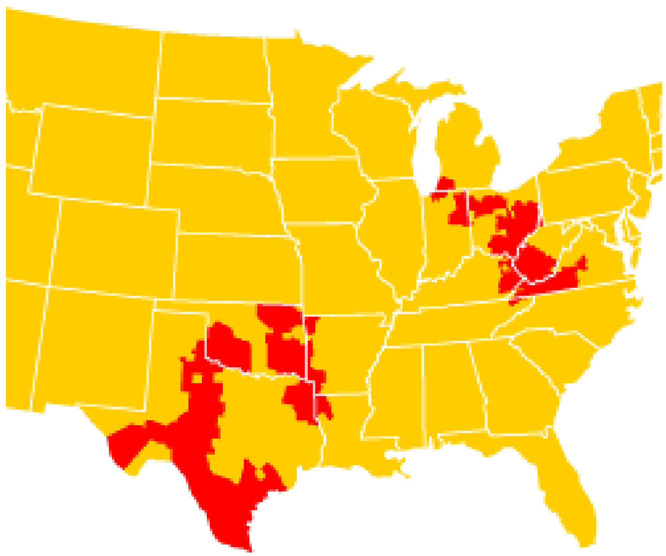
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



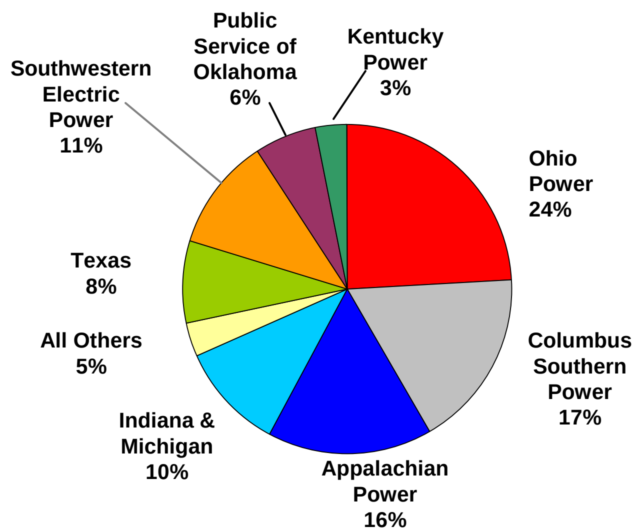
AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

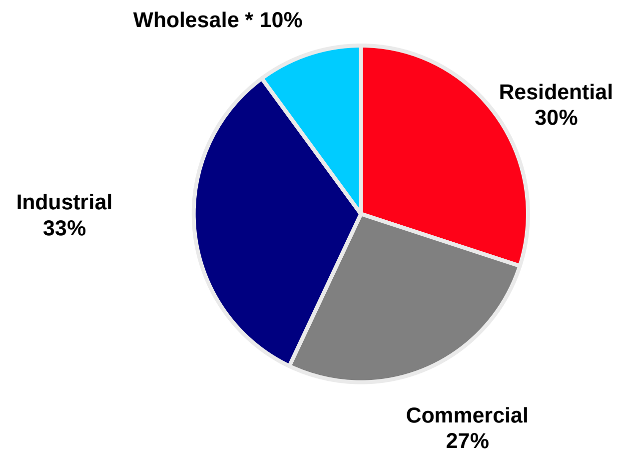
$17B Market Capitalization
BBB/Baa2/BBB credit rating

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



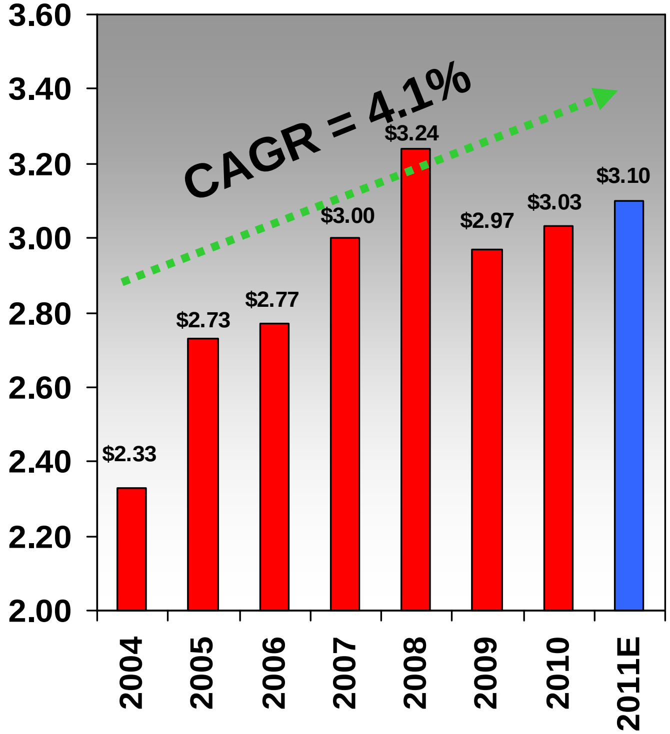
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

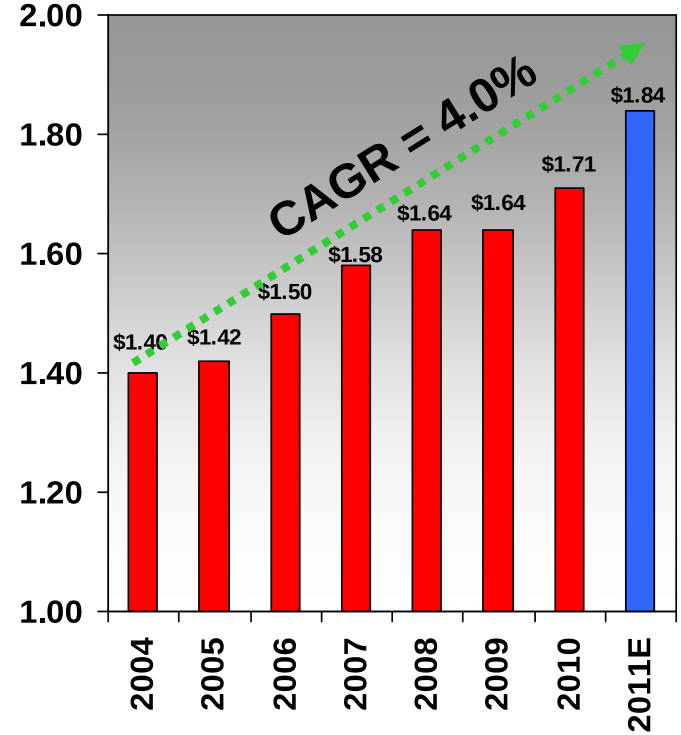
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

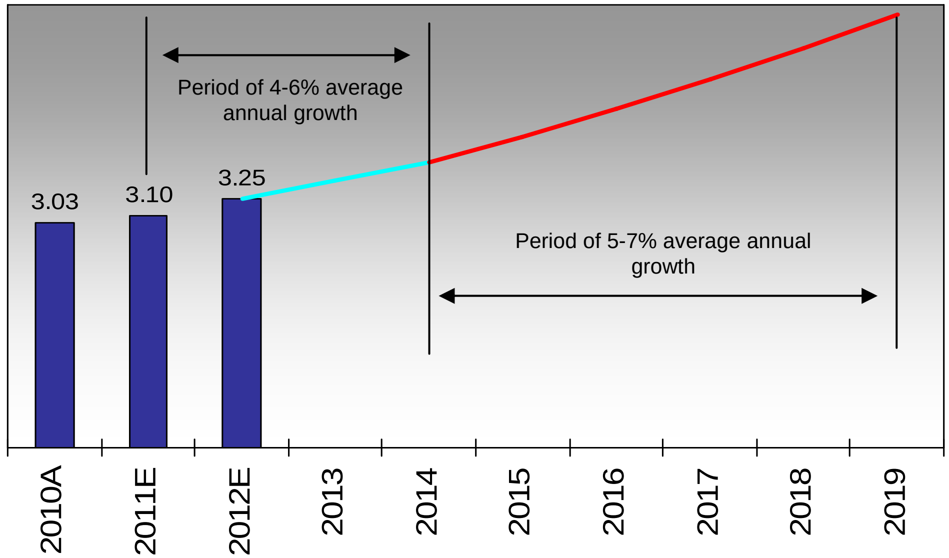
- Quarterly dividend <u>increased 12%</u> in 2010
- <u>403rd consecutive</u> quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Average ROE of 10.5 - 11%
  - Slow, steady recovery in economy

- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



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Detailed Ongoing Earnings Guidance

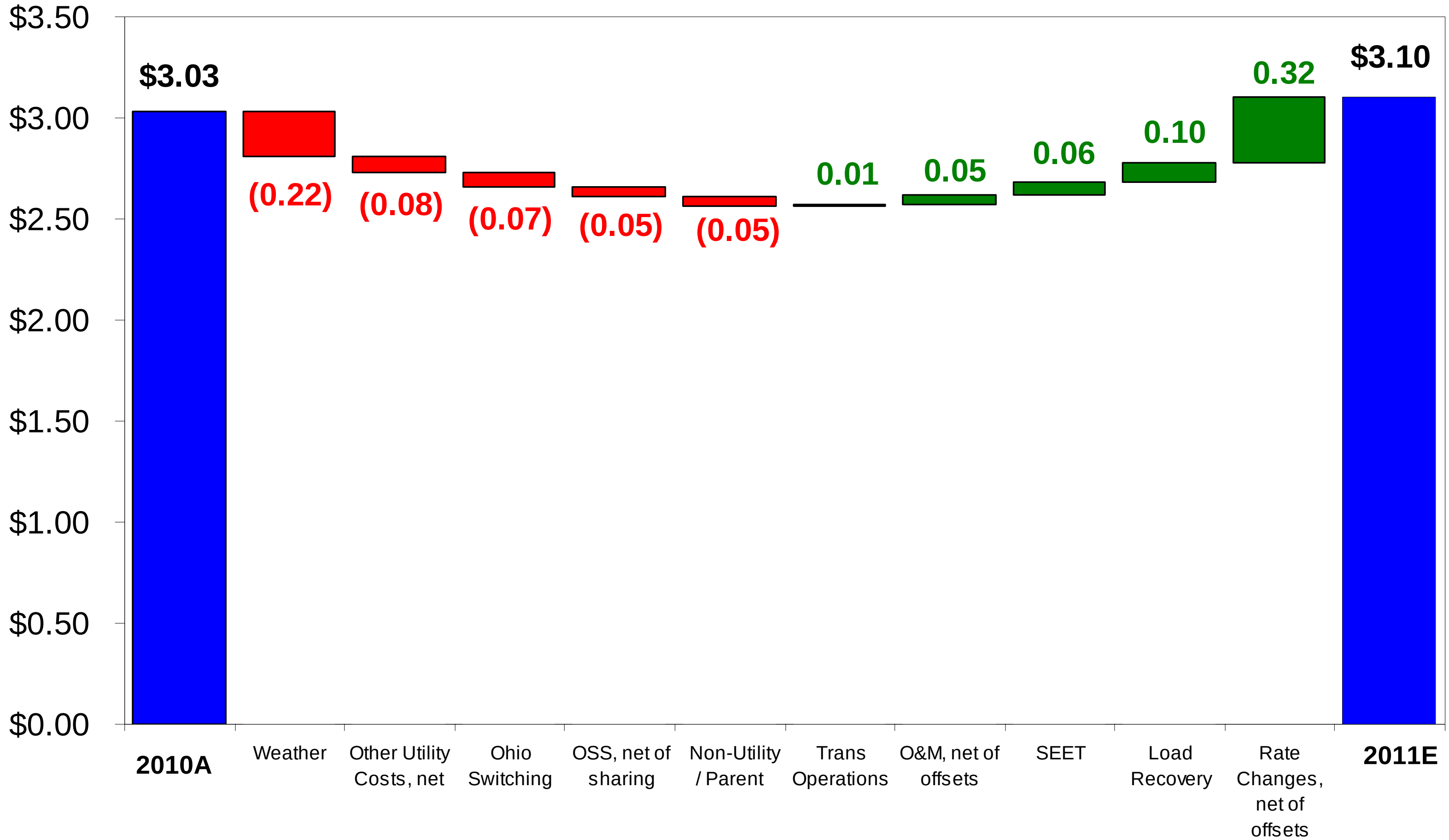
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

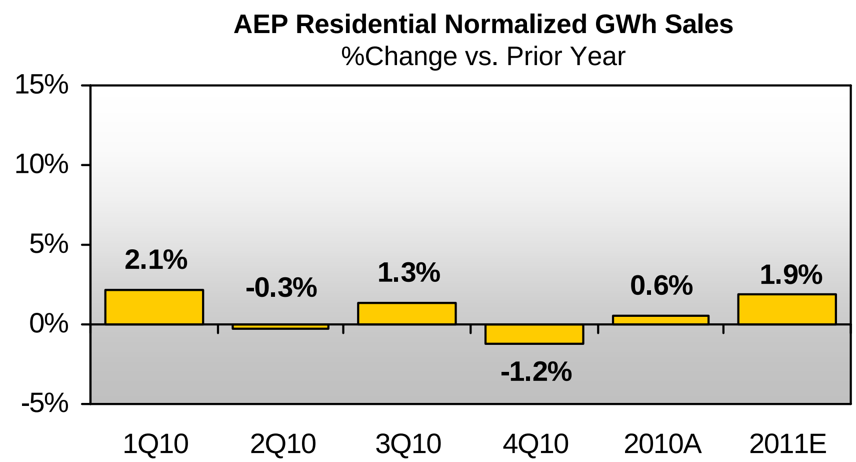
2011 Earnings Drivers

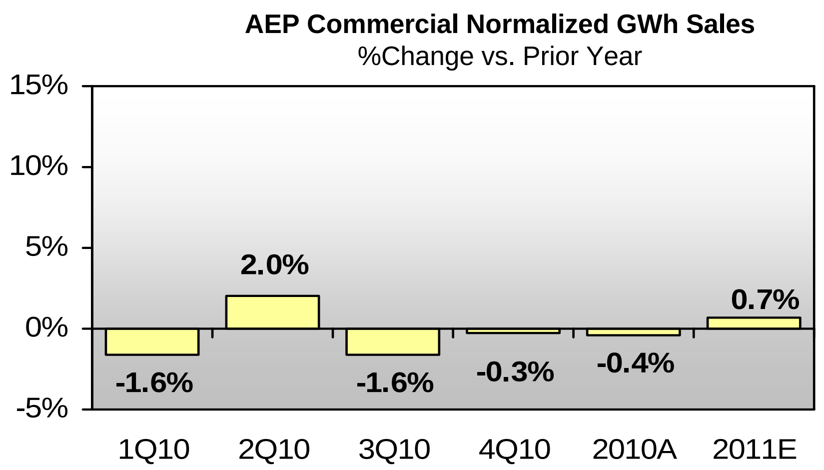


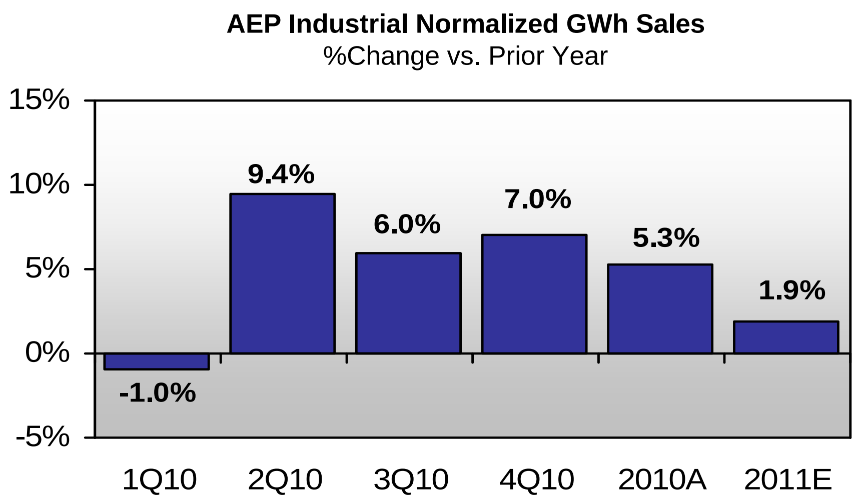
- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

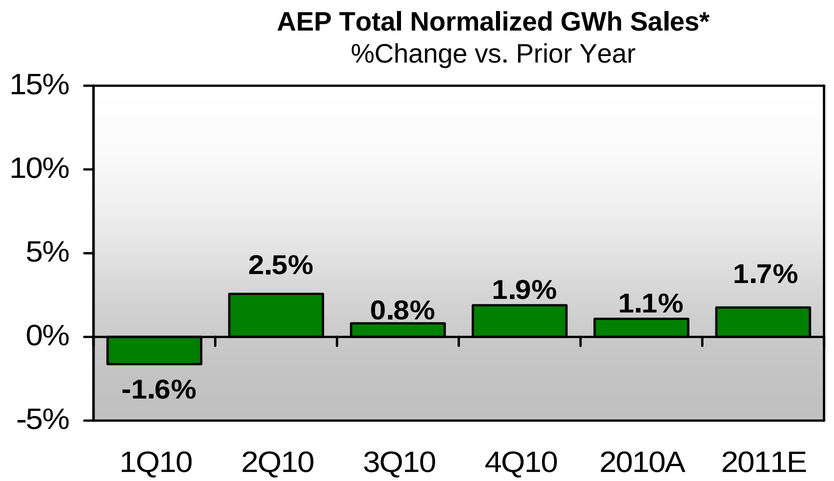
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends









*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

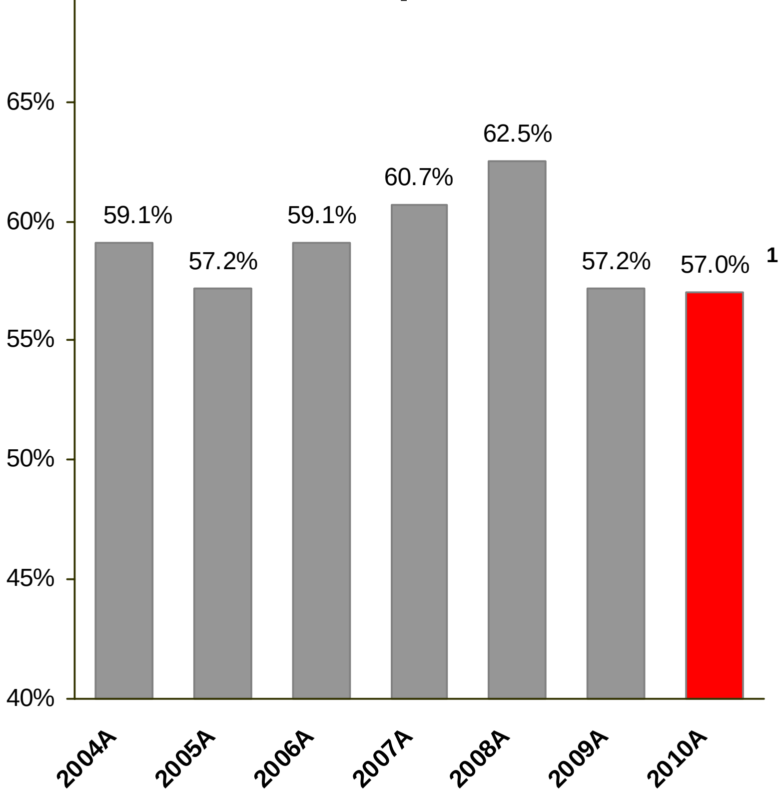
	2010A	2011E
	$ in millions	
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity

Total Debt/Capitalization



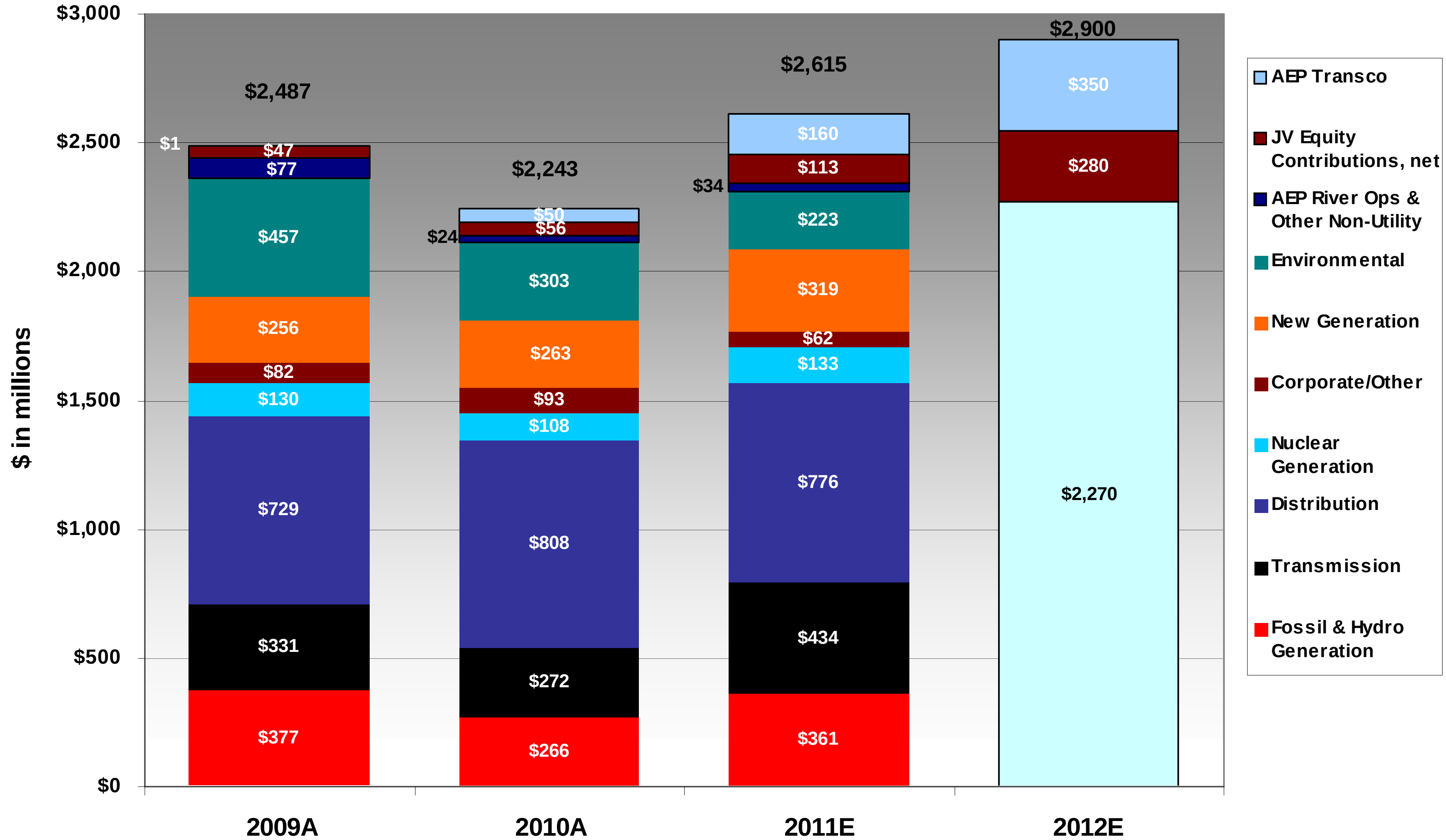
Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

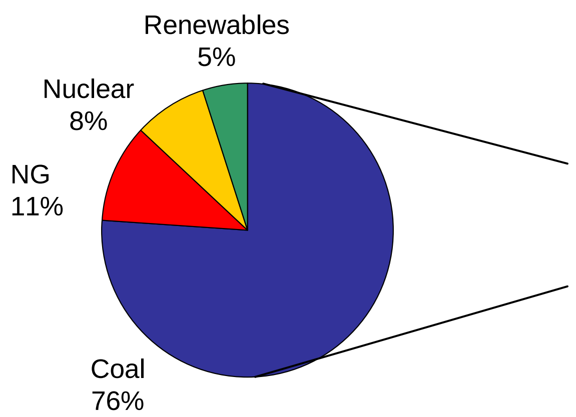
Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

AEP Generation Capacity

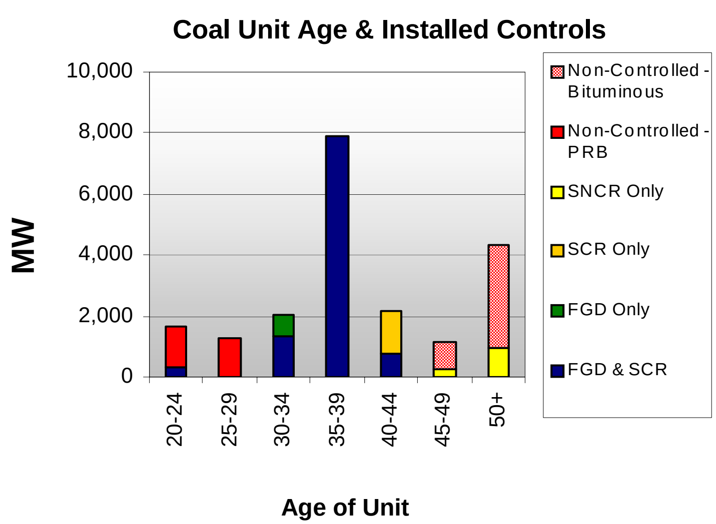
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



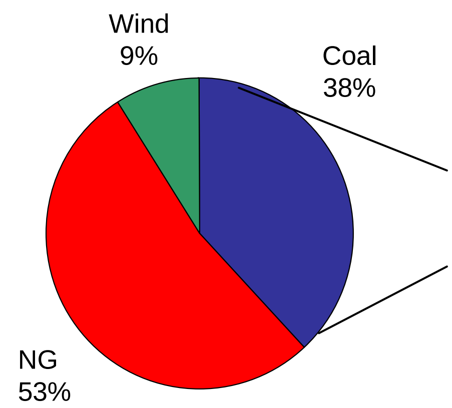
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



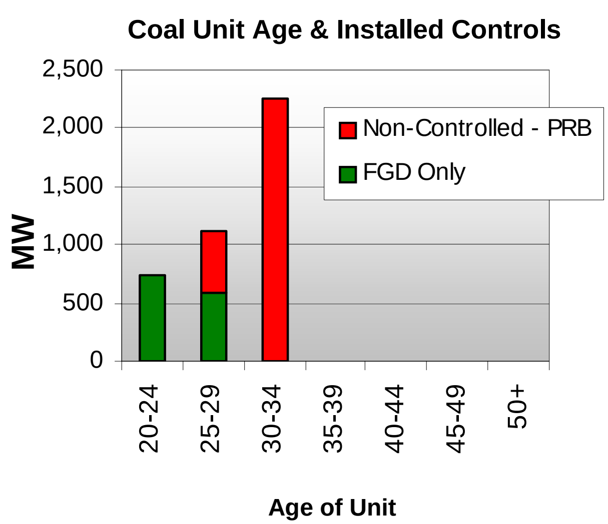
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

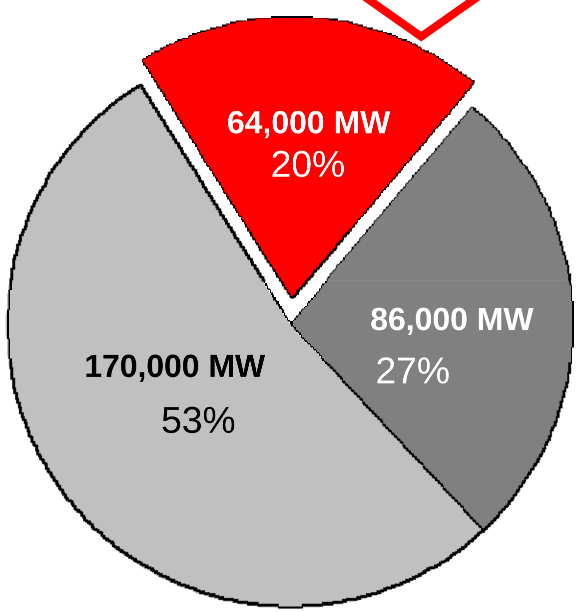


Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

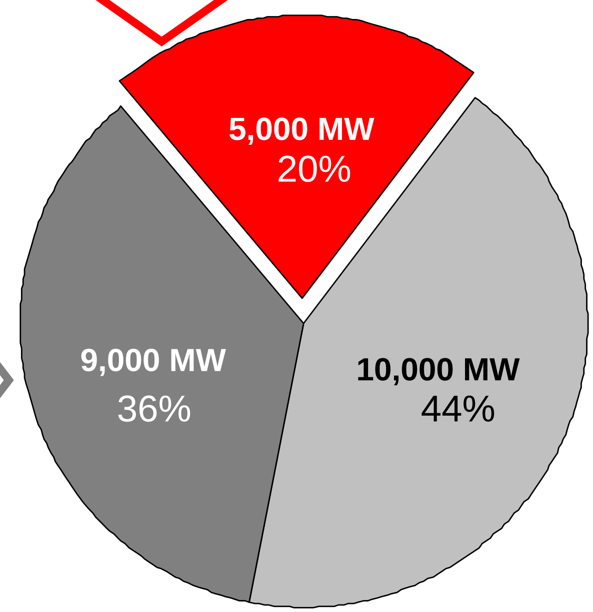
CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



US Coal

Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements



AEP Coal

Nearly 50% of U.S. coal plants are exposed

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Pending EPA Regulations

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion for solid waste option
- “Hazardous” option could cost DOUBLE this amount

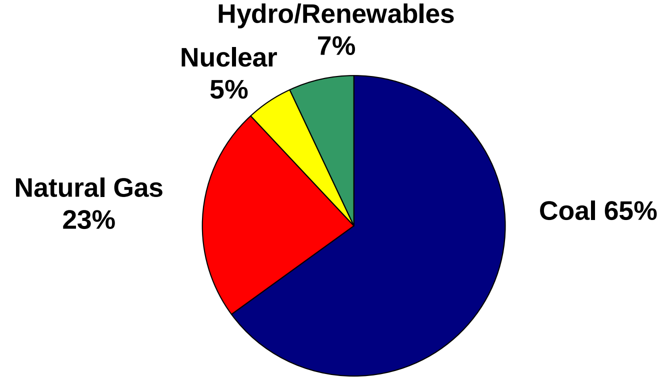
316b RULE

- EPA issued proposal March 28
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

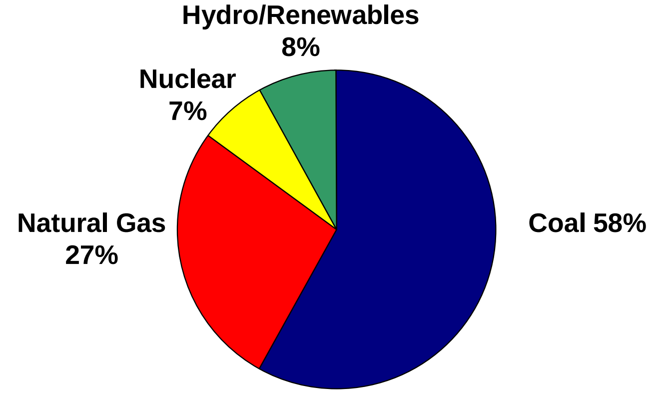
The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of "partially exposed" units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (under construction)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®

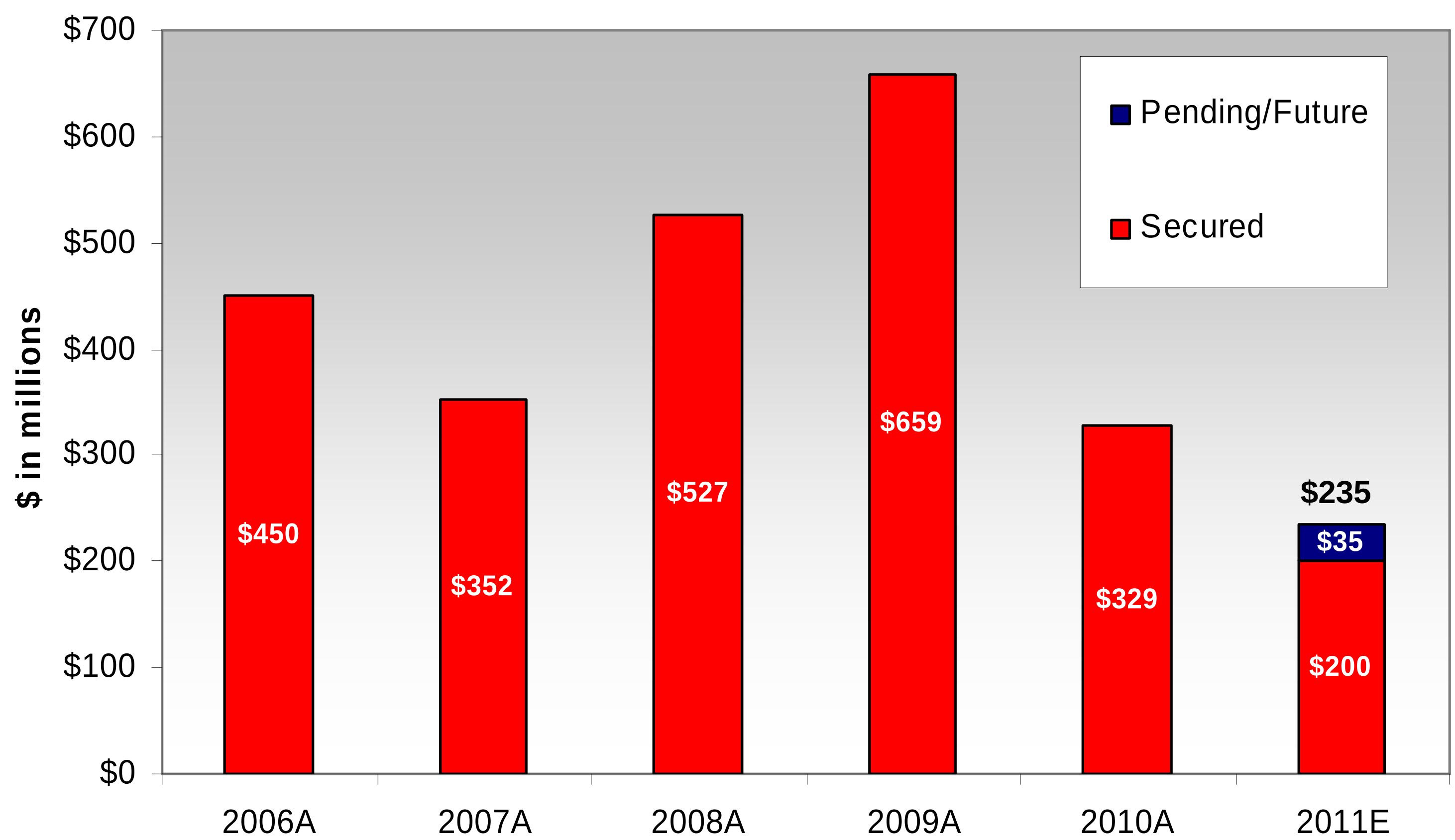


Capacity - 2010



Projected Capacity - 2017

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). A procedural schedule is pending from the VSCC.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule - TBD

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

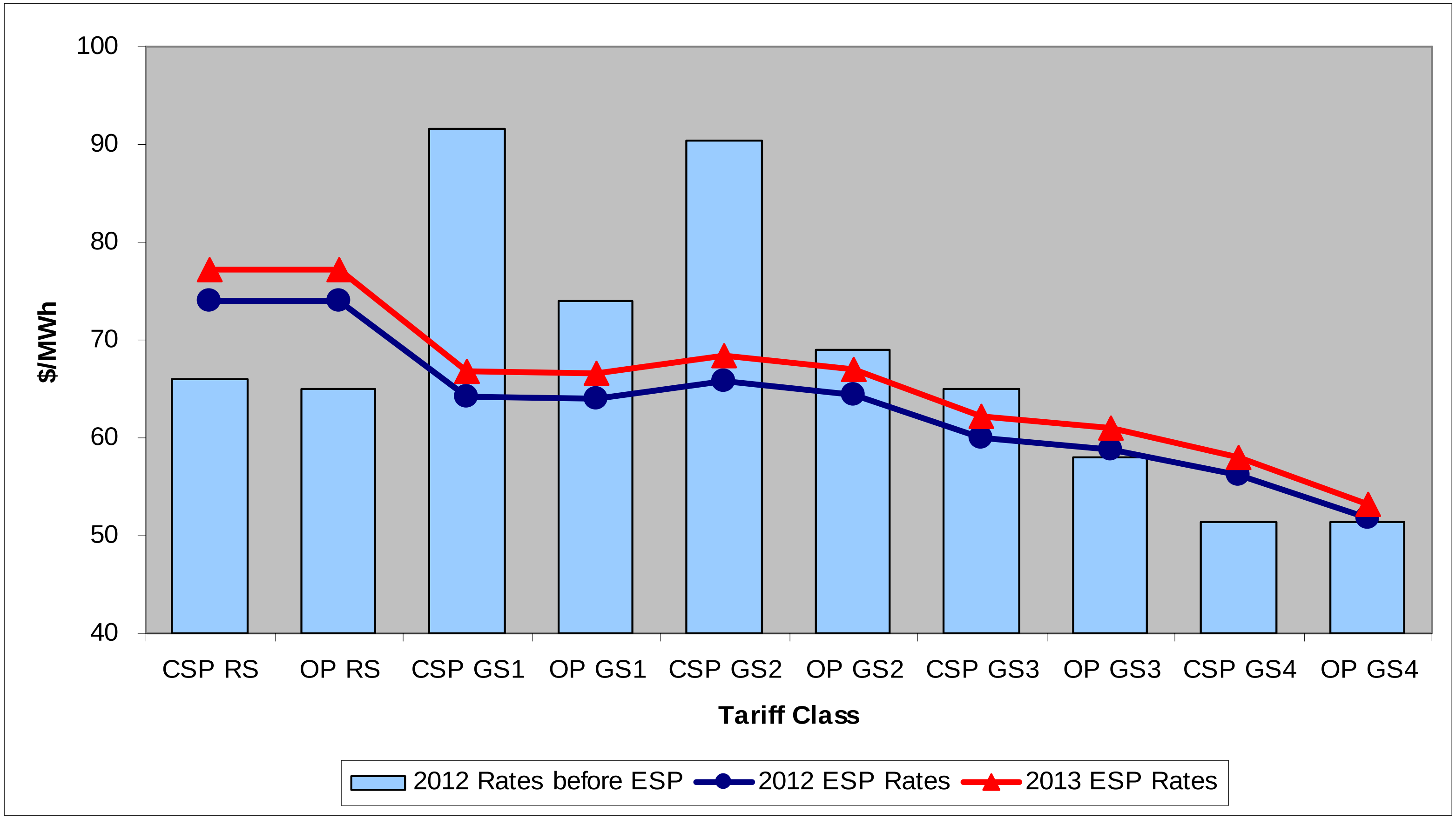
	2012			2013			2014		
	Revenue	$/MWh	%	Revenue	$/MWh	%	Revenue	$/MWh	%
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

AEP®

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

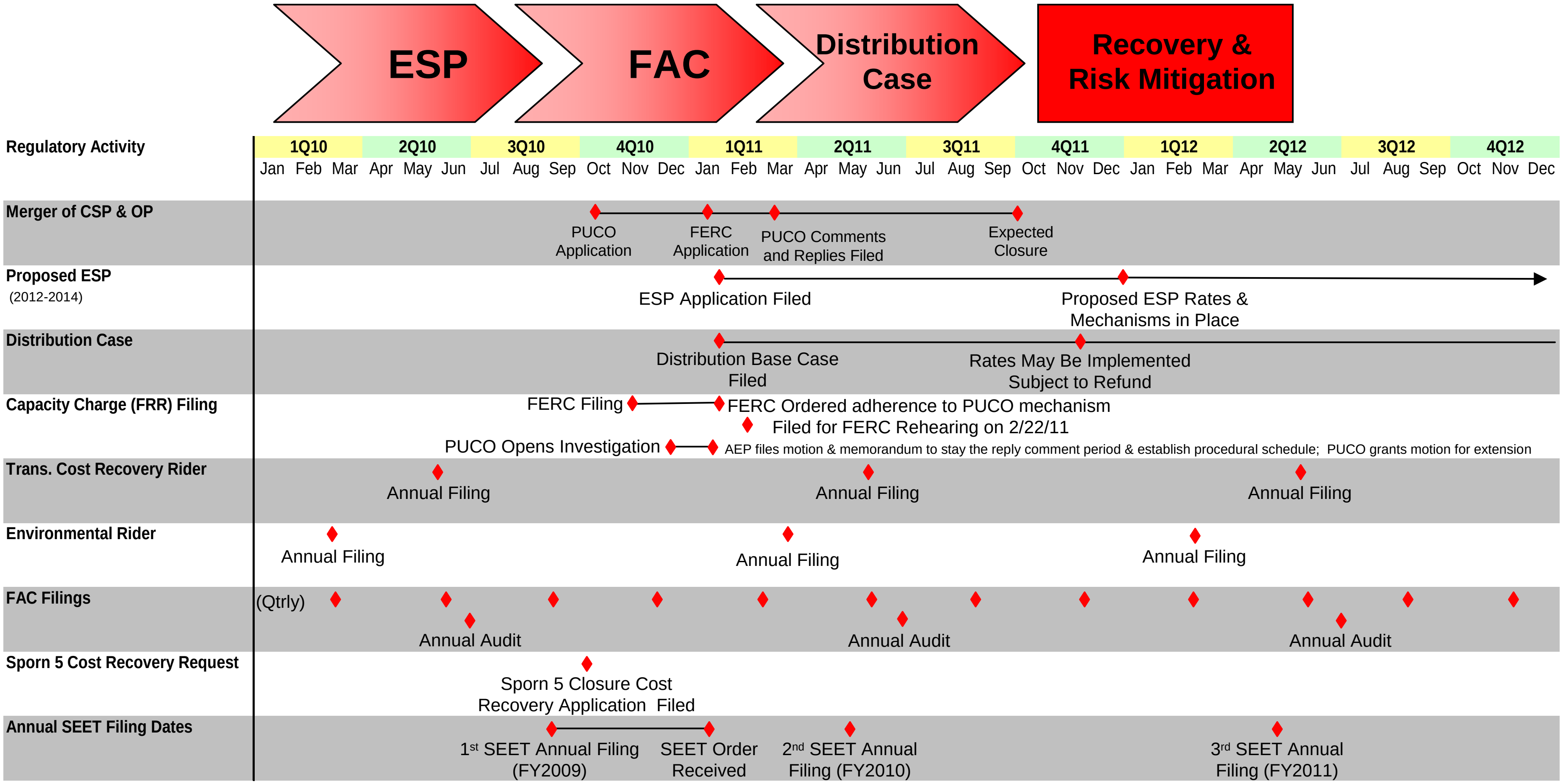
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total project cost of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. Expected ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:

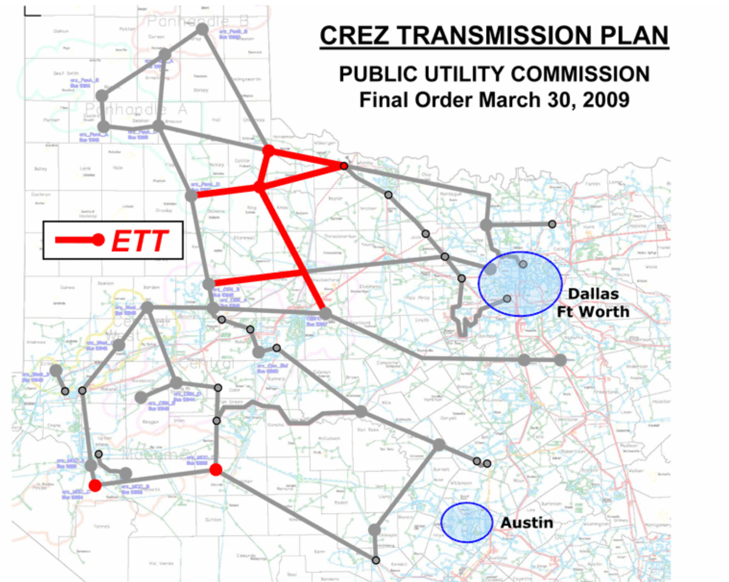
Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  – Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  – Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  – PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

Filing Status Update:

- ***Ohio*** *(filed and approved)* – PUCO approved the Ohio Transco December 29, 2010
- ***West Virginia*** *(filed)* – Procedural schedule is set, with company testimony filed January 6; Intervenor's testimony is due April 6 and rebuttal is due April 20; Hearings in June
- ***Arkansas and Louisiana*** – Filing date in Arkansas likely early 2011
- ***Texas-SPP*** – Expecting TX filing in mid 2011
- ***Kentucky*** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- ***Indiana*** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- ***Virginia*** *(withdrawn)* – Filing withdrawn to give additional time to resolve issues with Staff
- ***Michigan and Oklahoma*** – Do not require state filing

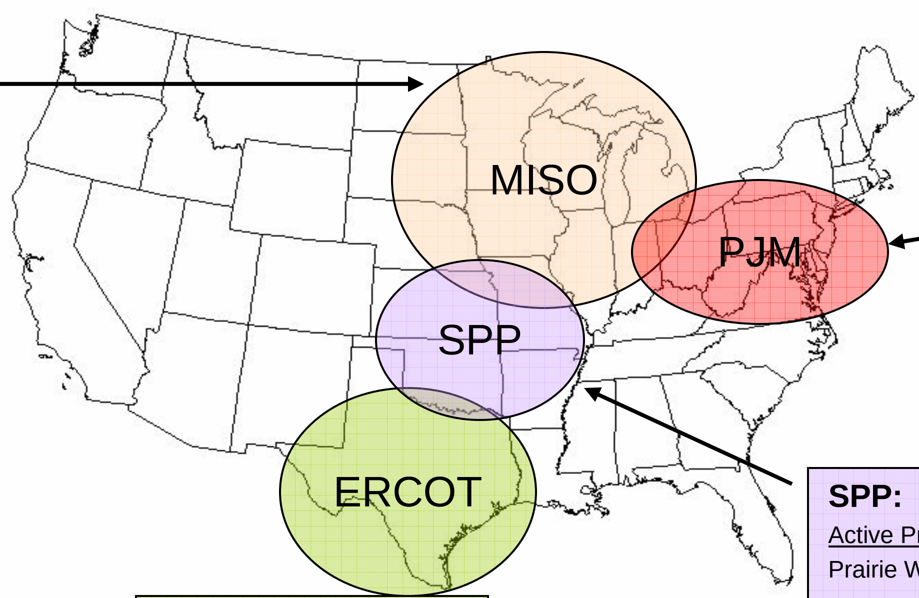
$160M capital spend forecasted for 2011

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

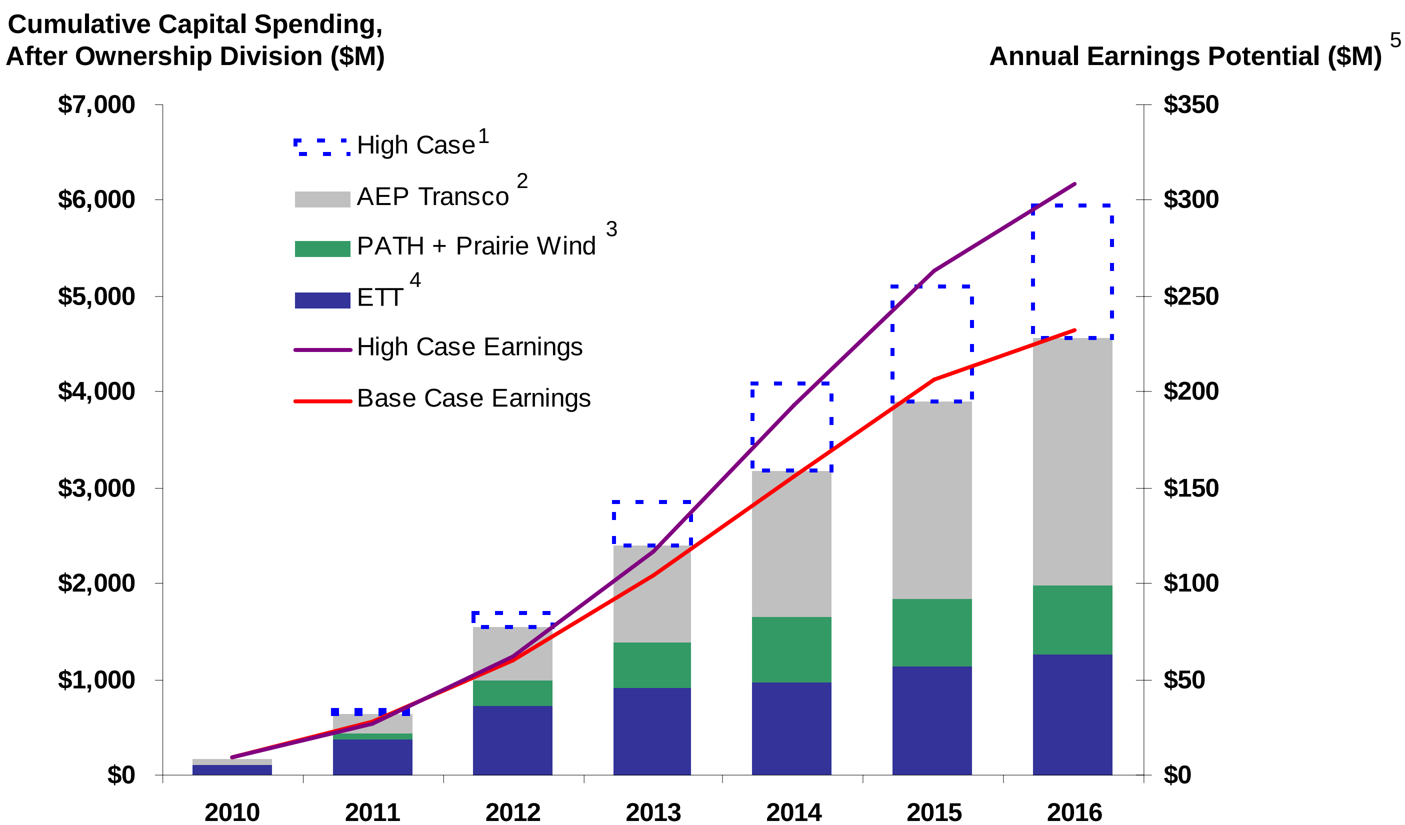
Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Transmission (Transco/JV's) – Capital/Earnings Profile

Transco and JV's have the potential to significantly add earnings growth to AEP.



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

AEP AMERICAN ELECTRIC POWER®

Spring EEI Investor Conference

New York, NY
May 25, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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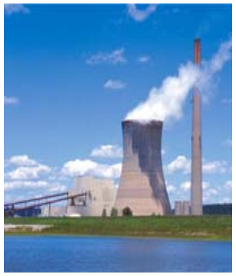
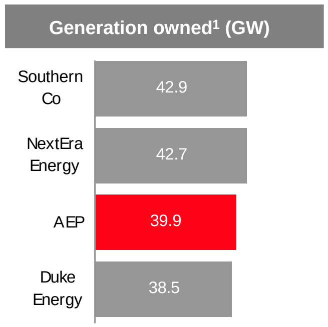
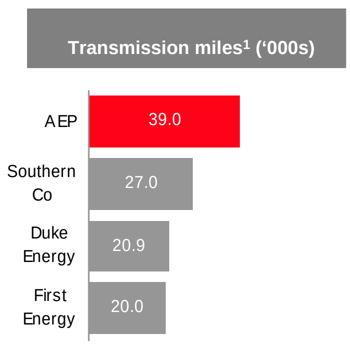
American Electric Power



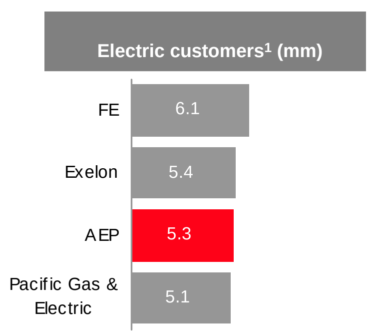
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

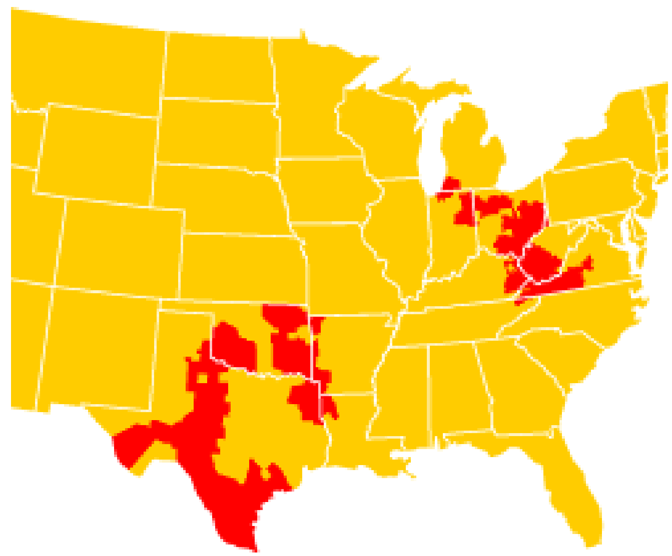


One of the largest U.S. electricity distributors



¹ : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

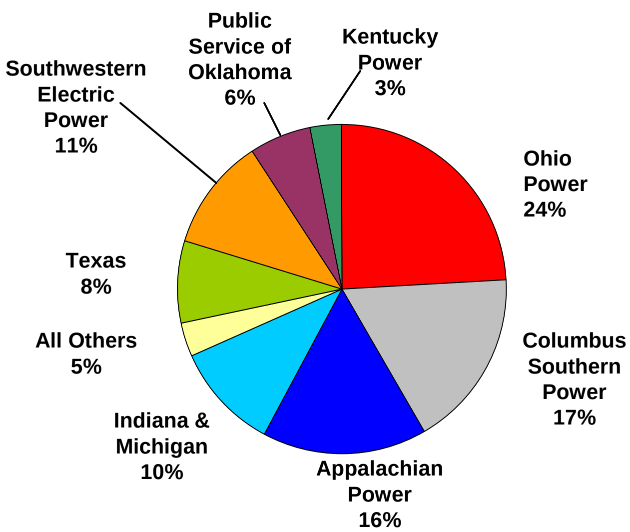
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$18.6B Market Capitalization
BBB/Baa2/BBB credit rating

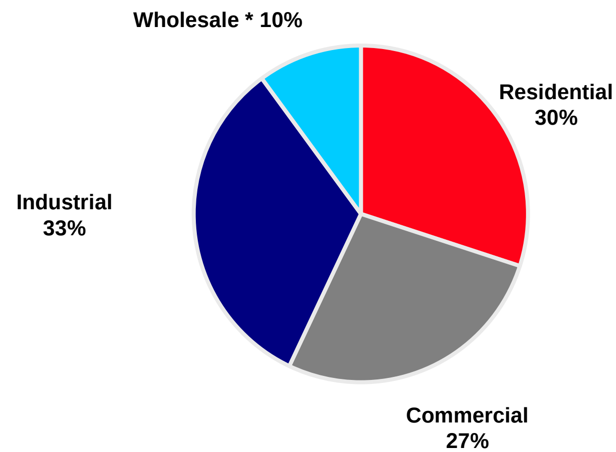
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



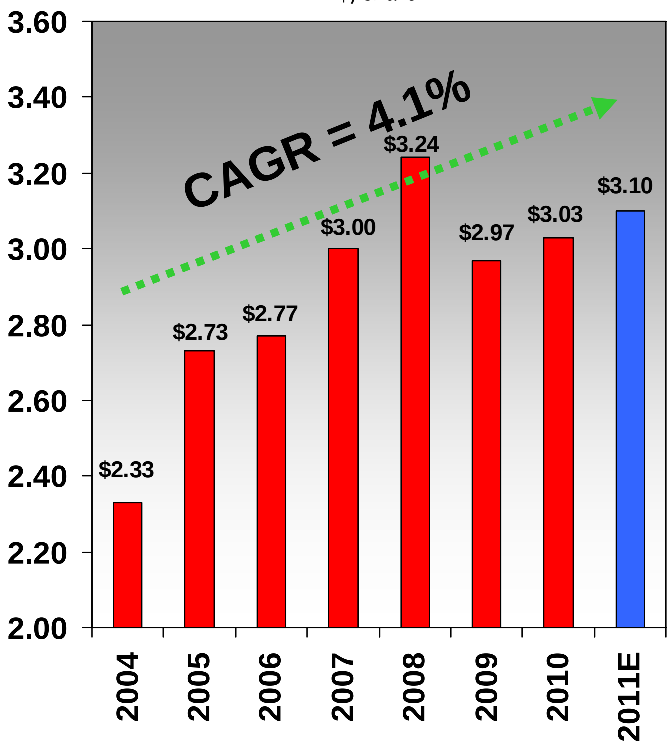
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

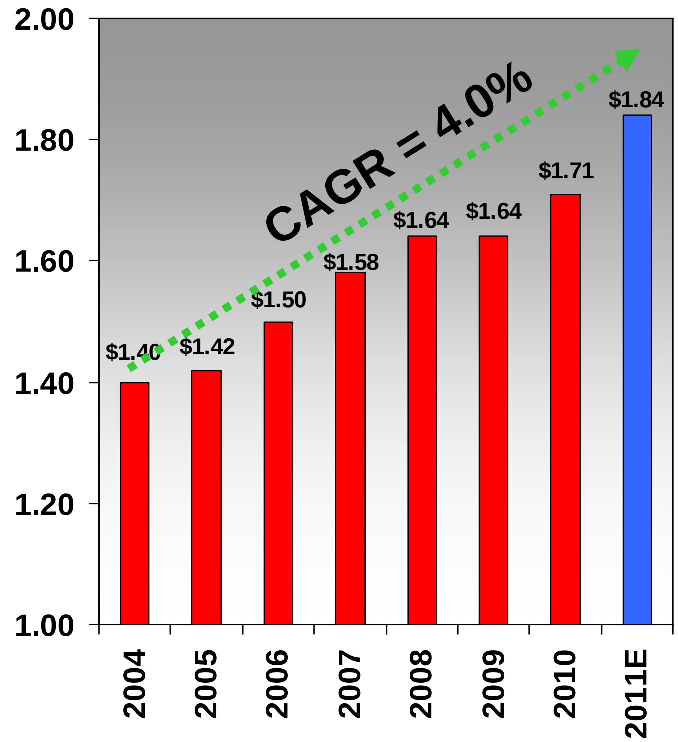
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend will be paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

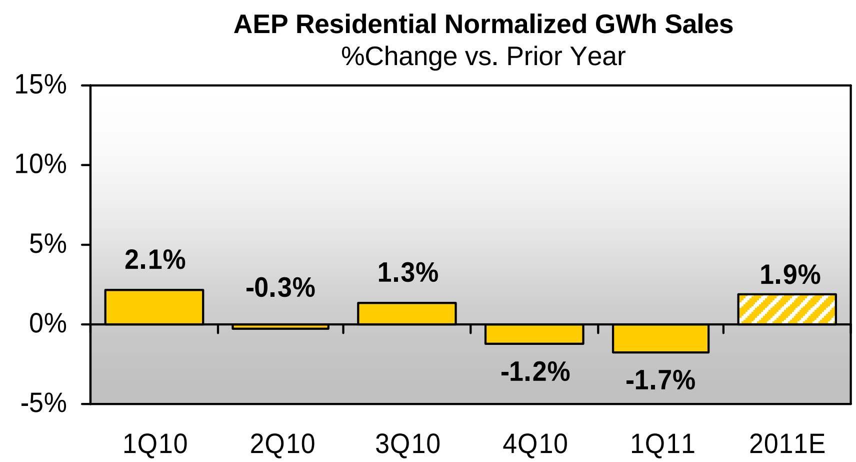
2010A: $3.03

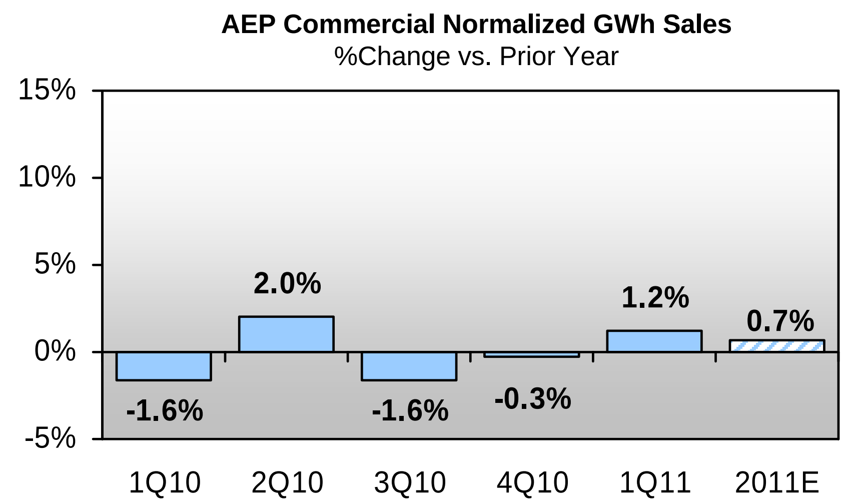
2011E: $3.00 - $3.20

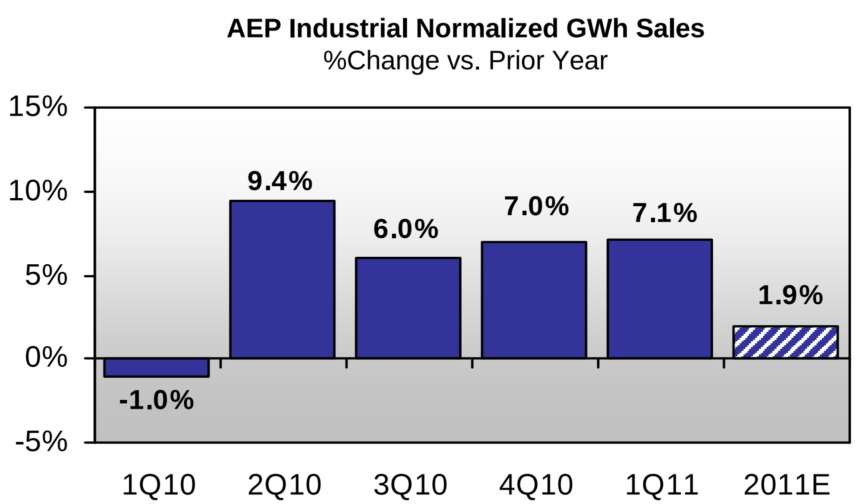
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

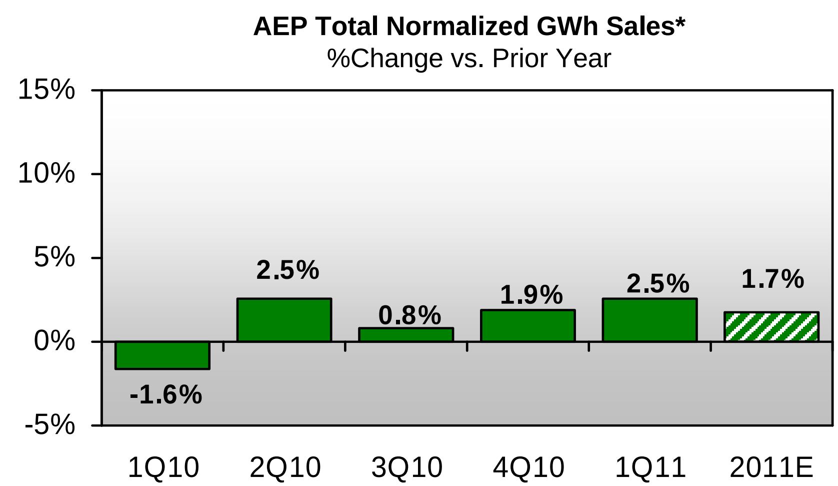
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends





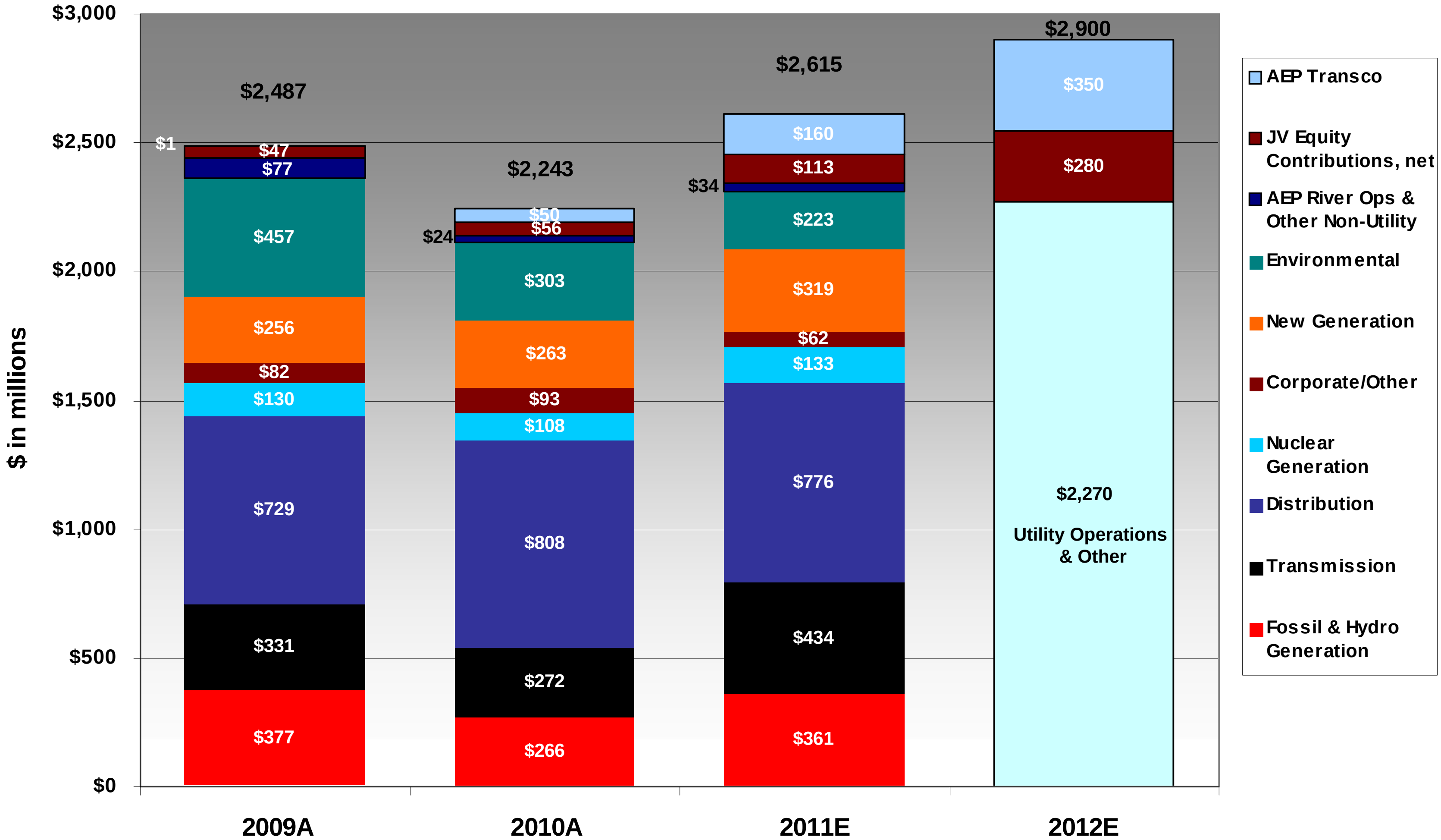




*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

9

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Cash Flow Guidance

$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company[1]	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
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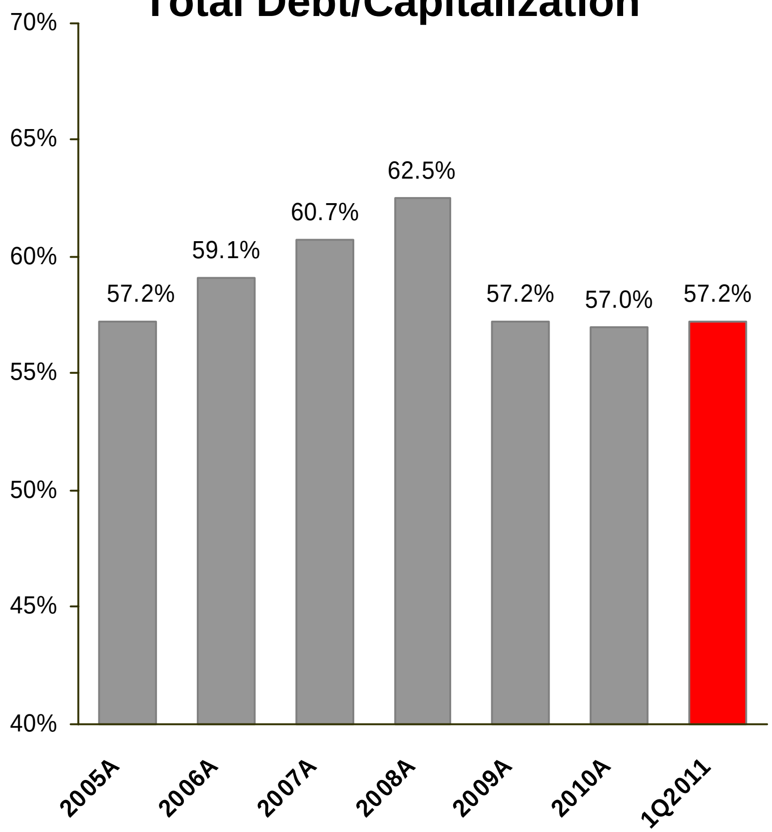
Capitalization & Liquidity

Total Debt/Capitalization

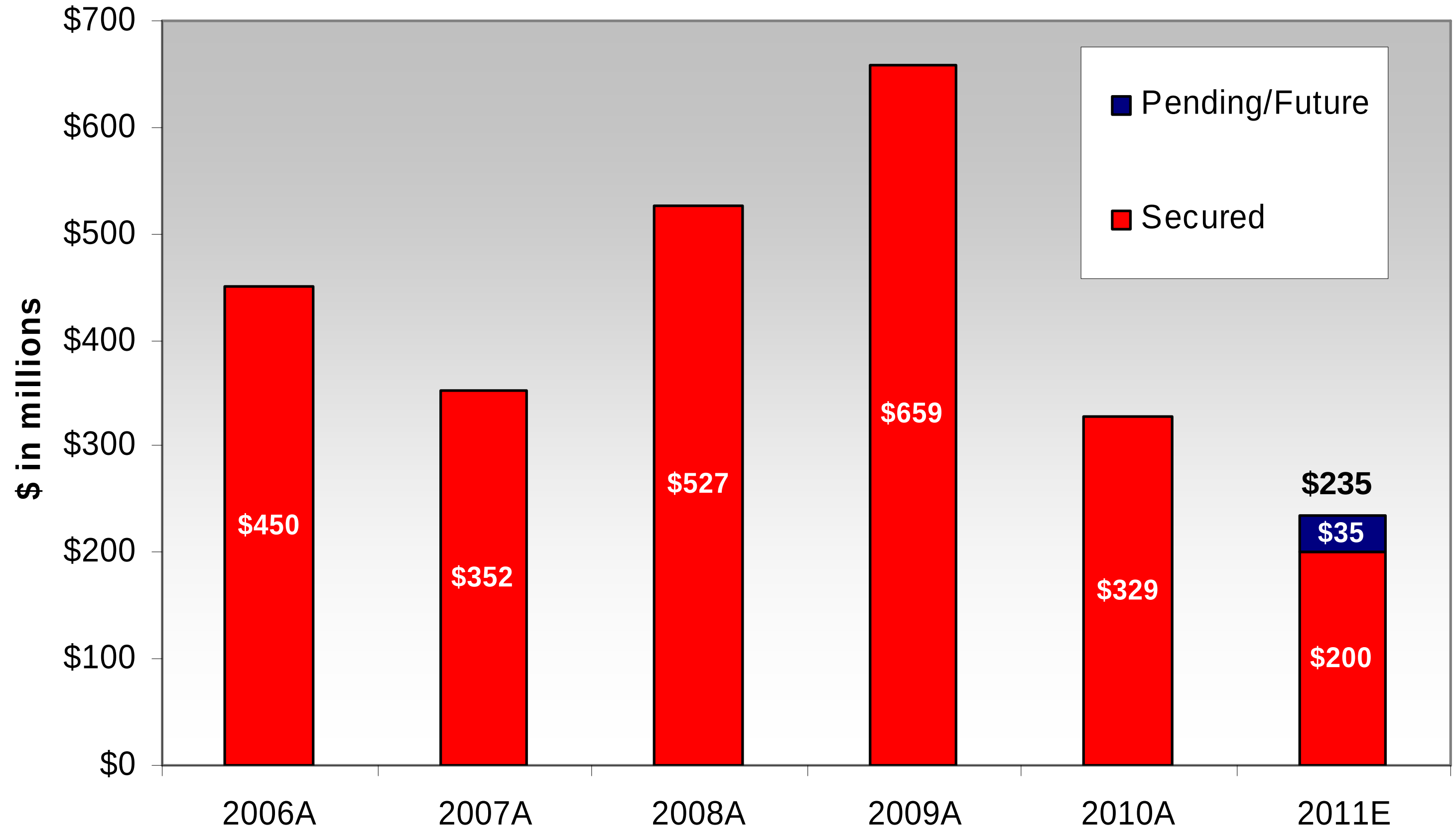


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	Actual 03/31/11	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – June 13; Staff testimony – June 27; Hearing July 20**

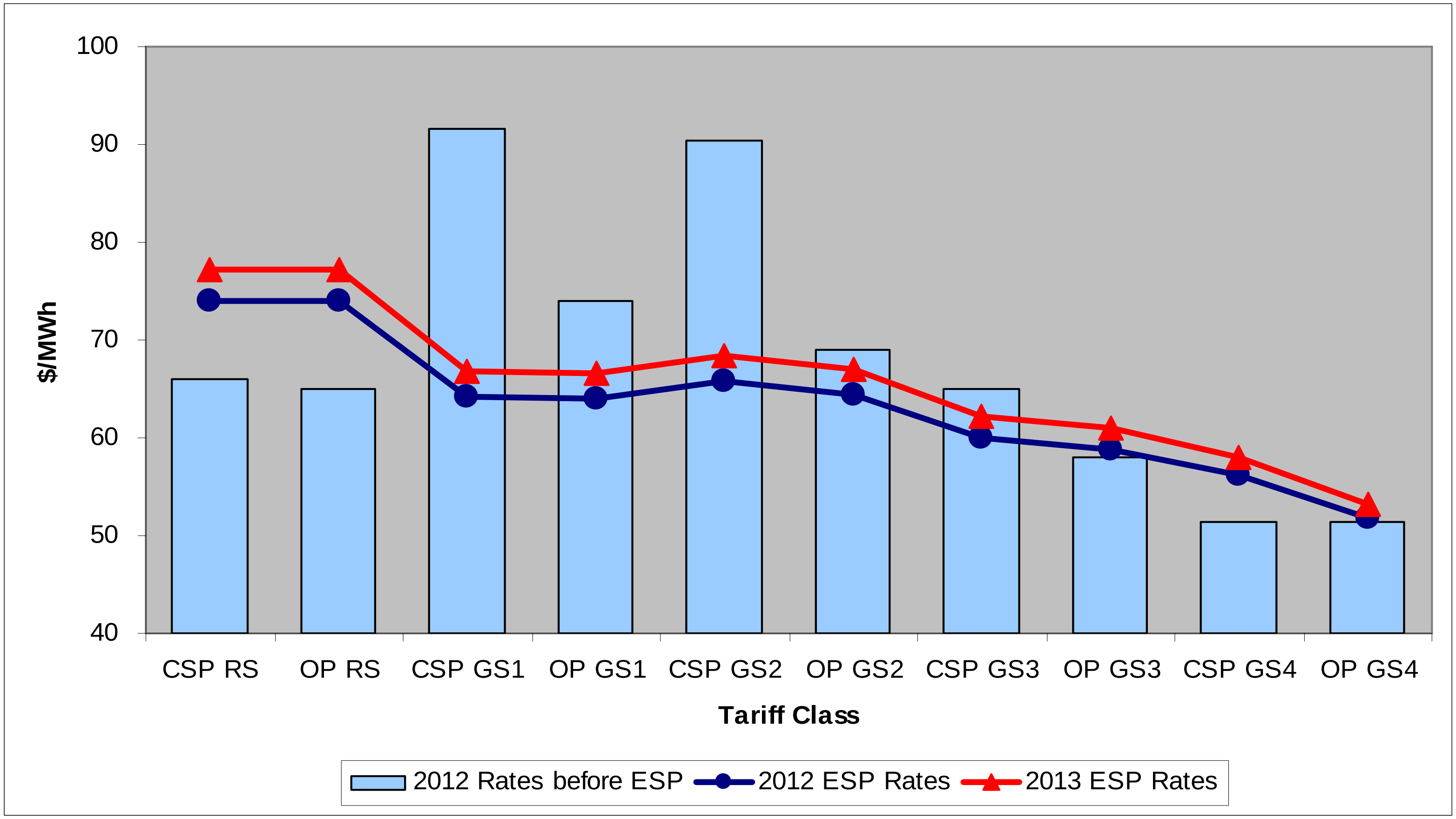
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

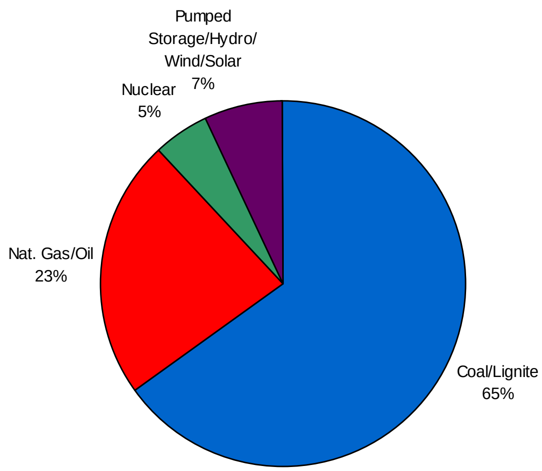
The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

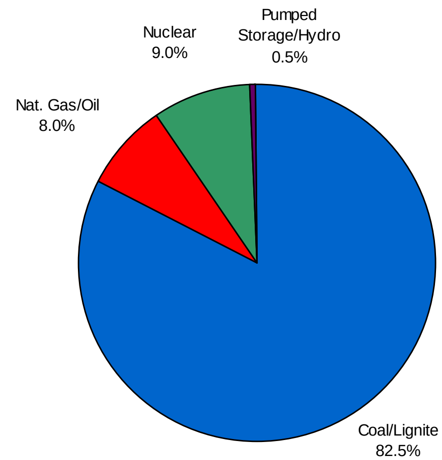
Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

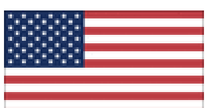
Domestic Generation Fleet

Generation Capacity by Fuel Type
Based on 39,910 MW

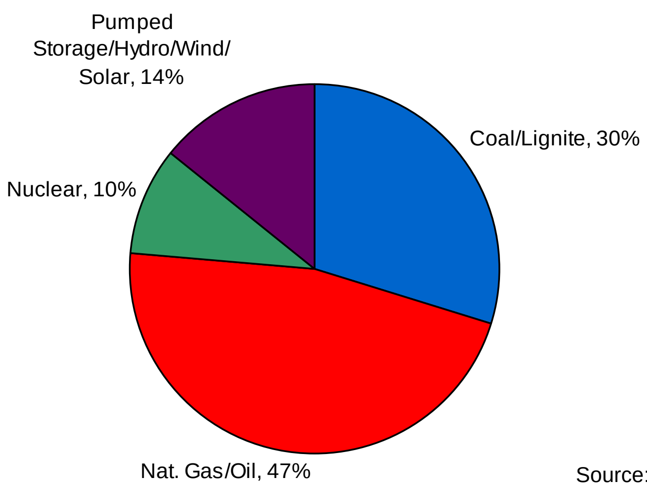


2010 Generation Production by Fuel Type
Based on 173.2 TWh

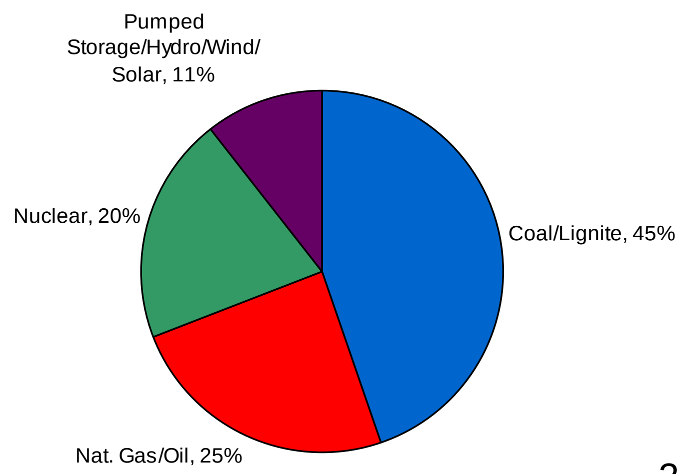




Generation Capacity by Fuel Type
Based on 1,063,848 MW



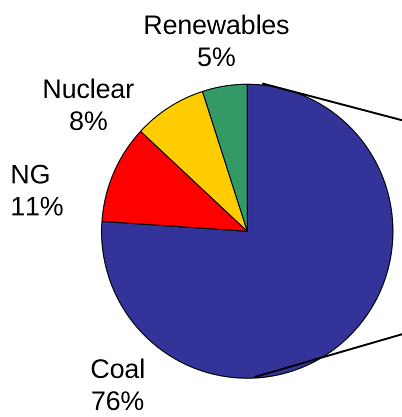
2009 Generation Production by Fuel Type
Based on 3,953.1 TWh



Source: www.eia.doe.gov

AEP Generation Capacity

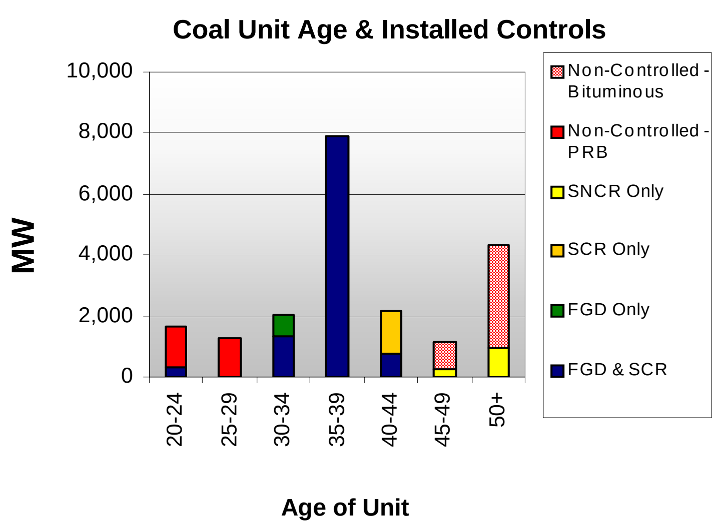
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



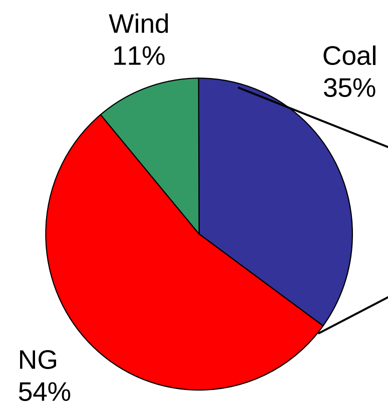
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



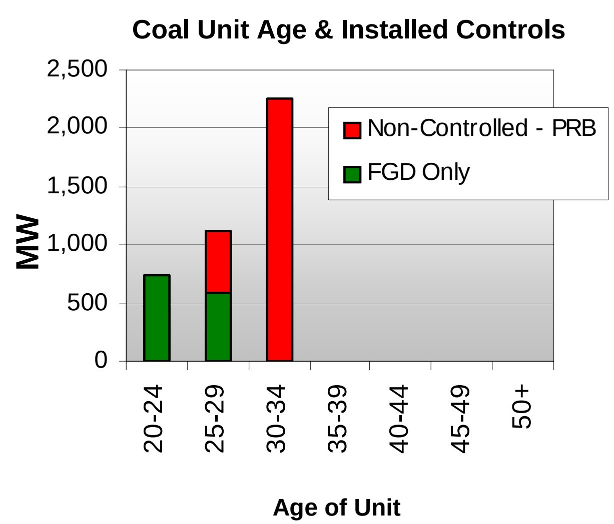
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Pending EPA Regulations

TRANSPORT RULE

- Proposed Transport Rule (July 2010) limits utility SO_2 and NOx emissions
- SO_2 and NOx subject to caps in 2012, with further SO_2 reductions required in most Eastern states by 2014
- Major concerns with the proposed rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - EPA costs of retrofitting units are grossly underestimated/ other incorrect assumptions used (though EPA has since modified some of these assumptions)
  - Rule does not account for recent improvements in air quality
  - Inability to trade and bank allowances effectively

MERCURY AND HAP MACT

- Proposed rule issued in March 2011
- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals, and acid gases, combustion practices for organics
- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension
- Very little flexibility in the proposal; opportunity to average across a plant and limited sub categorization
- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.

COAL ASH RULE

- Draft coal ash disposal rules issued in May 2010
- EPA proposed two different regulatory designations:
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020
- AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)
- AEP capital cost of ~$4 billion (including AFUDC) for solid waste option
- “Hazardous” option could cost DOUBLE this amount

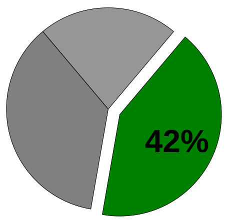
316b RULE

- EPA issued proposal March 28, 2011
- Addresses impingement and entrainment of aquatic species
- Proposes upgraded intake screens for impingement
- Suggests cooling towers as an effective technology for entrainment, but defers the decision until site-specific study is conducted
- Cost impact very uncertain at this time

The cumulative effect of the proposed rules is not achievable in the allowed timeframe.

AEP Coal Fleet Assessment

Least Exposed



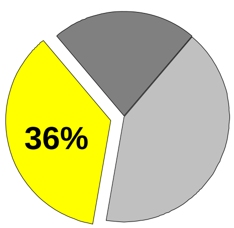
Operating Company	MW
APCo	3,353
CSPCo	1,277
Ohio Power	5,687
	10,317

2012 – 2020

Range of Capital ($Millions) [(1)]

Proposed Rules		Low		High
Water Rules [(2)]	$	5	$	9
CCR Rules	$	759	$	1,122
Air Rules [(3)]	$	766	$	1,046

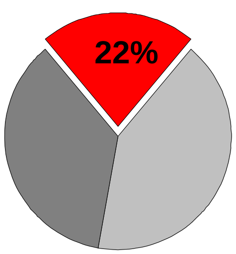
Partially Exposed



Operating Company	MW
CSPCo	803
I&M	2,600
KPCo	800
Ohio Power	585
PSO	1,025
SWEPCo	2,690
TNC	385
	8,888

Proposed Rules		Low		High [(4)]
Water Rules [(2)]	$	26	$	46
CCR Rules	$	357	$	726
Air Rules [(3) (5)]	$	2,225	$	6,417

Fully Exposed



Operating Company	MW
APCo	1,740
CSPCo	265
I&M	995
KPCo	260
Ohio Power	2,220
	5,480

		Low		High
Replacement Generation	$	973	$	1,807
Grand Total	**$**	**5,111**	**$**	**11,173**

(1) The impact of all proposed rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included. Proposed 316 (b) will impact some gas facilities.

(3) Proposed Air Rules include: HAPs, CATR and Regional Haze Federal Implementation Plans in OK & AR

(4) Potential replacement generation for partially exposed units is $1,700MM which could offset certain estimates in the high case shown.

(5) Includes NSR Compliance.

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

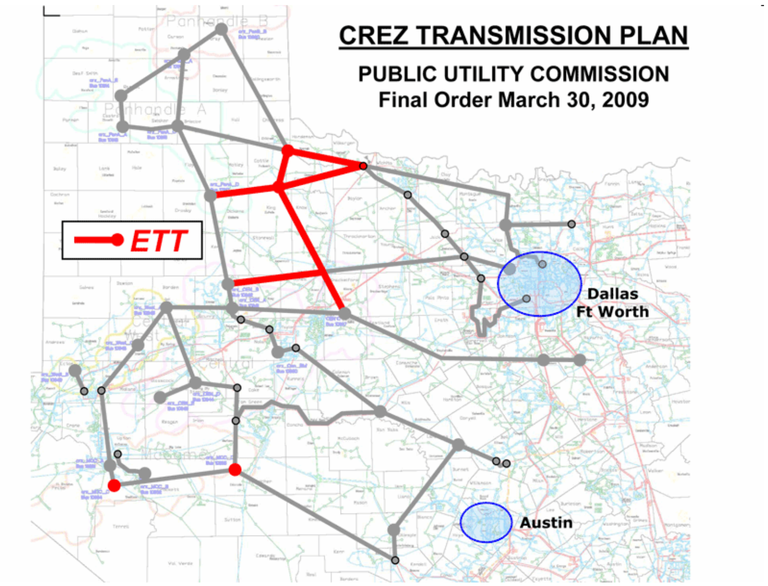
Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

ETT Electric Transmission Texas

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **<u>Additional Projects in the Pipeline ~$1.6 B:</u>**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **<u>Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:</u>**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transcos is 11.49%
  - ROE order for West Transcos is 11.20%

State Filing Status Update:

- **Ohio** – PUCO approved the Ohio Transco December 29, 2010
- **West Virginia** – Filing made January 6, 2011; Hearings in June
- **Arkansas** – Filing in Arkansas made May 6, 2011
- **Louisiana –** Expecting LA filing in 3Q 2011
- **Texas-SPP** – Expecting TX filing in mid 2011
- **Kentucky** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- **Indiana** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- **Virginia** – Filing withdrawn to give additional time to resolve issues with Staff
- **Michigan and Oklahoma** – Do not require state filing

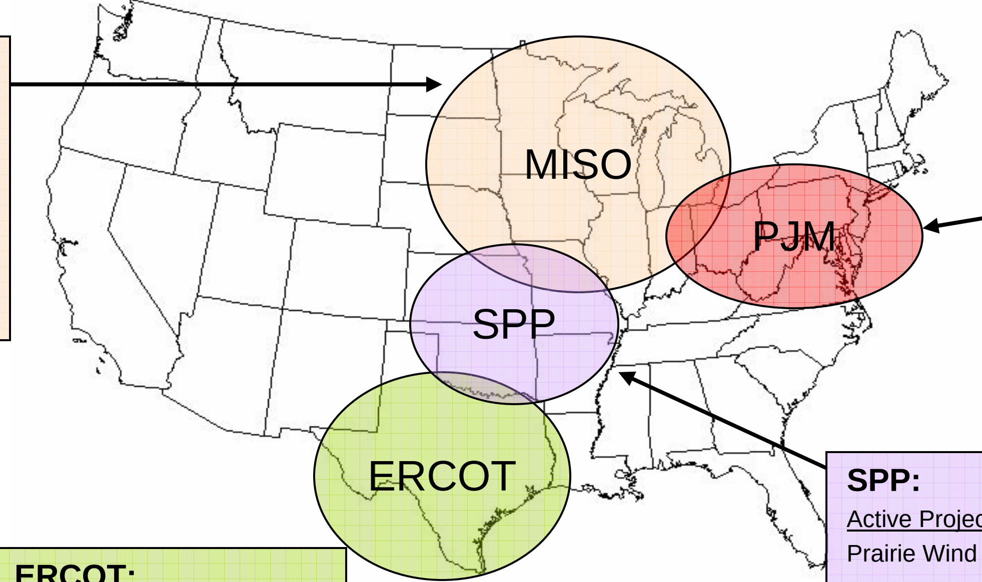
$160M capital spend forecasted for 2011; $350MM for 2012

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings. JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

AEP AMERICAN® ELECTRIC POWER

Annual EEI Finance Meeting
New York, NY
June 23, 2010

AEP®

A CENTURY OF DIVIDENDS • 1910 - 2010

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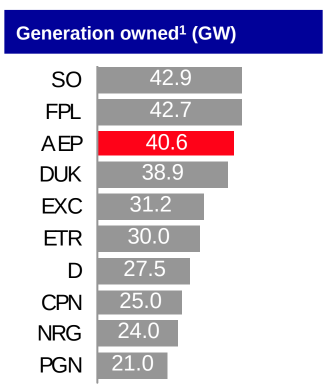
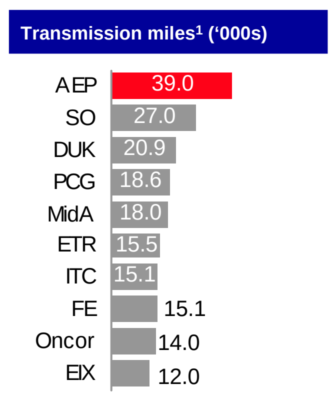
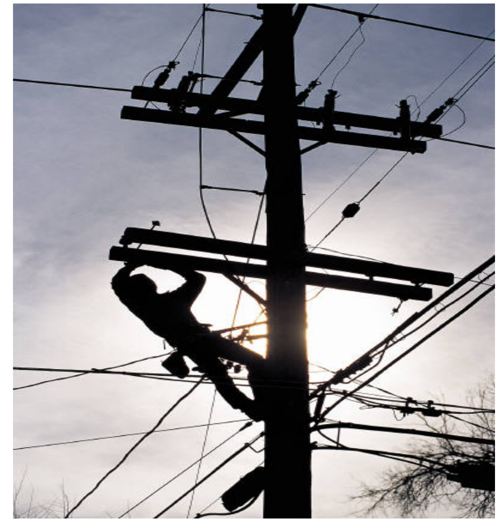
Industry Leadership

One of the largest U.S. electricity generators

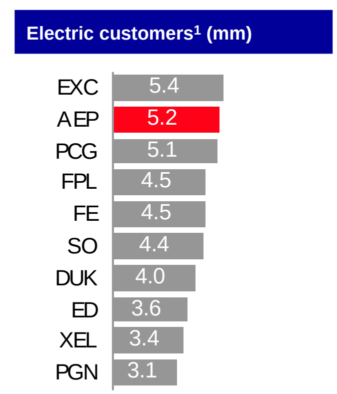


The largest U.S. electricity transmitter





One of the largest U.S. electricity distributors serving 5.2MM customers



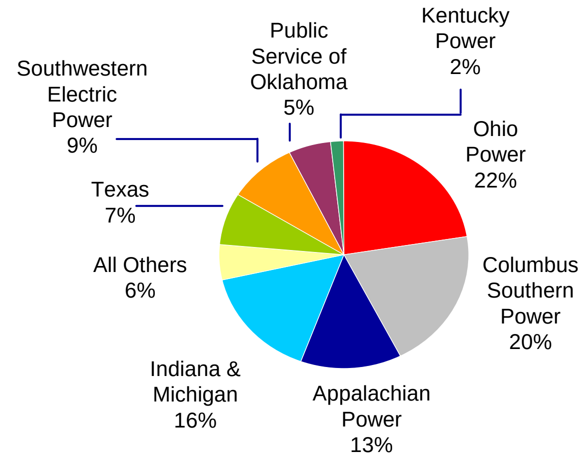
[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

Highly Diversified Regulated Utility Platform

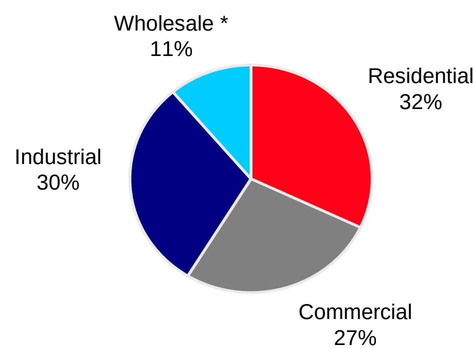
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



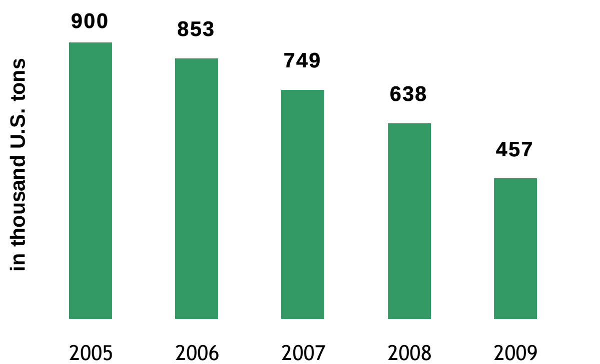
2009 Retail Load



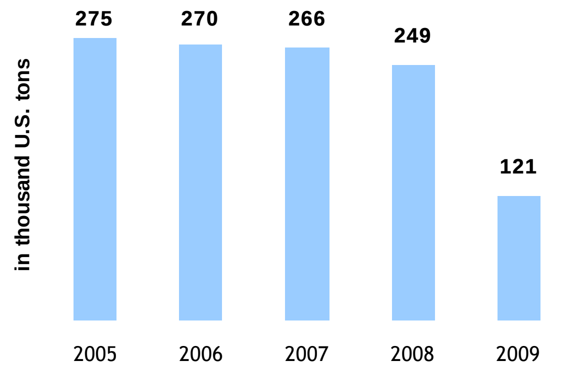
** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Our Fleet Will Continue to Transform

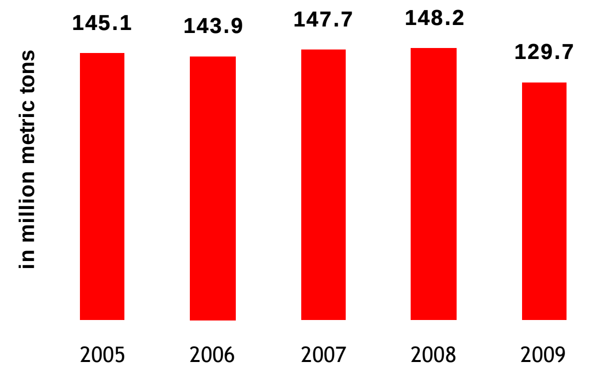
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



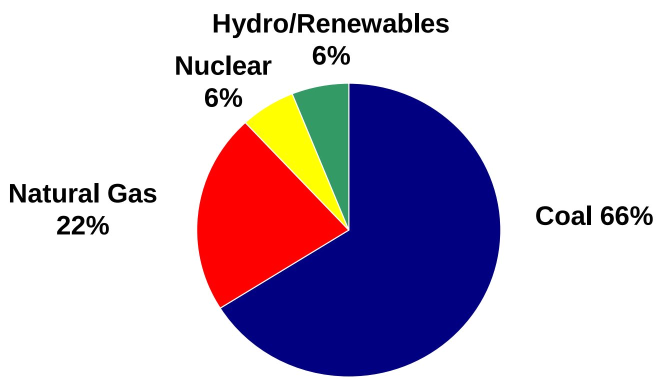
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



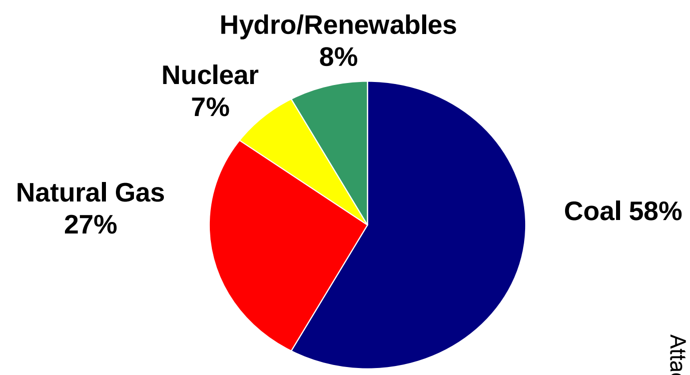
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ $5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



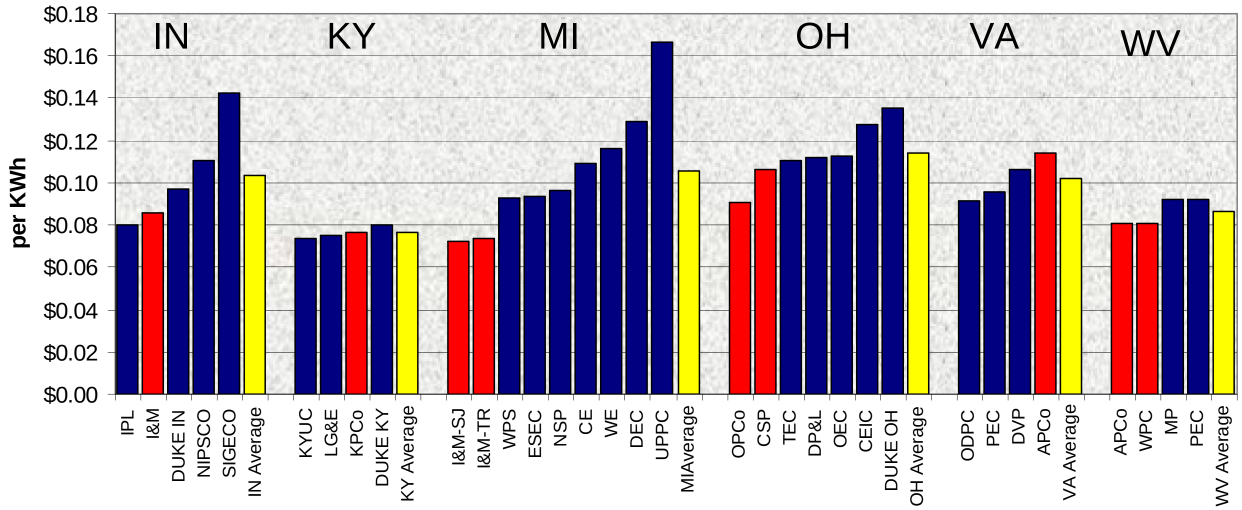
Projected Fuel Mix - 2017

Carbon Legislation Update

American Power Act of 2010 (Kerry-Lieberman) compared to H. R. 2454 (Waxman-Markey):

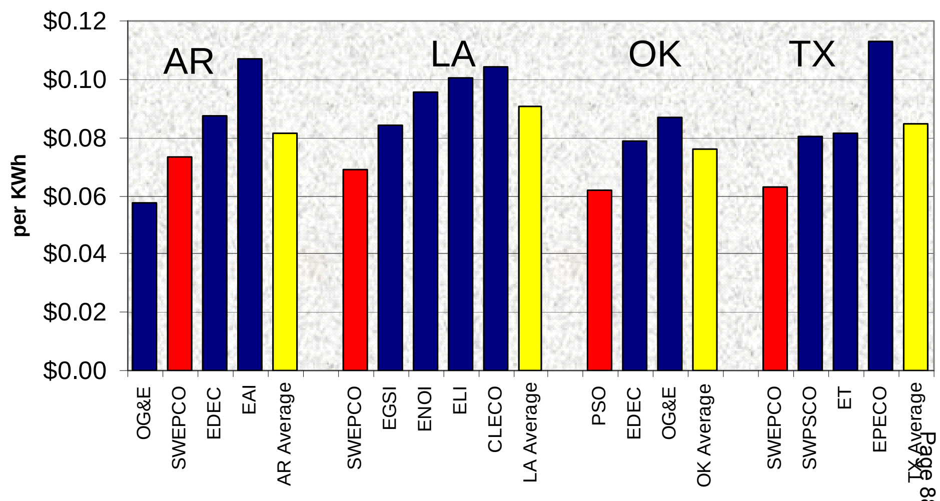
- **Positive Highlights:**
  - Significantly higher electric utility allowance allocation
  - More generous CCS bonus allowances
  - Program start date pushed out to 2013
  - Sound domestic offsets provisions
  - Price collar should help eliminate high price spikes
- **Problem Areas/Key Areas for Improvement:**
  - Removal of key EPA preemption language on CO_2 could lead to duplicative CO_2 regulatory measures
  - More restrictive international offsets provisions could drive up compliance costs
  - Early action credit is very limited
  - Market trading provisions are overly restrictive

Residential Rates Comparison



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP Company
Other Utilities within state
State Average



KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8860 of 9556

2010 Ongoing Earnings Guidance

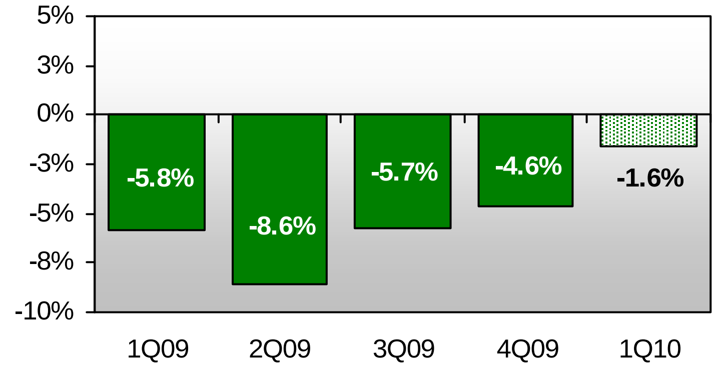
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**

AEP Total Normalized GWh Sales
Quarter %Change vs. Prior Year



<u>Quarter over Quarter change by segment:</u>
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

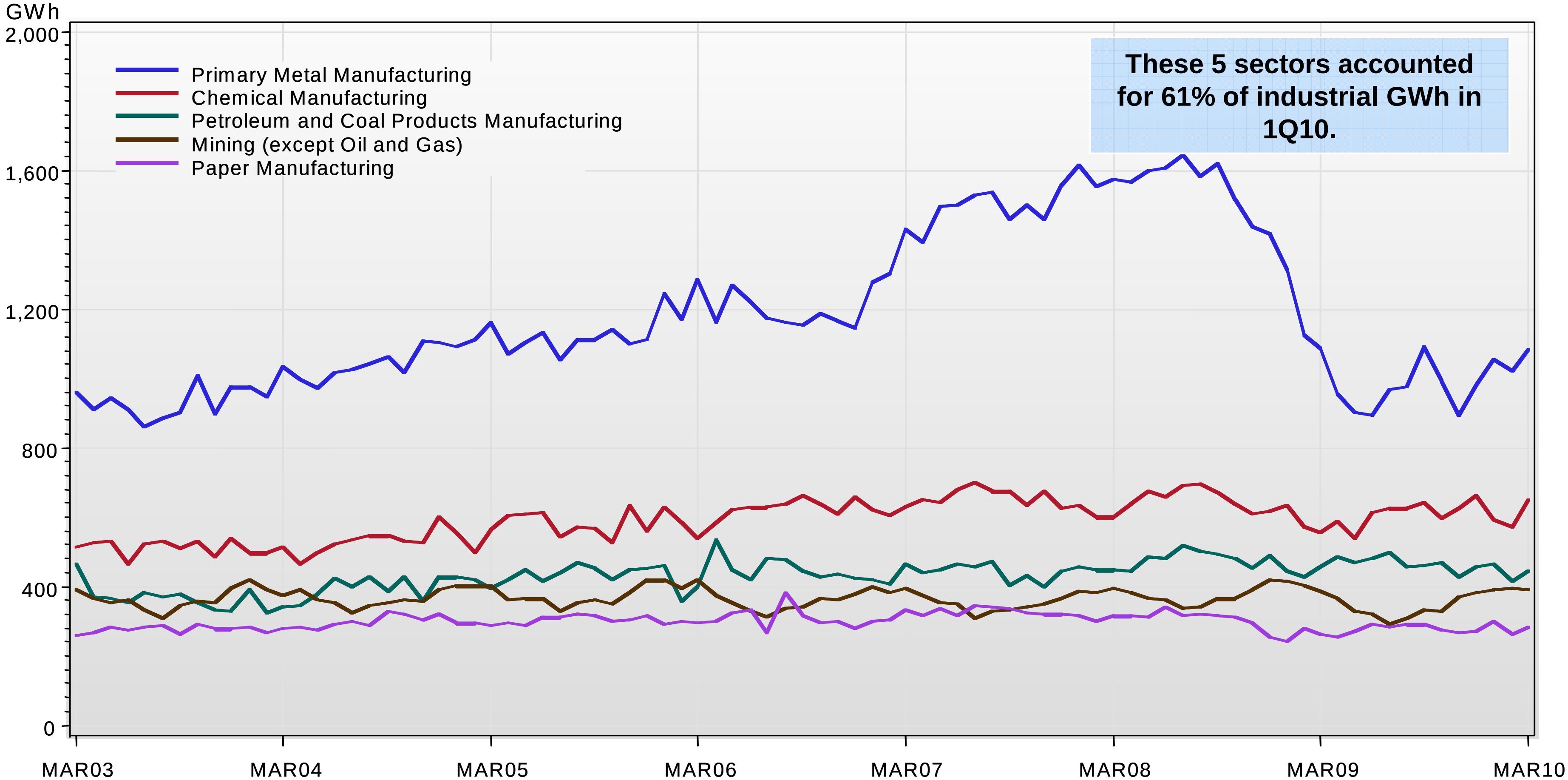
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

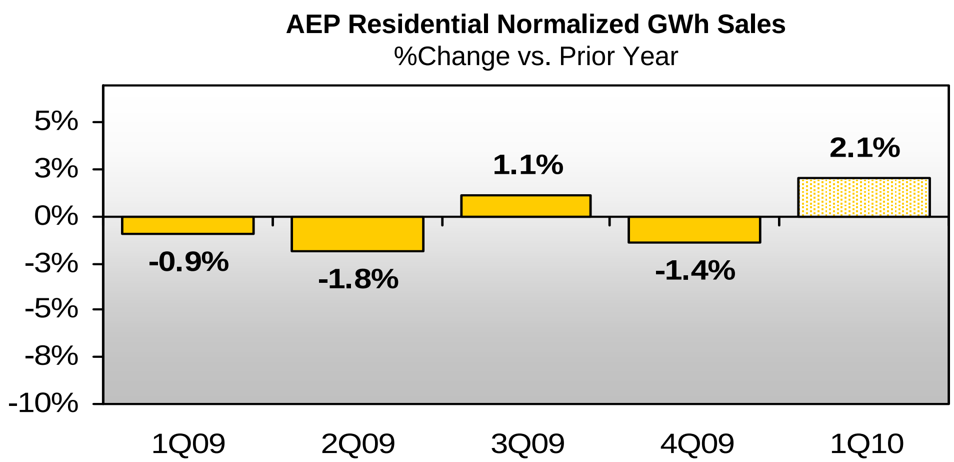
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

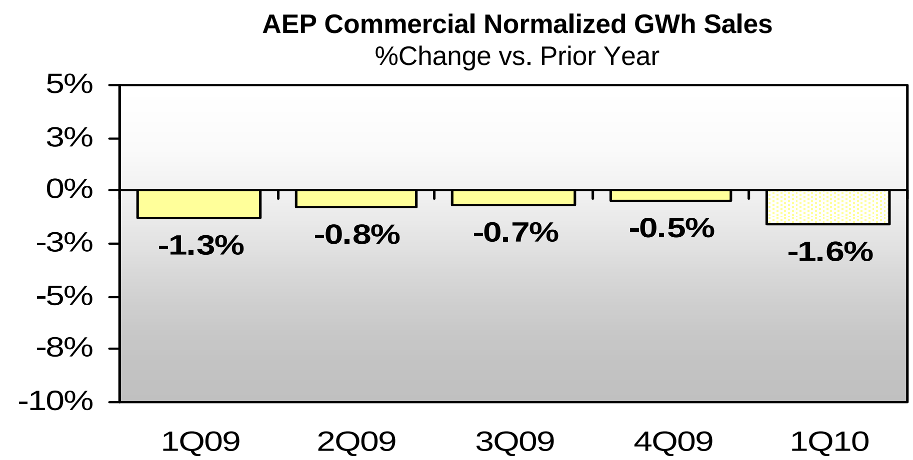
Industrial Sales

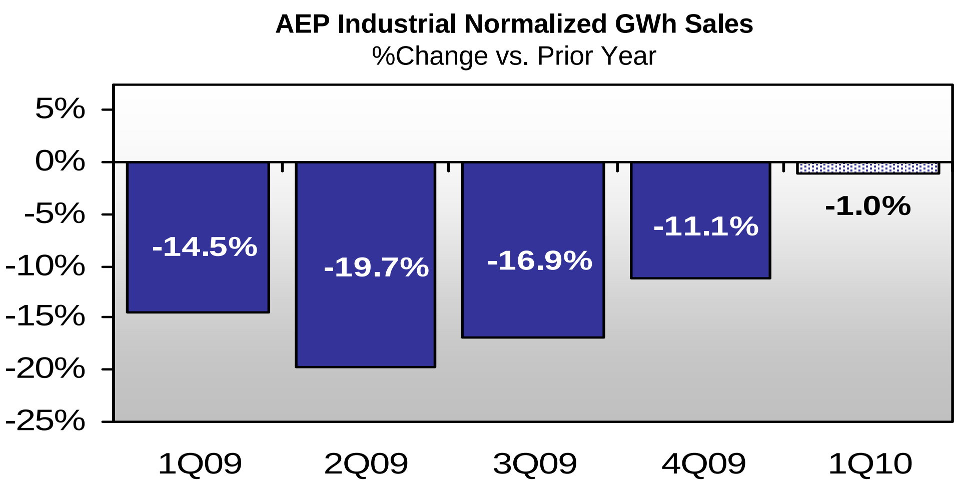
AEP Industrial GWh by Sector

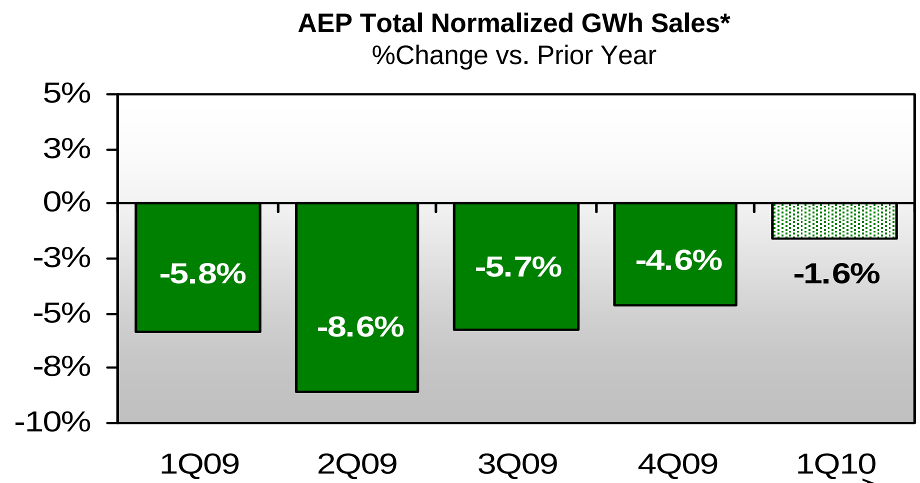


Normalized Load Trends



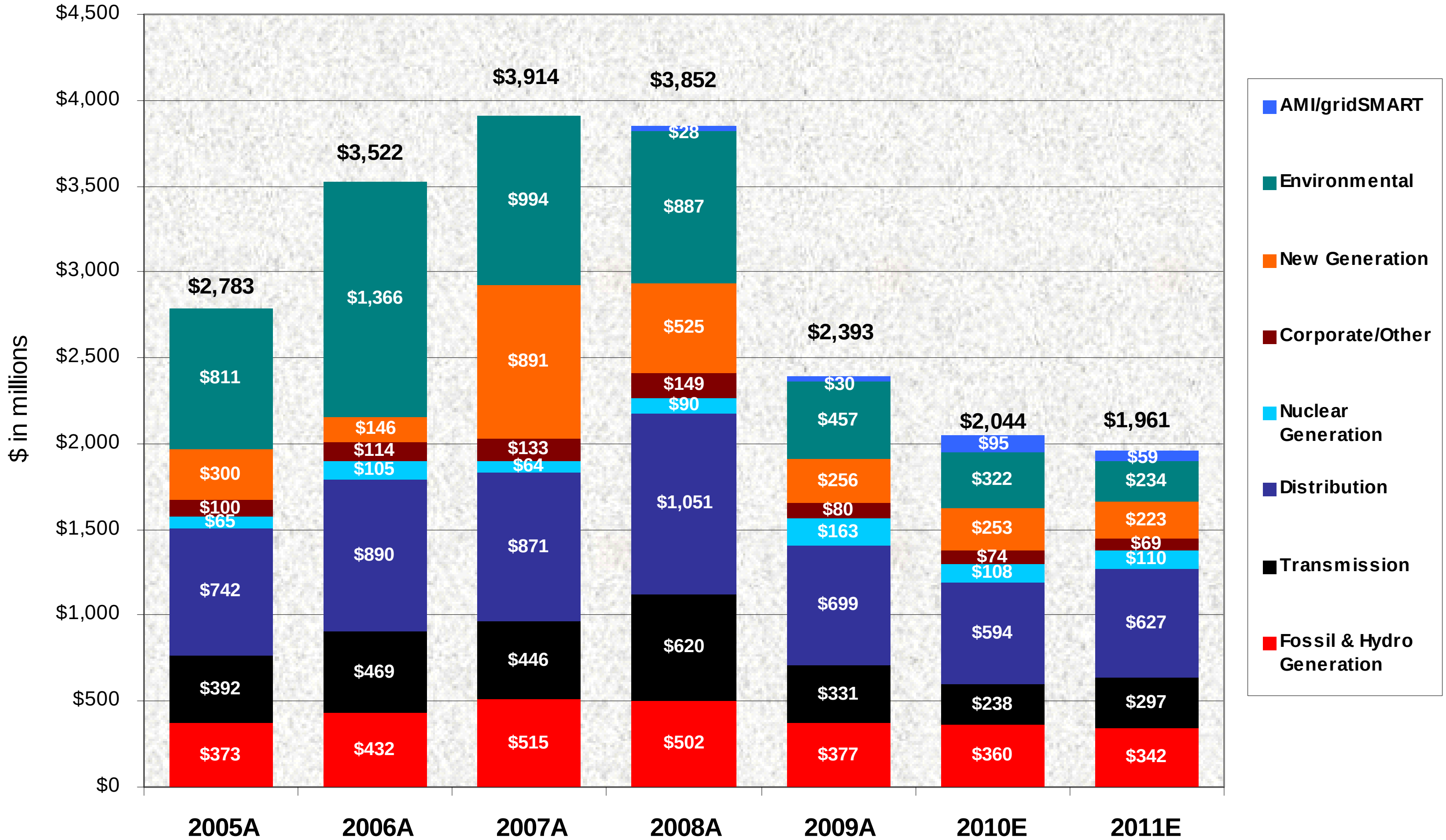






*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

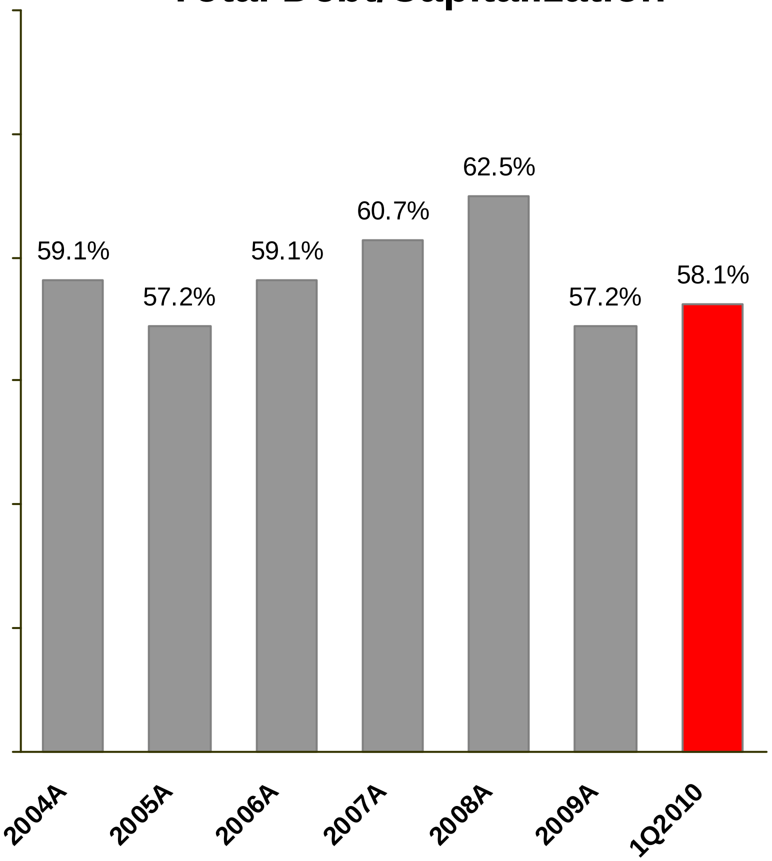
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary As of March 31, 2010

1, 2

	Amount (in millions)		Maturity
Commercial Paper Backup:			
Revolving Credit Facility	$	1,500	March 2011
Revolving Credit Facility		1,454	April 2012
Revolving Credit Facility		627	April 2011
Total		3,581	
Cash and Cash Equivalents		818	
Total Liquidity Sources		4,399	
Less: AEP Commercial Paper Outstanding		399	
Letters of Credit Issued		652	
Net Available Liquidity	$	3,348	

[1]: *Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $651 million are classified as short-term debt; The 1Q2010 debt/capitalization ratio would be 57.3%, excluding AEP Credit.*

[2]: *Ohio Power maturity of $400 million paid off on April 5, 2010*

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	$150	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$500	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)
Data as of May 21, 2010

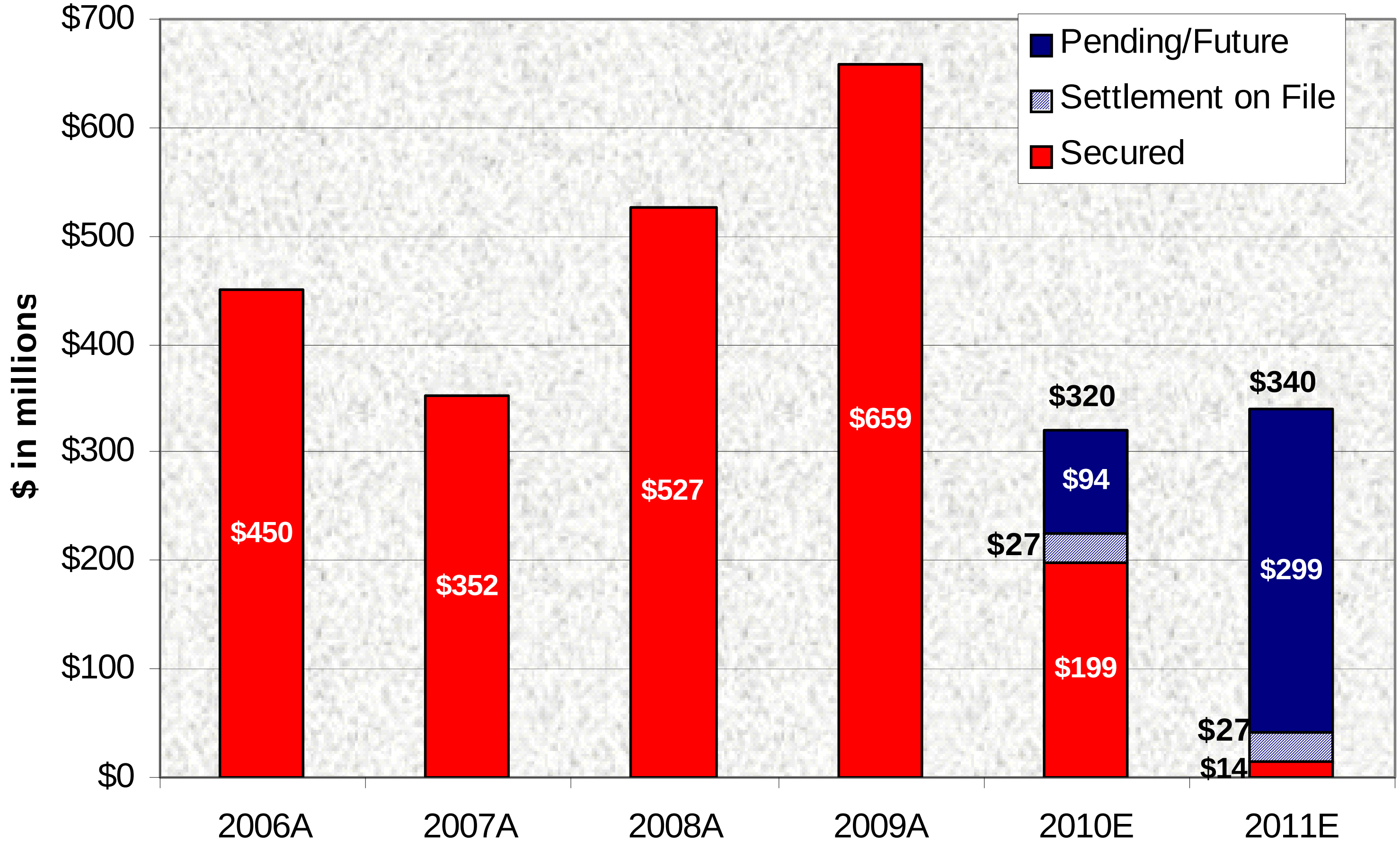
AEP Credit Ratings & Operating Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable, N=Negative Outlook

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Virginia, West Virginia and others yet to be filed

Settlement on File represents the Kentucky rate case

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4	*
Rate of Return		9.03%	
Operating Income Requirement	$	185.7	
Adjusted Operating Income	$	92.0	
Difference	$	93.7	
Revenue Conversion Factor		1.64	
Total Required Rate Relief	$	154	

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. A settlement agreement was filed with the KPSC on May 20, 2010, with a $64 million base rate increase, which includes $10 million on reliability spending at an ROE of 10.5%. Commission approval is pending.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. A procedural schedule is pending from the WVPSC. An order is expected in March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule - tbd

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

Making it Happen: EHV Projects Under Development

SPP

Prairie Wind — COD: 2013-14

- *110 miles of 765 kV*
- *Partners: Westar (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

ETT — COD: 2010-2017

- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — COD: 2014

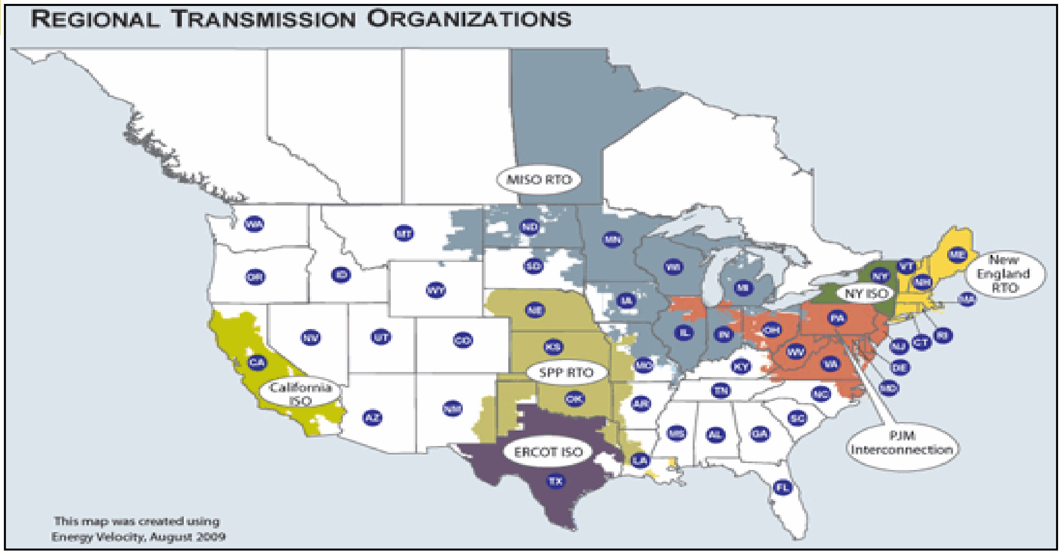
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015

- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*

ACTIVE PROJECTS



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay

- *Regional Expansion of 765 kV Backbone*

ETT — COD: various

- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion

- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio

- *700 miles of Proposed 765 kV*

SPP | **ERCOT** | **PJM** | **PJM/MISO**

Electric Transmission Texas, LLC

Overview:

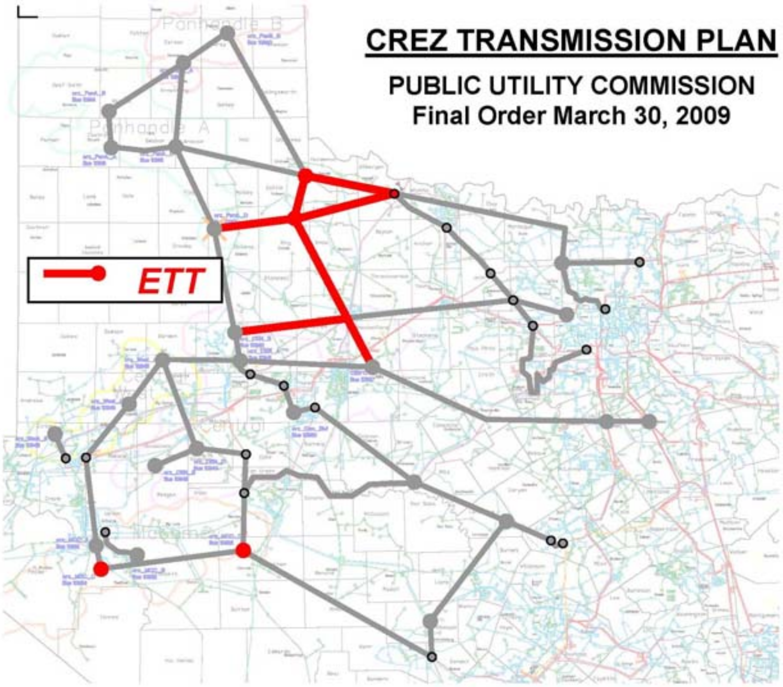
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Electric Transmission Texas

EHV Transmission in PJM: PATH

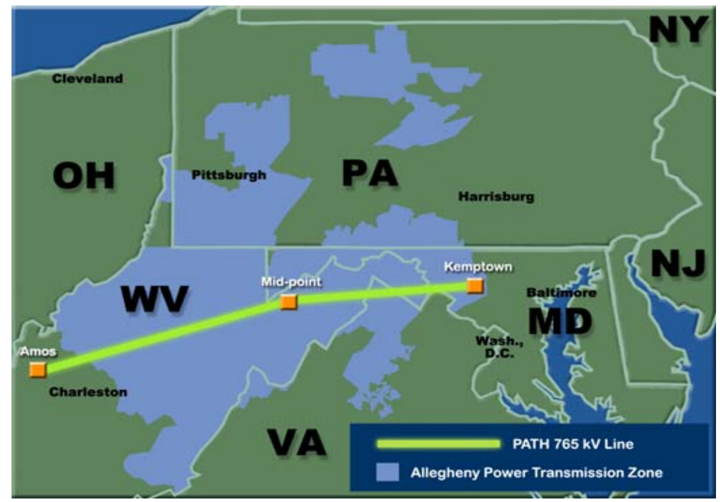
Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.



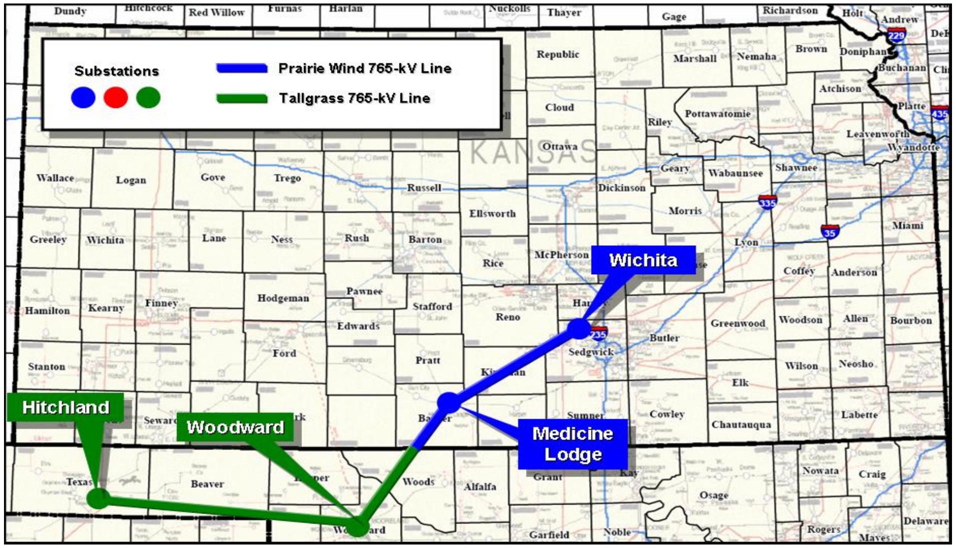
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Potomac-Appalachian Transmission Highline

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

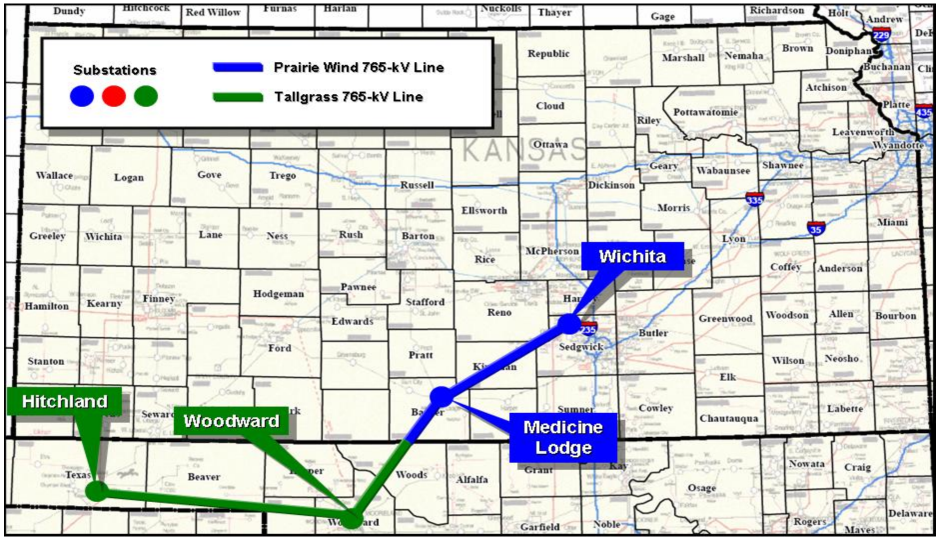
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - NTC anticipated to be received summer 2010. Currently pending approval of SPP cost allocation methodology at FERC.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

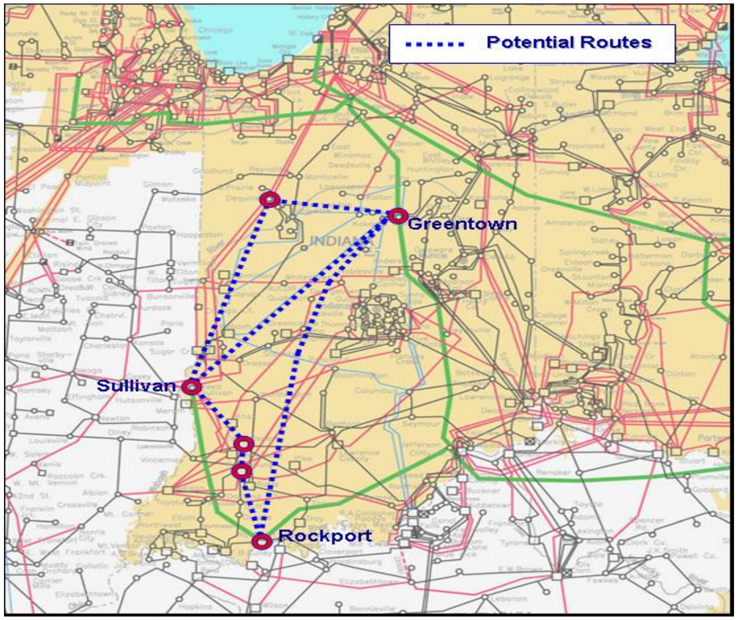
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

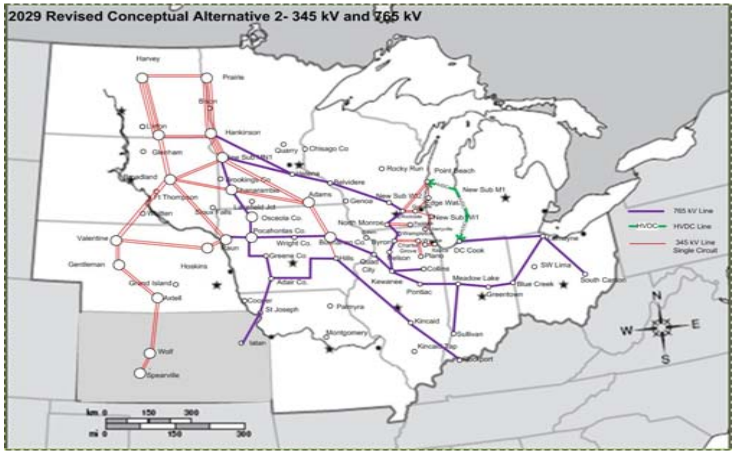
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

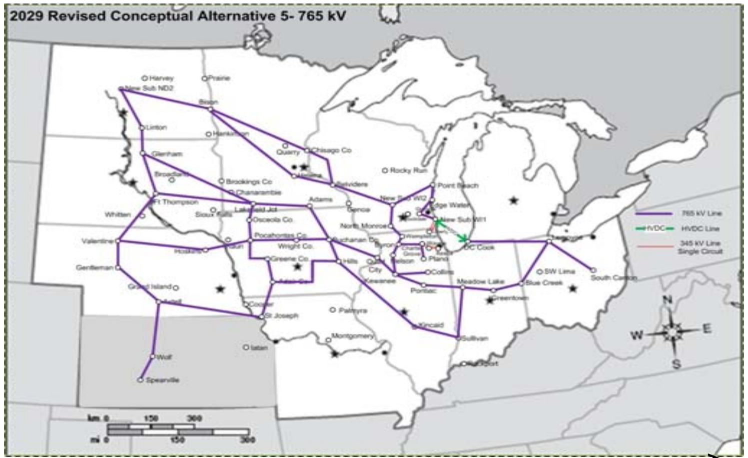
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives

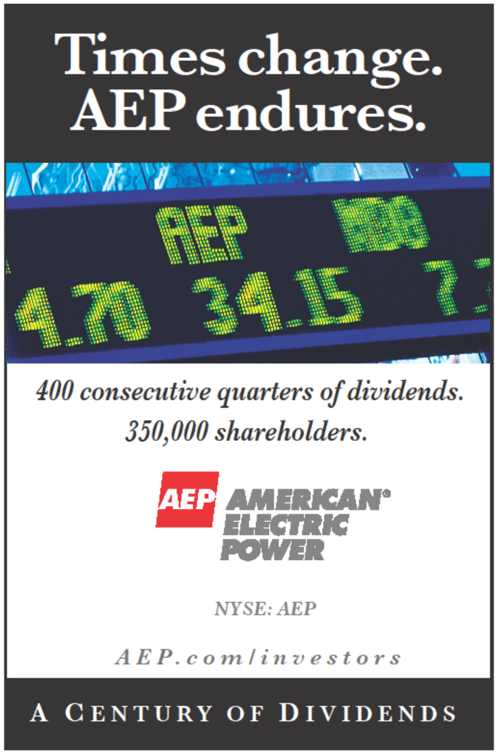




The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Value Proposition

- **Current Yield Opportunity of 5.0%[1]**
  - June 10th – 400th consecutive quarterly dividend was paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $33.68 on 06/16/2010

Spring EEI Investor Conference

Waldorf-Astoria
New York, NY
May 19, 2005

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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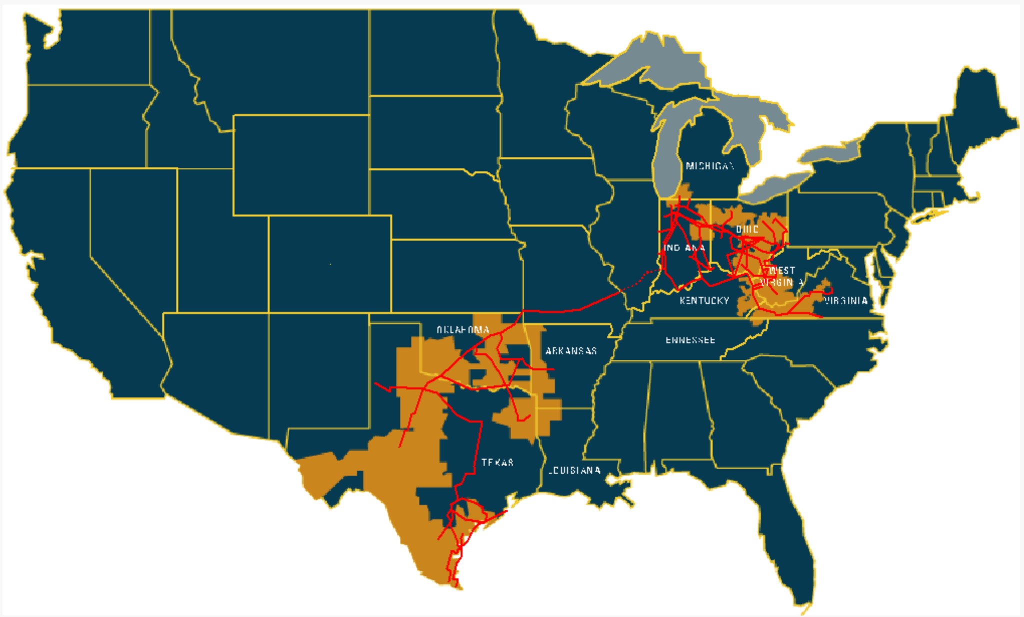
Asset Portfolio

Strength & Scale in Assets & Operations



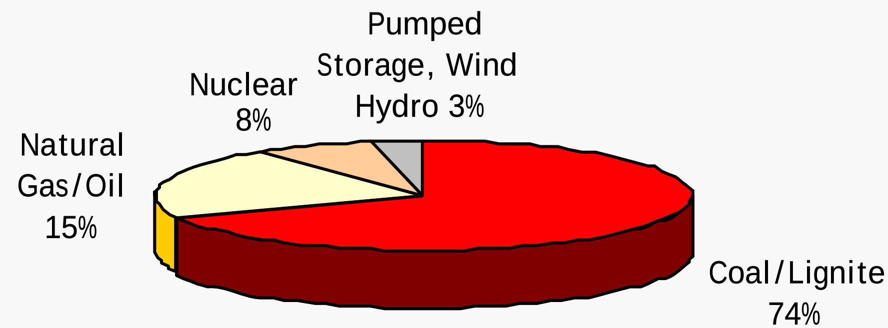
Generation	36,000 MW capacity
Transmission	38,953 miles
Distribution	200,930 miles
Customers	5 million

FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

- 36,000 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,226	0	586
ERCOT	1,719	0	0
SPP	4,828	3,516	188
Total*	**30,773**	**3,516**	**774**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity)

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Fuel, Emissions & Logistics

Introduction

The generation assets are co-managed by the Power Generation and the Commercial Operation Groups within AEP - each with a deliberate focus on roles and responsibilities within the organization

Power Generation
Operate 36,000 MW

Commercial Operations
Coal, gas, power and emissions markets

Fossil and Hydro Generation
Bill Sigmon, SVP

Generation Dispatch

Nuclear Generation

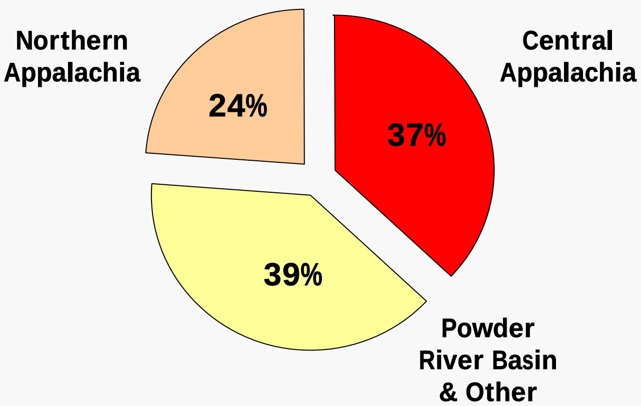
Energy Marketing
Brian Tierney, SVP

Engineering, Environmental & Technical Services
John McManus, VP Environmental Services

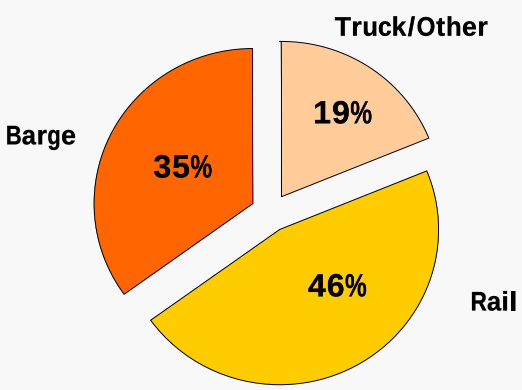
Fuel, Emissions & Logistics
Chuck Zebula, SVP

Fuel, Emissions & Logistics

FUEL BASIN DIVERSITY
73 million tons



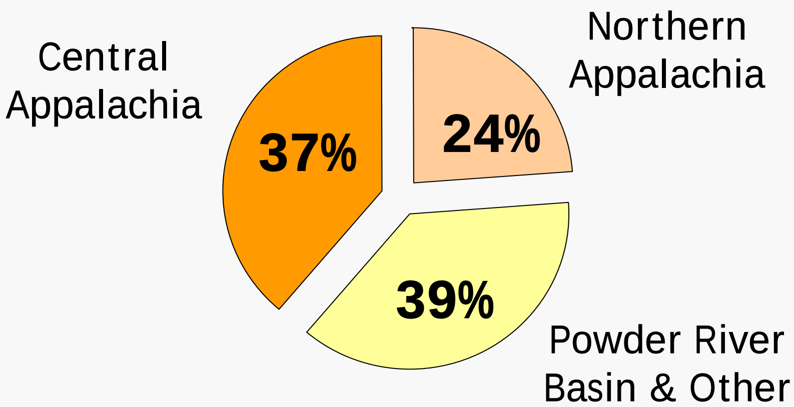
DELIVERY MODE DIVERSITY
25 GW coal capacity



- All fossil fuel activities including procurement, transportation, inventory, QA/QC, measurement, and coal trading;
- Market-based emission and renewable credit activities;
- Barge transportation, terminal, and railcar maintenance businesses;
- Procures all bulk consumables for use in combustion/emission removal;
- Optimizes all by-products of production including ash and gypsum;

Coal Procurement

AEP SYSTEM

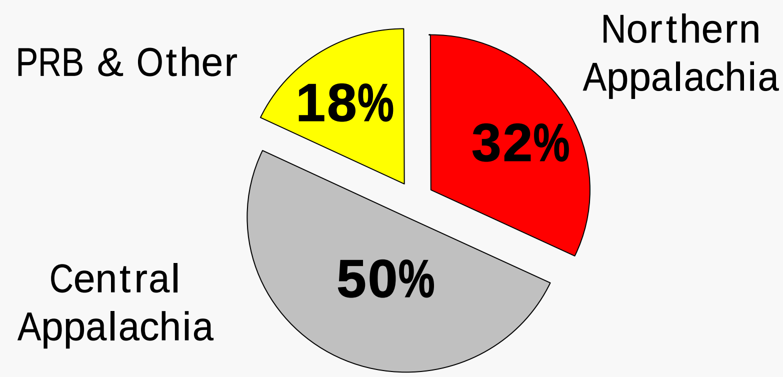


Coal Supply

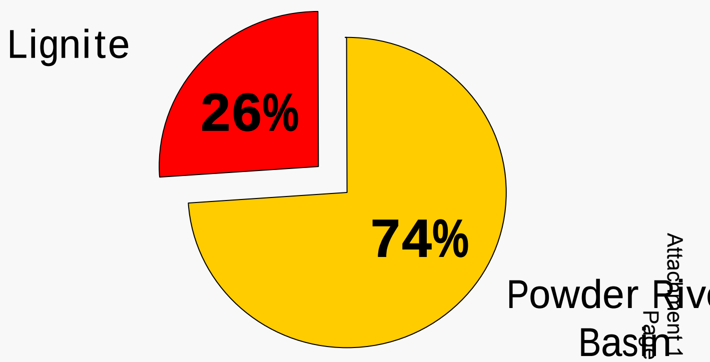
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 10% price increase in 2005

EASTERN SYSTEM

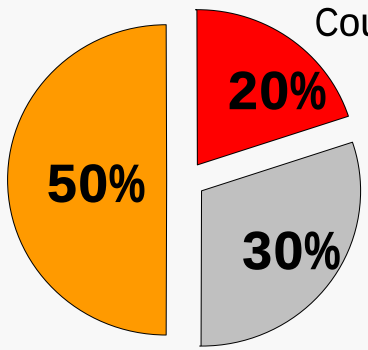


WESTERN SYSTEM



Fuel Recovery

AEP SYSTEM



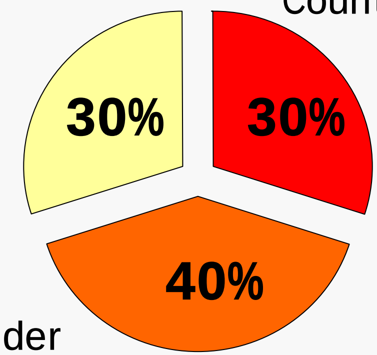
Fuel Cost Recovery

(on average)

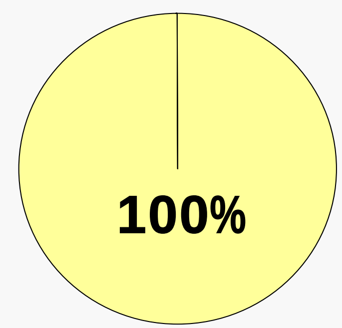
- ➢Fuel recovery varies by jurisdiction
- ➢70% of fuel cost is recoverable across the AEP System
- ➢Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

EASTERN SYSTEM

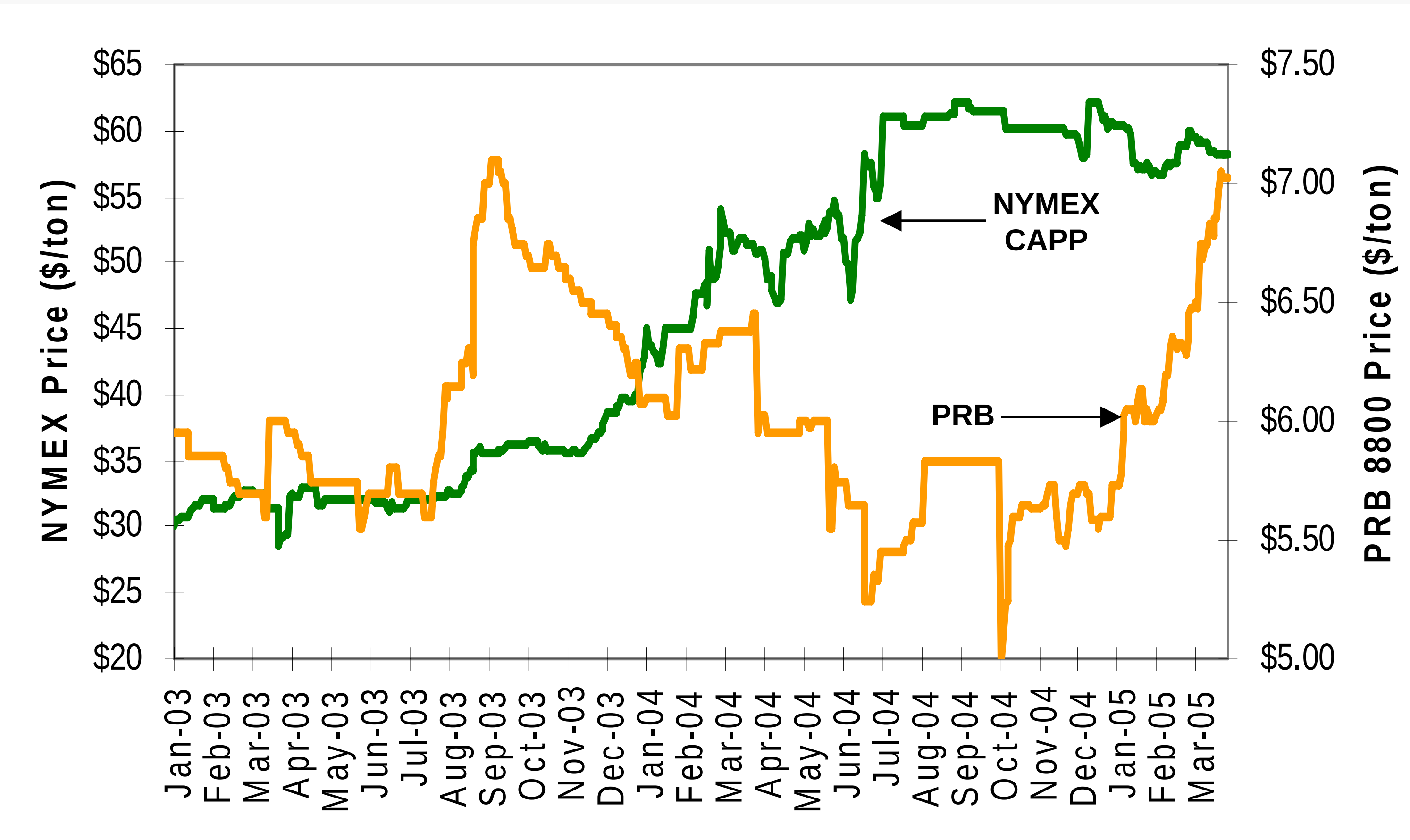


WESTERN SYSTEM



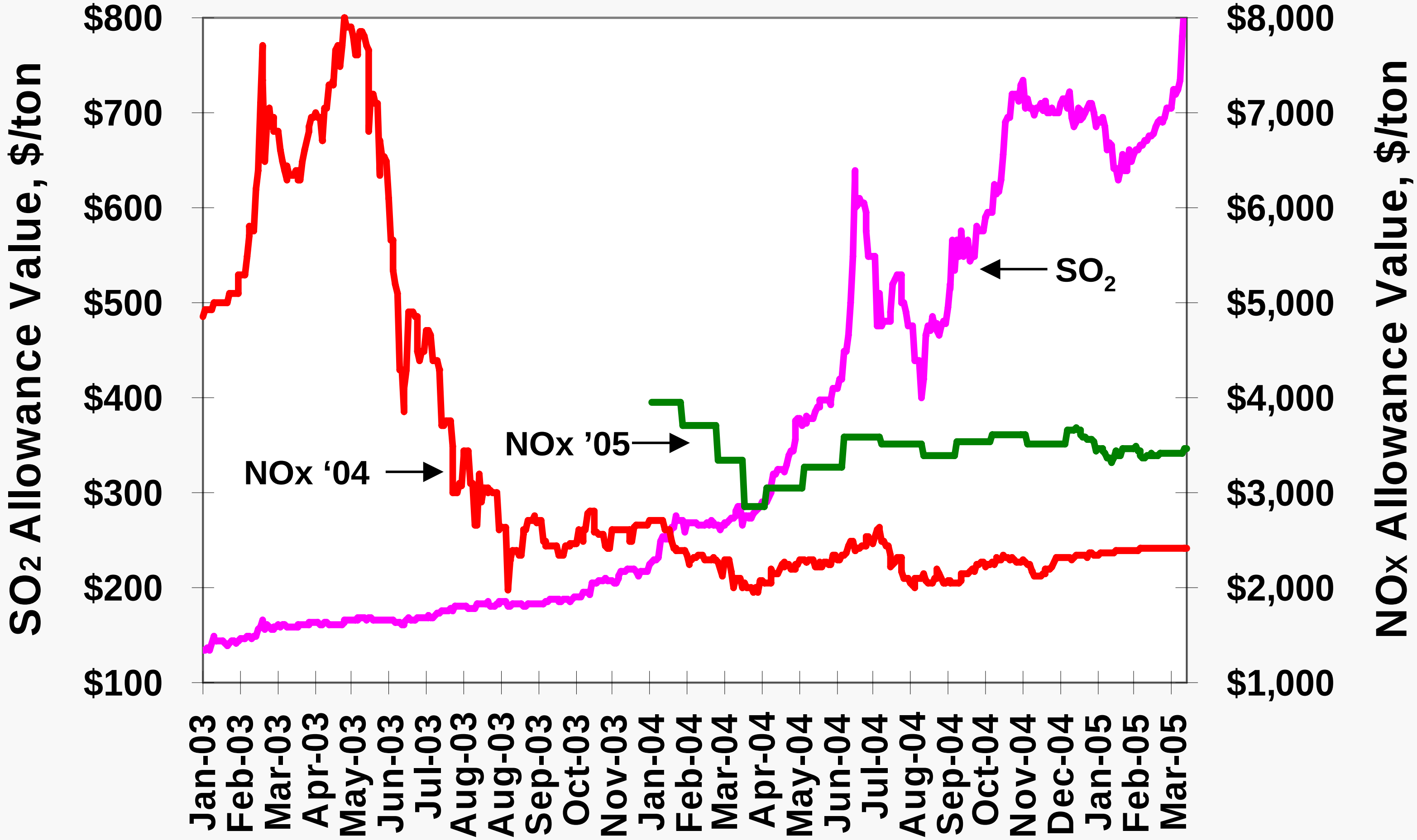
Coal Markets

The tale of two markets - one with labor, permitting and capacity constraints (CAPP) and the other with transportation bottlenecks and limited "immediate" substitution capability (PRB) but gaining strength



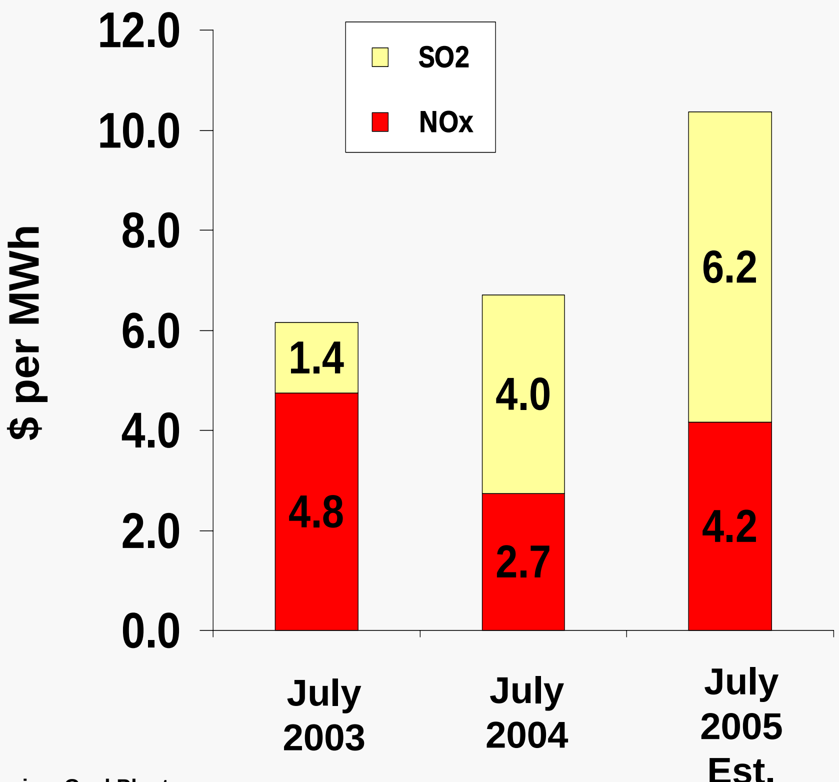
Emission Allowance Prices

Allowance prices for SO_2 and NOx have been extremely volatile since the beginning of 2003



Market Value vs. Inventory Cost

Profile of Uncontrolled Power Plant exposed to Market Value of Emission Credits



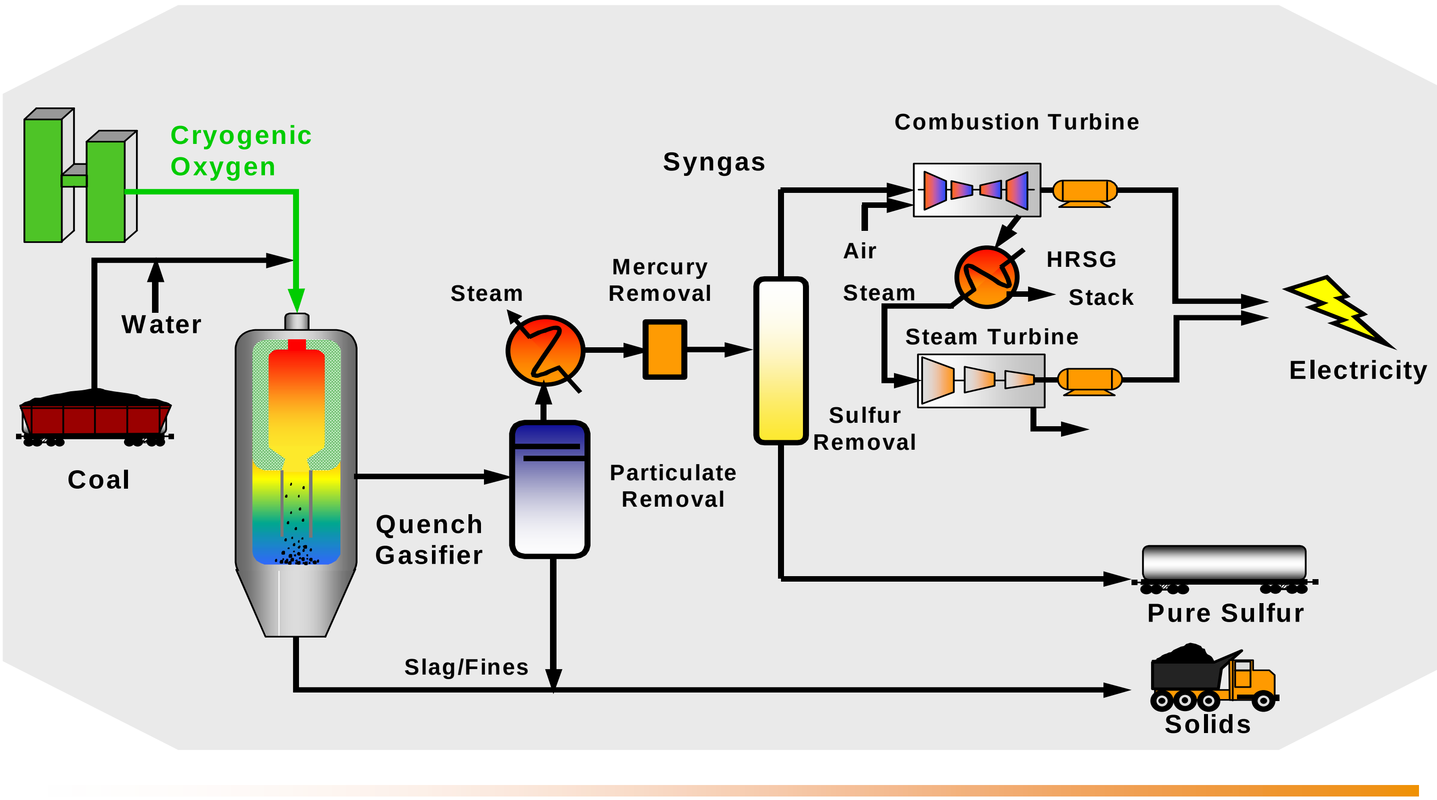
Basis – Coal Plant
9.5 MMBtu/MWh Heat Rate
0.25 lbs NOx/mmBtu
1.67 lbs SO_2/mmBtu

AEP has managed its exposure to rising emission allowance costs

- Inventory cost of emission credits is low
- Effective hedging program for SO_2 allowances
- Effective capital implementation in the NOx SIP Call ($1.3 B)
- Exposure in future years reduced by $3.7 B capital program and current inventory of allowances

Investing in IGCC

Looking to the Future - IGCC



AEP has announced its intention to construct a commercial-scale Integrated Gasification Combined Cycle (IGCC) Plant by the end of the decade.

Investing in IGCC

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	530
Heat Rate (BTU/kWh)	8700	8600	7200
EPC cost* ($/kW)	1290	1350	440
Total Plant cost** ($/kW)	1490	1610	475
Variable Production cost*** ($/MWh)	15	14	38
All-In Cost of Electricity (without CO2 Capture) ($/MWh)	47	50	57
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	76	70	91

Source: Electric Power Research Institute

* EPC includes the cost to engineer, procure and construct plant.
** Total plant cost include land, overheads, AFUDC, etc.
*** Assumes Northern App Coal @ $36/ton, no emission credits and $5.00 gas

Site Selection Considerations

- Brownfield site vs. Greenfield site
- Sufficient Space
  - Flat area with adequate construction access
  - 600 acres
- Fuel delivery options
  - Rail/barge/truck
  - Up to 4 million tons/year of coal
  - Access to water
- Transmission Line Costs
  - Distance from high-voltage lines
  - Costs for grid interconnects and stability impacts

PJM EVALUATION REQUESTED FOR 3 POTENTIAL SITES

IGCC Permitting Issues

- **Air** – to evaluate best available control technology (BACT)
- **Wastewater** – to understand wastewater streams
- **US COE** (Corp of Engineers) – to obtain permits for construction of river facilities
- **NEPA Process** – (National Environmental Policy Act)– Environmental site studies addressing wetlands, endangered species, historical artifacts

PERMIT PROCESS WILL TAKE 1 - 2 YEARS

Next Steps

2005

- ➢ Secure cost recovery plan – Summer
- ➢ Finalize site selection - Fall
- ➢ Negotiate with suppliers – Throughout 2005

- ➢ 2005—2007: Obtain permits and finalize engineering and procurement

- ➢ 2008—2009: Construct and start-up plant

AEP WILL PIONEER CONSTRUCTION OF LARGEST IGCC PLANT IN THE WORLD

Environmental

Clean Air Interstate Rule

- Rule Finalized March 2005
- CAIR designed to address the contribution of regional emissions to downwind $PM_{2.5}$ & 8-hour Ozone non-attainment
- CAIR reductions from 2003 emissions: ~73% SO_2; & ~61% NO_x
- Reductions occur in phases: Phase I (2009); Phase II (2015)
- CAIR established three Cap & Trade Programs:
  1. Annual SO_2 Trading Program
  2. Annual NO_x Trading Program
  3. Separate Ozone-Season only NO_x Trading Program

CAIR Applicability to AEP

- AEP-East States & Louisiana subject to all three trading programs
- Arkansas subject only to the Ozone-Season trading program
- Texas subject to only the Annual NO_x & SO_2 trading programs
- CAIR does not apply to Oklahoma

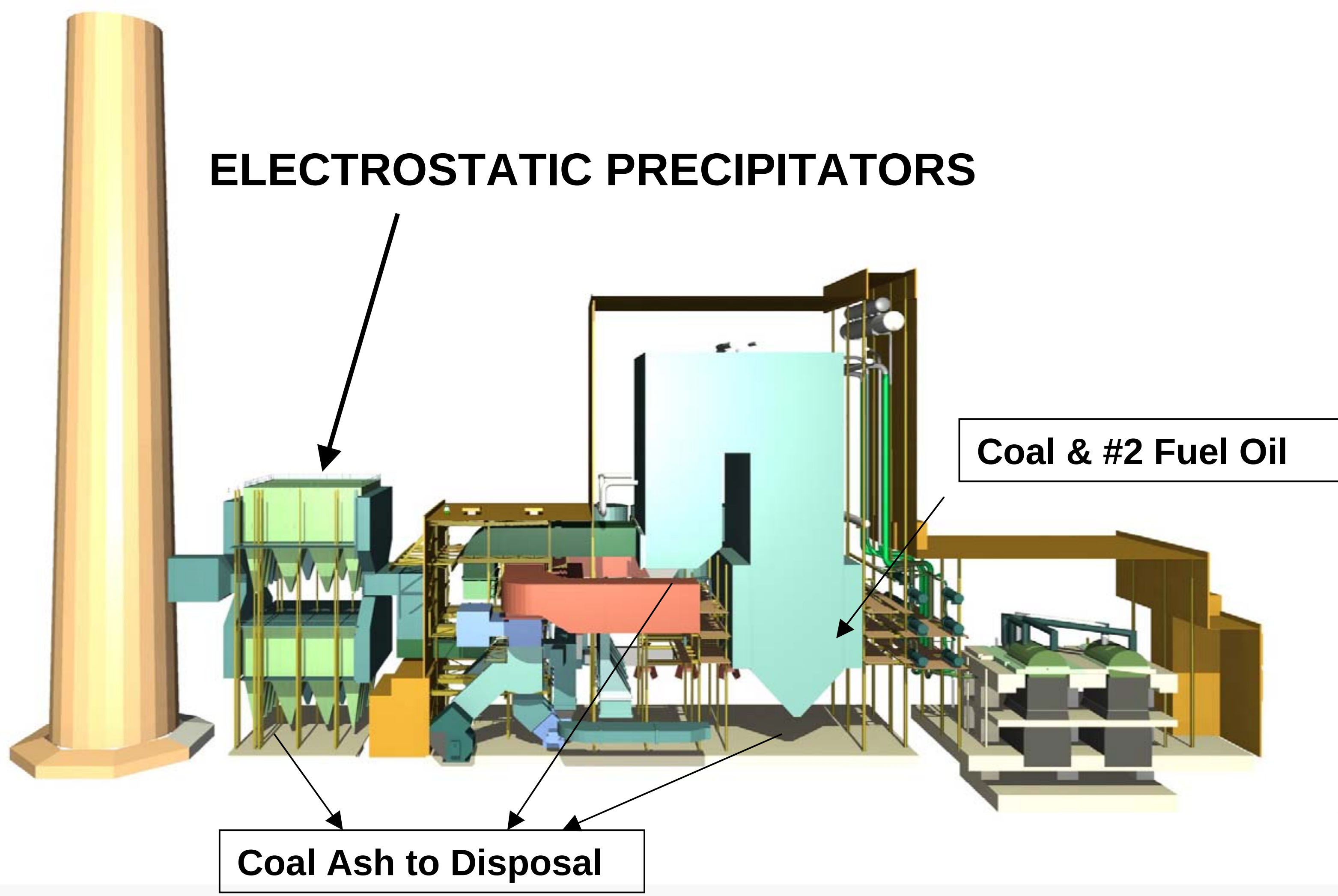
AEP WILL HAVE TO INSTALL ADDITIONAL SCR AND FGD SYSTEMS IN ORDER TO MEET THE EMISSION REDUCTIONS REQUIRED BY CAIR

Mercury Rule

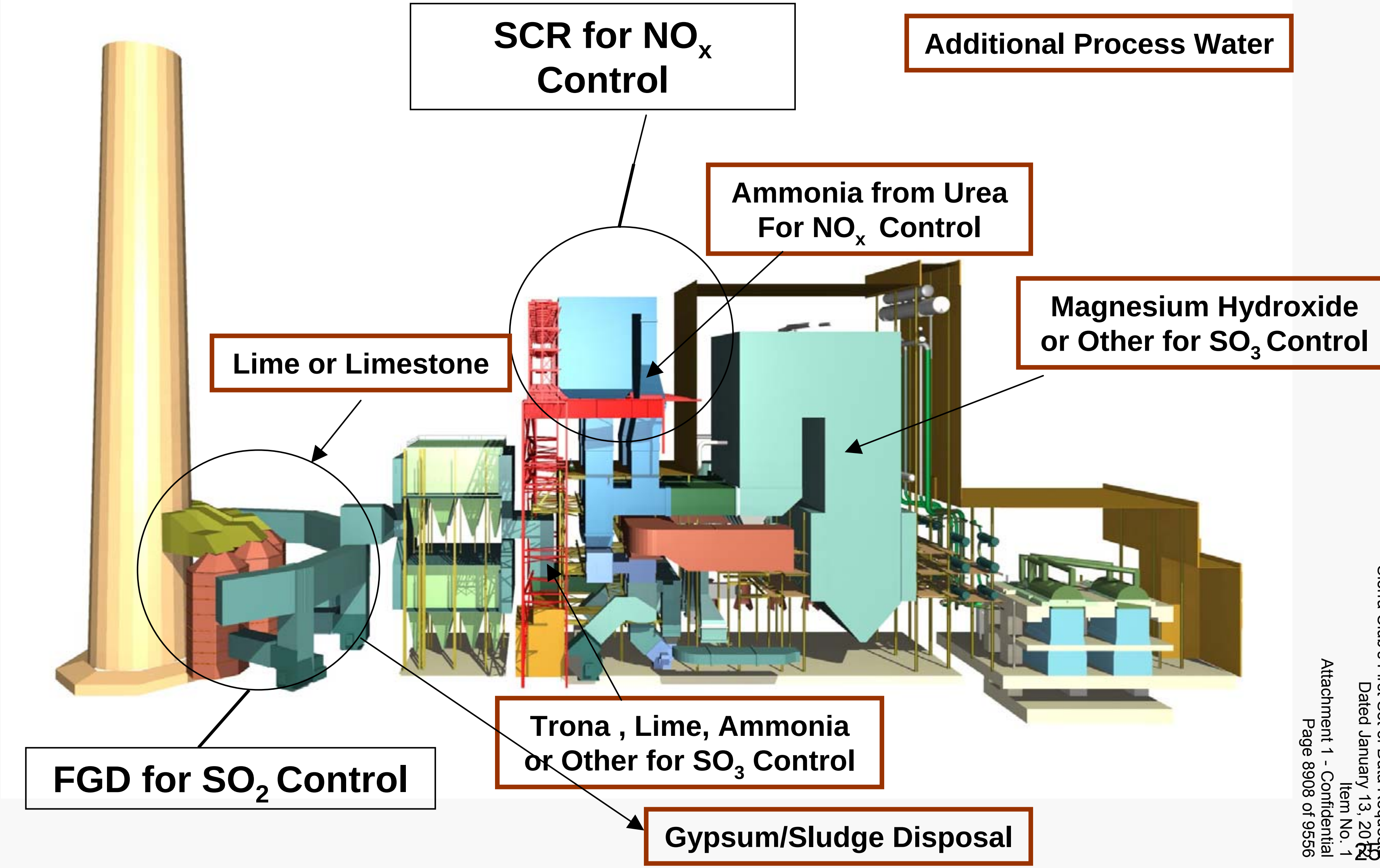
- Rule Finalized March 2005
- Designed to reduce mercury emissions by ~70% nationwide from electric utilities
- Reductions occur in phases: Phase I (2010); Phase II (2018)
- Establishes a Cap & Trade structure to achieve mercury reductions

AEP WILL ACHIEVE SOME MERCURY REDUCTIONS AS A CO-BENEFIT OF SCR AND FGD SYSTEMS, BUT MERCURY SPECIFIC CONTROL EQUIPMENT WILL BE NEEDED ON SOME UNITS

Pulverized Coal Unit as Built in 1970s

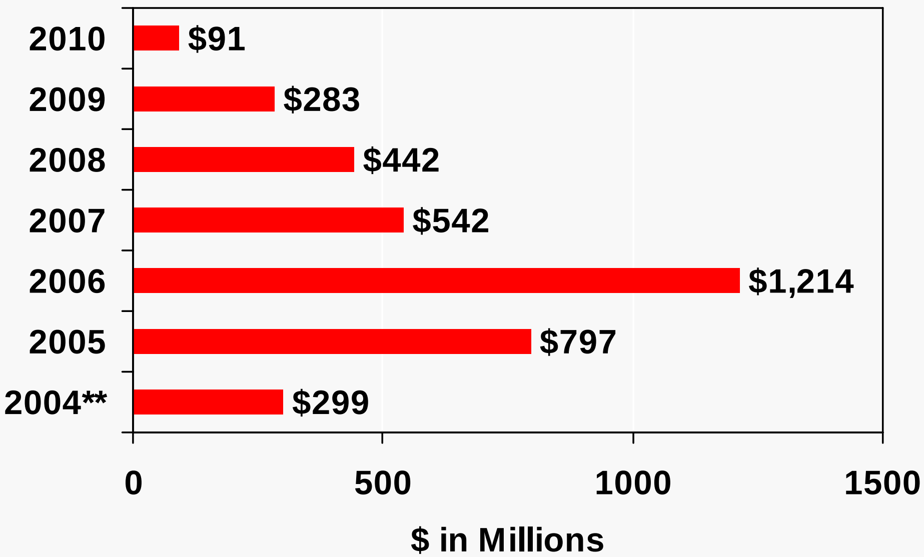


Pulverized Coal Unit Today Showing Retrofits & New Feedstock(s)

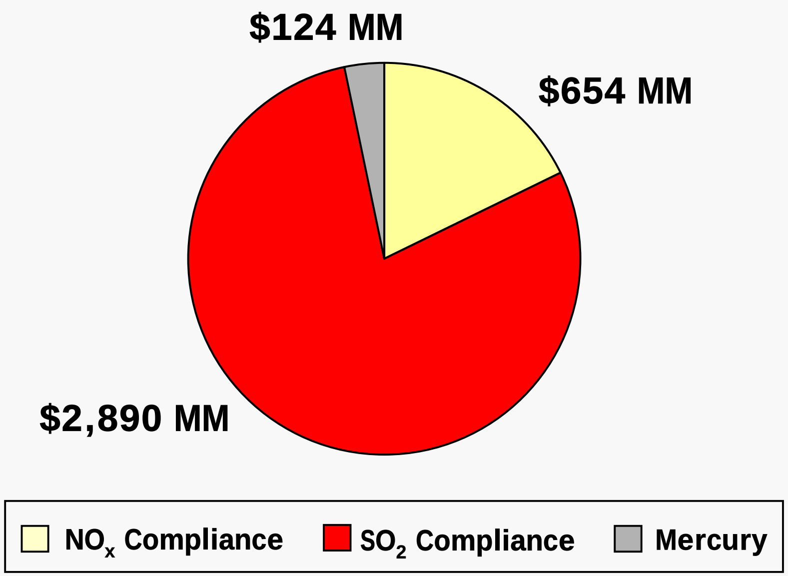


Environmental Investment: $3.7 Billion Through 2010

Environmental Capital Investment*



Compliance Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes
** Actual investment level in 2004

Current Programs

$1.9 Billion:

$0.6 billion for NOx

$1.2 billion for SO_2

Future Programs

$1.8 Billion:

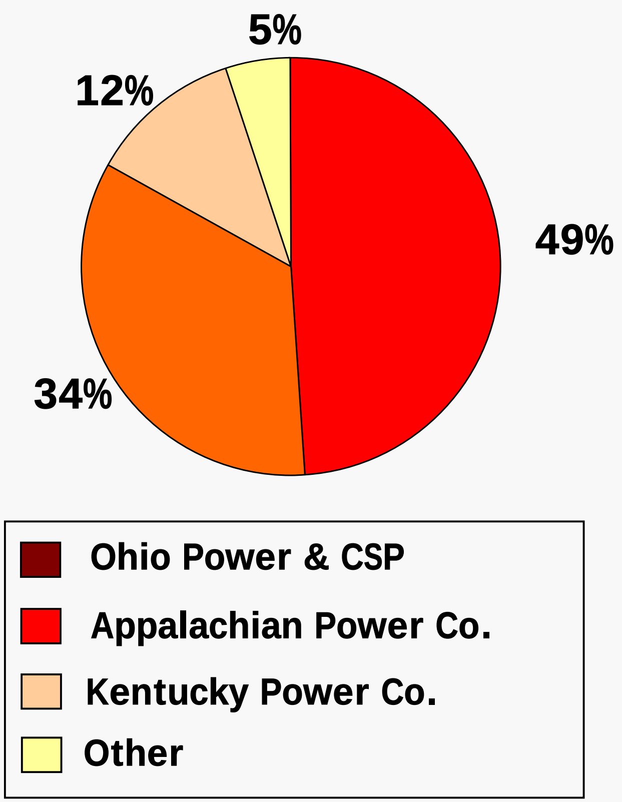
$1.7 billion for SO_2

$0.1 billion for Other

MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Spending by Company

Projected Environmental Investment Allocation



Funding the Environmental Investments

- **Ohio**: 49% ($1.8 billion)
  - Rate stabilization plan annual increases at CSP – 3% and OP – 7% beginning in 2006 through 2008
- **Virginia/West Virginia**: 34% ($1.2 billion)
  - VA: Environmental cost recovery mechanism/two rate case opportunities through 2010
  - WV: General rate case filing
- **Kentucky**: 12% ($433 million)
  - Surcharge mechanism

Environmental Investment

FGD

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

Planned or Under Construction

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8732**

2006 - 2010

SCR

Completed

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	608
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9723**

Planned or Under Construction

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

2005 - 2007

Note: MW capacity shown represents AEP's owned capacity only

AVERAGE VARIABLE COSTS WILL BE $18 - $21 PER MWh POST ENVIRONMENTAL ADDITIONS

Regulatory Overview

Managing the Regulatory Process

- **Current Regulatory Activity**
  - TCC Wires Rate Case
  - TCC Stranded Cost Recovery
  - Louisiana Rate Review
  - FERC Transmission Rate Case
- **Planned Regulatory Activity (2005-2007)**
  - General Rate Cases in all AEP East jurisdictions to seek recovery of investment:
    - IN, KY, MI, TN, VA, WV

BRING CASH IN THE DOOR TO COVER CAPITAL EXPENDITURES & GROW EARNINGS THROUGH ADDITIONS TO THE ASSET BASE

Components of TCC's Net True-up Regulatory Asset

	31-Mar-05	31-Dec-04
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1141	1136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1346	1361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

Carrying charge calculated using pre-tax cost of capital of 11.79%

Debt Component: 8.12% - $296 million recognized as income thru 3/31/05

Equity Component: $154 million to be recognized in income as collected

CARRYING CHARGES FOR 2005 EXPECTED TO BE $87 MILLION

Regulatory Matrix – East

Ohio (Restructured)
- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP ”G” rates to increase 3% per year (2006-2008).
  - OP “G” rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05, hearings scheduled to begin 8-8-05.

Virginia (Restructured)
- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause

West Virginia (Regulated)
- Base rates not frozen
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- No active fuel clause

Indiana (Regulated)
- Subject to IURC order approving a settlement agreement, base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Kentucky (Regulated)
- Base rates not frozen
- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- Rockport Unit Power Supply Agreement extension through 12-07-2022 was approved by FERC & KPSC in December 2004

Michigan (Restructured, but Regulated)
- Base rates not frozen.
- Active annual fuel clause.

Tennessee (Regulated)
- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Matrix - West

Texas (Regulated)
- SWEPCO-Texas retail competition delayed until at least 2007
- Bi-annual fuel clause adjustment opportunity

Texas (Restructured)
- TCC stranded cost true-up filing in first half of 2005. TCC wires rate case order expected in June 2005.
- TCC final fuel reconciliation (July 98-Dec. 01) decision issued in April 2005. TCC will appeal decision.
- TNC true-up order approved in April 2005 (retail clawback and fuel over-recovery only). No adjustments to revised amounts filed by TNC.
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received October 18, 2004. Appeals filed in state and federal courts in Dec. 2004.

Oklahoma (Regulated)
- General rate case filed Oct. 31, 2003
  - On 5-2-05 the OCC issued an order approving a settlement agreement which included a $6.9 million annual revenue reduction, offset by changed depreciation rates and deferral recoveries, changed the fuel clause from a quarterly to annual factor, and made permanent an $11.8 million annual system reliability rider.
- 2001 Fuel review case
  - Hearings expected in August 2005. Scope expanded to cover 2002-2004 margin allocation issue.
- 2003 Fuel review case
- Likely to include motions to expand scope to include prudence review

Louisiana (Regulated)
- Base rates capped through June 15, 2005
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Ohio Rate Stabilization Plan Recap

Summary of Impact (Columbus Southern Power & Ohio Power):

	Revenues				Incremental Cash			
Rate Stabilization Plan	**2005**	**2006**	**2007**	**2008**	**2005**	**2006**	**2007**	**2008**
Escalation of Generation Rate	0	83	173	271	0	83	173	271
POLR Rider/Recovery of RTO Costs**	21	0	0	0	0	7	7	7
POLR Rider/Return on Environmental Additions	44	26	26	26	0	41	41	40
Total RSP Impact	**65**	**109**	**199**	**297**	**0**	**131**	**221**	**318**
Pre-Existing Electric Transition Plan								
Elimination of 5% Residential Generation Credit*	0	25	25	26	0	25	25	26
Recovery of RTO costs**	0	29	29	29	0	29	29	29
Total ETP Impact	**0**	**54**	**54**	**55**	**0**	**54**	**54**	**55**

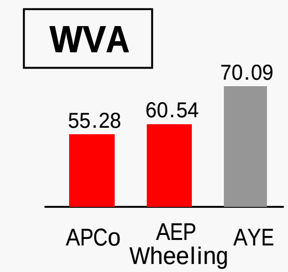
* Elimination of 5% credit is per Statute, and part of pre-existing ETP, not the RSP

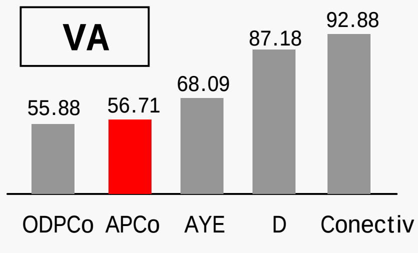
** Recovery of administrative RTO costs, net congestion fees and ancillary services permitted in pre-existing ETP, but the RSP allows for recovery of 2005 costs as well

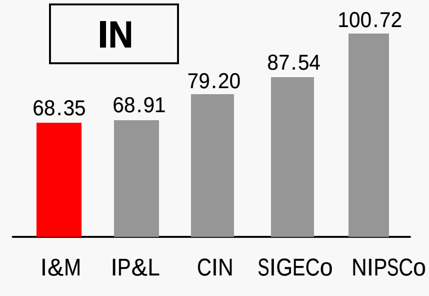
AEP WILL STILL HAVE AMONG THE LOWEST RETAIL RATES IN OHIO

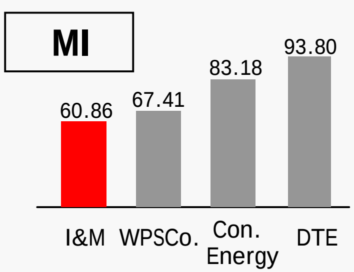
AEP: The Low Cost Provider

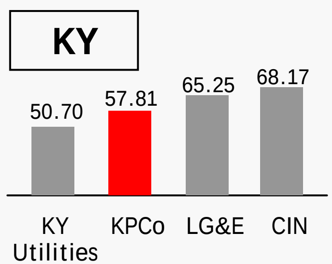
Regulated Rates

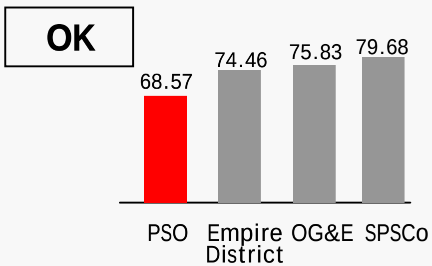


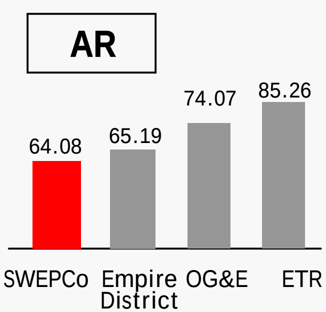


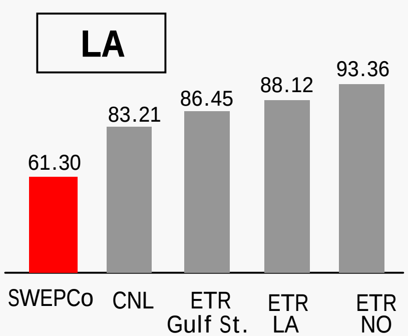


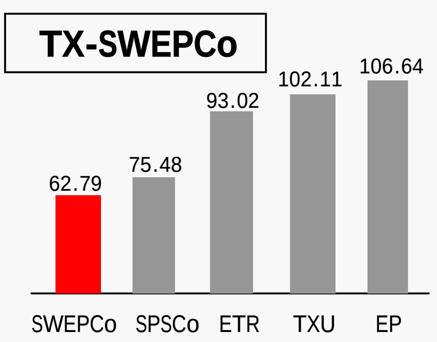






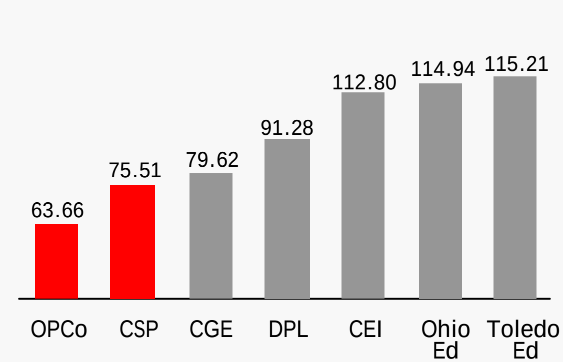






Note: Rate amounts reflect bundled residential rates and are expressed in $/MWh. The source for the shown rate amounts (excluding wholesale) is the EEI Typical Bills and Average Rates Report.

Unregulated Rates



OH (POLR bundled residential rates)

Wholesale

Fossil fleet variable cost of production:

- Today: $16-$18/MWh
- Tomorrow: $18-$21/MWh
  - Post-environmental retrofit installation

Finance

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2005 Cash Flow Projection

	2004 Actual	2005 Guidance
Beginning Cash Balance	**$ 976**	**$ 420**
Cash from Operations:		
Income from Continuing Operations	1,006	936 *
Depreciation & Amortization	1,300	1,305
Pension Funding in Excess of Expense	(200)	(353)
TCC ECOM/Carrying Cost	(304)	(101)
Extraordinary Loss (net of tax)	121	-
Other	674	136
Total from Operations	**$ 2,597**	**$ 1,923**
Cash from Investing:		
Capital Expenditures	(1,693)	(2,690)
Asset Sales	1,357	1,498 **
Other	(40)	(529) ***
Total from Investing	**$ (376)**	**$ (1,721)**
Cash from Financing:		
Common Equity	17	(155) ****
Net Long Term Debt Issued/(Retired)	(1,829)	621
Preferred Stock Redeemed	(10)	(66)
Short Term Debt Change, Net	(400)	16
Common Dividends	(555)	(545)
Total from Financing	**$ (2,777)**	**$ (129)**
Net Change in Cash	**$ (556)**	**$ 73**
Ending Cash Balance	**$ 420**	**$ 493**

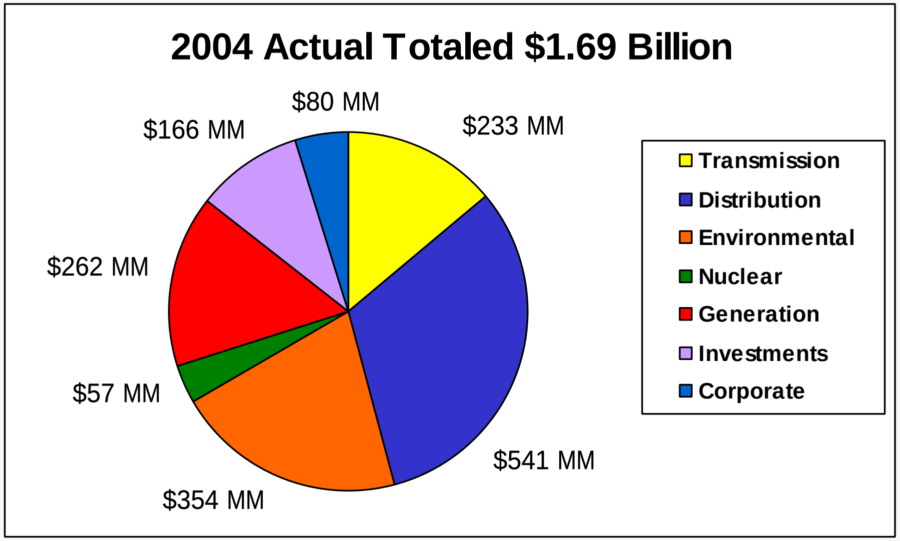
*** Assumes the midpoint range based upon $2.30 to $2.50 per share earnings guidance and 389 million shares outstanding**

**** Includes HPL, STP, Oklaunion & Pacific Hydro asset sales**

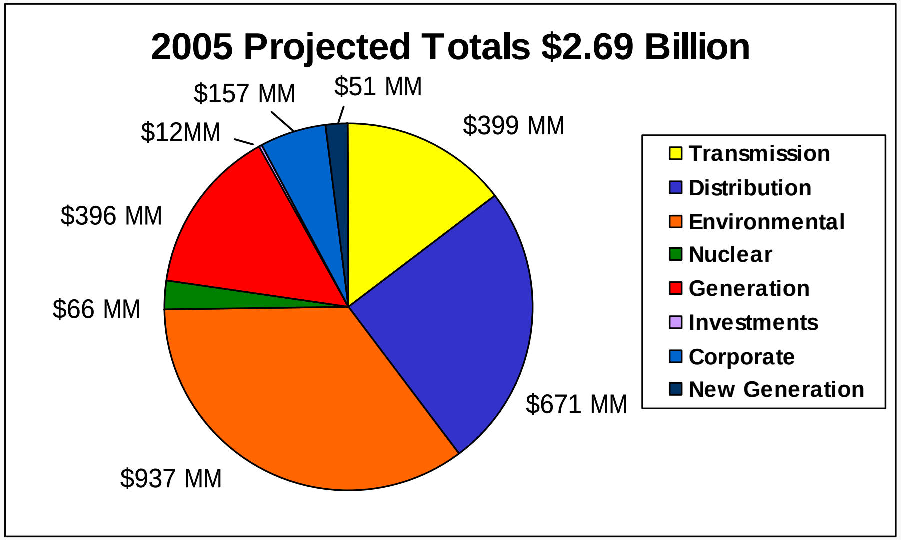
***** Includes $550MM of parent debt reduction**

******Equity units terms require issuance of $345MM common shares in August 2005; offset by $500MM share buyback program**

2005 Capex



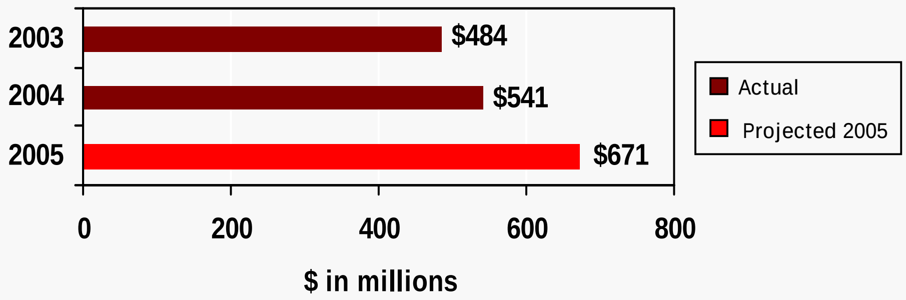
2004 Actual Totaled $1.69 Billion
$80 MM
$166 MM
$233 MM
$262 MM
$57 MM
$354 MM
$541 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate



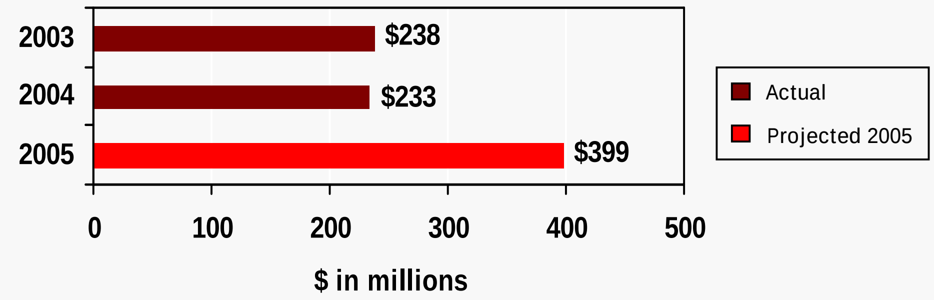
2005 Projected Totals $2.69 Billion
$157 MM
$51 MM
$12MM
$399 MM
$396 MM
$66 MM
$671 MM
$937 MM
Transmission
Distribution
Environmental
Nuclear
Generation
Investments
Corporate
New Generation

Energy Delivery Investment

Distribution Capital Expenditures



Transmission Capital Expenditures



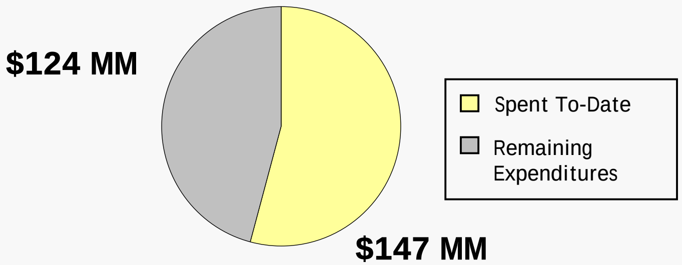
Operating Company	Transmission & Distribution 2003	2004	2005 *
AEP Ohio	$ 181	$ 210	$ 214
Appalachian Power	147	200	283
Indiana Michigan Power	69	68	89
Kentucky Power	27	25	35
AEP Texas	140	131	262
Public Service Co. of Oklahoma	70	70	85
Southwestern Electric Power	88	70	102
	$ 722	$ 774	$ 1,070

Notes:

* Represents projected capital expenditures for 2005

Major Capital Project

Wyoming/Jackson Ferry 765 kV Line



Project should increase average T&D rates from 2.0 cents to 2.04 cents/kWh

INVESTMENT IN ENERGY DELIVERY WILL CONTINUE TO BE SUBSTANTIAL

AEP®

Covering Capital Expenditures

Year	2005E	2006E	2007E	2008E	2009E	2010E
Environmental Capex	$797MM	$1,214MM	$542MM	$442MM	$283MM	$91MM
Total Capex	$2,690MM	Guidance not yet released				

Typical Investment Capitalization*	Approx. 60% debt / 40% equity
Expected Investment ROE*	11-13%

*Varies by jurisdiction

Sources of Cash

- **Cash Flow from Operations**: Continued earnings growth
- **Rate Relief**: Ohio cash rate relief begins in 2006; Rate proceedings expected in all other jurisdictions by 2007
- **Asset Sales**: HPL, STP, Oklaunion, Pacific Hydro & Bajio
- **Texas Securitization**: $1 billion plus in 2006 (Half goes to TCC debt paydown)
- **Texas Competition Transition Charge**: Approximately $190MM per year before securitization; $45MM per year after securitization
- **Debt Issuances**: Will maintain debt-to-capitalization ratio of approximately 60%

AEP HAS ADEQUATE SOURCES OF CASH FOR CAPEX PROGRAM

Long-term Debt Maturity Profile

Year		2005[1]		2006		2007
AEP Inc.[2]	$	9,268,000	$	945,860,000	$	345,000,000
AEP Generating Co.	$	-	$	-	$	-
Appalachian Power Co.	$	530,000,000	$	100,000,000	$	342,500,000
Columbus Southern Power	$	36,000,000	$	-	$	-
Kentucky Power	$	-	$	-	$	322,964,000
Indiana Michigan	$	-	$	365,000,000	$	50,000,000
Ohio Power Co.	$	12,354,000	$	12,354,000	$	17,854,000
Public Service of Oklahoma	$	50,000,000	$	-	$	-
Southwestern Electric Power	$	200,145,000	$	6,070,000	$	90,000,000
Texas Central Co.[3][4]	$	65,800,000	$	100,635,000	$	-
Texas North Co.	$	37,609,000	$	-	$	8,151,000
Total	$	**941,176,000**	$	**1,529,919,000**	$	**1,176,469,000**

(1) Maturities remaining as of March 31, 2005

(2) $550 million of Parent Company senior notes due in 2006 were repurchased on April 15, 2005

(3) Total includes $65.8 million of defeased mortgage bonds in 2005

(4) Excludes TCC securitization bonds

Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business Profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP Inc, Commercial Paper	P3	-	P	N/A	A2	-	S	F2	-	S
American Electric Power Company, Inc.	Baa3	-	P	6	BBB	-	S	BBB	-	S
AEP Texas Central Company	Baa2	Baa1	S	2	BBB	BBB	S	A-	A	S
AEP Texas North Company	Baa1	A3	S	2	BBB	BBB	S	A-	A	S
AEP Utilities, Inc	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	3	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	3	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Company	Baa1	A3	S	5	BBB	A-	S	A-	A	S

Risks and Uncertainties

2005 EPS Guidance Range is $2.30 to $2.50

2005

- *Outcome of pending regulatory proceedings*
  - *Texas & Louisiana*
- *Operations within PJM environment*
- *Plant availability*
- *Rising fuel costs*
- *Weather (storm damage and effect on sales)*

2005 Earnings Guidance

#		Performance Driver (2004)	2004 Actual ($ millions)	2004 Actual EPS	Performance Driver (2005)	2005 Forecast ($ millions)	2005 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities	102,090 GWh @ $ 29.4 /MWhr =	3,003		104,447 GWh @ $ 29.2 /MWhr =	3,049	
2	Ohio Cos.	46,725 GWh @ $ 41.9 /MWhr =	1,959		46,779 GWh @ $ 42.7 /MWhr =	1,998	
3	Texas Wires	25,581 GWh @ $ 17.2 /MWhr =	441		27,448 GWh @ $ 17.1 /MWhr =	469	
4	Texas Supply / REP	22,206 GWh @ $ 15.6 /MWhr =	347		5,806 GWh @ $ 34.1 /MWhr =	198	
5	Off-System Sales	32,264 GWh @ $ 14.6 /MWhr =	472		31,410 GWh @ $ 17.4 /MWhr =	547	
6	Other Wholesale Transactions		14			-	
7	Transmission Revenue - 3rd Party		451			410	
8	Other Operating Revenue		331			346	
9	Total Gross Margin		7,018			7,017	
10	Operations & Maintenance		(3,072)			(3,087)	
11	Depreciation & Amortization		(1,256)			(1,275)	
12	Taxes Other than Income Taxes		(700)			(728)	
13	Interest Exp & Preferred Dividend		(616)			(592)	
14	Other Income & Deductions		161			181	
15	Income Taxes		(489)			(529)	
16	Net Earnings Utility Operations		1,046	2.64		988	2.54
	INVESTMENTS:						
17	Gas Operations		(33)			3	
18	Other Investments		(18)			(15)	
19	Total Investments		(51)	(0.13)		(13)	(0.04)
20	Parent Company		(71)	(0.18)		(40)	(0.10)
21	**ON-GOING EARNINGS**		924	2.33		936	2.40
	Shares Outstanding (in millions)			396			389

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

SPRING EEI INVESTOR CONFERENCE

WALDORF=ASTORIA
NEW YORK, NY

MAY 24-25, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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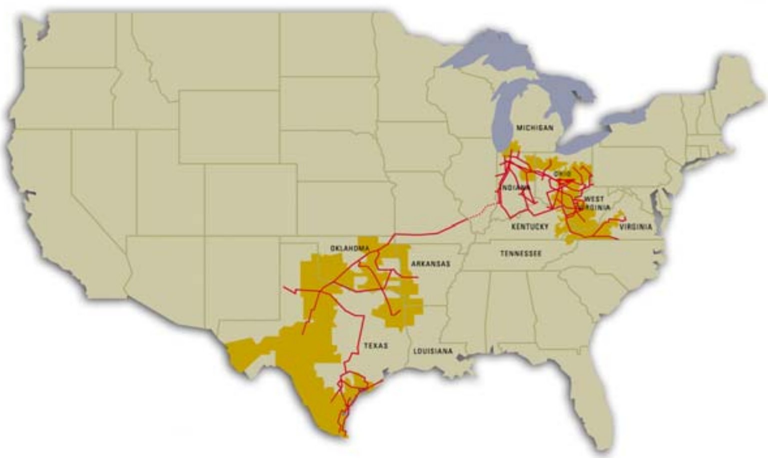
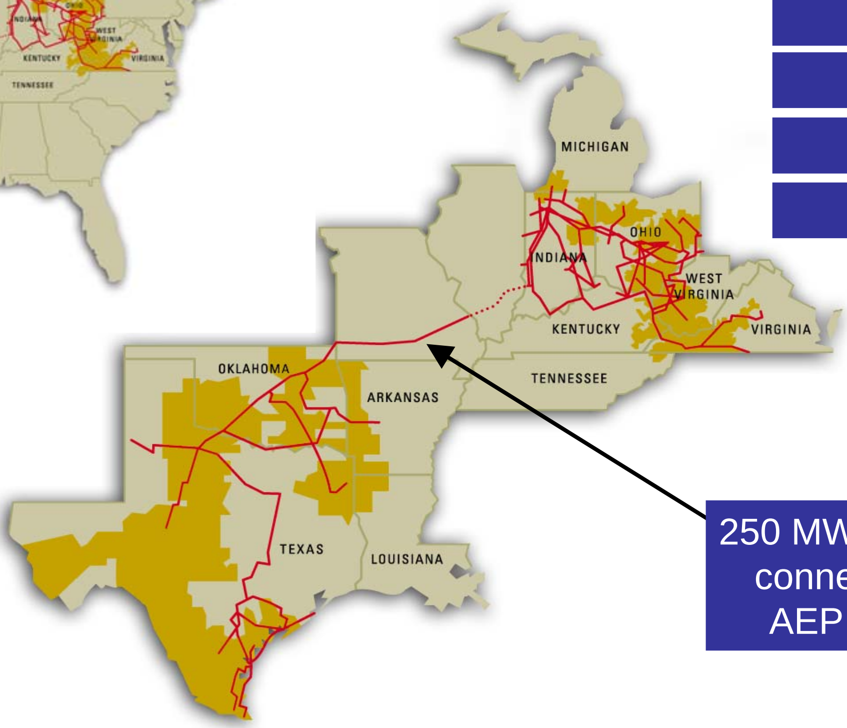
Company Overview

Where We Operate



- Ohio
- Indiana
- West Virginia
- Virginia
- Kentucky
- Michigan
- Tennessee



- Oklahoma
- Texas
- Louisiana
- Arkansas

250 MW transmission line connects AEP East & AEP West territories

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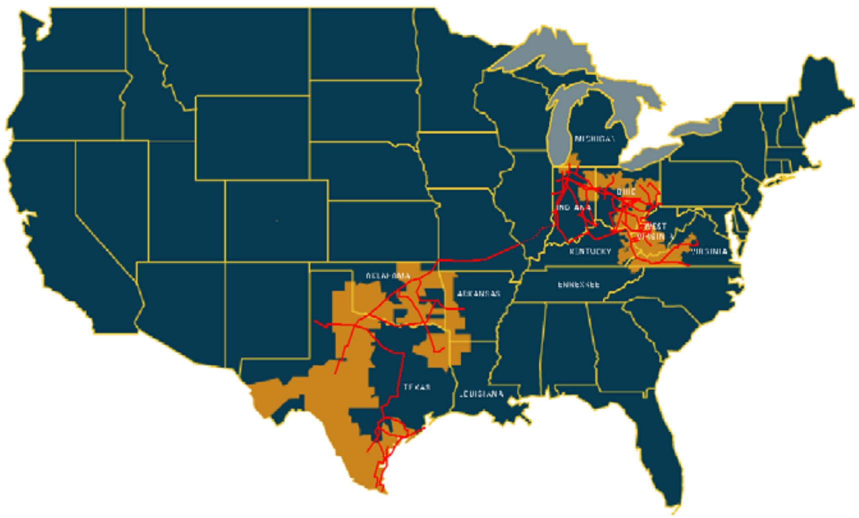
Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



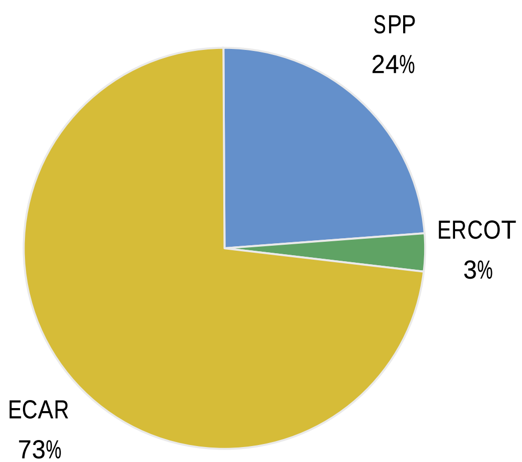
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

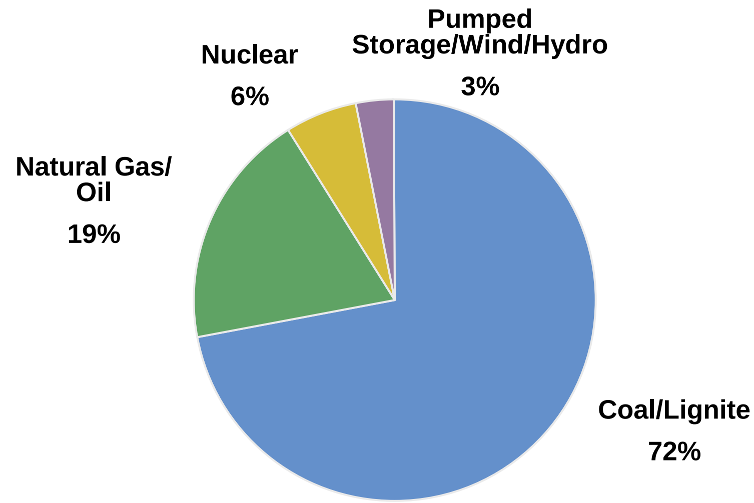
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



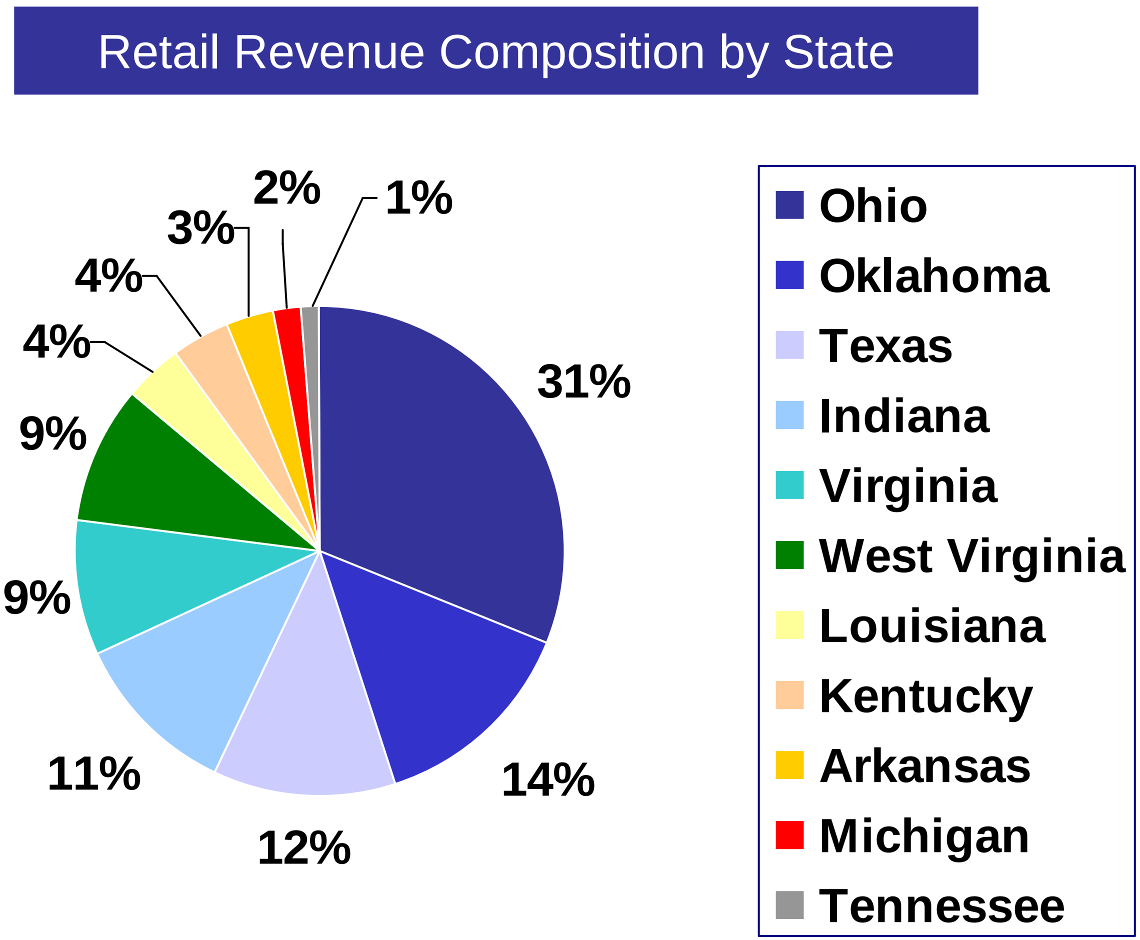
Does not sum to 100% due to rounding

Operating Statistics

Commercial Availability Factor	
2004	85.24%
2005	84.50%

Capacity Factor	
2004	62.06%
2005	62.53%

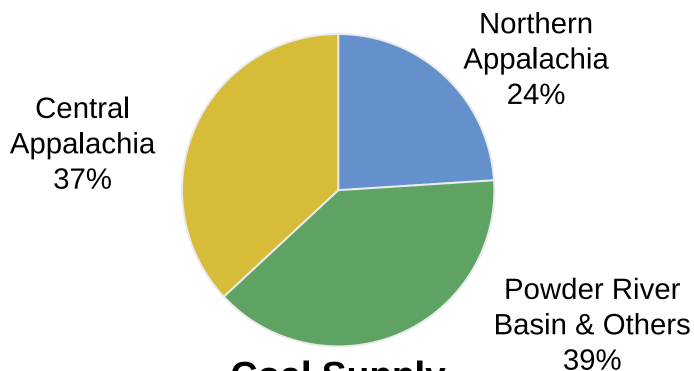
2005 Retail Revenue



Fuel

Coal Procurement

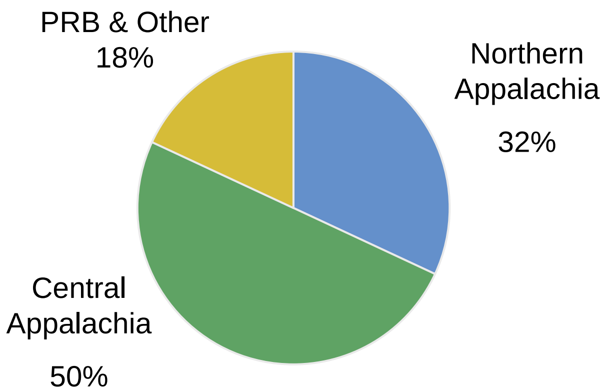
Total AEP System



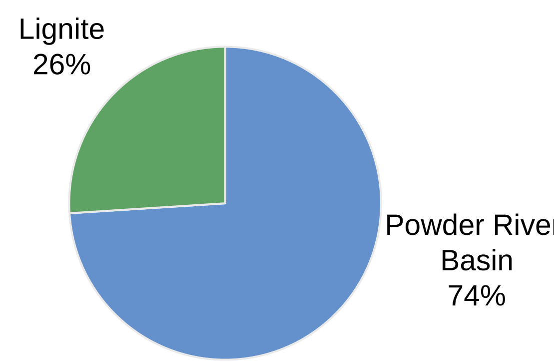
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 90%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System

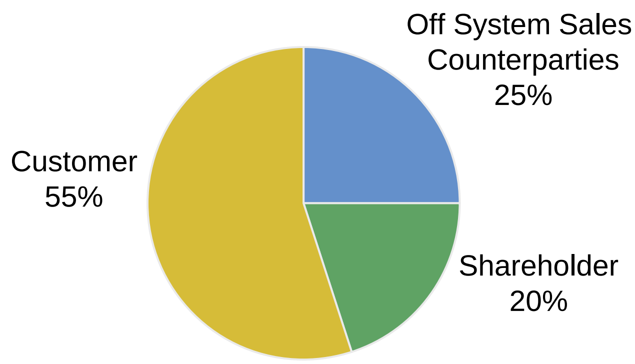


AEP Western System



Fuel Recovery

AEP System



Fuel Cost Recovery (on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

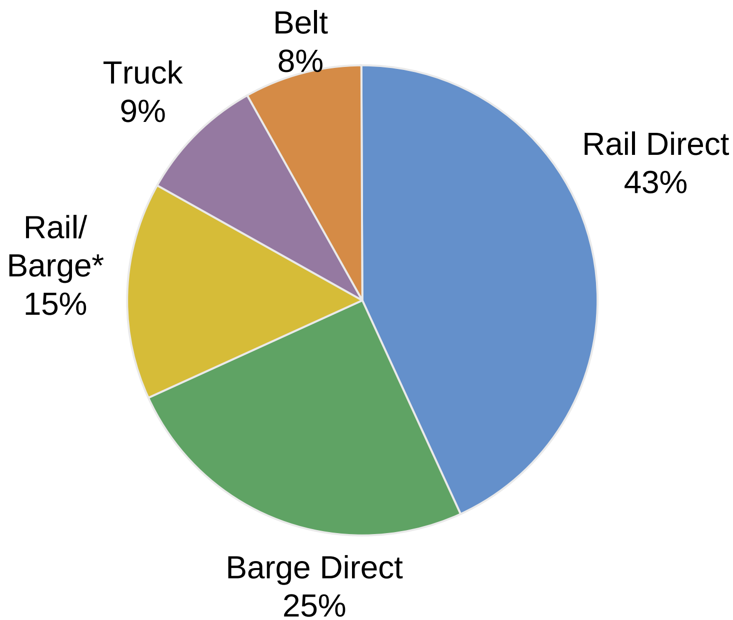
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Monthly
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Annually
Virginia	Yes	Annually
West Virginia	Yes	Annual ENEC currently suspended. On Jan 6, 2006, WVPSC approved deferral accounting for ENEC to begin July 1, 2006 and new rates to be effective July 28, 2006.

Coal Delivery

Total AEP System

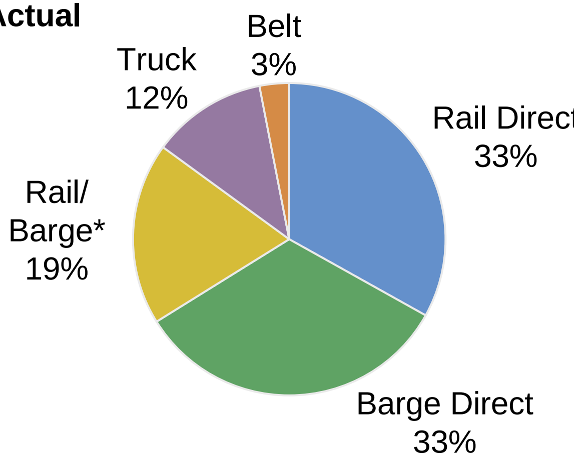
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

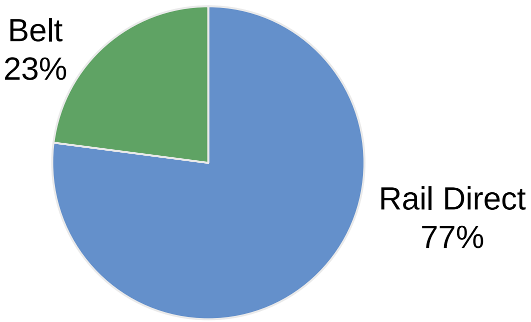
AEP Eastern System

2005 Actual



AEP Western System

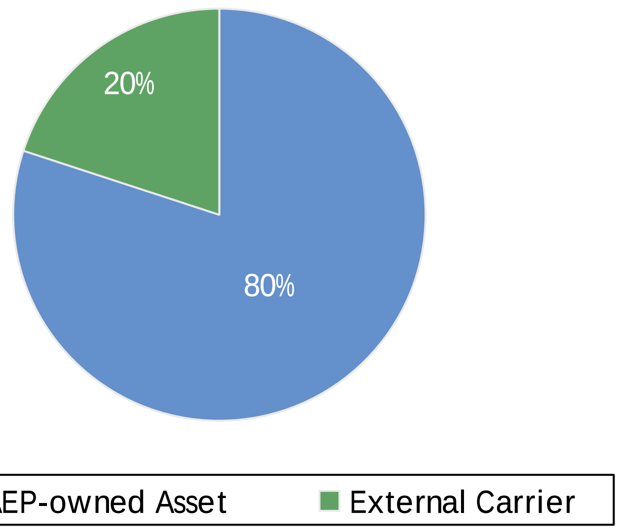
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

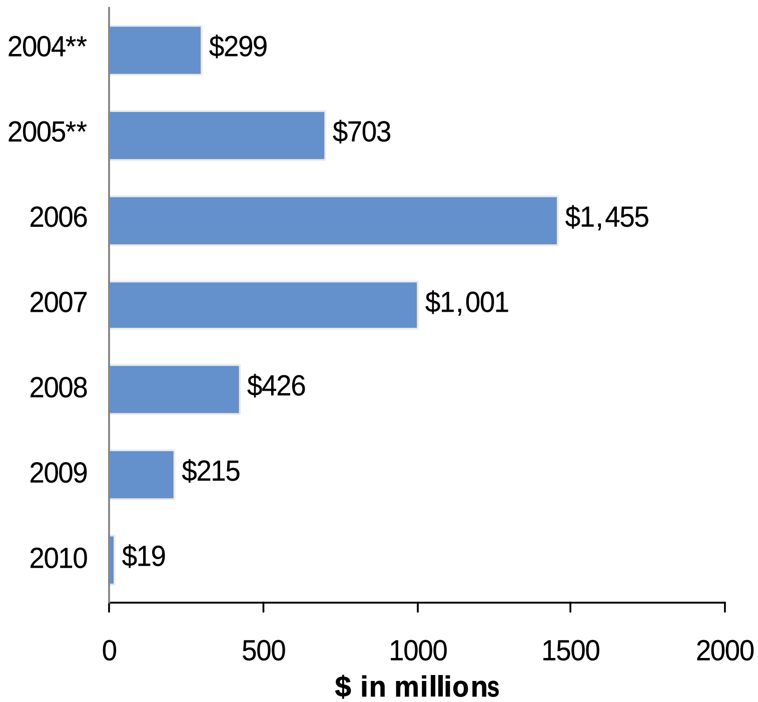
- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

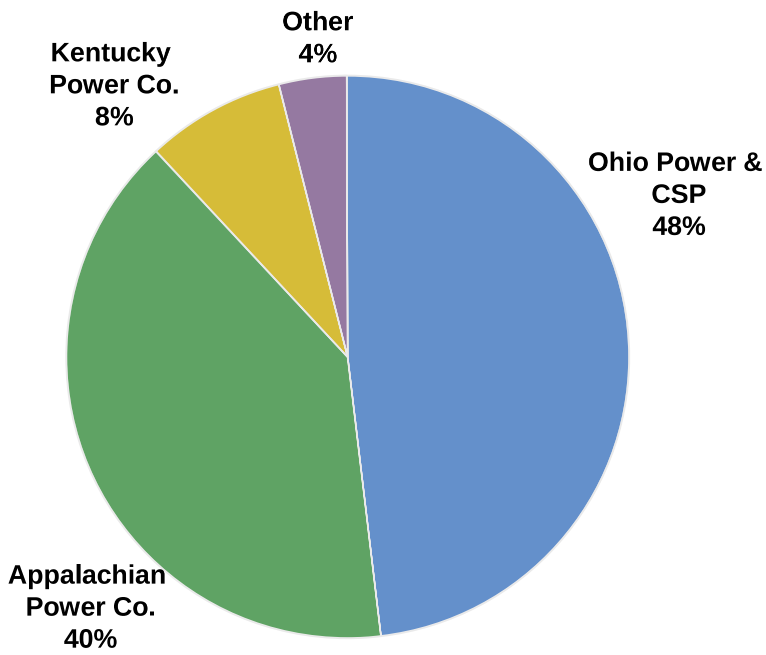
Environmental

$4.1 Billion Environmental Investment

Environmental Capital Investment*



Projected Environmental Investment Allocation



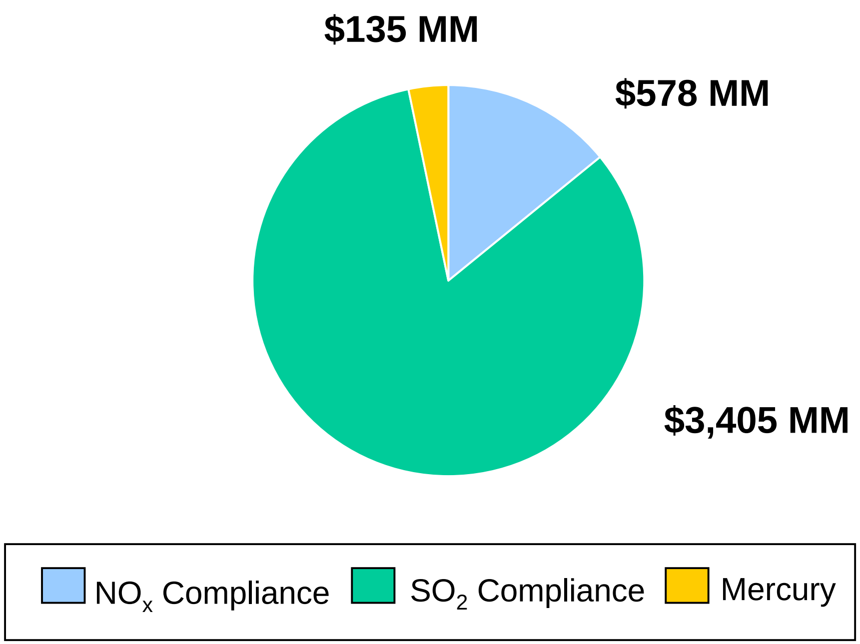
*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC

Environmental Installations

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD: 2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR: 2006 – 2009

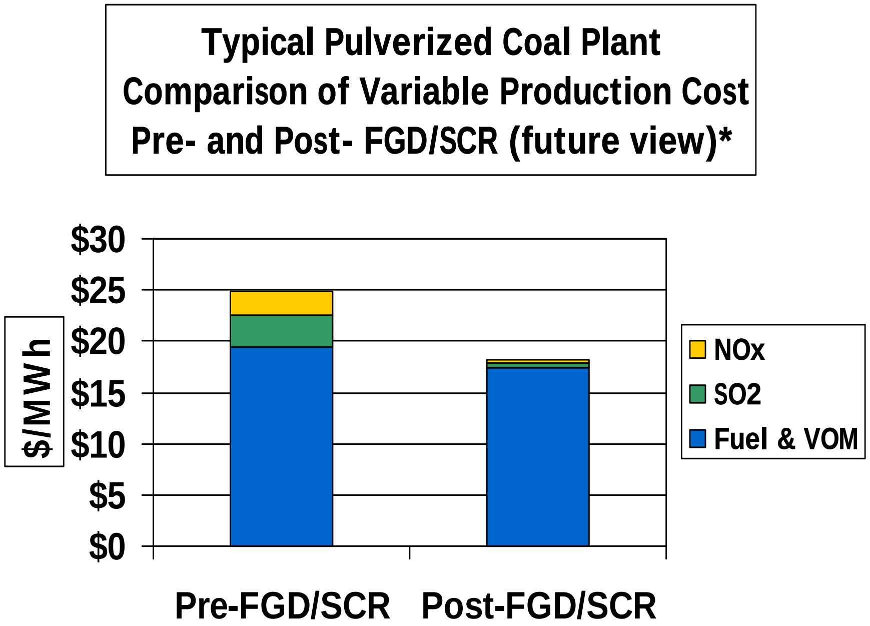
Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

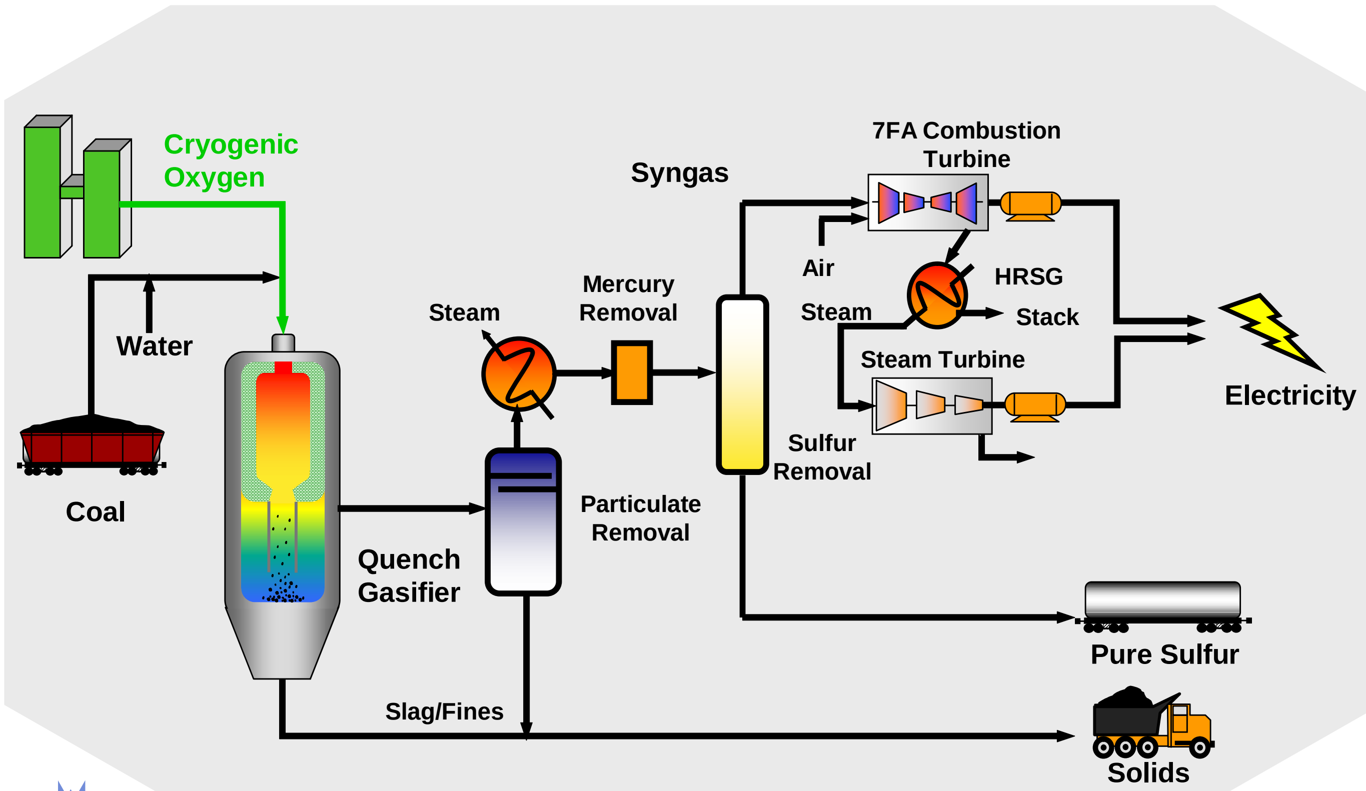
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



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AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8700**	**8600**	**7200**
Total Plant Cost (EPC) ($/kW)	**1700**	**1900**	**480**
Production Cost ($/MWh)	**17**	**16**	**57**
Cost of Electricity, without CO2 Capture ($/MWh)	**58**	**63**	**90**
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	**94**	**87**	**137**

Source: Results of AEP analysis based on EPRI studies

- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Regulatory Overview

Regulatory Activity Underway

- TCC Request for Securitization of Stranded Costs
- Ohio Companies filing for pass through of FERC OATT changes
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia – Settlement Pending
- IGCC – Received Rate Authorization of Pre-Construction Costs

YEAR-TO-DATE, SECURED $350 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- February 16, 2006 – PUCT final order provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
  - Final order expected in June or July 2006
  - September 2006 - Issuance of securitization bonds if no appeal

<u>Procedural Schedule for TCC Securitization</u>

- ✓ April 17, 2006 – Intervenors File Testimony
- ✓ April 24, 2006 – Staff Files Testimony
- ✓ April 27, 2006 – TCC Files Rebuttal Testimony
- ✓ May 25-26, 2006 – Hearing On Merits

- May/June 2006 – Request approval for CTC to address other true-up items
  - Expected $491 million credit to customers
  - Sept 2006 – CTC to be implemented

Regulatory Activity Underway

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Procedural schedule has been set with final order expected in third quarter 2006

Regulatory Activity Underway

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2006 – Joint Settlement Agreement

- Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs

Phased-In Settlement Agreement Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

*Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Settlement Details

✓Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
<u>$23MM</u>	WJF & FGD investment @ 12/31/05
$61MM	Gross revenue increase
<u>($17MM)</u>	ENEC over-recovery negative surcharge
$44MM	Net increase effective 7/28/06

✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

2007—2010:

- Construct and start-up plant

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 Million net revenue increase in 2006 from wholesale transmission

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- Interim surcharge will collect the under-recovery amount of $44 Million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 Million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

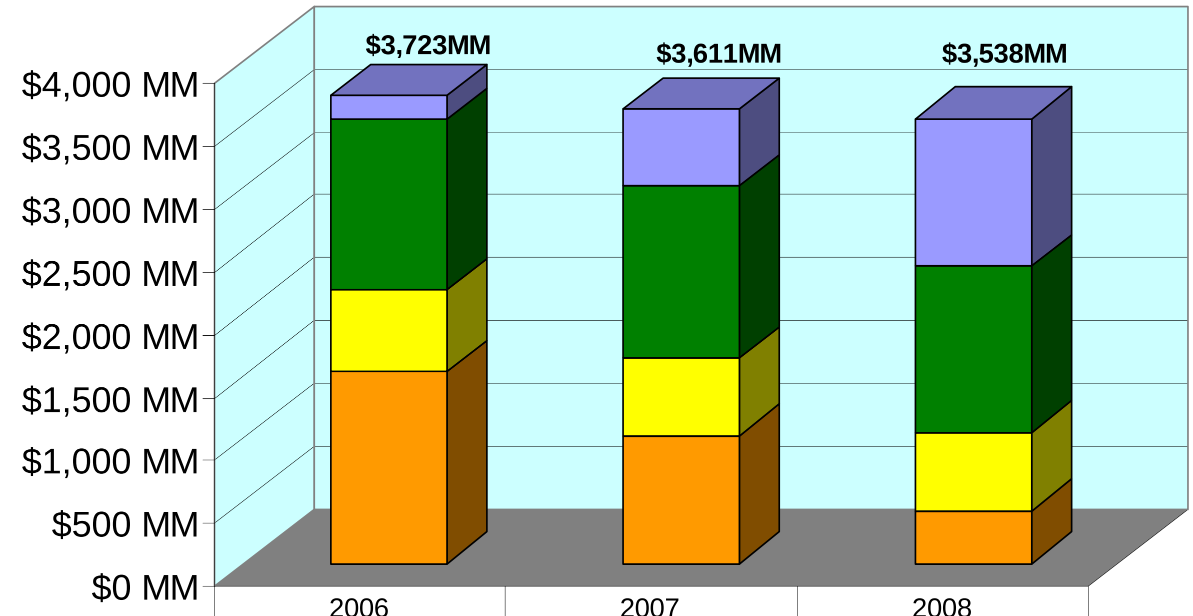
- $41 million annual increase in base rates
- To be effective March 30, 2006

Capital Investment

Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE - INVESTMENT LEVEL WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,877	$ 1,945	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 630	$ 1,692	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,804	$ -	$ -
Other	$ -	$ 126	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.404B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year

* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

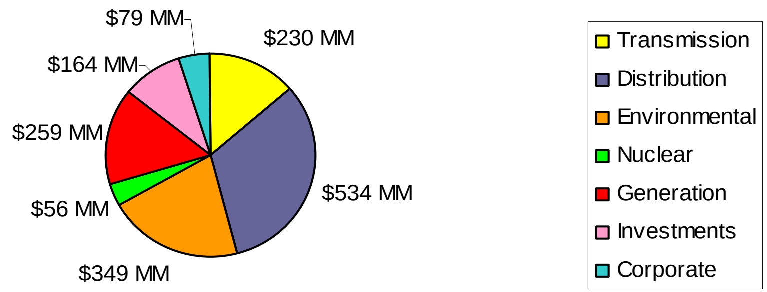
REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

New Generation

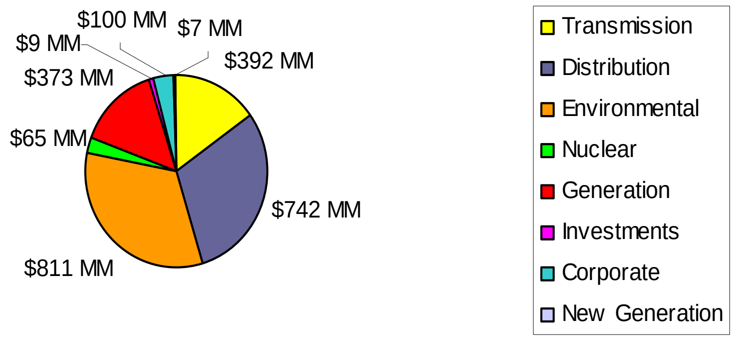
IGCC	PSO RFPs	SWEPCO RFPs
➢ Expect to obtain permits and finalize engineering by 2007 ➢ Construction of 600 megawatt facility to begin in 2007 ➢ Commercial operation date expected in 2010	➢ Submitted RFPs totaling 900 megawatts of baseload and peaking capacity ➢ Two peaking RFPs totaling 340 megawatts awarded ➢ Commercial operation dates expected in 2008 and 2011	➢ Submitted RFPs totaling 2,100 megawatts of baseload, intermediate, and peaking capacity ➢ PPAs expected 2006 through 2009, with commercial operation dates expected from 2008 through 2011

Capital Investment 2004 - 2006

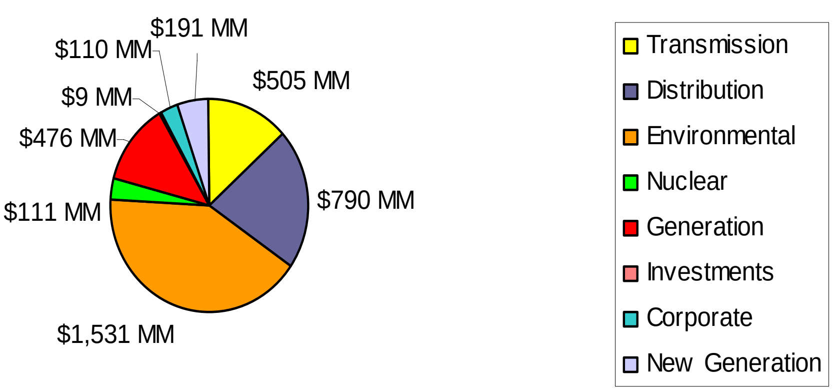
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



2006 Projected Totals $3.7 Billion



Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.
Figures exclude AFUDC.

Finance

2006 Earnings Guidance Range: $2.50 - $2.70

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 8964 of 9556

Summary of Major 2006 Financial Performance Drivers

- Load Growth of 2.5%
- $500MM rate recovery assured or in progress
- Rising fuel costs of 11-13%
- Higher planned outages, increased retail load and sale of TCC generation to impact off system sales
- Decline in utility O&M
- Parent Company improvement (debt & interest expense reduction)

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 PERFORMANCE

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance *
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	173	(315)
Total from Operations	**$ 1,877**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,404)	(3,723)
Asset Sales	1,246	28
Other	153	(163)
Total from Investing	**$ (1,005)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(25)	-
Net Long Term Debt Issued/(Retired)	(12)	2,434 **
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

* Assumes the midpoint of the $2.50 to $2.70 per share guidance range.

** Assumes $1.8 billion of securitization bonds issued in September 2006

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capital Structure

Capital Structure	Actual 12/31/2005			Actual 3/31/2006		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,226	-	12,226	12,142	-	12,142
Short-term Debt	10	-	10	226	-	226
Preferred Stock Subject to Mandatory Redemption	-	-	-	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	9,089	9,089	-	9,384	9,384
Total Capitalization per Balance Sheet	**12,237**	**9,149**	**21,386**	**12,368**	**9,445**	**21,813**
% of Capitalization per Balance Sheet	***57.2%***	***42.8%***	***100.0%***	***56.7%***	***43.3%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	30	(30)	-	30	(30)	-
Defeased First Mortgage Bonds	(30)	-	(30)	(30)	-	(30)
Off-balance Sheet Leases	1,213	-	1,213	1,213	-	1,213
Securitization Bonds	(617)	-	(617)	(617)	-	(617)
Spent Nuclear Fuel Trust	(228)	-	(228)	(238)	-	(238)
Total Adjusted Capitalization	**12,605**	**9,119**	**21,724**	**12,726**	**9,415**	**22,141**
% of Adjusted Capitalization	***58.0%***	***42.0%***	***100.0%***	***57.5%***	***42.5%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 57.5% AT 3/31/06

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

2005 Ratings Actions

- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Forecasted Capital Expenditures

Company	**2006**	**2007**	**2008**
(in thousands)			
AEP SYSTEM*	**$3,722,600**	**$3,611,400**	**$3,537,700**
AEGCo	$14,300	$30,000	$39,700
APCo	$942,800	$691,500	$751,700
CSPCo	$342,700	$473,700	$553,400
I&M	$311,200	$278,700	$262,000
KPCo	$100,000	$127,100	$144,000
OPCo	$1,070,400	$954,500	$581,600
PSO	$278,700	$342,800	$408,700
SWEPCo	$287,900	$366,700	$458,400
TCC	$278,400	$247,000	$222,100
TNC	$72,500	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

2006 Key Operating Company Highlights

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	(in millions) Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 (completed*)	42-45%
CSP	$343	$100 - $150	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$50 - $75	42-45%
OPCo	$1,070	$450 - $550	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$100 - $150	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

*Issuances completed in 2006 totaling $550 Million

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

MAINTAIN FINANCIAL STRENGTH OF SUBS BY RETAINING AND/OR INFUSING EQUITY CAPITAL DEPENDING ON THEIR CREDIT RATIOS AND FREE CASH FLOW

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Long-Term Debt Maturity Profile[1]

Year	2006[2]	2007	2008
AEP Service Corporation	$ 2,000,000[3]	$ 2,000,000[3]	$ 34,000,000
AEP Inc.	$ 395,860,000[4]	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Ohio Power Company	$ 7,640,000[3]	$ 17,854,000[3]	$ 55,188,409[3]
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 11,047,000[3]	$ 95,312,136[3]	$ 12,538,117[3]
Texas Central Company	$ -	$ -	$ 18,581,000
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 716,547,000**	**$ 1,133,781,136**	**$ 512,307,526**

(1) Excludes tax exempt bond remarketings and securitization bonds
(2) Maturities remaining as of March 31, 2006
(3) Includes sinking fund payments, where applicable
(4) AEP Inc. $396 million global bond matured on May 15, 2006

Debt Schedules

American Electric Power Service Corp			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	4.709%	08/16/2007	$345,000,000
Senior Notes	6.125%	05/15/2006	$395,860,000
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Weighted Average or Total	5.400%		$1,473,635,000

AEP Generating			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,192,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,340,800
Securitization Bonds	5.010%	01/15/2008	$103,272,491
Securitization Bonds	5.560%	01/15/2010	$107,094,258
Securitization Bonds	5.960%	07/15/2013	$214,926,738
Securitization Bonds	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,356,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,817,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Appalachian Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,783,600
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,058,600

Columbus Southern Power			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Indiana Michigan Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	6.550%	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/1/2015	$125,000,000
Weighted Average or Total	4.971%		$1,220,083,600

Kentucky Power

Series	Interest	Maturity	Amount
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$11,707,314
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,748,100
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/1/2015	$200,000,000
Weighted Average or Total	4.386%		$1,881,953,514

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of March 31, 2006

Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$24,974,947
Notes Payable	Floating	06/30/2008	$12,538,117
Notes Payable	6.360%	02/22/2007	$4,000,000
Notes Payable	7.030%	02/22/2012	$20,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	6.100%	04/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/01/2043	$113,403,000
Weighted Average or Total	4.750%		$702,020,664

Note: Debt Schedules as of March 31, 2006

Appendix

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. On April 24th, APCo and Wheeling Power, together with the PSC staff and the Consumer Advocate in WV, filed a joint settlement agreement in the companies' rate case. The agreement provides for an initial $44 million increase in revenues, effective July 28, 2006. The initial increase consists of a $56 million increase for fuel and purchased power expenses, and $23 million for recovery of WJF transmission line costs and environmental investments to date. These increases are partially offset by an $18 million base rate reduction and a $17 million credit to customers for previously over-recovered fuel costs. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure – Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base – Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Procedural Schedule

April 7, 2006	Rebuttal & Cross-rebuttal Testimony
April 18-21, 2006	Hearing
April 24, 2006	Settlement agreement filed
May 4, 2006	Legal briefs filed
May 15, 2006	Response briefs filed

Statutory Deadline: July 28, 2006

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

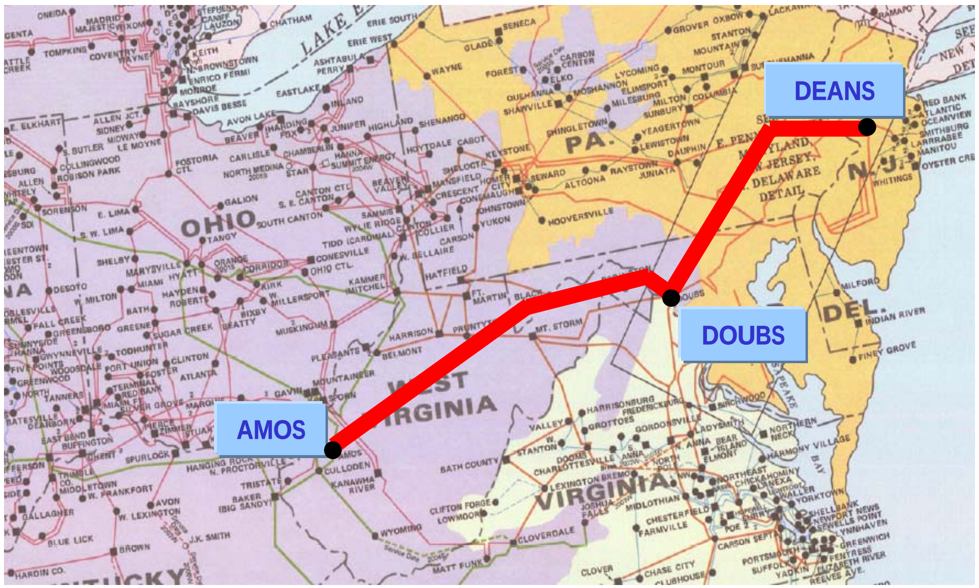
Capital Structure	**Company Position** (filed 7/1/05)	**Staff Position** (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	**Company Position** (filed 11/14/05)	**Staff Position** (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

AEP AMERICAN® ELECTRIC POWER

SunTrust Investor Luncheon

New York, NY
June 16, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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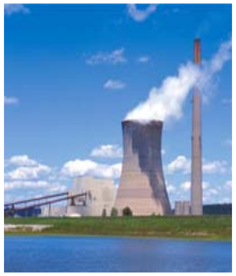
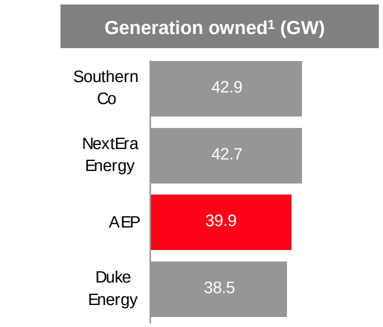
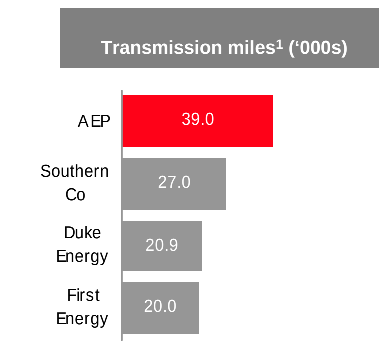
American Electric Power



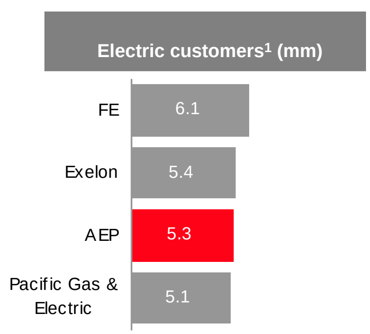
One of the largest
U.S. electricity generators



The largest U.S. electricity
transmitter

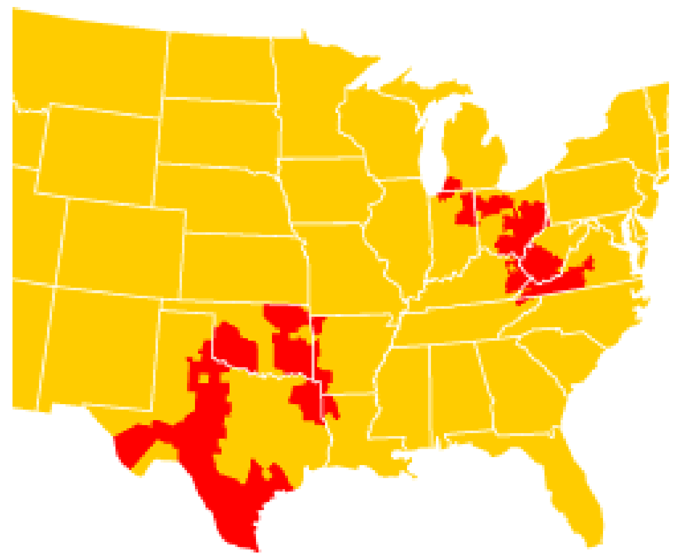


One of the largest U.S.
electricity distributors



[1]: Company Filings

Serving electric customers in 11 states



AEP Fast Facts

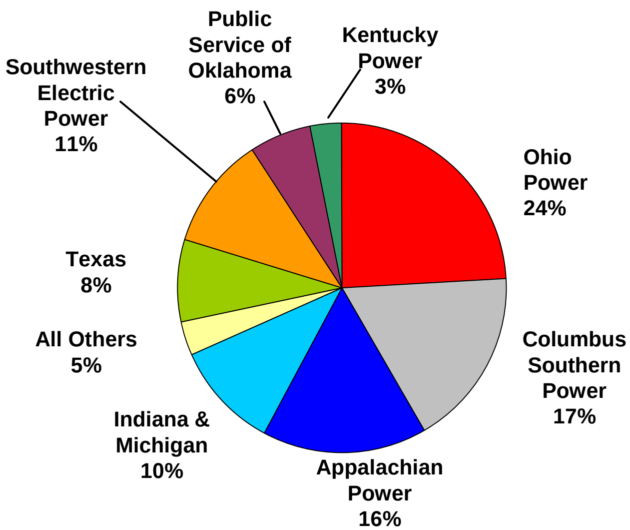
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$18.5B Market Capitalization
BBB/Baa2/BBB credit rating

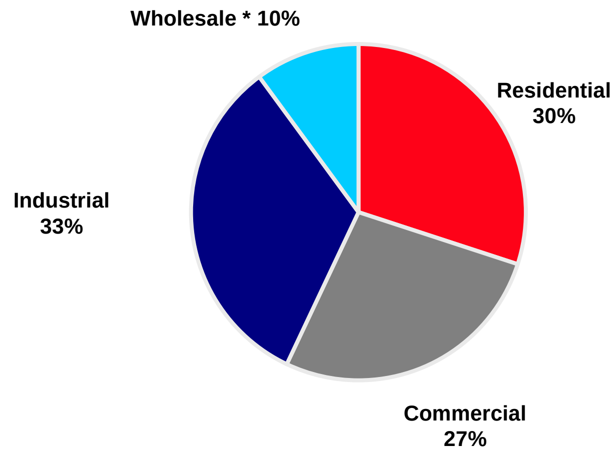
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



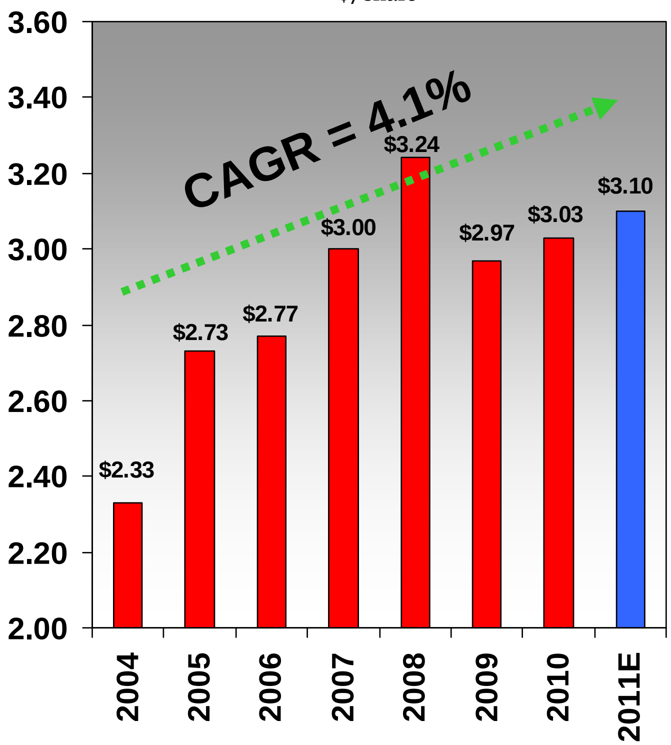
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

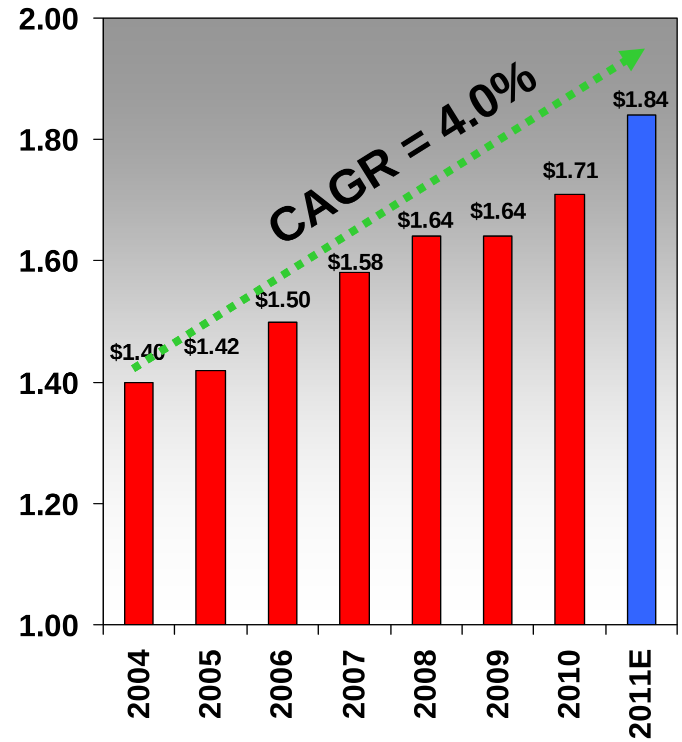
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

- Quarterly dividend <u>increased 12%</u> in 2010
- <u>404th consecutive</u> quarterly dividend paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Detailed Ongoing Earnings Guidance

2010A: $3.03

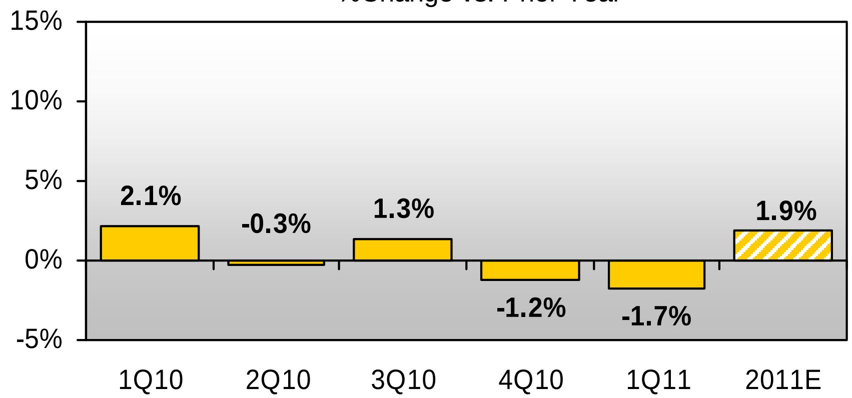
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

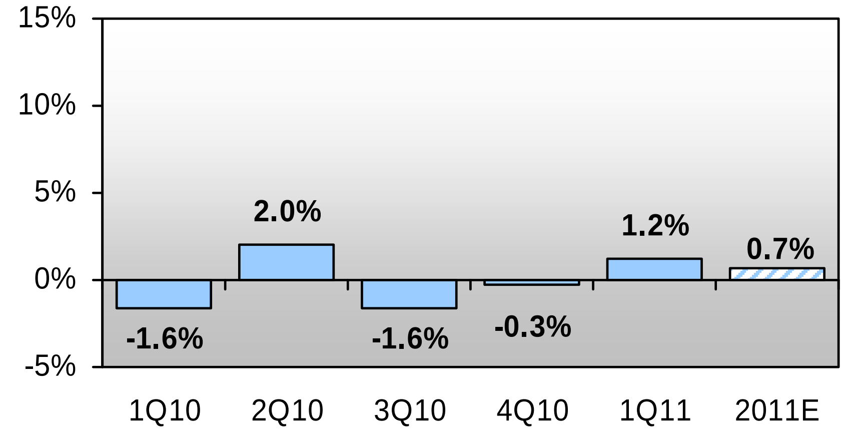
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

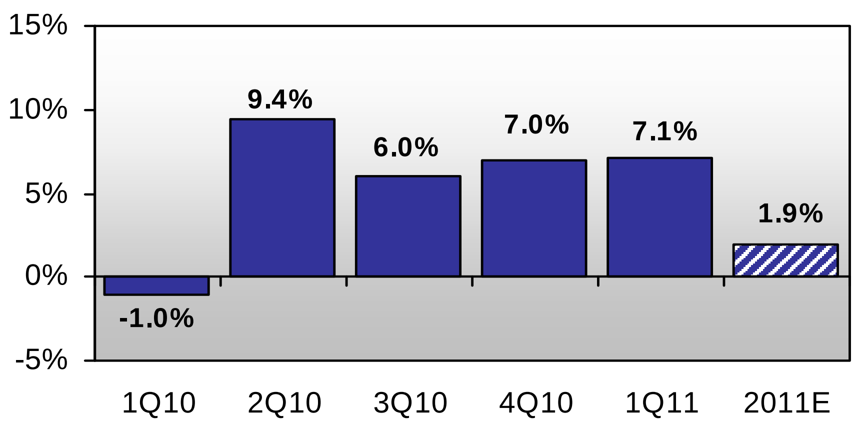
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



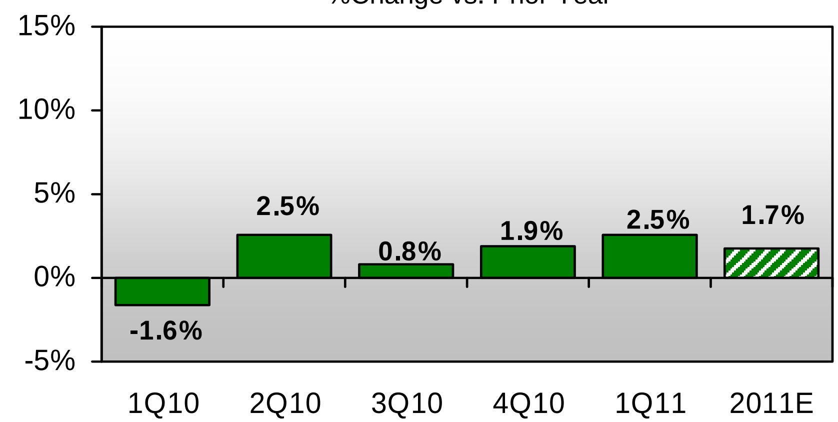
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



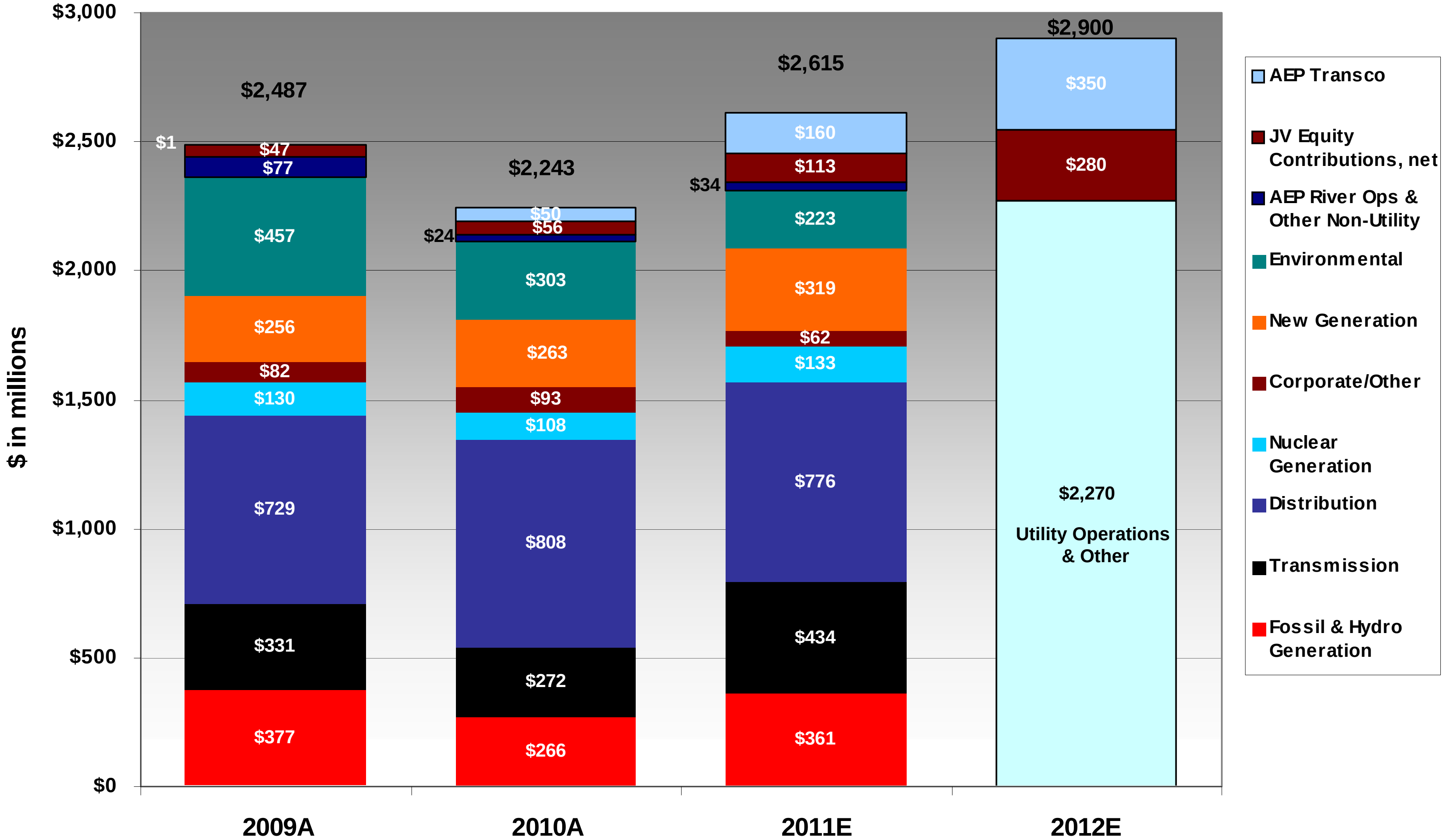
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	$250	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$77
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	$75	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company (1)	$120		$381
Texas North Company	-	-	$225
Total	$616	$630	$1,734

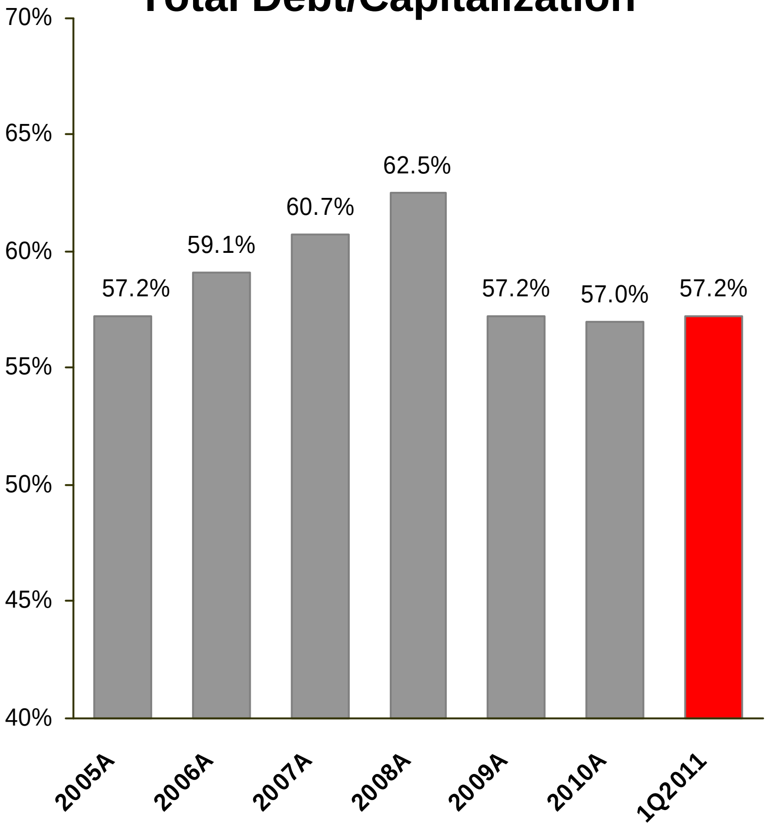
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of March 31, 2011

Capitalization & Liquidity

Total Debt/Capitalization

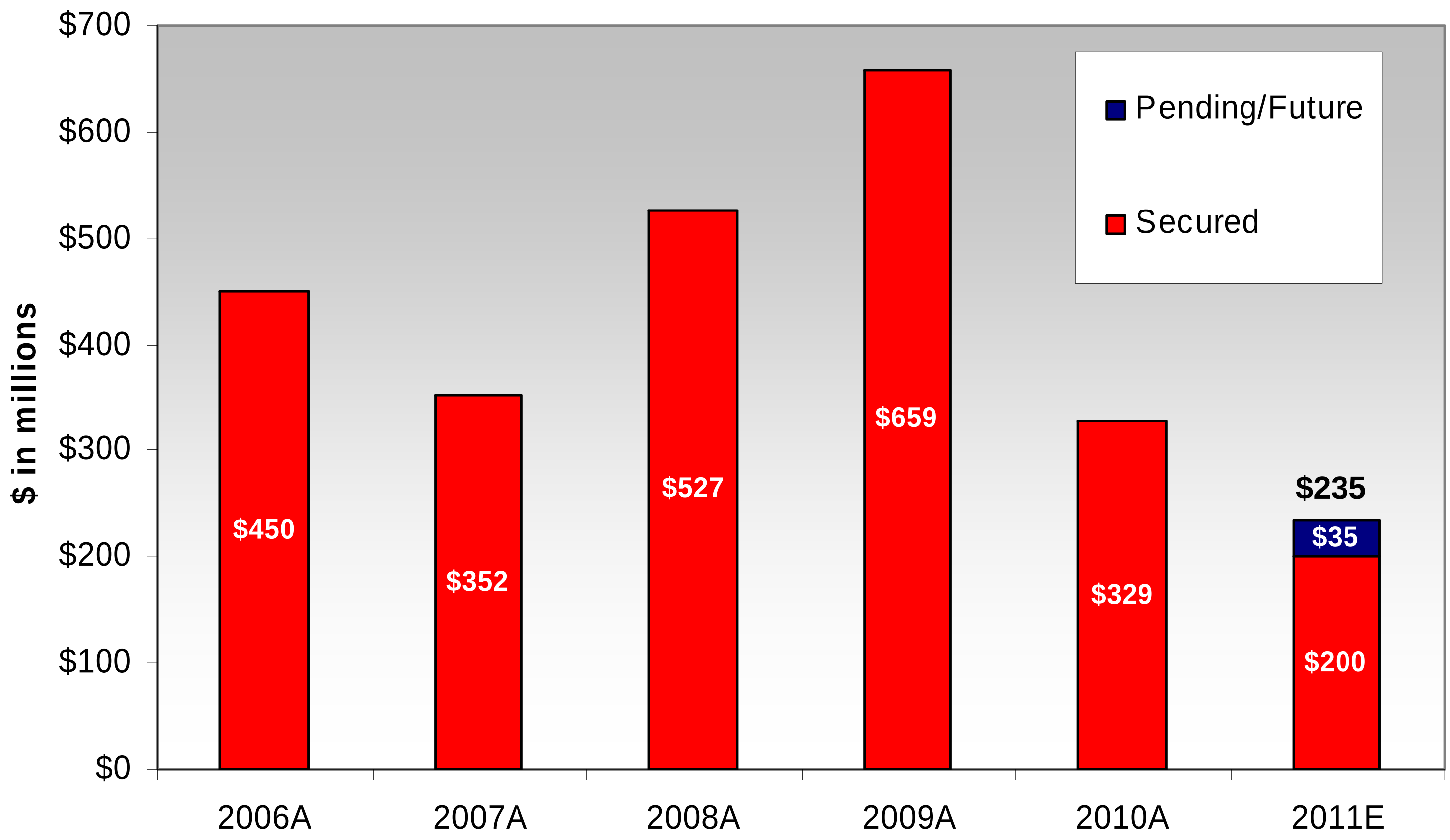


Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 03/31/11**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Total Credit Facilities	**2,954**	
Plus		
Cash & Cash Equivalents	625	
Less		
Commercial Paper Outstanding	(813)	
Letters of credit issued	(124)	
Net Available Liquidity	**$2,642**	

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases includes amounts from the Ohio environmental filing and cases yet to be filed

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31, 2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million associated with a potential change in depreciation rates). The requested ROE is 11.65%, including a 50 basis point adder for meeting 2010 RPS goal allowed by law.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect no later than 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	July 21, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – July 29; Hearing August 15**

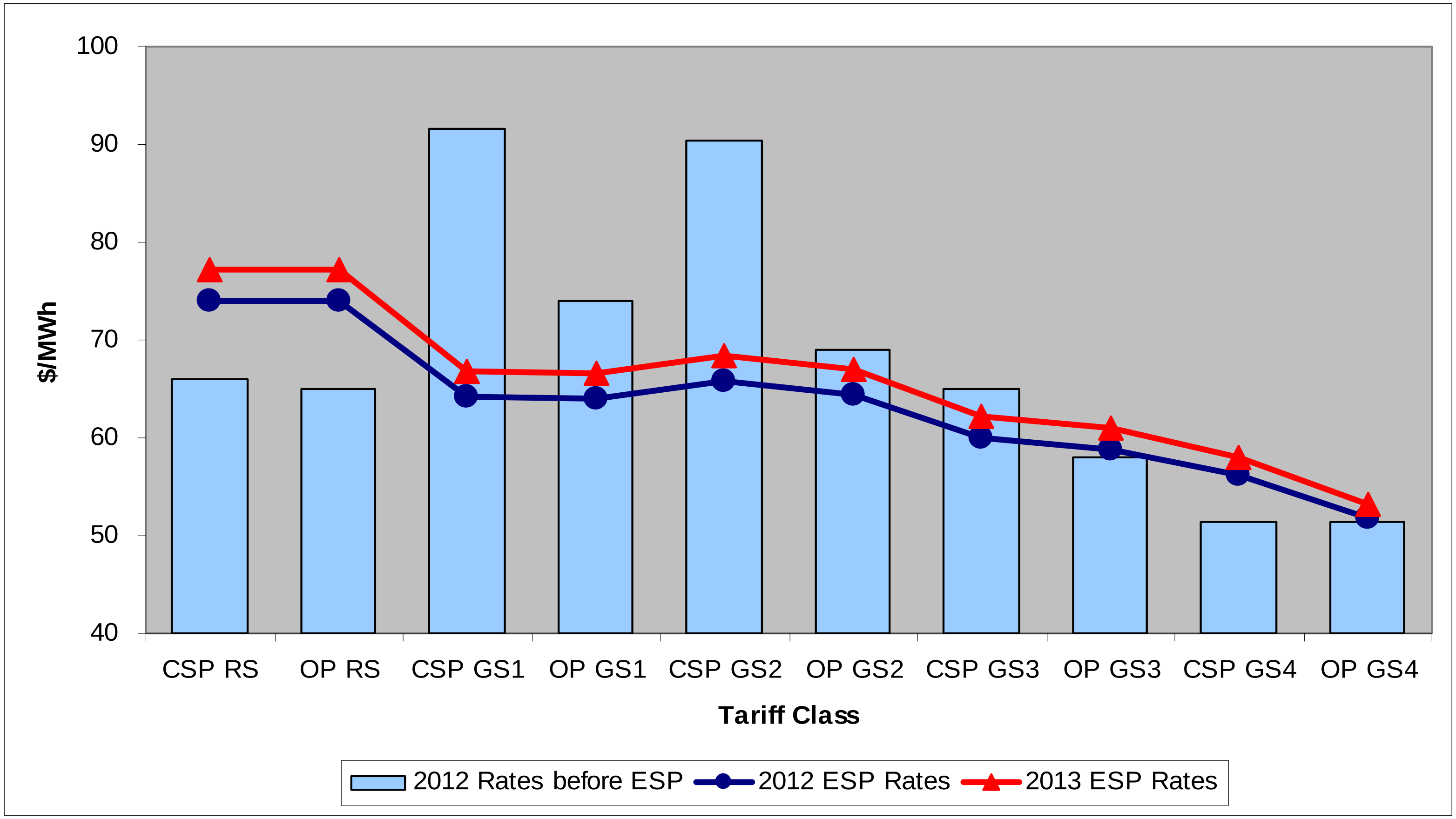
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

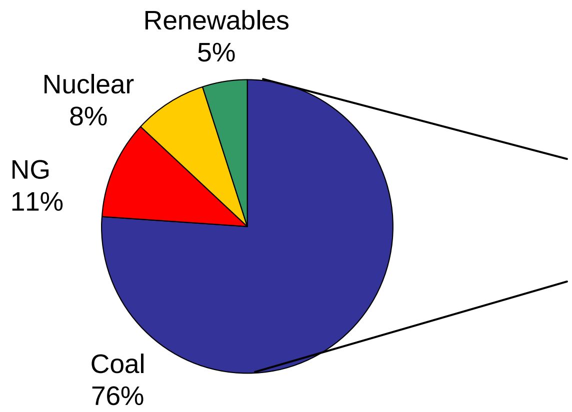
The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

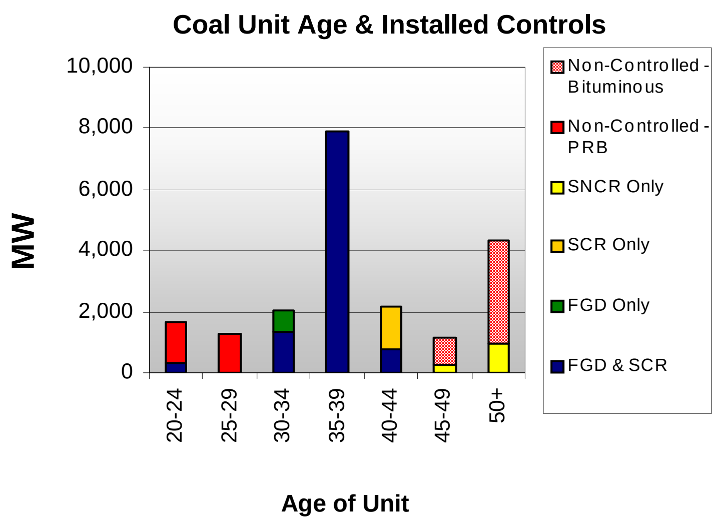
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



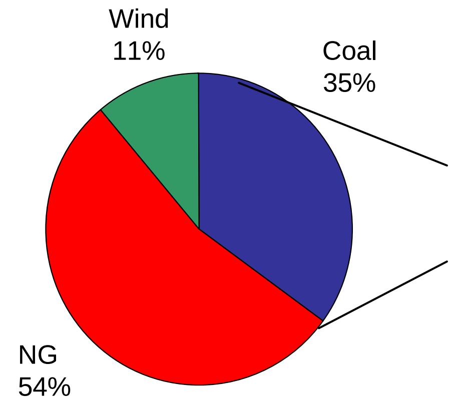
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



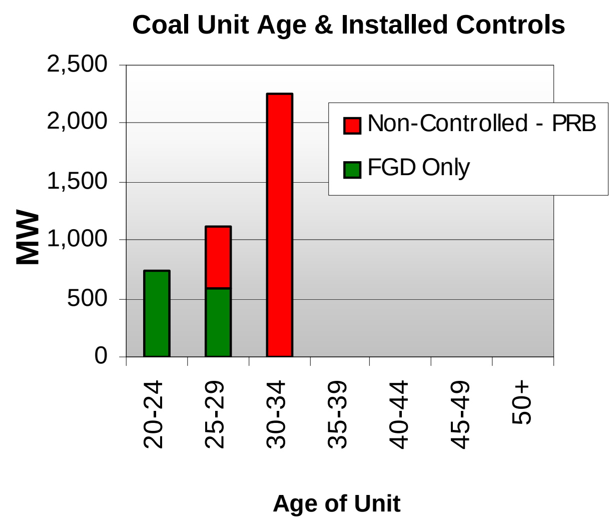
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



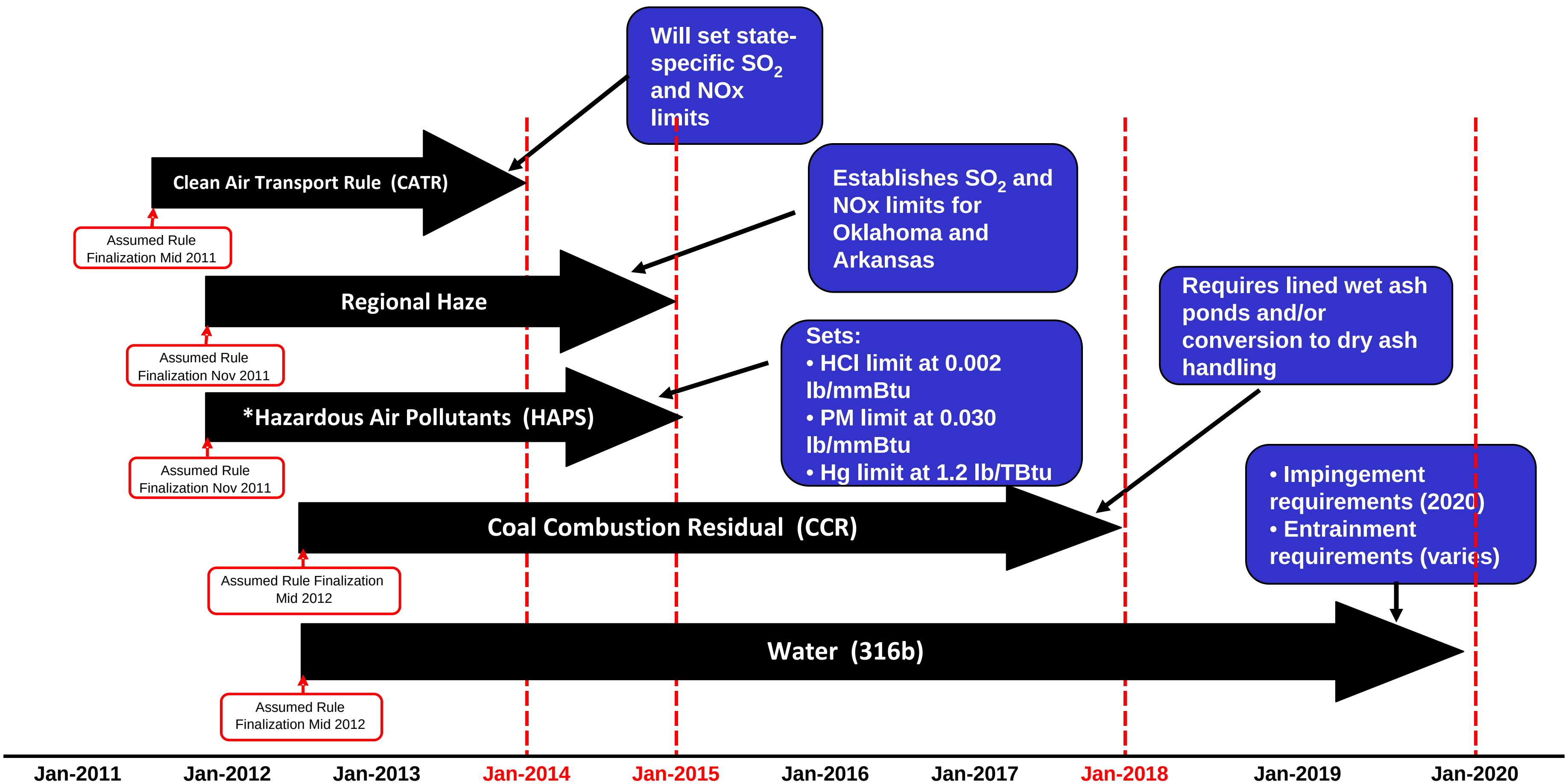
KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 9005 of 9556

Turk Plant

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.
- The cost of the plant and related transmission is anticipated at $1.7 billion with AEP's share approximately $1.3 billion (excluding AFUDC) and will begin commercial operation in 2012.
- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls

- $1.1 billion capitalized expenditures 3/31/11. SWEPCO's contractual commitments $260MM.
- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%)

Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
Conesville 5	400	SCR, DSI			
Conesville 6	400	SCR, DSI			
Muskingum River 5	510	Refuel with Natural Gas			
Gavin 1	1320	FGD upgrade			
Gavin 2	1320	FGD upgrade			
Zimmer 1	330	FGD upgrade			
Total Expected Cost			**2,100**	**2,800**	*
Clinch River 1	211	Refuel with Natural Gas			
Clinch River 2	211	Refuel with Natural Gas			
Dresden	580	New Natural Gas			
Total Expected Cost			**580**	**765**	**
Rockport 1	1320	FGD, SCR			
Rockport 2	1320	FGD, SCR			
Tanners Creek 4	500	DSI, ACI			
Total Expected Cost			**1,240**	**1,670**	***
Big Sandy 1	640	New Natural Gas			
Total Expected Cost			**400**	**525**	

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 1	470	FGD, ACI, Baghouse		
	Northeastern 2	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total Expected Cost			**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total Expected Cost			**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total Expected Cost			**80**	**100**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

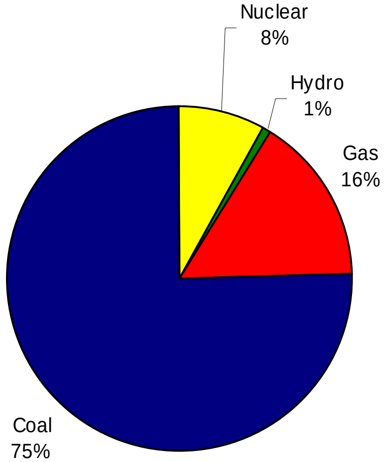
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Total MW	**2,485**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,856**	

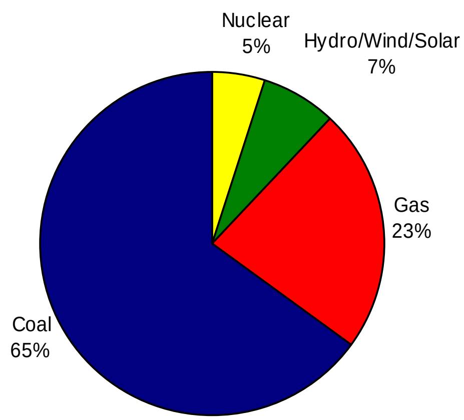
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

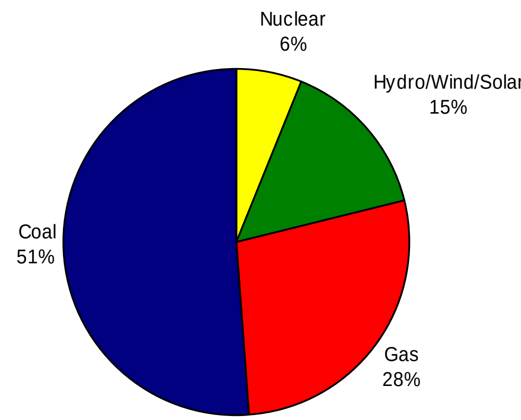
1990 AEP Generating Capacity by Fuel
37,428 total MW's



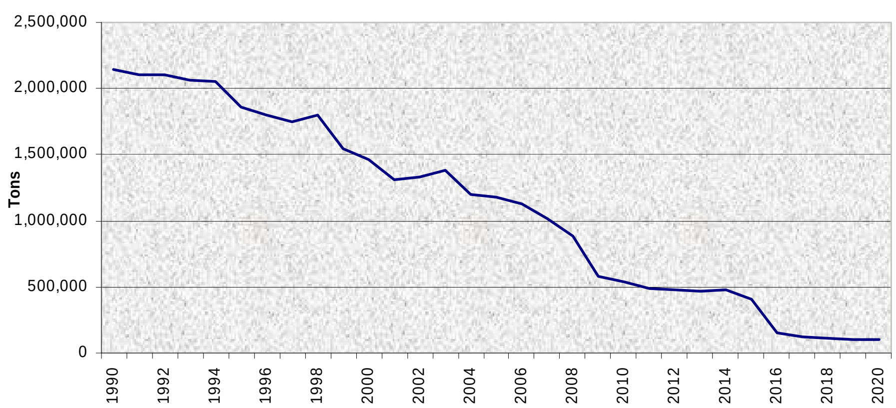
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

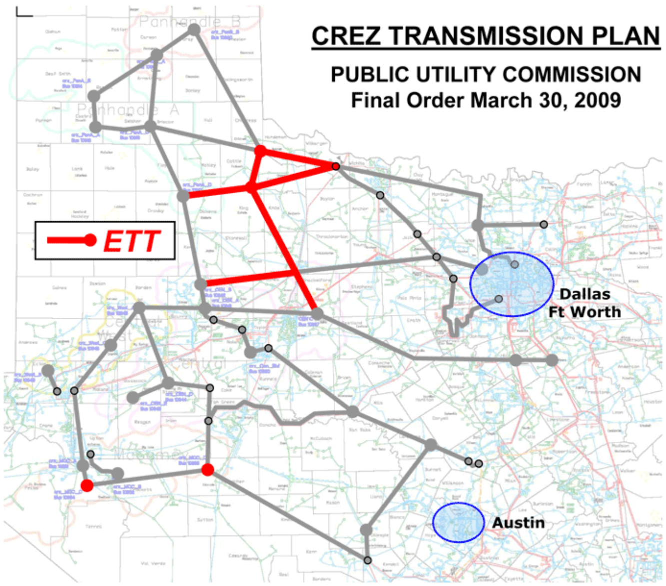
Growing Rate Base:

Current rate base is $412 million; expected to grow as follows:

2011: $473 million
2012: $778 million
2013: $1,352 million

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Transco Update

FERC:

- April 2011 -- The Commission finds in the order that the Settlement is just and reasonable and the business plan will provide benefits to AEP operating companies and customers.
  - ROE order for East Transcos is 11.49%
  - ROE order for West Transcos is 11.20%

State Filing Status Update:

- **Ohio** – PUCO approved the Ohio Transco December 29, 2010
- **West Virginia** – Filing made January 6, 2011; Hearings in June
- **Arkansas** – Filing in Arkansas made May 6, 2011
- **Louisiana –** Expecting LA filing in 3Q 2011
- **Texas-SPP** – Expecting TX filing in mid 2011
- **Kentucky** – Filing made February 4, 2011; Informal conference with staff held March 2, 2011
- **Indiana** – Filing made March 1, 2011; Pre-hearing conference March 28, 2011
- **Virginia** – Filing withdrawn to give additional time to resolve issues with Staff
- **Michigan and Oklahoma** – Do not require state filing

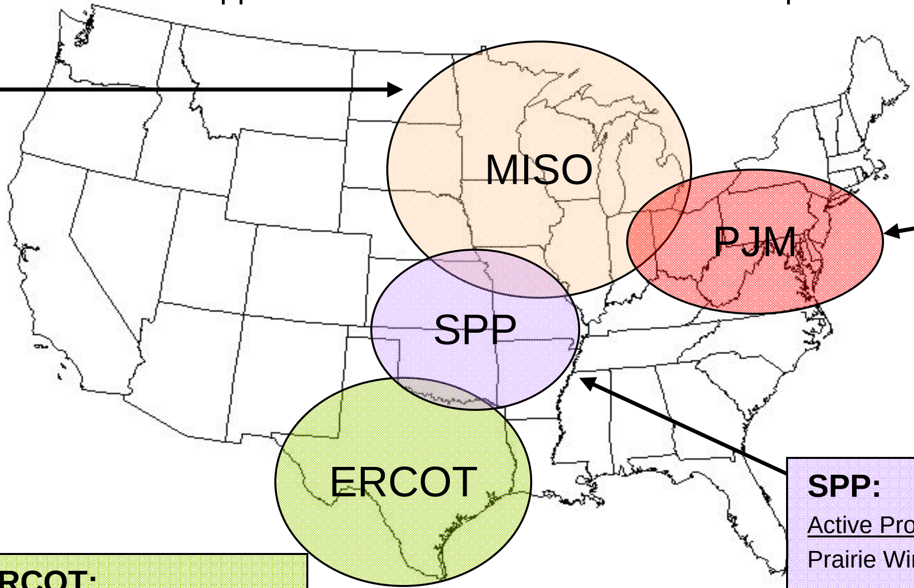
$160M capital spend forecasted for 2011; $350MM for 2012

Joint Venture Strategy: Long-term

- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.
- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.
- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Texas Fixed Income Investor Meetings

Hosted by Merrill Lynch

August 8, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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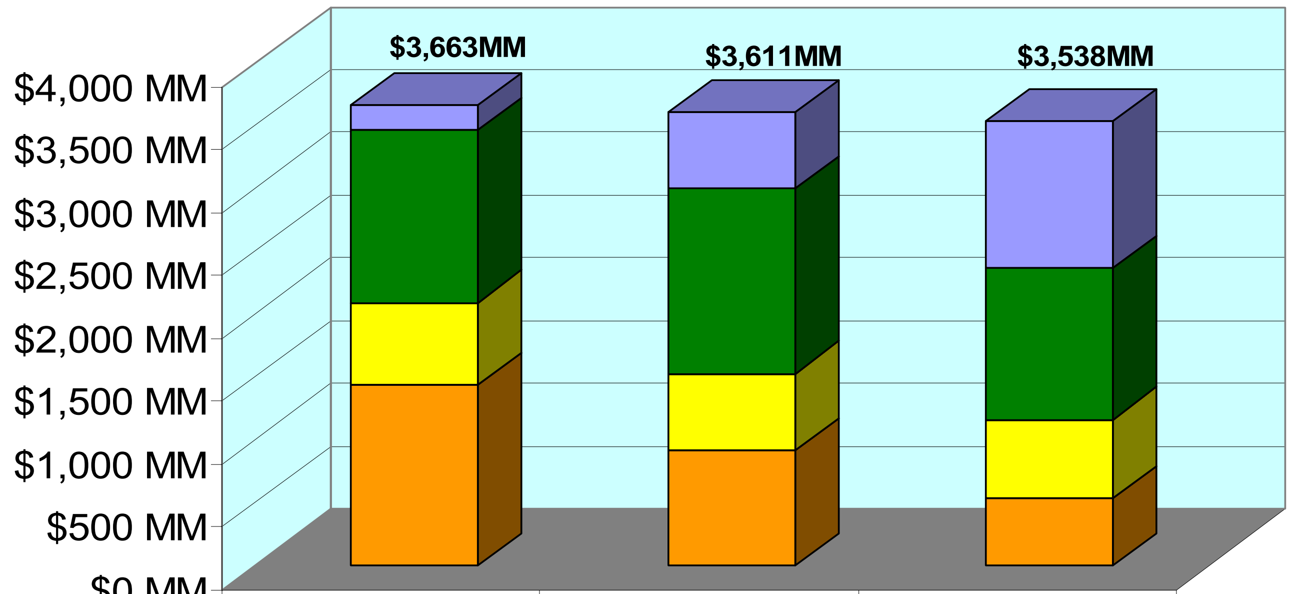
2006 Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC

New Build Generation & Ongoing Infrastructure Replacement investment can be throttled



	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,381	$1,473	$1,203
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,441	$912	$536

Note: Capital forecasts do not include amounts for AEP Interstate Project.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

New Generation

IGCC

- June 2006 – PUCO approved tariff to recover Phase 1 pre-construction costs ($24MM) over 12-month period effective July 1, 2006
- Expect to obtain permits and finalize engineering by 2007
- Construction of 600 MW facility to begin in 2007

SWEPCO

- On May 31, 2006 SWEPCo announced plans to build $1.4 billion of new generation
- Expected generation build includes a simple-cycle gas turbine totaling up to 480 MW, combined-cycle gas plant totaling 480 MW and a new base load coal- or lignite fueled plant
- Commercial operation dates between 2008 and 2011

PSO RFPs

- 2H05 - Submitted RFPs for up to 1100 MW of peaking and baseload capacity in aggregate
- March 2006 - Two peaking RFPs totaling 340 MW awarded; commercial operation 2008
- July 2006 - Entered into JVA with OG&E to build 950 MW coal-fueled unit with goal to use ultra-supercritical technology – PSO will own 50% or 425 MW; commercial operation 2011

p.

2006 Capital Investment Funding Revised

	Actual		Projection		
	2004	**2005**	**2006**	**2007**	**2008**
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,499)	$ (2,091)	$ (1,261)	$ (950)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,572)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,499)	$ (3,663)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (553)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,632	$ 1,877	$ 1,736	$ 2,403	$ 2,565
Proceeds from Sale of Assets	$ 1,357	$ 1,246	$ 111	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (25)	$ 6	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 663	$ 1,758	$ 1,648
TCC securitization bond issuance	$ -	$ -	$ 1,705		
Other	$ -	$ 126	$ (117)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (141)	$ (60)	$ -
Ending Cash Balance	$ 320	$ 401	$ 260	$ 200	$ 200

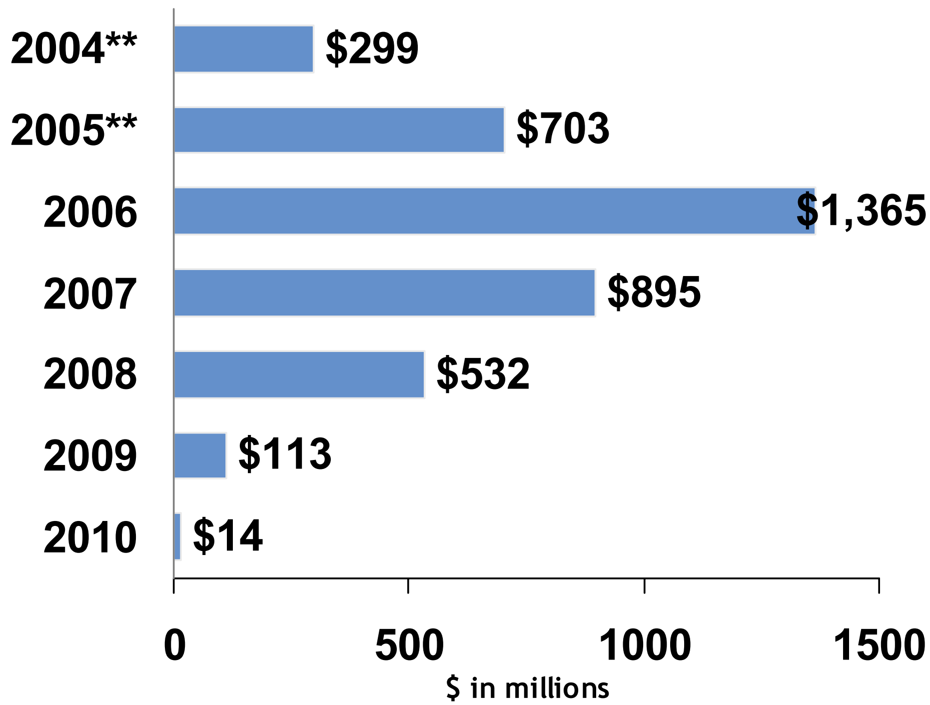
* Cash Flow from Operations assumes full rate recovery on capital expenditures.

2006 TOTAL CAPITAL INVESTMENT LEVEL HAS BEEN REDUCED BY $60MM TO $3.663 BILLION

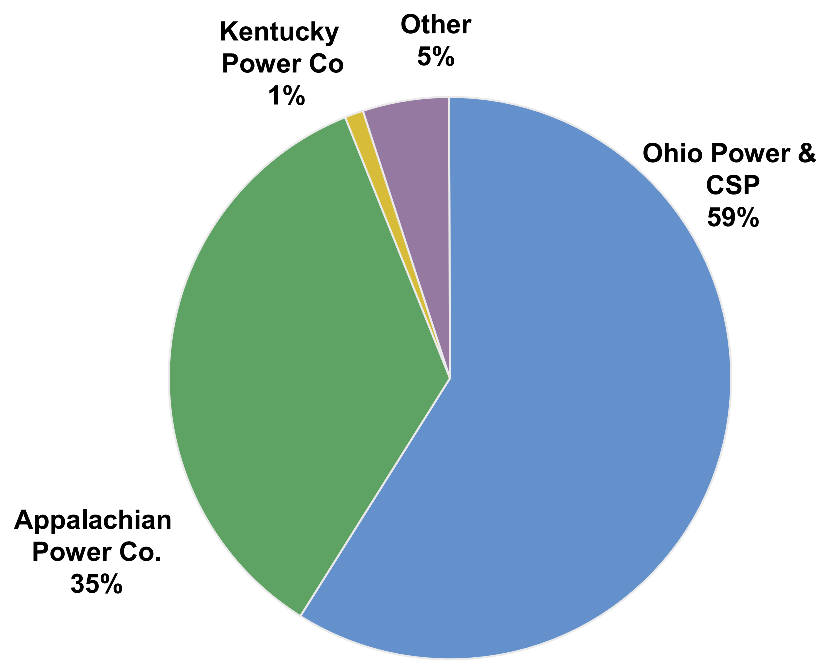
Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Environmental Investment: $3.9 Billion Through 2010

Environmental Capital Investment*



Projected Environmental Investment Allocation



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

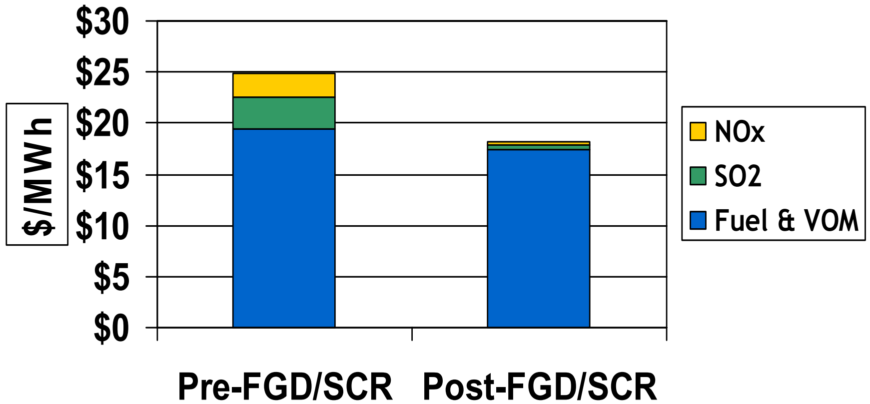
($3.9 billion figure reflects delay of Big Sandy 2 investment)

Majority of 2006 & 2007 dollars will be invested in Ohio & APCo

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP will remain the low cost producer following completion of environmental retrofit projects

Regulatory Activity Underway

- TCC Securitization of Stranded Costs
- Indiana Depreciation Petition
- APCo General Rate Case Filing in Virginia
- APCo Filing for Recovery of E&R Costs in Virginia
- IGCC – Received Rate Authorization of Pre-Construction Costs
- FERC Regional Rate Design

YEAR-TO-DATE, SECURED $415 MILLION OF THE $500 MILLION RATE RECOVERY ASSUMED IN 2006 EARNINGS GUIDANCE RANGE

Texas Regulatory Activity

TCC Stranded Cost Recovery Case

- April 4, 2006 – Final order, following rehearing, which provides for net true-up of $1.475 billion
- March 3, 2006 – Requested approval of financing order to issue $1.8 billion in low-cost securitization bonds
- May 22, 2006 – Settlement agreement filed with PUCT in securitization proceeding
  - Securitization financing order received June 20
  - Issuance of securitization bonds expected late 3Q06

Securitization Order:

- Securitization amount of $1.697 billion plus estimated bond issuance costs ($23 million resulting in $1.72 billion requested to be securitized)
- Securitization order not appealable
- $315 million cost-of-money benefit for ADFIT to be included in CTC
- The treatment of EDFIT and ADITC ($61 million in total) as a reduction to the securitized amount

- June 2006 – Requested approval for CTC to address other true-up items
  - Requested $355 million net credit to customers over 8 years
    - $475 million gross CTC refund proposed, offset by $7 million in rate case expense recovery
    - Requested portion be deferred, pending the outcome of 2 contingent federal matters
      - $16 million of FERC jurisdictional fuel over-recoveries
      - $97 million related to ADITC and EDFIT
  - Hearings set for Sept 2006

Regulatory Activity Underway

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- Hearings have been held with final order expected in third quarter 2006

Appalachian Power - Virginia E&R & General Rate Case Activity

Virginia E & R Cost Recovery Factor - Filed July 1, 2005 – Originally filed for recovery of $62.1 Million in new Environmental & Reliability costs

- Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- Hearings held, awaiting Commission Order

Virginia General Rate Case Filing – Filed May 4, 2006 – Seeking $225.8MM increase in base rates, partially offset by a proposed credit to reflect sharing of $27.3MM in margins from off system sales (OSS), resulting in a net annual increase of $198.5MM.

- May 30, 2006 – SCC suspended the effective date of the rates until 10/2/06, upon which, the full rate increase requested by APCO-VA will be implemented, subject to refund.

Procedural Schedule

Oct 4, 2006	Intervenor testimony due
Oct 24, 2006	SCC Staff testimony due
Nov 9, 2006	Company to file rebuttal testimony
Dec 6, 2006	Evidentiary Hearings to commence

IGCC Regulatory Activity

Ohio - Cost Recovery Filing

Phase 1 – PUCO AUTHORIZED

- Effective during 2006
- Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- Approximately $23.7 Million

Phase 2

- Effective 2007- mid 2010 (Construction Phase)
- Seeks recovery of carrying costs associated with plant construction

Phase 3

- Effective mid 2010 (Commercial Operation begins)
- Seeks recovery of projected $1.174 Billion cost of plant over its operating life

Ohio Next Steps

2006:

- Secure cost recovery plan
  - April 10, 2006 – PUCO authorized implementation of Phase 1 Rates
  - Phase 2 & 3 ruling – Post October 2006 – following completion of FEED study
- Finalize site selection
- Negotiate with suppliers

2006—2007:

- Obtain permits and finalize engineering and procurement

West Virginia IGCC Activity

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

Regulatory Activity Underway

FERC Regional Rate Design

- At our urging, the FERC instituted an investigation of PJM's zonal rate regime
  - Present regime may need to be replaced
  - Consider establishing regional rates that would compensate AEP, among others, for the regional transmission service proved by high voltage facilities they own that benefit customers throughout PJM
- July 13, 2006 ALJ rendered initial decision finding:
  - License Plate rates for existing facilities <u>are not</u> just and reasonable, and must be replaced (effective April 1, 2006 when SECA ended)
  - Staff's proposal for a "Postage Stamp" rate phased in so as to limit increases in any one pricing zone to 10% per year is best choice for replacing current rates
  - Staff's proposed rate design would produce slightly more net revenue for AEP than the original AEP/Allegheny Power proposal, when fully effective
- •Next Steps
  - Briefs on Exceptions to the initial decision by all parties
  - Order by the Commission late 2006/early 2007

Regulatory Activity Completed

Ohio – Rate Stabilization Plan (2006 – 2008)

- Annual 3% and 7% generation rate increases at CSP & OP, respectively
- POLR rate rider for environmental additions
- Ability to request additional 4% annual increase in generation rate, for certain specific incremental costs
- Elimination of 5% residential generation credit (stipulated in the pre-existing Electric Transition Plan of 2000)

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- Results in $22 million net revenue increase in 2006 from wholesale transmission

Ohio Companies Pass Through of FERC OATT Changes

May 26, 2006 – PUCO approved a final order allowing for adjustment of the transmission component of standard service tariffs to FERC-approved rates

- Transmission rate adjustment results in additional annual revenues of approximately $89 million ($63 million in 2006)

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 million
- Interim surcharge will collect the under-recovery amount of $44 million, including interest

Appalachian Power- Virginia Fuel Factor Increase

- $57.7 million increase in fuel factor approved on January 20, 2006

Kentucky Base Rate Case

Final order approved on March 14, 2006

- $41 million annual increase in base rates
- Rates effective March 30, 2006

Regulatory Activity Completed

APCo & WPCo West Virginia Rate Case

Settlement approved July 2006

- $44MM initial overall increase in rates effective July 28, 2006 comprised of:
  - $56MM increase in ENEC for fuel & purchased power expenses;
  - $23MM special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry (WJF) 765kV line;
  - $18MM general base rate reduction based on ROE of 10.5%, of which $9MM relates to a reduction in depreciation expense (affects cash flows but not earnings);
  - $17MM credit to refund a portion of deferred prior over-recoveries of ENEC costs of $51MM, currently recorded in regulatory liabilities; therefore, this item impacts cash flows bus has not effect on earnings;
- Agreement also provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments and the costs of WJF
- Reinstatement of the ENEC mechanism effective July 1, 2006

Steve Smith
Senior Vice President & Treasurer

Forecasted Capital Expenditures

Company	2006	2007	2008
AEP SYSTEM*	**$3,663,500**	**$3,611,400**	**$3,537,700**
AEGCo	$12,100	$30,000	$39,700
APCo	$928,300	$691,500	$751,700
CSPCo	$318,700	$473,700	$553,400
I&M	$329,800	$278,700	$262,000
KPCo	$53,400	$127,100	$144,000
OPCo	$1,065,400	$954,500	$581,600
PSO	$262,000	$342,800	$408,700
SWEPCo	$314,900	$366,700	$458,700
TCC	$286,100	$247,000	$222,100
TNC	$72,300	$71,600	$89,400

* Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.

Long-Term Debt Maturity

Year	2006[3]	2007	2008
AEP Service Corporation	$ 2,000,000 [2]	$ 2,000,000 [2]	$ 34,000,000
AEP Inc.	$ -	$ 345,000,000	$ -
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 342,500,000	$ 200,000,000
Columbus Southern Power	$ -	$ -	$ 112,000,000
Indiana Michigan	$ 300,000,000	$ -	$ 50,000,000
Kentucky Power	$ -	$ 322,964,000	$ 30,000,000
Ohio Power Company	$ 6,177,000 [2]	$ 17,854,000	$ 55,188,000 [2]
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ 9,361,000 [2]	$ 95,312,000 [2]	$ 5,000,000 [2]
Texas Central Company	$ -	$ -	$ 18,581,000
Texas North Company	$ -	$ 8,151,000	$ -
Total	**$ 317,538,000**	**$ 1,133,781,000**	**$ 504,769,000**

(1) Excludes tax exempt bond remarketings and securitization bonds.
(2) Includes sinking fund payments, where applicable.
(3) Maturities remaining as of June 30, 2006.

2006 Key Operating Company Highlights

(in millions)

Dependent on Actual Capital Investment

Company	Projected Capital Expenditures	Projected Issuances	Target Equity Ratio
APCO	$943	$500 - $600 *	42-45%
CSP	$343	$0	44-48%
I&M	$311	$400 - $500	38-42% (a)
KPCo	$100	$0	42-45%
OPCo	$1,070	$350 - $400	44-48%
PSO	$279	$150 - $200	44-48%
SWEPCo	$288	$150 - $200	44-48%
TCC (b)	$278	$0	40%
TNC	$73	$0	40%

* Issuances include potential new money tax-exempt issuances

(a) Ratios include impact of Rockport 2 lease.

(b) Excludes impact of securitization.

Maintain financial strength of subs by retaining and/or infusing equity capital depending on their credit ratios and free cash flow

Long-Term Debt Guidelines

Issuers:

- Issue at operating companies.

Size:

- Make transactions index eligible if possible.
- When possible, issue a size sufficient for competitive execution.

Maturity:

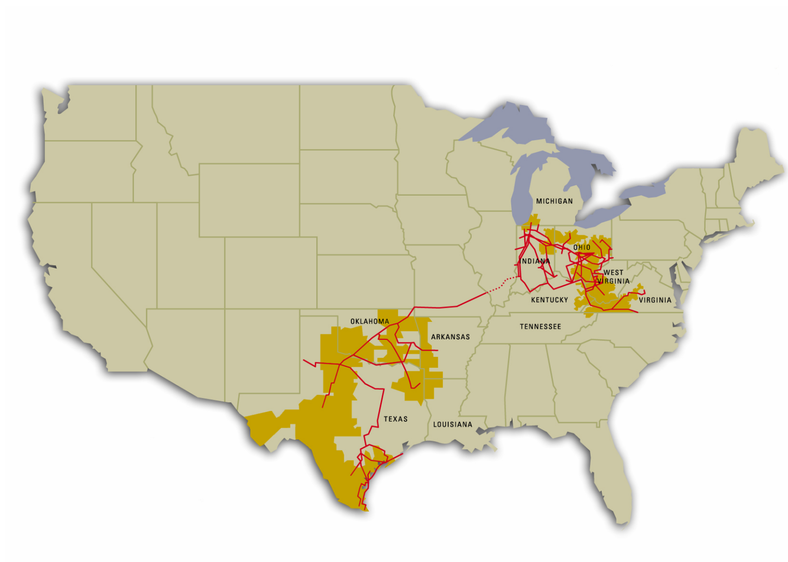
- Issue maturities for which the market has appetite.
- Achieve weighted average life targets for operating companies, generally between 10-15 years.

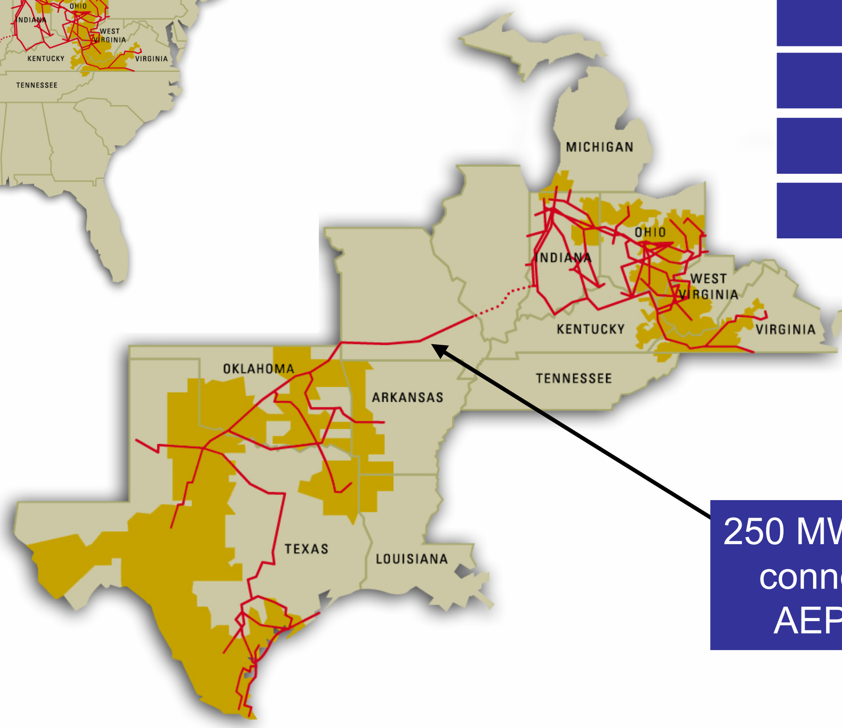
Timing:

- Will issue based on the timing of maturities and levels of short-term debt as driven by capital spending and operating cash flow.

Company Overview

Where We Operate





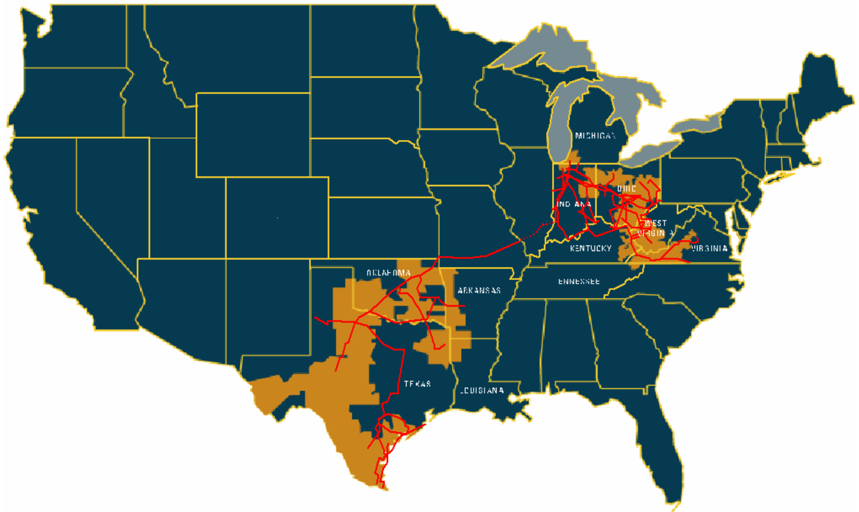
- Ohio
- Indiana
- West Virginia
- Virginia
- Kentucky
- Michigan
- Tennessee

- Oklahoma
- Texas
- Louisiana
- Arkansas

250 MW transmission line connects AEP East & AEP West territories

Strength & Scale in Assets & Operations

Utility Operations: The Platform for Growth



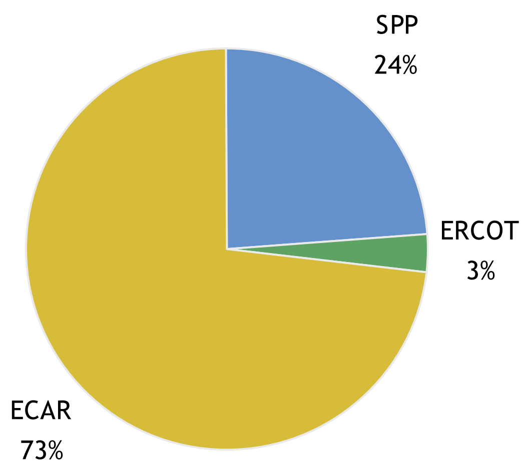
Generation*	**35,600 MW capacity**
Transmission	**39,000 miles**
Distribution	**205,500 miles**
Customers	**5 million**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity).

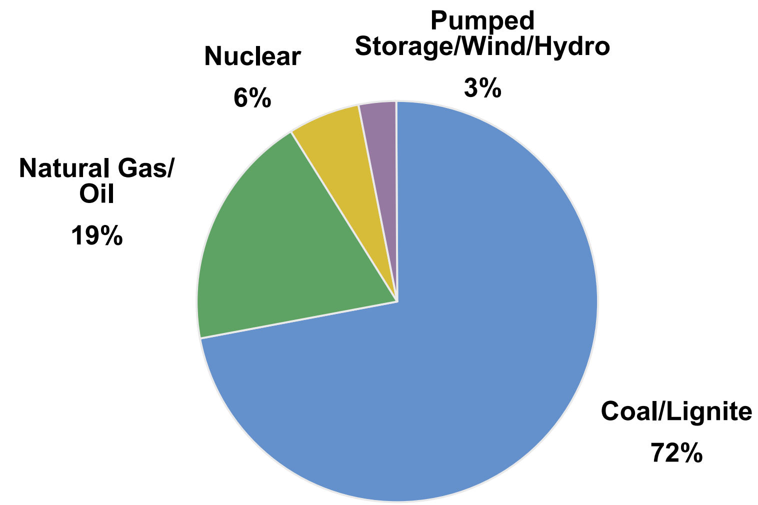
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Domestic Generation Fleet

Capacity by NERC Region



Capacity by Fuel Mix



Does not sum to 100% due to rounding

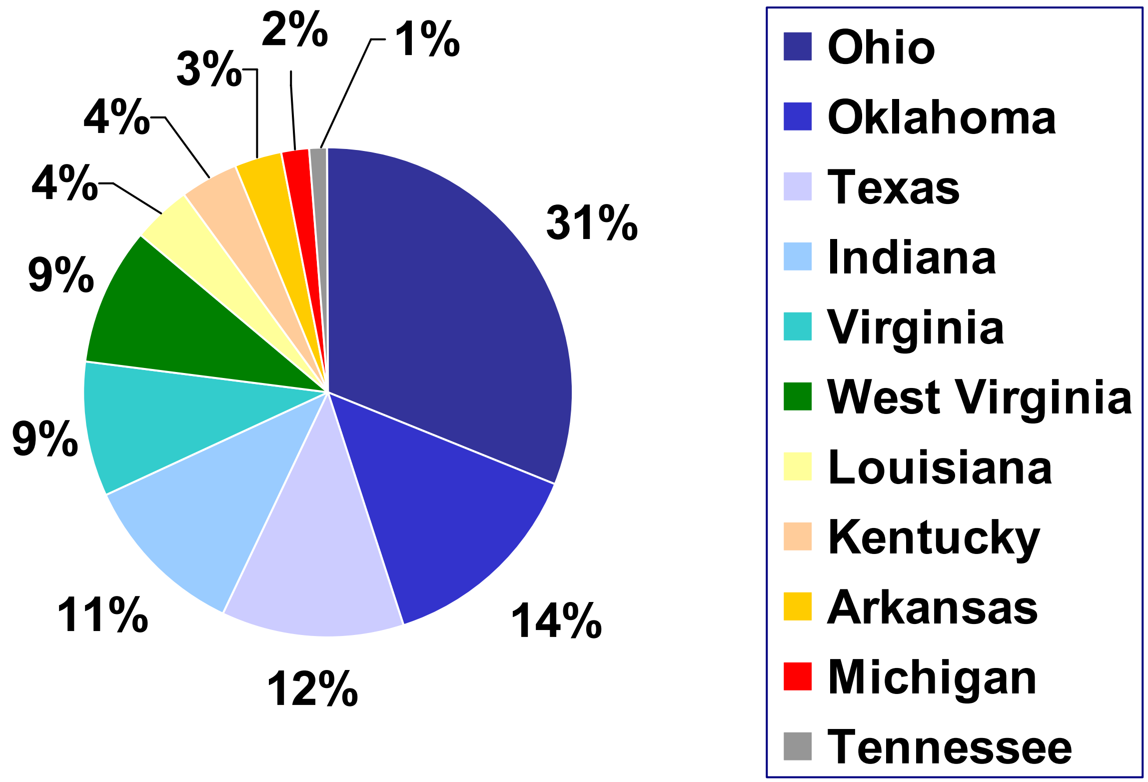
Operating Statistics

Commercial Availability Factor	
2004	85.24%
2005	84.50%

Capacity Factor	
2004	62.06%
2005	62.53%

2005 Retail Revenue

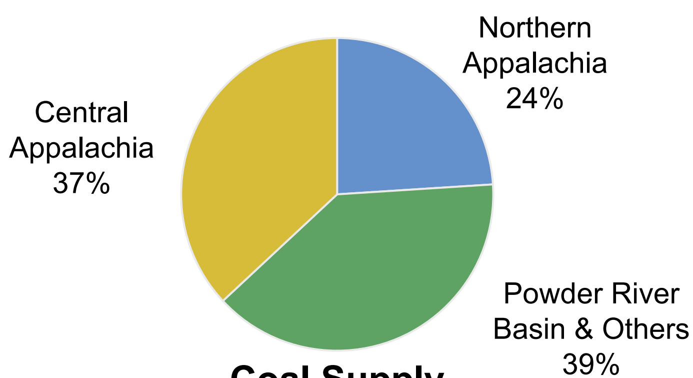
Retail Revenue Composition by State



Fuel

Coal Procurement

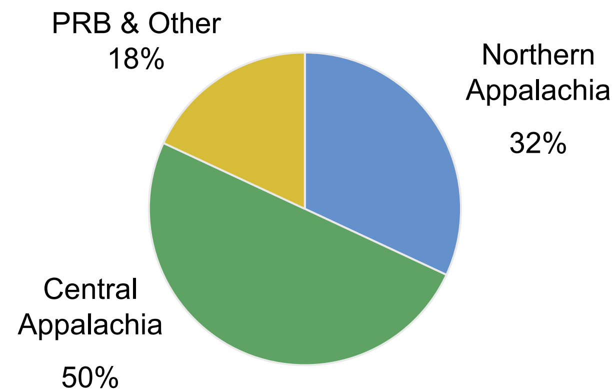
Total AEP System



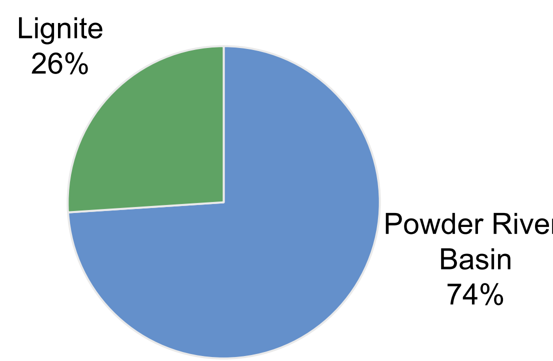
Coal Supply (on average)

- Purchase approximately 75 MM tons per year
- Avg. delivered price ~ $32.52/ton in 2005
- Fully contracted for 2006; 95%+ contracted for 2007
- Approximate 11%-13% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO2 Allowance prices drive low sulfur coal prices

AEP Eastern System

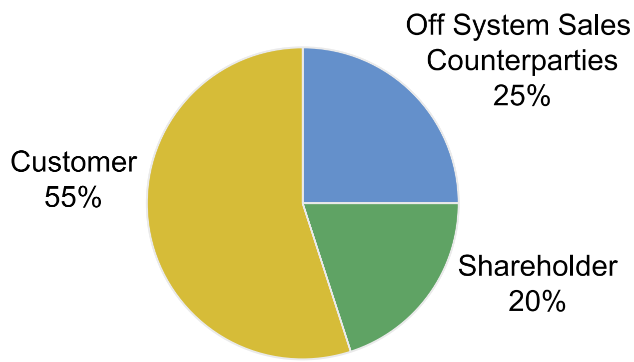


AEP Western System



Fuel Recovery

AEP System



Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 80% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: APCo, I&M, KPCo, KGP, WP
  - AEP WEST: PSO, SWEPCO

Note: Fuel recovery percentages are based on estimates for 2006 fiscal year

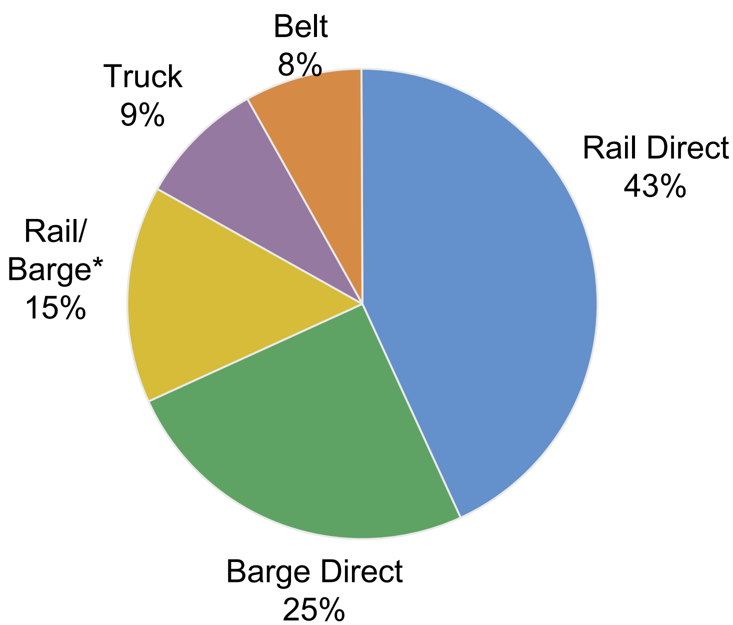
Jurisdictional Fuel Clause Summary

STATE	FUEL CLAUSE	ADJUSTMENT FREQUENCY
Arkansas	Yes	Annually
Indiana	Yes	Capped at increasing rates through June 30, 2007
Kentucky	Yes	Monthly
Louisiana	Yes	Monthly
Michigan	Yes	Annually
Ohio	No	Although there is no recovery mechanism in Ohio, the RSP provides for a 3% (CSP) and 7% (OP) increase in generation rates annually, which includes fuel beginning January 2006 and extending through December 2008.
Oklahoma	Yes	Annually
Tennessee	Yes	Monthly
Texas (SPP)	Yes	Semi-annually
Virginia	Yes	Annually
West Virginia	Yes	Anually; Deferral accounting for ENEC began July 1, 2006 and new rates became effective July 28, 2006.

Coal Delivery

Total AEP System

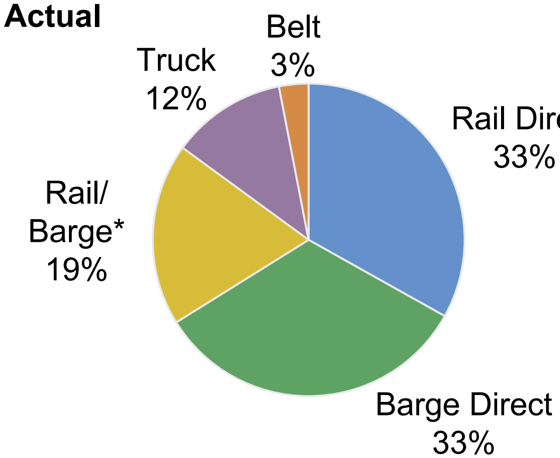
DELIVERY MODE DIVERSITY
2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

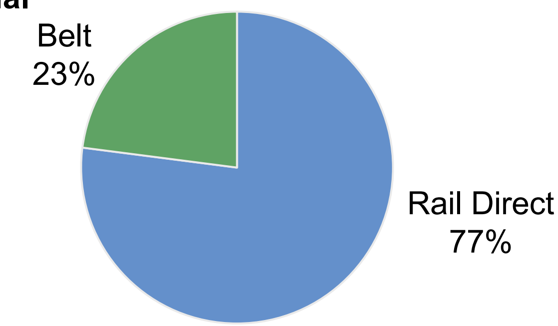
AEP Eastern System

2005 Actual



AEP Western System

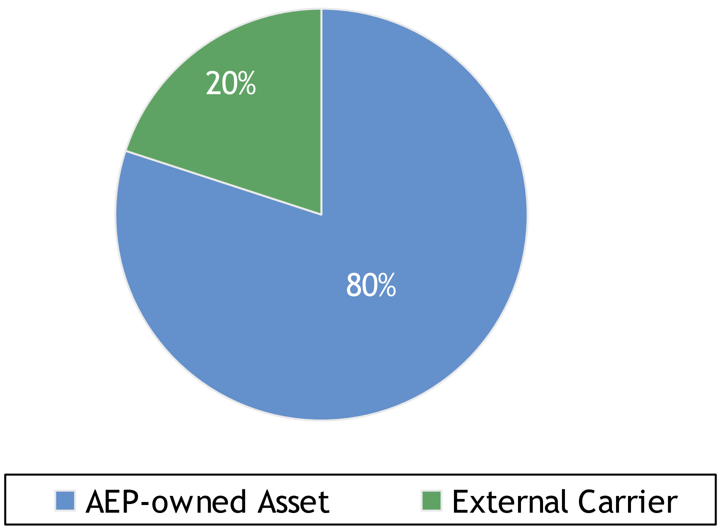
2005 Actual



AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*

2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

- 7,065 railcars
- 2,318 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

Environmental

AEP's Environmental Compliance Strategy

NOx and SO_2 emission reductions are part of AEP's on-going strategy to comply with the Clean Air Act, Title IV regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

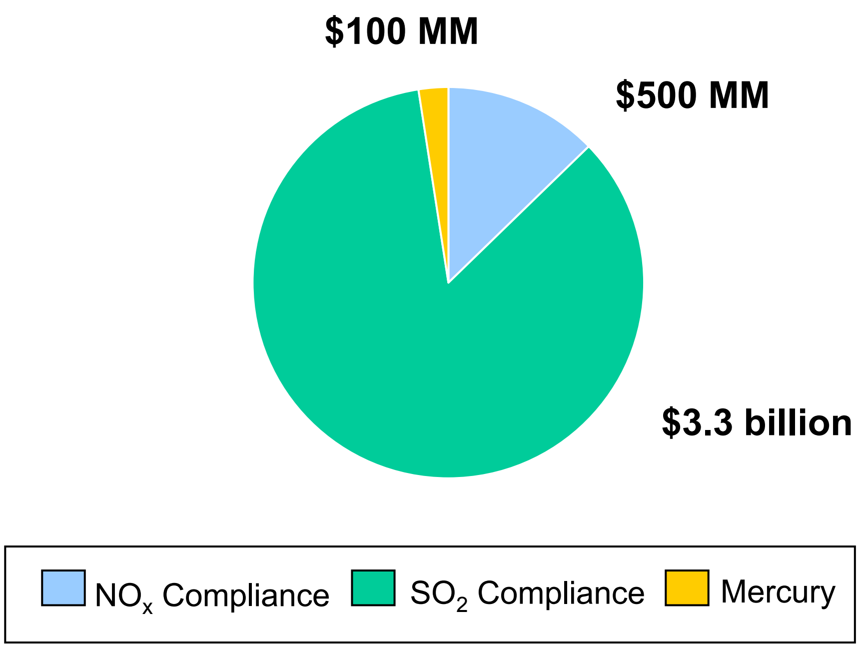
Much of this investment will position AEP to accomplish the following:

- Reduce nitrogen oxide emissions by 90% through installation of Selective Catalytic Reduction (SCR) systems
- Reduce sulfur dioxide emissions by 95% to 98%+ through installation of Flue Gas Desulfurization (FGD) systems (scrubbers)
- Realize co-benefit of mercury capture offered through SCR and FGD systems together
- Avoid future landfill costs through sale of gypsum (by-product) & build where landfill costs are lower
- Realize benefits achieved through fuel flexibility

Represents the best and least-cost compliance path to improve environmental performance on a fleet basis, while continuing to provide a reliable supply of power to customers at a reasonable price and a solid return for investors.

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$1.9 Billion:

$1.8 Billion for SO_2

$0.1 Billion for Other

$3.9 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

Note: Figures Include AFUDC; $3.9 billion figure reflects delay of Big Sandy 2 investment

Environmental Investment

FGD – Reduces SO_2 by 95% to 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Mountaineer	1300	2007
Cardinal 1	600	2007
Amos 1-3	2900	2008-09
Stuart 1-4	627	2009
Muskingum 5	585	2008
Conesville 4	339	2009
Total	**7951**	

SCR

Plant Name	MW Capacity	In-Service
Mitchell 1 & 2	1600	2007
Conesville 4	339	2009
Total	**1939**	

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Cost of Control Technology

AEP's compliance plan largely relies on SCR & FGD technology to meet the requirements of CAIR and CAMR. AEP also deployed other combustion related controls, such as low NOx burners and optimized boiler controls throughout the system.

Conventional Technology

	SCR	**FGD**
AEP Capital Cost	~$121/kW avg.	~$250/kW avg.
Pollutant(s)	NO_x	SO_2 (& Hg as co-benefit)
Removal Efficiency	85 to 93%	95%-98% (&~80%)
Aux. Power	Approx. 1%	1.5% to 3.0%

Investing in IGCC

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

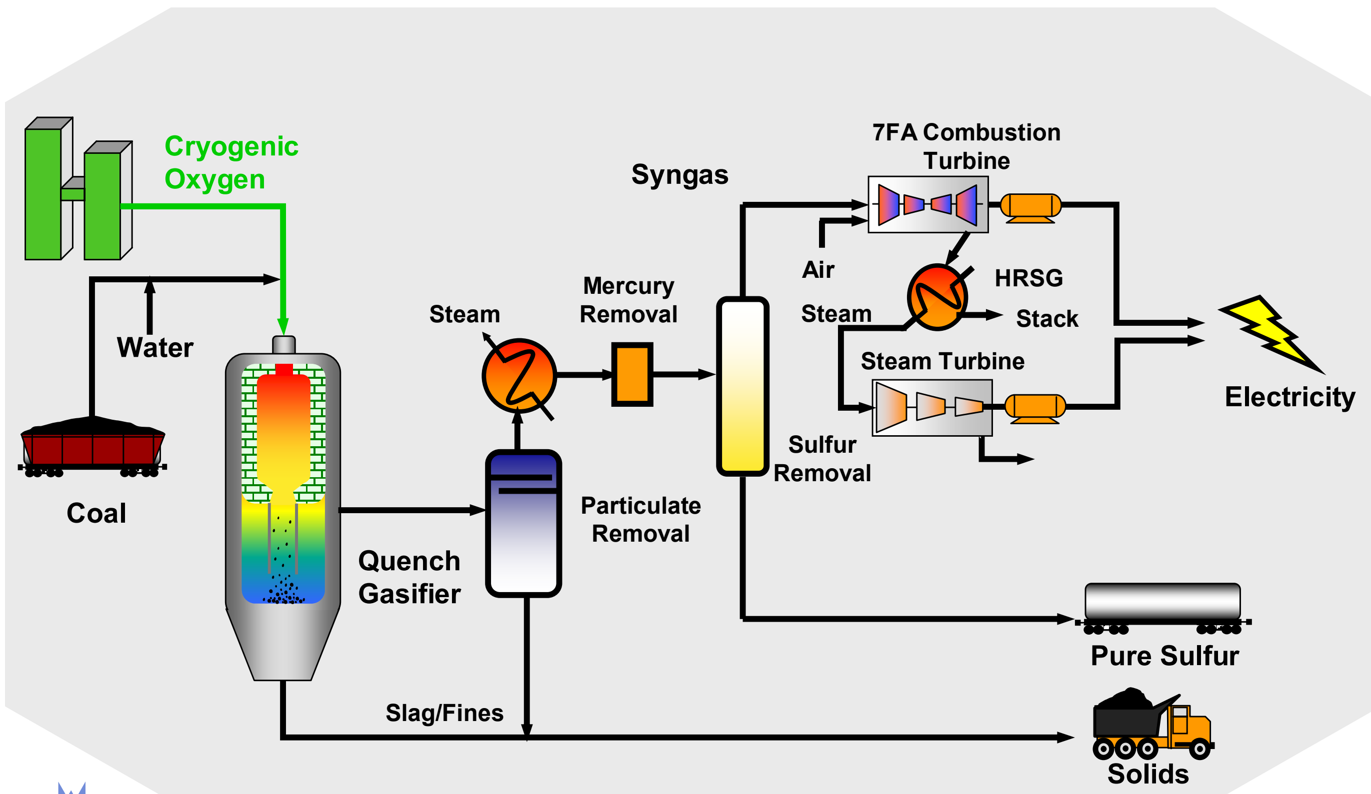
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006.   AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



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162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Generation Technology Comparative Stats

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

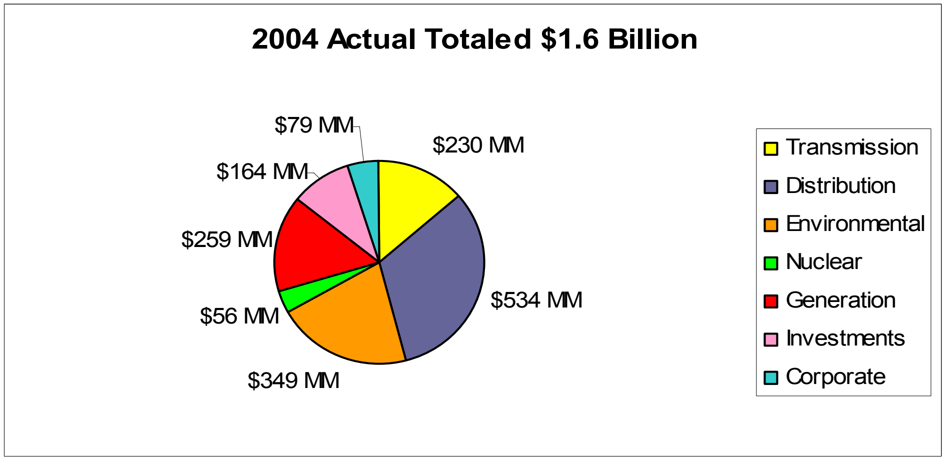
Source: Results of AEP analysis based on EPRI studies

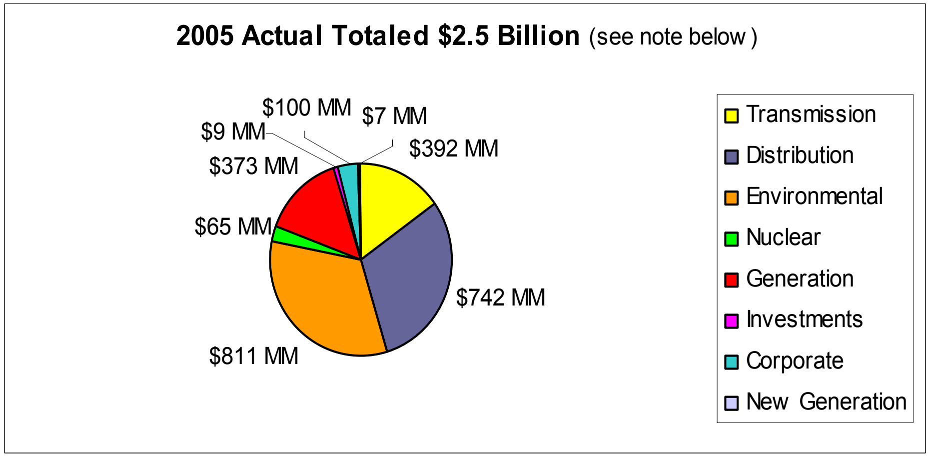
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

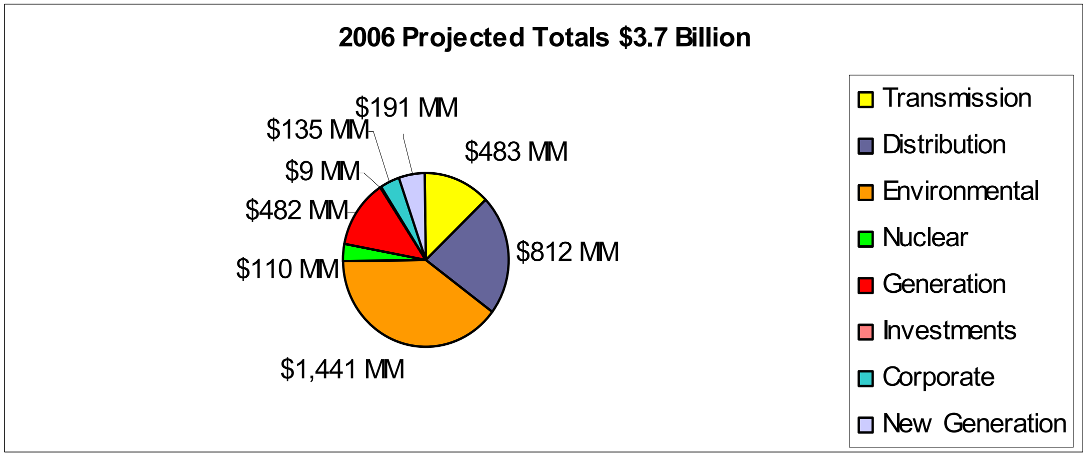
IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Capital Investment

Capital Investment 2004 - 2006







Notes: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005.

Figures exclude AFUDC.

Finance

2006 Guidance: $2.65 to $2.80 Per Share

American Electric Power
Financial Results for 2005 Actual vs. 2006 Forecast

		2005 Actual			2006 Forecast		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	East Regulated Integrated Utilities	65,656 GWh @ $31.5 /MWhr =	2,069		69,550 GWh @ $31.2 /MWhr =	2,173	
2	Ohio Companies	48,877 GWh @ $39.6 /MWhr =	1,937		46,185 GWh @ $47.3 /MWhr =	2,185	
3	West Regulated Integrated Utilities	40,213 GWh @ $22.3 /MWhr =	895		39,649 GWh @ $25.0 /MWhr =	990	
4	Texas Wires	26,525 GWh @ $17.4 /MWhr =	462		26,506 GWh @ $13.8 /MWhr =	366	
5	Off-System Sales	38,493 GWh @ $22.2 /MWhr =	853		37,280 GWh @ $17.7 /MWhr =	661	
6	Transmission Revenue - 3rd Party		411			262	
7	Other Operating Revenue		479			571	
8	Utility Gross Margin		7,106			7,208	
9	Operations & Maintenance		(3,142)			(3,139)	
10	Depreciation & Amortization		(1,285)			(1,280)	
11	Taxes Other than Income Taxes		(743)			(747)	
12	Interest Exp & Preferred Dividend		(595)			(666)	
13	Other Income & Deductions		264			199	
14	Income Taxes		(514)			(525)	
15	Utility Operations On-Going Earnings		1,091	2.80		1,050	2.66
	INVESTMENTS:						
16	Investments On-Going Earnings		24	0.06		26	0.07
17	Parent Company On-Going Earnings		(52)	(0.13)		(10)	(0.03)
18	ON-GOING EARNINGS		1,063	2.73		1,066	2.70
	Shares Outstanding (in millions)			390			394

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

2006 Cash Flow

	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,066
Depreciation and Amortization	1,318	1,311 *
Pension Funding in Excess of Expense	(626)	-
Extraordinary Items	225	-
Other	173	(641)
Total from Operations	**$ 1,877**	**$ 1,736**
Cash from Investing:		
Capital Expenditures ***	(2,404)	(3,663) **
Asset Sales	1,246	111
Other	153	(114)
Total from Investing	**$ (1,005)**	**$ (3,666)**
Cash from Financing:		
Common Equity	(25)	6
Net Long Term Debt Issued/(Retired)	(12)	2,235 ***
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	133
Common Dividends	(553)	(582)
Other Financing Activities	(122)	(3)
Total from Financing	**$ (791)**	**$ 1,789**
Net Change in Cash	**$ 81**	**$ (141)**
Ending Cash Balance	**$ 401**	**$ 260**

* Assumes point EPS estimate $2.70 per share.

** 2006 guidance excludes AFUDC; 2005 figure excludes equity portion of AFUDC

*** Assumes $1.7 billion of securitization bonds issued in September 2006

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

CASH ON HAND EXPECTED TO BE $260 MILLION AT YEAR END 2006

Credit Ratings

Current Ratings for AEP, Inc & Subsidiaries

	Moody's			S&P				Fitch		
Company	Senior Unsecured	Senior Secured	Outlook	Business profile	Senior Unsecured	Senior Secured	Outlook	Senior Unsecured	Senior Secured	Outlook
AEP, Inc.	Baa2	-	S	6	BBB	-	S	BBB	-	S
AEP, Inc. Short Term Rating	P2	-	S	N/A	A2	-	S	F2	-	S
Texas Central Company	Baa2	Baa1	S	3	BBB	BBB	S	A-	A	S
Texas North Company	Baa1	A3	S	3	BBB	BBB	S	A-	A	S
AEP Utilities, Inc.	-	-	-	N/A	BBB	BBB	S	-	-	-
Appalachian Power Company	Baa2	Baa1	S	5	BBB	BBB	S	BBB+	A-	S
Columbus Southern Power Company	A3	NR	S	4	BBB	NR	S	A-	NR	S
Indiana Michigan Power Company	Baa2	NR	S	6	BBB	NR	S	BBB	NR	S
Kentucky Power Company	Baa2	NR	S	5	BBB	NR	S	BBB	NR	S
Ohio Power Company	A3	NR	S	4	BBB	NR	S	BBB+	NR	S
Public Service Company of Oklahoma	Baa1	A3	S	5	BBB	A-	S	A-	A	S
Southwestern Electric Power Com	Baa1	A3	S	5	BBB	A-	S	A-	A	S

<u>2005 Ratings Actions</u>
- In September, Moody's upgraded the AEP, Inc. senior unsecured rating from Baa3 to Baa2
- In September, Moody's upgraded the AEP, Inc. short term rating from P3 to P2
- In July, S&P downgraded the business profile ratings at Texas Central and Texas North from 2 to 3
- In July, S&P downgraded the business profile ratings at Columbus Southern and Ohio Power from 3 to 4

Debt Schedules

American Electric Power Service Corp

Series	Interest	Maturity	Amount
Notes Payable	9.600%	12/15/2008	$38,000,000

American Electric Power Inc

Series	Interest	Maturity	Amount
Senior Notes	5.375%	03/15/2010	$490,000,000
Senior Notes	5.250%	06/01/2015	$242,775,000
Senior Notes	4.709%	08/16/2007	$345,000,000
Weighted Average or Total	5.134%		$1,077,775,000

AEP Generating

Series	Interest	Maturity	Amount
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Pollution Control Bond	4.050%	07/01/2025	$22,500,000
Weighted Average or Total	4.050%		$45,000,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

AEP Texas Central*

Series	Interest	Maturity	Amount
First Mortgage Bond*	7.125%	02/01/2008	$18,581,000
Pollution Control Bond	4.550%	11/01/2029	$100,635,000
Pollution Control Bond	Floating	11/01/2015	$40,890,000
Pollution Control Bond	6.000%	06/01/2020	$6,330,000
Pollution Control Bond	Floating	07/01/2028	$60,000,000
Pollution Control Bond	Floating	07/01/2028	$60,265,000
Pollution Control Bond	6.125%	05/01/2030	$60,000,000
Pollution Control Bond	Floating	05/01/2030	$111,700,000
Pollution Control Bond	Floating	05/01/2030	$50,000,000
Preferred Stock	4.000%	NA	$4,191,200
Preferred Stock	4.200%	NA	$1,747,600
Senior Notes	5.500%	02/15/2013	$275,000,000
Senior Notes	6.650%	02/15/2033	$275,000,000
Weighted Average or Total	4.097%		$1,064,339,800
Securitization Bond	5.010%	01/15/2008	$103,272,491
Securitization Bond	5.560%	01/15/2010	$107,094,258
Securitization Bond	5.960%	07/15/2013	$214,926,738
Securitization Bond	6.250%	01/15/2016	$191,856,858
Weighted Average or Total	5.822%		$617,150,345

AEP Texas North

Series	Interest	Maturity	Amount
First Mortgage Bond	7.750%	06/01/2007	$8,151,000
Pollution Control Bond	6.000%	06/01/2020	$44,310,000
Preferred Stock	4.400%	NA	$2,348,600
Senior Notes	5.500%	03/01/2013	$225,000,000
Weighted Average or Total	5.635%		$279,809,600

* TCC's First Mortgage Bond was defeased in May, 2004

Note: Debt Schedules as of June 30, 2006

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Debt Schedules

Appalachian Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	2.800%	05/01/2019	$30,000,000
Pollution Control Bond	2.700%	11/01/2007	$17,500,000
Pollution Control Bond	Floating	06/01/2019	$40,000,000
Pollution Control Bond	5.000%	11/01/2021	$19,500,000
Pollution Control Bond	5.500%	10/01/2022	$100,000,000
Pollution Control Bond	6.050%	12/01/2024	$30,000,000
Pollution Control Bond	Floating	02/01/2036	$50,275,000
Preferred Stock	4.500%	12/18/2040	$17,766,400
Senior Notes	4.400%	06/01/2010	$150,000,000
Senior Notes	5.000%	06/01/2017	$250,000,000
Senior Notes	Floating	07/01/2007	$125,000,000
Senior Notes	4.315%	11/12/2007	$200,000,000
Senior Notes	3.600%	05/15/2008	$200,000,000
Senior Notes	6.600%	05/01/2009	$150,000,000
Senior Notes	4.950%	02/01/2015	$200,000,000
Senior Notes	5.950%	05/15/2033	$200,000,000
Senior Notes	5.800%	10/01/2035	$250,000,000
Senior Notes	5.550%	04/01/2011	$250,000,000
Senior Notes	6.375%	04/01/2036	$250,000,000
Weighted Average or Total	4.796%		$2,530,041,400

Columbus Southern Power

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	08/01/2020	$48,550,000
Pollution Control Bond	Floating	12/01/2038	$43,695,000
Senior Notes	6.510%	02/01/2008	$52,000,000
Senior Notes	6.550%	06/26/2008	$60,000,000
Senior Notes	4.400%	12/01/2010	$150,000,000
Senior Notes	5.500%	03/01/2013	$250,000,000
Senior Notes	6.600%	03/01/2033	$250,000,000
Senior Notes	5.850%	10/01/2035	$250,000,000
Weighted Average or Total	5.324%		$1,104,245,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Indiana Michigan Power Company			
Series	**Interest**	**Maturity**	**Amount**
Pollution Control Bond	2.625%	10/01/2019	$25,000,000
Pollution Control Bond	2.625%	04/01/2025	$40,000,000
Pollution Control Bond	4.900%	06/01/2025	$50,000,000
Pollution Control Bond	Floating	05/01/2009	$45,000,000
Pollution Control Bond	Floating	11/01/2021	$52,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Pollution Control Bond	Floating	06/01/2025	$50,000,000
Preferred Stock	4.125%	NA	$5,536,900
Preferred Stock	4.120%	NA	$1,105,500
Preferred Stock	4.560%	NA	$1,441,200
Senior Notes	6.125%	12/15/2006	$300,000,000
Senior Notes	6.450%	11/10/2008	$50,000,000
Senior Notes	6.375%	11/01/2012	$100,000,000
Senior Notes	5.050%	11/15/2014	$175,000,000
Senior Notes	6.000%	12/31/2032	$150,000,000
Senior Notes	5.650%	12/01/2015	$125,000,000
Weighted Average or Total	4.702%		$1,220,083,600

Kentucky Power			
Series	**Interest**	**Maturity**	**Amount**
Senior Notes	5.500%	07/01/2007	$125,000,000
Senior Notes	6.910%	10/01/2007	$48,000,000
Senior Notes	4.315%	11/12/2007	$80,400,000
Senior Notes	4.368%	12/12/2007	$69,564,000
Senior Notes	6.450%	11/10/2008	$30,000,000
Senior Notes	5.625%	12/01/2032	$75,000,000
Weighted Average or Total	5.340%		$427,964,000

Note: Debt Schedules as of June 30, 2006

Debt Schedules

Ohio Power Company

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	07/01/2014	$50,000,000
Pollution Control Bond	Floating	12/01/2016	$50,000,000
Pollution Control Bond	Floating	04/01/2022	$35,000,000
Pollution Control Bond	Floating	06/01/2022	$50,000,000
Pollution Control Bond	5.625%	10/01/2022	$19,565,000
Pollution Control Bond	5.625%	01/01/2023	$19,565,000
Pollution Control Bond	5.150%	05/01/2026	$50,000,000
Pollution Control Bond	Floating	01/01/2029	$54,500,000
Pollution Control Bond	Floating	07/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2028	$54,500,000
Pollution Control Bond	Floating	10/01/2028	$54,500,000
Pollution Control Bond	Floating	04/01/2036	$65,000,000
Notes Payable	6.810%	03/31/2008	$10,243,904
Notes Payable	6.270%	03/31/2009	$28,250,000
Notes Payable	7.490%	04/15/2009	$70,000,000
Notes Payable	7.210%	06/15/2009	$11,000,000
Preferred Stock	4.080%	NA	$1,459,500
Preferred Stock	4.200%	NA	$2,282,400
Preferred Stock	4.400%	NA	$3,151,200
Preferred Stock	4.500%	NA	$9,737,500
Senior Notes	6.240%	12/04/2008	$37,225,000
Senior Notes	5.500%	02/15/2013	$250,000,000
Senior Notes	4.850%	01/15/2014	$225,000,000
Senior Notes	6.600%	02/15/2033	$250,000,000
Senior Notes	6.375%	07/15/2033	$225,000,000
Senior Notes	5.300%	11/01/2015	$200,000,000
Senior Notes	6.000%	06/01/2016	$350,000,000
Weighted Average or Total	4.638%		$2,230,479,504

Public Service Company of Oklahoma

Series	Interest	Maturity	Amount
Pollution Control Bond	Floating	06/01/2014	$33,700,000
Pollution Control Bond	6.000%	06/01/2020	$12,660,000
Preferred Stock	4.0000%	NA	$4,454,800
Preferred Stock	4.2400%	NA	$806,900
Senior Notes	4.700%	05/15/2011	$75,000,000
Senior Notes	4.700%	06/15/2009	$50,000,000
Senior Notes	4.850%	09/15/2010	$150,000,000
Senior Notes	6.000%	12/31/2032	$200,000,000
Weighted Average or Total	4.920%		$526,621,700

Note: Debt Schedules as of June 30, 2006

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Debt Schedules

Southwestern Electric Power Company			
Series	**Interest**	**Maturity**	**Amount**
Notes Payable	4.470%	04/23/2011	$23,288,281
Notes Payable	6.360%	02/22/2007	$7,000,000
Notes Payable	7.030%	02/22/2012	$23,000,000
First Mortgage Bond	6.200%	11/01/2006	$1,000,000
First Mortgage Bond	6.200%	11/01/2006	$5,070,000
First Mortgage Bond	7.000%	09/01/2007	$90,000,000
Pollution Control Bond	Floating	07/01/2011	$41,135,000
Pollution Control Bond	Floating	03/01/2018	$81,700,000
Pollution Control Bond	Floating	01/01/2019	$53,500,000
Preferred Stock	5.000%	NA	$3,770,300
Preferred Stock	4.650%	NA	$190,700
Preferred Stock	4.280%	NA	$738,600
Senior Notes	5.375%	04/15/2015	$100,000,000
Senior Notes	4.900%	07/01/2015	$150,000,000
Trust Preferred Stock	5.250%	10/10/2008	$113,403,000
Weighted Average or Total	4.135%		$693,795,881

Note: Debt Schedules as of June 30, 2006

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Appendix

What AEP Offers

Utility Operations: The Platform for Growth & Financial Strength

1. Strength and scale in assets and operations
2. Focused utility business model
3. Earnings growth driven by native load & capital investment
4. Pioneering advanced technologies in the sector
5. Solid liquidity position and stable credit profile
6. Attractive dividend yield in excess of 4%

Completed APCo West Virginia Rate Case

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed April 24, 2006 – Joint Settlement Agreement

- Estimated overall impact of revenue increases to be phased-in through 2009:
  - $129 Million
  - 16% Increase
- Provides for timely recovery of Wyoming-Jacksons Ferry 765kV line and Mountaineer & Amos FGDs
- Settlement Agreement approved July 26

Phased-In Increases:

- ✓ July 28, 2006 - $61 Million*
- ✓ July 1, 2007 - $36 Million**
- ✓ July 1, 2008 - $14 Million**
- ✓ July 1, 2009 - $18 Million**

* Excludes ENEC over-recovery negative surcharge ($17 million) -- surcharge does not have an earnings impact

** Estimated

Approved Settlement Details

- ✓ Increase effective July 28, 2006:

($18MM)	Base Rates
$56MM	ENEC
$23MM	WJF & FGD investment @ 12/31/05
$61MM	Gross revenue increase
($17MM)	ENEC over-recovery negative surcharge
$44MM	Net increase effective 7/28/06

- ✓ Phased-in revenue increases annually on July 1, 2007 – 2009 provides for timely recovery of FGD project balances at 12/31 of prior year

Summary Rate Case Information

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Hearings concluded in March. Briefs were filed in early April. We are awaiting a Commission order. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

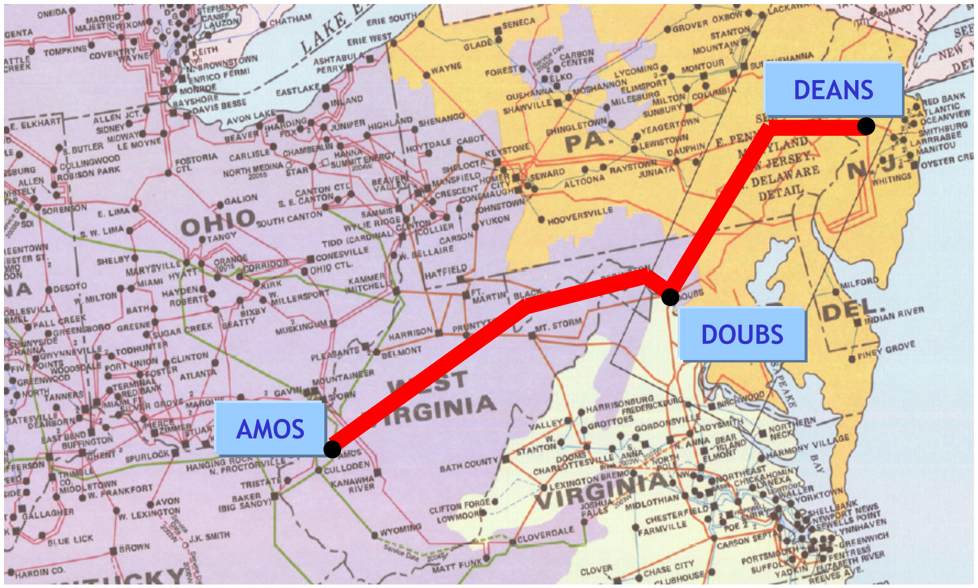
Capital Structure	Company Position (filed 7/1/05)	Staff Position (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	Company Position (filed 11/14/05)	Staff Position (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

AEP Interstate Project



Map of the Proposed AEP Interstate Project 765 kV Transmission Line (Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)

- Line connects AEP's Amos 765 kV station to Allegheny Power's Doubs 500 kV station in Maryland, and terminates at PSEG's Deans 500 kV station in New Jersey
- Total line length is approximately 550 miles
- Will improve power transfer capability from the Midwest to the Mid-Atlantic by 5,000 MW
- Expected to cost $3 billion (subject to change based on a detailed investigation)
- Not yet determined which other non-AEP companies may be interested in participating
- Any financing activity relating to this project would be structured to allow AEP to meet its consolidated debt-to-cap target of approximately 60% and maintain its BBB credit rating
- Project expected to be in service in 2014

OPERATING COMPANY DETAIL

AEP Texas Central Company

President and Chief Operating Officer: Charles Patton

AEP Texas Central Company (TCC)

(organized in Texas in 1945) is engaged in the generation (to an extremely limited extent), transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 729,000 retail customers through REPs in southern Texas, and (to a limited extent) in supplying and marketing electric power at wholesale to other electric utility companies and market participants. Under the Texas Act, TCC is completing the final stage of exiting the generation business and has already sold most of its generation assets, including STP. At December 31, 2005, TCC had 1,160 employees. In addition to its AEP System interconnections, TCC is a member of ERCOT.

As of 12/31/2005

Total Customers:
(Based on electric meters)

• **Residential**	**620,000**
• **Commercial**	**103,000**
• **Industrial**	**6,000**
Total	**729,000**

Generating Capacity	**54 MW***
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**5,000**
Distribution Miles	**28,000**

*** Includes TCC's 54-MW share of the Oklaunion plant**

Principal industries served:

Oil and gas extraction
Food processing
Apparel
Metal refining
Chemical and petroleum refining
Plastics
Machinery equipment

AEP Texas Central Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,291,625	1,214,989	3,506,614	1,907,505	1,274,583	3,182,088	1,935,576	953,570	2,889,146
% of Capitalization Per Balance Sheet	65.4%	34.6%	100.0%	59.9%	40.1%	100.0%	67.0%	33.0%	100.0%
Adjusted Capitalization	1,545,625	1,214,989	2,760,614	1,128,357	1,271,613	2,399,970	1,269,257	950,601	2,219,858
% of Adjusted Capitalization	56.0%	44.0%	100.0%	47.0%	53.0%	100.0%	57.2%	42.8%	100.0%
FFO Interest Coverage			2.7			2.9			1.4
FFO Total Debt			10.0%			14.3%			2.6%

2005 Financial Data (in thousands)

Revenue	$ 793,000
% of AEP Retail	5%
Net Income (Loss)	$ (174,000)
Capital Expenditure	$ 179,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 4,905,000
Net Plant Assets	$ 2,021,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 286,100	$ 247,000	$ 222,100

AEP Texas Central Company

AEP TEXAS CENTRAL
MAJOR CUSTOMERS

Valero Energy Corporation
Koch Industries, Inc.
Air Liquide America, LP
Equistar Chemicals LP
El Paso Energy Corp.
HEB Grocery Company LP
Ingleside Cogeneration Ltd Par
Citgo Petroleum Corporation
Wal-Mart Stores, Inc.
Formosa Utl Ven Ltd.

- **Top 10 customers = 67% of industrial sales* ($)**
- **Metropolitan areas account for 78% ultimate sales**
- **53 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas Central Power Plants (excluding mothballed and decommissioned plants)

Name	Location	Megawatt Capacity	Fuel
Oklaunion (TCC) (Sale to co-owners pending)	Vernon, Texas	54	Coal

AEP Texas North Company

President and Chief Operating Officer: Charles Patton

AEP Texas North Company (TNC)

(organized in Texas in 1927) is engaged in the generation, transmission and sale of power to affiliated and non-affiliated entities and the distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2005, TNC had 387 employees. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

As of 12/31/2005

Total Customers:
(Based on electric meters)

• **Residential**	**148,000**
• **Commercial**	**30,000**
• **Industrial**	**5,000**
Total	**183,000**

Generating Capacity **377 MW**
(excludes 1,015 MW mothballed plants)

Generating Capacity by Fuel Mix:

- **Coal:** **100%**

Transmission Miles	**4,500**
Distribution Miles	**12,000**

Principal industries served:

Agriculture and the manufacturing or processing of
Cotton seed products
Oil products
Precision and consumer metal products
Meat products
Gypsum products

AEP Texas North Company

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	356,754	240,632	597,386	314,357	312,777	627,134	276,845	316,275	593,120
% of Capitalization Per Balance Sheet	59.7%	40.3%	100.0%	50.1%	49.9%	100.0%	46.7%	53.3%	100.0%
Adjusted Capitalization	356,754	240,632	597,386	315,535	311,599	627,134	269,555	315,097	584,652
% of Adjusted Capitalization	59.7%	40.3%	100.0%	50.3%	49.7%	100.0%	46.1%	53.9%	100.0%
FFO Interest Coverage			4.8			5.8			5.0
FFO Total Debt			23.6%			33.4%			29.8%

2005 Financial Data (in thousands)

Revenue	$ 459,000
% of AEP Retail	1%
Net Income	$ 33,000
Capital Expenditure	$ 65,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 1,044,000
Net Plant Assets	$ 807,000

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 72,300	$ 71,600	$ 89,400

AEP Texas North Company

AEP TEXAS NORTH
MAJOR CUSTOMERS

Chevron Texaco Corporation
Kinder Morgan
Occidental Permian Ltd.
Crown Cork & Seal Co., Inc
Rhodia Inc.
Plains All American Pipeline (Equilon)
Georgia-Pacific Corporation
Ethicon, Inc.
Wal-Mart Stores, Inc.
Tyson Foods Inc. (Wright Brand)

- **Top 10 customers = 32% industrial sales* ($)**
- **Metropolitan areas account for 59% ultimate sales**
- **8 persons per square mile (U.S. = 95)**

* Industrial % is in terms of wires revenues

Texas North Power Plants (excluding mothballed and decommissioned plants)			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Oklaunion (TNC)	Vernon, Texas	377	Coal

Regulatory Information

Public Utility Commission of Texas (PUCT)

AEP Regulated Electric Utilities

Texas Central Company
Texas North Company
Southwestern Electric Power Company

Commissioners

Number: **3**	Appointed/Elected: **Appointed**	Term: **6 years**	Political Makeup: R:3

Qualifications for Commissioners

To be eligible for appointment, a commissioner must be: (1) a qualified voter; (2) a citizen of the United States; and (3) a representative of the general public. Chairman appointed by the Governor.

Commissioners

Paul Hudson, Chairman (Rep.), since August 2003; current term expires August 2009. Served as policy director in governor's office. Worked at PUCT as advisor and senior economic analyst. Served on National Governor's Association Task Force on Electric Infrastructure; Western Governor's Association Working Group on Cross Border Energy Issues. Master's degree from Arizona State.

Barry T. Smitherman, Commissioner (Rep.), since April 2004; current term expires August 2007. Attorney; Assistant DA; 16 years as a public finance investment banker. Law degree from the University of Texas School of Law, Master's in public administration from Harvard University.

Julie Parsley, Commissioner (Rep.), since November 2002; current term expires August 2011. Lawyer, private practice. Served as Solicitor General of Texas with Office of Attorney General. Also served as Deputy Solicitor General. Received law degree from Texas Tech University.

Appalachian Power

President and Chief Operating Officer: Dana Waldo

Appalachian Power Company (APCo)

(organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 942,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo covers a service territory of 19,049 square miles, and at December 31, 2005, APCo and its wholly owned subsidiaries had 2,408 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

Principal industries served:

Coal mining
Primary metals
Chemicals
Textile mill products

As of 12/31/2005

Total Customers:

• **Residential**	**804,000**
• **Commercial**	**126,000**
• **Industrial**	**4,000**
• **Other**	**7,000**
Total	**941,000**

Generating Capacity **6,389 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **79.4%**
- **Hydro/Pump:** **12.5%**
- **Nat Gas** **8.1%**

Transmission Miles	**6,700**
Distribution Miles	**49,000**

Appalachian Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,947,075	1,360,131	3,307,206	1,995,658	1,427,502	3,423,160	2,345,511	1,821,484	4,166,995
% of Capitalization Per Balance Sheet	58.9%	41.1%	100.0%	58.3%	41.7%	100.0%	56.3%	43.7%	100.0%
Adjusted Capitalization	1,947,075	1,360,131	3,307,206	2,004,550	1,418,610	3,423,160	2,354,403	1,812,593	4,166,996
% of Adjusted Capitalization	58.9%	41.1%	100.0%	58.6%	41.4%	100.0%	56.5%	43.5%	100.0%
FFO Interest Coverage			5.6			5.0			3.7
FFO Total Debt			27.2%			19.7%			12.4%

2005 Financial Data (in thousands)

Revenue	$ 2,176,000
% of AEP Retail	17%
Net Income	$ 131,000
Capital Expenditure	$ 598,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 6,254,000
Net Plant Assets	$ 4,652,000
Cash	$ 1,741

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 928,300	$ 691,500	$ 751,700

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Appalachian Power

APCo Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	32,901,943	29,551,752	32,949,364	31,801,020
Coal Consumption (tons burned)	13,015,569	11,604,352	13,187,986	12,602,636

Operating Information

2005 retail electric sales in megawatt-hours	30,327,723
2005 firm wholesale sales in megawatt-hours	2,480,850
Average cost per kilowatt-hour (residential)	5.41 cents
2005 System Peak	6,978 (January 24)

Appalachian Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Buck #1, 2, 3	Ivanhoe, Virginia	9	Hydro
Byllesby#1, 2, 3, 4	Byllesby, Virginia	22	Hydro
Ceredo #1,2,3,4,5,6	Ceredo, West Virginia	516	Nat Gas
Claytor #1, 2, 3, 4	Radford, Virginia	75	Hydro
Clinch River #1, 2, 3	Carbo, Virginia	705	Coal
Glen Lynn #1, 2	Glen Lynn, Virginia	335	Coal
Leesville #1, 2	Leesville, Virginia	50	Hydro
Niagara #1, 2	Roanoke, Virginia	2	Hydro
Reusens #1, 2, 3, 4, 5	Lynchburg, Virginia	13	Hydro
Smith Mountain #1, 2, 3, 4, 5	Penhook, Virginia	586	Pump
John E. Amos #1, 2, *(APCo owns 1/3 of 3)*	St. Albans, West Virginia	2,033	Coal
Mountaineer #1	New Haven, West Virginia	1,300	Coal
Kanawha River #1, 2	Glasgow, West Virginia	400	Coal
London #1, 2, 3	Montgomery, West Virginia	14	Hydro
Marmet#1, 2, 3	Marmet, West Virginia	14	Hydro
Philip Sporn #1, 3	New Haven, West Virginia	300	Coal
Winfield #1, 2, 3	Winfield, West Virginia	15	Hydro

Appalachian Power

APPALACHIAN AREA UTILITIES

West Virginia	**Customers**
APCo	**433,615**
Allegheny	485,295

Virginia	**Customers**
APCo	**496,994**
Dominion Virginia	2,131,281
Allegheny	92,878
Kentucky Utilities	29,801
Conectiv	21,529

Tennessee	**Customers**
APCo	**45,803**

TYPICAL BILL COMPARISON*

West Virginia	
APCo	**55.28**
AEP – Wheeling	**57.91**
Allegheny	70.09

Virginia	
APCo	**57.80**
ODPCo	58.07
Dominion Virginia	87.18
Conectiv	103.13

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

APPALACHIAN POWER COMPANY MAJOR CUSTOMERS

Massey Energy Company
CONSOL Energy
Roanoke Electric Steel Corporation
Georgia-Pacific Corporation
Elkem Metals Company
Greif Brothers Corporation
The Dow Chemical Co., Inc.
Arch Coal, Inc.
Dan River Inc.
Peabody Group

- **Top 10 Customers = 23% of industrial sales**
- **Metropolitan areas account for 37% of ultimate sales**
- **85 persons per square mile (U.S. = 95)**

Regulatory Information

Public Service Commission of West Virginia

AEP Regulated Electric Utilities

Wheeling Power Co.
Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup R:** 1 **D:** 2

Qualifications for Commissioners

The West Virginia Public Service Commission (WVPSC) consists of three members, appointed by the Governor, with the advice and consent of the senate. No more than two members of the commission may belong to the same political party. The Commissioners serve six year staggered terms, with one term expiring as of July 1 of each odd numbered year. One Commissioner is designated as Chairman of the Commission by the Governor. The Chairman serves as the chief fiscal officer of the Commission.

Commissioners

Edward H. Staats, (Dem.), since 2003, term expires June 2009. Former Chief of Operations in the Governor's office.

R. Michael Shaw, Commissioner (Rep.), since mid 2003, term expires June 2007. Attorney, former state legislator.

Jon W. McKinney, Chairman (Dem.), since 2005, term expires June, 2011. Formerly served as plant manager of Flexsys' Nitro, W Va operations, chairman of Chemical Industry Committee for W Va, board member of W Va Chamber of Commerce, W Va Manufacturer's Association, Chemical Alliance Zone, W Va Roundtable & Thomas Memorial Hospital.

Virginia State Corporation Commission

AEP Regulated Electric Utilities

Appalachian Power Co.

Commissioners

Number: 3	**Appointed/Elected**: Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 1

Qualifications for Commissioners

The Virginia State Corporation Commission (VSCC) is composed of three members elected by the General Assembly. Commissioners are elected to serve six-year terms, staggered in two year increments. The chair rotates annually among the three commissioners on February 1.

Commissioners

Theodore V. Morrison, Jr, (Dem.), since 1989; current term expires 2008. Member of the Virginia House of Delegates from 1968 to 1988. Member of Virginia Code Commission from 1974 and served as chairman from 1984 to 1988. Lawyer, private practice. Law degree from Emory University.

Mark C. Christie (Rep.), since 2004; current term expires February 2010. Current Chairman. Attorney, counsel to the Speaker of the House

Judith Williams Jagdmann, (Rep.), since 2006, current term expires 2012. Law degree from T.C. Williams School of Law. Prior to being elected to the Commission, she served as 43rd Attorney General for the Commonwealth of Virginia. Prior to work in Attorney in the Office of Attorney General, served 13 years as counsel to the SCC.

Columbus Southern Power

President and Chief Operating Officer: Kevin Walker

Columbus Southern Power Company (CSPCo)

(organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSP Co covers a service territory of 3,701 miles and at December 31, 2005, CSPCo had 1,178 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM. Pursuant to an acquisition that closed on December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio. As a result, in January 2006 approximately 29,000 customers in six southeastern Ohio counties, together with the transmission and distribution used to serve such customers, were added to CSPCo's service territory.

As of 12/31/2005

Total Customers:	
Residential	**636,000**
• **Commercial**	**71,000**
• **Industrial**	**3,000**
• **Other**	**300**
Total	**710,300**
Generating Cap	**3,270 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**72.5%**
• **Natural Gas**	**26.1%**
• **Hydro:**	**1.5%**
Transmission Miles	**2,200**
Distribution Miles	**17,200**

Principal industries served:

Food processing
Chemicals
Primary metals
Electronic machinery
Paper products

Columbus Southern Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Capitalization Per Balance Sheet	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
Adjusted Capitalization	904,081	897,881	1,801,962	987,626	898,650	1,886,276	1,214,529	981,546	2,196,075
% of Adjusted Capitalization	50.2%	49.8%	100.0%	52.4%	47.6%	100.0%	55.3%	44.7%	100.0%
FFO Interest Coverage			7.7			6.2			5.8
FFO Total Debt			37.9%			28.7%			24.3%

2005 Financial Data (in thousands)

Revenue	$ 1,542,000
% of AEP Retail	14%
Net Income	$ 134,000
Capital Expenditure	$ 165,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 3,433,000
Net Plant Assets	$ 2,526,000
Cash	$ 940

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 318,700	$ 473,700	$ 553,400

Columbus Southern Power

Columbus Southern Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	15,243,711	14,049,095	14,038,045	14,443,617
Coal Consumption (tons burned)	6,526,167	6,121,275	6,048,060	6,231,834

Operating Information

2005 retail sales in megawatt-hours	18,277,372
2005 firm wholesale sales in megawatt-hours	0
Average cost per kilowatt-hour (residential)	7.56 cents (CSP)
2005 System Peak	4,105 megawatts (CSP-July 25)

Columbus Southern Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Conesville *(Unit #4 co-owned by DP&L.CG&E) (Retire #1&2 250MW 12/31/05)*	Conesville, Ohio	1,260	Coal
J. M. Stuart #*1, 2, 3, 4 (Units co-owned by DP&L/CG&E. CSP 26%)*	Aberdeen, Ohio	627	Coal
Wm. H. Zimmer #*1 Co-owned by DP&L/CG&E,CSP 25.4%)*	Moscow, Ohio	330	Coal
Picway #1	Lockbourne, Ohio	100	Coal
Beckjord #1 *(Unit #6 co-owned by DP&L.CG&E. CSP 12.5%)*	New Richmond, Ohio	53	Coal
Waterford # 1,2,3,4	Washington County, Ohio	852	Nat Gas

Columbus Southern Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

COLUMBUS SOUTHERN POWER MAJOR CUSTOMERS

The Ohio State University
State of Ohio
Anheuser-Busch, Inc.
E I duPont de Nemours HQ
The Kroger Company
Nationwide Insurance Enterprise
Ohio University
Griffin Wheel Company
OhioHealth
Limited Brands

- **Top 10 customers = 31% of industrial sales**
- **Metropolitan areas account for 84% of ultimate sales**
- **244 persons per square mile (U.S. = 95)**

Regulatory Information

Ohio Public Utilities Commission

AEP Regulated Electric Utilities

Columbus Southern Power Co.
Ohio Power Co.

Commissioners

Number: 5	**Appointed/Elected**: Appointed	**Term:** 5 years	**Political Makeup: R:** 3 **D:** 0 **I:** 2

Qualifications for Commissioners

Five members, appointed by the governor and confirmed by the state senate; five year, staggered terms, full-time positions, commissioners shall be selected from the lists of qualified persons submitted to the governor by the PUC nominating council. Not more than three of the members of the PUCO shall be members of the same political party. The governor appoints one of the five as president, who serves at the pleasure of the governor until a successor has been designated.

Commissioners

Alan R. Schriber, Ph.D., Chairman, (Ind.), since 1999. Term expires April 2009. Economics professor, president of a radio broadcasting company, investment advisor. Previously served as commissioner on the PUCO from 1983-1989. Member NARUC Telecommunications Committee.

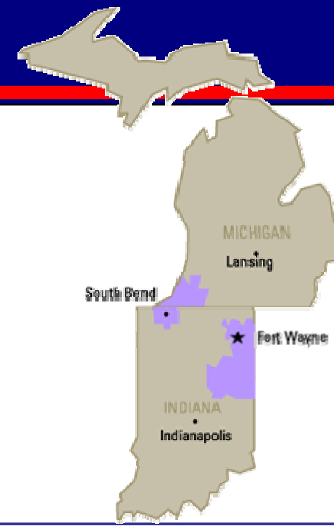
Ronda Hartman Fergus, Commissioner, (Rep.), since 1995, reappointed in 2000 & 2005. Term expires April 2010. Lawyer, Ohio State; previously served on the PUCO staff as an administrative law judge in the Legal Department. Later served as the chief of Telecommunications, Water and Sewer Section of the Legal Department, and then chief of the Telecommunications Technical Staff.

Judy A. Jones, Commissioner, (Rep.), since 1997, reappointed in 2002. Term expires April 2007. Masters degree in Biological Chemistry, Univ. of Michigan. Member NARUC Committee on Electricity, Clean Coal Technology Work Group and vice-chair of its International Relations Comm, member of the National Coal Council, and a government member of the North American Electric Reliability Council.

Donald L. Mason, Commissioner, (Rep.), since 1998, reappointed in 2003. Term expires April 2008. Lawyer, former chief of the Division of Oil and Gas at the Ohio Department of Natural Resources. He serves as chair of the NARUC Gas Committee and the NARUC Ad Hoc Committee on Electric Restructuring and Critical Infrastructure.

Clarence D. Rogers, Commissioner, (Ind.), since 2001, term expires April 2006. Lawyer, former executive deputy general manager Cleveland Regional Transit Authority, two terms as commissioner of the Ohio Turnpike Commission, assistant US Attorney, private practice as litigator.

Indiana Michigan Power



President and Chief Operating Officer:
Marsha Ryan

Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 581,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M has a service territory of 4,578 square miles and at December 31, 2005, I&M had 2,633 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

Principal industries served:
Primary metals
Transportation equipment
Electrical and electronic machinery
Fabricated metal products
Rubber and miscellaneous plastic products
Chemicals and allied products

As of 12/31/2005

Total Customers:	
• **Residential**	**507,000**
• **Commercial**	**66,000**
• **Industrial**	**5,000**
• **Other**	**2,000**
Total	**580,000**
Generating Capacity	**5,768 MW**
(includes AEG Rockport)	
Generating Capacity by Fuel Mix:	
• **Coal:**	**62.5%**
• **Nuclear:**	**37.1%**
• **Hydro:**	**0.4%**
Transmission Miles	**5,300**
Distribution Miles	**19,700**

Indiana *Michigan Power*

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	1,438,181	1,149,593	2,587,774	1,374,288	1,099,582	2,473,870	1,538,642	1,228,176	2,766,818
% of Capitalization Per Balance Sheet	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%	55.6%	44.4%	100.0%
Adjusted Capitalization	1,823,681	1,149,593	2,973,274	1,761,432	1,095,540	2,856,972	1,921,435	1,224,134	3,145,569
% of Adjusted Capitalization	61.3%	38.7%	100.0%	61.7%	38.3%	100.0%	61.1%	38.9%	100.0%
FFO Interest Coverage			4.0			4.1			4.7
FFO Total Debt			22.70%			23.20%			22.80%

2005 Financial Data (in thousands)

Revenue	$ 1,893,000
% of AEP Retail	13%
Net Income	$ 146,000
Capital Expenditure	$ 299,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 5,238,000
Net Plant Assets	$ 3,116,000
Cash	$ 854

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 329,800	$ 278,700	$ 262,000

Indiana Michigan *Power*

I&M Generation Production Statistics – 2003 – 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Avg.**
MWh Produced	28,075,125	21,258,001	31,535,226	26,956,117
Coal Consumption (tons burned)	7,189,655	7,186,066	7,011,370	7,129,030

Operating Information

2005 retail electric sales in megawatt-hours	19,248,200
2005 firm wholesale sales in megawatt-hours	2,169,221
Average cost per kilowatt-hour (residential)	6.61 cents
2005 System Peak	4,193 MW (August 3)

Indiana Michigan Power			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Rockport #1, 2 (includes AEG)	Rockport, Indiana	2,608	Coal
Berrien Springs #1, 2, 3	Berrien Springs, Michigan	7	Hydro
Buchanan #1, 2, 3, 4, 5	Buchanan, Michigan	4	Hydro
Constantine #1, 2, 3, 4	Constantine, Michigan	1	Hydro
Elkhart #1, 2, 3	Elkhart, Indiana	3	Hydro
Mottville	Mottville	2	Hydro
Tanners Creek #1, 2, 3, 4	Lawrenceburg, Indiana	995	Coal
Twin Branch #1, 2, 3, 4, 5, 6	Mishawaka, Indiana	5	Hydro
Donald C Cook #1, 2	Bridgman, Michigan	2,143	Nuclear

Indiana Michigan Power

INDIANA & MICHIGAN UTILITIES

Indiana	
I&M	**452,050**
IP & L	458,796
NIPSCO	442,554
Cinergy (PSI)	747,696
SIGECO	135,449

Michigan	Customers
I&M	**124,583**
CMS (Consumers)	1,760,882
DTE (Detroit Edison)	2,144,655

TYPICAL BILL COMPARISON*

Indiana	
I & M	**68.94**
IP & L	70.50
Cinergy (PSI)	79.53
SIGECo	88.67

Michigan	
I & M	**61.43**
Consumers Energy	82.97
Detroit Edison	93.80

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

INDIANA MICHIGAN POWER
MAJOR CUSTOMERS

Steel Dynamics Inc.
Mittal Steel Company
Air Products & Chemicals, Inc.
Boc Gases
Saint Gobain Corporation USA
Ball State University
New Energy Corp
Dock Foundry
Michelin North America, Inc.
Guide Indiana

- **Top 10 Customers = 39% of industrial sales**
- **Metropolitan areas account for 68% of ultimate sales**
- **205 persons per square mile (U.S. = 95)**

Regulatory Information

Indiana Utility Regulatory Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Number: 5	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup: R** 3 **D:** 2

<u>Qualifications for Commissioners</u>

Five members, appointed by the Governor from among persons nominated by a legislatively mandated utility commission nominating committee; four year, staggered terms, full time positions. Not more than three of the members of the IURC be members of the same political party. At lease one of the commissioners must be an attorney qualified to practice law before the Indiana Supreme Court. The governor appoints one of the five as chairman. Republican Mitch Daniels was elected Governor on November 2, 2004.

<u>Commissioners</u>

David L. Hardy, Chairman (Rep.), since September 2005, current term will expire April 2006. Commissioner Hardy is an attorney who has worked in private practice since 1997. Areas of expertise include: negotiation, contracts, litigation, finance and administration. He has 35 years regulatory experience at the state and federal levels.

Larry S. Landis, Commissioner (Rep.), since December 2002, current term ends January 2008. Former president of a marketing and advertising agency, VP Corporate Advertising, Bank One, Indiana. Bachelor's degrees in political science and economics.

David W. Hadley, Commissioner (Dem.), since 2000; Executive officer for Indiana AFL CIO, former legislative affairs representative for United Mine Workers of America, coal miner, former high school social studies teacher. Master's degree in secondary education.

Greg Server, Commissioner (Rep.), since September 2005, current term ends in April 2009. Former state senator since 1981 and before that served in the Indiana House or Representatives from 1972 to 1980. Served as chair of senate commerce committee, which handled IURC and utility industry legislation. Served as Director of Administration for the Evansville Water and Sewer Utility.

David E. Ziegner, Commissioner (Dem.), since 1990, current term ends April 2007. Lawyer, staff attorney for Legislative Services Agency, General Council for IURC. Member, NARUC Committee on Electricity. Law degree from the Indiana University School of Law in Indianapolis.

Regulatory Information

Michigan Public Service Commission

AEP Regulated Electric Utilities

Indiana Michigan Power Co.

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup:** :1 **D:** 2

<u>Qualifications for Commissioners</u>

The Michigan Public Service Commission (MPSC) is composed of three members appointed by the Governor with the advice and consent of the Senate. Commissioners are appointed to serve staggered six year terms. No more than two commissioners may represent the same political party. One commissioner is designated as chairman by the Governor.

<u>Commissioners</u>

<u>J. Peter Lark, Chair, (Dem)</u> since July 2003: current term expires July 2009. Lawyer, assistant Attorney General in charge of special litigation division, former assistant prosecuting attorney.

<u>Laura Chappelle, Commissioner, (Rep.)</u> since 2001: current term expires July 2007. Lawyer, former deputy legal advisor to the Governor, regulatory affairs advisor to Michigan House Republicans, assistant prosecuting attorney.

<u>Monica Martinez, Commissioner, (Dem)</u> since 2005, current term expires July 2011. Former Deputy Director of the Governor's Legislative Affairs Division where she served as the Governor's principal lobbyist. Previous to this she served as an analyst for the Senate Democratic Office, where she specialized in technology and energy, human services and family law policy issues.

Kentucky Power

President and Chief Operating Officer: Tim Mosher

Kentucky Power Company (KPCo)

(organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo encompasses a service territory of 4,813 square miles and at December 31, 2005, KPCo had 454 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

As of 12/31/2005
Total Customers:

• **Residential**	**145,000**
• **Commercial**	**29,000**
• **Industrial**	**1,000**
• **Other**	**400**
Total	**175,400**
Generating Capacity	**1,060 MW**
Generating Capacity by Fuel Mix:	
• **Coal:**	**100%**
Transmission Miles	**1,200**
Distribution Miles	**10,000**

Kentucky Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Capitalization Per Balance Sheet	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
Adjusted Capitalization	525,698	317,138	842,836	508,310	320,980	829,290	493,030	347,841	840,871
% of Adjusted Capitalization	62.4%	37.6%	100.0%	61.3%	38.7%	100.0%	58.6%	41.4%	100.0%
FFO Interest Coverage			4.7			3.9			3.4
FFO Total Debt			20.4%			16.6%			14.0%

2005 Financial Data (in thousands)

Revenue	$ 531,000
% of AEP Retail	4%
Net Income	$ 21,000
Capital Expenditure	$ 57,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 1,320,000
Net Plant Assets	$ 989,000
Cash	$ 526

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 53,400	$ 127,100	$ 144,000

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Kentucky Power

Kentucky Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	6,170,931	6,550,509	7,345,624	6,689,021
Coal Consumption (tons burned)	2,513,524	2,607,559	2,926,253	2,682,445

Operating Information

2005 retail electric sales in megawatt-hours	7,309,016
2005 firm wholesale sales in megawatt-hours	97,845
2005 average cost per kilowatt-hour (residential)	5.67 cents
2005 System Peak	1,685 MW (Jan 24)

Kentucky Power Plants			
Name	Location	Megawatt Capacity	Fuel
Big Sandy #1, 2	**Louisa, Kentucky**	**1,060**	**Coal**

Kentucky Power

KENTUCKY POWER UTILITIES

Kentucky	Customers
KPCo	**174,631**
Kentucky Utilities	485,627
LG & E	389,196

KENTUCKY POWER MAJOR CUSTOMERS

Marathon Ashland Petroleum
AK Steel Holding Corporation
James River Coal Co.
Massey Energy Company
TECO Energy, Inc.
Air Products & Chemicals, Inc.
KES Acquisition Company LLC.
Alliance Coal, LLC
Consol Energy
Weyerhaeuser Company

TYPICAL BILL COMPARISON*

Kentucky	
KPCo	**59.78**
Kentucky Utilities	62.40
LG&E	66.31
CIN	68.54

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 61% of industrial sales**
- **Metropolitan areas account for 42% of ultimate sales**
- **69 persons per square mile (U.S. = 95)**

Regulatory Information

Kentucky Public Service Commission

AEP Regulated Electric Utilities

Kentucky Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 4 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>

Three members, appointed by the governor and confirmed by the state senate for four years, staggered terms, full-time positions. The governor appoints one of the three as chairman and another of the three as vice chairman to serve in the chairman's absence. Not more than two members of the KYPSC shall be of the same profession or occupation.

<u>Commissioners</u>

Mark Goss (Chair) (Rep.), since 2004; current term expires June 2007. Attorney in private practice.

Teresa Hill (V. Chair.) (Rep.), since 2005; current term expires June 30, 2009. Served on the Governor's Executive Staff. She is an attorney.

Greg Coker (Rep.), since 2004; current term expires June 30, 2008. Formally V.P. External Affairs at ALLTEL; public policy positions at Bell South.

Ohio Power

President and Chief Operating Officer: Kevin Walker

Ohio Power Company (OPCo)

(organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. OPCO covers a service territory of 6,675 miles and at December 31, 2005, OPCo had 2,220 employees. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

As of 12/31/2005
Total Customers:

• **Residential**	**610,000**
• **Commercial**	**90,000**
• **Industrial**	**7,000**
• **Other**	**3,000**
Total	**709,000**

Generating Capacity **8,952 MW**

Generating Capacity by Fuel Mix:

- **Coal:** **94.6%**
- **Hydro:** **5.4%**

Transmission Miles	**6,500**
Distribution Miles	**26,000**

Principal industries served:

Primary metals
Rubber and plastic products
Stone, clay, glass and concrete products
Petroleum refining
Chemicals

p. 1

Ohio Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	2,082,195	1,487,920	3,570,115	2,053,641	1,490,479	3,544,120	2,280,107	1,784,586	4,064,693
% of Capitalization Per Balance Sheet	58.3%	41.7%	100.0%	57.9%	42.1%	100.0%	56.1%	43.9%	100.0%
Adjusted Capitalization	2,082,195	1,487,920	3,570,115	2,061,962	1,482,159	3,544,121	2,288,427	1,776,267	4,064,694
% of Adjusted Capitalization	58.3%	41.7%	100.0%	58.2%	41.8%	100.0%	56.3%	43.7%	100.0%
FFO Interest Coverage			6.5			4.9			6.2
FFO Total Debt			28.3%			22.6%			23.8%

2005 Financial Data (in thousands)

Revenue	$ 2,635,000
% of AEP Retail	17%
Net Income	$ 245,000
Capital Expenditure	$ 711,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 6,331,000
Net Plant Assets	$ 4,785,000
Cash	$ 1,240

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 1,065,400	$ 954,500	$ 581,600

Ohio Power

Ohio Power Generation Production Statistics – 2002 - 2004				
Production Stat	**2003**	**2004**	**2005**	**Three Year Average**
MWh Produced	53,099,905	52,156,749	52,080,585	52,445,746
Coal Consumption (tons burned)	20,936,936	20,534,361	20,382,116	20,617,804

Operating Information

2004 retail sales in megawatt-hours	28,929,494
2004 firm wholesale sales in megawatt-hours	2,225,194
Average cost per kilowatt-hour (residential)	6.56 cents (OPCo)
2004 System Peak	5,638 megawatts (OPCo-Aug 12)

Ohio Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Gen. JM Gavin #1,2	Cheshire, Ohio	2,600	Coal
Mitchell #1,2	Moundsville, West Virginia	1,600	Coal
Muskingum River #1, 2, 3, 4, 5	Beverly, Ohio	1,425	Coal
John E. Amos #3 *(2/3; 1/3 owned by APCo)*	St. Albans, West Virginia	867	Coal
Phillip Sporn # 2, 4, 5	New Haven, West Virginia	750	Coal
Kammer #1, 2, 3	Moundsville, West Virginia	630	Coal
Cardinal #1 *(Two other units owned by Buckeye Power)*	Brilliant, Ohio	600	Coal
Racine #1	Racine, Ohio	48	Hydro

Ohio Power

OHIO UTILITIES

Ohio	Customers
AEP Ohio*	**1,408,846**
First Energy**	1,099,919
Cinergy (CG&E)	647,329
DP&L	506,608
Monongahela Power***	29,196

* AEP Ohio - CSPCo = 702,006
OPCo = 706,840

** First Energy - Toledo Edison = 162,117
CEI = 251,965
Ohio Edison = 685,837

***December 31, 2005, CSPCo purchased the electric utility operations of Monongahela Power Company in Ohio

TYPICAL BILL COMPARISON*

Ohio	
AEP (OPCo)	**63.41**
AEP (CSP)	**75.35**
Cinergy (CG&E)	79.64
DP&L	91.12
FE (CEI)	113.19
FE (Toledo Ed)	115.70
FE (Ohio Ed)	115.75

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report. Ohio rates represent POLR bundled residential rates.

OHIO POWER MAJOR CUSTOMERS

Century Aluminum Company
The Timken Company
Wheeling Pittsburgh – WHX HQ
Premcor Refining Group, Inc.
Republic Engineered Products, LLC
Globe Metallurgical, Inc
Marathon Petroleum Company LLC
Duke Energy Corp
Linde Gas
Owens Corning Fiberglas Corp.

<u>**OPCo:**</u>

- **Top 10 customers = 50% of industrial sales**
- **Metropolitan areas account for 52% of ultimate sales**
- **135 persons per square mile (U.S. = 95)**

Public Service Company of Oklahoma

President and Chief Operating Officer: Stuart Solomon

Public Service Company of Oklahoma (PSO)

(organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 514,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO has a service territory of 30,000 square miles and at December 31, 2005, PSO had 1,176 employees. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

Principal industries served:

Natural gas and oil production
Oil refining
Steel processing
Aircraft maintenance
Paper manufacturing and timber products
Glass
Chemicals
Cement
Plastics
Aerospace manufacturing
Telecommunications
Rubber goods

As of 12/31/2005

Total Customers:

• **Residential**	**442,000**
• **Commercial**	**58,000**
• **Industrial**	**7,000**
• **Other**	**7,000**
Total	**514,000**

Generating Capacity	**4,153 MW**

Generating Capacity by Fuel Mix:

• **Coal:**	**25%**
• **Natural Gas:**	**75%**

Transmission Miles	**3,600**
Distribution Miles	**21,000**

Public Service Company of Oklahoma

CAPITAL STRUCTURE (thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	607,162	488,275	1,095,437	601,095	534,517	1,135,612	646,954	553,858	1,200,812
% of Capitalization Per Balance Sheet	55.4%	44.6%	100.0%	52.9%	47.1%	100.0%	53.9%	46.1%	100.0%
Adjusted Capitalization	607,162	488,275	1,095,437	603,726	531,886	1,135,612	649,585	551,228	1,200,813
% of Adjusted Capitalization	55.4%	44.6%	100.0%	53.2%	46.8%	100.0%	54.1%	45.9%	100.0%
FFO Interest Coverage			3.8			5.5			2.8
FFO Total Debt			20.4%			28.2%			9.5%

2005 Financial Data (in thousands)

Revenue	$ 1,304,000
% of AEP Retail	14%
Net Income	$ 58,000
Capital Expenditure	$ 134,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 2,355,000
Net Plant Assets	$ 1,819,000
Cash	$ 1,520

Estimated Capital Expenditures
(in thousands)

2006	2007	2008
$ 262,000	$ 342,800	$ 408,700

Public Service Company of Oklahoma

Public Service Company of Oklahoma Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	14,845,846	12,512,486	15,375,848	14,244,727
Coal Consumption (tons burned)	4,678,950	4,093,436	4,353,364	4,375,250

Operating Information

2005 retail electric sales in megawatt-hours	17,782,561
2005 firm wholesale sales in megawatt-hours	45,172
Average cost per kilowatt-hour (residential)	7.55 cents
2005 System Peak	4,043 MW (July 22)

Oklahoma Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Tulsa	Tulsa, Oklahoma	338	Nat Gas, Oil
Riverside	Jenks, Oklahoma	920	Nat Gas, Oil
Northeastern #1, 2	Oologah, Oklahoma	943	Nat Gas, Oil
Southwestern	Anadarko, Oklahoma	474	Nat Gas, Oil
Comanche	Lawton, Oklahoma	277	Nat Gas, Oil
Weleetka	Weleetka, Oklahoma	167	Nat Gas, Oil
Northeastern #3, 4	Oologah, Oklahoma	926	Coal, Oil
Oklaunion *(16% ownership)*	Vernon, Texas	108	Coal

Public Service Company of Oklahoma

PUBLIC SERVICE COMPANY OF OKLAHOMA UTILITIES

Oklahoma	Customers
PSO	507,214
OG&E	**668,766**

PUBLIC SERVICE COMPANY OF OKLAHOMA MAJOR CUSTOMERS

Weyerhaeuser Company
Sheffield Steel Corp.
Kimberly Clark Corp.
Goodyear Tire & Rubber Company
Transok Inc
AMR Corporation
Sunoco Inc.
Terra Nitrogen Limited Partner
Republic Paperboard
Wal-Mart Stores, Inc.

TYPICAL BILL COMPARISON*

Oklahoma		
OG&E	**73.33**	
PSO	**74.20**	
SPSCo	**82.52**	
Empire District	**85.25**	

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

- **Top 10 customers = 44% of industrial sales**
- **Metropolitan areas account for 75% of ultimate sales**
- **46 persons per square mile (U.S. = 95)**

Regulatory Information

Oklahoma Corporation Commission

AEP Regulated Electric Utilities

Public Service Company of Oklahoma

Commissioners

Number: **3**	**Appointed / Elected:** Elected	Term**: 6 years**	Political Makeup: **R: 3**

Qualifications for Commissioners

The Oklahoma Corporation Commission (OCC) is composed of three commissioners who are elected by state-wide vote. Commissioners serve staggered six-year terms so one commissioner vacancy occurs every two years. The election pattern was established when the Commission was created by the state constitution.

Commissioners

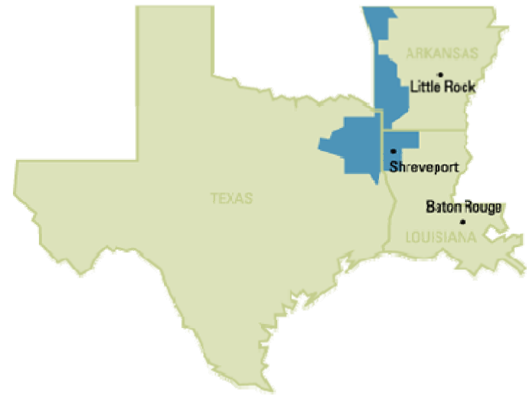
Jeff Cloud, Chairman (Rep.), since 2002; current term ends January 2009. Member, NARUC. Served as U.S. Congressman's District Director. Served as the Oklahoma City Mayor's Chief of staff. Law degree from Oklahoma City University.

Denise A. Bode, Vice-Chairman (Rep.), since 1997; current term ends January 2011. Member, NARUC. Former president of the Independent Petroleum Association of America (IPAA). Graduated with a bachelor's degree in political science from the University of Oklahoma. Founding partner of a Washington D.C. firm. Law degree from George Mason University and a master's of law in taxation from Georgetown University.

Bob Anthony, Commissioner (Rep.), since 1989; current term expires January 2007. Member, NARUC. Served on the boards of the Oklahoma State, Oklahoma City, and South Oklahoma City chambers of commerce. Earned a M.Sc. from the London School of Economics, a M.A. from Yale University, and an M.P.A. from the Kennedy School of Government at Harvard University.

Southwestern Electric Power

President and Chief Operating Officer: Nick Akins



Southwestern Electric Power Company (SWEPCo)

(organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 450,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo has a service territory of 25,000 square miles and at December 31, 2005, SWEPCo had 1,498 employees. The territory served by SWEPCo also includes several military installations, colleges, and universities. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

As of 12/31/2005

Total Customers:

• **Residential**	**381,000**
• **Commercial**	**61,000**
• **Industrial**	**7,000**
• **Other**	**<u>1,000</u>**
Total	**450,000**

Generating Capacity **4,487 MW**

Generating Capacity by Fuel Mix:

- **Coal/Lignite:** **60%**
- **Natural Gas:** **40%**

Transmission Miles	**3,500**
Distribution Miles	**19,300**

Principal industries served:

Natural gas and oil production
Petroleum refining
Manufacturing of pulp and paper
Chemicals
Food processing
Metal refining.

Southwestern Electric Power

CAPITAL STRUCTURE (in thousands)

CAPITAL STRUCTURE	2003			2004			2005		
	Debt	Equity	Total	Debt	Equity	Total	Debt	Equity	Total
Capitalization Per Balance Sheet	890,675	701,360	1,592,035	806,494	773,318	1,579,812	774,245	787,077	1,561,322
% of Capitalization Per Balance Sheet	55.9%	44.1%	100.0%	51.0%	49.0%	100.0%	49.6%	50.4%	100.0%
Adjusted Capitalization	890,675	701,360	1,592,035	808,844	770,968	1,579,812	776,595	784,727	1,561,322
% of Adjusted Capitalization	55.9%	44.1%	100.0%	51.2%	48.8%	100.0%	49.7%	50.3%	100.0%
FFO Interest Coverage			4.1			5.7			3.8
FFO Total Debt			22.9%			31.4%			18.1%

2005 Financial Data (in thousands)

Revenue	$ 1,405,000
% of AEP Retail	12%
Net Income	$ 74,000
Capital Expenditure	$ 158,000

2005 Asset Data (in thousands)

	As of 12/31/05
Total Assets	$ 2,797,000
Net Plant Assets	$ 2,230,000
Cash	$ 3,049

Estimated Capital Expenditures

(in thousands)

2006	2007	2008
$ 314,900	$ 366,700	$ 458,400

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Southwestern Electric Power

Southwestern Electric Power Generation Production Statistics – 2003 - 2005				
Production Stat	**2003**	**2004**	**2005**	**Three-Year Average**
MWh Produced	20,539,365	20,071,578	20,167,754	20,259,566
Coal Consumption (tons burned)	12,536,179	13,032,475	12,420,979	12,663,211

Operating Information

2005 retail electric sales in megawatt-hours	17,069,455
2005 firm wholesale sales in megawatt-hours	5,554,340
Average cost per kilowatt-hour (residential)	6.92 cents
2005 System peak	4725 MW (Aug 23)

SWEPCO Power Plants			
Name	**Location**	**Megawatt Capacity**	**Fuel**
Flint Creek #1 *(Own 50% and operate)*	Gentry, Arkansas	264	Coal
Arsenal Hill #5	Shreveport, Louisiana	110	Gas
Liberman #1, 2, 3, 4	Mooringsport, Louisiana	269	Gas
Dolet Hills #1 *(Own 40%: operated by CLECO)*	Mansfield, Louisiana	262	Lignite
Pirkey #1 *(Own 86% and operate)*	Hallsville, Texas	580	Lignite
Knox Lee #2, 3, 4, 5	Longview, Texas	486	Gas
Wilkes #1, 2, 3	Avlinger, Texas	882	Gas
Welsh #1, 2, 3	Cason, Texas	1,584	Coal
Lone Star #1	Lone Star, Texas	50	Gas

Southwestern Electric Power

SOUTHWESTERN ELECTRIC POWER UTILITIES

Arkansas	**Customers**
SWEPCO	**107,220**
Entergy AR	667,714

Louisiana	**Customers**
SWEPCO	**169,079**
CLECO	261,601

Texas	**Customers**
SWEPCO	**279,729**

TYPICAL BILL COMPARISON*

Arkansas	
SWEPCO	**66.15**
OG&E	**72.11**
Empire District	**74.71**
ETR	**88.92**

Louisiana	
SWEPCO	**68.83**
CLECO	90.13
Entergy Gulf St	92.69
Entergy NO	96.65
Entergy LA	102.08

Texas	
SWEPCO	**63.95**
SPSCo	83.19
ETR	93.43
EP	106.64
TXU	118.84

* Typical bills are displayed in $/month, based on 1,000 kwh of residential usage. Billing amounts sourced from the EEI 2005 Typical Bills and Average Rates Report.

Lone Star Steel Company
Tyson Foods Inc
Domtar, Inc
International Paper Company
Pilgrim Pride Corporation
Calumet Lubricants
General Motors Corporation
Wal-Mart Stores, Inc.
Cooper Tire & Rubber Company
Superior Industries Int

- **Top 10 customers = 38% of industrial sales**
- **Metropolitan areas account for 74% of ultimate sales**
- **77 persons per square mile (U.S. = 95)**

Regulatory Information

Arkansas Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 3	**Appointed/Elected:** Appointed	**Term:** 6 years	**Political Makeup:** R: 3

<u>Qualifications for Commissioners</u>

The Arkansas Public Service Commission (APSC) is composed of 3 members. The Governor appoints the Commissioners as well as the Chairman. Governor Huckabee has appointed all of the current commissioners.

<u>Commissioners</u>

Sandra Hochstetter, Chairman (Rep.), since 1999; current term ends Jan 2011. Executive Director of Arkansas Public Service Commission (1999-2000). Governor's Regulatory Liaison (1999). Assistant General Counsel, Reliant Energy (1986-1998). Attained Bachelor of Arts in Social Work at University of Arkansas. Juris Doctorate at Washington University School of Law.

Randy Bynum, Commissioner (Rep.), since 2003; current term ends in 2007. Lawyer, private practice in Washington D.C. and Little Rock, Arkansas, Certified Public Accountant in Arkansas (inactive), former President of Bynum Furniture Group. Bachelor's attained at University of Arkansas. Juris Doctorate at George Washington University.

Daryl E. Bassett, Commissioner (Rep.), since 2004; current term ends in 2009. Former policy advisor for Governor. Governor's state budget director (2002-2003). Investment Banker for First State Investments/Merrill Lynch Fenner and Pierce (1985-1995). Bachelor's attained at Harding University (Business-Public Administration).

Regulatory Information

Louisiana Public Service Commission

AEP Regulated Electric Utilities

Southwestern Electric Power Co.

Commissioners

Number: 5	**Appointed/Elected:** Elected	**Term:** 6 years	**Political Makeup: R:** 2 **D:** 3

Qualifications for Commissioners

The Louisiana Public Service Commission (LPSC) is composed of five elected members. The commissioners serve overlapping terms of six years.

Commissioners

Jack A. Blossman, Jr. (Rep.), since 1997; current term ends December 2008. Practicing attorney, member of NARUC Gas Committee. Board member of Parish National Bank, member, Lake Ponchartrain Basin Foundation. Juris Doctorate from Southern Law School.

James M. Field, (Rep.), since 1996; current term ends December 2006. Practicing attorney, member of Electrical Committee of NARUC. NFL contract advisor (1983-present), member, Sports Lawyers Association. Juris Doctorate from Louisiana State University.

Lambert C. Bossiere, III (Dem.), since 2005; current term ends December 2011. B.S. Business Administration from Southern University. American University of Paris – International Trade Law – Paralegal Certificate. Former First City Court Constable for the City of New Orleans.

C. Dale Sittig, (Dem.), since 1995; current term ends December 2010. Member, Louisiana House of Representatives, (1983-1995). Member, Chamber of Commerce.

Foster L. Campbell, (Dem.), since 2003; current term ends December 2008. Member, Louisiana State Senate (1976-2002). Independent insurance businessman and farmer, former school teacher and agricultural products salesman. Bachelor's degree from Northwestern State University.

Texas Investor Meetings
Hosted by Wells Fargo
August 17, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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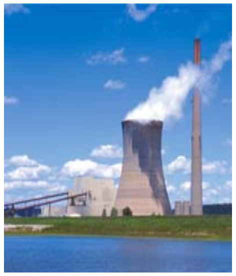
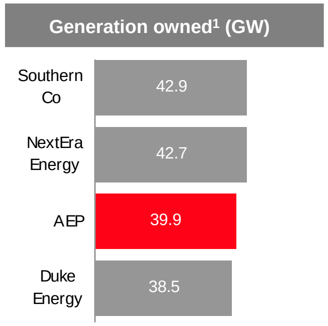
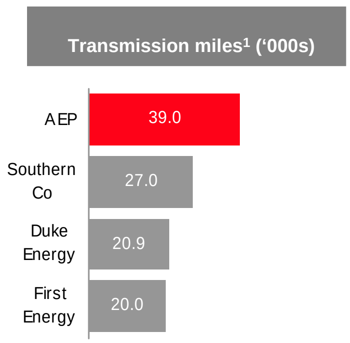
American Electric Power



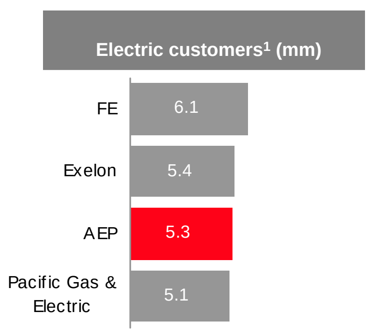
One of the largest
U.S. electricity generators



The largest U.S. electricity
transmitter

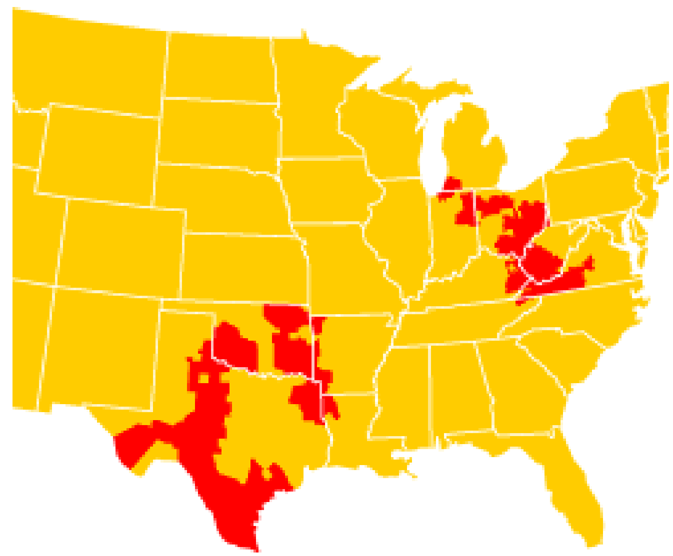


One of the largest U.S.
electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

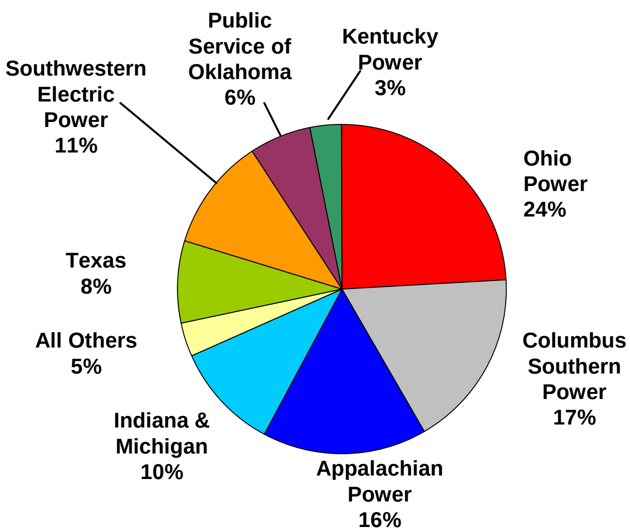
$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.0B Market Capitalization
BBB/Baa2/BBB credit rating

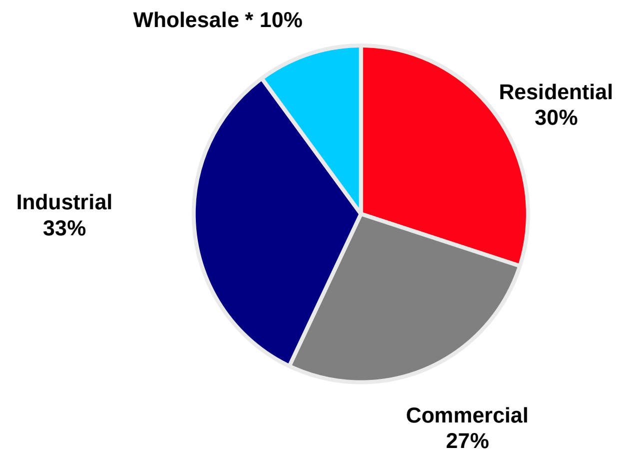
* - represents results for 2010

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load

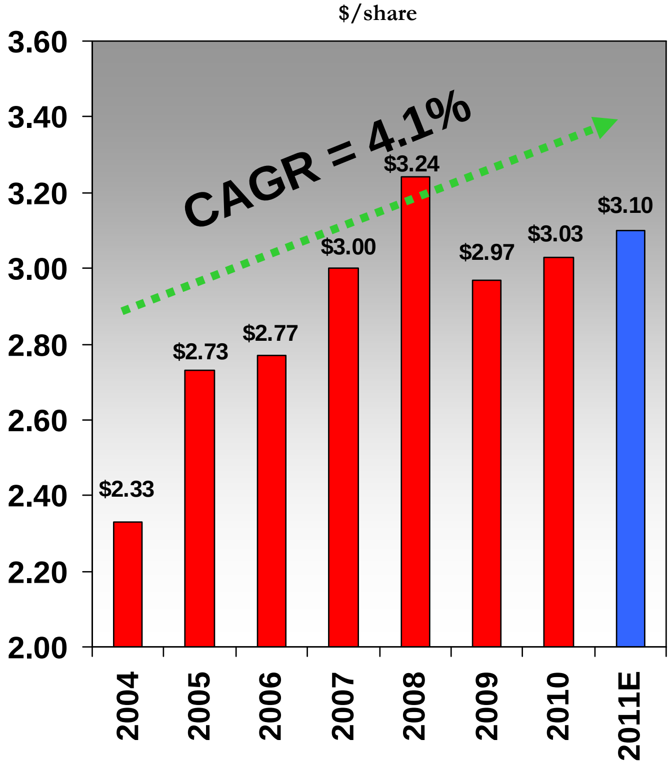


** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

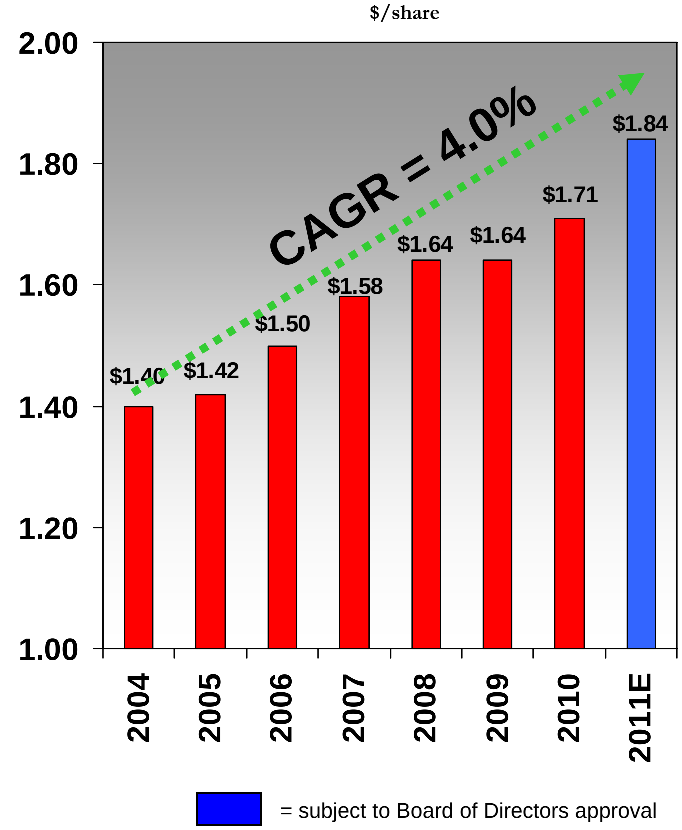
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004



- Quarterly dividend <u>increased 12%</u> in 2010
- <u>405th consecutive</u> quarterly dividend declared July 27, 2011
- 50-60% payout ratio target
- Current yield over 5.0%

7

Detailed Ongoing Earnings Guidance

AEP®

2010A: $3.03

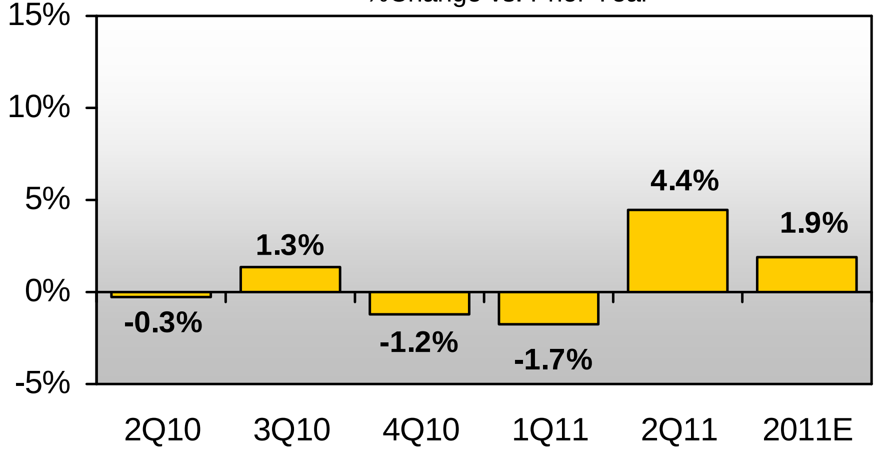
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

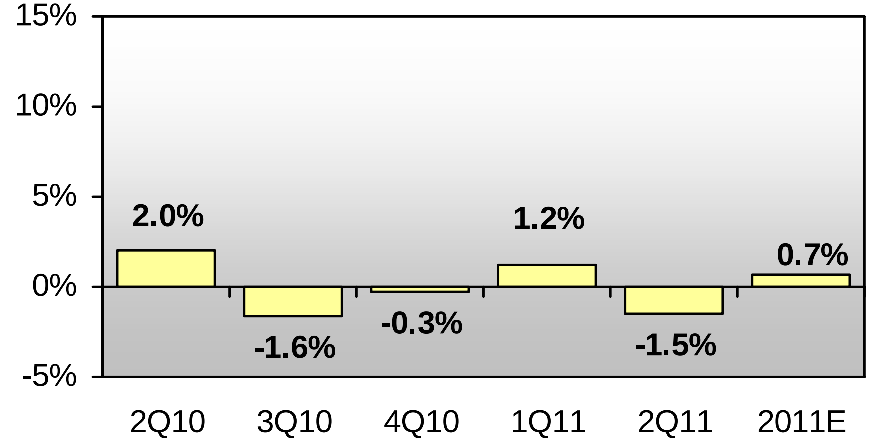
		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Normalized Load Trends

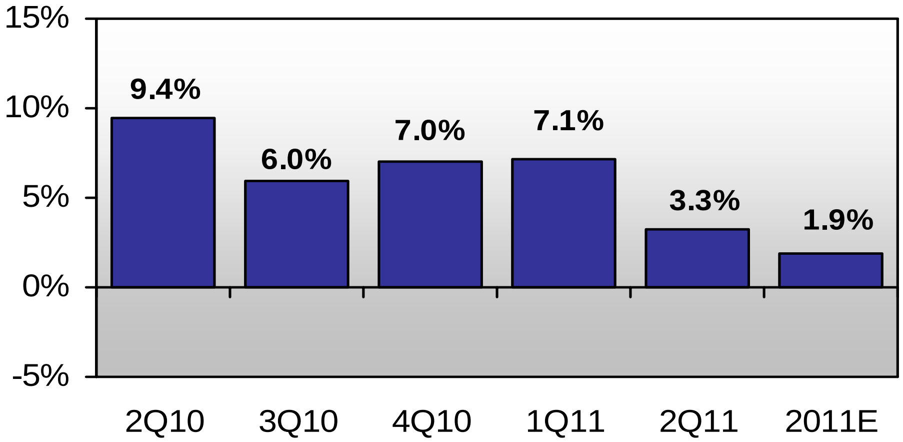
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



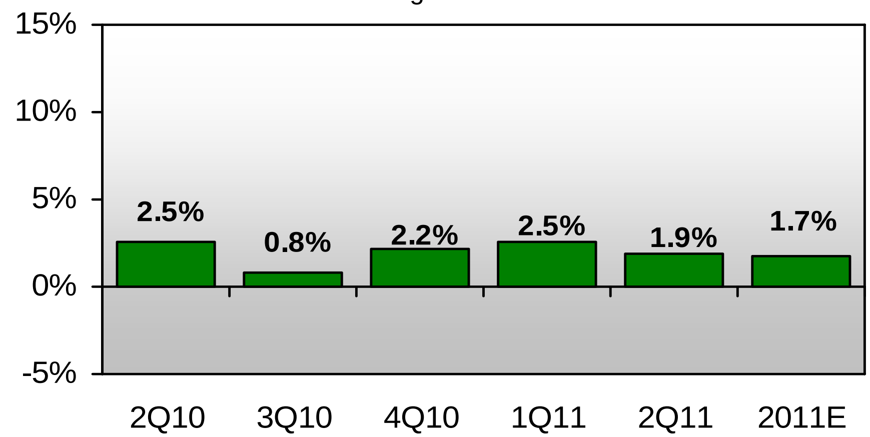
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



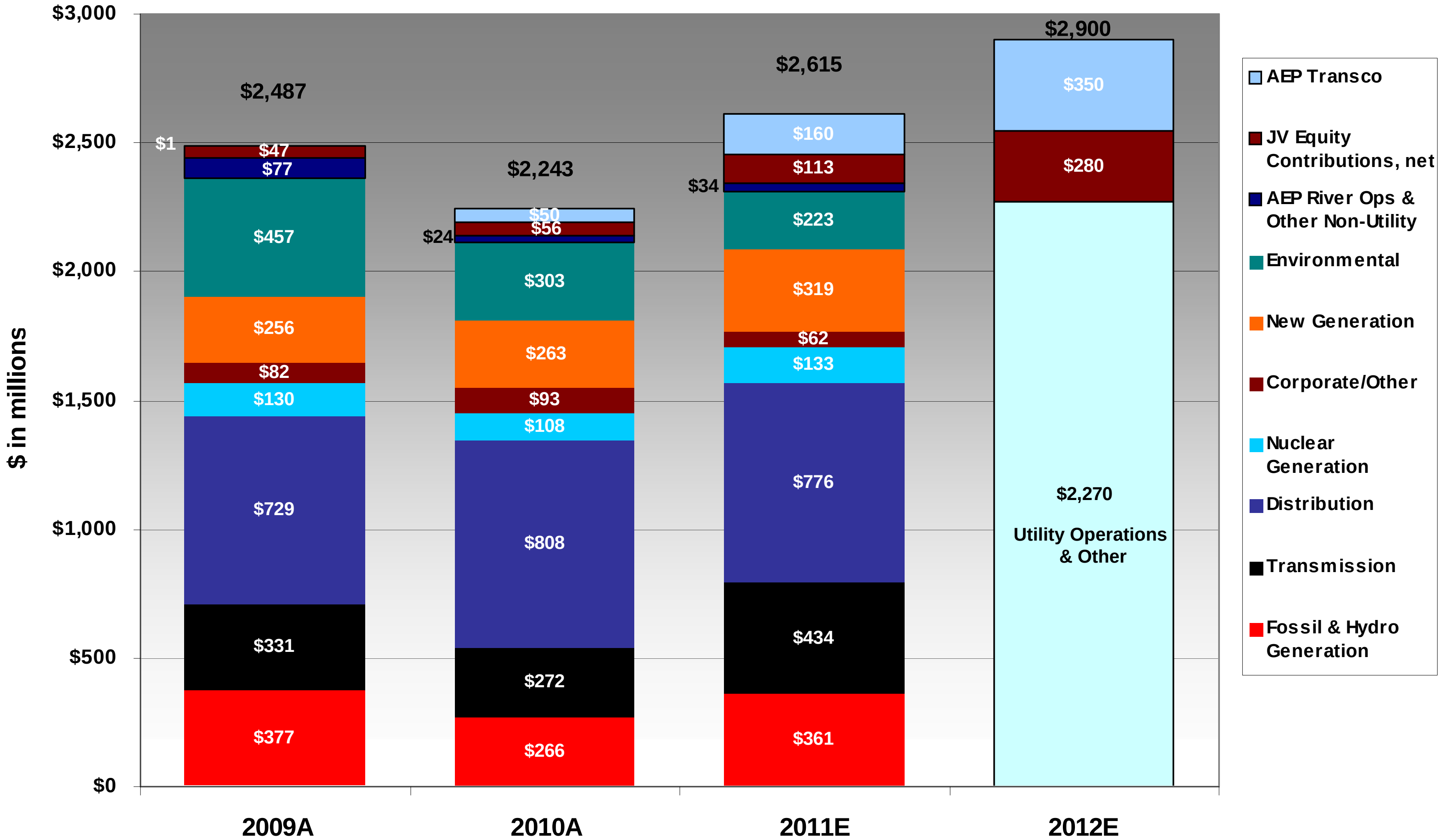
AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year provide rate base growth in 2011 and 2012

Cash Flow Guidance

	$ in millions 2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution	-	(211)
Working Capital	279	7
Cash From Operations	$ 3,297	$ 3,590
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(421)
Total Investing Activities	$ (2,502)	$ (3,065)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)	(160)	217
Common Equity	93	150
Other Financing Activities	(100)	(56)
Total from Financing Activities	$ (991)	$ (581)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 238

Long-term Debt Maturity Profile

($ in millions)

Year	2011	2012	2013
AEP, Inc.	-	-	-
AEP Generating Company	$130	-	-
Appalachian Power	-	$315	$195
Columbus Southern Power	-	$195	$306
Indiana Michigan Power	-	$100	$126
Kentucky Power	-	-	-
Ohio Power	-	-	$550
Public Service of Oklahoma	-	-	-
Southwestern Electric Power	$41	$20	-
Texas Central Company(1)	-	$60	$381
Texas North Company	-	-	$225
Total	$171	$690	$1,783

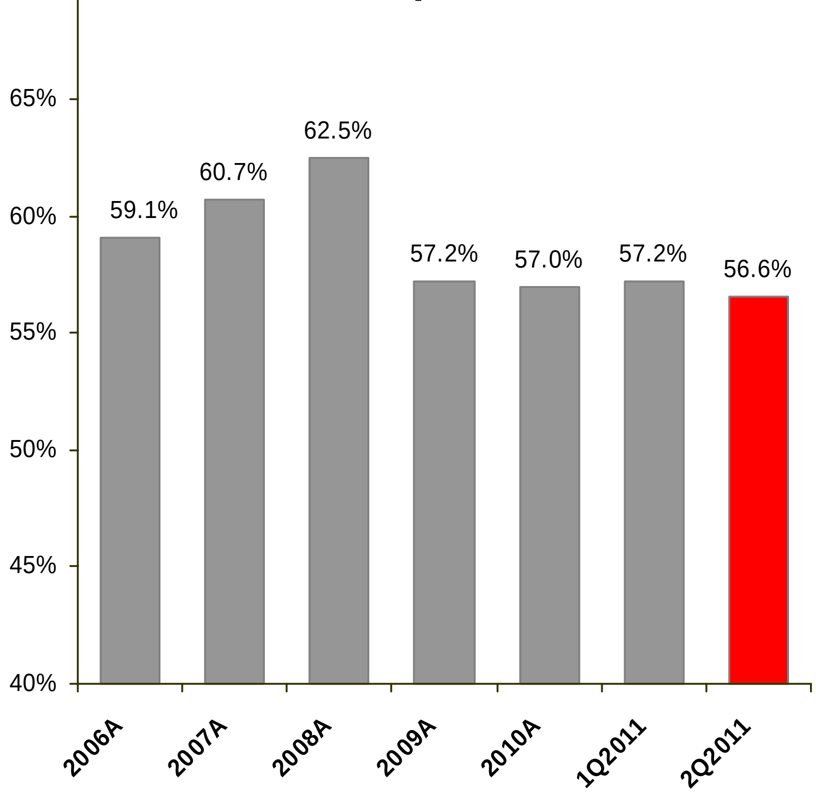
(1) Includes amortizing Texas Securitization Bonds

Includes mandatory tenders (put bonds)

Data as of June 30, 2011

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Liquidity Summary (06/30/2011)

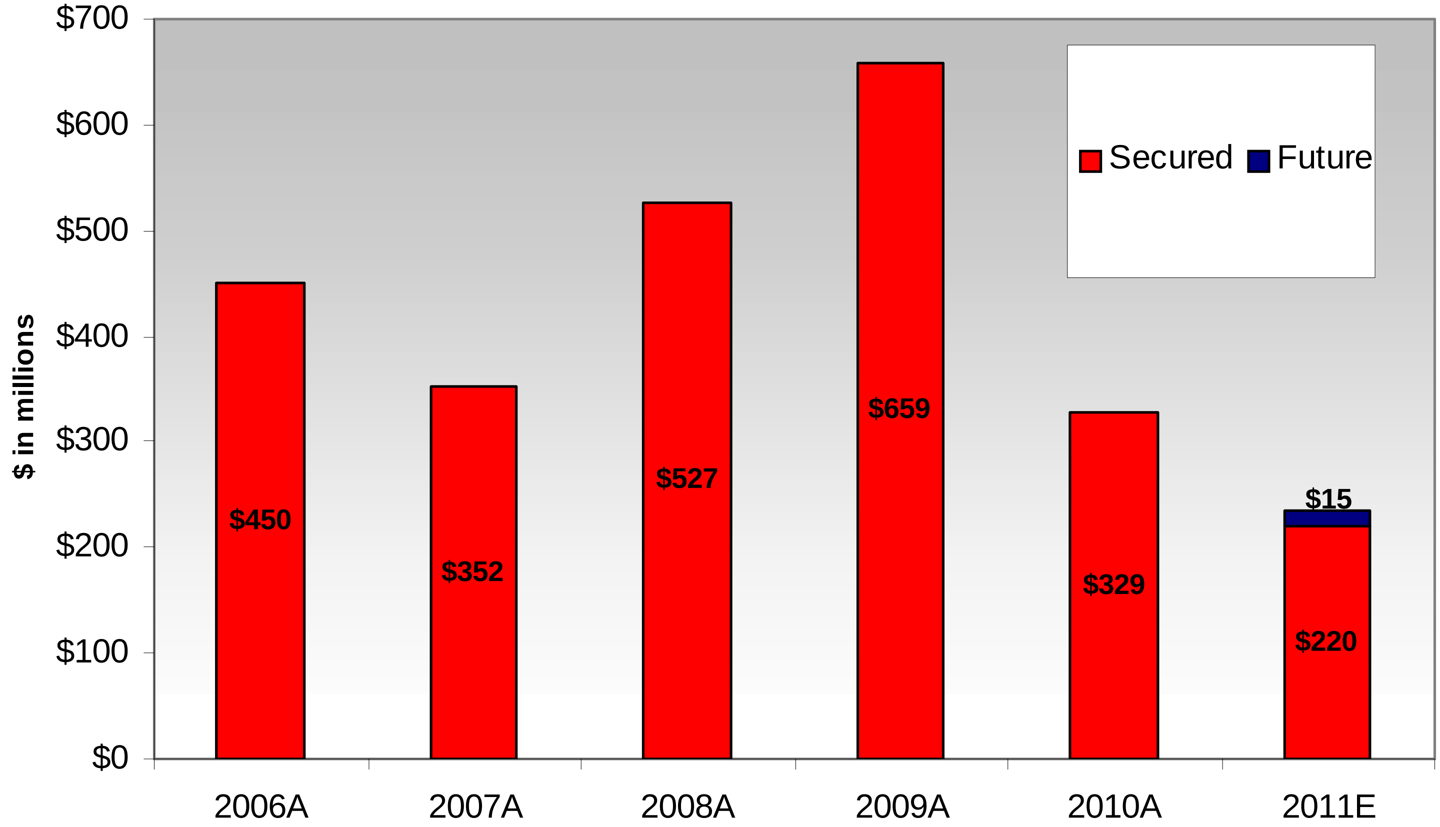
Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,500	Jun-13
Revolving Credit Facility		1,454	Apr-12
Total Credit Facilities		**2,954**	
Plus			
Cash & Cash Equivalents		417	
Less			
Commercial Paper Outstanding		(944)	
Letters of credit issued		(132)	
Net available Liquidity	**$**	**2,295**	

On July 26, 2011, we renewed and upsized the facility expiring in April 2012. The new facility has a capacity of $1.75B and expires in July 2016.

We also extended and repriced the facility expiring in June 2013. That facility now expires in June 2015.

This brings our total available capacity to $3.25B.

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo Virginia Base Rate Case - Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase). (Docket #:) A procedural schedule is pending from the VSCC.

In conjunction with this case, an environmental rate adjustment clause (E-RAC), generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed . APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Projected Capital Structure - Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Intervenor Testimony	August 5, 2011
Staff Testimony	August 19, 2011
Rebuttal Testimony	September 1, 2011
Hearing	September 13, 2011

Required Rate Relief - Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP®

I&M Michigan Base Rate Case (Docket# U-16801)

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M intends to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$2,428MM	10.00%	57/43	3/30/2011
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Summary of ESP Filing

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012); $106MM or 2.7% in year 2 (2013)**
  - **Intervenor Testimony – July 15; Staff testimony – August 4; Hearing August 29, unless settlement reached sooner**

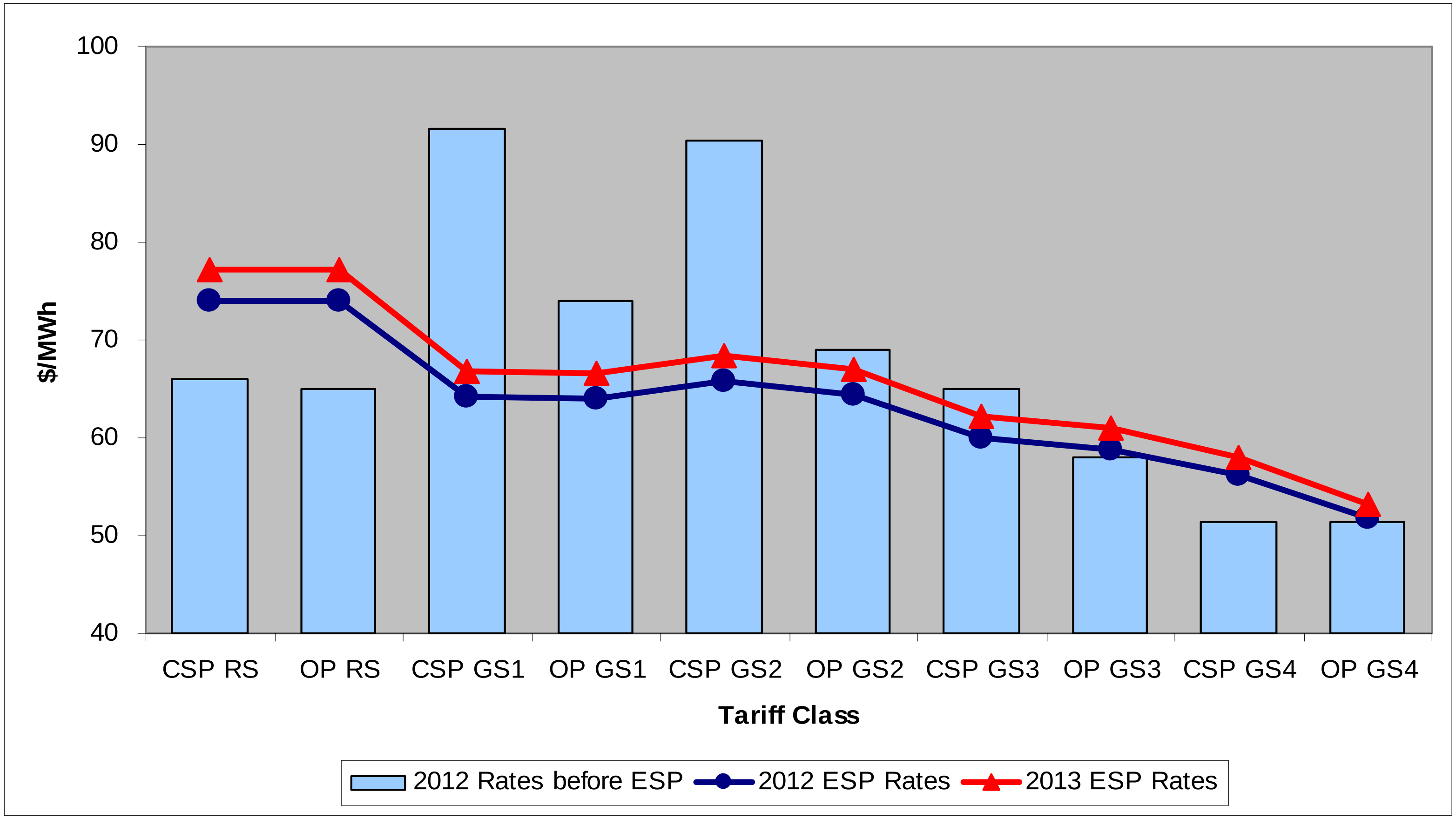
	2012			**2013**			**2014**		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Illustration of Market Transition Rider on ESP Generation Rate Increases

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

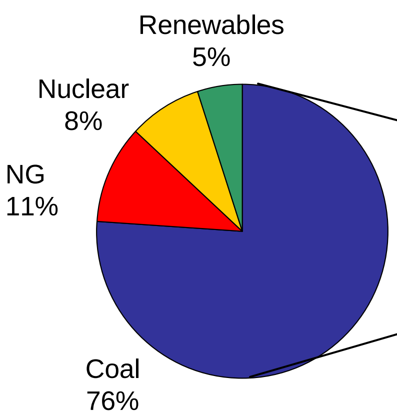
List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

AEP Generation Capacity

East Capacity – 27,253 MW

AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

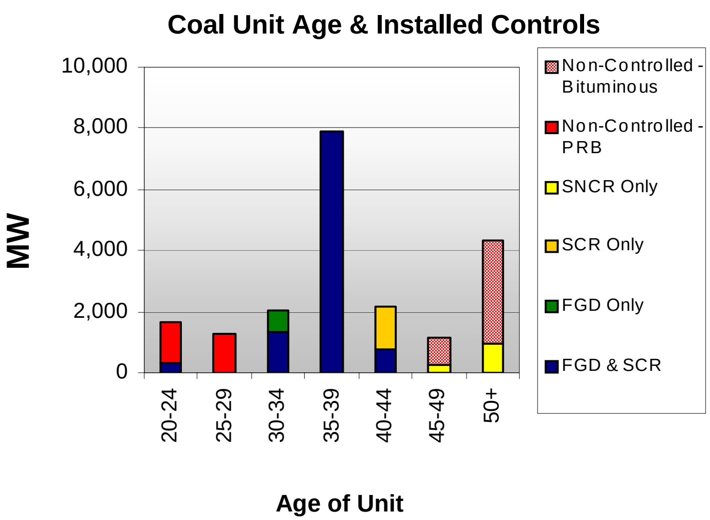


Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

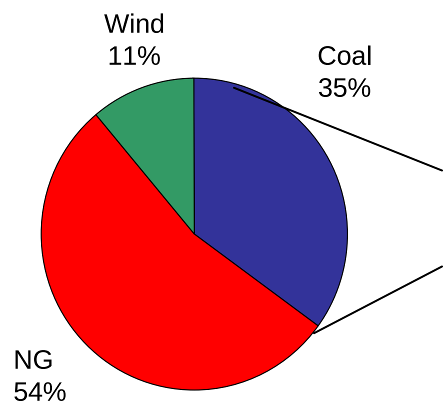
Avg. Delivered Cost

2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



West Capacity – 11,677 MW

PSO, SWEPCO, TNC, Wind

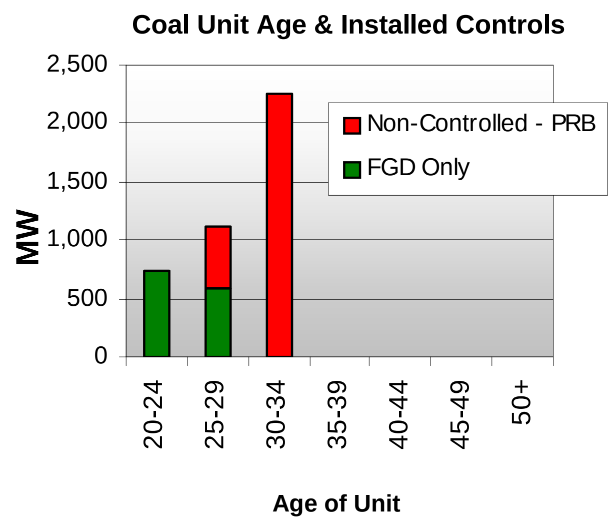


Coal Source

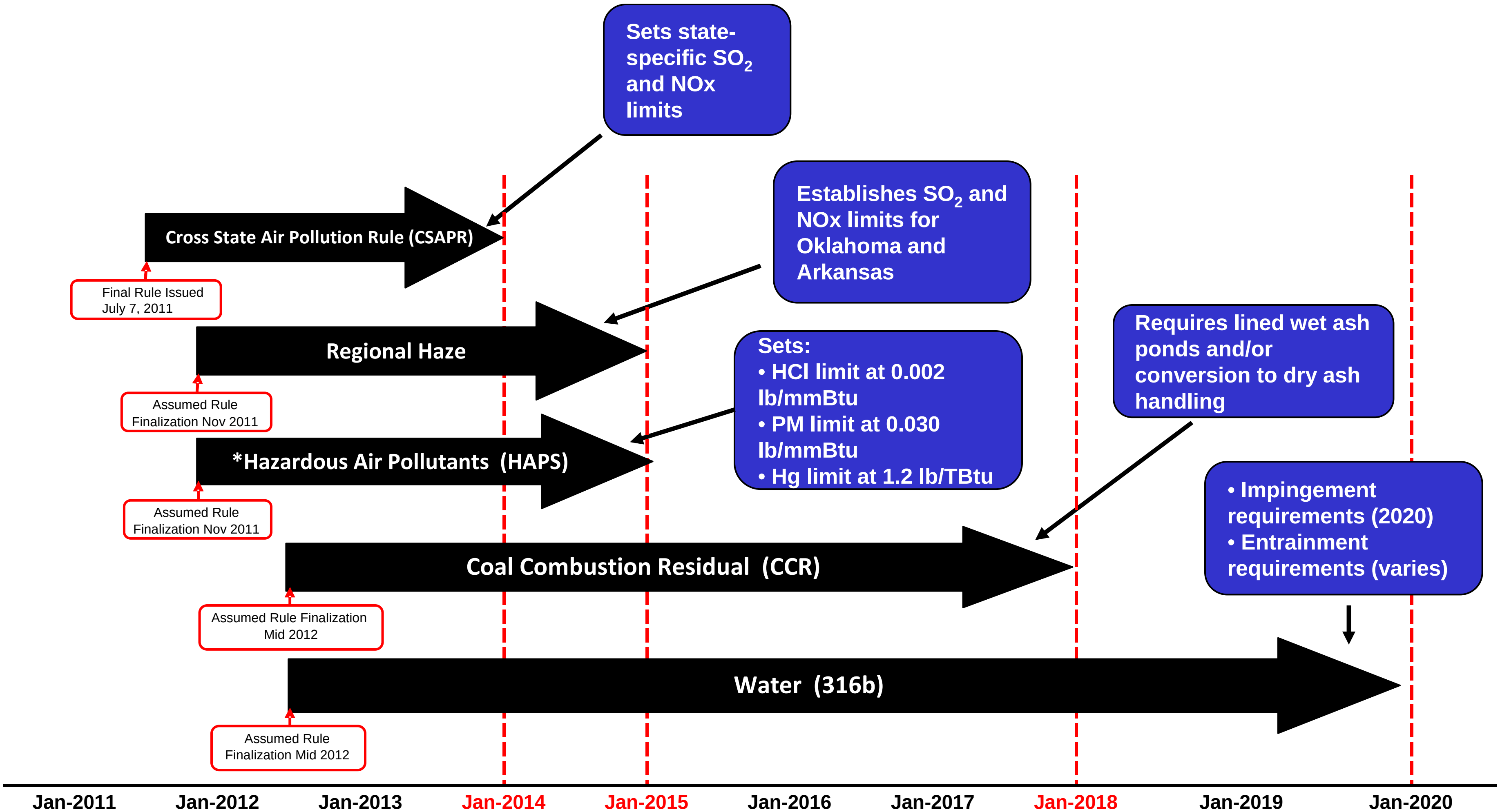
PRB	75%
Lignite	25%

Avg. Delivered Cost

2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



Anticipated environmental regulations and compliance deadlines



* Units that will be retrofit are eligible for a one year compliance extension from the EPA

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5	510	Refuel with Natural Gas			
	Gavin 1	1320	FGD upgrade			
	Gavin 2	1320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	*
APCO	Clinch River 1	211	Refuel with Natural Gas			
	Clinch River 2	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	**
I&M	Rockport 1	1320	FGD, SCR			
	Rockport 2	1320	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670**	***
KPCO	Big Sandy 1	640	New Natural Gas			
	Total MW	**640**	**Total Expected Cost**		**525**	

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

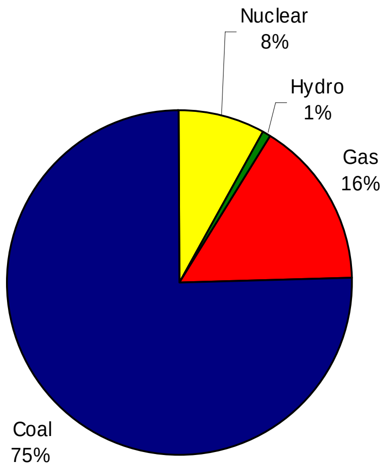
Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

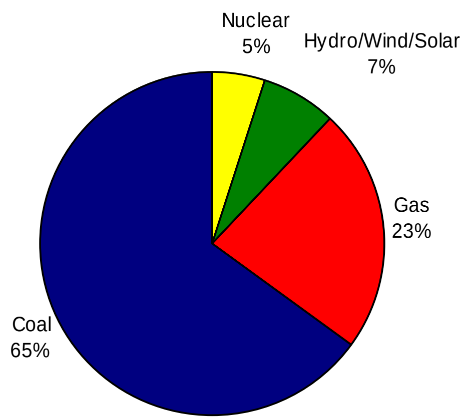
- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

Generation Transformation

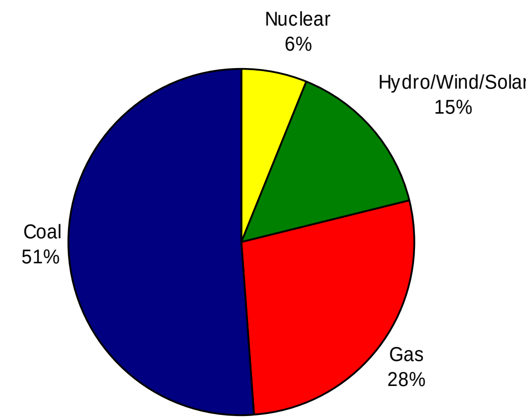
1990 AEP Generating Capacity by Fuel
37,428 total MW's



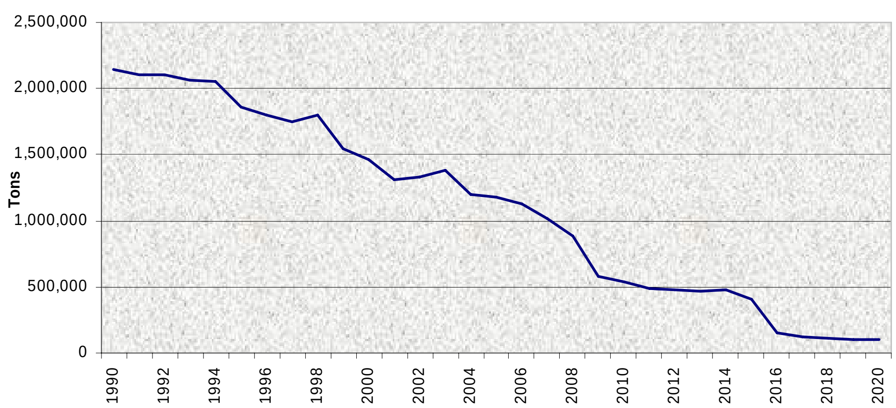
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

Environmental Project Status Report

AEP®

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	In-service
Amos 2	800	☑	In-service	☑	In-service
Amos 3	1300	☑	In-service	☑	In-service
Big Sandy 2	800	☑	In-service		
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375			☑	In-service
Conesville 6	375			☑	in-service
Gavin 1&2	2620	☑	In-service	☑	In-service
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service		
CCD Plants					
Conesville 4	339	☑	In-service	☑	In-service
Stuart 1-4	620	☑	In-service	☑	In-service
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262			☑	In-service
Oklaunion	485			☑	In-service
Pirkey	580			☑	In-service

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market. Total capital expenditures of $3 billion with a 9.96% ROE.

- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism. Will spend $160 million in 2011 and more than $350 million in 2012. ROE is in the 11.20%-11.49% range.

- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, reasonable ROEs and FERC incentives where appropriate.

Transmission has a diversified investment approach that positions it as one of the key AEP growth businesses.

Texas Transmission Growth Strategy : Near Term Investment

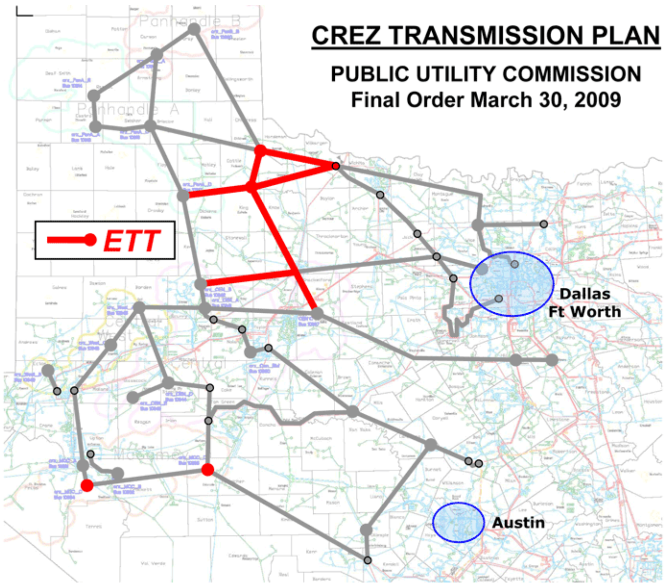
Ownership Structure: 50/50 (AEP/MidAmerican Energy Holding Company)

Total Project Cost: Over $3 Billion

Growing Rate Base:
Current rate base is $412 million; expected to grow as follows:
2011: $473 million
2012: $778 million
2013: $1,352 million

Interim TCOS filings twice per calendar year

Approved ROE: 9.96%



- **Additional Projects in the Pipeline ~$1.6 B:**
  - Approximately 822 miles of lines and 28 substations with in-service dates through 2017

- **Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:**
  - Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
  - PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

Joint Venture Strategy: Long-term

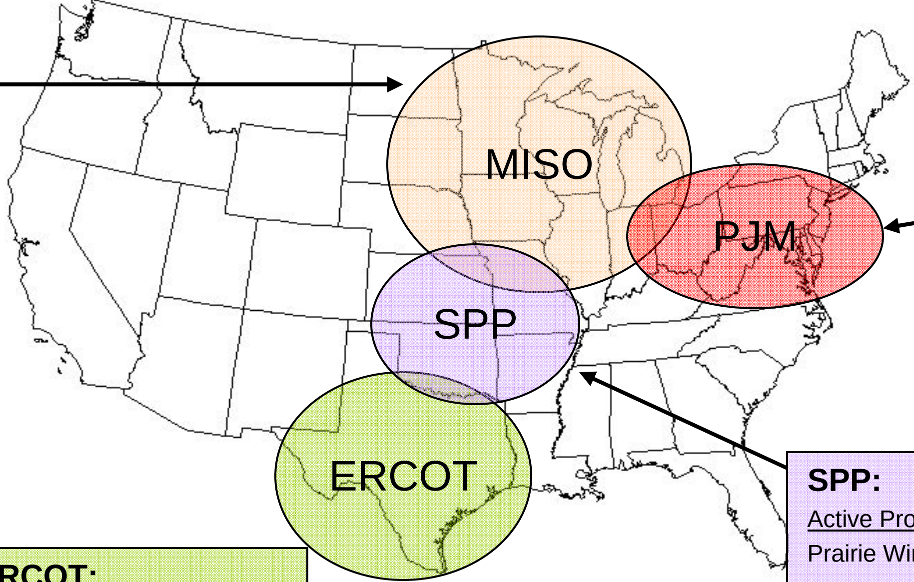
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

AMERICAN ELECTRIC POWER

Toronto Investor Meetings

Hosted by Keybanc

August 4, 2009

AEP AMERICAN® ELECTRIC POWER

STRONG
FLEXIBLE
ADAPTABLE

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
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Attachment 1 - Confidential
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“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of generating capacity and performance of generating plants including our ability to restore Indiana Michigan Power Company’s Donald C. Cook Nuclear Plant Unit 1 in a timely manner; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity and transmission lines (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth or contraction in our service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurred cots and recovery is long and the costs are material; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of the recently-passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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AEP AMERICAN ELECTRIC POWER

AEP Highlights

Premier utility platform

- Leadership position in electric generation, transmission and distribution operations
- Cash flow, earnings and regulatory diversity with more than 5 million customers in 11 states
- $6.3 billion capital expenditure program (2009-2011) will continue to drive rate base growth

Effective regulatory relationships

- Traditional recovery mechanisms with equitable risk allocation enhance both earnings and cash flow
- Emerging energy policies play to AEP's strengths (transmission, energy efficiency, reliability)
- Constructive local relationships deliver successful regulatory outcomes

High-growth transmission business

- The leading US transmission owner, operator, and developer
- Exceptional portfolio of high-quality development projects and project partners
- Attractive ROEs, regulatory support and access to capital will drive earnings growth beyond our traditional utility footprint

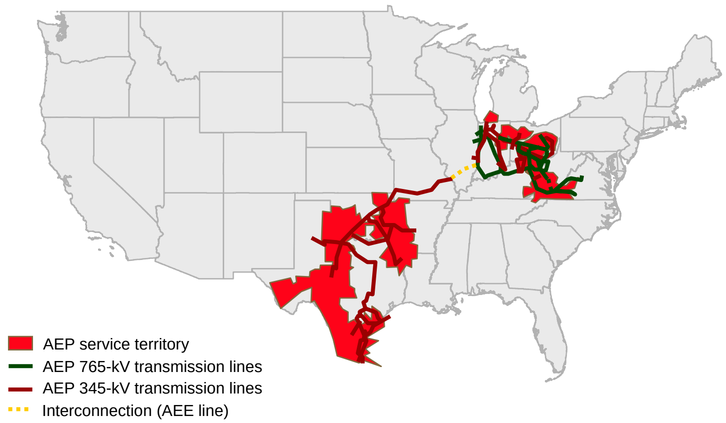
Stable financial position

- Maximization of shareholder value through regulated utility and transmission investments
- Balanced approach to cost containment and capital allocation
- Commitment to investment grade profile, prudent balance sheet, and liquidity management
- Conservative dividend payout with attractive yield

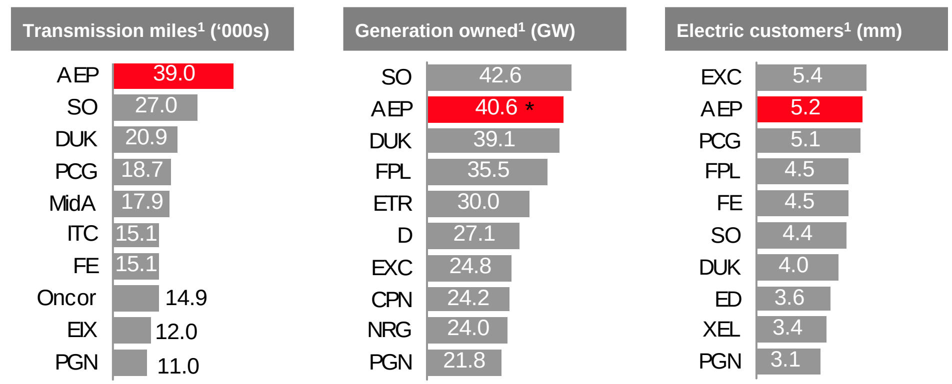
AEP AMERICAN ELECTRIC POWER

Premier Regulated Utility Platform

Overview

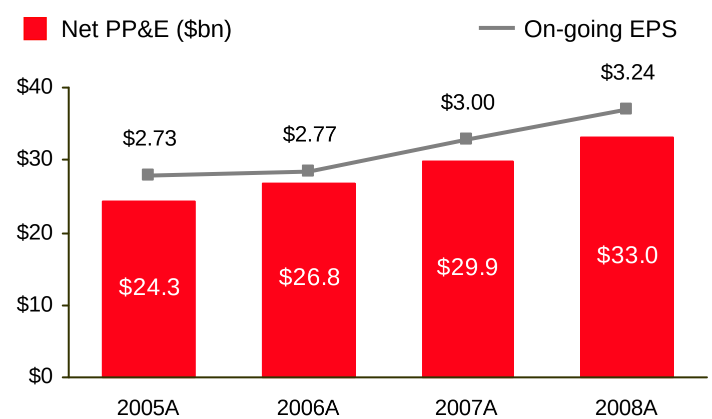


AEP's Leadership Position

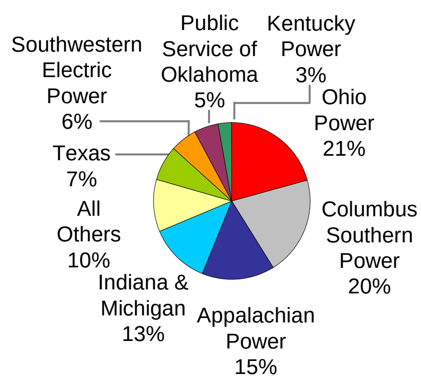


* - AEP generation includes long-term PPAs and generation under construction

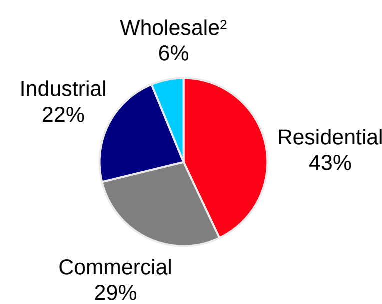
Regulated Operations



- *Net PP&E CAGR of 10.7% since 2005*
- *Earnings CAGR of 5.9% since 2005*



2008 On-going Earnings = $1.3bn



2008 Retail Base Revenue = $6.4bn

- *Highly diversified regulated utility earnings contribution*
- *Balanced customer mix*

¹ *Source: Company filings*
² *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

AMERICAN ELECTRIC POWER

Energy Policy Initiatives are Core to Our Strategy

Greenhouse Gas Reduction & Regulation

- Actively engaging in CO_2 policy debate – support cap & trade with allocated credits
- Leadership position in development of carbon capture and storage technology
- Reducing carbon footprint via offsets and other measures
- Founding member of Chicago Climate Exchange

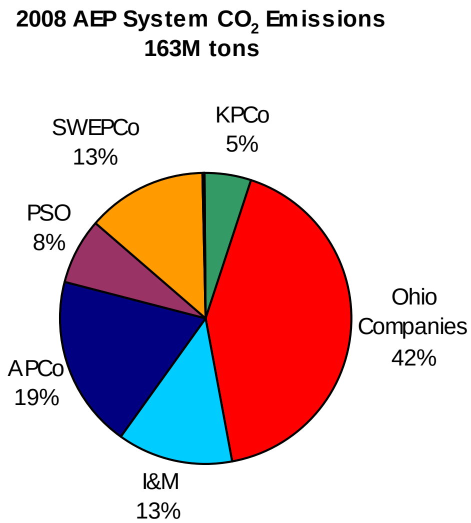
Renewable Energy

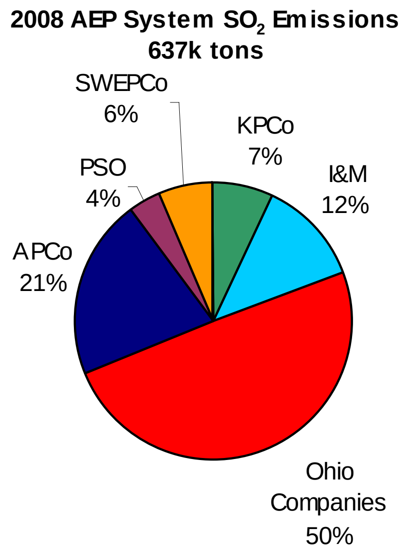
- Develop “transmission superhighway” to facilitate renewable energy projects
- Satisfy RES requirements in our jurisdictions – currently Ohio with 25% (renewables + advanced) by 2025, Texas with ~ 5% by 2015, West Virginia with 25% (renewables + advanced) and Michigan with 10% by 2015; Voluntary goal of 12% by 2022 in Virginia
- Add 2,000MW of wind capacity via long-term PPAs – 903MW achieved to-date

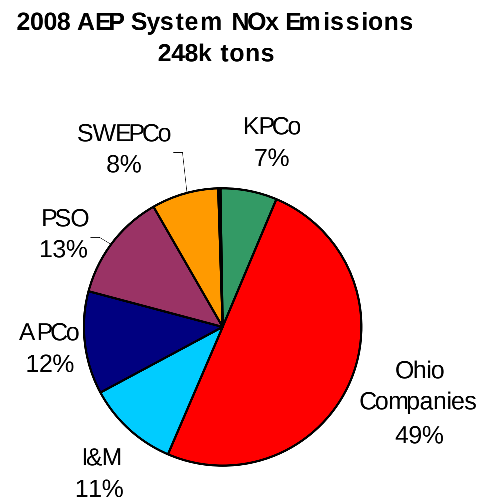
Energy Efficiency, Security & Reliability

- Develop high-voltage transmission projects to strengthen America’s power grid
- Build generation to ensure reliable supply
- Reduce 1,000MW of demand by 2012
- Reduce 2.25 million MWhs of consumption by 2012
- Diversify our fuel mix; have added 3,705MW of gas-fired capacity since 2005 and have 1,080MW under construction

CO_2 Cost Recovery – Should Follow SO_2 & NOx







- 100% of SO_2 and NOx allowance costs currently recovered through tracker or similar mechanisms
- Prudently incurred costs associated with carbon-based taxes and other carbon-related regulations explicitly included in Ohio Fuel Adjustment Clause

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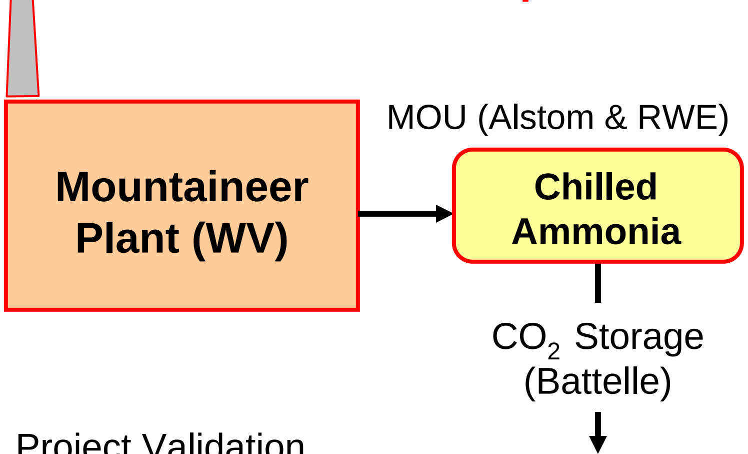
Carbon Capture & Storage

2009 Commercial Operation



Project Validation

- Alstom "Chilled Ammonia" Technology
- 20-30 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, in operation at We Energies' Pleasant Prairie Power Plant)
- Located at the AEP Mountaineer Plant in WV
- 100,000 - 300,000 tonnes CO_2 per year
- In operation 3Q 2009
- Geologic storage for CO_2
- Underground injection control permit received in May 2009 from WV Dept. of Environmental Protection

Represents Post-Combustion Capture

- **Conventional or Advanced Amines; Chilled Ammonia**
  - Amine technologies are currently available in other industrial applications
  - Relatively low CO_2 concentration in flue gas - more difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~ 25-30%
    - Chilled Ammonia target ~ 10-15%

Key Issues for CCS Development in the U.S.

- Overcoming the 'economic' hurdle
- High up-front capital investment
- Commercial demonstration at large coal-fired power plants
- National standards for permitting of storage reservoirs
- Potential institutional, legal and regulatory barriers to carbon storage

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
AEG	Dresden	Ohio	$322 MM	Gas	Combined-cycle	580	2013
SWEPCo	Stall	Louisiana	$385 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.6 B (1)	Coal	Ultra-supercritical	600 (1)	2012

(1) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $1.2 billion in capital investment.

- Turk – In June 2009, the Arkansas Court of Appeals overturned APSC decision granting CECPN & AEP filed appeal to Supreme Court. Air permit appeal hearings were held in June 2009 and a decision is expected by year end. Construction continues.
- Stall – Construction continues.
- Dresden – Construction suspended due to shifts in capital spending. Commercial operation date has been projected for 2013 (previously 2010).

AEP AMERICAN ELECTRIC POWER

DC Cook Unit 1 Update

- Previously identified technical challenges have solutions
  - Low pressure turbine rotors have been straightened
  - Foundation repair work is in progress and is the critical path
  - Generator and high pressure turbine repair work supports the critical path
- The unit is scheduled to return to service in the fourth quarter of 2009
  - The unit will operate without the last stage blades at 30 MW (summer) to 100 MW (winter) reduced capacity
- Root cause: “A blade-rotor system design that failed to provide adequate stress margin”
  - The root cause also found no operational or installation issues
- The replacement rotors are scheduled for installation in the spring of 2011
  - Different design with several years of fault-free commercial operation.
- We continue to receive $3.5MM per week from the accidental outage policy
  - Insurance proceeds are reflected as other operating revenue; During 2009 YTD, approximately 40% of the insurance payments ($40MM) were used to offset increased fuel costs to customers

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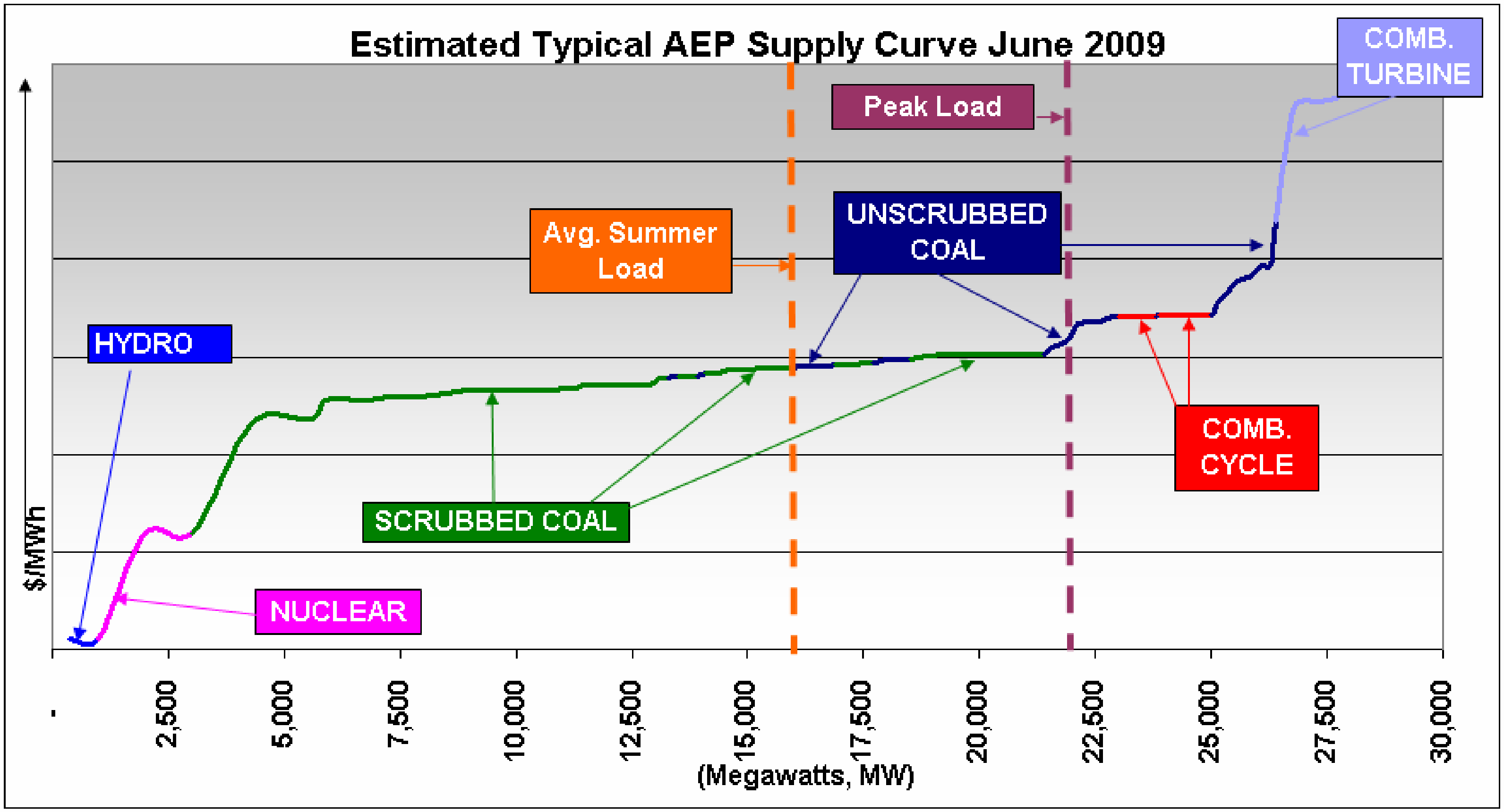
AEP Supply Stack

- Supply stack with Cook unit 1 outage would slide the supply stack 1,009 MW to the left.
- Planned outages typically shorten supply stack in the shoulder months by several thousand megawatts.
- Shoulder periods offer the flexibility to reschedule planned outages.



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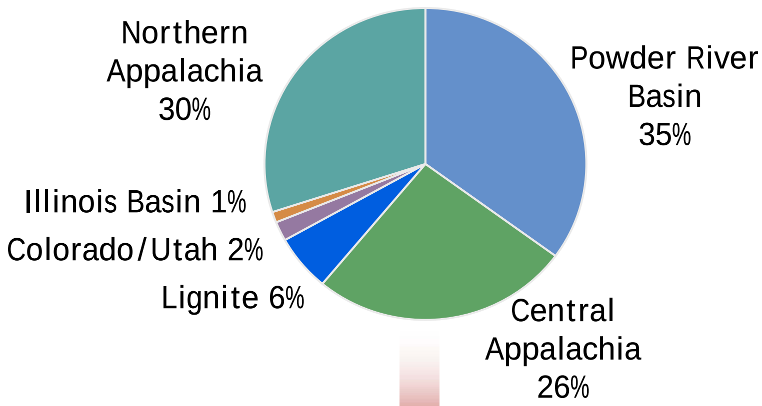
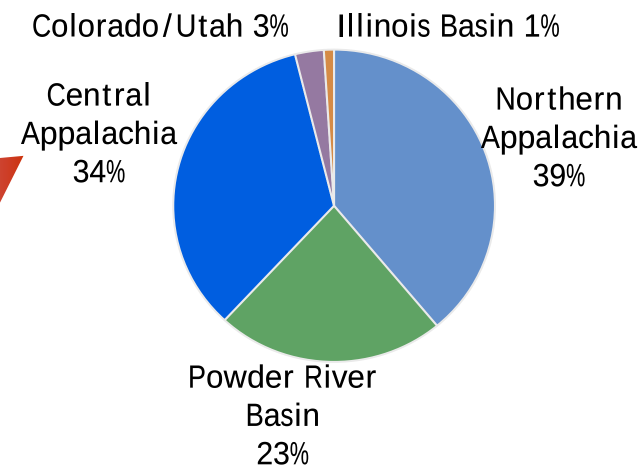
Coal Procurement - 2009 Projected

AEP burns approx. 77 million tons of coal per year

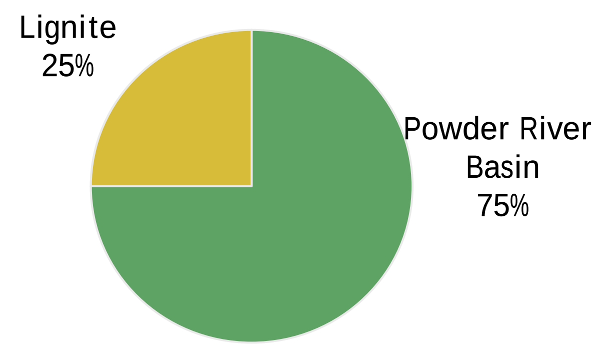
Total AEP System



AEP East



AEP West

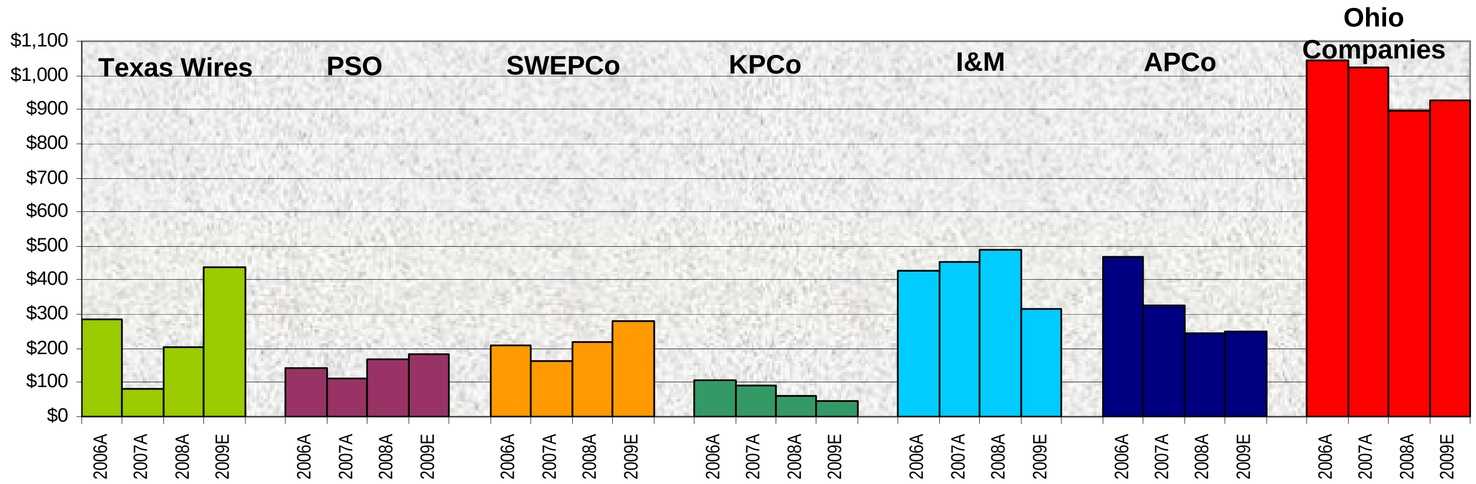


Coal Stats:

- 100% contracted for 2009
- 94% contracted for 2010
- Avg. delivered price ~ $46.61/ton in 2008
- Approximate 10% price increase in 2009 ~ $51.00/ton

AMERICAN ELECTRIC POWER

Cash Flow and Capex by Operating Company

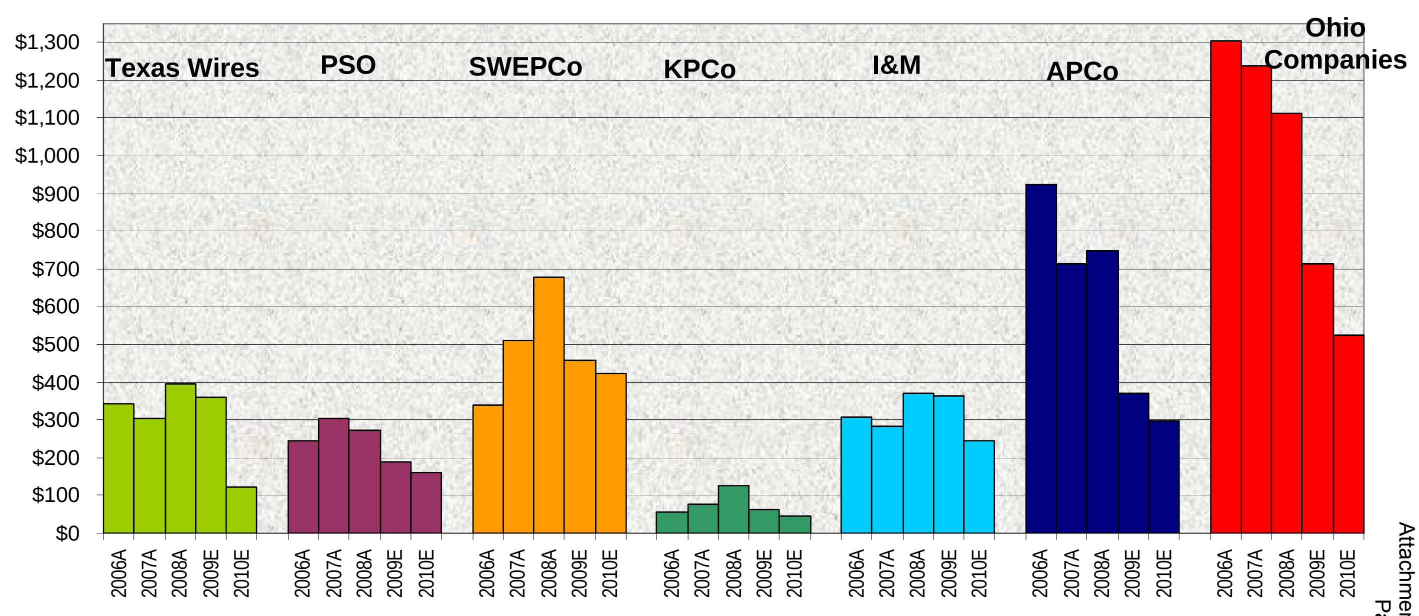


Cash Flow from Operations by Operating Company

($ in millions)

Capex by Operating Company

($ in millions)



AMERICAN ELECTRIC POWER

Detailed Ongoing Earnings Guidance

2008A: $3.24/share

2009E: $2.75-$3.05/share

American Electric Power
2008 Actual vs. 2009 Guidance

		Performance Driver	2008 Actual ($ millions)	Performance Driver	2009 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,725 GWh @ $ 31.3 /MWhr =	2,278	68,579 GWh @ $ 36.8 /MWhr =	2,523
2	Ohio Companies	52,181 GWh @ $ 46.6 /MWhr =	2,431	49,597 GWh @ $ 58.1 /MWhr =	2,879
3	West Regulated Integrated Utilities	41,907 GWh @ $ 25.2 /MWhr =	1,057	40,065 GWh @ $ 29.0 /MWhr =	1,163
4	Texas Wires	27,075 GWh @ $ 19.8 /MWhr =	537	27,267 GWh @ $ 20.6 /MWhr =	561
5	Off-System Sales	29,365 GWh @ $ 28.8 /MWhr =	845	22,763 GWh @ $ 11.4 /MWhr =	260
6	Transmission Revenue - 3rd Party		329		364
7	Other Operating Revenue		569		636
8	Utility Gross Margin		**8,046**		**8,386**
9	Operations & Maintenance		(3,366)		(3,361)
10	Depreciation & Amortization		(1,450)		(1,524)
11	Taxes Other than Income Taxes		(749)		(785)
12	Interest Exp & Preferred Dividend		(872)		(918)
13	Other Income & Deductions		168		97
14	Income Taxes		(567)		(608)
15	**Utility Operations On-Going Earnings**		**1,210**		**1,287**
16	**Transmission Operations On-Going Earnings**		**2**		**3**
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		55		48
18	Generation & Marketing		65		43
	Non-Utility Operations On-Going Earnings		**120**		**91**
19	**Parent & Other On-Going Earnings**		**(31)**		**(78)**
20	**ON-GOING EARNINGS**		**1,301**		**1,303**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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Overview of 2009 Guidance

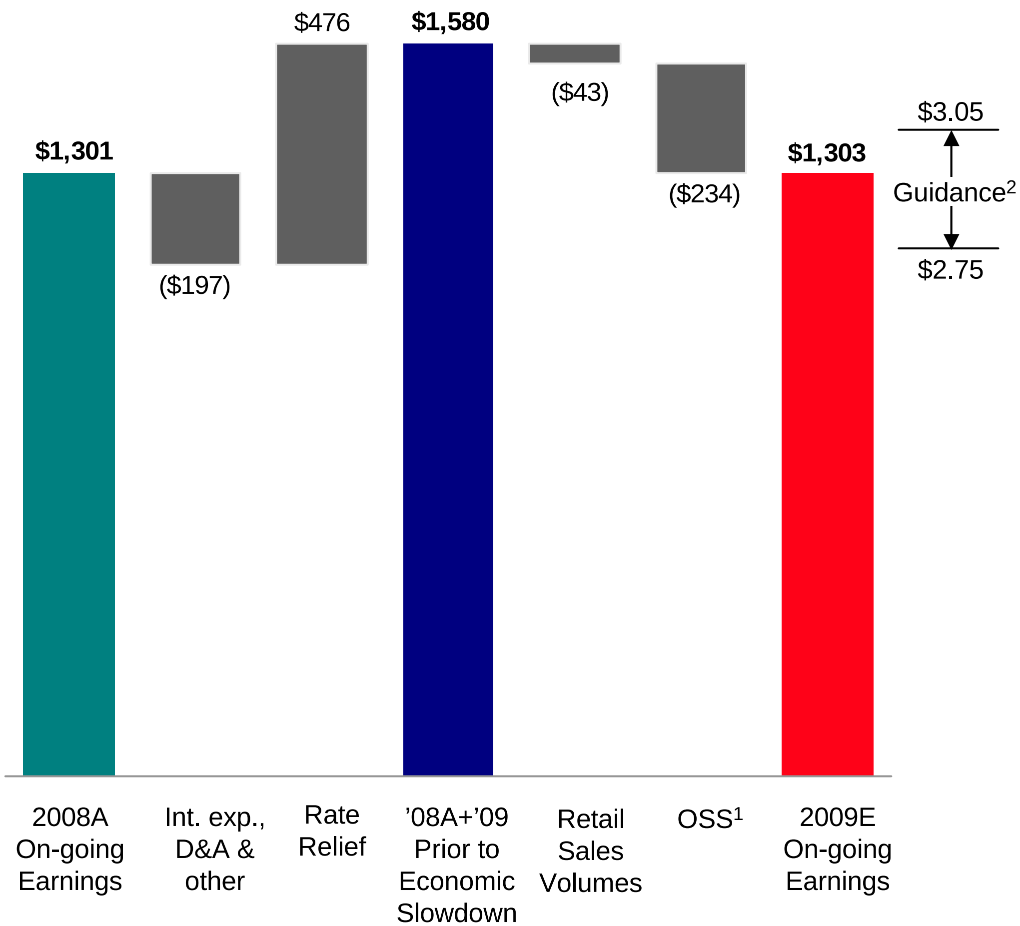
2009 Earnings Drivers:

- Positive Ohio outcome
- Rate relief - $732mm
- Economic slowdown
  - Lower OSS revenues
  - Lower loads

Long-term Earnings Drivers:

- Rate base investments
- Additional rate relief
- OSS/Retail load
- Transmission JV earnings

2008A-2009E Earnings Bridge ($mm)



Note all items are presented after-tax

[1] Net of sharing

[2] Assumes 2009 average shares outstanding ~ 450 million

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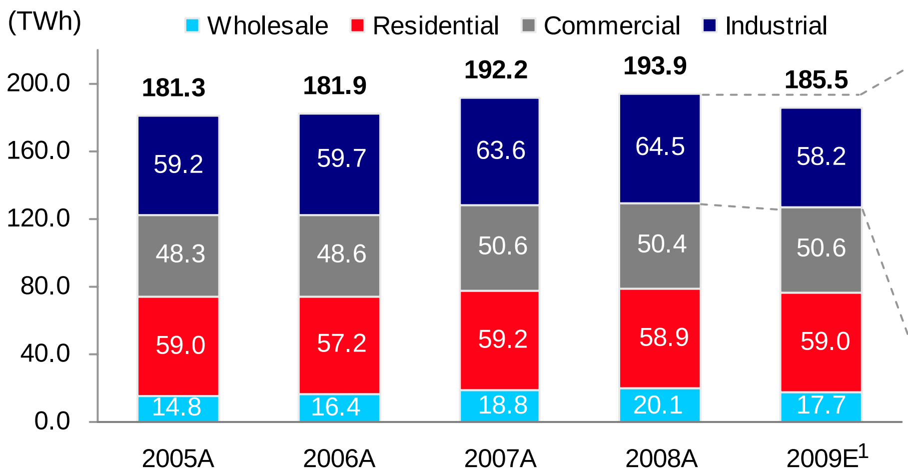
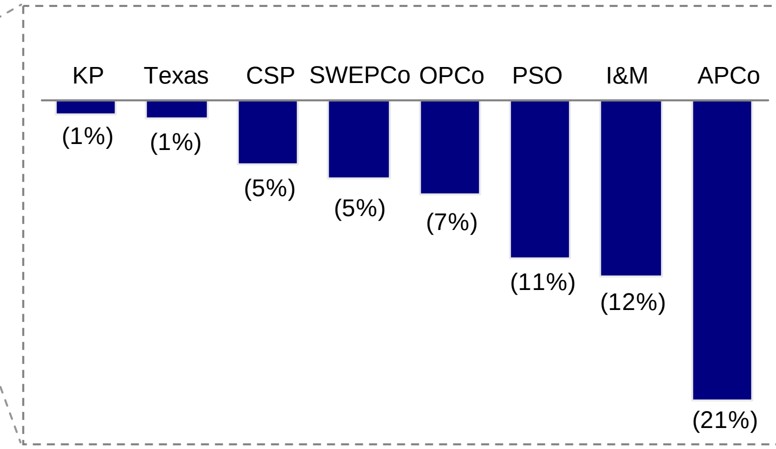
Key Drivers of 2009 Guidance: Retail Sales

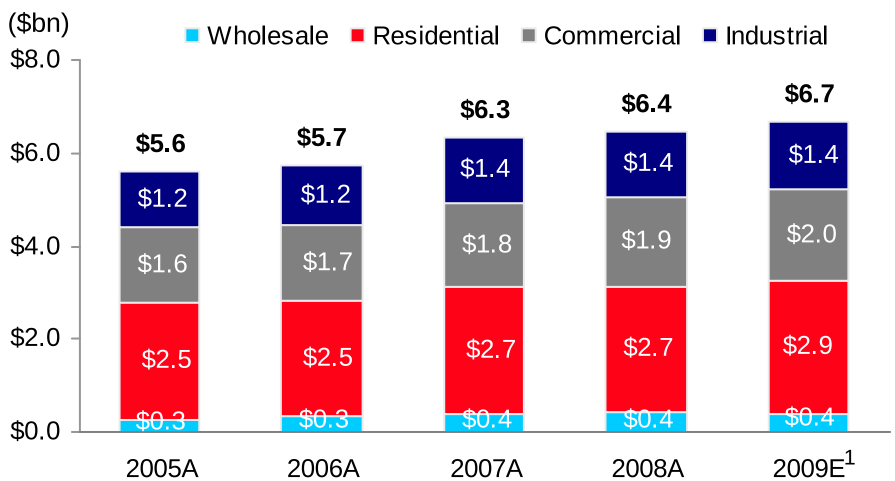
Retail Load by Customer Class



Forecast Drop in 2009 Industrial Sales



Retail Base Revenue[2] by Customer Class



Key Contributors to 2009E Industrial Volume Decline

- Primary metals (APCo, I&M, OPCo, CSP, SWEPCo, KP)
- Basic industries (I&M)
- Paper (PSO, SWEPCo)
- Oil & Gas extraction (PSO, SWEPCo)

[1] 2009E assumes normalized weather
[2] Excludes the impact of current year rate relief, fuel over/under recovery, PJM costs and consumables

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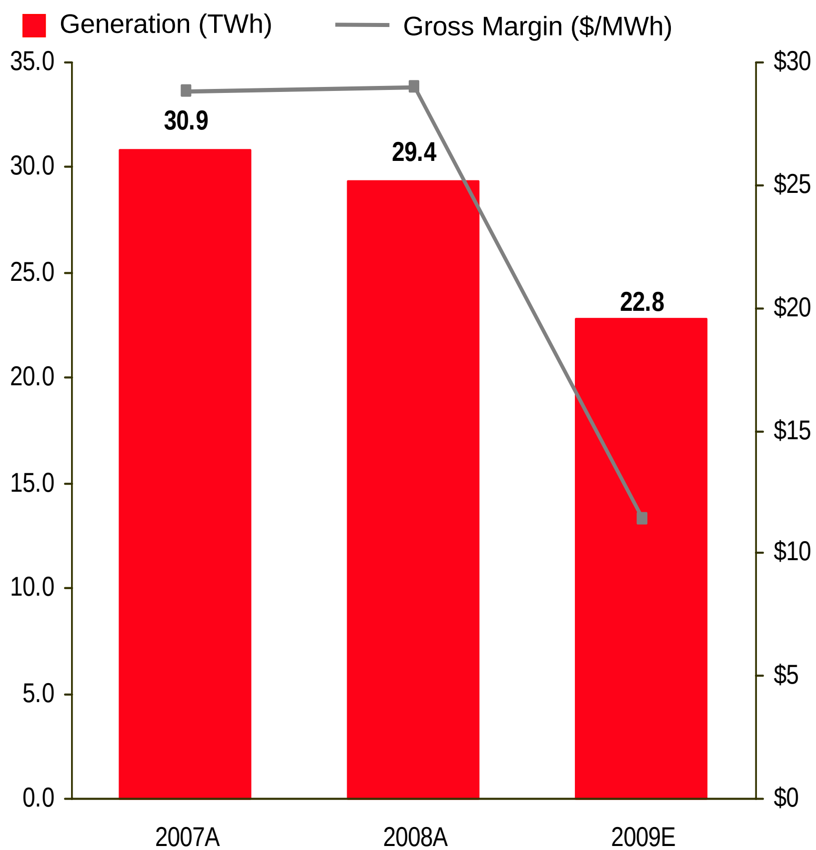
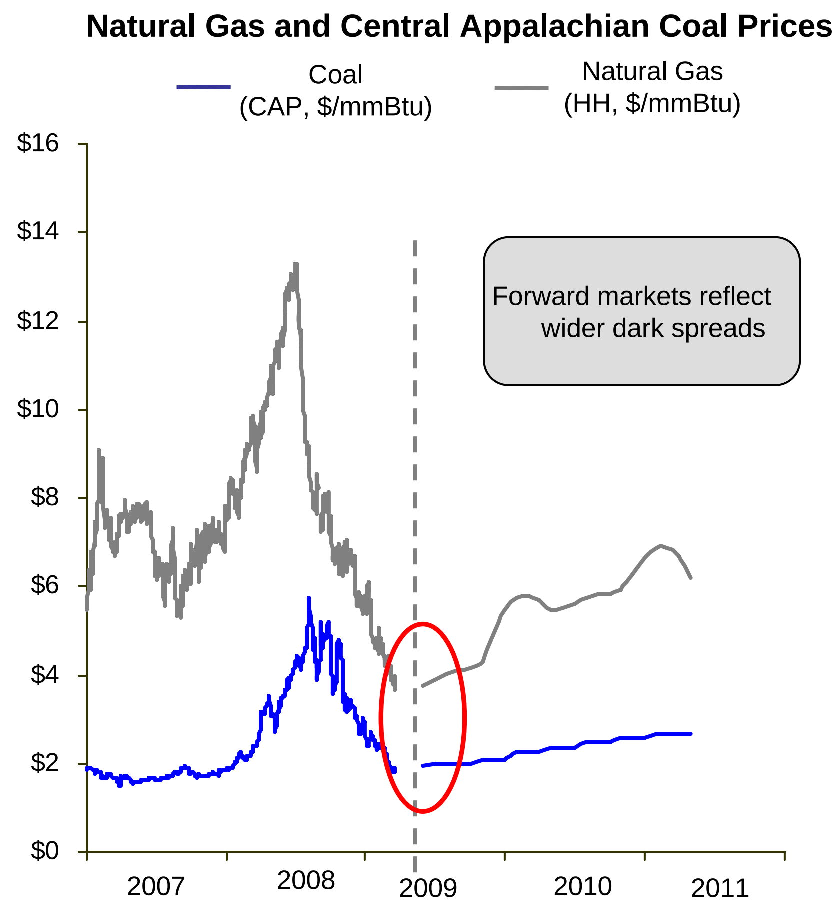
Key Drivers of 2009 Guidance: Off-System Sales



$ in millions		2007A		2008A		2009E
OSS Physical Sales	$	674	$	718	$	106
Oklaunion Payment		46		45		49
Marketing/Trading		170		82		105
Pre-sharing Gross Margin	$	890	$	845	$	260



Source: Bloomberg, Ventyx, CAP Coal Btu content of 12,000 Btu/lb
- *1 Month Forward NYMEX CAP coal price; Future values reflect NYMEX CAP coal forward strip*
- *Spot NYMEX Henry Hub natural gas price; Future values reflect NYMEX Henry Hub forward strip*

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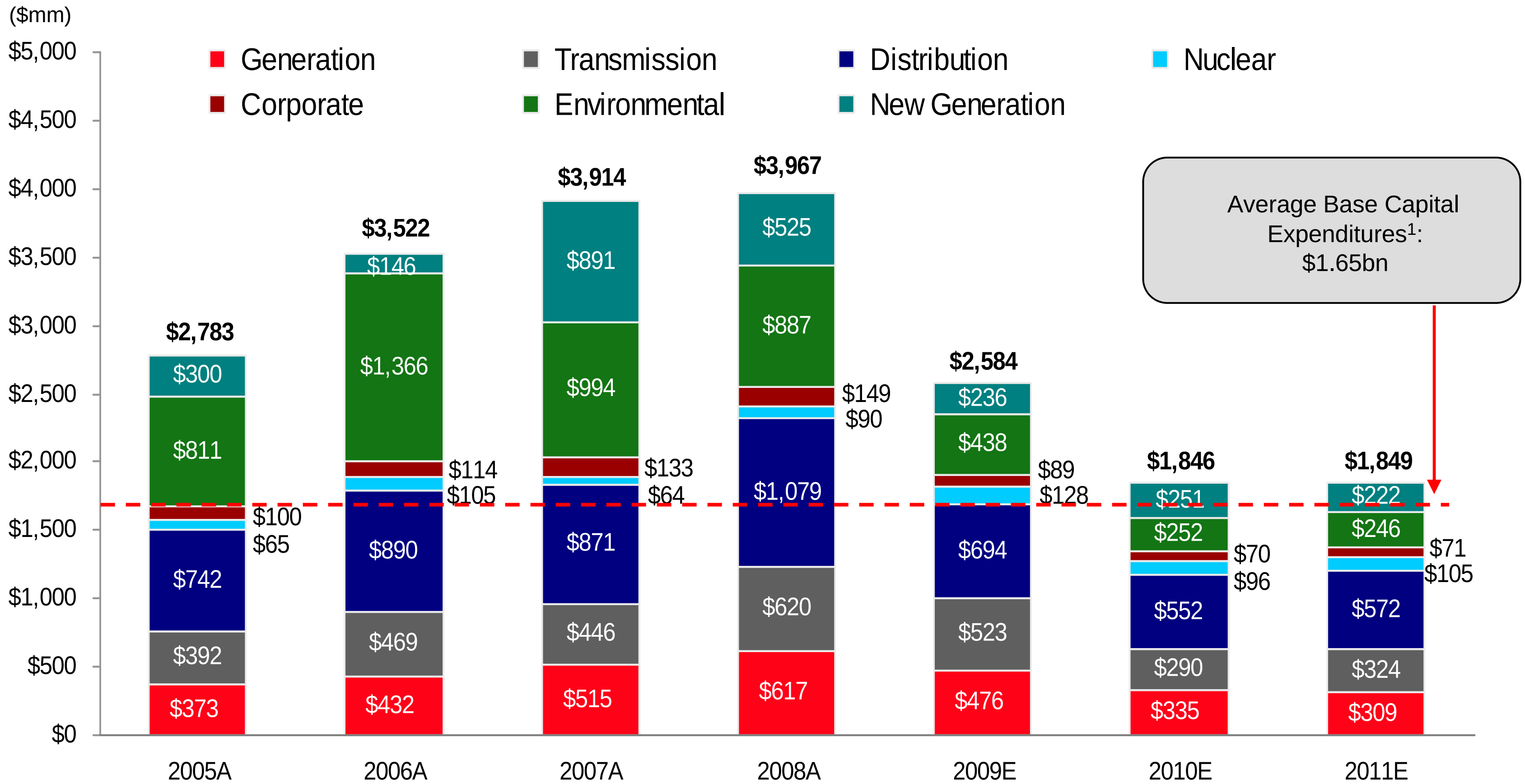
Utility Capital Expenditures Support Growth of 2 - 4%

Annual $1.8 billion capital program creates rate base growth over annual depreciation expense of $1.2 billion



Net PP&E ($bn)	$24.3	$26.8	$29.9	$33.0	$34.5	$35.2	$35.8

Note: Capital Expenditures shown exclude AFUDC
[1] Reflects 2002-2008 average base expenditures (excluding New Generation and Environmental)

AEP AMERICAN ELECTRIC POWER

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Capital Investment Drives Operating Company Growth

($ in millions)	2008A	2009E	2010E	Total
APCo	$749	$369	$297	**$1,415**
I&M	$372	$363	$246	**$981**
KPCo	$126	$62	$45	**$233**
TCC	$265	$222	$95	**$582**
TNC	$129	$138	$28	**$295**
PSO	$274	$189	$162	**$625**
SWEPCo	$680	$458	$423	**$1,561**
CSP	$438	$271	$231	**$940**
OPCo	$675	$441	$294	**$1,410**
Other Companies *	$259	$71	$25	**$355**
Total Capex	**$3,967**	**$2,584**	**$1,846**	**$8,397**

*** - Other Companies represents AEGCo, Kingsport Power, Wheeling Power and River Operations**

Note: amounts exclude AFUDC

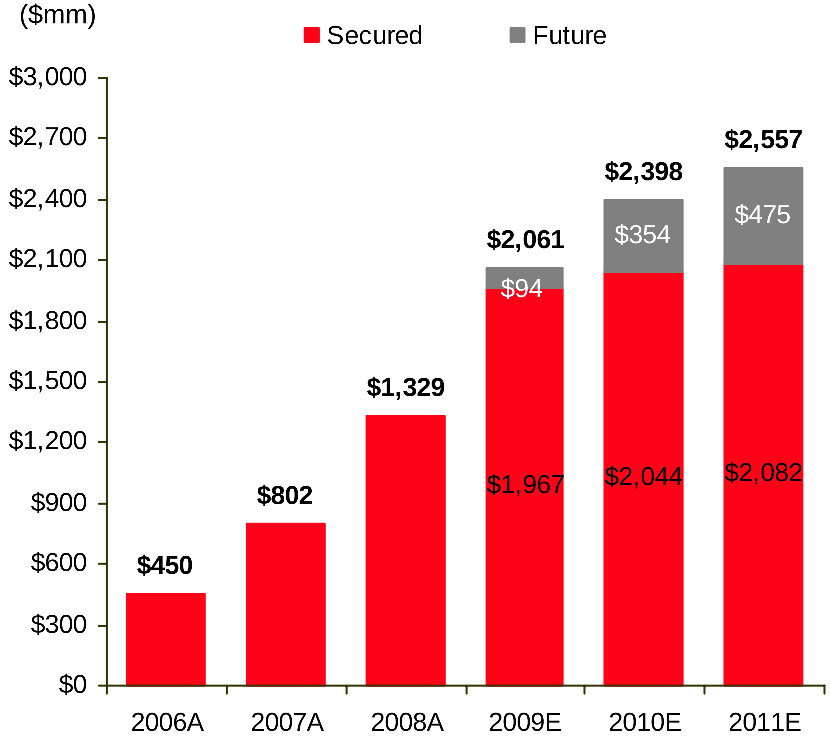
Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $24,855,326. Between $0 and $30 million, ratepayers receive 70%. Above $30 million, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	There are two jurisdictions: St Joe and Three Rivers. For St Joe, 100% of profits are shared with ratepayers. No profits are shared in Three Rivers, including base rates. St Joe represents 66% of the Michigan market.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

AEP AMERICAN ELECTRIC POWER

Track Record of Successful Regulatory Outcomes

Cumulative Rate Relief



Annual rate increases, $mm	$450	$352	$527	$732	$337[1]	$159[1]

[1] $77mm and $38mm was secured for 2010 and 2011, respectively, as of July 31, 2009

Our Regulatory Approach:

Maximize utility company returns:

- Successfully secured significant rate relief
- 2009 rate relief:
  - ✓ Ohio ($404MM)
  - ✓ I&M ($52MM)
  - ✓ APCo ($58MM)
  - ✓ PSO ($74MM)
- Pending rate relief including amount requested:
  - ✓ APCo WV ($20MM – in ENEC filing)
  - ✓ SWEPCo ($56MM)
  - ✓ APCo VA ($169MM)
  - ✓ Others to be determined

Minimize regulatory lag:

- Active fuel adjustment clauses now in place in <u>all</u> jurisdictions
- Increased frequency of rate cases
- Employing tracking features

Strong local relationships with regulators

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Overview of Ohio ESP Order

AEP OHIO - ELECTRIC SECURITY PLAN

FINANCIAL HIGHLIGHTS OF ESP

Description	2009 ESP Appl.	2009 PUCO Rehearing Order	2010 ESP Appl.	2010 PUCO Rehearing Order	2011 ESP Appl.	2011 PUCO Rehearing Order	Cumulative ESP Appl.	Cumulative PUCO Rehearing Order
	Incremental Revenue		Incremental Revenue		Incremental Revenue		Incremental Revenue	
Total Fuel Adjustment Clause (FAC) (Incl. OVEC of $68.8M)	214.5M	65.6M	455.1M	228.6M	510.8M	265.7M	2064.6M	919.9M
Non- FAC								
Environmental Capital (Carrying Costs)	110.0M	110.0M	0.0M	0.0M	0.0M	0.0M	330.0M	330.0M
Generation Assets	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
Non-FAC Generation (3% & 7%)	56.0M	0.0M	59.3M	0.0M	62.8M	0.0M	349.3M	0.0M
POLR	114.8M	100.1M	0.0M	0.0M	0.0M	0.0M	344.3M	300.3M
Distribution	45.0M	34.9M	48.1M	6.2M	51.4M	3.6M	282.6M	120.7M
Energy Efficiency/Demand Response	30.4M	0.0M	32.6M	0.0M	21.4M	0.0M	177.8M	0.0M
Other	-107.7M	-113.8M	0.0M	0.0M	38.0M	0.0M	-285.2M	-341.4M
Total Non-FAC	248.3M	131.2M	140.0M	6.2M	173.6M	3.6M	1198.7M	409.6M
Total Cash Increase	462.8M	196.8M	595.1M	234.9M	684.4M	269.4M	3263.3M	1329.5M
	Other Components		Other Components		Other Components		Other Components	
Partnership with Ohio Fund	-25.0M	-5.0M	0.0M	0.0M	0.0M	0.0M	-75.0M	-15.0M

- Revenue increases:

	2009	2010	2011
OPCo	8%	7%	8%
CSPCo	7%	6%	6%

- Fuel recovery mechanism
  - Any under-recoveries earn WACC similar to plant investment
  - Deferred fuel balances at end of ESP are amortized and recovered 2012-2018
  - Recovery of future costs of carbon regulation explicitly included in FAC
- Opportunity for distribution rate cases

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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Summary Rate Case Information

SWEPCo Arkansas General Rate Case

On February 19, 2009 SWEPCo filed a general base rate case with the Arkansas Public Service Commission (APSC) requesting an increase of $53.9 million. (Docket #:09-008-U) An order is expected in December 2009.

Projected Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	41.73%	6.61%	2.76%
Preferred Stock	0.12%	4.87%	0.01%
Common Equity	35.68%	11.50%	4.10%
Other Items	22.47%	various	0.13%
Total	100%		7.00%

Procedural Schedule

6/26/2009	Staff and intervenor testimony due
7/24/2009	Rebuttal testimony due
8/18/2009	Staff and intervenor rebuttal testimony due
8/25/2009	Surrebuttal testimony due
11/2/2009	Public hearing commences

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Adjusted Rate Base	$	608.9 *
Required Rate of Return		7.00%
Required Operating Income	$	42.6
Adjusted Operating Income	$	27.3
Difference	$	15.3
Revenue Conversion Factor		1.65
Revenue Deficiency	$	25.2
Generation Recovery Rider	$	28.7
Total Required Rate Relief	$	53.9

*Rate base as of December 31, 2008, updated for known and measurable changes through December 31, 2009.

AEP AMERICAN ELECTRIC POWER

Summary Rate Case Information

APCo Virginia General Rate Case

On July 15, 2009 APCo filed a pre-biennial base rate case with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $169.2 million. (Docket #: PUE-2009-00030) A procedural schedule is pending from the VSCC. A transmission rate adjustment clause (T-RAC) was filed in conjunction with this case as base rates will no longer include rates for transmission service (Docket #: PUE-2009-00031). APCo has requested that rates in both cases go into effect at the same time.

Projected Capital Structure – Company Position* (11/30/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.015%	1.365%	0.00%
Long-Term Debt	56.007%	6.383%	3.57%
Preferred Stock	0.280%	4.352%	0.01%
Common Equity	43.665%	13.350%	5.83%
Other Items	0.033%	9.421%	0.00%
Total	100.00%		9.42%

*AEP will refile by August 14, 2009 using an end-of-test-year capital structure per the recent Virginia SCC decision in case No. PUE-2009-00019.

Procedural Schedule TBD

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4*
Rate of Return		9.42%
Operating Income Requirement	$	193.8
Adjusted Operating Income	$	90.9
Difference	$	102.9
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	169.2

*Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

AEP AMERICAN ELECTRIC POWER

Capital Investment Funding Plan

$ in millions

	Actual 2008		Projection 2009	
Planned Capital Investment (Excluding AFUDC)	$	(3,967)	$	(2,584)
Planned Transmission Initiatives (JV Equity Contributions)		0		(49)
Dividend on Common Stock		(660)		(755)
Cash Sources (Uses)				
Cash from Operations		2,576		2,514
Proceeds from Sale of Assets		90		172
Common Stock Issued		159		1,763
Change in Debt, Net		2,266		(773)
Other		(231)		(498)
Change in Cash		233		(210)
Ending Cash Balance	$	411	$	201

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

Credit Ratings and Metrics

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook	Fitch Senior Unsecured	Fitch Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB+	N
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	A3	R	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook, R=Review for Downgrade

2008 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	3.65x	15.6%	61.6%
Appalachian Power Company	1.71x	4.6%	58.5%
Columbus Southern Power Company	5.24x	26.3%	55.1%
Indiana Michigan Power Company	4.44x	22.0%	60.8%
Kentucky Power Company	2.51x	9.9%	58.1%
Ohio Power Company	3.12x	13.3%	56.7%
Public Service Company of Oklahoma	4.30x	27.2%	56.0%
Southwestern Electric Power Company	3.26x	16.0%	56.1%
Texas Wires	4.12x	20.9%	57.4%

AEP AMERICAN ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)
(as of June 30, 2009)

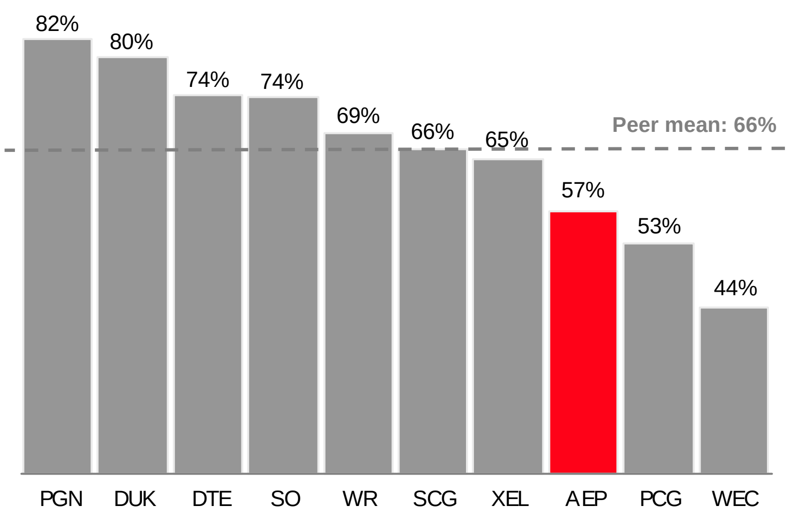
Year	2009	2010	2011
AEP, Inc.	$ -	$ 490	$ -
AEP Generating Company	$ -	$ -	$ 130
Appalachian Power	$ -	$ 200	$ 250
Columbus Southern Power	$ -	$ 150	$ -
Kentucky Power	$ -	$ -	$ -
Indiana Michigan Power	$ -	$ -	$ -
Ohio Power	$ -	$ 679	$ -
Public Service of Oklahoma	$ -	$ 150	$ 75
Southwestern Electric Power	$ -	$ -	$ 50
Texas Central Company	$ -	$ 122	$ 120
Texas North Company	$ -	$ -	$ -
Total	$ 0	$ 1,791	$ 625

AEP AMERICAN® ELECTRIC POWER

Dividend Overview

- We have paid 397 consecutive quarterly dividends to shareholders
- Dividend - $1.64/share
- Attractive yield
- Target dividend payout ratio of 50 – 60%

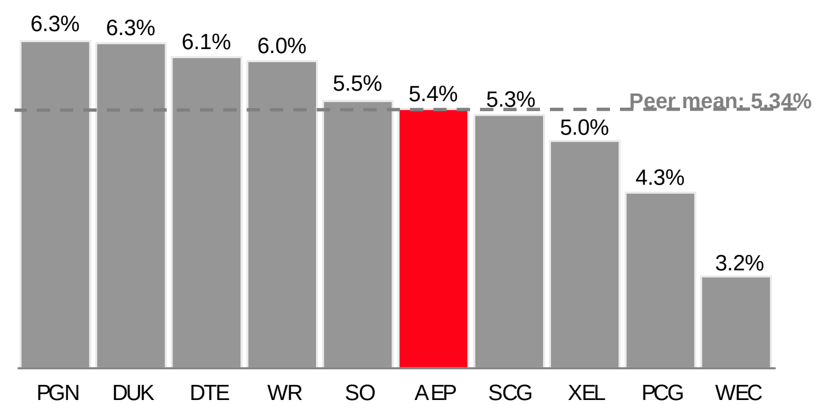
Payout Ratio vs. Integrated Electric Peers



Note: Payout ratio equals the indicated dividend rate annualized divided by First Call 2009 consensus estimate

Source: Bloomberg & First Call earnings estimates as of 7/28/09

Dividend Yield vs. Integrated Electric Peers



Note: Dividend yield equals the indicated dividend rate annualized divided by the share price

Source: ThomsonONE as of 7/28/09

AEP AMERICAN ELECTRIC POWER

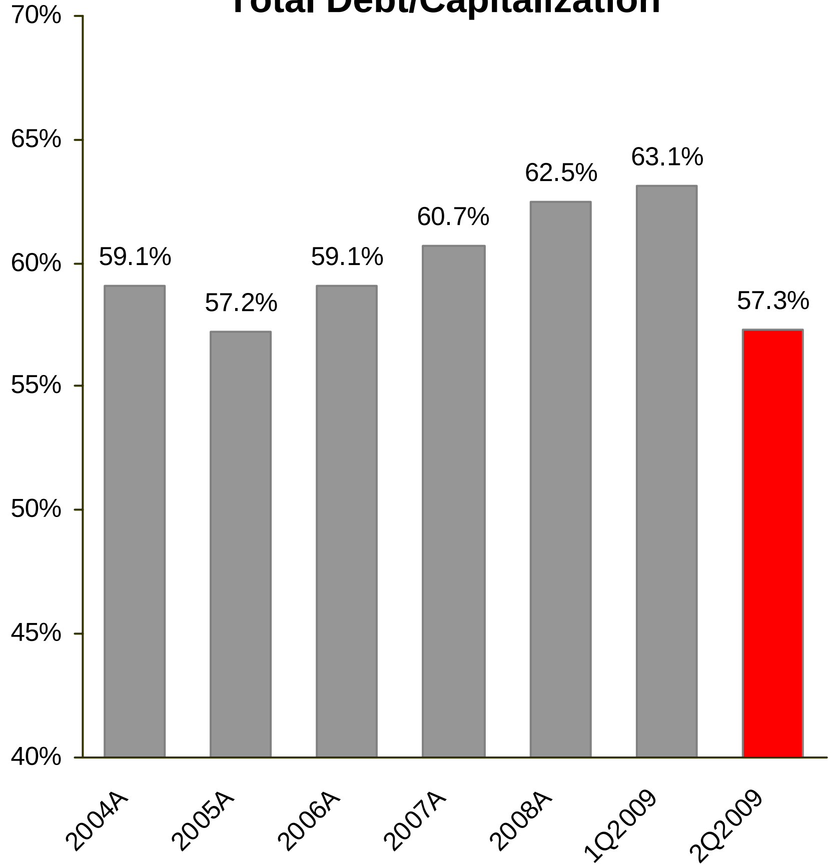
Pension and OPEB Estimate

- Our pension plan and OPEB funds investment returns were each down about 24% in 2008.
- Discount rates are assumed to be 6.0% for pension and 6.1% for OPEB.
- Investment losses increase plan expense for both pension and OPEB, but the investment losses are smoothed in over several years.
- We expect 2009 pension and OPEB expense to increase $104MM from 2008 to 2009 (pre-tax and pre-capitalization).
- OPEB contributions will increase along with OPEB expense, in accordance with agreements in most of our regulatory jurisdictions.
- We do not expect any mandatory contributions to pension in 2009. Pension trust contributions are estimated to be $475MM in 2010 and $283MM in 2011.

AEP AMERICAN ELECTRIC POWER

Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 6/30/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. Cash and Investments	358	
Less		
Draw on Credit Facilities	(219)	(a)
Commercial Paper Outstanding	(316)	
Letters of Credit Issued	(485)	
Net Available Liquidity	**$2,919**	

(a) Repaid in July 2009

AEP AMERICAN ELECTRIC POWER

Uniquely Positioned for Nationwide Grid Expansion

Active Projects:

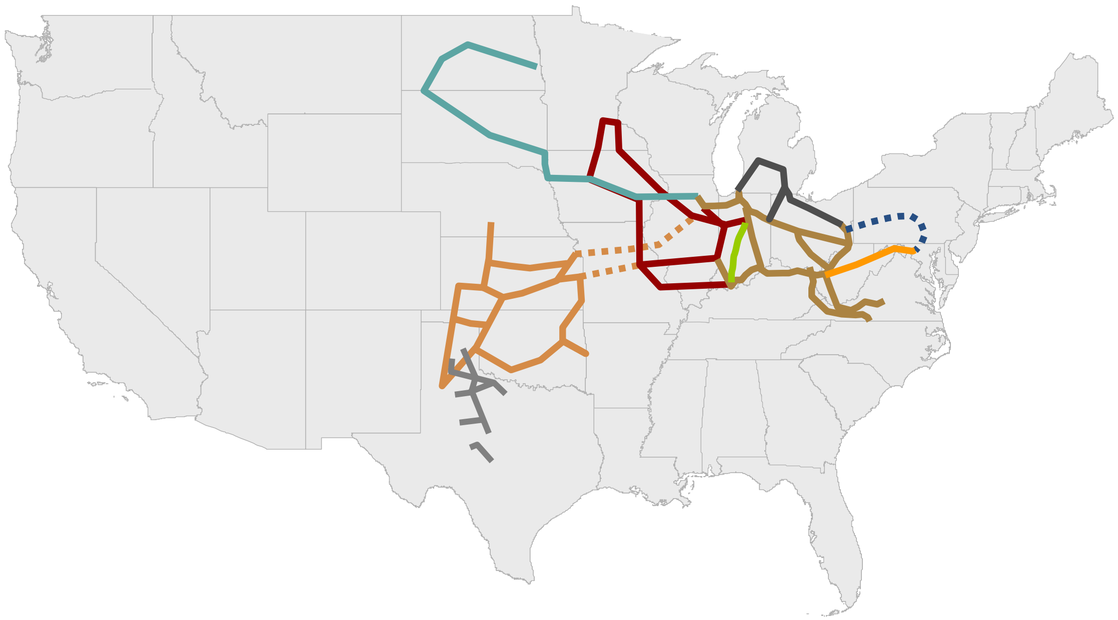
Pioneer — **COD: 2015**
- 240 miles of 765 kV
- Partner: Duke Energy (50%)
- Estimated Cost: $1 billion
- ROE: 12.54%

PATH-WV — **COD: 2014**
- 275 miles of 765 kV
- Partner: Allegheny Energy (50%)
- Estimated Cost: $1.2 billion
- ROE: 14.3%

Tallgrass — **COD: 2013-14**
- 170 miles of 765 kV
- Partners: OG&E (50%) & MidAmerican Energy (25%)
- Estimated Cost: $500 million
- ROE: 12.8%

Prairie Wind — **COD: 2013**
- 110 miles of 765 kV
- Partners: Westar Energy (50%) & MidAmerican Energy (25%)
- Estimated Cost: $400 million
- ROE: 12.8%

ETT — **COD: 2013**
- 345 kV in ERCOT
- Partner: MidAmerican Energy (50%)
- Estimated Cost: $400 million
- ROE: 9.96%



Future Projects:

EHV Michigan — **COD: ~2020**
- 700 miles of 765 kV

PJM Projects
- Enhance existing 765/345 kV

Hartland — **COD: ~2020**
- 1000+ miles of 765 kV

MISO Vision Plan
- 765 kV Backbone

SPP Overlay — **COD: 2013-14**
- 765 kV Backbone

ETT — **COD: ~2018**
- 345 kV in ERCOT
- Additional CREZ spend of $750-$850 million

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Note: The lines shown are conceptual in nature and do not represent actual routes. Plans are subject to change.

Equity Contributions Enhance Earnings Growth to 4 – 8%

AEP is the leader

- Largest US transmission footprint
- Interstate EHV highway vision
- National renewables transmission strategy

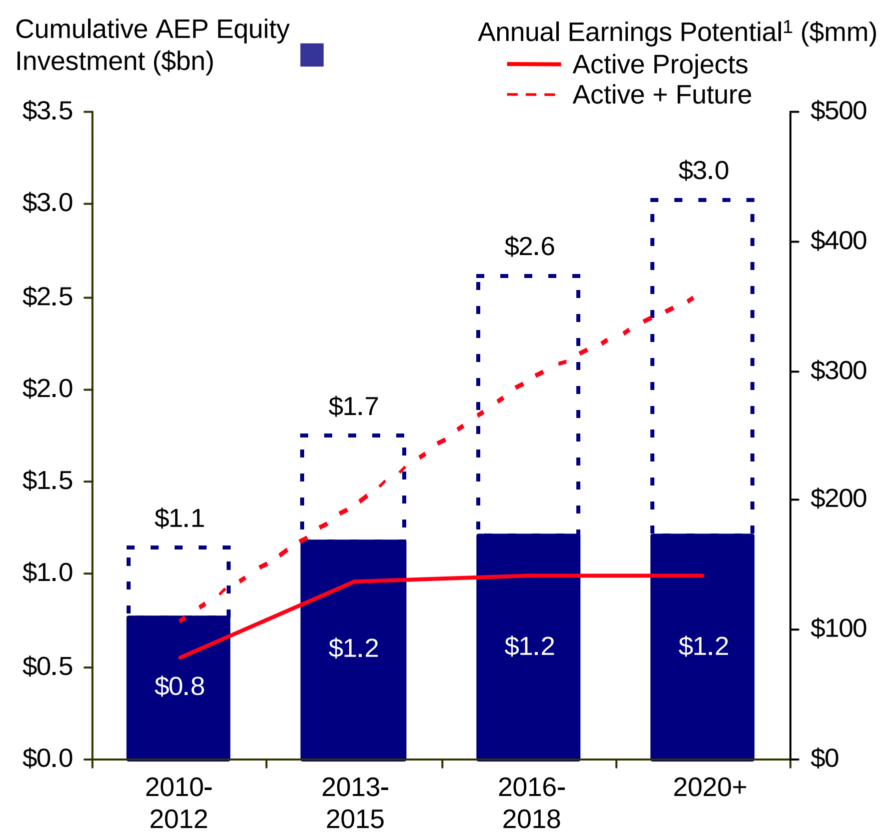
Quality projects

- 4 FERC-approved ($3.3 billion)
- Independent ERCOT transmission JV company (up to $2.6 billion)
- Robust pipeline of future 765 kV projects (up to $15 billion)

Attractive returns

- FERC incentive rates (12.5-14.3%)
- Strong cash flow with CWIP
- Long-term earnings potential of ~$140-$360 million annually[1]

Illustrative Earnings Potential of New Transmission Initiatives



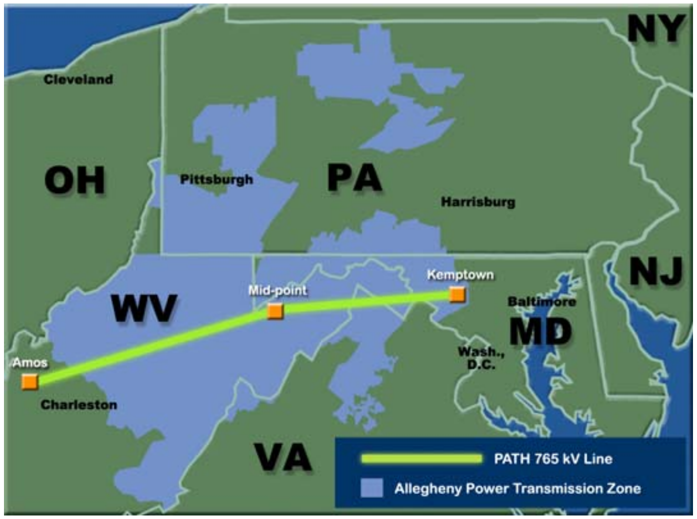
[1] *Illustrative calculation assumes 50/50 debt/equity capitalization and incentive ROE of ~13.0% for FERC projects and a 60/40 debt/equity capitalization and 10.5% ROE for ERCOT projects*

AEP AMERICAN ELECTRIC POWER

EHV Transmission in PJM: PATH

<u>Project Description:</u> 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

- **Near Term Risks**
  - Obtaining a CPCN in West Virginia or costly concessions with WV to receive the CPCN; CPCN filing made May 15, 2009
- **Pertinent Data**
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP and 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
    - Rates went into effect March 1, 2008; current annual revenue requirement is $15MM effective 1/1/09
  - Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million
  - Estimated completion date: 2014



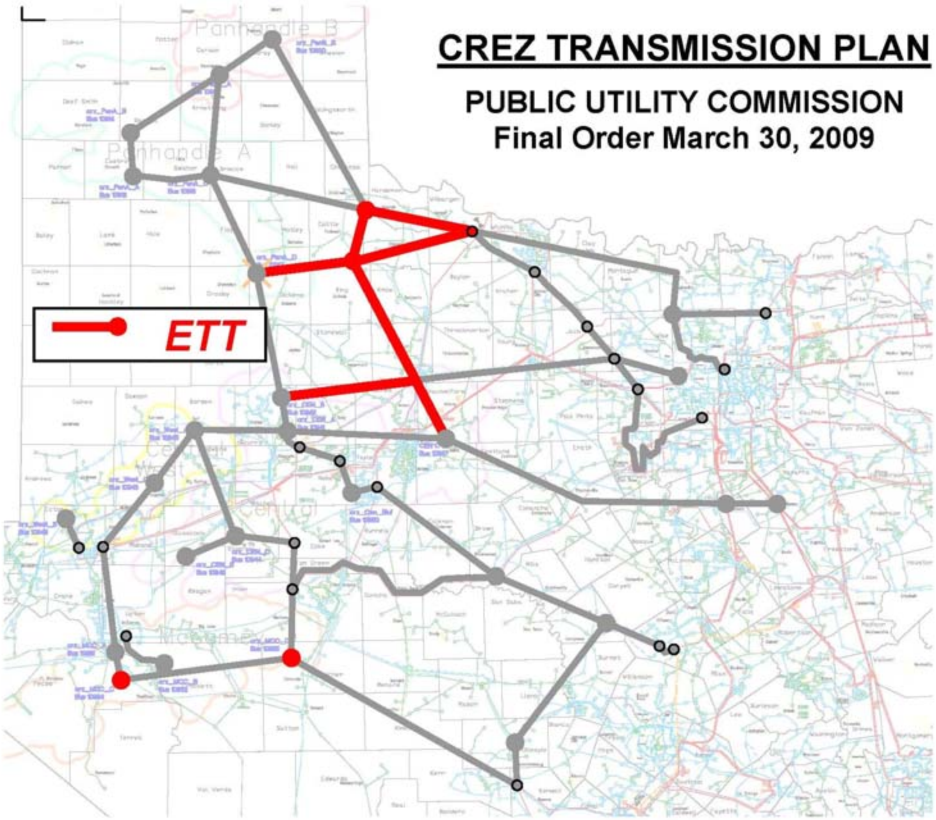
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

Texas CREZ Project

Strengthening the ERCOT grid to collect and deliver wind generation to load

- ***Status:***
  - On February 26, 2009, PUCT ordered its staff to stage the development of CREZ transmission lines.
  - Staging to occur in separate docket and consider timing of wind projects and congestion.
  - PUCT established 2 categories based on priorities. ETT has no first priority lines.
  - PUCT issued a final order assigning transmission service providers on March 30, 2009.
  - ETT's share of CREZ investment is approx. $840MM of $4.9B total.
  - The filing calls for completion of the plan by 2013.
- ***Next Steps***
  - Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

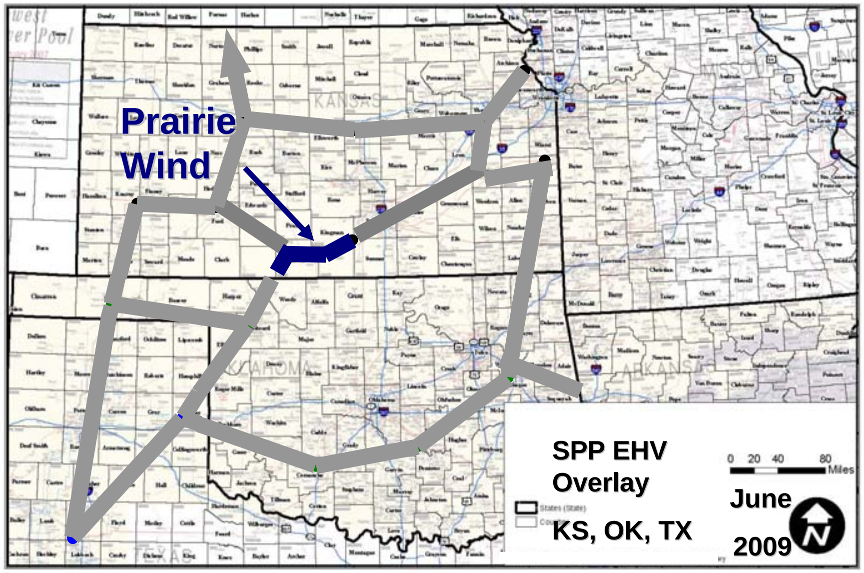
Electric Transmission Texas

AMERICAN ELECTRIC POWER

Prairie Wind Transmission, LLC

JV to build first segment of 765-kV transmission in SPP

- ***Overview***
  - In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
  - Following a settlement agreement with ITC on June 1, 2009 both entities agreed to split the mileage and costs of building the 765-kv transmission superhighway. The newly revised project is expected to cost approximately $400 million and in-service by 2013. Settlement was approved by the KCC on July 24, 2009.
  - PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS, west to a substation near Medicine Lodge, KS, and then south to the Kansas border from Medicine Lodge, KS.
  - The original proposed mileage prior to settlement was approximately 230 miles.
  - The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
  - AEP's ownership of the joint venture is 25%.
  - FERC order received in December 2008:
    - Cash return on CWIP and 12.8% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PWT or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.
The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

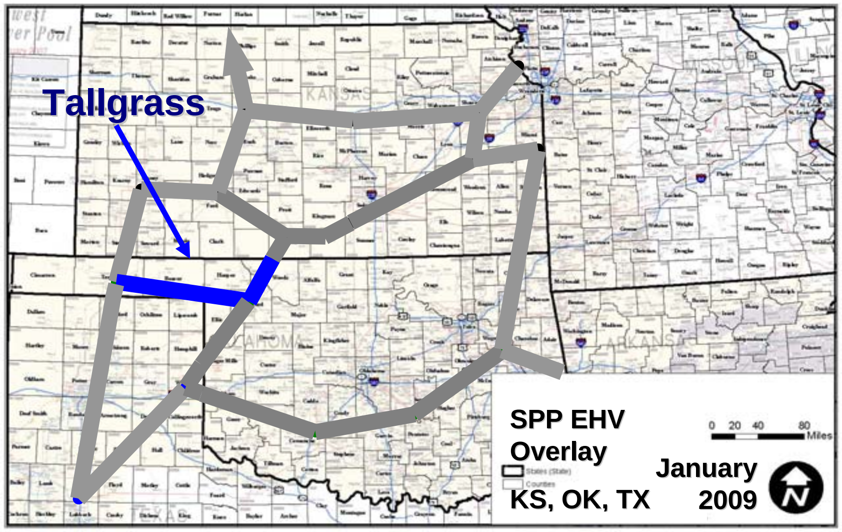
- ***Key Challenges***
  - Regional Cost allocation which enables the development of "system solutions"
  - RTO Approval

AEP AMERICAN ELECTRIC POWER

Tallgrass Transmission, LLC

JV to build second segment of 765-kV transmission in SPP

- ***Overview***
  - In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
  - TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines extending from the Kansas-Oklahoma border north of Woodward, OK, extending west into the Oklahoma panhandle to a new station that will be built near Guymon, OK.
  - The project will promote wind development in the western half of Oklahoma.
  - Project is expected to cost approximately $500 million and be in-service by 2013.
  - AEP's ownership of the joint venture is 25%.
  - Other responsibilities will be handled by the partners or outsourced.
  - FERC order received in December 2008:
    - ❑ Cash return on CWIP and 12.8% incentive ROE
    - ❑ Recovery of all costs incurred prior to the time rates go into effect, and
    - ❑ Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of TG or its parents.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

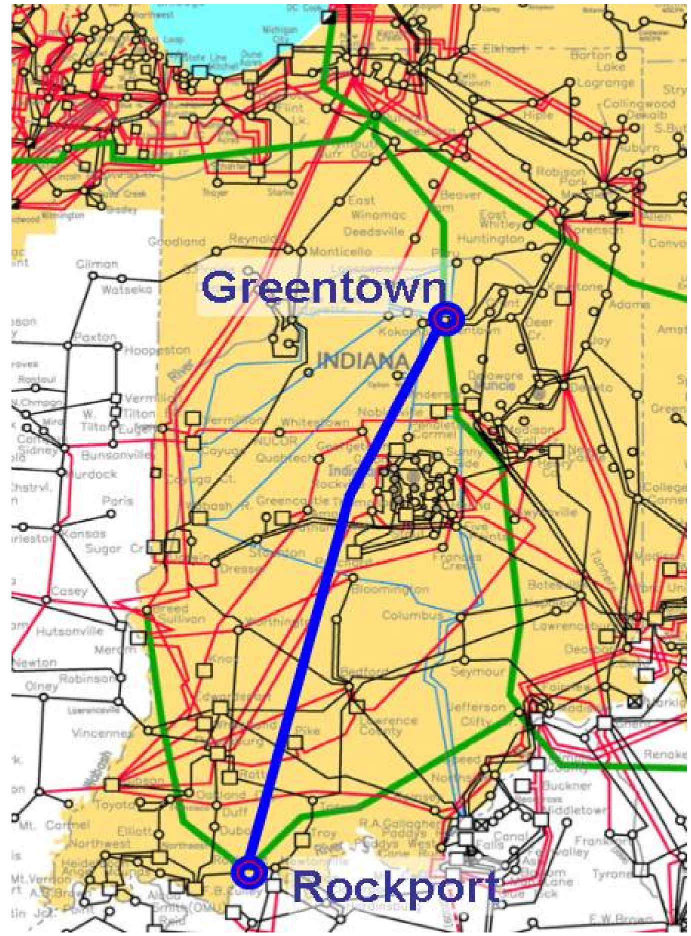
- ***Key Challenges***
  - Cost allocation which enables the development of "system solutions"
  - RTO Approval

AEP AMERICAN ELECTRIC POWER

Pioneer Transmission LLC

Overview

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- Project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- Other responsibilities will be handled by the partners or outsourced.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect, and
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PT or its parents.
  - Certain formula rate issues were set for hearing



Key Challenges

- Cost allocation which enables the development of "system solutions"
- RTO Approval - touches two RTOs – PJM & MISO
- Siting

AEP AMERICAN ELECTRIC POWER

Hartland Wind Concept EHV Development in Upper-Midwest

Project Description: 1000+ miles of 765-kV transmission linking Upper Midwest generation sources with the existing EHV infrastructure in the Chicago area expected to cost $5-$10 billion over a 10 year period.

- **Near Term Risks**
  - Technical feasibility study
  - Identification of willing and able partners
  - Obtaining cost allocation between states, PJM, and MISO
  - RTO Technical Approvals
  - Favorable 205 Order including 679 incentives
- **Mitigation**
  - Target the identified need for the project and its ability to provide access for wind energy to load centers
  - Collaboration in regulatory process for regional cost allocation between MISO, PJM, and Midwest Governors Association
  - Prepare comprehensive regulatory filing, including incentives

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER

UBS Conference
New York

February 16, 2006

A Century of Firsts

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Framework for 2006

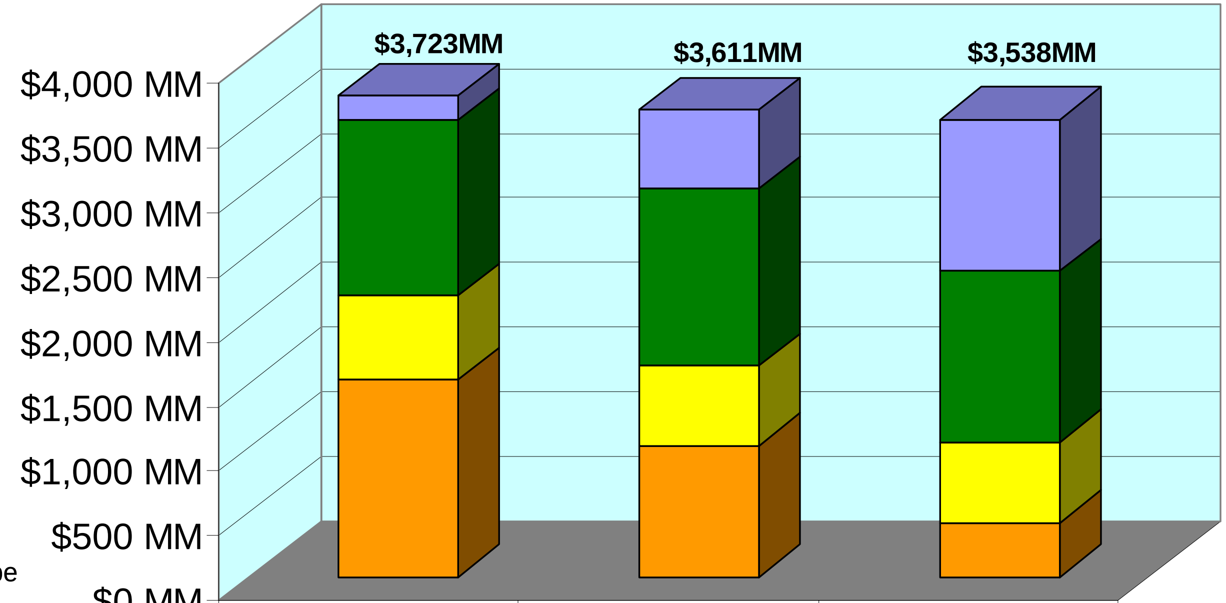
- 2006 Earnings Guidance Range: $2.50 to $2.70
- Controlled investment in utility operations
  - Reliability
  - Environmental
- Seek rate recovery for new investments
- Control costs

COMPANY'S STRATEGY REMAINS FOCUSED ON UTILITY OPERATIONS

Revised Capital Investment Forecast

Capital Investment Forecast

excluding AFUDC



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$191	$611	$1,174
Ongoing Infrastructure Replacement & Economically Justified	$1,351	$1,367	$1,319
Mandated T&D	$650	$615	$625
Environmental Compliance	$1,531	$1,018	$420

Note: Capital forecasts do not include amounts for AEP Interstate Project.

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

($ in millions)	Actual 2004	Actual 2005	Projection 2006	Projection 2007	Projection 2008
Planned Capital Investment, excluding AFUDC					
Committed Construction Expenditures *	$ (1,671)	$ (2,499)	$ (2,181)	$ (1,633)	$ (1,045)
Discretionary Cap Ex Predicated on Rate Recovery &/or Avail. Cash	n/a	n/a	$ (1,542)	$ (1,978)	$ (2,493)
Total Capital Expenditures, excluding AFUDC	$ (1,671)	$ (2,499)	$ (3,723)	$ (3,611)	$ (3,538)
Dividend on Common	$ (555)	$ (554)	$ (583)	$ (586)	$ (589)
Cash Sources					
Cash from Operations **	$ 2,632	$ 1,795	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,314	$ 1,294	$ 28	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 17	$ (24)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,238)	$ (91)	$ 2,434	$ 1,661	$ 1,623
Other	$ 43	$ 160	$ (177)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (458)	$ 81	$ (75)	$ (126)	$ -
Ending Cash Balance	$ 320	$ 401	$ 326	$ 200	$ 200

* Statement of Cash Flows shows $2.402B for 2005 and $1.637 for 2004 which reflects difference in accruals from previous year.

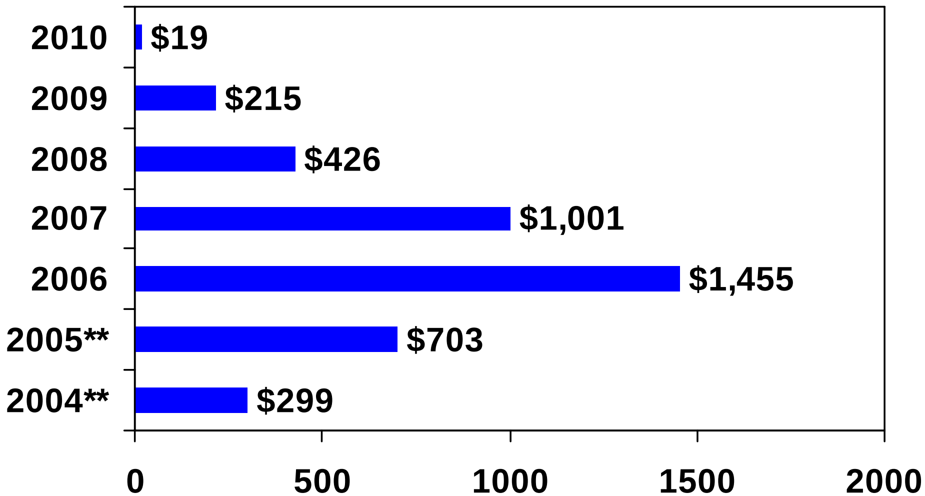
* * Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Capital forecasts do not include amounts for AEP Interstate Project. Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

$4.1 Billion Environmental Investment

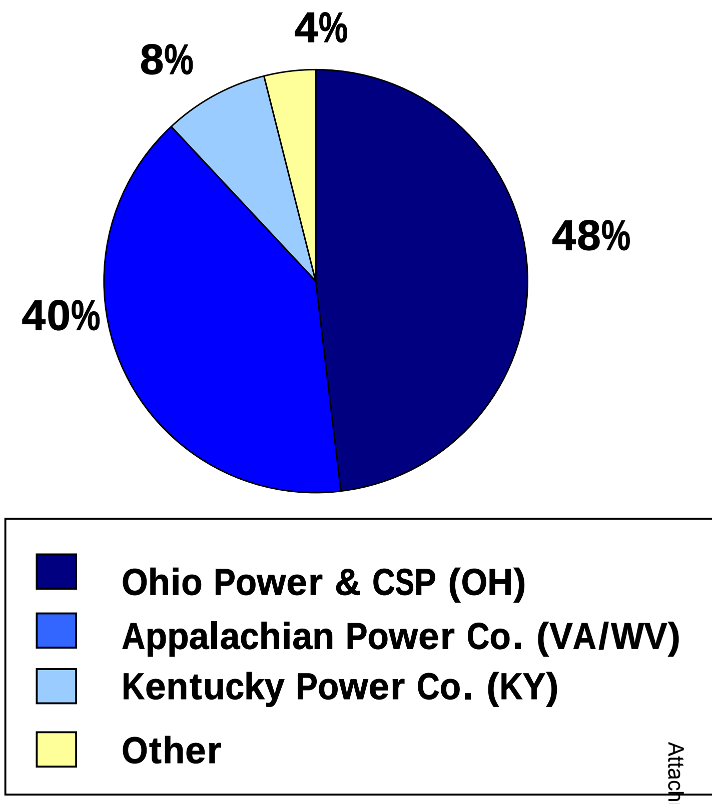
Environmental Capital Investment*



*Environmental investment for NOx, SO_2 , & Hg purposes including AFUDC

** Actual investment level in 2004 and 2005

Projected Environmental Investment Allocation

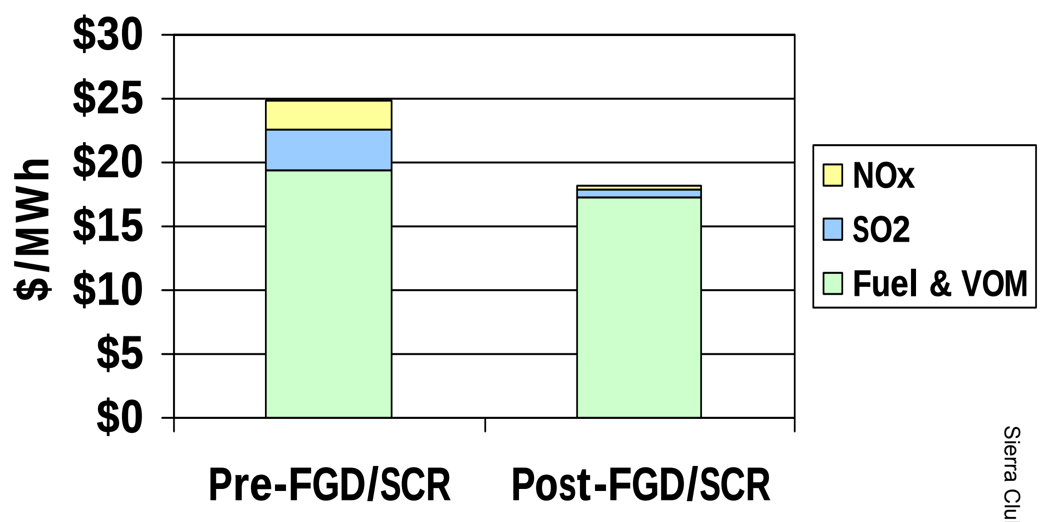


MAJORITY OF 2006 & 2007 DOLLARS WILL BE INVESTED IN OHIO & APCO

Low Cost Production Supports Investment & Investment Sustains Low Cost Production

- Lowers exposure to high cost emission allowances
- Creates opportunity to burn wider variety of lower cost fuels
- Improves baseload operation (higher capacity factor, higher margin)
- All-in cost of electricity, including FGD/SCR investment, remains low

Typical Pulverized Coal Plant
Comparison of Variable Production Cost
Pre- and Post- FGD/SCR (future view)*



* Assumes annual NOx program

AEP WILL REMAIN THE LOW COST PRODUCER FOLLOWING COMPLETION OF ENVIRONMENTAL RETROFIT PROJECTS

Regulatory Activity Underway

- ✓ TCC Stranded Cost Recovery True-up Filing
- ✓ Ohio Companies filing for pass through of FERC OATT changes
- ✓ APCo Filing for Recovery of E&R Costs in Virginia
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Cost (ENEC) Filing in West Virginia
- ✓ Kentucky Base Rate Filing – Settlement Pending
- ✓ Indiana Depreciation Petition
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

TCC Stranded Cost Recovery Case

- Seeking approval of true-up balances
  - ✓ February 6, 2006 – PUCT Draft order provides for net true-up of $1.475 billion
- February 2006 - Final written order expected, if not extended
  - ✓ Feb/Mar 2006 - Request for securitization
    - ➢ 4Q06 - Issuance of securitization bonds if no appeal
  - ✓ Mar/Apr 2006 – Request approval for CTC to collect other true-up items
    - ➢ Jan 2007 – CTC charge to be implemented

Ohio Companies Pass through of FERC OATT Changes

Filed Feb 3, 2006 - Seeking authority to pass through to customers the changes in the FERC OATT related to the elimination of the SECA revenues and the costs associated with the Wyoming-Jacksons Ferry transmission line

Regulatory Activity Underway

Appalachian Power – Virginia E & R Cost Recovery Factor

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14, 2005 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14, 2005 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred through Sept. 30, 2005 of $21.1 million
- ✓ Public hearings are scheduled to begin February 27, 2006

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

- ✓ APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million.

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $74 Million
- ✓ June 23, 2006 – $9 Million
- ✓ Jan 1, 2007 – $43 Million
- ✓ Jan 1, 2008 – $8 Million
- ✓ Jan 1, 2009 – $37 Million

Procedural Schedule

- ✓ March 8, 2006 – Staff and Intervenors Testimony
- ✓ March 16, 2006 – Rebuttal & Cross-rebuttal
- ✓ April 18 - 21, 2006 – Evidentiary Hearings
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ July 28, 2006 – Statutory deadline for an order

Regulatory Activity Underway

AEP®

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Parties to the case reached a settlement on Feb 6, 2006
  - ✓ $41 million annual increase in base rates
  - ✓ To be effective March 30, 2006
- ✓ Settlement was presented to the Commission at a public hearing on Feb 7, 2006
- ✓ Final order expected in March 2006

Indiana Depreciation Filing

December 1, 2005 – I&M filed petition with the IURC for accounting authorization to revise the depreciation rates applicable to its electric utility plant in service

- ✓ Based on a 2004 depreciation study, I&M recommends a decrease in annual depreciation expense of approximately $45 Million on an after-tax Indiana jurisdictional basis.
- ✓ Procedural schedule has been set with final order expected in June 2006

IGCC Regulatory Activity

AEP®

Ohio - Cost Recovery Filing

<u>Phase 1</u>

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

<u>Phase 2</u>

- ✓ Effective 2007 - mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

<u>Phase 3</u>

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Ohio - Next Steps

2006:

- ✓ Secure cost recovery plan
  - Final PUCO Order expected in 1Q06
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2006—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

<u>West Virginia IGCC Activity</u>

On January 11, 2006, Appalachian Power Co. filed a Certificate of Public Convenience and Necessity seeking authority to construct a 600-MW IGCC facility in West Virginia.

SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH IN OHIO

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Regulatory Activity Completed

Ohio - Rate Stabilization Plan

- ✓ Generation rate increases implemented January 1, 2006

AEP East FERC Transmission Case

December 20, 2005 – FERC approved settlement allowing wholesale transmission rates to increase

- ✓ Results in $22 Million net revenue in 2006 from wholesale transmission

Appalachian Power- Virginia Fuel Factor Increase

- ✓ $57.7 Million increase in fuel factor approved on January 20, 2006

SWEPCo Fuel Factor/Surcharge Filing

January 12, 2006 – Settlement approved by PUCT

- ✓ Fuel factor will increase SWEPCo's annual Texas retail fuel-related revenues by approximately $46 Million.
- ✓ Interim surcharge will collect the under-recovery amount of $44 Million, including interest.

PROGRESS IS BEING MADE ON THE REGULATORY FRONT

What AEP Offers

- Strength and scale in assets & operations
- Focused utility model
- Earnings growth driven by native load & capital investment
- Attractive dividend yield in excess of 4%
- Stable credit profile

Appendix

2006 Earnings Guidance Range: $2.50 - $2.70

AEP®

		2005 Actual Performance Driver	2005 Actual ($ millions)	2005 Actual EPS	2006 Forecast Performance Driver	2006 Forecast ($ millions)	2006 Forecast EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,656 GWh @ $ 31.6 /MWhr =	2,075		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,877 GWh @ $ 39.6 /MWhr =	1,937		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,214 GWh @ $ 22.3 /MWhr =	896		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,525 GWh @ $ 17.4 /MWhr =	462		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off-System Sales	38,491 GWh @ $ 22.3 /MWhr =	857		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		394			285	
7	Other Operating Revenue		485			515	
8	Total Gross Margin		7,106			7,283	
9	Operations & Maintenance		(3,142)			(3,045)	
10	Depreciation & Amortization		(1,285)			(1,332)	
11	Taxes Other than Income Taxes		(743)			(761)	
12	Interest Exp & Preferred Dividend		(595)			(688)	
13	Other Income & Deductions		264			153	
14	Income Taxes		(514)			(563)	
15	Net Earnings Utility Operations		1,091	2.80		1,047	2.66
	INVESTMENTS:						
21	Total Investments		24	0.06		(7)	(0.02)
22	Parent Company		(52)	(0.13)		(17)	(0.04)
23	ON-GOING EARNINGS		1,063	2.73		1,023	2.60
	Shares Outstanding (in millions)			390			393

Note: For analysis purposes, certain financial statements have been reclassified for this effect on earnings presentation

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Summary of Major 2006 Earnings Drivers

- ✓ Load growth of 2.5%
- ✓ $500MM rate recovery assured or in progress
- ✓ Rising fuel costs of 10-12%
- ✓ Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- ✓ Decline in utility operations O&M
- ✓ Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

Risks & Uncertainties

2006 EPS Guidance Range is $2.50 to $2.70

2006

- ✓ *Outcome of pending regulatory proceedings*
  - ✓ *Texas, Ohio, Virginia, West Virginia, Indiana, Kentucky, FERC*
- ✓ *Wholesale market volatility*
- ✓ *Plant availability*
- ✓ *Rising fuel costs*
- ✓ *Weather*

GUIDANCE RANGE DESIGNED TO WITHSTAND A REASONABLE RANGE OF RISKS AND UNCERTAINTIES

2006 Projected Cash Flow

($ in millions)	2005 Actual	2006 Guidance
Beginning Cash Balance	**$ 320**	**$ 401**
Cash from Operations:		
Income from Continuing Operations	787	1,023
Depreciation and Amortization	1,318	1,363
Pension Funding in Excess of Expense	(626)	(126)
Extraordinary items	225	-
Other	91	(315)
Total from Operations	**$ 1,795**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,402)	(3,723)
Asset Sales	1,294	28
Other	179	(163)
Total from Investing	**$ (929)**	**$ (3,858)**
Cash from Financing:		
Common Equity	(24)	-
Net Long Term Debt Issued/(Retired)	(78)	2,434
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(554)	(582)
Other Financing Activities	(50)	(3)
Total from Financing	**$ (785)**	**$ 1,838**
Net Change in Cash	**$ 81**	**$ (75)**
Ending Cash Balance	**$ 401**	**$ 326**

CASH ON HAND EXPECTED TO BE $326 MILLION AT YEAR END 2006

Capitalization

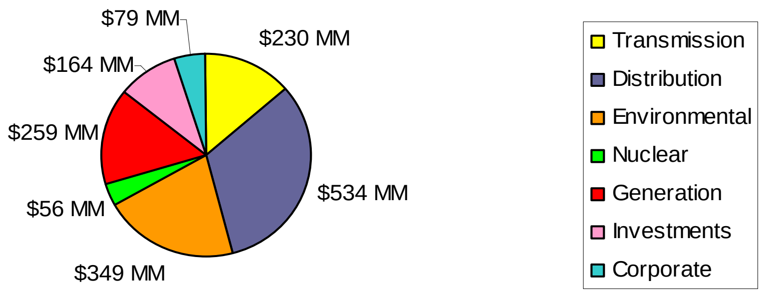
Capital Structure	Actual 12/31/04			Actual 12/31/2005		
	Debt	Equity	Total	Debt	Equity	Total
Balance Sheet Capitalization						
Long-term Debt	12,287	-	12,287	12,226	-	12,226
Short-term Debt	23	-	23	10	-	10
Preferred Stock Subject to Mandatory Redemption	66	-	66	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61	-	61	61
Common Equity	-	8,515	8,515	-	9,089	9,089
Total Capitalization per Balance Sheet	**12,376**	**8,576**	**20,952**	**12,237**	**9,149**	**21,386**
% of Capitalization per Balance Sheet	***59.1%***	***40.9%***	***100.0%***	***57.2%***	***42.8%***	***100.0%***
Adjustments						
Preferred Stock Not Subject to Mandatory Redemption	(66)	66	-	30	(30)	-
Defeased First Mortgage Bonds	(84)	-	(84)	(30)	-	(30)
Off-balance Sheet Leases	1,241	-	1,241	1,213	-	1,213
Securitization Bonds	(698)	-	(698)	(648)	-	(648)
Spent Nuclear Fuel Trust	(229)	-	(229)	(228)	-	(228)
Total Adjusted Capitalization	**12,540**	**8,642**	**21,182**	**12,574**	**9,119**	**21,694**
% of Adjusted Capitalization	***59.2%***	***40.8%***	***100.0%***	***58.0%***	***42.0%***	***100.0%***

ADJUSTED DEBT-TO-CAP OF 58.0% AT 12/31/05

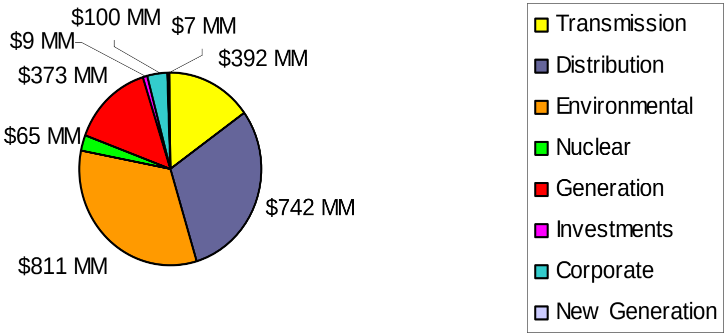
Capital Investment 2004 - 2006

Figures exclude AFUDC

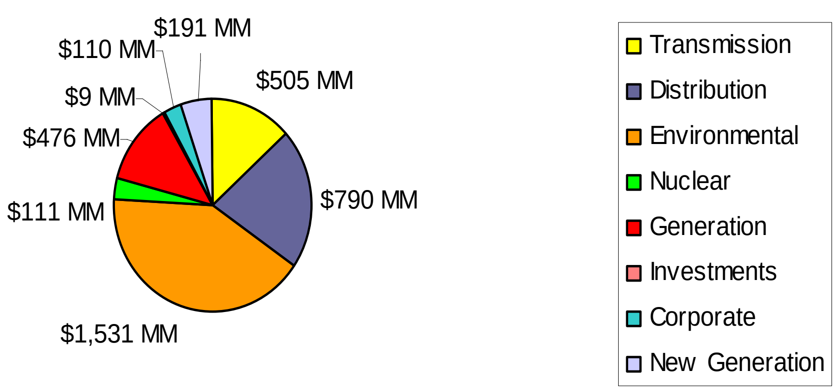
2004 Actual Totaled $1.6 Billion



2005 Actual Totaled $2.5 Billion (see note below)



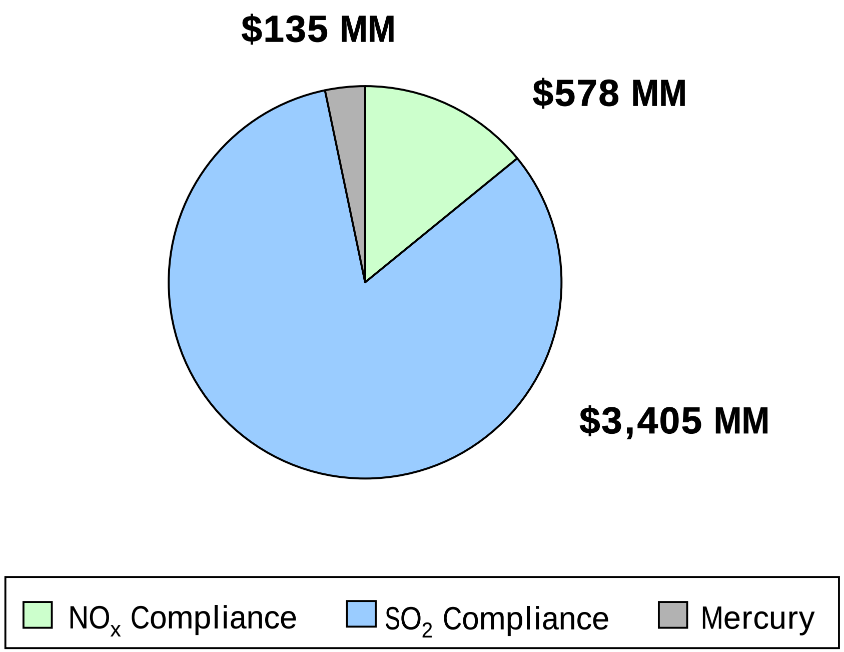
2006 Projected Totals $3.7 Billion



Note: 2005 Statement of Cash Flows shows $2.402B which reflects difference in accruals from 2004 to 2005

Environmental Compliance Investment

Compliance Allocation



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT
PROJECTED 2004 THROUGH 2010

Figures Include AFUDC

Environmental Installations

AEP®

FGD – Reduces SO_2 by 98% → **Co-Benefit Hg Capture** ← **SCR - Reduces NOx by 90%**

Completed

FGD

Plant Name	MW Capacity
Gavin 1 & 2	2600
Conesville 5 & 6	750
Pirkey	580
Oklaunion	539
Zimmer	330
Dolet Hills	262
Total	**5061**

SCR

Plant Name	MW Capacity
Gavin 1 & 2	2600
Amos 1-3	2900
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Zimmer	330
Total	**9742**

Planned or Under Construction

FGD: 2006 – 2010

Plant Name	MW Capacity
Amos 1-3	2900
Mitchell 1 & 2	1600
Mountaineer	1300
Big Sandy 2	800
Stuart 1-4	627
Cardinal 1	600
Muskingum 5	585
Conesville 4	339
Total	**8751**

SCR: 2006 – 2009

Plant Name	MW Capacity
Mitchell 1 & 2	1600
Conesville 4	339
Total	**1939**

Note: MW capacity shown represents AEP's owned capacity only

INSTALLATION OF SCR AND FGD WILL ALLOW OUR COAL FLEET TO REMAIN EXTREMELY COST COMPETITIVE

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called "syngas" – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

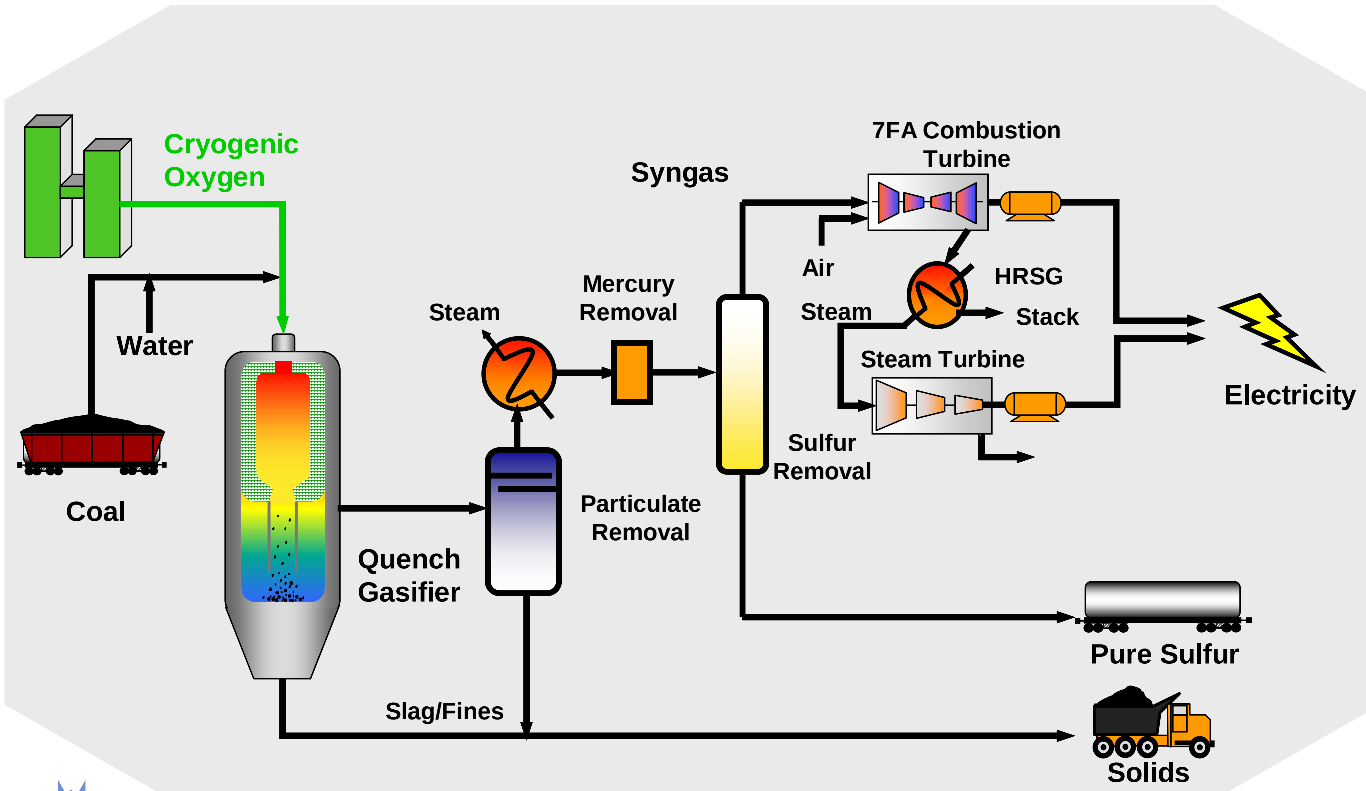
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP's eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking To The Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing In IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	600	600	600
Heat Rate (Btu/kWh)	8700	8600	7200
Total Plant Cost (EPC) ($/kW)	1700	1900	480
Production Cost ($/MWh)	17	16	57
Cost of Electricity, without CO2 Capture ($/MWh)	58	63	90
Estimated Cost of Electricity, with CO2 Capture ($/MWh)	94	87	137

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost (2005$'s) includes the cost to **E**ngineer, **P**rocure and **C**onstruct plant and owner's direct costs; does not include interconnections, transmission lines, transmission upgrades, contingency or AFUDC.
- Assumes Northern Appalachian Coal price of $1.60 /mmBtu for PC and IGCC, and natural gas price of $7.00/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 25% for NGCC.
- Production Cost includes Fuel Cost and Variable Operations & Maintenance (VOM) cost.
- Cost of Electricity based on EPC cost, does not include the cost of Emission Credits.
- Cost of Electricity with CO2 capture does not include sequestration cost.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

Summary Rate Case Information

West Virginia Base Case Rate Filing

On August 26, 2005, Appalachian Power Co. and Wheeling Power Co. filed an application with the West Virginia Public Service Commission (WVPSC) to increase electric rates and charges, a request for the reactivation and modification of the expanded net energy cost mechanism (ENEC), a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance, a request for implementation of a System Reliability Tracker mechanism, and a request for waiver of certain provisions of the Commission's Rules. APCo filed supplemental testimony on January 18, 2006 to reflect Ceredo plant purchase and other miscellaneous items resulting in a revised revenue requirement of $171 Million. (Docket #: 05-1278-E-PC-PW-42T)

Capital Structure – Company Position (8/26/05)

Capital Structure	Amount	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	$2,023,069,000	58.16%	5.57%	3.24%
Preferred Stock	$ 18,547,000	0.53%	4.35%	0.02%
Common Equity	$1,437,159,000	41.31%	11.50%	4.75%
Total	**$3,478,775,000**	**100.00%**		**8.02%**

Rate Base – Company Position (8/26/05; updated 1/18/06)

(in millions $)	7/1/2006	1/1/2007	1/1/2008	1/1/2009
Average Rate Base (WVa juris.)	1,612	1,611	1,609	1,609
Supplemental Increases:				
WJF 765-kv Trans. Line	64	124	119	114
Mountaineer FGD		235	221	207
Amos Unit # 3			69	65
Amos Unit # 2 & 3				258
Total	**1,676**	**1,970**	**2,018**	**2,253**

Remaining Procedural Schedule*

March 8, 2006	Staff & Intervenor Testimony
March 29, 2006	Company Rebuttal Testimony
April 18-21, 2006	Hearings

- Initial briefs due 20 days after receiving hearing transcript
- Reply briefs due 10 days after initial briefs

Statutory Deadline: July 28, 2006

* Procedural schedule subject to modification until order is issued.

Summary Rate Case Information

AEP®

Virginia E&R Factor Filing

On July 1, 2005, Appalachian Power Co. filed a request with the Virginia SCC to recover incremental actual and projected costs for environmental compliance and T&D System reliability in the amount of $62.1MM. The SCC has ruled that under applicable VA law, it does not have authority to approve the recovery of projected E&R costs before their actual incurrence and adjudication. APCo filed supplemental direct testimony which included actual costs incurred for E&R thru September 30, 2005 of $21.1 million. Docket # PUE-2005-00056

Capital Structure – Company vs. Staff

Capital Structure	**Company Position** (filed 7/1/05)	**Staff Position** (filed 1/11/06)
Long-Term Debt	53.43%	51.50%
Short-Term Debt	2.67%	2.20%
Preferred Stock	0.54%	0.53%
Common Equity	42.65%	45.16%
ITC	0.71%	0.61%
Total	**100.00%**	**100.00%**
Recommended ROE	**10.85%**	**9.80%**

Revenue Requirement – Company vs. Staff*

Revenue Requirement	**Company Position** (filed 11/14/05)	**Staff Position** (filed 1/11/06)
Environmental	13.3	8.2
Transmission	6.1	8.8
Distribution	1.7	2.6
Total	**$21.1MM**	**$19.6MM**

* Difference in positions does not reflect the relative earnings impact and is not necessarily a reflection of the ultimate outcome of the case.

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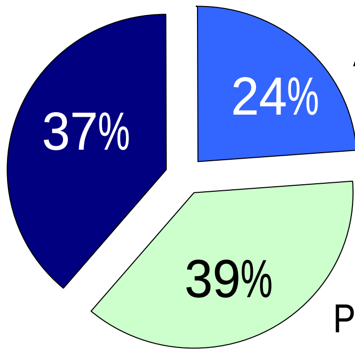
Coal Procurement

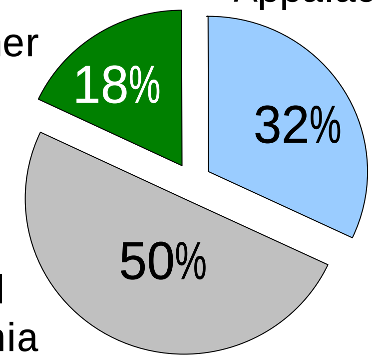
AEP SYSTEM



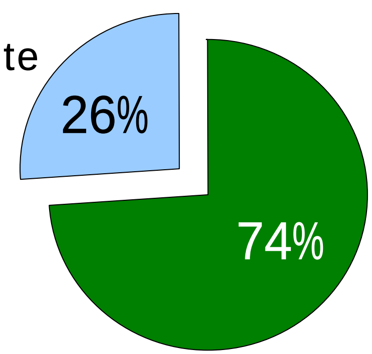
Coal Supply
(on average)

- ➢ Purchase 75 MM tons per year
- ➢ Avg. delivered price ~ $32.52/ton in 2005
- ➢ Essentially 95% purchased for 2006
- ➢ Approximately 10%-12% price increase in 2006
  - Rising costs at Eastern mines & safety issues
  - High SO_2 Allowance prices drive low sulfur coal prices

EASTERN SYSTEM



WESTERN SYSTEM



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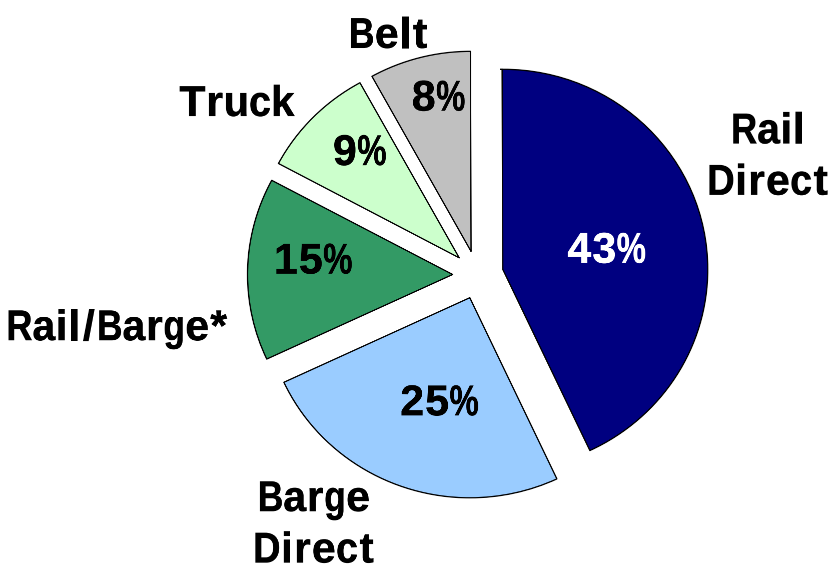
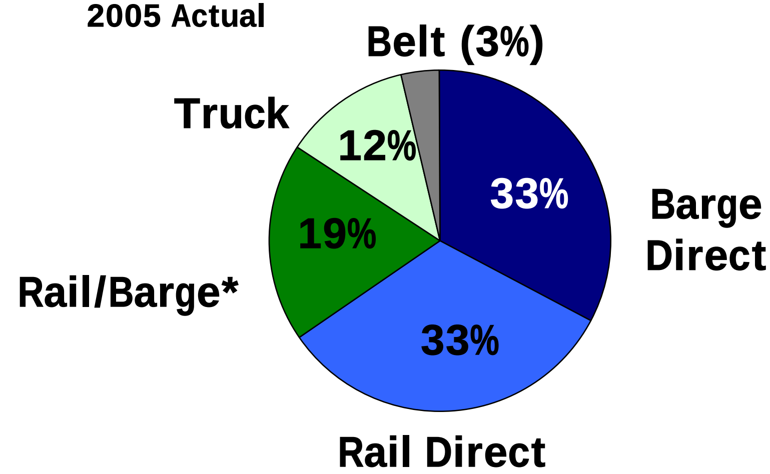
Coal Delivery

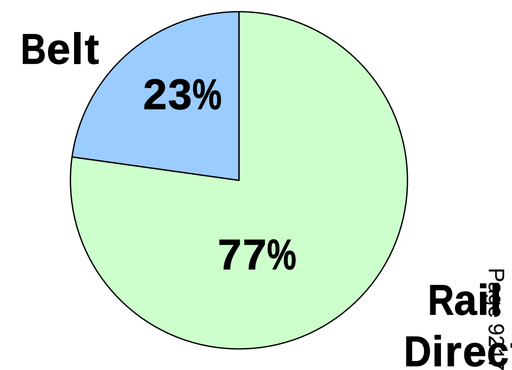
AEP SYSTEM DELIVERY MODE DIVERSITY
2005 Actual



EASTERN SYSTEM
2005 Actual



WESTERN SYSTEM
2005 Actual



*Coal delivered to AEP plants transported through combination of rail and barge

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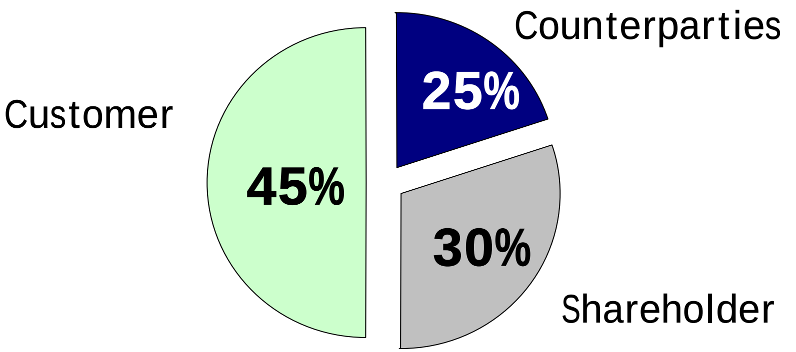
Fuel Recovery

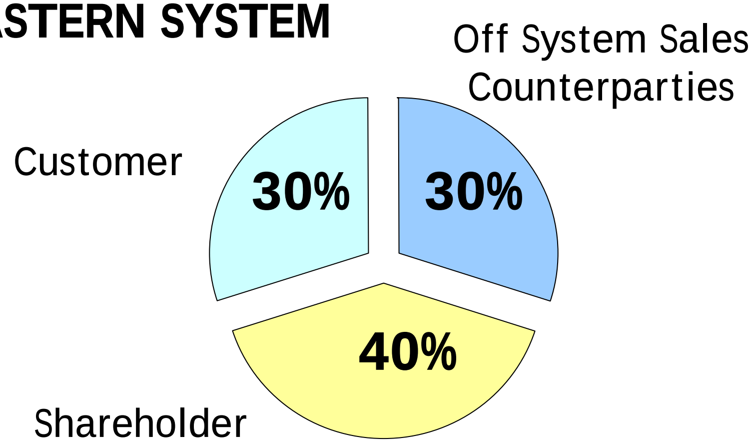
AEP SYSTEM



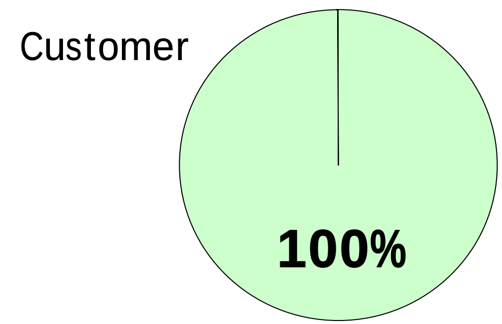
Fuel Cost Recovery
(on average)

- Fuel recovery varies by jurisdiction
- 70% of fuel cost is recoverable across the AEP System
- Active Fuel Clause Jurisdictions:
  - AEP EAST: AP-VA, I&M, KGP, KP
  - AEP WEST: PSO, SWEPCO

EASTERN SYSTEM



WESTERN SYSTEM



UBS 2010 Natural Gas, Electric Power and Coal Conference

Dallas, TX

March 4, 2010

Mountaineer Plant (WV)

345-kV Transmission Line

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load and customer growth, weather conditions, including storms, and our ability to recover significant restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance or the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including our dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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AEP AMERICAN ELECTRIC POWER®

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Rich Munczinski – SVP, Regulatory Services

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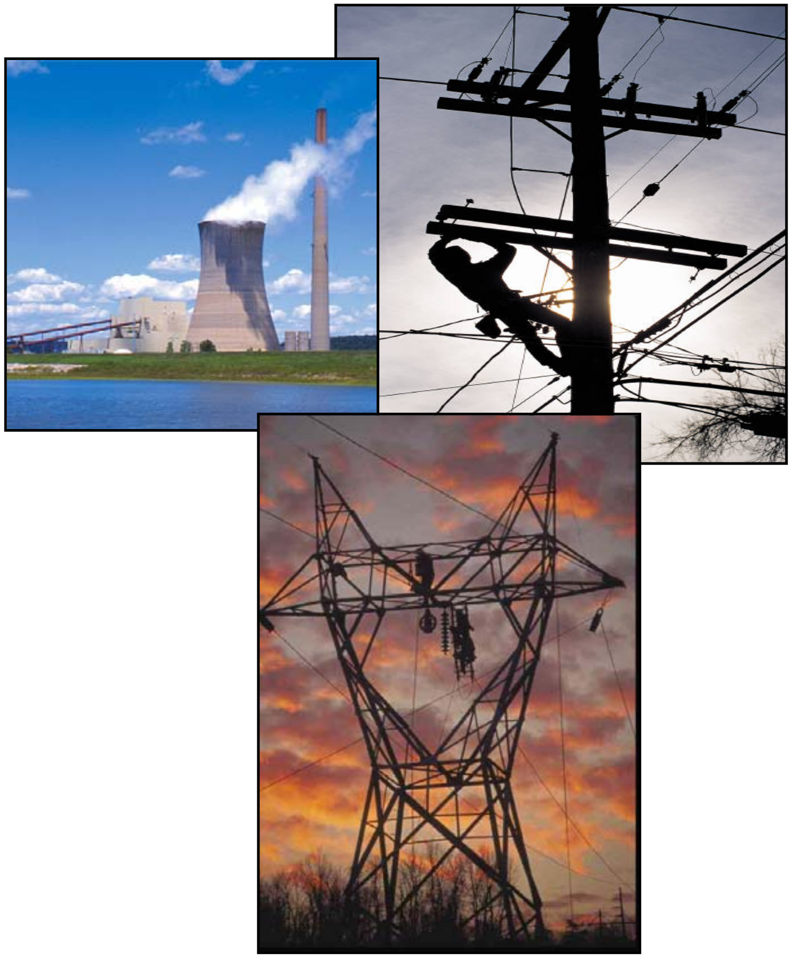
AEP Value Proposition

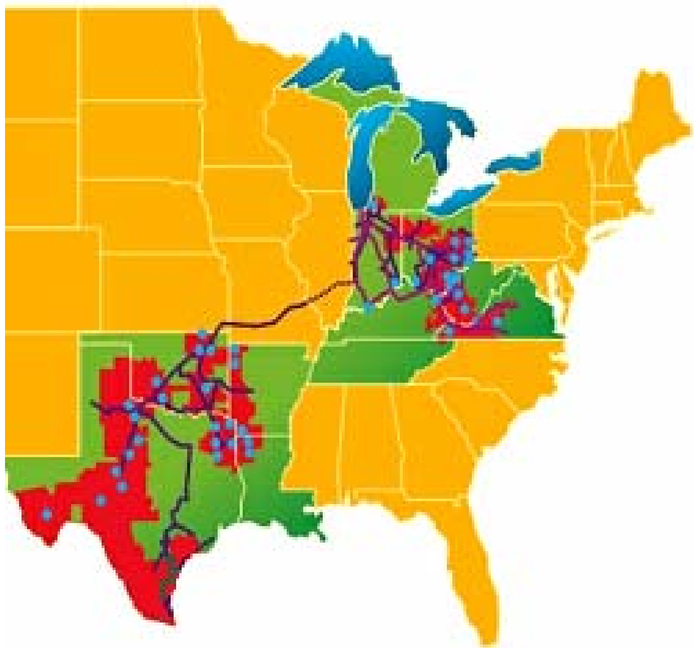
- **Regulated Utility Platform**
  - Diversified service territory
  - Successful regulatory track record
  - Value compared to regulated peer group
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)
- **Attractive Yield Opportunity of 4.8%[1]**
  - 50-60% payout ratio targeted
  - Nearly a century of dividend payments to shareholders



AEP AMERICAN ELECTRIC POWER®

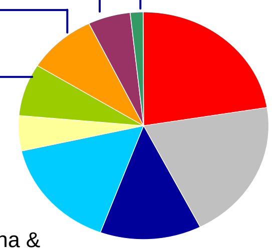
[1] yield percentage based on AEP closing price of $33.94 on 03/01/2010

Highly Diversified Regulated Utility Platform

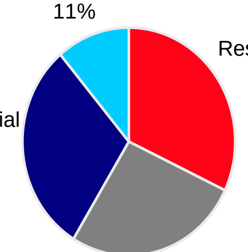


Serving 5.2 million customers in 11 states

2009 Earnings Contribution

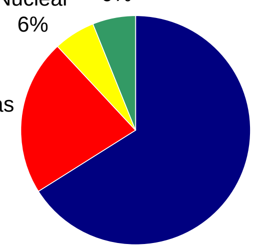


2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Fuel Mix



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Transmission Investment Opportunities

ETT: Projects in Texas ERCOT jurisdiction

- $600MM of projects est. in service 2010-2013
- ETT's opportunity could reach $3.0B in this decade

Transco: Within our existing footprint

- Provides opportunity to:
  - Develop new AEP-only projects
  - Reduce regulatory lag through FERC formula rates adjusted annually

Joint Ventures: Outside of our footprint, via ETA or with others

- Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
- Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
- Robust pipeline of projects up to $15B

765-kV Tower

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JV Strategy - Nationwide Grid Expansion

ACTIVE PROJECTS

SPP

Prairie Wind — COD: 2013-14
- *110 miles of 765 kV*
- *Partners: Westar (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $400 million*
- *ROE: 12.8%*

Tallgrass — COD: 2013-14
- *170 miles of 765 kV*
- *Partners: OG&E (50%) & MidAmerican Energy (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*

ERCOT

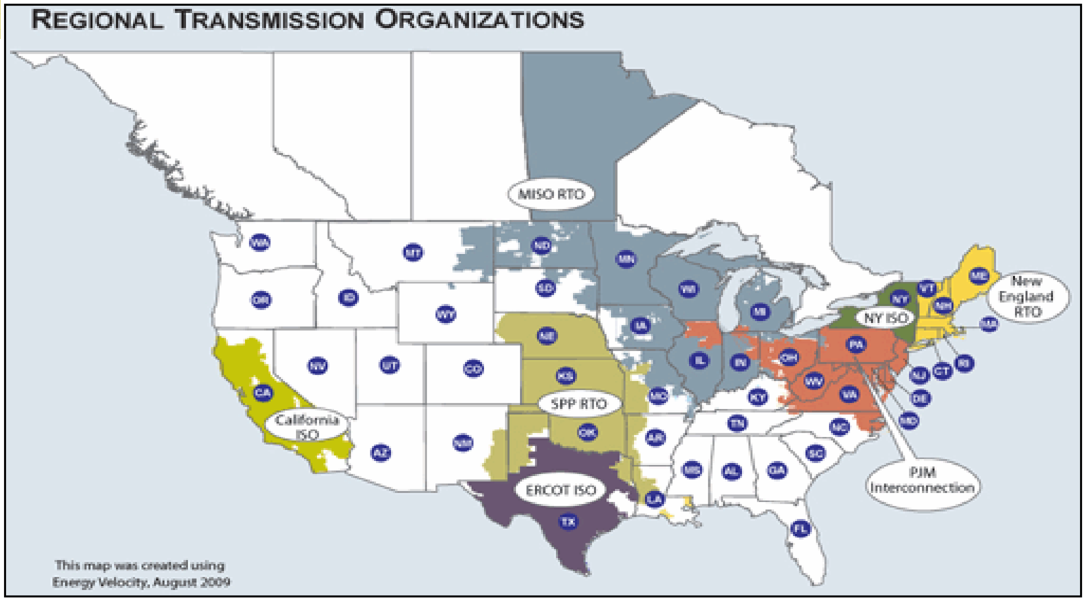
ETT — COD: 2010-2017
- *345 kV ERCOT Expansion*
- *Partner: MidAmerican Energy (50%)*
- *Estimated Cost: $1.4 billion*
- *ROE: 9.96%*

PJM

PATH-WV — COD: 2014
- *275 miles of 765 kV*
- *Partner: Allegheny Energy (50%)*
- *Estimated Cost: $1.2 billion*
- *ROE: 14.3%*

PJM/MISO

Pioneer — COD: 2015
- *240 miles of 765 kV*
- *Partner: Duke Energy (50%)*
- *Estimated Cost: $1 billion*
- *ROE: 12.54%*



FUTURE DEVELOPMENT

SMARTransmission Study
- *Interregional EHV & Wind Integration Study*
- *Partners: ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP EHV Overlay
- *Regional Expansion of 765 kV Backbone*

ETT — COD: various
- *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)*
- *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*

PJM Expansion
- *Regional Expansion of 765 kV, 500 kV and 345 kV systems*

EHV Michigan/Ohio
- *700 miles of Proposed 765 kV*

SPP | ERCOT | PJM | PJM/MISO

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KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Electric Transmission Texas, LLC

Overview:

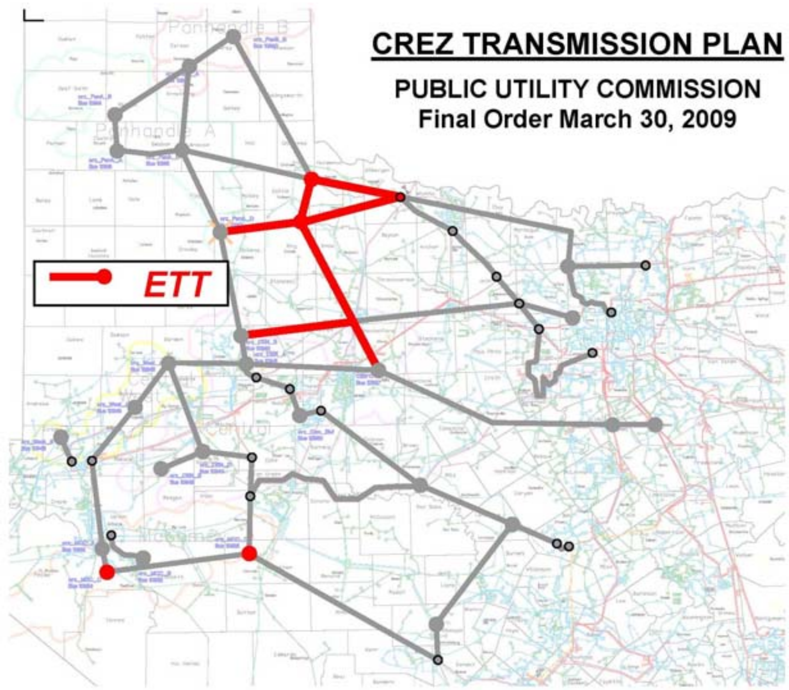
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with a debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2017: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects pending transfer in service 2010-2013: $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

ETT
Electric Transmission Texas

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EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
- Estimated completion date: 2014+, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

PATH
Potomac-Appalachian Transmission Highline

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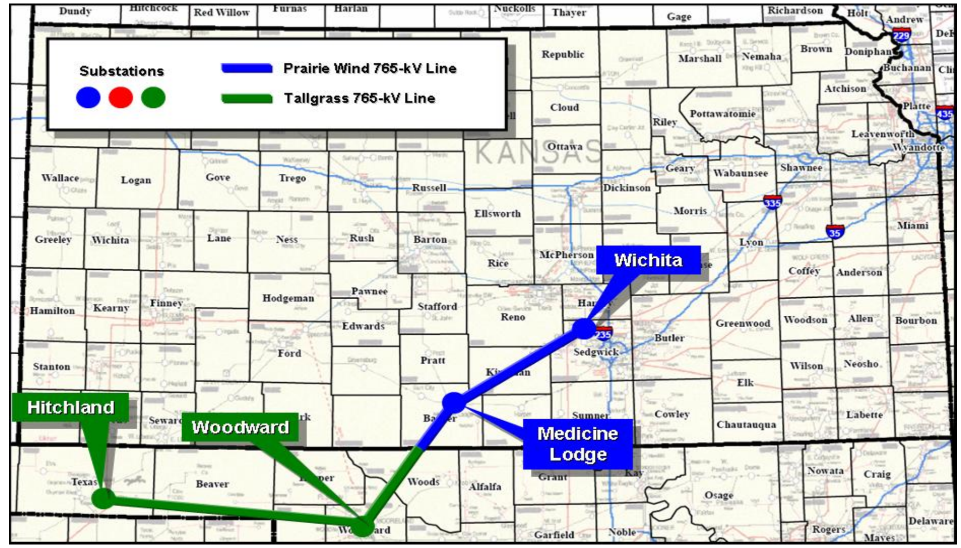
Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval
- Siting

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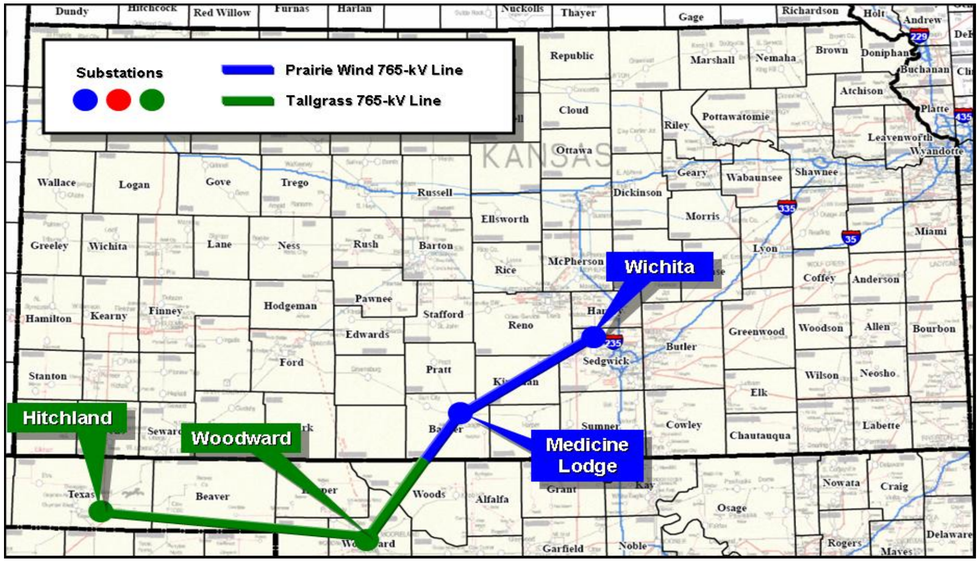
Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-14.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

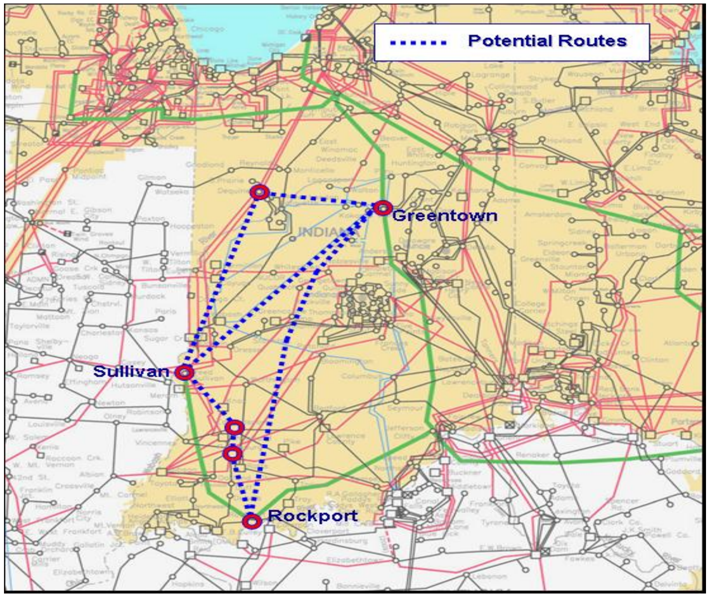
Key Challenges:

- RTO Approval
- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP’s Rockport Station to Duke’s Greentown station in Indiana.
- The project will improve the reliability of the nation's transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, protect national security and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP’s ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of “system solutions”
- Siting

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Upper Midwest EHV Development—SMART Study

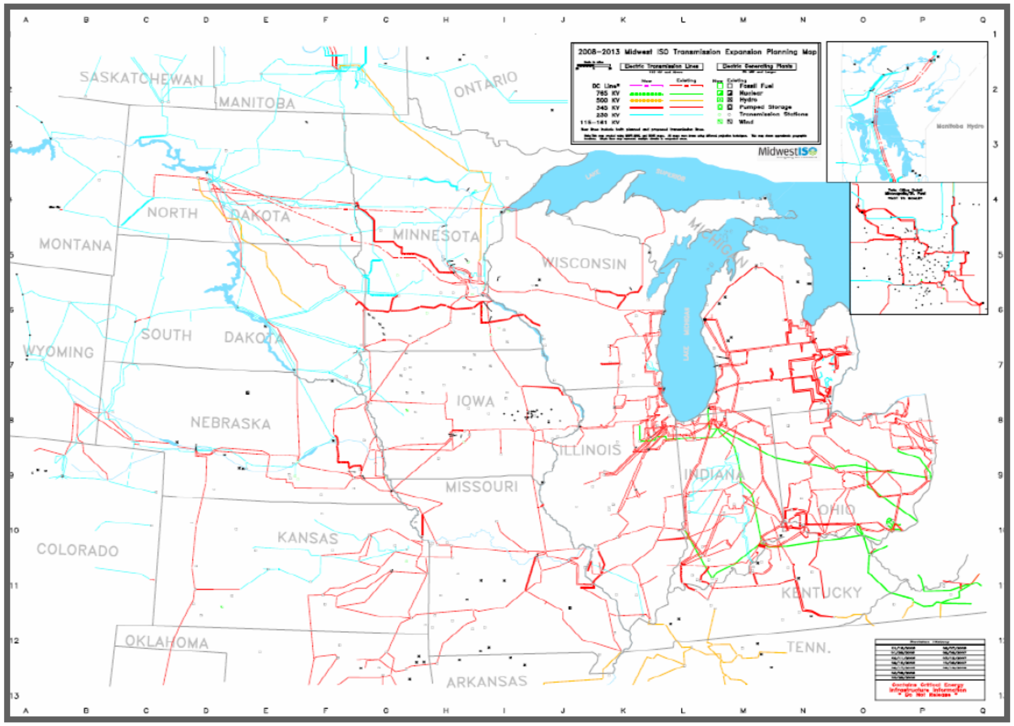
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternative that ensures reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

Overview:

- SMARTransmission Study announced August 2009
- Sponsors of the Study include ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Study due to be completed end of 2nd Qtr 2010 and will include "overlay" options and quantification of economic benefits

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives



Primary Focus Areas: North Dakota – South Dakota – Iowa – Nebraska – Indiana – Ohio – Illinois – Minnesota – Wisconsin – Michigan

Mitigation:

- Collaborative approach involving impacted utilities, RTOs, commissions and others

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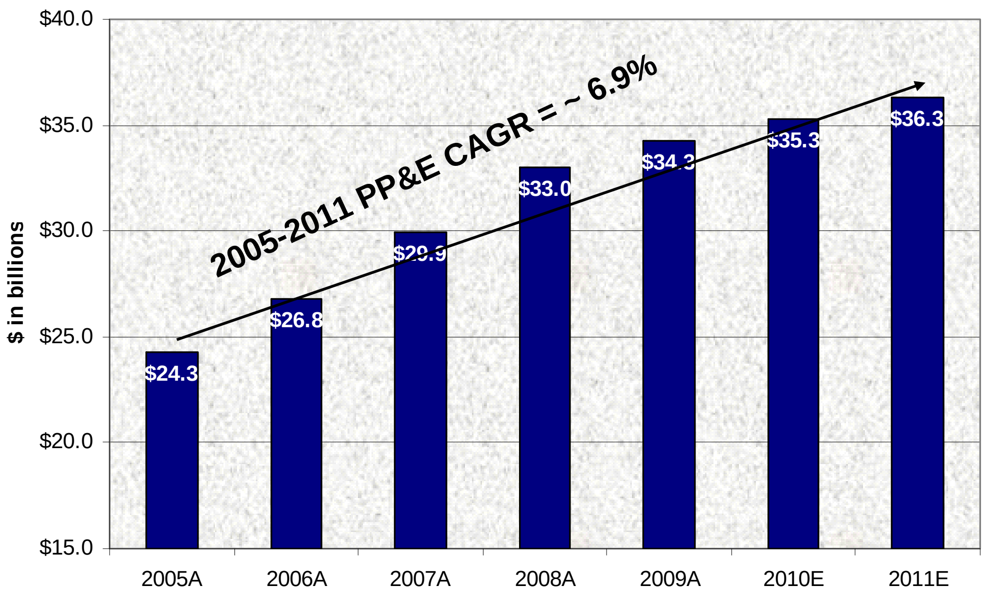
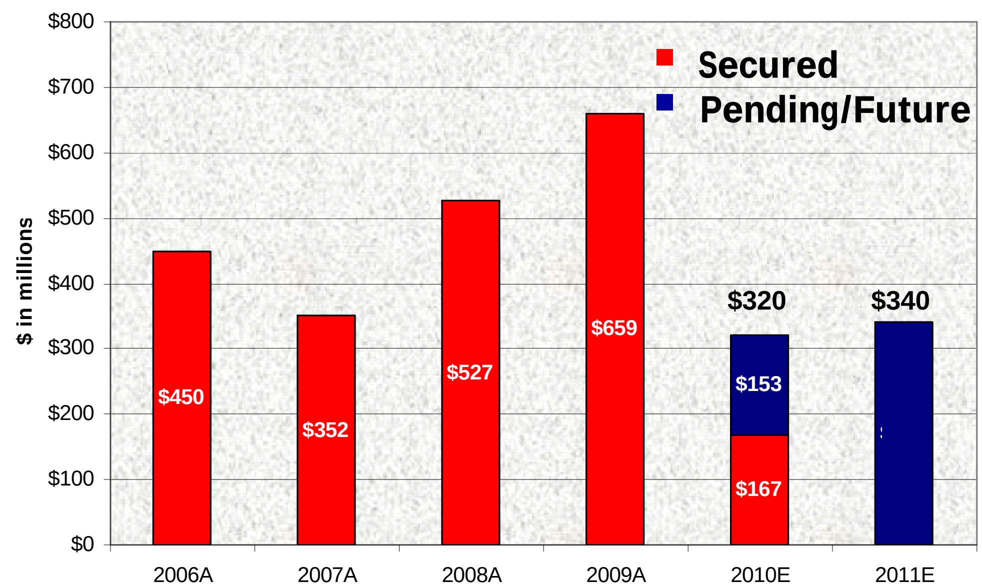
Traditional Rate Making Environment

Growth in Net PP&E



Track Record of Rate Relief



Note: rate relief in this chart excludes revenues with offsetting costs

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

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Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. A hearing will commence in March 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010. Represents Generation and Distribution Rate Base Only

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Summary Rate Case Information

SWEPCO Texas General Rate Case – Docket #37364

On August 28, 2009, SWEPCO filed a base rate case with the Public Utility Commission of Texas requesting an increase of $75 million to cover costs related to the construction of the Stall and Turk plants as well as enhanced distribution reliability spending. An order is expected in July 2010.

Proposed Capital Structure – Company Position (3/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.18%	6.00%	2.95%
Preferred Stock	0.17%	4.87%	0.01%
Common Equity	50.65%	11.50%	5.82%
Total	100.00%		8.78%

Procedural Schedule Suspended Pending Settlement

Required Rate Relief – Company Position (3/31/09)

($ in millions)

Rate Base	$	668.7
Rate of Return		8.78%
Operating Income Requirement	$	58.7
Adjusted Operating Income	$	42.2
Difference	$	16.5
Revenue Conversion Factor		1.64
Revenue Deficiency	$	27.1
Generation Recover Rider	$	31.6
Reliability Rider	$	16.3
Total Required Rate Relief	$	75.0

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Summary Rate Case Information

Kentucky General Rate Case – Docket #2009-00459

On December 29, 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase of $123.6 million to cover costs related to enhanced distribution reliability spending, depreciation of capital investments, investments in renewable energy and participation in PJM. An order is expected in the second half of 2010.

Proposed Capital Structure – Company Position (9/30/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	-2.17%	2.29%	-0.05%
Long-Term Debt	54.62%	6.48%	3.54%
Common Equity	42.91%	11.75%	5.04%
Other Items	4.640%	2.99%	0.14%
Total	100.00%		8.670%

Required Rate Relief – Company Position (9/30/09)

($ in millions)

Capitalization	$	994.69
Rate of Return		8.67%
Operating Income Requirement	$	86.2
Adjusted Operating Income	$	11.2
Difference	$	75.0
Revenue Conversion Factor		1.6476
Total Required Rate Relief	$	123.6

Procedural Schedule

April 7, 2010	Staff and Intervenor Testimony due
May 14, 2010	KPCo Rebuttal Testimony due
tbd	Hearing commences
July 15, 2010	Rates effective subject to refund

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Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. A procedural schedule is pending from the MPSC. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

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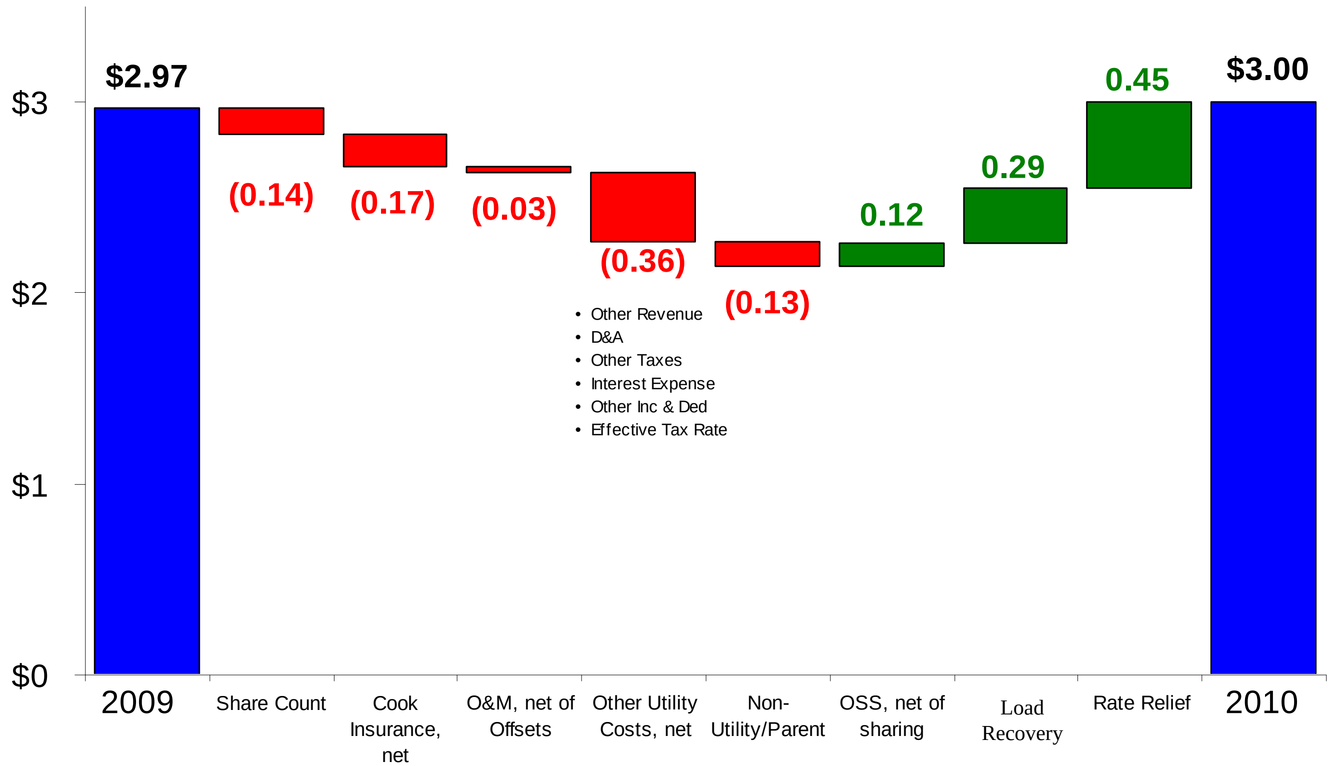
2010 Ongoing Earnings Guidance

	2009A: $2.97	2010E: $2.80-$3.20
Utility Operations	$ 2.87	$ 3.01
Transmission Operations	$ 0.01	$ 0.02
Nonutility Operations	$ 0.19	$ 0.09
Parent & Other	$(0.10)	$(0.12)



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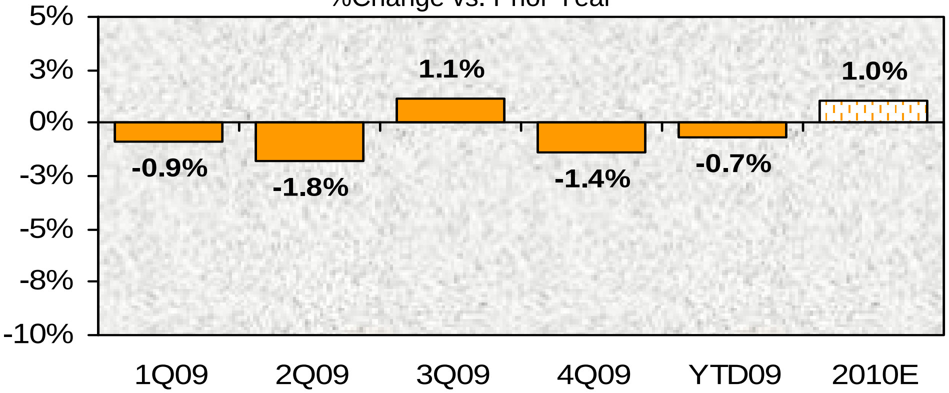
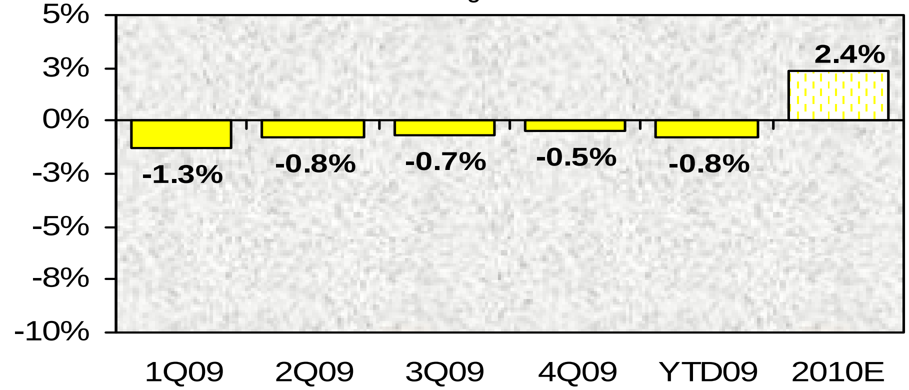
Normalized Load Trends

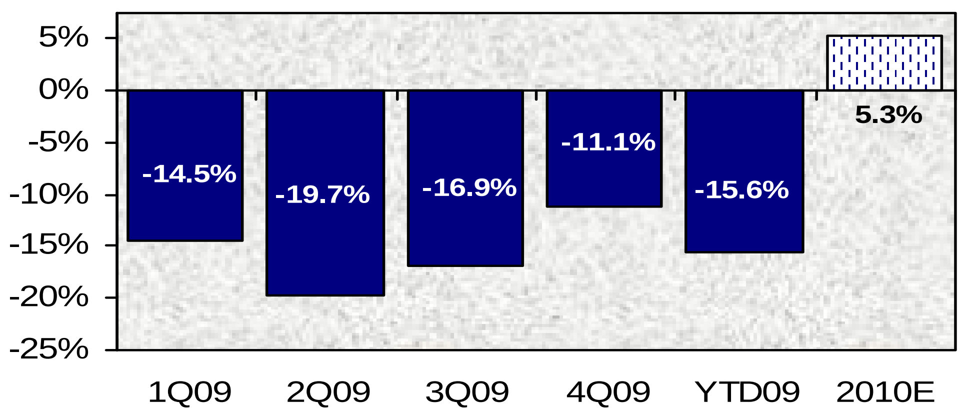
AEP Residential Normalized GWh Growth
%Change vs. Prior Year



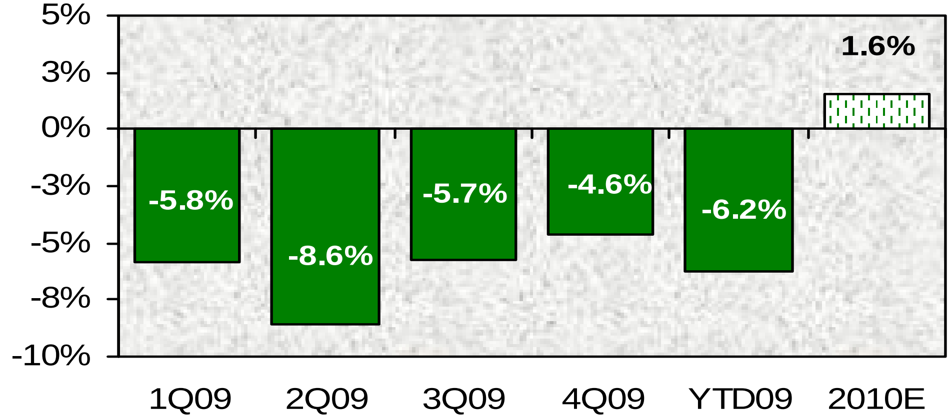
AEP Commercial Normalized GWh Growth
%Change vs. Prior Year



AEP Industrial Normalized GWh Growth
%Change vs. Prior Year



AEP Normalized GWh Growth*
%Change vs. Prior Year



*includes firm wholesale load

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Additional 2010 Earnings Drivers

O&M Assumptions

- $23MM increase over 2009, net of revenue offsets
- Includes $80MM increase in employee and operational expenses

Rate Relief Assumptions

- $320MM, net of trackers
- $167MM secured
  - AR, OH, OK, VA, WV
- Active or pending rate cases include KY, MI, TX, VA, WV and others

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Detailed Ongoing Earnings Guidance

2009A: $2.97

2010E: $2.80 - $3.20

American Electric Power
2009 Actual vs. 2010 Guidance

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
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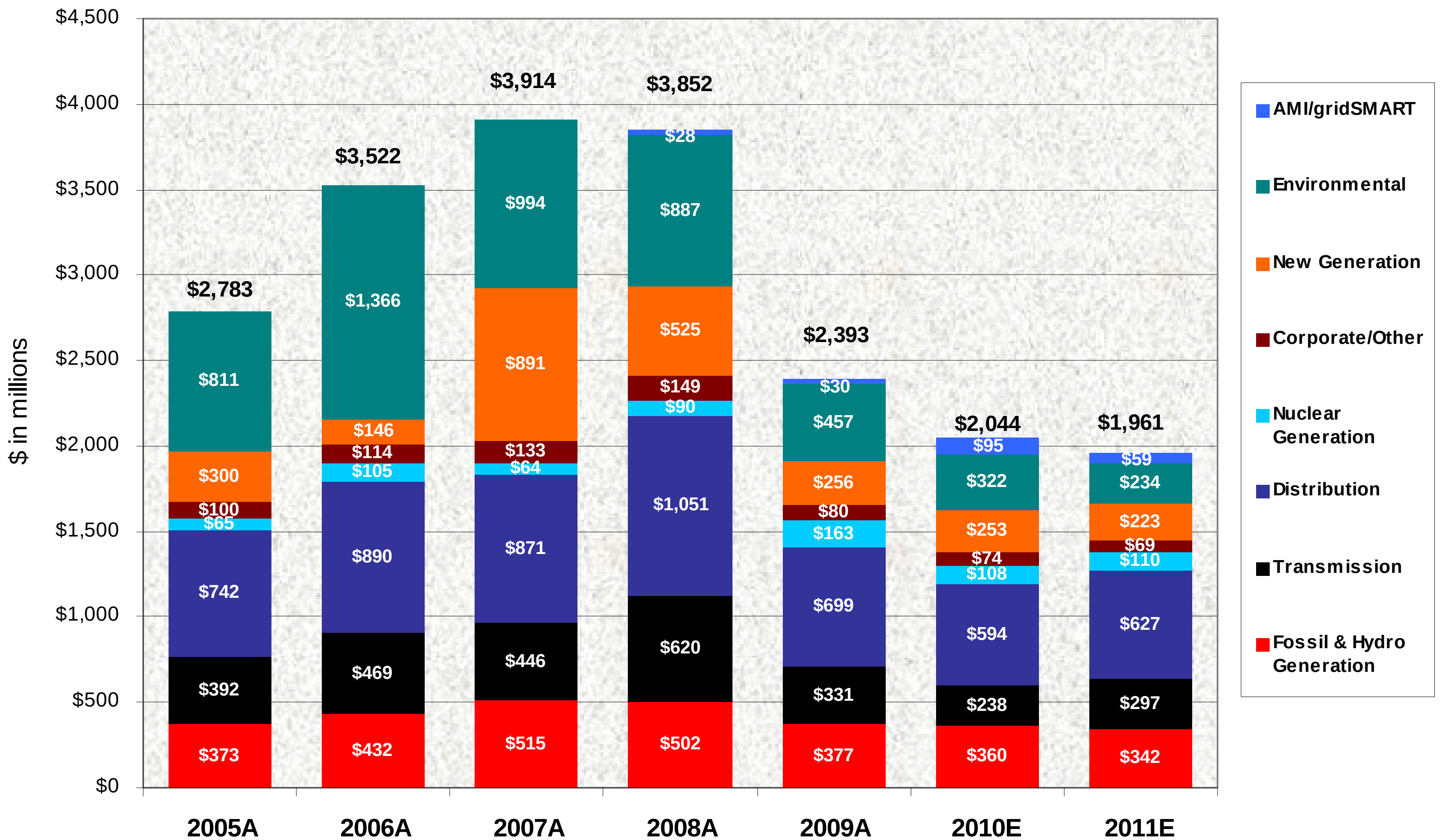
Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

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Multi-Year Capital Investment Funding Plan

	Actual 2009	Projection 2010
Capital Expenditures (Excluding AFUDC)	$ (2,791)	$ (2,310)
Transmission Initiatives (JV Equity Contributions)	(43)	(89)
Dividend on Common Stock	(759)	(786)
Cash Sources (Uses)		
Cash from Operations	2,484	3,775
Proceeds from Sale of Assets	278	129
Common Stock Issued	1,728	150
Change in Debt, Net	(360)	(632)
Other	(458)	(191)
Change in Cash	79	46
Ending Cash Balance	$ 490	$ 536

Utility Operations Capital by Subsidiary

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

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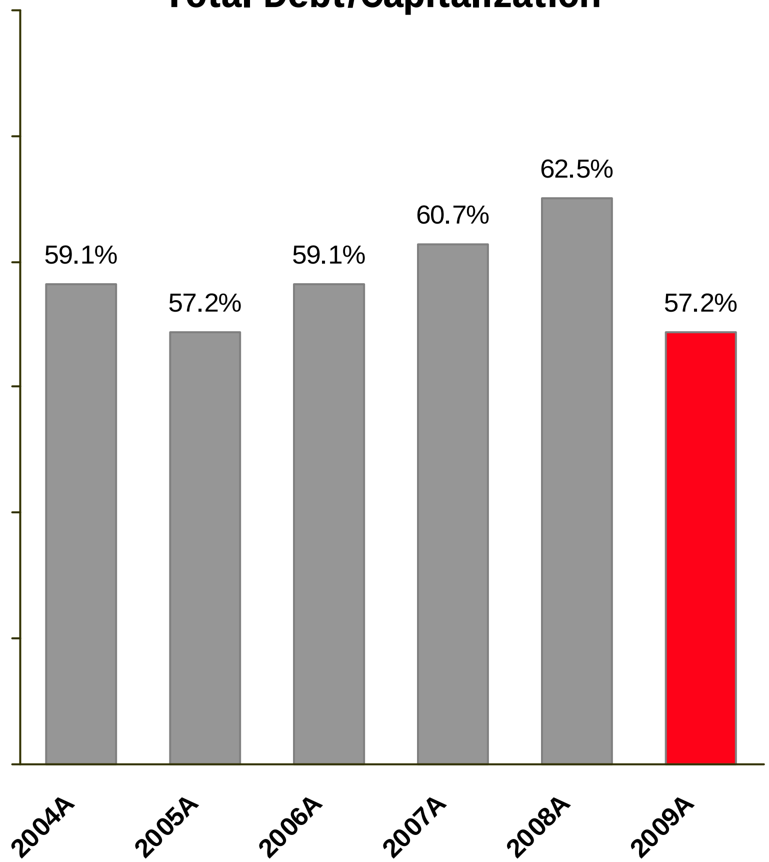
Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 12/31/09**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Mar-11
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	627	Apr-11
Total Credit Facilities	**3,581**	
Plus		
AEP, Inc. cash and investments	490	
Less		
Commercial Paper Outstanding	(119)	
Letters of credit issued	(568)	
Net Available Liquidity	**$3,384**	

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	N	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	N	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	N
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB+	N

S=Stable, N=Negative Outlook

AEP AMERICAN® ELECTRIC POWER

Long-term Debt Maturity Profile

($ in millions)

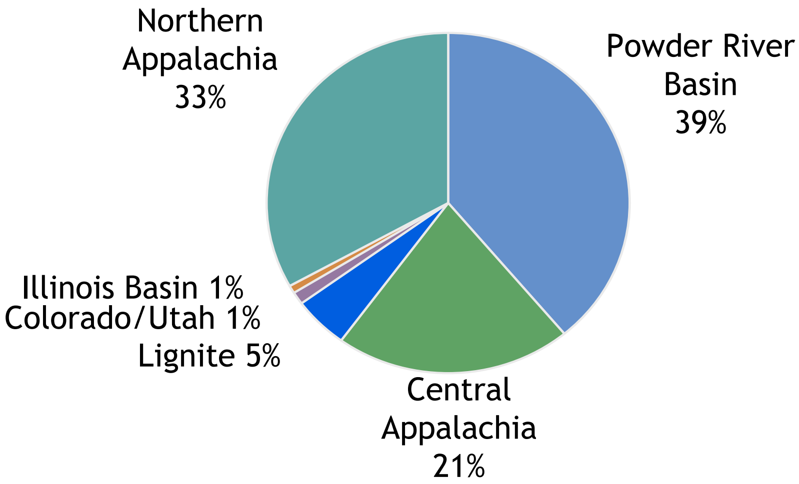
Year		2010		2011		2012
AEP, Inc.	$	490	$	-	$	-
AEP Generating Company	$	-	$	130	$	-
Appalachian Power	$	200	$	250	$	250
Columbus Southern Power	$	150	$	-	$	45
Indiana Michigan Power	$	-	$	-	$	100
Kentucky Power	$	-	$	-	$	-
Ohio Power	$	679	$	-	$	-
Public Service of Oklahoma	$	-	$	75	$	-
Southwestern Electric Power	$	-	$	48	$	-
Texas Central Company(1)	$	66	$	120	$	20
Texas North Company	$	-	$	-	$	-
Total	$	1,585	$	623	$	415

(1) Includes Texas securitization bonds based upon scheduled final payment date
Includes mandatory tenders (put bonds)
Data as of December 31, 2009

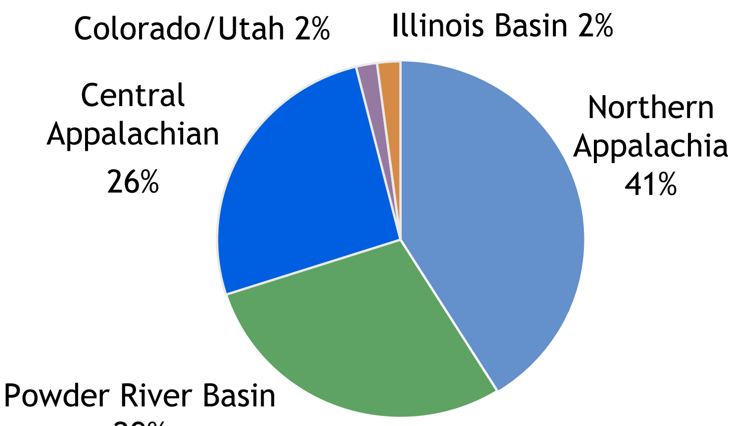
AMERICAN ELECTRIC POWER

Coal Procurement - 2010 Projected

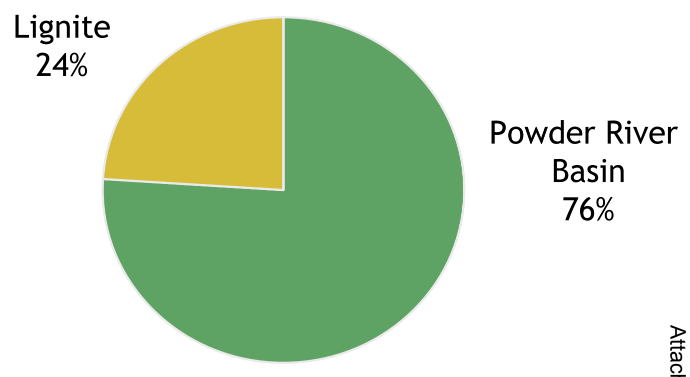
Total AEP System



AEP East



AEP West



Coal Stats:

- 100% contracted for 2010 and 75% for 2011
- Avg. delivered price ~ $50/ton in 2009
- Approximate 7% price decrease in 2010 ~$46/ton

AEP AMERICAN ELECTRIC POWER®

AEP AMERICAN® ELECTRIC POWER

UBS Gas, Power & Coal Conference
Dallas, Texas
March 3, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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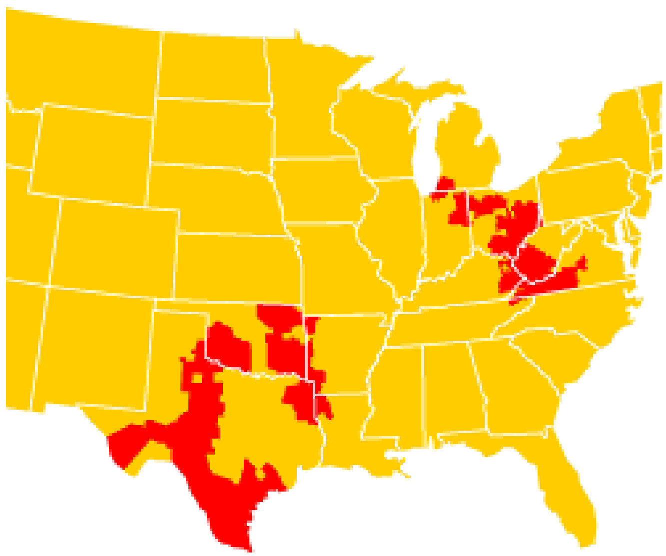
Table of Contents

American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield of 5%

Serving electric customers in 11 states



AEP Fast Facts

5.3 million customers
39 GW of generation capacity
39,000 miles of transmission lines

$17.7B Market Capitalization
BBB/Baa2/BBB credit rating

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Capital for Growth
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012
- Return of Capital to Shareholders
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings
- Capital to Reduce Risk
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Managing Operations and Investment

Challenges:

Required refinement of the operating company model and improved line-of-sight management due to decreased load growth, regulatory lag, reduced rate headroom, and environmental challenges

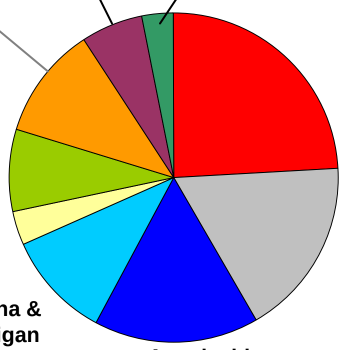
Actions:

- Empower operating company employees to drive results
- Efficiently allocate capital
- Demonstrate O&M and capital expenditure discipline
- Identify asset renewal strategy for investing in traditional distribution and transmission assets that enhance reliability and customer satisfaction
- Enable long-term planning discussions with regulators and legislators

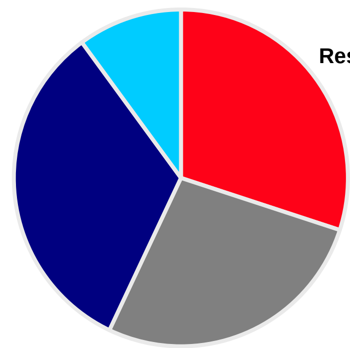
Expected Outcomes:
Optimize spending for more efficient return on investment
Improve dialogue with customers and regulators
Minimize lag in rate recovery

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



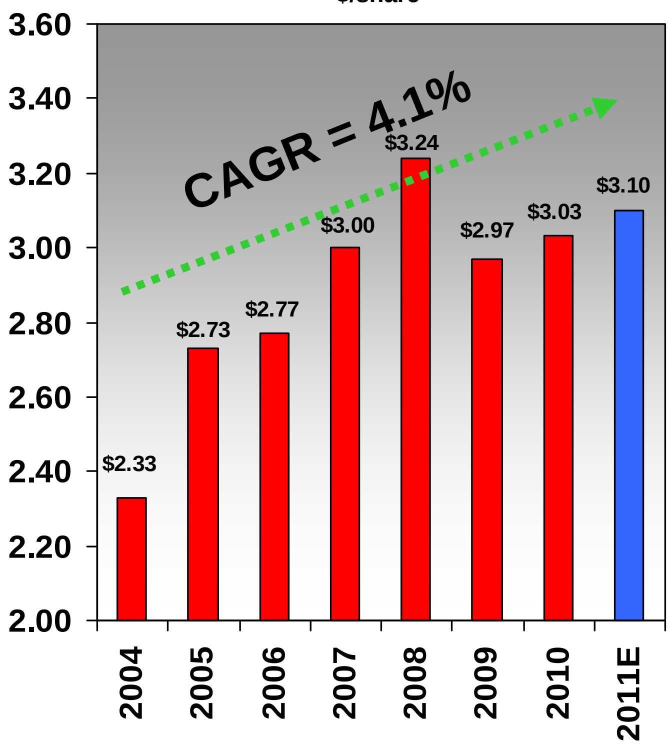
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Earnings and Dividends

On-Going EPS History Since 2004

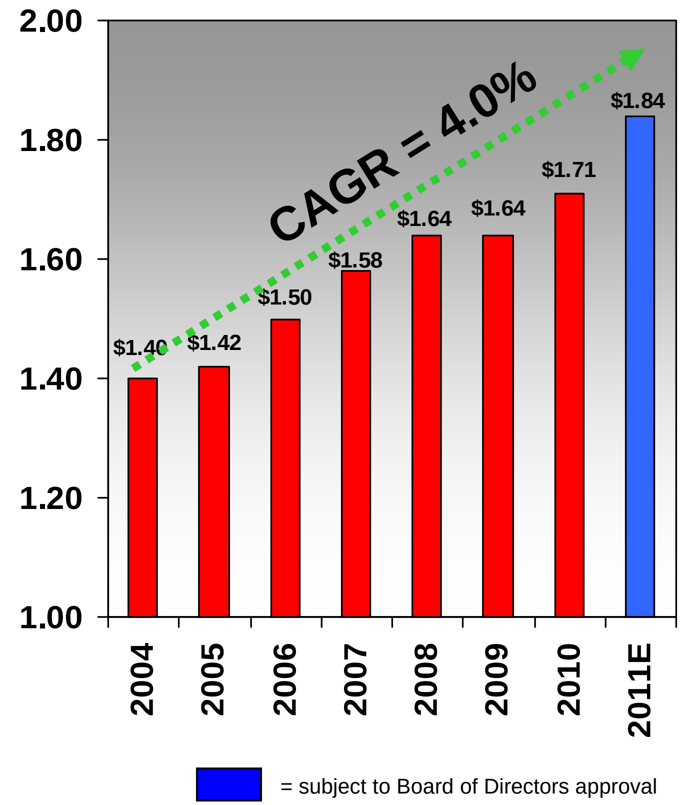
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share

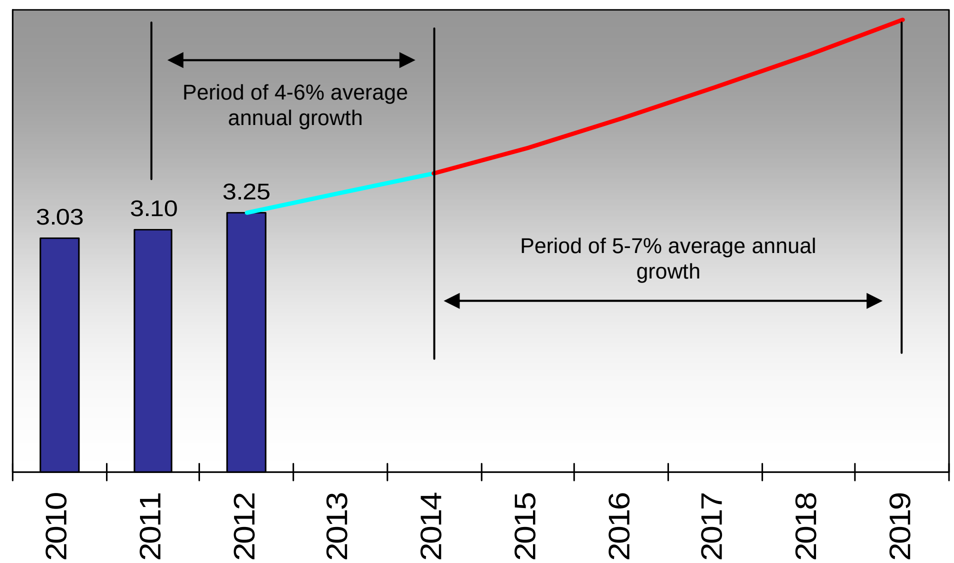


- Dividend increased 12% in 2010
- 403rd consecutive quarterly dividend declared in January 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Approved Rate Bases & ROEs

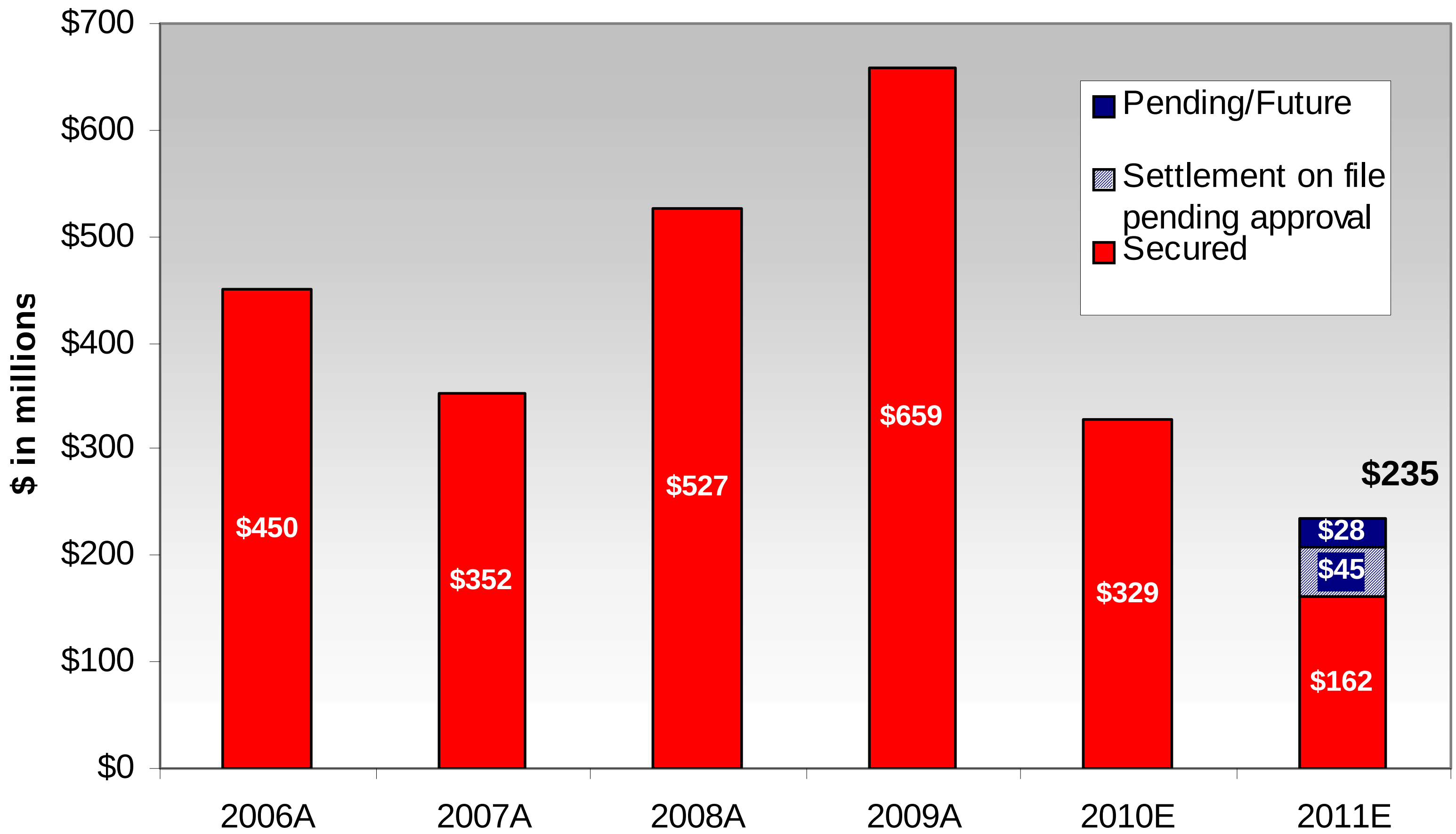
Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

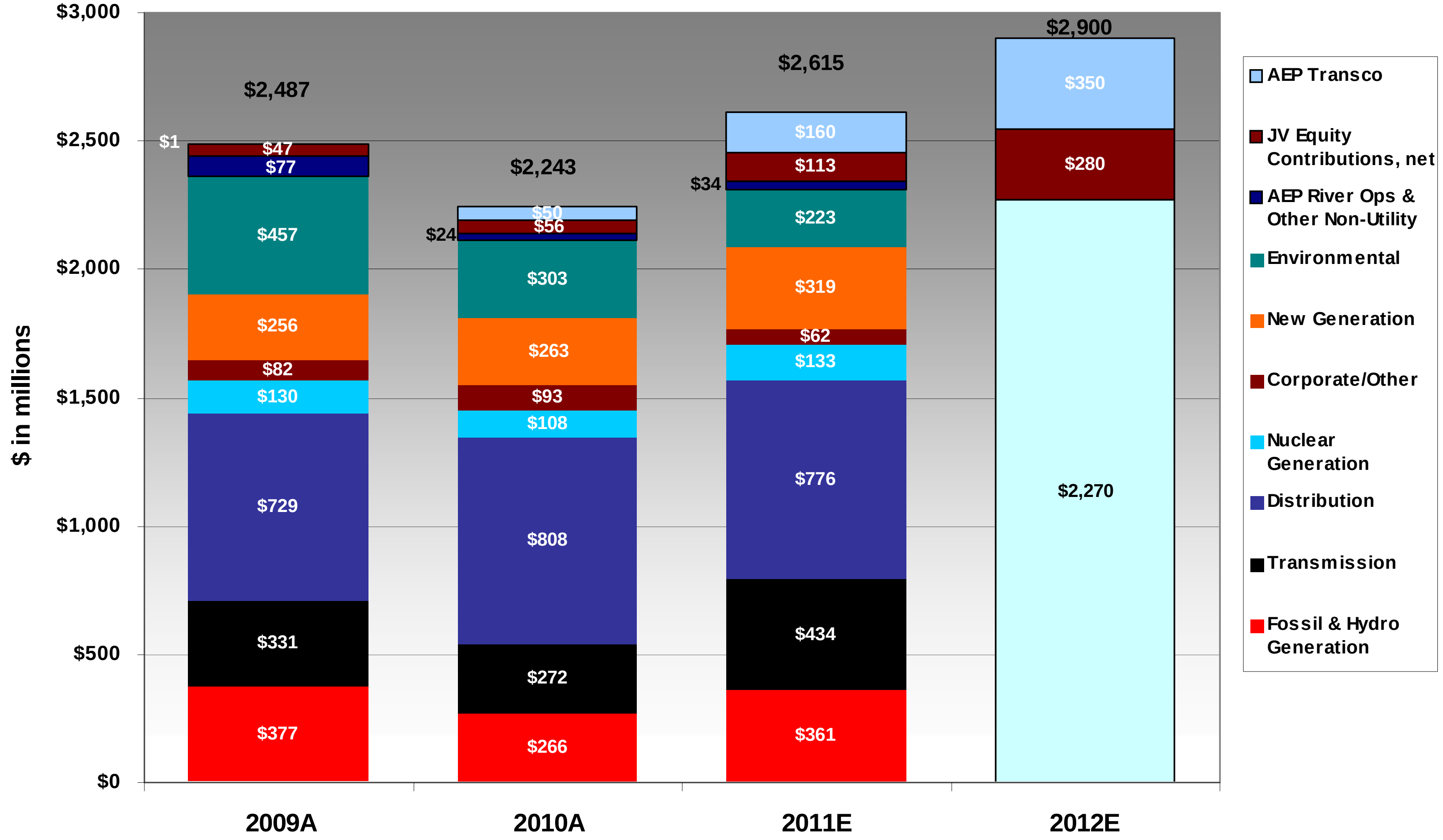
Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Active or pending rate cases include West Virginia and others yet to be filed

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Cash Flow Guidance

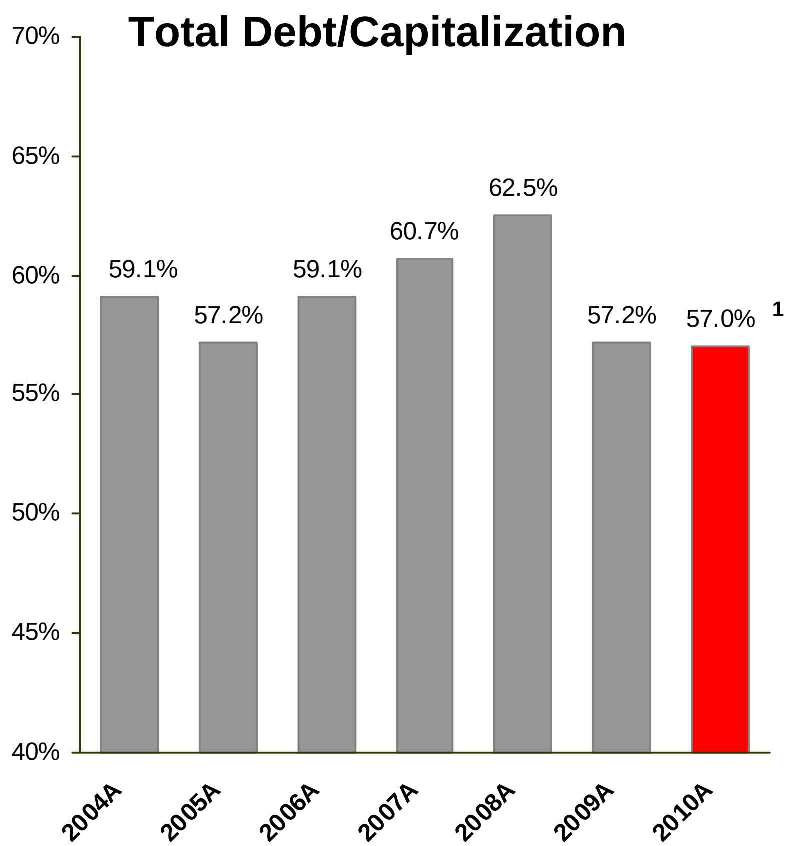
$ in millions

	2010A	2011E
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Ligigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to September 30, 2010 10Q *Enron Bankruptcy* pages 56-57 for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Detailed Ongoing Earnings Guidance

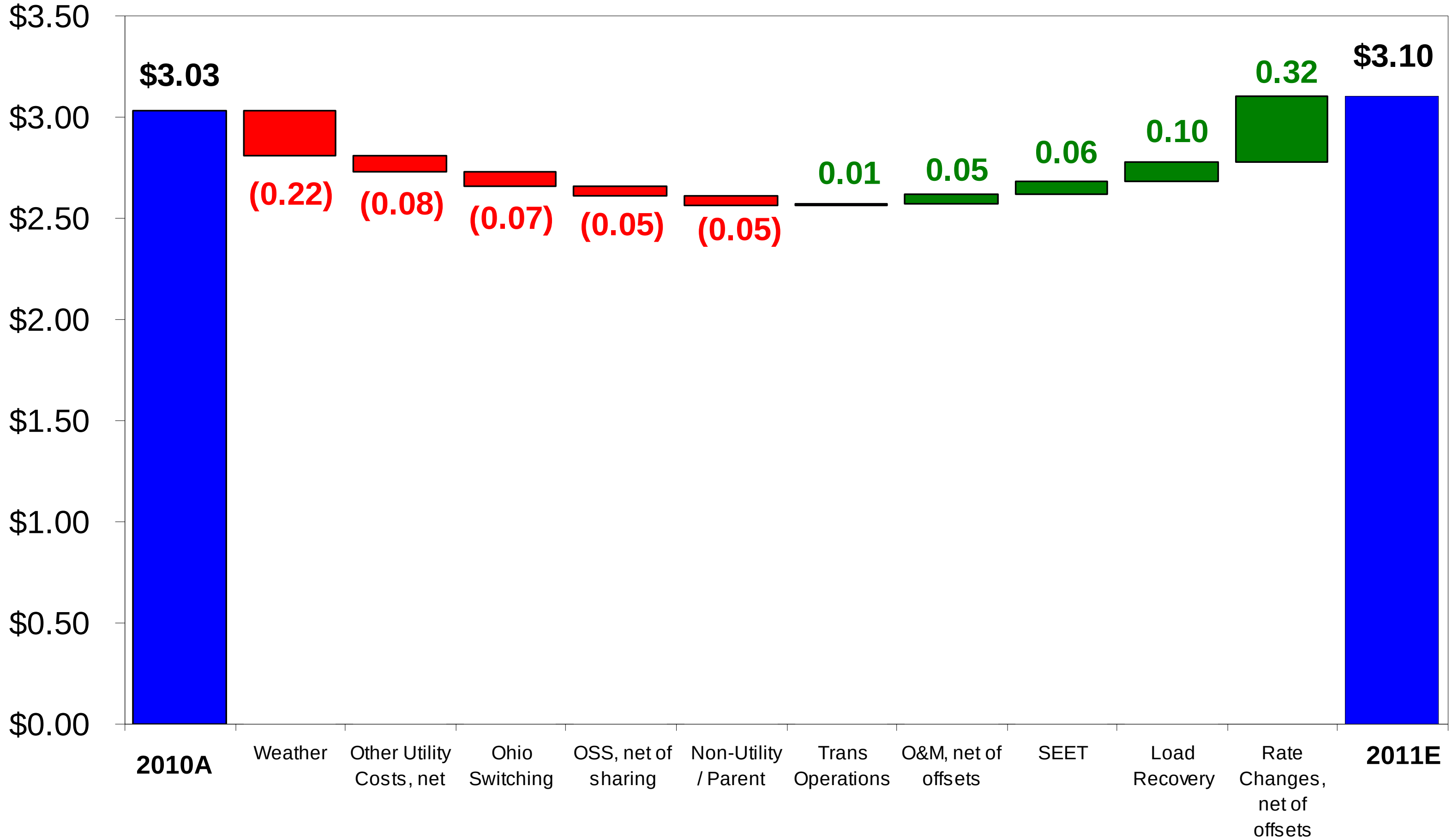
2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

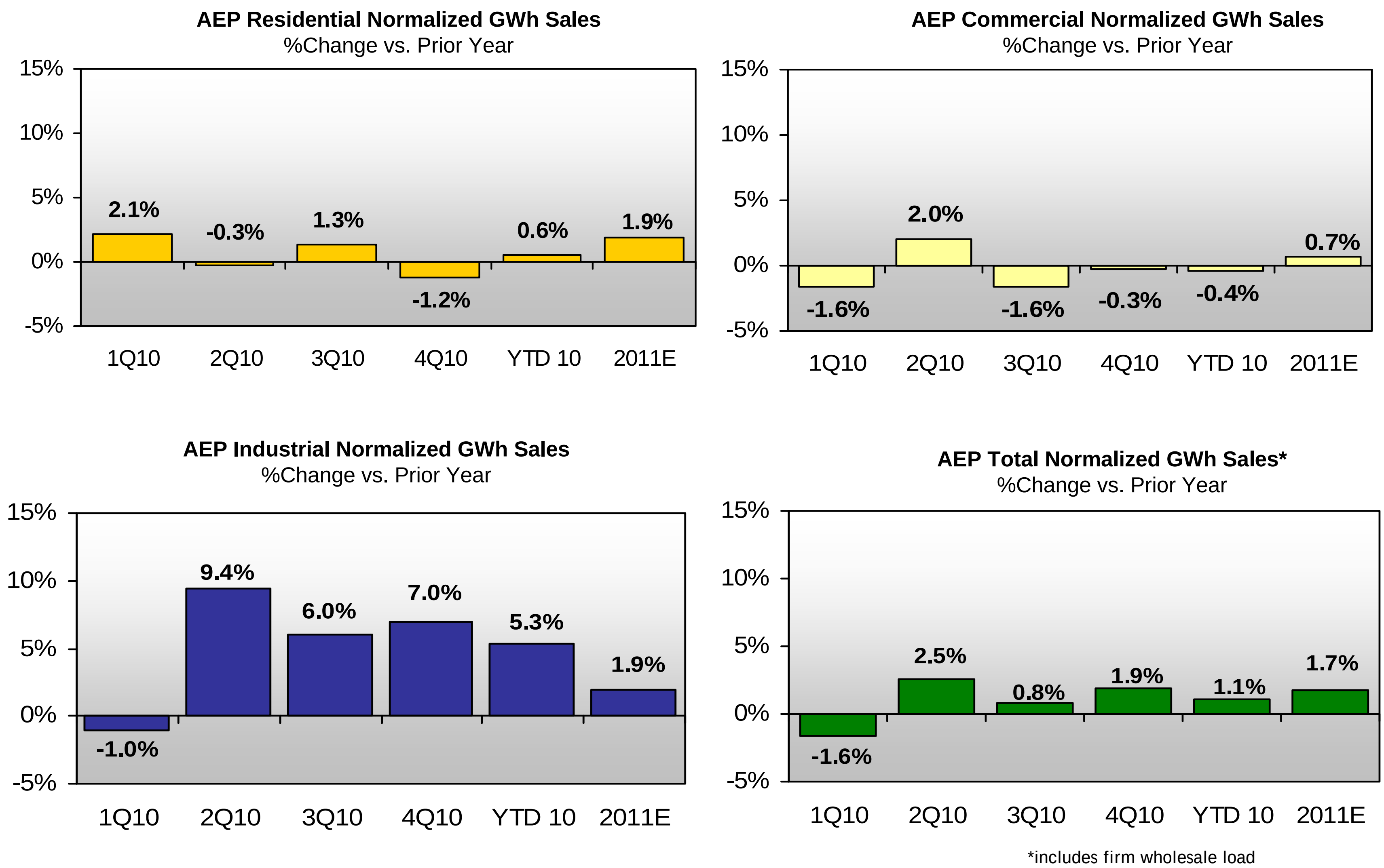
2011 Earnings Drivers



- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

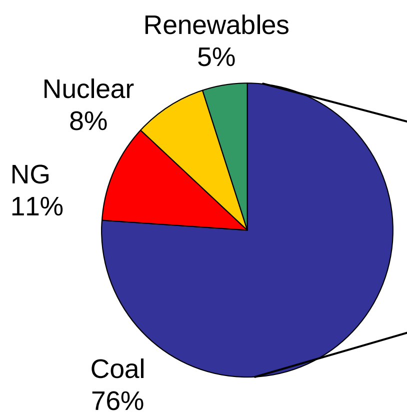


*includes firm wholesale load

Note: Chart represents connected load

AEP Generation Capacity

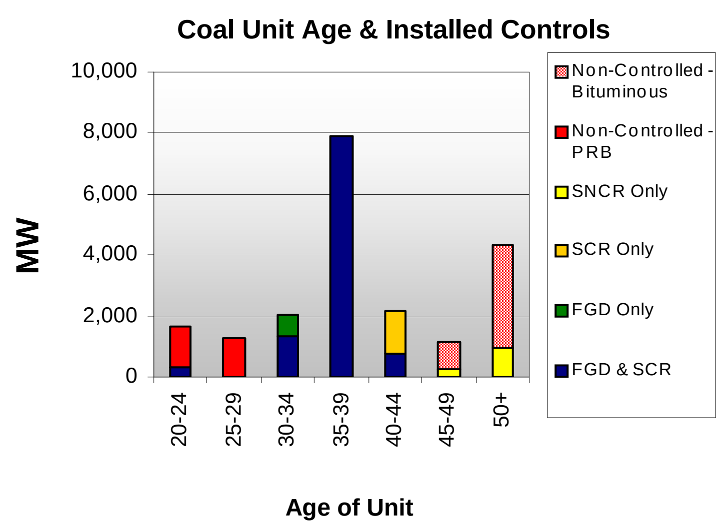
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



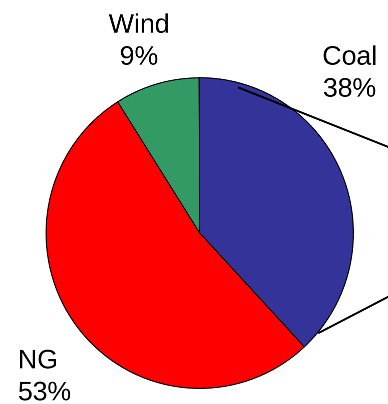
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



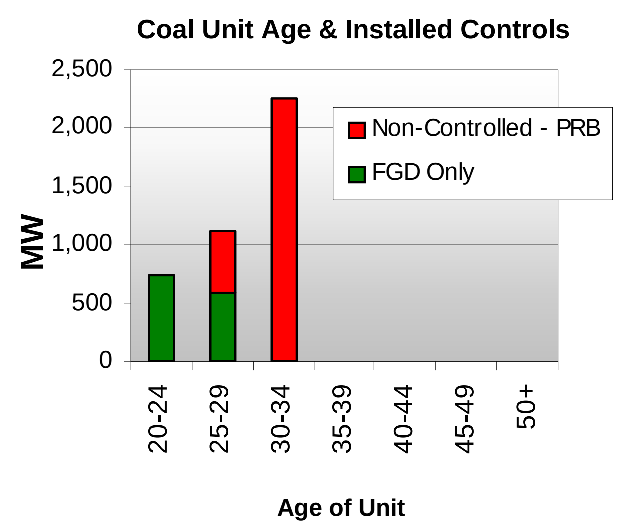
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton

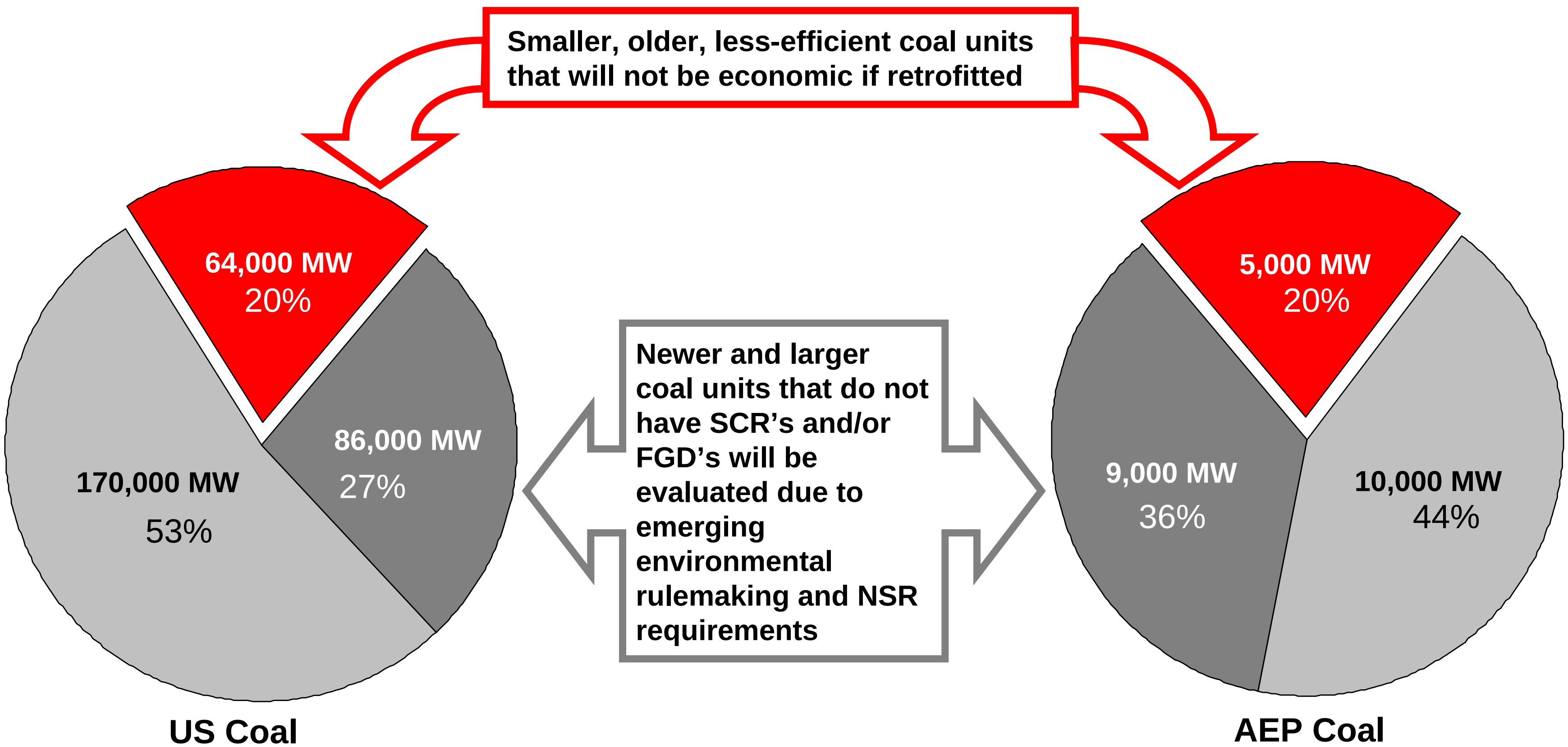


KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 9268 of 9556

Continual Evaluation is Required

"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

CCS Candidates

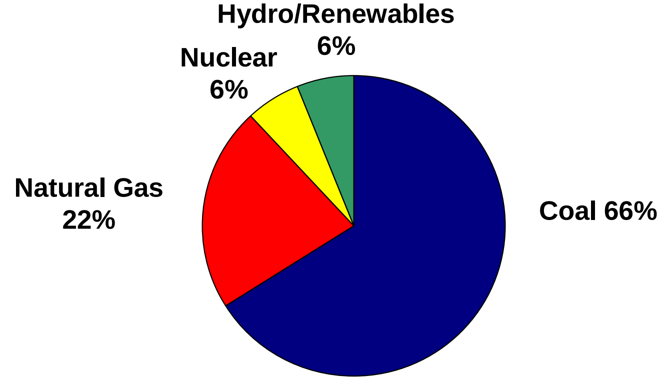


Nearly 50% of U.S. coal plants are exposed

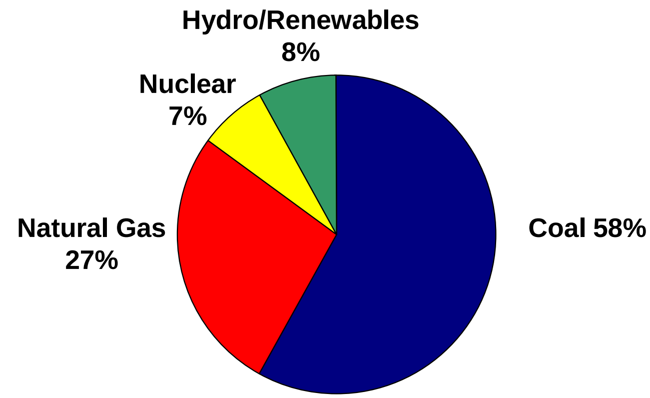
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

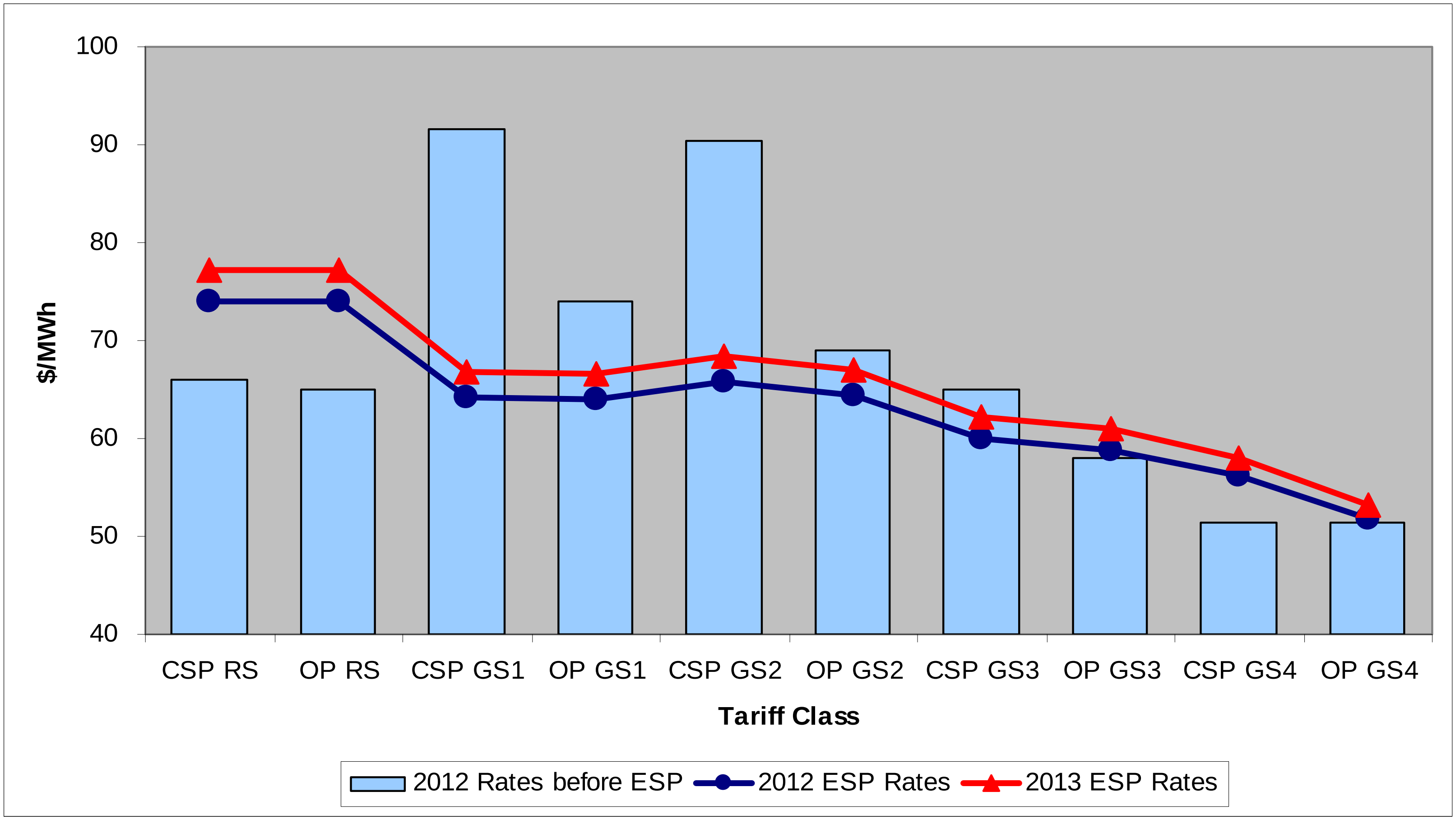
	2012			2013			2014		
	Revenue	$/MWh	%	Revenue	$/MWh	%	Revenue	$/MWh	%
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**

OPCo Current Customer Class	OPCo New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

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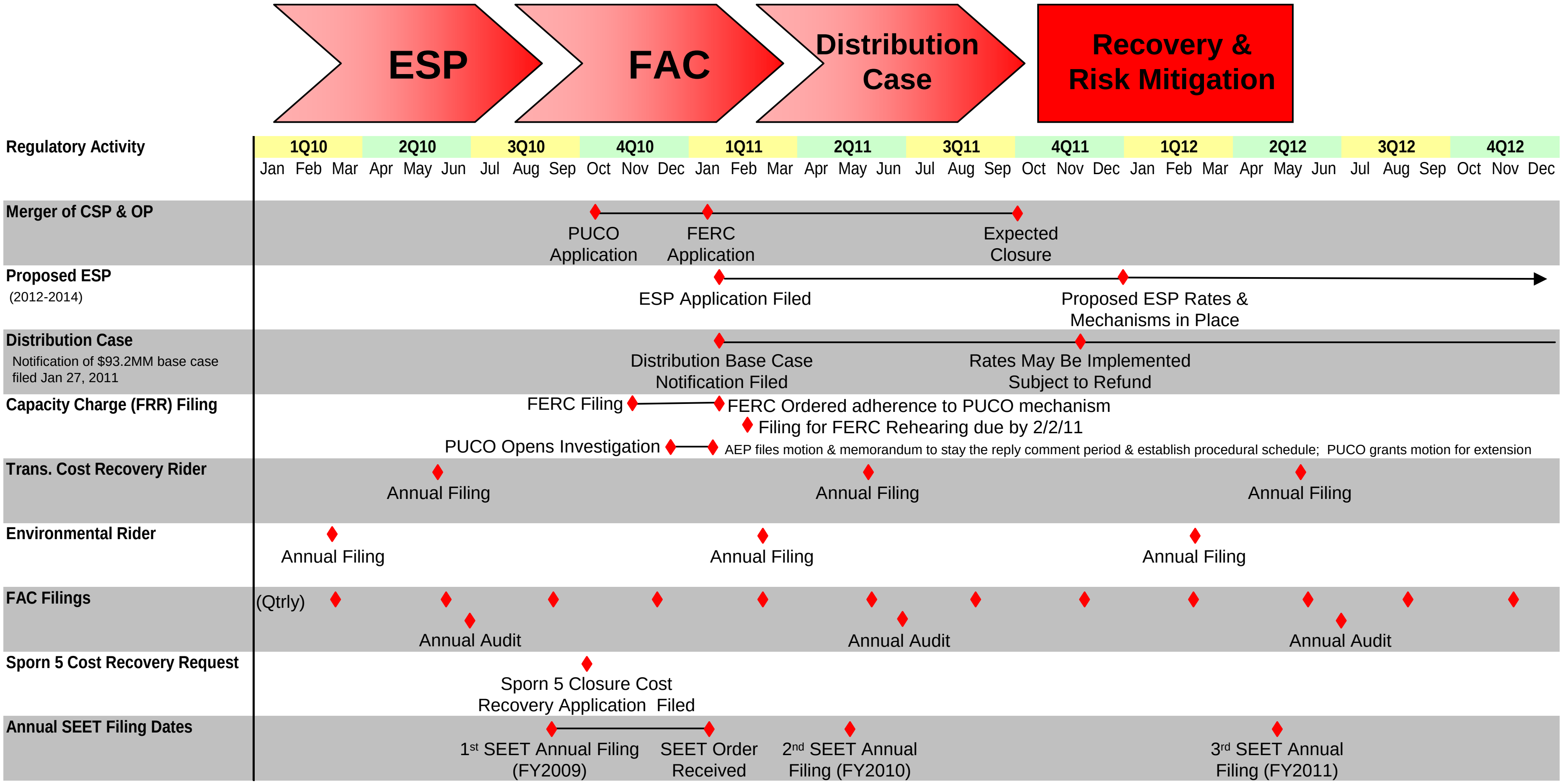
List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

December Utilities Week Handout

November 29 - December 1, 2005

New York, NY

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources and costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; new legislation, litigation and government regulation; timing and resolution of pending and future rate cases, negotiations, and other regulatory decisions; oversight and/or investigation of the energy sector or its participants; resolution of litigation; our ability to constrain operations and maintenance costs; our ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy related commodities; changes in creditworthiness in energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements; performance of pension plan interest rates; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Asset Portfolio

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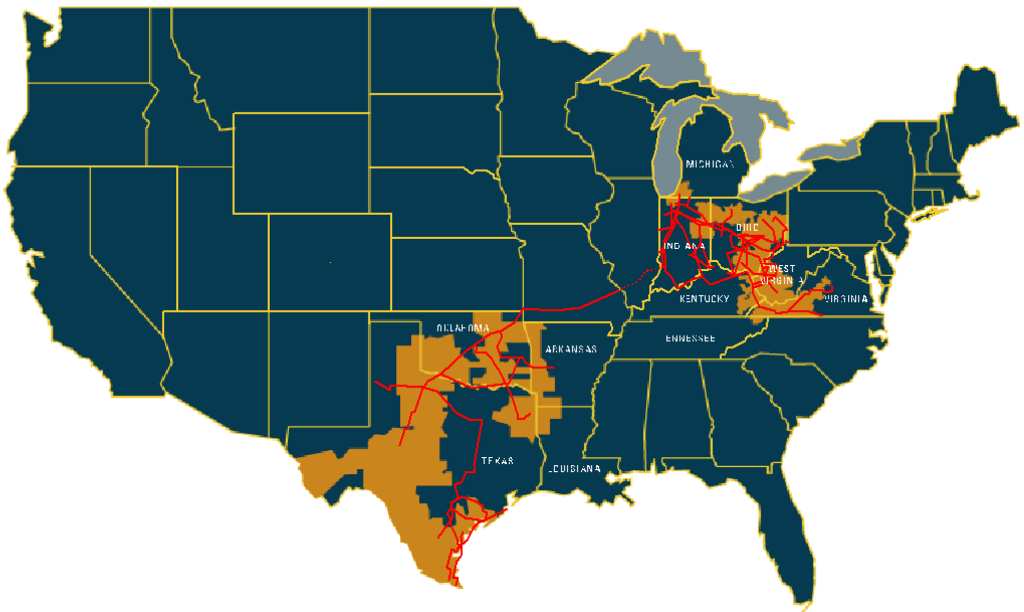
Strength & Scale in Assets & Operations

AEP AMERICAN ELECTRIC POWER



Generation	35,300 MW capacity
Transmission	39,000 miles
Distribution	202,000 miles
Customers	5 million

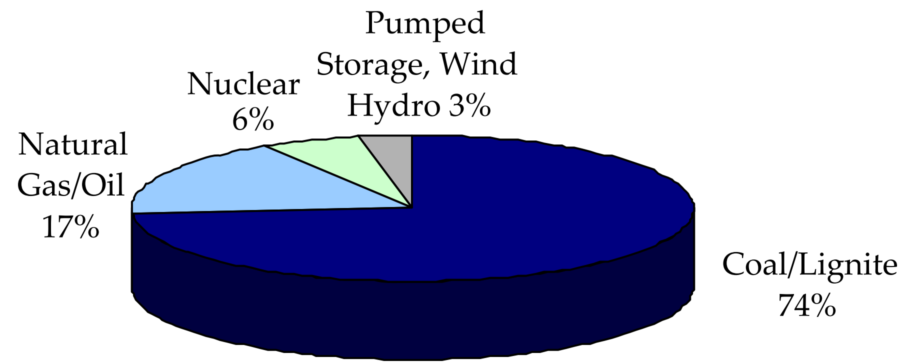
FUTURE EARNINGS GROWTH DRIVEN BY NATIVE LOAD GROWTH & SUBSTANTIAL UTILITY INVESTMENT OPPORTUNITY

Generation Fleet Composition

AEP AMERICAN ELECTRIC POWER

- 35,300 MW Domestic Capacity
- 85% System Availability Factor YE 2004
- 62% System Capacity Factor YE 2004

Capacity by Fuel Mix



	Baseload	Load-Following	Peaking
PJM	24,235	0	1,438
ERCOT	1,089	0	0
SPP	4,828	3,516	188
Total*	**30,152**	**3,516**	**1,626**

* Figures do not include mothballed or decommissioned units (1,015 MW of capacity). Also excludes the Ceredo generating facility.

GENERATION FLEET IS SUBSTANTIAL AND LOW COST

Generation Statistics

AEP AMERICAN ELECTRIC POWER

	Sept YTD Capacity Factor	Sept YTD Equivalent Availability Factor	Sept YTD EFOR	Sept YTD Generation
AEP East	**62.47%**	**84.96%**	**7.42%**	**115,668,803**
Coal*	61.53%	83.98%	8.05%	102,922,745
Hydro**	-2.58%	94.12%	17.14%	(98,866)
Nuclear	91.50%	92.54%	0.83%	12,844,924
AEP SPP	**45.31%**	**87.10%**	**5.86%**	**25,399,600**
Coal***	69.05%	82.87%	5.98%	16,791,955
Gas	27.11%	90.34%	5.73%	8,607,645
AEP Texas	**67.70%**	**82.91%**	**8.02%**	**4,472,275**
Coal*****	59.96%	82.74%	9.88%	2,710,119
Nuclear*******	84.48%	84.48%	3.52%	1,762,156
AEP System	**58.73%**	**85.44%**	**7.10%**	**145,540,678**

Notes:

* Includes 20,795 MW. Does not include Cardinal 2&3 or the Mone units.

** Includes Smith Mountain only including pumping.

*** Does not include Dolet Hills. Pirkey and Flint Creek reported as owned.

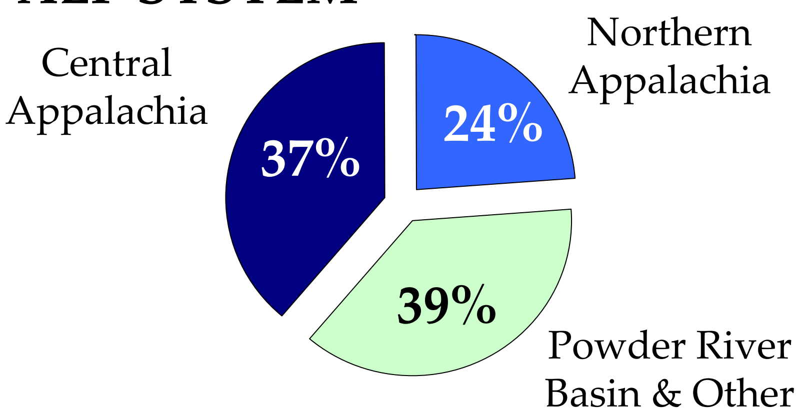
**** Oklaunion reported as owned.

***** South Texas Project generation reported through 5/18/05.

Fuel, Emissions & Logistics

Coal Procurement

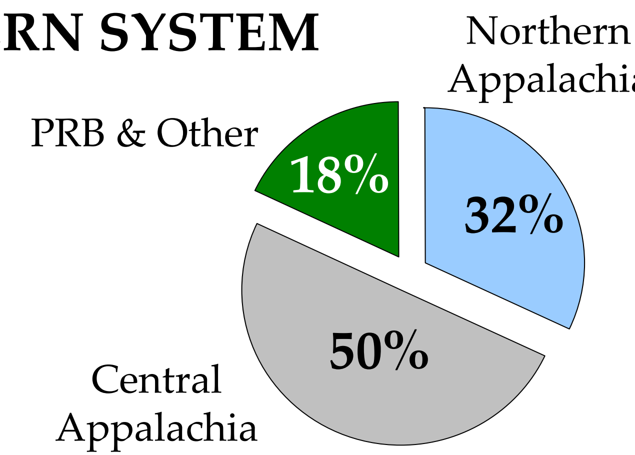
AEP SYSTEM



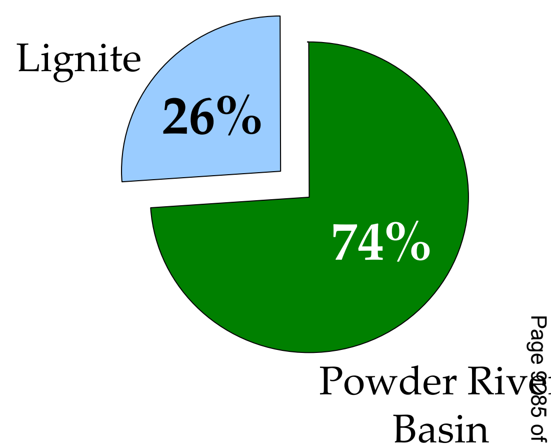
Coal Supply
(on average)

- Purchase 75 MM tons per year
- Avg. delivered price ~ $28.50/ton in 2004
- Essentially 100% purchased for 2005
- Approximately 12%-14% price increase in 2005
    - Increase being pressured by strong burn
    - PRB deliveries will impact results

EASTERN SYSTEM

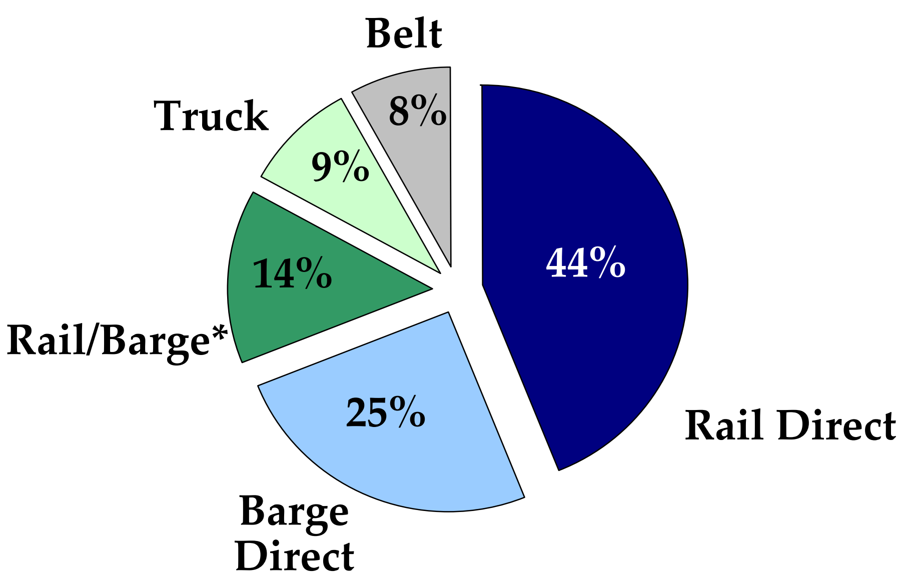


WESTERN SYSTEM

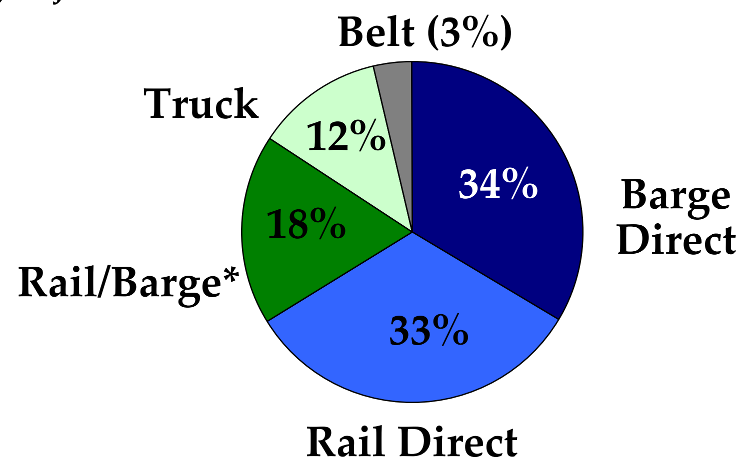


Coal Delivery

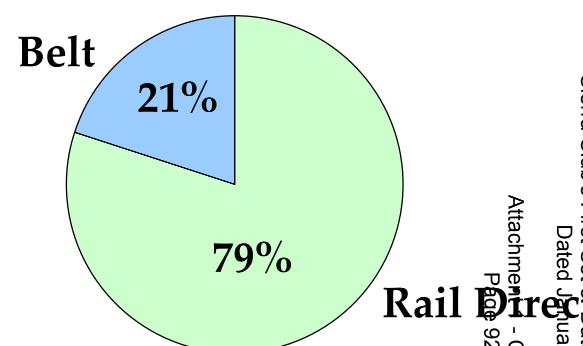
AEP SYSTEM
DELIVERY MODE DIVERSITY
Jan-June 2005 Actual



EASTERN SYSTEM
Jan-June 2005 Actual



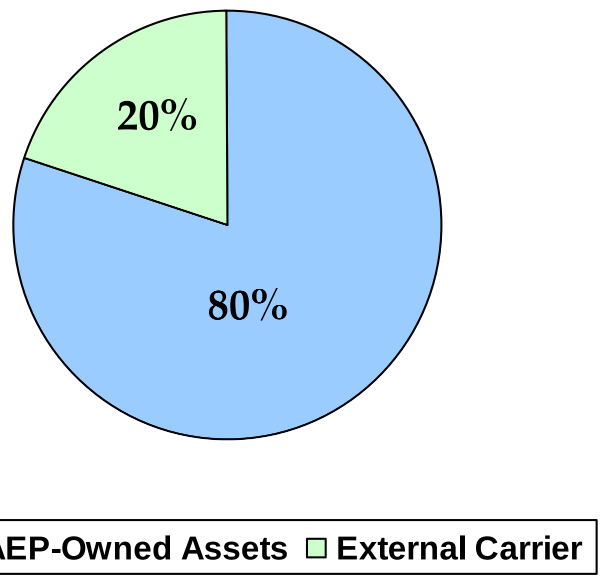
WESTERN SYSTEM
Jan-June 2005 Actual



* Coal delivered to AEP plants transported through combination of rail and barge

AEP's Coal Transportation Assets

Coal Transportation to AEP Plants*
Jan-June 2005 Actual



* Represents close approximations

AEP's substantial coal transportation assets include:

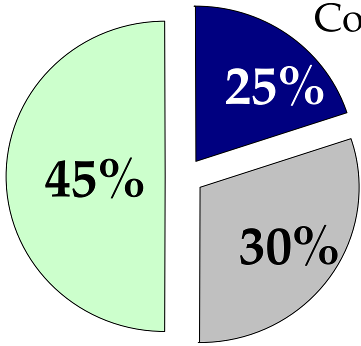
- 7,065 railcars
- 2,230 barges
- 53 towboats
- 1 active coal handling terminal (20 million tons of annual capacity)

AEP'S TRANSPORTATION ASSETS PROVIDE FLEXIBILITY IN A CONSTRAINED DELIVERY ENVIRONMENT

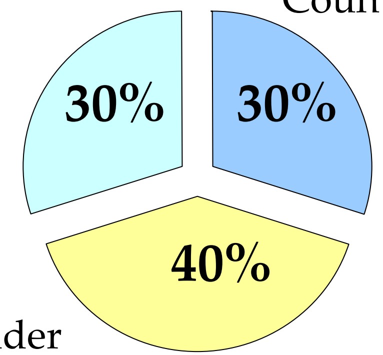
Fuel Recovery

AEP AMERICAN ELECTRIC POWER

AEP SYSTEM



EASTERN SYSTEM

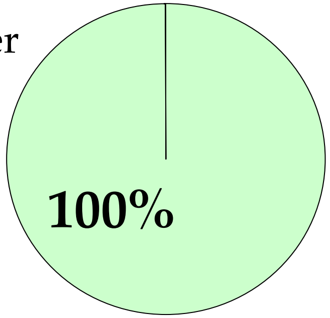


Fuel Cost Recovery
(on average)

- ➢Fuel recovery varies by jurisdiction
- ➢70% of fuel cost is recoverable across the AEP System
- ➢Active Fuel Clause Jurisdictions:

AEP EAST: AP-VA, I&M, KGP, KP
AEP WEST: PSO, SWEPCO

WESTERN SYSTEM



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Investing in IGCC

Integration Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC)

IGCC is a clean coal technology that combines two technologies – coal gasification and combined cycle -- to offer the benefits of a low cost fuel with superior thermal and environmental performance.

The IGCC process uses a gasifier in which coal or other fuels are partially combusted with oxygen and steam to form what is commonly called “syngas” – a combination of carbon monoxide, carbon dioxide and hydrogen. This syngas then is cleaned to remove the particulate and sulfur compounds. The sulfur compounds are converted to elemental sulfur or sulfuric acid, and ash is converted into glassy slag. Mercury can be removed in a bed of activated carbon.

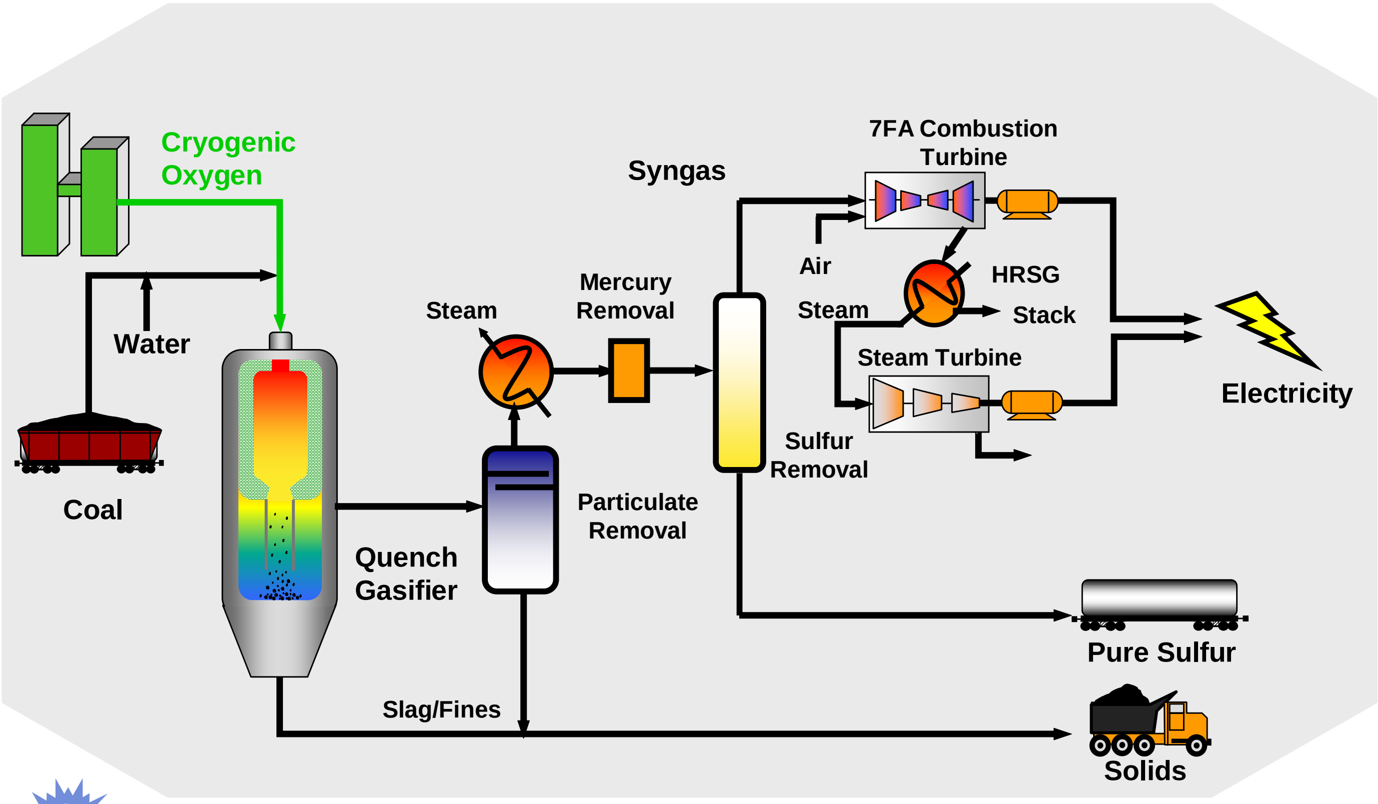
Coal gasification allows the removal of contaminants before the coal gas is combusted, as opposed to installing costly controls that capture emissions from the exhaust gas stream. The process is more efficient and results in lower emissions of NOx, SO_2, mercury and CO_2. Carbon dioxide capture is also expected to be more cost effective from an IGCC plant than from pulverized coal plants.

Combined-cycle plants generate electricity more efficiently than do conventional coal fired plants. A typical IGCC plant employs one or more gas turbines, a heat recovery steam generator (HRSG) and a steam turbine. The syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to the HRSG, which produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines.

One of the advantages of an IGCC plant is fuel flexibility, particularly the ability to use higher-sulfur coals while maintaining low sulfur emissions. The selected technology is well suited to the higher BTU coals, such as bituminous Appalachian coals readily available in AEP’s eastern service territory.

AEP is currently working with a technology provider to develop a firm price for an IGCC facility to be built in our eastern service region. This price will be available in 2006. AEP intends to seek regulatory recovery approvals in advance of building the plant.

Looking to the Future - IGCC



162110 - GJS/CE-01/1-23-02

AEP HAS ANNOUNCED ITS INTENTION TO CONSTRUCT A COMMERCIAL-SCALE INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT BY THE END OF THE DECADE

Investing in IGCC

Generation Technology Comparative Statistics

	PC	IGCC	NGCC
Nominal Capacity (MW)	**600**	**600**	**600**
Heat Rate (Btu/kWh)	**8690**	**8700**	**7200**
Total Plant Cost ($/kW)	**1290**	**1550**	**440**
Fuel cost ($/MWh)	**14**	**14**	**53**
Cost of Electricity (without CO2 Capture) ($/MWh)	**52**	**56**	**75**
Estimated Cost of Electricity (with CO2 Capture) ($/MWh)	**96**	**79**	**143**

- Source: Results of AEP analysis based on EPRI studies.
- Total Plant Cost includes the cost to engineer, procure and construct plant. It does not include escalation, owner's costs, transmission upgrades, or AFUDC.
- Assumes Northern Appalachian Coal price of $36/ton for PC and IGCC and natural gas price of $7.34/mmBtu for NGCC.
- Assumes 85% capacity factor for PC and IGCC, 40% for NGCC.

IGCC TECHNOLOGY IS STRATEGIC TO KEEPING COAL IN THE MONEY

IGCC Recovery Application Filed with PUCO

Cost Recovery

Phase 1

- ✓ Effective during 2006
- ✓ Seeks recovery of initial costs, including those already incurred, such as site engineering and various other engineering services
- ✓ Approximately $23.7 Million

Phase 2

- ✓ Effective 2007- mid 2010 (Construction Phase)
- ✓ Seeks recovery of carrying costs associated with plant construction

Phase 3

- ✓ Effective mid 2010 (Commercial Operation begins)
- ✓ Seeks recovery of projected $1.174 Billion cost of plant over its operating life.

Next Steps

2005:

- ✓ Secure cost recovery plan
  - ➢ Final PUCO Order expected by end of 2005 for Ohio IGCC filing
- ✓ Finalize site selection
- ✓ Negotiate with suppliers

2005—2007:

- ✓ Obtain permits and finalize engineering and procurement

2007—2010:

- ✓ Construct and start-up plant

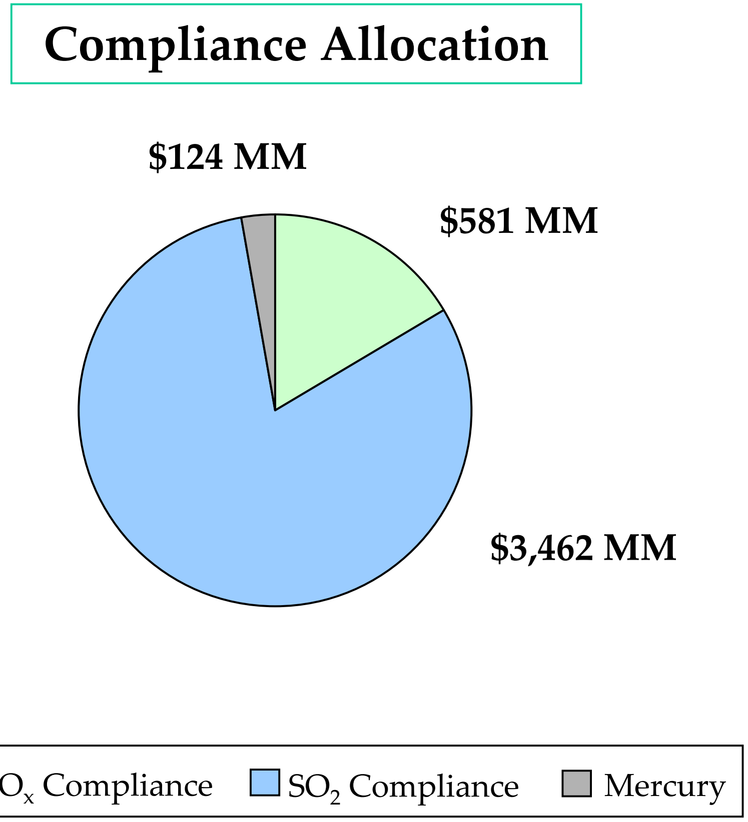
SEEKING AUTHORITY FOR THREE PHASE RECOVERY APPROACH

AEP AMERICAN ELECTRIC POWER

Environmental

Environmental Compliance Investment

AEP AMERICAN ELECTRIC POWER



Current Programs

$2.0 Billion:

$0.5 Billion for NOx

$1.5 Billion for SO_2

Future Programs

$2.1 Billion:

$1.9 Billion for SO_2

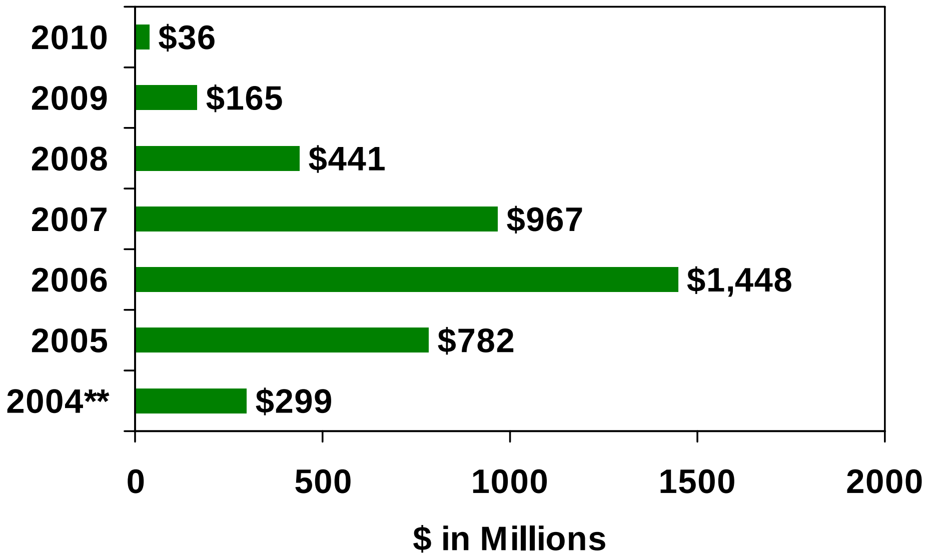
$0.2 Billion for Other

$4.1 BILLION ENVIRONMENTAL INVESTMENT PROJECTED 2004 THROUGH 2010

$4.1 Billion Environmental Investment

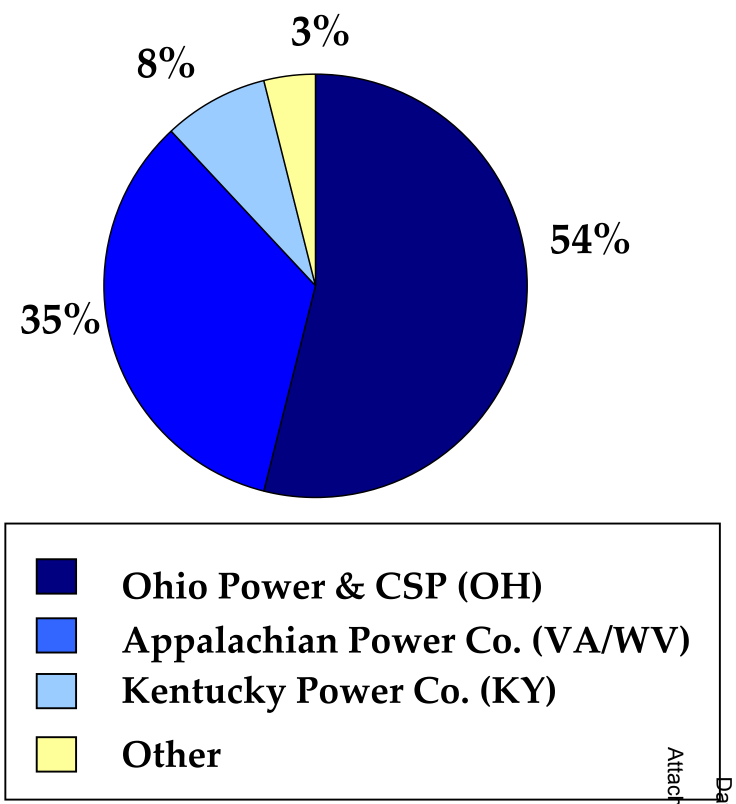
AEP AMERICAN ELECTRIC POWER

Environmental Capital Investment*



*Environmental investment for NOx, SO_2, & Hg purposes
** Actual investment level in 2004

Projected Environmental Investment Allocation



MAJORITY OF 2005 & 2006 DOLLARS WILL BE INVESTED IN OHIO & APCO

Regulatory Overview

Regulatory Activity Underway

AEP AMERICAN ELECTRIC POWER

- ✓ TCC Stranded Cost Recovery True-up Filing
- ✓ FERC Transmission Case
- ✓ APCo Filing for Recovery of E&R Costs in Virginia & Fuel Clause Increase
- ✓ APCo & WPCo Base Rate & Expanded Net Energy Clause (ENEC) Filing in West Virginia
- ✓ Kentucky Base Rate Filing
- ✓ SWEPCo - Texas Fuel Factor/Surcharge Filing
- ✓ IGCC

LEVEL OF CAPITAL INVESTMENT WILL BE ADJUSTED BASED ON RATE RECOVERY AND/OR CASH GENERATION

Regulatory Activity Underway

AEP AMERICAN ELECTRIC POWER

TCC Stranded Cost Recovery Case

- Seeking approval of true-up balances
  - ✓ $2 Billion in stranded costs and associated carrying costs
  - ✓ $400 Million in other true-up amounts including carrying costs
- Dec 2005/Jan 2006 - Final order expected, if not extended
  - ✓ Jan/Feb 2006 - Request for securitization
    - ➢ Sept 2006 - Issuance of securitization bonds if no appeal
  - ✓ Mar/April 2006 – Request approval for CTC to collect other true-up items
    - ➢ Jan 2007 – CTC charge to be implemented

AEP East FERC Transmission Case

Nov 7, 2005 - Announced Settlement agreement – Subject to FERC approval

- Results in $22 Million net revenue in 2006 from wholesale transmission

Regulatory Activity Underway

<u>Appalachian Power- Virginia Fuel Factor Increase</u>

Filed Oct 21, 2005 - Annual revenue increase of $57.7 Million

- ✓ Jan 1, 2006 - Interim fuel rate increase effective, subject to refund
- ✓ Jan 12, 2006 - Public hearing

<u>Appalachian Power – Virginia E & R Cost Recovery Factor</u>

Filed July 1, 2005 - Seeking recovery of $62.1 Million in new Environmental & Reliability costs

- ✓ Oct 14 – SCC ruled VA law does not allow recovery of prospective costs - $48.6 Million
- ✓ Nov 14 - APCo filed supplemental direct testimony which included updated actual E&R costs incurred of $21.1 million
- ✓ Public hearing set for February 7, 2006

Regulatory Activity Underway

AEP AMERICAN ELECTRIC POWER

Appalachian Power & Wheeling Power – West Virginia Base Rate Case & ENEC Reactivation

Filed August 26, 2005 – Seeking $183 Million increase in revenues for increasing costs for coal, purchased power and environmental improvement construction projects

Proposed Phase-in over 4 years

- ✓ June 23, 2006 – $82 Million
- ✓ July 1, 2006 – $9 Million
- ✓ Jan 1, 2007 – $44 Million
- ✓ Jan 1, 2008 – $10 Million
- ✓ Jan 1, 2009 – $38 Million

Procedural Schedule

- ✓ Feb 2, 2006 – Staff & Intervenors testimony
- ✓ Feb 22, 2006 – Rebuttal & Cross-rebuttal
- ✓ Feb 28 – Mar 3, 2006 – Evidentiary Hearing
- ✓ Initial Briefs – 20 days after receipt of transcripts
- ✓ Reply Briefs – 10 days after initial briefs
- ✓ June 23, 2006 – Statutory deadline for an order

Regulatory Activity Underway

AEP AMERICAN ELECTRIC POWER

Kentucky Base Rate Case

Filed Sept 26, 2005 – Seeking recovery of increasing costs associated with providing safe and reliable electric service

- ✓ Seek increase of $64.8 Million over existing rates
- ✓ Procedural schedule (subject to change)
  - ✓ Nov 29, 2005 through January 27, 2006 – Data Requests and Responses
  - ✓ Jan 9, 2006 – Intervenor Testimony
  - ✓ Feb 2, 2006 – KPC Rebuttal Testimony
  - ✓ To be Scheduled – Public Hearing and Briefs

SWEPCo Fuel Factor/Surcharge Filing

Filed Nov 7, 2005

- ✓ Annual revenue increase of $48.6 million per year to go into effect the first billing cycle in January, subject to future reconciliation
- ✓ Plus $46.4 million surcharge for a twelve-month period of Feb 2006 through Jan 2007, subject to future reconciliation

Regulatory Overview – East Companies

AEP AMERICAN ELECTRIC POWER

Ohio (Restructured)

- Unbundled rates for default customers frozen until 12/31/2005
- Pursuant to RSP Plan approved by PUCO 1-26-05:
  - Distribution rates in effect at December 31, 2005 are frozen, with certain exceptions, until the end of 2008.
  - Institute for 2006-2008 a non-bypassable distribution rider for provider of last resort (POLR) costs.
  - CSP "G" rates to increase 3% per year (2006-2008).
  - OP "G" rates to increase 7% per year (2006-2008).
  - Transmission rates can upon filing reflect change in RTO costs.
- No active fuel clause
- Application for IGCC plant recovery filed on 3-18-05. Hearings and briefs are done. Awaiting a PUCO order.
- On 11-9-05 the PUCO ordered CSP's acquisition of Mon Power's Ohio service territory effective 1-1-06.

West Virginia (Regulated)

- Base rates not frozen
- No active fuel clause
- Annual ENEC proceedings have been suspended, the factor is currently fixed at pre-2000 levels.
- On 8-26-05 AP & WP filed with the WVPSC for a $183 million revenue increase to be phased in over a four-year period beginning in mid 2006. The filing consists of a general rate case, reinstatement of the ENEC, to implement scheduled incremental rate increases for major clean air & transmission investments, and the implementation of a system reliability tracker mechanism.
- On 8-31-05 AP and Reliant jointly filed with the WVA PSC for approval to purchase the Ceredo generating station.

Virginia (Restructured)

- Capped rates for default customers frozen through end of 2010
- Capped rates can be adjusted by two rate cases prior to the end of 2010 and incremental environmental and reliability cost recovery mechanisms
- Active annual fuel clause; filed 10-21-05 for annual increase of $57.7 million.
- On 7-1-05 AP filed a request with the Virginia Commission seeking to recover incremental costs for environmental compliance and T&D System reliability (E&R) of $62.1 million based on actual costs through early 2005 and projected costs through June 2006. In an order dated 10-14-05, the Commission denied the Company's request for interim rate treatment and ruled that the Company may only seek to include actually incurred costs (i.e., no projected future costs) in the E & R cost recovery filing. The Company filed supplemental direct testimony on 11-14-05, which included updated incremental costs through 9-30-05 of $21.1 million. On 11-7-05 the SCC Staff filed a Motion In Limine to Dismiss Application in Part indicating that they did not believe the SCC had jurisdiction over transmission rates and therefore could not order a change to the transmission rate. We filed our response on 11-16-05. The Commission has scheduled hearings to begin 2-7-06.

Kentucky (Regulated)

- Fuel clause, adjusted monthly
- Environmental surcharge costs are adjusted monthly for approved environmental compliance plan
- On 9-26-05 the Company filed a base rate case requesting a $64.8 million annual increase. The Company expects the effective date to be approximately 4-1-06.

Michigan (Restructured, but Regulated)

- Base rates not frozen.
- Active annual fuel clause.

Indiana (Regulated)

Base rates are frozen and fuel cost recovery factors are capped at increasing rates through June 30, 2007.

Tennessee (Regulated)

- Base rates not frozen
- Automatic fuel clause, adjusted monthly

Regulatory Overview – West Companies

AEP AMERICAN ELECTRIC POWER

Texas (Regulated)
- SWEPCO Texas retail competition delayed until at least 2007. PUC Chairman believes the precursors for full and open competition are not yet in place and will not exist prior to 2009. The Chairman committed to the Texas Legislature that the commission would consider maintaining the current status of competition in the SWEPCO Texas (and SPP portion of TNC) areas in future proceedings.
- Bi-annual fuel clause adjustment opportunity, filed 11-7-05 for annual increase of $48.6 million plus a one-year surcharge of $46.4 million.

Texas ERCOT Area (Restructured)
- TCC stranded cost true-up filing in May 2005. ($2.4 billion true-up amount requested). Hearings concluded 10-4-05. TCC anticipates a Commission ruling in December 2005 or January 2006.
- The results of TNC's true-up case were filed in TNC's Competition Transition Charge (CTC) proceeding in August 2005, which was abated in November 2005 pending resolution of the PUCT's ruling regarding off-system sales margins (see below).
- TNC final fuel reconciliation (July 00-Dec. 01). Final order received 10-18-04. Texas District Court affirmed PUC on 9-9-05. TNC will appeal. On 9-29-05, the U.S. District Court precluding the PUCT from enforcing their ruling regarding the allocation of off-system sales margins.

Oklahoma (Regulated)
- On 6-3-05 PSO file to increase its Reliability Enhancement Plan annual spending to a $27.21 million level (up $15.4 million) pending OCC approval. Staff submitted testimony supporting an annual cap of $23.68 million up from the $11.81 million cap currently in place. The ALJ has recommended approval of the Staff proposed rider cap. The ALJ recommendation also allows for the recovery of return, depreciation, taxes, etc. associated with converting overhead distribution lines to underground. It is now pending a Commission decision.
- Annual Fuel Clause
- 2001 Fuel review case

  •Hearings scheduled for Sept. 2005 have now been continued to a later date to be determined. Scope expanded to cover 2002-2004 margin allocation issue. Intervenors have submitted testimony which would substantially off-set the recovery of PSO's $42 million Internal Cost Reconstruction (ICR) error.
- 2003 Fuel review case

  Scope has been expanded to include a prudence review.
- 2004 Fuel review case

  Staff has now filed for a review of PSO's 2004 fuel costs.

Louisiana (Regulated)
- Base rates not frozen
- Currently under a merger required financial review
- Fuel clause, adjusted monthly

Arkansas (Regulated)
- Base rates not frozen
- Fuel clause, adjusted annually

Finance

Summary of Major 2006 Earnings Drivers

AEP AMERICAN ELECTRIC POWER

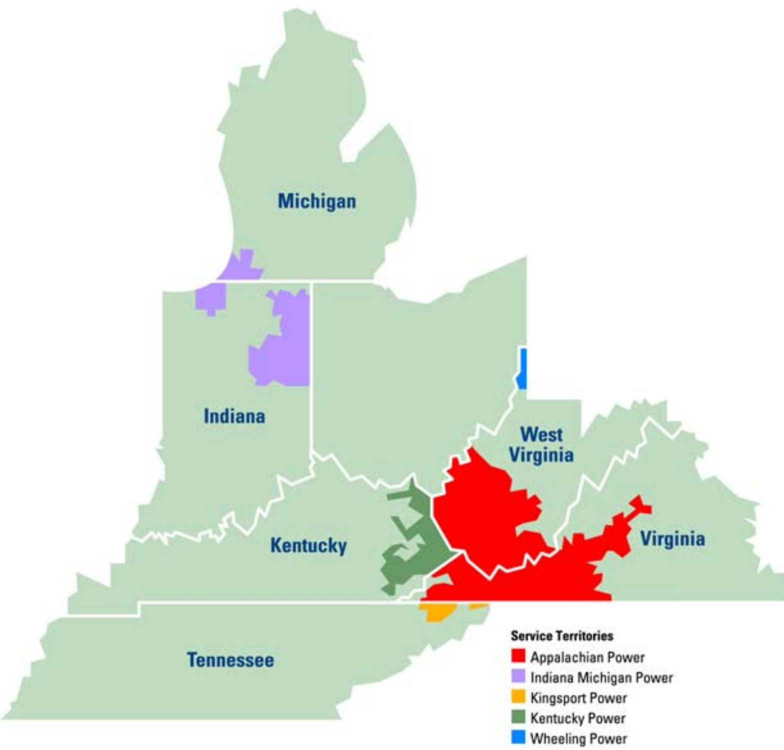
- Load growth of 2.5%
- $300MM new rate recovery in progress
- Rising fuel costs of 10-12%
- Higher planned outages, increased retail load, & sale of TCC generation to impact off system sales
- Decline in utility operations O&M
- Parent Company improvement

TRADITIONAL UTILITY FACTORS WILL DRIVE 2006 EARNINGS

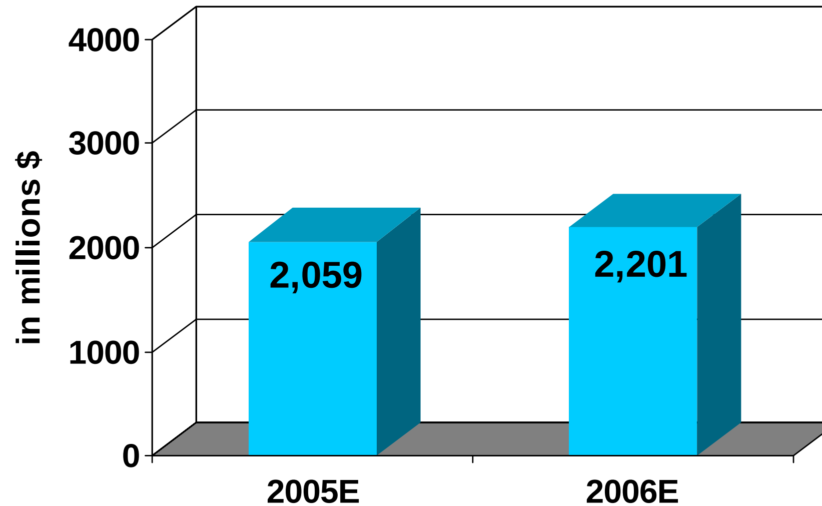
Utility Operations

AEP AMERICAN ELECTRIC POWER

East Integrated Companies



Gross Margin



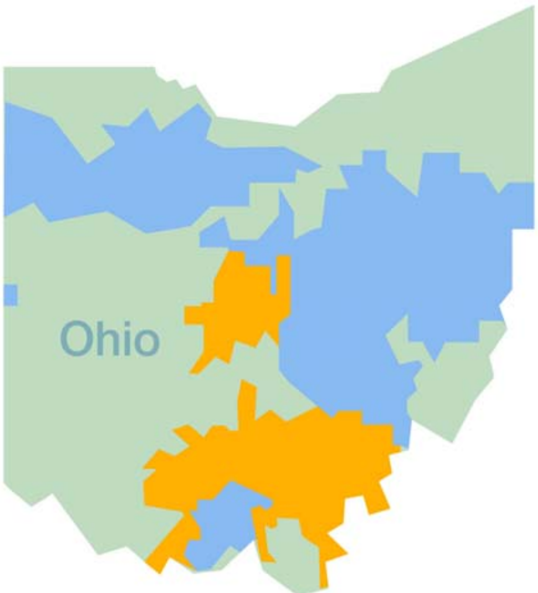
Earnings Drivers

Load Growth	134
Rate Changes	103
Fuel Cost	(53)
Emissions & Consumables	(19)
Other	(23)
	142

$142 MILLION INCREASE IN GROSS MARGIN FOR 2006

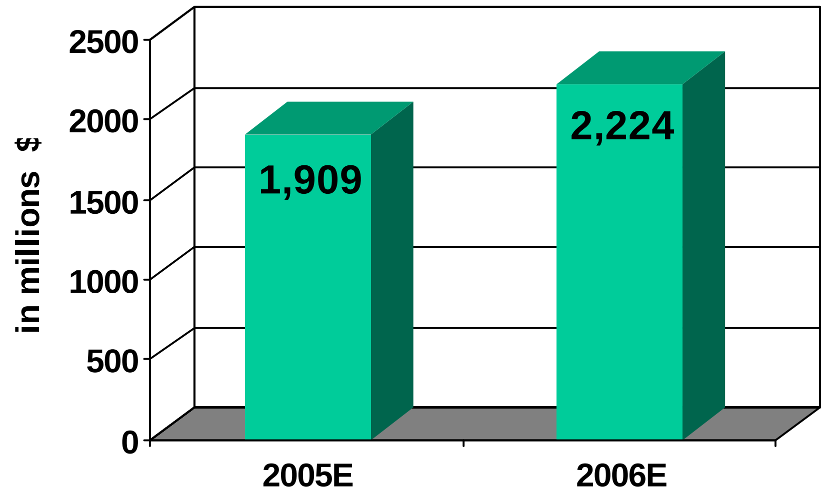
Utility Operations

Ohio Companies



Ohio Power Service Territory
Columbus Southern Power Service Territory

Gross Margin



Earnings Drivers

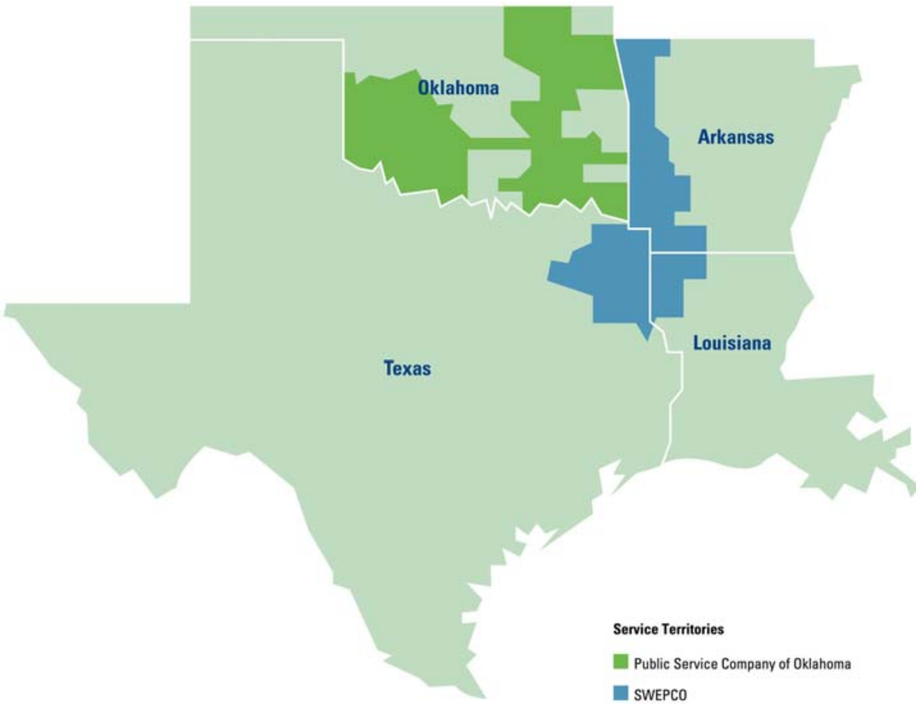
Load Growth	58
Fuel Cost	(13)
Rate Stabilization Plan	258
Emissions & Consumables	(15)
Other	27
	315

$315 MILLION INCREASE IN GROSS MARGIN FOR 2006

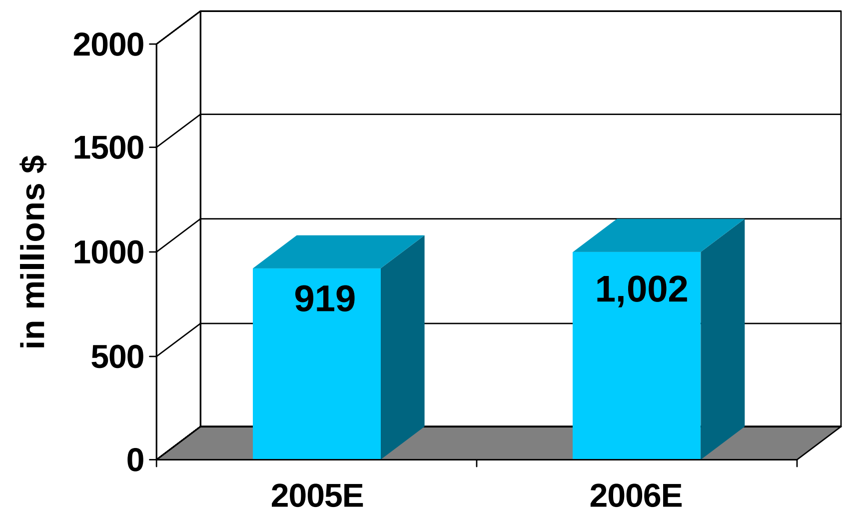
Utility Operations

AEP AMERICAN ELECTRIC POWER

West Integrated Companies



Gross Margin



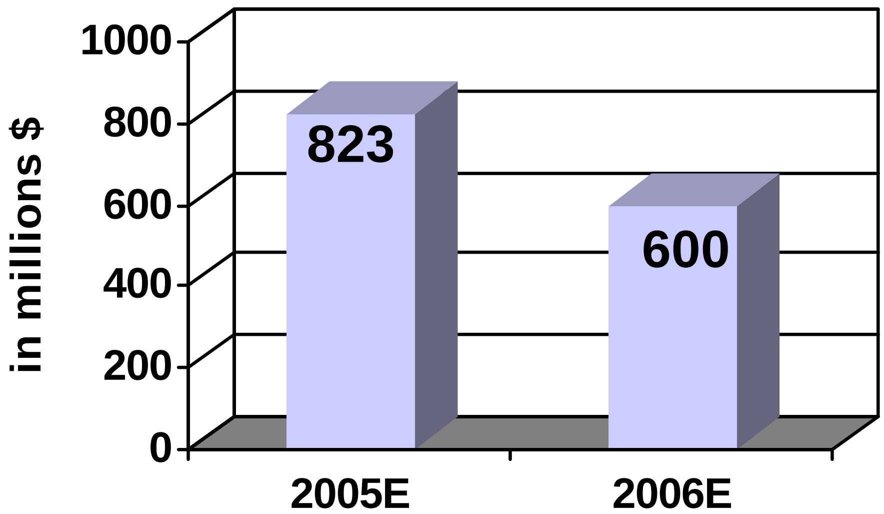
<u>Earnings Drivers</u>

Load Growth	15
Rate Changes	17
Margin Sharing, re: Fuel Clause	51
	83

$83 MILLION INCREASE IN GROSS MARGIN FOR 2006

Utility Operations

Off System Sales

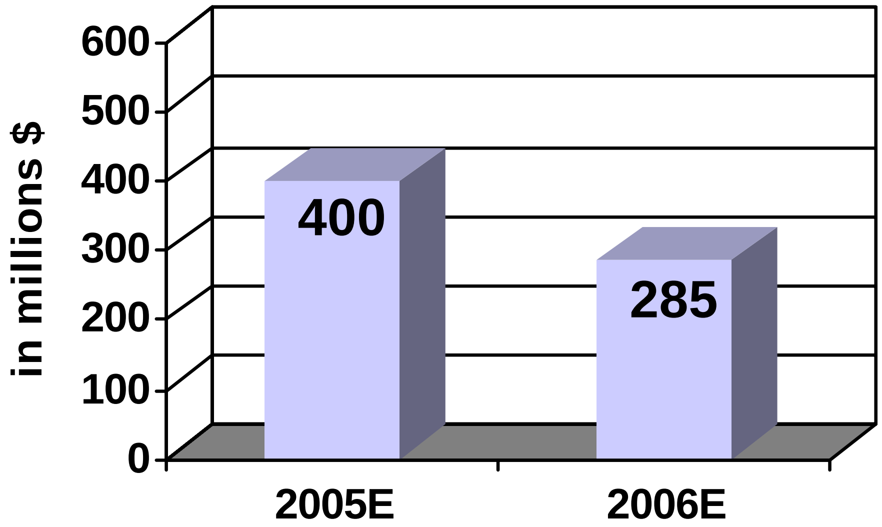


DECLINE IN OFF SYSTEM SALES GROSS MARGIN DRIVEN BY SALE OF TCC GENERATION, INCREASED PLANNED OUTAGE RATES, & INCREASED RETAIL LOAD

Utility Operations

AEP AMERICAN ELECTRIC POWER

Transmission Revenues – 3rd Party



Earnings Drivers

Cessation of SECA Rates	(128)
ECAR Zonal Rate Change	22
Other	(9)
	(115)

Offset to Decline in Trans Revenues

(Captured on lines 1 & 2)

Ohio OATT	49
APCO ENEC in WV	9
	58

CESSATION OF SECA RATES WILL BE LARGELY OFFSET BY ECAR ZONAL RATE CHANGE, OHIO OATT ADJUSTMENT, & REACTIVATION OF ENEC IN WEST VIRGINIA

Utility Operations

AEP AMERICAN ELECTRIC POWER

Expense Drivers

Operations & Maintenance		
Labor, including fringes	48	
Sale of STP	38	
Other	9	
	95	$95 million decrease
Depreciation & Amortization		
Plant additions	(53)	
Change in depreciation rates	90	
Amortizations (TCC Securitization*, Ohio regulatory asset**, Other)	(74)	
	(37)	$37 million increase
Taxes		
Taxes Other than Income Taxes	(22)	
Change in Pre-Tax Income	(21)	
Q4 Accrual True-ups	(15)	
COLI benefit (2005)	(7)	
Flow-through & permanent timing differences	(39)	
	(104)	$104 million increase
Interest Expense & Pref. Dividends		
Securitized Debt	(23) *	
Debt (construction funding)	(67)	
	(90)	$90 million increase
Total	(136)	

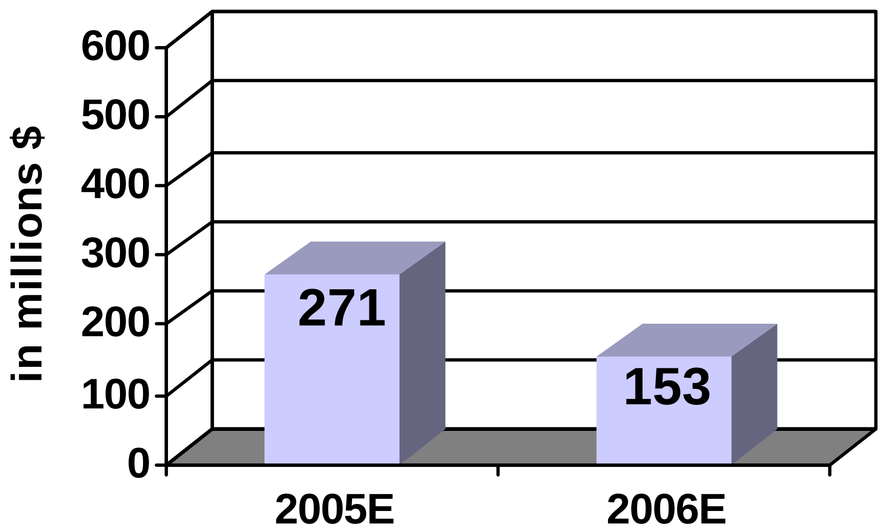
***Offset by TCC wires charge to cover securitization bonds issued 9/06**

****Offset by cash Ohio POLR charge which begins 1/1/06**

UTILITY OPERATIONS EXPENSES TO RISE $136MM IN 2006

Utility Operations

Other Income & Deductions



Earnings Drivers	
Reduction in Carrying Charges	
Ohio Companies*	(74)
Texas Central Company**	(12)
Reduction in Centrica Sharing	(20)
Other	(12)
	(118)

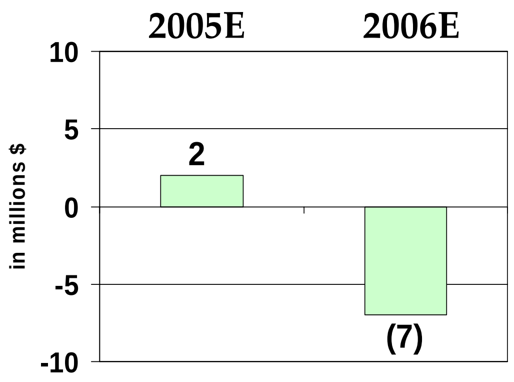
*Offset by cash POLR Rider Revenue
**TCC Carrying Charges decline upon issuance of securitization bonds 9/06

$118MM DECLINE IN OTHER INCOME & DEDUCTIONS DUE TO REDUCTION IN CARRYING CHARGES AND CENTRICA SHARING

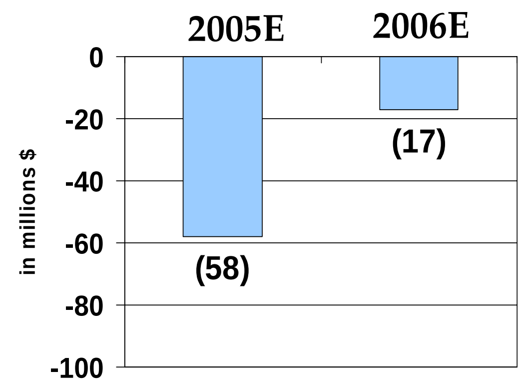
Investments & Parent Company

AEP AMERICAN ELECTRIC POWER

Investments



Parent Company



Investment Drivers:

- Misc. true-ups that provided positive impact in 2005 not repeated in 2006
- Ongoing loss from Dow

Parent Company Drivers:

- 2005 included debt call premiums to retire $550MM of LTD
- Reduction in outstanding debt drives decline in interest expense in 2006

$32 MILLION IMPROVEMENT IN CONTRIBUTION FROM INVESTMENTS & PARENT COMPANY

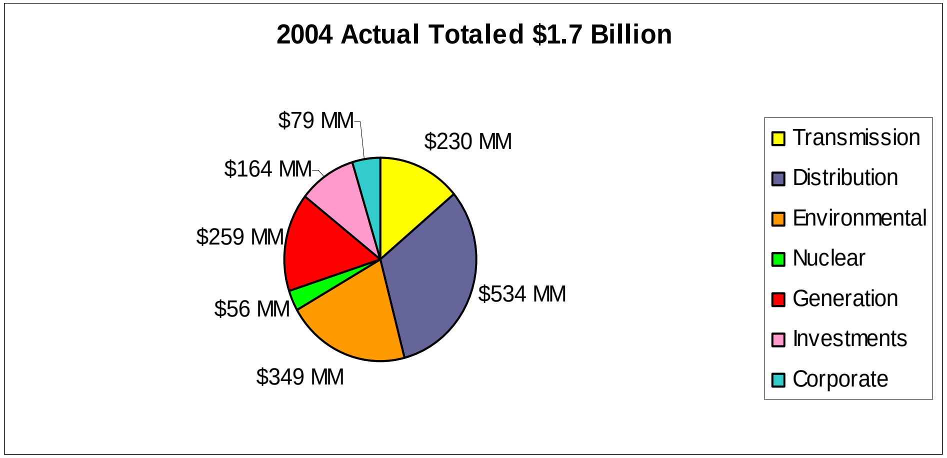
Projected Cash Flow

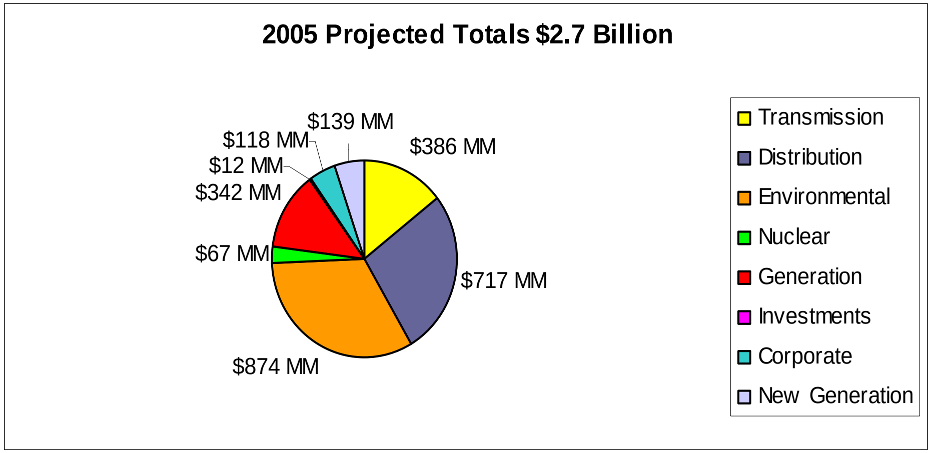
AEP AMERICAN ELECTRIC POWER

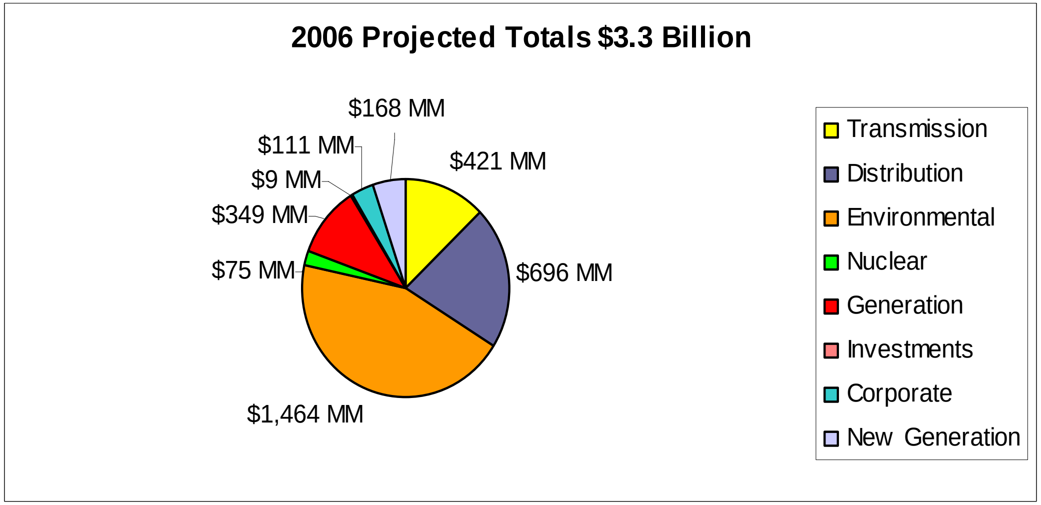
($ in millions)	2005 Guidance	2006 Guidance
Beginning Cash Balance	**$ 420**	**$ 399**
Cash from Operations:		
Income from Continuing Operations	1,014	1,023
Depreciation and Amortization	1,328	1,363
Pension Funding in Excess of Expense	(353)	(126)
TCC Carrying Charge	(51)	(66)
Other	(271)	(249)
Total from Operations	**$ 1,666**	**$ 1,945**
Cash from Investing:		
Capital Expenditures	(2,656)	(3,294)
AFUDC Debt	(27)	(37)
Asset Sales	1,628	-
Other	(8)	9
Total from Investing	**$ (1,063)**	**$ (3,322)**
Cash from Financing:		
Common Equity	(33)	-
Net Long Term Debt Issued/(Retired)	7	2,140
Preferred Stock Redeemed	(66)	-
Short Term Debt Change, Net	(13)	(11)
Common Dividends	(554)	(582)
Other Financing Activities	35	(3)
Total from Financing	**$ (624)**	**$ 1,544**
Net Change in Cash	**$ (21)**	**$ 167**
Ending Cash Balance	**$ 399**	**$ 566**

PROJECTED CASH ON HAND OF $399 MILLION AT YEAR END 2005

Capital Investment: 2004-2006

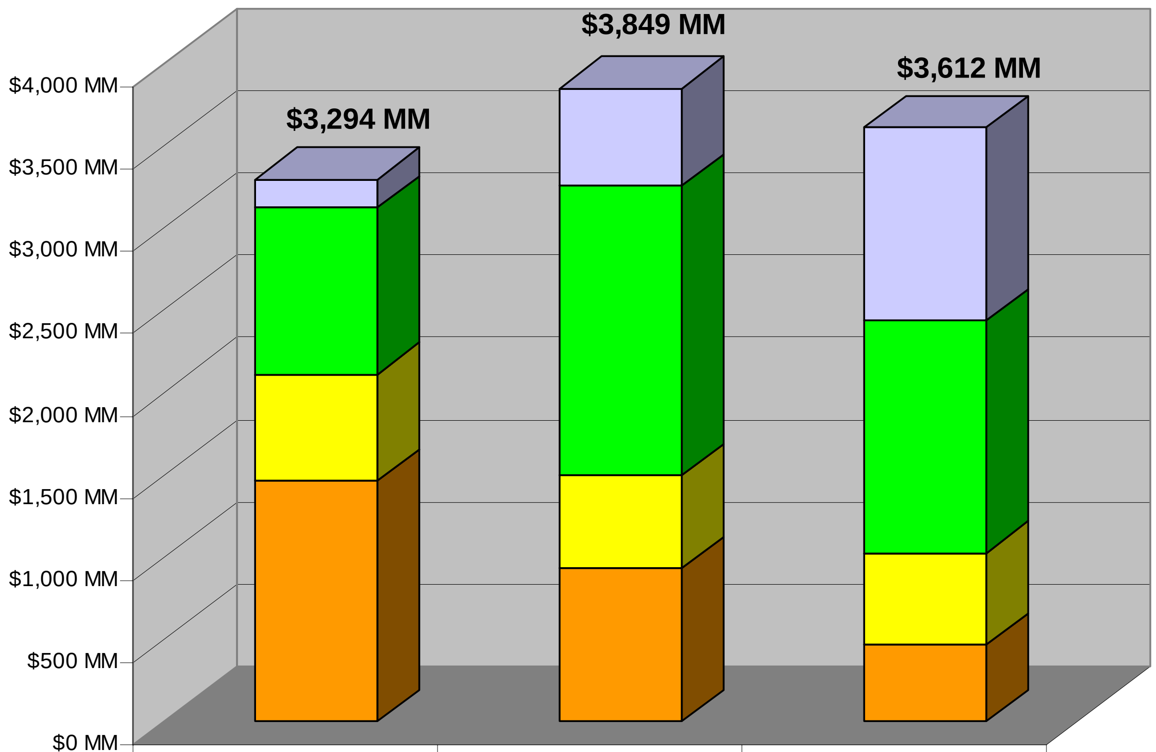






Capital Investment Forecast

AEP AMERICAN ELECTRIC POWER



New Build Generation & Ongoing Infrastructure Replacement investment can be throttled

	2006	2007	2008
New Build Generation	$168 MM	$593 MM	$1,176 MM
Ongoing Infrastructure Replacement/ Economically Justified	$1,016 MM	$1,757 MM	$1,412 MM
Mandated T&D	$646 MM	$568 MM	$554 MM
Environmental Compliance	$1,464 MM	$931 MM	$470 MM

MUCH OF CAPITAL INVESTMENT IS ADJUSTABLE

Capital Investment Funding

AEP AMERICAN ELECTRIC POWER

($ in millions)	Actual 2004	Projection 2005	2006	2007	2008
Planned Capital Investment					
Committed Construction Expenditures	$ (1,671)	$ (2,656)	$ (2,110)	$ (1,499)	$ (1,024)
Discretionary Cap Ex Predicated on Rate Recovery &/or Cash Generated	n/a	n/a	$ (1,184)	$ (2,350)	$ (2,588)
Total Capital Expenditures	$ (1,671)	$ (2,656)	$ (3,294)	$ (3,849)	$ (3,612)
Dividend on Common	$ (554)	$ (554)	$ (582)	$ (586)	$ (589)
Cash Sources					
Cash from Operations *	$ 2,597	$ 1,666	$ 1,945	$ 2,434	$ 2,590
Proceeds from Sale of Assets	$ 1,357	$ 1,628	$ -	$ 43	$ -
Common Stock Issued (Dividend Reinvestment Plan in 2007 & 2008)	$ 16	$ (33)	$ -	$ 80	$ 80
Change in Debt, Net	$ (2,230)	$ (6)	$ 2,129	$ 1,658	$ 1,697
Other	$ (72)	$ (67)	$ (31)	$ (147)	$ (166)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (556)	$ (21)	$ 167	$ (366)	$ 0
Ending Cash Balance	$ 420	$ 399	$ 566	$ 200	$ 200

* Cash Flow from Operations assumes full rate recovery on capital expenditures.

Note: Totals may not foot due to rounding.

REGULATORY RECOVERY WILL DRIVE CAPITAL INVESTMENT THROTTLE

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential

Capital Structure

AEP AMERICAN ELECTRIC POWER

Capital Structure	Actual 9/30/05		
$ in millions	Debt	Equity	Total
Balance Sheet Capitalization			
Long-term Debt	11,742	-	11,742
Short-term Debt	15	-	15
Preferred Stock Subject to Mandatory Redemption	-	-	-
Preferred Stock Not Subject to Mandatory Redemption	-	61	61
Common Equity	-	8,985	8,985
Total Capitalization per Balance Sheet	**11,757**	**9,046**	**20,803**
% of Capitalization per Balance Sheet	***56.5%***	***43.5%***	***100.0%***
Adjustments			
Preferred Stock Subject to Mandatory Redemption	-	-	-
Defeased First Mortgage Bonds	(19)	-	(19)
Off-balance Sheet Leases	1,227	-	1,227
Securitization Bonds	(648)	-	(648)
Spent Nuclear Fuel Trust	(234)	-	(234)
Equity Credit for Equity Units	-	-	-
Total Adjusted Capitalization	**12,085**	**9,046**	**21,130**
% of Adjusted Capitalization	***57.2%***	***42.8%***	***100.0%***

Note: Totals may not foot due to rounding.

ADJUSTED DEBT/CAPITALIZATION: 57.2%

Long-term Debt Maturity Profile

Year	2005 (1)	2006	2007
AEP Inc.	$ -	$ 395,860,000	$ 345,000,000
AEP Generating Company	$ -	$ -	$ -
Appalachian Power	$ -	$ 100,000,000	$ 342,500,000
Columbus Southern Power	$ 36,000,000	$ -	$ -
Kentucky Power	$ -	$ -	$ 322,964,000
Indiana Michigan	$ -	$ 300,000,000	$ -
Ohio Power Company	$ -	$ -	$ -
Public Service of Oklahoma	$ -	$ -	$ -
Southwestern Electric Power	$ -	$ 6,215,000	$ 94,000,000
Texas Central Company	$ -	$ -	$ -
Texas North Company	$ 37,609,000	$ -	$ 8,151,000
Total	**$ 73,609,000**	**$ 802,075,000**	**$ 1,112,615,000**

(1) Maturities remaining as of Sept 30th, 2005

Earnings Guidance Range
$2.55 to $2.65 for 2005
$2.50 to $2.70 for 2006

AEP AMERICAN ELECTRIC POWER

		2005 Projection			2006 Projection		
		Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
	UTILITY OPERATIONS:						
	Gross Margin:						
1	Regulated Integrated Utilities - East	65,270 GWh @ $ 31.5 /MWhr =	2,059		70,941 GWh @ $ 31.0 /MWhr =	2,201	
2	Ohio Companies	48,203 GWh @ $ 39.6 /MWhr =	1,909		46,649 GWh @ $ 47.7 /MWhr =	2,224	
3	Regulated Integrated Utilities - West	40,316 GWh @ $ 22.8 /MWhr =	919		40,006 GWh @ $ 25.0 /MWhr =	1,002	
4	Texas Wires	26,387 GWh @ $ 17.3 /MWhr =	455		26,803 GWh @ $ 17.0 /MWhr =	456	
5	Off System Sales	41,207 GWh @ $ 20.0 /MWhr =	823		37,186 GWh @ $ 16.1 /MWhr =	600	
6	Transmission Revenue - 3rd Party		400			285	
7	Other Operating Revenue		487			515	
8	Total Gross Margin		7,052			7,283	
9	Operations & Maintenance		(3,140)			(3,045)	
10	Depreciation & Amortization		(1,295)			(1,332)	
11	Taxes Other than Income Taxes		(739)			(761)	
12	Interest Exp & Preferred Dividend		(598)			(688)	
13	Other Income & Deductions		271			153	
14	Income Taxes		(481)			(563)	
15	Net Earnings Utility Operations		1,070	2.75		1,047	2.66
16	Investments		2	0.00		(7)	(0.02)
17	Parent Company		(58)	(0.15)		(17)	(0.04)
18	ON-GOING EARNINGS		1,014	2.60		1,023	2.60
	Shares Outstanding			390MM			393MM

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

AEP AMERICAN® ELECTRIC POWER

Utilities Week Investor Meeting Handout

New York

November 29-30, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Detailed Ongoing Earnings Guidance

AEP®

2010A: $3.03

2011E: $3.07 - $3.17

American Electric Power

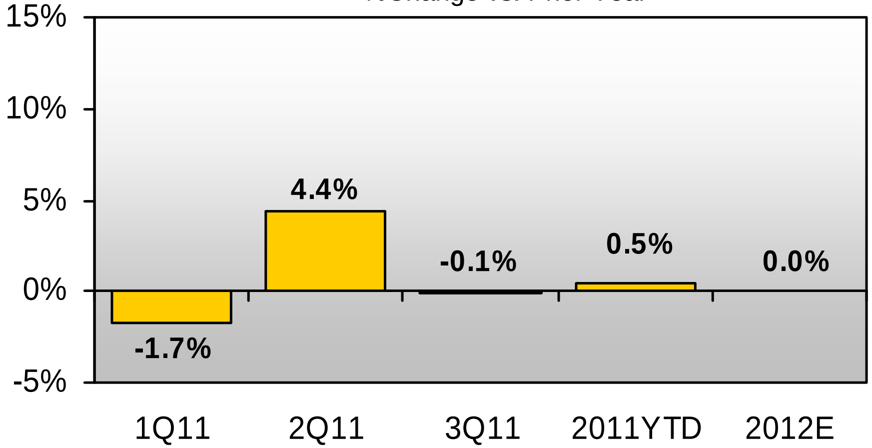
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

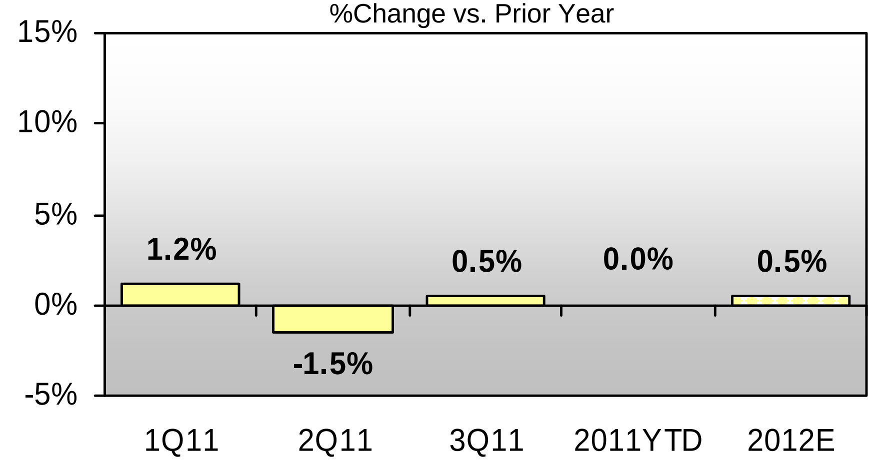
*****original guidance given 01/28/2011*

Normalized Load Trends

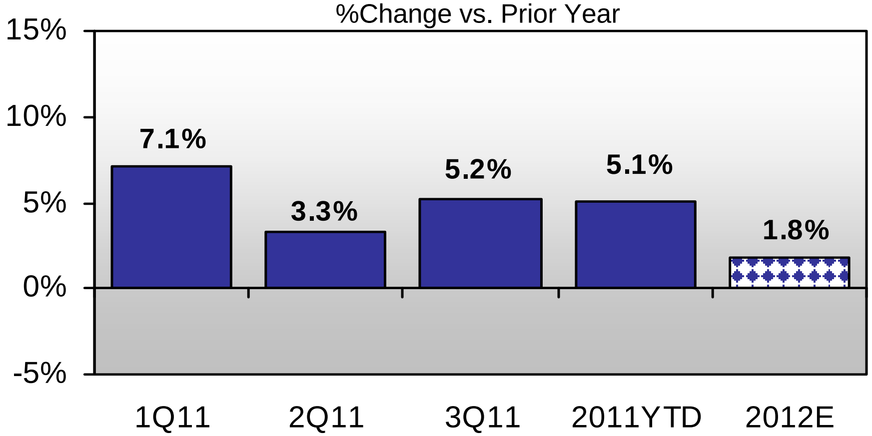
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



AEP Commercial Normalized GWh Sales
%Change vs. Prior Year

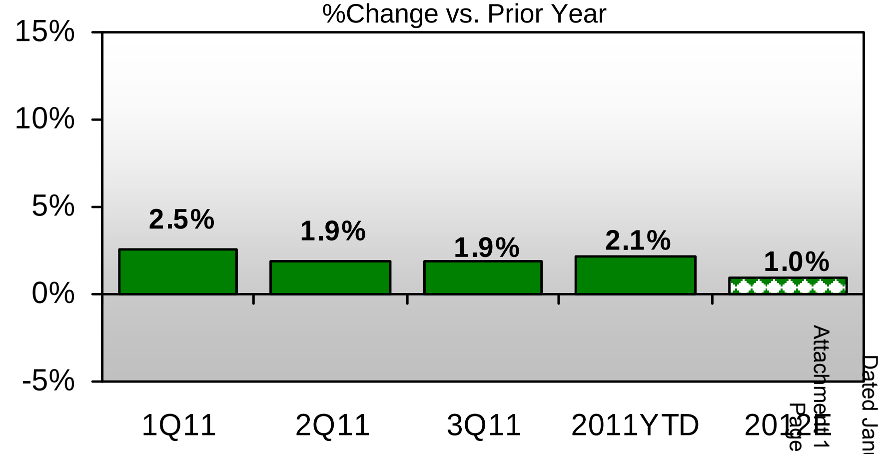


AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



Note: Chart represents connected load

AEP Total Normalized GWh Sales*
%Change vs. Prior Year

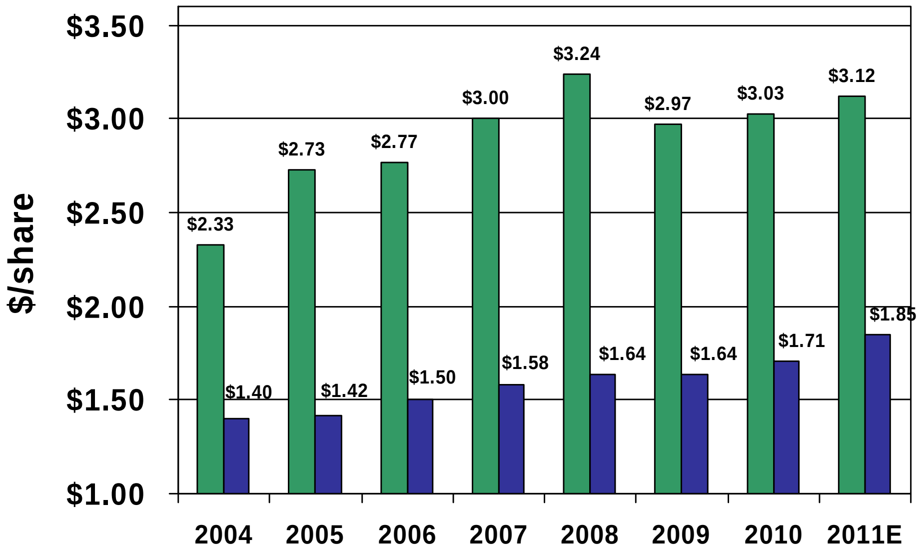


*includes firm wholesale load

Earnings and Dividend Growth

AEP®

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

Dividend payout ratio target of 50–60%

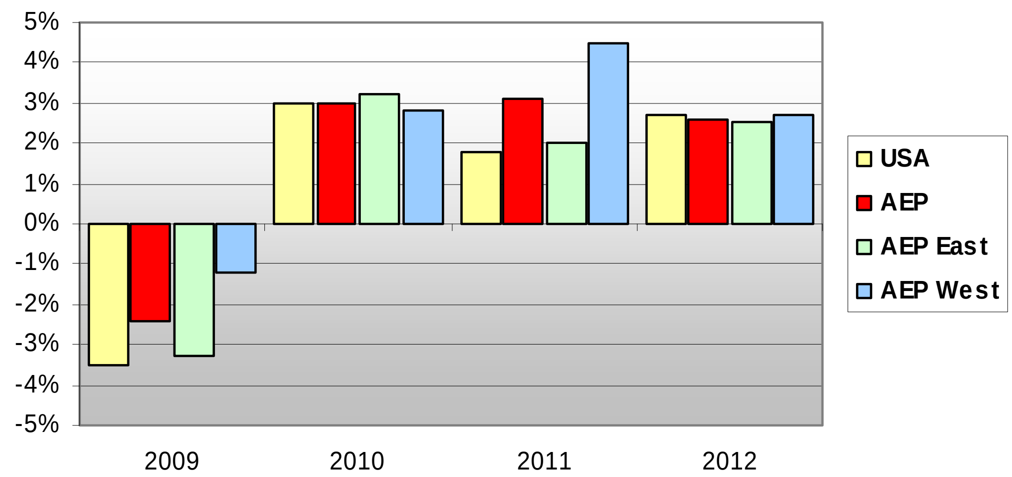
2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

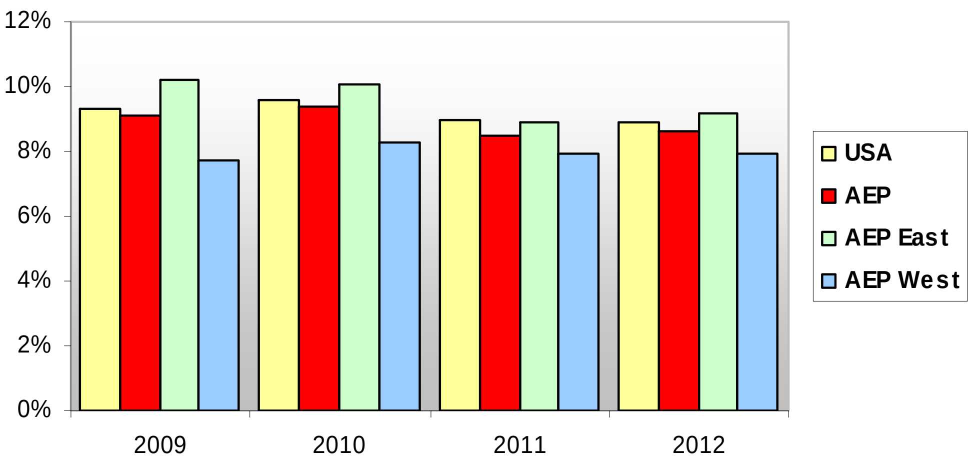
Economic Conditions/Load

- AEP's GDP growth at 3.1% in 2011 has been better than the US at 1.8%
- AEP West region continues to experience stronger growth than AEP East

Annual GDP Growth



Annual Unemployment Rate



- AEP East unemployment remains higher than AEP West
- AEP Total unemployment has started to improve relative to the US

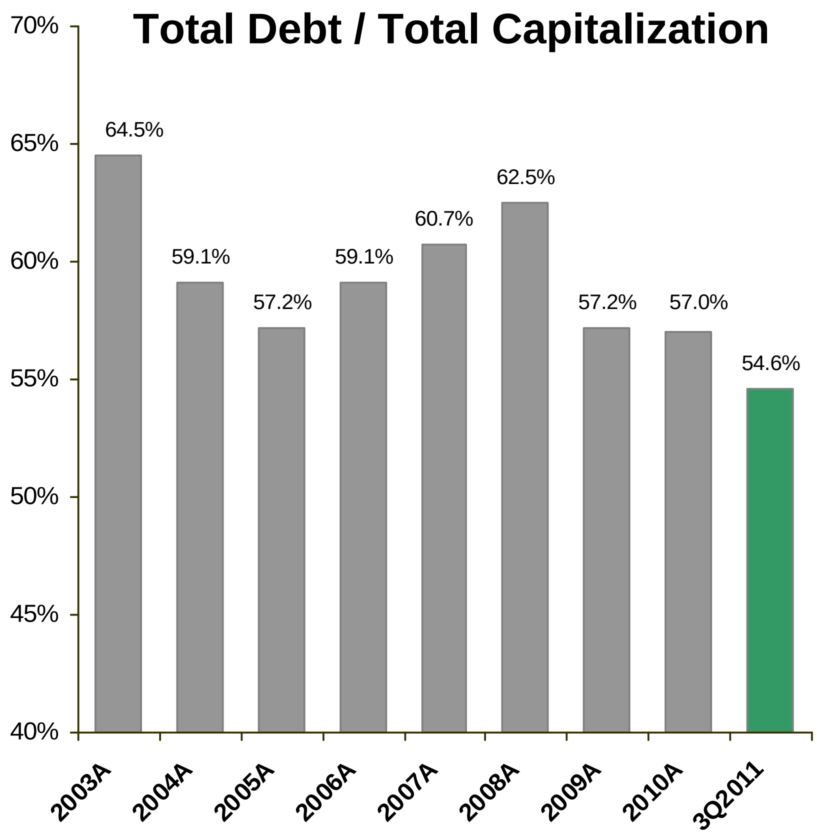
Sensitivities for 2012

EPS Sensitivities

Major Drivers		
Driver	**Driver Change**	**EPS Effect**
Average Load Growth	1%	$0.10
Off System Sales, net of sharing	10%	$0.05
Utility O&M	1%	$0.04
Capital Spending	$250M	$0.02

Operating Company Returns		
Company	**% Earnings Contribution**	**EPS Effect of 1% ROE Change**
AEP Ohio	42%	$0.10
APCo (incl WPCo)	16%	$0.06
SWEPCO	11%	$0.04
I&M	10%	$0.04
AEP Texas	8%	$0.02
PSO	6%	$0.02
KPCo	3%	$0.01
Other	4%	$0.02

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.50%	15%- 20%

Note: Credit statistics represent the 12 month trailing as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

8

TCC Remand Case – PUCT Docket No. 39722

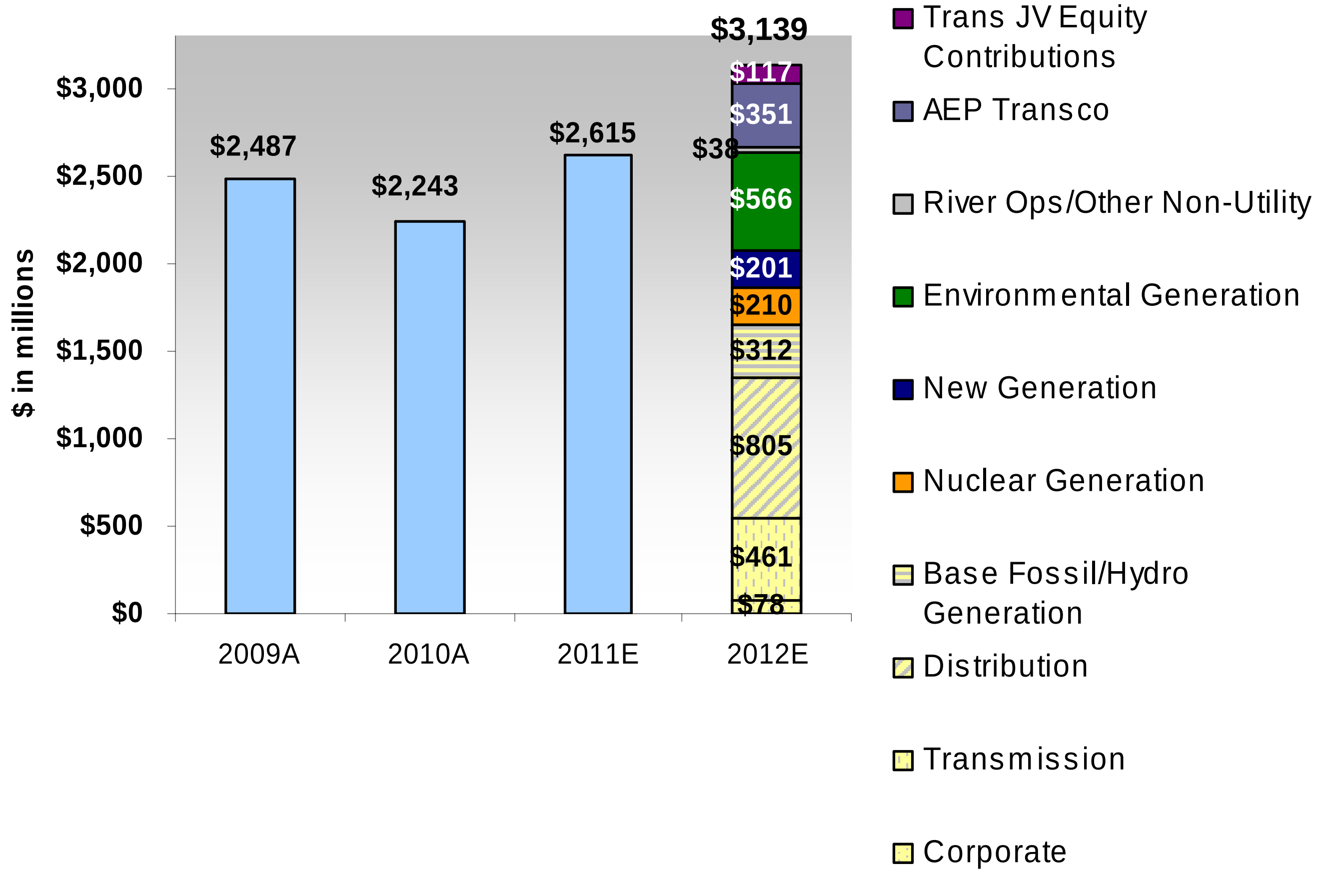
- In July 2011, the Supreme Court of Texas reversed the PUCT's decision of the disallowance of capacity auction costs. This opened the docket for TCC to file on October 10, 2011, an application to confirm the capacity auction true-up balance.
- Based on the Commission's Preliminary Order in the case, the capacity auction true-up balance would be approximately $817M inclusive of a carrying charge rate of 7.47%(based on ruling that modified the rate in 2007).
- The regulatory hearing is scheduled to take place November 29-30, 2011, but settlement is likely. A filing for a securitization order will occur soon after an order is issued on the remand case. TCC expects to issue the securitization bonds in the first quarter of 2012.
- TCC recorded a $425MM net-of-tax favorable special item related to this case in 3Q2011, ($421MM principal & $234MM interest, less related taxes). AEP also recorded $28MM on-going interest YTD in 3Q2011.
- Upon securitization, TCC will begin recognizing the equity component of the carrying cost prorated over the life of the securitization bonds (estimated to be $116MM, based on the PUCT preliminary order).
- Filing also seeks order to resolve tax normalization issues.

Pension and OPEB Estimate

- Investment returns for our pension plan remain slightly positive for the year despite volatility in the market, OPEB funds are slightly negative year to date.
- With very low short term interest rates, it is beneficial to pre-fund a portion of the required contributions to the plan.
- After making a discretionary contribution of $300 million by year end, cash contributions to the pension will total $450 million for 2011.
- We do not expect any required cash contributions to the pension for 2012, although we may make additional discretionary contributions.
- We expect combined pension and OPEB expense to increase $88M from 2011 to 2012 ($62MM O&M, pre-tax and $26MM capitalized).
- Discount rates are 5.05% for pension and 5.25% for OPEB for 2011, and are currently estimated to be 4.35% and 4.60% for 2012 and beyond.
- Estimates for expense and contribution figures are very sensitive to changes in interest rates and investment returns between now and year-end.

Capital Allocation

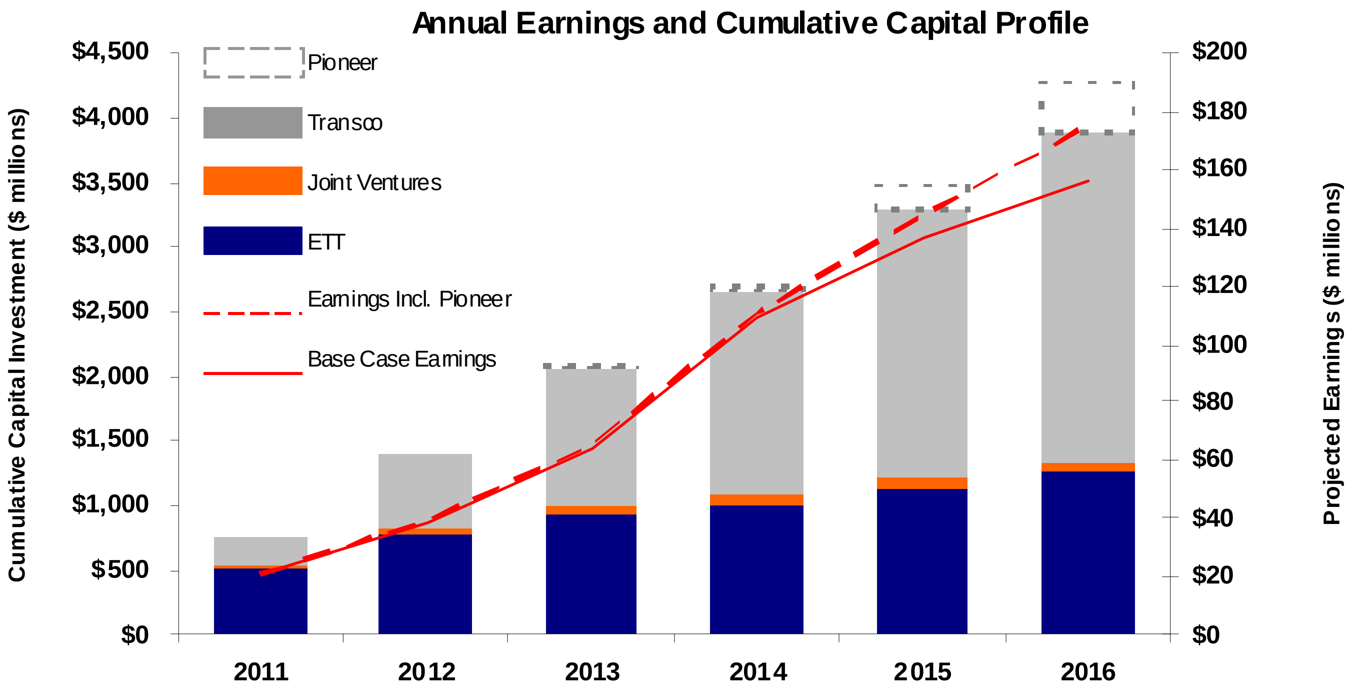
2012 AEP System Capital $3.1B



Major projects include: Turk Plant, Reliability upgrades, ETT contributions and Transco growth

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 9332 of 9556

Transmission Earnings & Capital Profile



[1] High Case includes AEP's share of Pioneer (50% ownership)

[2] Transco base case includes approximately $21MM in 2012 capital spend that is dependent upon state approval of Arkansas and Kentucky

[3] Joint Ventures include: PATH (50% ownership) assuming an ongoing suspension and Prairie Wind (25% ownership) assuming construction at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 11-13% for FERC projects; 60/40 debt/equity capitalization and 9.96% ROE (through 2013) and 55/45 debt/equity capitalization and 10% ROE (2014 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission Investment Opportunities

Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:**
  Current rate base is $482 million; expected to grow as follows:
  - 2011: $495 million
  - 2012: $750 million
  - 2013: $1,200 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $210 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

ROE Optimization

AEP®

ROE by Jurisdiction		
Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia	10.53%	6.88%
APCO – West Virginia	10.00%	
Wheeling	10.00%	
I&M – Indiana	10.50%	8.24%
I&M – Michigan	10.35%	
SWEPCO – Louisiana	10.57%	10.05%
SWEPCO – Arkansas	10.25%	
SWEPCO – Texas	10.33%	
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Ohio ESP Settlement

AEP®

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012) the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

AEP®

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule

Hearing has been delayed pending settlement discussions

Summary Rate Case Information

AEP®

APCo Virginia Base Rate Case – Docket #PUE-2011-00037

On March 31,2011 APCo filed an update to its pre-biennial base rate case for recovery of generation and distribution costs requesting an increase of $75 million ($126 million total increase less $51 million deferral of depreciation increase).

In conjunction with this case, an environmental rate adjustment clause (E-RAC), a generation rate adjustment clause (G-RAC) and a renewable portfolio standard rate adjustment clause (RPS-RAC) were filed. APCo has requested that rates in the base case, E-RAC and RPS-RAC go into effect on 2/1/2012 and the G-RAC on 3/1/2012.

Historical Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.76%	0.33%	0.01%
Long-Term Debt	53.25%	5.90%	3.14%
Common Equity	42.72%	11.65%	4.98%
Preferred Stock	0.27%	4.35%	0.01%
Total	100.00%		8.14%

Procedural Schedule

Order expected November 30, 2011, with implementation effective February 1, 2012

Required Rate Relief – Company Position (12/31/10)

($ in millions)

Rate Base	$	2,192.5
Rate of Return		8.14%
Operating Income Requirement	$	178.5
Adjusted Operating Income	$	102.8
Difference	$	75.7
Revenue Conversion Factor		1.6650
Total Revenue Requirement	$	126.0

Summary Rate Case Information

AEP

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M requested to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

Recovery Mechanisms Across Jurisdictions

AEP®

	SO_2 Allowances*	NO_x Allowances*	CO_2 Allowances	GHG Offsets	Environmental Investment	Energy Efficiency	Renewables	Purchased Power	OATT
AEP East									
Indiana	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**CCTR/BR**	**Rider**	**FAC**	**FAC/BR**	**PJM Tracker**
Kentucky	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**		**FAC**	**Base Rates**
Michigan	**PSCR**	**PSCR**	**PSCR**	**PSCR**	**Base Rates**	**Surcharge**	**PSCR/REP**	**PSCR**	**Base Rates**
Ohio	**FAC**	**FAC**	**FAC**	**FAC**	**SSO**	**Rider**	**FAC**	**FAC**	**TCRR**
Tennessee	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**			**FERC Tariff**	**PPAR**
Virginia	**ERAC**	**ERAC**	**ERAC**	**ERAC**	**ERAC/BR**	**RAC**	**RPSRAC**	**FAC/BR**	**TRAC**
West Virginia	**ENEC**	**ENEC**	**ENEC**	**ENEC**	**ENEC/BR**	**Rider**	**ENEC**	**ENEC**	**ENEC**
AEP West									
Arkansas	**ECR**	**ECR**	**FAC**	**FAC**	**Surch/BR**	**EECR**	**FAC**	**ECR/BR**	**Base Rates**
Louisiana	**EAC**	**EAC**	**Rider**	**Rider**	**Formula BR**		**FAC**	**EAC/FRP**	**Formula BR**
Oklahoma	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Rider**	**FAC**	**FAC/PPC**	**SPP tracker**
Texas(SWP)	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**EECRF**	**FAC**	**FAC/BR**	**TCRF**

* - For certain jurisdictions where necessary, confirmation of the replacement of CAIR with CSAPR is occurring with applicable commissions

ECCR	Environmental Compliance Cost Rider
CCTR	Clean Coal Technology Rider
BR	Base Rates
FAC	Fuel Adjustment Clause
PSCR	Power Supply Cost Recovery Rider
REP	Renewable Energy Plan
SSO	Standard Service Offer
TCRR	Transmission Cost Recovery Rider
PPAR	Purchased Power Adjustment Rider
ERAC	Environmental Rate Adjustment Clause
RAC	Rate Adjustment Clause
RPSRAC	Renewable Portfolio Standard Rate Adjustment Clause
TRAC	Transmission Rate Adjustment Clause
ENEC	Expanded Net Energy Cost
ECR	Energy Cost Recovery Rider
EECR	Energy Efficiency Cost Rate
FRP	Formula Rate Plan
PPC	Purchased Power Capacity Rider
EECRF	Energy Efficiency Cost Recovery Rider
TCRF	Transmission Cost Recovery Factor

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).

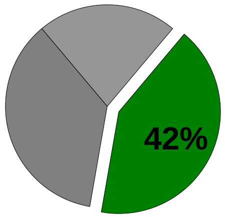
- Various legal challenges are on-going related to the plant (see 10-Q).

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

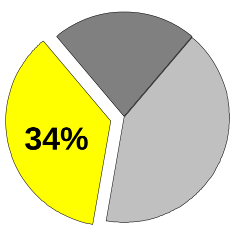
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

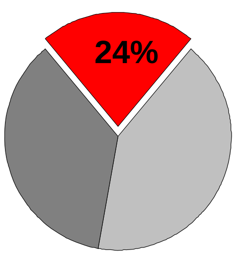
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	Has FGD
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Lawrenceburg **	1,186	2004	NG Combined Cycle
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	4,921		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**13,432**		

* May need FGD upgrades

** CSP has a PPA with AEGCo for the Lawrenceburg Plant. The contract extends through 2017, with a two-year optional renewal.

Total Ohio Generation	13,432 MW
Less units slated for retirement	2,500 MW
Total remaining portfolio	10,932 MW
Remaining Portfolio:	
Coal	77%
Has FGD & SCR - 83%	
Has FGD; may require SCR - 10%	
May be replaced with gas - 7%	
Natural gas & hydro units	23%
	100%

KPSC Case No. 2011-00401
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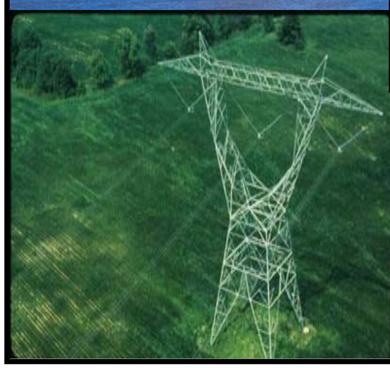
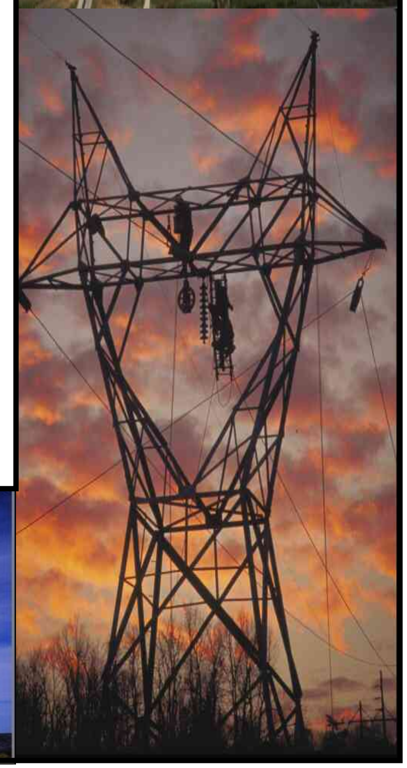
Van Kampen Asset Management Office Visit
Houston, TX

AEP AMERICAN® ELECTRIC POWER

April 18, 2008

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters); our ability to constrain operation and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; volatility in the financial markets, particularly development affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust; prices for power we generate and sell at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Forms 10-K and 10-Q, filed from time to time by the company with the SEC.

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Chairman, President & CEO

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Company Overview

- 5.2 million customers in 11 states

Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~37,700 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~213,000 miles	# 1

Source: Company research

- Coal & transportation assets
  - Control over 8,400 railcars
  - Own/lease and operate over 2,650 barges & 52 towboats
  - Coal handling terminal with 20 million tons of capacity
- 20,800 employees

AEP Generation Portfolio				
Coal	**Gas**	**Nuclear**	**Hydro**	**Wind**
68%	**23%**	**6%**	**2%**	**1%**

AEP enjoys significant presence throughout the energy value chain.

AEP Strategy

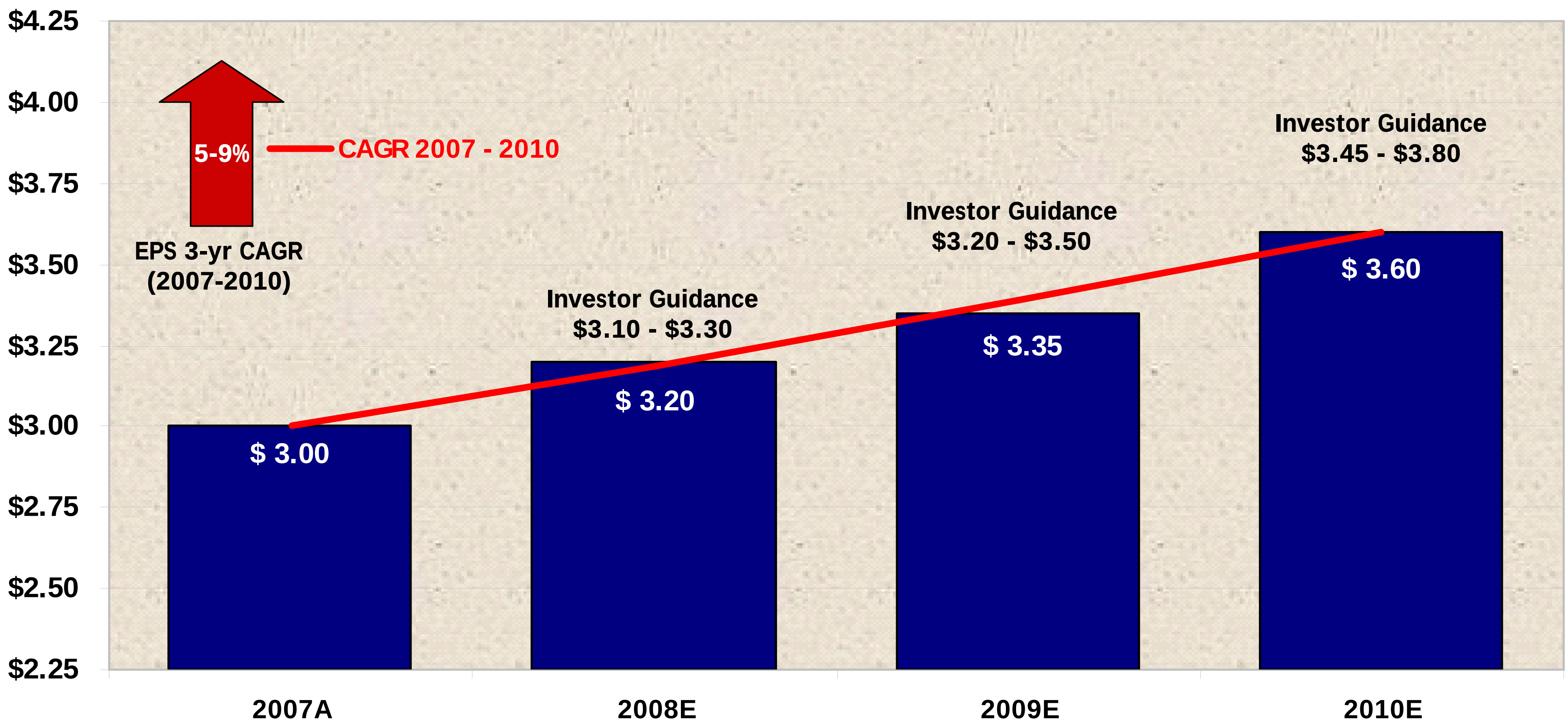
Strategy: grow our core utility business at a consistent rate through major investment supported and funded by innovative programs for regulatory recovery as well as develop our independent, federally regulated Transmission Company for the pursuit of new major interstate projects.

Our 2008 Focus:

- Prepare for post-2008 transition in Ohio
- Invest in and evolve infrastructure to support future technology and customer needs focused on efficiency, conservation and load management
- Enhance cash flow & earnings through rate recovery mechanisms
- Take advantage of AEP's size to benefit our customers and shareholders through regulatory-supported investment

Sustained capital investment opportunities support earnings growth.

4-Year Earnings Range Forecast

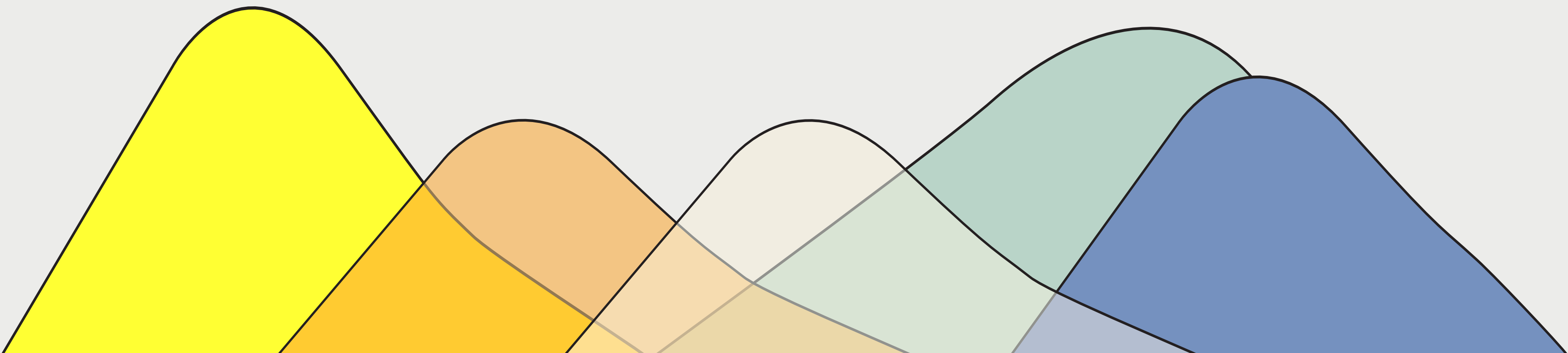


5% to 9% earnings growth

Capital Investment Earnings Catalysts

Capital Investment - Consistent Waves of Opportunity

Environmental Retrofits	New Generation Projects	GridSMART Technology	Transmission Ventures	Adv Generation/ CO_2
$5.4B	$1.3B+	$1-2B	$2.25B - $3.75B*	$2.0B+



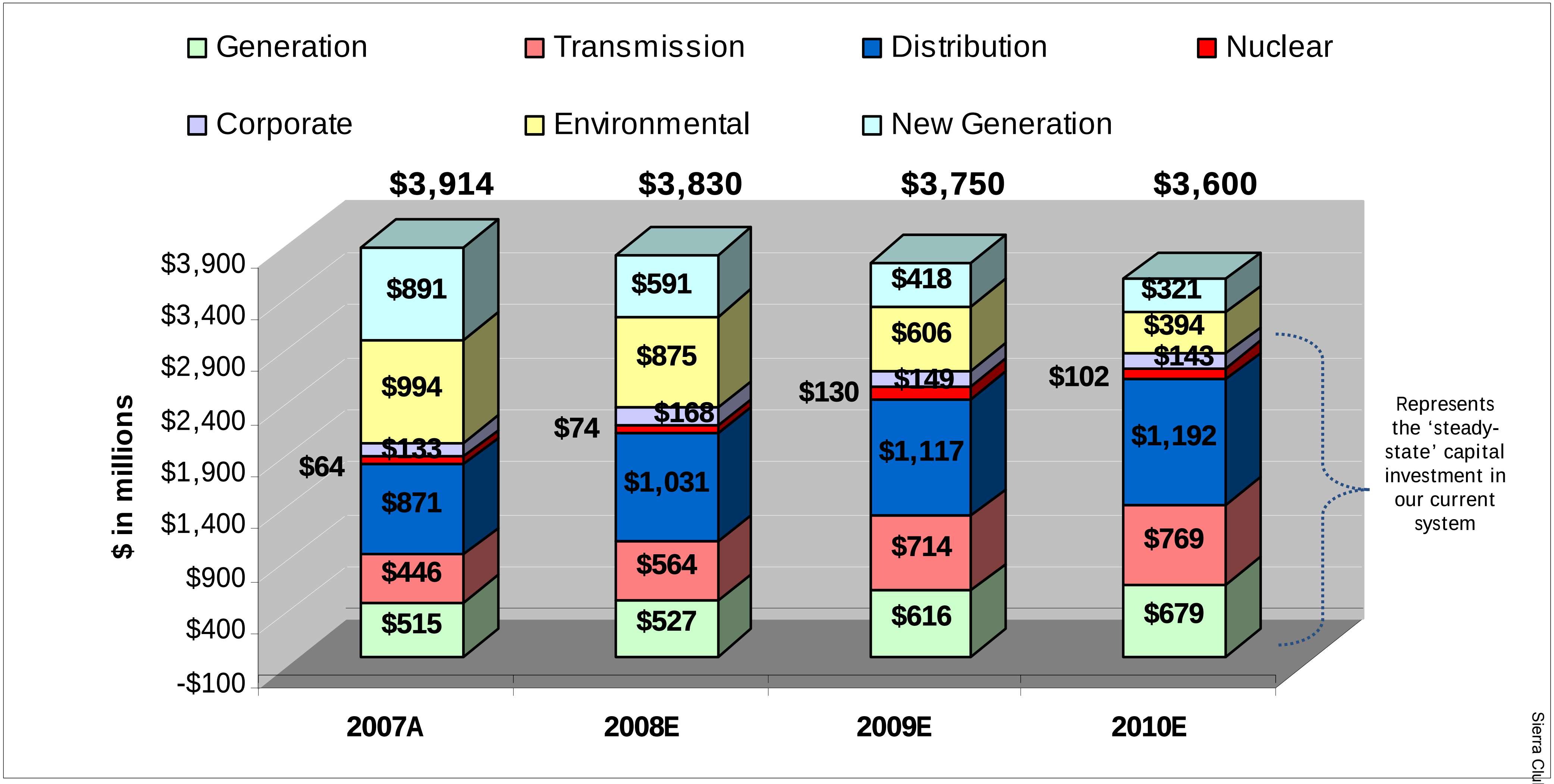
Baseline capital investment of approximately $2.5B/year for Transmission, Distribution & Generation versus annual depreciation of $1.1B/year

2005 → 2010 → 2020 →

Note: This slide represents current capital investment plans as well as future capital investment opportunities. For current capital investment guidance through 2010, please refer to page 10. *The transmission opportunity is shown utilizing anticipated JV ownership structure.

Capital investment opportunities combined with associated rate relief will drive sustainable earnings growth.

4-Year Capital Investment Forecast



Note: amounts exclude AFUDC, $472MM related to gridSMART[SM] and $566MM related to transmission joint venture projects

Capital Investment + Rate Relief = Earnings Growth

Capital Investment Drives Operating Company Growth

($ in millions)	2007A	2008E	2009E	2010E	Total
APCo	$712	$726	$753	$629	**$2,820**
I&M	$282	$386	$440	$380	**$1,488**
KPCo	$76	$127	$105	$129	**$437**
TCC	$212	$208	$251	$245	**$916**
TNC	$93	$120	$156	$146	**$515**
PSO	$303	$277	$363	$463	**$1,406**
SWEPCo	$511	$741	$620	$638	**$2,510**
CSP	$432	$404	$351	$330	**$1,517**
OPCo	$805	$635	$591	$550	**$2,581**
Other Companies	$488	$206	$120	$90	**$904**
Total Capex	**$3,914**	**$3,830**	**$3,750**	**$3,600**	**$15,094**

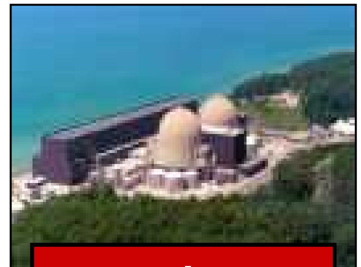
Note: amounts exclude AFUDC

Capital Investment + Rate Relief = Earnings Growth

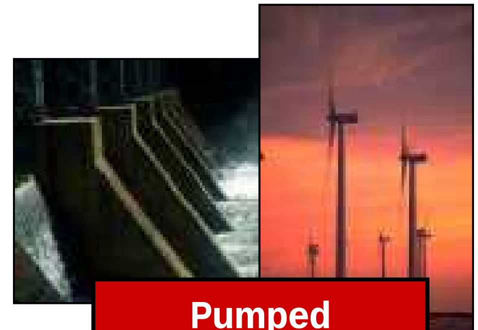
Domestic Generation Fleet

Coal/Lignite
68%

Nat. Gas/Oil
23%



Nuclear
6%



Pumped Storage/ Hydro/Wind
3%

AEP's Generation Fleet
37,736 * MW Capacity

* Includes 270MW of retired/decommissioned generating capacity.

Operating Statistics

	Equivalent Availability Factor	Equivalent Capacity Factor
2005	84.76%	63.18%
2006	82.62%	60.06%
2007	81.84%	59.54%

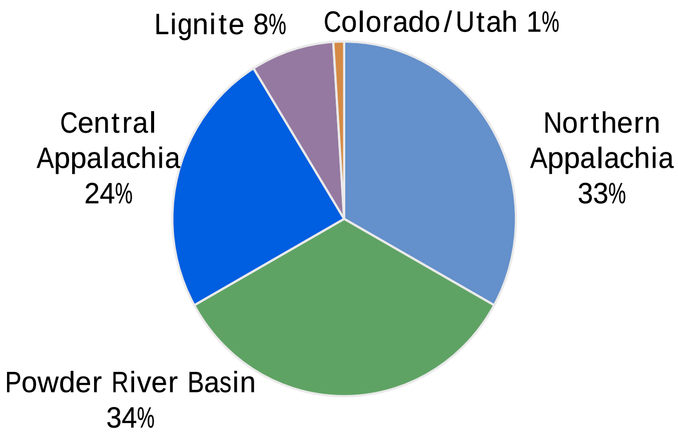
NERC Regional Presence

RFC	**72%**
SPP	**23%**
ERCOT	**5%**

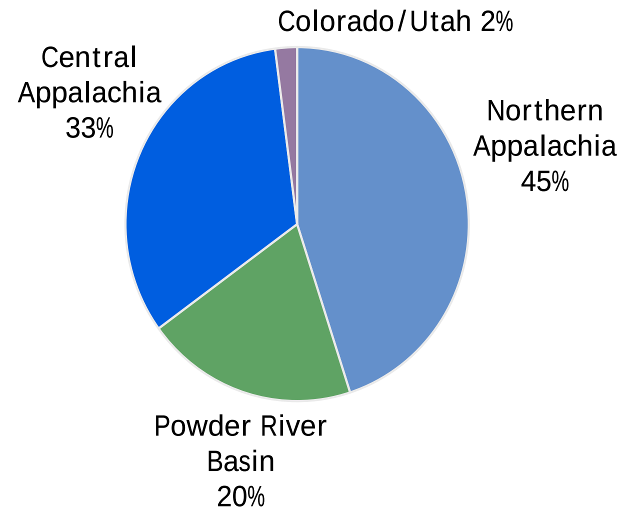
Coal Procurement - 2008 Projected

AEP burns approx. 76 million tons of coal per year

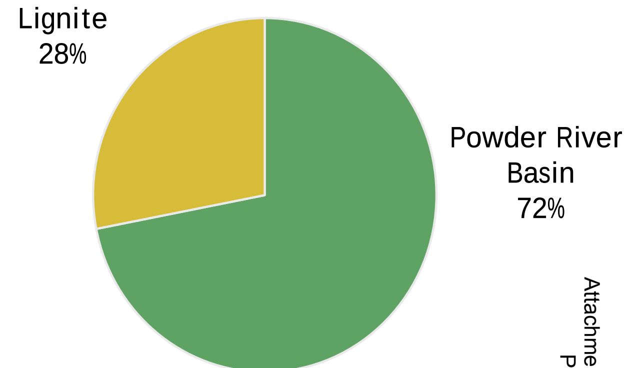
Total AEP System



AEP East



AEP West



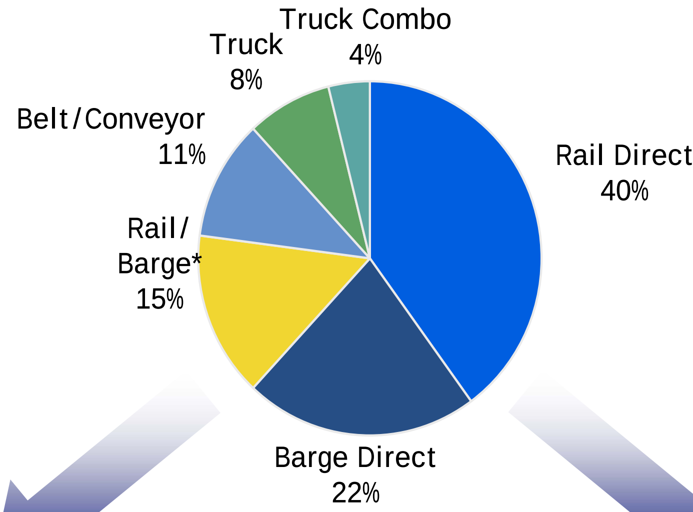
Coal Stats:

- Approximately 93% contracted for 2008
- Avg. delivered price ~ $36.58/ton in 2007
- Approximate 13% price increase in 2008 based on 2007 actual results.

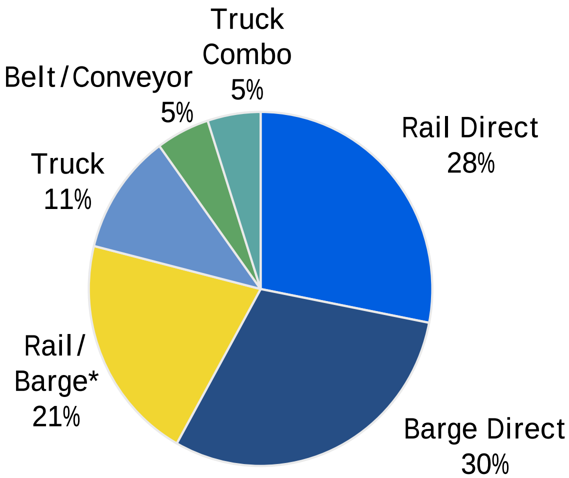
Coal Delivery

Total AEP System

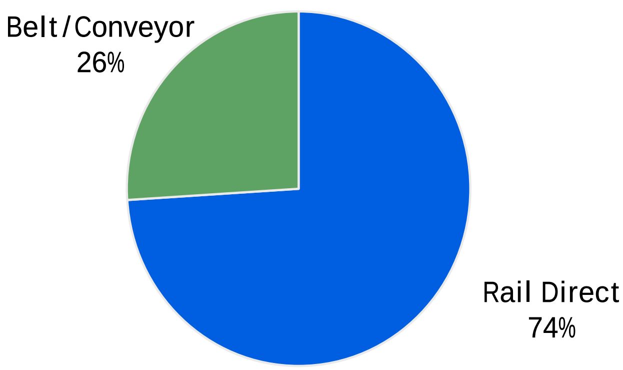
2007 Actual



AEP East



AEP West



* Reflects coal delivered to AEP plants transported through a combination of rail and barge

Generation - Environmental Project Status Report

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	☑	In-service	☑	Projected 2010
Amos 2	800	☑	In-service	☑	Projected 2009
Amos 3	1300	☑	In-service	☑	Projected 2009
Big Sandy 2	800	☑	In-service	☑	Projected 2014
Cardinal 1	600	☑	In-service	☑	In-service
Conesville 5	375		N/A	☑	Upgrade In-service
Conesville 6	375		N/A	☑	Upgrade projected 2008
Gavin 1&2	2620	☑	In-service	☑	In-service; Upgrade projected 2010
Mitchell 1&2	1600	☑	In-service	☑	In-service
Mountaineer	1320	☑	In-service	☑	In-service
Muskingum River 5	585	☑	In-service	☑	Projected 2015
Rockport 1	1300	☑	Projected 2017	☑	Projected 2017
Rockport 2	1300	☑	Projected 2019	☑	Projected 2019
CCD Plants					
Conesville 4	339	☑	Projected 2009	☑	Projected 2009
Stuart 1-4	620	☑	In-service	☑	Projected 2008
Zimmer	330	☑	In-service	☑	In-service
West Plants					
Dolet Hills	262		N/A	☑	In-service; Upgrade projected 2012
Flint Creek 1	264		N/A	☑	Projected 2014
Northeastern 3	450		N/A	☑	Projected 2012
Northeastern 4	450		N/A	☑	Projected 2014
Oklaunion	485		N/A	☑	In-service
Pirkey	580		N/A	☑	Upgrade In-service
Welsh 2	528		N/A	☑	Projected 2012

At the conclusion of our current environmental retrofit program, over 58% of our 24,630 MW coal-fired generation fleet will be equipped with SCRs and over 73% will be scrubbed (FGDs).

New Generation

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
PSO	Riverside	Oklahoma	$59 MM	Gas	Simple-cycle	170	2Q 2008
AEG	Dresden	Ohio	$266 MM	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$378 MM	Gas	Combined-cycle	480	2010
SWEPCo	Turk	Arkansas	$1.3 B (1)	Coal	Ultra-supercritical	600 (1)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	629	2012
CSP/OP	Great Bend	Ohio	$2.7 B (2)	Coal	IGCC	629	tbd

(1) SWEPCo will own approximately 73%, or 438 megawatts, totaling about $950 million in capital investment.
(2) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the current Supreme Court of Ohio remand to the PUCO of the PUCO's April 10, 2006 Opinion and Order.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities.

gridSMART^{SM}

gridSMART^{SM}: implementing AEP's vision for the distribution and customer services business in the future, including the development of new customer programs to reduce consumption and peak demand, and a plan to deploy advanced technologies.

- **Enables customers to better manage energy**
- **Improves service to our customers by enhancing customer choice and customer control**
- **Improves efficiency**
- **Integrates distributed energy resources into our grid**
- **Transforms the way we do business**

Capital Investment, Subject to Regulatory Approval *
$ in millions

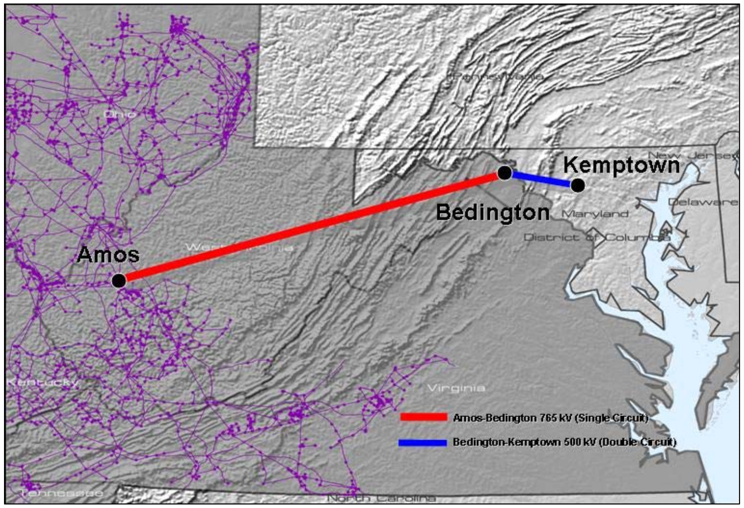
Technology	2008	2009	2010
Metering & Communications	$83	$138	$146
Distribution Technology Enhancements	$40	$ 63	$ 82

*$472MM of the $552MM not in current forecast; spending contingent upon regulatory approval

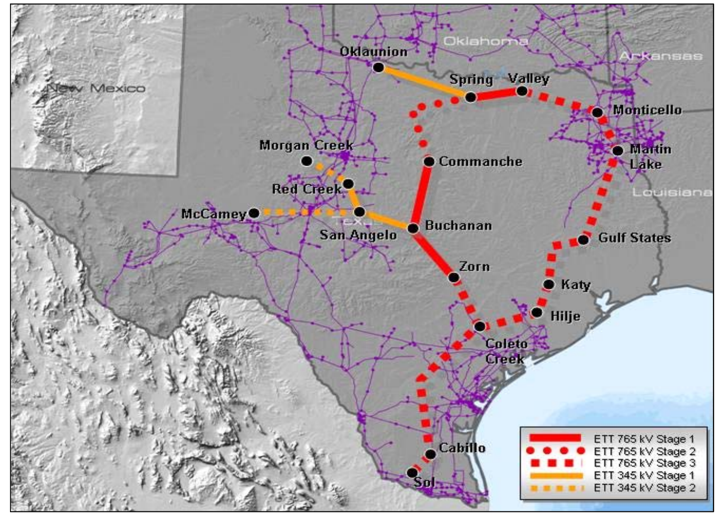
AEP will continue to be an industry leader in deploying advanced technology on a commercial scale. $552MM capital investment by 2010, subject to regulatory approval

I-765™ Transmission: Investment Opportunities

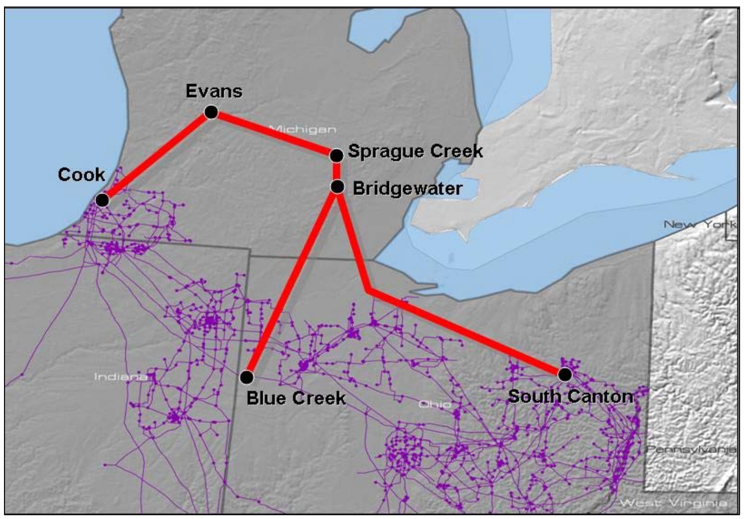
AEP is Advancing the Development of a National Interstate Today



PATH Project (PJM)



ETT Proposal (ERCOT)



AEP-ITC Michigan Proposal (PJM/MISO)

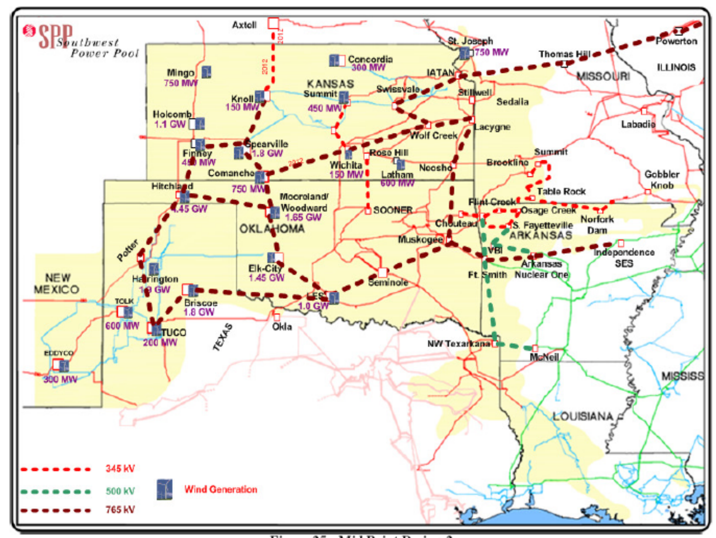


Figure 25: Mid Point Design 2

SPP Overlay Study – Mid Design 2

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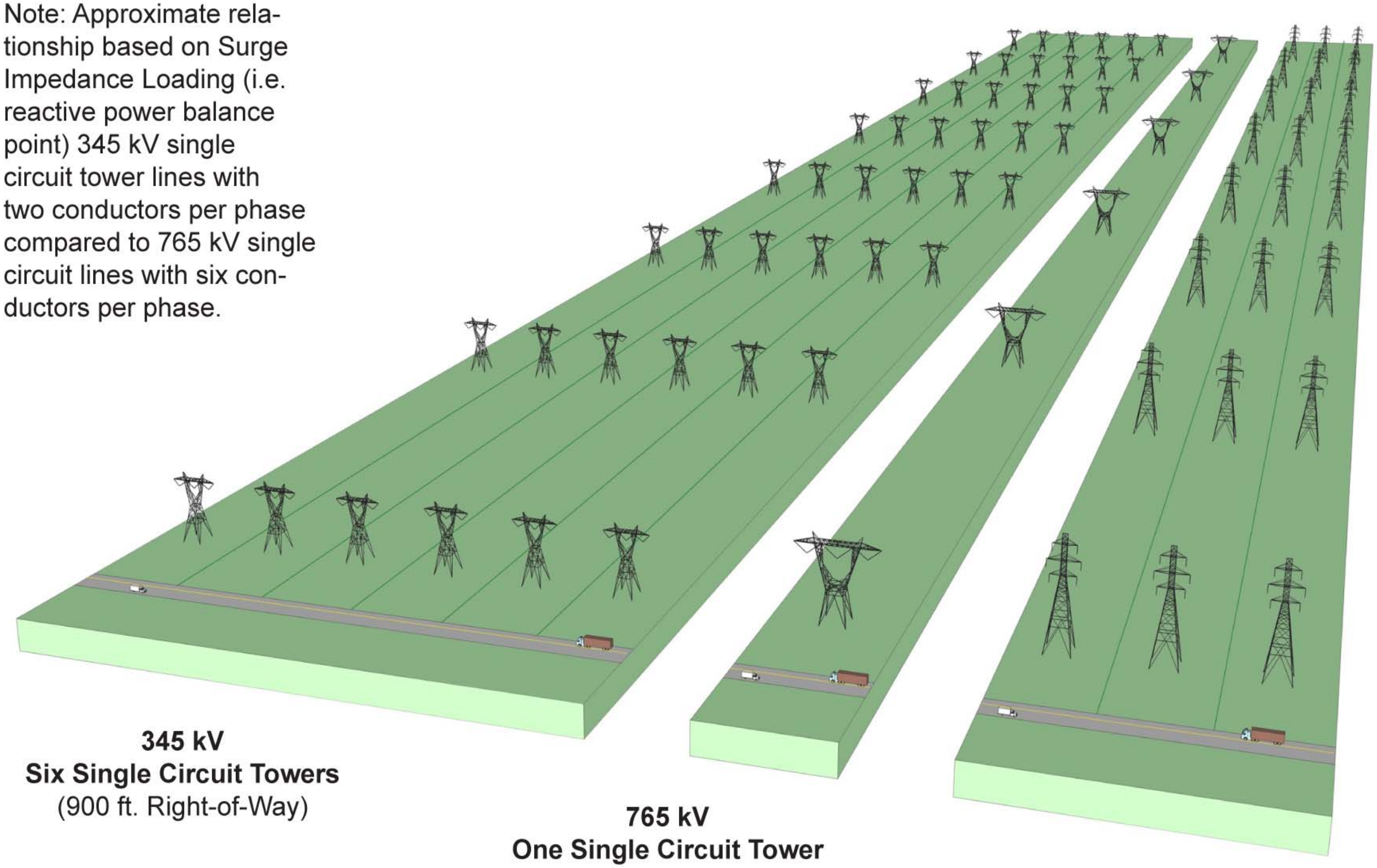
765 Right-of-Way Comparison

Note: Approximate relationship based on Surge Impedance Loading (i.e. reactive power balance point) 345 kV single circuit tower lines with two conductors per phase compared to 765 kV single circuit lines with six conductors per phase.



345 kV
Six Single Circuit Towers
(900 ft. Right-of-Way)

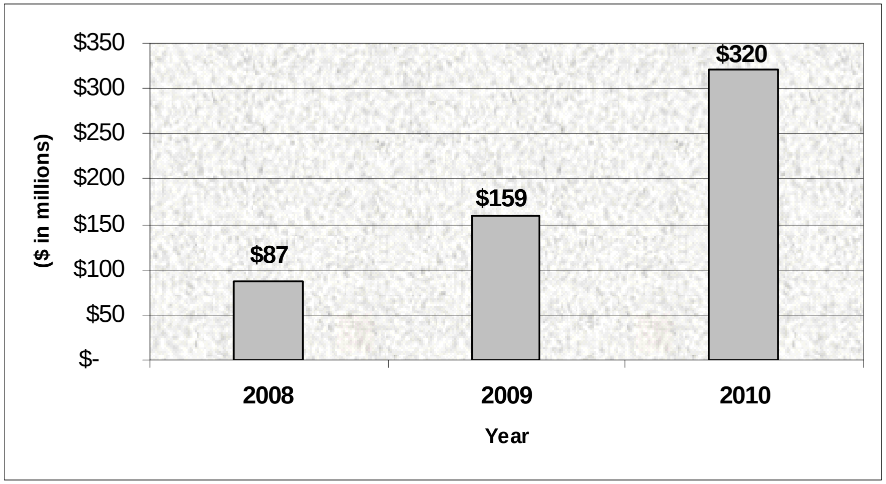
765 kV
One Single Circuit Tower
(200 ft. Right-of-Way)

345 kV
Three Double Circuit Towers
(450 ft. Right-of-Way)

From a siting standpoint, 765-kV is more efficient in terms of economies of scale and right-of-way than lower capacity lines.

Transmission - Investments and Earnings Contributions

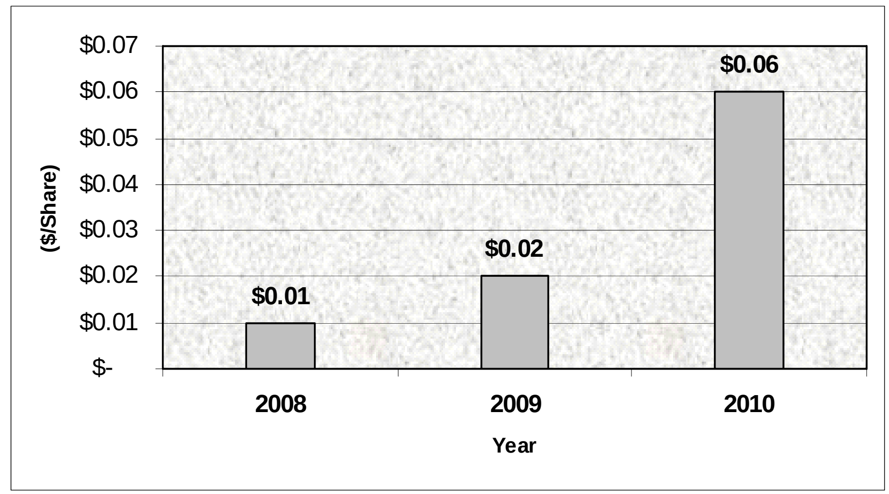
Projected Transmission Capital Spending*



* ETT and PATH joint ventures included in above projection. Amounts represent AEP's 50% share of total transmission joint venture capital expense. These amounts are excluded from AEP's base capital forecast because the joint ventures are not consolidated for financial reporting purposes. AEP will be responsible for funding 40-50% of these amounts with equity contributions, and the remainder will be financed with debt issued by the joint ventures.

Electric Transmission Texas

Projected Transmission EPS Contributions*



* Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

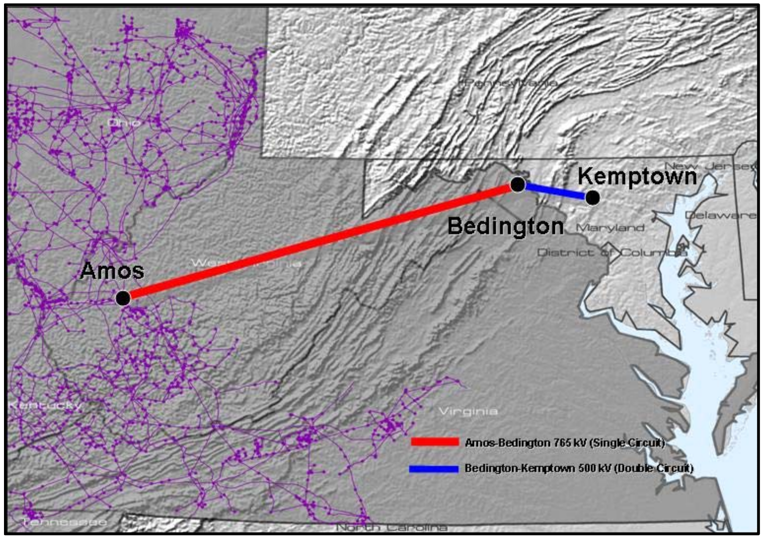
Potomac-Appalachian Transmission Highline

Transmission will provide a near and long term catalyst for growth.

I-765™ Transmission in PJM: PATH

Execution in Action

- *PATH Progress to Date*
  - PJM approved project in its Regional Transmission Expansion Plan in June 2007
  - On September 1, 2007 AEP and Allegheny Energy formed a new joint venture -- Potomac-Appalachian Transmission Highline (PATH) and its subsidiaries -- to construct the 290 miles West Virginia-Maryland line authorized by PJM.
  - Total estimated cost of $1.8 billion; AEP portion approximately $600 million
  - FERC order issued on February 29, 2008 approving:
    - Cash return on CWIP
    - 14.3% incentive ROE
    - Recovery of all costs incurred prior to the time rates go into effect, and
    - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents.
  - FERC ordered the formula rate mechanism be set for hearing, pending settlement judge procedures
- *Funding Plans/Transaction Structure*
  - AEP and Allegheny share ownership of Amos – Bedington line and contribute equally to this portion of the project through PATH West Virginia Transmission Company, LLC
  - AEP's investment will be held in the AEP Transmission Holding Company LLC subsidiary
- *Key Next Steps*
  - Siting Approval from WV and MD – 2010
  - Targeted Completion – 2012



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

PATH
Potomac-Appalachian Transmission Highline

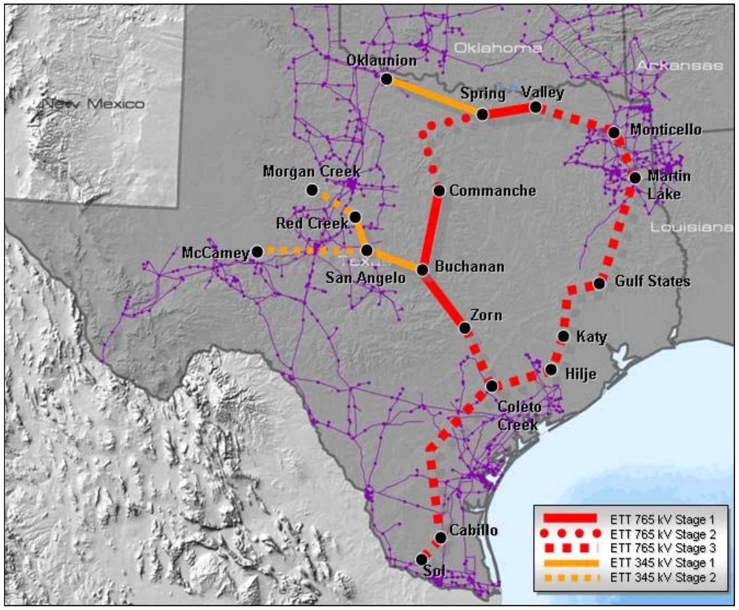
I-765™ Transmission in Texas (ETT)

Electric Transmission Texas Update

- *Transaction Structure*
  - 50/50 utility joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC
  - ETT capital structure is 60% debt / 40% equity with a 9.96% ROE
  - Services provided by AEP and investment opportunities can be offered by either partner

- *Next Steps*
  - ETT project opportunities to be evaluated on a case by case basis
  - Anticipate offering projects in Q2 2008

- *ETT ERCOT Backbone Proposal*
  - ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
  - Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
  - Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
  - $4.2 billion investment (long-term backbone).*



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

* Before ownership division.

Electric Transmission America (ETA)

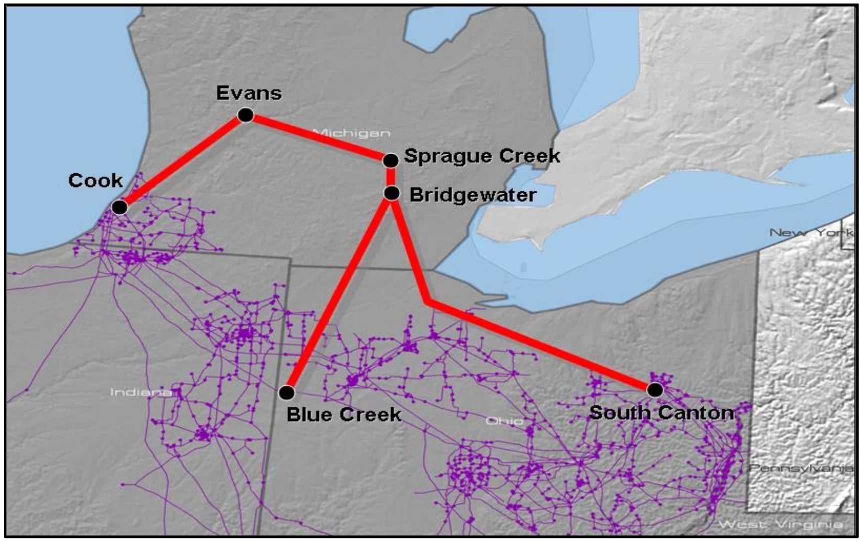
- AEP signed an agreement with MidAmerican Energy Holdings Company on September 13, 2007 to form Electric Transmission America, a 50/50 joint venture.
- Both MidAmerican and AEP desire to utilize ETA as a vehicle to invest in select transmission projects located in North America, outside the Electric Reliability Council of Texas.
- Projects taken on by ETA would entail transmission facilities:
  - 345 kV and above
  - Within, adjacent to and outside the Companies' respective service areas (excluding ERCOT)
  - Greater than $100 million
- ETA is working on identifying investment opportunities and collaborating with likeminded, qualified investment partners in different regions of the country.

ETA reflects a natural progression and expansion of AEP's partnership with MidAmerican.

I-765™ Transmission in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- *Overview*
  - ITC and AEP conducted a technical study for a new 765-kV from Ohio to Michigan
  - Study was released Q3 2007
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.6 billion investment (before ownership division)
  - AEP and ITC are in discussions to form a Joint Venture
- *Benefits*
  - Up to 5,000 MW improved transfer capability
  - Reduces network line losses by 250 MW
- *Next Steps*
  - Agreement on JV (AEP/ITC) - Summer 2008
  - JV Formation - 2008
  - MISO and PJM Review/Approval - 2009
  - FERC Formula Rate and Cost Allocation Filing - Fall 2009
  - Siting Approval – 2011-2012
  - Estimated Completion –2015-2021



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

I-765^{TM} Transmission in SPP

Significant opportunity for 765-kV transmission in SPP

- ***Overview***
  - Sent non-binding Letter of Commitment to SPP to construct 765-kV and 500-kV projects in SPP region consistent with SPP Overlay Study – Summer 2007
  - Updated EHV Overlay Study completed by SPP – March 2008
- ***Benefits***
  - Overall reliability reinforcement with improved voltage support throughout the SPP system
  - Significantly increased transfer capability
  - Provides access to new generation resources, especially renewables
  - Allows for effective interconnections for EHV system development
- ***Next Steps***
  - ETA Partnering Agreements - 2008
  - SPP RTO EHV Overlay Approval – 2009
  - FERC Formula Rate and Cost Allocation Filing (postage stamp) – 2009
  - Siting Approval for projects – 2009-2011
  - Estimated Completion (in segments) – 2012-2017

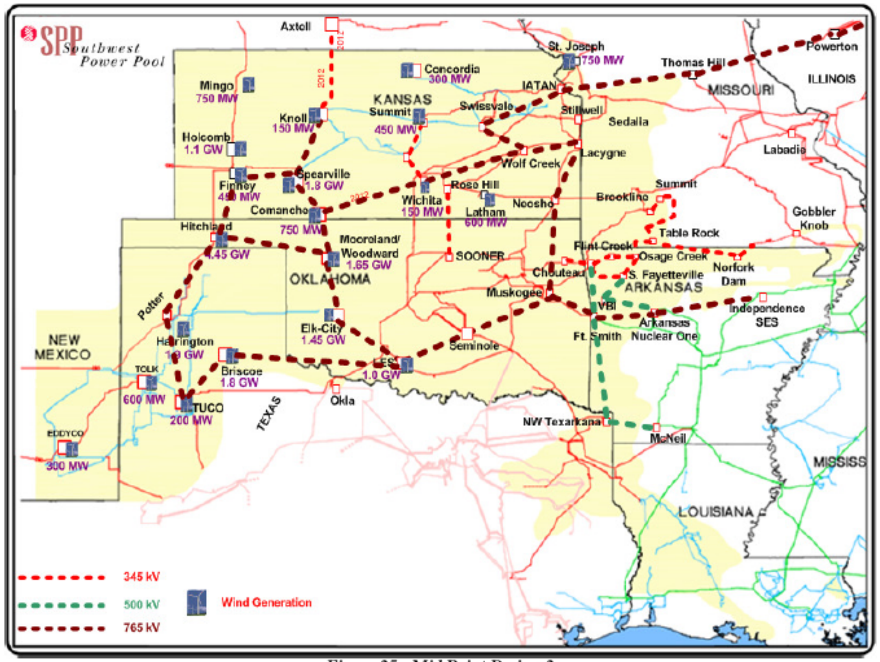


Figure 25: Mid Point Design 2

Total SPP 765-kV Overlay estimated to cost approximately $5 Billion by SPP March 2008 study, a portion of which could be built by ETA.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve.

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal.

Advanced Generation & CO_2

Near Term:

- Chilled Ammonia project at Mountaineer moving to commercial scale at the Northeastern Plant in 2012

$ in millions				
		2008	2009	2010
Mountaineer Chilled Ammonia Project		$30	$39	$0

Long Term Strategy (Post-2010):

- IGCC
- Chilled Ammonia
- Oxy Coal Technology
- Nuclear COL

We are committed to validating and deploying technologies that ensure coal remains a viable resource for AEP and America.

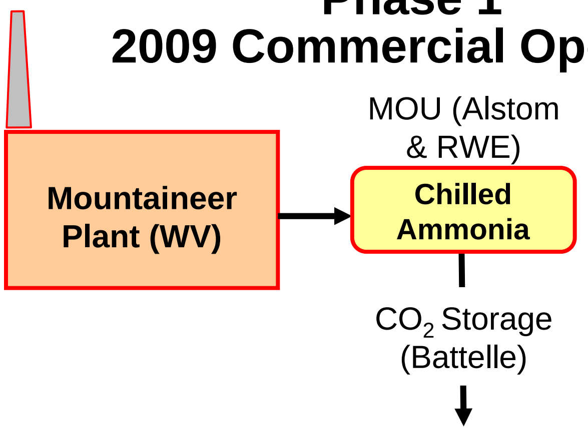
AEP's Carbon Capture & Storage Initiative

In March 2007, AEP announced a major new carbon capture and storage initiative:

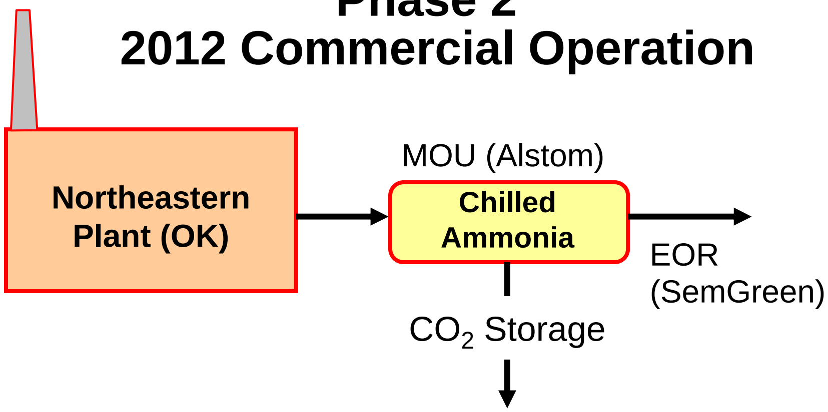
Chilled Ammonia CCS--We will install carbon capture on two coal-fired power plants, the first commercial use of technologies to significantly reduce carbon dioxide emissions from existing plants.

- **The first carbon capture project, at the Mountaineer plant in West Virginia, is expected to complete its product validation phase in 2009.**
- **The second, at the Northeastern plant in Oklahoma, will begin commercial operation in 2012.**

Phase 1
2009 Commercial Operation



Phase 2
2012 Commercial Operation



CO_2 Capture Techniques

Post-Combustion Capture

- Conventional or Advanced Amines, Chilled Ammonia
  - Amine technologies commercially available in other industrial applications
  - Relatively low CO_2 concentration in flue gas – More difficult to capture than other approaches
  - High parasitic demand
    - Conventional Amine ~25-30%, Chilled Ammonia target ~10-15%
  - Amines require **<u>very</u>** clean flue gas

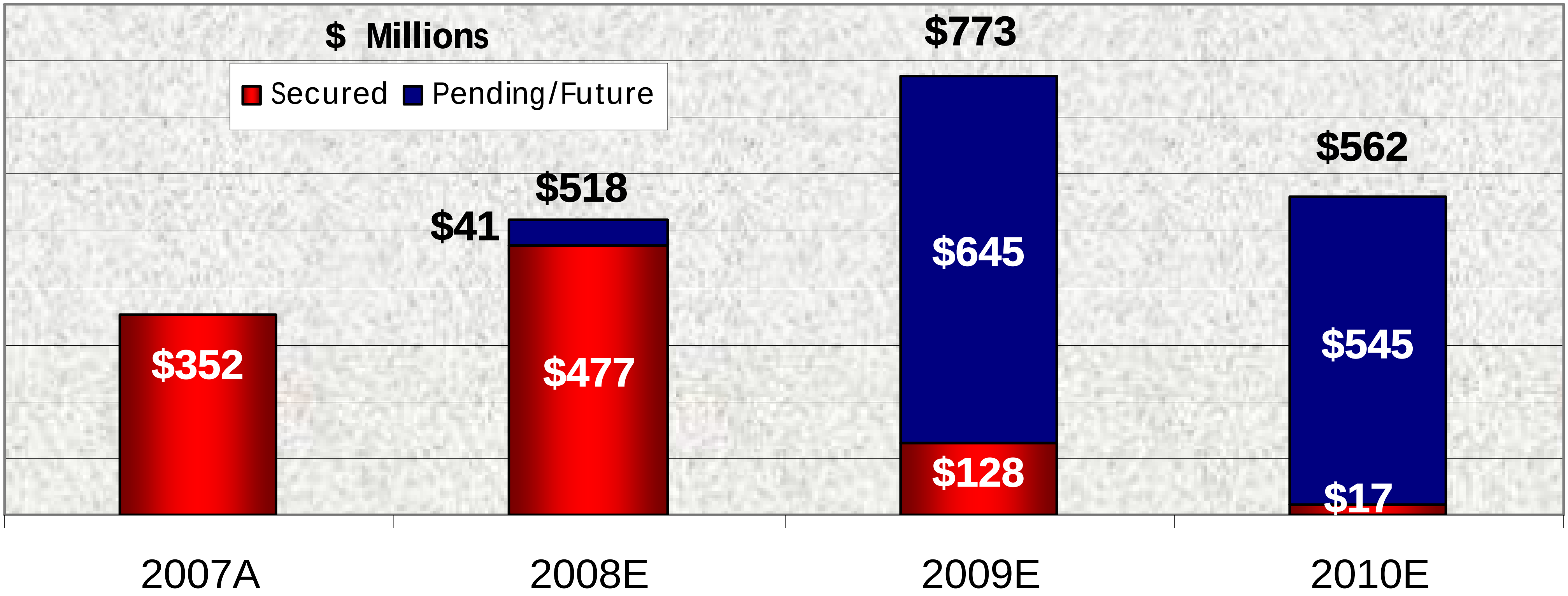
Modified-Combustion Capture

- Oxy-Coal
  - Technology not yet proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - High parasitic demand, >25%

Pre-Combustion Capture

- IGCC with Water-Gas Shift
  - Most of the processes commercially available in other industrial applications
    - Have never been integrated together
  - Turbine modified for H_2-based fuel, which has not yet been proven at commercial scale
  - Creates stream of very high CO_2 concentration
  - Parasitic demand (~20%) for CO_2 capture - lower than amine or oxy-coal

Incremental Rate Relief Assumptions

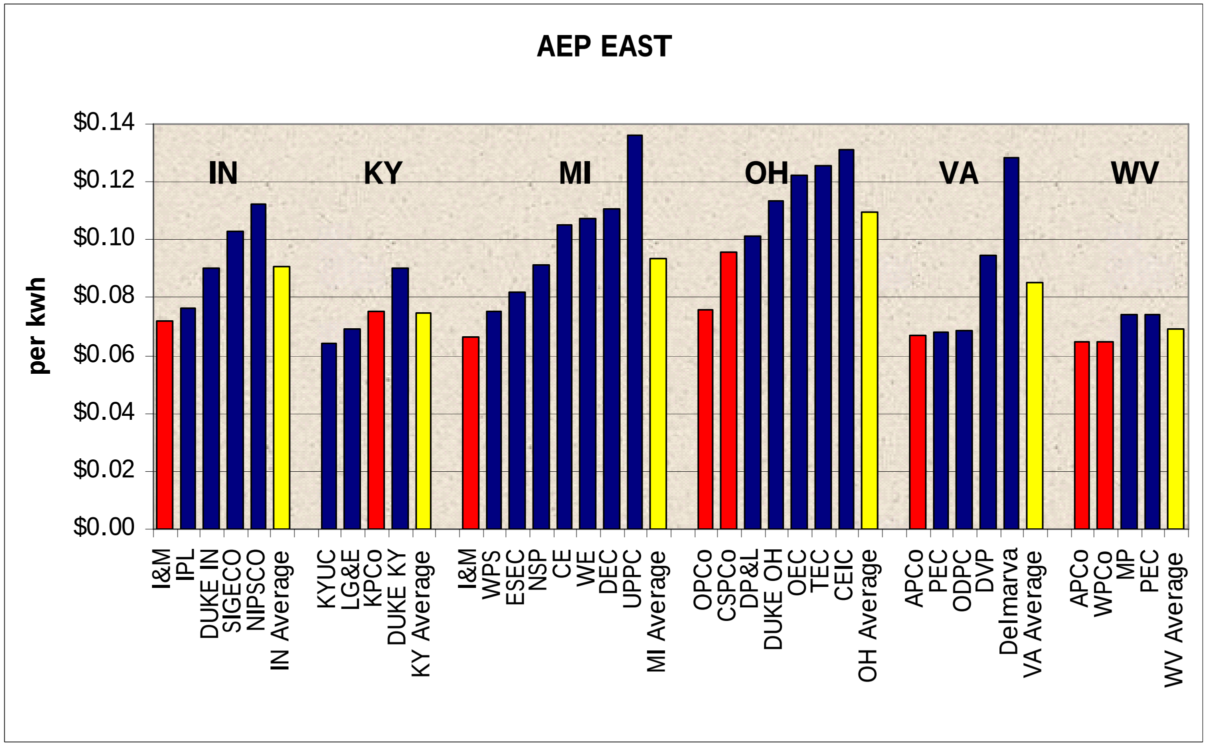


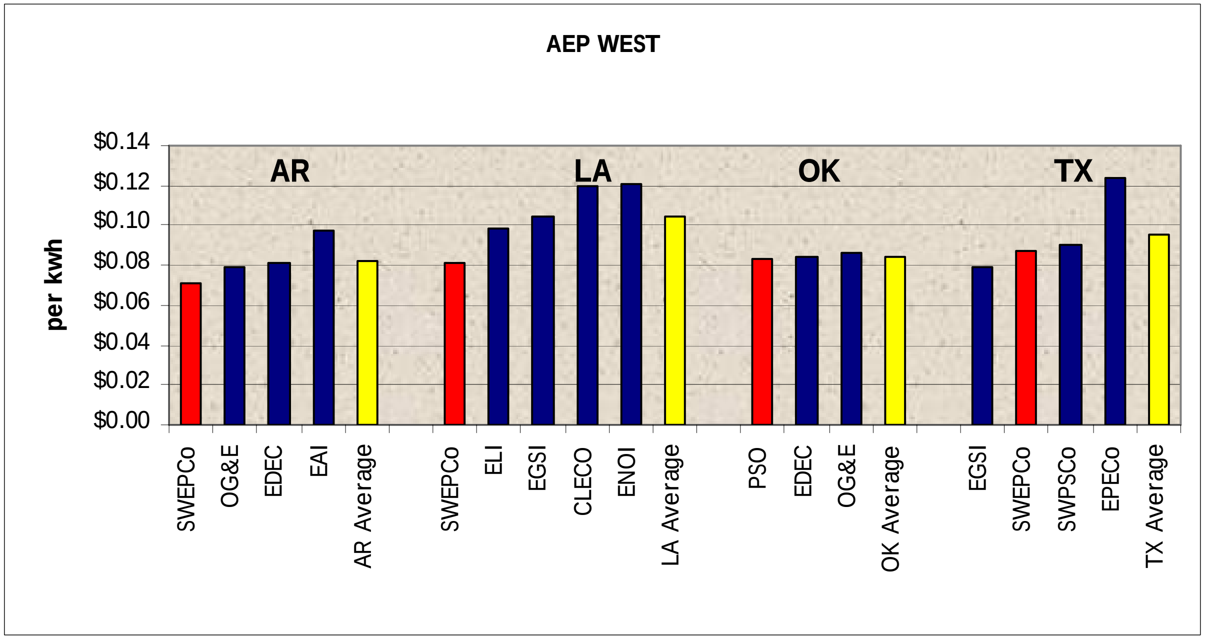
- **92% of 2008 Rate Relief Secured: I&M Depreciation, APCo – WV Surcharge, TCC & TNC General Rate Cases, Ohio RSP (3% & 7%), PSO Peaking Generation & General Rate Case, Ohio 4% Generation Rider and Marginal Loss Recovery, APCo - Virginia Fuel Factor, 2007 TCC/TNC TCRF filings, PSO 2007 Storm Recovery.**

- **2008 Pending: SWEPCo – LA Financial Review, 2008 TCC/TNC TCRF filings, other cases yet to be filed.**

Our goal is to maximize utility company cash flow and returns by minimizing regulatory lag.

AEP Provides Low Cost Electric Service





Residential Average rates for 1,000 kWh - 12 months ended 7/01/2007

Source: Summer 2007 EEI Typical Bills and Average Rates Report

AEP's low cost provider status in most of its jurisdictions will allow AEP's pricing to remain competitive following anticipated rate increases

- AEP Company
- Other Company within state
- State Average

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 9377 of 9556

2008 Regulatory Activity Completed

- AEP-Ohio Application for 4% Provision on Generation Rate
- APCo (Virginia) Fuel Factor Filing (including 75%/25% Off-System Sales Sharing)
- PSO Storm Cost Recovery Filing
- New Generation:
    - IGCC Filing in West Virginia - Certificate of Public Convenience and Necessity and approval of a cost recovery mechanism
    - SWEPCo Turk Plant Filing in Louisiana – construction approval

Regulatory Activity Underway

- I&M - Indiana Base Rate Case
- PSO Red Rock Generating Facility Cost Recovery Filing
- SPP OATT Formula Rate Filing
- New Generation:
  - IGCC Filing in Virginia - approval of a cost recovery mechanism
  - IGCC Phase 2 Filings in Ohio - on hold pending resolution of Supreme Court remand to PUCO
  - SWEPCo Turk Plant Filing in Texas
  - SWEPCo Stall Plant Filings in Louisiana and Arkansas

Summary Rate Case Information

I&M Indiana General Rate Case

On January 31, 2008, I&M filed a general base rate case with the Indiana Utility Regulatory Commission (IURC) requesting an increase of $128.5 million ($82.4 million in base revenues and $46.1 million in tracker mechanisms). (Docket #: 43306).

Projected Capital Structure - Company Position (9/30/07)

	% of Capitalization	Cost Rate	Weighted Cost
Long-Term Debt	43.53%	5.98%	2.60%
Preferred Stock	0.27%	11.19%	0.03%
Common Equity	45.80%	11.50%	5.27%
Other Items	10.40%	various	0.20%
Total	100%		8.10%

Procedural Schedule

January 31, 2008	Case filed
May 5, 2008	Hearing presenting I&M Case-In-Chief
August 1, 2008	Public & Intervenors' filing of Cases-In-Chief
August 15, 2008	Settlement Hearing
September 15, 2008	Filing of rebuttal by I&M
October 21, 2008	Hearing presenting public and intervenors' Cases-In-Chief and I&M rebuttal

Required Rate Relief - Company Position (9/30/07)
($ in millions)

Rate Base	$	2,007.1 *
Rate of Return		8.10%
Operating Income Requirement	$	162.6
Pro-Forma Operating Income	$	112.3
Difference	$	50.2
Revenue Conversion Factor		1.64
Revenue Deficiency	$	82.4
Reliability Enhancement Tracker	$	28.9
DSM / EE Tracker	$	3.8
Off-System Sales Margins Tracker	$	(48.0)
PJM Tracker	$	45.1
Environmental Compliance Tracker	$	16.3
Total Required Rate Relief	$	128.5

* - rate base as of September 30, 2007, updated for value of plant additions to the hearing date of May 5, 2008

Regulatory Activity Underway

PSO Red Rock Generating Facility Recovery Filing

- On December 28, 2007, PSO filed an application with the Oklahoma Corporation Commission to defer, amortize and recover costs related to the Red Rock Generating Facility, which was denied construction and recovery pre-approval in October 2007.
- On March 13, 2008, PSO signed a settlement agreement with various parties regarding recovery of costs incurred in the Red Rock project. The agreement provides for recovery from customers of 50% of the costs ($10.5MM). The settlement agreement has not yet been approved by the OCC.

Regulatory Activity Underway

SPP OATT Formula Rate Filing

- On June 22, 2007, PSO and SWEPCo filed revised tariff sheets for the AEP pricing zone of the SPP OATT.
- The revised tariff sheets seek to establish an up-to-date revenue requirement for transmission services over the PSO and SWEPCo facilitates and implement a transmission cost of service formula rate.
- The new rate is a formula rate that will be used to update the revenue requirements each May, with new rates effective each July 1.
- The current revenue requirement is $88.7MM and the new revenue requirement requested is $140MM. Approximately $10MM of the increase relates to 3rd party and the rest, if approved, would be recovered through retail jurisdictional filings in SWEPCo and PSO, as appropriate.
- We requested an effective date of September 1, 2007 for the revised tariff, which the FERC suspended for an additional five months, which extended the effective date to February 1, 2008, with rates subject to refund.
- Settlement discussions are currently on-going.

Regulatory Activity Underway

APCo Mountaineer IGCC Filing

Virginia

- Testimony filed with the Virginia State Corporation Commission on July 16, 2007 seeking a prudence determination and approval to recover, beginning in 2009, Virginia's share of the carrying costs associated with the proposed plant.
- We received an order on April 14, 2008, denying our request. We will petition for rehearing.

West Virginia

- Air permit anticipated in the third or fourth quarter of 2008.

AEP Ohio Great Bend IGCC Filing

- Phase I – In April 2006, the PUCO authorized cost recovery of initial costs such as site engineering and various other engineering services totaling approximately $24 million. All costs were recovered as of June 30, 2007.
- Phase II – Seeks recovery of carrying costs associated with plant construction. Filing of detailed cost estimates to support the PUCO's further consideration of this request is currently on hold pending resolution of the Ohio Supreme Court challenge of the PUCO's authority in this matter.
- An informational filing was made to the PUCO on June 18, 2007, informing it of APCo's filing and stating that the Ohio companies intend to make their Phase II cost recovery filing upon a favorable Supreme Court of Ohio opinion.
- In March 2008, the Ohio Supreme Court remanded the original order back to the PUCO, giving the PUCO the opportunity to supplement the record. No refund of Phase I costs was mandated by the Supreme Court in its decision.
- We now await further clarity from the PUCO on the remanded issues as well as the outcome of current legislative discussions in Ohio regarding the post-2008 landscape for generation in Ohio.

Regulatory Activity Underway

SWEPCo Turk Plant Filings

Arkansas

- On December 8, 2006, SWEPCo filed with the Arkansas Public Service Commission an Application for a Certificate of Environmental Compatibility and Public Need for the construction of a coal-fired baseload generating facility in Hempstead County, Arkansas.
- The PSC issued its order on November 21, 2007, approving construction of the plant.
- Air permit anticipated in the third or fourth quarter of 2008.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The peaking facility has been addressed and the intermediate facility is under review. The remaining baseload facility issue relates to the Turk Plant proposed for Hempstead County, Arkansas.
- The LPSC issued its order on March 19, 2008, approving construction of the plant.

Texas

- On February 20, 2007, SWEPCo filed with the Public Utility Commission of Texas a petition seeking Certificate of Convenience and Necessity authorization for a coal-fired power plant to be located in southwest Arkansas.
- Public hearings commenced October 17, 2007. On January 17, 2008, the ALJ recommended the PUCT deny the request. The commissioners have requested another hearing where they can directly cross examine some of the witnesses. The additional hearing is scheduled for May 29-30, 2008.

Regulatory Activity Underway

SWEPCo Stall Plant Filings

Arkansas

- Proceeding is currently suspended pending outcome in Louisiana.

Louisiana

- On August 25, 2006, SWEPCo filed with the Louisiana Public Service Commission an Application to purchase, operate, own and install Peaking, Intermediate and Baseload Generating Facilities. The intermediate facility, known as the Stall Plant and sited in Shreveport, LA, was bifurcated from the original filing and had a procedural schedule established on January 9, 2008.
- Staff and intervenor testimony was completed on February 15, 2008, rebuttal testimony was due February 29, 2008 and hearings were held in April 2008. Staff testimony was favorable.
- Air permit received on March 20, 2008.

Texas

- PUCT order approving plant was issued on March 8, 2007.

Approved Rate Bases and ROEs

Jurisdiction	Rate Base	Approved ROE	Effective Date
APCo - Virginia	$2,022MM	10.00%	10/2/2006
APCo - West Virginia	$1,656MM	10.50%	7/28/2006
KPCo - Kentucky	$858MM	10.50%	3/31/2006
I&M - Indiana	$1,805MM	12.00%	11/19/1993
I&M - Michigan	$268MM	13.00%	4/1/1991
CSPCo - Ohio	$1,558MM	12.46%	5/12/1992
OPCo - Ohio	$2,183MM	12.81%	3/23/1995
PSO - Oklahoma	$1,120MM	10.00%	10/9/2007
SWEPCo - Louisiana	$434MM	11.10%	12/29/1999
SWEPCo - Arkansas	$408MM	10.75%	9/23/1999
SWEPCo - Texas	$474MM	15.70%	2/15/1983
TCC - Texas	$1,566MM	9.96%	6/1/2007
TNC - Texas	$530MM	9.96%	6/1/2007

Detailed Ongoing Earnings Guidance

2007A: $3.00

2008E: $3.10 - $3.30

American Electric Power
2007 Actual vs 2008 Guidance

		Performance Driver	2007 Actual ($ millions)	Performance Driver	2008 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	72,535 GWh @ $ 29.7 /MWhr =	2,154	74,434 GWh @ $ 31.3 /MWhr =	2,332
2	Ohio Companies	51,040 GWh @ $ 47.2 /MWhr =	2,410	51,816 GWh @ $ 48.3 /MWhr =	2,503
3	West Regulated Integrated Utilities	41,904 GWh @ $ 23.7 /MWhr =	994	42,046 GWh @ $ 26.2 /MWhr =	1,102
4	Texas Wires	26,682 GWh @ $ 19.8 /MWhr =	529	27,134 GWh @ $ 19.8 /MWhr =	537
5	Off-System Sales	30,895 GWh @ $ 29.1 /MWhr =	898	35,907 GWh @ $ 22.5 /MWhr =	807
6	Transmission Revenue - 3rd Party		296		346
7	Other Operating Revenue		536		519
8	**Utility Gross Margin**		**7,817**		**8,146**
9	Operations & Maintenance		(3,326)		(3,337)
10	Depreciation & Amortization		(1,483)		(1,451)
11	Taxes Other than Income Taxes		(748)		(779)
12	Interest Exp & Preferred Dividend		(790)		(839)
13	Other Income & Deductions		124		128
14	Income Taxes		(508)		(602)
15	**Utility Operations On-Going Earnings**		**1,086**		**1,266**
16	**Transmission Operations On-Going Earnings**		**0**		**2**
	NON-UTILITY OPERATIONS:				
17	MEMCO		61		57
18	Generation & Marketing		37		20
19	**Non Utility On-Going Earnings**		**98**		**77**
20	**Parent Company & Other On-Going Earnings**		**15**		**(61)**
21	**ON-GOING EARNINGS**		**1,199**		**1,284**

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

Multi-Year Capital Investment Funding Plan

$ in millions

	Actual	Projection		
	2007	**2008**	**2009**	**2010**
Planned Capital Investment (Excluding AFUDC) *	$ (3,914)	$ (3,830)	$ (3,750)	$ (3,600)
Planned Transmission Initiatives	$ -	$ (75)	$ (57)	$ (194)
Dividend on Common Stock	(630)	(659)	(664)	(669)
Cash Sources				
Cash from Operations	2,388	2,572	2,691	3,324
Proceeds from Sale of Assets	222	-	-	-
Common Stock Issued (Dividend Reinvestment Plan)	143	150	150	150
Change in Debt, Net	1,902	1,796	2,119	1,180
Other	(234)	(6)	(458)	(247)
Change in Cash	(123)	(52)	31	(56)
Ending Cash Balance	$ 178	$ 126	$ 157	$ 101

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on the earnings presentation.

* - 2007 actual amount includes distressed generation purchases of $512 million

Capital investment is funded from cash from operations and debt issuances.

Commitment to Credit Quality

- Maintain adequate liquidity
- $150MM annually in new equity from Dividend Reinvestment and 401(k) plans
- Target 60% maximum consolidated AEP debt/cap ratio on an adjusted basis
- Target utility company capitalization structures:

Company	Target Equity Ratio
APCo	42-44%
CSP	45-47%
I&M	40-42%
KPCo	41-43%
OPCo	44-46%
PSO	43-45%
SWEPCo	43-45%
TCC	40%
TNC	40%

- Target long term dividend payout ratio range of 55-60%
- Maintain adequate coverage ratios to support current credit ratings

We are committed to maintaining our current credit ratings.

Sustainable Business Model

- *Strength and scale in assets & operations*
- *Continued innovation and deployment of leading technology advancements*
- *Sustainable earnings growth through near and long term capital investment opportunities*
- *Comprehensive regulatory strategy focused on maximization of cash flow and return through minimized regulatory lag*
- *Strong dividend yield with respect to peers*
- *Balance sheet and credit profile stability*

AMERICAN ELECTRIC POWER, INC.

Wall Street Analyst Forum – August 16, 2007

ENERGY – EXPERIENCE - HISTORY

AMERICAN ELECTRIC

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements, which are subject to risks and uncertainties. These factors include electric load and customer growth; weather conditions, including storms; available sources, costs and transportation for fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and performance of generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions; resolution of litigation; our ability to constrain operations and maintenance costs; the economic climate and growth in our service territory and changes in market demand and demographic patterns; inflationary and interest rate trends; our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy related commodities; changes in creditworthiness of participants in the energy trading market; changes in the financial markets; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, the potential for new legislation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements; performance of pension and other postretirement benefit plans; prices for power we generate and sell at wholesale; changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events; and other factors discussed in the reports, including Form 10-K, filed from time to time by the company with the SEC.

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Chairman, President & CEO

Near Term Investor Communication Activities

- September 26, 2007 – Merrill Lynch 2007 Power & Gas Leaders Conference, NYC
- October 4, 2007 – Strategic Direction: Financial Analyst/Investor Conference, NYC
- October 11, 2007 – Dublin Investor Meetings
- October 25, 2007 – 3Q07 Earnings Call

*Note: these activities represent upcoming Mike Morris attended events and are not all encompassing for AEP scheduled/attended events.

Agenda

- AEP Footprint/Strategic Direction
- Transmission Opportunities/Advantages
- Transmission Legislation
- Investment Strategies
- Ongoing Transmission Initiatives & Updates
  - PJM I765 TM
  - Michigan
  - Southwestern Power Pool
  - Electric Transmission Texas LLC

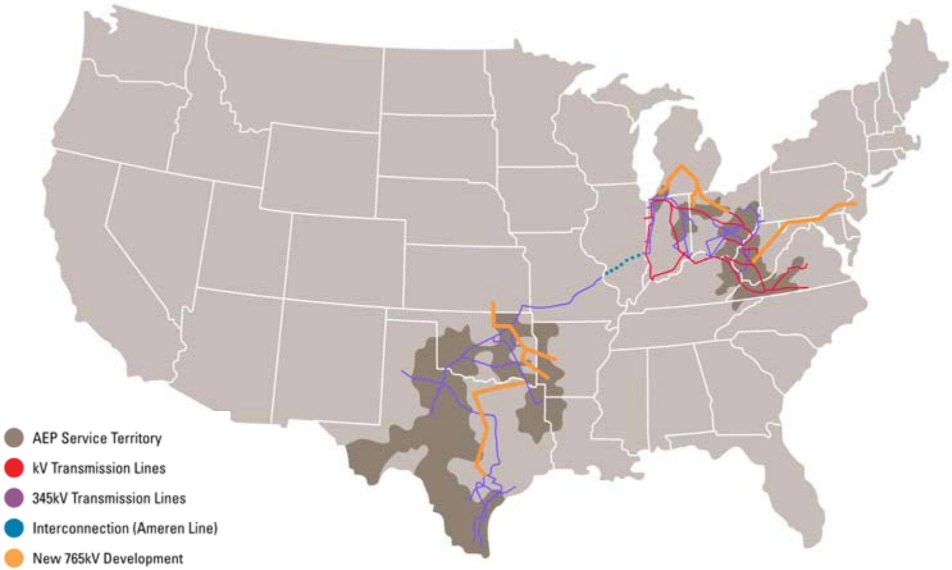
The AEP Footprint

Strength & Scale in Assets & Operations

- 5.1 million customers in 11 states
- Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~38,400 MW	#2
Transmission	~39,000 miles	#1
Distribution	~208,000 miles	#1

- Coal & transportation assets:
  - Control over 8,000 railcars
  - Own/lease and operate over 2,600 barges & 51 towboats
  - Coal handling terminal with 20 million tons of capacity



AEP Generation Portfolio				
Coal	Gas	Nuclear	Hydro	Wind
67%	24%	6%	2%	1%

AEP enjoys significant presence throughout the energy value chain

AEP Strategic Direction

Delivering Value to Investors and Cost Effective Service to our Customers

- Invest in our established utility business
- Achieve continued environmental improvements of existing facilities
- Buy or build additional generation to meet franchise service obligations
- Upgrade our energy delivery infrastructure
- **GROW OUR TRANSMISSION BUSINESS**
- Achieve adequate returns on all assets

Our Core Utility Mission: Bring Reasonably Priced Electric Service To Our Customers, Thereby Strengthening Our Communities And Rewarding Our Investors

Significant Opportunity for Investment

The current U.S. transmission system cannot support the demand of tomorrow's energy supply needs

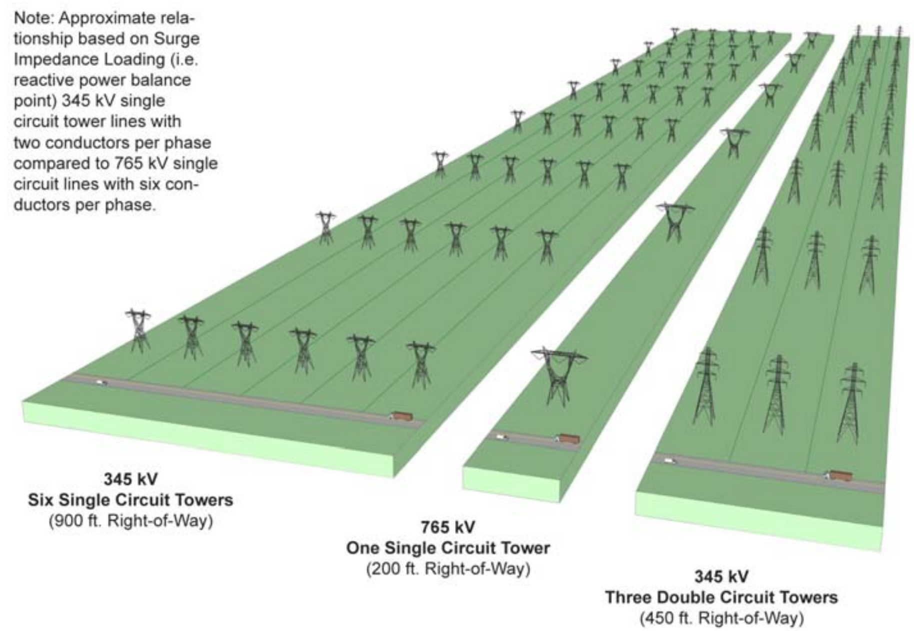
- Investment in transmission has lagged load growth
- Transmission congestion equates to increased costs to customers
- Large-scale wind generation in remote areas requires a high-capacity transmission system for efficient energy movement to load centers

Key Advantages of 765-kV

Advanced Technology

- Advanced six-conductor bundles for higher capacity, lower line losses and reduced noise
- Fiber-optic shield wires for better protection and control
- Wide-area monitoring, control, and remote diagnostics
- Independent-phase operation for improved line performance
- Line design and right-of-way usage for least environmental impact

Environmental Stewardship



765-kV maximizes land use thus providing more capacity in less right of way

Key Legislation Supporting Transmission Growth

Federal & State Support

- **Federal Actions (FERC Order 679):**
  - Return on equity at the high end of the zone of reasonableness
  - Return on CWIP
  - Return on premium for acquired assets
  - Full recovery of construction costs and costs of cancelled or abandoned facilities due to factors beyond the Utility's control
- **State Actions:**
  - Regional planning-supporting role in RTO area
  - Siting-first course of action
  - Wholesale transmission pricing-provides regional benefits
  - Retail cost recovery

AEP supports a national interstate grid - our core transmission strength

AEP Transmission Key Investment Strategies

AEP is well positioned to be a key player in the development of tomorrow's interstate transmission system

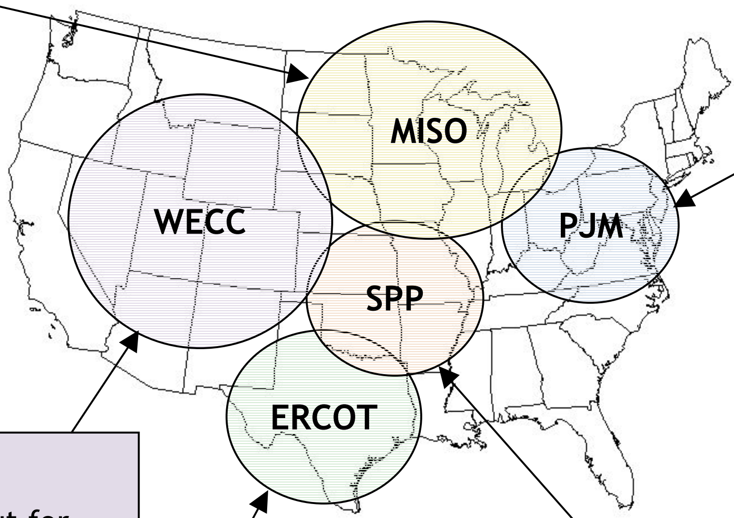
- Leverage our extra-high voltage (EHV) expertise and existing infrastructure
- Maximize optionality for shareholders
- Advocate regulation for interstate transmission
- Collaborate with qualified partners
- Continue our present top-tier performance in safety, health, operations, reliability

Transmission Investment Opportunities

Investigation of opportunities needs to be mindful of regional drivers

MISO

ITC 765-kV project may be test case for cross-border cost recovery and seams issues



PJM

Congestion will be reduced and reliability will be increased

WESTERN STATES

Opportunity for 765-kV build-out for long-haul transportation from remote resources to load

ERCOT

Load growth and access to wind resources driving transmission investment

SPP

Regional rate design under development to encourage investment and accommodate new generation sources

Transmission ~ $9-$15 Billion Opportunity

Creating a business model to manage capital requirements for enhanced returns with partners

Potential Opportunities

~ $3 Billion I765™ Project in PJM
~ $2 Billion 765-kV study in Michigan w/ ITC
~ $3 Billion Project filed with SPP
~ $1-7 Billion in ERCOT via Electric Transmission Texas, LLC (ETT)

1) ~$9-$15 billion investment opportunity not included in current capital guidance forecasts

2) Ultimate earnings contribution dependent on ownership structure, capitalization, ROE and timing of project completion.

Assumptions

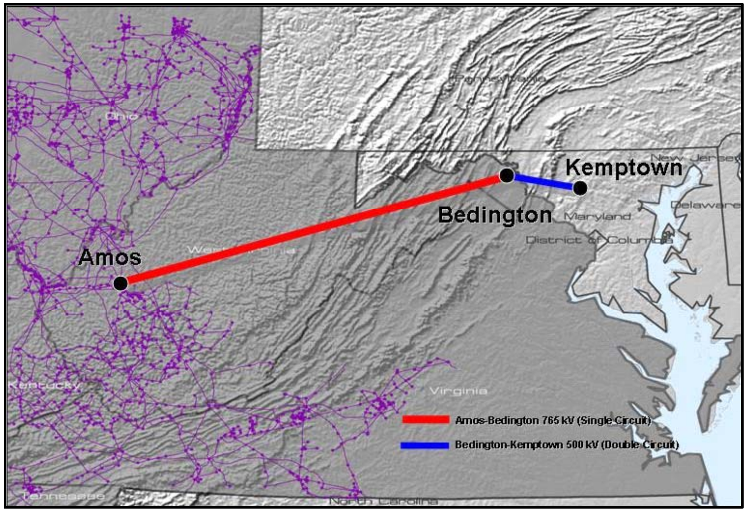
Estimated Investment Opportunity	$9 - $15 Billion
Ownership Structure w/ Partner	50% / 50%
Debt / Equity Ratio	50% debt / 50% equity
Return on Equity	11.00% - 13.00%
Potential EPS Impact (based on 396 MM shares)	$1.00+

Building the next US interstate system for enhanced reliability and market efficiency

PJM I-765$_{TM}$

Execution in Action

- **_Overview_**
  - $3 billion investment (before ownership division)
  - 550 line miles
  - 5000MW improved transfer capability
  - To be completed in 2 phases (1st phase PJM approved)

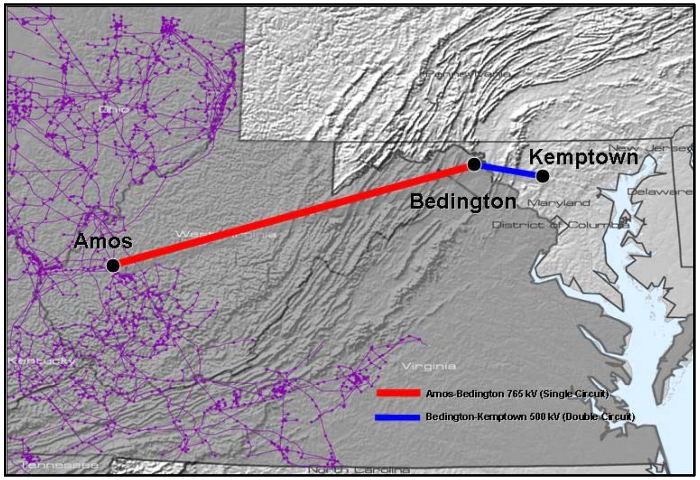


- **_Benefits_**
  - Improves eastern grid reliability
  - Improves market efficiency with reduced congestion
  - Reduces consumer cost $1B (est.) annually in the east
  - Reduces network line losses by 280 MW at peak
  - Provides AEP rate base opportunity for transmission investment with ROE upside & other FERC incentives
  - Provides off-system sales and siting opportunity for AEP and other low-cost mid-western generation
- **_Phase I Progress to Date_**
  - AEP and Allegheny entered into a MOU to construct the 290 mile West Virginia-Maryland line
  - Total estimated cost of $1.8 billion
  - AEP portion approximately $600 million
  - Expected completion 2012

PJM I-765$_{TM}$ Phase I cont'd

Execution in Action

- **_Funding Plans/Transaction Structure_**
  - Forming a joint venture with Allegheny Energy for 250 miles of the proposed 550 mile project
  - JV portion of the I-765$_{TM}$ Interstate Project approved by PJM in its Regional Transmission Expansion Plan in June 2007
  - Equity – 50% AEP / 50% Allegheny
  - AEP's 50% investment will be held at the AEP Transmission Holding Company LLC subsidiary
  - Operations to commence in the second half of 2007
  - I-765$_{TM}$ Interstate Project included in the DOE's draft National Interest Electric Transmission Corridor issued in April 2007



- **_Key Regulatory Activity Completed_**
  - FERC declaratory order approved July 2006
  - PJM approved plan June 2007

- **_Key Next Steps_**
  - Complete JV negotiations – Fall 2007
  - Complete FERC Filing – Fall 2007
    - *Pursuing new project FERC incentives: cash return on CWIP, higher ROE, recovery of pre-commercial operation costs and recovery of abandonment costs.*
  - Siting Approved – Fall 2009
  - Completion – Fall 2012

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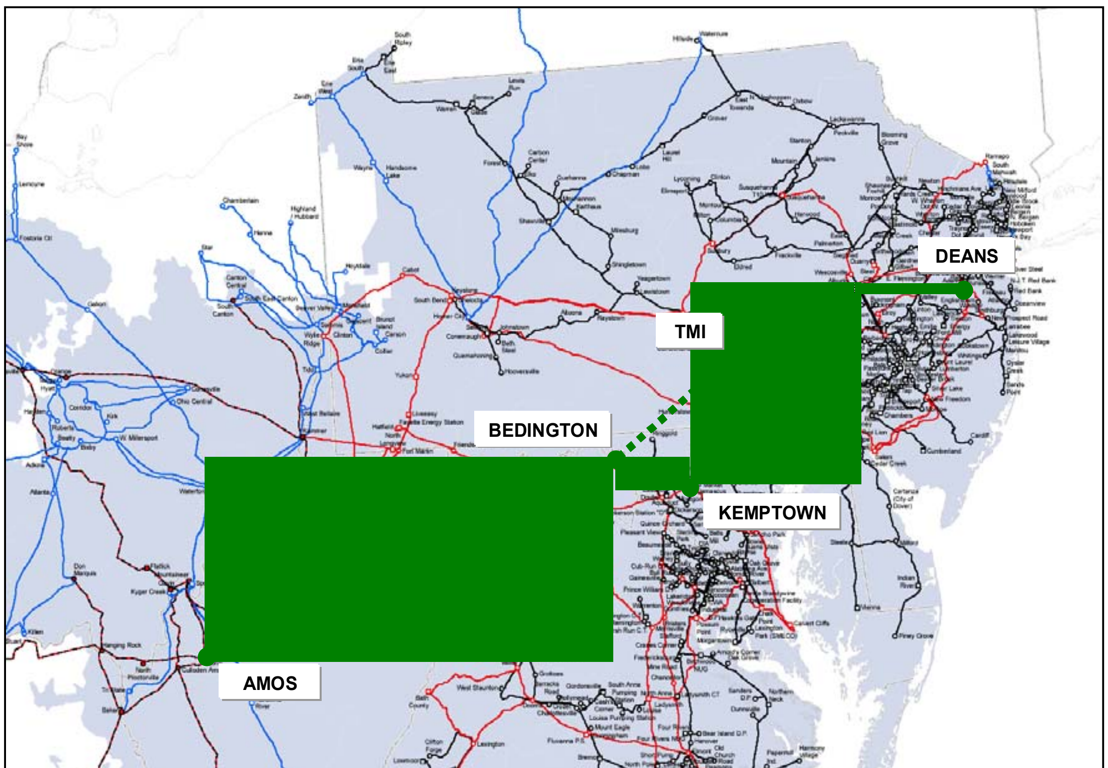
PJM I-765™ Phase II (Bedington-Deans)

Second phase of original AEP 550-mile I-765 proposal

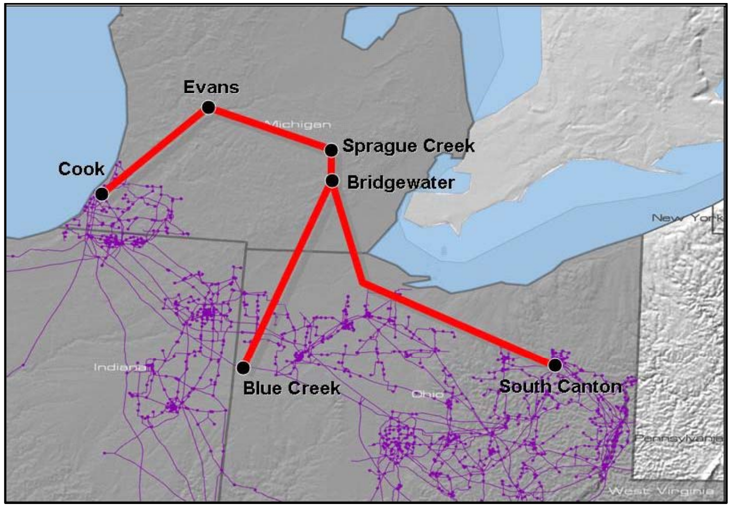
- Approximately 250 miles from West Virginia-Maryland border to Public Service Electric & Gas Deans Station in New Jersey.
- Currently under consideration by PJM as part of Regional Transmission Expansion Plan (RTEP).
- Based on PJM RTEP approval, AEP will seek a suitable business partner (JV partner) to complete the second leg of the original proposal.



765-kV in Michigan

Supporting Michigan's 21st Century Energy Plan to address severe capacity constraints

- ***Overview***
  - Agreement with ITC Transmission for 765-kV study
  - 700 miles of 765-kV line in Ohio and Michigan
  - $2.0 billion investment (before ownership division)



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

- ***Benefits***
  - 3,000 MW improved transfer capability
  - Reduces network line losses by 250 MW

- ***Next Steps***
  - PJM/MISO filing – Summer 2007
  - Release of study results – Fall 2007
  - JV formation – Fall 2007
  - PJM.MISO approval - Summer 2008
  - FERC Filing - Fall 2008
  - Siting approval – Summer 2010
  - Estimated completion – Summer 2013

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765-kV in SPP

Significant opportunity for 765-kV transmission in SPP

Overview

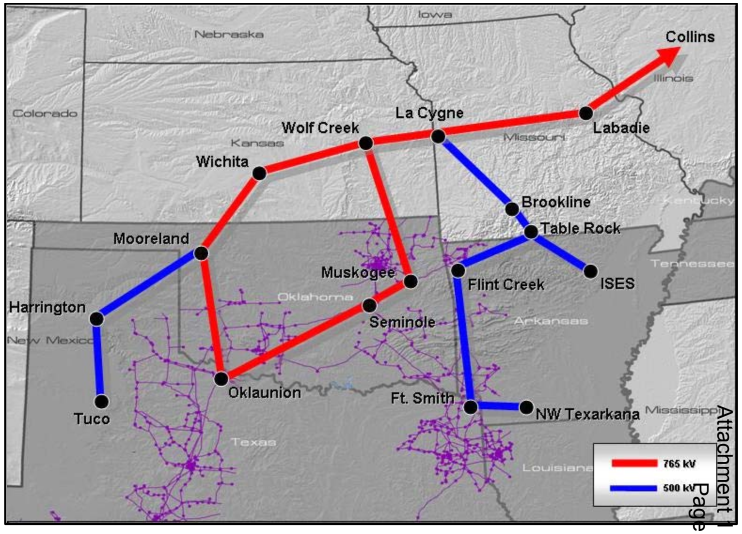
- July 2006 AEP submitted conceptual project for six 765-kV lines
- Proposed 765-kV Kansas / Oklahoma / Arkansas connecting to MISO/PJM
- 610 miles from Kansas to Arkansas
- $3.0 billion investment (before ownership division)
- Proposed 2012-2017 construction period
- SPP proposes 765-kV in Texas / Oklahoma / Kansas / Missouri connecting to MISO/PJM
- SPP also proposes 500-kV in Texas / Oklahoma / Arkansas / Missouri

Benefits

- 4,000 MVA capability

Next Steps

- Study disclosure – Fall 2007
- JV formation (Partner-TBD) – Fall 2007
- SPP RTO/BOD EHV Overlay approval – Summer 2009
- SPP RTO FERC Filing – Fall 2009
- Siting approval – Fall 2011
- Estimated completion – Summer 2017



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AMERICAN ELECTRIC POWER: ENERGY – EXPERIENCE - HISTORY

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ETT Status Update

ETT: Delivering Power for Texas' Future

- ***Transaction Structure***
  - 50/50 joint venture between AEP Utilities, Inc. and MEHC Texas Transco, LLC.
  - ETT capital structure is 60% debt / 40% equity (PUCT requirement).
  - Executive manager provided by AEP; business manager provided by MidAmerican.
  - Investment opportunities can be offered by either partner and accepted or rejected by ETT.

- ***Transaction Status***
  - Formation documents finalized and Participation Agreement signed Jan. 9, 2007.
  - Texas regulatory filing on Jan. 22, 2007.
    - Requested utility status, transfer of initial assets, establishment of TCOS transmission recovery mechanism.
    - Hearings conducted July 16-17, 2007, commission order expected in September 2007.
  - FERC approval for asset transfer received April 20, 2007.
  - Closing deadline of Nov. 1, 2007 can be extended by mutual agreement.

Benefits & Attraction of Texas Transco JV

JV Benefits	ERCOT Attraction

- Opportunity to grow ERCOT interest in a timely, resource-efficient manner
- Maximization of asset value
- Formation of strategic relationship that could permit growth beyond current footprint

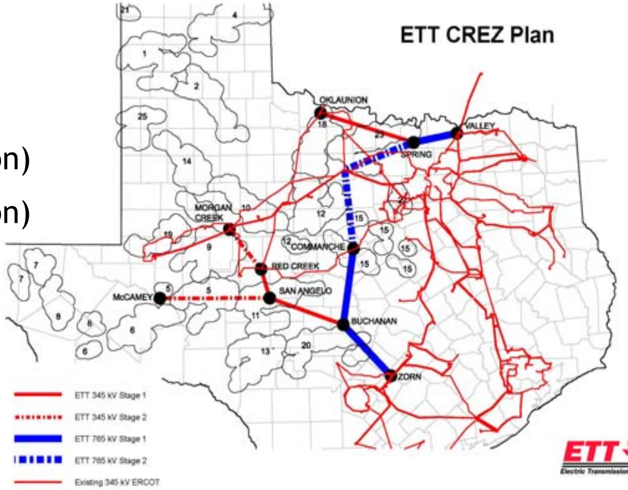
- Growing electric demand
- State's commitment to:
  - Wind generation
  - Promotion of merchant generation
  - Relief of congestion
  - Facilitation of transmission planning in support of the Texas competitive market

AEP is uniquely positioned to develop substantial transmission to capture the benefits of load growth

CREZ & Backbone Opportunities

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

- **ETT CREZ Overview**
  - Strengthen ERCOT grid to collect and deliver wind generation to load
  - Build transmission in the most cost effective manner, addressing:
    - Future generation development
    - Load growth pockets
    - Market efficiency (reduce congestion)
    - Competitive wholesale markets
    - Economic growth
  - $1.5 billion investment Phase 1 – 2012 (before ownership division)
  - $1.5 billion investment Phase 2 – 2015 (before ownership division)



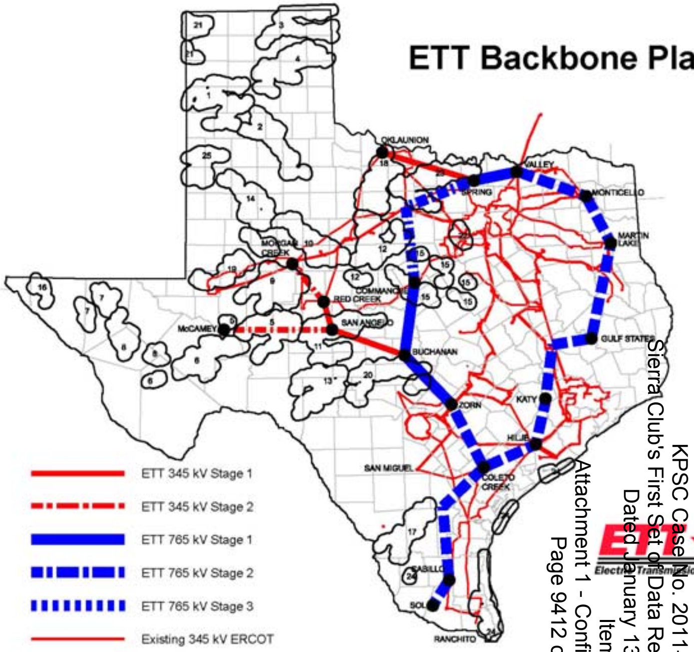
- **CREZ Approval Stages as outlined by the PUCT**
  - Stage 1 – Final order designating power regions – August 2007
  - Stage 2 – CREZ Transmission Optimization Study – January 2008
  - Stage 3 – PUCT selection of transmission construction designees – February 2008
  - Stage 4 – CCN development and submission – February 2009
  - Stage 5 – CCN approval – August 2009
  - Stage 6 – Construction (TBD)

CREZ & Backbone Opportunities - cont'd

Harnessing the Wind: Competitive Renewable Energy Zones offer unique opportunities to showcase ETT

ETT ERCOT Backbone Proposal

- ETT proposal for ERCOT and PUCT to consider CREZ transmission in context of long-term vision for transmission system.
- Current 5-year planning horizon results in higher ultimate costs, lower system efficiency.
- Long-term 15-20 year perspective provides better plan, supports development of high voltage backbone at 765-kV.
- $4.2 billion investment (long-term backbone).



Summary

The AEP Advantage: Proven Experience

- **AEP will continue to:**
  - Support the development of a federally regulated (FERC) high voltage, interstate transmission grid, which will:
    - Improve reliability and efficiency of interstate transmission
    - Enhance market competition, and optimal economic dispatch
    - Reduce the need for additional generation across an expanded market area.
  - Work with partners to accelerate development opportunities and provide shareholder value.
  - Engage regulators to ensure rapid deployment of appropriate technological solutions and associated cost recovery.

Questions

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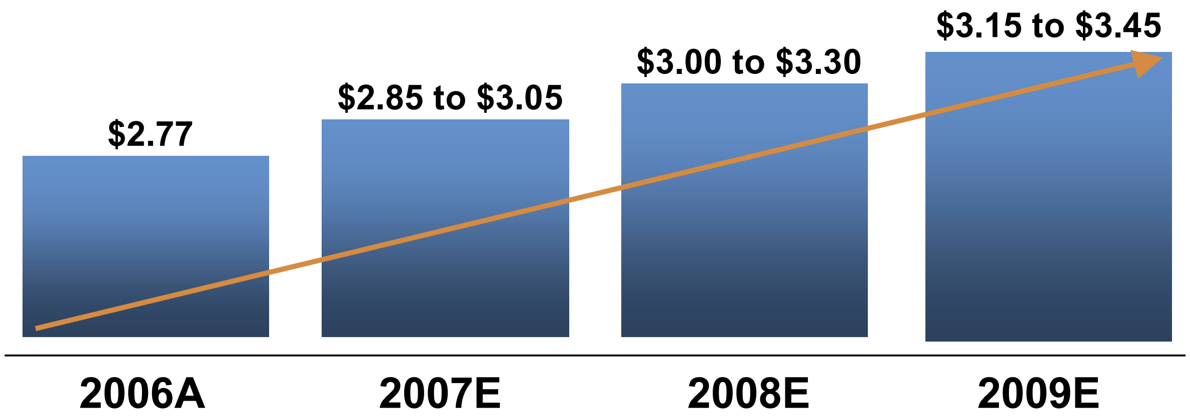
Appendix

Long Range Performance - Consistent and Predictable Growth

2007, 2008 & 2009 Ongoing Earnings Guidance Ranges: 5-7% Annual Growth



- Continued disciplined investment in existing utility operations:
  - Reliability
  - Environmental
  - New Generation & Distribution Infrastructure
- Investment in new transmission opportunities
- New investment coupled with rate recovery
- Continued cost control
- Timely Rate Relief
- Maintain Credit Ratings
  - BBB/Baa2/BBB

Future Earnings Growth Driven by Native Load Growth and Substantial Utility Investment Opportunity Focused On Regulated Operations

Summary of 5-7% Long-Range Growth Components

Energy sales growth of 1.5%

Rate base investment

- Generation plant purchases & build
- Transmission – interstate & intrastate
- Distribution
- Reliability

Transmission company

Commercial operations

Regulatory strategy

- Achieve timely returns
- Seek cash returns on investment during construction
- Create & secure innovative rate plans
  - Pursue post-2008 solution in Ohio
  - Expand use of trackers
  - Formula rates

New Generation and Transmission Projects Largely Reflect Upside to the Long-Range Earnings Growth Targets of 5-7%

Utility Investment Drives Growth

Capital Investment Forecast (2007-2009)

($ in millions)	2007	2008	2009	Total (2007-09)
Environmental	$935	$521	$301	**$1,757**
New Generation - Purchase	$118	$0	$0	**$528** *
New Generation - Build	$474	$485	$573	**$1,532**
Nuclear	$50	$57	$60	**$167**
Generation	$456	$417	$327	**$1,200**
Transmission	$496	$521	$583	**$1,600**
Distribution	$848	$915	$1,016	**$2,779**
Corporate	$165	$110	$114	**$389**
Total Capex	**$3,542**	**$3,026**	**$2,974**	**$9,952**

Add: Lawrenceburg Plant Purchase	$325
Add: Dresden Plant Purchase	$85
2007 Including Lawrenceburg & Dresden	**$3,952**

Note: Excludes AFUDC and recently announced CO_2 and transmission projects

* Includes Lawrenceburg purchase of $325MM and Dresden purchase of $85MMin 2007

Growth investment to be funded by cash from operations via rate relief and debt issuances

AMERICAN ELECTRIC POWER: ENERGY - EXPERIENCE - HISTORY

Environmental Investment

Plant Name	MW Capacity	SCR	Status	FGD	Status
East Plants					
Amos 1	800	✓	In-service	✓	Projected 2009
Amos 2	800	✓	In-service	✓	Projected 2010
Amos 3	1300	✓	In-service	✓	Projected 2009
Big Sandy 2	800	✓	In-service	☐	Delayed
Cardinal 1	600	✓	In-service	✓	Projected 2008
Conesville 5 & 6	750		N/A	✓	Unit 5 Upgrade In-service
Gavin 1 & 2	2620	✓	In-service	✓	In-service
Mitchell 1&2	1600	✓	In-service	✓	In-service
Mountaineer	1320	✓	In-service	✓	In-service
Muskingum River 5	585	✓	In-service	☐	Delayed
CCD Plants					
Conesville 4	339	✓	Projected 2009	✓	Projected 2009
Stuart 1-4	620	✓	In-service	✓	Projected 2009
Zimmer	330	✓	In-service	✓	In-service
West Plants					
Dolet Hills	262		N/A	✓	In-service
Oklaunion	485		N/A	✓	In-service
Pirkey	580		N/A	✓	Upgrade In-service

At the conclusion of our current environmental retrofit program, over 47% of our coal-fired generation fleet will be equipped with SCRs and over 50% will be scrubbed (FGD). AEP's total coal fleet capacity = 24,710 megawatts*

*Excludes AEP's 44% ownership in OVEC (980 MWs of coal-fired capacity)

Purchased Generation

Waterford

821 MW combined-cycle gas plant
- $220MM purchase price
- Columbus Southern Power completed purchase on Sept. 28, 2005
- $268/kW

Ceredo

505 MW simple-cycle gas plant
- $100MM purchase price
- APCo completed purchase on Dec. 15, 2005
- $198/kW

2,946 MW of gas-fired generation added since 2005

Darby

- 480 MW simple-cycle gas plant
- $102MM purchase price
- Columbus Southern Power completed purchase on April 25, 2007
- $227/kW

Lawrenceburg

- 1140 MW combined-cycle gas plant
- $325MM purchase price
- AEG completed purchase on May 16, 2007
- $295/kW

Additional gas-fired generation allows us to meet the growing needs of our customers and provides the company with greater fuel flexibility

New Generation Facilities

Operating Company	Project Name	State	Projected Cost	Fuel Type	Plant Type	MW Capacity	Commercial Operation Dat (Projected)
SWEPCo	Mattison	Arkansas	$130 MM	Gas	Simple-cycle	340 (1)	2007
PSO	Southwestern	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	$57 MM	Gas	Simple-cycle	170	2008
AEG	Dresden	Ohio	$348-406 MM (2)	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	$300 MM	Gas	Combined-cycle	500	2010
SWEPCo	Turk	Arkansas	$1.3 B (3)	Coal	Ultra-supercritical	600 (3)	2011
PSO	Red Rock	Oklahoma	$1.8 B (4)	Coal	Ultra-supercritical	900 (4)	2012
APCo	Mountaineer	West Virginia	$2.23 B	Coal	IGCC	630	2012
CSP/OP	Great Bend	Ohio	Under Review (5)	Coal	IGCC	630	2017

(1) 150MW were declared in commercial operation on July 12, 2007.
(2) We are currently developing contracts and estimates to complete the project. It is anticipated that the unit can be completed between $600 to $700 per kW using an "all-in" cost basis
(3) SWEPCo will own approximately 73%, or 440 megawatts, totaling about $986 million in capital investment.
(4) PSO will own 50%, or 450 megawatts, totaling approximately $900MM in capital investment.
(5) FEED (front-end engineering and design) study with GE/Bechtel is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 10, 2006 Opinion and Order.

AEP is meeting the growing electricity needs of customers through the pursuit of new economic generation facilities

Investing In IGCC

Generation Technology Comparative Statistics

US2006$	Eastern Bituminous		NGCC
	USC	IGCC	
Nominal Capacity (MW)	618	629	530
Capacity Factor (%)	85%	85%	25%
Total Plant Cost (EPC + Owner's Cost) ($/kW)	$2,152	$2,717	$572
Production Cost ($/MWh)	$22	$22	$45
Cost of Electricity, without CO_2 Capture ($/MWh)	$72	$83	$87
Estimated Cost of Electricity, with 90% CO_2 Capture ($/MWh)	$118	$108	$135

Source: Results of AEP analysis based on EPRI studies.

- Total Plant Cost (Overnight EPC 2006$s) includes the cost to engineer, procure and construct plant and owner's direct costs.
- Assumes Northern Appalachian coal price of $2.25/mmBtu for USC and IGCC and natural gas price of $6.00/mmBtu for NGCC.
- Production cost includes fuel cost plus variable operations and maintenance (VOM) cost.
- Cost of electricity represents first year estimates only in 2006$ and are based on total plant cost plus generic cost estimates for AFUDC, emission credits, infrastructure, interconnections, transmission lines and upgrades.
- Cost of electricity with CO_2 capture provides pressurized CO_2 at the fence line and does not include transportation, storage and monitoring costs.

IGCC technology is strategic to keeping coal in the money

AEP's Climate Position

- AEP supports a reasonable approach to carbon controls in the US
- AEP has taken measurable, voluntary actions to reduce its GHG emissions and will support a well-thought out US mandate to achieve additional, economy-wide reductions
- Global warming is a global issue and AEP supports the US taking a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China
- A certain and consistent national policy for reasonable carbon controls should include the following principles:
  - Comprehensiveness
  - Cost-effectiveness
  - Realistic emission control objectives
  - Monitoring, verification and adjustment mechanisms
  - Technology development & deployment
- Regulatory or economic barriers must be addressed
- Recognition provided for early action/investment made for GHG mitigation
- Inclusion of adjustment provision if largest emitters in developing world do not take action

A reliable and reasonably-priced electric supply is necessary to support the economic well-being of the areas we serve

Highlights of Bingaman-Specter Proposal

"Low Carbon Economy Act of 2007"

Key Components:

- Start date for greenhouse-gas reductions is 2012
- Goals: 2006 levels by 2020; 1990 levels by 2030
- Includes a safety valve of $12 per metric ton, increasing at an annual rate of 5% above inflation
- Support for allowance allocations
- International action

AEP endorses this proposal because it sets reasonable and achievable reduction targets and includes the AEP-IBEW trade proposal

AEP's Long-term CO_2 Reduction Commitment

Existing Programs

- Renewables
  - 800 MWs of Wind
  - 300 MWs of Hydro
- Domestic Offsets
  - Forestry – 0.35MM tons/yr @ $500K/year
  - Over 63MM trees planted through 2006
  - 1.2MM tons of carbon sequestered
- International Offsets
  - Forestry projects have resulted in 1MM tons of carbon sequestered through 2006
- Chicago Climate Exchange

New Program Additions

Incremental Reduction quantity: 5MM tons/yr

Timing: To take effect/receive credits by 2011

Methods

- +1000 MWs of Wind PPAs – 2MM tons/yr
- Domestic Offsets (methane) – 2MM tons/yr (e.g., livestoc methane capture deal of 0.6MM tons/yr)
- Forestry – Tripling annual investment to increase to 0.5M tons/yr by 2015
- Fleet Vehicle/Aviation Offsets – 0.2MM tons/yr
- Additional actions to include DSM and end use energy efficiency, biomass and power plant efficiency – 0.2MM tons/yr

New Technology Additions

Commercial solutions for existing fleet

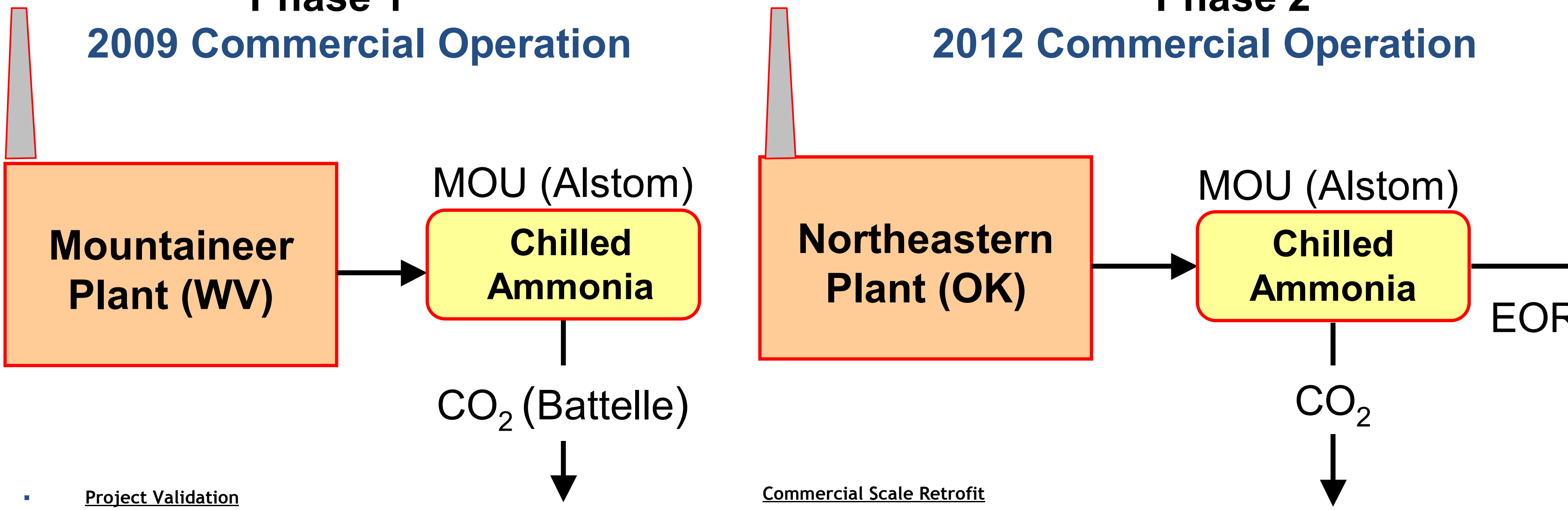
- Chilled Ammonia
- Oxy-Coal

AEP is committed to a 5mm ton/yr reduction in CO2 emissions which offsets approx half of the emissions projected from new generation projects previously announced

Chilled Ammonia Technology Program

Phase 1
2009 Commercial Operation

Phase 2
2012 Commercial Operation



- **Project Validation**
- 20 MW_e (megawatts electric) scale (a scale up of Alstom/EPRI 1.7 MW_e field pilot, under construction at WE Energies)
- 100,000 – 300,000 tonnes CO_2 per year
- In operation 1Q 2009
- Approximate total cost $50 – $80M
- Using Alstom "Chilled Ammonia" Technology
- Located at the AEP Mountaineer Plant in WV
- CO_2 for geologic storage

Commercial Scale Retrofit

- ~ 200 - 300 MW_e scale (megawatt electric)
- ~ 600 MW_t scale (megawatt thermal)
- ~1.5MM tonnes CO_2 per year
- In operation late 2011
- Approx. capital $250 – $300M ($CO_2$ capture & compression)
- Approx. O&M cost $12M per year
- Energy penalty ~ 35 – 50 MW steam, 25 – 30 MW for CO_2 compression
- Retrofit Wet FGD Required: ~$225 – $300M
- Located at AEP's Northeastern Plant Unit 3 or 4 in Oklahoma
- CO_2 for Enhanced Oil Recovery (EOR)

Post-combustion carbon solution provides pure CO2 stream for capture

Oxy-Coal CO_2 Capture & Storage Project

Pilot Scale Demonstration

10 MW_e scale

Teamed with B&W at its Alliance Research Center and 16 other utilities

Demo complete 3Q 2007

AEP funding of $50k

Commercial Scale Retrofit

Retrofit on existing AEP sub-critical unit (several available)

150 – 230 MW_e scale retrofit

4,000 – 5,000 tons CO_2 per day

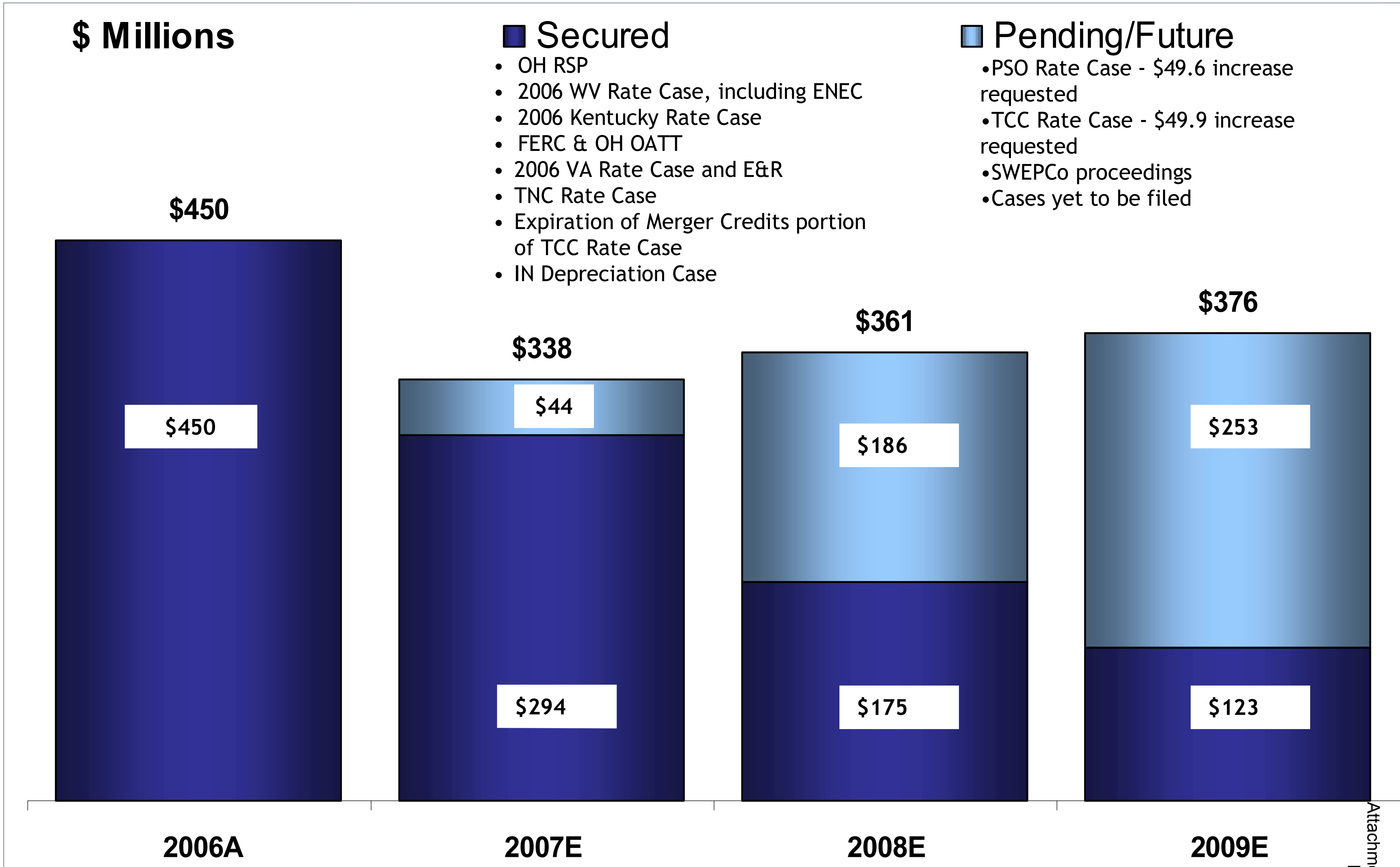
Team with B&W

AEP funding of ~ $1.5M for feasibility study

Feasibility study to be completed in late 2007/early 2008

Combustion conversion technology for existing coal fleet - longer lead time with enhanced viability and long term potential

Incremental Rate Relief Composition



Rate relief is a critical element to AEP's financial success

2007 Ongoing Guidance: $2.85 to $3.05 per share

American Electric Power
Financial Results for 2006 Actual vs. 2007 Estimate

		Performance Driver	2006 Actual ($ millions)	Performance Driver	2007 Estim ($ million
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	69,107 GWh @ $ 30.5 /MWhr =	2,111	73,325 GWh @ $ 33.3 /MWhr =	2,44
2	Ohio Companies	45,880 GWh @ $ 46.0 /MWhr =	2,110	50,452 GWh @ $ 48.2 /MWhr =	2,43
3	West Regulated Integrated Utilities	40,506 GWh @ $ 25.1 /MWhr =	1,018	41,927 GWh @ $ 24.9 /MWhr =	1,04
4	Texas Wires	26,382 GWh @ $ 18.0 /MWhr =	476	26,628 GWh @ $ 19.5 /MWhr =	52
5	Off-System Sales	33,340 GWh @ $ 24.9 /MWhr =	829	30,289 GWh @ $ 20.4 /MWhr =	61
6	Transmission Revenue - 3rd Party		271		27
7	Other Operating Revenue		527		62
8	**Utility Gross Margin**		7,342		7,95
9	Operations & Maintenance		(3,201)		(3,35
10	Depreciation & Amortization		(1,411)		(1,47
11	Taxes Other than Income Taxes		(735)		(77
12	Interest Exp & Preferred Dividend		(670)		(77
13	Other Income & Deductions		246		10
14	Income Taxes		(543)		(56
15	**Utility Operations On-Going Earnings**		1,028		1,11
	NON-UTILITY OPERATIONS:				
16	MEMCO		80		6
17	Generation & Marketing		12		2
18	**Non-Utility Operations On-Going Earnings**		92		9
19	**Parent & Other On-Going Earnings**		(27)		(4
20	**ON-GOING EARNINGS**		1,093		1,1

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

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2007 Projected Cash Flow

($ in millions)	2006 Actual	2007 Guidance *
Beginning Cash Balance	**$ 401**	**$ 301**
Cash from Operations:		
Income from Continuing Operations	992	1,173
Depreciation and Amortization	1,467	1,527
Asset Impairments	209	-
Other	64	(347)
Total from Operations	**$ 2,732**	**$ 2,353**
Cash from Investing:		
Capital Expenditures	(3,528)	(3,867)
Asset Sales	186	43
Other	(401)	(84)
Total from Investing	**$ (3,743)**	**$ (3,908)**
Cash from Financing:		
Common Equity	99	80
Net Long Term Debt Issued/(Retired)	1,413	1,111
Short Term Debt Change, Net	7	899
Common Dividends	(591)	(620)
Other Financing Activities	(17)	(11)
Total from Financing	**$ 911**	**$ 1,459**
Net Change in Cash	**$ (100)**	**$ (96)**
Ending Cash Balance	**$ 301**	**$ 205**

* Assumes the midpoint of th $2.85 to $3.05 per share guidance rang

Cash on hand is expected to be $205 Million by the end of 2007

Multi-Year Capital Investment Funding Plan

	Actual	Projection		
	2006	2007	2008	2009
Planned Capital Investment (Projection amts. exclude AFUDC)	$ (3,528)	$ (3,867)	$ (3,026)	$ (2,974)
Dividend on Common	$ (591)	$ (620)	$ (624)	$ (627)
Cash Sources				
Cash from Operations *	$ 2,732	$ 2,353	$ 2,642	$ 2,671
Proceeds from Sale of Assets	$ 186	$ 43	$ -	$ -
Common Stock Issued (Dividend Reinvestment Plan)	$ 99	$ 80	$ 80	$ 80
Change in Debt, Net	$	$ 2,010	$ 1,176	$ 967
Change in Other Temporary Cash Investments, Net	$ (291)	$ -	$ -	$ -
Other Investing and Financing Activities	$ (127)	$ (95)	$ (137)	$ (29)
Cash Sources Less Capital Expenditures, Dividends & Other	$ (100)	$ (96)	$ 111	$ 88
Ending Cash Balance	$ 301	$ 205	$ 316	$ 404

Projected 2007-2009 AEP Consolidated Credit Metric Ranges:

Debt to total capital (adjusted - rating agency view) range of 58% to 60%

FFO to Interest range of 3.6x to 4.0x

FFO/Total Debt range of 16% to 18%

* Cash Flow from Operations projections assume full rate recovery on capital expenditures.

Capital Investment if Funded by Cash from Operations and Debt Issuances

Why Invest in AEP?

- Strength and scale in assets & operations
- Disciplined utility model focus - investing in established utility business to drive 5-7% consistent annual earnings growth
- Annual dividend of $1.56 per share providing an above average dividend yield of 3.4%
- Positive dividend outlook
- Stable credit profile

AEP AMERICAN® ELECTRIC POWER

Wells Fargo 10th Annual Pipeline, MLP & Energy Symposium Handout

December 7, 2011

“Safe Harbor” Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.07 - $3.17

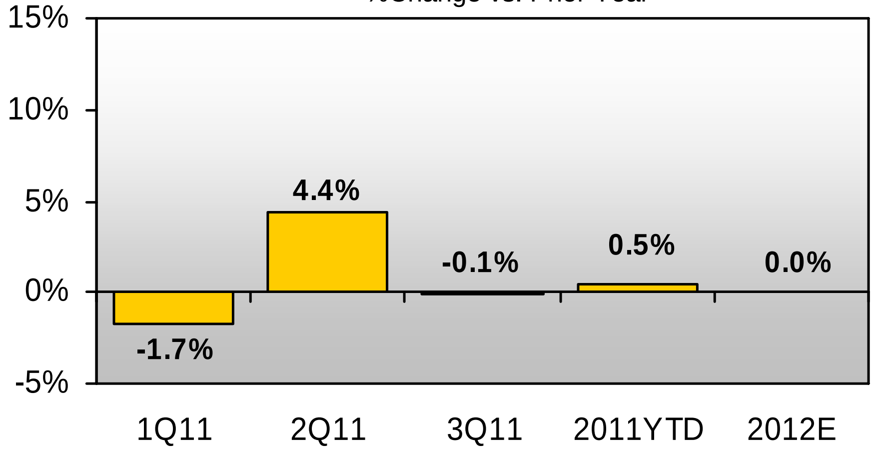
American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

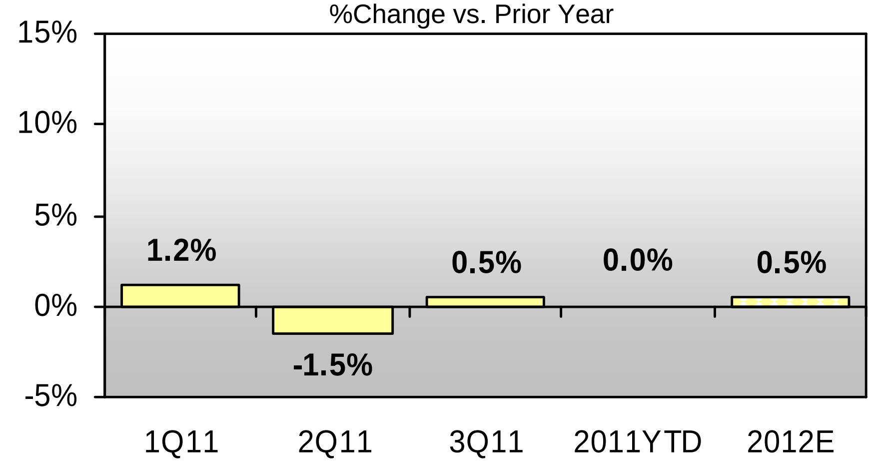
**original guidance given 01/28/2011*

Normalized Load Trends

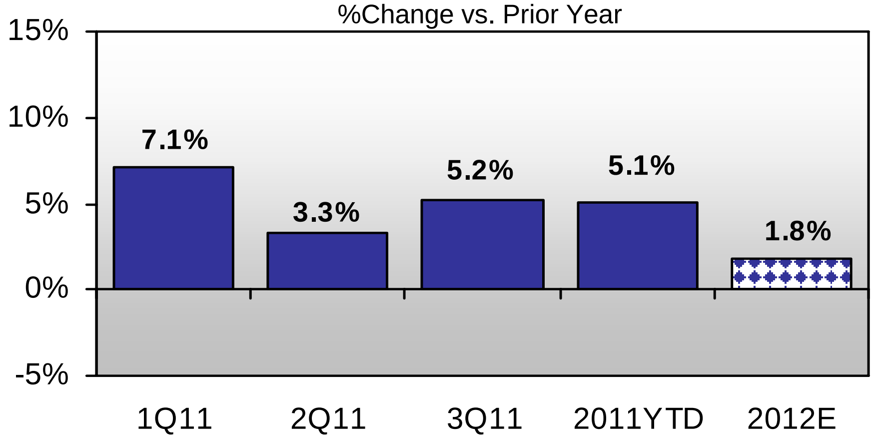
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



AEP Commercial Normalized GWh Sales
%Change vs. Prior Year

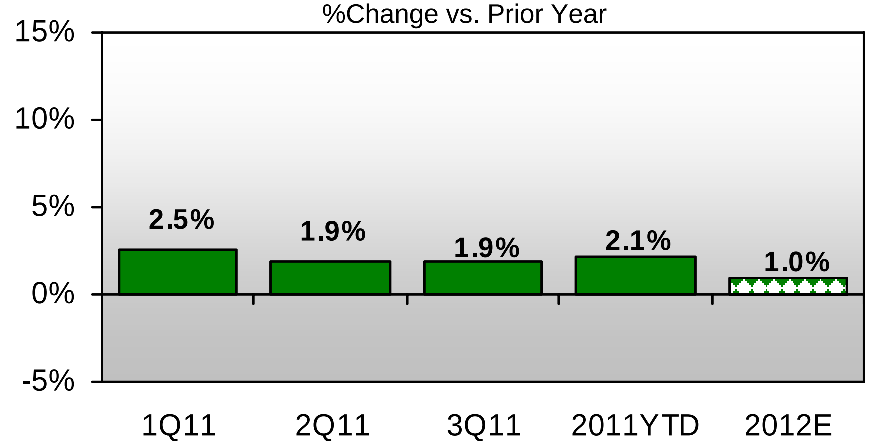


AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



Note: Chart represents connected load

AEP Total Normalized GWh Sales*
%Change vs. Prior Year

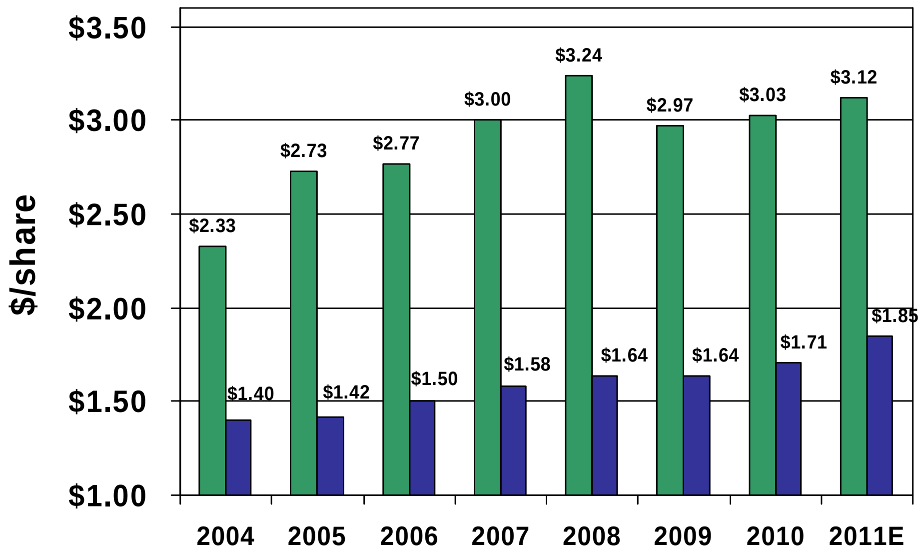


*includes firm wholesale load

Earnings and Dividend Growth

AEP®

Earnings and dividend history since 2004



4.3% average annual earnings growth

4.1% average annual dividend growth

Dividend payout ratio target of 50–60%

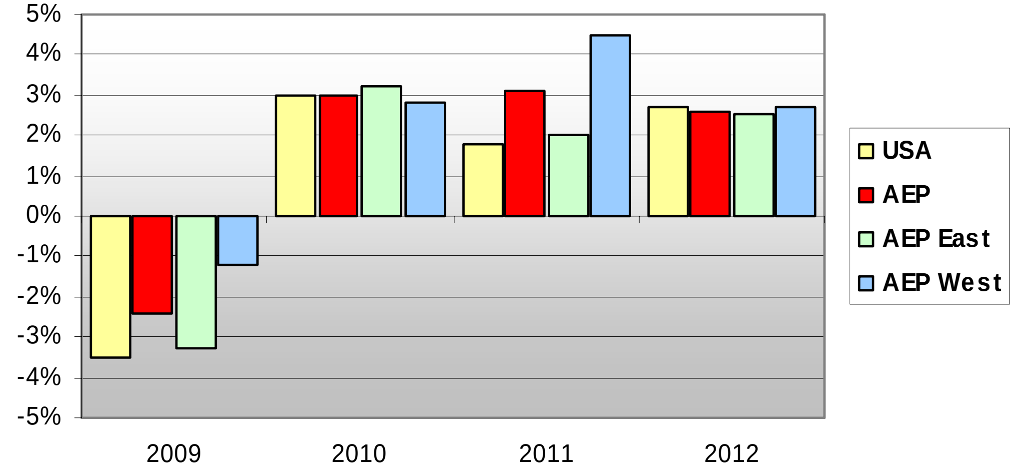
2012 Earnings Drivers

- **Recovering Economy**
  - System Load Growth of 1.0%
  - Off-System Sales
- **Successful Rate Case Outcomes**
  - Ohio ESP Stipulation
  - Ohio Distribution Case
  - Virginia Rate Case
  - Michigan Rate Case
- **Continued Transmission Growth**
- **O&M Discipline**

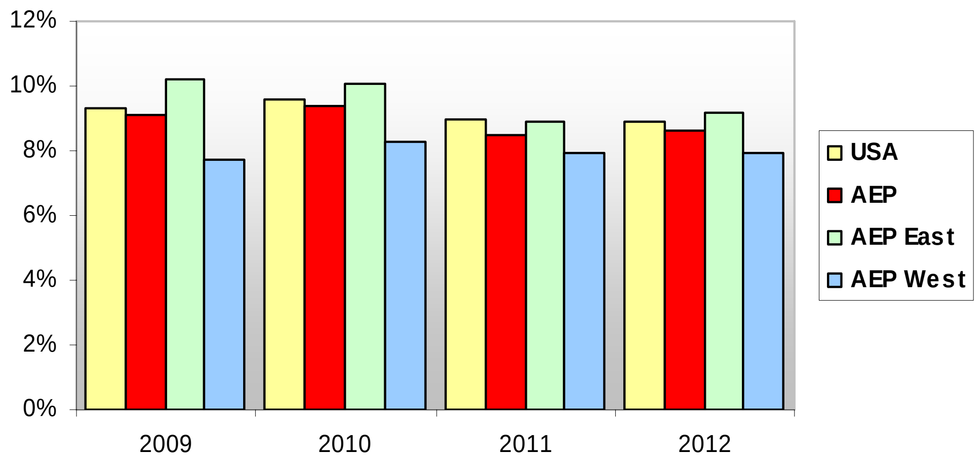
Economic Conditions/Load

- AEP's GDP growth at 3.1% in 2011 has been better than the US at 1.8%
- AEP West region continues to experience stronger growth than AEP East

Annual GDP Growth



Annual Unemployment Rate



- AEP East unemployment remains higher than AEP West
- AEP Total unemployment has started to improve relative to the US

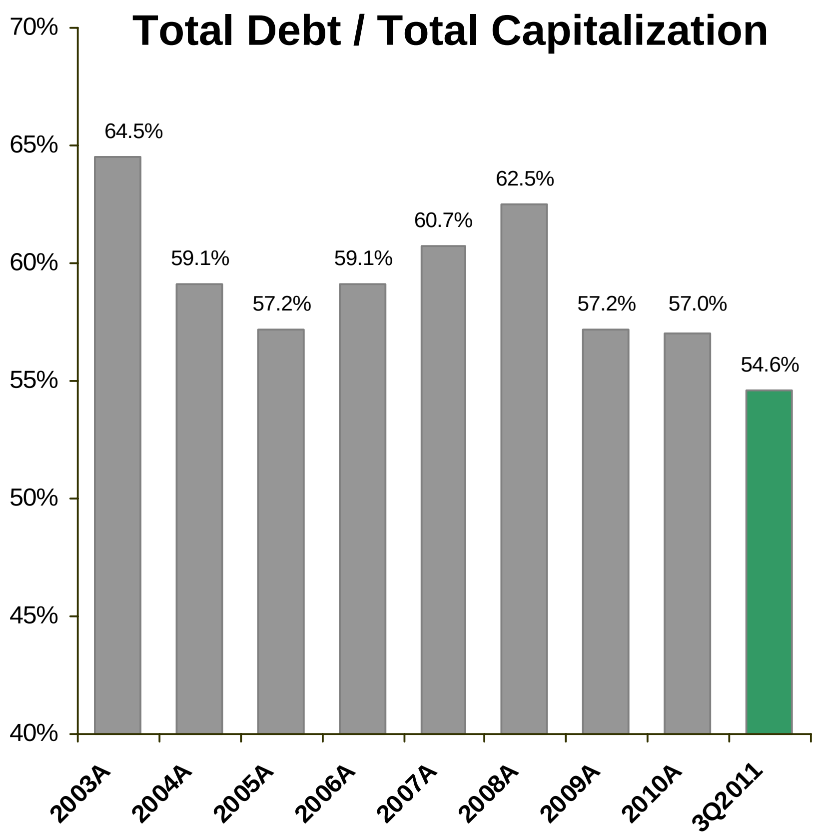
Sensitivities for 2012

EPS Sensitivities

Major Drivers		
Driver	**Driver Change**	**EPS Effect**
Average Load Growth	1%	$0.10
Off System Sales, net of sharing	10%	$0.05
Utility O&M	1%	$0.04
Capital Spending	$250M	$0.02

Operating Company Returns		
Company	**% Earnings Contribution**	**EPS Effect of 1% ROE Change**
AEP Ohio	42%	$0.10
APCo (incl WPCo)	16%	$0.06
SWEPCO	11%	$0.04
I&M	10%	$0.04
AEP Texas	8%	$0.02
PSO	6%	$0.02
KPCo	3%	$0.01
Other	4%	$0.02

Capitalization & Liquidity



Note: Total Debt is calculated according to GAAP and includes securitized debt

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.9	>3.6x
FFO To Total Debt	21.50%	15%- 20%

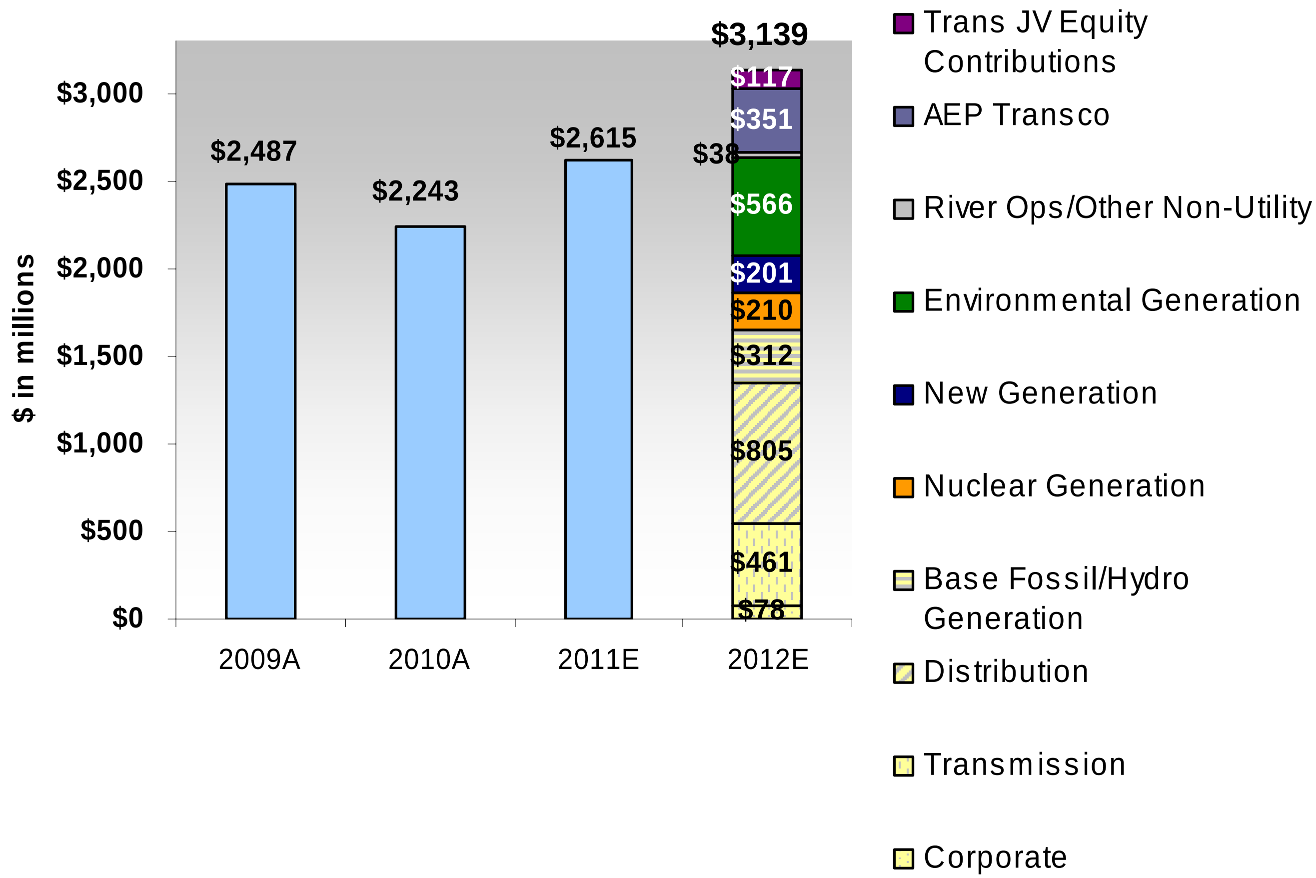
Note: Credit statistics represent the 12 month trailing as of 09/30/2011

Liquidity Summary (09/30/2011)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		546	
Less			
Commercial Paper Outstanding		(529)	
Letters of credit issued		(103)	
Net available Liquidity	**$**	**3,164**	

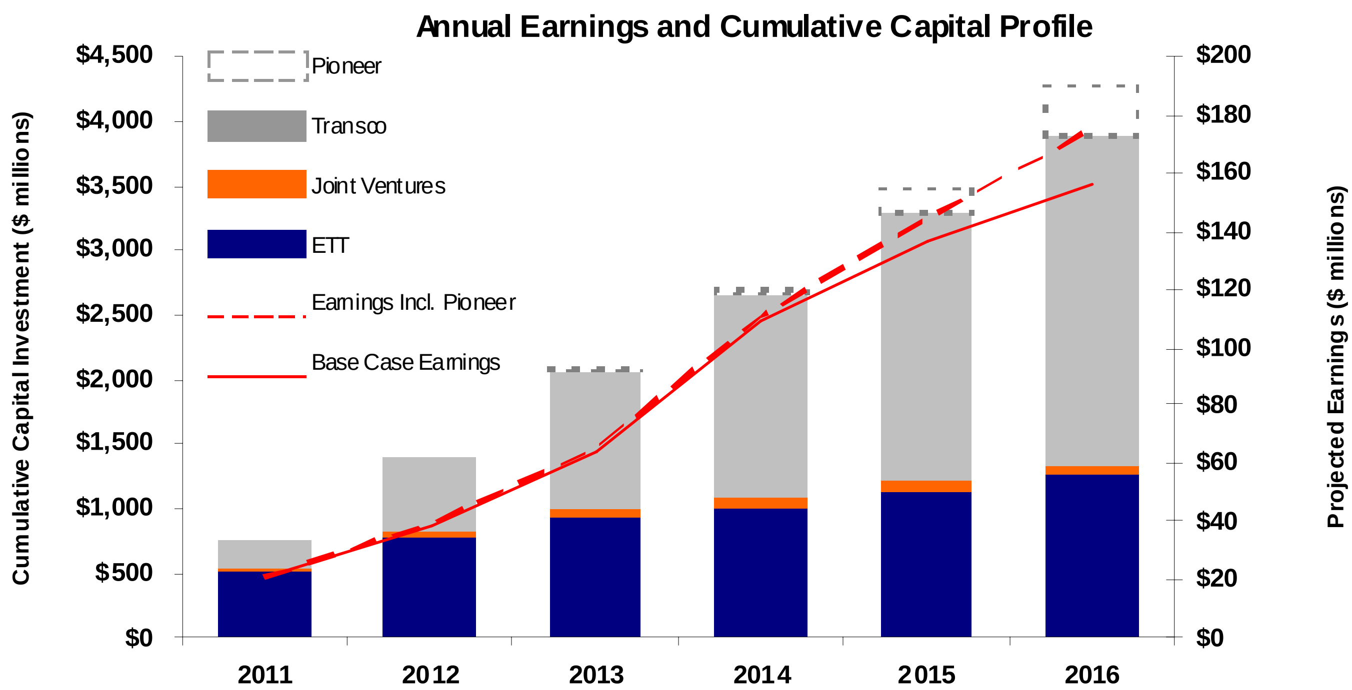
Capital Allocation

2012 AEP System Capital $3.1B



Major projects include: Turk Plant, Reliability upgrades, ETT contributions and Transco growth

Transmission Earnings & Capital Profile



[1] High Case includes AEP's share of Pioneer (50% ownership)

[2] Transco base case includes approximately $21MM in 2012 capital spend that is dependent upon state approval of Arkansas and Kentucky

[3] Joint Ventures include: PATH (50% ownership) assuming an ongoing suspension and Prairie Wind (25% ownership) assuming construction at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 11-13% for FERC projects; 60/40 debt/equity capitalization and 9.96% ROE (through 2013) and 55/45 debt/equity capitalization and 10% ROE (2014 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Transmission Investment Opportunities

AEP®

ETT
Electric Transmission Texas

- **Ownership Structure:** 50/50 (AEP/MidAmerican Energy Holding Company)
- **Total Project Cost**: Over $3 Billion
- **Growing Rate Base:**
  Current rate base is $482 million; expected to grow as follows:
  2011: $495 million
  2012: $750 million
  2013: $1,200 million
- **Interim TCOS filings twice per calendar year**
- **Approved ROE:** 9.96%

AEP Transcos

- Seven wholly-owned Transcos
- Expansion and growth within AEP's existing utility footprint
- Efficient recovery mechanism via FERC formula rates
- Forecasted capital investment of $210 million in 2011 and more than $350 million in 2012
- Approved ROE: 11.20%-11.49%

ROE Optimization

ROE by Jurisdiction		
Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia	10.53%	6.88%
APCO – West Virginia	10.00%	
Wheeling	10.00%	
I&M – Indiana	10.50%	8.24%
I&M – Michigan	10.35%	
SWEPCO – Louisiana	10.57%	10.05%
SWEPCO – Arkansas	10.25%	
SWEPCO – Texas	10.33%	
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Ohio ESP Settlement

Gradual Transition to Market and Regulatory Stability in Ohio

- **Parties to the Settlement** - Signed by more than 20 organizations representing customers, competitive retail electricity suppliers, environmental groups, communities and other key stakeholders
- **Cases included in Settlement** - 2012 Electric Security Plan, Capacity Charges, Merger
- **Generation** - Corporate separation of Ohio generation assets targeted by May 2013 and transition all of Ohio generation supply to market by mid-2015; the company may pursue recovery of Pool modification costs once they exceed $50 million
- **Transition to market** - company will make a specific percentage of the Ohio retail load open to competitive retail suppliers at the RPM price for a three-year period. The remaining capacity that switches will be priced at $255/MW-day
  - Year one (2012), approximately 20 percent will be available
  - Year two (2013), approximately 30 percent will be available
  - Year three (2014 through May 2015), approximately 40 percent will be made available.
  - Standard service offer price beginning in June 2015 will be determined through auctions involving multiple suppliers of generation service. Auctions will begin as early as September 2013.
- **Fuel Adjustment Clause** - continues through May 31, 2015; parties to support legislation for securitization of fuel deferrals
- **Nonbypassable Generation Resource Rider** – allows the distribution company to recover costs related to building new generating assets dedicated solely to Ohio customers. Project-related costs will be presented in future PUCO cases.
- **Distribution Investment Rider** – Costs associated with new distribution investment to maintain and improve reliability will be recovered under this rider with an ROE of 10.5% based on a capital structure of 47% debt/53% equity. In its first year (2012), the rider will be capped at $86 million. An additional $18 million will be added in 2013 and an additional $20 million in 2014.
- **SEET ROE threshold of 13.5%**.

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #11-351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

		CSP		OPCO
Rate Base	$	911.0	$	1,015.2
Rate of Return		8.36%		8.43%
Operating Income Requirement	$	76.2	$	85.6
Adjusted Operating Income	$	54.3	$	47.8
Difference	$	21.9	$	37.8
Revenue Conversion Factor		1.5657		1.5765
Total Revenue Requirement	$	34.2	$	59.6

Procedural Schedule

Hearing has been delayed pending settlement discussions

Summary Rate Case Information

I&M Michigan Base Rate Case – Docket # U-16801

On July 1, 2011 I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $24.5 million. Rates proposed in this filing are based on projected 2012 cost of service and will not go into effect until 2012, therefore rates will reflect a current cost of service. This filing includes revised depreciation rates to include additions since the last approved depreciation study as well as accelerated retirement of Tanners Creek Units 1, 2 and 3. The requested ROE is 11.15%. In accordance with Michigan law I&M requested to implement rates, subject to refund, on January 1, 2012. An order is expected by mid-year 2012.

Projected Capital Structure – Company Position (12/31/12)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.50%	0.68%	0.00%
Long-Term Debt	38.91%	6.32%	2.46%
Common Equity	43.08%	11.15%	4.80%
Other Items	1.22%	8.79%	0.11%
Other Tax Items	16.10%	0.00%	0.00%
Preferred Stock	0.19%	4.58%	0.01%
Total	100.00%		7.38%

Procedural Schedule

Intervenor Testimony	November 29, 2011
Staff Testimony	November 29, 2011
Rebuttal Testimony	December 14, 2011
Hearing	January 5, 2012

Required Rate Relief – Company Position (12/31/12)

($ in millions)

Rate Base	$	680.8
Rate of Return		7.38%
Operating Income Requirement	$	50.2
Adjusted Operating Income	$	33.0
Difference	$	17.2
Revenue Conversion Factor		1.6460
Subtotal Revenue Requirement	$	28.4
OATT Costs	$	(3.4)
Misc. Costs	$	(0.4)
Total Revenue Requirement	$	24.5

Summary Rate Case Information

I&M Indiana Base Rate Case Cause #44075

On September 23, 2011 I&M filed a base rate case with the Indiana Utility Regulatory Commission requesting an increase of $148.7 million ($178.4 million in base revenues offset by $29.7 million in proposed changes to the OSS, PJM and CCT riders). Rates proposed in this filing are based on a historical 03/31/2011 cost of service and will not go into effect until an order is issued. The requested ROE is 11.15%. An order is expected by the end of 2012 or early 2013.

Historical Capital Structure – Company Position (03/31/2011)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	38.74%	6.33%	2.45%
Common Equity	42.67%	11.15%	4.76%
Preferred Stock	0.20%	4.58%	0.01%
Other Items	18.39%	various	0.16%
Total	100.00%		7.38%

Procedural Schedule

Case Filed	September 23, 2011
Hearing on I&M Case in Chief	February 20 - March 2, 2012
Public and Intervenor filing	April 27, 2012
Rebuttal Filing by I&M	May 25, 2012
Hearing	June 18 -29, 2012
Proposed Order	July 16, 2012

Required Rate Relief – Company Position (03/31/2011)

($ in millions)

Rate Base	$	2,411.9
Rate of Return		7.38%
Operating Income Requirement	$	178.0
Adjusted Operating Income	$	72.2
Difference	$	105.8
Revenue Conversion Factor		1.6655
Subtotal Revenue Requirement	$	176.1
OATT Costs	$	(17.4)
Fair Value Adjustment	$	19.7
Total Required Rate Relief	$	178.4
OSS Margin Sharing Rider	$	(13.8)
PJM Rider	$	(9.0)
Clean Coal Tech Rider	$	(6.9)
Total Revenue Requirement	$	148.7

Recovery Mechanisms Across Jurisdictions

	SO_2 Allowances*	NO_x Allowances*	CO_2 Allowances	GHG Offsets	Environmental Investment	Energy Efficiency	Renewables	Purchased Power	OATT
AEP East									
Indiana	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**ECCR Rider**	**CCTR/BR**	**Rider**	**FAC**	**FAC/BR**	**PJM Tracker**
Kentucky	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**	**Surcharge**		**FAC**	**Base Rates**
Michigan	**PSCR**	**PSCR**	**PSCR**	**PSCR**	**Base Rates**	**Surcharge**	**PSCR/REP**	**PSCR**	**Base Rates**
Ohio	**FAC**	**FAC**	**FAC**	**FAC**	**SSO**	**Rider**	**FAC**	**FAC**	**TCRR**
Tennessee	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**	**FERC Tariff**			**FERC Tariff**	**PPAR**
Virginia	**ERAC**	**ERAC**	**ERAC**	**ERAC**	**ERAC/BR**	**RAC**	**RPSRAC**	**FAC/BR**	**TRAC**
West Virginia	**ENEC**	**ENEC**	**ENEC**	**ENEC**	**ENEC/BR**	**Rider**	**ENEC**	**ENEC**	**ENEC**
AEP West									
Arkansas	**ECR**	**ECR**	**FAC**	**FAC**	**Surch/BR**	**EECR**	**FAC**	**ECR/BR**	**Base Rates**
Louisiana	**EAC**	**EAC**	**Rider**	**Rider**	**Formula BR**		**FAC**	**EAC/FRP**	**Formula BR**
Oklahoma	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Rider**	**FAC**	**FAC/PPC**	**SPP tracker**
Texas(SWP)	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**Base Rates**	**EECRF**	**FAC**	**FAC/BR**	**TCRF**

* - For certain jurisdictions where necessary, confirmation of the replacement of CAIR with CSAPR is occurring with applicable commissions

ECCR	Environmental Compliance Cost Rider	RAC	Rate Adjustment Clause
CCTR	Clean Coal Technology Rider	RPSRAC	Renewable Portfolio Standard Rate Adjustment Clause
BR	Base Rates	TRAC	Transmission Rate Adjustment Clause
FAC	Fuel Adjustment Clause	ENEC	Expanded Net Energy Cost
PSCR	Power Supply Cost Recovery Rider	ECR	Energy Cost Recovery Rider
REP	Renewable Energy Plan	EECR	Energy Efficiency Cost Rate
SSO	Standard Service Offer	FRP	Formula Rate Plan
TCRR	Transmission Cost Recovery Rider	PPC	Purchased Power Capacity Rider
PPAR	Purchased Power Adjustment Rider	EECRF	Energy Efficiency Cost Recovery Rider
ERAC	Environmental Rate Adjustment Clause	TCRF	Transmission Cost Recovery Factor

New Generation – Turk Plant

John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant, located in AEP's SWEPCO region. AEP owns 73 percent or roughly 440 megawatts of the total unit.

- The cost of the plant and related transmission is anticipated at $1.8 billion with AEP's share approximately $1.4 billion and will begin commercial operation in the fourth quarter of 2012.

- The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

- Third party owners include: Arkansas Electric Cooperative Corp. (12%), East Texas Electric Cooperative (8%), and Oklahoma Municipal Power Authority (7%).

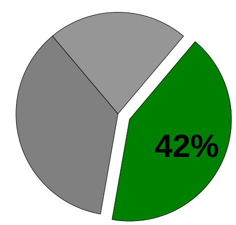
- Various legal challenges are on-going related to the plant (see 10-Q).

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

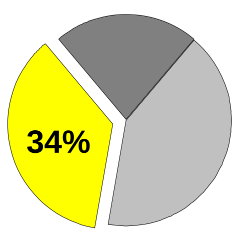
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

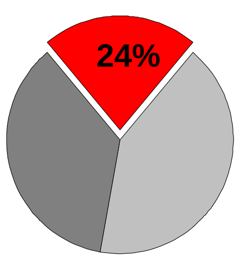
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

- The tables below represent our estimated \$6 - \$8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)	
AEP Ohio	Conesville 5	400	SCR, DSI			
	Conesville 6	400	SCR, DSI			
	Muskingum River 5/6*	510	Refuel/ New Natural Gas			
	Gavin 1	1,320	FGD upgrade			
	Gavin 2	1,320	FGD upgrade			
	Zimmer 1	330	FGD upgrade			
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800**	**
APCO	Clinch River 1***	211	Refuel with Natural Gas			
	Clinch River 2***	211	Refuel with Natural Gas			
	Dresden	580	New Natural Gas			
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765**	****
I&M	Rockport 1	1,310	FGD, SCR			
	Rockport 2	1,310	FGD, SCR			
	Tanners Creek 4	500	DSI, ACI			
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670**	*****
KPCO	Big Sandy 2	800	FGD			
	Total MW	**800**	**Total Expected Cost**		**525**	

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

**** Total capital invested is expected to be \$366 million for the Dresden plant once completed; \$343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	

AEP Ohio Generation Portfolio

Plant Name	Nominal Capacity (MW)	Year Plant Commissioned	Status
Columbus Southern Power Company			
Conesville 5&6	800	1976-1978	Has FGD
Conesville 4	340	1973	Has FGD & SCR
Stuart (CCD)	600	1971	Has FGD & SCR
Zimmer (CCD)	330	1991	Has FGD & SCR*
Lawrenceburg **	1,186	2004	NG Combined Cycle
Waterford	840	2003	NG Combined Cycle
Darby	507	2001	NG Simple Cycle
Conesville Unit 3	165	1962	Will be retired
Picway	100	1926	Will be retired
Beckjord (CCD)	53	1969	Will be retired
	4,921		
Ohio Power Company			
Racine	26	1982	Hydro
Amos (3)	870	1973	Has FGD & SCR
Cardinal	595	1967	Has FGD & SCR
Gavin	2,640	1974	Has FGD & SCR*
Mitchell	1,560	1971	Has FGD & SCR
Muskingum River 5	600	1968	Replace with gas
Muskingum River 1-4	840	1953-1958	Will be retired
Kammer	630	1958	Will be retired
Sporn 5	450	1968	Will be retired
Sporn 2 & 4	300	1950-1952	Will be retired
	8,511		
Total AEP Ohio	**13,432**		

* May need FGD upgrades

** CSP has a PPA with AEGCo for the Lawrenceburg Plant. The contract extends through 2017, with a two-year optional renewal.

Total Ohio Generation	13,432 MW
Less units slated for retirement	2,500 MW
Total remaining portfolio	10,932 MW

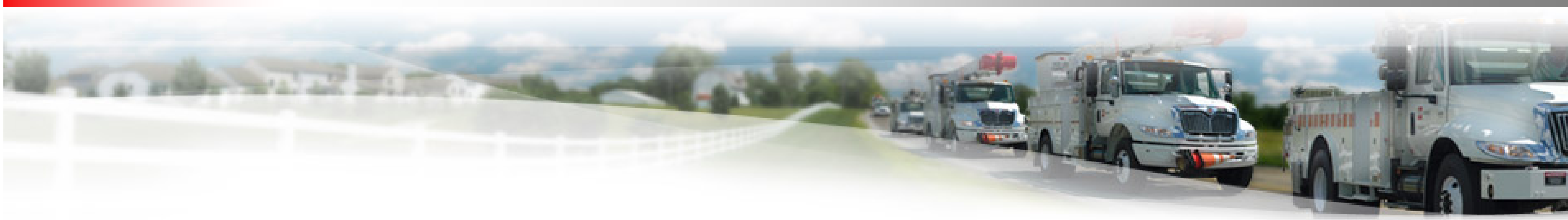
Remaining Portfolio:

Coal	77%
Has FGD & SCR - 83%	
Has FGD; may require SCR - 10%	
May be replaced with gas - 7%	
Natural gas & hydro units	23%
	100%

AEP AMERICAN® ELECTRIC POWER

Wells Fargo 9th Annual Pipeline, MLP & Energy Symposium

December 08, 2010
New York, NY



"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

AEP®

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Lisa Barton – SVP Transmission Strategy & Business Development

Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

Two New Anchor Projects

ETA – AEP - Exelon: The RITE Line

Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

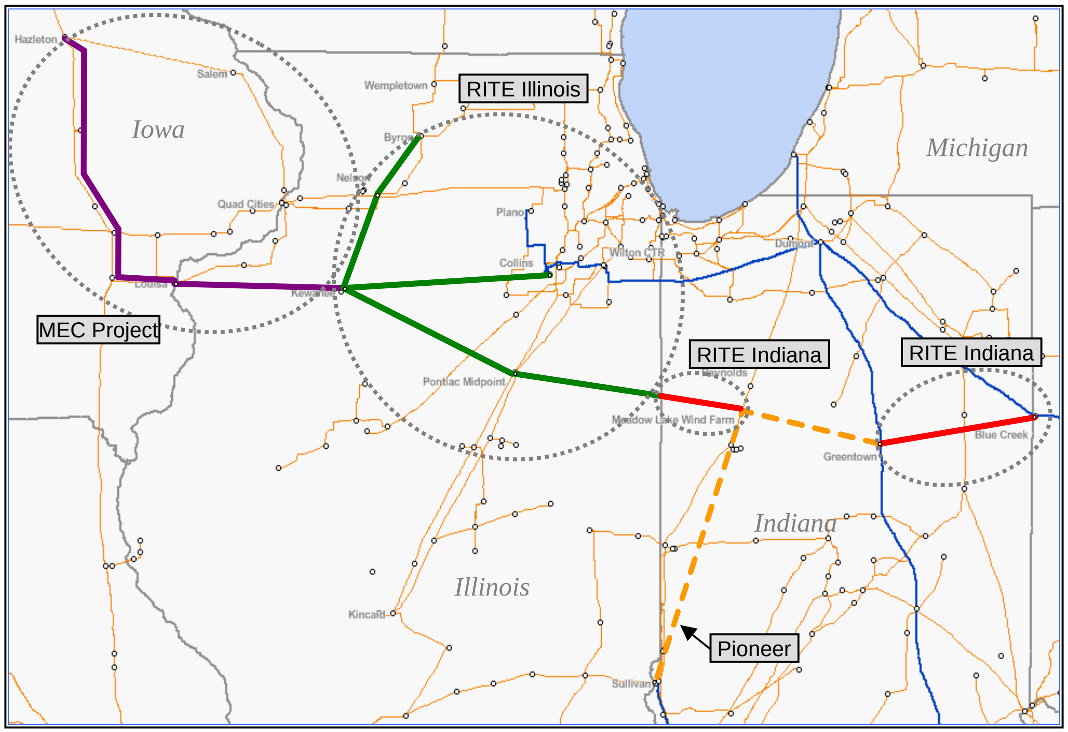
ETA – MidAmerican Energy Co: MEC Project

Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

AEP Total Investment:

~$500M



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

AEP AMERICAN ELECTRIC POWER®

Wells Fargo Analyst Visit
AEP Headquarters
Columbus, OH
July 9, 2010

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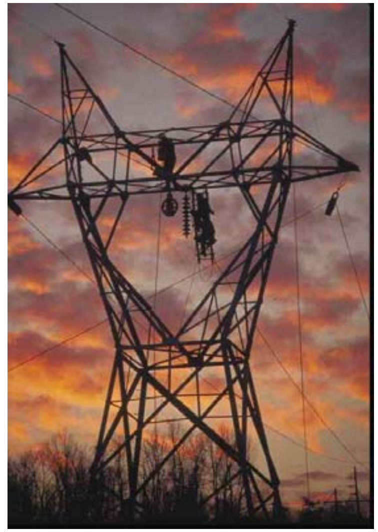
Industry Leadership

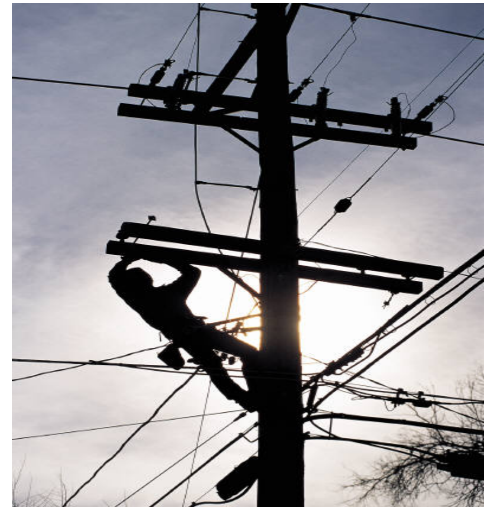
One of the largest U.S. electricity generators

Generation owned[1] (GW)	
SO	42.9
FPL	42.7
AEP	40.6
DUK	38.9
EXC	31.2
ETR	30.0
D	27.5
CPN	25.0
NRG	24.0
PGN	21.0



The largest U.S. electricity transmitter

Transmission miles[1] ('000s)	
AEP	39.0
SO	27.0
DUK	20.9
PCG	18.6
MidA	18.0
ETR	15.5
ITC	15.1
FE	15.1
Oncor	14.0
EIX	12.0



One of the largest U.S. electricity distributors serving 5.2MM customers

Electric customers[1] (mm)	
EXC	5.4
AEP	5.2
PCG	5.1
FPL	4.5
FE	4.5
SO	4.4
DUK	4.0
ED	3.6
XEL	3.4
PGN	3.1

[1] Source: Company Filings
*AEP generation includes long-term PPAs and generation under construction

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
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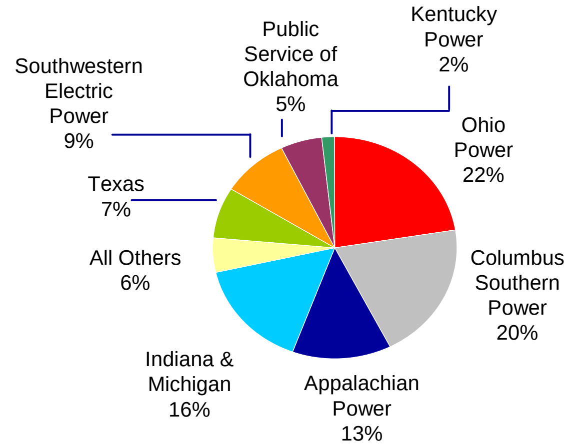
Highly Diversified Regulated Utility Platform

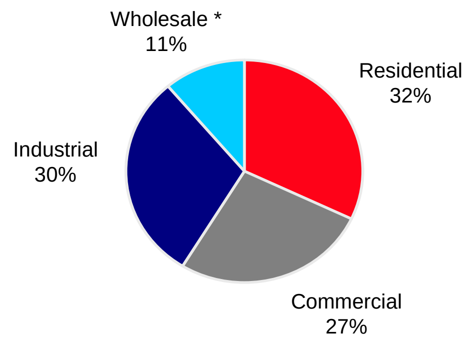
5.2 million customers in 11 states

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

2009 Earnings Contribution



2009 Retail Load



** Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

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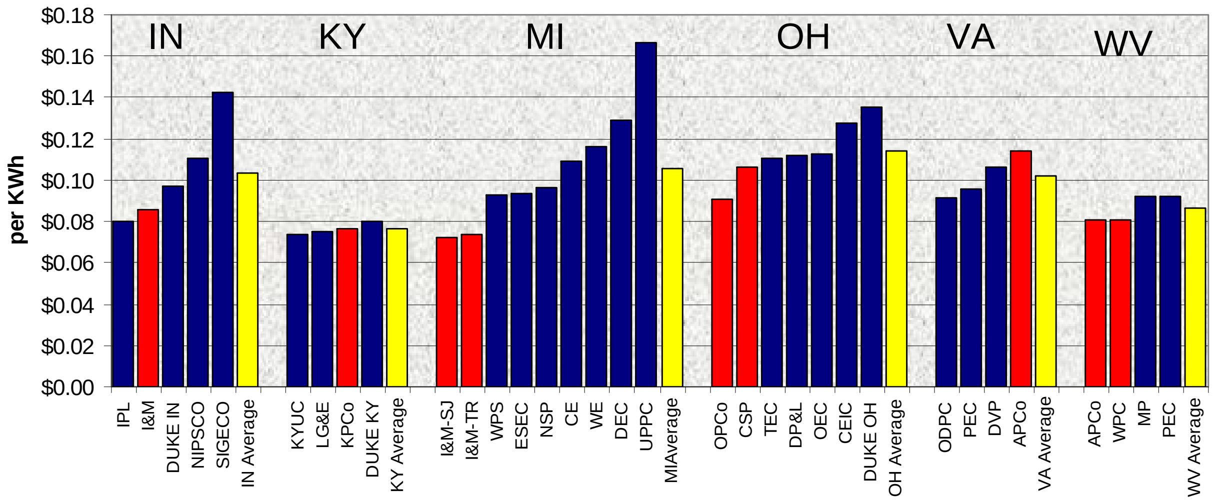
Residential Rates Comparison

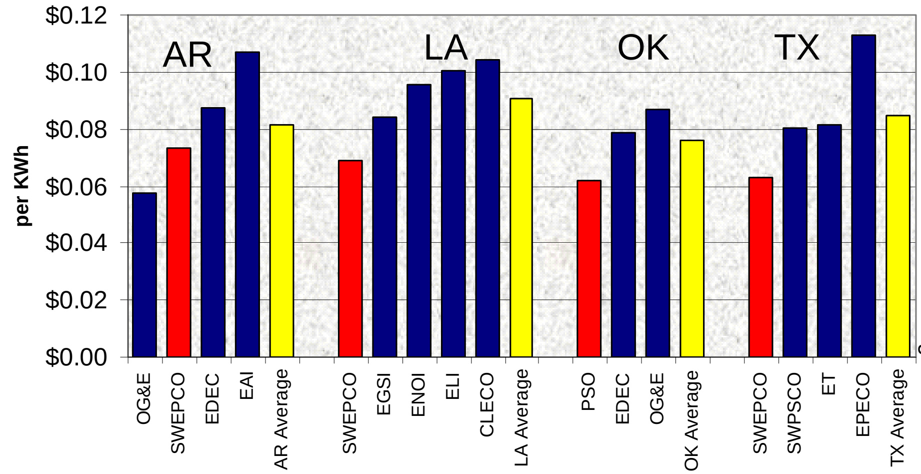
AEP East



Residential Average Rates for 1,000kWh
12 months ended 1/01/2010
Source: Winter 2010 EEI Typical Bills and Average Rates Report

AEP Company
Other Utilities within state
State Average

AEP West



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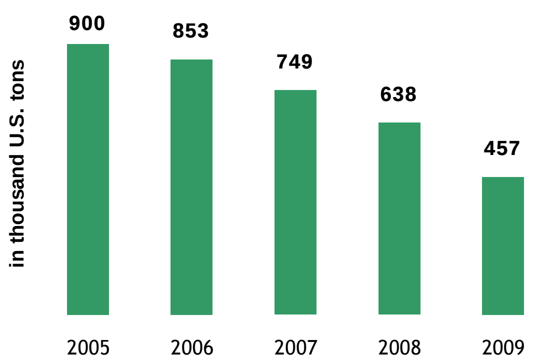
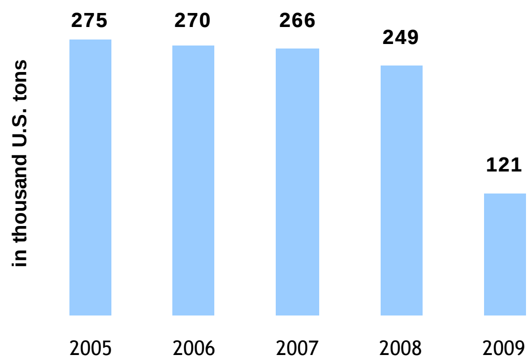
Our Fleet Will Continue to Transform

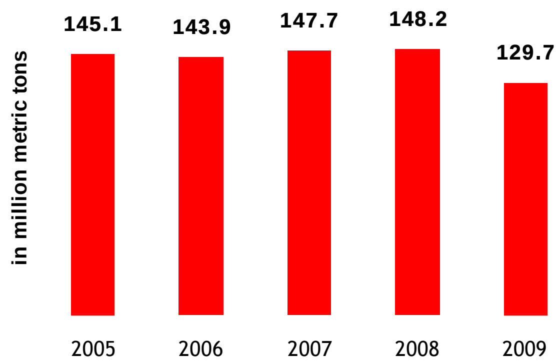
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS



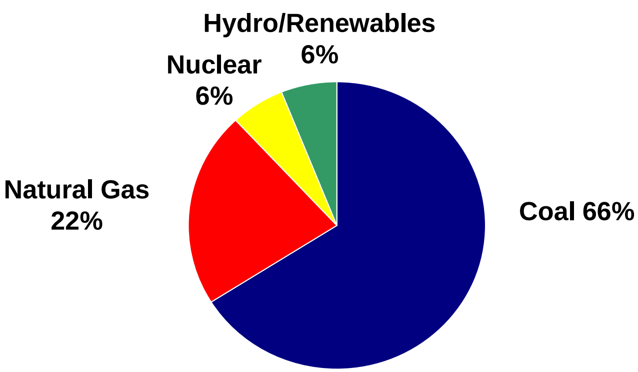
TOTAL SYSTEM – ANNUAL NOx EMISSIONS



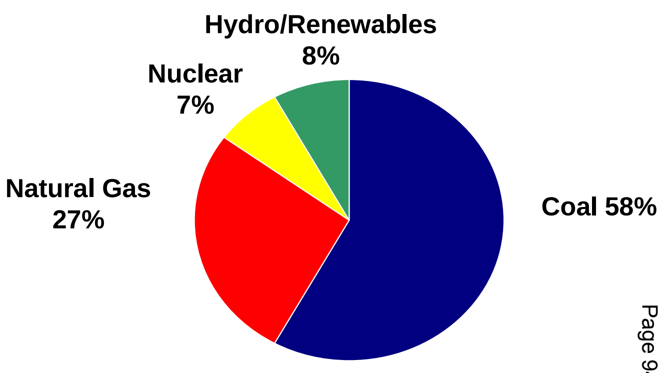
TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS



~ $5.2B capital invested from 2004-2010 to reduce SO_2, NOx and Mercury emissions



Fuel Mix - 2009



Projected Fuel Mix - 2017

New Generation Projects

J. Lamar Stall Combined-Cycle Gas Plant

- J. Lamar Stall Combined-Cycle gas plant is a 508-MW unit that began commercial operations in June 2010.
  - The total projected cost of the plant is $380 million.
  - The plant is located in AEP's SWEPCo region at its existing Arsenal Hill Power Plant in Shreveport, Louisiana.
  - The plant serves the needs of customers in the Arkansas, Louisiana and Texas service territories.

- John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in AEP's SWEPCo region. AEP owns 73 percent or roughly 440 megawatts of the total unit.
  - The cost of the plant is anticipated at $1.7 billion with AEP's share approximately $1.3 billion and will begin commercial operation in 2012.
  - The Turk Plant will use low-sulfur coal and state-of-the art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.
  - Various legal challenges are on-going related to the plant (see 10-Q). Recently, following the Arkansas Supreme Court decision regarding CECPN, SWEPCO filed notice to the APSC that the 88MW will now be merchant and will not be included in rate base.

John W. Turk Jr. Ultra-Supercritical Coal Plant

Carbon Capture and Storage

Carbon Capture and Storage project located at AEP's Mountaineer Plant in New Haven, WV

PHASE I – Validation

Captured CO_2 – September 2009
Injected CO_2 – October 2009

CO_2 Capture

Project employs Alstom's chilled ammonia process for post-combustion CO_2 capture.

CO_2 Storage

Compressed CO_2 is injected about 1.5 miles below the earth's surface.

PHASE I - Validation

20 MWe scale validation project designed to remove 90% of CO_2 from flue gas and store 100,000 metric tons/year. Currently in operation.

PHASE II - Commercialization

235 MWe commercial scale project designed to capture and store 1.5 million metric tons of CO_2/year. Awarded 50% US DOE funding. Commercial operation in 2015.

2010 Ongoing Earnings Guidance

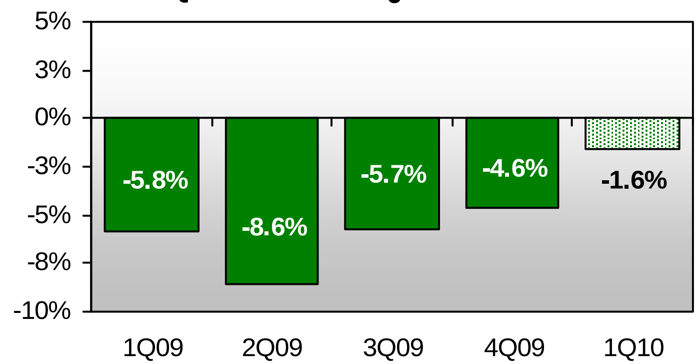
2009A: $2.97/share

2010E: $2.80-$3.20/share

Near-term Earnings Drivers

- **Rate recovery from returns on capital investment**
- **Load growth (and recovery)**
- **Increase in off-system sales volumes and/or prices**
- **O&M discipline and cost-cutting initiatives**

AEP Total Normalized GWh Sales
Quarter %Change vs. Prior Year



Quarter over Quarter change by segment:
Residential: +2.1%
Commercial: -1.6%
Industrial: -1.0%

Detailed Ongoing Earnings Guidance

2009 Actual: $2.97

American Electric Power
2009 Actual vs. 2010 Guidance

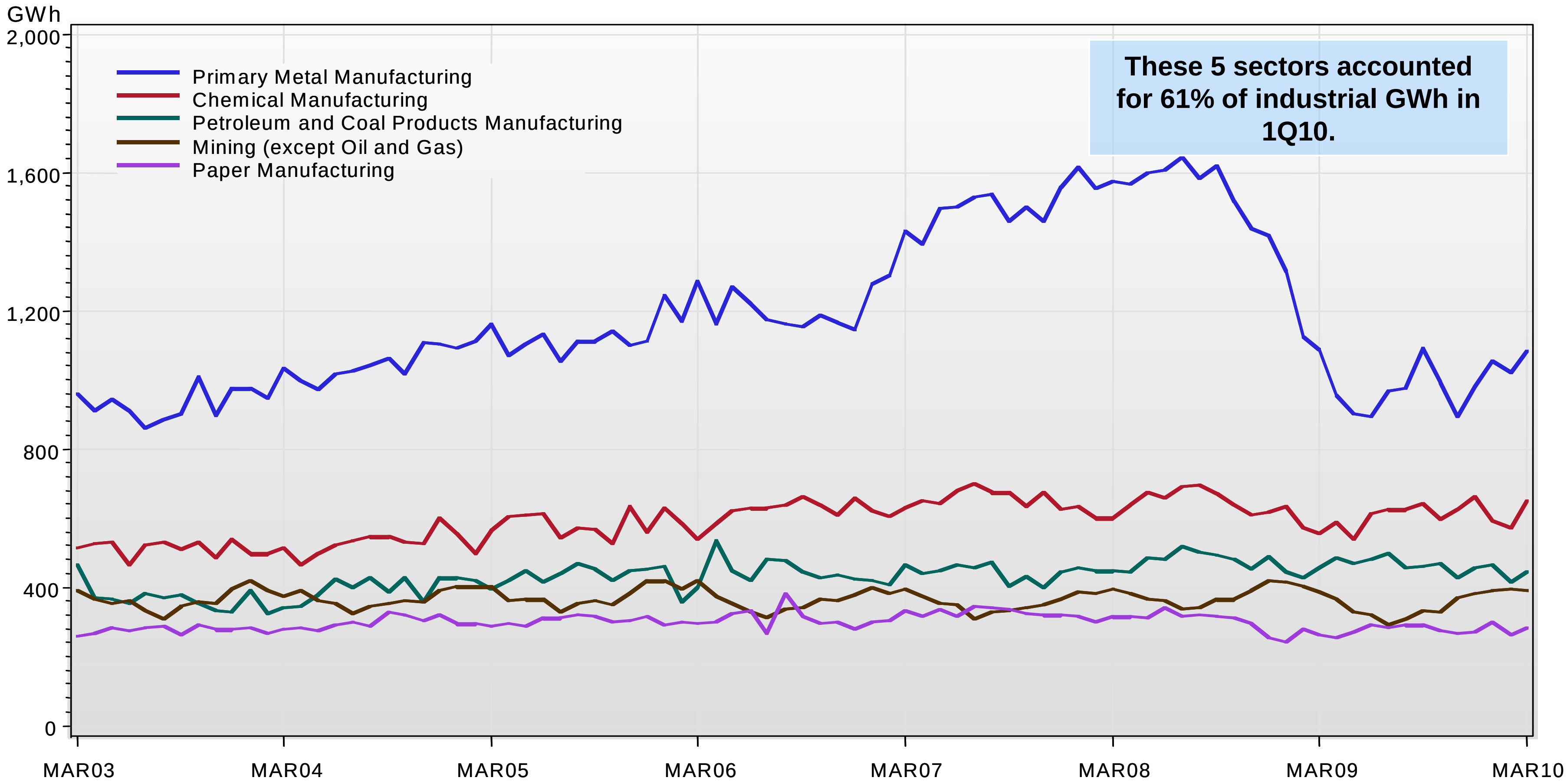
2010E: $2.80-$3.20

		Performance Driver	2009 Actual ($ millions)	Performance Driver	2010 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	66,976 GWh @ $ 38.0 /MWhr =	2,544	68,249 GWh @ $ 42.2 /MWhr =	2,878
2	Ohio Companies	47,468 GWh @ $ 57.6 /MWhr =	2,733	47,922 GWh @ $ 63.6 /MWhr =	3,048
3	West Regulated Integrated Utilities	38,947 GWh @ $ 30.0 /MWhr =	1,167	41,165 GWh @ $ 31.3 /MWhr =	1,287
4	Texas Wires	27,573 GWh @ $ 20.7 /MWhr =	571	27,510 GWh @ $ 22.2 /MWhr =	610
5	Off-System Sales (net of sharing)	14,795 GWh @ $ 16.7 /MWhr =	247	23,992 GWh @ $ 13.7 /MWhr =	329
6	Transmission Revenue - 3rd Party		354		352
7	Other Operating Revenue		767		541
8	Utility Gross Margin		8,383		9,045
9	Operations & Maintenance		(3,410)		(3,620)
10	Depreciation & Amortization		(1,561)		(1,637)
11	Taxes Other than Income Taxes		(751)		(793)
12	Interest Exp & Preferred Dividend		(919)		(957)
13	Other Income & Deductions		128		148
14	Income Taxes		(553)		(736)
15	Utility Operations On-Going Earnings		1,317		1,450
16	Transmission Operations On-Going Earnings		4		9
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		47		43
18	Generation & Marketing		41		2
19	Parent & Other On-Going Earnings		(47)		(63)
20	ON-GOING EARNINGS		1,362		1,441

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

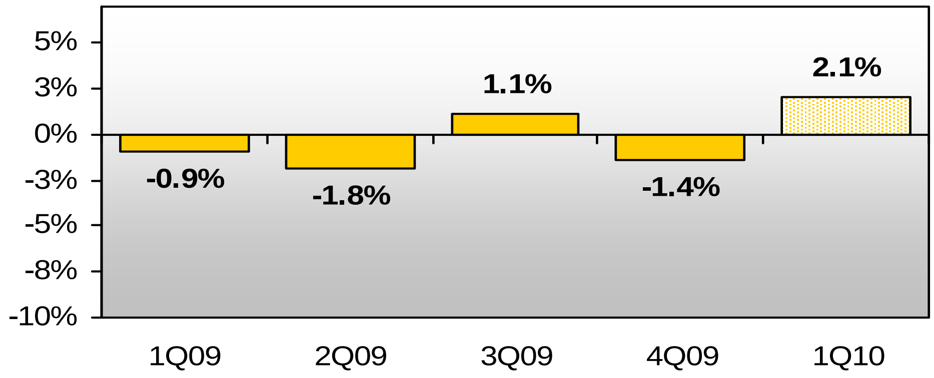
Industrial Sales

AEP Industrial GWh by Sector

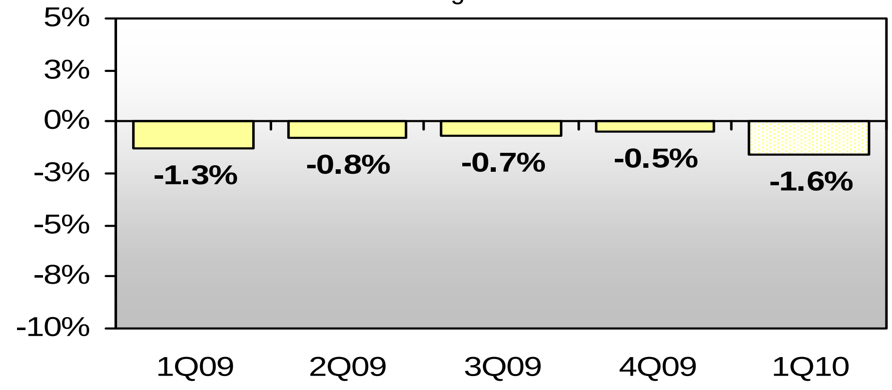


Normalized Load Trends

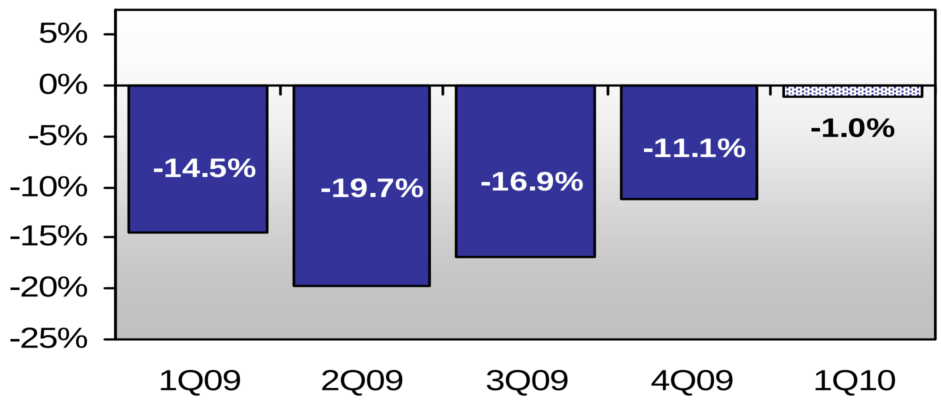
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



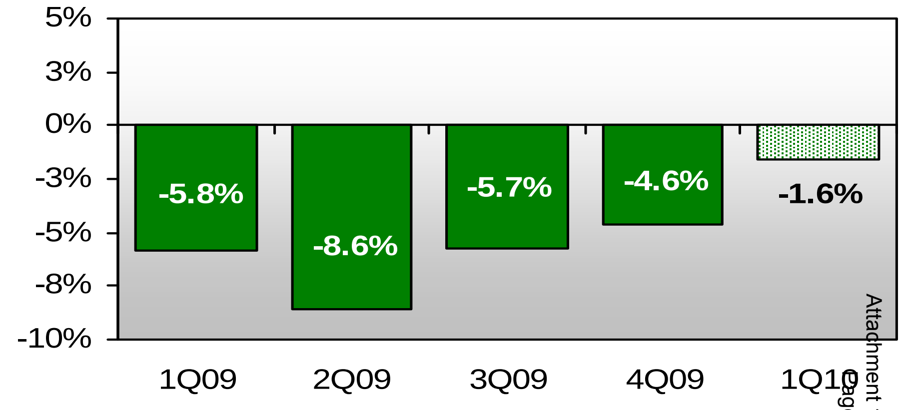
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year

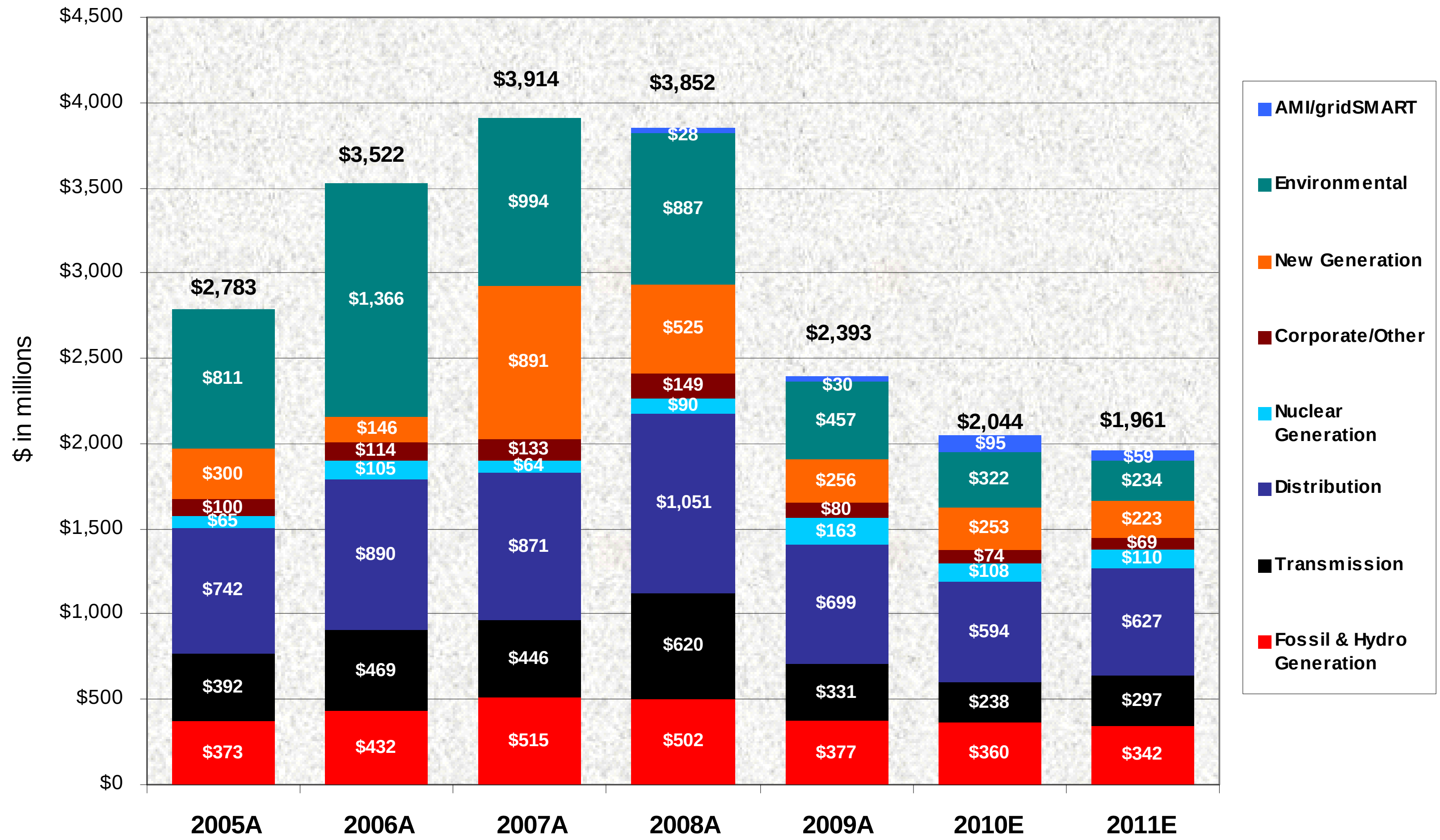


AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Utility Operations Capital Expenditures



Non-Utility Operations Capital (not included above)

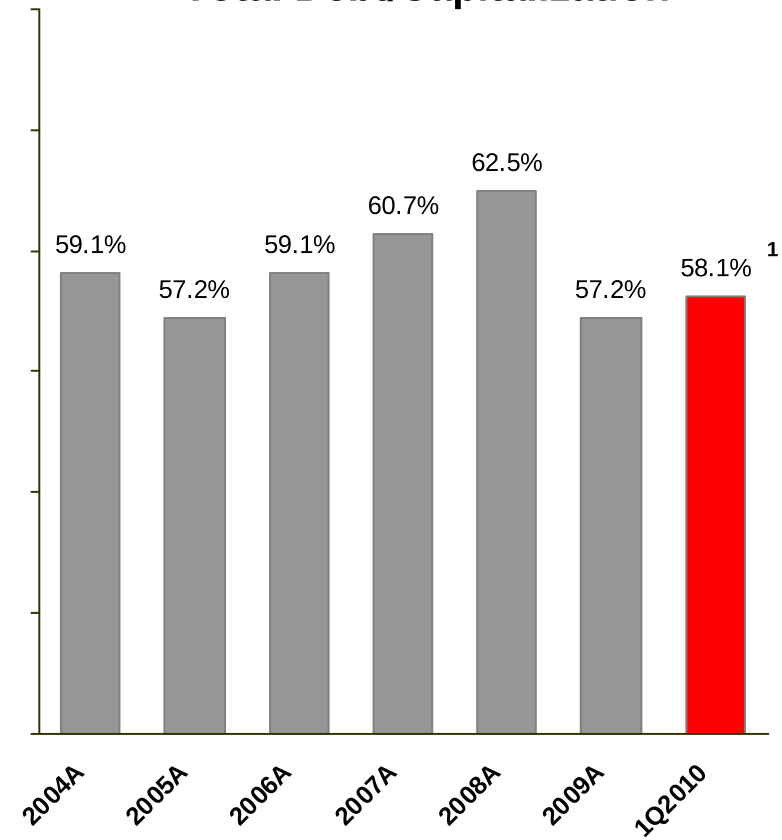
$ in millions	2008A	2009A	2010E	2011E
AEP River Operations	$115	$77	$16	$20
AEP Transco	0	1	$121	$175 - $325
Joint Venture Equity	$5	$47	$89	$155 - $355

Capital Expenditures by Operating Company

($ in millions)	2010E	2011E	Total
APCo	$380	$294	**$674**
I&M	$265	$238	**$503**
KPCo	$52	$71	**$123**
Texas Wires	$142	$256	**$398**
PSO	$166	$150	**$316**
SWEPCo	$446	$461	**$907**
CSP	$256	$187	**$443**
OPCo	$302	$267	**$569**
Other Utility Companies	$35	$37	**$72**
Total Utility Operations Capital	**$2,044**	**$1,961**	**$4,005**

Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $651 million are classified as short-term debt; The 1Q2010 debt/capitalization ratio would be 57.3%, excluding AEP Credit.

Current Liquidity Summary
As of June 24, 2010

Liquidity Summary (unaudited)	**Actual 06/24/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	740	
Less		
Commercial Paper Outstanding	(747)	
Letters of credit issued	(638)	
Net Available Liquidity	**$2,787**	

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 1
Attachment 1 - Confidential
Page 9475 of 9556

Long-term Debt Maturity Profile

($ in millions)

Year	2010	2011	2012	2013
AEP, Inc.	-	-	-	-
AEP Generating Company	-	$130	-	-
Appalachian Power	-	$250	$250	$70
Columbus Southern Power	$150	-	$195	$306
Indiana Michigan Power	-	-	$100	$102
Kentucky Power	-	-	-	-
Ohio Power	$200	-	-	$500
Public Service of Oklahoma	-	$75	-	-
Southwestern Electric Power	-	$41	$20	-
Texas Central Company(1)	-	$120	-	$535
Texas North Company	-	-	-	$225
Total	$350	$616	$565	$1,738

(1) Includes $535 million of amortizing Texas Securitization Bonds based upon scheduled final payment date

Includes mandatory tenders (put bonds)
Data as of June 24, 2010

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

	Moody's		S&P		Fitch	
Company	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB	S	BBB	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Central Company	Baa2	S	BBB	S	BBB+	S
AEP Texas North Company	Baa2	S	BBB	S	A-	S
Appalachian Power Company	Baa2	S	BBB	S	BBB	S
Columbus Southern Power Company	A3	S	BBB	S	A-	S
Indiana Michigan Power Company	Baa2	S	BBB	S	BBB	S
Kentucky Power Company	Baa2	S	BBB	S	BBB	S
Ohio Power Company	Baa1	S	BBB	S	BBB+	S
Public Service Company of Oklahoma	Baa1	S	BBB	S	BBB+	S
Southwestern Electric Power Company	Baa3	S	BBB	S	BBB	S

S=Stable, N=Negative Outlook

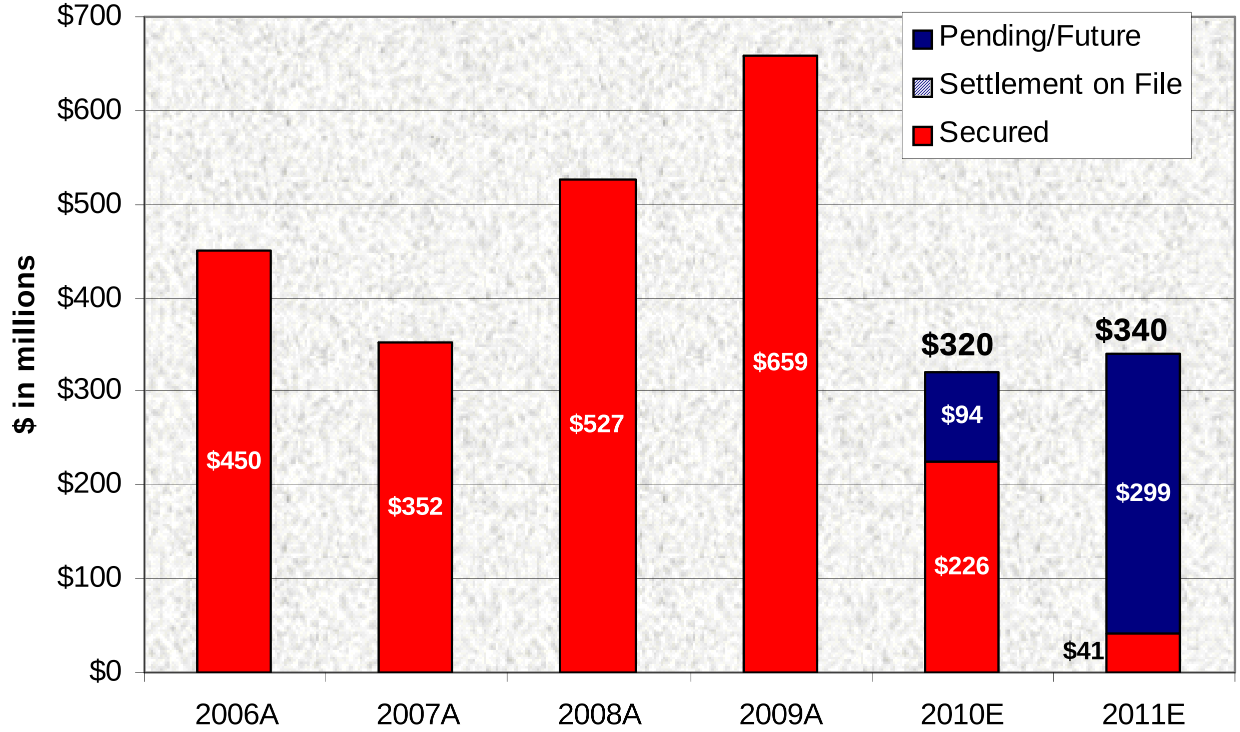
AEP & Operating Company Metrics

2009 Operating Company Metrics

Company	FFO Interest Coverage	FFO-to-Debt	Debt-to-Capitalization
American Electric Power Company Inc.	4.35x	18.6%	57.2%
Appalachian Power Company	3.02x	11.4%	57.1%
Columbus Southern Power Company	5.31x	25.9%	53.4%
Indiana Michigan Power Company	5.91x	28.9%	55.3%
Kentucky Power Company	4.20x	19.9%	56.0%
Ohio Power Company	5.34x	22.1%	49.9%
Public Service Company of Oklahoma	4.01x	18.7%	54.2%
Southwestern Electric Power Company	4.14x	19.3%	49.2%
Texas Wires [1]	3.48x	15.6%	57.0%

(1) Debt to Capitalization excludes securitization bonds

Traditional Rate Making Environment



Note: Rate relief in this chart excludes revenues with offsetting costs

Active or pending rate cases include Michigan, Virginia, West Virginia and others yet to be filed

Growth in rate base resulted in $2 billion of rate relief secured from 2006 through 2009

Base Rate Cases Recap

APCo - Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$154**	$33-$63
Rate base/investment	$2,057	$2,116
Return on equity	13.35%	10.1% - 10.4%
Equity component	41.61%	41.53%

Status: Hearings concluded on April 2, 2010. Briefs filed on May 18, 2010. Commission Order due July 15, 2010. Rates to be effective August 1, 2010.

APCo - West Virginia

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$224**	n/a
Rate base/investment	$2,640	
Return on equity	11.75%	
Equity component	42.63%	
Riders requested	Transmission/PJM	

Status: Case filed on May 14, 2010. Staff & Intervenor testimony due November 10, 2010.

I&M - Michigan

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$63**	n/a
Rate base/investment	$601	
Return on equity	11.75%	
Equity component	44.19%	
Riders requested	Numerous	

Status: Case filed on January 27, 2010. Hearings scheduled for August 9-17, 2010. Interim rates in effect July 26, 2010 ($44.3MM of original $62.4MM request). Proposal for decision expected by November 16, 2010.

Rate Case Settled

KPCo - Kentucky

	Company Filing	Staff / Intervenor Testimony
Rate increase	**$124**	$41
Rate base/investment	$995	$995
Return on equity	11.75%	10.10%
Equity component	42.91%	42.91%
Riders requested	Wind & Reliability	

Status: On May 19, a settlement agreement was filed with the KPSC providing for a $64 million annual rate increase, effective June 29, 2010. Ordered received June 28, 2010.

$441 million of total base rate increase requests on file

Summary Rate Case Information

APCo Virginia General Rate Case – Docket #PUE-2009-00030

On August 14, 2009, APCo filed an update to its pre-biennial base rate case, originally filed July 15, 2009 with the Virginia SCC, per the statute, for recovery of generation and distribution costs requesting an increase of $154 million. Hearings began on March 30, 2010 and an order is due no later than July 15, 2010.

Proposed Capital Structure – Company Position (12/31/08)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.135%	3.906%	0.12%
Long-Term Debt	54.815%	6.065%	3.32%
Preferred Stock	0.307%	4.352%	0.01%
Common Equity	41.607%	13.350%	5.55%
Other Items	0.136%	9.193%	0.01%
Total	100.00%		9.027%

Procedural Schedule

February 8, 2010	APCo Revised Testimony due
March 8, 2010	Staff Testimony due
March 17, 2010	APCo Rebuttal Testimony due
March 30, 2010	Hearing Commences
July 15, 2010	Final order

Required Rate Relief – Company Position (12/31/08)

($ in millions)

Rate Base	$	2,057.4 *
Rate of Return		9.03%
Operating Income Requirement	$	185.7
Adjusted Operating Income	$	92.0
Difference	$	93.7
Revenue Conversion Factor		1.64
Total Required Rate Relief	$	154

Rate base as of December 31, 2008, updated for known and measurable changes through November 30, 2010.

*Represents Generation and Distribution Rate Base Only

Summary Rate Case Information

I&M Michigan General Rate Case – Docket #U-16180

On January 27, 2010, I&M filed a base rate case with the Michigan Public Service Commission requesting an increase of $62.5 million to cover increased costs related to distribution O&M, taxes, interest and employee related expenses. I&M also requested new tracker mechanisms for enhanced distribution reliability spending, energy efficiency, investments in generation and participation in PJM. The requested ROE is 11.75%. An order is expected in early 2011.

Forecasted Capital Structure – Company Position (12/31/10)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	0.88%	1.54%	0.01%
Long-Term Debt	43.95%	6.40%	2.81%
Common Equity	44.19%	11.75%	5.19%
Other Items	10.77%	1.22%	0.13%
Preferred Stock	0.21%	7.19%	0.02%
Total	100.00%		8.16%

Procedural Schedule

July 1, 2010	Staff and Intervenor Testimony due
July 16, 2010	I&M Rebuttal Testimony due
July 26, 2010	Rates effective subject to refund
August 9, 2010	Hearing commences
November 16, 2010	Proposal for Decision due

Required Rate Relief – Company Position (12/31/10)
($ in millions)

Rate Base	$	600.9
Rate of Return		8.16%
Operating Income Requirement	$	49.0
Adjusted Operating Income	$	19.7
Difference	$	29.4
Revenue Conversion Factor		1.6171
Revenue Deficiency	$	47.5
OATT Costs	$	4.7
OSS Sharing	$	5.1
Net Loss Revenue Recovery Rider	$	1.2
gridSMART Cost Recovery Rider	$	1.5
Distribution Reliability Cost Recovery Rider	$	2.6
Generation Investment Cost Recovery Rider	$	-
Total Required Rate Relief	$	62.5

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Transmission Investment Opportunities

- ETT: Projects in Texas ERCOT jurisdiction
  - $600MM of projects est. in service 2010-2013
  - ETT's opportunity could reach $3.0B in this decade
- Transco: Within our existing footprint
  - Provides opportunity to:
    - Develop new AEP-only projects
    - Reduce regulatory lag through FERC formula rates adjusted annually
- Joint Ventures: Outside of our footprint, via ETA or with others
  - Opportunity to earn FERC incentive rates (12.5% - 14.3%) and CWIP recovery
  - Currently four FERC-approved projects ($3.3B), estimated in-service 2013-2015
  - Robust pipeline of projects up to $15B

765-kV Tower

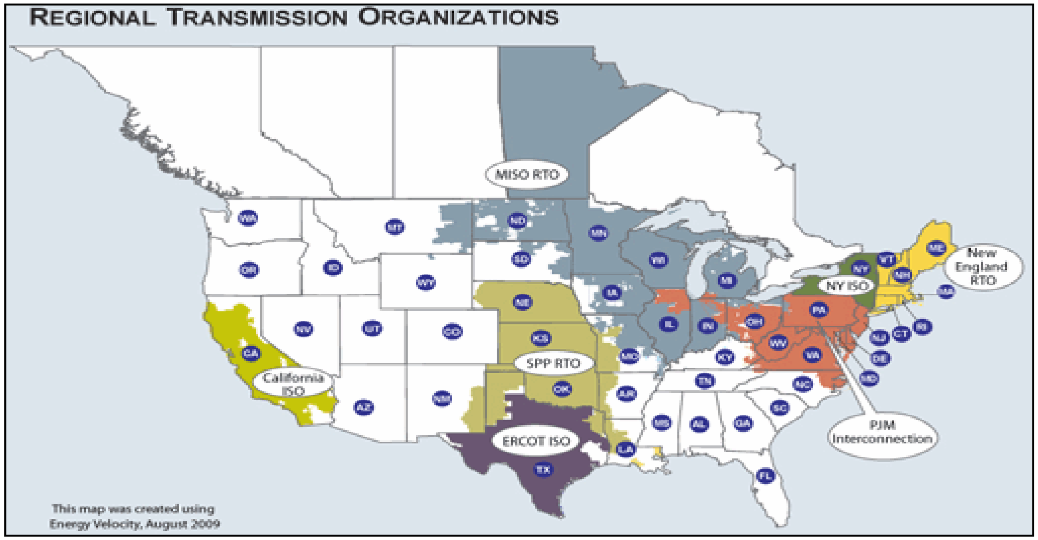
Making it Happen: EHV Projects Under Development

ACTIVE PROJECTS

SPP	ERCOT	PJM	PJM/MISO
Prairie Wind — COD: 2013-14	**ETT** — COD: 2010-2017	**PATH-WV** — COD: 2015	**Pioneer** — COD: 2015
■ *110 miles of 765 kV* ■ *Partners: Westar (50%) & Electric Transmission America (50%)* ■ *Estimated Cost: $400 million* ■ *ROE: 12.8%*	■ *345 kV ERCOT Expansion* ■ *Partner: MidAmerican Energy (50%)* ■ *Estimated Cost: $1.4 billion* ■ *ROE: 9.96%*	■ *275 miles of 765 kV* ■ *Partner: Allegheny Energy (50%)* ■ *Estimated Cost: $1.2 billion* ■ *ROE: 14.3%*	■ *240 miles of 765 kV* ■ *Partner: Duke Energy (50%)* ■ *Estimated Cost: $1 billion* ■ *ROE: 12.54%*

Tallgrass — COD: 2013-14

- *170 miles of 765 kV*
- *Partners: OG&E (50%) & Electric Transmission America (50%)*
- *Estimated Cost: $500 million*
- *ROE: 12.8%*



FUTURE DEVELOPMENT

SMARTransmission Study

- *Interregional EHV & Wind Integration Study*
- *Study Sponsors: ETA, ATC, Exelon, MidAmerican Energy, Northwestern Energy, Xcel Energy*

SPP	ERCOT	PJM	PJM/MISO
SPP EHV Overlay	**ETT** — COD: various	**PJM Expansion**	**EHV Michigan/Ohio**
■ *Regional Expansion of 765 kV Backbone*	■ *Additional CREZ spend of ~ $1.1 billion (COD 2012-2013, subject to a 6-month routing approval)* ■ *Other Projects Pending Transfer of ~ $600 million (COD 2010-2013)*	■ *Regional Expansion of 765 kV, 500 kV and 345 kV systems*	■ *700 miles of Proposed 765 kV*

Electric Transmission Texas, LLC

Overview:

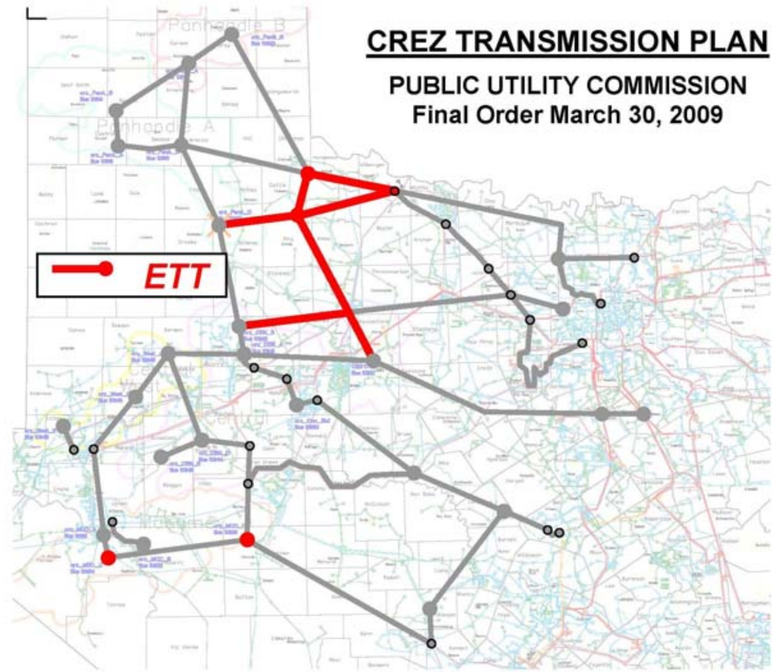
- ETT is a 50/50 JV between AEP and MidAmerican Energy Holding Company that plans to construct and operate transmission projects within ERCOT with an investment opportunity of more than $3 billion.
- Current JV rate base is $127 million with an additional $262 million requested in the current ITCOS filing, resulting in a total anticipated rate base of $389 million; debt to capital ratio of 60/40 and an authorized ROE of 9.96%.

Opportunities:

- Projects in service 2010-2018: $1.4 billion
- CREZ projects in service 2012-2013: $1.1 billion
- Other projects representing recent and pending transfers in service 2010-2014: approaching $600 million

Next Steps:

- Perform preliminary engineering and routing work on assigned projects, in order to file for transmission line CCN approvals in 2010.



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

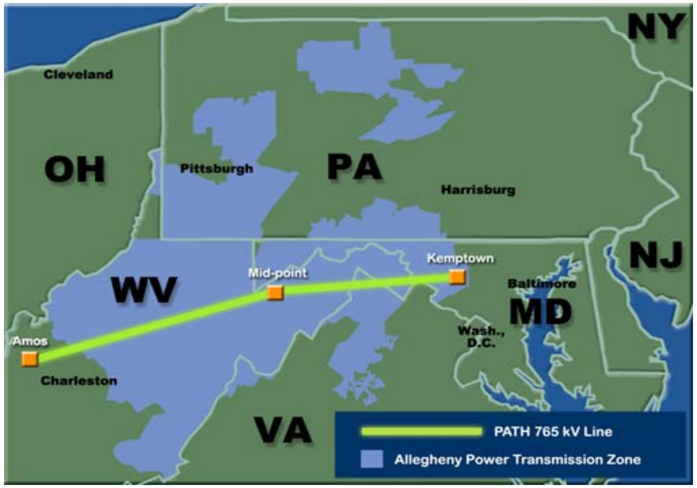
Electric Transmission Texas

EHV Transmission in PJM: PATH

Project Description: 275 miles of 765-kV transmission line from AEP's John Amos substation near St. Albans, W.Va., through a new midpoint station, ending at a new substation near Kemptown, MD.

Overview:

- FERC order issued on February 29, 2008 approving:
  - Cash return on CWIP and 14.3% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned as a result of factors beyond the control of PATH or its parents
  - Rates went into effect March 1, 2008
- Total estimated cost of entire line is $1.8 billion; AEP's 50/50 JV with Allegheny will develop West Virginia section at a cost of $1.2 billion. AEP share is approximately $600 million.
  - A budget reforecast effort is currently underway. Total project cost will likely increase due to delays in the original 2012 in-service date.
- Estimated completion date: June 1, 2015, pending outcome of the 2010 PJM Regional Transmission Expansion Plan (2010 RTEP).



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

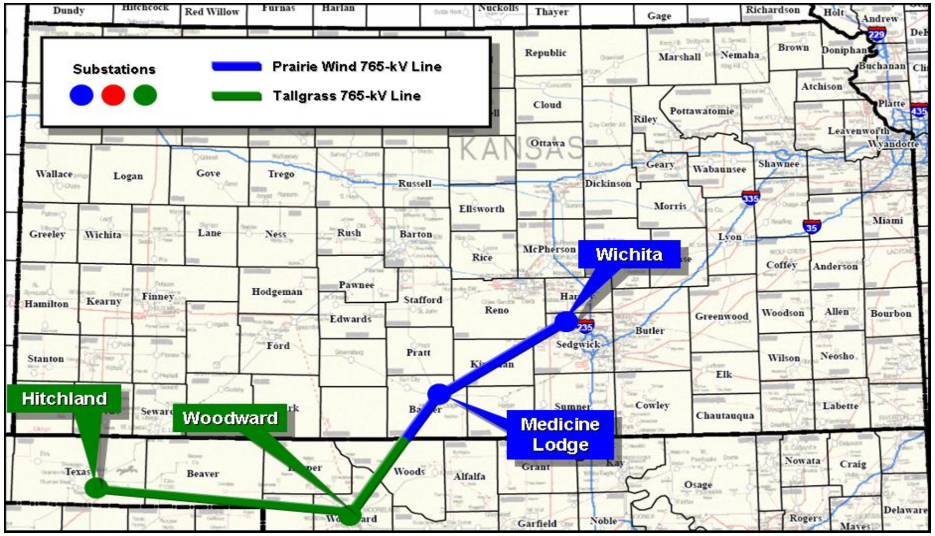
- Obtaining a CPCN in West Virginia, Virginia and Maryland. CPCN applications in West Virginia and Maryland are pending because their procedural schedule allows the consideration of the 2010 RTEP. A new application in Virginia is expected in the third quarter of 2010 after consideration of the 2010 RTEP.

PATH
Potomac-Appalachian Transmission Highline

Prairie Wind Transmission, LLC

Overview:

- In May 2008, ETA signed an agreement with Westar Energy to form Prairie Wind Transmission, LLC (PWT).
- PWT is a 50/50 JV that is proposing to build approximately 110 miles of 765-kV lines extending from Wichita, KS.
- The project will provide enhanced electricity transport in Kansas and support expansion of renewable electricity generation in the region.
- The project is expected to cost approximately $400 million and be in-service by 2013-2014 and was approved by the KCC on July 24, 2009.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice to construct anticipated to be received summer 2010.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $165 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

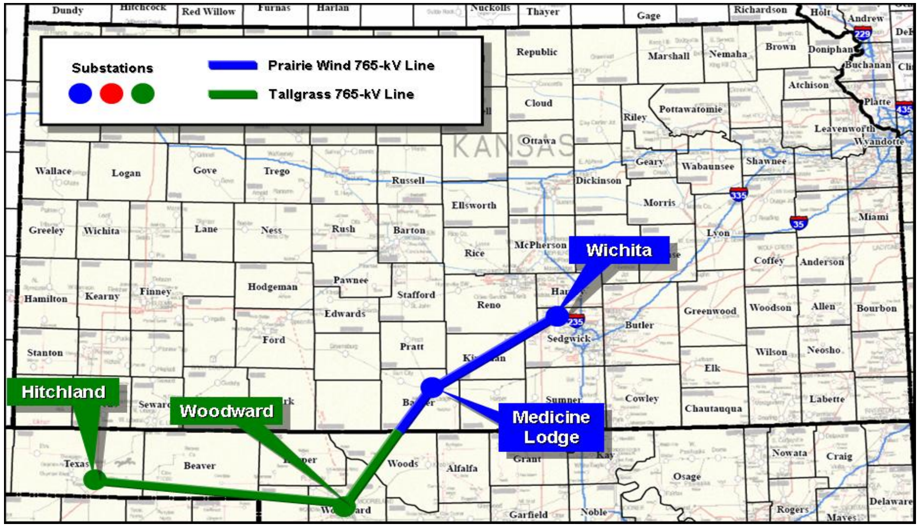
Key Challenges:

- Siting

Tallgrass Transmission, LLC

Overview:

- In July 2008, ETA signed an agreement with Oklahoma Gas & Electric to form Tallgrass Transmission, LLC (TG).
- TG is a 50/50 JV that is proposing to build approximately 170 miles of 765-kV lines in Oklahoma.
- The project will promote wind development in the western half of Oklahoma.
- Project is expected to cost approximately $500 million and be in-service by 2013-2014.
- AEP's ownership of the joint venture is 25%.
- FERC order received in December 2008:
  - Cash return on CWIP and 12.8% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned
- Project was approved as SPP Priority Project in April 2010
  - Notice to construct anticipated to be received summer 2010.
  - Currently approved at 345 kV. Cost at 345 kV estimated to be $350 mm. May revert to 765 kV depending on results of SPP ITP study.



Total SPP 765-kV Overlay estimated to cost approximately $7 Billion by SPP March 2008 study, portions of which are proposed for construction by ETA and its partners.

The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

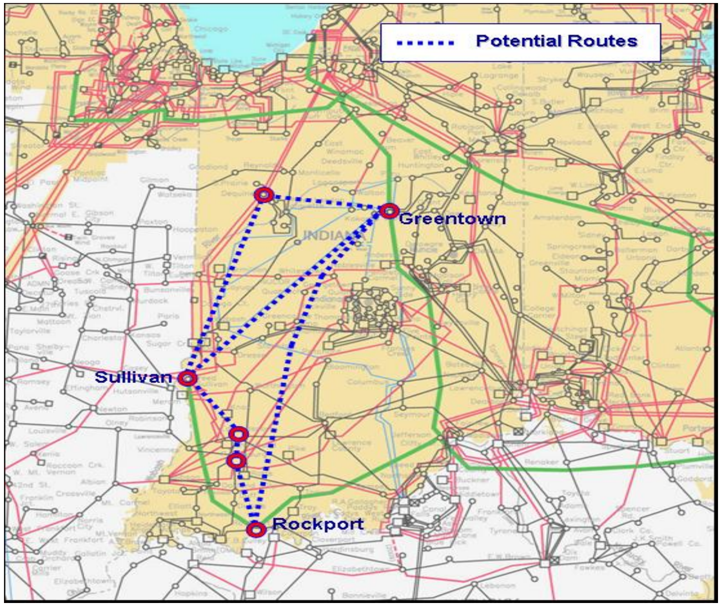
Key Challenges:

- Siting

Pioneer Transmission, LLC

Overview:

- In August 2008, AEP signed an agreement with Duke Energy to form Pioneer Transmission, LLC (PT).
- PT is a 50/50 JV that is proposing to build approximately 240 miles of 765-kV lines extending from AEP's Rockport Station to Duke's Greentown station in Indiana.
- The project will improve the reliability of the transmission grid, allow more efficient use of existing electricity production and delivery infrastructure, and expand opportunities for new generation, including renewables.
- The project is expected to cost approximately $1 billion and be in-service by 2015.
- AEP's ownership of the joint venture is 50%.
- FERC order received March 2009:
  - Cash return on CWIP and 12.54% incentive ROE
  - Recovery of all costs incurred prior to the time rates go into effect
  - Recovery of all prudently incurred development and construction costs if the project is abandoned



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Key Challenges:

- RTO Approval (PJM & MISO)
- Cost allocation which enables the development of "system solutions"
- Siting

Upper Midwest EHV Development—SMART Study

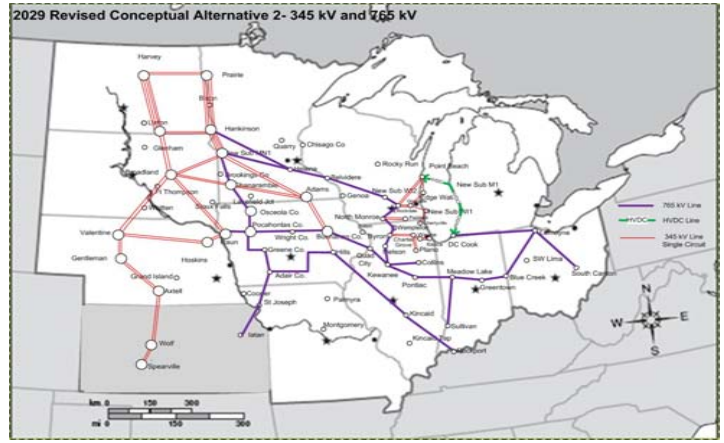
Project Description: a comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development and transporting that energy to consumers throughout the study area. The SMART Study will develop EHV overlay alternatives that ensure reliable service for sponsors' communities, is environmentally friendly, and supports national energy policy.

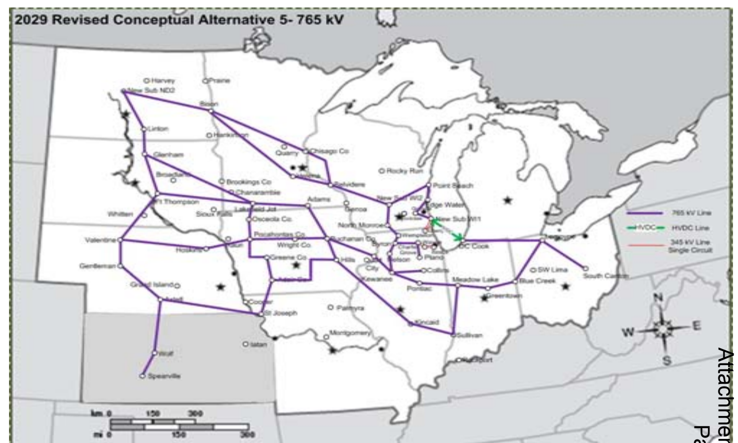
Overview:

- SMARTransmission Study announced August 2009
- Primary Focus Areas: North Dakota, South Dakota, Iowa, Nebraska, Indiana, Ohio, Illinois, Minnesota, Wisconsin, Michigan
- Study Sponsors include: ETA, Exelon, ATC, Northwestern, MidAmerican Energy Company, and Xcel
- Phase 1 completed April 30
- Phase 2 anticipated completion: June 30
  - Studying two alternatives in Phase 2. One combination 345 kV / 765 kV. One primarily 765 kV.

Next Steps:

- Investment structure
- Obtaining cost allocation between states, PJM, and MISO
- RTO technical approvals
- Favorable 205 Order including incentives

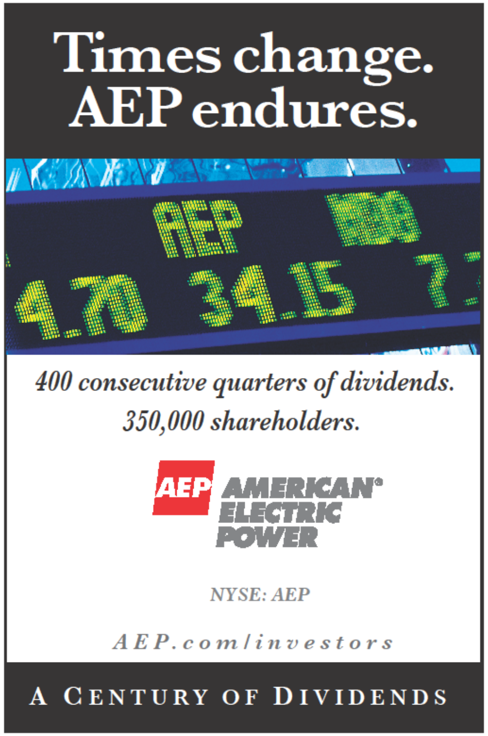




The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Value Proposition

- **Current Yield Opportunity of 5.1%[1]**
  - June 10th - 400th consecutive quarterly dividend was paid to shareholders
  - 50-60% payout ratio targeted
  - Dividend increased 2.44% on April 27th
- **Earnings Growth Prospects**
  - Investment in utility platform greater than depreciation level (2 - 4%)
  - With transmission opportunities (4 - 8%)



Attractive total return potential

[1] yield percentage based on AEP closing price of $32.99 on 06/25/2010

AEP AMERICAN® ELECTRIC POWER

Wells Fargo 9th Annual Pipeline, MLP & Energy Symposium Handout

December 8, 2010
New York, NY

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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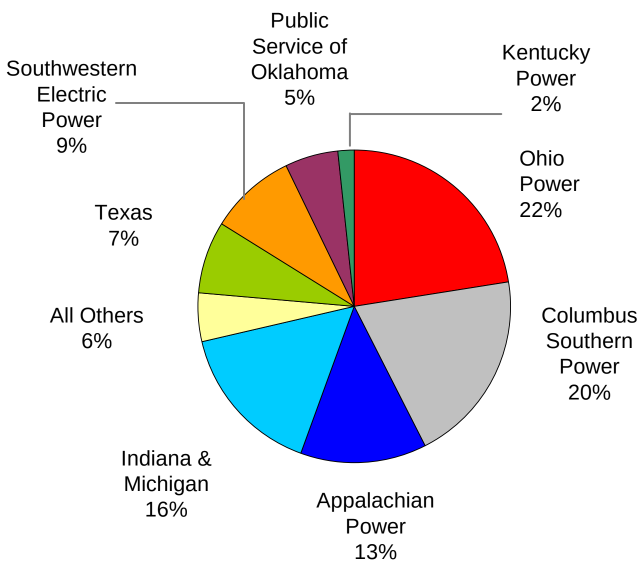
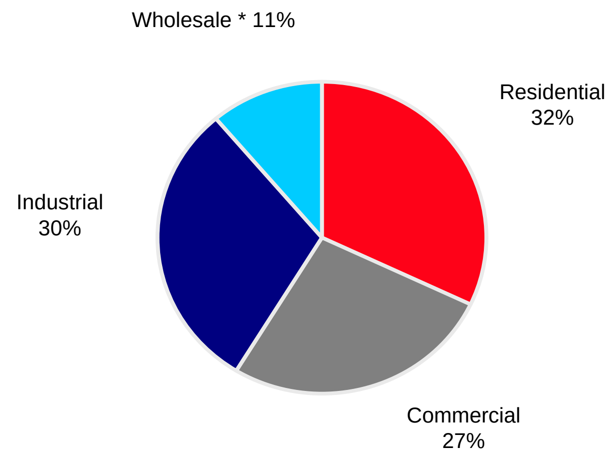
Highly Diversified Regulated Utility Platform

2009 Earnings Contribution



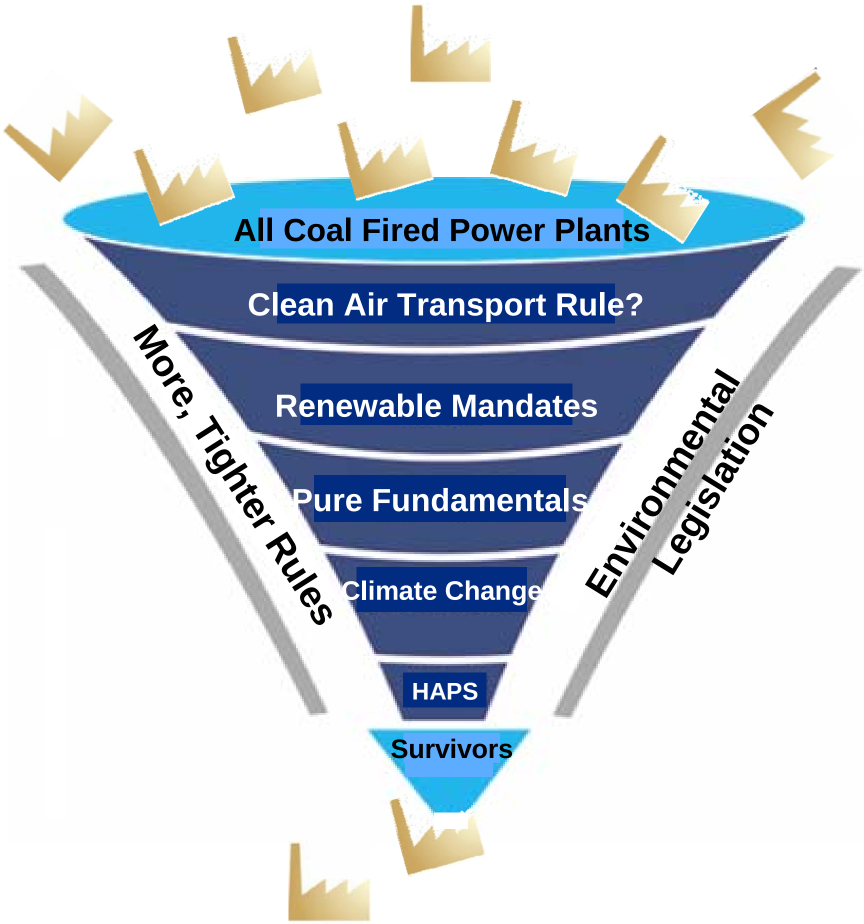
2009 Retail Load



* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,006,000
Indiana & Michigan	583,000
Kentucky Power	175,000
Ohio & Wheeling	1,500,000
PSO (Oklahoma)	531,000
SWEPCO (AR, LA, TX)	474,000
Texas	951,000

The Pressure on Coal Generation



Dark Spread Compression
NYMEX coal

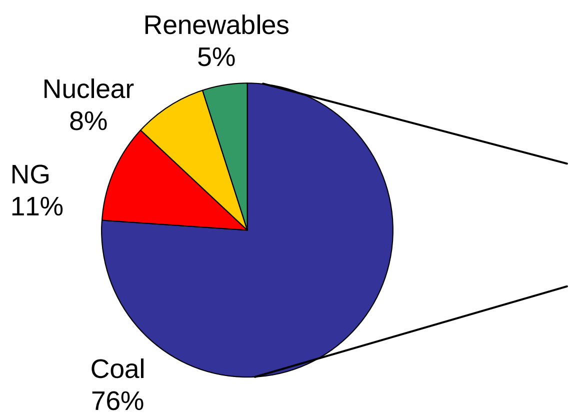
Key EPA Actions Pending

- Transport Rule – Proposed July 2010
- “Coal Ash” Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in Spring 2011

The threshold level for coal is being defined

AEP Generation Capacity

East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro

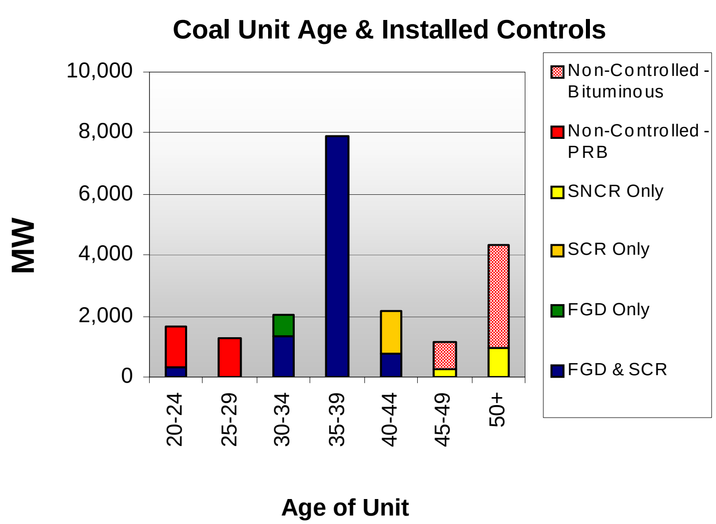


Coal Source

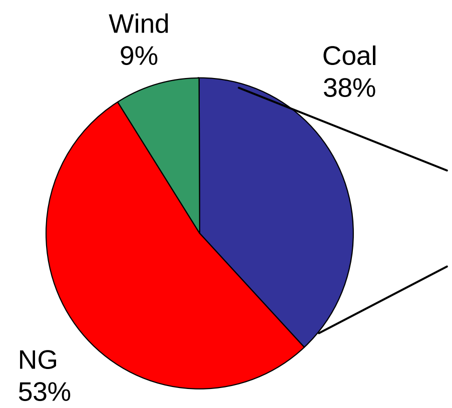
NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - \$56/ton
2010E - \$52/ton
2011E[1] - \$51/ton

[1] Represents cost of committed position (91%)



West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind

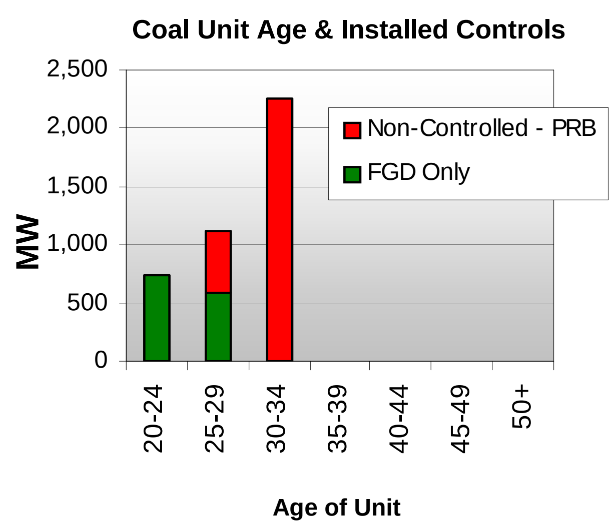


Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - \$29/ton
2010E - \$29/ton
2011E[1] - \$29/ton

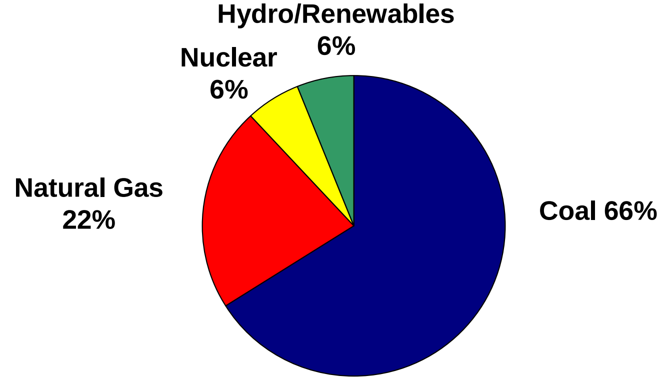
[1] Represents cost of committed position (90%)



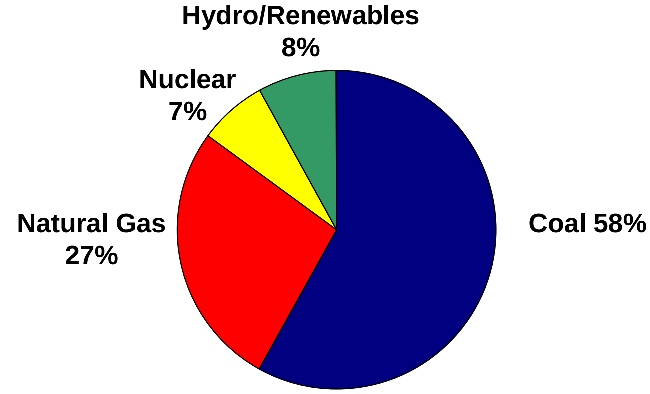
Continued Investment in Utility Platform

AEP®

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of "partially exposed" units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2009



Projected Capacity - 2017

Transmission as a Growth Engine

- Electric Transmission Texas (ETT)
  - Growing Rate Base
  - $1.1B CREZ opportunity; Received CCN approval on first CREZ line; 3 more approvals expected in 2011
  - $1.6B Non-CREZ projects in the pipeline
- AEP Transmission Company (AEP Transco)
  - Settlement filed at FERC for wholesale rates
  - $50M spend for 2010; $160M forecasted for 2011
- Progress on Joint Ventures in 2010
  - PATH
  - Prairie Wind
  - Pioneer
  - SMART Transmission study

Transmission investments present significant growth opportunities within and outside of AEP's traditional service territories

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ETT: An Operating Utility

AEP®

ETT Electric Transmission Texas

Growing Rate Base:

- Current rate base is $385 million; expected to grow as follows:
  - 2010: $405 million
  - 2011: $465 million
  - 2012: $765 million
  - 2013: $1,415 million
- Interim TCOS filings twice per calendar year

Assigned Competitive Renewable Energy Zone (CREZ) Projects ~$1.1 B:

- Seven double-circuit 345kV transmission lines (~$750 M), eight major 345kV stations and several series compensation installations (~$350 M)
- PUCT Certificate of Convenience and Necessity (CCN) proceedings underway

CREZ Transmission Line	Number of miles	Estimated Cost ($M)	CCN Filing Date	CCN Decision by PUCT
Clear Crossing to Dermott	**95**	**$160**	**5/3/2010**	**Unanimously Approved 9/30/2010**
Tesla to Riley	65	$110	8/18/2010	2/15/2011
Riley to Edith Clarke to Cottonwood	115	$199	9/8/2010	3/8/2011
Tesla to Edith Clarke to Clear Crossing to West Shackelford	145	$280	Anticipated 10/20/2010	4/20/2011

Additional Projects in the Pipeline ~$1.6 B:

- Approximately 822 miles of lines and 28 substations with in-service dates through 2017

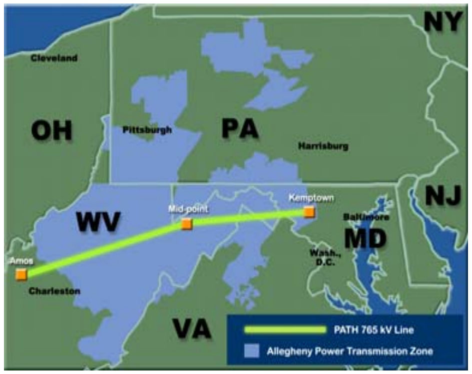
AEP Transco was established in 2010

- Formula rate settlement filed with FERC in September; awaiting final order
  - ROE: 11.49% in PJM and 11.2% in SPP
- $50 M invested in three states in 2010 (OH, MI & OK)
  - Ohio application for public utility status pending; approval expected in 2010
  - Oklahoma and Michigan did not require filings
- “Baseline” capital spending targets for OH, MI & OK
  - $160 M for 2011
  - $350 M for 2012
- Will pursue regulatory approvals for other states in 2011 (AR, LA, WV, VA, IN & KY)
  - Additional capital spending opportunity in these states for 2012+

Progress on Joint Ventures in 2010

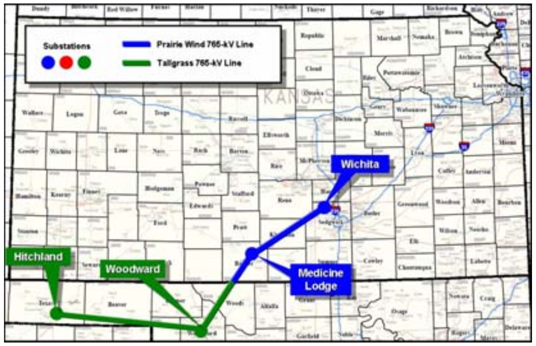
PATH:

- Re-filed for certification in VA
- Letter from PJM confirmed the 2015 in-service date
- PJM Testimony “RTEP final with respect to PATH”
- FERC approved formula rate (14.3% ROE), subject to rehearing



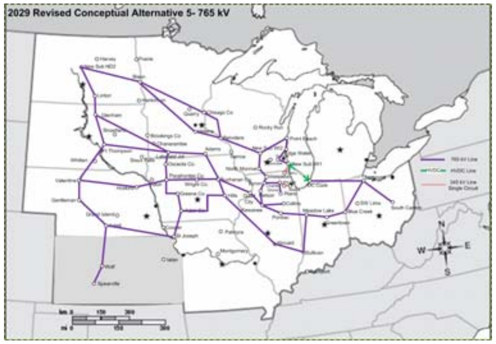
Prairie Wind:

- Approved by SPP as a Priority Project (Notice To Construct rcv’d)
- Cost allocation approved by SPP and FERC
- FERC approved formula rate (12.8% ROE)
- In-service date is 2013-2014



Pipeline of Future Projects:

- Pioneer
  - FERC approved formula rate (12.54% ROE)
  - Awaiting RTO project approval; MISO included Pioneer in its proposed EHV plan
- Tallgrass
  - Will move forward if approved at 765 kV
- Smart Transmission Study
  - Comprehensive study of the transmission needed in the Upper Midwest to support renewable energy development



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Two New Anchor Projects

ETA – AEP - Exelon: The RITE Line

Approximately 420 miles of 765 kV lines connecting AEP's 765 kV system in Indiana with Exelon's 765 kV system west of Chicago, and other Exelon substations

- Total Project Cost ~$1.6B
- Ensures reliability, renewables integration
- Bridges AEP's and Exelon's 765 kV systems
- PJM approval of seams project required
- Includes 765 kV and 345 kV voltages, and their electrical equivalents

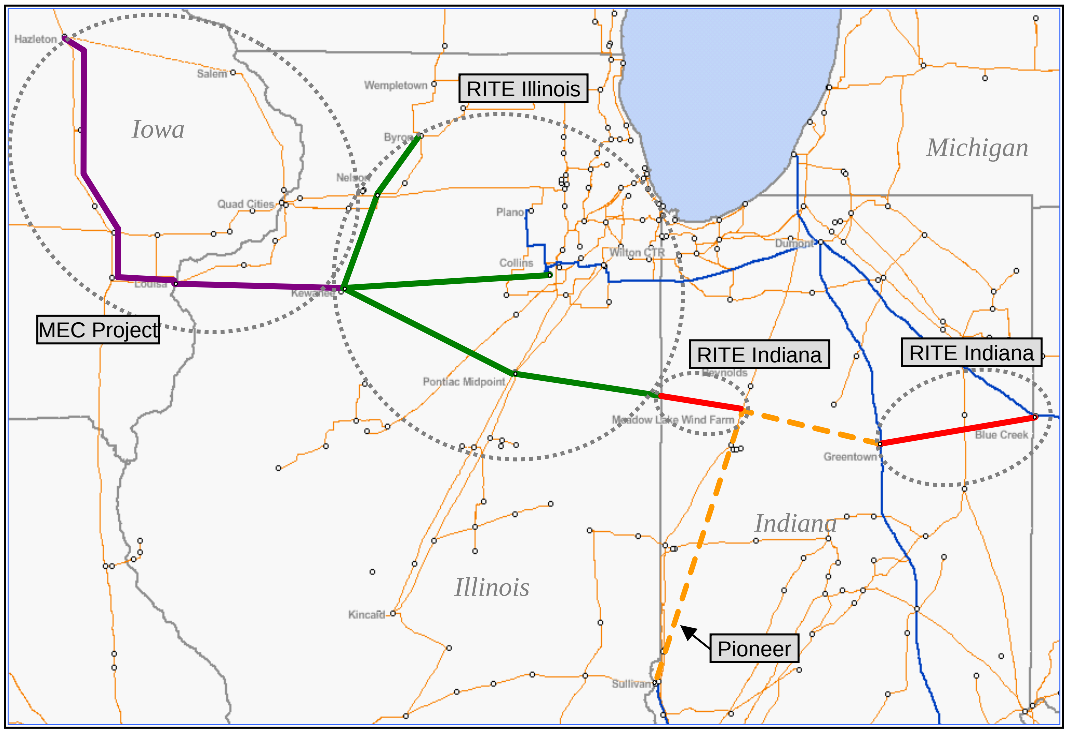
ETA – MidAmerican Energy Co: MEC Project

Approximately 180 miles of 765 kV lines connecting MEC's EHV system in eastern Iowa to proposed 765 kV expansion in western Illinois.

- Total Project Cost: ~$650M
- Project part of SMARTransmission study and Midwest ISO RGOS planning effort
- MISO approval
- Includes 765kV and 345kV voltages, and their electrical equivalents

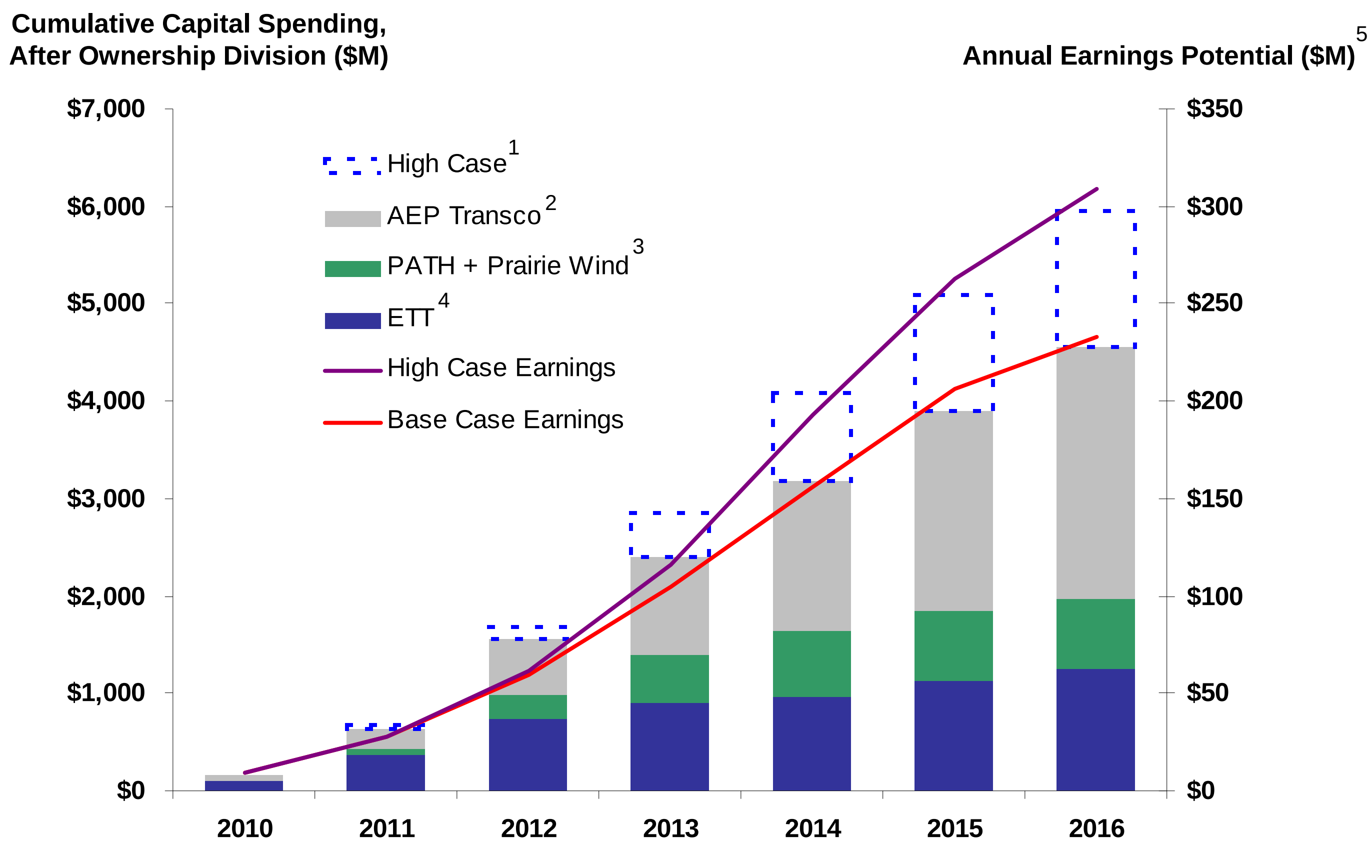
AEP Total Investment:

~$500M



The ROW routes shown on this diagram are for illustrative purposes only and may not depict the actual route that could eventually be selected. The substation locations may also be modified.

Capital Investment and Earnings Profile



[1] High Case includes: Pioneer (50% ownership), Prairie Wind at 765kV (25% ownership), Tallgrass at 765kv (25% ownership) and other future opportunities

[2] AEP Transco (100% ownership) includes spending in OH, MI & OK only through 2011 and in other jurisdictions for 2012 and beyond

[3] PATH (50% ownership) assumes an in-service date of 2015 and Prairie Wind (25% ownership) assumed at 345kV

[4] ETT (50% ownership) includes CREZ and additional projects

[5] Projection of earnings potential at the transmission holding company level assuming 50/50 debt/equity capitalization and ROE of 12-13% for FERC projects; 60/40 debt/equity capitalization and 10.25% ROE (2011 forward) for ERCOT projects; and 50/50 debt/equity capitalization and ROE of 11.2-11.49% for Transco projects

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

- Capital for Growth
  - Increased capital budget by $150M for 2011 to $2.6B
  - Announced capital budget plan of $2.9B for 2012
- Return of Capital to Shareholders
  - 9.5% increase in quarterly dividend to $0.46/share declared by the board of directors on October 26th
  - Future dividend increases will grow with earnings
- Capital to Reduce Risk
  - Voluntarily funding pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Detailed Ongoing Earnings Guidance

2010E: $2.95 - $3.05

2011E: $3.00 - $3.20

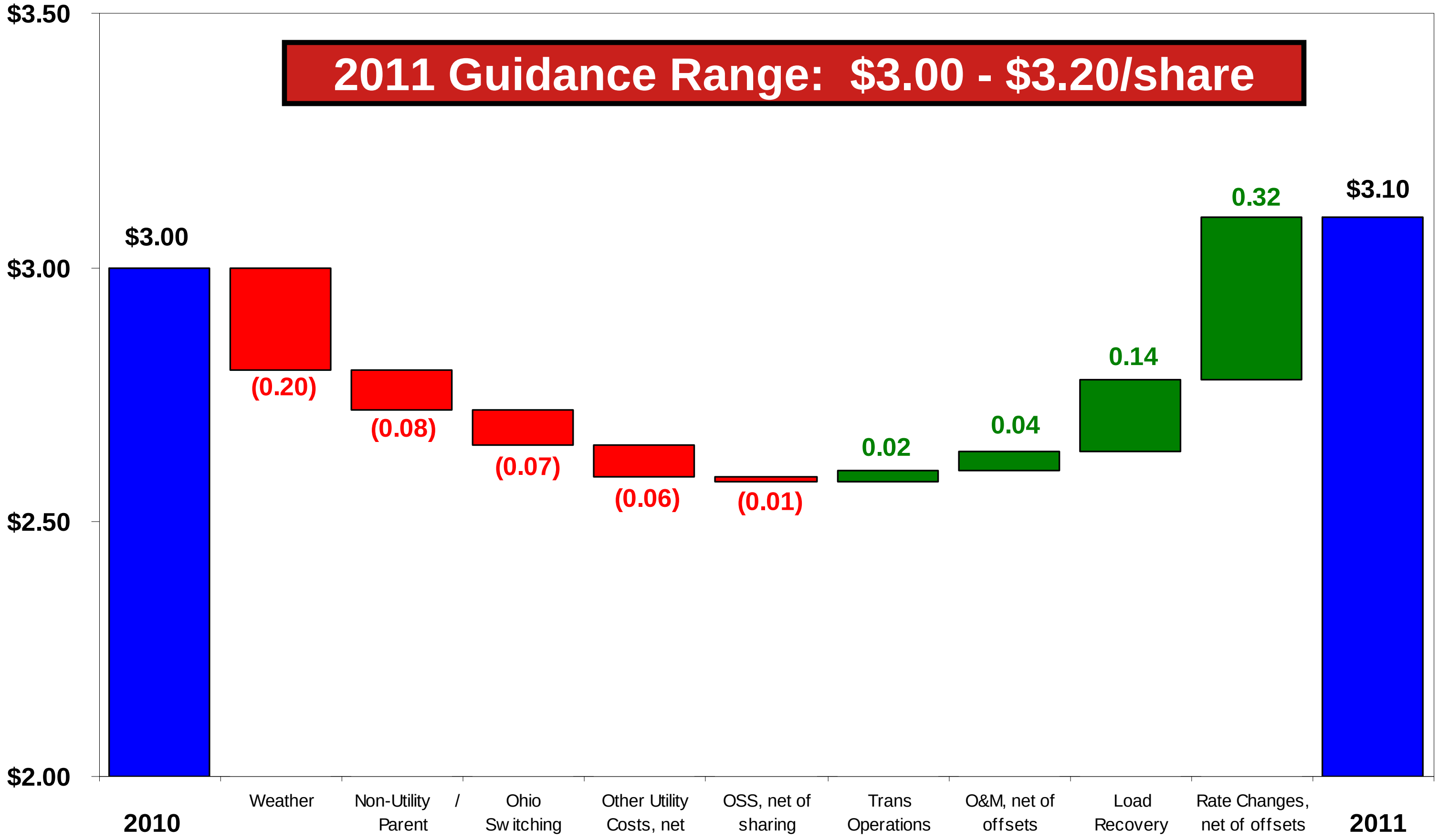
American Electric Power

Financial Results for 2011 Guidance vs 2010 Projection

		Performance Driver	2010 Projection ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,057 GWh @ $ 41.9 /MWhr =	2,851	67,739 GWh @ $ 43.8 /MWhr =	2,969
2	Ohio Companies	48,771 GWh @ $ 57.6 /MWhr =	2,810	49,770 GWh @ $ 55.7 /MWhr =	2,772
3	West Regulated Integrated Utilities	41,912 GWh @ $ 31.5 /MWhr =	1,321	41,536 GWh @ $ 33.1 /MWhr =	1,375
4	Texas Wires	27,783 GWh @ $ 22.2 /MWhr =	618	27,870 GWh @ $ 22.0 /MWhr =	613
5	Off-System Sales	19,413 GWh @ $ 15.1 /MWhr =	293	21,648 GWh @ $ 13.2 /MWhr =	286
6	Transmission Revenue - 3rd Party		359		425
7	Other Operating Revenue		527		445
8	Utility Gross Margin		8,779		8,885
9	Operations & Maintenance		(3,418)		(3,516)
10	Depreciation & Amortization		(1,617)		(1,538)
11	Taxes Other than Income Taxes		(804)		(814)
12	Interest Exp & Preferred Dividend		(957)		(940)
13	Other Income & Deductions		146		187
14	Income Taxes		(740)		(791)
15	Utility Operations On-Going Earnings		1,389		1,473
16	Transmission Operations On-Going Earnings		10		23
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		42		51
18	Generation & Marketing		20		2
19	Parent & Other On-Going Earnings		(22)		(53)
20	ON-GOING EARNINGS		1,439		1,496

Note: For analysis purposes, certain financial statement amounts have been reclassified for this effect on earnings presentation.

2011 Earnings Drivers



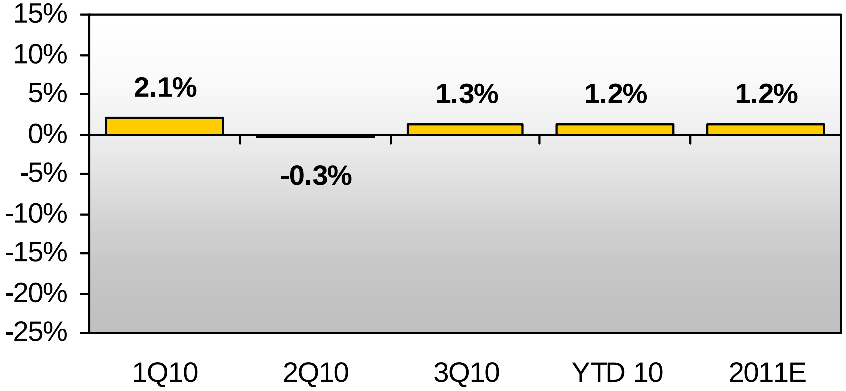
- $235M in rate changes (67% secured)
- Weather normalized load growth of 1.7%
- Transmission operations contributes $13M
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

Note: represents incremental change from 2010 to 2011

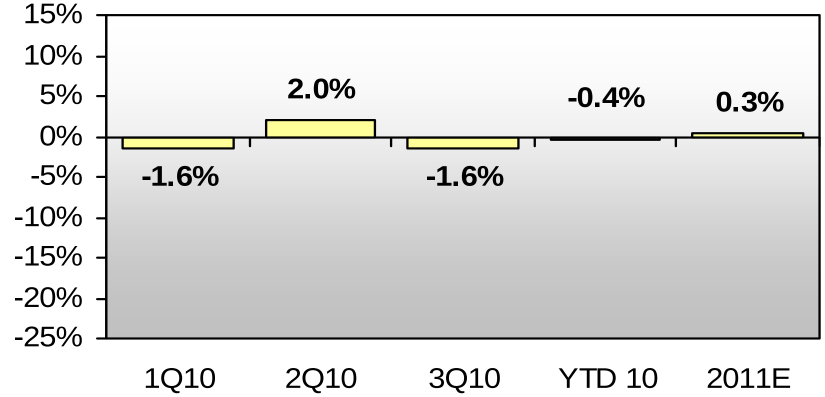
2012 EPS Target: $3.25/share

Normalized Load Trends

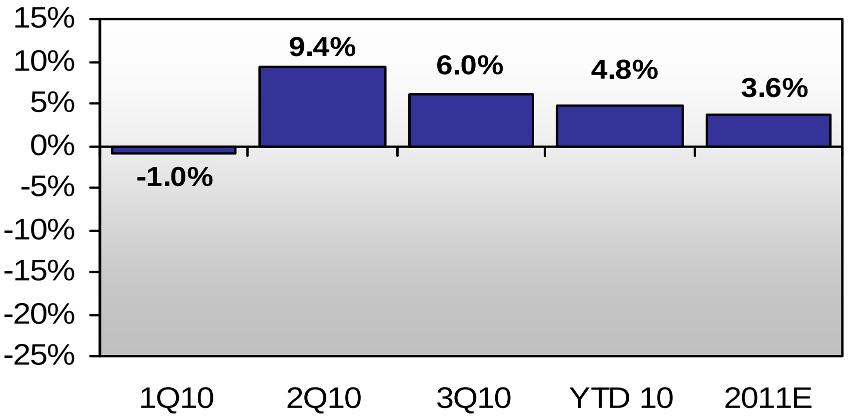
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



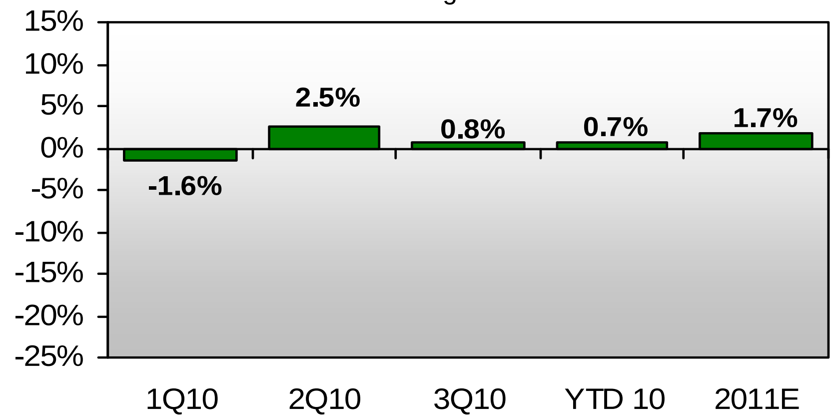
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: 2011E is based off of full year 2010 results
Chart represents connected load

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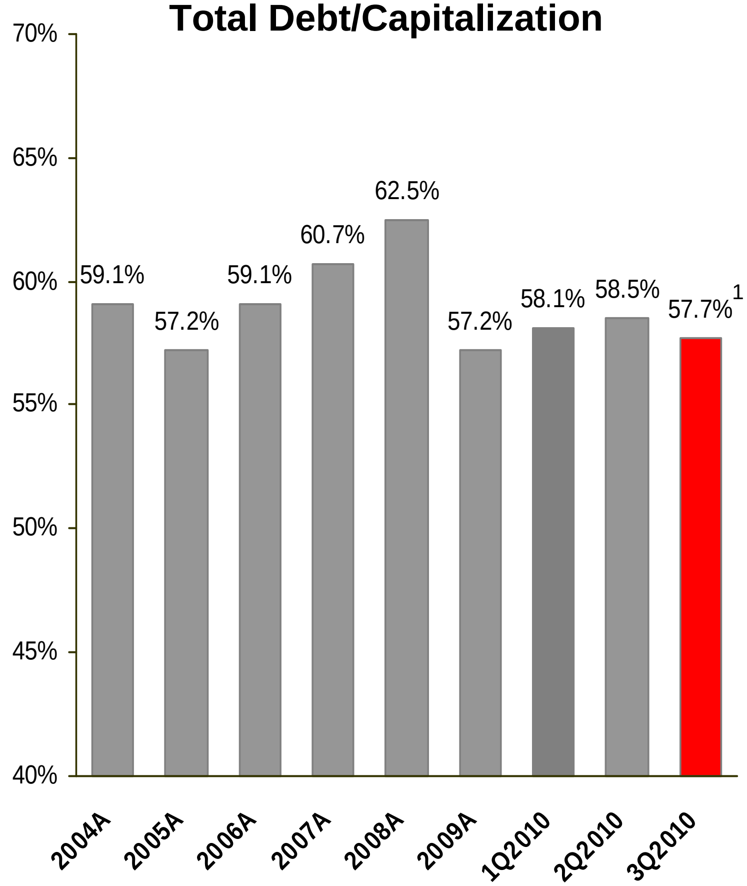
Maintaining Strong Capitalization & Liquidity

Total Debt/Capitalization



Note: Total Debt is calculated according to GAAP and includes securitized debt

1: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 3Q2010 debt/capitalization ratio would be 56.8%, excluding AEP Credit.

Current Liquidity Summary

Liquidity Summary (unaudited)	**Actual 09/30/10**	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
AEP, Inc. cash and investments	1,090	
Less		
Commercial Paper Outstanding	(713)	
Letters of credit issued	(602)	
Net Available Liquidity	**$3,207**	

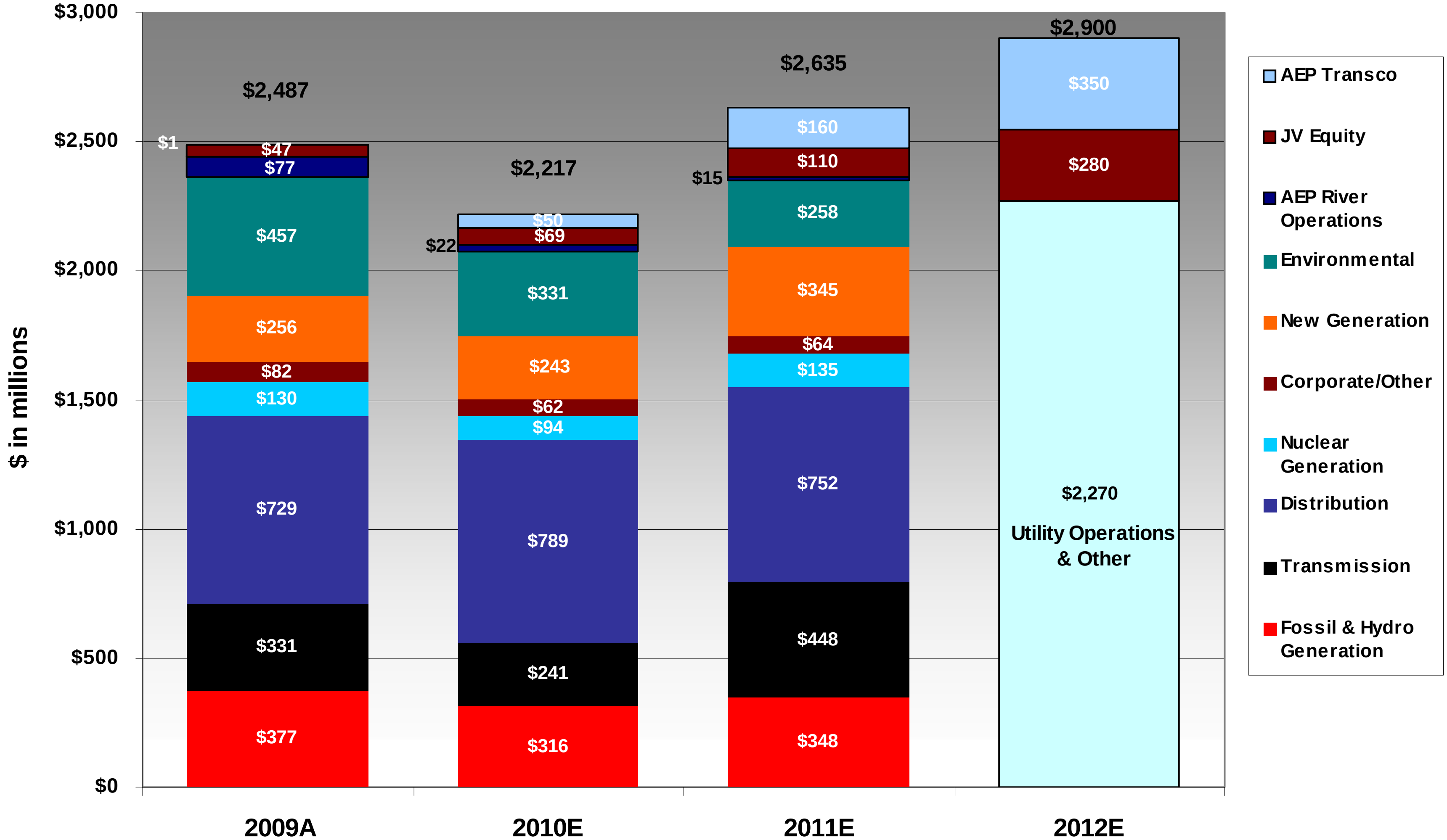
Cash Flow Guidance

$ in millions

		2010E		2011E
Cash From Operations				
Income from Continuing Operations	$	1,205	$	1,499
Depreciation & Amortization		1,654		1,588
Pension Funding		(500)		(150)
Other Cash Flow Items		653		234
Working Capital[1]		(218)		424
Cash From Operations	$	2,794	$	3,595
Investing Activities				
Construction Expenditures		(2,217)		(2,635)
Other Investing Activity		(352)		(265)
Total Investing Activities	$	(2,569)	$	(2,900)
Financing Activities				
Dividends		(826)		(893)
Net Debt Issued/(Retired)[1]		190		48
Common Equity		121		150
Total from Financing Activities	$	(515)	$	(695)
Beginning Cash Balance	$	490	$	200
Ending Cash Balance	$	200	$	200

[1] 2010 pro forma to exclude effects of consolidation of AEP Credit ($656)

Capital Expenditures



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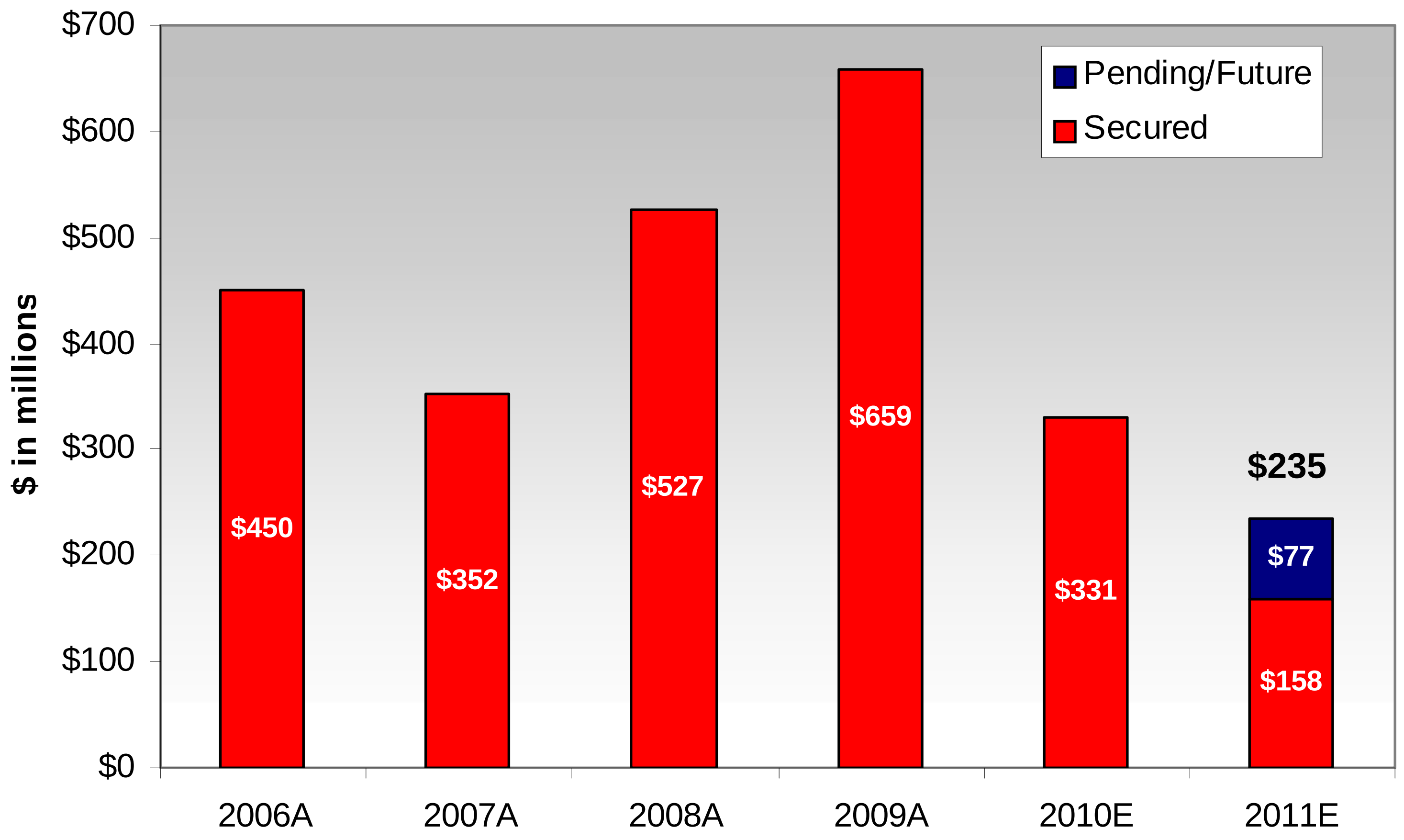
Rate Changes



Note: Rate changes in this chart excludes revenues with offsetting costs

Active or pending rate cases include Oklahoma, West Virginia and others yet to be filed

Summary Rate Case Information

AEP®

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE is 11.75%. An order is expected at the end of March 2011. Staff and Intervenor testimony recommended increases in the range of $41MM--$57MM.

Actual Capital Structure – Company Position (12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09)

($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5

Summary Rate Case Information

PSO General Rate Case – Docket #201000050

On July 9, 2010, PSO filed a base rate case with the Oklahoma Corporation Commission requesting a net increase of $52.4 million, comprised of a $82.7 million base rate increase and a $30.3 million decrease in the capital investment rider. The requested ROE is 11.50%. A settlement agreement was filed on Nov. 19, 2010 resulting in no change to current rates and a 10.15% ROE. Hearing scheduled December 6, 2010, with rates going into effect February 2011.

Actual Capital Structure – Company Position (2/28/10)

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	53.86%	6.52%	3.51%
Common Equity	45.84%	11.50%	5.27%
Preferred Stock	0.30%	4.02%	0.01%
Total	100.00%		8.79%

Procedural Schedule

October 26, 2010	Staff & Intervenor testimony due
November 16, 2010	Rebuttal testimony due
November 29, 2010	Settlement Conference
Debember 6-17, 2010	Hearing
January 5, 2011	Rates Effective, Subject to Refund

Required Rate Relief – Company Position (2/28/10)

($ in millions)

Rate Base	$	1,687.2
Rate of Return		8.79%
Operating Income Requirement	$	148.3
Adjusted Operating Income	$	97.9
Difference	$	50.4
Revenue Conversion Factor		1.6391
Total Revenue Requirement	$	82.7
Elimination of Capital Investment Rider	$	(30.3)
	$	52.4

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,467MM	10.50%	54/46	1/14/2009
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

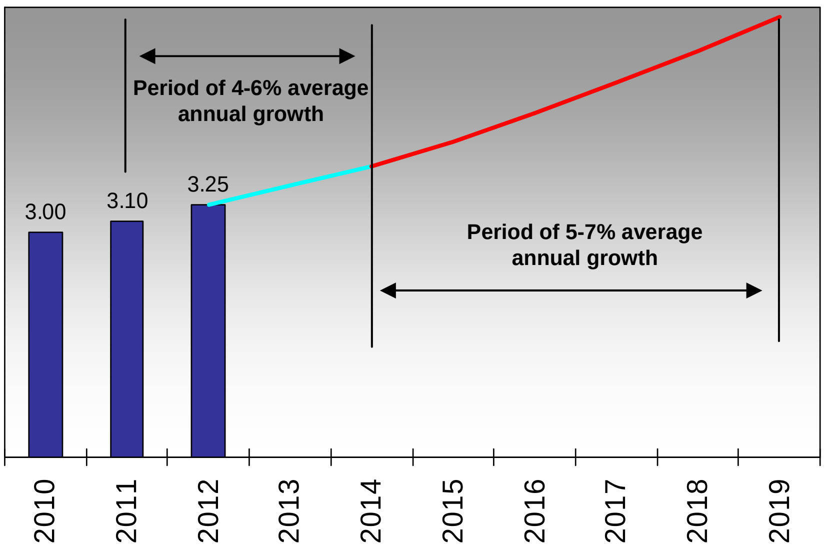
* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

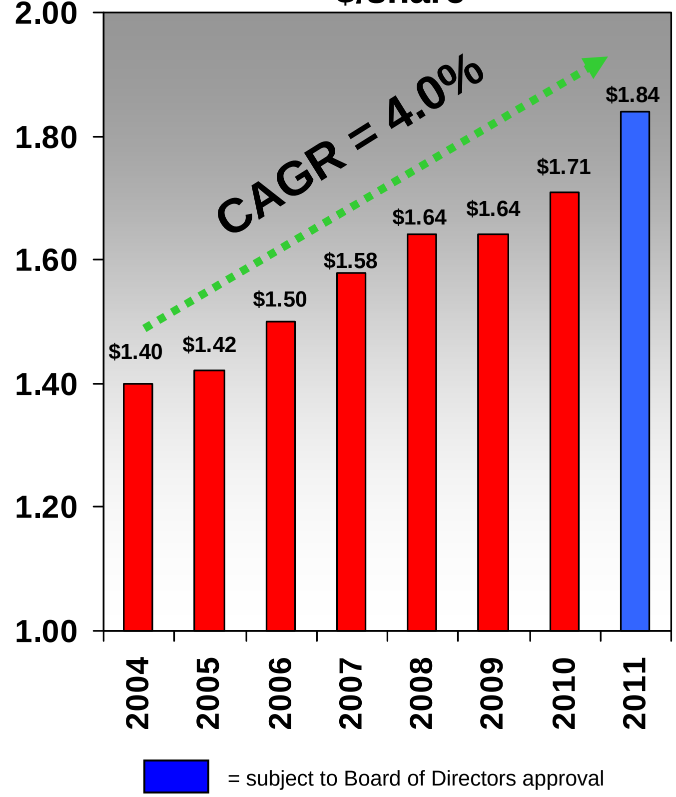
Value Proposition

Average Annual EPS Growth defined over two periods



- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy
- 5-7% EPS growth post 2014
  - Base utility platform capital plus higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Dividend History Since 2004 $/share



- <u>9.5% increase</u> in quarterly dividend to $0.46/share declared on October 26th
- <u>402nd consecutive</u> quarterly dividend will be paid December 10, 2010
- 50-60% payout ratio target
- Current yield about 5%

Barclays Capital Utilities Day
Zurich, Switzerland
March 17, 2011

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events and our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

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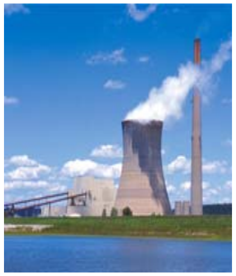
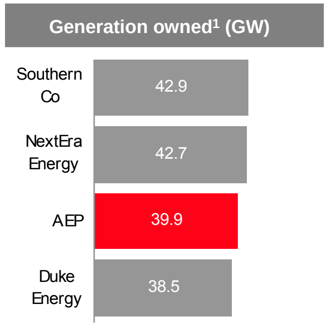
Brian Tierney – EVP and CFO

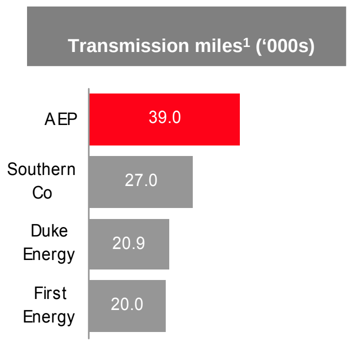
American Electric Power



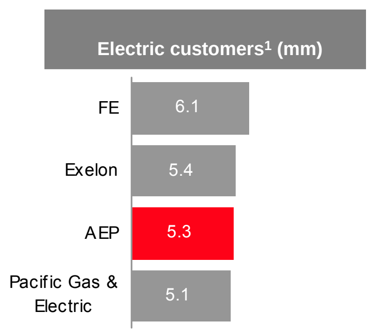
One of the largest U.S. electricity generators



The largest U.S. electricity transmitter

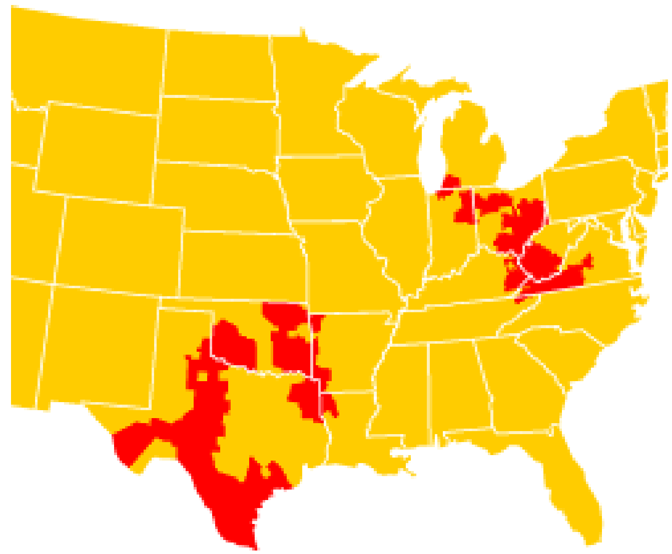


One of the largest U.S. electricity distributors



[1] : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

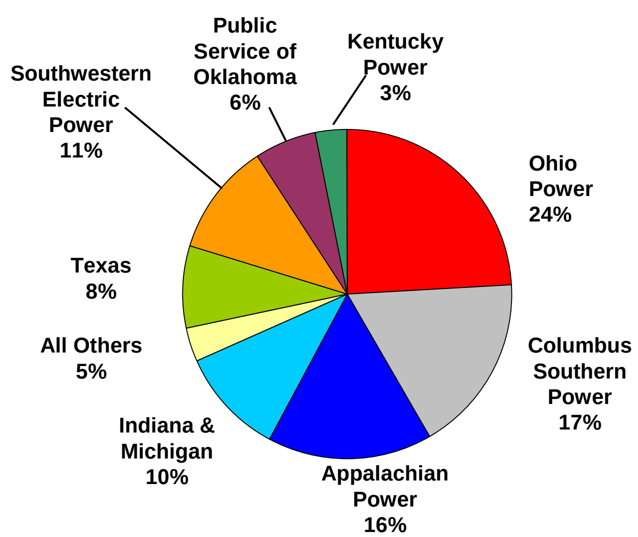
$17B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

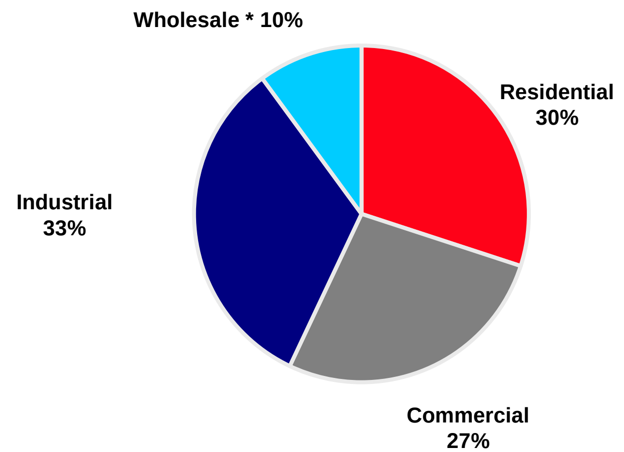
Highly Diversified Regulated Utility Platform

AEP®

2010 On-Going Earnings Contribution



2010 Retail Load



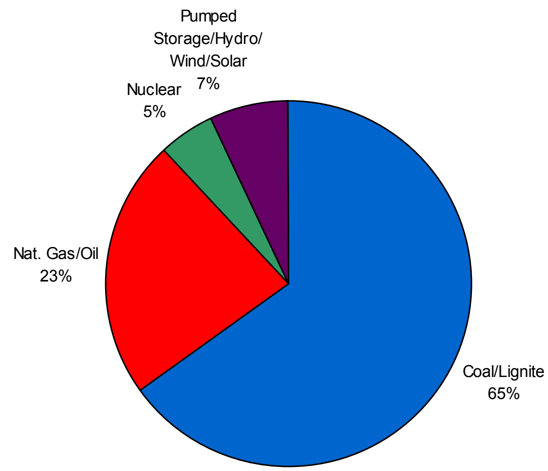
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Domestic Generation Fleet

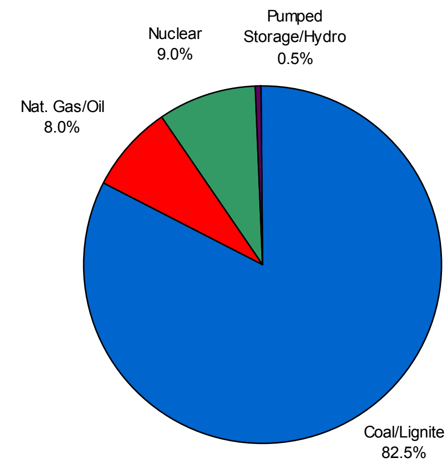
Generation Capacity by Fuel Type

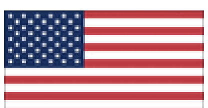
Based on 39,910 MW



2010 Generation Production by Fuel Type

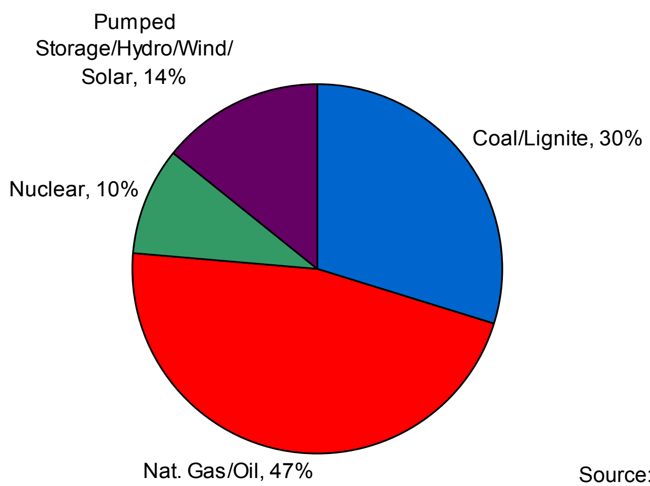
Based on 173.2 TWh





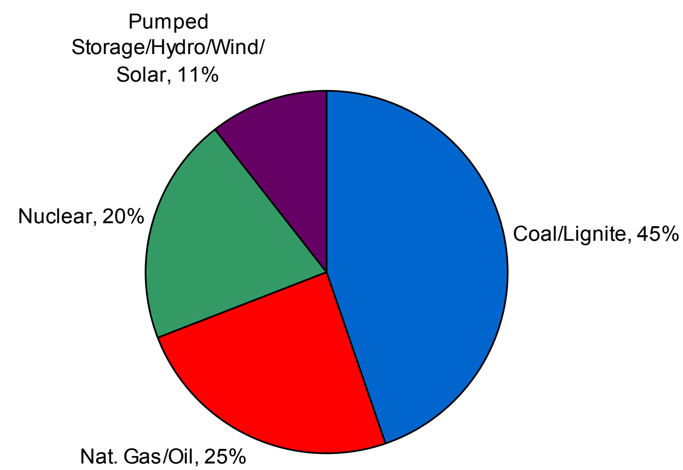
Generation Capacity by Fuel Type

Based on 1,063,848 MW



2009 Generation Production by Fuel Type

Based on 3,953.1 TWh

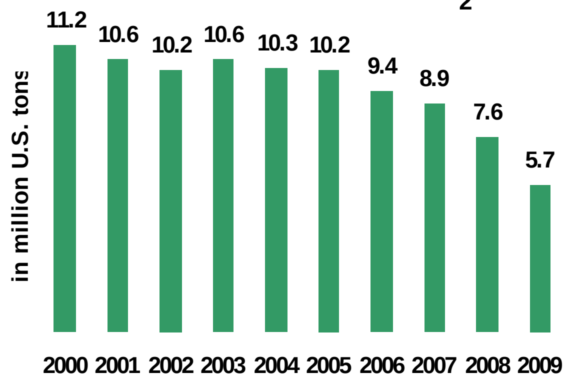


Source: www.eia.doe.gov

Emissions Reductions since 2000

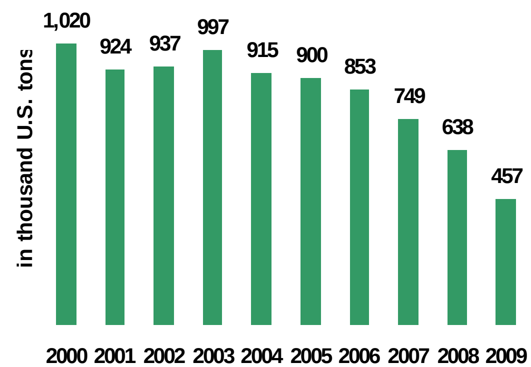
AEP®

U.S. Power Plant SO_2 Emissions



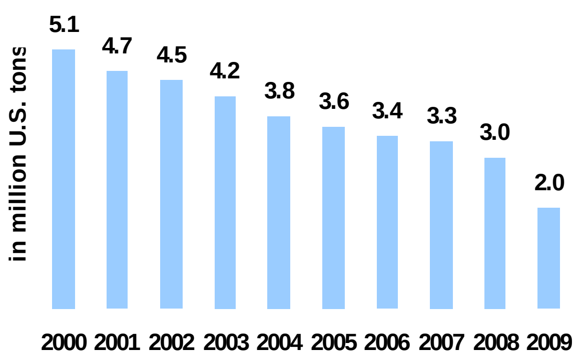
49% reduction since 2000

AEP SO_2 Emissions



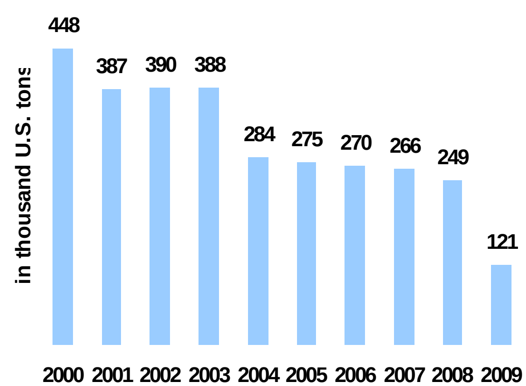
55% reduction since 2000

U.S. Power Plant NOx Emissions



61% reduction since 2000

AEP NOx Emissions

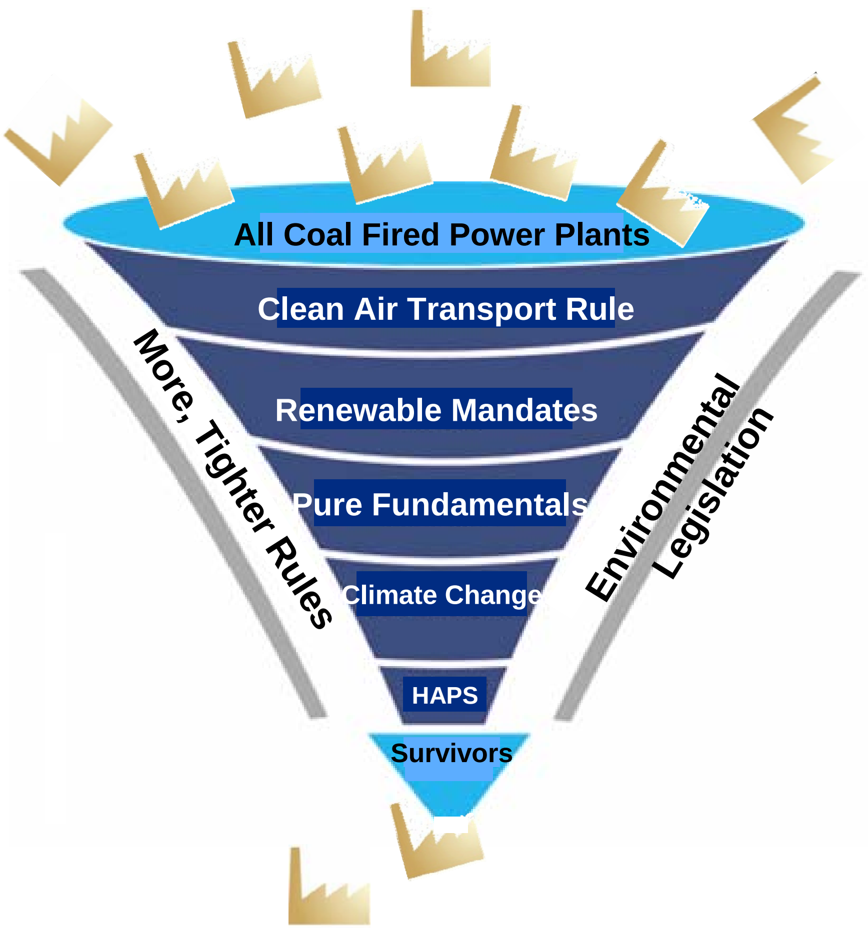


73% reduction since 2000

Source: EPA, 2010; Acid Rain Program

Over $5B capital invested by AEP from 2004-2010 to reduce emissions

The Pressure on Coal Generation



Key EPA Actions Pending

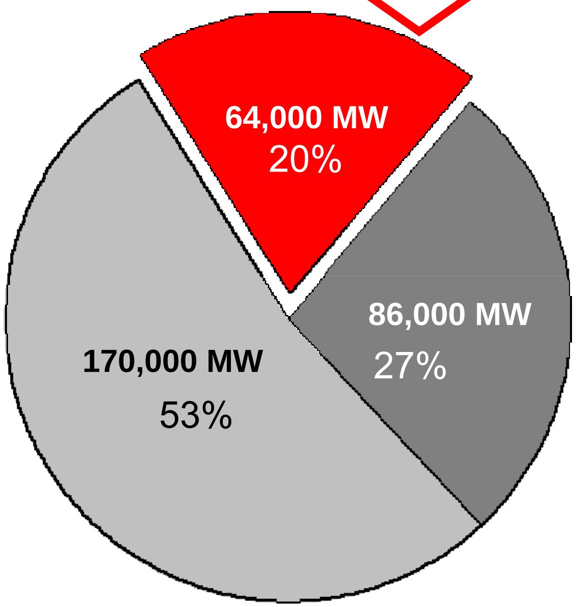
- Transport Rule – Proposed July 2010
- "Coal Ash" Rule – Proposed May 2010
- Mercury and other Hazardous Air Pollutants (HAPs) Rule – Expect Proposed Rule in March 2011
- Cooling Water Intakes – Expect Proposed Rule in Spring 2011
- Greenhouse Gas Tailoring Rule – January 2011

Continual Evaluation is Required

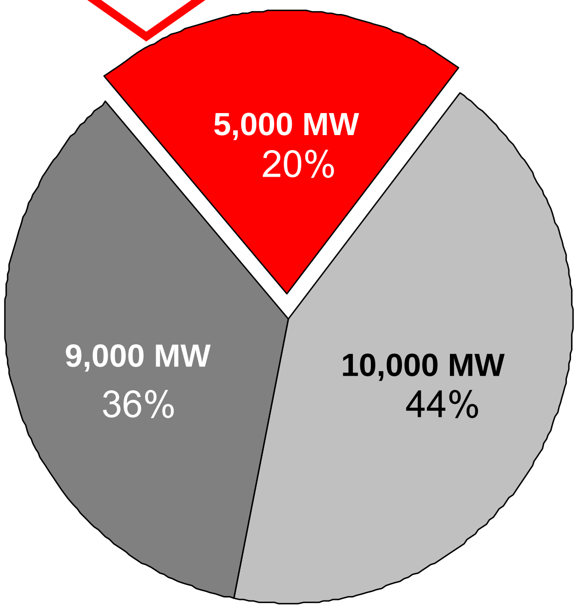
"Fully-Exposed"	"Partially-Exposed"	"Least-Exposed"
Probable Retirement	*Evaluating potential retirement*	*Not likely to be retired*

CCS Candidates

Smaller, older, less-efficient coal units that will not be economic if retrofitted



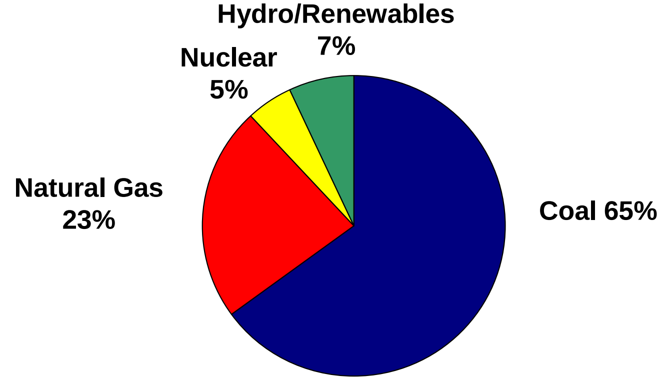
Newer and larger coal units that do not have SCR's and/or FGD's will be evaluated due to emerging environmental rulemaking and NSR requirements



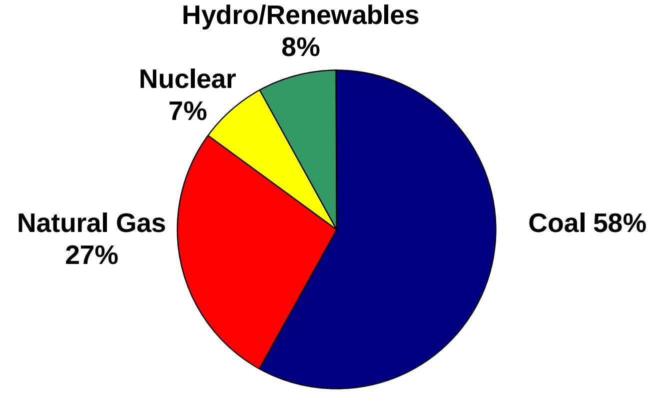
Nearly 50% of U.S. coal plants are exposed

Continued Investment in Utility Platform

- Plan for old, small coal units
  - Initially operate seasonally
  - Transition towards retirement
  - Regulatory plan for recovery
- Continue evaluation of “partially exposed” units for additional controls
- Add non-coal capacity when needed
  - Dresden NGCC (partially complete)
  - New NGCC at existing site
  - Cook plant uprate (under study)
  - Renewables
- Deploy technology as appropriate
  - Continue pursuit of CCS technology
  - Energy storage technologies
  - gridSMART®



Capacity - 2010



Projected Capacity - 2017

Transmission Investment Strategy

- **Near-Term Investment** – Electric Transmission Texas (ETT) secures near term investment opportunities, allowing AEP to invest in the large, growth-oriented Texas transmission market.
  - Total project cost: $3 billion with a 9.96% ROE
- **Mid-Term Investment** – Seven wholly-owned transcos allow for expansion and growth within AEP's existing utility footprint through an efficient recovery mechanism.
  - Will spend $160 million in 2011 and more than $350 million in 2012; Expected ROE will be in the 11.2%-11.49% range
- **Long-Term Investment** – Joint ventures provide opportunities for longer-term growth outside of AEP's existing utility footprint with forward looking formula rates, higher ROEs and FERC incentives, and mitigated risk profiles.

765-kV Tower

Joint Venture Strategy: Long-term

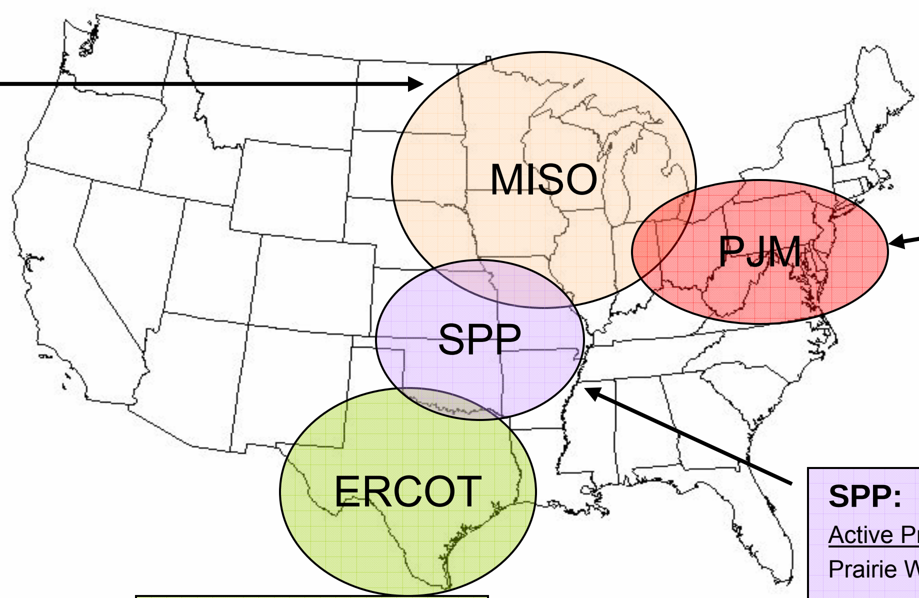
- **Strategy**: JV's secure new investment opportunities with local utilities to diversify AEP's investment outside AEP's traditional footprint while providing longer-term incremental earnings**.** JV projects are well-suited for FERC formula rate recovery mechanism, including potential for incentive rates.

- **Future:** Federal/regional initiatives may accelerate expansion of EHV transmission (e.g. cap-and-trade, renewable portfolio standards, inter-region wide planning). Securing first mover advantage will enable AEP to secure LT investment opportunities.

- **Future flexibility**: Passive investment opportunities can be considered and can provide entry beyond SPP/PJM/ERCOT

MISO:
Active Projects:
MEC Project
Pioneer

Drivers for Growth:
Reliability
Wind Integration



PJM:
Active Projects:
PATH
Pioneer
RITELine

Drivers for Growth:
Congestion
Reliability
Operational

SPP:
Active Projects:
Prairie Wind

Drivers for Growth:
Reliability
Wind Integration

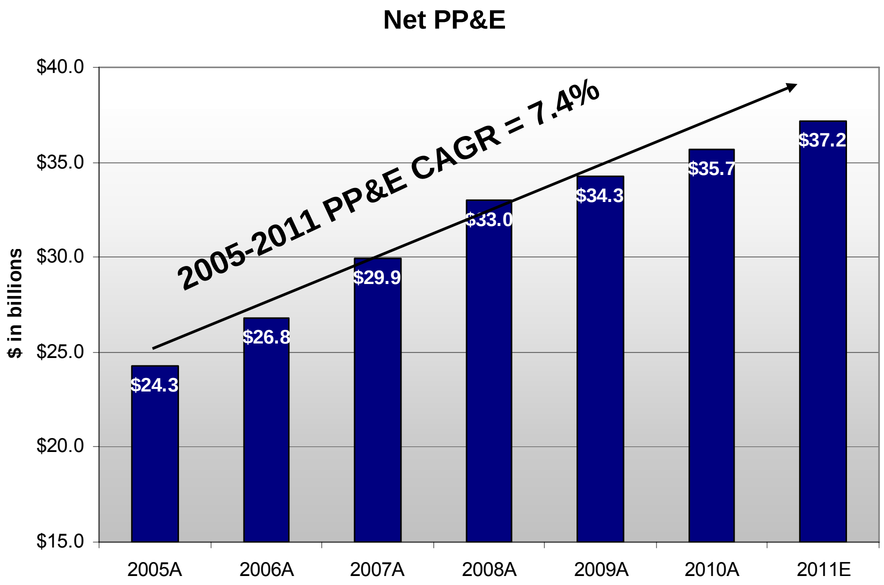
ERCOT:
Active Projects:
ETT

Drivers for Growth:
Wind Integration
Insufficient EHV Transmission

Traditional Ratemaking Environment

AEP®

Growth in Net PP&E



Growth in rate base resulting in $2.3 billion of rate relief secured from 2006 through 2010

Regulatory Framework

- Base Rates
  - Recovery of capital and financing costs
  - Recovery of set level of O&M costs
- Recovery of Fuel Costs
  - Active fuel clauses in all jurisdictions
- Opportunities to Reduce Regulatory Lag
  - Contemporaneous recovery for construction costs, reliability, environmental spending, etc.
- Ohio Generation Rates set by PUCO according to SB221 (non-cost based)

AEP Ohio ESP Filing – Core Policy Issues

AEP®

Investment in Ohio

Supports economic development and essential tax base

Fundamental barriers must be addressed to attract investment for Environmental Compliance and New Generation

Jobs in Ohio

Jobs are a key component of growth potential in Ohio

Without regulatory assurances over time we could see loss of direct & indirect jobs related to power generation, and business relocations to surrounding states

Energy Security

Secure, reliable and predictable electricity supply is basis for sustained investment and employment in Ohio

Volatility in power prices can lead to major loss of economic activity over time

Primary objective of ESP: Stabilize rates and support economic development in the state of Ohio

Merged AEP Ohio

Single merged AEP Ohio company presumed with supporting information on an individual OP/CSP basis

Rate Redesign

Generation rates redesigned to resemble market pricing structures

29-Month ESP Period

ESP period Jan 1, 2012 through May 31,2014 (May 31 date aligns with PJM annual planning cycle)

Alternative Long Term Option

Alternative longer-term price certainty option offered for qualifying commercial & industrial customers

Ohio Growth Fund

Creation of significant private sector economic development to attract investment and job growth in AEP Ohio service territory

Distribution Components Included

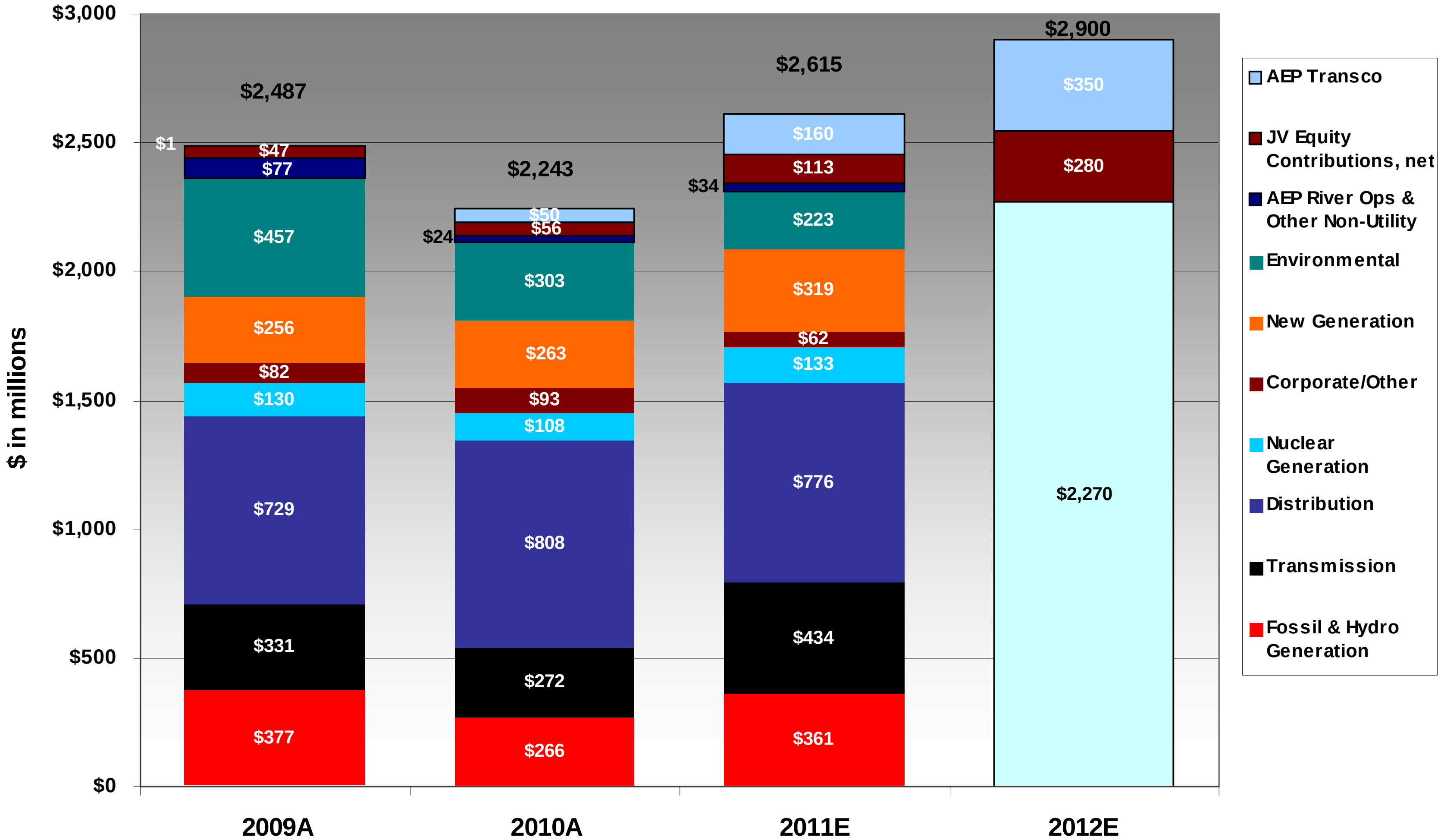
Inclusion of certain distribution components while pursuing a parallel distribution base rate case

Capital Allocation

In this economic recovery cycle, capital allocation requires balance for spending that considers the obligation to serve, the ability to obtain rate increases, a balance sheet to support the plan, and the total return proposition to shareholders

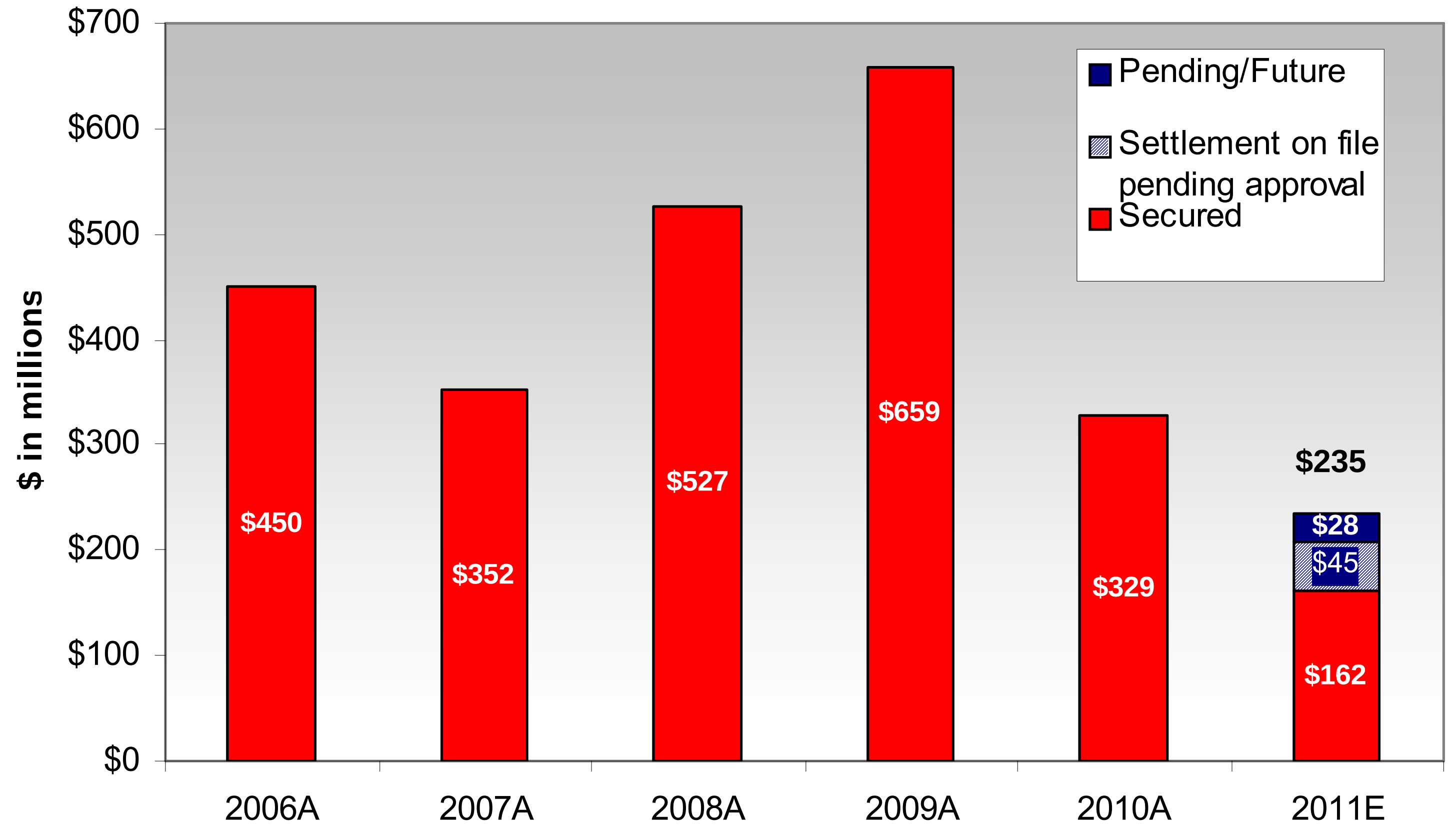
- Capital for Growth
  - Capital budget of $2.6B for 2011
  - Capital budget plan of $2.9B for 2012
- Return of Capital to Shareholders
  - 12% increase in quarterly dividend in 2010
  - Future dividend increases will grow with earnings
- Capital to Reduce Risk
  - Voluntarily funded pension $500M in 2010
  - Allocating an additional $150M of funding for pension in 2011

Capital Expenditures



Investment levels greater than depreciation of $1.4B per year cause rate base growth in 2011 and 2012

Rate Changes



Note: Rate changes in this chart exclude revenues with offsetting costs

Pending/future rate cases include cases yet to be filed

Settlement on file pending approval relates to the WV base rate case

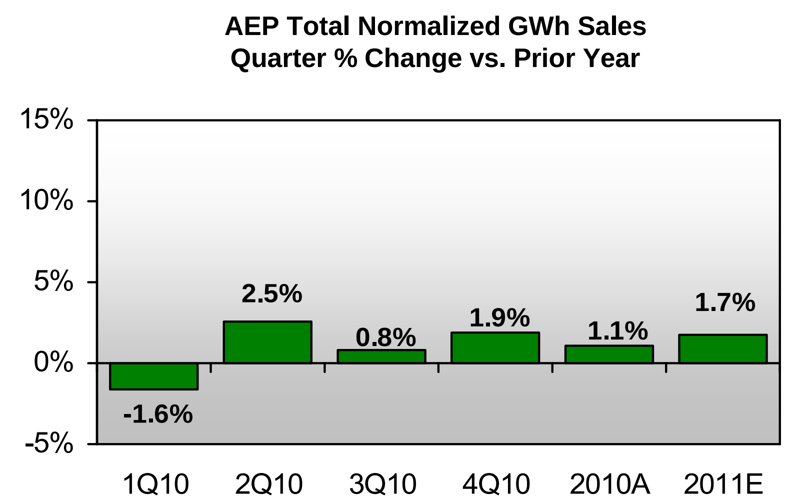
2011 Ongoing Earnings Guidance

2010A: $3.03/share

2011E: $3.00-$3.20/share

Near-Term Earnings Drivers

- Recovering economy
- Rate recovery from returns on capital investment
- Continued O&M discipline

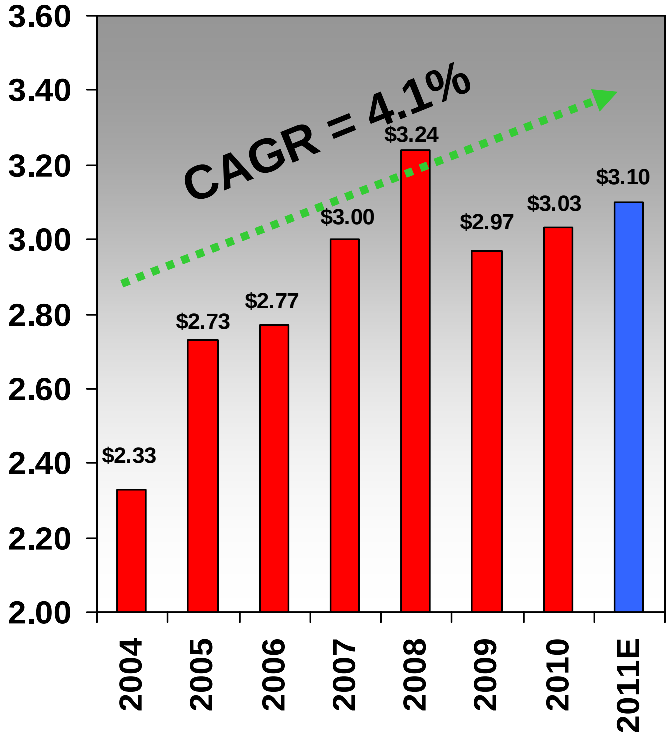


Year over Year change by segment:
Residential: 1.9%
Commercial: 0.7%
Industrial: 1.9%

Earnings and Dividends

On-Going EPS History Since 2004

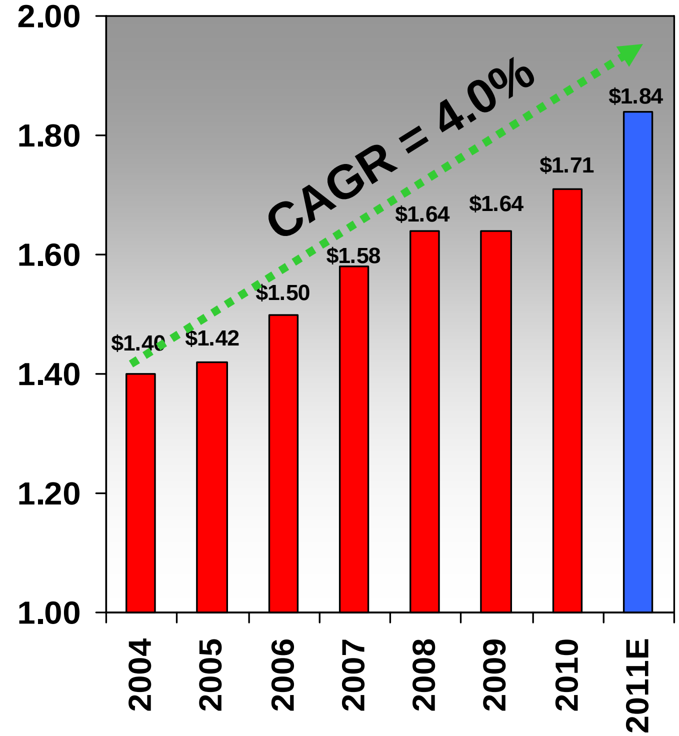
$/share



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- Equity offering in 2009 stabilized credit and strengthened balance sheet
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004

$/share



= subject to Board of Directors approval

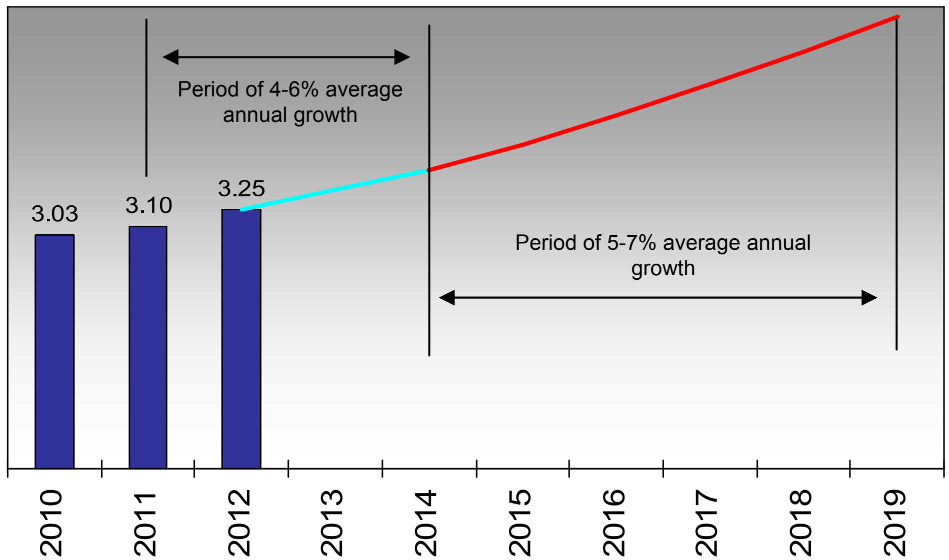
- Dividend increased 12% in 2010
- 403rd consecutive quarterly dividend paid March 10, 2011
- 50-60% payout ratio target
- Current yield over 5%

Long-term EPS Growth Rate

- 4-6% EPS growth 2012-14
  - Average annual capital spend between $2.9-3.4B
    - Utility platform replacement capital of about $1.4B (annual depreciation)
    - Growth in rate base of $1.5-2.0B per year, allocated between utility platform and transmission projects
  - Blended ROE of 10.5 - 11%
  - Slow, steady recovery in economy

- 5-7% EPS growth post 2014
  - Base utility platform capital including generation transformation
  - Higher allocation of discretionary capital going to opportunities in the transmission development pipeline
  - Higher overall blended ROE opportunity
  - Robust economic growth

Average Annual EPS Growth defined over two periods



AEP Highlights

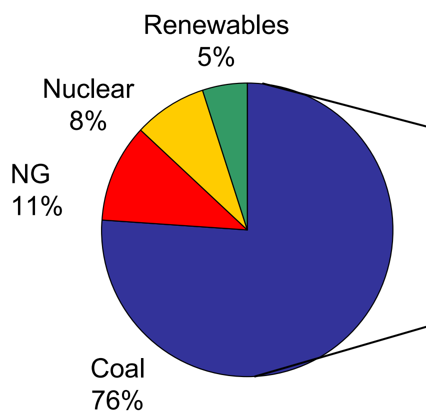
- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Mountaineer Plant (WV)

Appendix

AEP Generation Capacity

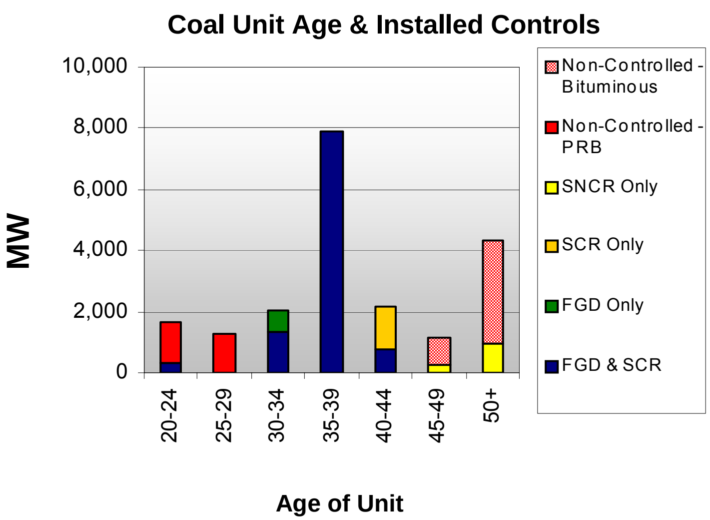
East Capacity – 27,253 MW
AEP Ohio, APCo, I&M, AEG, KPCo, Wind, Solar, Hydro



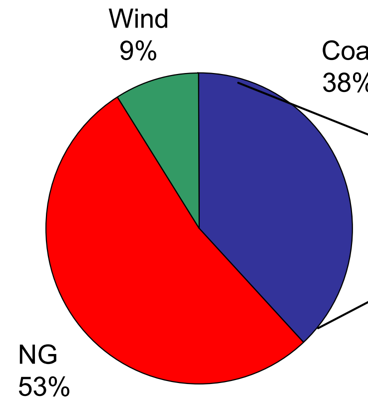
Coal Source

NAPP	46%
CAPP	30%
PRB	22%
Others	2%

Avg. Delivered Cost
2009A - $56/ton
2010A - $52/ton
2011E - $51/ton



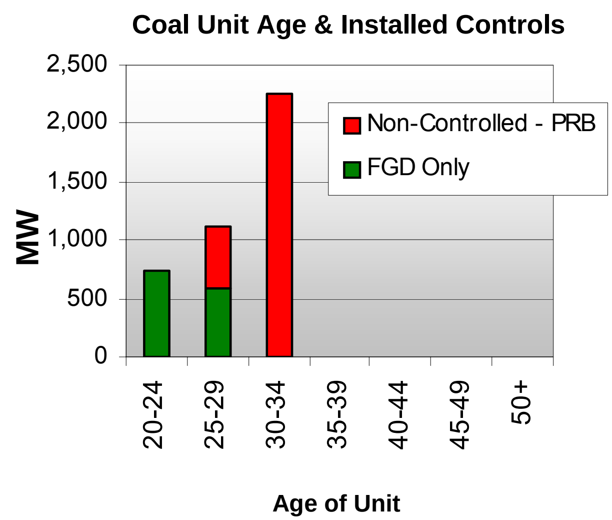
West Capacity – 11,677 MW
PSO, SWEPCO, TNC, Wind



Coal Source

PRB	75%
Lignite	25%

Avg. Delivered Cost
2009A - $29/ton
2010A - $29/ton
2011E - $29/ton



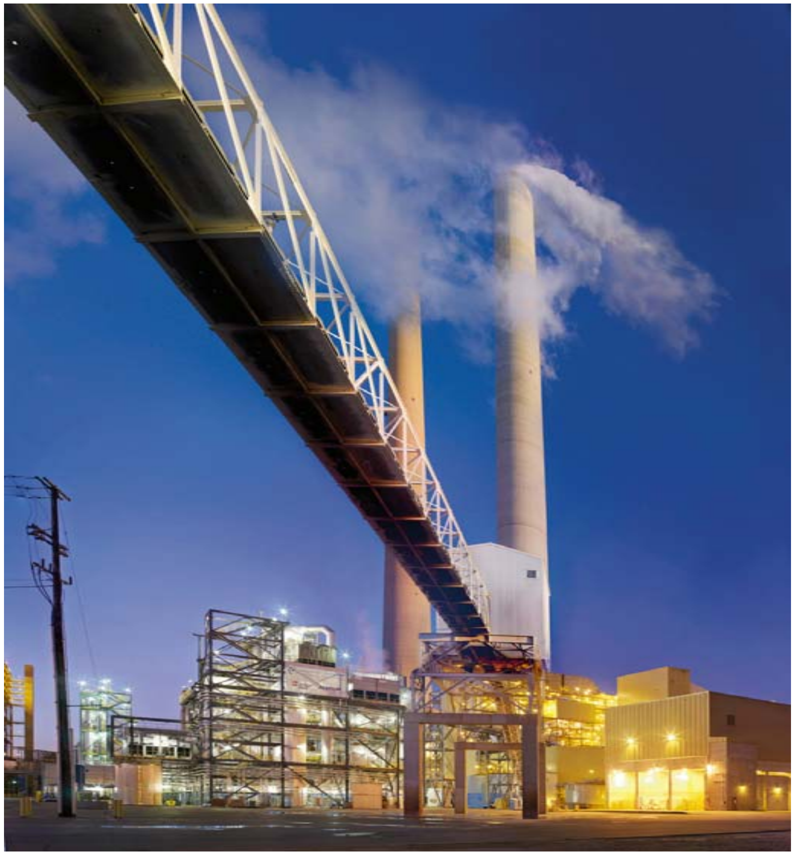
Carbon Capture and Storage

PHASE I - Validation

- World's first operating CCS facility on a coal fired power plant
- Gained competitive advantage through technology development
- Currently testing key performance parameters: auxiliary power, removal efficiency, reliability, CO_2 product quality

PHASE II - Commercialization

- Initiated in January 2010
- Designed to capture and store 1.5 million metric tons of CO_2/year
- Estimated cost of $668 million with 50% DOE funding
- Pursuing additional funding/participation
- Scheduled in service date is mid-2015
- Key activities through July 2011 include conceptual engineering, detailed cost estimate and National Environmental Policy Act process



Carbon Capture and Storage project Mountaineer Plant - New Haven, WV

AEP's "Smart Grid" Deployment – Pilot Projects

Indiana Michigan Power - South Bend Pilot (Completed – September 2010)

- 10,000 AMI meters
- Integrated Mesh communication network
- Distribution grid management – centralized & decentralized
- Consumer programs: 2-tier time-of-day rates and technology enabled direct load control using PCTs
- Customer web portal
- Initial meter data management system development

AEP Ohio– central Ohio– (2009-2013)

- Awarded US DOE Smart Demonstration Project
- 133,000 meters using integrated mesh network
- Advanced distribution grid management with volt-VAR control
- Advanced consumer programs including critical peak and real-time pricing
- Extensive consumer outreach and communication
- Innovative web portal
- Large scale distributed storage
- Concentrated PHEV implementation
- Smart appliance deployment
- Industry first smart grid cyber security center

AEP Texas – Statewide (2009-2012)

- Legislature enabled and commission directed T&D service providers to deploy advanced metering
- 970,000 meters using mesh network communications
- Enable Texas retail service providers to provide innovative pricing and in-home consumer technologies
- 10,000 in-home displays for low income customers
- Statewide portal for usage and home device provisioning

PSO– Owasso Pilot (Implement in 2011)

- 13,000 AMI meters
- AMI and distribution control communication networks
- Distribution automation
- Distribution Volt-VAR control
- High level of in-home devices – displays and PCTs
- Customer programs – time-of-day and direct load control programs
- Web portal

gridSMART® attributes from the utility side of the meter look promising; customers with low rates may not see material savings/benefits

Detailed Ongoing Earnings Guidance

2010A: $3.03

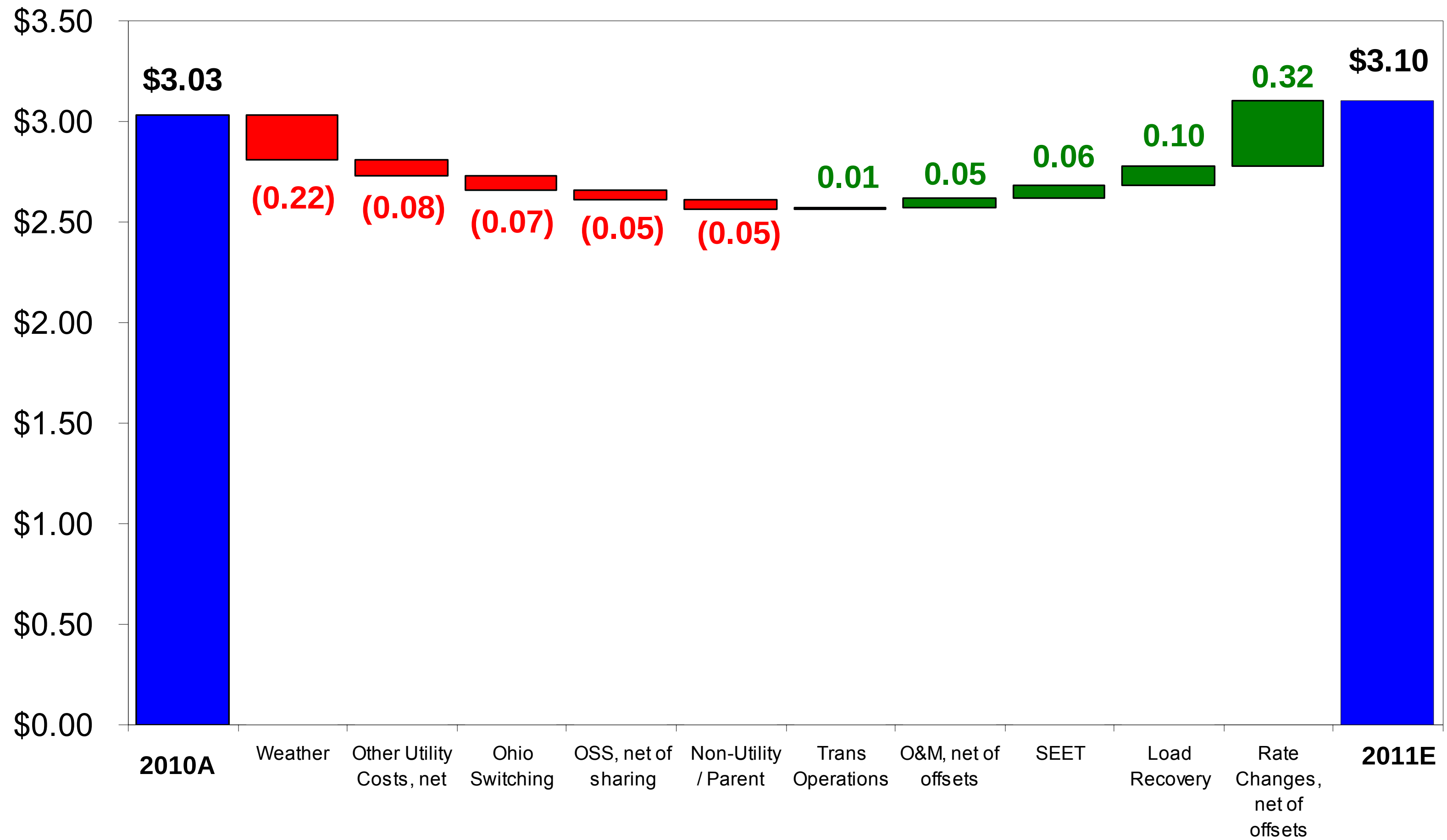
2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		Performance Driver	2010 Actual ($ millions)	Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	Interest Exp & Preferred Dividend		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

2011 Earnings Drivers

AEP®

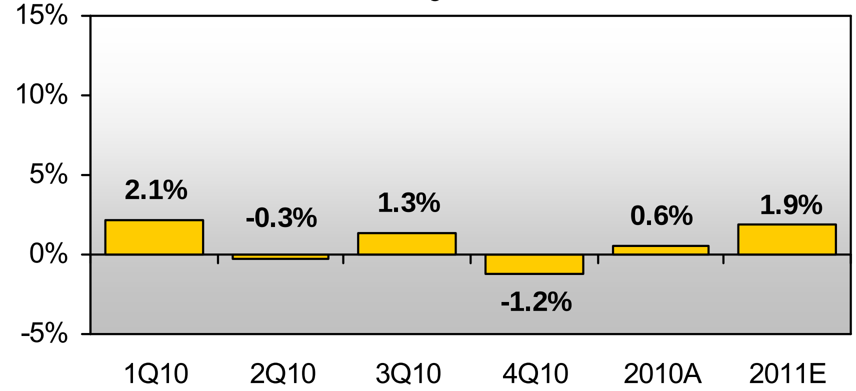


- $235M in rate changes (69% secured)
- Weather normalized load growth of 1.7%
- Continued discipline in O&M
- Ohio switching assumptions ($53M – 14% of CSP total load)

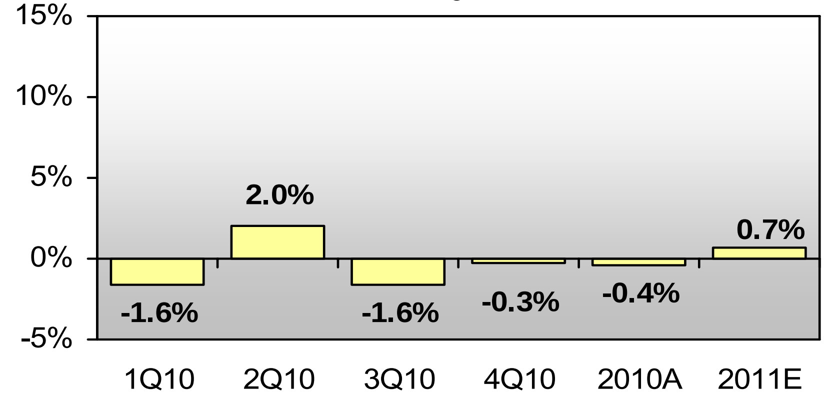
2011 Guidance Range: $3.00 - $3.20/share

Normalized Load Trends

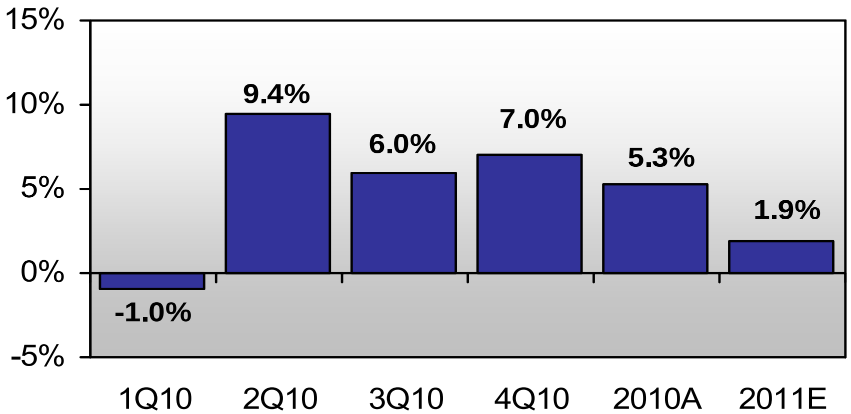
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



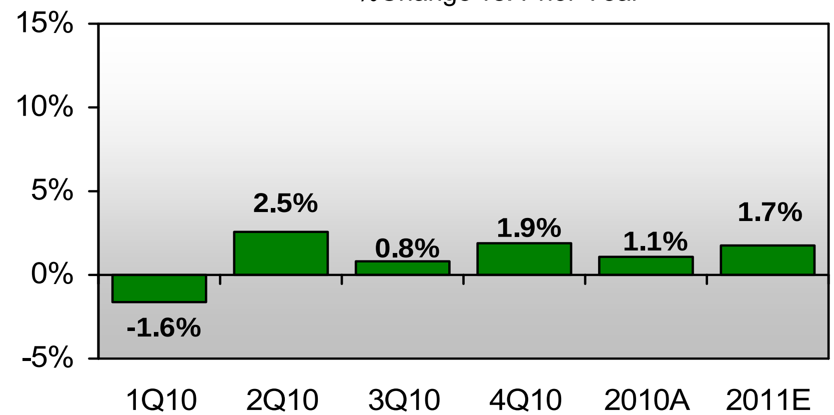
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

Note: Chart represents connected load

Cash Flow Guidance

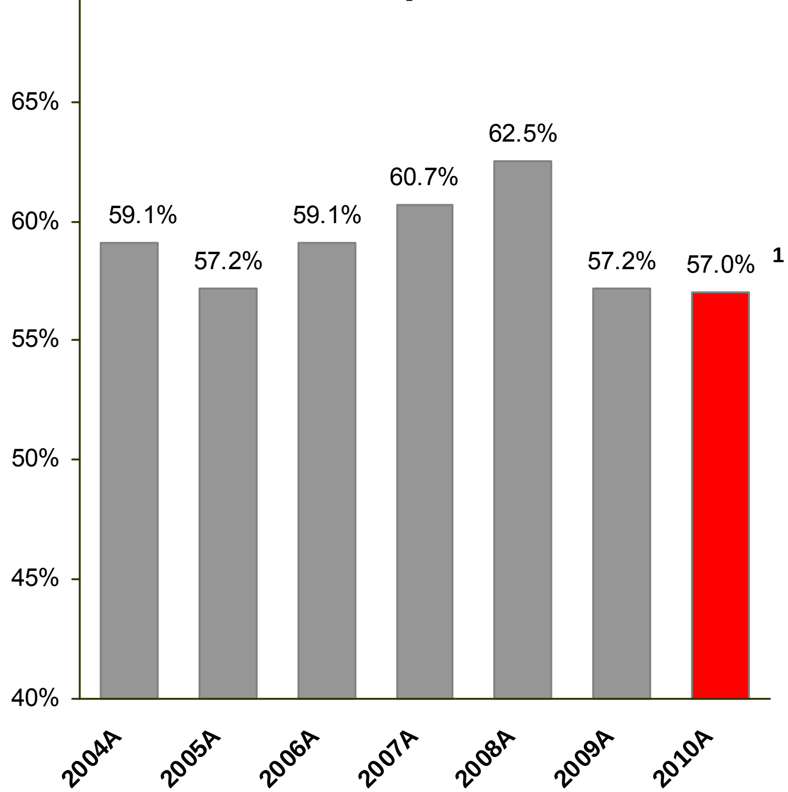
	$ in millions	
	2010A	**2011E**
Cash From Operations		
Income from Continuing Operations	$ 1,218	$ 1,499
Depreciation & Amortization	1,641	1,611
Pension Funding	(500)	(150)
Other Cash Flow Items	659	834
Litigation Resolution [1]	-	(449)
Working Capital [2]	279	7
Cash From Operations	$ 3,297	$ 3,352
Investing Activities		
Construction Expenditures	(2,318)	(2,644)
Other Investing Activity	(184)	(205)
Total Investing Activities	$ (2,502)	$ (2,849)
Financing Activities		
Dividends	(824)	(892)
Net Debt Issued/(Retired)[1]	(160)	234
Common Equity	93	150
Other Financing Activities	(100)	(72)
Total from Financing Activities	$ (991)	$ (580)
Beginning Cash Balance	$ 490	$ 294
Ending Cash Balance	$ 294	$ 217

[1] Refer to the Enron Bankruptcy section of Footnote 6 in the December 31, 2010 10K for futher discussion

[2] Pro forma to exclude effects of consolidation of AEP Credit ($656M) in 2010

Capitalization & Liquidity

Total Debt/Capitalization



Current Liquidity Summary

Liquidity Summary (unadited)	Actual 12/31/10	
($ in millions)	**Amount**	**Maturity**
Revolving Credit Facility	$1,500	Jun-13
Revolving Credit Facility	1,454	Apr-12
Revolving Credit Facility	478	Apr-11
Total Credit Facilities	**3,432**	
Plus		
Cash & Cash Equivalents	294	
Less		
Commercial Paper Outstanding	(650)	
Letters of Credit Issued	(124)	
Letters of Credit Issued for VRDNs	(477)	
Net Available Liquidity	**$2,475**	

Note: Total Debt is calculated according to GAAP and includes securitized debt

[1]: Effective January 1, 2010 in accordance with Transfers and Servicing accounting guidance (formerly SFAS 166), factored receivables of AEP Credit of $750 million are classified as short-term debt; The 4Q2010 debt/capitalization ratio would be 56.1%, excluding AEP Credit.

Approved Rate Bases & ROEs

Jurisdiction	Rate Base	Approved ROE	Approved Debt/Equity	Effective Date
APCo-Virginia	$2,060MM*	10.53%	58/42	8/1/2010
APCo-West Virginia	$1,656MM	10.50%	57/43	7/28/2006
KPCo-Kentucky	$995MM	10.50%	57/43***	6/30/2010
I&M-Indiana	$2,000MM	10.50%	44/56	3/4/2009
I&M-Michigan	$595MM	10.35%	50/50	10/14/2010
PSO-Oklahoma	$1,706MM	10.15%	54/46	1/5/2011
SWEPCo-Louisiana	$649MM	10.57%**	50/50	8/1/2010
SWEPCo-Arkansas	$612MM	10.25%	54/46	11/25/2009
SWEPCo-Texas	$665MM	10.33%	49/51	4/15/2010
TCC-Texas	$1,566MM	9.96%	60/40	10/17/2007
TNC-Texas	$530MM	9.96%	60/40	6/1/2007

* represents Generation and Distribution rate base only.

** represents the midpoint of the ROE range approved in the formula rate case settled in April 2008.

***represents a negotiated settlement

Summary of ESP Filing - Continued

- Pre-tax earnings impact from proposed ESP (excluding potential earnings impact from trackers)
  - **Net base $54MM or 1.4% in year 1 (2012)**
  - **Net base $106MM or 2.7% in year 2 (2013)**

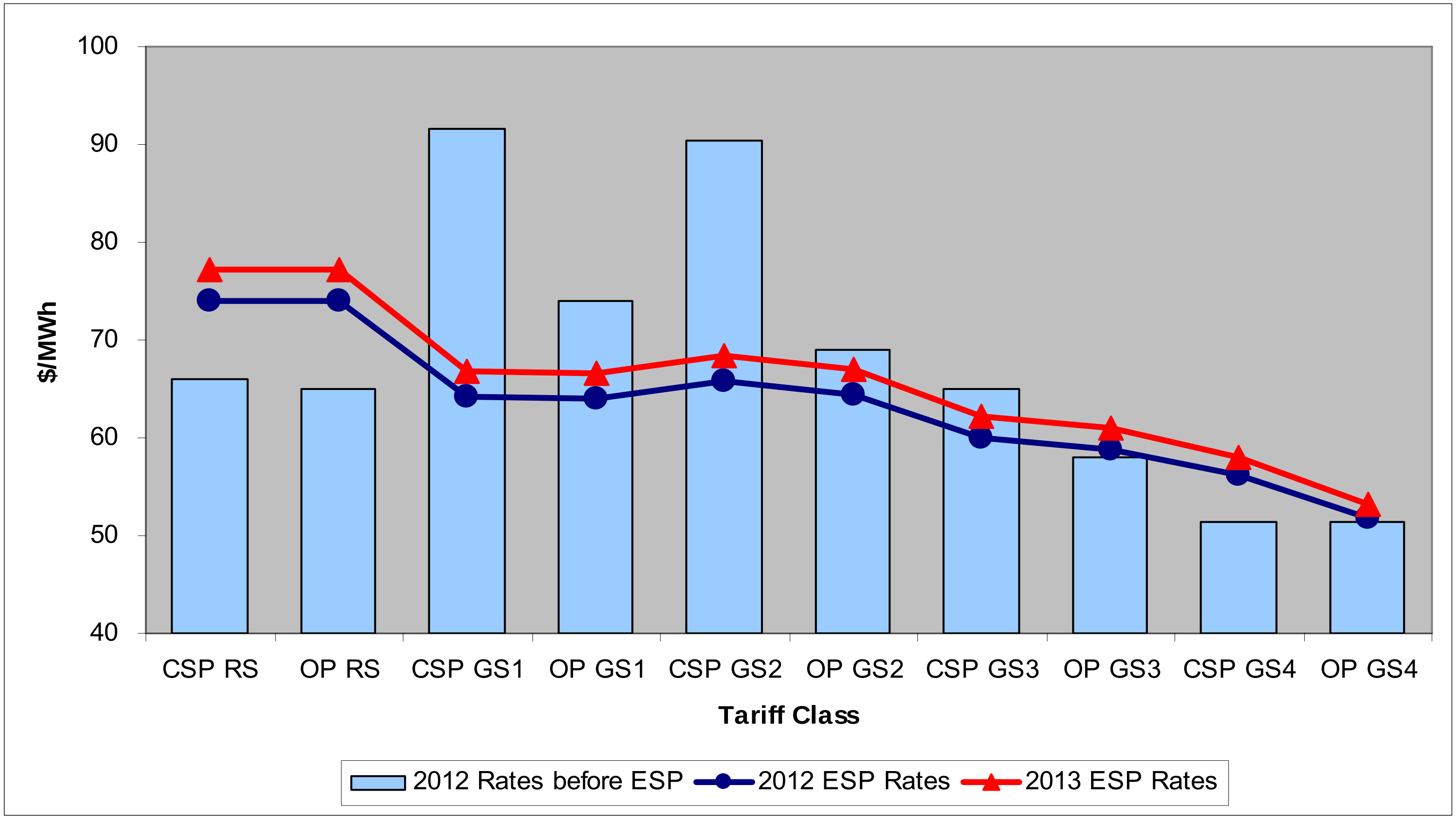
	2012			2013			2014		
	Revenue	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**	**Revenue**	**$/MWh**	**%**
Proposed ESP Changes									
Base Generation	**$65MM**	**$1.50**	**1.7%**	**$106MM**	**$2.43**	**2.7%**	**N/C***	**N/C***	**N/C***
POLR	**($11MM)**	**($0.23)**	**(0.3%)**	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***	**N/C***
FAC Actual Recovery 2012-2014	**Actual**			**Actual**			**Actual**		

N/C* = No change from prior year

While the ESP includes a small base generation increase, the move to a market-based rate design, consistent with state policy, will result in varying impacts for different customer groups.

Price to Compare

Proposed **SSO** Rates Redesigned To Resemble Market Pricing Structures



Rates do not reflect mitigation impact of market transition rider
2012 Rates before ESP reflect current 2011 rates for generation & transmission service, adjusted to reflect full cost 2011 fuel and environmental costs.

The realignment of rates with market should provide all customers with equivalent opportunities to shop. Additionally, since the proposed design eliminates explicit demand charges, customers should be more easily able to evaluate competitive offers. To ease the rate impact that customers will experience from the realignment, we have proposed a Market Transition Rider.

Market Transition Rider – Mitigates the Initial Impact of Rate Realignment

Three-Year Market Transition Plan
Summary of AEP Ohio ESP Generation Rate Changes

CSP Current Customer Class	CSP New Customer Class	2012 Increase	2013 Increase	2014 Increase	Total Increase
Residential	Residential	5.0%	3.9%	1.0%	10.2%
GS1	GS Non-Demand	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2		(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	GS Demand	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP		2.3%	7.7%	4.7%	15.3%
Total CSP		**2.2%**	**2.7%**	**0.0%**	**5.0%**
OPCo Current Customer Class	**OPCo New Customer Class**	**2012 Increase**	**2013 Increase**	**2014 Increase**	**Total Increase**
Residential	Residential	6.0%	3.1%	0.3%	9.7%
GS1	GS Non-Demand	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2		0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	GS Demand	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP		(6.6%)	5.8%	3.0%	1.7%
Total OPCo		**0.4%**	**2.7%**	**0.0%**	**3.1%**
AEP Ohio		1.4%	2.7%	0.0%	4.2%

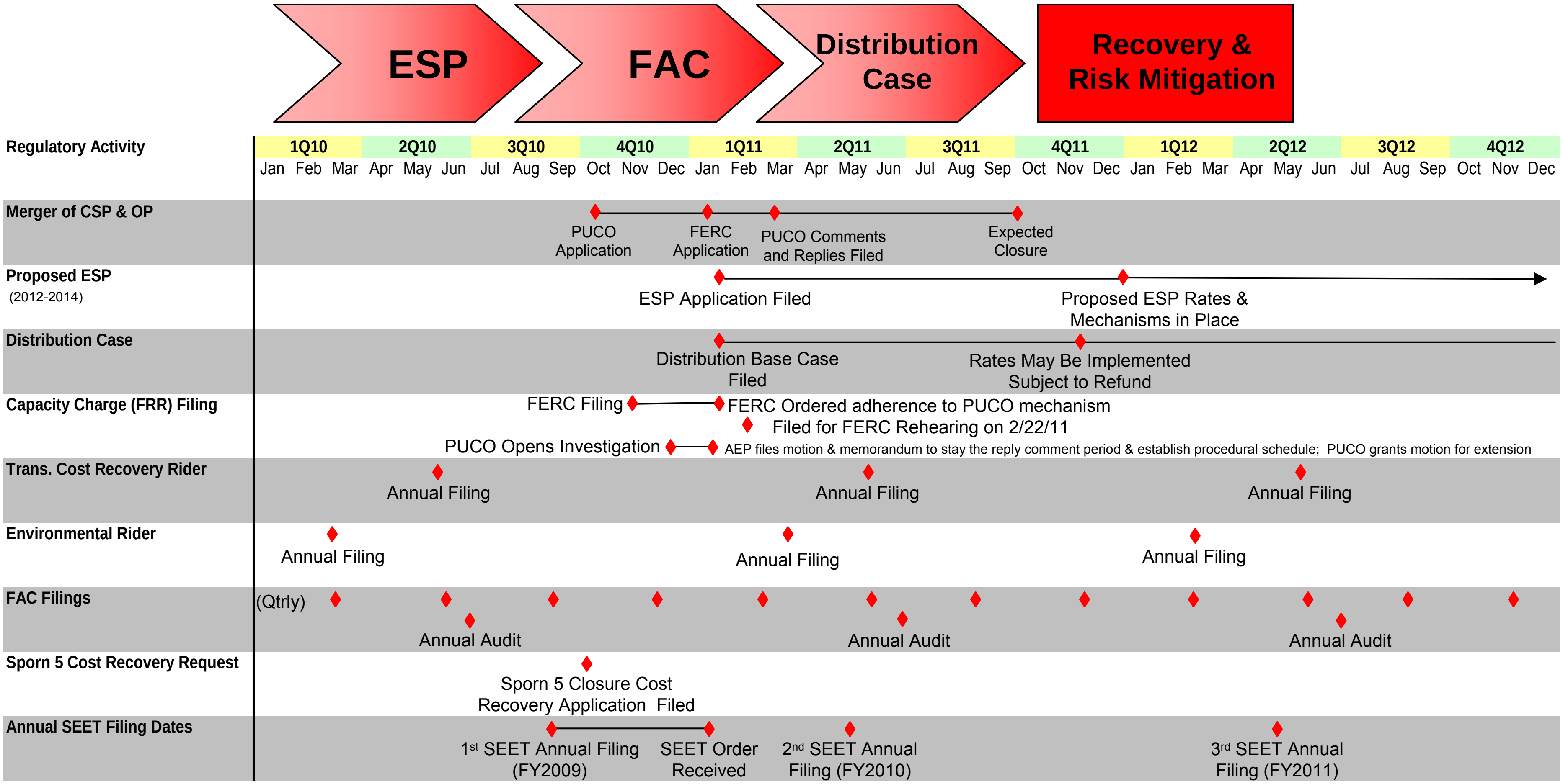
Illustration of Market Transition Rider on ESP Generation Rate Increases

The Market Transition Rider is a transition rider designed to facilitate the transition from AEP Ohio's current rates to market-based SSO Generation Service rates. It is a non-bypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

List of ESP Riders – Existing and Proposed

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		the current bypassable rider is proposed to be nonbypassable in the new ESP
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Ohio Timeline



AEP Ohio's long-term strategy is designed to produce rate relief for items currently known as well as anticipated future items. The filings and riders we seek today are designed to be broad and flexible enough to accommodate a variety of circumstances, because it is impossible to know all variables and specific items for which we will desire to seek rate relief or what regulatory circumstances will prevail at the time.

Summary Rate Case Information

AEP Ohio Distribution Rate Case – Docket #351/352-EL-AIR

On February 28, 2011, AEP Ohio filed a distribution base rate case with the Public Utilities Commission of Ohio requesting a net increase of $93.8 million, and requesting authority to recover previously approved regulatory assets. The requested increase relates to capital investments made and to recover increased costs. The requested ROE was 11.15%. A procedural schedule from the PUCO is pending.

Actual Capital Structure – Company Position – 08/31/10

CSP

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	49.36%	5.50%	2.71%
Common Equity	50.64%	11.15%	5.65%
Total	100.00%		8.36%

OPCO

	% of Capitalization	Cost Rate	Weighted Return
Long-Term Debt	45.93%	5.27%	2.42%
Common Equity	53.79%	11.15%	6.00%
Preferred Stock	0.28%	4.40%	0.01%
Total	100.00%		8.43%

Required Rate Relief – Company Position (08/31/10)

($ in millions)

	CSP	OPCO
Rate Base	$ 911.0	$ 1,015.2
Rate of Return	8.36%	8.43%
Operating Income Requirement	$ 76.2	$ 85.6
Adjusted Operating Income	$ 54.3	$ 47.8
Difference	$ 21.9	$ 37.8
Revenue Conversion Factor	1.5657	1.5765
Total Revenue Requirement	$ 34.2	$ 59.6

Procedural Schedule - tbd

Summary Rate Case Information

APCo West Virginia General Rate Case – Docket #10-0699-E-42T

On May 14, 2010, APCo filed a base rate case with the West Virginia Public Service Commission requesting a net increase of $155.5 million, comprised of a $223.8 million base rate increase and a $68.3 million decrease in the construction surcharge. The filing related to capital investments made and to recover increased costs. In addition, APCo requested to establish a separate transmission tracker related to PJM charges. The requested ROE was 11.75%. A settlement is on file which stipulates a rate increase of $60MM and the ability to defer $18MM of storm damage expenses. An order is expected by the end of March 2011.

Actual Capital Structure – Company Position (@12/31/09)

	% of Capitalization	Cost Rate	Weighted Return
Short-Term Debt	3.66%	0.89%	0.03%
Long-Term Debt	53.42%	6.04%	3.23%
Common Equity	42.64%	11.75%	5.01%
Preferred Stock	0.28%	4.35%	0.01%
Total	100.00%		8.28%

Procedural Schedule

July 23, 2010	Company testimony due
November 10, 2010	Staff & Intervenor testimony due
November 24, 2010	Rebuttal testimony due
December 13, 2010	Hearing commences
March 31, 2011	Rates effective

Required Rate Relief – Company Position (12/31/09) ($ in millions)

Rate Base	$	2,639.6
Rate of Return		8.28%
Operating Income Requirement	$	218.6
Adjusted Operating Income	$	86.0
Difference	$	132.6
Revenue Conversion Factor		1.6872
Total Revenue Requirement	$	223.8
Elimination of Construction Surcharge	$	(68.3)
	$	155.5